PHOENIX NATURAL GAS LTD. RESPONSE

to the

UTILITY REGULATOR

PRICE CONTROL FOR NORTHERN IRELAND'S GAS DISTRIBUTION NETWORKS

GD17 DRAFT DETERMINATION

MAY 2016

Contents

1 INTRODUCTION

Phoenix Natural Gas Ltd. ("**PNGL**") is the largest natural gas distribution business in Northern Ireland ("**NI**"), being the owner and operator of the Licence for the distribution of natural gas in the Greater Belfast Area and Larne.

We are responsible for the development of the pipeline network and also for providing a 24/7 operational and transportation service platform to Gas Suppliers.

At the time of its launch in 1996, the Phoenix project was one of the largest greenfield, private sector-led integrated gas transmission, distribution and supply investments in Western Europe. Our task was an unusual project in the United Kingdom, since it involved retrofitting a gas distribution network in a major city. Most importantly, we faced the challenge of developing a network and a market for natural gas from scratch.

The PNGL network currently extends to c.3,500 kilometres of pipeline which distributes natural gas throughout our Licensed Area representing c.40 per cent. of the population of NI:

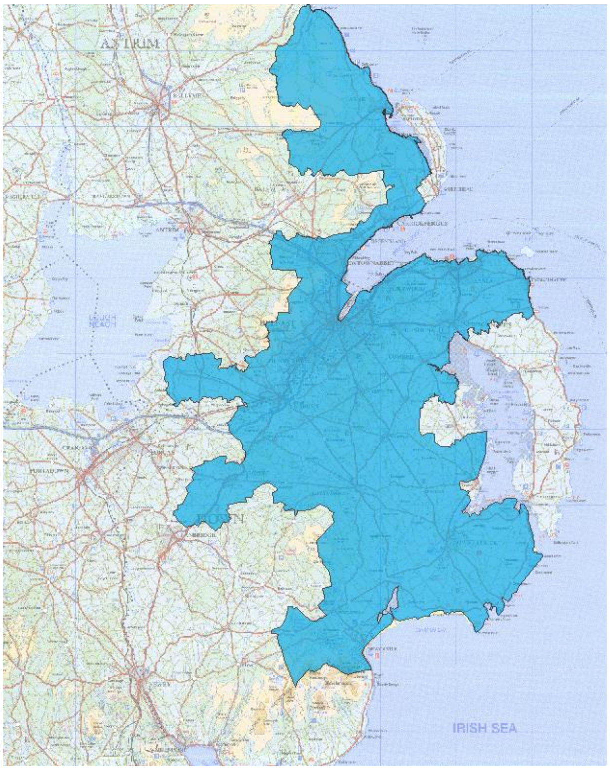


Figure 1 *- the Phoenix Licensed Area is shown in blue*

A fundamental part of the Phoenix plan has been to extensively develop all sectors of the market, delivering the benefits of natural gas to homes and businesses throughout our Licensed Area. To that end, PNGL has had a clear focus in meeting (and in fact exceeding) its licence obligations in respect of coverage of the network. As at 31 December 2015, we had made gas available (in accordance with the terms of the Licence) to c.313,000 properties and connected c.192,000 (61 per cent.) properties to our network.

Our Vision and Corporate Objectives are detailed in Figure 2:

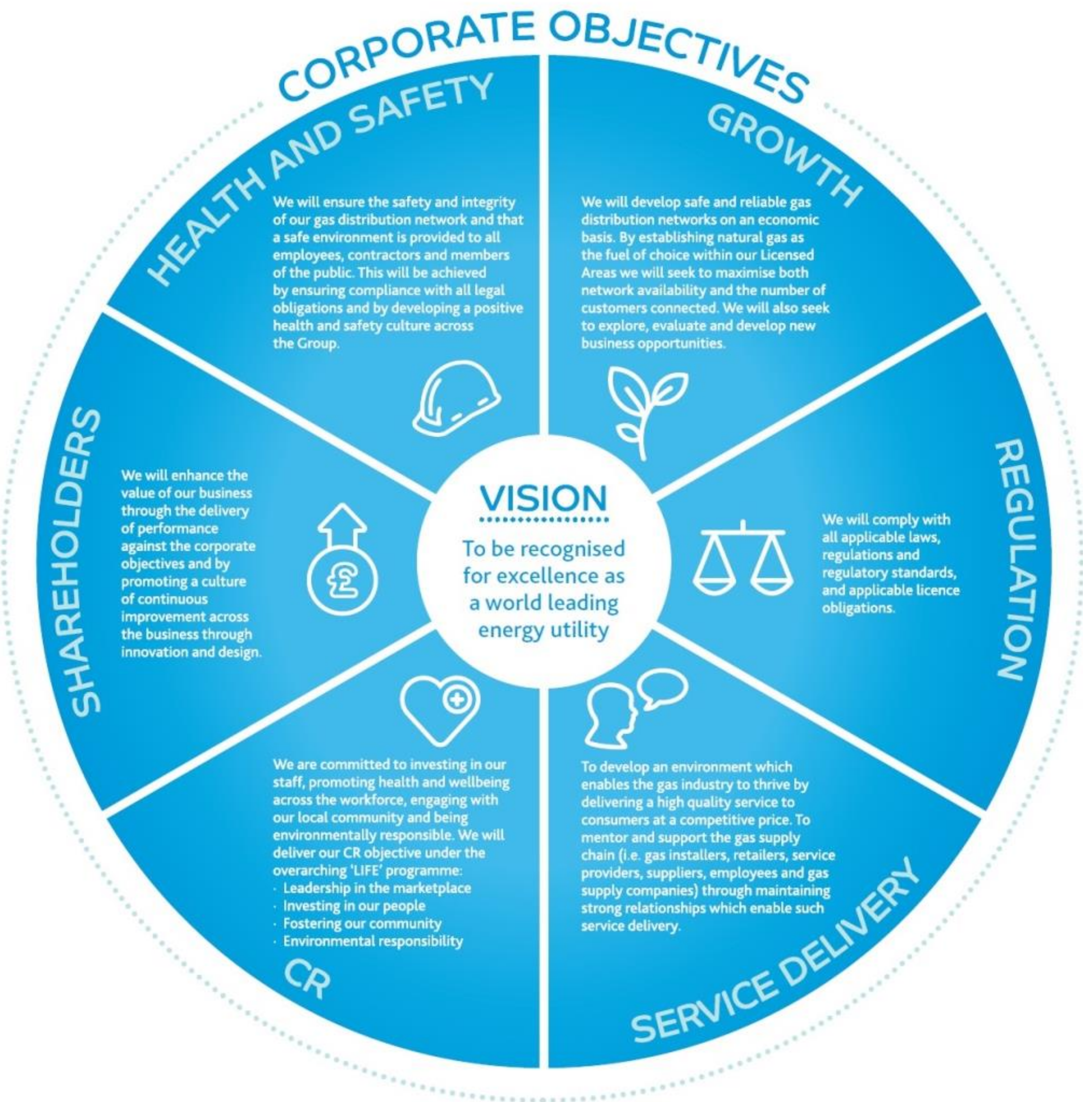


***Figure 2** - Our Vision and Corporate Objectives*

Not only has PNGL achieved its strategic goals and operational success, it has also taken particular pride in being recognised for its outstanding safety and corporate social responsibility performance.

From an environmental point of view, PNGL is dedicated to helping make NI a cleaner, healthier place to live and work. In operating the business we have attained International Standard ISO 14001 (Environmental Management System) accreditation. In addition, the conversion of properties to natural gas produces c.25 per cent. less carbon dioxide emissions than other fossil fuels. In the last c.20 years natural gas consumers across the PNGL Licensed Area - businesses in the public and private sectors and households - have prevented c.4m tonnes of carbon dioxide from entering the atmosphere.

1.1 PURPOSE OF THIS RESPONSE

Our business is regulated under licence by the NI Authority for Utility Regulation (the Utility Regulator, "**UR**"). UR carries out price controls on PNGL and the other network companies in NI to ensure that we remain amongst the most efficient operators in the UK.

The GD17[1] price control process formally commenced in June 2015[2], three months in advance of the date required under PNGL's Licence, with PNGL's submission of a number of key papers which would form the basis of PNGL's detailed price control submission in September 2015. The information provided in both June and September was extensive. PNGL has subsequently responded quickly and efficiently to UR's information requests and has co-operated in all discussions with UR throughout the review.

In parallel to the GD17 price control process, PNGL was granted an extension of its Licensed Area to East Down in January 2016 to allow for 13 new towns to be connected to the natural gas network[3]. The implications of extending our Licensed Area to East Down have now been incorporated within the scope of the GD17 price control review, with forecasts etc. updated accordingly.

PNGL welcomes the opportunity to respond to UR's consultation on its price control for NI's Gas Distribution Networks ("**the consultation**" or "**the draft determination**"). Following the shorter term PNGL12 and GD14 price controls[4], PNGL believes that this six-year GD17 price control will be vital in reinforcing stability, transparency and predictability to the regulatory process and will give NI's Gas Distribution Networks ("**GDNs**") an appropriate opportunity to align their operations with the GD17 price control ultimately determined by UR.

PNGL has already taken the opportunity to inform UR of a number of concerns with the draft determination during the consultation period, and the remainder of this response expands further on the issues arising therefrom. Given that UR intends to publish its GD17 final determination in September 2016, PNGL would welcome further engagement and discussion with UR on the price control so as to reach a satisfactory final determination which protects the interests of consumers of natural gas and secures that PNGL is able to finance the carrying on of the activities which it is authorised or required under Licence to carry on.

[1] The GD17 price control runs for six years from 2017 to 2022

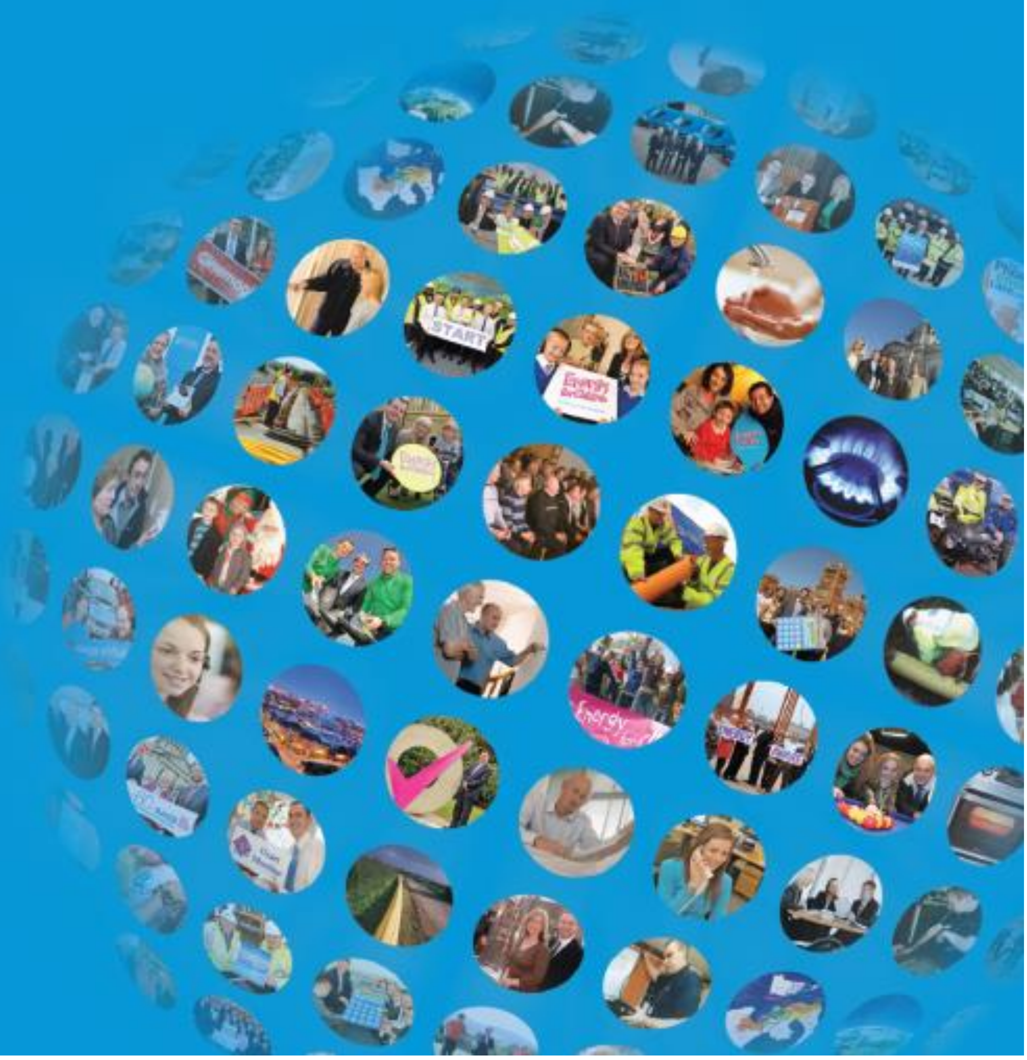
[2] Following engagement with UR on its December 2014 discussion document on its overall approach to the GD17 price control

[3] Annahilt, Ballygowan, Ballynahinch, Castlewellan, Crossgar, Downpatrick, Dromore, Drumaness, Dundrum, Hillsborough, Newcastle, Saintfield and The Spa

[4] The PNGL12 price control ran for two years from 2012 to 2013. The GD14 price control ran for three years from 2014 to 2016

PHOENIX NATURAL GAS

EXECUTIVE SUMMARY



2. EXECUTIVE SUMMARY

UR's proposed price control package is unreasonable and unjustified as it loads significant downside risk onto PNGL. PNGL has already taken the opportunity to inform UR of a number of concerns with the draft determination during the consultation period. PNGL's key areas of concern are:

- Rate of Return;
- the Connection Incentive;
- Manpower;
- Infill Mains; and
- Real Price Effects, productivity improvements and top-down benchmarking.

The remainder of this section summarises each of these key areas of concern.

2.1 RATE OF RETURN

Section 3.1 discusses PNGL's concerns with UR's proposed rate of return. PNGL engaged Frontier Economics ("**Frontier**") and NERA Economic Consulting ("**NERA**") to respond to UR's rate of return proposals set out in the draft determination.

Our updated view of PNGL's rate of return is a real pre-tax WACC of 5.3% - 5.6%. This is higher than the real pre-tax WACC in UR's draft determination of 4.3%. The comparison is shown in Table 1.

Frontier and NERA highlight a number of errors and inconsistencies in UR's draft determination WACC estimation which renders UR's real pre-tax WACC of 4.3% incorrect. We summarise these in sections 2.1.2 and 2.1.3.

	UR's draft determination	Frontier/NERA estimate
Tax rate	20%	20%
Inflation	3.08%	2.2%
Gearing	55%	55%
Risk-free rate	1.25%	1.25%
ERP	5.25%	5.25%
TMR	6.50%	6.50%
Asset beta	0.40	0.40 - 0.45
Debt beta	0.10	0
Equity beta	0.77	0.89 - 1.00
Real post-tax cost of equity	5.3%	5.8% - 6.4%
Real cost of debt (pre-tax)	2.26%	3.26%
Real pre-tax WACC	4.21% (rounded to 4.3%)	5.3% - 5.6%

Source: Frontier, NERA, UR's draft determination.

Note: We assume gearing of 55% in line with UR's draft determination.

Table 1 *- Summary of proposed WACC vs UR draft determination*

We begin with PNGL's concerns with UR's financeability assessment.

2.1.1 FINANCEABILITY

Financeability tests are an important part of reaching an appropriate price control determination. The test should answer the question of whether the overall package of cost allowances provided by UR is sufficient for PNGL to be able to finance investment efficiently in line with appropriate benchmark operators.

UR's draft determination does not achieve this. UR has not applied the financeability thresholds appropriately because it has designed a test which ***assumes*** the price control allowances are reasonable in the first place, rather than testing those allowances against financeability levels based on appropriate readily available benchmarks.

This can be demonstrated by the way that UR have simply applied a gearing assumption of 55% as an acceptable threshold, without recognising that this gearing level is significantly below comparable UK regulatory determinations; and outside the benchmark levels highlighted within the ratings methodologies (and the level under which the company operates). The consequence of the unduly low gearing assumption is that it masks the inadequacy of the proposed cost allowances overall, since it means PNGL's PMICR ratios appear better than they in fact are.

If the financeability tests were implemented correctly, UR would have identified that its draft determination creates significant financeability issues for PNGL. The proposed income levels, once adjusted for specific factors unique to NI, are not consistent with GB comparators. This has resulted in a risk of a downgrade below PNGL's existing rating as highlighted in the response by both Fitch and Moody's to the draft determination, with the consequence of a such a downgrade being higher debt costs. In the remainder of this section we will explain each of the following issues in turn:

i. UR's draft determination of 55% gearing is inconsistent with PNGL's current Baa2 rating;

ii. UR's gearing assumption also does not reflect relevant regulatory precedent;

iii. UR's statements in relation to PNGL's dividend policy are misleading;

iv. UR's financeability tests target a credit rating which is out of line with wider regulatory practice;

v. UR's financeability tests also do not reflect other relevant regulatory precedent, including for example by failing to undertake any assessment of reasonable downside; and

vi. the consequence of the above issues is that rating agencies have indicated that the draft determination results in a risk of potential downgrade.

It is important to highlight upfront that both of PNGL's main ratios (i.e. gearing, as measured by TRV/net debt; and PMICR, PNGL's interest cover ratio) allow for the deferral of income through the profile adjustment mechanism, a NI specific factor. Therefore in doing so the ratios as calculated for PNGL are much more broadly consistent with the comparator set within a wider GB environment. These ratios should therefore serve as appropriate benchmarks in assessing PNGL's financeability. As a further consequence of this point it is important to note that the calculation of PMICR ratios will not look any more favourable if there is a decision to no longer defer income in this manner.

UR's Draft Determination of 55% gearing is inconsistent with our current Baa2 rating

UR states that its financeability test assumes gearing levels which are consistent with the notional gearing level used in UR's WACC calculation of 55%. UR then tests whether, at this notional gearing level, PNGL's adjusted interest cover ratio falls below 1.4x. UR concludes that the interest cover ratio does not fall below 1.4x, and therefore that PNGL is financeable.

The problem with UR's approach is that UR's assumption on gearing is well below the level which ***should*** be consistent with a Baa2 rated business like PNGL. Table 2 and Table 3 below replicate, respectively, the Moody's and Fitch target ratios and indicative credit ratings for UK network utilities. These were published in the Competition and Markets Authority's ("**CMA**") Final Determination for NIE.

Moody's rating	Adjusted interest cover	Gearing	FFO/Net debt %	RCF/capex %
A1	2.5 – 3.5	40-50%	12-20	1.5 – 2.5x
A2	1.8 – 2.5	50-60%		
A3	1.6 – 1.8	60-68%		
Baa1	1.4 – 1.6	68-75%	8-12	1.0 – 1.5x
Baa2	1.2 – 1.4	75-85%		

Source: Table 17.2 of CMA NIE final determination - CMA based on Exhibit 4 of 'UK Water Sector: Speed of Money cannot address Potential Financeability Concerns', 16 May 2013

Table 2 *- Moody's - Target ratios and indicative credit ratings—UK Regulated Water and Energy*

Issue Default Rating ("IDR")	Senior unsecured	Adjusted PMICR	Debt/RCV %
A-	A	<1.9	<60
BBB+	A–	1.6–1.9	60–75
BBB	BBB+	1.4–1.6	75–80
BBB–	BBB	1.3–1.4	85–90

Source: Fitch, CMA NIE Final Determination, Table 17.3. Note that Moody's Baa2 rating is equivalent to Fitch BBB Issue Default Rating.

Table 3 *- Fitch - Indicative ratings guidelines for UK DNOs*

The tables show that companies with a PMICR of 1.4 - 1.5x (i.e. as modelled by UR for PNGL under the draft determination) ***should*** be able to gear up to around 65% and maintain a credit rating of Baa2/BBB under Moody's or Fitch's ratings methodologies. Moody's states:

"[Redacted quote]"[5]

However, if PNGL were to gear at that level, we estimate our PMICR would fall as low as 1.2x over the GD17 period. Clearly this would breach the benchmark cover ratio, and would therefore result in

[5] Moody's Credit Opinion, "*Phoenix Natural Gas Finance PLC Update following outlook change to negative and Baa2 rating affirmation*", May 13, 2016

a deterioration of our credit rating. A PMICR of 1.2x would also breach the covenant on our existing bond.

We also note that – despite the inappropriate gearing assumption - UR's analysis implies the PMICR threshold is reached exactly in 2021, leaving no headroom in the ratio. Moody's most recent ratings review clearly linked PNGL's Baa2 rating with the existing covenants on PNGL's debt, which include a dividend lock up at 1.4x PMICR. Since UR's draft determination now implies PNGL will fall to that level by 2021, this further jeopardises the Baa2 rating (since agencies would typically expect some buffer over the covenant level).

UR's gearing assumption is inconsistent with regulatory precedent

Table 4 shows the gearing decisions of UK utility regulators since 2009.

Decision	Date	Gearing (%)
Ofwat PR09 (WASCs)	April 2009	57.5%
Ofwat PR09 (WOCs)	April 2009	52.5%
Ofgem DPCR5	December 2009	65%
CC Bristol	February 2010	60%
Ofgem RIIO-GD1	December 2012	65%
CAA Heathrow	January 2014	60%
CAA Gatwick	January 2014	55%
CMA NIE	March 2014	45%
Ofgem RIIO ED1	November 2014	65%
Ofwat PR14	December 2014	62.5%
CMA BW 2015	October 2015	62.5%

Source: Analysis of regulatory decisions

Table 4 *- Regulatory precedent on gearing determinations*

UR states that it has based its decision of 55% on the mid-point of the range of previous regulatory decisions (i.e. between 45% and 65%). Table 4 shows that lower bound of UR's range is distorted by the CMA's NIE decision of 45%.

i. The **average** gearing across the whole set of comparators is close to 60% (specifically 59.09%).

ii. Excluding the NIE decision, the range of relevant regulatory precedent is 55% - 65% and the mid-point would be 60%.

NIE is an outlier in the range of previous decisions. In the NIE case, the CMA assumed that the appropriate notional level was equal to NIE's ***actual*** gearing level at the time of around 45%[6]. Similar

[6] CMA, NIE Final Determination, 6th October 2015, paragraph 10.37

reasoning can be found in the Bristol Water case, where the CMA noted that the proposed notional 62.5% gearing was comparable with Bristol Water's own gearing[7].

In other words, in both cases the CMA cross-checked its notional gearing assumption against the actual gearing of the company in question, and concluded the notional gearing was reasonable because it was close to the actual gearing. UR's method embeds no such cross-check – instead it is based on the unreasonable inclusion of the NIE notional gearing decision in the comparator set (since the rationale for the CMA's decision on NIE has no relevance for the appropriate notional gearing for PNGL).

As explained in the Frontier/NERA paper submitted in June 2015[8], a gearing level of 60% - 65% is consistent with PNGL's observed gearing since 2010. Had UR followed the CMA's approach, it would have therefore established higher notional gearing on the basis of PNGL's actual gearing levels. This would have been more consistent with the substantial majority of relevant regulatory precedent (i.e. excluding NIE).

UR's statements in relation to PNGL's dividend policy are misleading

UR's draft determination implies that a higher gearing assumption is inappropriate, since PNGL's actual gearing is above the notional level due to PNGL's decisions "*including those in relation to dividend policy*."[9] As a result, although UR acknowledges that higher gearing would result in "more challenging financial ratios", UR effectively ignores this – implying that gearing above 55% is not efficient.

These statements seem to misunderstand the issue. As shown above, PNGL's target gearing level is consistent with an efficient financing structure and is well within the financeability guidance as set out by rating agencies; and PNGL's gearing levels are not out of line with GB comparators. The dividend policy of the company is therefore consistent with reasonable and efficient gearing levels.

It is therefore misleading to suggest the actions of PNGL's equity investors in respect of its dividend policy are the cause of financeability issues, resulting from higher gearing than UR's notional 55%. Indeed it should be recognised that dividend policy tends to be educated by rather than the driver for gearing levels. The real source of the issue lies in the inadequacy of UR's wider price control allowances. If UR's overall price control package were appropriate, a notionally efficient company should be able to finance both equity and debt investment in line with the gearing levels which PNGL has been targeting. This means that the notional company should be able to offer a dividend to investors; and also maintain gearing levels at around 65% in line with other benchmark operators, while maintaining its Baa2 credit rating.

[7] CMA, Bristol Water Final Determination, 6th October 2015, paragraph 10.27 – 10.28

[8] "*Appendix A - PNGL Cost of Capital for GD17*" of PNGL's "*GD17 Rate of return paper*" submitted to UR in June 2015

[9] Paragraph 10.65 of the consultation

UR is targeting a credit rating which is out of line with wider regulatory practice

UR has stated that it performs its financeability tests to be consistent with obtaining a BBB rating. However, regulators in GB have normally targeted a strong investment grade (i.e. between A- and BBB+).

In the NIE case, the CMA highlighted that the typical distribution of ratings in the utilities sector *"may provide an indication of the appropriate credit rating to adopt"*. The CMA noted that in the 2010 Bristol Water inquiry, the CC targeted a Baa1/BBB+ rating. In the Airports inquiries, the CC targeted a BBB+ rating for Heathrow and Gatwick and an A– rating for Stansted[10]. Similarly in the BW 2015 decision the CMA targeted a credit rating of BBB+[11].

Ofgem similarly targets a "comfortable" investment grade:

> *"In setting price controls, we are required to have regard to the ability of efficient network companies to secure financing to facilitate the delivery of their regulatory obligations. This is also in the interests of consumers. We define this ability as indicated by a notional efficient network company attaining a "comfortable investment grade‟ credit rating (i.e. in the BBB-A range)"* [12]

Indeed, in the NIE case, UR itself targeted a credit rating of Baa1/BBB+[13]. Given this, we consider that UR's financeability tests should be more cautious to ensure its price control allowances are sufficient.

UR's application of the financeability tests is inconsistent with regulatory precedent

UR says that it has followed the CMA's approach for NIE in undertaking its financeability tests. However, there are several aspects of the CMA's approach – and broader regulatory practice - which UR has not acknowledged in its GD17 assessment.

First, UR has performed quite a narrow financeability check, assessing just PMICR and gearing. The CMA stated that the target for NIE's financeability test should be a gearing of 70% or less, and a PMICR of 1.4x or more. However, the CMA also decided that it was important to look at other financial ratios which the ratings agencies considered, as shown in Table 5.

[10] See CMA, NIE Final Determination, paragraph 17.54

[11] BW 2015 Final determination, paragraph 11.26 and 11.33. *"Bristol Water said that its preferred approach to financial ratio analysis was consideration of its actual financial structure, but with a notional level of gearing. Bristol Water said that to be consistent, either a notional structure should be used with a notional target credit rating of BBB+, or Bristol Water's actual financial structure should be used with Bristol Water's stated target credit metrics (either derived from Moody's and S&P's guidance material, or set explicitly in discussion with the relevant agency)." "..we compare the financial ratios under this structure to rating agency targets, consistent with a notional company broadly comparable to Bristol Water."*

[12] https://www.ofgem.gov.uk/ofgem-publications/48156/3riiogd1fpfinanceanduncertainty.pdf

[13] See CMA, NIE Final Determination, paragraph 17.69

	CC target ratio averaged across the NIE price control period
PMICR	1.4 or more
FFO/ net interest payable	3.5 or more
FFO/net debt	10% or more
Gearing	70% or less

Source: *CMA NIE final determination Table 17.4*

Table 5 *- CMA's view of "appropriate targets for the efficient licence holder for forecast credit risk financial ratios"*

More widely, other regulators have also tended to evaluate a wider set of metrics than UR has considered[14].

Second, we note that in order to avoid breaching the PMICR threshold, UR's model in fact implies gearing ***below*** the notional 55% level - i.e. its model implies further de-gearing to around 53% by the end of the GD17 period[15]. In the 2015 Bristol Water case, the CMA tested ratios under both an unconstrained gearing model (i.e. where gearing was allowed to fluctuate) and a constrained gearing model (where the gearing assumption was fixed at the notional level for Bristol Water of 62.5%)[16]. UR has not assessed the expected PMICR ratio which is consistent with its assumed notional gearing level.

Third, UR does not appear to have conducted any scenario analysis at all. In particular UR has not tested the effect of its asymmetric connections incentive mechanism on PNGL's cashflows. In the Bristol Water case the CMA explained that *"We consider it good regulatory practice to consider the impact of downside shock on financial ratios."*[17] The CMA noted that there are some mitigating factors which would mean that a breach of benchmark ratios in reasonable downside scenarios may be acceptable – but notably, one of these mitigating factors was the existence of headroom in BW's ratios (headroom which does not exist for PNGL).

Rating agency opinion makes clear that the DD cost allowances are insufficient and result in a risk of downgrade

UR's conclusion that the draft determination results in acceptable financeability ratios is contradicted by the response of the rating agencies. Both Fitch and Moody's have already placed PNGL on negative watch and negative outlook respectively, suggesting the proposed allowed income is insufficient to maintain PNGL's current BBB rating. This also indicates that UR's financeability tests are not well specified.

[14] See, for example, Joint Regulators Group (JRG), "Cost of Capital and Financeability", March 2013

[15] Table 182 of the consultation

[16] CMA, Bristol Water Final Determination, 6th October 2015, Table 11.4: https://assets.digital.cabinet-office.gov.uk/media/56279924ed915d194b000001/Bristol_Water_plc_final_determination.pdf

[17] CMA, Bristol Water Final Determination, 6th October 2015, paragraph 11.52

A negative watch action has not occurred following the draft determinations in any of the recent UK reviews[18], despite rating agencies such as Moody's noting, for example, that the draft determination in the water review was "challenging"[19]. In relation to UR's GD17 draft determination, Moody's stated:

"[Redacted quote]"[20]

In particular Moody's noted the pressures associated with UR's proposed cost allowances for connections and the asymmetric connections incentive:

"[Redacted quote]"[21]

This statement by Moody's further illustrates the necessity of UR performing financeability tests under reasonable downside scenarios for connections.

Overall, Moody's explained that it *"[Redacted quote]"*[22]

Given these statements, UR's draft determination poses a significant risk that downgrading would occur. The magnitude of the impact of such a downgrade is difficult to assess, since there are almost no comparable regulated UK utilities with a rating of Baa3.

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[18] i.e. Ofwat PR14; Ofgem RIIO-GD1, RIIO-T1, and RIIO-ED1

[19] Moody's, 14th October 2014: https://www.moodys.com/research/Moodys-Stable-outlook-for-UK-Water-Sector-despite-challenging-regulatory--PR_310349

[20] Moody's, 10th May 2016: https://www.moodys.com/research/Moodys-changes-outlook-on-Phoenix-Natural-Gass-Baa2-rating-to--PR_348607

[21] ibid

[22] ibid

Conclusion

As noted in the Frontier/NERA June paper, the financeability test is particularly important to get right for GD17 in the context of significant refinancing. Overall, however, the draft determination results in significant financeability issues, driven in particular by the low WACC allowance and the inappropriate and asymmetric allowances for connections costs. This is clear from the fact that both rating agencies have placed PNGL on negative watch or negative outlook; and from the fact that PNGL's PMICR falls to 1.2x across GD17 if efficient gearing levels are assumed. UR's financeability test has failed to identify these issues because of its inappropriate gearing assumption. The consequence of this is that there is a higher risk that UR's price control will result in a credit downgrade and as a result an increase in debt costs.

A more appropriate specification of UR's test would recognise that efficient gearing is higher than its 55% proposal. Increasing the notional gearing level would allow UR to properly test the impact of its broader allowances on PMICR. UR should also test reasonable downside connections scenarios to be consistent with regulatory precedent.

"[Redacted quote]"

2.1.2 COST OF EQUITY

PNGL engaged Frontier to evaluate UR's draft determination for PNGL's cost of equity allowance in the GD17 regulatory period review. In this section, we summarise Frontier's overall conclusions, and we attach Frontier's more detailed technical report at Appendix 1.

UR has made a number of errors in its approach to setting the cost of equity. Most notably these errors relate to UR's provisional determination on beta. In addition, UR's calculation of the real pre-tax WACC allowance results in under-remuneration of tax costs.

We also do not agree with UR's evidence on Total Market Return ("**TMR**") and its component parts. However, we focus in this section on the two primary errors in UR's approach relating to beta and tax.

2.1.2.1 Beta

UR has stated its view that PNGL's beta allowance for GD17 should be at the top end of the range of allowed betas for UK network utility comparators.

> "*For this draft determination, we use a value of 0.40. This gives recognition, in particular, to the fact that there are differences with PNGL's and FE's regulatory model from the standard model, e.g. the Profile Adjustment, and notwithstanding the analysis that we have summarised above, the possibility that investors may not be wholly familiar with these*

> *differences. While we regard this as a small and potentially short term factor, our initial view is that a cautious approach is appropriate and this therefore warrants placing the GDNs at the top of the betas that regulators have judged appropriate for low-risk network utility businesses*."[23]

We agree with UR that PNGL is relatively higher risk than other UK utilities, although UR's relative risk assessment does not fully reflect the range of evidence in support of that conclusion (which has been set out fully in our earlier submissions).

UR considers that "typical" UK network utilities have been allowed an asset beta in the range of 0.3 - 0.4. However, UR has incorrectly interpreted the UK precedent range. This is because UR has failed to control for differences in the debt beta assumption which was used in those regulatory decisions. As a result, the range presented by UR is not like-for-like.

UR has provisionally assumed a debt beta of 0.1 for NI GDNs. Given this assumption, UR should have re-stated the UK regulatory determinations on asset beta on a consistent basis. If UR had done this correctly, the like-for-like range for UK comparator asset betas would be in fact 0.36 – 0.43. This shows that UR has not in fact proposed an asset beta at the top end of the range of UK comparators, but rather the proposed asset beta is in the middle of the range.

The result is a cost of equity allowance which is too low. If UR intends to continue to assume a debt beta of 0.1, UR must at the very least utilise an asset beta of 0.43, reflecting its view that PNGL is at the top end of the range of precedent.

We also note that UR (and its advisor, First Economics) has provided very little justification for its proposed debt beta assumption of 0.1. UK regulators including Ofgem and Ofwat have assumed that debt beta is zero; and in its most recent determination for Bristol Water the CMA also assumed a debt beta of zero. In general, practitioners expect that the debt beta assumption (if applied correctly) will not have a material effect on equity beta estimates, or consequently on the final allowed cost of equity. Given this, we propose that UR removes the debt beta assumption from its analysis, in line with GB precedent.

Finally, we note that UR has not relied on up-to-date empirical beta estimates to inform its assessment. First Economics has provided empirical estimates which UR states are a reasonable cross-check of its beta proposals. However, the First Economics analysis has not replicated the CMA's approach to estimating beta (despite its stated intention to do so); and relies entirely on data from the post-financial-crisis period in which betas were clearly distorted downwards, relative to longer term trends. Both of these issues mean that First Economic's empirical beta analysis is an unreliable cross-check.

In the first paper submitted to UR in June 2015[24], we observed that since early 2012, beta estimates have been gradually increasing in line with the normalisation of market conditions; and were close to the levels observed before the Global Financial Crisis ("**GFC**") in 2008. Empirical estimates of beta have continued to trend upwards since that paper, and are now much more in line with pre-GFC

[23] Paragraph 10.34 of the consultation

[24] "*Appendix A - PNGL Cost of Capital for GD17*" of PNGL's "*GD17 Rate of return paper*" submitted to UR in June 2015

observed levels. We consider that UR must take the latest empirical evidence properly into account, rather than simply rely on out-dated regulatory precedent or distorted empirical estimates. Frontier's updated analysis shows that the ***average*** asset beta across the peer group is now 0.44, assuming a debt beta of zero. This is equivalent to an average asset beta of 0.48, assuming a debt beta of 0.1.

Overall, we consider that the latest market evidence - combined with the relevant regulatory precedent and the evidence that PNGL is relatively higher risk - supports an asset beta at the top end of the range of 0.40 - 0.45 (assuming a debt beta of zero). This remains within the range we proposed in June 2015, but recognises that market evidence since then supports an increase in the lower bound of that range. If UR wishes to retain its debt beta assumption of 0.1, the asset beta estimate must be adjusted upwards accordingly.

2.1.2.2 Tax allowance

UR's regulatory model requires it to set a real, pre-tax WACC allowance. In practice, corporates incur tax liability calculated on the basis of nominal profits. The tax allowance should therefore capture the fact that inflation will increase profits in nominal terms over time.

UR's pre-tax WACC calculation should calculate the tax wedge on the basis of the ***nominal*** post-tax cost of equity. UR's current approach does not do this and as a result underestimate the tax allowance.

Although not many regulators set a pre-tax WACC allowance, we note that the UK telecoms regulator Ofcom; a number of decisions made by the Irish energy regulator CER; and the Italian energy regulator have all ensured that expected tax costs are fully funded via a pre-tax WACC.

2.1.2.3 Conclusion

Frontier's updated view of the best estimate of PNGL's cost of equity for GD17 is shown in Table 6, compared to UR's draft determination. This proposal is based on an asset beta range of 0.40 - 0.45, as in our original June 2015 paper. However, updated market evidence now point towards the top end of that range and therefore, our best estimate of PNGL's cost of equity is closer to the top end of the estimated cost of equity range of 5.8% - 6.4%. As noted above we have utilised the UR's proposals for TMR, ERP and RFR, although we continue to consider that the evidence set out in the June 2015 paper supports a TMR above this level.

Frontier considers this a conservative estimate given the recent return of observed betas to their longer-term levels; and the evidence supporting a higher TMR.

	UR's draft determination	Frontier estimate
Gearing	55%	55%
Risk-free rate	1.25%	1.25%
ERP	5.25%	5.25%
TMR	6.50%	6.50%
Asset beta	0.40	0.40 - 0.45
Debt beta	0.10	0
Equity beta	0.77	0.89 - 1.00
Post-tax cost of equity	5.3%	5.8% - 6.4%
Pre-tax cost of equity	6.6%	7.8% - 8.5%

Source: Frontier Economics, UR's draft determination.

Note: We assume gearing of 55% in line with UR's draft determination. We also assume inflation of 2.2% in line with break-even inflation over the GD17 period as set out in Appendix 2.

***Table 6** - Summary of proposed cost of equity vs UR draft determination*

2.1.3 COST OF DEBT

PNGL engaged NERA to review UR's proposals in relation to the ex-ante cost of debt estimate.

On the cost of debt, UR proposed an ex-ante cost allowance for embedded and new debt, and a true-up mechanism, where the ex-ante cost of new debt is proposed to be adjusted for 80% of the difference between PNGL's actual issuance costs and the cost of new debt assumption set at review[25]. In this section, we summarise NERA's overall response to UR's ex-ante cost of debt estimate, and we attach NERA's more detailed technical report at Appendix 2. We set out our response to UR's proposed true-up mechanism in section 2.1.3.1.

UR understates PNGL's cost of debt by around 100 basis points ("bps").

Table 7 sets out UR's Draft Determination estimate for the cost of debt, and NERA's estimate which corrects for a number of concerns with UR's approach and also updates for the latest market data. Overall, we calculate a real cost of debt of 3.26% using our preferred market based (or break even) measure of inflation, or 2.42% if we use inflation published by the Office for Budget Responsibility ("**OBR**"), as UR proposes.

[25] Paragraph 10.8 of the consultation

	UR draft determination (Dec 2015)[a]	NERA (May 2016)[b]	
		OBR inflation	Breakeven inflation
Embedded debt costs			
Average interest costs	4.3	4.3	
Transaction costs	0.3	0.4	
New debt costs			
BBB-index yield	4.4	4.3	
Forward rate adjustment	0.4	0.3	
PNGL premium	0.4	0.64	
Transaction costs	0.3	0.4	
Weighting - embedded debt	10%	10%	
Weighting - new debt	90%	90%	
Inflation	3.1	2.4 for embedded, 3.1 for new	2.1 for embedded, 2.2 for new
Real Cost of debt	2.26	2.42	3.26

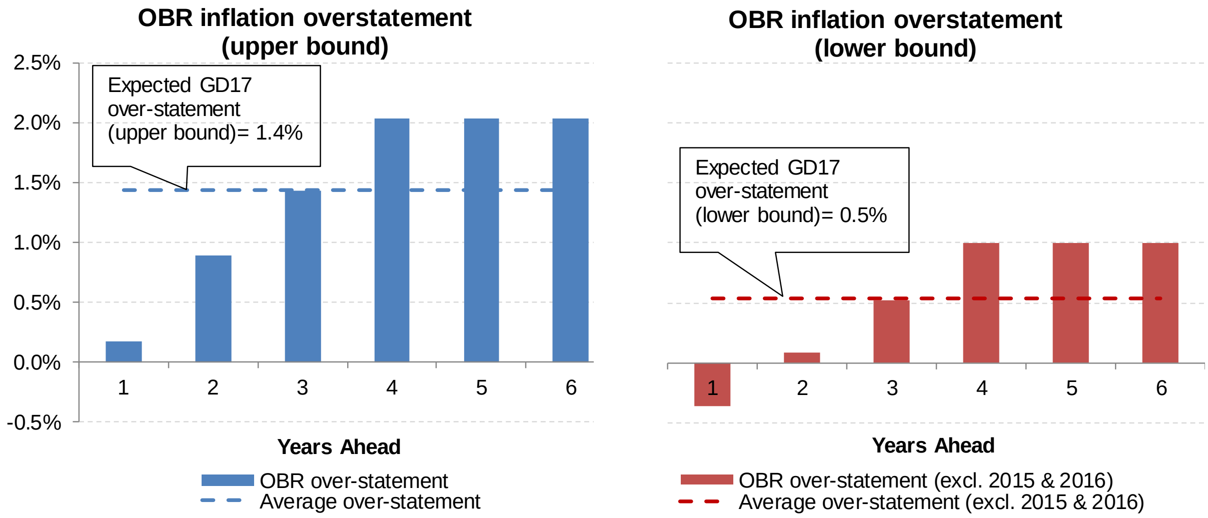
Source: NERA analysis. Notes: a) information date = end December 2015; b) information date = 13 May 2016

Table 7 *- We estimate an ex-ante cost of debt allowance around 100 bps higher than UR's draft determination*

OBR overstates inflation; UR should use market based forecasts

To convert nominal cost of debt into real terms, UR uses an inflation rate of 3.08% p.a. based on OBR inflation forecasts for GD17. OBR forecasts have historically overstated outturn inflation which means that PNGL does not have a reasonable prospect of recovering its actual nominal debt costs.

NERA's analysis of all historical OBR published forecasts (over the period 2010 to 2016) shows that OBR has systematically overstated inflation, and that the overstatement increases with forecast length (see Figure 3). Based on OBR's historical performance, the expected forecast error over GD17 is 1.4%. Even excluding OBR's forecasting errors for 2015 and 2016, where its performance is particularly poor, the expected forecast error over GD17 remains at 0.5%.



Source: NERA calculations based on OBR and ONS data.

Figure 3 *- OBR Expected Forecast Error over GD17 is 0.5% (excluding 2015 and 2106 errors) to 1.4% (all years)*

The CMA in its NIE decision acknowledged that the OBR forecasts are at the high-end, and explicitly selected an allowed rate of return at the top-end of its WACC range to accommodate the noted bias in its cost of debt allowance from its use of OBR. Ofgem and Ofwat use market based evidence – "break-even" inflation derived from the difference between nominal and real yields on gilts – to determine a real cost of debt allowance.

Consistent with regulatory precedent, UR should use break-even inflation to derive an ex-ante real cost of debt for GD17. As of mid-May 2016, the break-even inflation rate is 2.2%, i.e. 0.9% lower than the March 2016 OBR forecast[26]. Break-even inflation reflects the market consensus view of inflation rather than the view of a single organisation, and one with a noted bias, as demonstrated by NERA's research and acknowledged by the CMA.

UR understates real embedded debt costs by using average inflation over the period

UR uses average GD17 inflation to convert its nominal estimate of embedded and new debt into real terms, although embedded debt is expected to mature on average by the end of 2017. Given the expected increase in inflation over the GD17 period, UR materially overstates inflation for embedded debt and therefore materially understates real embedded debt costs.

The error in the understatement of historical debt costs will not be corrected under UR's proposed true-up mechanism. Under UR's proposed approach, PNGL will bear the full cost of UR's overstatement of inflation on embedded debt as there is no true-up for the real ex ante allowance. By contrast, there will be no offsetting outperformance on the new debt cost allowance, as we

[26] We note that a further likely explanation of the difference is falling inflation expectations over the recent period, as well as the noted bias in OBR's forecast. That is, the break-even inflation rate reflects current market expectations of inflation, whereas the OBR forecast (in March 2016, but with an effective date prior to March) does not reflect the changes in expectations. The fact that break-even is up-to-date provides a further reason to use break-even.

expect UR to take into account actual inflation in trueing up new debt costs subject to an 80:20 sharing factor.

The real cost of embedded debt should be estimated using inflation over the period for which it remains outstanding, i.e. 2017, and the real cost of new debt should be estimated using inflation over the rest of GD17. NERA calculates a break-even inflation estimate for 2017 of 2.1% to derive the real cost of embedded debt and a break-even inflation estimate of 2.2% for the rest of GD17 to derive the real cost of new debt.

UR should use BBB index yield over one year to mitigate volatility risk

UR used the spot BBB-index yield adjusted for forward rate uplift but disallowed our proposed volatility risk premium which takes account of the volatility in the benchmark index. In the absence of the volatility risk premium, UR should use a longer term average to smooth for short-term market volatility. In its 2015 Bristol Water decision, the CMA recognised the need to use a long-run average to smooth for market volatility, and used a one-year average. We have adopted the same approach – resulting in a nominal benchmark BBB cost of 4.3% as of mid-May.

UR's forward rate adjustment ignores bank debt falling due mid-2018

To estimate the cost of new debt, UR adjusted its spot estimate of BBB costs by 40bps to allow for an increase in interest rates by mid-2017 for PNGL. We agree with UR's proposed approach to draw on market data to make an adjustment for the expected increase in yields to the point of refinancing. However, UR's forward rate adjustment assumes a mid-2017 refinancing point, based on the redemption date of PNGL's public bond. UR ignores bank debt falling due in late 2018. UR should instead assume an end 2017 refinancing point, the approximate mid-point of the bond and bank debt refinancing. NERA's updated estimate of the forward rate as of mid-May is 30 bps.

UR's estimate of the PNGL premium needs to be adjusted for tapering effect

In estimating the cost of new debt, UR allows for a 40 bps PNGL premium based on the most recent empirical evidence of the difference in bond yields between PNGL and a set of comparators. UR's use of recent data understates the premium due to the effect of tapering as the PNGL bond approaches maturity.

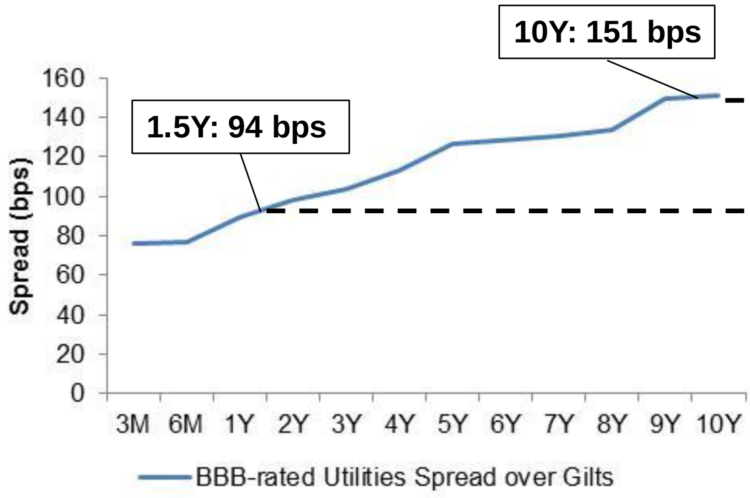
As explained in our June 2015 cost of capital report[27], spreads for both PNGL and comparator bonds taper as the bonds approach maturity. As a result of tapering in the spreads over time, the observed premium for PNGL's bond relative to the comparators will also taper to zero at maturity. The effect of tapering on spreads is evident from the upward sloping term structure of credit spreads (see Figure 4). Bond investors require a lower credit spread the lower the remaining tenor to maturity to compensate for risk, which explains why spreads for shorter maturities are lower than for longer maturities.

Since our June 2015 cost of capital report, NERA have undertaken further work to quantify the tapering effect and derive the PNGL premium. We have quantified the effect of tapering from the term structure of credit spreads, and used this estimate to adjust UR's premium of 40 bps. UR's

[27] "*Appendix A - PNGL Cost of Capital for GD17*" of PNGL's "*GD17 Rate of return paper*" submitted to UR in June 2015

premium is based on a period where the remaining tenor is 1.5 years, whereas in fact we expect PNGL tenor at issuance to be much longer. Taking the ratio of the spreads on 1.5 and 10 year BBB bonds of 1.6 (=151 bps/94bps), and applying this to UR's premium of 40 bps, we derive a premium of 64 bps, and we have adjusted our cost of debt estimate for our revised estimate[28].

This estimate is similar to our own estimate of PNGL premium of 69 bps based on the period prior to the PNG12 Draft Determination, selected to avoid the effect of tapering.



Sources: NERA analysis of Bloomberg data

***Figure 4** - We draw on term structure of credit spreads to estimate the tapering effect, and to adjust UR's PNGL premium*

UR does not allow for the cost of carry, and unnecessarily deflates all COD adjustments

UR allowed for a transaction cost of 30 bps which is close to PNGL's actual transaction costs incurred on its current bond. However, UR provides no allowance for the fact that PNGL also needs to maintain a back-stop facility to fund capex, which imposes a cost even when the funds are undrawn, as well as facilities to provide liquidity to support its BBB credit rating, as well as additional liquidity to back-stop the expected refinancing of the bond. NERA consider that these costs support a total adjustment of at least 40 bps rather than the 30 bps allowed by UR.

Finally, we note that UR deflated the various adjustments to the allowed cost of debt (e.g. forward rate adjustment, PNGL premium, transaction costs etc.) with inflation to derive the real cost of debt which is unnecessary and understates the real cost of debt.

2.1.3.1 Cost of Debt Mechanism

In its draft determination, UR questioned its ability to set appropriate cost of debt allowances for PNGL and firmus which reflect what would be an efficient market based cost of debt given the scale and timing of their refinancing in uncertain market conditions. To address this issue, UR proposed to

[28] NERA adopt a 10Y tenor as this is consistent with the tenor of the constituent bonds in the iBoxx 10Y+ corporate financial index which UR uses to set its proposed ex-ante allowance for new debt costs.

implement a cost of debt sharing mechanism with an 80%:20% split between pass-through to customers and retained by PNGL and firmus[29].

PNGL engaged NERA to review UR's proposed approach, and to propose an alternative approach. Below, we summarise our key concerns with UR's approach, and our proposed alternative. In Appendix 3, we attach NERA's technical report.

Our Concerns with UR's Approach

First, UR's approach is without precedent: GB regulators have always set an ex ante cost of debt allowance, or in the case of Ofgem, set the cost of debt allowance based on a benchmark cost of debt index in order to provide incentives to minimise costs. UR's proposed approach is more akin to cost-pass through regulation than incentive-based, and is likely to lead to higher costs to customers. Second, UR's approach to measuring actual debt costs will be costly and complex, and creates regulatory risk. Third, UR needs to establish a clear set of rules for calculating new debt costs at the true-up, and how it will resolve any dispute. So far, UR has provided no details.

The Established Regulatory Solution

Ofwat developed a simple cost of debt mechanism for the Thames Tideway Tunnel to address the same issues faced by UR at GD17, namely how to set an efficient cost allowance in uncertain market conditions. The mechanism updates the allowed return in line with observed changes in the market cost of debt, drawing on an established market index. Such a mechanism has the following clear advantages:

- Addresses UR's key concern of forecasting error, driven by uncertainty about future interest rates.
- Preserves the power of incentive-based regulation.
- Recognises only (market-based) efficient debt costs and therefore ensures customers do not pay for inefficiently incurred costs.
- Is a simple mechanism based on precedent which relies on a small number of inputs and the need for one single adjustment, minimising regulatory costs and scope for disagreement.
- Can easily be applied across the NI gas industry.

In NERA's report, we explain how the mechanism would work in practice for PNGL.

Next Steps

We have met with UR to present our proposed approach to trueing-up the cost of debt allowance based on an efficiency benchmark. We would welcome further discussions with UR in order to understand and resolve any remaining concerns, in the expectation that we can agree to an efficient benchmark approach in time for the final determination.

[29] Paragraphs 10.7-10.9 of the consultation

2.2 CONNECTION INCENTIVE

Section 3.2 discusses PNGL's concerns with UR's draft determination for Advertising and Market Development ("**AMD**") allowances available under the Owner Occupied ("**OO**") connection incentive. In summary:

It is imperative that the mechanism utilised to set allowances available for AMD provides PNGL with sufficient resources to grow the natural gas market.

The mechanism proposed by UR is not fit for purpose:

- The OO connection targets proposed by UR are unrealistic and are not achievable under current and forecast market conditions;
- UR's proposals are insufficient to allow PNGL to grow the market:
    - UR fails to provide sufficient allowances to achieve its connection targets and takes no consideration of the actual AMD costs PNGL have incurred (over the previous 20 years) or are likely to incur in the GD17 period; and
    - UR is signalling that there will be limited support for developing OO connections in PNGL's Licensed Area in GD17 and beyond. UR's message will have a negative impact on the wider natural gas industry, from installers (converting homes to natural gas) to retailers (providing natural gas appliances).
- The "*simple economic test"* is based on an arbitrary recovery period that with only minor amendment, significantly impacts the allowances available;
- The mechanism utilises a mixture of methodologies - allowances are set based on marginal costs but are expected to cover both marginal and *core utility costs* (namely *"shared corporate overheads"* that are reallocated into the mechanism). The inclusion of fixed costs in the mechanism unnecessarily increases the risk faced by PNGL as cost recovery of fixed costs is not certain;
- The concept of "*non-additionality*" is not appropriate for current and forecast market conditions. It is likely to be more difficult during the GD17 period than in the previous price control periods for PNGL to obtain OO connections. UR's proposal that no allowance be given for the first 33% of OO connections serves only to magnify the downside risk loaded onto PNGL; and
- The mechanism includes a penalty (for underperformance) and reward (for overperformance) that is asymmetric and unfairly adds risk to PNGL. Asymmetric penalty versus reward is contrary to the principle of pain/gain sharing as is standard in regulatory price controls and in normal regulatory practice.

Overall, the incentive mechanism proposed by UR inappropriately loads downside risk onto PNGL, and does not deliver an appropriate framework in which to continue expanding the natural gas market in NI.

The setting of unrealistically high OO connection targets in conjunction with insufficient allowances is incorrect and will not deliver on UR's primary objective of growing the natural gas market.

PNGL would therefore request that UR considers fully the evidence and views expressed by PNGL and that a realistic target for OO connections, with sufficient and appropriate allowances, is set for the GD17 period.

2.3 MANPOWER

Section 3.3 discusses PNGL's concerns with UR's proposed manpower allowances. In summary:

UR's proposal to base PNGL's GD17 allowances for manpower using 2014 FTEs as the baseline is inappropriate due to the significantly higher than normal levels of staff turnover experienced at that time.

In addition, UR's proposal is inappropriate as it excludes the additional 1 FTE allowed by UR in its GD14 determination and employed by PNGL in 2015 to facilitate the introduction of the new asset management system, ISO 55001.

A more appropriate baseline, which should be used by UR in its final determination, is the latest actual number of FTEs employed by PNGL i.e. 124.3 FTEs in Q1 2016. These FTEs are in line with the FTEs granted by UR for 2016 under its GD14 determination.

The minor increase in FTEs within Customer Management proposed by UR, "*given the expected increase in customer connections in GD17*"[30] is not sufficient to cover the additional activity required to service these additional connections and our existing customer base. It is imperative that additional FTEs commensurate with the additional level of activity likely to be performed are provided for within Customer Management.

It is also essential that additional FTEs are provided for future activities, namely the ongoing compliance with the ISO 55001 asset management standard, the ongoing provision of the 24/7 control room and the increase in new build activities performed within Network Development.

UR's proposal to only allow a minor increase in FTEs over the GD17 period does not fully reflect the growth of the customer base forecast for GD17 and the future needs of the business. PNGL request that UR reconsiders its proposed number of FTEs for GD17 as part of its final determination.

"[Redacted paragraph]"

[30] Paragraph 6.257 of the consultation

2.4 INFILL MAINS

Section 3.4 discusses PNGL's concerns with UR's proposals[31] for passing existing properties[32] in its existing Licensed Area[33] between 2017 and 2022. In summary:

PNGL is proposing to make natural gas available to a further c.5,700 properties in line with the practice for standard infill projects established over the last 20 years where consumers are not required to pay an upfront cost to PNGL for making natural gas available to their property. In doing so, we believe that we are treating all potential consumers in our Licensed Area on an equitable basis and by increasing the number of consumers using natural gas, hope that we will be contributing to reducing the current levels of fuel poverty in NI together with NI's carbon footprint.

UR has concluded, via what PNGL believe to be a flawed economic test (see section 3.4.3), that our proposal to make natural gas available to a further c.5,700 properties is unwarranted[34]. In reality this means that those consumers who have not been provided access to the natural gas network to date will have to pay for doing so, unlike similar consumers in our Licensed Area who have already been provided access. Future consumers will be required to pay:

- an upfront cost to PNGL for making natural gas available to their property (c.£330 for a standard infill project[35]). Consumers are not currently required to pay an upfront cost to PNGL for standard infill projects; and

- their installer for converting their existing heating system to natural gas (c.£2,400 for an average gas conversion).

PNGL would request that UR engages with consumers and consumer bodies as part of the GD17 consultation process to discuss the impact of the implementation of UR's proposals on the fuel poor and on the development and maintenance of an economic and coordinated natural gas industry so that any issues arising are fully understood and accepted. Notably, fuel poor consumers[36] who have not been provided access to the natural gas network to date and who qualify for a fully-funded central heating upgrade through one of NI's fuel poverty schemes (e.g. Affordable Warmth) would, under UR's proposals, now have to pay c.£330 to make natural gas available to their property.

Furthermore the remaining properties that PNGL would like to make gas available to across GD17 are (i) not isolated sites; and (ii) not at the extreme of our existing network. UR's proposal for passing properties during GD17 would mean that:

[31] Paragraphs 7.157 to 7.162 "*Infill Mains – Growth (Excluding East Down)*" of the consultation

[32] excluding new build housing

[33] excluding East Down

[34] Paragraph 7.162 of the consultation

[35] c.£690 forecast by PNGL for a standard infill project less the c.£360 allowance proposed by UR at Table 89 of the consultation. Notably PNGL would be neutral to UR's proposals as any costs that it is unable to recover via its cost base will simply be charged to individual consumers under the terms of its Connection Policy

[36] 42% of households in NI are in fuel poverty according to the NI House Condition Survey 2011

- a property in one street may already have natural gas available and have not been required to pay an upfront cost to PNGL for making natural gas available; whereas

- a property in the adjacent street may not have natural gas available and would be required to pay an upfront cost to PNGL for making natural gas available.

UR's proposal is unjustified and may be interpreted by consumers and their representatives as being discriminatory.

As we detail in section 3.4, PNGL could have made natural gas available to these properties under UR's previous price control determinations at no upfront cost to the property owner as long as it met, on aggregate, UR's average allowance per property passed.

Furthermore if PNGL's proposal for passing properties during GD17 were adopted, the average cost of passing a property from 1997 to 2022 would still be below the "economic" allowance granted by UR in GD14, c.£400[37] and **significantly below the £620[38] "economic" allowance proposed by UR for firmus in GD17**.

PNGL would therefore urge UR to review the basis of its current analysis and to reconsider the message that its proposal to ignore the long-term average cost of passing a property will have on the development of the natural gas network and on consumers, including the fuel poor, in our Licensed Area. UR is signalling that there will be no further development of the natural gas network in PNGL's Licensed Area without financial contribution from consumers. This is unwarranted.

[37] this is the allowance in 2016 excluding management fee

[38] Table 89 of the consultation

2.5 REAL PRICE EFFECTS, PRODUCTIVITY IMPROVEMENTS AND TOP-DOWN BENCHMARKING

Section 3.5 discusses PNGL's concerns with UR's proposed real price effects ("**RPEs**") and indicative top-down benchmarking. In summary:

2.5.1 REAL PRICE EFFECTS AND PRODUCTIVITY IMPROVEMENTS

PNGL engaged NERA to respond to UR's RPE and productivity forecasts set out in the draft determination.

2.5.1.1 UR's approach to RPEs is inconsistent with regulatory practice

Overall, NERA finds that there are a number of areas where UR's proposed approach to forecasting RPEs is not in line with established economic principles or regulatory practice.

In forecasting labour input costs over GD17, UR relies on OBR forecasts where NERA has identified the following issues:

- UR used OBR's forecast for economy-wide average-earnings growth, while it should use private sector earnings, given that we face private sector wage growth pressure; and
- UR draws on weekly wage changes whereas the correct approach is to use hourly earnings growth, as this measure is unaffected by changes in hours worked.

For our material input costs, UR assumes that material prices will grow at a below trend growth rate before achieving UR's assumed long-term average of 0.3% per annum towards the end of GD17. Despite recognising that the price levels are below trend, UR ignores the tendency of price indices to grow more quickly following economic shocks (i.e. the global financial crisis). By contrast, Ofgem assumed that material prices would revert immediately to their long-term growth rates, as a practicable and objective approach to allowing for the tendency for prices to grow above trend as the UK economy continues to emerge from the crisis. Using UR's proposed indices and long term average but applying Ofgem's practical approach, implies an RPE of 0.3% per annum on average over GD17 as opposed to UR's draft determination assumption of *minus* 0.3% per annum.

For plant and equipment, UR relies only on one index (ONS PPI Machinery and Equipment index) in contrast to UR's approach at GD14, CMA NIE and Ofgem, which considered an additional second index, BCIS Plant and Road Vehicles. Taking into account both indices would lead to an average RPE of *minus* 0.3% per annum on average over 2015-2022, compared to the current UR average estimate of *minus* 0.7% per annum over the same period.

Table 8 summarises the required changes to UR's RPE to correct for these issues. Overall, the restated estimates are much more in line with the unit cost pressures that we currently face as a business (notably in relation to increasing wage pressures), and the proposed changes to the RPE forecasts are an important element of ensuring the cost allowances are sufficient for us to deliver a safe and reliable network over GD17.

	UR - Draft Determination	UR - Corrected Approach
Labour	0.8%	1.2%
Materials	-0.3%	0.3%
Plant and Equipment	-0.7%	-0.3%
Transport/ Other	0%	0%

***Table 8** - Proposed Changes to UR's RPE Assumptions to Ensure Adequate Cost Allowances Average RPE per annum over 2015-2022*

2.5.1.2 For productivity, UR selects an upper bound estimate although the evidence supports a lower bound estimate

As set out in NERA's report, UR's draft determination estimates are at the upper-end of regulatory decisions and empirical evidence, whereas the PNGL specific factors would suggest a value at the lower end. Specifically, PNGL is a new utility, with far less scope to reduce costs relative to incumbent former publically owned utilities. NIE – UR's principal comparator – is not a reasonable comparator.

Overall, we consider that UR should use a value of 0.6% per annum and 0.8% per annum for capex and opex respectively as set out in our GD17 business plan submission[39]. As NERA explains in its report, our recommended values are based on the improvements achieved by comparable businesses over the long-run. UR's draft determination of 1% for both capex and opex is higher than that supported by the empirical evidence, and has a material impact on our overall cost allowance given that the reduction compounds over time. As with RPEs, our proposed changes to UR's productivity assumption is an important element of ensuring that the overall cost allowances are sufficient for us to deliver safe and reliable network services for our customers over GD17.

2.5.2 REAL WAGE ADJUSTMENT AND TOP-DOWN BENCHMARKING

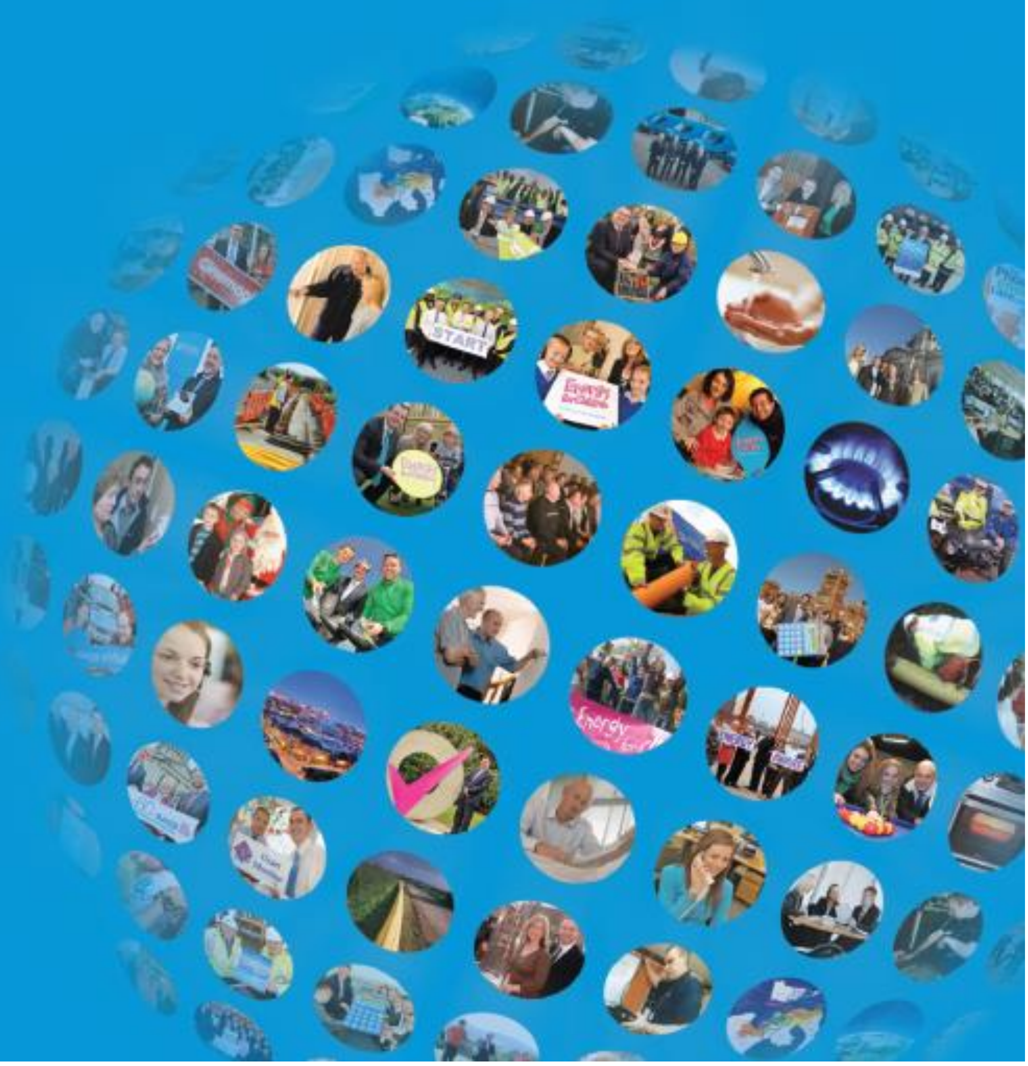
As part of the top-down benchmarking analysis for GD17, UR make a regional labour adjustment to PNGL's operating costs of c.9% to account for UR's view that PNGL face lower wage costs than GB GDNs. This adjustment to PNGL's costs almost entirely explains UR's assessed efficiency gap.

PNGL engaged NERA to review UR's regional wage adjustment and the implications for the top-down benchmarking. NERA concludes that there are a number of areas where UR does not follow sound economic principles, and established regulatory practice, and as a consequence, UR overstates the required adjustment for differences in real wages in NI relative to GB.

Based on standard practice, NERA calculates a required real wage adjustment of between 2% and 3%, far lower than UR's 9% adjustment. NERA concludes that if UR were to use this corrected value in the top-down modelling, PNGL would be on the efficiency frontier. Therefore, there is no basis for reducing our expenditure allowances based on UR's own top-down modelling. Indeed, the top-down modelling supports PNGL's view that our business plan costs are efficient and should be recognised in full.

[39] Worksheet 1.5 of PNGL's GD17 BPT submission

KEY ISSUES



KEY ISSUES

UR's proposed price control package is unreasonable and unjustified as it loads significant downside risk onto PNGL. PNGL has already taken the opportunity to inform UR of a number of concerns with the draft determination during the consultation period. PNGL's key areas of concern are:

- Rate of Return;
- the Connection Incentive;
- Manpower;
- Infill Mains; and
- Real Price Effects, productivity improvements and top-down benchmarking.

The remainder of this section addresses each of these key areas of concern.

3.1 RATE OF RETURN

This section discusses PNGL's concerns with UR's proposed rate of return. PNGL engaged Frontier and NERA to respond to UR's rate of return proposals set out in the draft determination.

Our updated view of PNGL's rate of return is a real pre-tax WACC of 5.3% - 5.6%. This is higher than the real pre-tax WACC in UR's draft determination of 4.3%. The comparison is shown in Table 9.

Frontier and NERA highlight a number of errors and inconsistencies in UR's draft determination WACC estimation which renders UR's real pre-tax WACC of 4.3% incorrect. We summarise these in sections 3.1.2 and 3.1.3.

	UR's draft determination	Frontier/NERA estimate
Tax rate	20%	20%
Inflation	3.08%	2.2%
Gearing	55%	55%
Risk-free rate	1.25%	1.25%
ERP	5.25%	5.25%
TMR	6.50%	6.50%
Asset beta	0.40	0.40 - 0.45
Debt beta	0.10	0
Equity beta	0.77	0.89 - 1.00
Real post-tax cost of equity	5.3%	5.8% - 6.4%
Real cost of debt (pre-tax)	2.26%	3.26%
Real pre-tax WACC	4.21% (rounded to 4.3%)	5.3% - 5.6%

Source: Frontier, NERA, UR's draft determination.

Note: We assume gearing of 55% in line with UR's draft determination.

***Table 9** - Summary of proposed WACC vs UR draft determination*

We begin with PNGL's concerns with UR's financeability assessment.

3.1.1 FINANCEABILITY

Financeability tests are an important part of reaching an appropriate price control determination. The test should answer the question of whether the overall package of cost allowances provided by UR is sufficient for PNGL to be able to finance investment efficiently in line with appropriate benchmark operators.

UR's draft determination does not achieve this. UR has not applied the financeability thresholds appropriately because it has designed a test which ***assumes*** the price control allowances are reasonable in the first place, rather than testing those allowances against financeability levels based on appropriate readily available benchmarks.

This can be demonstrated by the way that UR have simply applied a gearing assumption of 55% as an acceptable threshold, without recognising that this gearing level is significantly below comparable UK regulatory determinations; and outside the benchmark levels highlighted within the ratings methodologies (and the level under which the company operates). The consequence of the unduly low gearing assumption is that it masks the inadequacy of the proposed cost allowances overall, since it means PNGL's PMICR ratios appear better than they in fact are.

If the financeability tests were implemented correctly, UR would have identified that its draft determination creates significant financeability issues for PNGL. The proposed income levels, once adjusted for specific factors unique to NI, are not consistent with GB comparators. This has resulted in a risk of a downgrade below PNGL's existing rating as highlighted in the response by both Fitch and Moody's to the draft determination, with the consequence of a such a downgrade being higher debt costs. In the remainder of this section we will explain each of the following issues in turn:

vii. UR's draft determination of 55% gearing is inconsistent with PNGL's current Baa2 rating;

viii. UR's gearing assumption also does not reflect relevant regulatory precedent;

ix. UR's statements in relation to PNGL's dividend policy are misleading;

x. UR's financeability tests target a credit rating which is out of line with wider regulatory practice;

xi. UR's financeability tests also do not reflect other relevant regulatory precedent, including for example by failing to undertake any assessment of reasonable downside; and

xii. the consequence of the above issues is that rating agencies have indicated that the draft determination results in a risk of potential downgrade.

It is important to highlight upfront that both of PNGL's main ratios (i.e. gearing, as measured by TRV/net debt; and PMICR, PNGL's interest cover ratio) allow for the deferral of income through the profile adjustment mechanism, a NI specific factor. Therefore in doing so the ratios as calculated for PNGL are much more broadly consistent with the comparator set within a wider GB environment. These ratios should therefore serve as appropriate benchmarks in assessing PNGL's financeability. As a further consequence of this point it is important to note that the calculation of PMICR ratios will not look any more favourable if there is a decision to no longer defer income in this manner.

UR's Draft Determination of 55% gearing is inconsistent with our current Baa2 rating

UR states that its financeability test assumes gearing levels which are consistent with the notional gearing level used in UR's WACC calculation of 55%. UR then tests whether, at this notional gearing level, PNGL's adjusted interest cover ratio falls below 1.4x. UR concludes that the interest cover ratio does not fall below 1.4x, and therefore that PNGL is financeable.

The problem with UR's approach is that UR's assumption on gearing is well below the level which ***should*** be consistent with a Baa2 rated business like PNGL. Table **10** and Table 11 replicate, respectively, the Moody's and Fitch target ratios and indicative credit ratings for UK network utilities. These were published in the CMA's Final Determination for NIE.

Moody's rating	Adjusted interest cover	Gearing	FFO/Net debt %	RCF/capex %
A1	2.5 – 3.5	40-50%	12-20	1.5 – 2.5x
A2	1.8 – 2.5	50-60%		
A3	1.6 – 1.8	60-68%		
Baa1	1.4 – 1.6	68-75%	8-12	1.0 – 1.5x
Baa2	1.2 – 1.4	75-85%		

Source: Table 17.2 of CMA NIE final determination - CMA based on Exhibit 4 of 'UK Water Sector: Speed of Money cannot address Potential Financeability Concerns', 16 May 2013

Table 10 *- Moody's - Target ratios and indicative credit ratings—UK Regulated Water and Energy*

Issue Default Rating ("IDR")	Senior unsecured	Adjusted PMICR	Debt/RCV %
A-	A	<1.9	<60
BBB+	A–	1.6–1.9	60–75
BBB	BBB+	1.4–1.6	75–80
BBB–	BBB	1.3–1.4	85–90

Source: Fitch, CMA NIE Final Determination, Table 17.3. Note that Moody's Baa2 rating is equivalent to Fitch BBB Issue Default Rating.

Table 11 *- Fitch - Indicative ratings guidelines for UK DNOs*

The tables show that companies with a PMICR of 1.4 - 1.5x (i.e. as modelled by UR for PNGL under the draft determination) ***should*** be able to gear up to around 65% and maintain a credit rating of Baa2/BBB under Moody's or Fitch's ratings methodologies. Moody's states:

"[Redacted quote]"[40]

However, if PNGL were to gear at that level, we estimate our PMICR would fall as low as 1.2x over the GD17 period. Clearly this would breach the benchmark cover ratio, and would therefore result in a deterioration of our credit rating. A PMICR of 1.2x would also breach the covenant on our existing bond.

[40] Moody's Credit Opinion, "*Phoenix Natural Gas Finance PLC Update following outlook change to negative and Baa2 rating affirmation*", May 13, 2016

We also note that – despite the inappropriate gearing assumption - UR's analysis implies the PMICR threshold is reached exactly in 2021, leaving no headroom in the ratio. Moody's most recent ratings review clearly linked PNGL's Baa2 rating with the existing covenants on PNGL's debt, which include a dividend lock up at 1.4x PMICR. Since UR's draft determination now implies PNGL will fall to that level by 2021, this further jeopardises the Baa2 rating (since agencies would typically expect some buffer over the covenant level).

UR's gearing assumption is inconsistent with regulatory precedent

Table 12 shows the gearing decisions of UK utility regulators since 2009.

Decision	Date	Gearing (%)
Ofwat PR09 (WASCs)	April 2009	57.5%
Ofwat PR09 (WOCs)	April 2009	52.5%
Ofgem DPCR5	December 2009	65%
CC Bristol	February 2010	60%
Ofgem RIIO-GD1	December 2012	65%
CAA Heathrow	January 2014	60%
CAA Gatwick	January 2014	55%
CMA NIE	March 2014	45%
Ofgem RIIO ED1	November 2014	65%
Ofwat PR14	December 2014	62.5%
CMA BW 2015	October 2015	62.5%

Source: Analysis of regulatory decisions

Table 12 *- Regulatory precedent on gearing determinations*

UR states that it has based its decision of 55% on the mid-point of the range of previous regulatory decisions (i.e. between 45% and 65%). Table 12 shows that lower bound of UR's range is distorted by the CMA's NIE decision of 45%.

iii. The **average** gearing across the whole set of comparators is close to 60% (specifically 59.09%).

iv. Excluding the NIE decision, the range of relevant regulatory precedent is 55% - 65% and the mid-point would be 60%.

NIE is an outlier in the range of previous decisions. In the NIE case, the CMA assumed that the appropriate notional level was equal to NIE's ***actual*** gearing level at the time of around 45%[41]. Similar reasoning can be found in the Bristol Water case, where the CMA noted that the proposed notional 62.5% gearing was comparable with Bristol Water's own gearing[42].

[41] CMA, NIE Final Determination, 6th October 2015, paragraph 10.37

[42] CMA, Bristol Water Final Determination, 6th October 2015, paragraph 10.27 – 10.28

In other words, in both cases the CMA cross-checked its notional gearing assumption against the actual gearing of the company in question, and concluded the notional gearing was reasonable because it was close to the actual gearing. UR's method embeds no such cross-check – instead it is based on the unreasonable inclusion of the NIE notional gearing decision in the comparator set (since the rationale for the CMA's decision on NIE has no relevance for the appropriate notional gearing for PNGL).

As explained in the Frontier/NERA paper submitted in June 2015[43], a gearing level of 60% - 65% is consistent with PNGL's observed gearing since 2010. Had UR followed the CMA's approach, it would have therefore established higher notional gearing on the basis of PNGL's actual gearing levels. This would have been more consistent with the substantial majority of relevant regulatory precedent (i.e. excluding NIE).

UR's statements in relation to PNGL's dividend policy are misleading

UR's draft determination implies that a higher gearing assumption is inappropriate, since PNGL's actual gearing is above the notional level due to PNGL's decisions "*including those in relation to dividend policy*."[44] As a result, although UR acknowledges that higher gearing would result in "more challenging financial ratios", UR effectively ignores this – implying that gearing above 55% is not efficient.

These statements seem to misunderstand the issue. As shown above, PNGL's target gearing level is consistent with an efficient financing structure and is well within the financeability guidance as set out by rating agencies; and PNGL's gearing levels are not out of line with GB comparators. The dividend policy of the company is therefore consistent with reasonable and efficient gearing levels.

It is therefore misleading to suggest the actions of PNGL's equity investors in respect of its dividend policy are the cause of financeability issues, resulting from higher gearing than UR's notional 55%. Indeed it should be recognised that dividend policy tends to be educated by rather than the driver for gearing levels. The real source of the issue lies in the inadequacy of UR's wider price control allowances. If UR's overall price control package were appropriate, a notionally efficient company should be able to finance both equity and debt investment in line with the gearing levels which PNGL has been targeting. This means that the notional company should be able to offer a dividend to investors; and also maintain gearing levels at around 65% in line with other benchmark operators, while maintaining its Baa2 credit rating.

UR is targeting a credit rating which is out of line with wider regulatory practice

UR has stated that it performs its financeability tests to be consistent with obtaining a BBB rating. However, regulators in GB have normally targeted a strong investment grade (i.e. between A- and BBB+).

[43] "*Appendix A - PNGL Cost of Capital for GD17*" of PNGL's "*GD17 Rate of return paper*" submitted to UR in June 2015

[44] Paragraph 10.65 of the consultation

In the NIE case, the CMA highlighted that the typical distribution of ratings in the utilities sector *"may provide an indication of the appropriate credit rating to adopt"*. The CMA noted that in the 2010 Bristol Water inquiry, the CC targeted a Baa1/BBB+ rating. In the Airports inquiries, the CC targeted a BBB+ rating for Heathrow and Gatwick and an A– rating for Stansted[45]. Similarly in the BW 2015 decision the CMA targeted a credit rating of BBB+[46].

Ofgem similarly targets a "comfortable" investment grade:

> *"In setting price controls, we are required to have regard to the ability of efficient network companies to secure financing to facilitate the delivery of their regulatory obligations. This is also in the interests of consumers. We define this ability as indicated by a notional efficient network company attaining a "comfortable investment grade" credit rating (i.e. in the BBB-A range)"* [47]

Indeed, in the NIE case, UR itself targeted a credit rating of Baa1/BBB+[48]. Given this, we consider that UR's financeability tests should be more cautious to ensure its price control allowances are sufficient.

UR's application of the financeability tests is inconsistent with regulatory precedent

UR says that it has followed the CMA's approach for NIE in undertaking its financeability tests. However, there are several aspects of the CMA's approach – and broader regulatory practice - which UR has not acknowledged in its GD17 assessment.

First, UR has performed quite a narrow financeability check, assessing just PMICR and gearing. The CMA stated that the target for NIE's financeability test should be a gearing of 70% or less, and a PMICR of 1.4x or more. However, the CMA also decided that it was important to look at other financial ratios which the ratings agencies considered, as shown in Table 13.

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45 See CMA, NIE Final Determination, paragraph 17.54

46 BW 2015 Final determination, paragraph 11.26 and 11.33. *"Bristol Water said that its preferred approach to financial ratio analysis was consideration of its actual financial structure, but with a notional level of gearing. Bristol Water said that to be consistent, either a notional structure should be used with a notional target credit rating of BBB+, or Bristol Water's actual financial structure should be used with Bristol Water's stated target credit metrics (either derived from Moody's and S&P's guidance material, or set explicitly in discussion with the relevant agency)." "..we compare the financial ratios under this structure to rating agency targets, consistent with a notional company broadly comparable to Bristol Water."*

47 https://www.ofgem.gov.uk/ofgem-publications/48156/3riiogd1fpfinanceanduncertainty.pdf

48 See CMA, NIE Final Determination, paragraph 17.69

	CC target ratio averaged across the NIE price control period
PMICR	1.4 or more
FFO/ net interest payable	3.5 or more
FFO/net debt	10% or more
Gearing	70% or less

Source: CMA NIE final determination Table 17.4

Table 13 *- CMA's view of "appropriate targets for the efficient licence holder for forecast credit risk financial ratios"*

More widely, other regulators have also tended to evaluate a wider set of metrics than UR has considered[49].

Second, we note that in order to avoid breaching the PMICR threshold, UR's model in fact implies gearing ***below*** the notional 55% level - i.e. its model implies further de-gearing to around 53% by the end of the GD17 period[50]. In the 2015 Bristol Water case, the CMA tested ratios under both an unconstrained gearing model (i.e. where gearing was allowed to fluctuate) and a constrained gearing model (where the gearing assumption was fixed at the notional level for Bristol Water of 62.5%)[51]. UR has not assessed the expected PMICR ratio which is consistent with its assumed notional gearing level.

Third, UR does not appear to have conducted any scenario analysis at all. In particular UR has not tested the effect of its asymmetric connections incentive mechanism on PNGL's cashflows. In the Bristol Water case the CMA explained that *"We consider it good regulatory practice to consider the impact of downside shock on financial ratios."*[52] The CMA noted that there are some mitigating factors which would mean that a breach of benchmark ratios in reasonable downside scenarios may be acceptable – but notably, one of these mitigating factors was the existence of headroom in BW's ratios (headroom which does not exist for PNGL).

Rating agency opinion makes clear that the DD cost allowances are insufficient and result in a risk of downgrade

UR's conclusion that the draft determination results in acceptable financeability ratios is contradicted by the response of the rating agencies. Both Fitch and Moody's have already placed PNGL on negative watch and negative outlook respectively, suggesting the proposed allowed income is insufficient to maintain PNGL's current BBB rating. This also indicates that UR's financeability tests are not well specified.

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49 See, for example, Joint Regulators Group (JRG), "Cost of Capital and Financeability", March 2013

50 Table 182 of the consultation

51 CMA, Bristol Water Final Determination, 6th October 2015, Table 11.4: https://assets.digital.cabinet-office.gov.uk/media/56279924ed915d194b000001/Bristol_Water_plc_final_determination.pdf

52 CMA, Bristol Water Final Determination, 6th October 2015, paragraph 11.52

A negative watch action has not occurred following the draft determinations in any of the recent UK reviews[53], despite rating agencies such as Moody's noting, for example, that the draft determination in the water review was "challenging"[54]. In relation to UR's GD17 draft determination, Moody's stated:

"[Redacted quote]"[55]

In particular Moody's noted the pressures associated with UR's proposed cost allowances for connections and the asymmetric connections incentive:

"[Redacted quote]"[56]

This statement by Moody's further illustrates the necessity of UR performing financeability tests under reasonable downside scenarios for connections.

Overall, Moody's explained that it *"[Redacted quote]"*[57]

Given these statements, UR's draft determination poses a significant risk that downgrading would occur. The magnitude of the impact of such a downgrade is difficult to assess, since there are almost no comparable regulated UK utilities with a rating of Baa3.

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53 i.e. Ofwat PR14; Ofgem RIIO-GD1, RIIO-T1, and RIIO-ED1

54 Moody's, 14th October 2014: https://www.moodys.com/research/Moodys-Stable-outlook-for-UK-Water-Sector-despite-challenging-regulatory--PR_310349

55 Moody's, 10th May 2016: https://www.moodys.com/research/Moodys-changes-outlook-on-Phoenix-Natural-Gass-Baa2-rating-to--PR_348607

56 ibid

57 ibid

Conclusion

As noted in the Frontier/NERA June paper, the financeability test is particularly important to get right for GD17 in the context of significant refinancing. Overall, however, the draft determination results in significant financeability issues, driven in particular by the low WACC allowance and the inappropriate and asymmetric allowances for connections costs. This is clear from the fact that both rating agencies have placed PNGL on negative watch or negative outlook; and from the fact that PNGL's PMICR falls to 1.2x across GD17 if efficient gearing levels are assumed. UR's financeability test has failed to identify these issues because of its inappropriate gearing assumption. The consequence of this is that there is a higher risk that UR's price control will result in a credit downgrade and as a result an increase in debt costs.

A more appropriate specification of UR's test would recognise that efficient gearing is higher than its 55% proposal. Increasing the notional gearing level would allow UR to properly test the impact of its broader allowances on PMICR. UR should also test reasonable downside connections scenarios to be consistent with regulatory precedent.

[Redacted quote]

3.1.2 COST OF EQUITY

PNGL engaged Frontier to evaluate UR's draft determination for PNGL's cost of equity allowance in the GD17 regulatory period review. In this section, we summarise Frontier's overall conclusions, and we attach Frontier's more detailed technical report at Appendix 1.

UR has made a number of errors in its approach to setting the cost of equity. Most notably these errors relate to UR's provisional determination on beta. In addition, UR's calculation of the real pre-tax WACC allowance results in under-remuneration of tax costs.

We also do not agree with UR's evidence on TMR and its component parts. However, we focus in this section on the two primary errors in UR's approach relating to beta and tax.

3.1.2.1 Beta

UR has stated its view that PNGL's beta allowance for GD17 should be at the top end of the range of allowed betas for UK network utility comparators.

> "*For this draft determination, we use a value of 0.40. This gives recognition, in particular, to the fact that there are differences with PNGL's and FE's regulatory model from the standard model, e.g. the Profile Adjustment, and notwithstanding the analysis that we have summarised above, the possibility that investors may not be wholly familiar with these*

differences. While we regard this as a small and potentially short term factor, our initial view is that a cautious approach is appropriate and this therefore warrants placing the GDNs at the top of the betas that regulators have judged appropriate for low-risk network utility businesses."[58]

We agree with UR that PNGL is relatively higher risk than other UK utilities, although UR's relative risk assessment does not fully reflect the range of evidence in support of that conclusion (which has been set out fully in our earlier submissions).

UR considers that "typical" UK network utilities have been allowed an asset beta in the range of 0.3 - 0.4. However, UR has incorrectly interpreted the UK precedent range. This is because UR has failed to control for differences in the debt beta assumption which was used in those regulatory decisions. As a result, the range presented by UR is not like-for-like.

UR has provisionally assumed a debt beta of 0.1 for NI GDNs. Given this assumption, UR should have re-stated the UK regulatory determinations on asset beta on a consistent basis. If UR had done this correctly, the like-for-like range for UK comparator asset betas would be in fact 0.36 – 0.43. This shows that UR has not in fact proposed an asset beta at the top end of the range of UK comparators, but rather the proposed asset beta is in the middle of the range.

The result is a cost of equity allowance which is too low. If UR intends to continue to assume a debt beta of 0.1, UR must at the very least utilise an asset beta of 0.43, reflecting its view that PNGL is at the top end of the range of precedent.

We also note that UR (and its advisor, First Economics) has provided very little justification for its proposed debt beta assumption of 0.1. UK regulators including Ofgem and Ofwat have assumed that debt beta is zero; and in its most recent determination for Bristol Water the CMA also assumed a debt beta of zero. In general, practitioners expect that the debt beta assumption (if applied correctly) will not have a material effect on equity beta estimates, or consequently on the final allowed cost of equity. Given this, we propose that UR removes the debt beta assumption from its analysis, in line with GB precedent.

Finally, we note that UR has not relied on up-to-date empirical beta estimates to inform its assessment. First Economics has provided empirical estimates which UR states are a reasonable cross-check of its beta proposals. However, the First Economics analysis has not replicated the CMA's approach to estimating beta (despite its stated intention to do so); and relies entirely on data from the post-financial-crisis period in which betas were clearly distorted downwards, relative to longer term trends. Both of these issues mean that First Economic's empirical beta analysis is an unreliable cross-check.

In the first paper submitted to UR in June 2015[59], we observed that since early 2012, beta estimates have been gradually increasing in line with the normalisation of market conditions; and were close to the levels observed before the Global Financial Crisis ("**GFC**") in 2008. Empirical estimates of beta have continued to trend upwards since that paper, and are now much more in line with pre-GFC

[58] Paragraph 10.34 of the consultation

[59] "*Appendix A - PNGL Cost of Capital for GD17*" of PNGL's "*GD17 Rate of return paper*" submitted to UR in June 2015

observed levels. We consider that UR must take the latest empirical evidence properly into account, rather than simply rely on out-dated regulatory precedent or distorted empirical estimates. Frontier's updated analysis shows that the ***average*** asset beta across the peer group is now 0.44, assuming a debt beta of zero. This is equivalent to an average asset beta of 0.48, assuming a debt beta of 0.1.

Overall, we consider that the latest market evidence - combined with the relevant regulatory precedent and the evidence that PNGL is relatively higher risk - supports an asset beta at the top end of the range of 0.40 - 0.45 (assuming a debt beta of zero). This remains within the range we proposed in June 2015, but recognises that market evidence since then supports an increase in the lower bound of that range. If UR wishes to retain its debt beta assumption of 0.1, the asset beta estimate must be adjusted upwards accordingly.

3.1.2.2 Tax allowance

UR's regulatory model requires it to set a real, pre-tax WACC allowance. In practice, corporates incur tax liability calculated on the basis of nominal profits. The tax allowance should therefore capture the fact that inflation will increase profits in nominal terms over time.

UR's pre-tax WACC calculation should calculate the tax wedge on the basis of the ***nominal*** post-tax cost of equity. UR's current approach does not do this and as a result underestimate the tax allowance.

Although not many regulators set a pre-tax WACC allowance, we note that the UK telecoms regulator Ofcom; a number of decisions made by the Irish energy regulator CER; and the Italian energy regulator have all ensured that expected tax costs are fully funded via a pre-tax WACC.

3.1.2.3 Conclusion

Frontier's updated view of the best estimate of PNGL's cost of equity for GD17 is shown in Table 14, compared to UR's draft determination. This proposal is based on an asset beta range of 0.40 - 0.45, as in our original June 2015 paper. However, updated market evidence now point towards the top end of that range and therefore, our best estimate of PNGL's cost of equity is closer to the top end of the estimated cost of equity range of 5.8% - 6.4%. As noted above we have utilised the UR's proposals for TMR, ERP and RFR, although we continue to consider that the evidence set out in the June 2015 paper supports a TMR above this level.

Frontier considers this a conservative estimate given the recent return of observed betas to their longer-term levels; and the evidence supporting a higher TMR.

	UR's draft determination	Frontier estimate
Gearing	55%	55%
Risk-free rate	1.25%	1.25%
ERP	5.25%	5.25%
TMR	6.50%	6.50%
Asset beta	0.40	0.40 - 0.45
Debt beta	0.10	0
Equity beta	0.77	0.89 - 1.00
Post-tax cost of equity	5.3%	5.8% - 6.4%
Pre-tax cost of equity	6.6%	7.8% - 8.5%

Source: Frontier Economics, UR's draft determination.

Note: We assume gearing of 55% in line with UR's draft determination. We also assume inflation of 2.2% in line with break-even inflation over the GD17 period as set out in Appendix 2.

***Table 14** - Summary of proposed cost of equity vs UR draft determination*

3.1.3 COST OF DEBT

PNGL engaged NERA to review UR's proposals in relation to the ex-ante cost of debt estimate.

On the cost of debt, UR proposed an ex-ante cost allowance for embedded and new debt, and a true-up mechanism, where the ex-ante cost of new debt is proposed to be adjusted for 80% of the difference between PNGL's actual issuance costs and the cost of new debt assumption set at review[60]. In this section, we summarise NERA's overall response to UR's ex-ante cost of debt estimate, and we attach NERA's detailed technical report at Appendix 2. We set out our response to UR's proposed true-up mechanism in section 3.1.3.1.

UR understates PNGL's cost of debt by around 100 bps.

Table 15 sets out UR's Draft Determination estimate for the cost of debt, and NERA's estimate which corrects for a number of concerns with UR's approach and also updates for the latest market data. Overall, we calculate a real cost of debt of 3.26% using our preferred market based (or break even) measure of inflation, or 2.42% if we use inflation published by the OBR, as UR proposes.

[60] Paragraph 10.8 of the consultation

	UR draft determination (Dec 2015)[a]	NERA (May 2016)[b]	
		OBR inflation	Breakeven inflation
Embedded debt costs			
Average interest costs	4.3	4.3	
Transaction costs	0.3	0.4	
New debt costs			
BBB-index yield	4.4	4.3	
Forward rate adjustment	0.4	0.3	
PNGL premium	0.4	0.64	
Transaction costs	0.3	0.4	
Weighting - embedded debt	10%	10%	
Weighting - new debt	90%	90%	
Inflation	3.1	2.4 for embedded, 3.1 for new	2.1 for embedded, 2.2 for new
Real Cost of debt	2.26	2.42	3.26

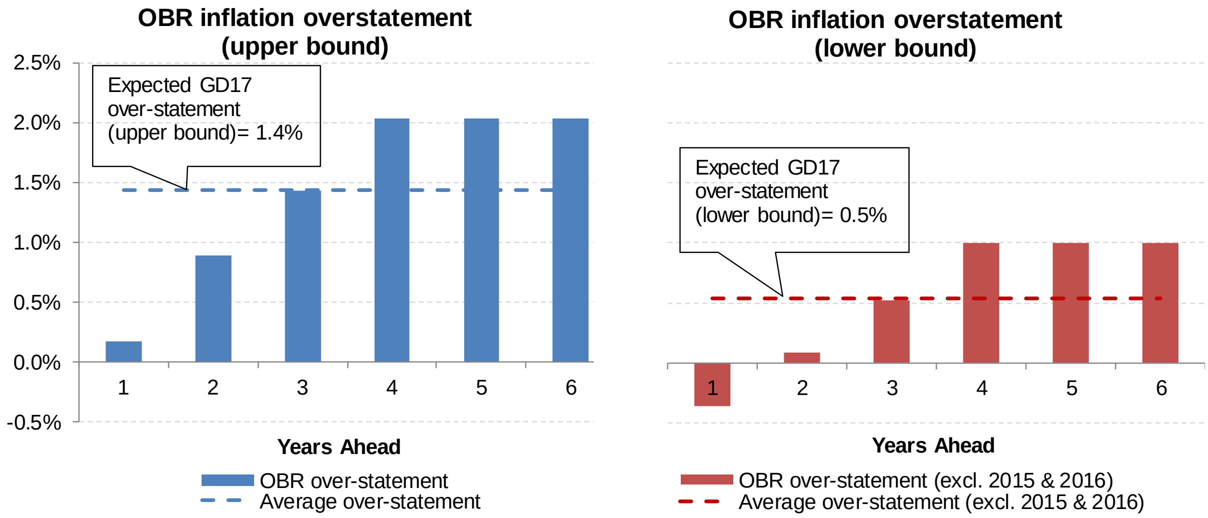
Source: NERA analysis. Notes: a) information date = end December 2015; b) information date = 13 May 2016

Table 15 *- We estimate an ex-ante cost of debt allowance around 100 bps higher than UR's draft determination*

OBR overstates inflation; UR should use market based forecasts

To convert nominal cost of debt into real terms, UR uses an inflation rate of 3.08% p.a. based on OBR inflation forecasts for GD17. OBR forecasts have historically overstated outturn inflation which means that PNGL does not have a reasonable prospect of recovering its actual nominal debt costs.

NERA's analysis of all historical OBR published forecasts (over the period 2010 to 2016) shows that OBR has systematically overstated inflation, and that the overstatement increases with forecast length (see Figure 5). Based on OBR's historical performance, the expected forecast error over GD17 is 1.4%. Even excluding OBR's forecasting errors for 2015 and 2016, where its performance is particularly poor, the expected forecast error over GD17 remains at 0.5%.



Source: NERA calculations based on OBR and ONS data.

Figure 5 *- OBR Expected Forecast Error over GD17 is*
0.5% (excluding 2015 and 2106 errors) to 1.4% (all years)

The CMA in its NIE decision acknowledged that the OBR forecasts are at the high-end, and explicitly selected an allowed rate of return at the top-end of its WACC range to accommodate the noted bias in its cost of debt allowance from its use of OBR. Ofgem and Ofwat use market based evidence – "break-even" inflation derived from the difference between nominal and real yields on gilts – to determine a real cost of debt allowance.

Consistent with regulatory precedent, UR should use break-even inflation to derive an ex-ante real cost of debt for GD17. As of mid-May 2016, the break-even inflation rate is 2.2%, i.e. 0.9% lower than the March 2016 OBR forecast[61]. Break-even inflation reflects the market consensus view of inflation rather than the view of a single organisation, and one with a noted bias, as demonstrated by NERA's research and acknowledged by the CMA.

UR understates real embedded debt costs by using average inflation over the period

UR uses average GD17 inflation to convert its nominal estimate of embedded and new debt into real terms, although embedded debt is expected to mature on average by the end of 2017. Given the expected increase in inflation over the GD17 period, UR materially overstates inflation for embedded debt and therefore materially understates real embedded debt costs.

The error in the understatement of historical debt costs will not be corrected under UR's proposed true-up mechanism. Under UR's proposed approach, PNGL will bear the full cost of UR's overstatement of inflation on embedded debt as there is no true-up for the real ex ante allowance. By contrast, there will be no offsetting outperformance on the new debt cost allowance, as we

[61] We note that a further likely explanation of the difference is falling inflation expectations over the recent period, as well as the noted bias in OBR's forecast. That is, the break-even inflation rate reflects current market expectations of inflation, whereas the OBR forecast (in March 2016, but with an effective date prior to March) does not reflect the changes in expectations. The fact that break-even is up-to-date provides a further reason to use break-even.

expect UR to take into account actual inflation in trueing up new debt costs subject to an 80:20 sharing factor.

The real cost of embedded debt should be estimated using inflation over the period for which it remains outstanding, i.e. 2017, and the real cost of new debt should be estimated using inflation over the rest of GD17. NERA calculates a break-even inflation estimate for 2017 of 2.1% to derive the real cost of embedded debt and a break-even inflation estimate of 2.2% for the rest of GD17 to derive the real cost of new debt.

UR should use BBB index yield over one year to mitigate volatility risk

UR used the spot BBB-index yield adjusted for forward rate uplift but disallowed our proposed volatility risk premium which takes account of the volatility in the benchmark index. In the absence of the volatility risk premium, UR should use a longer term average to smooth for short-term market volatility. In its 2015 Bristol Water decision, the CMA recognised the need to use a long-run average to smooth for market volatility, and used a one-year average. We have adopted the same approach – resulting in a nominal benchmark BBB cost of 4.3% as of mid-May.

UR's forward rate adjustment ignores bank debt falling due mid-2018

To estimate the cost of new debt, UR adjusted its spot estimate of BBB costs by 40bps to allow for an increase in interest rates by mid-2017 for PNGL. We agree with UR's proposed approach to draw on market data to make an adjustment for the expected increase in yields to the point of refinancing. However, UR's forward rate adjustment assumes a mid-2017 refinancing point, based on the redemption date of PNGL's public bond. UR ignores bank debt falling due in late 2018. UR should instead assume an end 2017 refinancing point, the approximate mid-point of the bond and bank debt refinancing. NERA's updated estimate of the forward rate as of mid-May is 30 bps.

UR's estimate of the PNGL premium needs to be adjusted for tapering effect

In estimating the cost of new debt, UR allows for a 40 bps PNGL premium based on the most recent empirical evidence of the difference in bond yields between PNGL and a set of comparators. UR's use of recent data understates the premium due to the effect of tapering as the PNGL bond approaches maturity.

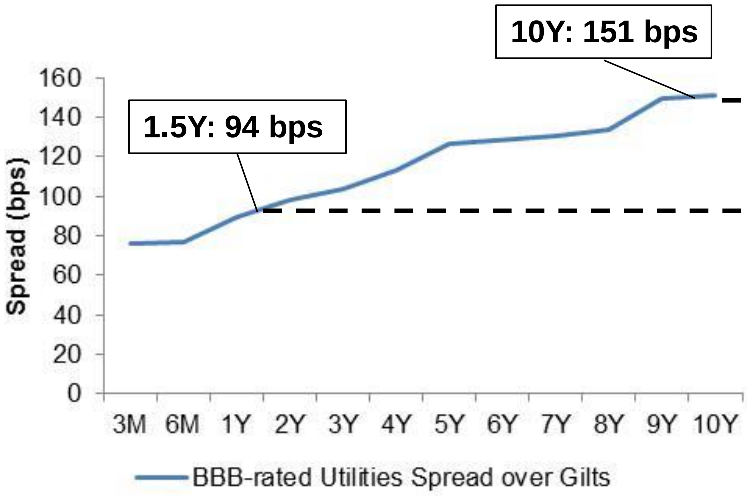
As explained in our June 2015 cost of capital report[62], spreads for both PNGL and comparator bonds taper as the bonds approach maturity. As a result of tapering in the spreads over time, the observed premium for PNGL's bond relative to the comparators will also taper to zero at maturity. The effect of tapering on spreads is evident from the upward sloping term structure of credit spreads (see Figure 6). Bond investors require a lower credit spread the lower the remaining tenor to maturity to compensate for risk, which explains why spreads for shorter maturities are lower than for longer maturities.

Since our June 2015 cost of capital report, NERA have undertaken further work to quantify the tapering effect and derive the PNGL premium. We have quantified the effect of tapering from the term structure of credit spreads, and used this estimate to adjust UR's premium of 40 bps. UR's

[62] "*Appendix A - PNGL Cost of Capital for GD17*" of PNGL's "*GD17 Rate of return paper*" submitted to UR in June 2015

premium is based on a period where the remaining tenor is 1.5 years, whereas in fact we expect PNGL tenor at issuance to be much longer. Taking the ratio of the spreads on 1.5 and 10 year BBB bonds of 1.6 (=151 bps/94bps), and applying this to UR's premium of 40 bps, we derive a premium of 64 bps, and we have adjusted our cost of debt estimate for our revised estimate[63].

This estimate is similar to our own estimate of PNGL premium of 69 bps based on the period prior to the PNG12 Draft Determination, selected to avoid the effect of tapering.



Sources: NERA analysis of Bloomberg data

***Figure 6 -** We draw on term structure of credit spreads to estimate the tapering effect, and to adjust UR's PNGL premium*

UR does not allow for the cost of carry, and unnecessarily deflates all COD adjustments

UR allowed for a transaction cost of 30 bps which is close to PNGL's actual transaction costs incurred on its current bond. However, UR provides no allowance for the fact that PNGL also needs to maintain a back-stop facility to fund capex, which imposes a cost even when the funds are undrawn, as well as facilities to provide liquidity to support its BBB credit rating, as well as additional liquidity to back-stop the expected refinancing of the bond. NERA consider that these costs support a total adjustment of at least 40 bps rather than the 30 bps allowed by UR.

Finally, we note that UR deflated the various adjustments to the allowed cost of debt (e.g. forward rate adjustment, PNGL premium, transaction costs etc.) with inflation to derive the real cost of debt which is unnecessary and understates the real cost of debt.

3.1.3.1 Cost of Debt Mechanism

In its draft determination, UR questioned its ability to set appropriate cost of debt allowances for PNGL and firmus which reflect what would be an efficient market based cost of debt given the scale and timing of their refinancing in uncertain market conditions. To address this issue, UR proposed to

[63] NERA adopt a 10Y tenor as this is consistent with the tenor of the constituent bonds in the iBoxx 10Y+ corporate financial index which UR uses to set its proposed ex-ante allowance for new debt costs.

implement a cost of debt sharing mechanism with an 80%:20% split between pass-through to customers and retained by PNGL and firmus[64].

PNGL engaged NERA to review UR's proposed approach, and to propose an alternative approach. Below, we summarise our key concerns with UR's approach, and our proposed alternative. In Appendix 3, we attach NERA's technical report.

Our Concerns with UR's Approach

First, UR's approach is without precedent: GB regulators have always set an ex ante cost of debt allowance, or in the case of Ofgem, set the cost of debt allowance based on a benchmark cost of debt index in order to provide incentives to minimise costs. UR's proposed approach is more akin to cost-pass through regulation than incentive-based, and is likely to lead to higher costs to customers. Second, UR's approach to measuring actual debt costs will be costly and complex, and creates regulatory risk. Third, UR needs to establish a clear set of rules for calculating new debt costs at the true-up, and how it will resolve any dispute. So far, UR has provided no details.

The Established Regulatory Solution

Ofwat developed a simple cost of debt mechanism for the Thames Tideway Tunnel to address the same issues faced by UR at GD17, namely how to set an efficient cost allowance in uncertain market conditions. The mechanism updates the allowed return in line with observed changes in the market cost of debt, drawing on an established market index. Such a mechanism has the following clear advantages:

- Addresses UR's key concern of forecasting error, driven by uncertainty about future interest rates.
- Preserves the power of incentive-based regulation.
- Recognises only (market-based) efficient debt costs and therefore ensures customers do not pay for inefficiently incurred costs.
- Is a simple mechanism based on precedent which relies on a small number of inputs and the need for one single adjustment, minimising regulatory costs and scope for disagreement.
- Can easily be applied across the NI gas industry.

In NERA's report, we explain how the mechanism would work in practice for PNGL.

Next Steps

We have met with UR to present our proposed approach to trueing-up the cost of debt allowance based on an efficiency benchmark. We would welcome further discussions with UR in order to understand and resolve any remaining concerns, in the expectation that we can agree to an efficient benchmark approach in time for the final determination.

[64] Paragraphs 10.7-10.9 of the consultation

3.2 CONNECTION INCENTIVE

This section discusses PNGL's concerns with UR's draft determination for Advertising and Market Development ("**AMD**") allowances available under the OO connection incentive.

3.2.1 INTRODUCTION

Both UR[65] and the NI Executive[66] recognise that the economic, social, health and environmental benefits emanating from the growth of NI's natural gas industry are significant. These benefits can be realised by extending the natural gas network to new areas, and by maximising potential further development within existing Licensed Areas.

UR and PNGL are both committed to the growth of NI's natural gas industry. PNGL has virtually completed the rollout of the natural gas network across its Licensed Area. As at 31 December 2015, PNGL had made gas available to c.313,000 properties within its Licensed Area, of which c.192,000 (61%) have been connected to the network. Whilst a huge amount has been done to date, the OO market remains the lowest in terms of overall penetration, c.48%, and therefore provides the greatest opportunity for growth in the utilisation of natural gas - over 100,000 properties are still to be connected.

Sustained levels of marketing activity during the GD17 period and beyond are critical to establishing natural gas as the fuel of choice in PNGL's Licensed Area. We would therefore welcome a strong incentive to connect customers, providing the incentive mechanism is well-designed and calibrated to achieve an appropriate risk and reward balance, based on an appropriate and achievable target level of connection growth. Unfortunately, UR's current proposals fail to deliver this, as:

i. The OO connection targets proposed by UR are unrealistic and are not achievable under current and forecast market conditions; and

ii. The allowances available under the mechanism are insufficient to allow PNGL to grow the market at this stage in its lifecycle.

Both concerns are equally important and <u>both must be addressed</u> by UR in reaching its final determination. UR's current proposals are insufficient to allow PNGL to grow the market. UR is signalling that there will be limited support for developing OO connections in PNGL's Licensed Area in GD17 and beyond. UR's message will have a negative impact on the wider natural gas industry, from installers (converting homes to natural gas) to retailers (providing natural gas appliances).

[65] http://www.uregni.gov.uk/news/utility_regulator_approves_gas_network_extension_to_east_down
[66] "*The concept of a gas extension to East Down has been subject to a positive economic appraisal by DETI in 2012 and endorsement from the NI Executive in January 2013*." See, for example, http://www.uregni.gov.uk/uploads/publications/2015-10-15_Consultation_Notice_to_Extend_the_Licence_Area_and_Modify_Licence_of_PNGL_-_East_Down.pdf

The "*Advertising & Market Development (OO Properties)*" expenditures proposed by PNGL[67] are the direct costs that we will incur to develop OO connections across GD17. PNGL was not given sufficient opportunity to engage with UR on UR's current proposals prior to the publication of the draft determination. We expressed our concerns with UR's approach to allowing AMD costs when the mechanism was introduced at PNGL12 and again when UR expanded the scope of the allowance in GD14. Despite the fundamental weaknesses of the mechanism the actual allowances available during PNGL12 and GD14 were "in and around" the costs PNGL forecast (and did spend) on AMD. **However, PNGL's concerns with the mechanism are of increased importance for the GD17 period as UR's proposed allowances for GD17 are considerably less that than the costs PNGL forecast will be required to achieve UR's target connections.**

For the avoidance of doubt, reducing target connections to a more realistic value (i.e. PNGL's average forecast connections of c.4,300 per annum (including East Down[68])) will still not, under UR's proposed mechanism, provide PNGL with sufficient resources to achieve this; PNGL estimate that if the connections target is reduced to c.4,300 per annum, the allowances available under UR's proposed mechanism will still be c.£6.6m short (or £1.1m per annum) of the costs required to achieve the reduced target connections. Further detail is provided in 3.2.3.2.

We also remain concerned with the detailed cost allocation approaches UR has taken for subsuming indirect costs under the connection incentive mechanism (i.e. costs which are not marginal). Furthermore, the majority of indirect costs proposed by UR to be reallocated into the mechanism are *core utility costs* that PNGL will require to operate the network, regardless of the volume of OO connections achieved. These costs must be removed from the mechanism before any attempt is made to calculate the allowances available for OO connections. PNGL provides specific comments on this cost allocation and the incentive properties of UR's proposals in section 3.2.3.4.

Given the shared objective to expand the industry, the design of the regulatory framework should provide PNGL with appropriate incentives to connect customers. Those incentives must be strong enough to encourage connection growth in an economic and co-ordinated manner while ensuring risk is shared appropriately between the company and customers. As with any regulatory incentive mechanism, the connections target and the penalty/reward parameters have to be carefully calibrated in order to achieve the desired effect. UR's current proposals fail to deliver this.

PNGL's detailed concerns with UR's proposed connection incentive are provided in:

- Section 3.2.2 - Connection Targets; and
- Section 3.2.3 - Allowances available under the mechanism.

[67] row 32 of worksheet "*3.0 Opex Summary*" of PNGL's GD17 BPT submission

[68] PNGL's September 2015 GD17 submission forecast 4,000 OO connections per annum excluding East Down

3.2.2 CONNECTION TARGETS

3.2.2.1 The OO connection targets proposed by UR for the GD17 period are unrealistic and are not achievable by PNGL under current and forecast market conditions

Table 16 details the OO connection targets proposed by UR for each year of the GD17 control and the OO connections forecast by PNGL:

	2017	2018	2019	2020	2021	2022	Total
UR Draft Determination (incl. East Down)	**5,800**	**5,650**	**5,500**	**5,350**	**5,200**	**4,900**	**32,400**
PNGL Submission (excl. East Down)	4,000	4,000	4,000	4,000	4,000	4,000	**24,000**
PNGL Submission (East Down)	145	145	238	433	452	428	**1,840**
PNGL Total	**4,145**	**4,145**	**4,238**	**4,433**	**4,452**	**4,428**	**25,840**
Difference (%)	**1,655** (40%)	**1,505** (36%)	**1,262** (30%)	**917** (21%)	**748** (17%)	**472** (11%)	**6,560** (25%)

***Table 16** - OO Connections*

UR's proposed target for OO connections for the GD17 period is too high. Overall UR's target is 25% higher than PNGL's forecast. At the same time UR has proposed to reduce the level of allowance available to achieve this higher connections target, both relative to GD14 and relative to the level of costs currently being incurred by PNGL to deliver connections in its Licensed Area. PNGL forecast that, based on achieving 4,300 OO connections each year during GD17, it will receive c.£5.1m allowances under the OO incentive mechanism; c.£5.5m less than if PNGL achieved UR's target OO connections (see Table 17). It should be noted that this deficit relates only to the allowance proposed by UR. As described in section 3.2.3.2, PNGL believe that much higher allowances are required.

	2017	2018	2019	2020	2021	2022	Total
UR's Target Connections	5,800	5,650	5,500	5,350	5,200	4,900	**32,400**
Target Allowance	£2,137,300	£1,968,460	£1,842,500	£1,684,715	£1,567,800	£1,378,860	**£10,579,635**
PNGL's Forecast Connections	4,145	4,145	4,238	4,433	4,452	4,428	**25,840**
Forecast Allowance	£704,464	£714,398	£796,598	£932,992	£966,867	£1,010,881	**£5,126,200**
Difference	**£1,432,836**	**£1,254,062**	**£1,045,902**	**£751,723**	**£600,933**	**£367,979**	**£5,453,435**

***Table 17** - Comparison of Forecast Allowances with Target Allowances*

3.2.2.1.1 Historical Connections Performance

In Table 51 in the consultation UR highlights PNGL's history of outperformance on OO connections relative to targets set in PNGL12 and GD14. In the *"GD17 Owner Occupied Connections"* paper submitted to UR in June 2015 and again in meetings with UR on 5 February 2016 and on 12 May 2016, PNGL provided UR with detailed evidence exploring the key drivers that have contributed to the higher than average levels of interest and numbers of homeowners connecting to the natural gas network in PNGL's Licensed Area during PNGL12 and GD14. PNGL also explained in detail why it expects performance in this sector to return to a normal and predictable level of c.4,000 OO connections (excluding East Down) across GD17. PNGL demonstrated the factors that affect the level of new connections across the GD17 period and the impact the trend of falling connections across GD14 will have on OO connection targets across GD17. A summary of the detailed information presented to UR is provided below.

A graphical representation of the issues influencing OO connection numbers from 2009 to the start of the GD17 period is shown in Figure 7.

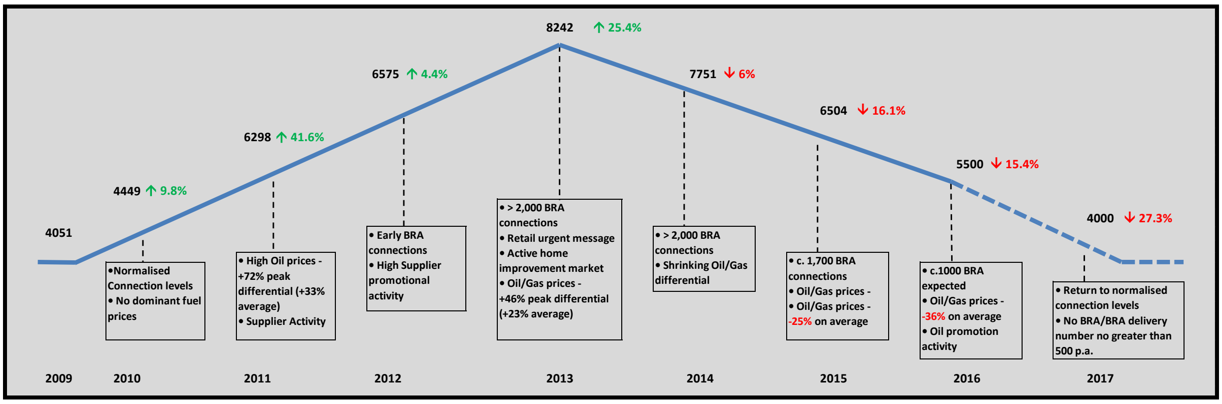


Figure 7 *- Issues influencing OO connection numbers 2009 to 2017*

In the four years prior to 2010, PNGL achieved normalised levels of OO connections of c.4,000 per annum. From 2011 to 2014 PNGL achieved unforeseen levels of OO connections as a direct consequence of the following unique external factors:

i. <u>Introduction of supply competition and promotional activity from gas suppliers</u>
   Following the introduction of domestic supply competition in the PNGL Licensed Area, NI gas supply companies engaged in high levels of promotional activity (e.g. TV adverts) that positively raised the profile of natural gas. These new promotional activities equated to new streams of advertising and promotion of natural gas, at no additional cost to PNGL, which lead to additional connections between 2011 and 2013.

   From 2014 onwards the level of promotional activity performed by domestic gas suppliers has significantly fallen and currently shows no indication of returning to pre-2014 levels.

ii. <u>High price of oil</u>

   UR notes that:

   "while there is likely to be some connection between oil/gas price differential and connections there is no evidence here that the link is the primary driver for growth in the gas industry".[69]

[69] Paragraph 6.221 of the consultation

We do not disagree with this statement in times when the price differential is small; price will not be a primary driver. However, we believe the key driver is unusually high or unusually low price differentials.

At times of high or rising oil prices, discussions surrounding prices either in the media or when consumers feel it most - i.e. when they order 900 litres of oil - create ideal conditions for a customer to consider an alternative form of heating. These are typically consumers who have had the aspiration to install natural gas for some time but the cost of installation has been a barrier and their central heating system is functioning to a satisfactory level.

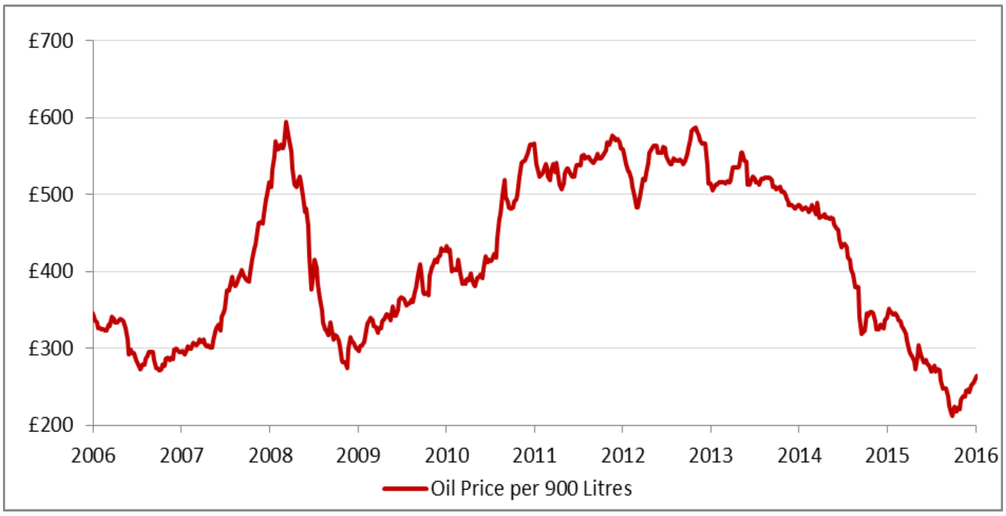


Figure 8 *- Oil price (per 900 litres) vs OO connections*

At times of high oil prices, as experienced from 2011 to 2014 (see Figure 8), householders start to make decisions based not only on the aspiration for a more convenient fuel but also based on the economics of switching to a fuel that is, at that time, priced significantly lower than their existing fuel. The impact of switching to a significantly lower priced fuel, combined with the increased efficiencies of a new boiler can be an attractive proposal for those basing their decision on an economic payback.

In contrast, at times of lower oil prices, as has been experienced since late 2014, you lose both the tranche of potential customers that was driven primarily by economic savings and an additional percentage of potential customers that although typically motivated by the benefits of natural gas, their urgency to proceed is diluted by the fact that they are currently experiencing 'good value' from their existing fuel type.

Householders using home heating oil are not typically aware of the price differential between the two fuel types. What they are however astutely aware of is the current price of their existing fuel and recent movements in it. Generally householders' knowledge on pricing is not based on the dollars per barrel or price per kWh, but instead on the price per 900 litres when ordered from their local distributor.

It will the price per 900 litres that will influence the customer driven primarily by economic consideration to either progress their interest in an alternative fuel (at times of higher oil prices) or to delay any decision to change fuel type (at times of lower oil prices).

In October 2014 oil prices fell below the price of natural gas for the first time since October 2009. Oil prices are currently at the lowest they have been in over 10 years and show no indication of significant increase.

The sustained high price of home heating oil experienced between 2011 and 2014 was hugely influential in the unforeseen levels of OO connections experienced between 2011 and 2014.

iii. Boiler Replacement Allowance

Between 2010 and 2012 PNGL obtained c.1,100 OO connections from government initiatives (e.g. NISEP, Warm Homes) each year.

The Boiler Replacement Allowance ("**BRA**") was introduced in 2012 to support and encourage homeowners to upgrade their 15 year old plus central heating boilers. Under the scheme eligible homeowners were able to avail of £500 / £1,000 grants to assist with the cost of converting their homes to natural gas. PNGL saw the opportunity to promote the scheme, which very quickly became the most successful and time limited campaign it has ever adopted.

Figure 9 demonstrates the impact of government heating schemes (including the BRA) on PNGL's OO connections:

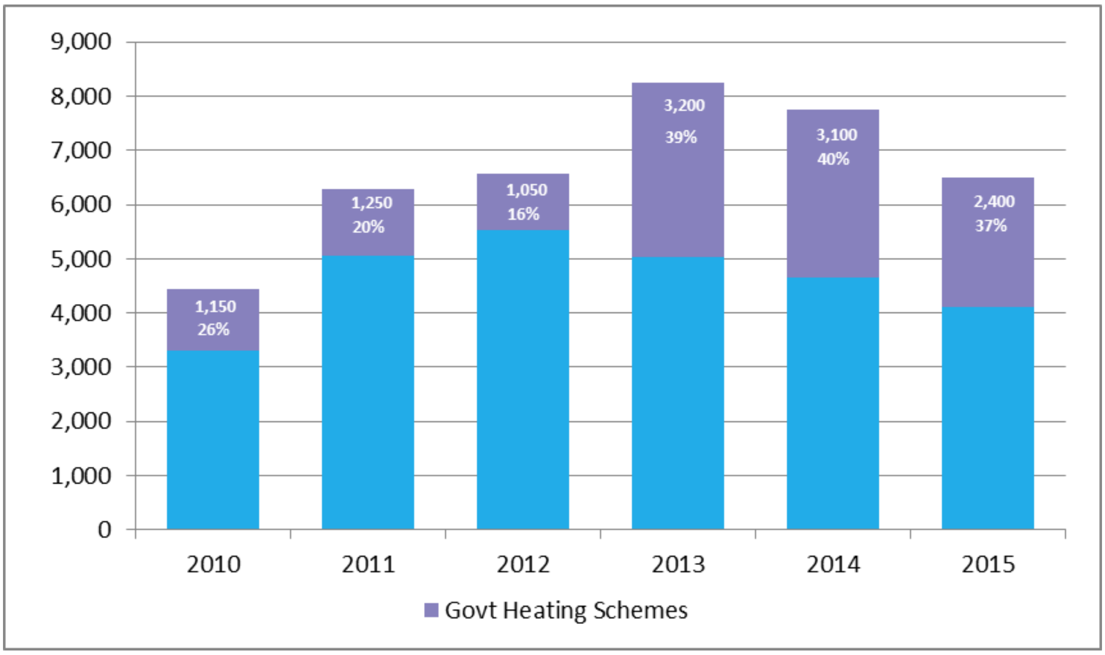


***Figure 9** - PNGL OO connection numbers with government heating schemes*

The introduction of the BRA was the biggest factor that explained PNGL's unforeseen connections between 2011 and 2014. In 2013 and 2014 the scheme was responsible for connecting over 2,000 additional customers to the gas network each year.

The BRA is scheduled to end on in March 2017 (i.e. 3 months into the GD17 period) and PNGL has no knowledge of the introduction of an equivalent scheme that could have a material impact on OO connections.

In 2015 PNGL achieved c.2,400 OO connections from government schemes, of which c.1,600 were under the BRA. It is anticipated that PNGL will continue to obtain c.800 OO connections per annum from ongoing government initiatives (i.e. similar to the level obtained in 2015) during the GD17 period.

PNGL has no control over the introduction of future government funded schemes, similar to the BRA, which may generate increased levels of OO connections (i.e. over and above the typical c.800 connections per annum from the ongoing social initiatives e.g. Affordable Warmth).

The OO connections target for the GD17 period must <u>not</u> be set assuming an equivalent scheme to the BRA is introduced. Furthermore, even if an equivalent scheme is introduced, it is unlikely to have a material impact on connection numbers as the government grants available under the BRA were so generous that property owners eligible for the BRA have either (i) already connected; or (ii) are unlikely to connect.

iv. <u>Collapse of the housing market and subsequent performance of the home improvement market</u>

The collapse of the housing market following the recent economic downturn encouraged homeowners to invest in home improvements (including conversion to natural gas) rather than buying and selling property. The subsequent revival of the housing market from 2014 has reduced this incentive for property owners to invest in major home improvements, which is reflected in PNGL's decreasing OO connections.

3.2.2.1.2 GD17 Horizon

As outlined in section 3.2.2.1.1, the four factors that explain PNGL's unforeseen OO connections performance between 2011 and 2014 are not applicable to the GD17 period. In particular, the current 10 year low in the oil price and the end of the BRA will negatively impact on OO connections. Furthermore during the GD17 period PNGL will be targeting OO properties that will have had natural gas available for an average of 15 years and to date have not been sufficiently persuaded to connect. At the start of the GD17 period, c.50% of the OO properties in PNGL's Licensed Area, where gas is available, will be connected to the PNGL network.

Sales Appointments and OO Connection Numbers

Figure 10 charts PNGL's actual rolling OO connections for the period 2008- Q1 2016 and our forecast OO connections up until the start of the GD17 period. The number of new OO connections has been reducing each year. The decline in OO connections is exacerbated as the BRA has brought forward connections where their boiler would have been typically replaced later.

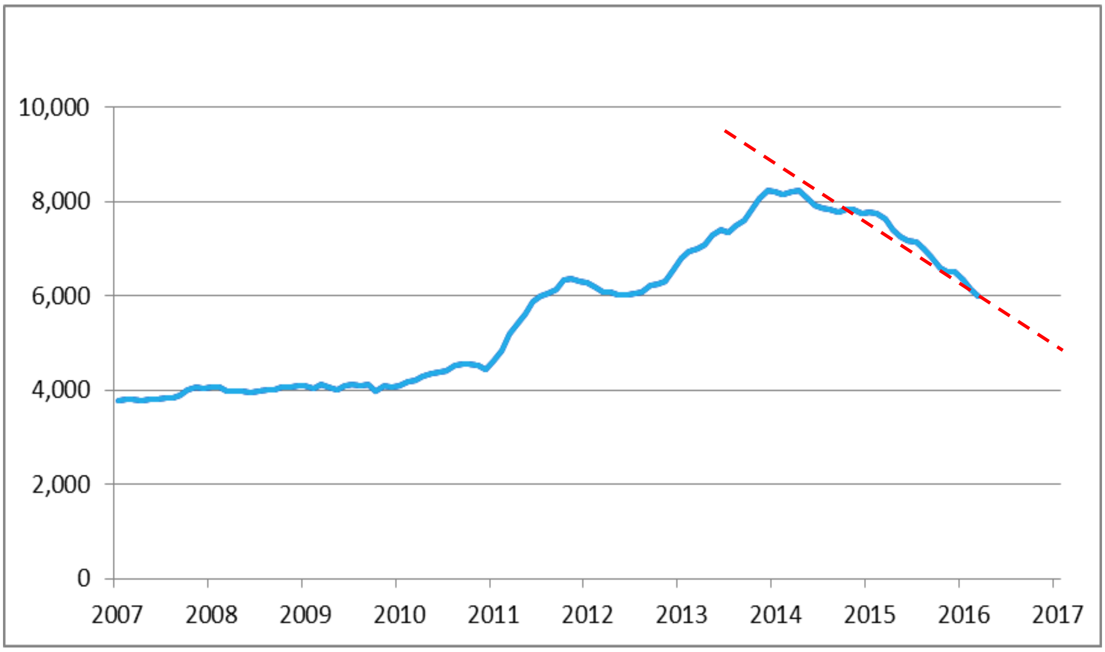


Figure 10 - PNGL's 12 month rolling OO connections

Figure 11 demonstrates the correlation between PNGL sales activity and the level of OO connections achieved:

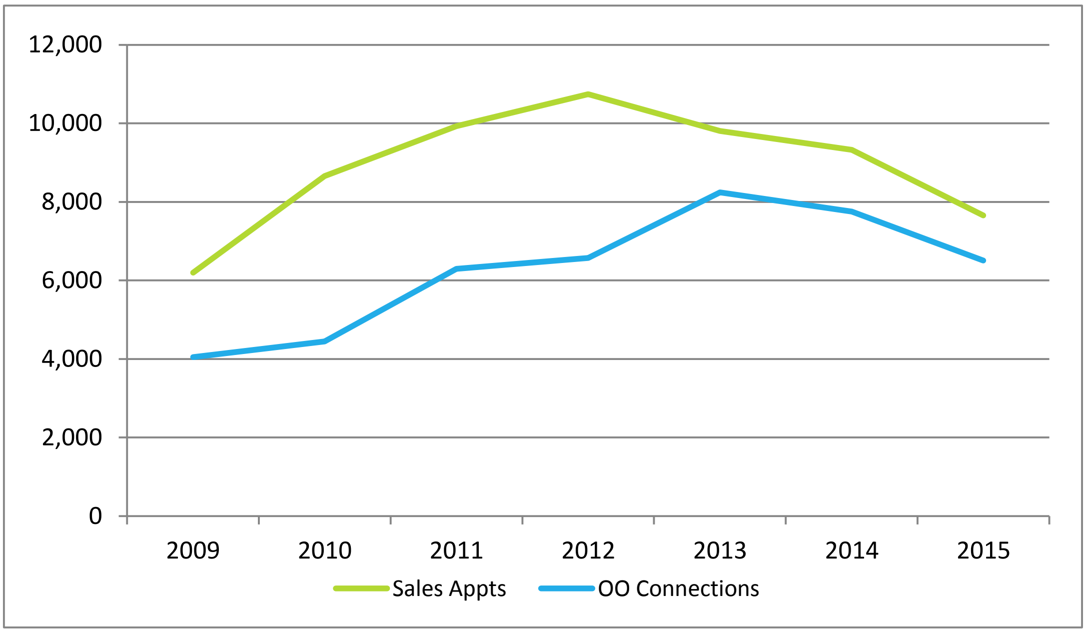


***Figure 11** - Sales appointments compared with OO connection numbers*

In recent years (2013 to 2015) PNGL has achieved a conversion rate in excess of 80% from sales appointments. Figure 12 demonstrates that the volume of sales appointments PNGL have been able to arrange is falling, despite the increased levels of self-generated appointments (see section

3.2.3.4.2). This will influence the level of connections that can be achieved. PNGL's actual data to March 2016 suggests that this trend has continued into 2016.

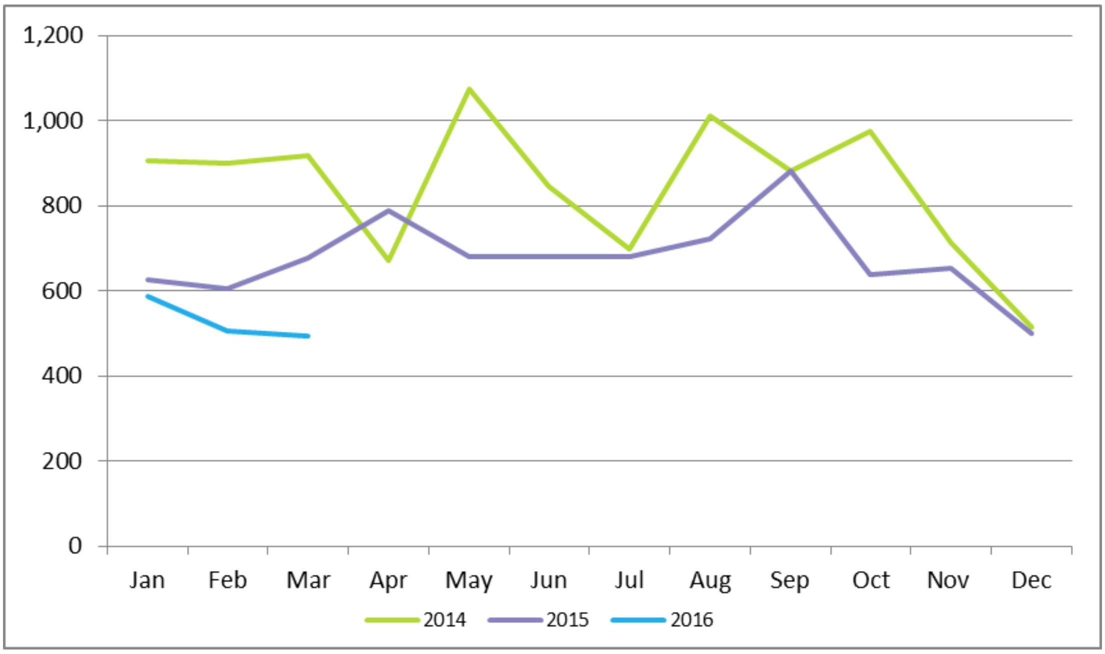


Figure 12 *- PNGL sales appointments 2014 to 2016*

The volume of sales appointment attended in Q1 2016 has fallen by c.17% compared with the same period in 2015.

Figure 13 provides information on the actual OO connections achieved from 2014 to 2016:

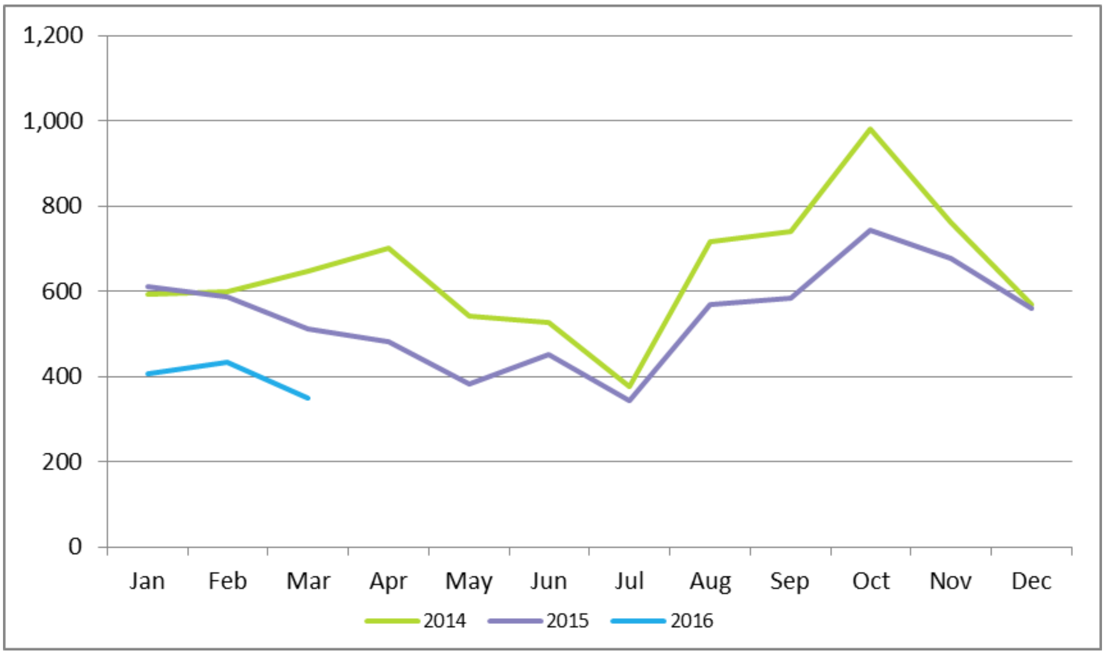


Figure 13 *- PNGL OO connection numbers 2014 to 2016*

The volume of OO connections achieved in Q1 2016 has fallen by c.31% compared with the same period in 2015. As part of our GD17 submission, PNGL forecast OO connections numbers of 5,500 for

2016. **However, connections to the end of March 2016 suggest our actual 2016 OO connections may be closer to 4,500.**

PNGL forecast c.4,300 OO connections per annum during the GD17 period. This connection rate can only be achieved if continued levels of AMD spend are made available.

Prior to the publication of the draft determination, PNGL outlined to UR that its outperformance in PNGL12 and GD14 was the direct result of unforeseen unique market conditions. Consumers also benefited from bringing on of additional revenues earlier. PNGL also explained in detail why it expects performance in this sector to return to a normal and predictable level of c.4,000 OO connections across GD17 (excluding East Down). UR has not demonstrated that it has engaged with this evidence at all, or provided any reason to suggest that PNGL's analysis can be dismissed.

To achieve an appropriate balance of risk and reward, UR must base its connections target on a reasonable assessment of the evidence available to it to understand how many connections PNGL is likely to be able to achieve (c.4,300 per annum). No information of any substance has been provided by UR to support its position on the connections target. The use of the average OO connection level over the previous 15 years is not appropriate when considering current market conditions.

PNGL note UR's proposals to reduce the annual OO connections target each year (i.e. from 5,800 in 2017 to 4,900 in 2022) and to reduce the incentive allowance per connection each year (i.e. from £550 in 2017 to £420 in 2022). However, as we believe PNGL will be facing the same market conditions in relation to generating OO connections in each year of the GD17 period, we request that UR sets a flat profile for OO connection targets and allowances across the entire period (e.g. 4,300 per annum).

3.2.3 ALLOWANCES AVAILABLE UNDER THE MECHANISM

PNGL has the following concerns with the allowances available under UR's proposed mechanism[70]:

3.2.3.1 Allowances available under the OO connection incentive mechanism bear no relation to the actual costs PNGL have incurred in the past or are likely to incur in the GD17 period

The mechanism proposed by UR to develop allowances for AMD for OO connections takes no consideration of the actual AMD costs PNGL have incurred over the previous 20 years or are likely to incur in the GD17 period. This is in stark contrast to the remainder of the allowances in the price control that are assessed based on actual costs incurred.

The "*Advertising & Market Development (OO Properties)*"expenditures proposed by PNGL[71] are the direct costs that we will incur to develop OO connections across GD17 – namely advertising,

[70] These concerns were discussed with UR at a meeting on 12 May 2016

[71] Row 32 of worksheet "*3.0 Opex Summary*" of PNGL's GD17 BPT submission

marketing and incentives costs as well as salary and associated costs of the following direct sales personnel[72]:

- One Domestic Sales Manager - 100% allocation
- Seven Energy Advisors - 100% allocation
- One Business Development Manager - 85% allocation
- Corporate Affairs (one Communications Manager, one Marketing Manager and two Marketing Assistants) - 35% allocation

These direct costs have been ignored by UR through the use of the mechanism.

As outlined by UR[73] the connection incentive *"is unique to NI and was created due to initial difficulties in driving gas connections as the public had limited experience of the fuel."*

UR's rationale is no longer applicable. PNGL has 20 years' experience of operating and developing the natural gas market in NI and has detailed information on the actual AMD costs incurred to grow the OO sector.

We expressed our concerns with UR's approach to the mechanism when it was introduced at PNGL12 and again when UR expanded the scope of the allowance in GD14. Despite the fundamental weaknesses of the mechanism the actual allowances available during PNGL12 and GD14 were "in and around" the costs PNGL forecast (and did) spend on AMD. However, the allowances available under the mechanism for GD17 are significantly less than PNGL's forecasted costs. PNGL anticipate a funding gap of more than £900k per annum (£5.6m in total) even if we are able to achieve UR's extremely unrealistic OO connections target. Further information on this funding gap is provided in section 3.2.3.2.

The mechanism to set the allowances available for AMD to encourage OO connections in GD17 should be based on actual costs and forecast activity levels.

3.2.3.2 Allowances available under the OO connection incentive will not provide PNGL with sufficient resources to grow the OO sector

Despite the fact that the NI gas market cannot yet be considered mature[74], UR has proposed to reduce the connection incentive allowance per connection from £570 at GD14[75] (or from £789 at PNGL12[76]) to £420 at GD17, a 26% reduction.

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[72] New Build Sales personnel were incorrectly included in AMD (OO Properties) in our GD17 submission. Further information is provided in section 4.3

[73] Paragraph 6.200 of the consultation

[74] At the start of 2016, only c.48% of the OO properties in the PNGL network area with gas available to them were connected

[75] £540 in 2012 prices (£570 in 2014 prices)

PNGL has 20 years' experience of operating and growing the natural gas market in NI. We have utilised our actual costs to connect OO properties in 2014 to develop a bottom up forecast for the GD17 period.

Figure 14 provides a comparison of the allowances for AMD available to PNGL should we achieve UR's target level of OO connections with an estimate of the costs PNGL forecast we would spend to deliver these.

Even if we were to assume that the level of AMD expenditure can be reduced on a linear basis in relation to the volume of OO connections obtained (see "*Cost (linear)*" line in Figure 14), allowances provided under GD17 would be insufficient. However, in reality the various aspects of AMD costs (namely staff and marketing) would not reduce linearly as their costs are fixed – the "*Cost (adj)*" line in Figure 14 reflects uplifts for fixed costs in these areas.

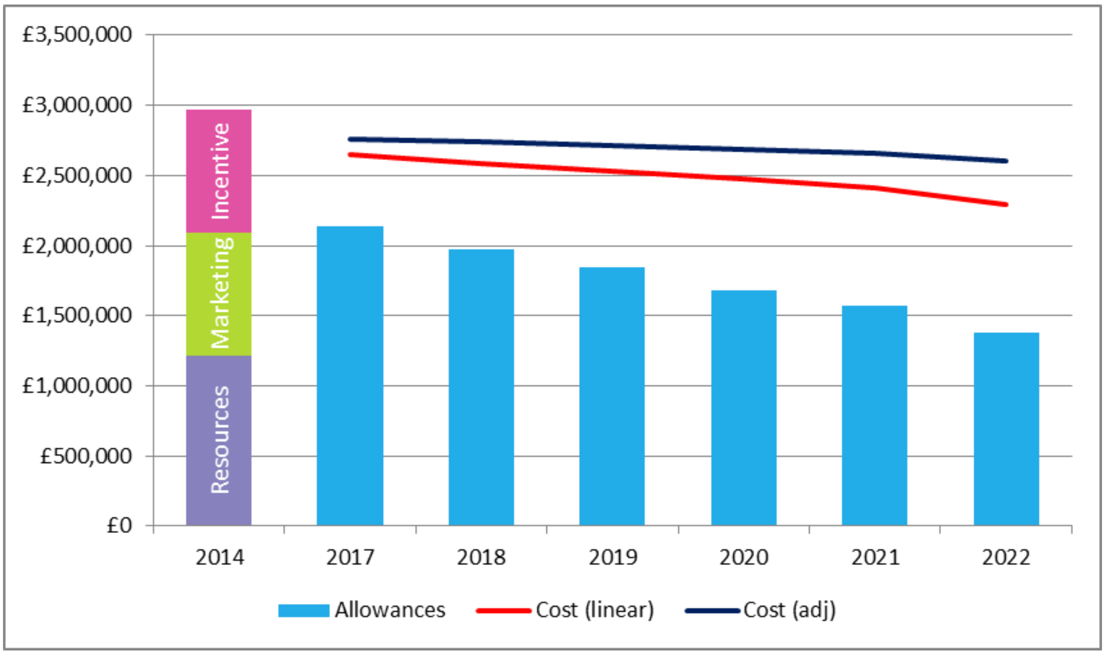

Figure 14 *- OO AMD allowances compared with OO AMD costs (UR's Target Connections)*

Figure 15 demonstrates that even should PNGL achieve UR's targeted level of OO connections there will be a funding gap of c.£5.6m over the GD17 period (or £900k per annum).

[76] £690 in 2010 prices (£789 in 2014 prices)

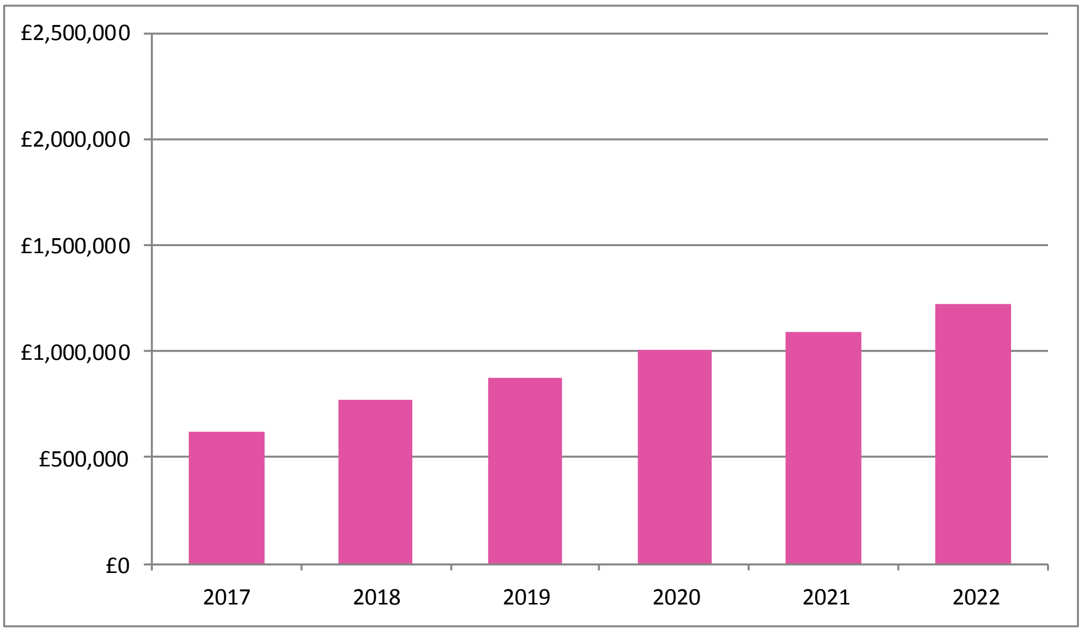

Figure 15 - Funding gap should PNGL achieve UR's targeted level of OO connections

The analysis summarised in Figure 14 and Figure 15 assumes that PNGL achieve the OO connection targets proposed by UR. However, as outlined in our GD17 Business Plan Template ("**BPT**") submission and in our subsequent discussions with UR prior to the publication of the draft determination, PNGL believe an annual OO connections target of c.4,300 (including East Down) is realistically achievable for each year in the GD17 period. Further information on the appropriateness of the OO connections target is provided in section 3.2.2.

PNGL's bottom up analysis of the proposed OO connections allowances available during the GD17 period and related AMD costs required to achieve PNGL's forecast levels of OO connections (i.e. c.4,300 per annum) is provided in Figure 16:

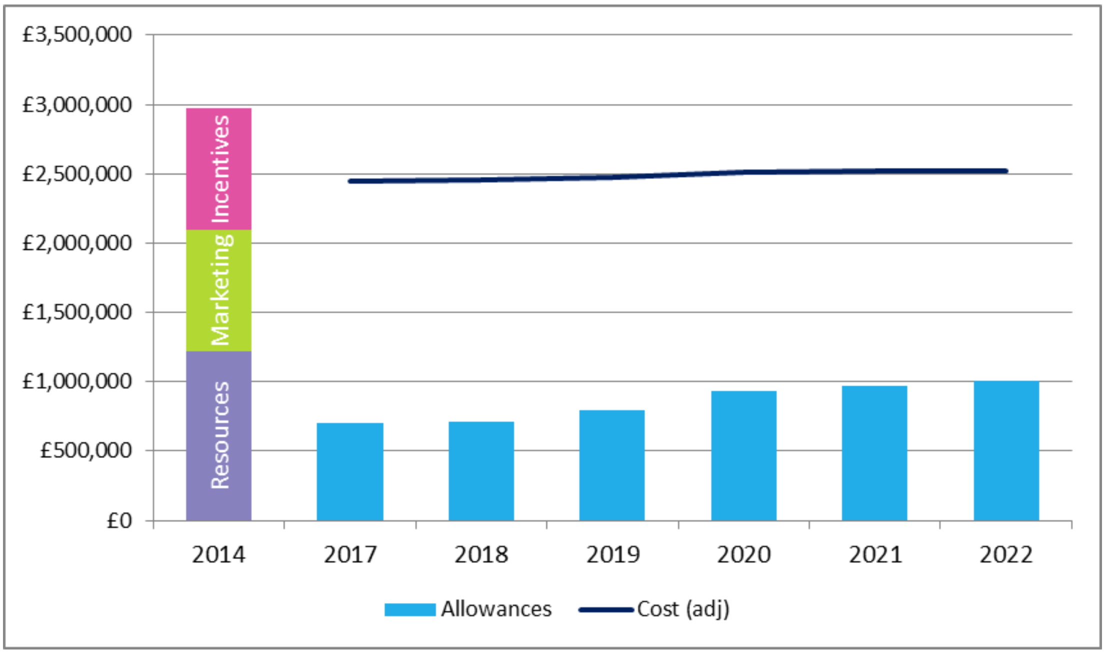

Figure 16 - OO AMD allowances compared with OO AMD costs (Forecast Connections)

Figure 16 demonstrates that the allowances provided under the proposed OO connection incentive mechanism for AMD costs significantly reduce (compared to Figure 14) if PNGL deliver its forecast c.4,300 OO connections per annum. A primary reason for the dramatic fall in allowances is as a consequence of the penalty PNGL will incur under the mechanism for underperformance. Further information on the reward versus penalty elements of the mechanism is provided in section 3.2.3.6.

Figure 17 demonstrates that should PNGL achieve its forecast level of OO connections (i.e. c.4,300 per annum) the funding gap over the GD17 period will increase to c.£9.8m (or £1.6m per annum):

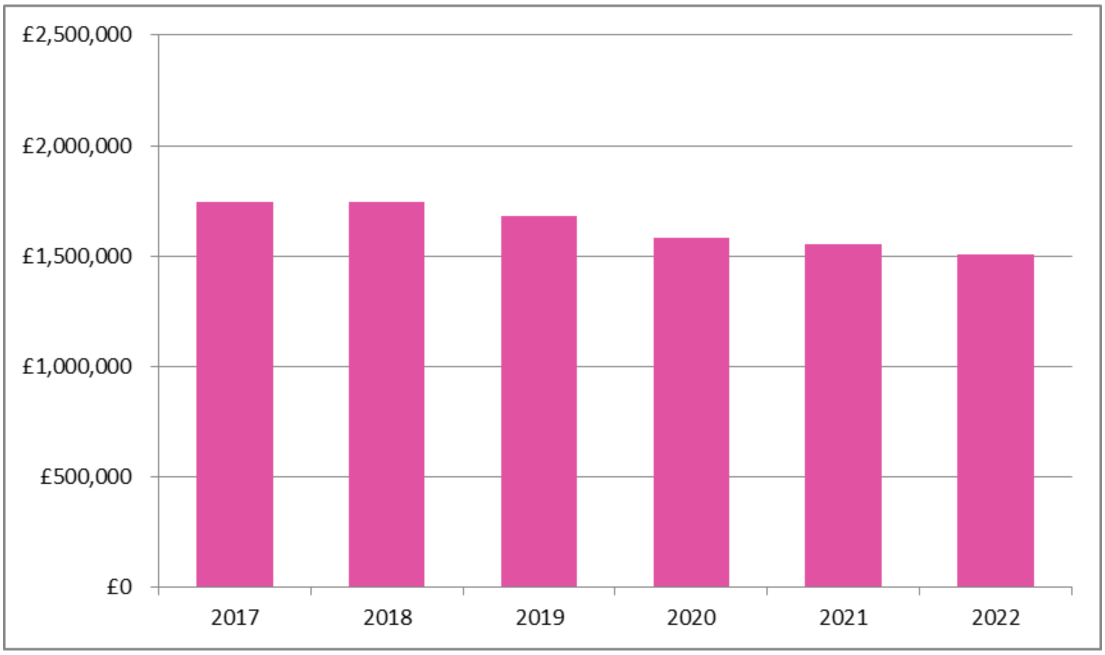

Figure 17 *- Funding gap should PNGL achieve its forecast level of OO connections (i.e. 4,300 per annum)*

Figure 18 and Figure 19 demonstrate that even if UR amends the connections target to c.4,300 per annum, the allowances available under the proposed mechanism will still be c.£6.6m short (or £1.1m per annum) of the costs required to achieve the reduced level of target connections.

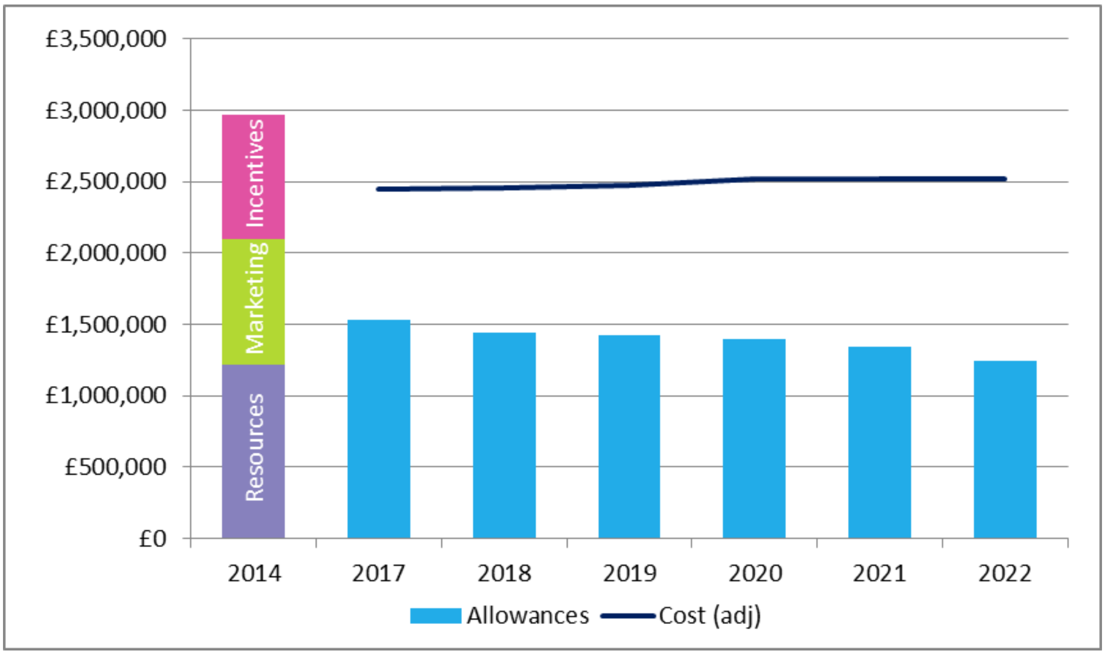

Figure 18 - OO AMD allowances compared with OO AMD costs (Target Connections reduced to 4,300 per annum)

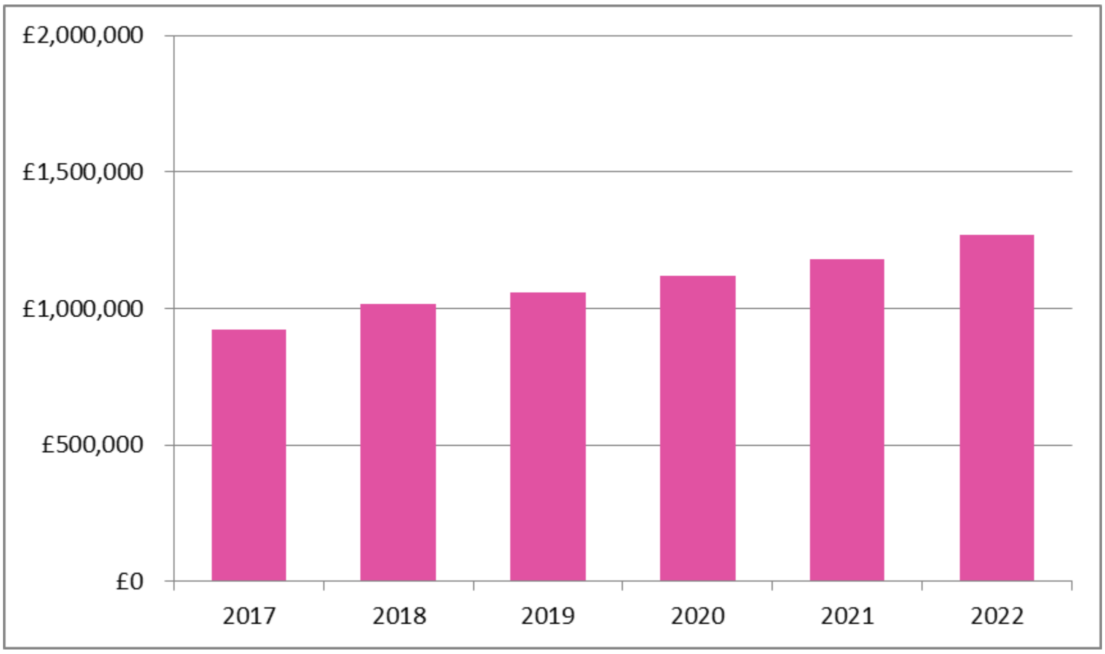

Figure 19 - Funding gap should PNGL achieve revised target level of OO connections (4,300 per annum)

Engaging with and in turn persuading new customers to connect to the natural gas network in the GD17 period will be more challenging than at any other time in PNGL's history. Further information on the specific challenges PNGL will face during GD17 is provided in sections 3.2.2 and 3.2.3.5.

PNGL's AMD expenditure can broadly be broken down into:

- Marketing;
- Incentives; and
- Sales.

Marketing

As with all products, but in particular with items of high capital spend, the natural gas market requires continued marketing spend to build on the aspiration of natural gas and to stimulate connections in future years.

There are many benefits of natural gas and each will have a different appeal. However, as property owners generally convert to natural gas to avail of the aspirational benefits (e.g. instantaneous hot water), PNGL must continue to spend on marketing to inform potential new customers of these benefits. Consumers need to be reminded constantly about the benefits of natural gas so that they remain at the forefront of their minds when they are considering an alternative fuel.

Unlike other commercial organisations who build up a loyal customer base over a period of time and whose marketing efforts concentrate both on new customer acquisition and protecting brand loyalty, PNGL do not have a customer base.

The primary objective of PNGL's marketing strategy is therefore to engage with householders whom to date have not declared an interest in connecting to natural gas.

When developing a marketing campaign, the marketing spend to achieve the most effective response is linked directly to the level of activity required to target PNGL's potential customer base (of c.100,000 properties) as opposed to the connections that may result. As such, PNGL require the same level of marketing activity to connect 4,000 or 6,000 OO customers as they must engage with the same number of potential customers.

It is therefore difficult to understand the logic behind UR's proposal that PNGL enter into the GD17 period with less marketing spend and yet be able to continue to effectively engage with potential customers with the success that we have had to date based on a typical AMD spend of c.£3m per annum.

PNGL have successfully demonstrated an ability to coordinate robust, effective and innovative marketing campaigns that have resulted in both creating strong consumer brand awareness as well as maximising new connections.

We acknowledge that although the relevancy of our message and style in which it is presented can make some campaigns more effective than others, the peaks and troughs in annual connections is largely determined by other influencing market conditions. Further information is provided in section 3.2.2.

PNGL anticipate achieving 4,300 OO connections per annum during the GD17 period. This connection rate can only be achieved if current levels of marketing spend are sustained.

We believe that UR's reduced marketing costs would result in a reduced marketing strategy with less consumer engagement, less 'Phoenix' branding, less direct 'call to actions' and overall a diluted promotion of natural gas. This would result in the OO connections market performing below its potential and creating a downward spiral with the natural gas message getting increasingly lost in the increasingly competitive consumer messaging space.

Furthermore the impact of a reduced marketing spend by PNGL will have a detrimental impact on the investment of the wider natural gas industry.

Incentives

The most typical barrier for homeowners to convert to natural gas is the significant upfront cost; an average gas conversion in NI costs c.£2,400.

PNGL utilise the payment of incentives[77] to tactically increase connection activity, in order to:

i. Act as a motivator for those who have an aspiration to convert to natural gas to take action at that particular time and install natural gas above other competing products and services (e.g. holidays); and

ii. Generate new leads from customers who remain unsure about the benefits of natural gas but like the thought of availing of an incentive.

Products competing for the same consumer spend (e.g. holidays, replacement car or other consumer 'feel good' products) will often have an immediate short term satisfaction associated with them that a boiler replacement will not necessarily compete with.

It is therefore important that those potential customers that identify themselves as being 'interested' are offered every encouragement to make the decision to convert to natural gas. The potential receipt of an incentive payment provides that encouragement.

Creating the aspiration to have natural gas within our base of potential customers is hugely challenging. It is therefore critically important that where we have been successful creating an aspiration, we develop this interest to the purchase stage as often as possible. The payment of incentives has been a key method utilised by PNGL to convert customer interest into actual connections.

[77] Monetary payments to customers to assist alleviate the financial burden of converting their heating systems to natural gas

Incentives do this by:

- Assisting with the financial burden of conversion costs; and

- Introducing urgency to communications and an accelerant to consumers' decisions due to the scheme end dates that are synonymous with any offer period.

<u>Targeted Incentives</u>

It has been our experience that targeting incentives at specific groups is the most efficient way to increase the level of interest and in turn connection levels.

Within the current connection incentive mechanism, PNGL are responsible for determining how AMD costs are effectively targeted i.e. how much is used for incentives and how much is allocated to direct selling/marketing.

If the level of funding available to incentives was to be evenly split across all new OO connections rather than a targeted group (e.g. over 60s) the amount of money available per customer is extremely unlikely to offer adequate incentive to either persuade customers convinced of the benefits of natural gas to convert or in offering financial support to those unable to fund the cost of conversion.

PNGL must therefore introduce incentive campaigns that are capable of targeting those micro markets that we believe will respond positively to effective campaigns, creating an additional level of consumer interest and connection activity.

Three such examples of targeted schemes are:

- '*Saver 60 Scheme'* – The Saver 60 Scheme is an incentive that was introduced in 2015 to target the over 60s. Through PNGL's work with groups such as Age Sector Platform, it became apparent that this sector had disposable income, had an interest in home improvements that added comfort to their homes and were more interested in home improvements that offered long term savings over short term satisfaction;

- '*New Home Owner Grant'* – The Royal Institute of Chartered Surveyors report that the average householder spends £6,000 in home improvements in the first year of owning a property, however not typically on central heating upgrades. This incentive was introduced to elevate the upgrading of a home heating system amongst the competing measures; and

- 0% Finance – The main reason customers who understand the benefits of natural gas do not proceed with installation, is the cost of conversion. This incentive was introduced to allow the householder to spread the cost.

Sales

PNGL has a very experienced Sales team, with robust procedures and processes in place for training and development.

The roles of Domestic Energy Advisors include identifying and engaging with prospective consumers to persuade them that the benefits of natural gas are a worthwhile investment, managing customer expectations and liaising with Engineering to locate domestic service and meters. Their training includes a City & Guild qualification on "energy efficiency in the home". This advice is channelled through an energy audit of a property completed during all appointments with prospective consumers.

Although PNGL's research reports a high level of customer satisfaction with the connection process, due to the number of different elements involved in the process it can appear complex to a new customer. New connecting customers therefore rely on an appropriate level of support from a Domestic Energy Advisor to coordinate the process.

Although those householders who contact PNGL have demonstrated an interest in natural gas, the knowledge they have on the process is very limited; c.80% of householders PNGL visit have yet to contact a Gas Safe registered installer.

Domestic Energy Advisors have two main roles that have an influence on annual OO connections:

a) Attending appointments and both persuading homeowners of the benefits of natural gas and assisting them through the connection process. This includes an explanation of the connection to the network, identifying the most appropriate meter position at the property and meter box type, choosing a gas supplier, introducing gas appliance retail outlets and introducing Gas Safe registered installers; and

b) Identifying new sales prospects through a range of sales generating activity. This includes field canvassing, telesales and outreach events.

The provision of sales resource is vitally important in ensuring the continued high standard of customer service and to ensure connection levels are maximised through the additional leads generated by Domestic Energy Advisors who, without direct stimulation, would not respond to more conventional marketing media.

Conclusion

It is imperative that the mechanism that sets the allowances available for AMD to encourage OO connections in GD17 generates sufficient allowances to cover the costs required to generate the targeted level of OO connections. The current mechanism proposed by UR does not do this. PNGL suggest UR give consideration to simplifying the proposed incentive mechanism. A simplified mechanism gives clearer signals to the company about what the regulator is trying to achieve, simplifies trade-offs, and is more likely to avoid unintended consequences.

3.2.3.3 Weaknesses of the "simple economic test"

In determining the economics of new connections, there is a value to connecting a customer to the network if there is a reasonable expectation that the cost of connecting that customer will be recovered over the economic life of that connection. This provides a cap to the level it is worth spending to attract new customers. This spend may be on investment in infill or it may be through attracting customers through advertising or incentives, or both. UR has proposed utilising a "*simple economic test*" to calculate the value of allowance per connection that should be made available to cover AMD for OO connections in the GD17 period. The same "*simple economic test"* that was utilised in PNGL12 and in GD14 has been proposed for GD17.

PNGL expressed concerns with the "*simple economic test"* when it was introduced at PNGL12 and again when UR expanded the scope of the allowance in GD14. PNGL's concerns remain for GD17 and are now of critical importance as the level of allowance proposed by UR for each OO connection in the GD17 period, as calculated by the "*simple economic test"*, are now significantly below the allowances required to enable PNGL to achieve UR's target level of OO connections. As detailed in section 3.2.3.2, PNGL estimate a shortfall of over c.£900k per annum (£5.6m in total) should PNGL achieve UR's unrealistic OO connection targets and a shortfall of over c.£1.6m per annum (£9.8m in total) should PNGL achieve its forecasted OO connections (c.4,300 per annum).

PNGL has the following issues with the "simple economic test":

i. <u>Arbitrary recovery period</u>

   The recovery period included within the proposed *"simple economic test"* (i.e. 15 years) is entirely subjective, and with only minor amendment, has significant impact on the calculated OO allowance per connection, i.e.

   - *"Recovery Period (Yrs)"* - if amended from 15 years to 20 years the allowance increases from £420 to £790 per OO connection.

   When challenged on the proposed recovery period, UR acknowledged that the recovery period is subjective.

   Note: The arbitrary recovery period of 15 years is in conflict with the current depreciation period for services of 35 years. In fact UR is suggesting[78] depreciating services over 40 years. It is therefore far from clear why the connection incentive is based on a recovery period of 15 years.

ii. <u>Marginal analysis utilised to calculate allowances are required to cover indirect fixed costs</u>

   The *"simple economic test"* proposed by UR (to calculate the allowance for AMD) is based on the marginal analysis of additional growth from new OO connections over a defined recovery period.

[78] Paragraph 10.74 of the consultation

The "*simple economic test"* assesses the revenue reasonably anticipated to be recovered by a new OO connection over a defined period (15 years) relative to the marginal costs of the connection (namely service, meter, infill and AMD costs).

PNGL will recover costs over the average life of assets (up to 40 years). UR's analysis assumes marginal costs of connection are recovered over 15 years. Therefore, the remaining costs PNGL incur to develop and run the network (e.g. mains construction, and normal utility costs such as maintenance, office costs, manpower) must be recovered in the remaining period (i.e. up to 25 years).

A major flaw with the OO incentive mechanism proposed to be utilised by UR is that allowances are set based on marginal costs but are expected to cover both marginal and fixed costs (namely *"shared corporate overheads"* - the majority of which are *core utility costs*, that are reallocated into the mechanism). The inclusion of *core utility costs* to be covered by the allowances in the mechanism is the equivalent of the penalty on PNGL. Further information on the *core utility costs* included within the mechanism is provided in section 3.2.3.4.

The "*simple economic test"*, which is a key constituent of the mechanism utilised to set the allowances available for AMD, is not fit for purpose. A mechanism that utilises a mixture of methodologies (i.e. whereby marginal analysis is expected to cover more than marginal costs) and that includes arbitrary values, is fundamentally flawed and should not be utilised by UR to set PNGL's GD17 AMD allowances. It is imperative that a different approach (e.g. assessment based on actual costs) is introduced by UR to assess the allowances to be provided to PNGL for AMD during the GD17 period. *Core utility costs* should be allocated to the core allowances of the business and not form part of the AMD mechanism.

3.2.3.4 Costs included in the OO connections mechanism are not marginal

We expressed our concerns with UR's approach to allowing AMD costs when the mechanism was introduced at PNGL12 and again when UR expanded the scope of the allowance in GD14. The "*Advertising & Market Development (OO Properties)*" expenditures proposed by PNGL in its GD17 submission[79] are the <u>direct</u> costs that we will incur to develop OO connections across GD17, i.e.

- advertising, marketing and PR;
- incentives;
- costs attributable to employees involved with the OO sector e.g. salaries, travel and subsistence and car allowance; and
- marginal costs such as postage, stationary, billing and entertainment.

[79] row 32 of worksheet "*3.0 Opex Summary*" of PNGL's GD17 BPT submission

PNGL accepts that some opex may be attributable to OO connections and to an extent could be seen as marginal e.g. postage, stationary and billing. PNGL also accepts that salary and non-salary costs (e.g. travel and subsistence and car allowance) attributable to employees involved with the OO sector should be considered when determining the allowance for OO connections.

However, we remain concerned with the detailed cost allocation approaches UR has taken for subsuming *core utility costs* ("shared corporate overheads"), costs incurred by PNGL to run the network which are required regardless of the level of OO connections, under the connection incentive mechanism i.e. costs which are not marginal. In addition, some costs that are attributable to OO connections are fixed. These costs cannot be treated on a marginal variable basis and as such the allowance granted by UR must acknowledge this and provide the appropriate fixed element of costs within the mechanism.

The costs proposed by UR to be replaced by the OO connection incentive are:

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

The only elements of AMD costs that are truly marginal are incentives, which based on our historical performance are estimated at £189 per OO connection[80]. The remaining AMD costs are not marginal (i.e. are fixed and will be required to be incurred by PNGL regardless of the actual volumes of OO connections achieved):

- Advertising, Marketing & PR;
- OO Sales Related Staff; and
- Shared corporate overheads (including the Business Development Director).

3.2.3.4.1 Advertising, Marketing & PR

PNGL has 20 years' experience of growing the natural gas network in NI and has detailed information on actual costs incurred on advertising, marketing and PR and its impact on OO connections. Based on our knowledge and past experience, we estimate that the minimum spend PNGL must incur in order to run marketing campaigns to achieve our forecasted level of connections (i.e. c.4,300 connections per annum) is c.£850k per annum.

The costs associated with the effective targeting of c.100,000 potential new customers in a set geographic area remain consistent and fixed regardless of actual connections achieved (i.e. c.£850k

[80] Incentives are not paid on connections generated via government heating initiatives (e.g. BRA, NISEP etc.)

advertising, marketing and PR spend is required regardless if PNGL achieve 4,000 or 6,000 OO connections per annum in the GD17 period).

It is not possible to identify, segment and in turn target a specific unconnected householder audience in an already small geographic area whilst using the most effective, tested forms of communication such as:

- Radio
- Outdoor Activity (e.g. billboards)
- Television
- Local Press
- Door Drop
- Bus Wraps
- Competitions

PNGL's marketing strategy's primary objective is to maximise the amount of new connections to the natural gas network. The costs associated with this activity are linked not to connections achieved but to the size of the audience to which the campaign is reaching and the communication channels being utilised. PNGL's campaigns have sought to maximise new leads generation whilst protecting the long term development of natural gas locally.

PNGL have found that it is neither effective, efficient nor economical to focus marketing activity on targeted groups of potential new customers whether based on geographical locations or customer demographics.

For example, door drop communication (leaflet drops) has consistently demonstrated that it is an effective media for engaging with unconnected householders.

PNGL typically use the services of Royal Mail who distribute this communication across its Licensed Area at a cost of £28,000 per campaign leaflet (c.26 pence per unconnected home).

An alternative method would be to distribute this via a targeted direct marketing campaign – targeting those householders that are not currently connected to the gas network. The costs associated with this sort of targeted activity are much more expensive at £47,000 (c.43 pence per unconnected home).

3.2.3.4.2 OO Sales Related Staff

The costs associated with direct selling remain fixed regardless of the level of connections achieved. PNGL require the same OO sales personnel whether we achieve 4,000 or 6,000 connections. In the same way the OO sales personnel did not rise whenever PNGL achieved its peak connections, neither will it fall as we return to normalised connection levels.

When favourable market conditions exist, particularly to the extent they did between 2012 and 2015 (see section 3.2.2.1.1), the level of response to marketing campaigns is significantly higher than average. The sales resource is therefore primarily focused on responding to high levels of customer enquiries and in turn facilitating their smooth connection to the network. Although some self-generated[81] appointments are still made by the sales resource at times of high interest, it is much less than average. At times when market conditions do not support the same level of customer initiated appointments, OO sales personnel are tasked with both providing a sales service to a lower level of leads as well as self-generating new potential customers for new connections. For example in 2013, 14% of appointments were self-generated by the sales team compared with 38% in Q1 2016.

This level of self-generated activity is required to maximise connection levels in the absence of a more responsive audience. Thus the sales resource required remains consistent albeit focused on different activities.

3.2.3.4.3 Shared Corporate Overheads

The majority of costs included within *"shared corporate overheads"* proposed by UR to be reallocated into the OO connections mechanism are *core utility costs* that are required by PNGL to continue to run the network regardless of the level of OO connections achieved. These costs are neither marginal in nature nor are they attributable to OO connections.

UR's allocation of *core utility costs* into the mechanism is inappropriate. Setting allowances to cover fixed core utility costs on the basis of the volume of OO connections cannot be justified and unnecessarily increases the downside risk faced by the business. All *core utility costs* must be excluded from the mechanism.

Core utility costs can be split into staff costs and non-staff costs:

Staff Costs

UR considers the following corporate support personnel are required to manage OO connections:

- Customer Management;
- CEO & Group Management;
- Audit, Finance & Regulation; and
- Procurement.

[81] Self-generated appointments are householder appointments generated as a direct result of field based sales personnel canvassing activity such as door knocking, telesales or referral

As detailed below, the level of corporate support identified for the OO sales function is excessive and out of proportion with the time devoted to this area of activity.

Customer Management

UR has proposed that c.£370k relating to Customer Management staff costs is reallocated to the connection incentive mechanism each year; an allocation of c.42.5%. In GD14 the equivalent allocation was c.£170k per annum and was based on the allocation of 7.66 FTEs.

Discussions with UR held following the publication of the draft determination confirmed that UR is again proposing to include the costs of 7.66 Customer Management FTEs into the mechanism for GD17. This equates to £185k per annum not £370k per annum. UR should amend its proposal accordingly.

PNGL's analysis of the activities currently performed by the FTEs included within Customer Management calculates that only 6.05 FTEs (rather than URs proposed 7.66 FTEs as was applied during GD14) are involved in OO connections. A breakdown of the Customer Management FTEs involved in OO connections activities is provided in Table 18:

Role	FTEs relevant for OO connections
Connections	2.55
Outbound Call Handlers	1.0
Customer Management System	0.5
Incentives Management	1.0
Inbound Call Handlers	1.0
Total	**6.05**

Table 18 *- Customer Management personnel involved in OO connections activities to OO Connections*

UR proposed reallocation of Customer Management costs into the mechanism is therefore overstated by an additional £40k per annum.

CEO & Group Management

UR has proposed that 15% of the staff costs associated with the CEO and the Finance Director and 50% of the Business Development Director are reallocated into the OO connection incentive mechanism. PNGL did not include these FTEs within its "*Advertising & Market Development (OO Properties)*" cost proposals given that these roles:

i. are required regardless of the level of OO connections;

ii. have already and will continue to will evolve to reflect the changing focus of PNGL as the business develops; and

iii. more accurately sit within the costs collated under "*CEO & Group Management*" in the GD17 BPT.

There is no rational basis for including the CEO and the Finance Director within the OO connection incentive mechanism. These roles are fundamental to the business irrespective of the level of OO connections. To suggest that combined they devote one and a half days a week to OO connections in a business as complex as PNGL is simply not correct. UR's proposal is unjustified and inappropriately applies downside risk onto PNGL. The CEO and the Finance Director should be excluded from the proposed connection incentive mechanism.

There is no plausible rationale to suggest that 50% of the Business Development Director's time is devoted to OO connections. UR's proposal is unjustified and inappropriately applies downside risk onto PNGL. The PNGL Business Development Director has numerous core business responsibilities of which sales (including OO sales) are just one. PNGL estimate that 27.5% of the Business Development Director's time is allocated to supporting OO sales activities. A breakdown of time the Business Development Director currently spends on each activity is provided in Table 19:

Area	Time %	OO Sales
Sales (OO)	**15%**	**Yes**
Sales (non-OO)	5%	No
Corporate Responsibility	10%	No
Marketing and Brand Mgt (OO)	**10%**	**Yes**
Marketing and Brand Mgt (non-OO)	10%	No
Trade Development	10%	No
HR	10%	No
Customer Service (OO)	**2.5%**	**Yes**
Customer Service (non-OO)	7.5%	No
Contracts and Procurement	10%	No
Communications	10%	No

Table 19 *- A breakdown of the Business Development Director's time*

The remainder of the costs of the Business Development Director (i.e. the remaining 72.5%) are *core utility costs* that are required to continue to run the PNGL network regardless of the volume of OO connections achieved.

PNGL have only one Business Development Director and regardless of the volume of OO connections achieved during the price control period, PNGL will be required to maintain as a minimum one Business Development Director and associated costs.

Audit, Finance & Regulation

The level of support from Audit, Finance & Regulation staff to the OO sales function is equally disproportionate:

- Revenue Protection is not a function of OO sales. These FTEs should be excluded from the proposed connection incentive mechanism;

- Regulation and Business Planning are not a function of OO sales and are required irrespective of the levels of connections being undertaken. These FTEs should be excluded from the mechanism; and

- PNGL would suggest that UR uses a **3.5% allocation** to OO activities for the **Finance team**; this represents the 0.5 FTE within the finance team that is involved in OO activities (i.e. 0.5 FTE out of the 13.5 FTEs allocated to Audit, Finance & Regulation).

PNGL believe UR's current proposal for Audit, Finance & Regulation costs to be included within the OO connection incentive mechanism is overstated by c.£60k per annum.

<u>Procurement</u>

UR has proposed that 15% of staff costs associated with procurement is included in the OO incentives mechanism. The main activities performed by personnel within procurement are:

- Setting Procurement Policy and Procedure, drafting Invitation to Tender documents, managing and administering formal tender processes (both non-EU and EU related). In connection with the latter, ensuring compliance of Company practices with current Utilities Contract Regulations including the preparation and submission of all notices, documentation requirements and statistical reports;

- Drafting of contract documentation, including negotiation of bespoke terms with specialist Service Providers, where applicable. Resolution of any pre and post contract issues associated with contractual matters that may arise; and

- Maintaining all Company executed Contracts and associated documentation on "Procon" System and advising department Managers of contractual administrative requirements.

The performance of these activities is fundamental to the business irrespective of the level of OO connections. Staff costs for procurement personnel are *core utility costs* and should be excluded entirely from the OO incentives mechanism.

Staff Costs Summary

UR's apportionment of corporate FTEs is therefore overstated. Furthermore the relationship between these FTEs and OO connections is not a linear e.g. the CEO is fundamental to the business even if PNGL does not connect any more OO properties. These FTEs will be required irrespective of the level of new connections to allow PNGL to operate and maintain the network and serve its existing customer base. This should be reflected in UR's connection incentives mechanism.

Non-Staff Costs

The following opex cost lines which UR considers are required to assist manage OO connections, are not variable in line with OO connections:

Cost Line	AMD Allocation as proposed by UR
Property Management	15% of building rates
IT & Telecoms	15% of non-staff costs
Insurance	15% of car and buildings insurance
HR	15% of professional and legal costs

Table 20 *- Non-Staff AMD Allocations*

All of the non-staff costs proposed by UR to be reallocated into the mechanism are *core utility costs* required by PNGL to continue the operational of the network. These costs will be required by PNGL regardless of the volume of OO connections achieved.

For example,

- The costs of managing and maintaining PNGL's office space at Airport Road West are fixed *core utility costs* (i.e. a marginal change in FTEs does not reduce the building rates or insurance on Airport Road West); and

- The FTEs directly involved with OO connections are field-based and do not have a defined office space. Their demand on the facilities of Airport Road West is significantly less than office-based staff e.g. they do not require access to IT (they do not have a computer or landline) and other related facilities.

Non-Staff Costs Summary

UR's proposed reallocation of non-staff costs into the mechanism is inappropriate and loads downside risk onto PNGL. These costs will be incurred irrespective of the level of new connections to allow PNGL to operate and maintain the network and serve its existing customer base. This should be reflected in UR's connection incentives mechanism.

3.2.3.5 The reduction of allowances through the concept of "non-additionality"

The OO connection incentive mechanism proposed by UR to establish the allowances available for AMD in the GD17 period continues to include the concept of "*non-additionality*". UR suggests that there "*will be a certain number of OO connections that would occur anyway without any direct* *marketing or selling to these customers. We describe these connections as non-additional*'[82] and that '*no allowance will be applicable for these customers*"[83].

In the PNGL12 and GD14 price controls the volume of *"non-additional"* connections was set at 25% of target OO connections. However, UR now proposes to increase the volume for the GD17 period to 33% of target OO connections as "*the awareness of gas has increased since 2014 in the PNGL area*"[84].

It should also be noted that in the GD14 Final Determination UR proposed to cut the overall allowances for AMD for OO connections by 50% in the GD17 period[85], which was contested by PNGL "*as entirely arbitrary and unjustifiable*"[86].

The percentage of OO connections proposed to be classed as "*non-additional*" is entirety arbitrary. PNGL has not been provided with any supporting documentation or evidence of analysis to justify the application of 25% as "*non-additional*" or for the proposed increase to 33% for GD17. PNGL are not aware of any material increase in the awareness of gas since 2014 and as stated in section 3.2.2 consumers' awareness of natural gas only becomes relevant when other circumstances provide householders with a stimulant to consider upgrading their heating system (e.g. high oil prices).

PNGL disagree entirely with the concept of "*non-additionality*" and its application to reduce allowances available in the GD17 period for the following reasons:

a) <u>PNGL's marketing strategy does not have the ability to focus marketing budget on only householders who are likely to need *"direct marketing or selling"*.</u>

   In any given year it is not possible for PNGL to be able to identify which potential new customers (from a prospect base of more than 100,000 householders) are more likely than others to connect. The marketing spend required to achieve the most effective response is linked directly to the level of activity that is required to target the prospect base as opposed to the connections (or new sales) that may come as a result of the campaign. As such, PNGL require the same level of marketing activity to connect 4,000 or 6,000 OO customers per annum.

   It is therefore illogical to remove marketing and direct selling costs to customers that would *'occur anyway'*, if indeed such connections existed.

   For example, in the last number of years PNGL has demonstrated the effective use of outdoor advertising using a range of sites that include billboards, bus shelters and bus wraps in prominent locations spread across the Greater Belfast area. This is a fixed cost of advertising that is designed to get a message in front of a mass audience. PNGL are not able to target a selected audience with this type of marketing (i.e. we cannot restrict / select who views a billboard).

[82] Paragraph 6.233 of the consultation
[83] Paragraph 6.233 of the consultation
[84] Paragraph 6.237 of the consultation
[85] GD14 Final Determination paragraph 5.52
[86] Page 11 of PNGL's response to UR's GD14 draft determination, September 2013

The types of media used by PNGL are consistent with those used by advertisers whose objective it is to communicate with a broad prospect base. The inability to specifically target a certain customer base is consistent with all main uses of media (radio, door drop distribution, social media, and local press).

b) We do not agree that a material number of OO connections would occur anyway without any direct marketing or selling.

Whilst we accept that there may be some customers who will request to connect to natural gas without stimulation during the GD17 period, as they have already been persuaded of the benefits of natural gas, these customers will be small in number. The draft determination suggests that c.1,800 customers per annum will contact PNGL directly to request to connect without any stimulation, assistance or encouragement from PNGL. This is simply incorrect and not in line with our experience or understanding of the marketplace.

We recognise that in any given year there is an amount of householders whose circumstances mean that they are more likely to be influenced by PNGL marketing activity than other householders. This does not mean they do not require direct marketing or selling activity. Indeed it is these people that ultimately our marketing activity is targeted at.

Instead, campaign messages attempt to capture the attention of those householders most likely to have an interest in natural gas and develop their interest to one of purchase mentality.

It should also be noted that even if PNGL did not incur any AMD expenditure, any OO connections that PNGL achieve will still require resources and hence allowances to process the connection i.e. to:

- Receive the contact from the customer (either by telephone call centre, in writing or email). This role in the new connection process is currently performed by Customer Management personnel;
- Explain to the customers the implications of natural gas. This role in the new connection process is currently performed by direct OO sales personnel;
- Identify the most appropriate meter position at the property and meter box type. This role in the new connection process is currently performed by direct OO sales personnel; and
- Plan the connection. This role in the new connection process is currently performed by Customer Management personnel.

It is therefore inappropriate that "*non-additionality*" is applied to these costs.

As discussed with UR at a meeting on 12 May 2016, in the absence of any AMD expenditure, PNGL would require additional allowances to continue to manage the new connection process. For example, engineering personnel would be required to perform site visits to identify most appropriate meter positions and meter box types.

c) PNGL believe that engaging with and in turn persuading new customers through AMD expenditure to connect to the natural gas network in the GD17 period will be more challenging than at any other time in our recent history

Specific challenges include:

- On average householders who remain unconnected from 2017 will typically have had gas available to them for an average of 15 years.

  The fact that these householders have not connected to date and that the vast majority of them have not "registered their interest" with PNGL suggests that these householders have not been sufficiently persuaded by the natural gas message and will need continued stimulation;

- Remaining potential customers will include householders who have already replaced their oil boiler with another oil boiler – since gas was available (i.e. they have already actively chosen not to convert their heating system to natural gas). These householders will be more unlikely to change in the medium term as a result of having a "newer" oil boiler and have already demonstrated their preference for oil as a fuel. They will therefore require significant persuasion in the future;

- Unconnected householders have had access in recent years to the most generous suite of government schemes offering grant support and to date have not been persuaded. For example, the BRA scheme offers financial support of up to £1,000 to householders upgrading to a natural gas boiler. Given the fact that householders have had the opportunity to change system and avail of the BRA and as yet not done so, demonstrates just how challenging changing their mind-set is likely to be in the future;

- UR is signalling that there will be no further development of the natural gas network in PNGL's Licensed Area without financial contribution from consumers. As such, our ability to obtain additional OO connections from early adopters is eliminated. Further information is provided in section 3.4;

- In the last 24 months, coinciding with the significant drop in retail home heating oil prices, the oil industry both collectively and individually have increasingly engaged in their own promotional messages. The messaging supporting these campaigns has primarily been focused on the fact that home heating oil is cheaper than natural gas.

  This very direct messaging has both an immediate impact on interest levels of current unconnected householders and also creates a certain stigma and uncertainty amongst householders regarding the economic benefits of switching to natural gas; and

- Accelerated connections as a result of short term market stimulants experienced between 2012 and 2014 (i.e. high oil price, BRA scheme etc.) has reduced the prospect base for potential new customers in GD17.

Impact of Non-Additionality on the Allowance Available

UR has proposed that the OO connection incentive available to PNGL decreases from £570[87] per connection in GD14 (or indeed from £789 in PNGL12[88]) to £420 in 2022, see Table 21:

Year	PNGL12	GD14	2017	2018	2019	2020	2021	2022
Allowance (per OO connection)	£789	£570	£550	£520	£500	£470	£450	£420

Table 21 *- UR's OO Connection Incentive (per connection)*

However, with the inclusion of "*non-additionality*", the actual allowances available to PNGL for each OO connection will reduce to £281 in 2022.

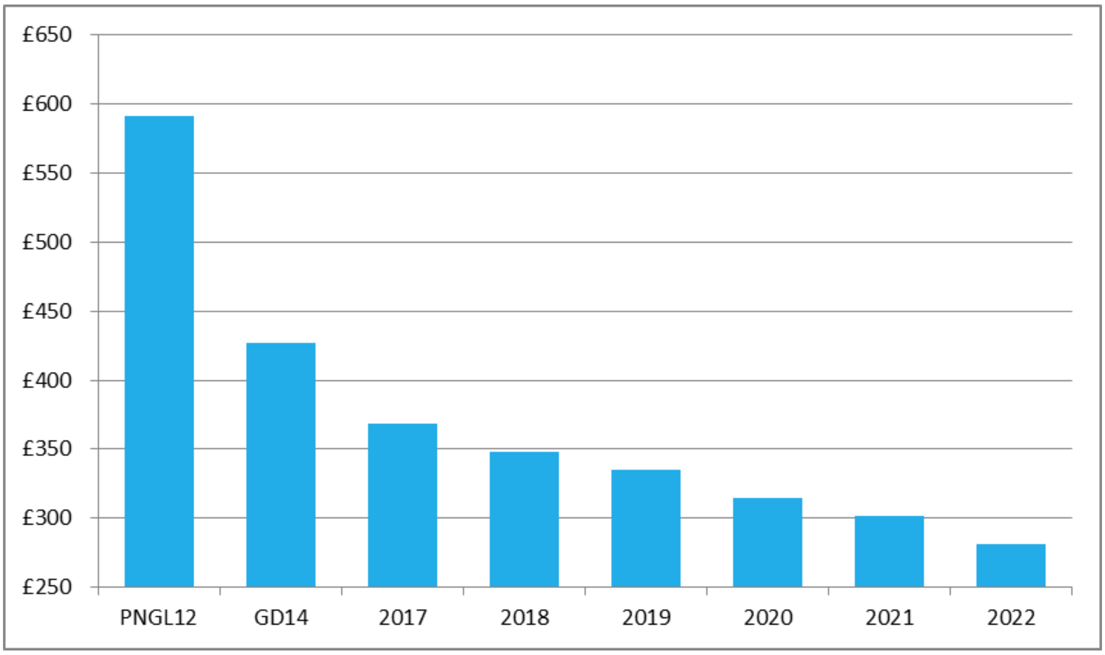

Figure 20 *– UR's OO Connection Incentive – post "non-additionality" adjustment (PNGL12 to 2022)*

For the reasons already outlined in section 3.2.3.2, PNGL believe that it is inappropriate that the allowances available for AMD under GD17 decrease. Furthermore there are compelling arguments for why the allowances available should increase rather than decrease if UR wants the PNGL network to continue to grow (e.g. it is more challenging than at any time in our recent history to persuade property owners to convert to natural gas).

The implication of UR's proposals is that PNGL will have an allowance for GD17 which is 35% below the GD14 allowance (and 52% below the PNGL12 allowance) at a time when the opportunity to connect consumers from new areas where natural gas has just been made available, is falling. This makes it all the more challenging for PNGL to continue to increase its customer base as PNGL will

[87] £540 in 2012 prices
[88] £690 in 2010 prices

have to encourage more consumers within existing areas to convert. As each of these areas becomes more mature, the early adopters who were persuaded to convert to natural gas have already connected. In many cases those who are still to convert have not yet been convinced of the benefits and require significantly more time and effort to be educated and persuaded to make the switch. PNGL would urge UR to reconsider its proposals in light of its primary objective to promote the development and maintenance of an efficient, economic and co-ordinated gas industry in NI. Appropriate levels of investment in AMD are fundamental to PNGL's ability to deliver further growth in the NI gas market.

There is no basis for the proposal that no allowance be given for the first 33% of owner occupied connections:

- Any costs incurred below the economic level on AMD should rightly be considered economic. Given this, it is far from clear why UR should propose that no allowance be given for the first 33% of OO connections. PNGL has not been provided with any supporting documentation or evidence of analysis from UR to justify its "*non-additionality*" proposals;

- The cost of AMD varies by consumer. The historical allowances for sales-related costs reflected the required average cost per customer across all of the customers that switched to natural gas (i.e. those who required a higher stimulus and those who would still have switched with a lower incentive). If UR proposes to disallow costs for customers who need less incentive to switch, it must recognise that the average cost required to attract the remaining customers is higher;

- PNGL has no control over the number of people who view a billboard / advertisement, read a door drop etc. Given this, it is far from clear why UR should propose that no allowance be given for the first 33% of OO connections;

- UR's statement that "*…PNGL could in theory avoid any sales-related costs to connect such ["non-additional"] customers…*"[89] is incorrect. PNGL's costs for connecting OO are largely fixed e.g. PNGL must have a Customer Services department to answer the call from a customer wishing to connect and in the majority of cases a sales representative will be required to visit the customer to talk them through the connection process and to answer any technical product related questions. It is therefore illogical that "*non-additionality*" should be applied to indirect costs (i.e. "*shared corporate overheads"*);

- As noted previously, it is getting progressively more difficult to persuade a consumer to switch to natural gas. PNGL would contend that those customers who could genuinely be considered to be in the "*non-additional*" category are minimal and equate to only a few percent of the overall connections generated each year. This recognises the circumstances PNGL faces, including the fact that despite natural gas having been in its Licensed Area for many years and the awareness of natural gas having increased since 1996, more than 50% of

[89] Paragraph 6.233 of the consultation

OO properties with gas available to them in the PNGL network area have yet to make the switch. UR's proposed 33% "*non-additionality"* is unreasonable and unjustifiable; and

- PNGL has not asked for nor has UR granted any mobilisation costs for bringing natural gas to East Down. PNGL will provide East Down with access to the natural gas network for the first time during GD17. On this basis PNGL contend that "*non-additionality*" should not be applied to East Down in line with UR's proposal not to apply any "*non-additionality*" to SGN given that natural gas is new to SGN's Licensed Area.

Reducing the value of allowances available to PNGL per connection (i.e. from £789 in PNGL12 to £570 in GD14 and to £420 in 2022) whilst also increasing the volume of "*non-additional*" connections is arbitrarily penalising PNGL. The application of *"non-additionality*" to a price control period that PNGL anticipates to be more challenging than in its recent past to obtain OO connections, is particularly punitive. UR's proposal that no allowance be given for the first 33% of OO connections serves only to magnify the downside risk loaded onto PNGL. The concept of *"non-additionality*" should be removed in its entirety from the GD17 determination.

3.2.3.6 Asymmetric nature of the mechanism for under or over performance

UR has proposed to maintain the same mechanism as was utilised in PNGL12 and GD14 to reward PNGL if we exceed target connections and to penalise PNGL if we fail to achieve the target connections. PNGL has major concerns in relation to the asymmetry of the proposed mechanism in that if PNGL exceeds the target, the connections allowance is only increased for **incremental** connections, whereas if PNGL underperforms the target, the connections allowance is reduced for **all** connections.

A worked example that is based on PNGL's actual and forecast performance during GD14, which clearly demonstrates the asymmetric nature of the mechanism is provided below:

Case Study: Asymmetric Nature of the OO Connections Mechanism

UR set PNGL a target of 6,500 OO connections per year during GD14 (19,500 OO connections in total). Table 22 outlines the allowances available to PNGL should targeted connections be achieved:

Year	Gross Connections	Net Connections [90]	Unit Rate	Total Allowance
2014	6,500	4,875	£540	£2,632,500
2015	6,500	4,875	£540	£2,632,500
2016	6,500	4,875	£540	£2,632,500
Total	**19,500**			**£7,897,500**

***Table 22** - GD14 OO Connections Allowances – Target Connections Achieved*

[90] Excludes non-additional target fixed at 1,625 connections

PNGL's performance during GD14 (including 2016 forecasts) is in line with the overall target connections (i.e. 19,500 OO connections in total) but with c.1,000 additional connections in 2014 and c.1,000 less connections in 2016. However given that the mechanism is asymmetric, PNGL's allowance would be c.£320k less (£2012) than if it had met the target in line with UR's profile, as displayed in Table 23:

Year	Gross Connections	Net Connections [91]	Connections above target		Connections up to target		Total Allowance
			Connections	Unit Rate	Connections	Unit Rate	
2014	7,500	5,875	1,000	£651[92]	6,500	£540	£3,283,269
2015	6,500	4,875	-	-	6,500	£540	£2,632,500
2016	5,500	3,875	-	-	5,500	£429[93]	£1,663,269
Total	**19,500**						**£7,579,038**

Table 23 *- GD14 OO Connections Allowances – Actual Connections Achieved*

In reality PNGL has connected c.1,000 OO properties two years ahead of UR's forecast (i.e. in 2014 instead of 2016). These consumers have been contributing to the costs of the network for two extra years, therefore reducing the overall cost to consumers - c.£320k[94] additional benefit had been achieved by bringing on 1,000 OO properties two years early. Despite this, PNGL has received c.£320k less revenues compared to an outcome where PNGL had in fact met the annual target specified by UR. In short, despite achieving a better outcome for customers (i.e. the same total level of connections, with more customers connected sooner) PNGL is left worse off, and unable to cover c.£320k of the reasonable and efficient costs PNGL has incurred an achieving these early connections.

The example demonstrates the clear distortions in incentives PNGL faces as a result of UR's annual connections target combined with the asymmetric penalties for outperformance vs. underperformance. A c.£320k penalty on PNGL is not therefore an appropriate balance of risk and reward given that PNGL met UR's overall owner OO target in the GD14 period.

Principles of incentive design – lessons from Ofgem

There are two key problems with the AMD mechanism as it is currently specified, when evaluated against best practice incentive design principles:

- First, the AMD mechanism gives distorted/confusing incentive signals and is likely to lead to unintended outcomes; and
- Second, the AMD mechanism results in an overall asymmetric package of incentives.

[91] Excludes non-additional target fixed at 1,625 connections
[92] i.e. 5,875/4,875*£540
[93] i.e. 3,875/4,875*£540
[94] No. connections * consumption (therms per annum) * price * years (= 1,000 * 400tps * £0.4 x 2 years)

We discuss each of these issues below, highlighting where the AMD mechanism contrasts with approaches that have been adopted by Ofgem.

Distorted/confusing incentive signals

Within Ofgem's overall incentive package, there are a range of different types of incentive used to encourage the delivery of any particular output. Some incentives are reputational; some are simply minimum standards required by law; and some have financial rewards/penalties. Ofgem states that it carefully considers what the appropriate incentive mechanism is, given its objectives for any particular output.

> *"Our objective is to create a streamlined and balanced package of outputs and incentives which are clear to DNOs and do not create any perverse incentives. Our intention is that the total incentive package ensures that those DNOs that deliver for consumers earn an attractive rate of return, whereas those that demonstrably do not deliver will earn low returns."*[95]

In general Ofgem is looking to design incentives which are simple and clear; and which limit the prospect of *"perverse incentives"* and unintended outcomes.

In contrast, as illustrated by the example set out above, PNGL's incentives under the AMD mechanism are not clear or simple. This is particularly because UR's AMD mechanism is designed both to cover the costs PNGL requires to achieve connections; and to incentivise PNGL to meet or beat the target connections. In contrast, Ofgem's price controls set an ex ante level of cost allowances which are sufficient to deliver the baseline or target level of outputs. Unlike most incentive mechanisms, therefore, the AMD model is intended to perform the dual function of efficient cost recovery and incentive mechanism.

This difference with normal regulatory practice results in distortions to PNGL's incentives. This is particularly the case as a large share of the costs PNGL must incur to achieve connections are fixed in the short term (i.e. the staff and overheads required to run a marketing department). Given this cost structure, and the fact that connections numbers can fluctuate annually around the target connection level, PNGL could incur reasonable and efficient fixed costs but fail to recover sufficient revenues to cover these efficient costs. This is clearly illustrated by the GD14 outcome.

The design of the AMD mechanism therefore forces PNGL to consider whether it would be less risky simply to halt all marketing and advertising activity, and remove the fixed overhead/staffing costs. In contrast, Ofgem's approach of allowing sufficient ex ante cost allowances to meet output target levels would not result in this distortion.

[95] RIIO-ED1 Strategy Decision (4 March 2013) https://www.ofgem.gov.uk/sites/default/files/docs/2013/02/riioed1decoutputsincentives_0.pdf

Overall asymmetric package of risk

Ofgem (and other regulators like Ofwat) have developed a wide package of incentives, covering both cost efficiency incentives and a range of output targets. This overall incentive package leads to both upside and downside potential. In general Ofgem targets a range of potential equity returns where very well-performing companies can receive upwards of 10% return on equity; while very poor performing companies can receive equity returns at or below the cost of debt. It is clear from the RoRE analysis published by Ofgem for the RIIO price controls that the range of plausible returns is broadly (albeit not exactly) symmetric. GB companies have tended to outperform their price controls overall, and evidence from the first years of the RIIO controls (and from the immediately preceding controls such as DPCR5) shows that companies are actually achieving returns significantly above the allowed cost of equity.

This situation should be contrasted with that of PNGL. We are faced with only one significant output incentive, namely the connection incentive. However, the combination of an unreasonably high annual target, the reallocation of *core utility costs* into the mechanism, exclusion of "non-additional" connections and asymmetric penalties means that PNGL faces an overall package of risk which is skewed to the downside. Further, since PNGL only faces a small set of incentives, the expected downside impact of the AMD mechanism cannot be offset by outperformance elsewhere.

To illustrate this, we have calculated the expected loss PNGL will make during GD17 given the current AMD mechanism design, and our assumptions about the split between fixed and variable costs associated with achieving any given level of connections:

- In 2017, the expected outcomes are as follows:
  - If PNGL achieves the target level of connections (5,800 connections), we expect to incur costs of £2.76m, but only to recover allowances of 2.14m, implying a loss of c.£623k. This is over 4.5% of UR's draft determination allowed opex for 2017; and
  - If PNGL exceeds the current target by 50% (8,700 connections), we expect to only achieve incremental allowances (over the expected costs) of £1.2m. In contrast, if we achieve connections 50% below the target (2,900 connections), we expect to incur losses of £2m (14% of opex allowances for 2017).
- The degree of asymmetry is more stark if UR's 2022 parameters are used:
  - Meeting the 2022 target (4,900 connections) implies a loss of £1.2m;
  - Missing the target by 50% (2,450 connections) implies a loss of £2m; and
  - Even if PNGL beats the target by 50% (7,350 connections), we still expect to incur a loss of over £150k.

The results of this analysis illustrate that the degree of asymmetry is significant, and will have a material effect on our cashflows.

The disparity between the penalty and reward caused by the asymmetry of the mechanism is of particular significance for the GD17 period because of the unrealistic OO connection targets proposed by UR in the draft determination. The asymmetric nature of the penalty included within the mechanism is accentuated when target connections numbers are set too high. Should PNGL achieve forecasted OO connections (i.e. c.4,300 per annum) we will receive c.£5.5m less allowances than if we were able to achieve the target level of OO connections. c.£3.3m (60%) of the lower allowance is attributable to the lower connection volumes (e.g. 4,145 instead of 5,800 for 2017) and the remaining c.£2.2m (40%) is directly attributable to the penalties under the mechanism for under performance.

In GD14 UR restricted (via a cap and collar approach) the unit connections allowance payable if PNGL under/over performed against connection target to +/- 50% of the connection allowance. PNGL welcomes UR's proposal to include this restriction for GD17. **However, PNGL requests that UR gives consideration to adjusting the cap and collar included in the mechanism from a % of connection allowance to set monetary values with a minimum connection target.** For example, a maximum under/over performance reward of +/- £250k per annum provided PNGL achieve a minimum of 3,500 connections per annum.

UR has misunderstood PNGL's concerns in paragraph 6.242 of the consultation. PNGL does not believe that the connection incentive should be calculated over the entire price control period rather than on an annual basis. This would be extremely difficult to manage. PNGL propose that a flat OO connection target is set for GD17 which would take into consideration the fact that OO connections in the Greater Belfast area will be reducing over the period at the same time as the opportunity for OO connections in East Down increases. A flat profile of c.4,300 OO connections per annum is a realistic but challenging target for the GD17 period.

PNGL propose that the mechanism utilised to reward outperformance and penalise for under performance is amended to be symmetric i.e. that it is only the connections from outperformance or underperformance that is subject to the increased / lower allowance. Furthermore, UR should consider adjusting the cap and collar included in the mechanism from a percentage of connection allowance to set monetary values with a minimum connection target.

3.2.4 CONCLUSION

It is imperative that the mechanism utilised to set allowances available for AMD provides PNGL with sufficient resources to grow the natural gas market.

The mechanism proposed by UR is not fit for purpose:

- The OO connection targets proposed by UR are unrealistic and are not achievable under current and forecast market conditions;
- UR's proposals are insufficient to allow PNGL to grow the market:

- UR fails to provide sufficient allowances to achieve its connection targets and takes no consideration of the actual AMD costs PNGL have incurred (over the previous 20 years) or are likely to incur in the GD17 period; and
- UR is signalling that there will be limited support for developing OO connections in PNGL's Licensed Area in GD17 and beyond. UR's message will have a negative impact on the wider natural gas industry, from installers (converting homes to natural gas) to retailers (providing natural gas appliances).

- The "*simple economic test"* is based on an arbitrary recovery period that with only minor amendment, significantly impacts the allowances available;

- The mechanism utilises a mixture of methodologies - allowances are set based on marginal costs but are expected to cover both marginal and *core utility costs* (namely *"shared corporate overheads"* that are reallocated into the mechanism). The inclusion of fixed costs in the mechanism unnecessarily increases the risk faced by PNGL as cost recovery of fixed costs is not certain;

- The concept of "*non-additionality*" is not appropriate for current and forecast market conditions. It is likely to be more difficult during the GD17 period than in the previous price control periods for PNGL to obtain OO connections. UR's proposal that no allowance be given for the first 33% of OO connections serves only to magnify the downside risk loaded onto PNGL; and

- The mechanism includes a penalty (for underperformance) and reward (for overperformance) that is asymmetric and unfairly adds risk to PNGL. Asymmetric penalty versus reward is contrary to the principle of pain/gain sharing as is standard in regulatory price controls and in normal regulatory practice.

Overall, the incentive mechanism proposed by UR inappropriately loads downside risk onto PNGL, and does not deliver an appropriate framework in which to continue expanding the natural gas market in NI.

The setting of unrealistically high OO connection targets in conjunction with insufficient allowances is incorrect and will not deliver on UR's primary objective of growing the natural gas market.

PNGL would therefore request that UR considers fully the evidence and views expressed by PNGL and that a realistic target for OO connections, with sufficient and appropriate allowances, is set for the GD17 period.

3.3 MANPOWER

This section discusses PNGL's concerns with UR's draft determination for manpower.

3.3.1 MANPOWER LEVELS

PNGL submitted a paper[96] as part of its GD17 price control submission on the manpower resources required to run its business over the six year GD17 price control period. It is not proposed that all of the views provided therein are repeated in this consultation response. However the more pertinent issues and areas that have progressed from the September 2015 submission are explored in more detail in this section.

UR considers it appropriate to base the levels of FTEs allowed for the GD17 period on 2014 actuals with a small increase to Customer Management to reflect increased connections.

Table 24 provides information on the FTEs requested by PNGL and the FTEs proposed by UR for the GD17 period.

	2017	2018	2019	2020	2021	2022
PNGL Requested FTEs	127.8	128.2	128.7	129.1	129.6	130.0
UR Proposed FTEs	120.8	120.8	120.8	120.8	120.8	120.8
Difference	**-7.0**	**-7.4**	**-7.9**	**-8.3**	**-8.8**	**-9.2**
%	(-5.5%)	(-5.8%)	(-6.1%)	(-6.4%)	(-6.8%)	(-7.1%)

***Table 24** - Manpower FTEs requested by PNGL and proposed by UR*

PNGL has three major issues with UR's proposed manpower allowances for the GD17 period:

i. UR's proposal to base PNGL's GD17 allowances for manpower on 2014 FTE actuals as the starting point is inappropriate as PNGL's actual number of FTEs for 2014 was lower than required being abnormally impacted by staff turnover;

ii. UR's proposal to base PNGL's GD17 allowances for manpower on 2014 FTE actuals as the starting point is inappropriate as PNGL's actual number of FTEs for 2014 did not include the FTE required to prepare for the introduction and the ongoing operation of a formalised asset management system; and

iii. UR's proposal to only allow a minor increase in FTEs within Customer Management over the GD17 period does not fully reflect the growth of the customer base forecast for GD17 and the future needs of the business. Therefore, it inherently assumes a level of efficiently whenever there is a separate process to apply efficiency factors to the business.

We discuss the impact of these issues in the following sections:

[96] PNGL's *"GD17 Manpower Paper"*

3.3.1.1 PNGL's actual number of FTEs for 2014 was impacted by staff turnover

Table 25 provides information on the manpower allowances granted by UR for the GD14 price control period:

	2014	2015	2016
PNGL Manpower Allowances (FTEs)	124.2	125.7	124.8

Table 25 *- GD14 Manpower allowances (FTEs)*

PNGL's "*Cost Reporting Template 2014"* reports the average FTEs employed across 2014 i.e. 118.8 FTEs after adjusting for the resource element associated to activities undertaken on behalf of our affiliate PES. It is these FTEs that UR proposes to utilise as a baseline for the GD17 allowances.

The variance between the allowed FTEs in 2014 within GD14 (i.e. 124.2) and the 118.8 FTEs employed in 2014 has been abnormally impacted by the high volume of staff turnover experienced in the year.

PNGL experienced significantly higher than normal levels of staff turnover in 2014 and 2015 for the following reasons:

i. <u>Large volumes of highly qualified personnel were lost to competitors</u>

As the preeminent company responsible for the introduction of natural gas in NI, PNGL's base of experienced personnel is attractive to companies working in the energy sector, specifically the natural gas market.

The development of projects such as Gas to the West, and the introduction of a third natural gas distribution network in NI[97],has placed specific pressure on resources within PNGL as new and existing players target PNGL's skilled resources to support their business plan requirements. During 2014 and indeed again in 2015, PNGL have lost numerous highly qualified members of staff to a variety of energy companies operating in NI.

It could be viewed that PNGL is the training ground of engineering personnel for the NI natural gas industry as a whole and indeed the unprecedented growth in gas infrastructure assets which is expected to arise in the next few years is only going to fuel these pressures further. As we have indicated to UR previously, our forecasts are based on the specific requirements of our business and our ability to respond to demands created by such pressures are limited in nature. There is a strong argument in this price control for PNGL to be provided a greater resource than that requested to offset such pressures going forward, so that the industry as a whole has the capacity needed collectively in the next few years. PNGL's GD17 submission is based on the minimum level required to run an efficient operation in a normal environment and any reduction thereto will place additional pressures on the business at a time when pressures are likely to be enhanced.

[97] SGN, a company with limited experience of operating a natural gas distribution network in NI

Whilst PNGL continues to replenish its skills through development and training of new engineers[98], it is difficult and takes considerable time to recruit and train appropriate replacement personnel.

ii. <u>The revival in the job market following economic recovery</u>

Higher than normal levels of job insecurity experienced in NI during the economic crisis reduced the propensity for employees to look for alternative employment. However following the recent revival in the job market coupled with specific pressures from investment in the gas market, PNGL experienced higher than normal levels of staff turnover, especially within specialist areas, in recent years. Employees who had deferred seeking new employment until the job market stabilised have begun to leave PNGL in greater numbers than previously. Staff turnover during 2014 and 2015 was particularly high within the customer services department where numerous employees moved to perform the same or similar roles with different organisations. At one point in 2014 PNGL's customer services team were 5 FTEs down.

Staff shortages experienced in recent years has made it challenging for PNGL to continue to operate and support the natural gas network. This was only achieved through the utilisation of a combination of the following short term measures:

- *Goodwill of employees* – employees worked longer hours to ensure core activities continued. Where appropriate, overtime was utilised as a method to recompense employees for their additional effort. Reliance on employee goodwill and the payment of overtime is not sustainable or economical in the medium to long term;

- *Prioritisation of activities* – effort was focused on essential time bound activities. This resulted in back logs of non-priority work;

- *Training programme* – PNGL were able to use an accelerated training and development programme for engineers as existing employees from areas such as grid control had a knowledge and strong aptitude for Engineering and thereby were utilised to fill gaps. Having had to replenish this team anew, our ability to provide such flexibility has lessened and;

- *Assistance from external organisations* – PNGL obtained assistance from contractors and advisors in the short term to perform essential services. External organisations are useful to provide cover in the short term but are not an economical or a guaranteed alternative for the medium to long term.

PNGL's lower FTE levels during 2014 was not a consequence of whole FTEs missing for the entire period, but rather numerous periods of short term gaps (e.g. 3 month vacancy of position A = 0.25 FTEs, 2 month vacancy of position B = 0.16 FTEs etc.).

[98] PNGL has a robust training and development programme for engineering personnel

It should also be noted that in Q1 2016 (latest employee data available) PNGL employed 124.3 FTEs, which is in line with the forecasts provided in our submissions. This is also broadly in line with the GD14 allowance for 2016 of 124.8 FTEs.

UR's proposal to base PNGL's GD17 allowance for manpower using 2014 FTEs as the baseline is inappropriate due to the significantly higher than normal levels of staff turnover. A more appropriate baseline, which should be used by UR in its final determination, is the latest actual FTEs employed by PNGL i.e. 124.3 FTEs in Q1 2016. These FTEs are in line with the FTEs granted by UR for 2016 under its GD14 determination.

3.3.1.2 Delay in the employment of the FTE required to prepare for and introduce a formalised asset management system

UR provided PNGL with an allowance for 1 additional FTE in 2014 and 2015 to facilitate the introduction of the new asset management system, which will ultimately be accredited to the new ISO Asset Management Standard - ISO55001[99]. However, this FTE was employed during 2015 and not 2014 as forecast by PNGL at the time of its GD14 submission.

UR's proposal to use 2014 as a starting point is inappropriate as it would then be excluding this FTE.

3.3.1.3 UR's proposal to only allow a minor increase in FTEs within Customer Management over the GD17 period does not fully reflect the growth of the customer base forecast for GD17 and the future needs of the business

As outlined in section 3.3.1.1, the starting position for assessing the GD17 manpower allowances should be the latest actual FTEs employed by PNGL i.e. 124.3 FTEs employed in Q1 2016.

This baseline level of resources must also be updated to reflect the growth in customer numbers forecast for the GD17 period and the future needs of the business.

Information on the adjustments to the manpower allowances for the GD17 period required to enable PNGL to continue to safely operate the natural gas network is provided below:

Customer Management

PNGL welcomes UR's small increase in Customer Management FTEs "*given the expected increase in customer connections in GD17*"[100].

[99] GD14 determination paragraph 5.121
[100] Paragraph 6.257 of the consultation

However, the proposed increase in FTEs for Customer Management is not sufficient as:

i. PNGL's 2014 average FTEs for Customer Management were understated due to high levels of staff turnover experienced in 2014 and 2015. The actual FTEs currently employed are 37.5 FTEs.

ii. The proposed increase is not sufficient when compared with the increase in connections forecast during the GD17 period.

Table 26 provides information on the connections forecast across the GD17 period:

	Actual	Forecast[101]						
	2015	2016	2017	2018	2019	2020	2021	2022
Connections	9,668	9,103	9,303	9,230	9,039	8,998	8,853	8,582
Cumulative Connections	191,782	200,885	210,188	219,418	228,457	237,455	246,308	254,890

***Table 26** - Forecast connections*

UR is proposing that PNGL connect an additional c.54k properties[102], or 24%, during the GD17 period. However, UR is proposing to only allow an additional 1.6 FTEs (or 4%) to service both these additional connections and our existing customer base. PNGL does not anticipate that the level of manpower required to serve natural gas consumers in its Licensed Area can or should be increased or decreased linearly. However, a deficit of c.20% (24% additional connections less 4% additional Customer Management FTEs) between the increased volume of connections and the proposed increase of FTEs clearly does not make sense.

PNGL's 2015 call volumes equate to, on average, 0.7 contacts per customer connected. Therefore based on UR's proposed growth of c.9,000 connections per annum over the GD17 period, an additional 0.35 FTEs per annum (as requested by PNGL) is representative of the future needs of the business and is warranted simply to answer the increasing call volumes alone.

UR's determination should include sufficient increase in FTEs within Customer Management to appropriately account for the forecast growth in connections.

Operations

As part of its GD17 submission, PNGL requested 1 additional FTE within Operations as a direct consequence of the forecast growth of customer numbers in the GD17 period. The maintenance activities proposed to be performed by the additional FTE is directly related to the volume of connected properties. UR proposes to disallow this additional FTE even though the proposed increases in FTEs amounts to only 9%[103] within Operations compared to a forecast increase of c.54k connections (or 24%) over the GD17 period.

[101] 2016 based on PNGL's forecast. 2017 to 2022 based on UR's proposed connections for the GD17 period

[102] Including East Down

[103] 11 FTEs proposed to increase to 12

UR's proposal that the end-of-life replacement for larger Industrial and Commercial meters is extended beyond the industry standard of 20 years will also impact on the resources required within Operations. Further detail is provided in section 5.6.

UR's determination should include the additional requested FTE for GD17.

Asset Management

PNGL's asset management resource increased during 2015 to facilitate the introduction of a formalised asset management system, which will ultimately be accredited to the new ISO Asset Management Standard - ISO55001. PNGL notes that UR does not consider that an additional FTE is required in the GD17 period as this is "*already included in the PNGL costs base*"[104].

"PNGL has provided justification for 1 additional FTE in 2014 and 2015 to facilitate the introduction of the new asset management system. PNGL advises that this FTE will not be needed in 2016"[105]

The additional asset management FTE allowed by UR for the GD14 price control period was based on PNGL's forecast of the FTEs required to prepare for and to introduce a formalised asset management system.

At the time of the GD14 price control submission, PNGL estimated that 1 additional asset management FTE would be sufficient to develop and introduce an ISO55001 compliant asset management system. However, at that time PNGL did not fully comprehend the significant volume of new activities required in order to ensure ongoing compliance with the standard. These activities include:

- Monitoring and reporting on asset performance and system controls;
- Identification and implementation of improvements/innovations aimed at increasing asset performance;
- Management and completion of new internal auditing processes to ensure maintaining quality;
- Completion of actions generated from accreditation reports;
- Facilitation of asset management communication/training exercises throughout the organisation;
- Reviewing and updating asset management system processes and procedures;
- Monitoring and review of Asset Management competency throughout the work force;

[104] Paragraph 6.251 of the consultation
[105] GD14 determination paragraph 5.121

- Completion of operational and financial assessments forecasting reliability and detailed lifecycle costs aimed at generating optimal asset intervention points;

- Providing bottom-up linkage between the on-site operational technicians and the core asset management team to ensure their knowledge, ideas and concerns are fully utilised in the continual improvement of the asset management system; and

- Providing linkage with the customer services department to facilitate a new more detailed planning procedure for all asset maintenance activities.

The additional FTE now requested by PNGL for the GD17 period reflects the actual resource required to administer and manage an asset management system that remains compliant with ISO55001 each year.

UR's determination should include this additional FTE for GD17.

Grid Control / Transportation Services

Grid Control relates to the provision of a 24/7 service required to monitor and control the distribution network. A 24/7 Transportation Service is also required to deliver the operation of the PNGL Network Code.

Whilst ten staff are required as a minimum to operate a 24/7 shift pattern (so that a minimum of two operatives are on site at any one time to man the control room), our experience of being able to retain staff in sufficient levels requires periods when staff must overlap to provide a continually manned service. The effect of this overlap is that on average it takes 11 FTEs to provide a 10 FTE continually manned rota.

UR's determination should include one additional FTE for GD17 to ensure that eleven staff can be retained on a shift basis rather than ten.

Network Development

As part of its GD17 submission, PNGL requested 0.5 additional FTEs within Network Development as a result of a revision of roles and responsibilities with respect to new build connections; engineering has taken on a greater aspect of the planning of works thereby enabling retail operations to focus on relationship management.

The additional 0.5 FTEs is required as the new build market continues to recover in the GD17 period; an issue accentuated by the change in nature of new build development following the economic downturn (i.e. higher numbers of smaller sites).

UR's determination should include the additional 0.5 FTEs for GD17.

3.3.2 MANPOWER COSTS

[Redacted section]

3.3.3 CONCLUSION

UR's proposal to base PNGL's GD17 allowances for manpower using 2014 FTEs as the baseline is inappropriate due to the significantly higher than normal levels of staff turnover experienced at that time.

In addition, UR's proposal is inappropriate as it excludes the additional 1 FTE allowed by UR in its GD14 determination and employed by PNGL in 2015 to facilitate the introduction of the new asset management system, ISO 55001.

A more appropriate baseline, which should be used by UR in its final determination, is the latest actual number of FTEs employed by PNGL i.e. 124.3 FTEs in Q1 2016. These FTEs are in line with the FTEs granted by UR for 2016 under its GD14 determination.

The minor increase in FTEs within Customer Management proposed by UR, "*given the expected increase in customer connections in GD17"*[106] is not sufficient to cover the additional activity required to service these additional connections and our existing customer base. It is imperative that additional FTEs commensurate with the additional level of activity likely to be performed are provided for within Customer Management.

It is also essential that additional FTEs are provided for future activities, namely the ongoing compliance with the ISO 55001 asset management standard, the ongoing provision of the 24/7 control room and the increase in new build activities performed within Network Development.

UR's proposal to only allow a minor increase in FTEs over the GD17 period does not fully reflect the growth of the customer base forecast for GD17 and the future needs of the business. PNGL request that UR reconsiders its proposed number of FTEs for GD17 as part of its final determination.

[Redacted paragraph]

[106] Paragraph 6.257 of the consultation

3.4 INFILL MAINS

This section discusses PNGL's concerns with UR's proposals[107] for passing existing properties[108] in its existing Licensed Area[109] between 2017 and 2022.

3.4.1 SUMMARY

PNGL are proposing to make natural gas available to a further c.5,700 properties within its existing Licensed Area between 2017 and 2022 in line with the practice for standard infill projects established over the last 20 years where consumers are not required to pay an upfront cost to PNGL for making natural gas available to their property. In doing so, we believe that we are treating all potential consumers in our Licensed Area on an equitable basis and by increasing the number of consumers using natural gas, hope that we will be contributing to reducing the current levels of fuel poverty in NI together with NI's carbon footprint.

UR has concluded, via what PNGL believe to be a flawed economic test, that our proposal to make natural gas available to a further c.5,700 properties is unwarranted[110]. In reality this means that those consumers who have not been provided access to the natural gas network to date will have to pay for doing so, unlike similar consumers in our Licensed Area who have already been provided access. Future consumers will be required to pay:

- an upfront cost to PNGL for making natural gas available to their property (c.£330 for a standard infill project, see section 3.4.3). Consumers are not currently required to pay an upfront cost to PNGL for standard infill projects; and

- their installer for converting their existing heating system to natural gas (c.£2,400 for an average gas conversion).

This also means that fuel poor consumers[111] who have not been provided access to the natural gas network to date and who qualify for a fully-funded central heating upgrade through one of NI's fuel poverty schemes (e.g. Affordable Warmth) would still have to pay c.£330 to make natural gas available to their property.

As detailed in section 3.4.3, PNGL could have made natural gas available to these properties under UR's previous price control determinations at no upfront cost to the property owner as long as PNGL met, on aggregate, UR's average allowance per property passed.

UR is signalling that there will be no further development of the natural gas network in PNGL's Licensed Area without financial contribution from consumers. This is unwarranted.

[107] Paragraphs 7.157 to 7.162 "*Infill Mains – Growth (Excluding East Down)*" of the consultation
[108] excluding new build housing
[109] excluding East Down
[110] Paragraph 7.162 of the consultation
[111] 42% of households in NI are in fuel poverty according to the NI House Condition Survey 2011

3.4.2 PNGL'S PROPOSAL

The natural gas distribution network in Greater Belfast is largely well established. PNGL considers that the remaining properties to be passed in its Licensed Area are of a similar nature to the c.313,000 properties that already have access to natural gas.

As UR is aware, PNGL embarked on a project to determine all domestic properties yet to be passed within its Licensed Area and presented its findings to UR as part of the PNGL12 price control review. A similar review was undertaken by PNGL in advance of its GD14 price control submission. Further desktop analysis and designs have been completed since then with a paper summarising the latest findings presented to UR in June 2015[112].

PNGL believes that there is a potential to construct network to a further c.5,700 properties (Owner Occupied, NIHE and Commercial) during GD17 at a marginal cost of £692 for passing each property.

3.4.3 UR'S ECONOMIC TEST

UR has on many occasions in the past reviewed PNGL's cost forecasts for infill on a project-by-project basis and found those forecasts to be accurate and efficient. UR has not fully audited PNGL's proposed properties passed submission as part of this GD17 review and instead proposes to carry out an economic test in determining the proposed infill allowance.

As explained at a meeting with UR on 14 January 2016, the economic test conducted by UR in GD14 was based on (i) an average street with an average throughput per customer; and (ii) an average service and meter cost per customer. This determined the level of costs available for passing properties in that average street based on the costs that could be absorbed by the revenue generated from that average street.

Based on this analysis UR has concluded that our proposal to make natural gas available to a further c.5,700 properties is unwarranted[113]. In reality this means that those consumers who have not been provided access to the natural gas network to date will have to pay:

- an upfront cost to PNGL for making natural gas available to their property (c.£330 for a standard infill project[114]). Consumers are not currently required to pay an upfront cost to PNGL for standard infill projects; and
- their installer for converting their existing heating system to natural gas (c.£2,400 for an average gas conversion).

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[112] See PNGL's "*GD17 Infill Allowances paper*"

[113] Paragraph 7.162 of the consultation

[114] c.£690 forecast by PNGL for a standard infill project less the c.£360 allowance proposed by UR at Table 89 of the consultation. Notably PNGL would be neutral to UR's proposals as any costs that it is unable to recover via its cost base will simply be charged to individual consumers under the terms of its Connection Policy

Furthermore PNGL provides at Appendix 4 a sample of developments which illustrate that the remaining properties that PNGL would like to make gas available to across GD17 are (i) not isolated sites; and (ii) not at the extreme of our existing network. UR's proposal for passing properties during GD17 would mean that:

- a property in one street may already have natural gas available and have not been required to pay an upfront cost to PNGL for making natural gas available; whereas
- a property in the adjacent street may not have natural gas available and would be required to pay an upfront cost to PNGL for making natural gas available.

UR's proposal is unjustified and may be interpreted by consumers and their representatives as being discriminatory.

UR's economic test is flawed. PNGL could have made natural gas available to these properties under UR's previous price control determinations at no upfront cost to the property owner as long as it met, on aggregate, UR's average allowance per property passed. Specifically if PNGL's £692 marginal cost proposal for passing properties during GD17 were adopted, the average cost of passing a property from 1997 to 2022 would equate to c.£340. This is still below the "economic" allowance granted by UR in GD14, c.£400[115] and **significantly below the £620[116] "economic" allowance proposed by UR for firmus in GD17**. PNGL's forecast average cost per property passed of £692 is therefore "economic".

PNGL does not understand why UR has used an economic test to determine the average allowance for an average street and then disallowed PNGL's proposal on the basis that the <u>marginal</u> cost for a street during GD17 is higher. This is a fundamental misinterpretation by UR of its own economic test.

3.4.4 STAKEHOLDER ENGAGEMENT

PNGL would request that UR engages with consumers and consumer bodies as part of the GD17 consultation process to discuss the impact of the implementation of UR's proposals on the fuel poor and on the development and maintenance of an economic and coordinated natural gas industry so that any issues arising are fully understood and accepted. Notably, fuel poor consumers who have not been provided access to the natural gas network to date and who qualify for a fully-funded central heating upgrade through one of NI's fuel poverty schemes (e.g. Affordable Warmth) would, under UR's proposals, now have to pay c.£330 to make natural gas available to their property.

PNGL has always recognised the importance of effective engagement with a broad range of stakeholders to achieve our Corporate Objectives. Our stakeholders provide us with a better

[115] this is the allowance in 2016 excluding management fee
[116] Table 89 of the consultation

understanding of the impacts that may be felt by an individual or group and allow us to articulate our own values, strategy, explain our commitments and proactively improve relationships.

To ensure that our GD17 Business Plan reflected current views, we undertook additional research to explore current attitudes and perceptions of gas consumers and potential gas consumers on a number of aspects of our GD17 submission, notably (i) our assumption for the level of owner occupied connections per year across GD17; (ii) our proposals to make natural gas available to additional properties within our Licensed Area during the GD17 price control period; and (iii) our assumption for the level of market development required across GD17. **There were high levels of support for extending the gas network within our Licensed Area despite the marginal increase in cost for consumers[117].**

Furthermore 13 representatives of key stakeholders took part in our research to ensure that, as well as developing quantitative trends, there was an opportunity to gather more qualitative views of organisations in key areas of the business in GD17. The results of the stakeholder consultation[118] broadly reflected the results of the consumer survey with respect to network operation, new connections to the network, extension of the gas network and marketing initiatives to support the development of the natural gas industry. **Perhaps more so than consumers, stakeholders were favourable to the extension of the network for both domestic and commercial properties.**

3.4.5 CONCLUSION

PNGL would urge UR to review the basis of its current analysis and to reconsider the message that its proposal to ignore the long-term average cost of passing a property will have on the development of the natural gas network and on consumers, including the fuel poor, in our Licensed Area.

UR is signalling that there will be no further development of the natural gas network in PNGL's Licensed Area without financial contribution from consumers. This is unwarranted and may be interpreted by consumers and their representatives as being discriminatory.

[117] See PNGL's "*GD17 Stakeholder Engagement paper*" submitted to UR in June 2015
[118] See PNGL's "*GD17 Stakeholder Engagement paper*" submitted to UR in June 2015

3.5 REAL PRICE EFFECTS, PRODUCTIVITY IMPROVEMENTS AND TOP-DOWN BENCHMARKING

This section discusses PNGL's concerns with UR's proposed real price effects ("**RPEs**") and indicative top-down benchmarking.

3.5.1 REAL PRICE EFFECTS AND PRODUCTIVITY IMPROVEMENTS

In calculating draft opex and capex allowances, UR has included a so-called frontier shift element, which is the sum of input price growth (or RPEs) less the expected improvement in productivity.

PNGL engaged NERA to provide expert technical advice on RPEs and productivity improvements which informed our GD17 business plan submission[119]. We have also engaged NERA to respond to UR's RPE and productivity forecasts set out in the draft determination. We attach NERA's technical review of UR's draft determination as Appendix 5[120], and we summarise the key points from NERA's review below.

3.5.1.1 UR's approach to RPEs is inconsistent with regulatory practice

Overall, NERA finds that there are a number of areas where UR's proposed approach to forecasting RPEs is not in line with established economic principles or regulatory practice.

In forecasting labour input costs over GD17, UR relies on OBR forecasts where NERA has identified the following issues:

- UR used OBR's forecast for economy-wide average-earnings growth, while it should use private sector earnings, given that we face private sector wage growth pressure; and
- UR draws on weekly wage changes whereas the correct approach is to use hourly earnings growth, as this measure is unaffected by changes in hours worked.

Correcting for these two issues increases the labour RPE from 0.8% per annum on average over GD17 to 1.2%, and closer to the wage cost pressures we currently experience as a business.

For our material input costs, UR assumes that material prices will grow at a below trend growth rate before achieving UR's assumed long-term average of 0.3% per annum towards the end of GD17. Despite recognising that the price levels are below trend, UR ignores the tendency of price indices to grow more quickly following economic shocks (i.e. the global financial crisis). By contrast, Ofgem assumed that material prices would revert immediately to their long-term growth rates, as a practicable and objective approach to allowing for the tendency for prices to grow above trend as

[119] Worksheet 1.5 of PNGL's GD17 BPT submission

[120] and submitted to UR on 29 April 2016

the UK economy continues to emerge from the crisis. Using UR's proposed indices and long term average but applying Ofgem's practical approach, implies an RPE of 0.3% per annum on average over GD17 as opposed to UR's draft determination assumption of *minus* 0.3% per annum.

For plant and equipment, UR relies only on one index (ONS PPI Machinery and Equipment index) in contrast to UR's approach at GD14, CMA NIE and Ofgem, which considered an additional second index, BCIS Plant and Road Vehicles. Taking into account both indices would lead to an average RPE of *minus* 0.3% per annum on average over 2015-2022, compared to the current UR average estimate of *minus* 0.7% per annum over the same period.

Table 27 summarises the required changes to UR's RPE to correct for this issues that we have summarised here. Overall, the restated estimates are much more in line with the unit cost pressures that we currently face as a business (notably in relation to increasing wage pressures), and the proposed changes to the RPE forecasts are an important element of ensuring the cost allowances are sufficient for us to deliver a safe and reliable network over GD17.

	UR - Draft Determination	UR - Corrected Approach
Labour	0.8%	1.2%
Materials	-0.3%	0.3%
Plant and Equipment	-0.7%	-0.3%
Transport/ Other	0%	0%

***Table 27** - Proposed Changes to UR's RPE Assumptions to Ensure Adequate Cost Allowances Average RPE per annum over 2015-2022*

3.5.1.2 For productivity, UR selects an upper bound estimate although the evidence supports a lower bound estimate

UR assumes a productivity shift of 1% per annum for both opex and capex, higher than PNGL's estimates[121] of 0.6 per annum for capex and 0.8% per annum for opex.

As set out in NERA's report, UR's draft determination estimates are at the upper-end of regulatory decisions and empirical evidence, whereas the PNGL specific factors would suggest a value at the lower end. Specifically, PNGL is a new utility, with far less scope to reduce costs relative to incumbent former publically owned utilities. NIE – UR's principal comparator – is not a reasonable comparator.

Overall, we consider that UR should use a value of 0.6% per annum and 0.8% per annum for capex and opex respectively as set out in our GD17 business plan submission. As NERA explains in its report, our recommended values are based on the improvements achieved by comparable

[121] Worksheet 1.5 of PNGL's GD17 BPT submission

businesses over the long-run. UR's draft determination of 1% for both capex and opex is higher than that supported by the empirical evidence, and has a material impact on our overall cost allowance given that the reduction compounds over time. As with RPEs, our proposed changes to UR's productivity assumption is an important element of ensuring that the overall cost allowances are sufficient for us to deliver safe and reliable network services for our customers over GD17.

3.5.2 REAL WAGE ADJUSTMENT AND TOP-DOWN BENCHMARKING

3.5.2.1 Summary

As part of the top-down benchmarking analysis for GD17, UR make a regional labour adjustment to PNGL's operating costs of c.9% to account for UR's view that PNGL face lower wage costs than GB GDNs. This adjustment to PNGL's costs almost entirely explains UR's assessed efficiency gap.

PNGL also engaged NERA to review UR's regional wage adjustment and the implications for the top-down benchmarking. As set out in NERA's report included as Appendix 6[122], NERA concludes that there are a number of areas where UR does not follow sound economic principles, and established regulatory practice, and as a consequence, UR overstates the required adjustment for differences in real wages in NI relative to GB.

Based on standard practice, NERA calculates a required real wage adjustment of between 2% and 3%, far lower than UR's 9% adjustment. NERA concludes that if UR were to use this corrected value in the top-down modelling, PNGL would be on the efficiency frontier. Therefore, there is no basis for reducing our expenditure allowances based on UR's own top-down modelling. Indeed, the top-down modelling supports PNGL's view that our business plan costs are efficient and should be recognised in full.

3.5.2.2 Key Issues with UR's Approach

UR estimates that real wages in NI are 82% of the average in GB, and applies this adjustment to around 50% of PNGL's opex. NERA finds that UR's approach does not follow standard practice in a number of respects:

- First, UR compares median private sector wages for all industries across regions. In using economy-wide wage date, UR does not use wage data for those industries or professions that are relevant to GDNs. By contrast, all other GB regulators who have estimated real wages adjustments in a comparative efficiency context (e.g. CMA, Ofgem and Ofwat) compare wages for occupations relevant to the industry in question, drawing on wage data for individual Standard Occupational Codes ("**SOCs**") from ONS.
- Second, UR does not control for differences in the hours worked per week across different regions. The average working week in NI is lower than in GB, and the shorter working week will in part explain lower earnings in NI. Under UR's approach, PNGL is penalised for the

[122] and submitted to UR on 29 April 2016

shorter NI working week. However, if PNGL's employees actually worked shorter working weeks than the GB GDN peers, PNGL would have to employ more staff in order to perform the same tasks as its GB GDN peers, entirely offsetting the apparent lower weekly wage. Instead of using weekly wages, the correct comparison is hourly wages.

- Third, by applying UR's real wage estimate of 82% to around 50% of opex, UR's approach ignores the fact that the market for much of GDNs' labour costs is national, and therefore should not be subject to a regional labour adjustment.

By contrast, drawing on wage data for occupations relevant to GDNs, NERA calculates that real wages for PNGL are around 91-93% of the GB average – far closer to the average than UR's approach (based on entirely irrelevant occupations) of 82%. In addition, NERA calculates that the adjustment should be applied to an estimate of labour employed within the GB GDNs' regions, which it calculates as 26% of total opex. Overall, NERA finds that the real wage adjustment applied to our opex should be 2-3% (i.e. (1-92%)*26%), instead of the 9% applied by UR.

3.5.2.3 Conclusion: UR Should Not Rely on its Top-Down Modelling

Under its preferred model (model 3), UR concludes that PNGL is "*reasonably close to being an upper quartile performer, but an efficiency gap does exist (estimated to be around 7% to 8% in 2014)*"[123]. However, these results are based on an upward adjustment of 9% to PNGL's costs for UR's estimated real labour adjustment which entirely explains the so-called efficiency gap.

As NERA shows, the adjustment should be in the region of 2-3%. If UR adjusts PNGL's costs by only 2-3% to account for real labour adjustments, it is very likely that the top-down benchmarking analysis would show that PNGL's costs are efficient based on UR's own preferred efficiency models.

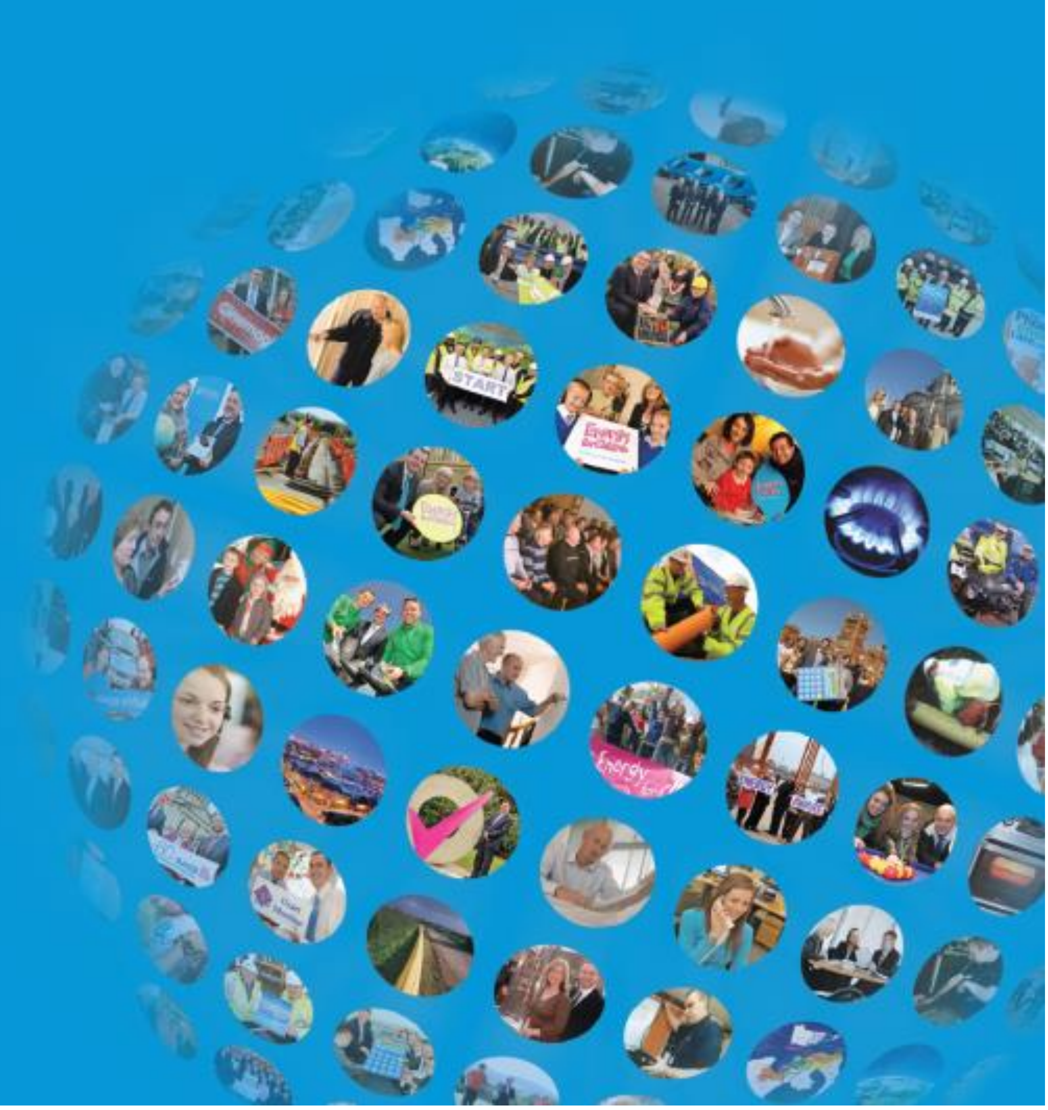
In addition to our concerns with UR's real wage adjustment, PNGL also has other potential concerns with the top-down modelling around model-specification, and in particular, adjustments for special factors. However, despite a request from PNGL, UR has not provided the data set and modelling analysis for us to effectively respond to UR's top-down modelling on these issues.

The only reasonable conclusion that UR can draw from the top-down analysis is that PNGL's costs are efficient. To draw any other conclusion based on the current real wage adjustment, would be inconsistent with sound economic principles, and established regulatory practice. UR has also not provided us with the model dataset for PNGL to effectively respond to other modelling issues which means that no reliance should be placed on the modelling results.

[123] UR (2016) Indicative Findings from Top-Down Benchmarking, GD17, p.15

PHOENIX
NATURAL GAS

OPERATING EXPENDITURE (OPEX)



4. OPERATING EXPENDITURE

Overall UR has proposed opex allowances which are 23% lower than PNGL's submitted cost forecasts for GD17. We consider that cuts of this scale are unjustified, and result in significant downside risk being placed on PNGL.

While the GD17 BPT required change in cost reporting categories, two cost items require detailed analysis due to their impact on overall opex i.e. manpower and the connection incentive. We begin with these cost items and then discuss PNGL's concerns with UR's draft determination for the remaining opex cost items detailed in Table 47 of the consultation. Where no comments have been made e.g. under "*HR & Non-Ops Training*", PNGL acknowledges, in the round, the GD17 draft determination provides an appropriate allowance to operate and maintain the PNGL network in GD17.

4.1 MANPOWER

We provide our detailed view on UR's proposed manpower allowances in section 3.3. In addition:

4.1.1 APPRENTICESHIP LEVY

From 6 April 2017 all employers in the UK with a pay bill in excess of £3m per annum will be required to pay an Apprenticeship Levy to HMRC.

The Apprenticeship Levy is set at 0.5% of an employer's gross total employee earnings. Table 28 provides information on PNGL's forecast payments for the GD17 period:

	2017	2018	2019	2020	2021	2022
Total employee earnings[124]	£5,533,312	£5,626,911	£5,635,234	£5,643,566	£5,651,757	£5,660,152
Apprenticeship Levy (0.5%)	**£20,750**[125]	**£28,135**	**£28,176**	**£28,218**	**£28,259**	**£28,301**

Table 28 *- PNGL forecast Apprenticeship Levy payments during GD17*

Employers paying the Apprenticeship Levy will be eligible to an allowance of £15,000 to spend on Apprenticeship training. However, there is currently no guarantee PNGL will receive this allowance as the NI Executive is yet to communicate on how it will use the new income from the Apprenticeship Levy.

PNGL request that UR considers the impact of the new Apprenticeship Levy as part of its final determination.

[124] Source: "*Staff Salaries*" and "*Other Staff Costs*" as detailed in PNGL's GD17 BPT "*3.4 Staff & Agency – Costs*"

[125] 2017 payment is for 9 months (Levy introduced from April 2017)

4.1.2 NATIONAL LIVING WAGE

The Government's National Living Wage ("**NLW**") was introduced on 1 April 2016. Employers are required by law to pay applicable employees a minimum of £7.20 per hour worked. NLW is scheduled to increase to £9 per hour by 2020. In order to comply with the NLW PNGL has been required to provide (in 2016), and will continue to be required to provide (during the GD17 period), salary increases to lower paid workers in excess of the level of inflation. PNGL estimate that these salary increases will, in total, amount to £25k-£30k per annum.

UR's final determination should include these additional salary costs across GD17.

4.2 CONNECTION INCENTIVE

We provide our detailed view on UR's proposed connection incentive in section 3.2.

4.3 ADVERTISING & MARKET DEVELOPMENT (NON-OO)

PNGL's New Build Sales Manager and New Build Sales Consultant are responsible for all aspects of private new build sales. PNGL incorrectly used an 85% allocation to owner occupied activities in its GD17 BPT submission. As advised by PNGL during the consultation process[126], UR should therefore reallocate New Build Sales exclusively to non-owner occupied activities, to accurately reflect the activities undertaken.

4.4 EMERGENCY COSTS

Following UR's GD14 determination, PNGL undertook a review of the activities undertaken by the National Grid Emergency Control Centre in Hinckley, and identified one area where it believed efficiencies could be achieved, "*non-emergency call handling*". This largely covers calls which do not involve the escape of gas e.g. meter issues, consumer education etc. As a result, PNGL has transferred "*non-emergency call handling*" to its Contact Centre in Belfast where its operatives have been trained in resolving non-emergency issues.

PNGL acknowledges the GD17 draft determination allowance as an appropriate allowance to deliver an emergency response service under non-extreme conditions across the PNGL network in GD17. Winter 2010/11 however provided a warning to the natural gas industry that even in challenging economic conditions and the drive to ensure that costs are minimised, utilities must have resources available to manage extreme events. In Great Britain it is reasonable to assume that, given the size and operation of the networks, extreme events could be alleviated by diverting resources from other regions or areas of the business. As UR is aware however, PNGL is a relatively small company and the

[126] See PNGL's email to UR of 6 April 2016 and follow-up discussions between PNGL and UR on 8 April 2016

climate of NI is relatively similar e.g. if Belfast in the PNGL Licensed Area is experiencing an extreme weather event it is likely that Antrim in the firmus Licensed Area is experiencing a similar extreme event; PNGL does not therefore have the option of drafting resources from other regions or areas of the business. While PNGL was able to meet the short-term spike in demand in Winter 2010/11, PNGL is concerned that the allowances proposed by UR would make managing a similar extreme event in GD17 unfeasible. Notably PNGL's contract for utilisation of the National Grid Emergency Control Centre in Hinckley requires consultation where call volumes increased by over 15% for a period of time[127].

PNGL would highlight that the benefits arising from this change have arisen across two relatively benign winters and as such activity levels have been set in that context. PNGL would therefore be concerned that in the context of a more extreme winter, emergency response costs are likely to be abnormally affected.

PNGL would request that UR consider how additional expenditure required in an extreme event is accounted for under its proposal for GD17.

4.5 MAINTENANCE

PNGL acknowledges the GD17 draft determination allowance for maintenance (excluding exceptional items e.g. the "*Valve Accessibility Project*" as detailed below) as an appropriate allowance to deliver PNGL's regular maintenance programme and maintain the PNGL network in GD17.

4.5.1 MAINTENANCE EXPENDITURE CORRECTION

As advised by PNGL during the consultation process[128], PNGL notes an error in Table 65 of the consultation; the maintenance costs included in UR's draft determination make no allowance for the staff costs nor transport and plant attributed by PNGL to maintenance activities (rows 263 and 268 of worksheet 3.1 of PNGL's GD17 BPT submission respectively). UR's draft determination allowance is therefore understated by c.£230k each year.

4.5.2 VALVE ACCESSIBILITY PROJECT

PNGL has recently completed a trial aimed at quantifying the level of resource and budget required to undertake an Underground Valve Accessibility Project. Over the years a large proportion of valve chambers have been clogged with dirt or valve lid bolts have seized making them inaccessible. The purpose of this project is to ensure that all valve chambers are accessible and free from debris to ensure that they can be immediately operated to control or isolate gas flows during emergency operations.

[127] In December 2010 call volumes increased by c.130% above the previous 5-year average for December

[128] See PNGL's email to UR of 6 April 2016 and follow-up discussions between PNGL and UR on 8 April 2016

Paragraph 6.291 of the consultation states that UR's consultants would expect that the strategy adopted by PNGL would differentiate the valve population and assess maintenance frequencies on the basis of strategic importance and risk.

Difficulties however arise when trying to compare one valve's importance to another; although a mains valve may isolate numerous properties, a single Industrial and Commercial valve is of critical importance in the event of a leak or fire within the connected property. In fact every valve is of importance where it is required to control or isolate gas flows during an emergency operation and cannot be immediately operated. Therefore PNGL would contend that its proposed strategy for including the entire underground valve asset within the project is the most prudent and appropriate approach with regards to controlling the risks posed by inaccessibility across the underground valve asset. UR should therefore reconsider its position in the draft determination accordingly and provide an allowance to cover works on the entire underground valve asset.

PNGL as an efficient operator will always attempt to negotiate lower unit costs with its contractor by increasing productivity via specific area planning and dedicated teams. However the valve accessibility project is large with unknowns as well as knowns; there is therefore an equal possibility that unit costs may increase. UR's proposed unit rate decrease of 43% is excessive and as such PNGL would ask UR to reconsider its position and to grant the allowances as requested by PNGL in its GD17 submission.

4.6 <u>IT & TELECOMS</u>

PNGL notes that UR has based its allowance for GD17 on the 2014 costs. However:

- PNGL has been able to sweat the benefits of its telecoms equipment over a prolonged period. However technological advancement and lack of flexibility in a disaster situation, has meant that PNGL has had to replace its existing switch in 2016. The maintenance and support costs of such equipment is substantially higher than the costs we experienced historically and will therefore have not been properly accounted for within UR's proposals. PNGL estimate an additional allowance of c.£7k per annum will be required during the GD17 period.

- The evolution of the use of 'the cloud' to support system development and operation has provided PNGL with a more viable solution to support the business in the event that it needs to vacate existing facilities in an emergency. This has grown in importance due to the more direct involvement PNGL have in the handling of emergency calls thereby making it more important than in the past that a more seamless solution to managing calls and email can be provided. The additional cost of such a solution using 'mimecast' will be incurred by PNGL for the first time in 2016 and therefore is not included within UR's proposals. PNGL estimate an additional allowance of c.£6k per annum will be required during the GD17 period.

- Cyber security risks have become a growing feature of the IT strategy in recent years with all infrastructure providers having to take extra steps to safeguard its assets and IT infrastructure. In that respect PNGL have had to employ additional services to protect its network and internet and mail services, to try to avoid risks of attack from various sources. These costs have not been properly accounted for within UR's proposals and are necessary if PNGL on one hand can continue to make use of technology but on the other avoid the risks associated to such technology. PNGL estimate an additional allowance of c.£5k per annum will be required during the GD17 period.

- PNGL have been able to make use of extremely competitive financial software solutions. These solutions are assumed to continue to be available going forward however it is subject to upgrade costs if it is to continue to be fit for purpose. PNGL therefore have assumed that the next upgrade will arise in 2017 with further routine upgrade 5 years thereafter. This is additional to the costs included by UR. PNGL estimate an additional allowance of c.£5k per annum will be required during the GD17 period.

- PNGL have had to review hosting requirements with its current service providers to obtain more robust solutions in relation to service and security. PNGL estimate an additional allowance of c.£5k per annum will be required during the GD17 period.

PNGL would request UR to reconsider its proposal on this basis.

4.7 <u>PROPERTY MANAGEMENT</u>

4.7.1 NETWORK RATES

Ofgem's three price control reviews under the RIIO model (RIIO-T1, RIIO-GD1, and RIIO-ED1) treat business rates as non-controllable opex and therefore treat network rates as pass-through.

The effect of the Competition Commission's decision in relation to PNGL's network rates was essentially to implement a pass-through mechanism for rates since 1996.

Furthermore it would be unreasonable for UR to align the price controls of NI's GDNs while treating this uncontrollable cost differently for PNGL and the other NI GDNs.

PNGL would therefore expect UR to allow a pass-through of rates in line with the body of relevant precedent.

PNGL's GD17 submission assumes that rates will be calculated on the basis of the current formula and rates arising out of the 2015 revaluation throughout GD17. However PNGL noted that UR should recognise that the current formula will be subject to review at the next revaluation which is currently expected in the latter years of GD17.

4.8 AUDIT, FINANCE & REGULATION

UR has proposed allowances for Professional and Legal costs within "*Audit, Finance & Regulation*" based on actual costs incurred by PNGL during 2014 of £308k. PNGL disagrees with the use of 2014 as the base year as 2014 does not reflect the underlying average costs PNGL has incurred or will incur during the GD17 period. For example:

- 2014 was the first year of the GD14 price control;
- there were no major changes to PNGL's structure or activities;
- supply competition had stabilised; and
- there were no major Licence modifications.

PNGL's actual expenditure in 2013 was £595k, and PNGL forecasts spend of c.£437k per annum on average over the GD17 period (as detailed in Table 29).

	2013	2014		2017	2018	2019	2020	2021	2022	GD17 Average
Professional & Legal	£595,495	£308,345		£468,855	£421,188	£420,117	£375,829	£468,681	£466,454	**£436,854**

Table 29 *- PNGL Professional and Legal costs 2013, 2014 and GD17 forecast*

The allowances proposed by UR for the GD17 period are understated by c.£130k per annum. PNGL would request UR to reconsider its proposal on this basis.

In addition the 2014 costs will not account for:

- Any costs in relation to the NI European Development ("**NIED**") project. UR has recognised in its e-mail to PNGL on 21 May 2015, that the scope and scale of the NIED project is not within PNGL's control, but is determined by European requirements, industry, and the TSO, which is as directed by UR. UR has also stated that associated costs cannot be treated as "business as usual" and lay outside the scope of the current price control GD14. Further detail is provided in PNGL's "*GD17 Commentary*". The scope and scale of the NIED project for GDNs has not been properly defined, which has prevented putting out a business plan of all identified costs; it may span over the GD14 and GD17 price control periods. To provide clarity on how costs of the NIED project will be recovered, UR states in its email of 21 May 2015 that it will use the Uncertainty Mechanism for GD14 and GD17, where relevant. **PNGL therefore expects that any costs associated with the NIED project will be included within the GD17 Uncertainty Mechanism**; and

- Additional consultancy costs forecast around each price control review e.g. in 2015, 2016 and 2017 for the GD17 review; in 2021, 2022 and 2023 for the GD23 review. **Given the scope[129] and the duration[130] of this and future price control reviews, PNGL would request UR to reconsider its proposal on this basis.**

[129] e.g. the determination of rate of rate of return from 2016

[130] e.g. moving from a 2 year (PNGL12) and 3 year (GD14) price control to a 6 year (GD17) price control

4.9 INSURANCE

4.9.1 BUSINESS INSURANCE

UR is proposing to grant PNGL a business insurance allowance based on a three-year average of the actual costs incurred during 2012 to 2014. PNGL provided the rationale and drivers for its GD17 business insurance forecasts in response to PNGL-036. PNGL's GD17 business insurance forecasts are driven by inflation, turnover, capex and number of employees. PNGL's business insurance requirements will therefore flex with the outputs of UR's final determination.

4.9.2 CAR INSURANCE

PNGL notes[131] that the AA's average premium for annual comprehensive car insurance in NI for Q4 2015 was c.£750. The actual premium paid by PNGL in 2015 was £882 per vehicle. In contrast to the average NI car, PNGL's fleet is made up of a high proportion of high mileage vehicles.

In recent years PNGL has negotiated reduced car insurance premiums. PNGL's car insurance premiums have reduced from £1,393 per vehicle in 2011 to £882 in 2015 (see Table 30).

	2011	2012	2013	2014	2015
Car Insurance Premium (per vehicle)	£1,393	£1,280	£1,233	£894	£882

***Table 30** - PNGL Car Insurance Premium (per vehicle)*

PNGL has no scope to reduce the car insurance premiums further. **The allowances provided by UR should be sufficient to cover the actual premiums paid by PNGL.**

PNGL's car insurance cost line[132] includes other vehicle costs on top of the insurance premium. Other vehicle costs include:

- Excess payments for accidental damage – PNGL are required to pay the first £500 of vehicle insurance claims; and
- Abnormal wear and tear – PNGL are liable for all costs to vehicles associated with abnormal wear and tear i.e. those minor damages that may occur from time to time which are not covered by contract hire costs yet are not attributable to any one particular accident or incident and, as such, fall outside anything that may be referred to the fleet insurance provider e.g. stone chippings, scratches to paintwork, tyre replacements (over and above that which is covered by contract hire costs).

PNGL made other vehicle payments of c.£7k per annum between 2012 and 2015. It would appear that these other vehicle costs have not been considered by UR in its proposal and therefore PNGL has been benchmarked incorrectly.

PNGL would request UR to reconsider its proposal on this basis.

[131] Paragraph 6.337 of the consultation

[132] "*Vehicles and Wheeled Plant*" cost line in PNGL's GD17 BPT "*3.1 Opex Matrix*"

4.10 CEO & GROUP MANAGEMENT

As noted above, the main difference between PNGL's submission and UR's proposal is that UR's proposal disallows a significant proportion of the remuneration packages forecast by PNGL for its management team despite PNGL's objections in PNGL12 and in GD14. PNGL's detailed response is provided in section 3.3.2.

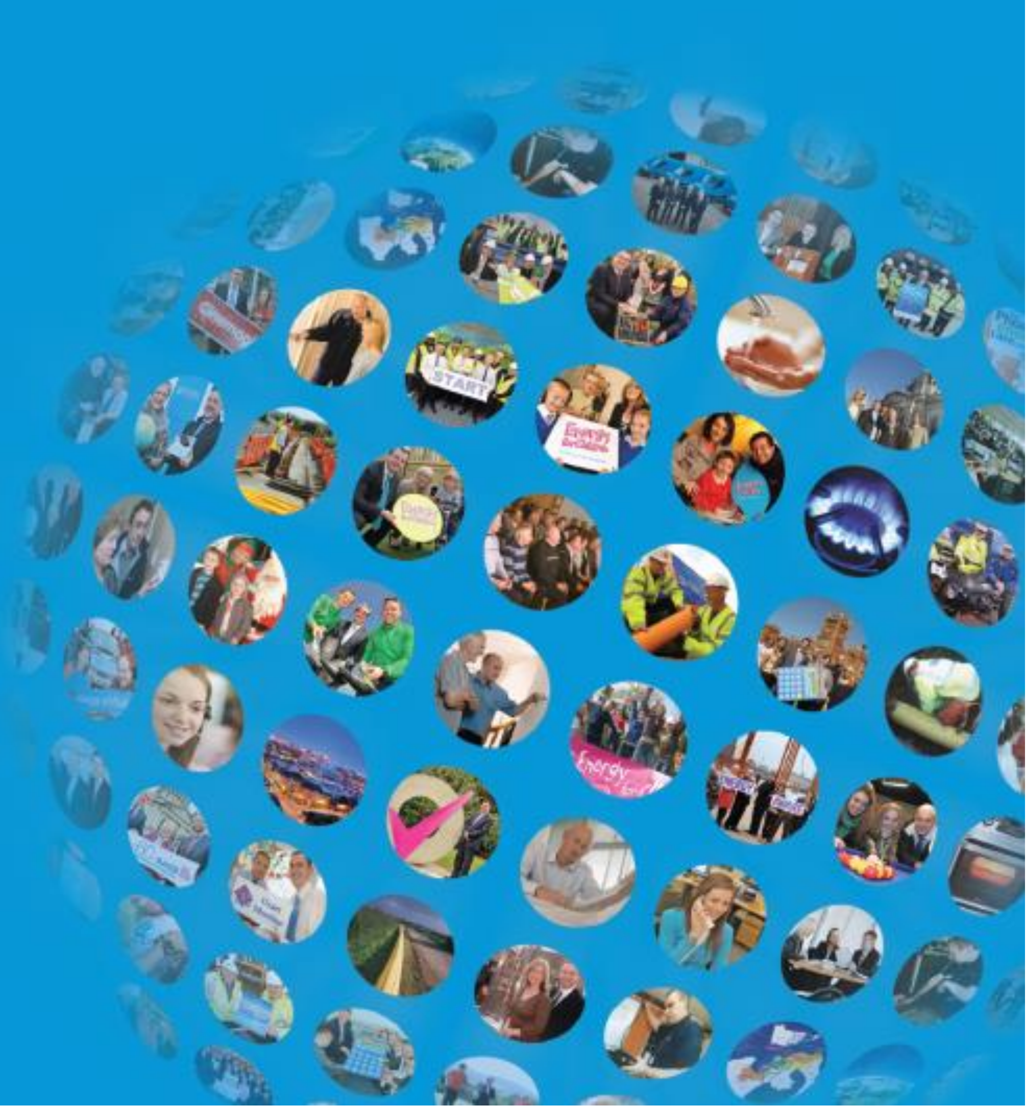
4.11 NON-CONTROLLABLE OPEX

Licence Fees

PNGL welcomes UR's proposal to treat licence fees as pass-through and therefore retrospectively adjust them to reflect the actual fees levied on PNGL by UR.

PHOENIX NATURAL GAS

CAPITAL EXPENDITURE (CAPEX)



5. CAPITAL EXPENDITURE

UR's use of synthetic unit rates restricts PNGL's ability to comment on UR's capex proposals other than at an overall level. Our detailed commentary on UR's proposals is restricted to a handful of individual capex cost lines:

- Reinforcement;
- Infill Mains – Growth (Excluding East Down);
- New Build Mains – Growth (Excluding East Down);
- Low and Medium Pressure Mains – East Down;
- Domestic Meters – End-of-life Replacement;
- Industrial and Commercial ("**I&C**") Meters – End-of-life Replacement; and
- Traffic Management Act.

Where no comments have been made e.g. under "*Service Connections"* or under *"Domestic Meters - Growth"*, PNGL acknowledges, in the round, the GD17 draft determination provides an appropriate allowance to develop the PNGL network in GD17.

5.1 <u>REINFORCEMENT</u>

PNGL has included a project to reinforce the intermediate pressure main for the Bangor / Donaghadee / Millisle area during GD17. PNGL is required[133] to review its design for a 1 in 20 year event recurrence interval with interruptible supply loads switched off to confirm the need for the project. PNGL's review is detailed in Appendix 7 and supports the need to reinforce the intermediate pressure main for the Bangor / Donaghadee / Millisle area during GD17. UR's final determination for GD17 should therefore reflect the investment as proposed in Table 119 of the consultation.

PNGL acknowledges the GD17 draft determination allowance as an appropriate allowance to undertake the reinforcement.

[133] Paragraph 7.153 of the consultation

5.2 INFILL MAINS – Growth (Excluding East Down)

We provide our detailed view on UR's proposals for passing existing properties in section 3.4. In addition:

5.2.1 I&C PROPERTIES PASSED CORRECTION

As advised by PNGL during the consultation process[134], PNGL notes an error in Table 88 of the consultation; PNGL is proposing infill for small numbers of I&C properties in GD17 as detailed in in Table 3 of "*Appendix A - GD17 Infill Projects*" submitted to UR in June 2015. As noted in the paper and reiterated in the GD17 BPT submission and in the GD17 Commentary (see extract below), the existing properties designed to be passed were not broken down by tenure:

4.4 Project List Summaries

A11 Note that, as per PNGL's June GD17 Infill Allowances submission ("Appendix A - GD17 Infill Allowances"), the existing properties designed to be passed are not broken down by tenure

For the purposes of this worksheet, the numbers of existing properties passed from 2016 are all recorded under "OO" to ensure that the costs are captured in worksheet 4.0

Note, as per worksheet 4.5, some of the existing NIHE and I&C properties to be passed in 2015 are included within the "OO" project driver

10% of the existing properties PNGL is proposing to pass are I&C properties (which is consistent with the property split in GD14) as detailed in Table 3 of "*Appendix A - GD17 Infill Projects*" submitted to UR in June 2015.

5.3 NEW BUILD MAINS – Growth (Excluding East Down)

PNGL notes that UR is basing its draft determination on 2,000 new build properties passed per annum across GD17[135]. This is below PNGL's forecast of 3,000 new build properties passed per annum[136]. PNGL does not dispute UR's proposal however on the basis that its capex allowance will be retrospectively adjusted via the capex uncertainty mechanism[137] based on actual number of properties passed at the next price control review.

[134] See PNGL's email to UR of 6 April 2016 and follow-up discussions between PNGL and UR on 8 April 2016

[135] Table 122 of the consultation

[136] Table 121 of the consultation

[137] Table 172 of the consultation

5.4 LOW AND MEDIUM PRESSURE MAINS - EAST DOWN

PNGL does not dispute UR's total allowance for infill mains in East Down in Table 124 of the consultation. However, as detailed in section 10.4, the properties passed detailed in Appendix 4 of the consultation must be aligned with PNGL's forecast development plan for each town e.g. Appendix 4 of the consultation targets PNGL to pass 1,025 properties in Newcastle by 2017 when the infill will only commence in 2019.

As part of the licence extension application, PNGL provided a programme of mainlaying for East Down. UR's property passed target does not align with this. A more reasoned profile of passing existing properties in each of the 13 towns is provided in Table 34 of section 10.4. This results in a different profile of costs than those proposed by UR in Table 124 of the consultation. UR's final determination for GD17 should therefore reflect PNGL's cost profile presented in Table 31:

	East Down	2016	2017	2018	2019	2020	2021	2022	Total
UR (Table 124)	New Build (m)	-	1,064	1,064	1,064	1,064	1,064	1,064	**6,384**
	Other (m)	19,414	49,414	49,414	35,607	35,607	35,607	35,607	**260,670**
	Total (m)	**19,414**	**50,478**	**50,478**	**36,671**	**36,671**	**36,671**	**36,671**	**267,054**
	Total (£k)	**£1,856**	**£3,926**	**£3,926**	**£2,448**	**£2,448**	**£2,448**	**£2,448**	**£19,500**
PNGL re-profiled	New Build (m)	-	1,064	1,064	1,064	1,064	1,064	1,064	**6,384**
	Other[138] (m)	7,366	11,992	22,546	61,883	60,636	56,615	39,632	**260,670**
	Total[139] (m)	**7,366**	**13,056**	**23,610**	**62,947**	**61,700**	**57,679**	**40,696**	**267,054**
	Total (£k)	**£538**	**£953**	**£1,724**	**£4,596**	**£4,505**	**£4,212**	**£2,972**	**£19,500**

***Table 31** – East Down Low and Medium Pressure Mains*

5.5 DOMESTIC METERS – END-OF-LIFE REPLACEMENT

PNGL notes the number of approaches to uncertainty and incentives for this new strand of investment presented by UR in paragraph 7.91 of the consultation.

As detailed in response to PNGL-037 on 3 December 2015, the industry standard for replacing domestic meters at the end of their useful life is based on the approach adopted by National Grid[140] i.e.

- Domestic Credit Meters – 20 years; and
- Domestic Prepayment Meters – 10 years.

PNGL as a prudent operator believes that the tried and tested approach of National Grid is a reasonable basis for replacement meter times.

[138] Total "other" infill per table 124 of the consultation pro-rata with re-profiled annual properties passed in Table 35 of section 10.4

[139] Total allowance per table 124 of the consultation pro-rata with re-profiled total infill

[140] Source: '*National Grid Metering 2012/2013 Pricing Consultation*'

PNGL has assumed an end of useful life replacement time for all meters types (i.e. including prepayment) of 20 years. PNGL has adopted a longer replacement time for prepayment meters than has been adopted by National Grid, as the batteries of all prepayment meters operated by PNGL are exchanged and the meters visually inspected after 10 years. PNGL is therefore deferring the replacement of domestic prepayment meters and consumers are already benefitting in the long term from an extended economic life of domestic prepayment meters.

PNGL does not consider a volume driver for domestic meter replacements is required. PNGL's forecast of the number of domestic meter replacements included within its GD17 submission is based on the data held within its asset register which records the meter installation date. PNGL would therefore be provided with a pre-determined amount of investment with PNGL carrying the risk and benefit of having over or under-forecast the number of meters to be replaced across GD17.

5.6 I&C METERS – END-OF-LIFE REPLACEMENT

PNGL requested allowances to replace all I&C meters that reach the end of their useful life during the GD17 period. As detailed in response to PNGL-037 on 3 December 2015, the industry standard for replacing meters at the end of their useful life is the approach adopted by National Grid.

PNGL as a prudent operator believes that the tried and tested approach of National Grid is a reasonable basis for replacement meter times.

UR proposes to allow the costs for the end-of-life replacement of domestic meters[141] and U6 I&C meters[142] over a 20 year life cycle. However, UR states that:

> *"In view of the higher replacement cost estimated by PNGL for larger I&C meters and the opportunities for extending the life of these assets by maintenance and partial replacement of key components, we have not included the end-of-life replacement for larger meters at 20 years as proposed by PNGL. We expect the company to assess options for managing these high value assets and their associated whole life costs to allow us to reach an informed decision for the final determination. This should consider replacement on age, targeted replacement of key components or the continued maintenance of the plant over a longer life. We will consider the evidence the company presents before reaching our final determination."*[143]

UR has been notified by PNGL during previous price control reviews that it intends to perform end-of-life meter replacement on all meter types (domestic and I&C) after 20 years. At no point prior to the publication of the GD17 draft determination has UR indicated to PNGL that its proposal was not satisfactory.

[141] Paragraph 7.88 of the consultation

[142] Paragraph 7.98 of the consultation

[143] Paragraph 7.97 of the consultation

PNGL has now considered UR's request to *"assess options for managing these high value assets and their associated whole life costs"* and has developed a process for how the end-of-life replacement of the larger (and more expensive) I&C meters could be extended. Information on the process and on PNGL's assessment of the costs required during the GD17 period is provided below.

5.6.1 OVERVIEW

PNGL as the owner and operator of metering assets across all customer groups (domestic and I&C) has a primary responsibility to maintain meters in proper order.

For I&C customer installations PNGL utilise three meter variants:

- Diaphragm Capacity U16 – U40
- Rotary (RPD) Capacity U65 – U400
- Turbine Capacity U650 – U2500

Diaphragm e.g. U40

Rotary e.g. U400

Turbine e.g. U1000

Mechanical diaphragm meters are simple and relatively low cost devices that do not have replaceable parts and as such are not easily inspected or maintained by PNGL or suitable for overhaul.

For rotary and turbine meters, replacement of key working components is possible but would have to be completed as part of a meter refurbishment undertaken by specialist service providers.

With few exceptions, meters are fitted as part of a customer regulator installation and operate as part of a "metering system" and are subject to service conditions that are dependent on a number of variable factors that are often specific to the site or network. Such factors include:

- Configuration of the meter installation;
- Setup and performance of pressure control equipment;
- Customer load characteristics;

- Environmental conditions; and
- Quality of the distributed gas.

In addition to the above, the mechanical wear and tear on a meter and rate of deterioration for similar service conditions may be influenced by the quality of the meter and components which may vary across meter manufacturers and change depending on the year of manufacture, place of manufacture, construction materials used etc.

With these factors in mind PNGL propose the following:

5.6.2 DIAPHRAGM METERS

Diaphragm meters have the smallest capacity and are the least expensive I&C meters utilised by PNGL.

U6 meters, which UR has proposed to allow PNGL costs for 20 year end-of-life replacement, are diaphragm meters and are mechanically similar to diaphragm meters operated by PNGL for larger capacity I&C installations.

U6

U40

PNGL proposes that all mechanical diaphragm meters (U16 to U40) be replaced at 20 years consistent with that accepted for domestic meters. The rationale behind this is that diaphragm meters, irrespective of size, have the same design, operating principles and failure modes / effects and therefore the expected life associated with ageing and mechanical deterioration will be similar. Diaphragm meters do not have replaceable parts and as such are not easily inspected or maintained by PNGL.

UR should allow PNGL the costs to replace all diaphragm meters (U6 to U40) at 20 years.

5.6.3 ROTARY AND TURBINE METERS

In the absence of the results and analysis from an extensive testing programme on the performance of rotary and turbine meters beyond 20 years (most notably continued measurement accuracy), PNGL recommend that in line with the industry standard all meters are replaced after 20 years.

However, PNGL has proposed a testing and inspection process that could be commenced in the GD17 period to attempt to extend the life of rotary and turbine meters from 20 to 25 years.

PNGL's proposed process for end-of-life assessment would utilise a combination of the following activities:

- Independent Accuracy / Recalibration Testing Of Meters;
- On Site Functional Testing Of Meters (where possible and practical); and
- Visual Inspection of Meters.

This end-of-life assessment relates solely to the meter itself and not the customer meter installation and therefore will focus on factors directly influencing meter integrity.

For all meters, end-of-life will be assessed under the following headings:

- Gas Soundness;
- Corrosion;
- Damage;
- Liquid Contamination;
- Mechanical Failure; and
- Meter Accuracy.

Throughout the meter testing / inspection process information and data captured would be recorded within PNGL's asset management system. This will ensure specific details of faults are logged enabling analysis for trends and identifying those issues affecting wider meter populations and / or network issues requiring action.

Independent Accuracy / Recalibration Testing Of Meters

Approved meter testing service providers would have to be identified by PNGL, contractual agreements set up and the costs for transport, handling and testing established.

Where meters test as accurate, they could be considered for re-use subject to further 5 year life being guaranteed. Guidance on subsequent re-calibration / retesting frequencies would have to be determined.

PNGL propose that all rotary and turbine meters are still replaced after 20 years but the meters removed from the network are sent to an approved meter testing service provider for accuracy and calibration testing. Meters deemed to remain accurate following testing would be returned to PNGL, subject to conditions previously stated, and reinstalled in the natural gas network facilitating further removal / rotation of meters on an ongoing basis. Inaccurate meters would be scrapped.

353 rotary and turbine meters are anticipated to reach 20 years in service during the GD17 period. A breakdown of these meters is provided in Table 32:

Meter Type		2017	2018	2019	2020	2021	2022	Total
Rotary	U65	30	30	30	30	30	37	**187**
	U100	1	1	1	1	1	1	**6**
	U160	5	5	5	5	5	5	**30**
	U250	10	10	10	10	10	14	**64**
	U400	0	0	0	0	0	0	**0**
Turbine	U650	2	2	2	2	2	2	**12**
	U1000	8	8	8	8	8	8	**48**
	U1600	0	0	0	0	0	0	**0**
	U2500	1	1	1	1	1	1	**6**
	Total	**57**	**57**	**57**	**57**	**57**	**68**	**353**

Table 32 *- 20 year old Rotary and Turbine meters during GD17*

On Site Functional Testing

Subject to the development of an appropriate test procedure and the receipt of complete test criteria from relevant manufacturers, it is proposed that PNGL could utilise annual onsite functional tests on reinstalled rotary meters to confirm ongoing performance in order to assist extend end-of-life beyond 20 years.

The potential for onsite testing of turbine meters is limited and further investigation will be required on the possibility of proving meters through a spin down test and / or checking the health of the turbine wheel if tip sensors are fitted. PNGL's initial investigations indicate that onsite functional testing of turbine meters will not be possible for the GD17 period.

It is proposed that on site testing for rotary meters would take the form of two tests:

- Gas Rating / Flowrate Check against a known gas load (e.g. single boiler operating at 100%); and
- Measurement of the pressure drop / differential across the meter against a known gas flow.

These tests could be completed together and will be reliant on;

- Existence of a suitable pressure test points;
- Accuracy of load determination / appliance rating;
- Availability of manufacturer's meter performance curves (ΔP versus Flow); and

- Purchase of a pressure differential tester (Rotary Meters) and availability of test points on meter.

It is proposed that annual onsite functional tests would be performed on all rotary meters deemed accurate following accuracy and calibration testing and that have been reinstalled into the PNGL network.

Visual Inspection of Meters

It is proposed that annual visual inspections would be performed on rotary and turbine meters reinstalled into the PNGL network following accuracy and calibration testing for which onsite functional testing could not be performed.

5.6.4 COSTS

In order to implement the proposed end-of-life extension for rotary and turbine meters PNGL will require capex and opex allowances in the GD17 period:

- Capex allowances – to replace meters (at a lower volume than if they were all replaced at 20 years)
- Opex allowances – to perform:
    i. Independent accuracy and recalibration tests[144];
    ii. Onsite functional tests (where possible); and
    iii. Visual inspections.

PNGL's analysis of the allowances required to extend the end-of-life for rotary and turbine meters in comparison with the allowances requested to perform 20 year end-of-life replacement is provided in Table 33:

[144] PNGL has obtained provisional costs to perform accuracy and recalibration tests from an OFGEM approved meter tester for relevant rotary and turbine meters

	2017	2018	2019	2020	2021	2022	Total
PNGL requested end-of-life replacement costs[145]	£610,250	£610,417	£606,319	£605,645	£605,783	£732,397	£3,770,811
Extend end-of-life CAPEX costs[146]	£756,003	£376,002	£376,002	£376,002	£376,002	£800,003	£3,060,014
Extend end-of-life OPEX costs	£33,452	£33,452	£34,986	£36,519	£38,053	£44,045	£220,507
GD17 Saving	**-£179,205**	**£200,963**	**£195,331**	**£193,124**	**£191,728**	**-£111,651**	**£490,290**

Table 33 *- Proposed Capex and Opex costs to extend end-of-life for Rotary and Turbine meters*

It is estimated that the implementation of processes to extend the end-of-life of rotary and turbine meters from 20 to 25 years would save c.£500k (or 13%[147]) over the GD17 period.

In the absence of actual outcomes from independent accuracy tests on 20 year rotary and turbine meters, PNGL as a prudent operator has assumed a pass / failure rate of accuracy and recalibration testing, and hence the volume of meters older than 20 years that can be reinstalled in the PNGL network, of 50%. The collation of actual results during the GD17 period will allow more accurate analysis of costs for the GD23 price control period. Further information on PNGL's analysis can be provided to UR upon request.

UR should either (i) provide PNGL with appropriate capex allowances to replace all rotary and turbine meters at 20 years; or (ii) provide PNGL with appropriate capex and opex allowances to implement procedures to attempt to extend the end-of-life of rotary and turbine meters from 20 to 25 years.

5.7 TRAFFIC MANAGEMENT ACT (TMA)

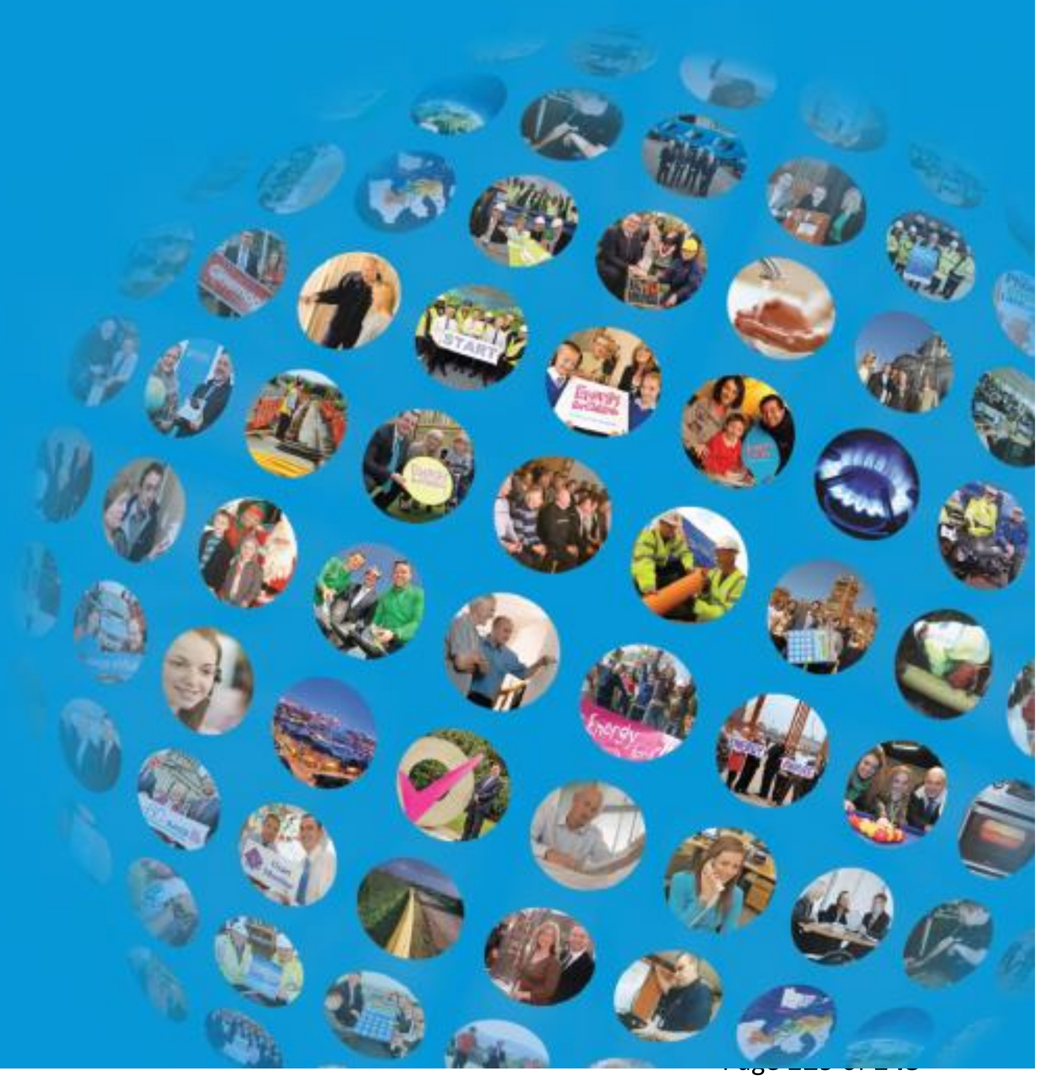
PNGL welcomes UR's proposal that TMA costs will continue to be subject to retrospective adjustment at the time of the next price control review given the uncertainty in terms of the timing of implementation of TMA in NI and the impact on costs. PNGL notes UR's analysis retains TMA forecasts as a separate capex cost line to better facilitate the retrospective adjustment.

[145] Table 4.12a of PNGL's GD17 BPT submission

[146] PNGL has utilised UR's proposed *'Basket of Works Unit Rates'* for the costs to replace meters - Table 93 of the consultation

[147] i.e. £490,290 / £3,770,811 in Table 34

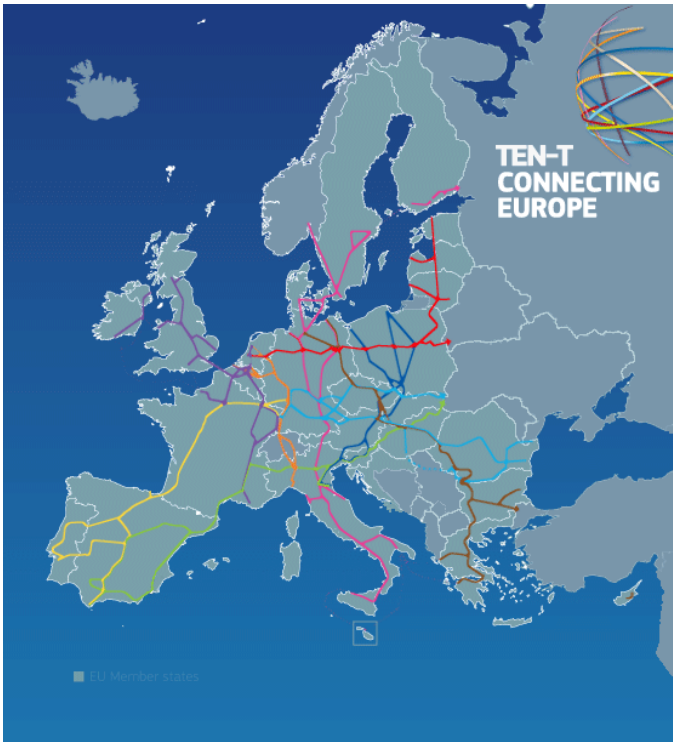
OTHER AREAS



6. INNOVATION

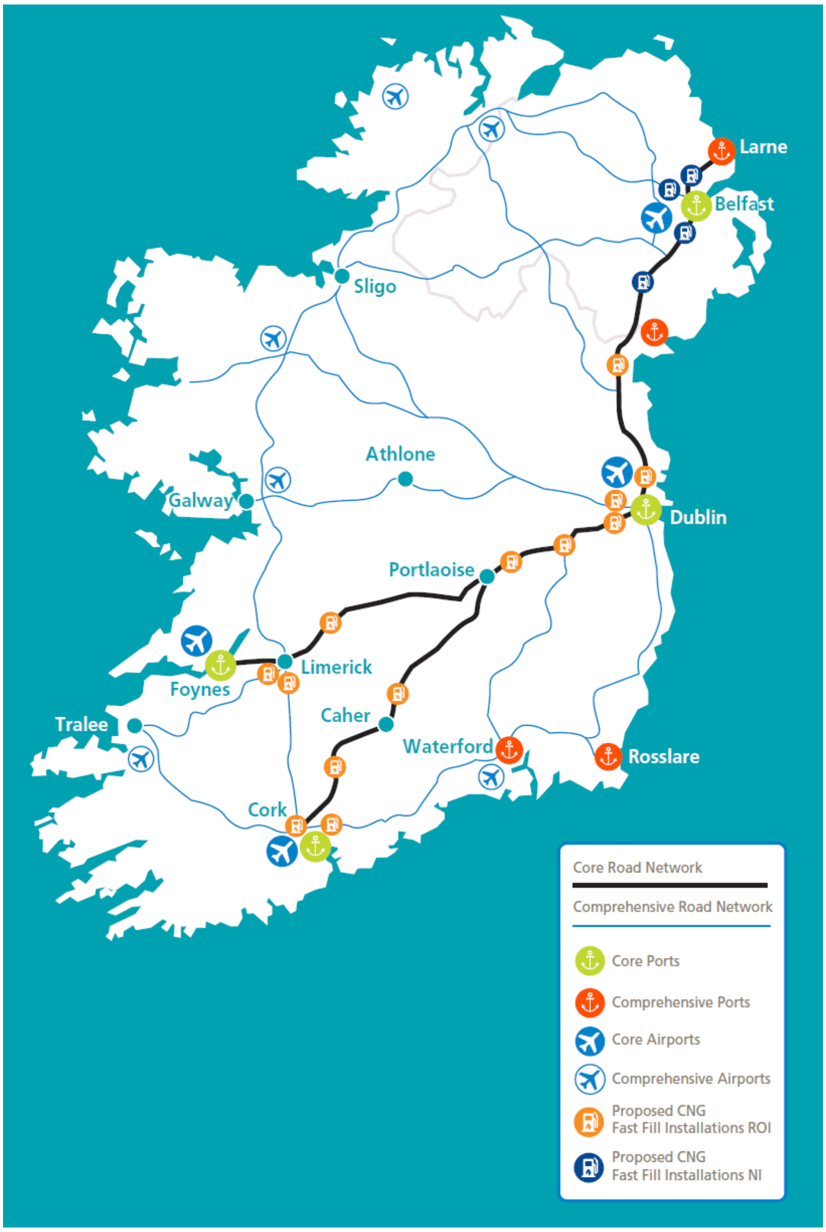
6.1 DEVELOPMENT OF INFRASTRUCTURE FOR COMPRESSED NATURAL GAS VEHICLES

As detailed in PNGL's "*GD17 Innovation Paper*" submitted to UR in June 2015, PNGL has applied to the European Union for funding (alongside project partners firmus, Ervia and the Technology Centre for Biorefining and Bioenergy) of a cross-border Compressed Natural Gas ("**CNG**") network impact study involving the development and study of a system of CNG fast fill installations along Ireland's TEN-T (Trans-European Transport Network) core road network. The study proposes to examine the impacts from increased levels of CNG fast fill installations on the operation of the transmission and distribution gas networks in both the Republic of Ireland and NI.



The introduction of a comprehensive network of CNG refuelling facilities poses some significant questions regarding the operation of the gas network into the future. The purpose of this study is to further develop Network Operators' understanding of the operation and planning of the network by examining CNG equipment and user behaviour.

Gas Network Operators across Ireland have come together under this project to facilitate an All-Island study of the impacts from CNG on the total gas system. The four project partners will develop a pilot network of 17 CNG stations along the TEN-T core road network (as illustrated below) between the Republic of Ireland (13 stations) and NI (three stations in PNGL's Licensed Area and one station in the firmus Licensed Area) in order to assess the impacts on the gas network.



The isolated nature of the Irish gas system means that relatively few CNG stations can have a proportionately larger operational impact than might be the case in other more integrated systems. This offers the Irish gas grid as an ideal location to investigate the impacts of higher levels of CNG infrastructure as Europe moves towards higher levels of CNG deployment.

This CNG project lies outside the scope of PNGL's routine price control activities. However given that the scope and scale of the CNG project is not sufficiently advanced, PNGL is not in a position to provide a business plan of all identified costs at this stage.

PNGL agrees that there is a reasonable prospect that the CNG project may not be sufficiently advanced to allow for a decision on cost allowances at the time of the GD17 determination.

PNGL therefore agrees with UR's proposal and expects that any costs associated with the CNG project will be included within the GD17 Uncertainty Mechanism.

7. UNCERTAINTY MECHANISM

7.1 UNCERTAINTY MECHANISM

PNGL notes that an uncertainty mechanism has been proposed for GD17 in line[148] with that currently being applied for GD14.

PNGL comments on the treatment of network rates within the mechanism in section 4.7.1.

UR should include the following projects in the uncertainty mechanism and in Table 173 of the consultation:

1. PNGL comments in section 4.8 that any costs associated with the NIED project must be included within the Uncertainty Mechanism given that the scope and scale of the NIED project for GDNs has not been properly defined and is not therefore within PNGL's control;

2. PNGL comments in section 9 on the proposed treatment of costs associated with a Supplier of Last Resort ("**SoLR**") event; and

3. PNGL comments in section 6.1 that any costs associated with the CNG project must be included within the Uncertainty Mechanism given that the scope and scale of the CNG project may not be sufficiently advanced to allow for a decision on cost allowances at the time of the GD17 determination.

7.2 MATERIALITY THRESHOLDS

UR's proposal to increase the materiality threshold for requests for additional projects[149] to £150k is misguided. **The proposed threshold is not appropriate to the size of PNGL's operations and should be removed.**

To put this threshold into context, the cost of developing the semi-automated IT system which facilitated the introduction of supply competition within PNGL's Licensed Area was less than £100k. Under UR's materiality threshold proposal, PNGL would have had to fund fully development of the switching system, which benefits suppliers and consumers, for the Greater Belfast area but which is of no direct benefit to PNGL.

The application of such a materiality threshold over a cost category such as IT, further demonstrates the inappropriateness of this threshold. Given the replacement cost of PNGL's current IT

[148] Updated for GD17 unit rates and activities

[149] PNGL acknowledges (paragraph 11.58 of the consultation) that the materiality threshold will not be applicable to SoLR events. This should be stated in the GD17 Uncertainty Mechanism

infrastructure, PNGL's IT allowance is already fully committed and therefore there would be no margin for absorbing any such de minimus expenditure.

Another example is the potential for PNGL to have to develop with GDNs and PTL:

- a Forecasting Party Agreement;
- Network Code arrangements; and
- a supporting system

to allow the exchange of nomination and allocation information. Although the scope and scale of the project for GDNs is yet to be properly defined, PNGL envisages that it will cost significantly less than the materiality threshold. This is just one example. Under UR's materiality threshold proposal, PNGL would likely have to fund all projects arising out of European Directives or equivalent local legislation which it is required to implement. As GDNs have no ability to influence or control such legislation they should not be exposed to unnecessary risk.

8. FINANCIAL ASPECTS

The consultation sets out UR's rate or return proposals for GD17; the financeability analysis UR proposes to undertake; and UR's proposals to align the depreciation profiles of PNGL and firmus. We address each of these in turn below.

PNGL will continue to work with UR under the separate Pi modelling workstream[150] to find a pragmatic solution to the current Pi modelling challenges. This workstream incorporates inclusion of the Postalised Distribution Pipeline within the model such that prices are completely unaffected (see section 9.2).

8.1 RATE OF RETURN

Section 3.1 discusses PNGL's concerns with UR's proposed rate of return.

8.2 FINANCEABILITY

Section 3.1.1 discusses PNGL's concerns with UR's financeability assessment.

8.3 PROFILE ADJUSTMENT

PNGL notes[151] that UR plan to progress further analysis of the profile adjustment along with the interlinked areas of depreciation and adjusting the Forecast Horizon.

The application of a profile adjustment mechanism was created to facilitate the orderly development of the natural gas industry within PNGL's Licensed Area.

The utilisation of such a mechanism was based on the principle of equalisation of prices in the long-run, on a real basis. This avoided prices being unnecessarily high at a time when the industry was in development thereby ensuring that the natural gas industry developed to its fullest extent.

PNGL's GD17 submission is based on both continuing to develop the market within our Licensed Area and commencing development to East Down. Therefore the argument for continuing to use the profile adjustment mechanism from a development point of view still pertains to the GD17 price control period.

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[150] See PNGL's email to UR of 3 May 2016 and follow-up discussions between PNGL and UR on 11 May 2016

[151] Paragraph 10.96 of the consultation

Furthermore, as detailed in section 3.1.1, PNGL's key financial ratios adjust for the profile adjustment so as not to impact on financeability of the business. Therefore there is no strong reason on a pure financeability basis to accelerate the removal of the profile adjustment at this time.

8.4 DEPRECIATION

PNGL notes the differences between the PNGL and firmus asset life assumptions. PNGL is not averse to UR's proposal to align the depreciation approaches within the GDNs; in fact a 5 year depreciation of IT expenditure seems more appropriate than the 40 year depreciation currently applied under PNGL's regulatory model.

However PNGL does not agree that services should change from 35 to 40 years. This would only serve to lengthen PNGL's cost recovery period. PNGL would therefore suggest that the following asset lives are used:

Asset Categories	Asset Lives (years)
Mains	40
Services	35
Meters	15
Other	5

8.5 2015 ACTUALS

PNGL has already raised with UR the issue of resubmitting its BPT, updated with 2015 actuals, by 30 June 2016[152]. PNGL will continue to work with UR to find a pragmatic solution to the current challenge of providing UR with 2015 actuals in an appropriate format in advance of the GD17 determination.

[152] Paragraph 3.11 of the consultation

9. OUTPUTS, OUTCOMES AND ALLOWANCES

PNGL notes UR's initial view on the issues to be considered during the GD17 price control period but after the GD17 final determination include:

1. **Customer Service / Consumer Engagement** PNGL would suggest that the Gas Distribution Forum is reconvened following UR's GD17 determination to address Customer Service / Consumer Engagement issues and agree a suitable timetable for any future reporting requirements. Further detail is provided in Chapter 11;

2. **Shrinkage** PNGL is unclear what is required in the report under paragraph 11.47 of the consultation which states that UR "…*would expect the GDNs to provide a report including a professional estimate of leakage and own use gas as a basis for estimation of shrinkage due to theft*." PNGL would suggest that the Gas Distribution Forum is reconvened following UR's GD17 determination to facilitate UR's proposed shrinkage review and agree a suitable timetable for any future reporting requirements. Further detail is provided in Chapter 11; and

3. **Supplier of Last Resort (SoLR)** PNGL is working with UR and GDNs to develop appropriate SoLR processes. PNGL notes[153] that, in a SoLR event, it will be required to pay the allowed SoLR costs determined by UR to the SoLR within its Licensed Area. ***These costs must be an automatic pass through item for GDNs under the Uncertainty Mechanism[154]; GDNs have no ability to influence or control costs they should not be exposed to unnecessary risk.***

   PNGL remains concerned with the first option presented by UR for building SoLR costs into the GD17 price control for the reasons presented in the joint submission by GDNs on SoLR payments of 12 January 2016 – option one could result in significant delay in GDN ability to start to recover costs as adjustments would only be made at the next price control (potentially up to 6 years). ***Option one is not therefore acceptable to PNGL.***

   Furthermore PNGL has concerns with option two[155] as the specific monetary allowance is subjective and may still result in significant delay in GDN ability to start to recover costs. The costs included in the Uncertainty Mechanism would be based on a set of assumptions and

[153] Paragraph 11.57 of the consultation

[154] PNGL acknowledges (paragraph 11.58 of the consultation) that the materiality threshold will not be applicable to SoLR events. This should be stated in the GD17 Uncertainty Mechanism

[155] Under the current Uncertainty Mechanism for pass through costs, any difference between the allowance in the determination and the actual costs incurred will result in a retrospective adjustment at the next review. This adjustment equals the variance together with the return (at the GD14 rate of return) on this variance. PNGL would therefore expect the adjustment would equal the variance between the allowance in the GD17 determination and the actual costs incurred together with the return (at the GD17 rate of return) on this variance. PNGL would welcome confirmation from UR that this is the adjustment proposed at paragraph 11.58 of the consultation

given that a SoLR event will be determined by the portfolio of the failing gas supplier, it is difficult to assess the impact of any such event. Key to this is the estimated cost which the appointed SoLR will incur and although discussions with UR are ongoing, little progress has been made; potential allowable costs have not yet been identified to allow a proper consideration of cost recovery amounts. Furthermore it is essential that UR provides clarity on the treatment of cost incurred by the SoLR for providing additional credit support as this could significantly affect the level of costs required under any Uncertainty Mechanism. It cannot therefore be assumed that the proposed SoLR cost recovery process will not present financing issues under option two given that the scope and scale of the SoLR may never be sufficiently advanced to allow for a decision on cost allowances at the time of the GD17 determination. ***Option two therefore continues to present PNGL with significant risk as scope and scale of the SoLR is unknown and outside the control of both UR and PNGL.***

PNGL notes that option two is UR's preferred option[156]. As presented in the joint submission by GDNs on SoLR payments of 12 January 2016, a more pragmatic solution would be to amend GDN Licences to allow SoLR payments to be recovered through a specific and limited Special Review (under Licence Condition 4.7 in the SGN Natural Gas Licence although a new Licence Condition would be required for PNGL to allow SoLR payments to be recovered). As set out in the SGN Natural Gas Licence currently, if the claim is made in the first 6 months of the Formula Year, an adjustments could be made the following Formula Year but if a claim is made in the last 6 months, a special tariff modification could be considered for the following Formula Year (if necessary mid-year but with a minimum 6 months' notice period for Suppliers). This would ensure that GDNs are not exposed to unnecessary risk.

Irrespective of the SoLR cost recovery solution, PNGL would encourage UR to reconsider the inclusion of appropriate wording within GDN licences which details the SoLR cost recovery process to provide the necessary transparency and governance of the cost recovery process.

PNGL will continue to work with UR and GDNs under the separate SoLR workstream to develop appropriate SoLR processes and to find a pragmatic solution to the current challenges.

PNGL's comments on the remainder of Section 11 of the consultation are detailed below.

9.1 RISK SHARING MECHANISM

PNGL agrees with UR[157] that the current principles of risk sharing i.e. a 5-year capex rolling incentive mechanism for PNGL, are reasonable for GD17.

[156] Paragraph 9.21 of the consultation
[157] Paragraph 11.11 of the consultation

PNGL also notes UR's current thinking[158] that a simplified 50:50 risk sharing mechanism could be a reasonable alternative. PNGL understands the simplification and clarity that such a risk sharing mechanism may bring. However, UR has not presented as part of its draft determination the rationale for amendment to the current principle of risk sharing nor has UR provided detail on how this would be applied in practice.

UR has not discussed a 50:50 risk sharing mechanism with PNGL. Application of such a complex mechanism will require detailed discussions to investigate and, if appropriate, develop and model.

PNGL is content that its current 5-year capex rolling incentive mechanism is appropriate and should be maintained for GD17. PNGL would be happy to engage with UR to investigate a simplified 50:50 risk sharing mechanism as part of the GD23 price control process.

9.2 <u>EAST DOWN</u>

PNGL notes[159] that the inclusion of the Postalised Distribution Pipeline should have no impact on distribution tariffs. PNGL does not believe that the Pis model published by UR currently achieves this. PNGL will continue to work with UR under the separate Pi modelling workstream[160] to find a pragmatic solution to the current Pi modelling challenges, notably inclusion of the Postalised Distribution Pipeline within the model such that prices are completely unaffected.

PNGL would welcome early sight of UR's proposed licence modifications so that any queries can be raised at the earliest opportunity.

9.3 <u>DESIGNATED PARAMETERS AND DETERMINATION VALUES</u>

As advised by PNGL during the consultation process[161], there is a typo in Table 189 of the consultation - "*m*" should be 2016 (not 2017) in line with Licence Condition 2.3.26 which states that "*m*" is:

"The Formula Year that was n for the preceding review"

[158] Paragraph 11.18 of the consultation
[159] Paragraph 11.109 of the consultation
[160] See PNGL's email to UR of 3 May 2016 and follow-up discussions between PNGL and UR on 11 May 2016
[161] See PNGL's email to UR of 6 April 2016 and follow-up discussions between PNGL and UR on 8 April 2016

10. LICENCE IMPLICATIONS

PNGL notes that UR will modify PNGL's Licence to reflect the GD17 Designated Parameters and GD17 Determination Values in order to bring into effect its GD17 determination. PNGL's comments on UR's additional licence modification proposals are detailed below.

10.1 FUTURE TREATMENT OF PROFILE ADJUSTMENT

PNGL's views are addressed in section 8.3.

10.2 USE OF OPEX AND CAPEX ROLLERS

PNGL's views are addressed in section 9.1.

10.3 LICENCE ALIGNMENT BETWEEN GDNs PURSUANT TO THE GAS TO THE WEST PROJECT

PNGL notes UR's intention to modify the PNGL and the firmus licences to include equivalent licence conditions as contained in the SGN licence.

- In relation to Condition 1.16.1 we note that the equivalent provision in the SGN Licence also includes the following wording: "(a) *it conveys, or is authorised to convey, gas through low pressure pipe-lines*;". This appears to be an oversight, and should be included for consistency with the SGN Licence.

- In relation to Conditions 2.4.19 and 2.4.20, it is unnecessary to duplicate legislative requirements within PNGL's Licence. PNGL is already obliged to meet the requirements of The Gas (Individual Standards of Performance) Regulations (Northern Ireland) 2014.

- In relation to Condition 2.8A.2 we note that the code of practice for the handling of consumer complaints would require PNGL to establish and operate an accessible, equitable and transparent, simple and inexpensive complaints procedure which shall enable **any person** to bring and have promptly dealt with **any complaint they may have in respect of PNGL's activities**. The definition of a complaint has been discussed at length at the Distribution Operators' Forum and PNGL does not reiterate its concerns here. However PNGL would ask UR to confirm if the changes are required as the current definition contained in the PNGL and in the firmus licences is unduly narrow and is no longer deemed to be IME3 complaint?

PNGL notes that these licence modifications will require the GDNs to co-ordinate on a number of areas including:

- delivering a common branding approach in relation to promoting natural gas in NI; and
- delivering a common low pressure network tariff in NI; and
- producing a single low pressure network code together with a consistent switching system and consistent switching processes.

PNGL's comments on each area are detailed below.

10.3.1 A COMMON BRANDING APPROACH

In relation to Condition 2.16.1(a) we note that GDNs would be required to develop, implement and comply with the Common Branding Approach in conjunction and co-operation with any other person that holds a licence granted under Article 8 of the Order i.e. GDNs and transmission, supply and storage licence holders. This appears to be an oversight, and should include the following wording: "(a) *in conjunction and co-operation with all other distribution system operators authorised to convey gas through low pressure pipelines*;" given that the Common Branding Approach would apply to GDNs only. This wording would ensure consistency with that proposed for delivering a common low pressure network tariff (Condition 2.17.1) and with that proposed for producing a single low pressure network code (Condition 2.5.13).

PNGL has established and continues to maintain good relations with its stakeholders, third parties and consumers. PNGL has established a strong and trusted brand and has a world class reputation as a responsible business.

PNGL's brand awareness in its Licensed Area is well established and with the vast majority of those connected saying that they would recommend the benefits of natural gas to a friend, there is a high level understanding of the benefits of natural gas amongst homeowners.

Although an element of this brand awareness may transfer to other Licensed Areas, PNGL is mindful that homeowners in other Licensed Areas will not have had regular exposure to PNGL marketing. In new Licensed Areas there is likely to be limited first-hand experience of using natural gas resulting in even less exposure to friends and families positive experience of natural gas.

As the natural gas network expands into new Licensed Areas, there will be distinct consumer needs from established Licensed Areas such as PNGL's e.g. in the early stages of its development PNGL hosted information events with each community to offer customers the opportunity to find out more about natural gas and the construction programme in their area. These events took place in easily accessible community areas that attracted homeowners, key stakeholders and community representatives and covered issues such as:

- timescales of gas availability;
- mains construction techniques;
- safety of natural gas;
- connection process; and
- the role of a Gas Safe Registered Installer.

While still relevant, albeit to a lesser extent, PNGL now has an established natural gas network and its current focus is on developing one market sector, domestic connections.

Any common branding approach must allow each GDN to meet the distinct needs of consumers in its Licensed Area and not force GDNs into diluting their current practices by overextending the focus of their campaigns or by forcing GDNs to make generic points in each campaign. This could hinder GDNs ability to launch targeted campaigns unique to their Licensed Area and may prove detrimental to the overall development of the natural gas market in NI.

Any common branding approach should therefore focus on continuing to promote the benefits of natural gas to position natural gas as a clean, flexible, contemporary and value for money fuel for the modern home.

PNGL continues to monitor its business operations to ensure that where synergies are identified which could be used throughout NI, GDNs could work together to maintain an efficient and growing natural gas industry.

10.3.2 COMMON LOW PRESSURE NETWORK TARIFF IN NI

PNGL notes that these licence modifications will require the GDNs to co-ordinate on delivering a common low pressure network tariff in NI.

PNGL, firmus and UR[162] met in 2014 to discuss UR's suggestion that GDNs work together on a common understanding and charging methodology across all conveyance charge classes and, where differences do occur, to aim to understand why this is so.

PNGL set out some of the key differences between the GDNs' licence requirements and these, together with other fundamental differences such as stages of network development, future target markets, competing fuels and legacy issues, were discussed in detail at a meeting in May 2014. It was recognised by UR that the GDNs' ability to align charging methodologies would be a medium term project of c.5 years or more.

[162] At that time there were two GDNs in NI, PNGL and firmus

The 2014 discussions focussed on two specific differences in the current charges levied by the GDNs - CHP charges and capacity charging. It was agreed that the GDNs alone could not provide the rationale behind any disparity in charges or deliver appropriate solutions and that both areas required significant input from UR and wider industry, including potential input from the electricity sector.

10.3.3 SINGLE LOW PRESSURE NETWORK CODE, A CONSISTENT SWITCHING SYSTEM AND CONSISTENT SWITCHING PROCESSES

PNGL has an established Network Code and has successfully facilitated the delivery of a competitive retail market, including retail competition processes and all necessary supporting systems, within its Licensed Area. In fact the PNGL Network Code and its key processes is the blueprint for expanding the competitive arena to other Licensed Areas in NI - the PNGL Network Code came into effect in September 2005 and was developed using many of the key Network Code processes already utilised in the Great Britain gas market i.e. it used these tried and tested processes and simplified them to meet the requirements of the NI natural gas market.

PNGL notes that these licence modifications will require the GDNs to co-ordinate on delivering a single Low Pressure Network Code for NI and a consistent switching system and processes.

Given that the PNGL Network Code including retail competition processes and all necessary supporting systems was (i) the blueprint for expanding the competitive arena to other Licensed Areas in NI; and was (ii) developed using many of the key Network Code processes already utilised in the Great Britain gas market, many of the synergies of a single Low Pressure Network Code and a consistent switching system and processes have already been achieved.

UR recognises such synergies and requires GDNs to deliver, under Licence[163], Network Code Modification Rules. These rules are published on PNGL's website[164]. Each GDN has its own set of Network Code Modification Rules; however these are consistent across NI GDNs. Furthermore NI GDNs submit their own Network Code modifications however (i) these are consistent across GDNs; and (ii) UR consents to each Network Code modification at the same time.

Based on PNGL's experience of the development of a single transmission network code, even if GDNs established a single low pressure Network Code, processes such as accession to the Code and Code credit arrangements would still need to be undertaken with each GDN. Similarly other key Network Code activities such as nominations, allocations and distribution charging would still need to be undertaken at individual network level.

PNGL is therefore struggling to understand what benefit a single Low Pressure Network Code will bring.

[163] PNGL Licence Condition 2.5.5
[164] http://www.phoenixnaturalgas.com/fs/doc/Distribution%20Code%20Modification%20Rules.pdf

10.4 LICENCE MODIFICATIONS PURSUANT TO THE EXTENSION OF THE PNGL LICENSED AREA TO EAST DOWN

PNGL does not dispute UR's proposal to include a development plan for East Down in PNGL's Licence. However the following principles must be applied:

Firstly the properties passed detailed in Appendix 4 of the consultation must be aligned with PNGL's forecast development plan for each town e.g. Appendix 4 of the consultation targets PNGL to pass 1,025 properties in Newcastle by 2017 when the infill will only commence in 2019. PNGL's model submitted as part of its licence extension application provided a breakdown of the proposed network build programme of works[165] and as such a more reasoned profile of passing existing properties in each of the 13 towns can be established.

Secondly UR must apply the same principle for East Down as was applied to PNGL's original Licensed Area i.e. New Build properties must be excluded from the development plan as the construction, timing and magnitude of new build developments are not within PNGL's control.

Applying these two principles gives rise to the following development plan for East Down with respect to annual and cumulative properties passed:

Year / Location	2016	2017	2018	2019	2020	2021	2022	Total
Hillsborough		142	530	530	554			**1,756**
Ballygowan	639	483						**1,122**
Ballynahinch		322	580	580	580	671		**2,733**
Annahilt		66	151	162				**379**
Spa		28	162					**190**
Saintfield				486	486	534		**1,507**
Crossgar			252	252	327			**830**
Drumaness			49	217	172	69		**507**
Downpatrick			232	929	929	1,393	1,442	**4,926**
Newcastle				971	971	971	989	**3,901**
Castlewellan				302	302	302	311	**1,217**
Dundrum				274	274	305		**852**
Dromore				668	668	668	698	**2,702**
Total	**639**	**1,041**	**1,957**	**5,370**	**5,262**	**4,913**	**3,439**	**22,622**

Table 34 *– Annual Properties Passed*

[165] See worksheet "*Build Programme*" of PNGL's East Down licence application submission spreadsheet

Year / Location	2016	2017	2018	2019	2020	2021	2022
Hillsborough		142	672	1,202	1,756	1,756	1,756
Ballygowan	639	1,122	1,122	1,122	1,122	1,122	1,122
Ballynahinch		322	902	1,482	2,062	2,733	2,733
Annahilt		66	217	379	379	379	379
Spa		28	190	190	190	190	190
Saintfield				486	973	1,507	1,507
Crossgar			252	503	830	830	830
Drumaness			49	266	438	507	507
Downpatrick			232	1,161	2,090	3,484	4,926
Newcastle				971	1,942	2,912	3,901
Castlewellan				302	604	906	1,217
Dundrum				274	547	852	852
Dromore				668	1,336	2,004	2,702
Total	**639**	**1,680**	**3,637**	**9,007**	**14,269**	**19,183**	**22,622**

***Table 35** – Cumulative Properties Passed*

The profile of passing existing properties in each of the 13 towns in Table 34 will result in a different profile of costs than those proposed by UR in Table 124 of the consultation. The re-profiled costs are detailed in Table 31 of section 5.4.

Finally in determining whether PNGL has succeeded in its obligations under the development plan, UR must apply the same principles as was applied to PNGL's original mandatory development plan. The original development plan is detailed in Schedule 4 of the Licence and specifically required PNGL to develop a sustainable network through which natural gas was available to no less than 81% of all properties within the Licensed Area within a fixed rolling timescale. For reference the relevant extracts of Schedule 4, paragraphs 1(b) and 1(e) are:

"(b) the Licensee shall subject to sub-paragraphs (d) and (e) below instal and bring into operation or make readily capable of being brought into operation distribution pipe-lines such that not less than ninety per cent of premises then in a district may be readily connected to the Network no later than the infill date for that district, which shall be a date five years after the infill start date for that district shown in Annex 1 to this Schedule 4;

…

(e) in further determining whether the Licensee has succeeded in its obligations under sub-paragraphs (b) and (c) above the Licensee shall be treated as having fulfilled its obligation if it had succeeded in respect of all but ten (or less) per cent of the stated percentage of numbers of premises identified by those sub-paragraphs; and…"

PNGL would welcome early sight of UR's proposed licence modifications so that any discrepancies are addressed at the earliest opportunity.

11. NEXT STEPS

PNGL has already taken the opportunity to inform UR of a number of concerns with the draft determination during the consultation period. Given that UR intends to publish its GD17 final determination in September 2016, PNGL would welcome further engagement and discussion with UR on the price control so as to reach a satisfactory final determination which protects the interests of consumers of natural gas and secures that PNGL is able to finance the carrying on of the activities which it is authorised or required under Licence to carry on.

PNGL notes UR's initial view on the issues to be considered during the GD17 price control period but after the GD17 final determination include:

1. Consumer Engagement;
2. Shrinkage Review;
3. Review of Conveyance Charges; and
4. Revision of Annual/Cost Reporting templates and associated RIGs.

PNGL also notes in section 10.3 a number of licence modifications are being proposed which would require the GDNs to co-ordinate on further areas such as:

5. Producing a single low pressure network code together with a consistent switching system and consistent switching processes;
6. Delivering a common branding approach in relation to promoting natural gas in NI; and
7. Delivering a common low pressure network tariff in NI (this will be addressed within the review of conveyance charges at point 3).

PNGL would suggest that the Gas Distribution Forum is reconvened following UR's GD17 determination to agree a suitable timetable for addressing these areas so that GDNs may prioritise UR's most relevant aspects e.g. delivering a common branding approach[166]. This will ensure that there is a transparent and workable timetable for both UR and GDNs to manage workloads into the future.

[166] Paragraph 12.112 of the consultation

RESPONSE TO GD17 DRAFT DETERMINATION

Cost of equity

27 May 2016

Confidential

CONTENTS

1 EXECUTIVE SUMMARY

1.1 In this paper we evaluate UR's Draft Determination for PNG's cost of equity allowance in the GD17 regulatory period.

1.2 UR has made a number of errors in its approach to setting the cost of equity. Most notably these errors relate to UR's provisional determination on beta. In addition, UR's calculation of the real pre-tax WACC allowance results in under-remuneration of tax costs.

1.3 We also do not agree with UR's evidence on Total Market Return (TMR) and its component parts. However, we focus in this paper on the two primary errors in UR's approach relating to beta and tax.

Beta

1.4 UR has stated its view that PNG's beta allowance for GD17 should be at the top end of the range of allowed betas for UK network utility comparators.

> "*For this draft determination, we use a value of 0.40. This gives recognition, in particular, to the fact that there are differences with PNGL's and FE's regulatory model from the standard model, e.g. the Profile Adjustment, and notwithstanding the analysis that we have summarised above, the possibility that investors may not be wholly familiar with these differences. While we regard this as a small and potentially short term factor, our initial view is that a cautious approach is appropriate and this therefore warrants placing the GDNs at the top of the betas that regulators have judged appropriate for low-risk network utility businesses*."[1]

1.5 We agree with UR that PNG is relatively higher risk than other UK utilities, although UR's relative risk assessment does not fully reflect the range of evidence in support of that conclusion (which has been set out fully in our earlier papers).

1.6 UR considers that 'typical' UK network utilities have been allowed an asset beta in the range of 0.3 - 0.4. However, UR has incorrectly interpreted the UK precedent range. This is because UR has failed to control for differences in the debt beta assumption which was used in those regulatory decisions. As a result, the range presented by UR is not like-for-like.

1.7 UR has provisionally assumed a debt beta of 0.1 for NI GDNs. Given this assumption, UR should have re-stated the UK regulatory determinations on asset beta on a consistent basis. If UR had done this correctly, the like-for-like range for UK comparator asset betas would be in fact 0.36 – 0.43. This shows that UR has not in fact proposed an asset beta at the top end of the range of UK comparators, but rather the proposed asset beta is in the middle of the range.

[1] UR, GD17 DD, paragraph 10.34

1.8 The result is a cost of equity allowance which is too low. If UR intends to continue to assume a debt beta of 0.1, UR must at the very least utilise an asset beta of 0.43, reflecting its view that PNG is at the top end of the range of precedent.

1.9 We also note that UR (and its advisor, First Economics) has provided very little justification for its proposed debt beta assumption of 0.1. UK regulators including Ofgem and Ofwat have assumed that debt beta is zero; and in its most recent determination for Bristol Water the CMA also assumed a debt beta of zero. In general, practitioners expect that the debt beta assumption (if applied correctly) will not have a material effect on equity beta estimates, or consequently on the final allowed cost of equity. Given this, we propose that UR removes the debt beta assumption from its analysis, in line with GB precedent.

1.10 Finally, we note that UR has not relied on up-to-date empirical beta estimates to inform its assessment. First Economics has provided empirical estimates which UR states are a reasonable cross-check of its beta proposals. However, the First Economics analysis has not replicated the CMA's approach to estimating beta (despite its stated intention to do so); and relies entirely on data from the post-financial-crisis period in which betas were clearly distorted downwards, relative to longer term trends. Both of these issues mean that First's empirical beta analysis is an unreliable cross-check.

1.11 In our first Frontier/NERA joint paper submitted to UR in June 2015, we observed that since early 2012, beta estimates have been gradually increasing in line with the normalisation of market conditions; and were close to the levels observed before the Global Financial Crisis (GFC) in 2008. Empirical estimates of beta have continued to trend upwards since that paper, and are now much more in line with pre-GFC observed levels. We consider that UR must take the latest empirical evidence properly into account, rather than simply rely on out-dated regulatory precedent or distorted empirical estimates. Our updated analysis shows that the ***average*** asset beta across the peer group is now 0.44, assuming a debt beta of zero. This is equivalent to an average asset beta of 0.48, assuming a debt beta of 0.1.

1.12 Overall, we consider that the latest market evidence - combined with the relevant regulatory precedent and the evidence that PNG is relatively higher risk - supports an asset beta range at the top end of the range of 0.40 - 0.45 (assuming a debt beta of zero). This remains within the range we proposed in June 2015, but recognises that market evidence since then supports an increase in the lower bound of that range. If UR wishes to retain its debt beta assumption of 0.1, the asset beta estimate must be adjusted upwards accordingly.

Tax allowance

1.13 UR's regulatory model requires it to set a real, pre-tax WACC allowance. In practice, corporates incur tax liability calculated on the basis of nominal profits. The tax allowance should therefore capture the fact that inflation will increase profits in nominal terms over time.

1.14 UR's pre-tax WACC calculation should calculate the tax wedge on the basis of the ***nominal*** post-tax cost of equity. UR's current approach does not do this and as a result underestimate the tax allowance.

1.15 Although not many regulators set a pre-tax WACC allowance, we note that the UK telecoms regulator Ofcom; a number of decisions made by the Irish energy regulator CER; and the Italian energy regulator have all ensured that expected tax costs are fully funded via a pre-tax WACC.

Conclusion

1.16 Our updated view of the best estimate of PNG's cost of equity for GD17 is shown in Table 1, compared to UR's draft determination. This proposal is based on an asset beta range of 0.40 - 0.45, as in our original paper. However, updated market evidence now point towards the top end of that range and therefore, our best estimate of PNG's cost of equity is closer to the top end of the estimated cost of equity range of 5.8% - 6.4%. As noted above we have utilised the UR's proposals for TMR, ERP and RFR, although we continue to consider that the evidence set out in our June 2015 paper supports a TMR above this level.

1.17 We consider this a conservative estimate given the recent return of observed betas to their longer-term levels; and the evidence supporting a higher TMR.

Table 1. Summary of proposed cost of equity vs UR draft determination

	UR's draft determination	Frontier estimate
Gearing	55%	55%
Risk-free rate	1.25%	1.25%
ERP	5.25%	5.25%
TMR	6.50%	6.50%
Asset beta	0.40	0.40 - 0.45
Debt beta	0.10	0
Equity beta	0.77	0.89 - 1.00
Post-tax cost of equity	5.3%	5.8% - 6.4%
Pre-tax cost of equity	6.6%	7.8% - 8.5%

Source: *Frontier Economics, UR's draft determination.*

Note: *We assume gearing of 55% in line with UR's draft determination. We also assume inflation of 2.2% in line with break-even inflation over the GD17 period as set out in NERA's paper.*

2 INTRODUCTION

2.1 In its March 2016 Draft Determination (DD) for GD17, the Utility Regulator (UR) estimated PNG's real pre-tax WACC to be 4.3%. This was calculated on the basis of a pre-tax cost of equity (CoE) of 6.6% (equivalent to a post-tax CoE of 5.3%); cost of debt (CoD) of 2.3%; and gearing of 55%. UR commissioned a paper by First Economics (First) which provides supporting evidence for UR's WACC estimate[2].

2.2 In this paper, we evaluate UR's DD on the cost of equity. A separate paper has been prepared by NERA evaluating UR's cost of debt proposals.

2.3 Frontier and NERA submitted a joint paper in June 2015 on behalf of PNG, setting out our estimate of the WACC for GD17 (the Frontier/NERA paper). We also attended a meeting with UR on 19th January 2016; and subsequently submitted a second joint paper in February 2016 providing further evidence on PNG's cost of capital (the Frontier/NERA supplemental paper).

2.4 In this paper we focus on issues around UR's draft determination in relation to beta and tax allowances. In the last section of this paper we also summarise our view on the other parameters of the cost of equity, i.e. TMR and its constituent parts.

[2] See Annex 7 of the Draft Determination

3 BETA

3.1 UR has proposed an asset beta of 0.4 and a debt beta of 0.1. Based on UR's assumption of 55% gearing, this combination of parameters gives an equity beta of 0.77.

3.2 UR's approach for estimating the asset beta is incorrect for three reasons:

- UR has failed to implement its stated intention for the PNG beta to be at the top end of the range of comparators, because UR has not controlled for differences in debt beta across its comparator set, and therefore the range presented by UR is incorrect;
- UR's asset beta estimates do not reflect recent empirical evidence that support a higher asset beta than 0.4; and
- UR has not applied the CMA precedent for empirically estimating betas correctly.

3.3 In this section we first evaluate UR's general approach to estimating the PNG beta, before discussing each of the above issues in turn.

UR's general approach to estimating beta

3.4 UR reviewed other regulatory decisions to inform its provisional view on the asset beta for PNG. The evidence considered by UR is shown in Table 2.

Table 2. Breakdown of UR's asset beta comparator analysis

Regulator / company	Asset beta
Ofgem, gas distribution networks	0.38
Ofgem, electricity distribution networks	0.38
CC, NIE	0.40
Ofwat, water and sewerage networks	0.30
SGN Gas to the West years 6-10	0.43 to 0.45
Commission for Energy Regulation, Bord Gais	0.35

Source: Table 177 of UR's GD17 Draft Determination

3.5 Based on this precedent, UR concluded that asset betas for a conventional network utility are in the range 0.3 - 0.4. The bottom end of that range is consistent with UR's representation of Ofwat's determination; and the top end with UR's representation of the CMA's NIE determination.

3.6 For PNG, UR proposes an asset beta of 0.4 i.e. at the top end of UR's comparator range and in line with UR's representation of the CMA's NIE decision. UR explained this proposal as follows:

> *"For this draft determination, we use a value of 0.40. This gives recognition, in particular, to the fact that there are differences with PNGL's and FE's regulatory model from the standard model, e.g. the Profile Adjustment, and notwithstanding the analysis that we have summarised*

above, the possibility that investors may not be wholly familiar with these differences. While we regard this as a small and potentially short term factor, our initial view is that a cautious approach is appropriate and this therefore warrants placing the GDNs at the top of the betas that regulators have judged appropriate for low-risk network utility businesses."[3]

3.7 We agree with UR's conclusion that PNG is more risky than the GB comparators, and that this must be reflected in PNG's beta estimate. We set out the full range of evidence supporting this view in both the Frontier/NERA paper[4], and the Frontier/NERA supplemental paper[5].

3.8 Although we agree with UR's conclusion, we consider that UR has failed to recognise the full range of causes of incremental risk; and the evidence we have put forward supporting this conclusion. As a result, we consider UR's relative risk assessment to be incomplete. We set out our views on UR's assessment in Annexe 1.

Errors in UR's application of debt beta

3.9 UR's provisional equity beta is 6bps below the CMA's NIE decision. Since the final cost of equity is driven from the equity beta, UR's draft determination fails to allow a cost of equity which is consistent with its own stated view of PNG as being at the top end of the range of comparators in terms of risk.

3.10 Although UR's ***asset beta*** is at the top end of the comparator range, UR's provisional ***equity beta*** is in fact in the middle of the range for the same comparator set, as shown in Table 3.

Table 3. Comparison of equity betas

	Asset beta (reported by UR)	Equity beta (re-geared to 55%)
CMA/CC NIE	0.40	0.83
Ofgem RIIO-GD1	0.38	0.71
Ofgem RIIO-ED1	0.38	0.71
Bord Gais, CER	0.35	0.78
Ofwat, RP4	0.30	0.67
Range of comparators	**0.30-0.40**	**0.67-0.83**
UR's DD GD17	**0.40**	**0.77**

Source: *Frontier calculations using UR's DD GD17. We apply the Miller formula to calculate the equity beta.*

Note: *We present re-geared parameters to allow consistency in the comparison with UR's DD parameters. We note that Ofgem in RIIO-ED1 did not present an asset beta (or an equity beta), but in the DD UR has inferred an estimate by making assumptions on the other parameters of the cost of equity.*

We exclude from the comparator set SGN's year 6-10 asset beta in its Gas to the West application, since the UR in DD did not consider this precedent to be comparable to PNG and FE.

3.11 The reason for this discrepancy is that UR has failed to control for differences in ***debt beta*** across its comparator set. UR presents an asset beta range of 0.3-0.4. However, the comparator set underlying this range uses different debt beta

[3] UR, GD17 DD, paragraph 10.34

[4] Frontier/NERA, June 2015, Section 3.

[5] Frontier/NERA, February 2016, Section 2.

assumptions. This means the range presented by UR does not compare like-with-like and is incorrect.

3.12 UR proposes to assume a debt beta of 0.1 in its draft determination. As we explain further below, if we use UR's debt beta assumption, the asset betas for UR's comparator set are in fact in the range 0.36 – 0.43. Therefore, to set a beta at the top end of the range, UR should set an asset beta of at least 0.43 (assuming a debt beta of 0.1).

3.13 Below we explain why, in principle, the assumed debt beta should not have a material impact on the cost of equity. We then explain why, in practice, UR's provisional approach to debt beta does have a material impact, and why UR's analysis is incorrect.

The assumed debt beta should not have a material impact on CoE

3.14 The process for estimating asset betas generally starts with directly observed empirical estimates of equity beta for a comparator set. Once equity betas have been estimated, these are de-levered to back out a range of comparable asset betas[6]. Once an assumed asset beta for PNG is determined on the basis of the comparator analysis, the asset beta is re-levered (using PNG's gearing assumption), to reach a final equity beta estimate.

3.15 The assumption on debt beta affects the process of de-levering and re-levering. In theory, incorporating a non-zero debt beta implies an assumption that debt investors are exposed to some systematic risk. As the CMA/CC explained in its review for Heathrow and Gatwick Airports:

> *"A debt beta measures the (systematic) riskiness of debt relative to the market portfolio in the same way that an equity beta measures the (systematic) riskiness of equity relative to the market as a whole."*[7]

3.16 Notably, if the intention is to assume a non-zero debt beta, the same assumption must be applied for the purposes of **both** de-levering equity betas to asset betas; and re-levering the asset beta to the equity beta.

3.17 The net effect on PNG's equity beta of assuming a different debt beta should not be material. For illustrative purposes, we show in Table 4,the calculations of PNG's equity beta based on a single comparator, United Utilities[8], using two different debt beta assumptions (zero and 0.1). If the debt beta assumption is used consistently to de-lever and re-lever betas, the debt beta should have little impact on the estimated equity beta. The small difference in the final equity beta is the result of United Utilities' slightly lower gearing relative to PNG under the two debt beta assumptions.

[6] De-levering effectively controls for differences in gearing across the comparator group, meaning asset betas are directly comparable.

[7] CMA, Heathrow Airport Ltd and Gatwick Airport Ltd price control review, September 2007, Appendix F, Paragraph 90.

[8] We have chosen this comparator for illustrative purposes.

Table 4. Illustration of impact of debt beta assumption based on empirical estimates of beta for United Utilities

	Assuming zero debt beta	Assuming 0.1 debt beta
Empirically observed United Utilities equity beta (A)	0.78	0.78
Debt beta assumed (B)	0	0.1
United Utilities gearing (C)	50%	50%
De-levered asset beta (D) = [A*(1-C)+B*C]	0.39	0.44
PNG gearing (E)	55%	55%
Re-levered PNG equity beta = [D – (B*E)] / [1-E]	0.86	0.85

Source: Frontier Economics calculations using Bloomberg data.

Note: Cut-off date of the analysis: 13 May 2016.

3.18 In the Frontier/NERA paper we explained that the debt beta is expected to have an immaterial impact on the analysis, and therefore we assumed a debt beta of zero[9]. The CMA has also acknowledged that the debt beta should not lead to big differences in the final CoE. For example, in the NIE determination the CMA stated:

> *"[..], debt beta assumption makes little difference to estimated cost of capital as long as the gearing assumption in the WACC is not too different from the gearing of the companies for which the equity beta was estimated"*[10]

3.19 The CMA made a similar statement in its Bristol Water decision[11].

UR has failed to control for differences in debt beta, and has therefore made an error interpreting the regulatory precedent

3.20 As explained above, UR has presented a range for asset beta determinations by different GB regulators of 0.3 – 0.4. However, UR has failed to acknowledge the fact that each of these regulatory decisions uses a different debt beta assumption. As a result, UR has not compared like-with-like. Since UR proposes to assume a debt beta of 0.1 for PNG, UR must also re-evaluate the regulatory precedent and empirical beta estimates using a consistent debt beta assumption.

3.21 Ofwat's PR14 draft determination illustrates that regulators have adjusted their assessment of the regulatory precedent to account for differences in debt beta assumptions. Ofwat sought to compare its proposed asset beta of 0.3 with the CMA's previous 2010 determination of asset beta for Bristol Water[12]. In its Bristol Water decision the CMA assumed a debt beta of 0.1, and a corresponding asset

[9] Frontier/NERA, June 2015, footnote 29

[10] CMA NIE 2014 Final Determination, paragraph 13.175

[11] *"This analysis was based on a debt beta of 0, although as noted in CC10, PR14, and NIE, the debt beta has very little impact on the overall cost of capital if Bristol Water's gearing level (and the level of gearing used to calculate the WACC) is similar to the comparators used to estimate the asset beta."* CMA Bristol Water 2015 Final Determination, paragraph 10.150

[12] At the time the CMA was the Competition Commission, but for simplicity we refer to the CMA here.

beta range of 0.27 to 0.36. However, for its PR14 determination, Ofwat proposed to assume a debt beta of zero. Accordingly, Ofwat adjusted its view of the CMA's 2010 decision for the purposes of comparison:

> *"The Competition Commission in the Bristol Water reference in 2010 selected an asset beta range for the water sector of 0.21 to 0.31 assuming a zero debt beta."*[13]

3.22 Table 5 shows the implicit debt beta assumption which UR has used and which underlies the asset betas reported by UR (as shown in Table 2 above). It is clear that UR has not normalised correctly across its comparator set, since different debt beta assumptions are used.

Table 5. UR's comparator analysis

UR's evidence	Asset beta reported by UR	Debt beta implicit in UR's reported asset beta
Ofgem RIIO-GD1	0.38	0.1
Ofgem RIIO-ED1	0.38	0.1
CC, NIE	0.40	0.05
Ofwat, water and sewerage networks	0.30	0
SGN Gas to the West years 6-10	0.43 to 0.45	0.1
CER, Bord Gais	0.35	0

Source: *First column source is Table 177 of UR's GD17 Draft Determination. Second column source is regulatory decision documents.*

3.23 UR appears to have recognised this issue for some of its comparator analysis. For example, UR has re-stated Ofgem's RIIO-GD1 asset beta on the basis of an assumed debt beta of 0.1 (even though Ofgem itself did not assume that debt beta). We assume UR made this adjustment so as to compare the Ofgem decision on a like-for-like basis. Given this, UR should have made the same adjustment for the other regulatory decisions it presented.

3.24 Table 6 shows the normalised asset beta comparators, assuming the 0.1 debt beta which UR has provisionally proposed to use. We also compare this corrected range to UR's proposed asset beta for GD17.

[13] Ofwat RP14, Final price control determination notice: policy chapter A7 – risk and reward.

Table 6. UR's asset beta comparator analysis with a consistent debt beta of 0.1

UR's evidence	Asset beta reported by UR	Implied debt beta [assumed by UR]	Re-stated asset beta assuming 0.1 debt beta
Ofgem RIIO-GD1	0.38	0.1	0.38
Ofgem RIIO-ED1	0.38	0.1	0.38
CC, NIE	0.40	0.05	0.43
Ofwat, water and sewerage networks	0.30	0	0.36
CER, Bord Gais	0.35	0	0.41
UR equivalent range	**n.a.**	**n.a.**	**0.36-0.43**
UR's PNG DD	**0.40**	**0.1**	**0.40**

Source: Frontier Economics using the regulatory decision documents.

Note: Re-calculated asset beta using the Miller formula (asset beta = (equity beta) x (1-g)+(debt beta) x g)

3.25 When re-stated on a comparable basis, the asset beta range for a typical network utility is 0.36 – 0.43. UR's GD17 DD in fact gives PNG an asset beta near the middle of the range for comparator utilities, not at the top of the range as UR states.

3.26 To correct for this, UR could modify its approach as follows:

- If UR wants to retain a debt beta of 0.1 for PNG, UR should set an asset beta of 0.43 for PNG, to be consistent with UR's clear stated intention to set an asset beta at the top end of the range.
- Alternatively, UR could change its debt beta assumption. An asset beta of 0.40 for PNG would be consistent with a debt beta assumption of 0.05; or an asset beta of 0.39 would be consistent with a debt beta assumption of 0[14].

A debt beta of 0 is more appropriate given GB regulatory precedent and for simplicity

3.27 UR has provisionally set a debt beta of 0.1 for PNG without explaining the basis of this assumption. The First Economics paper states that a debt beta of 0.1 is: *"a value that the CC used in its inquiries for companies with approximately the same gearing and nominal cost of debt."*[15]

3.28 In theory, we agree that there is a link between the level of gearing and the debt beta assumption. As gearing increases, debt beta should increase (effectively, more systematic risk is borne by debt holders if gearing is higher). The CMA also reflected this in its NIE decision, stating: *"The debt beta is assumed to increase with gearing"*[16]

[14] Re-calculated asset beta using the Miller formula(asset beta = (equity beta) x (1-g)+(debt beta) x g) and CMA's NIE equity beta of 0.7.

[15] GD17 Annex 7 Cost of Capital by First Economics, page 3.

[16] CMA NIE 2014 Final Determination, paragraph 13.175

3.29 However, in practice the CMA has not applied a mechanistic link between gearing and debt beta. Table 7 shows the gearing and debt beta assumptions from recent CMA determinations.

Table 7. CMA precedent on debt beta

CMA decision	Debt beta	Gearing
NIE Provisional determination	0.1	50%
NIE Final determination	0.05	45%
BW 2015 Final determination	0	62.5%
BW 2010 Final determination	0.1	60%

Source: CMA decision documents

3.30 In its 2015 Bristol Water decision the CMA assumed a debt beta of 0 and 62.5% gearing; but in its 2010 Bristol Water decision the CMA assumed a higher debt beta (0.1) despite lower gearing (60%). Further, the NIE provisional determination and the Bristol Water final determination both assumed a debt beta of 0.1, despite a 10% difference in gearing between these determinations. It is clear there is no established CMA precedent governing the relationship between gearing and the debt beta assumption. It is therefore inaccurate to refer to CMA precedent as justification for assuming a debt beta of 0.1.

3.31 No further justification is given by First or UR for the assumed debt beta. UR has not acknowledged that Ofgem and Ofwat have generally assumed a debt beta of zero; or that the debt beta was zero in the most recent CMA determination (Bristol Water in 2015).

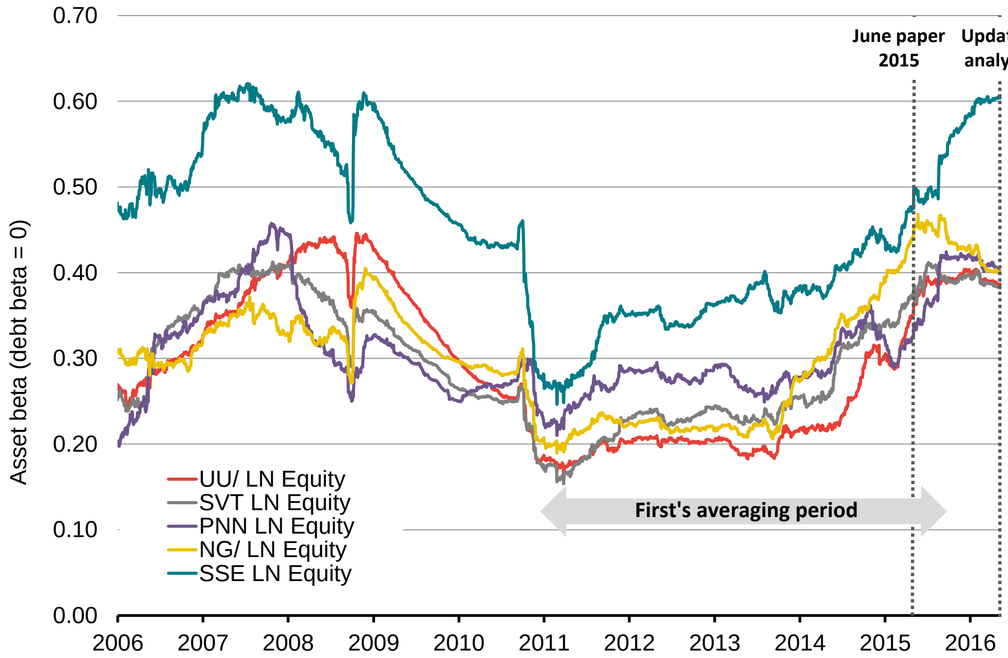
3.32 Given the mixed precedent and most importantly the fact that debt beta in general should have an immaterial impact on WACC anyway, we would propose that UR uses a debt beta of zero in its final determination.

Updated empirical estimates

3.33 In the Frontier/NERA report we presented empirical evidence showing that since early 2012, betas have been gradually increasing as market conditions have normalised following the Global Financial Crisis (GFC) in 2008. At the time, we estimated an average asset beta across the relevant comparator set of 0.39.

3.34 An update of our beta analysis since our June 2015 report is shown in Exhibit 8.

Exhibit 8. Two-year rolling asset beta for GB Utilities



Source: Frontier Economics using Bloomberg data. Cut-off date 13 May 2016.

Note: 2Y rolling asset betas based on daily data, Miller adjusted using net debt to market capitalisation data from Bloomberg.

Note 2: The cut-off date of First Economics' beta analysis is not explicit but is likely to be December 2015. This would imply a five year averaging period of betas between December 2010 - 2015.

3.35 The updated empirical evidence shows a higher average asset beta of 0.44, assuming a debt beta of 0. If a debt beta of 0.1 is assumed, the average asset beta is 0.48.

3.36 A comparison of the observed spot betas relative to our June report is shown in Table 9.

Table 9. Updated empirical evidence

	Frontier/NERA June report	Updated analysis
National Grid	0.44	0.40
SSE	0.48	0.61
United Utilities	0.35	0.39
Severn Trent	0.37	0.38
Pennon	0.32	0.40
Average	0.39	0.44

Source: Frontier Economics

Empirical evidence reflects daily two year asset beta estimates for the GB utility comparator set.

Cut-off date of updated analysis 13/05/2016

Misapplication of the CMA precedent

3.37 First Economics has provided empirical analysis that shows an asset beta range of 0.31 – 0.37. We expect that First's analysis assumes a debt beta of 0.1, although we understand that UR has been unable to provide PNG with the analysis underlying First's empirical estimates. First's estimates are approximately equivalent to an asset beta range of 0.26 – 0.32, if a debt beta of zero and gearing of 55% is assumed. UR has not relied directly on these estimates to set PNG's provisional asset beta, but UR states that the empirical analysis by First is a reasonable cross check on its comparator analysis.

3.38 First's asset beta range is considerably lower than the range we estimated in the Frontier/NERA report. This is primarily because First takes a five year average of asset betas over the period December 2010 - December 2015[17]. As can be seen from Exhibit 8 above, this period only incorporates the distorted period following the GFC, when observed betas were below their longer term averages.

3.39 First characterises its choice of the five year averaging period "*to be consistent with recent CC/CMA precedent*"[18]. However, this is incorrect.

- For its NIE decision, the CMA used approximately a 10 year averaging period from 2002 to 2013 (based on two-year daily beta estimates). The CMA also ignored outliers, by taking only the 95% interval of the distribution of observed betas to inform its range. The CMA therefore did not consider 5% of data points that were outliers at the top and bottom end of the distribution, relative to the long term average.[19]
- For its Bristol Water 2015 decision, the CMA looked at different estimation windows, sampling and averaging periods for large public water companies. The CMA then took a 50% interval of the distribution of those estimates, again to remove outliers from the sample.[20]

3.40 In addition, First's analysis excludes SSE from the comparator set. However, in its NIE decision the CMA included SSE in its comparator set[21]. Ultimately the fact that the CMA included SSE in its comparator set, and that First says they are following the CMA precedent, means that SSE should be included in the comparator set.

3.41 Exhibit 10 replicates the CMA's empirical beta analysis for NIE, including updated data since the CMA's decision. It shows that a direct replication of the CMA's approach as of today would result in an asset beta closer to 0.5.

[17] UR DD describes the cut-off date of First Economics' report to be 31 December 2015. UR DD GD17, paragraph 10.46.

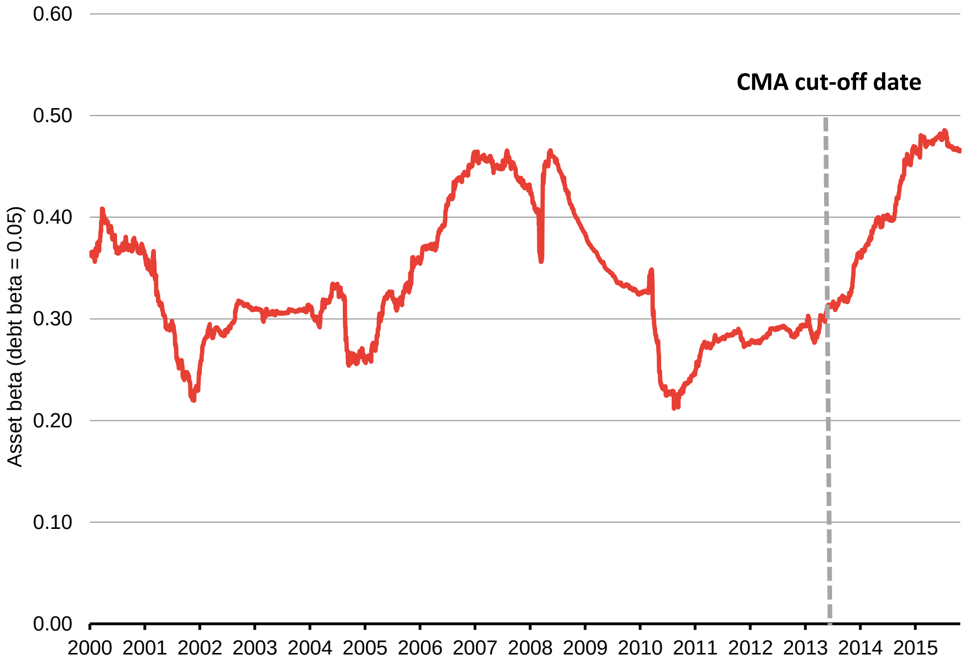
[18] GD17 Annex 7 Cost of Capital by First Economics, page 3.

[19] CMA NIE 2014 Appendix 13.3, Table 1 and CMA NIE Final Determination, Table 13.9.

[20] CMA BW 2015 Appendix 10.1, paragraph 98-99.

[21] CMA NIE 2014 Appendix 13.3, Table 1.

Exhibit 10. CMA's NIE Portfolio asset beta



Source: Frontier Economics analysis using Bloomberg data. Cut -off date 13 May 2016.

Note: The CMA calculated a Portfolio asset beta that reflects a weighted average asset beta for GB comparator Utilities (United Utilities, Pennon, Severn Trent, SSE and National Grid). The weights are calculated using each utility's market capitalisation rate.

3.42 Ultimately, the CMA exercised some judgement when determining NIE's asset beta. For NIE, the CMA set an asset beta of 0.4, despite the fact that the ten year average for its Portfolio asset beta was 0.33. The CMA's decision was towards the top of its 95% interval (0.24 to 0.45). The CMA implemented this approach because it considered NIE faced some incremental NI-specific risks relative to the peer group.

> "Taking into account that our comparator set is not an exact match for NIE and its regulatory framework we have selected a range for beta towards the upper end of the range suggested by these estimates"[22]

3.43 Empirical estimates of asset beta have been rising since CMA's NIE decision. Based on the updated data shown in Table 11:

- the average asset beta for the CMA's Portfolio has increased from 0.33 to 0.35[23]; and
- the upper bound of the CMA's 95% interval has increased from 0.45 to 0.48[24].

[22] CMA NIE 2014 Final Determination, Paragraph 13.183.

[23] Assuming a debt beta of 0.05

[24] Assuming a debt beta of 0.05

Table 11. CMA/NIE analysis with updated data (debt beta of 0.05)

	CMA decision			CMA analysis with updated data		
	Mean	95% interval		Mean	95% interval	
SSE	0.43	0.26	0.62	0.46	0.29	0.62
National Grid	0.32	0.23	0.42	0.33	0.23	0.47
United Utilities	0.30	0.20	0.46	0.31	0.21	0.46
Seven Trent	0.28	0.10	0.43	0.31	0.20	0.43
Pennon	0.25	0.02	0.46	0.31	0.02	0.46
Portfolio	**0.33**	**0.24**	**0.45**	**0.35**	**0.23**(1)	**0.48**

Source: Table 13.9 of CMA/NIE FD and Frontier Economics analysis using Bloomberg data. Cut-off date 13/05/2016.

(1) The updated lower bound of the 95% interval is 0.23, 1 basis point lower than CMA's NIE lower bound at the time of the decision. However, we think this is an artefact of some rounding applied by the CMA. If the CMA was to apply the same methodology to updated data, we do not expect it would have estimated a lower Portfolio lower-bound asset beta, given that the lower bound of individual utilities is now higher.

3.44 The CMA's determination of 0.4 for NIE, with a debt beta of 0.05, is equivalent to an asset beta of 0.43, if a debt beta of 0.1 had been assumed. Similarly, the above estimates are equivalent to an asset beta of 0.39 if a debt beta of 0 is assumed. Given the increase in observed betas, if the CMA's NIE approach were directly replicated today it would result in a higher asset beta for NIE. In addition, as we explained at length on our supplemental paper[25], PNG faces incremental risk relative to NIE, notably in relation to stranding. We conclude that an asset beta at the top end of our original range 0.40 – 0.45 now represents a reasonably conservative estimate of PNG's beta (assuming a debt beta of zero), given the CMA's approach for NIE.

[25] Supplemental report, page 7.

4 TAX ALLOWANCE

4.1 Corporates incur tax liability calculated on the basis of nominal profits. The tax allowance should therefore capture the fact that inflation will increase profits in nominal terms over time.

4.2 However, in estimating the real pre-tax WACC, UR's DD applies a tax wedge to the ***real*** post-tax cost of equity, to derive the real pre-tax cost of equity. This sequencing means that the tax wedge does not reflect the impact of inflation on profits.

4.3 To avoid under-remuneration, UR should use expected inflation to convert the real risk-free rate to a nominal risk-free rate, such that it calculates a nominal post-tax cost of equity, before calculating the tax wedge. The resulting nominal pre-tax cost of equity can be converted back to the real pre-tax cost of equity using the same inflation assumption. This calculation is shown in Table 12.

Table 12. Correction to UR's DD approach for allowing tax

	UR's approach (applying tax then inflation)	New proposed approach (applying inflation then tax)
Risk-free rate (real) [A]	1.25%	
ERP [B]	5.25%	
Equity beta [C]	0.77	
Cost of equity (post-tax, real) [D]	5.3%	N/A
Tax assumption [E]	20%	
Cost of equity (pre-tax, real) [F]	**6.6% F=[D/(1-E)]**	**7.2% F=[(1+J)/(1+G)-1]**
Inflation assumption [G]	3.08%	
Risk free rate (nominal) [H]	N/A	4.4% H=[(1+A)*(1+G)-1]
Cost of equity (post-tax, nominal) [I]	N/A	8.4% I=[H+B*C]
Cost of equity (pre-tax, nominal) [J]	N/A	10.5% J=[I/(1-E)]

Source: *Frontier Economics using UR's DD WACC parameters.*

4.4 Other regulators who set a pre-tax WACC allowance also use this approach:

- In the majority of its price control decisions, the GB telecoms regulator, Ofcom, sets a pre-tax nominal WACC allowance[26]. Since Ofcom's allowance is nominal, its approach allows for tax paid on nominal profits on the same basis as we propose above.
- In some decisions, Ofcom has in fact set a pre-tax real WACC[27] - i.e. the same as UR's approach for the network operators. Ofwat derives its pre-tax real figure using the same sequence of steps set out above, thereby

[26] For example Ofcom's latest decision is the Business Connectivity Market Review (BCMR) which determines a WACC for BT, published on 28th April 2016.

[27] E.g. spectrum licence fees and mobile call termination

incorporating a tax wedge calculated on nominal post-tax equity returns before converting this to real pre-tax[28]. The CMA reviewed a price control decision brought against Ofcom by BT, EE, Hutchison 3G and Vodafone[29] in which Ofcom set a real, pre-tax WACC allowance. The CMA concluded that Ofcom's WACC allowance was appropriate[30]. This is at least an implicit endorsement of Ofcom's methodology for calculating the real pre-tax WACC.

- The Irish Regulator, CER in historic decisions[31] as well as CER's mid-term WACC review for EirGrid, ESB and ESBN for 2014 – 2015[32]; and
- The Italian regulator, AEEGSI.[33]

4.5 Applying the corrected approach would result in a higher pre-tax WACC of 4.5%, relative to 4.21% estimated by the UR at the Draft Determination, given UR's inflation expectation of 3.1% and holding all else equal.

[28] See for instance, Ofcom's Mobile call termination market review 2015-18. Ofcom use an updated real WACC which is based on deflating the nominal WACC by CPI. This calculation has applied the tax wedge on a nominal cost of equity (instead of a real cost of equity) as described in Table 12.

[29] CMA determination on Ofcom's wholesale mobile voice call termination, 2012 (BT, Everything Everywhere, Hutchison 3G and Vodafone v Ofcom).

[30] CMA determination on Ofcom's wholesale mobile voice call termination, 2012, Paragraph 3.922.

[31] CER calculated tax allowance using the nominal WACC in CER's 'Decision on October 2012 to September 2017 distribution revenue for Bord Gais Networks'

[32] CER's mid-term WACC review for 2014-2015 for EirGrid, ESB and ESB Networks.

[33] Oxera paper prepared for AEEGSI, Estimating the cost of capital for Italian electricity and gas networks, Section 1.1.

5 TOTAL MARKET RETURN, RISK FREE RATE, AND EQUITY RISK PREMIUM

5.1 UR has provisionally determined the total market return (TMR); risk free rate (RFR); and Equity Risk Premium (ERP) for PNG as follows.

- TMR of 6.5%. UR explains this is in line with both the CMA/NIE 2014 final determination and the CMA/BW 2015 final determination.
- RFR of 1.25%. UR explains this is in line with CMA/BW 2015 final determination. This is lower than CMA/NIE 2014 determination of the risk free rate of 1.5%.
- ERP of 5.25%, calculated as the residual of the RFR and TMR.

5.2 We continue to believe that the CMA precedent is inappropriate for the reasons we put forward in our June paper. However, in order to focus this paper on the two main errors described above (i.e. on beta and tax), we have adopted UR's TMR, RFR and ERP parameters in this submission. In this section, we summarise in turn our view on the estimation of TMR and the decomposition of this into RFR and ERP.

Total Market Return

5.3 As set out in the Frontier/NERA report, we agree with the general approach of directly estimating TMR first and decomposing this into its constituent parts. However, we do not consider the CMA's recent TMR estimates are directly applicable to the GD17 price control.

5.4 In the Frontier/NERA paper we proposed to use long-run estimates of the TMR derived from the Dimson Marsh and Staunton (DMS) database. The long-run arithmetic average of DMS data supports a TMR of 7.1%. We noted that using a long-run average of realised returns had been recommended in the 2003 Smithers & Co report for UK regulated utilities; and by DMS. Ofgem has also tended to rely on this approach, and did so for its RIIO-GD1 and RIIO-T1 decisions.

5.5 Our report acknowledged that the CMA had deviated from this previously well-established approach. The CMA's NIE decision - which has since been replicated in its Bristol Water decision – relied more heavily on prevailing economic conditions observed since the 2008 GFC, rather than longer term averages. We explained in our June report the reasons the CMA's approach is inappropriate from both a methodological point of view as well as for the period of PNG's price control[34].

5.6 In its Draft Determination, UR argues that most UK regulators have set a TMR of 6.5% to be consistent with CC/CMA precedent.[35] However, a number of recent regulatory decisions have not used the CMA's TMR figure.

[34] Frontier/NERA paper, June 2015, Section 2.2.3

[35] UR GD17 DD, Paragraph 10.22

- It is important to recognise that Ofgem did not publish its own TMR assumption for its RIIO-ED1 decision. Instead, Ofgem explained that its final cost of equity allowance was consistent with parameter estimates put forward by the CMA in NIE's provisional determination. However, Ofgem's academic consultants (Stephen Wright and Andrew Smithers) recommended a central estimate of the TMR of 6.75%[36].
- As noted by UR, Ofwat's final determination for PR14 (published in December 2014) set a TMR of 6.75% for the period 2015 - 2020[37]. Ofwat's consultants PwC stated that "*there is insufficient evidence for a revision to Ofwat's point estimates for TMR*"[38].
- CER's price control determination for ESBN, published in December 2015, set a TMR of 6.65%, with a risk free rate of 1.9% and ERP of 4.75%[39].

Risk-free rate and Equity Risk Premium

5.7 UR has provisionally decided to base its RFR estimate on the CMA/BW 2015 decision (1.25%). This was lower than the CMA's NIE decision (1.5%) and almost all other GB regulatory precedent since 2009[40].

5.8 Given this, it is important to understand the basis for the CMA's low risk-free rate estimate in the BW case. The CMA explained its decision as follows:

> "*market conditions have been similar for the past three years (as seen in Figure 10.2, above), and we put weight on regulatory precedent on the RFR from this period, in particular the CC/CMA determination in NIE 2014. This would support an RFR of between 1% and 1.5%.*
>
> *We therefore found that a point estimate rate of 1.25% (which was also used by Ofwat and Bristol Water) was an appropriate figure for the RFR.*"[41]

5.9 We consider that the CMA used a lower point estimate for RFR in the Bristol Water decision primarily to be consistent with submissions from Ofwat and Bristol Water as part of that price control review. Since the parties did not disagree, the CMA saw no reason to diverge from their assumptions. It is not clear that this is sufficient basis for UR to set its risk-free rate at the same level for GD17.

36 Stephen Wright and Andrew Smithers, The Cost of Equity Capital for Regulated Companies, A Review for Ofgem, January 2014

37 Ofwat (December 2014), Final price control determination – risk and reward, p34.

38 PwC, Updated evidence on the WACC for PR14, A report prepared for Ofwat.

39 CER, Decision on DSO Distribution Revenue for 2016 to 2020, December 2015

6 ANNEXE 1

6.1 As set out in detail in our previous papers, PNG faces incremental stranding risk due to its size and development stage. PNG's revenue deferral model implies a longer duration of cashflows and greater prospect of longer-term stranding risk, as the recovery of investment is deferred into the future. PNG also has greater exposure to market uncertainty as a result of lower market penetration relative to GB.

6.2 The conclusion that PNG faces overall greater risk is supported both by market evidence on bond yields; and by credit rating agencies' assessments which recognise that PNG faces additional risk and weaker cashflows than GB utilities. We noted that recent regulatory precedent – including the CMA's decision for NIE and UR's decision for NIW – had taken into account the view of rating agencies that NI utilities face specific incremental risk relative to GB peers.

6.3 In our supplemental paper, we noted that UR should ensure it is consistent in its regulatory approach. We argued that UR cannot continue to defer revenues into the future, while simultaneously suppressing the cost of capital allowance by ignoring the associated stranding risk and immaturity. We set out an approach for directly estimating the impact of incremental stranding risk relative to NIE; the term premium associated with PNG's revenue deferral; and noted the interaction between these effects. We concluded that PNG's beta should be at the top end of the range of 0.4 – 0.45 set out in our June paper; and that recent increases in directly observed betas meant the upper end of the range should be considered a conservative estimate.

6.4 In its DD, UR has judged that, on balance, the evidence does imply a higher beta for PNG, noting in particular the difference in regulatory model. UR has not explicitly recognised or commented on a number of the sources of evidence we have provided. As a result, although we agree with UR's conclusion, we consider that its assessment of the evidence is incomplete.

6.5 In particular the evidence we have provided contradicts some of UR's statements:

- UR states that there are similarities across sectors *"between the overall strength of opex/capex/totex incentives and the amounts of money that are tied to output or service quality schemes across different price controls, even if the detailed design of such incentives differs from industry to industry."*[42] We explained in the Frontier/NERA paper[43] that investors in GB networks in fact have significantly greater scope for outperformance than is available to PNG, and indeed have consistently achieved higher returns than the headline cost of equity allowance. The GB precedent cannot be evaluated in isolation of this.

- In relation to PNG's comparatively low ongoing expenditure as a share of the TRV, UR states that it has made adjustments for this in setting beta for SONI,

[42] UR, GD17 DD, paragraph 10.26

[43] Frontier/NERA, June 2015, Section 3, page 31 and 32

and that *"other regulators, including the CC/CMA, have done the same."*[44] We explained in our supplemental paper that there is no basis for assuming this adjustment is standard GB practice, or that the CMA would necessarily apply this methodology to PNG. Neither Ofgem nor Ofwat has applied an operational gearing adjustment; and the CMA also did not do so in the NIE case[45]. UR concludes that quantification of this adjustment is *"difficult to judge"* and concludes that *"it may be necessary to tackle the issue of quantification more explicitly at future price reviews"*[46] – but as our supplemental paper explains, no such quantification is warranted either at GD17 or at future reviews.

- In relation to stranding risk, UR stated that *"it is only if PNGL and FE were to suffer a catastrophic loss of customers that there could be any serious questions about stranding. It is difficult for us to see why such a collapse would occur, or crucially, why the risk of a collapse occurring is any higher in Northern Ireland than it is in Great Britain."* In our supplemental paper we explained that PNG clearly faces incremental stranding risk ***relative to NIE***, given longer term uncertainty surrounding gas demand and wider decarbonisation objectives. In any case, we also explained that stranding risk is greater for PNG relative to GB gas distribution companies given the lower market penetration in Northern Ireland; evidence that NI customers are price sensitive; and the fact that structural cost differences exist between NI and GB, which means that in expectation any alternative fuels will reach cost parity in Northern Ireland earlier than in GB (irrespective of any short-term comparisons of tariffs).

- UR has also mis-understood the Ofgem precedent on stranding risk. UR stated that *"Ofgem has not attached any real weight to this eventuality in its WACC analysis (Ofgem concluded that the GB gas distribution networks were, if anything, slightly less risky investments than the GB electricity distribution networks)"* As we explained in our supplemental paper, Ofgem ***did*** attach significant weight to long-term stranding risk in its RIIO-GD1 decision, because it took the significant step of accelerating the recovery of investment in GB gas networks. In contrast, UR continues to implement a revenue deferral model for PNG, implying incremental stranding risk which should be reflected in WACC.

[44] UR, GD17 DD, paragraph 10.28

[45] Frontier/NERA, February 2016, Section 2.1.

[46] UR, GD17 DD, paragraph 10.28

NERA
ECONOMIC CONSULTING

Response to UR's Draft Determination on Cost of Debt Issues

For Phoenix Natural Gas

May 2016

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Executive Summary

The Utility Regulator (UR) published its GD17 Price Control Draft Determination ("DD") for PNG in March 2016. On the cost of debt, UR proposed an ex-ante cost allowance for embedded and new debt, and a true-up mechanism, where the ex-ante cost of new debt is proposed to be adjusted for 80% of the difference between PNG's actual issuance costs and the cost of new debt assumption set at review.[1] This report sets out our response to UR's ex-ante cost of debt estimate. In a separate report, we set out our response to UR's proposed true-up mechanism.[2]

UR understates PNG's cost of debt by around 100 basis points (bps)

Table 1 sets out UR's Draft Determination estimate for the cost of debt, and our estimate which corrects for a number of concerns with UR's approach and also updates for the latest market data. Overall, we calculate a real cost of debt of 3.26% using our preferred market based (or break even) measure of inflation, or 2.42% if we use inflation published by the Office for Budget Responsibility (OBR), as UR proposes.

Table 1
We estimate an ex-ante cost of debt allowance around 100 bps higher than UR DD

	UR DD (Dec 2015)[1]	NERA (May 2016)[2]	
		OBR inflation	Breakeven inflation
Embedded debt costs			
Average interest costs	4.3	4.3	
Transaction costs	0.3	0.4	
New debt costs			
BBB-index yield	4.4	4.3	
Forward rate adjustment	0.4	0.3	
PNG premium	0.4	0.64	
Transaction costs	0.3	0.4	
Weighting - embedded debt	10%	10%	
Weighting - new debt	90%	90%	
Inflation	3.1	2.4 for embedded, 3.1 for new	2.1 for embedded, 2.2 for new
Real Cost of debt	2.26	2.42	3.26

Source: NERA analysis. Notes: 1) information date = end December 2015; 2) information date = 13 May 2016

[1] Utility Regulator (March 2016), Price Control for Northern Ireland's Gas Distribution Networks GD17, p. 225, para 10.8.

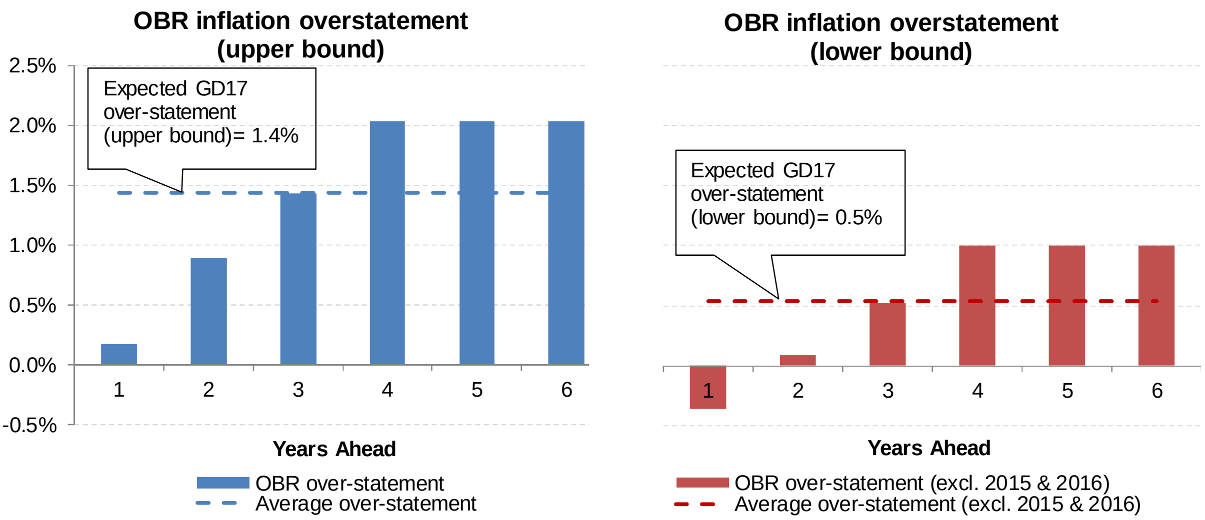
[2] NERA (May 2016) Cost of Debt Indexation Mechanism for GD17

OBR overstates inflation; UR should use market based forecasts

To convert nominal cost of debt into real terms, UR uses an inflation rate of 3.08% p.a. based on OBR inflation forecasts for GD17. OBR forecasts have historically overstated outturn inflation which means that PNG does not have a reasonable prospect of recovering its actual nominal debt costs.

Our analysis of all historical OBR published forecasts (over the period 2010 to 2016) shows that OBR has systematically overstated inflation, and that the overstatement increases with forecast length (see Figure 1). Based on OBR's historical performance, the expected forecast error over GD17 is 1.4%. Even excluding OBR's forecasting errors for 2015 and 2016, where its performance is particularly poor, the expected forecast error over GD17 remains at 0.5%.

Figure 1
OBR Expected Forecast Error over GD17 is
0.5% (excluding 2015 and 2106 errors) to 1.4% (all years)



Source: NERA calculations based on OBR and ONS data.

The CMA in its NIE decision acknowledged that the OBR forecasts are at the high-end, and explicitly selected an allowed rate of return at the top-end of its WACC range to accommodate the noted bias in its cost of debt allowance from its use of OBR. Ofgem and Ofwat use market based evidence – "break-even" inflation derived from the difference between nominal and real yields on gilts – to determine a real cost of debt allowance.

Consistent with regulatory precedent, UR should use break-even inflation to derive an ex-ante real cost of debt for GD17. As of mid-May, the break-even inflation rate is 2.2%, i.e. 0.9% lower than the March 2016 OBR forecast.[3] Break-even inflation reflects the market

[3] We note that a further likely explanation of the difference is falling inflation expectations over the recent period, as well as the noted bias in OBR's forecast. That is, the break-even inflation rate reflects current market expectations of inflation, whereas the OBR forecast (in March 2016, but with an effective date prior to March) does not reflect the changes in expectations. The fact that break-even is up-to-date provides a further reason to use break-even.

consensus view of inflation rather than the view of a single organisation, and one with a noted bias, as demonstrated by our research and acknowledged by the CMA.

UR understates real embedded debt costs by using average inflation over the period

UR uses average GD17 inflation to convert its nominal estimate of embedded and new debt into real terms, although embedded debt is expected to mature on average by the end of 2017. Given the expected increase in inflation over the GD17 period, UR materially overstates inflation for embedded debt and therefore materially understates real embedded debt costs.

The error in the understatement of historical debt costs will not be corrected under UR's proposed true-up mechanism. Under UR's proposed approach, PNG will bear the full cost of UR's overstatement of inflation on embedded debt as there is no true-up for the real ex ante allowance. By contrast, there will be no offsetting outperformance on the new debt cost allowance, as we expect UR to take into account actual inflation in trueing up new debt costs subject to an 80:20 sharing factor.

The real cost of embedded debt should be estimated using inflation over the period for which it remains outstanding, i.e. 2017, and the real cost of new debt should be estimated using inflation over the rest of GD17. We calculate a break-even inflation estimate for 2017 of 2.1% to derive the real cost of embedded debt and a break-even inflation estimate of 2.2% for the rest of GD17 to derive the real cost of new debt.

UR should use BBB index yield over one year to mitigate volatility risk

UR used the spot BBB-index yield adjusted for forward rate uplift but disallowed our proposed volatility risk premium which takes account of the volatility in the benchmark index. In the absence of the volatility risk premium, UR should use a longer term average to smooth for short-term market volatility. In its 2015 Bristol Water decision, the CMA recognised the need to use a long-run average to smooth for market volatility, and used a one-year average. We have adopted the same approach – resulting in a nominal benchmark BBB cost of 4.3% as of mid-May.

UR's forward rate adjustment ignores bank debt falling due mid-2018

To estimate the cost of new debt, UR adjusted its spot estimate of BBB costs by 40bps to allow for an increase in interest rates by mid-2017 for PNG. We agree with UR's proposed approach to draw on market data to make an adjustment for the expected increase in yields to the point of refinancing. However, UR's forward rate adjustment assumes a mid-2017 refinancing point, based on the redemption date of PNG's public bond. UR ignores bank debt falling due in late 2018. UR should instead assume an end 2017 refinancing point, the approximate mid-point of the bond and bank debt refinancing. Our updated estimate of the forward rate as of mid-May is 30 bps.

UR's estimate of the PNG premium needs to be adjusted for tapering effect

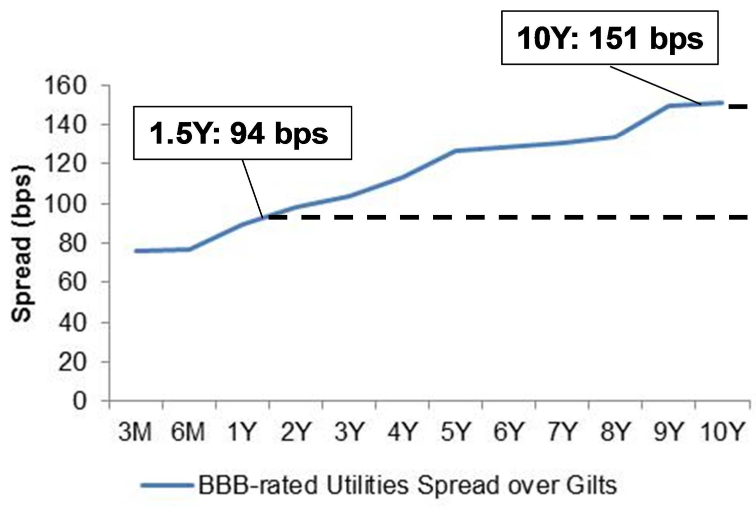
In estimating the cost of new debt, UR allows for a 40 bps PNG premium based on the most recent empirical evidence of the difference in bond yields between PNG and a set of comparators. UR's use of recent data understates the premium due to the effect of tapering as the PNG bond approaches maturity.

As explained in our July 2015 cost of capital report, spreads for both PNG and comparator bonds taper as the bonds approach maturity. As a result of tapering in the spreads over time, the observed premium for PNG's bond relative to the comparators will also taper to zero at maturity. The effect of tapering on spreads is evident from the upward sloping term structure of credit spreads (see Figure 2). Bond investors require a lower credit spread the lower the remaining tenor to maturity to compensate for risk, which explains why spreads for shorter maturities are lower than for longer maturities.

Since our June 2015 cost of capital report, we have undertaken further work to quantify the tapering effect and derive the PNG premium. We have quantified the effect of tapering from the term structure of credit spreads, and used this estimate to adjust UR's premium of 40 bps. The UR's premium is based on a period where the remaining tenor is 1.5 years, whereas in fact we expect PNG tenor at issuance to be much longer. Taking the ratio of the spreads on 1.5 and 10 year BBB bonds of 1.6 (=151 bps/94bps), and applying this to the UR's premium of 40 bps, we derive a premium of 64 bps, and we have adjusted our cost of debt estimate for our revised estimate.[4]

This estimate is similar to our own estimate of PNG premium of 69 bps based on the period prior to the PNG12 Draft Determination, selected to avoid the effect of tapering.

Figure 2
We draw on term structure of credit spreads to estimate the tapering effect, and to adjust UR's PNG premium



Sources: NERA analysis of Bloomberg data

UR does not allow for the cost of carry, and unnecessarily deflates all COD adjustments

UR allowed for a transaction cost of 30 bps which is close to PNG's actual transaction costs incurred on its current bond. However, UR provides no allowance for the fact that PNG also

4 We adopt a 10Y tenor as this is consistent with the tenor of the constituent bonds in the iBoxx 10Y+ corporate financial index which UR uses to set its proposed ex-ante allowance for new debt costs.

needs to maintain a back-stop facility to fund capex, which imposes a cost even when the funds are undrawn, as well as facilities to provide liquidity to support its BBB credit rating, as well as additional liquidity to back-stop the expected refinancing of the bond. We consider that these costs support a total adjustment of at least 40 bps rather than the 30 bps allowed by UR.

Finally, we note that UR deflated the various adjustments to the allowed cost of debt (e.g. forward rate adjustment, PNG premium, transaction costs etc.) with inflation to derive the real cost of debt which is unnecessary and understates the real cost of debt.

1. Introduction

On 16 March Utility Regulator (UR) published its GD17 Price Control Draft Determination ("DD") for PNG, Firmus Energy (FE) and SGN.[5] On the cost of debt, UR proposed an approach where an ex-ante cost of debt is determined at the beginning of GD17, followed by an ex-post true-up mechanism based on GDNs' actual re-financing costs.[6]

This report sets out PNG's response to UR's ex-ante cost of debt Draft Determination. In a separate report, we set out our response to UR's proposed true-up mechanism for the cost of new debt.[7]

This report is structured as follows:

- Section 2 sets out PNG's detailed response on the issues identified in the DD; and
- Section 3 concludes.

[5] Utility Regulator (March 2016), Price Control for Northern Ireland's Gas Distribution Networks GD17.

[6] Utility Regulator (March 2016), Price Control for Northern Ireland's Gas Distribution Networks GD17, p. 225, para 10.8.

[7] NERA (May 2016) Cost of Debt Indexation Mechanism for GD17

2. Detailed Response on Key Issues

In this section, we present our concerns with UR's estimate of the ex-ante cost of debt set out in its DD. .

2.1. UR Should Estimate Inflation Separately for Embedded and New Debt

UR used average GD17 inflation to convert its nominal estimates of embedded and new debt into real terms, although embedded debt is expected to mature end of 2017 on average. Given current market expectation of increasing inflation, UR's approach materially underestimates the real cost of embedded debt and is therefore incorrect.

The error in the understatement of historical debt costs will not be corrected under UR's proposed true-up mechanism. Under UR's proposed approach, PNG will bear the full cost of UR's overstatement of inflation on embedded debt as there is no true-up for the real ex ante allowance. By contrast, to the extent that the use of average inflation leads to a (relative) understatement of inflation for new debt costs, there will be no offsetting outperformance, as we expect UR to take into account actual inflation in true-ing up new debt costs based on an 80:20 sharing factor. [8]

UR needs to ensure that the ex-ante allowance represents best forecasts of inflation for both embedded and new debt (rather than a forecast that is correct only on average). Specifically, the real cost of embedded debt should be estimated using inflation over the period for which it remains outstanding (i.e. 2017) and real cost of new debt should be estimated using inflation over the rest of GD17.

For reasons we discuss in section 2.2 below, we consider UR should use break-even inflation as OBR forecasts overstate outturn inflation. As of cut-off date of 13 May 2016, we calculate a break-even inflation estimate for 2017 of 2.06% which should be used to derive the real cost of embedded debt and a break-even inflation estimate of 2.22% for the rest of GD17 which should be used to derive the real cost of new debt.[9] Taken together, the two forecasts are consistent with our estimate of break-even inflation for the period of 2.19 %.

Even if the UR continues to use OBR forecasts, it should use 2017 OBR inflation forecast of 2.4% to derive the real embedded cost of debt, and average 2018-2022 forecast to derive the new cost of debt of 3.12% drawing on the latest OBR March 2016 publication.

---

[8] As we set out in our report on the cost of debt mechanism, the new cost of debt allowance should be trued up based on actual nominal refinancing costs and outturn inflation in order to derive the actual real cost of new debt. The true-up for outturn inflation should be undertaken irrespective of whether the UR uses PNG's actual cost of new debt, as it currently proposes, or our proposed benchmark approach. If the UR does not true-up for inflation, there is material risk that customers could pay far more (or far less) than efficient debt costs. The risk arises because nominal debt costs at the time of issuance will reflect inflation expectations at that time. If inflation turns out higher than UR's forecast, nominal debts will also be higher. If UR uses the outturn nominal debt costs minus its (lower) ex ante inflation assumption, consumers will pay more than the efficient real debt cost.

[9] The shortest maturity of the break-even inflation provided Bank of England is 2.08 years. We use the 2.08Y break-even as a proxy for inflation in 2017. We use the 6.5Y break-even and 2Y break-even to derive the inflation for the rest of GD17 (i.e. 2018-2022).

As shown in Table 2.1, the UR implied real cost of embedded debt is materially understated by 70-100 bps, depending on whether we draw on break-even or OBR inflation.

Table 2.1
UR materially understates real cost of embedded debt

	UR DD (OBR Average)	NERA (OBR 2017)	NERA (break-even 2017)
Nominal cost of debt	**4.3**	**4.3**	**4.3**
Inflation	3.1	2.4	2.1
Real cost of embedded debt	1.2	1.9	2.2

Source: NERA analysis

2.2. OBR Inflation Forecasts Overstate Outturn Inflation

To convert the nominal cost of debt into real terms, UR used an inflation rate of 3.08% based on the average inflation forecasts over GD17 provided by the Office of Budget Responsibility (OBR). As discussed in our June 2015 cost of capital report[10], OBR forecasts have historically overstated outturn inflation which means UR understates real debt costs.

2.2.1. OBR has historically overstated inflation by at least 50 bps

To quantify the magnitude of OBR forecasting error, we have reviewed all thirteen historical OBR forecasts (published over the period 2010 to 2016) and compared them to outturn inflation. We have also examined the forecasting error according to the number of years ahead (different forecasting horizons). The average forecasting error for different forecasting horizons is presented in Table 2.2.

[10] Frontier/NERA (June 2015), PNG Cost of Capital for GD17, p.52

Table 2.2
OBR Inflation Overstatement by Forecasting Horizon

Forecasting horizon	OBR forecasting error	OBR forecasting error (excl. 2015 & 2016)**
1	0.2%	-0.4%
2	0.9%	0.1%
3	1.4%	0.5%
4	2.0%	1.0%
5 and 6	2.0%*	1.0%*
Expected error over GD17	1.4%	0.5%

Source: NERA analysis of OBR publications from November 2010 to March 2016.
** We proxy forecast error for 5 and 6 years ahead using forecast error for 4 years ahead (in the absence of longer term forecasts).*
*** Given forecast error is especially high for 2015 and 2016 (ultra-low outturn inflation), we also estimate OBR forecasting error excluding forecasts for these two years.*

The table shows that OBR historical forecasts have overstated outturn inflation across all forecasting horizons, and the forecasting error tends to increase with the forecasting horizon. For example, the forecasting error 2 years ahead is 0.9% on average across the 13 historical forecasts published by OBR but increases to 2.0% for 4 years ahead.

Overall, we show that the expected forecasting error over the GD17 period (i.e. based on an average of the historical errors in forecasting 1 to 6 years ahead) is 1.4%. Even excluding OBR's forecasting errors for 2015 and 2016 from our analysis, years where its performance is particularly poor, the expected forecast error over GD17 remains at 0.5%.

2.2.2. The CMA draws only on near term OBR forecasts, and acknowledges OBR is "high-end"

The CMA used OBR inflation in its NIE decision, and therefore UR is ostensibly aligned with the CMA's approach. However, the CMA decisions are published 1 or even 2 years into the price control. As a result, when setting inflation, the CMA typically draws on 1-2 years of actual data plus short-term OBR forecasts which are more accurate than long term forecasts (as demonstrated in Table 2.2). The CMA use of OBR results in a much smaller forecasting error than using OBR inflation over the entire review period, as UR proposes.

We can observe the material difference in outcome in the CMA's approach relative to UR by comparing CMA's late 2015 decision for Bristol Water where it determined an inflation rate of 2.42%, far lower than UR's DD proposal of 3.08% for GD17, despite the similar forecast period and forecast date.[11]

[11] CMA (October 2015), Bristol Water Decision, para. 10.91

Finally, the CMA in its NIE decision acknowledged that the OBR forecasts were at the high-end, and determined an upper-end WACC to offset the bias:[12]

> *"the OBR estimate may be towards the upper end of the range. Given that a lower inflation forecast would tend to increase the real cost of debt and thus the WACC, we consider that this supports the choice of a number towards the upper end of the WACC range."*

2.2.3. UR should use market based data which is more up-to-date, and reflects consensus market view

As discussed in our June 2015 cost of capital report[13], we consider UR should use market data (i.e. breakeven inflation) to estimate inflation for GD17. The use of market data ensures that the forecast is up-to-date, and draws on a consensus market view as opposed to the view of a single forecasting entity.

Using a cut-off date of 13 May 2016, we calculate a break-even inflation estimate for GD17 of 2.19%, i.e. 0.9% lower than the OBR forecast of 3.1% as of March 2016.[14] We note that one further likely explanation of the substantive difference between current break-even and OBR's March 2016 inflation estimate is falling inflation expectations over the recent period, as well as the noted bias in OBR's forecast. That is, the break-even inflation rate reflects current market expectations of inflation, whereas the OBR forecast (in March 2016, but with an effective date prior to March) will not reflect the recent changes in expectations. The fact that break-even is up-to-date provides a further reason to use it.

The use of breakeven inflation is supported by GB regulatory precedent, for example, both Ofgem and Ofwat use break-even inflation to derive a real cost of debt allowance.[15]

There is also strong reason to suggest that the break-even rate will overstate outturn inflation over GD17 given the existence of an inflation risk premium. This implies that even with break-even inflation there is a risk PNG does not recover its debt costs, although the historical bias is less than observed for OBR. For example, at PR14 Ofwat accounted for this bias by subtracting 30 bps from break-even data, drawing on Bank of England estimates.[16] A recent 2015 paper by the Bank of England confirmed that break-even inflation is likely to overstate outturn inflation as it includes "*an inflation risk premium to compensate for uncertainty about future inflation [and] liquidity risk premia*" which are likely to be "*non-trivial*".[17]

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12 CMA (March 2014): Northern Ireland Electricity Limited price determination, para. 13.188

13 Frontier/NERA (June 2015), PNG Cost of Capital for GD17, p.53

14 We use 6.5Y break-even inflation published by the Bank of England to proxy average inflation for GD17.

15 We note that our break-even inflation estimate (2.46%) is consistent with the OBR forecast used by UR (3.08%) corrected for our lower-bound estimate of OBR's historical bias of 50 bps.

16 Frontier/NERA (June 2015), PNG Cost of Capital for GD17, p.51

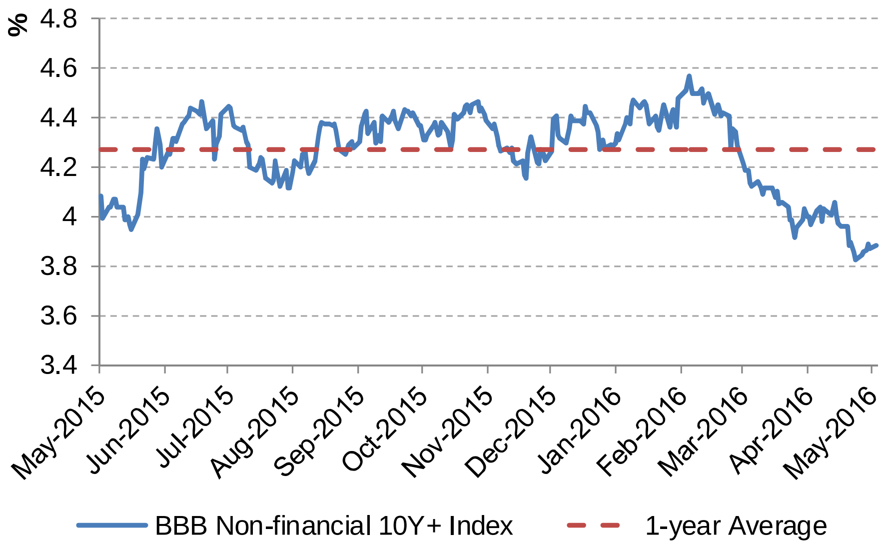
17 Zhuoish Lui et al (2105) Staff Working Paper No. 551 The informational content of market-based measures of inflation expectations derived from government bonds and inflation swaps in the United Kingdom, p. 1.

2.3. UR Should Use Long Run BBB Index to Mitigate Volatility Risk

In the DD UR used the spot BBB-index yield adjusted for forward rate uplift as its benchmark nominal debt cost. The UR's use of a spot estimate exposes PNG to material volatility risk. As shown in Figure 2.1 below, the benchmark BBB index has been very volatile over the past year, ranging from 3.8% to 4.6%.

In our June 2015 report, we proposed a volatility risk premium to compensate PNG for the marked volatility in the benchmark index. As set out in our June report, we showed that there substantive expected variation in market rates. For example, we showed that there was a 25% probability that the realised market cost of debt at the time of PNG's refinancing could be 58 bps above the market's central expectation.[18]

Figure 2.1
iBoxx BBB Index Yield ranges from 3.8% to 4.6% over the past year



Source: NERA analysis of Datastream data

The CMA considered how to compensate regulated networks for current high levels of market volatility in its Bristol Water decision. In this decision, the CMA set the cost of new debt for Bristol Water based on a 1-year average of market data. It noted:

> *"…there does appear to have been a certain degree of volatility recently which could represent short-term distortions… We therefore consider it appropriate to use a short historical average (rather than simply the current rate), and judged that a one-year average should have been sufficient to remove the effects of short-term distortions, whilst still reflecting the up to date market views"*[19]

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[18] Frontier/NERA (June 2015), PNG Cost of Capital for GD17, p.45

[19] CMA (2010), Bristol Water Final Determination, p. A10(1)-16, para. 66-67

Consistent with CMA, and in the absence of a "volatility adjustment", UR should use a 1-year historical average of BBB index yield in setting the benchmark cost of new debt for PNG to smooth for market movements. As of May 13th 2016, we calculate an annual yield of 4.3%.

2.4. UR Understates Forward Rate Adjustment due to Incorrect Refinancing Point Assumption

To estimate cost of new debt, UR adjusted its spot estimate of BBB costs by 40bps and 80bps to allow for an increase in interest rates by mid-2017 and mid-2019 for PNG and firmus respectively. The adjustment was calculated based on forward rate evidence from the gilt markets (forward rate adjustment).[20]

We agree with UR's use of a forward rate adjustment to account for the expected increase in yields between now and the point of refinancing of PNG's debt. This is consistent with the approach we used in our June 2015 cost of capital report.[21] However, UR's forward rate adjustment is calculated assuming the incorrect refinancing point, resulting in an understatement of the forward rate adjustment for PNG.

As explained in our June 2015 cost of capital report[22], PNG's existing debt includes a £275m bond which matures in July 2017 and £169m of bank debt repayable in August 2018. The correct re-financing point is therefore around the end of 2017 taking a time weighted average of the bond and bank debt. Using the correct re-financing date of end-2017, we calculate a forward rate adjustment of 29 bps.[23]

2.5. Illiquidity/PNG Premium is Understated Due to Tapering

In estimating cost of new debt, UR included a 40 bps premium *"to allow for the possibility that PNGL and FE have to pay a small premium in comparison to other borrowers"*.[24] UR's estimate is based on the premium observed in the pricing of PNG's debt "*since the resolution of PNG's CC reference in 2012*"[25].

2.5.1. UR's approach fails to correct for the effects of tapering

UR's use of recent data understates the size of the premium due to the effect of tapering on the size of the premium as the PNG bond approaches maturity.

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20 Utility Regulator (March 2016), Price Control for Northern Ireland's Gas Distribution Networks GD17, p. 232 para 10.44.

21 Frontier/NERA (June 2015), PNG Cost of Capital for GD17, p.39

22 Frontier/NERA (June 2015), PNG Cost of Capital for GD17, p.37

23 We calculate the forward rate based on Bank of England data, as of 13 May 2016

24 Utility Regulator (March 2016), Price Control for Northern Ireland's Gas Distribution Networks GD17, p. 232 para 10.44.

25 Utility Regulator (March 2016), Price Control for Northern Ireland's Gas Distribution Networks GD17, p. 232 para 10.44

As explained in our July 2015 cost of capital report, spreads for both PNG and the comparator bonds taper as the bonds approach maturity (by definition, at maturity spreads are equal to zero). As a result of tapering in the spreads over time, the observed premium for PNG's bond will also taper to zero at maturity.

The effect of tapering on spreads is evident from the upward sloping term structure of credit spreads for BBB benchmark bond index (as shown in Figure 2.2 below). Bond investors require a lower credit spread the lower the remaining tenor to maturity to compensate for risk, which explains why spreads for shorter maturities are lower than for longer maturities. For the same reason, investors in PNG will also require a lower premium as the tenor to maturity for PNG's bond shortens over time.

As we explained in our June report, we considered that the period prior to PNG Draft Decision (DD) in 2012 is the most relevant for estimating the expected premium over GD17, yielding a premium of 69 bps. This period avoids the most recent period which is affected by tapering, whilst also avoiding the period associated with the PNG CMA inquiry when the premium was extremely high.

2.5.2. Using 40 bps value but adjusting for tapering provides a revised estimate of 64 bps

Since our June 2015 cost of capital report, we have developed an alternative method to estimate the premium for the GD17 period. We estimate the premium by adjusting the current estimate of the premium for the tapering effect, where the tapering effect is estimated based on the term structure of credit spreads.

UR's premium of 40 bps is based on a period where the remaining tenor to maturity on PNG's bond is around 1.5 years. Assuming PNG issues a 10 year bond when it re-finances, we can calculate the tapering effect by observing the change in spread on BBB benchmark 10 year bond relative to a 1.5 bond.[26]

As shown in Figure 2.2, the credit spread of BBB-rated utility bonds over gilts decreases from 151 bps for 10-year maturity to 94 bps for 1.5-year maturity. We quantify the tapering effect by taking a ratio of the spreads for the different maturities, i.e. the ratio of a 10Y and 1.5Y spread is 1.6 (=151 bps/ 94 bps). Applying the ratio of 1.6 to UR's estimate of 40 bps yields a PNG premium of 64 bps, and we have adjusted our cost of debt estimate for our revised estimate.

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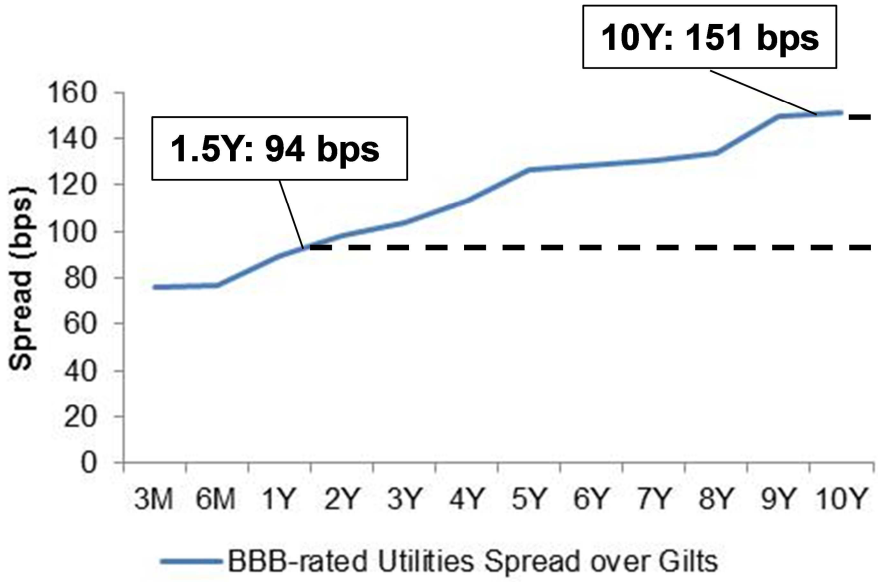
[26] We assume PNG issues a ten year tenor as this is consistent with the tenor of the constituent bonds in the iBoxx 10Y+ corporate financial index. UR uses this index to set its proposed ex-ante allowance for PNG's new debt costs. This is also the index that Ofgem and CMA consider reflects an efficient benchmark for GB utilities, and is used by Ofgem and Ofwat (for the Thames Tideway Tunnel) in its cost of debt indexation mechanism. We note that the spread for the BBB rated utilities is relatively flat beyond 10 years, so a tenor beyond 10 years should not increase the PNG premium materially. We discuss the merits of the iBoxx 10 Y+ non-financial corporate index as a relevant benchmark index for PNG in greater detail in our report on the proposed cost of debt indexation mechanism. See: NERA (May 2016) Cost of Debt Indexation Mechanism for GD17.

Figure 2.2
Term Structure of Benchmark Spread



Source: NERA analysis of Bloomberg data

The premium calculated using current data and adjusted for the effect of tapering of 64 bps is consistent with our PNG premium estimate based on the period prior to PNG Draft Decision (DD) in 2012 (Oct 2009- Aug 2011) of 69 bps, a period to selected to avoid the effects of tapering.

2.6. Transaction Cost Allowance Provides No Headroom for the Cost of Carry

In the Draft Determination, UR included a 30 bps allowance for transaction costs for PNG *"in line with the costs incurred in the company's last debt raising exercise"*[27]. UR provides no allowance for the costs associated with providing liquidity support for funding capex and for refinancing its bond. These costs are referred to as the "cost of carry", and the CMA recognised such costs in its BW decision.[28]

PNG needs to maintain a back-stop facility to fund capex, which imposes a cost even when the funds are undrawn, facilities to provide liquidity to support its BBB credit rating, as well as additional liquidity to back-stop the expected refinancing of the bond. These requirements give rise to an overall cost of carry which needs to be included in addition to the UR's proposed transaction cost allowance.

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27 Utility Regulator (March 2016), Price Control for Northern Ireland's Gas Distribution Networks GD17, p. 232 para 10.44

28 CMA (2010), Bristol Water Final Determination, Appendix N, p N11, para 48 and footnote 20

We provided evidence on the cost of carry in our June report which supported an allowance of 20 bps. Given this, the evidence supports an overall transaction cost allowance of at least 40bps, as set out in our June 2015 cost of capital report.

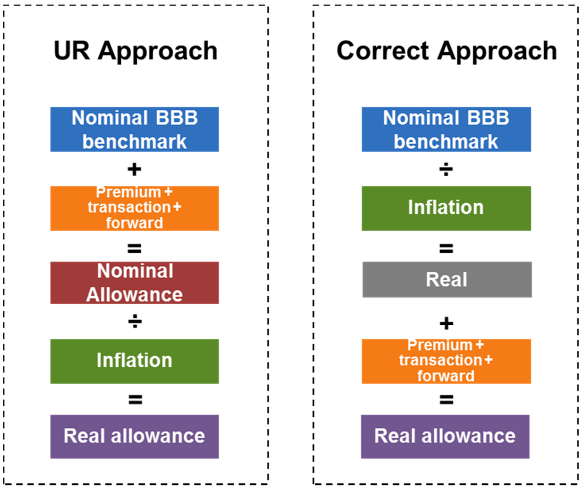
2.7. UR Incorrectly Deflates Adjustments to Cost of Debt

In the Draft Determination UR first calculated the full cost of debt allowance in nominal terms (including all adjustments, e.g. illiquidity premium, forward rate adjustment, transaction costs) and then deflated the nominal figure using its inflation forecast to derive a cost of debt allowance in real terms. UR's approach implicitly deflates the different adjustments applied to the cost of debt with forecast inflation which is incorrect.

The different adjustments to the cost of debt are calculated as differentials between two values (e.g. difference between spot and forward rates on gilts for the forward rate adjustment) and hence have no defined unit. It is therefore incorrect to deflate them with forecast inflation. The correct approach is to first deflate the interest costs into real terms (i.e. average interest cost for embedded debt and BBB-rated index yield for new debt), and then add the relevant adjustments to derive the real cost of debt. This methodology is consistent with how the adjustments were derived, i.e. as differentials.

Figure 2.3 contrasts UR's approach with the correct procedure for calculating the real cost of debt allowance. As shown, UR should adjust only the nominal benchmark cost of debt with inflation, and then add the required adjustments to the cost of debt.[29]

Figure 2.3
Correction for DD Errors in Deflating Cost of Debt Adjustments



Source: NERA illustration

[29] The overall impact of the error is around 3 bps using UR's DD figures. This is calculated as (1+ 40 bps for PNG premium + 40 bps for forward rate + 30 bps for transaction cost) – [(1+ 40 bps for PNG premium + 40 bps for forward rate + 30 bps for transaction cost) divided by 1+ 3% inflation (1.031)]

3. Conclusions

Table 3.1 compares UR Draft Determination estimate for the cost of debt and our own estimate. Overall, we calculate a real cost of debt of 3.26% for PNG based on break-even inflation or 2.42% based on OBR inflation forecasts, as of 13 May 2016. Our estimates compare to UR's estimate of 2.26% as of DD information date (end December 2015).

As well as our proposed used of breakeven instead of OBR inflation, we have corrected UR's estimate of the cost of debt for the following issues: we draw on an annual average for the BBB-index yield to address short-term market volatility; adjust the UR's premium for the tapering effect; incorporate an allowance for the cost of carry; and, avoid deflating the adjustments to the cost of debt, e.g. in relation to PNG premium, transaction and forward rate adjustment.

As well as our proposed adjustments, UR should apply an adjustment for inflation to its estimate of new and embedded nominal debt costs which reflects the period for which the debt is in place, given that we assume UR will (as it should) true-up for outturn inflation under its proposed cost of debt mechanism.

Table 3.1
We estimate an ex ante cost of debt allowance around 100 bps higher than UR DD

	UR DD (Dec 2015)[1]	NERA (May 2016)[2]	
		OBR inflation	Breakeven inflation
Embedded debt costs			
Average interest costs	4.3	4.3	
Transaction costs	0.3	0.4	
New debt costs			
BBB-index yield	4.4	4.3	
Forward rate adjustment	0.4	0.3	
PNG premium	0.4	0.64	
Transaction costs	0.3	0.4	
Weighting - embedded debt	10%	10%	
Weighting - new debt	90%	90%	
Inflation	3.1	2.4 for embedded, 3.1 for new	2.1 for embedded, 2.2 for new
Real Cost of debt	2.26[1]	2.42	3.26

Source: NERA analysis. Notes: 1) information date = end December 2015; 2) information date = 13 May 2016

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Cost of Debt Indexation Mechanism for GD17

A Report for PNG

May 2016

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Contents

1. Introduction

1.1. UR's DD Proposals

In its Draft Determination (DD), UR questioned its ability to set appropriate cost of debt allowances for PNGL and FE which reflect what would be an efficient market based cost of debt given the scale and timing of their refinancing in uncertain market conditions. To address this issue, UR proposed to implement a cost of debt sharing mechanism with an 80%:20% split between pass through to customers and retained by PNGL and FE.[1]

In this report we set out our concerns with UR's intended approach, and our proposed solution based on regulatory precedent.

1.2. Concerns with UR's Approach

First, UR's approach is without precedent: no other regulator in GB has proposed to true-up the allowance for new debt costs based on companies' actual debt costs. GB regulators have always set an ex ante cost of debt allowance, or in the case of Ofgem, set the cost of debt allowance based on a benchmark cost of debt index. The use of an ex-ante allowance or an index leaves risk within the review period with companies, and creates an incentive to minimise debt costs for the long term benefit of consumers. UR's proposed approach to set the allowance based on 80% of actual debt costs reduces substantially such incentives, making the approach significantly closer to cost-pass through regulation than incentive-based. We discuss our concerns with the incentive properties of the approach in more detail in section 4.1 of this paper.

Second, UR's approach to measuring actual debt costs will be costly and complex, and creates regulatory risk. As we explain in section 4.2, financial accounting data will not provide the requisite data, e.g. accounting data does not distinguish clearly between embedded and new debt costs, or transaction costs from debt interest costs. Instead, UR will need to examine the costs of each individual debt instrument; it will also need to consider the costs of associated derivative contracts, e.g. interest and inflation swaps which will be complex, as these form an integral part of companies' debt issuance.

Third, UR has provided no details on the implementation of its proposed approach. UR needs to establish a set of rules for calculating new debt costs (i.e. the issues set out above, and in more detail in section 4.2). UR also needs to set out its approach to converting observed nominal costs into a real allowance, i.e. its proposed measure of inflation, and how it will weight individual debt instruments to calculate a single real allowance. It will also need to allow for an effective appeals mechanism in the event of a dispute over the application of the rules. No network could reasonably accept a final determination without a detailed set of rules of how the true-up will work, and without recourse to appeal at the time of the true-up.

1 UR (March 2016), Price Control for Northern Ireland's Gas Distribution Networks GD17, p.224, para 10.7-10.9

1.3. The Established Regulatory Solution

There is recent relevant regulatory precedent in cost of debt mechanism designed by Ofwat for the Thames Tideway Tunnel (TTT) which addresses a similar situation as at GD17. Current market data suggest interest rates will rise during GD17 but the precise level is uncertain, as demonstrated by the volatility in forward (as well as spot) rates. Ofwat faced similar issues of uncertain market conditions when setting the allowed rate of return for TTT, a greenfield development to improve wastewater provision in London. Specifically:

- The greenfield nature of the investment meant that there was no existing debt with new debt to be issued over construction period of ca. 8 years; and,
- Market forecasts suggested interest rates would rise in the future but the size as well as timing of the increase were uncertain, resulting in significant risk of (forecasting) error when using a fixed ex-ante allowance for the cost of debt.

To address the above issues, Ofwat developed a simple cost of debt mechanism which updates the allowed return in line with observed changes in market cost of debt, where the market cost of debt is measured by iBoxx BBB 10+ years corporate non-financials benchmark index.

We consider Ofwat's cost of debt mechanism for TTT provides relevant precedent for UR's approach to setting cost of debt allowances in GD17. A mechanism based on the TTT approach has the following attractions:

- Addresses UR's key concern of forecasting error, driven by uncertainty about future interest rates.
- Recognises only (market-based) efficient debt costs and therefore ensures customers do not pay for inefficiently incurred debt costs.
- Preserves the power of incentive-based regulation by providing strong incentives to minimise debt costs, given that the allowance is independent of actual financing costs, for the long term benefit of consumers.
- Uses the same benchmark cost of debt (BBB iBoxx index) as used by UR in determining *"best current forecasts"* of GD17 debt costs in its Draft Determinations. This is also the same benchmark adopted by Ofgem.
- Is a simple mechanism based on precedent which relies on a small number of inputs and the need for one single adjustment, minimising regulatory costs and scope for disagreement.
- Can easily be applied across the NI gas industry.

1.4. Structure of this Report

The rest of the report is structured as follows:

- Section 2 sets out how the proposed mechanism for GD17 would work in practice.
- Section 3 addresses UR's key questions raised in relation to the proposed mechanism in our meeting with UR on 6 May 2016.

- Section 4 sets out the conceptual and practical issues associated with UR's DD proposals.

Throughout this report, we illustrate the proposed cost of debt mechanism with reference to the parameters set out in UR's DD. In a separate report, we respond to UR's proposed ex ante embedded and new debt allowance.[2]

Along with this report, we have also provided UR with a summary presentation of the proposed mechanism, and a simple spreadsheet model setting out the required calculations to implement the mechanism at GD17.[3]

2 NERA (May 2016) Response to UR's Draft Determination on Cost of Debt Issues

3 NERA (April 2016) GD17 Cost of Debt Indexation, A presentation to UREG. The excel model has file name: "*160415_COD_mechanism_example_DRAFT.xls*".

2. How the Mechanism Could Work In Practice

We draw on Ofwat's cost of debt mechanism developed for TTT to design a cost of debt mechanism for GD17. We provide more detail on the TTT mechanism in Appendix B. In this section, we describe how our proposed mechanism would work in practice.

2.1. A Simple Two-Step Approach

We understand UR's main concern in setting an ex-ante cost of debt allowance related to the difficulty of forecasting market movements in debt costs over GD17, and its concern to avoid windfall gains and losses.[4] To address the risk of UR misestimating future market movements, we propose to adopt a cost of debt mechanism where the cost of new debt estimate is adjusted ex-post (up or down) to reflect changes in the market cost of debt between FD and the time of actual refinancing. The principle of our proposed mechanism is the same one as applied to the cost of debt mechanism for TTT, where the allowed cost of debt is updated in line with changes in market cost of debt measured by the iBoxx BBB 10+ years corporate non-financials index.

We propose the cost of debt mechanism for GD17 is implemented in the following two steps:

- Step 1: At FD, UR will determine its best estimate of cost of debt over GD17 as of the FD information date, calculated as the weighted average of cost of embedded and new debt.[5]
- Step 2: At the end of GD17, the FD estimate of the cost of new debt will be adjusted (up or down) to reflect the difference between forecast market cost of debt assumed at FD and actual market cost of debt at the time of refinancing, with the market cost of debt proxied by the iBoxx BBB 10+ years corporate non-financials index (as per TTT).

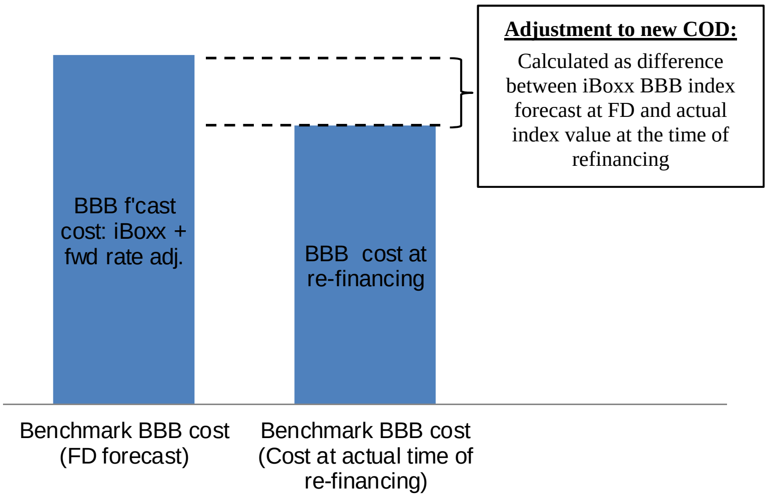
Figure 2.1 below sets out an illustration of how the ex-post adjustment to the cost of new debt would be calculated, based on changes in the iBoxx BBB index value relative to the FD forecast.

---

4 UR (March 2016) op cit., p 224, para 10.6.

5 Using UR's DD proposed weights of embedded and new debt yields an FD estimate of the allowed cost of debt for PNG as follows: $Allowed\ COD_{FD\ estimate} = 10\% * Embedded\ COD_{FD\ estimate} + 90\% * New\ COD_{FD\ estimate}$

Figure 2.1
Illustration of Adjustment to Cost of New Debt



Source: NERA illustration

The proposed cost of debt mechanism can also be combined with a sharing factor, where the cost/benefit associated with the movement in market cost of debt (as measured by the iBoxx BBB index) is shared between customers and PNG based on an ex-ante determined sharing factor. Using UR's DD proposed 80%:20% sharing factor as an illustration yields a final COD allowance:

$$Allowed\ COD_{Final} = 10\% * Embedded\ COD_{FD\ estimate} + \\ 90\% * \left(20\% * New\ COD_{FD\ estimate} + 80\% * (New\ COD_{FD\ estimate} + Adjustment)\right)$$

Table 2.1 below summarises key design features of our proposed cost of debt indexation mechanism for GD17. We provide a more detailed description of the key design features in Appendix A.

Table 2.1
Design features of proposed cost of debt mechanism for GD17

COD Meachanism Design Features	
Benchmark index	▪ Use iBoxx BBB corporate non-financials index with 10+ years maturity as benchmark index ▪ Consistent with UREG's approach at DD, which draws on iBoxx BBB 10+ index to estimate "best current forecasts" of cost of new debt
iBoxx averaging period	▪ Use month average iBoxx yield corresponding to the month in which the new debt instrument was issued
Weightings of iBoxx values for new issuances	▪ iBoxx for each debt issuance weighted by share of new debt issuance in total GD17 new debt (time and value weighted)
Inflation	▪ Derive real COD by deflating benchmark cost of new debt (estimated based on nominal iBoxx and weights as per above) with outturn inflation, specifically the inflation used to index TRV over the GD17 period
Embedded debt	▪ Embedded debt allowance as per UREG FD, other than inflation used to derive real COD corresponds to period until redemption of existing debt for consistency with cost of new debt calculation
Weightings of new and embedded debt	▪ Weightings of new and embedded debt as per UREG FD assumptions
Sharing factor	▪ We include a sharing factor of 20%:80% in line with UREG's DD proposals for illustration
Timing and form of adjustment	▪ Apply adjustment at the end of GD17 as a capitalised sum within the TRV

2.2. Our Approach Requires Small Set of Inputs

Our proposed cost of debt mechanism involves a simple calculation which relies on a small number of inputs. Figure 2.2 provides an extract of the simple spreadsheet model that we have developed to implement the approach at GD17.

Figure 2.2
Our proposed mechanism requires only a small number of inputs

Inputs

FD inputs

- This section sets out inputsfor the COD mechanism which need to be determined as part of the FD. For illustration purposes, we have included UREG's proposed DD estimates for all parameters.

Real embedded debt cost	1.5%
Real new debt cost (ex-ante)	2.4%
Benchmark real cost of new debt (ex-ante)	1.7%
Embedded debt weight	10%
New debt weight	90%
Notional gearing	55%
Sharing factor (customer share)	80.0%

Approach requires UR to identify only amount issued, issue date, iBoxx in month of issuance and outturn inflation

PNG debt instrument inputs

- This section sets out all the necessary inputs which will be determined at the end of GD17 to implement the cost of debt mechanism.
- Company specific inputs include: assumptions on amounts of new debt issued and timing of issuances (for calculation of weights). For illustration, we have assumed two new debt issuances used to refinance existing instruments.
- Market inputs include: outturn iBoxx costs in month of issue and outturn inflation used to index allowed revenues/TRV over GD17. For illustration, we have assumed outturn cost to equal UREG DD forecasts.

	Amount issued	Issue date	iBoxx in month of issue
New debt 2017	275,000	01-Jul-17	4.3%
New debt 2018	169,000	01-Sep-18	4.3%

	2017	2018	2019
Inflation (outturn, as per inflation used to index revenues/TRV)	3.1%	3.1%	3.1%

Source: NERA illustration

The inputs required for calculating the allowed cost of debt, taking into account actual market costs at the time of refinancing include:

- *FD inputs*: ex-ante WACC allowances and constituent elements, including breakdown of the allowed cost of new debt into benchmark real cost of debt (BBB iBoxx + forward adjustments) and other adjustments (PNG/illiquidity premium+transaction cost allowance).
- *Information on refinancings* (for each new debt issuance): i) date of refinancing; ii) amount of new debt issued.
- *Market data*: Outturn BBB iBoxx for each month when new debt issued and outturn inflation.

3. Addressing UR's Questions on the Model

We met with UR on 6th May 2016 to discuss our proposed approach. At this meeting, UR raised three specific issues with our proposed mechanism:

- Whether the iBoxx index reflects efficient market costs, and in particular, in relation to the tenor;
- The appropriateness of incorporating UR's estimate of the PNG premium within the mechanism or not; and,
- The reason for calculating the real cost of debt based on outturn inflation as opposed to UR's ex ante inflation estimate.

We address each of the points in the following sections.

3.1. Why the Benchmark Reflects Efficient Network Costs

At the meeting UR questioned whether iBoxx BBB 10Y+ index is a suitable benchmark for PNG's new debt costs. For example, UR expressed concern that the tenor of the iBoxx BBB 10Y+ index (the fact that it comprises 10Y+ bonds) may not be reflective of PNG's tenor.

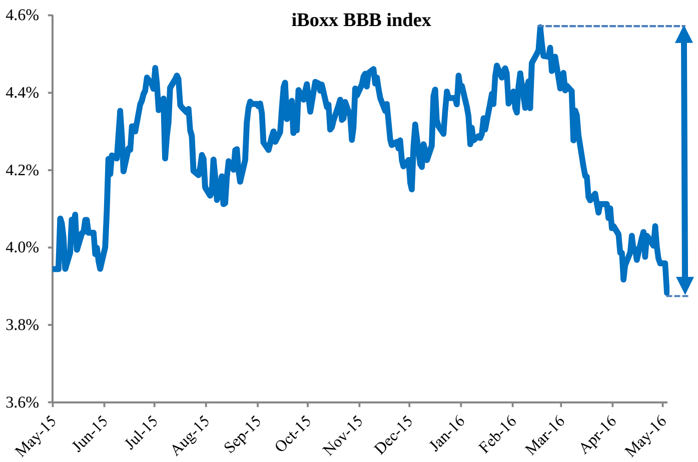
3.1.1. The UR uses iBoxx 10Y+ index

UR used the iBoxx BBB 10Y+ index to determine the ex ante cost of debt allowance, and therefore we necessarily use the same index to measure market movements. The purpose of the benchmark index in our mechanism is to measure the *change* in market conditions and to calculate a corresponding *adjustment* to the ex-ante allowed cost of debt.

The iBoxx BBB 10Y+ is also the index used by other GB regulators for setting ex-ante allowances (Ofwat at PR14 as well as UR itself at DD) as well as cost of debt indexation mechanisms (Ofwat for TTT and Ofgem at RIIO). Therefore, the UR's approach to use the index as the basis for setting debt costs is entirely consistent with the approach of other regulators, and we necessarily propose to use the same index to update the allowance for the change in market conditions.

As set out in Figure 3.1, there has been substantive volatility in iBoxx benchmark, e.g. with a decline in the index value from 4.6% to 3.9% over the past three months (as indicated by the arrow in the Figure). By consistently using the iBoxx index for the ex-ante allowance and the ex-post benchmark, our mechanism will capture the difference in market conditions between the Final Determination and the time of refinancing.

Figure 3.1
The use of iBoxx benchmark will capture the change in market conditions



Source: NERA calculations based on Datastream data

3.1.2. PNG bond is highly Correlated with the iBoxx index, and GB networks' bonds

We understand that UR is concerned that PNG's debt costs may move in the opposite direction to the benchmark index. This concern is unwarranted: there is strong empirical evidence to show that PNG's bond price moves in tandem with the iBoxx index. For example, our analysis shows that the change in the PNG bond yield is highly correlated with the iBoxx index, with a correlation co-efficient of 0.89.[6]

Investors in the PNG bond will price the bond against similar BBB rated utility bonds, which are the main constituents of the iBoxx index[7], and therefore PNG cost of debt will reflect the market/index price plus a premium to its peers. For example, the PNG bond has an even higher correlation coefficient with GB network comparators than with the iBoxx index, equal to 0.95 (see Figure 3.2).[8]

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6 The correlation coefficient is measured as correlation between weekly change in PNG yield, and weekly change in iBoxx 10Y+ yield measured for the one-year period following issuance (i.e. 2009/10). We have selected this period as the tenor to maturity is closer to the expected tenor at issuance of PNG's new bond, and therefore this period is more reflective of how the expected yield at issuance for PNG's new bond issuance will track market movements.

7 For example, Ofgem's analysis shows utilities comprise around 50% of the iBoxx 10Y+ indices. Source: https://www.ofgem.gov.uk/ofgem-publications/53838/t1decisionfinance.pdf page 22

8 The set of comparators are Southern Gas Networks (SGN) Nov 2018; Electricity North West Capital Finance June 2015; Wales and West Utilities Finance Dec 2016; London Power Networks Nov 2016; Scottish Power UK Plc Feb 2017; Northern Gas Networks July 2019: The correlation coefficient is measured as weekly change in PNG yield, and weekly change in set of comparator bonds, over the entire period of PNG bond issuance excluding the period associated with CMA appeal. If we include the period during CMA appeal the correlation co-efficient declines marginally to 0.93.

Figure 3.2
The change in PNG bond yield is highly correlated with iBoxx index, and its main constituents (GB utilities)

Source: NERA calculations based on Bloomberg data

3.1.3. Ofgem considers iBoxx 10Y+ index efficient benchmark for networks

Ofgem used iBoxx 10Y+ index (with broad A and broad BBB rating) as the benchmark index in the cost of debt indexation mechanism for electricity and gas transmission companies (RIIO-T1) and distribution companies (RIIO-GD1, RIIO-ED1). In making this decision, Ofgem considered a number of candidate indices and concluded that iBoxx is better rated than the alternative index (Bloomberg) in terms of "representative of the networks" and "transparency of methodology". Specifically, in relation to the "representative of the networks" criterion, Ofgem stated that the iBoxx index includes a higher proportion of utilities compared to the Bloomberg index. In relation to considerations of tenor, Ofgem noted that *"the cost of debt for 10-year bonds and longer issues do not tend to be materially different from each other"*[9] and concluded that the iBoxx index has a remaining maturity which is "*broadly in line*" with the tenor at issuance of network companies' debt.[10]

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9 Ofgem (17 December 2010) Consultation on strategy for the next transmission and gas distribution price controls - RIIO-T1 and GD1 Financial issues, p. 31

10 Ofgem (31 March 2011) Decision on strategy for the next transmission and gas distribution price controls - RIIO-T1 and GD1 Financial issues, para. 3.34; https://www.ofgem.gov.uk/ofgem-publications/48262/gd1decisionfinance.pdf

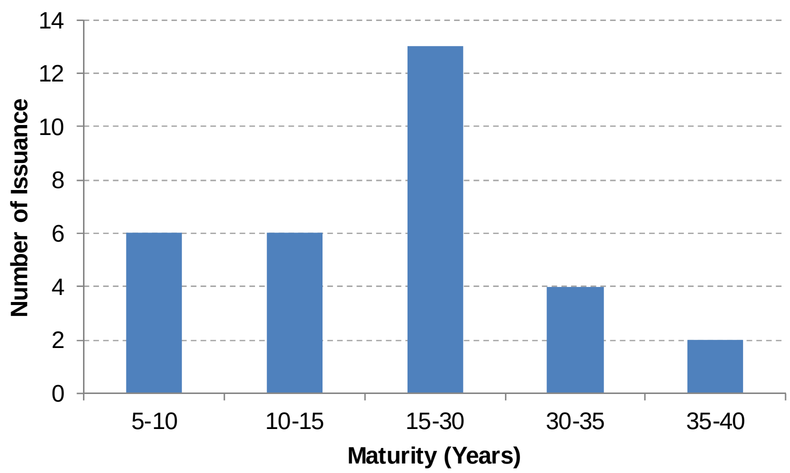
The CMA supported Ofgem's view that the index reflects efficient network costs in its consideration of the appeal of RIIO-ED1 by British Gas Trading.[11]

We consider that the index is also relevant for PNG. It comprises a high proportion of utility companies which should have similar debt financing requirements and therefore debt costs as PNGL. As we show in Figure 3.2, the change in the PNG bond price closely tracks comparator GB networks with a correlation co-efficient of 0.95.[12]

In relation to the tenor, as acknowledged by Ofgem, the tenor of the iBoxx index (i.e. 10Y+) is also broadly in line with the tenor of the industry. There is no clear reason why PNG's efficient tenor should not be in line with GB networks taking into consideration:

- The investment grade credit rating requirement both PNG and GB networks are subject to. This poses a constraint on a borrower's ability to concentrate maturities of its debt liabilities without raising liquidity concerns, and particularly curtails reliance on shorter tenor debt; conversely, spreading maturities delivers stronger credit profile and ultimately, a lower cost of debt.
- PNG and GB networks would be under similar incentives to adopt different tenors than the index, longer or shorter. Yet, GB networks have by enlarge chosen to diversify maturities while remaining broadly in line in tenor with the iBoxx index (see Figure 3.3), possibly also due to aforementioned rating constraints. It would be illogical to assume this would be any different for PNG.

Figure 3.3
Energy networks tenor at issuance depends on market conditions at time of issuance[13]



Sources: NERA analysis of Bloomberg data

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11 CMA (29 September 2015) British Gas Trading appeal, para 8.33; https://assets.digital.cabinet-office.gov.uk/media/5609588440f0b6036a00001f/BGT_final_determination.pdf

12 See footnote 8.

13 Figure shows tenor at issuance for energy networks bonds at information date 12 May 2016.

3.2. Benchmarking PNG premium

Our proposed mechanism adjusts the allowed cost of new debt for market movements as measured by the BBB iBoxx index but does not adjust for the realised PNG premium at issuance. UR has asked us to consider whether the mechanism could incorporate an adjustment for the PNG premium.

First, we note that UR's estimate of the premium in the DD of 40 bps understates the size of the premium for a new debt issuance. As we explain in our separate report,[14] the UR has drawn on recent market evidence for the premium and has failed to correct for the decline in the premium as the PNG bond approaches maturity (referred to as tapering effect). At issuance, we expect the premium to be 69 bps. Therefore, we do not see any scope for PNG to outperform, while there is material scope (of around 30 bps) for underperformance under our proposed mechanism and UR's DD ex-ante allowance. If it were feasible to incorporate an adjustment to the premium in our proposed mechanism, we would do so to correct for UR's understatement of the premium.

The reason why we cannot incorporate a revision to the PNG premium within our proposed mechanism is that there is no established benchmark to draw on to reset this element of the allowance, e.g. no iBoxx equivalent. Instead, an ex post adjustment to the premium would necessitate a detailed benchmarking exercise following refinancing similar to the exercise we have conducted to calculate the PNG premium in our June 2015 cost of capital report.[15] To be acceptable, the precise approach to benchmarking would need to be set out in detail at Final Determination, e.g. in terms of the comparators and time periods used. The difference at DD between our estimate (69bps) and the UR's DD proposals (40 bps) shows the potential for dispute (even though we agree in this instance on the set of comparators). In Appendix B, we have sketched out one potential approach to the benchmarking exercise, but it involves regulatory risk and cost. It is also not viable if PNG does not issue a public bond, e.g. where instead PNG opts for a private placement.

In conclusion, we do not consider that an ex-post adjustment to the PNG/illiquidity premium is required or practicable. UR's current approach of setting a 40 bps leaves PNG with material downside risk, and should be set at 69 bps.

3.3. Inflation Adjustment

The UR also asked why it was necessary to adjust for inflation under our proposed mechanism. We consider that it is imperative to adjust for inflation both under our proposed mechanism, and equally if UR implements its own approach. To fail to calculate the updated real cost of debt allowance using outturn inflation exposes PNG and customers to material risk of under or over recovery of actual nominal debt costs, and therefore fails to meet UR's policy intent.

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[14] NERA (May 2016) Response to UR's Draft Determination on Cost of Debt Issues

[15] Frontier/NERA (June 2015), PNG Cost of Capital for GD17

3.3.1. We propose to use same inflation as applied to TRV

The outturn BBB iBoxx index value measures the cost of debt in nominal terms. It is therefore necessary to deflate the iBoxx into real terms for consistency with the allowed cost of debt and WACC being set in real terms.

Under our proposed mechanism, the real benchmark market cost of debt at refinancing will be calculated by deflating nominal BBB iBoxx with outturn inflation used to index the TRV. The company will therefore receive (and the consumer will pay no more than) the nominal benchmark cost through a combination of: i) the real benchmark cost derived as the nominal benchmark cost minus outturn inflation, and ii) the outturn inflation component capitalised within the TRV (i.e. through the indexation of the TRV).

Failure to use outturn inflation to calculate the real benchmark market cost of debt could result in customers potentially paying far more than the efficient debt cost (or indeed too little). Nominal debt costs at the time of issuance will reflect inflation expectations at that time. If inflation turns out higher than UR's forecast, nominal debts will also be higher. If UR uses the outturn nominal debt costs minus its (lower) ex ante inflation assumption, consumers will pay more than the efficient real debt cost.[16]

Updating inflation to derive the real BBB iBoxx benchmark is consistent with regulatory precedent. The cost of debt mechanisms developed by Ofwat for TTT and Ofgem for energy networks both deflate the nominal iBoxx cost with average breakeven inflation calculated over the same period as the iBoxx nominal cost.

The use of breakeven inflation by Ofgem and Ofwat ensures customers pay the actual nominal iBoxx cost over a number of regulatory periods (assuming on average breakeven inflation is unbiased). However, break-even inflation may not equal outturn inflation over a single or even multiple regulatory periods, e.g. where break-even inflation is lower than outturn inflation over the review period, companies over-recover debt costs under Ofgem's approach. The use of breakeven inflation is therefore only appropriate for regimes where the cost of debt mechanism is retained over successive regulatory periods, like for Ofgem or TTT. In the case of PNG, the cost of debt mechanism may not be in place over extended regulatory periods. We therefore propose to use actual inflation to ensure that customers pay the correct actual BBB iBoxx cost in nominal terms in GD17.

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16 To take a simple example, using UR's figures from the DD, UR expects BBB nominal debt costs at the time of refinancing to be 4.8% (=4.4% iBoxx BBB spot + 0.4% forward rate adjustment), and inflation of 3.1%, implying a real cost of debt of 1.7% (=4.8%-3.1%). However, if inflation is 3.6% at the time of issuance (i.e. 0.5% higher than UR's DD assumption), then we expect nominal debt costs to increase by 0.5%, i.e. to 5.3%, as nominal rates move lock-step with inflation, i.e. investors require compensation for inflation. If UR fails to update for inflation outturn at time of issuance, its real cost of debt allowance would be 2.2% (=5.3% – 3.1%), but in fact the real cost of debt is unchanged from DD (5.3%-3.6% = 1.7%). Consumer will pay more than the real cost of debt in this example. Of course, if inflation outturn is lower than UR's DD assumption, consumers will pay too little and PNG will not recover its costs.

4. Practical and Conceptual Problems with UR's Approach

In this section, we summarise the conceptual as well as practical issues with UR's proposed approach of adjusting the allowed cost of debt ex-post based on PNG's actual refinancing costs.

4.1. UR's Approach Is Not Incentive Compatible

UR's DD proposals imply a pass-through to consumers of 80% of the difference between the ex-ante cost of new debt and PNG and firmus' actual cost of new debt. UR states that its "*intention is that this sharing rule will give the companies strong incentives to minimise the costs that they pay on their new borrowings, to the long-term benefit of customers in the GD23 period and beyond.*"[17]

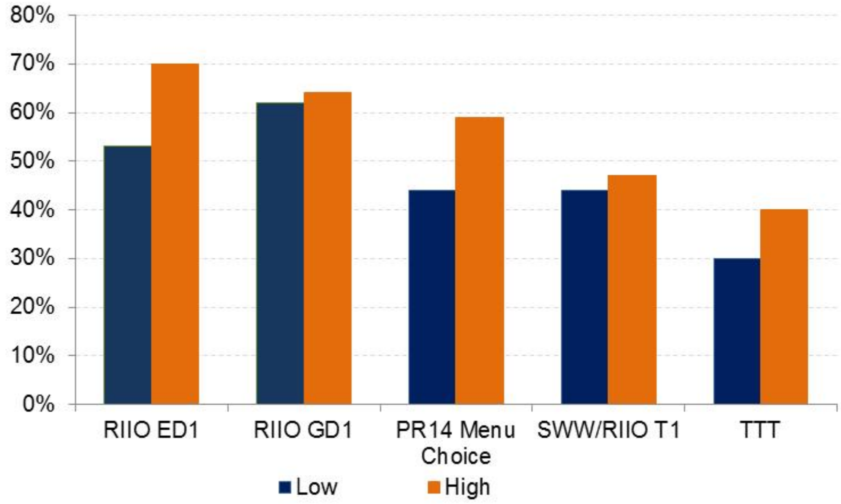
We do not consider that UR's proposal realises its policy intent. The proposed sharing rule – with 80% cost pass-through – provides only a very weak incentive to minimise debt costs with the clear risk that consumers will pay higher bills overall at GD23 and beyond.

In terms of the strength of the incentive, the proposed 80% pass-through of actual debt costs is entirely out of line with sharing factors proposed by UR itself in relation to cost performance[18], as well as all GB regulators' proposed sharing factors for cost expenditures. As shows in Figure 4.1, GB networks typically bear more than 50% of any out or under performance whereas UR proposes that PNG only bears 20% of out/under-performance.

[17] UR (March 2016) Price Control for Northern Ireland's Gas Distribution Networks GD17, Draft Determination, p. 225.

[18] In relation to opex and capex sharing factors, UR states: "*Our current thinking is that a simplified mechanism of 50:50 sharing could be a reasonable proposition and this would be applied to FE and PNGL in GD17.*" See UR (March 2016) Price Control for Northern Ireland's Gas Distribution Networks GD17, Draft Determination, p. 225

Figure 4.1
Cost sharing factors: GB networks typically bear more than 50% of any out/underperformance



Source: NERA review of regulatory determinations

The UR itself acknowledges that its approach is "*novel*" but goes on to say that "*the general principles of pain/gain sharing and adjusting debt allowances to reflect more updated actual costs of debt are well established.*"[19]

We disagree that re-setting the cost of debt based on actual debt costs is well-established. UR's proposed mechanism is significantly closer to cost pass-through regulation than incentive-base regulation. Indeed, the use of companies' actual debt costs is in contrast to the approach of all GB regulators, all of whom set either an ex-ante allowance or, alternatively, set an allowance based on an efficient benchmark cost (as we propose in our GD17 mechanism). Such approaches are incentive compatible (i.e. encourage efficient behaviour), as the allowed cost is entirely independent of companies' actual debt issuance costs, assigning risk with companies during the review. Customers then benefit from the efficiency effects of the incentive mechanism through the pass-through of any outperformance (or underperformance) at review, i.e. on average three years later under a six year control.

The UR cites an NAO report on water regulation and Ofwat's approach to setting cost of debt allowances in UK water sector, presumably because UR considers it is in line with NAO's approach.[20] But the NAO provides support to Ofgem's approach, based on a benchmark, rather than an approach based on companies' own costs, as UR proposes.[21]

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19 UR (March 2016) op. cit. 225.

20 UR (March 2016) op. cit. p. 224.

21 The NAO described the potential benefit of adopting Ofgem's benchmark approach, and it recommends that Ofwat investigates how the approach in GB energy could be applied by Ofwat in the water sector. For example, NAO states: "*Ofgem allows a cost of debt that changes based on the borrowing costs of similar companies. This approach removes gains or losses to companies resulting from general interest rate movements, but increases the variability of customer*

Our approach based on a benchmark, independent of PNG's costs, is entirely incentive compatible, with any outperformance (or underperformance) of the efficient benchmark passed through to customers at review. By contrast, the UR's approach is not incentive compatible, and will not reduce the long-term costs to consumers. Overall, we consider that UR's proposal fails to deliver its policy intent.

4.2. Measuring Actual Debt Costs is Impractical

4.2.1. Financial accounting data does not provide the required information

We also have a number of practical concerns around UR's approach to calculating companies' actual debt costs. UR cannot simply observe companies' debt interest costs and outstanding amounts from companies' financial accounts, in order to calculate new debt costs. There a number of obstacles to using financial accounting data without any adjustments, including:

- There are differences in companies' accounting policies which could lead to inconsistencies of ex-post allowances across companies, and perverse financing incentives. Conversely our proposed approach is unaffected by such accounting differences.
- The accounts do not distinguish debt costs by instrument, or therefore distinguish existing debt costs (which is subject to an ex ante allowance, and no true-up) and new debt costs (which will be trued-up).
- The accounts will not provide the costs in the format required by UR. For example, the accounts may not separate out transaction costs (which are allowed separately) from other debt costs. The accounting treatment of transaction costs is also potentially complex, e.g. in relation to the annuitisation of the up-front fees, and therefore difficult to isolate from actual new debt costs.
- UR has not stated its approach to derivative contracts associated with any new debt issuance, e.g. interest rate and inflation swaps; the accounting treatment of derivative positions is complex.
- The set of accounts will state opening and closing debt positions; UR needs to understand the date of issuance and amount drawn down (for bank debt) on a continuous basis to calculate the correct interest rate for new debt.

4.2.2. Measuring debt costs instrument-by-instrument will require a set of detailed rules

The numerous difficulties with using financial accounting data imply that UR will need to review debt costs instrument-by-instrument. We consider that there are acute difficulties here too.

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bills. We estimate that, had Ofwat used a similar indexation approach in 2009, total customer bills would have been £840 million lower between 2010 and 2015." It goes on to recommend: "*It [Ofwat] should use evidence from energy distribution and transmission companies to analyse results under Ofgem's different approach.*" NAO (2015) The Economic Regulation of the Water Sector, p.8&11.

For example, for any public bond issuances, will UR provide a cost allowance based upon the coupon or yield-to-maturity (YTM)? If UR allows for a cost based on YTM, what is the formula it intends to use?

The difficulties with measuring variable bank debt are yet more acute. Bank debt is generally variable, e.g. issued as Libor plus a premium. For example, an element of PNG's debt is issued at Libor + 2%. How will UR allow for such variable debt – based on outturn Libor over the period of review, or forecast Libor at time of issuance?

Companies generally engage in derivative contracts to accompany the debt issuance, e.g. interest rate, inflation, currency swaps (e.g. where PNG decides to access the euro market), to manage financial risk. For example, PNG has swapped part of its existing variable Libor related debt for a fixed rate debt instrument. The UR needs to set out whether it will include the costs of the derivatives – which could be in or out-of-the-money – within its true-up for the new cost of debt.

It would not be possible for UR to ignore derivative contracts just because pricing the derivatives is complicated. A derivative contract is likely to be an integral part of the overall debt cost. To take a simple example, a company could enter into a debt instrument at a high (relative to benchmark efficient cost) headline rate but also engage in a derivative contract (e.g. an interest rate swap) which is favourable to the borrower, and which offsets the high market headline rate. In this instance, UR would want to take into account the derivative contract position, and its value over time.

There are yet more complicated questions on derivatives. For example, if a company engaged in an interest swap at a later date relative to the date of issuance, will such an instrument be considered as an integral part of debt costs, or, alternatively, assumed to be at company's risk? If a company closes out the derivative contract prior to the redemption of the debt, will the contract be included or excluded from the true-up?

In general, UR will need to set out what is included in the true-up (e.g. transaction costs; derivative contracts), and what is excluded, and then publish detailed rules on how in practice it will identify those costs borne by companies, and those borne by customers. UR will need to be careful that the regulatory rules do not lead to perverse incentives, i.e. do not create a bias for one form of financing over another.

4.2.3. UR has not set out its view on weighting or approach to inflation

As well as addressing the issues specific to measuring companies' actual cost of debt, UR also needs to address all of the issues that our proposed benchmarking approach addresses. For example, the UR needs to set out how it will weight multiple debt issuances in determining the overall cost of new debt, e.g. on time-value weighted basis as we propose? Will UR recognise face value or drawn amount? And will the weighting reflect any repayment of instruments within GD17 period? How would a time-value weighting reflect the varying nature of certain debt balances on a continuous basis?

UR also needs to set out its approach to inflation. To derive real cost of debt from observed nominal cost, as we explain in section 3.3, the UR must use a contemporaneous inflation estimate to derive the actual cost of debt otherwise consumers may pay too much or indeed too little. Given that nominal debt costs at the time of issuance will reflect inflation at that time, if UR uses nominal cost of debt at issuance, but retains its ex-ante inflation (of 3.1% at

DD), the UR's mechanism rather than mitigating risk will accentuate out and under-performance risk.[22]

4.2.4. UR needs to establish an appeal process

UR has noted that regulators determine embedded debt costs taking into account actual costs, which it considers implies its approach is viable. However, in general most regulators do not calculate companies' actual embedded debt costs at review, in part because of the complexity. For example, both Ofwat and Ofgem (prior to the indexation approach) used a benchmark approach.[23] CAA estimates debt for London Heathrow based on limited number of bond issuances because of the difficulty in identifying debt costs for all instruments.

In relation to the embedded debt allowance, UR is required to consult on its approach and intended value, and PNG has an opportunity to respond to the consultation, and appeal the final determination. Similarly, any ex-post determination would require an effective consultation and an appeals process.

4.3. Conclusions

We draw the following conclusions in relation to the UR's proposals to update the allowed cost of debt ex-post based on companies' actual debt costs over GD17:

- UR's approach is akin to a cost pass-through, is not incentive compatible, and therefore fails to meet UR's policy intent to minimise costs to customers over GD23 and beyond.
- There is no readily available source of companies' actual interest debt costs which would meet UR's needs. Financial accounts will not provide the requisite level of detail, and different approaches to accounting for debt interest and transaction costs means PNG and FE accounting data may not be comparable.
- Measuring the actual cost of individual debt instruments will be complex, and could provide perverse incentives, e.g. in relation to how costs are incurred or reported.
- There is no regulatory precedent to support UR's approach – all other GB regulators use an ex-ante allowance or benchmark costs.

By contrast, our proposed approach achieves the UR's stated objective of addressing concerns around windfall gains and losses by linking the allowance to an efficient benchmark but without any of the shortcomings of UR's proposed approach. Namely, our approach:

- Preserves the power of incentive-based regulation by providing strong incentives to minimise debt costs, given that the allowance is independent of PNG's actual financing costs, for the long term benefit of consumers.

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[22] On inflation, we have proposed to deflate the benchmark nominal costs drawing on the inflation used to index TRV, as set out in section 3.3.1.

[23] Ofwat (December 2014), Setting price controls for 2015-20, Final price control determination, policy chapter A7, p.37
http://www.ofwat.gov.uk/wp-content/uploads/2015/10/det_pr20141212riskreward.pdf
Ofgem (December 2009), Electricity Distribution Price Control Review Final Proposals, p.49
https://www.ofgem.gov.uk/ofgem-publications/46746/fp1core-document-ss-final.pdf

- Ensures consumers pay only the efficient benchmark cost of debt over GD17.
- Uses the same benchmark cost of debt (BBB iBoxx index) as used by UR in determining *"best current forecasts"* of GD17 debt costs in its Draft Determinations, which is the benchmark considered relevant by Ofgem and Ofwat.
- Is a simple mechanism based on precedent which relies on a small number of inputs and the need for one single adjustment, minimising regulatory costs and scope for disagreement.
- Can be easily applied across the NI gas industry.

Appendix A. Detailed Mechanism Design

In this appendix, we discuss the detailed design issues of our proposed cost of debt indexation mechanism for GD17.

We also include a simple spreadsheet ("160415_COD_mechanism_example_DRAFT.xlsx") which sets out the calculations for how the allowed cost of debt would be re-calculated under our proposed cost of debt mechanism. We have populated the spreadsheet using illustrative assumptions on refinancing and UREG's DD proposals on the cost of debt mechanism parameters (e.g. sharing factors).

A.1. Benchmark index

We propose to measure the change in market cost of debt between FD and the actual time of refinancing, using the iBoxx BBB 10+ years corporate non-financials index as a proxy of the benchmark market cost of debt. This is the same index that UREG relied on to derive its DD estimate of cost of new debt. It is also the same index that Ofwat used as the benchmark for the cost of debt indexation mechanism for TTT and it is also the index Ofgem uses for debt indexation (together with the equivalent A rated iBoxx index).

A.2. iBoxx averaging period

For each new debt issuance, we propose to proxy the benchmark market cost of debt at the time of refinancing using a month average of BBB iBoxx values where the actual debt issuance is the mid-point.[24]

Given considerable market volatility in market yields observed over the recent period, we consider it is appropriate to use a short-run average of the BBB iBoxx index rather than a spot value on the day of issuance to mitigate risk around spot movements. We consider a month average is sufficiently long to smooth for daily spot movements while also sufficiently short to reflect the market conditions at the time of new debt issuance.

A.3. Weighting of iBoxx values for new issuances

We propose the BBB iBoxx index value for each issuance (month average) is weighted by the share of the new debt issued in total GD17 new debt. That is, the weight for each iBoxx index value will represent a time and value weighted share of that particular issuance in total new debt issued in GD17.

We set out the calculation of weights under our proposed approach in the illustrative spreadsheet "160415_COD_mechanism_example_DRAFT.xlsx" lines 37-44. The inputs required for this calculation are: i) quantum of debt issued and ii) date of issuance, for each of the new debt issuances.

[24] More precisely, we propose to use the average defined as +/- 10 working days relative to the data of issuance.

In the event of actual gearing being above/below notional, our proposed approach will ensure all the debt issuances are proportionately written-down/up, but the average weight measured in % terms remains unaffected.

A.4. Inflation

The BBB iBoxx index value measures the cost of debt in nominal terms. It is therefore necessary to deflate the iBoxx into real terms for consistency with the allowed cost of debt and WACC being set in real terms.

We propose to deflate the nominal iBoxx cost (estimated based on outturn iBoxx BBB costs and weights as described above) with actual outturn inflation, specifically, the inflation used to index the TRV over the GD17 period corresponding to the period of new debt issuance. The use of actual inflation over GD17 to deflate the iBoxx index will ensure that customers only pay for the correct actual market cost of debt in nominal terms.

We set out how the actual BBB iBoxx cost is deflated into real term using outturn inflation in the illustrative spreadsheet “160415_COD_mechanism_example_DRAFT.xlsx” lines 49-53.[25]

A.5. Embedded debt

Consistent with UR’s approach, we propose the mechanism is applied to new debt only and therefore the embedded debt allowance remains fixed as per UREG’s FD estimate.

As explained in our separate response on the ex-ante cost of debt estimate[26], the embedded debt cost in real terms needs to be estimated using inflation over the period for which it remains outstanding, i.e. inflation forecast for 2017 and real cost of new debt should be estimated using inflation over the rest of GD17.

A.6. Weightings of embedded debt and new

Consistent with UR’s approach, we propose that weightings for embedded and new debt are fixed ex-ante. In our illustrative spreadsheet, we have used 10:90 weightings for embedded:new debt, as per UREG’s DD for PNG.

A.7. Sharing factor

Our proposed cost of debt mechanism provides an adjustment to the cost of new debt to reflect changes in the market cost of debt between FD and the time of actual refinancing (as measured by the iBoxx BBB index). In principle, the cost/benefit associated with the change in market cost of debt can be shared between the customer and the GDN based on an ex-ante defined sharing factor.

---

[25] For illustration, we have assumed actual outturn inflation is in line with UREG’s DD estimate.

[26] NERA (May 2016) Response to UR's Draft Determination on Cost of Debt Issues, section 2.1.

In our illustrative spreadsheet, we have included a sharing factor of 20%:80% in line with UREG's DD proposals. We have used this assumption for illustrative purposes only and would be happy to engage in a discussion with UR on the determination of the sharing factor.

A.8. Timing and form of adjustment

We propose to apply the adjustment to give effect to the cost of debt mechanism at the end of the GD17 period. This approach is preferable for its simplicity and also will help mitigate volatility in customer charges over the GD17 period which would otherwise arise if changes in the allowed WACC are implemented within the GD17 period.

For simplicity, we propose to calculate the adjustment in £m amounts by multiplying the difference between the ex-ante and ex-post allowed WACC with the nominal TRV in each year of the GD17 period. This will give the adjustment to allowed revenues for each year of the GD17 period. Each of the annual figures should be brought forward to the beginning of GD17 at the recalculated (ex-post) WACC, uplifted to nominal terms using outturn inflation used to index the TRV. This will provide a total £m adjustment figure for the effect of the difference between the ex-ante and ex-post WACC in PV terms at the start of GD17. We propose that the adjustment is reflected in allowed revenues via a log-down/log-up of the opening TRV for GD23.

Appendix B. PNG Premium - A Possible Benchmarking Approach

As explained in section 3, we do not consider that an ex-post adjustment to the PNG/illiquidity premium is required or practicable. UR's current approach of setting a 40 bps leaves PNG with material downside risk, and should be set at 64 bps. In this appendix, we have sketched out one potential approach of adjusting the premium ex-post, but the benchmarking approach involves regulatory risk and cost. It is also not viable if PNG does not issue a public bond.

B.1. A possible approach

In theory, it would be possible to estimate the size of the premium ex-post by calculating the difference between the yield on PNG's (new) bond against a set of suitable comparators, consistent with the methodology used to derive the premium at DD. To mitigate risk to customers and PNG, it would be necessary to specify upfront how this calculation would be carried out in practice.

For example, we would need to set out criteria for selecting comparators. As an example, we propose the criteria as set out in our July 2015 cost of capital report (which also aligned with CMA's criteria). These are:

- sector (energy networks);
- rating (BBB);
- tenor;
- GBP issuance in GB;
- Bullet bond (i.e. repayable at maturity); and
- Exclude index-linked.

In relation to the tenor, we propose that we would specify a tenor +/- X years relative to the tenor at issuance of PNG's new bond, for example, where X may be defined to ensure that it includes a minimum sample size.

We would also need to prescribe the time period over which the premium would be calculated. We consider the premium should be measured at or around the time of the new bond issuance to reflect the premium that PNG incurs, but also over a sufficiently long time-frame to remove the effect of any short-term market movements.

Unlike in the case of the adjustment for market movements, where there is confidence that the benchmark reflects efficient costs from its established use by GB regulators, the comparator bonds may not provide reasonable benchmarks (despite the selection criteria), e.g. because of specific characteristics of the comparators bond or PNG bond that we cannot foresee now; the small number of comparators. To mitigate risk to both PNG and customers, we consider that any ex-post adjustment is limited to the ex ante estimate of the size of the PNG premium, i.e. +/- 64 bps based on our estimates around the central estimate of 64 bps.[27]

Finally, we note that the proposed ex-post calculation of the premium assumes PNG issues a public bond within GD17. If PNG refinances with alternative debt instruments, such as bank debt or chooses a private placement, then the proposed benchmarking of the premium would not be possible.

[27] However, if the UR assumes a central estimate of the PNG/illiquidity premium of 40 bps, we propose the variation to be *asymmetric* (e.g. +80 bps/ - 40 bps) as the central point understates the expected size of the premium.

Appendix C. Overview of TTT Mechanism

The cost of debt mechanism for Thames Tideway Tunnel (TTT) adjusts the allowed cost of debt over time with changes in the market cost of debt. The final cost of debt allowance for TTT consists of two components:

- An *ex-ante allowance*; and
- An *adjustment* in line with changes in market cost of debt (positive and negative) based on the difference between i) the benchmark cost of debt at the time of new debt issuance and ii) the benchmark cost of debt measured at the FD, where the benchmark market cost of debt is proxied by the iBoxx BBB 10+ years corporate non-financials benchmark index (see equation below).

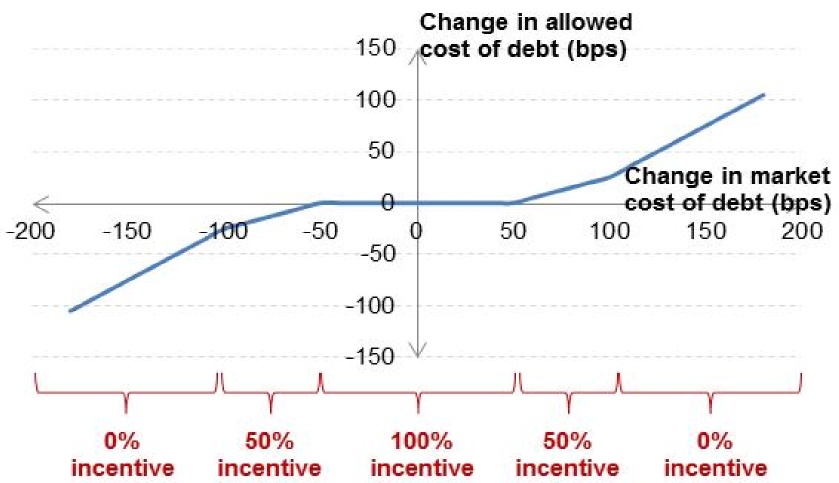
$$Debt\ return\ adjustment_t = \sum_{n=1}^{t} New\ debt_n * \left(iBoxx\ BBB_n - iBoxx\ BBB_{baseyear}\right) * Sharing\ factor$$

The adjustment for changes in market cost of debt for TTT is subject to a sharing mechanism, which employs different sharing factors within certain deadbands. Specifically:

- For movements of +/- 0 to 50bps, TTT retains the full benefit/bears the full cost of market movements (0% sharing);
- For movements between +/- 50 to 100bps, TTT shares the cost/benefit in excess of the 50bps equally with customers (50% sharing)
- For movements in excess of +/-100 bps, TTT passes through the full cost/benefit in excess of 100bps to customers (100% sharing).

The incentive rates applicable to the different deadbands under the TTT mechanism are summarized in Table 2.1 below.

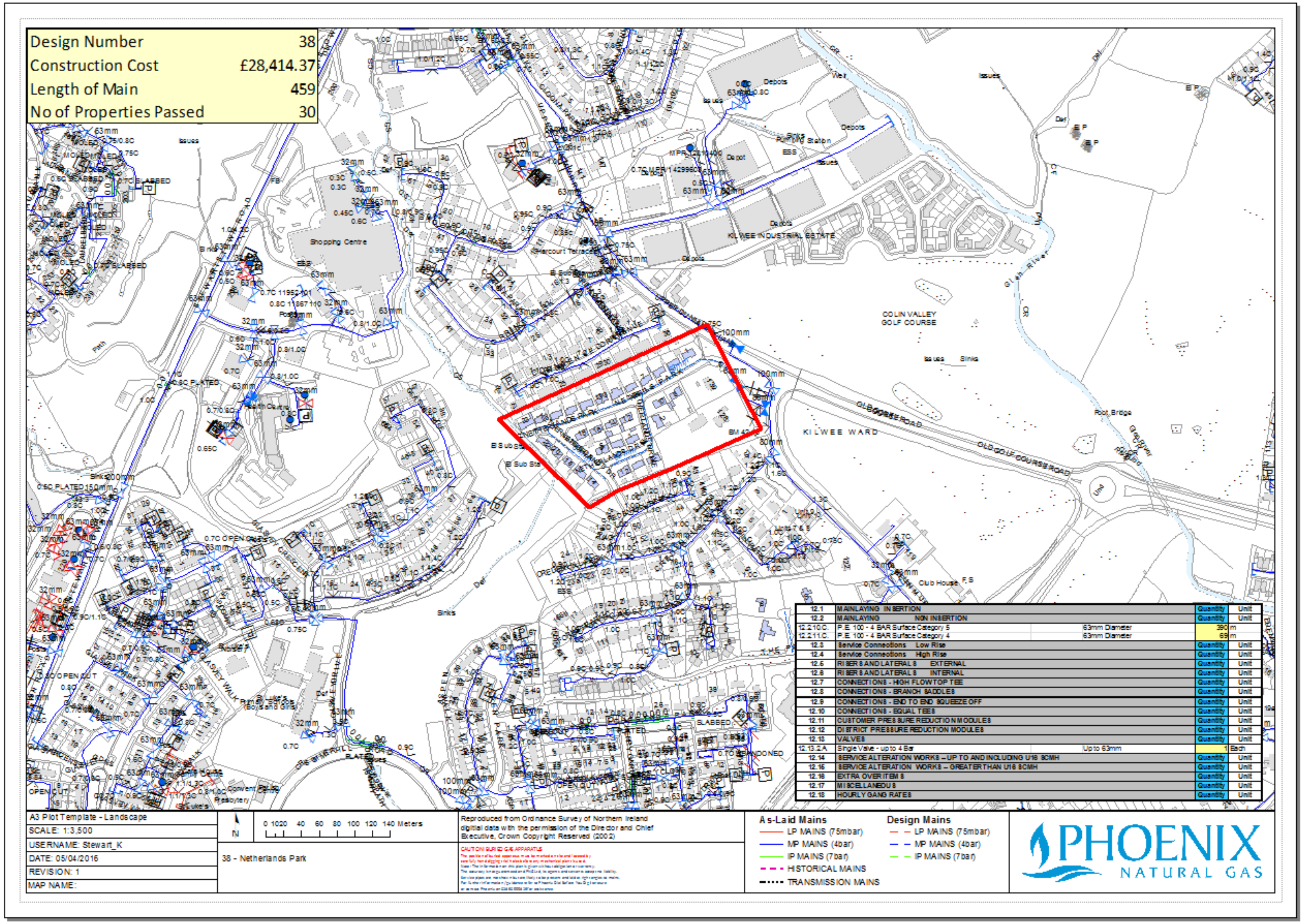
Figure C.1
Sharing of Market Cost of Debt Movements under TTT Mechanism



Source: NERA illustration

NERA Economic Consulting
Marble Arch House, 66 Seymour Street
London W1H 5BT
United Kingdom
Tel: 44 20 7659 8500 Fax: 44 20 7659 8501
www.nera.com

1. Netherlands, Dunmurry




Corrina Ave
Dunmurry Ln
Netherlands Park
Netherlands Park
Netherlands Park
Netherlands Park
Netherlands Park
Netherlands Dr
Our Lady Queen
of Peace Parish

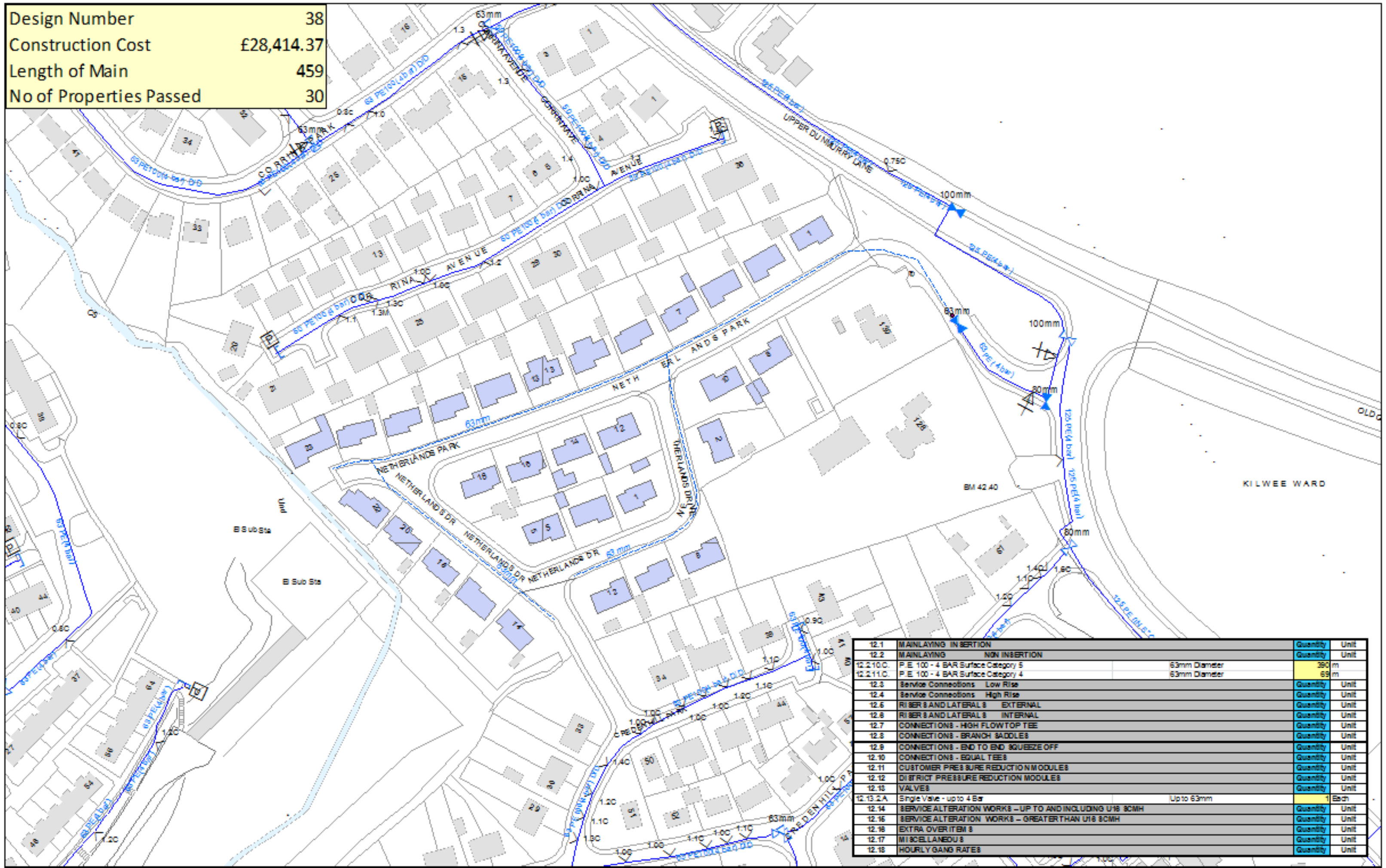
Design Number		38
OO	***NIHE***	***Total New Props Passed***
30		**30**

Total Length	**459**

Total Construction Cost
£28,414

Price Per Prop Passed
£947

Design Number	38
Construction Cost	£28,414.37
Length of Main	459
No of Properties Passed	30



12.1	MAINLAYING INSERTION		Quantity	Unit
12.2	MAINLAYING NON INSERTION		Quantity	Unit
12.2.10.C.	P.E. 100 - 4 BAR Surface Category 5	63mm Diameter	390	m
12.2.11.C.	P.E. 100 - 4 BAR Surface Category 4	63mm Diameter	69	m
12.3	Service Connections Low Rise		Quantity	Unit
12.4	Service Connections High Rise		Quantity	Unit
12.5	RISERS AND LATERALS EXTERNAL		Quantity	Unit
12.6	RISERS AND LATERALS INTERNAL		Quantity	Unit
12.7	CONNECTIONS - HIGH FLOW TOP TEE		Quantity	Unit
12.8	CONNECTIONS - BRANCH SADDLES		Quantity	Unit
12.9	CONNECTIONS - END TO END SQUEEZE OFF		Quantity	Unit
12.10	CONNECTIONS - EQUAL TEES		Quantity	Unit
12.11	CUSTOMER PRESSURE REDUCTION MODULES		Quantity	Unit
12.12	DISTRICT PRESSURE REDUCTION MODULES		Quantity	Unit
12.13	VALVES		Quantity	Unit
12.13.2.A	Single Valve - up to 4 Bar	Up to 63mm	1	Each
12.14	SERVICE ALTERATION WORKS – UP TO AND INCLUDING U16 SCMH		Quantity	Unit
12.15	SERVICE ALTERATION WORKS – GREATER THAN U16 SCMH		Quantity	Unit
12.16	EXTRA OVER ITEMS		Quantity	Unit
12.17	MISCELLANEOUS		Quantity	Unit
12.18	HOURLY GANG RATES		Quantity	Unit

A3 Plot Template - Landscape
SCALE: 1:1,250
USERNAME: Stewart_K
DATE: 05/04/2016
REVISION: 1
MAP NAME:

N

0 10 20 40 Meters

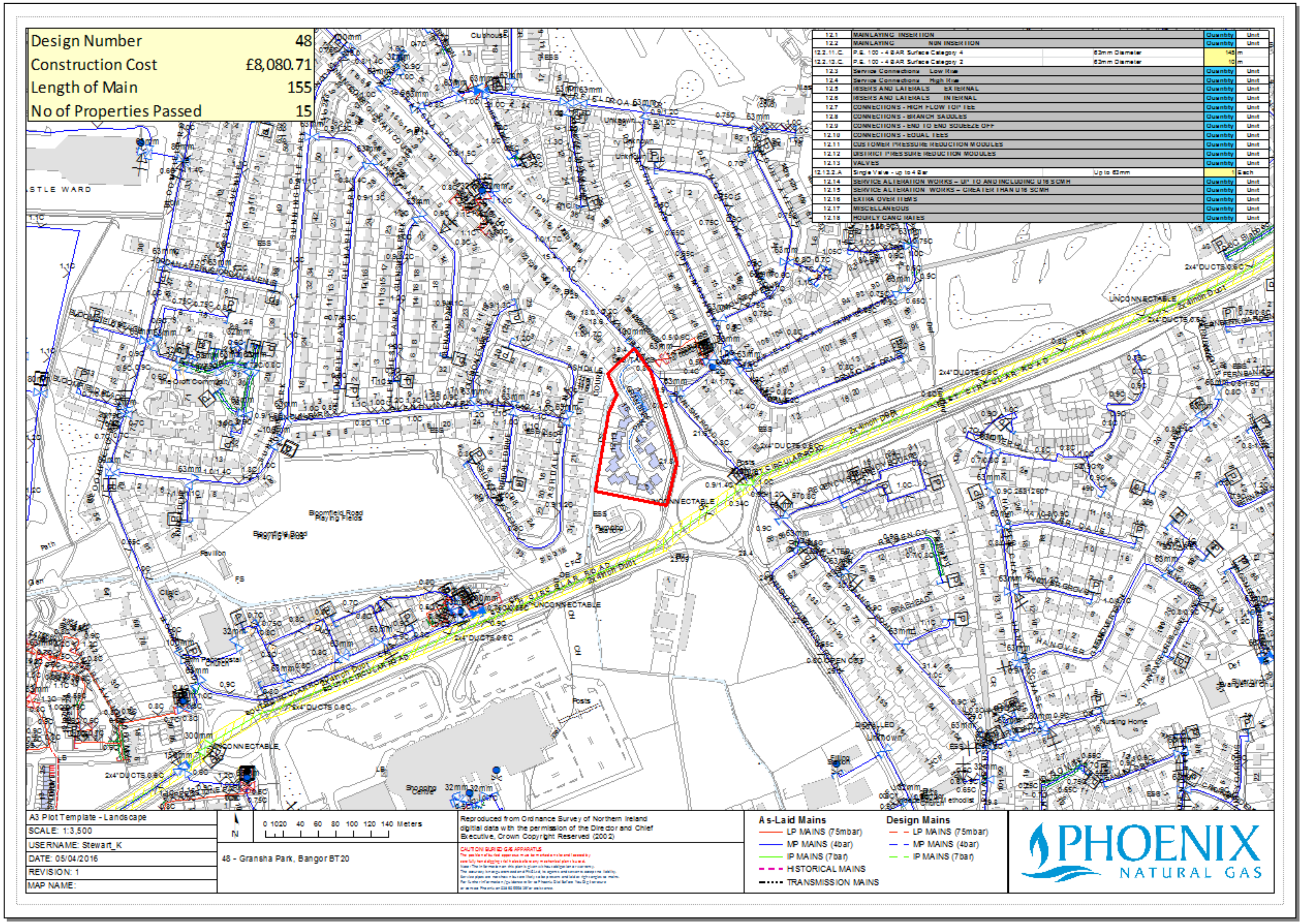
38 - Netherlands Park

CAUTION! BURIED GAS APPARATUS

As-Laid Mains
- LP MAINS (75mbar)
- MP MAINS (4bar)
- IP MAINS (7bar)
- HISTORICAL MAINS
- TRANSMISSION MAINS

Design Mains
- LP MAINS (75mbar)
- MP MAINS (4bar)
- IP MAINS (7bar)

2. Gransha Park, Bangor




Gransha Rd
Gransha Park
Ashdale Cr
Ashdale Cres
Dellmount Rd
Fairfield Rd
Dellmount Dr
Glendun Park
A2
3D

Design Number		48
OO	***NIHE***	***Total New Props Passed***
15		**15**

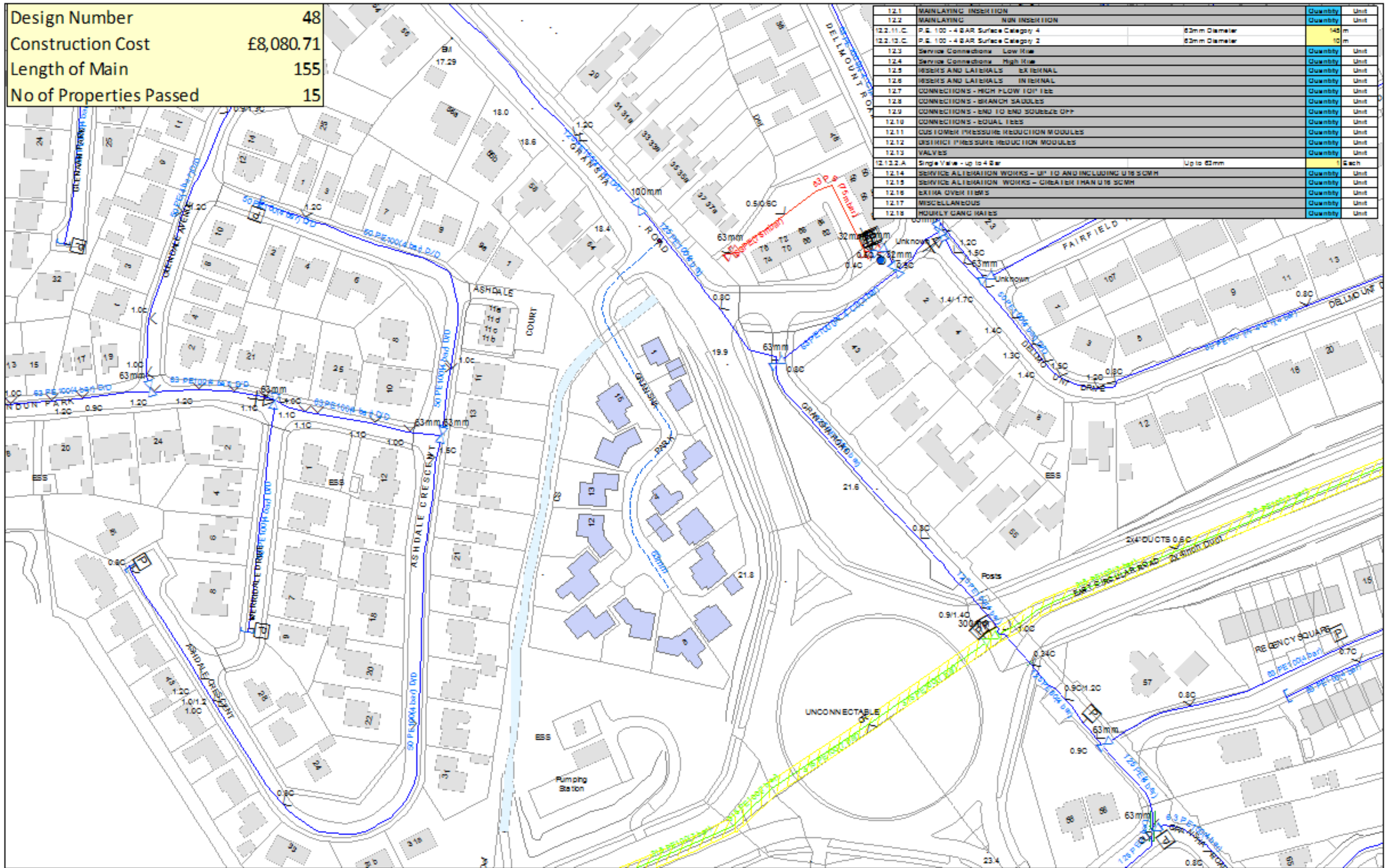
Total Length	**155**

Total Construction Cost
£8,081

Price Per Prop Passed
£539

Design Number	48
Construction Cost	£8,080.71
Length of Main	155
No of Properties Passed	15

12.1	MAINLAYING INSERTION		Quantity	Unit
12.2	MAINLAYING NON INSERTION		Quantity	Unit
12.2.11.C.	P.E. 100 - 4 BAR Surface Category 4	63mm Diameter	145	m
12.2.13.C.	P.E. 100 - 4 BAR Surface Category 2	63mm Diameter	10	m
12.3	Service Connections Low Rise		Quantity	Unit
12.4	Service Connections High Rise		Quantity	Unit
12.5	RISERS AND LATERALS EXTERNAL		Quantity	Unit
12.6	RISERS AND LATERALS INTERNAL		Quantity	Unit
12.7	CONNECTIONS - HIGH FLOW TOP TEE		Quantity	Unit
12.8	CONNECTIONS - BRANCH SADDLES		Quantity	Unit
12.9	CONNECTIONS - END TO END SQUEEZE OFF		Quantity	Unit
12.10	CONNECTIONS - EQUAL TEES		Quantity	Unit
12.11	CUSTOMER PRESSURE REDUCTION MODULES		Quantity	Unit
12.12	DISTRICT PRESSURE REDUCTION MODULES		Quantity	Unit
12.13	VALVES		Quantity	Unit
12.13.2.A	Single Valve - up to 4 Bar	Up to 63mm	1	Each
12.14	SERVICE ALTERATION WORKS – UP TO AND INCLUDING U16 SCMH		Quantity	Unit
12.15	SERVICE ALTERATION WORKS – GREATER THAN U16 SCMH		Quantity	Unit
12.16	EXTRA OVER ITEMS		Quantity	Unit
12.17	MISCELLANEOUS		Quantity	Unit
12.18	HOURLY GANG RATES		Quantity	Unit

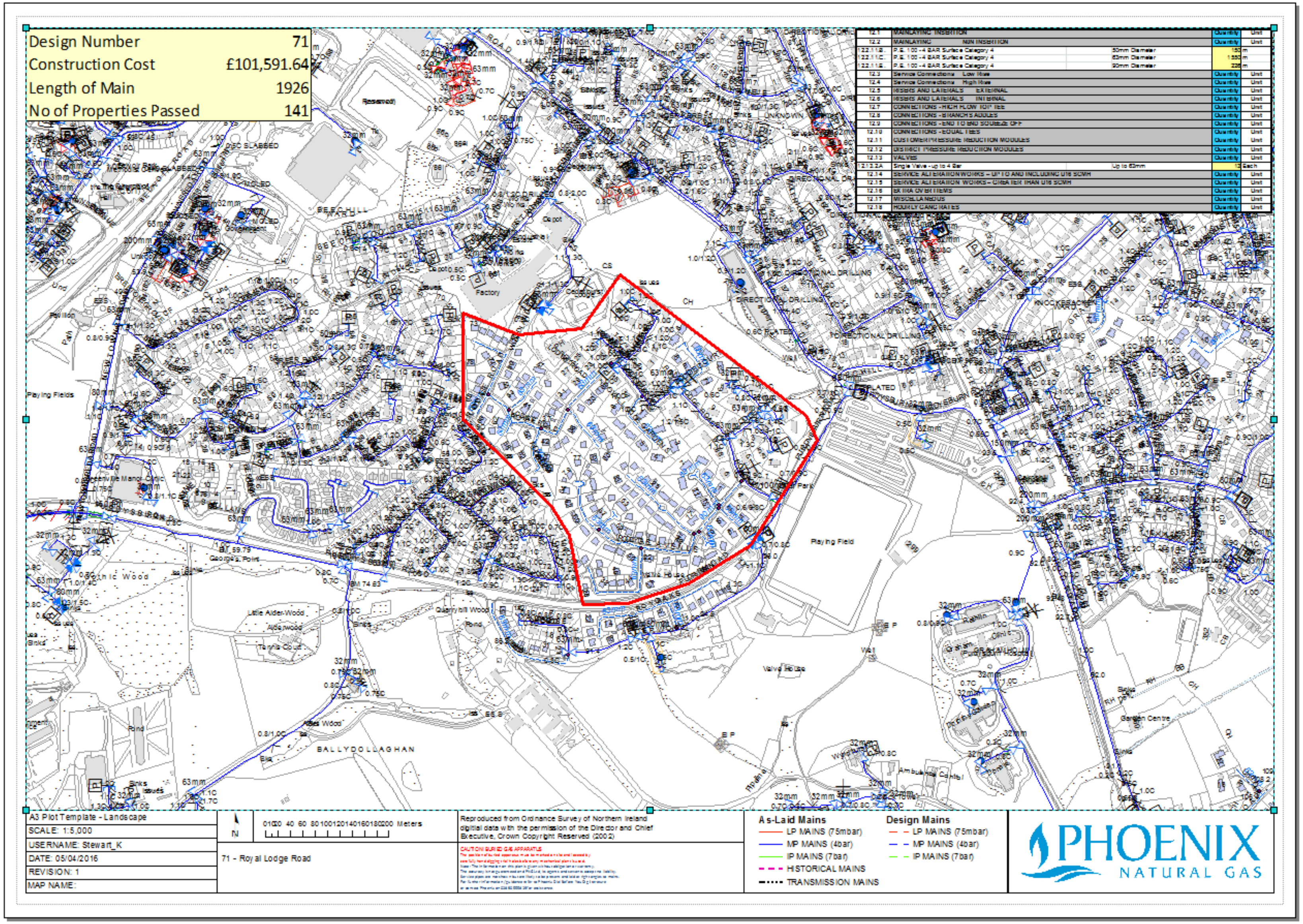


A3 Plot Template - Landscape	N 0 10 20 40 Meters	Reproduced from Ordinance Survey of Northern Ireland digitial data with the permission of the Director and Chief Executive, Crown Copyright Reserved (2002)	
SCALE: 1:1,250			
USERNAME: Stewart_K	48 - Gransha Park, Bangor BT20	CAUTION! BURIED GAS APPARATUS	
DATE: 05/04/2016			
REVISION: 1			
MAP NAME:			

As-Laid Mains
- LP MAINS (75mbar)
- MP MAINS (4bar)
- IP MAINS (7bar)
- HISTORICAL MAINS
- TRANSMISSION MAINS

Design Mains
- LP MAINS (75mbar)
- MP MAINS (4bar)
- IP MAINS (7bar)

3. Royal Lodge, Belfast




Care Home
Woodland Manor
Beechill Inn
Royal Lodge Mews
Beechill Rd
AECOM
Northern Ireland
Medical & Dental...
Royal Lodge Rd
PC Fxr [IT Solutions]
[Productions] [Repair]...
Beechill Care Home
Royal Lodge Rd
Royal Lodge Rd
Royal Lodge Rd
Royal Lodge Ave
Royal Lodge Ave
Purdysburn Rd
Purdysburn Rd
Purdysburn Rd
Purdysburn Rd
Purdysburn Rd
Alderwood Hill
Google

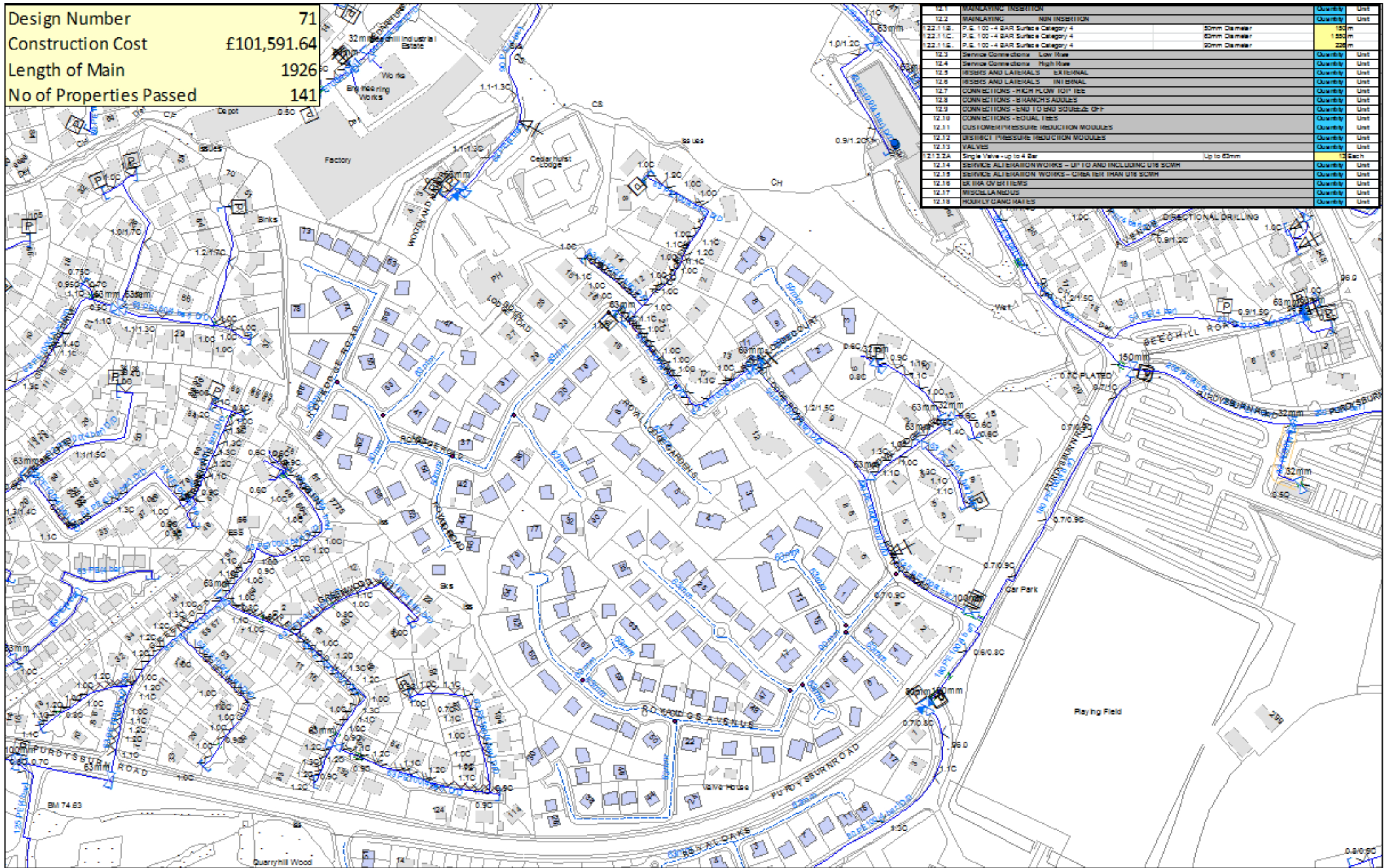
Design Number		71
OO	***NIHE***	***Total New Props Passed***
141		**141**

Total Construction Cost
£101,592

Total Length	**1,926**

Price Per Prop Passed
£721

Design Number	71
Construction Cost	£101,591.64
Length of Main	1926
No of Properties Passed	141



12.1	MAINLAYING INSERTION		Quantity	Unit
12.2	MAINLAYING NON INSERTION		Quantity	Unit
12.2.1.1.B.	P.E. 100 - 4 BAR Surface Category 4	50mm Diameter	150	m
12.2.1.1.C.	P.E. 100 - 4 BAR Surface Category 4	63mm Diameter	1550	m
12.2.1.1.E.	P.E. 100 - 4 BAR Surface Category 4	90mm Diameter	226	m
12.3	Service Connections Low Rise		Quantity	Unit
12.4	Service Connections High Rise		Quantity	Unit
12.5	RISERS AND LATERALS EXTERNAL		Quantity	Unit
12.6	RISERS AND LATERALS INTERNAL		Quantity	Unit
12.7	CONNECTIONS - HIGH FLOW TOP TEE		Quantity	Unit
12.8	CONNECTIONS - BRANCH SADDLES		Quantity	Unit
12.9	CONNECTIONS - END TO END SQUEEZE OFF		Quantity	Unit
12.10	CONNECTIONS - EQUAL TEES		Quantity	Unit
12.11	CUSTOMER PRESSURE REDUCTION MODULES		Quantity	Unit
12.12	DISTRICT PRESSURE REDUCTION MODULES		Quantity	Unit
12.13	VALVES		Quantity	Unit
12.13.2A	Single Valve - up to 4 Bar	Up to 63mm	12	Each
12.14	SERVICE ALTERATION WORKS – UP TO AND INCLUDING U16 SCMH		Quantity	Unit
12.15	SERVICE ALTERATION WORKS – GREATER THAN U16 SCMH		Quantity	Unit
12.16	EXTRA OVER ITEMS		Quantity	Unit
12.17	MISCELLANEOUS		Quantity	Unit
12.18	HOURLY GANG RATES		Quantity	Unit

A3 Plot Template - Landscape
SCALE: 1:2,500
USERNAME: Stewart_K
DATE: 05/04/2016
REVISION: 1
MAP NAME:

N

0 10 20 40 60 80 100 Meters

71 - Royal Lodge Road

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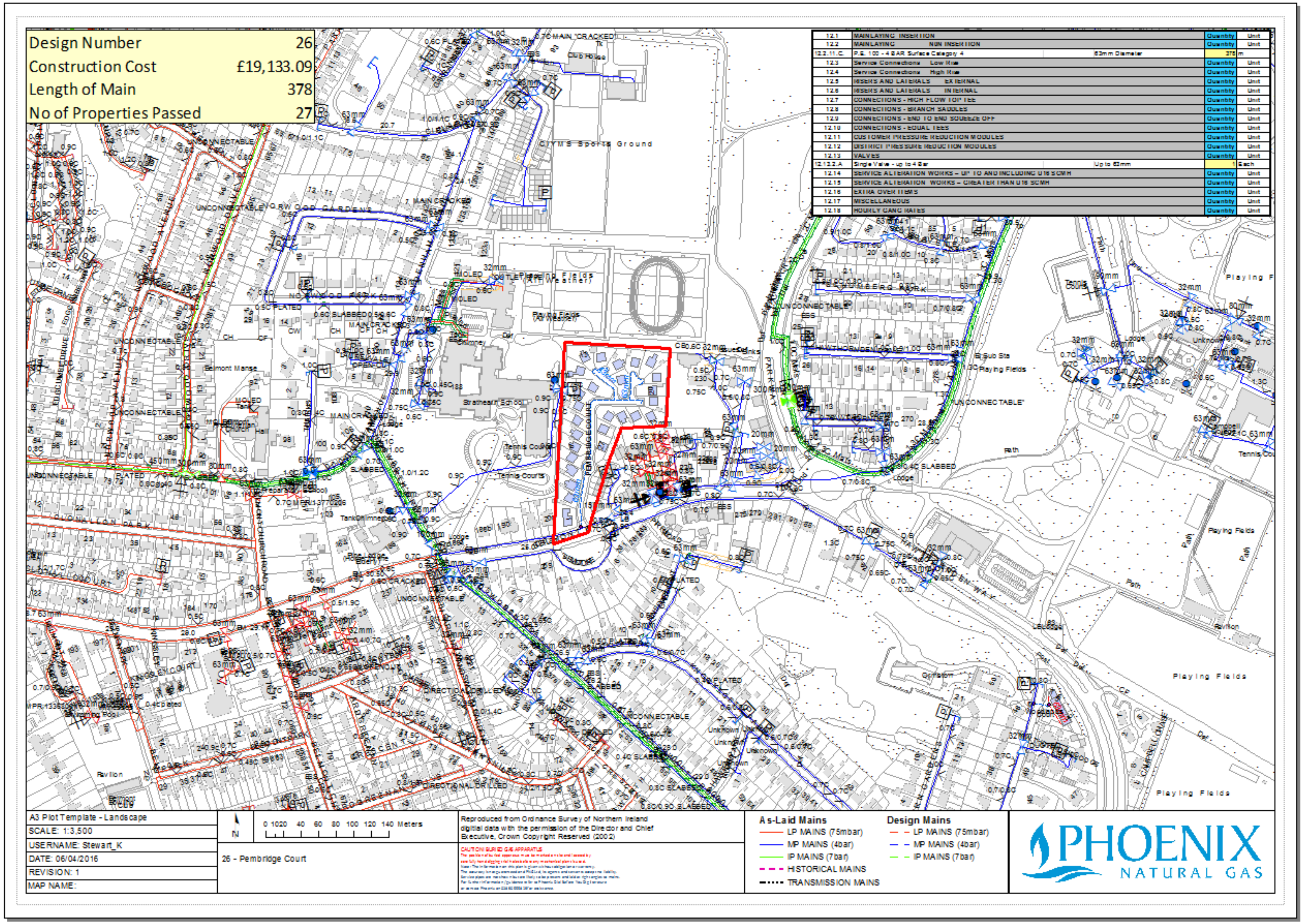
CAUTION! BURIED GAS APPARATUS

As-Laid Mains
- LP MAINS (75mbar)
- MP MAINS (4bar)
- IP MAINS (7bar)
- HISTORICAL MAINS
- TRANSMISSION MAINS

Design Mains
- LP MAINS (75mbar)
- MP MAINS (4bar)
- IP MAINS (7bar)

PHOENIX NATURAL GAS

4. Pembridge Court, Belfast



Design Number	26
Construction Cost	£19,133.09
Length of Main	378
No of Properties Passed	27

12.1	MAINLAYING INSERTION		Quantity	Unit
12.2	MAINLAYING NON INSERTION		Quantity	Unit
12.2.11.C.	P.E. 100 - 4 BAR Surface Category 4	63mm Diameter	378	m
12.3	Service Connections Low Rise		Quantity	Unit
12.4	Service Connections High Rise		Quantity	Unit
12.5	RISERS AND LATERALS EXTERNAL		Quantity	Unit
12.6	RISERS AND LATERALS INTERNAL		Quantity	Unit
12.7	CONNECTIONS - HIGH FLOW TOP TEE		Quantity	Unit
12.8	CONNECTIONS - BRANCH SADDLES		Quantity	Unit
12.9	CONNECTIONS - END TO END SQUEEZE OFF		Quantity	Unit
12.10	CONNECTIONS - EQUAL TEES		Quantity	Unit
12.11	CUSTOMER PRESSURE REDUCTION MODULES		Quantity	Unit
12.12	DISTRICT PRESSURE REDUCTION MODULES		Quantity	Unit
12.13	VALVES		Quantity	Unit
12.13.2.A	Single Valve - up to 4 Bar	Up to 63mm	1	Each
12.14	SERVICE ALTERATION WORKS – UP TO AND INCLUDING U16 SCMH		Quantity	Unit
12.15	SERVICE ALTERATION WORKS – GREATER THAN U16 SCMH		Quantity	Unit
12.16	EXTRA OVER ITEMS		Quantity	Unit
12.17	MISCELLANEOUS		Quantity	Unit
12.18	HOURLY GANG RATES		Quantity	Unit


Strathearn School
Pembridge Ct
Pembridge Ct
Pembridge Ct
Foster Care Associates - Belfast Office
Barnardo's
JPR
Ormiston Square
B170
Belmont Rd
B170
Pirrie Rd

Design Number		26
OO	***NIHE***	***Total New Props Passed***
27		**27**

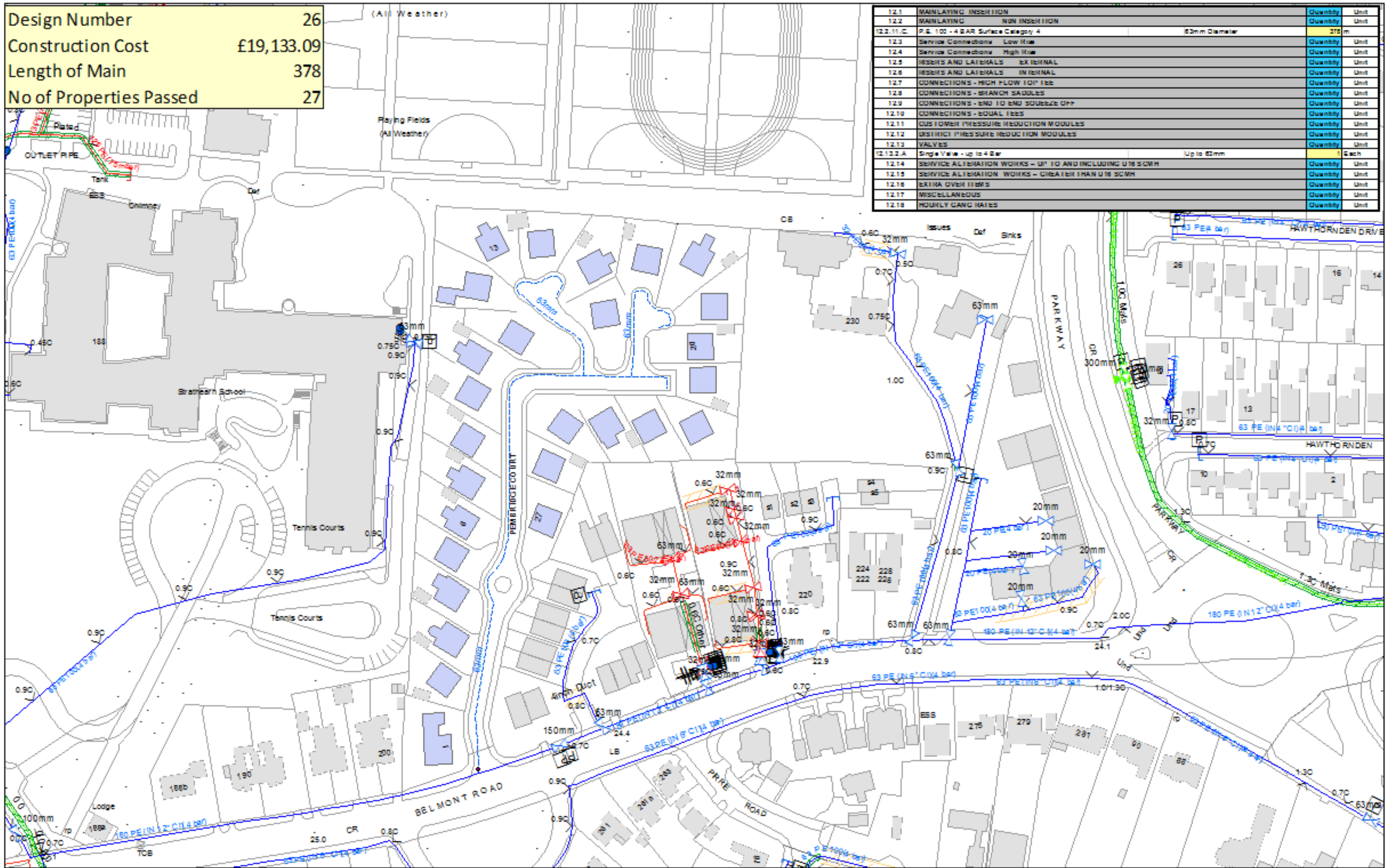
Total Construction Cost
£19,133

Total Length	**378**

Price Per Prop Passed
£709

Design Number	26
Construction Cost	£19,133.09
Length of Main	378
No of Properties Passed	27

12.1	MAINLAYING INSERTION		Quantity	Unit
12.2	MAINLAYING NON INSERTION		Quantity	Unit
12.2.11.C.	P.E. 100 - 4 BAR Surface Category 4	63mm Diameter	378	m
12.3	Service Connections Low Rise		Quantity	Unit
12.4	Service Connections High Rise		Quantity	Unit
12.5	RISERS AND LATERALS EXTERNAL		Quantity	Unit
12.6	RISERS AND LATERALS INTERNAL		Quantity	Unit
12.7	CONNECTIONS - HIGH FLOW TOP TEE		Quantity	Unit
12.8	CONNECTIONS - BRANCH SADDLES		Quantity	Unit
12.9	CONNECTIONS - END TO END SQUEEZE OFF		Quantity	Unit
12.10	CONNECTIONS - EQUAL TEES		Quantity	Unit
12.11	CUSTOMER PRESSURE REDUCTION MODULES		Quantity	Unit
12.12	DISTRICT PRESSURE REDUCTION MODULES		Quantity	Unit
12.13	VALVES		Quantity	Unit
12.13.2.A	Single Valve - up to 4 Bar	Up to 63mm	1	Each
12.14	SERVICE ALTERATION WORKS – UP TO AND INCLUDING U16 SCMH		Quantity	Unit
12.15	SERVICE ALTERATION WORKS – GREATER THAN U16 SCMH		Quantity	Unit
12.16	EXTRA OVER ITEMS		Quantity	Unit
12.17	MISCELLANEOUS		Quantity	Unit
12.18	HOURLY GANG RATES		Quantity	Unit



A3 Plot Template - Landscape
SCALE: 1:1,250
USERNAME: Stewart_K
DATE: 06/04/2016
REVISION: 1
MAP NAME:

N
0 10 20 40Meters

26 - Pembridge Court

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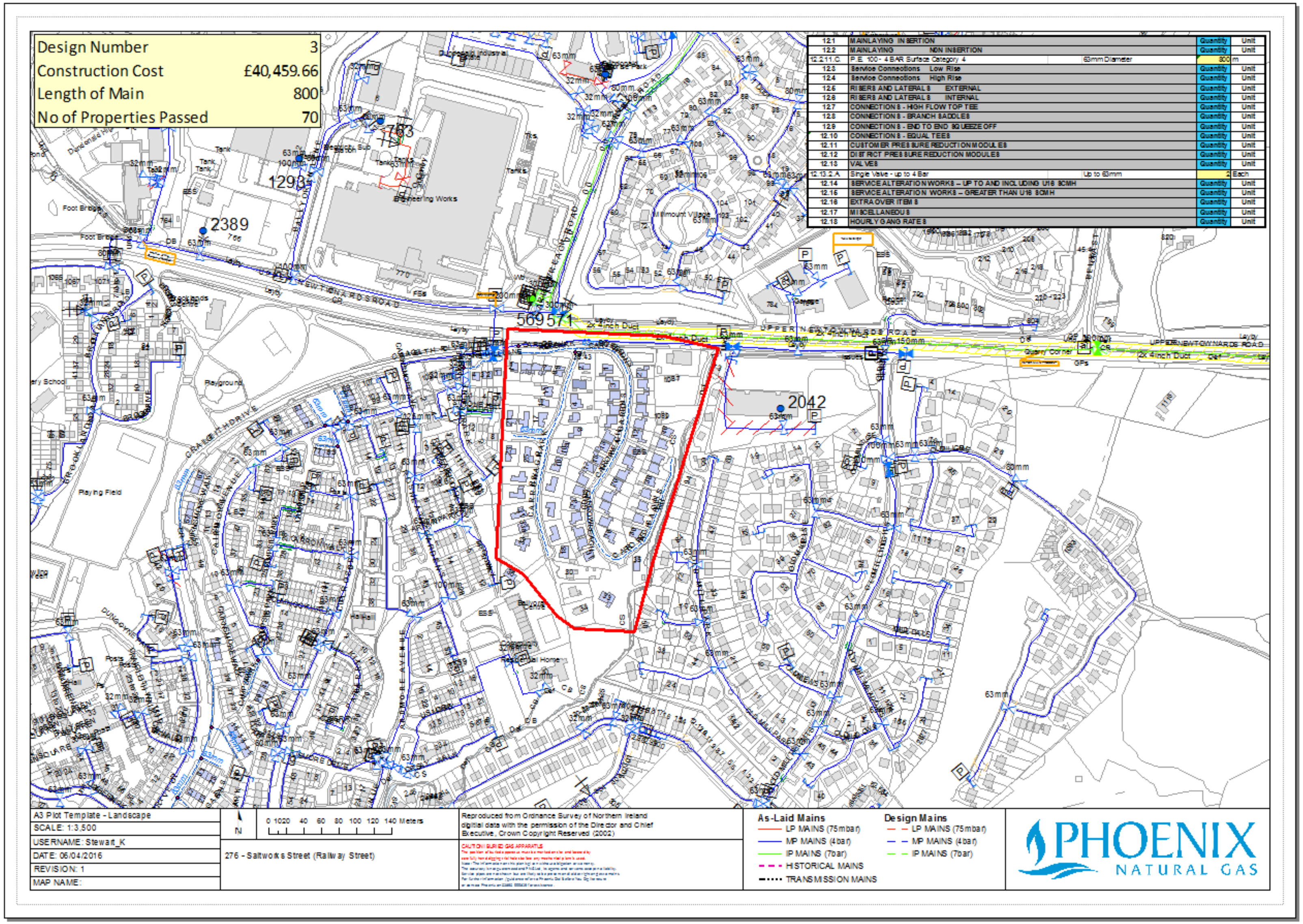
CAUTION! BURIED GAS APPARATUS

As-Laid Mains
- LP MAINS (75mbar)
- MP MAINS (4bar)
- IP MAINS (7bar)
- HISTORICAL MAINS
- TRANSMISSION MAINS

Design Mains
- LP MAINS (75mbar)
- MP MAINS (4bar)
- IP MAINS (7bar)

5. Carrowreagh Park, Belfast




Upper Newtownards Rd
A20
A20
A20
Craigleith Dr
Craigleith Dr
Craigleith Dr
Millreagh Motors
Strone Park
Strone Park
Carrowreagh Park
Carrowreagh Park
Carrowreagh Gardens
Carrowreagh Gardens
Carrowreagh Gardens
Carrowreagh Gardens
Carrowreagh Ln
Old Mill Park
Old Mill Park
Brodick Way
Brodick Way
Ballyoran Centre

Design Number		3
OO	NIHE	Total New Props Passed
70		70

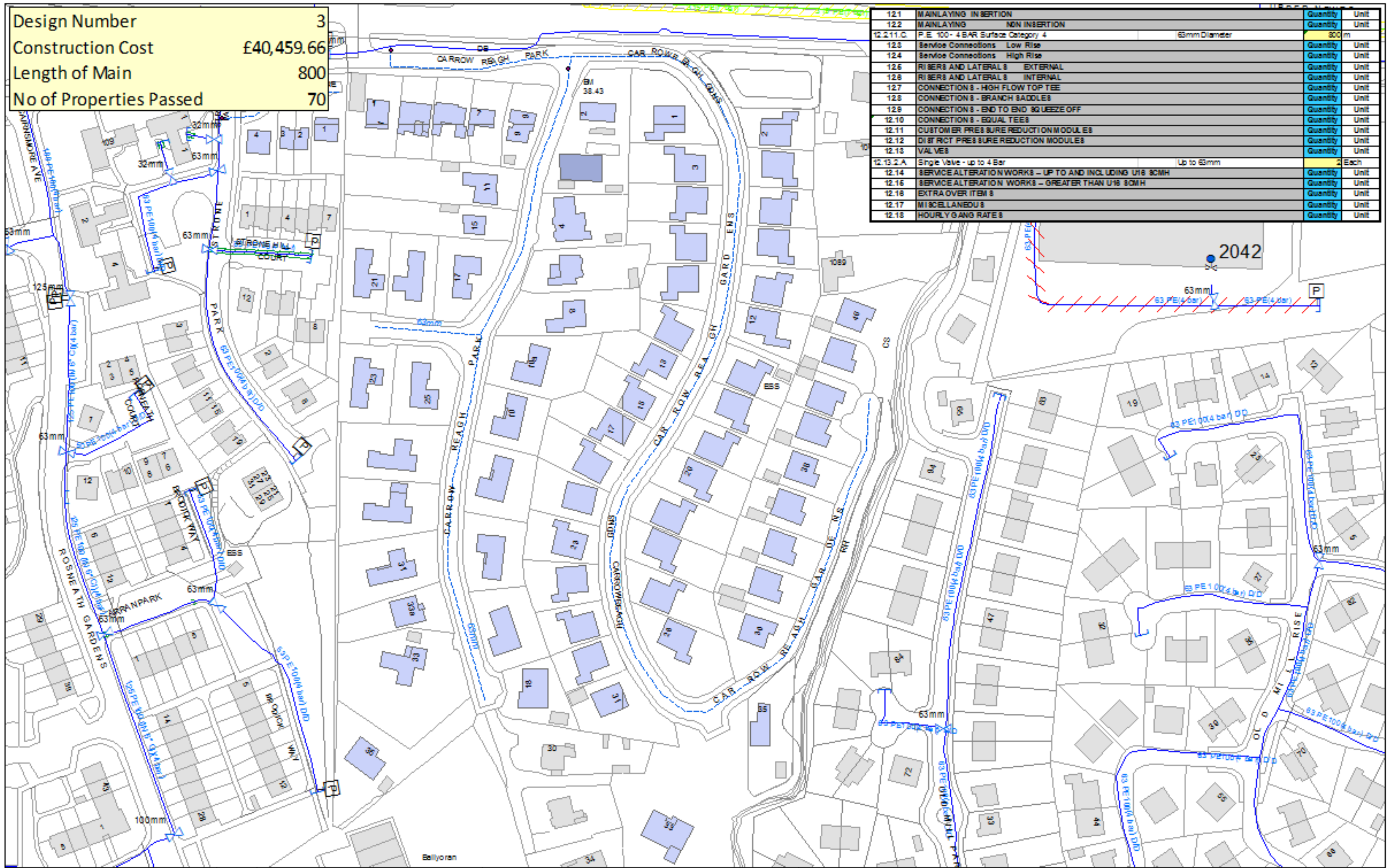
Total Length	800

Total Construction Cost
£40,460

Price Per Prop Passed
£578

Design Number	3
Construction Cost	£40,459.66
Length of Main	800
No of Properties Passed	70

12.1	MAINLAYING INSERTION		Quantity	Unit
12.2	MAINLAYING NON INSERTION		Quantity	Unit
12.2.11.C.	P.E. 100 - 4 BAR Surface Category 4	63mm Diameter	800	m
12.3	Service Connections Low Rise		Quantity	Unit
12.4	Service Connections High Rise		Quantity	Unit
12.6	RISERS AND LATERALS EXTERNAL		Quantity	Unit
12.6	RISERS AND LATERALS INTERNAL		Quantity	Unit
12.7	CONNECTIONS - HIGH FLOW TOP TEE		Quantity	Unit
12.8	CONNECTIONS - BRANCH SADDLES		Quantity	Unit
12.9	CONNECTIONS - END TO END SQUEEZE OFF		Quantity	Unit
12.10	CONNECTIONS - EQUAL TEES		Quantity	Unit
12.11	CUSTOMER PRESSURE REDUCTION MODULES		Quantity	Unit
12.12	DISTRICT PRESSURE REDUCTION MODULES		Quantity	Unit
12.13	VALVES		Quantity	Unit
12.13.2.A	Single Valve - up to 4 Bar	Up to 63mm	2	Each
12.14	SERVICE ALTERATION WORKS – UP TO AND INCLUDING U16 SCMH		Quantity	Unit
12.15	SERVICE ALTERATION WORKS – GREATER THAN U16 SCMH		Quantity	Unit
12.16	EXTRA OVER ITEMS		Quantity	Unit
12.17	MISCELLANEOUS		Quantity	Unit
12.18	HOURLY GANG RATES		Quantity	Unit



A3 Plot Template - Landscape
SCALE: 1:1,250
USERNAME: Stewart_K
DATE: 06/04/2016
REVISION: 1
MAP NAME:

N
0 10 20 40 Meters

276 - Saltworks Street (Railway Street)

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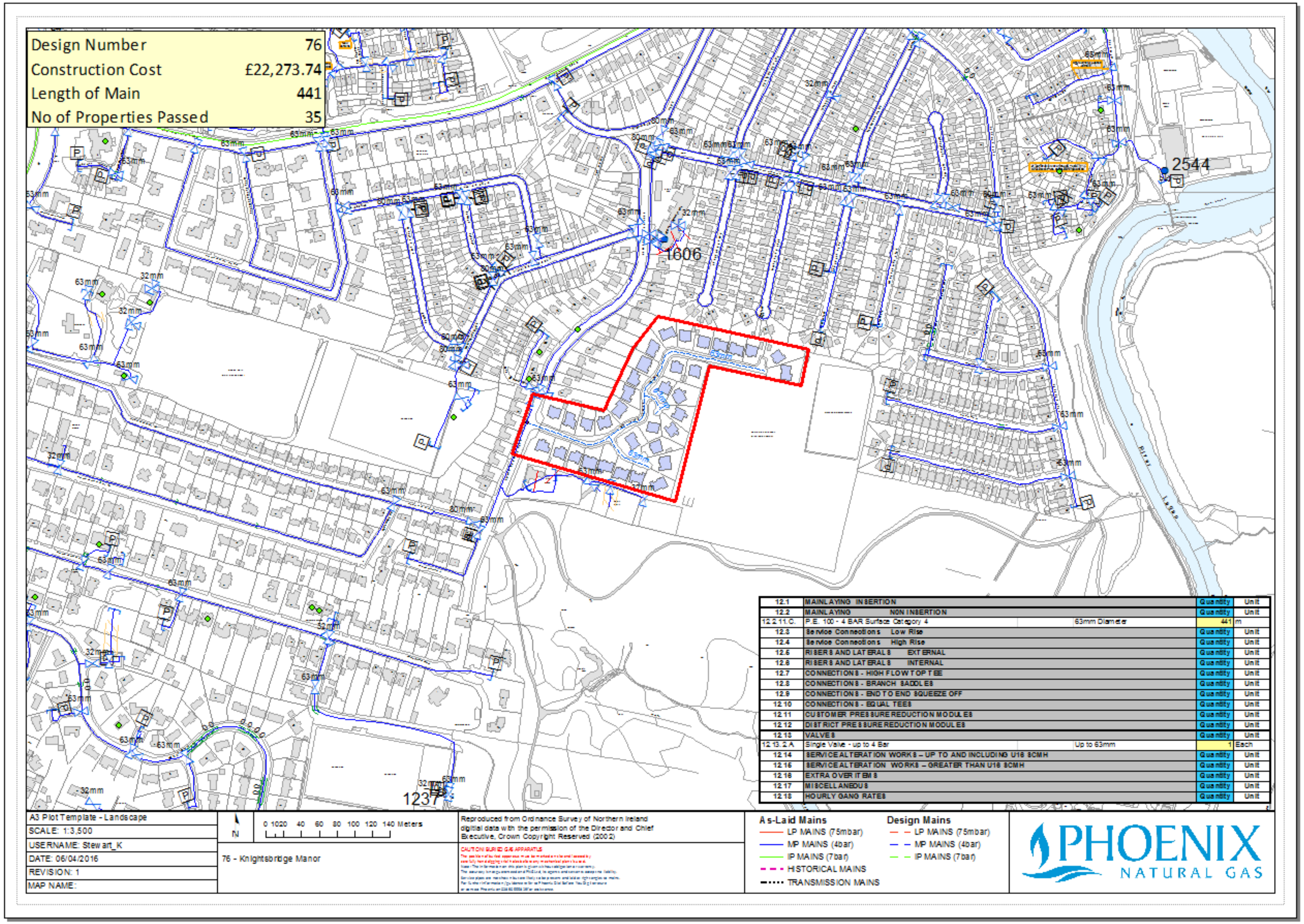
CAUTION! BURIED GAS APPARATUS

As-Laid Mains
- LP MAINS (75mbar)
- MP MAINS (4bar)
- IP MAINS (7bar)
- HISTORICAL MAINS
- TRANSMISSION MAINS

Design Mains
- LP MAINS (75mbar)
- MP MAINS (4bar)
- IP MAINS (7bar)

6. Knightsbridge Manor, Belfast, BT9




Knightsbridge Park
Knightsbridge Park
Knightsbridge Park
Dunn Landscapes
Knightsbridge Manor
Knightsbridge Manor
Knightsbridge Manor
Knightsbridge Manor
Belfast YMCA

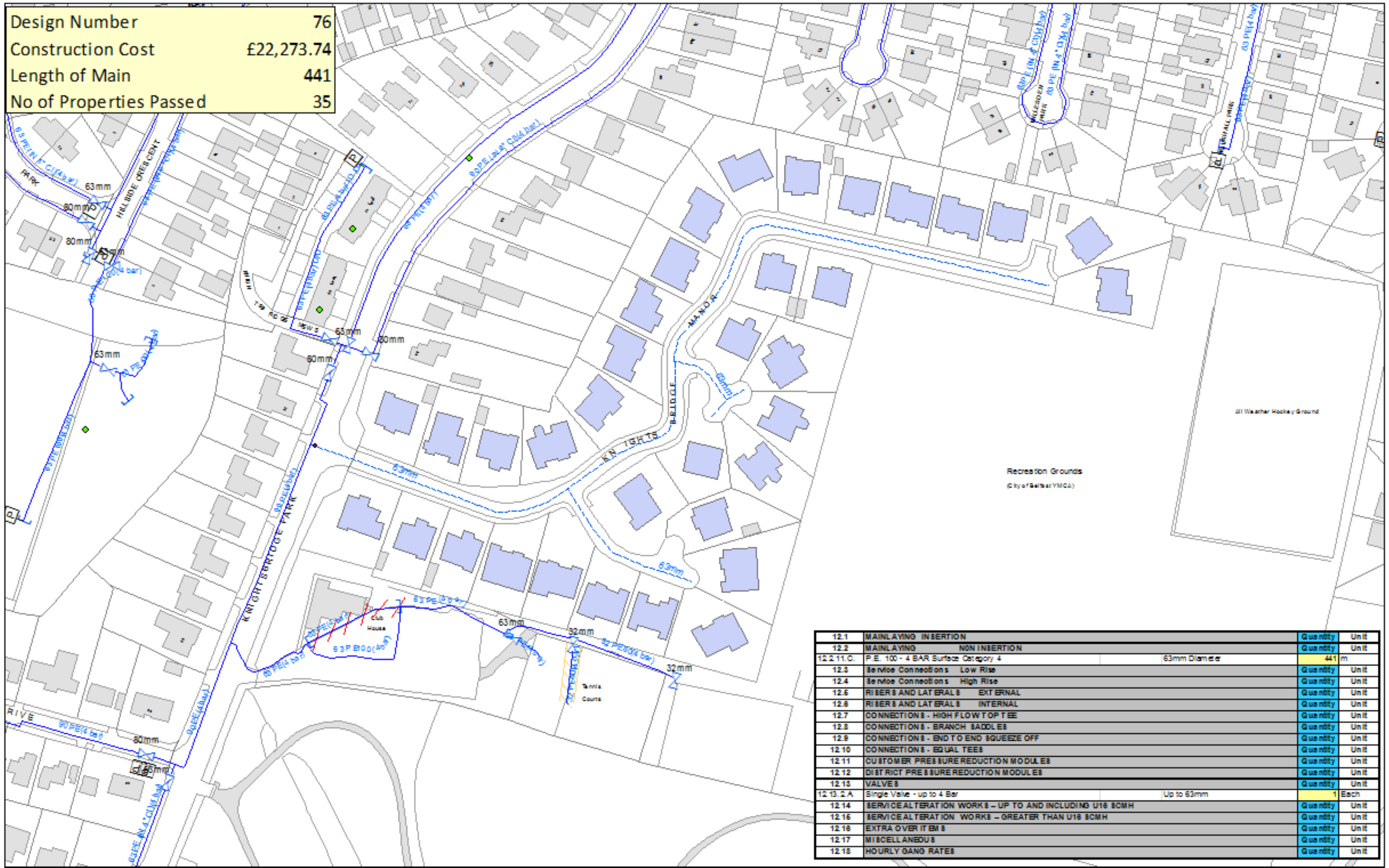
Design Number		76
OO	***NIHE***	***Total New Props Passed***
35		**35**

Total Length	**441**

Total Construction Cost
£22,274

Price Per Prop Passed
£636

Design Number	76
Construction Cost	£22,273.74
Length of Main	441
No of Properties Passed	35



12.1	MAINLAYING INSERTION		Quantity	Unit
12.2	MAINLAYING NON INSERTION		Quantity	Unit
12.2.11.C.	P.E. 100 - 4 BAR Surface Category 4	63mm Diameter	441	m
12.3	Service Connections Low Rise		Quantity	Unit
12.4	Service Connections High Rise		Quantity	Unit
12.5	RISERS AND LATERALS EXTERNAL		Quantity	Unit
12.6	RISERS AND LATERALS INTERNAL		Quantity	Unit
12.7	CONNECTIONS - HIGH FLOW TOP TEE		Quantity	Unit
12.8	CONNECTIONS - BRANCH SADDLES		Quantity	Unit
12.9	CONNECTIONS - END TO END SQUEEZE OFF		Quantity	Unit
12.10	CONNECTIONS - EQUAL TEES		Quantity	Unit
12.11	CUSTOMER PRESSURE REDUCTION MODULES		Quantity	Unit
12.12	DISTRICT PRESSURE REDUCTION MODULES		Quantity	Unit
12.13	VALVES		Quantity	Unit
12.13.2.A	Single Valve - up to 4 Bar	Up to 63mm	1	Each
12.14	SERVICE ALTERATION WORKS – UP TO AND INCLUDING U16 SCMH		Quantity	Unit
12.15	SERVICE ALTERATION WORKS – GREATER THAN U16 SCMH		Quantity	Unit
12.16	EXTRA OVER ITEMS		Quantity	Unit
12.17	MISCELLANEOUS		Quantity	Unit
12.18	HOURLY GANG RATES		Quantity	Unit

A3 Plot Template - Landscape
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DATE: 06/04/2016
REVISION: 1
MAP NAME:

N

0 10 20 40 Meters

76 - Knightsbridge Manor

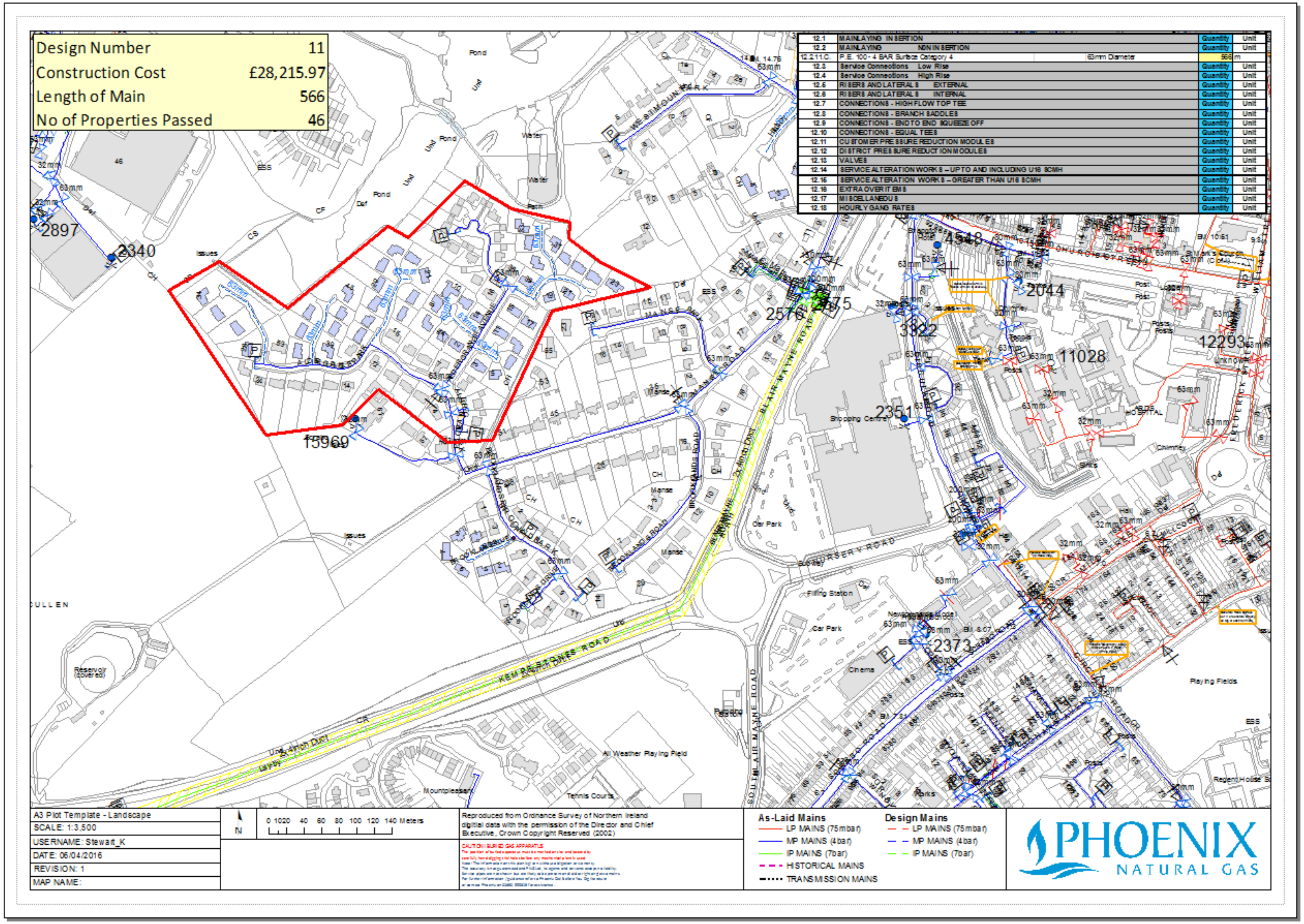
CAUTION! BURIED GAS APPARATUS

As-Laid Mains
- LP MAINS (75mbar)
- MP MAINS (4bar)
- IP MAINS (7bar)
- HISTORICAL MAINS
- TRANSMISSION MAINS

Design Mains
- LP MAINS (75mbar)
- MP MAINS (4bar)
- IP MAINS (7bar)

PHOENIX NATURAL GAS

7. Aldergrange, Newtownards, BT23



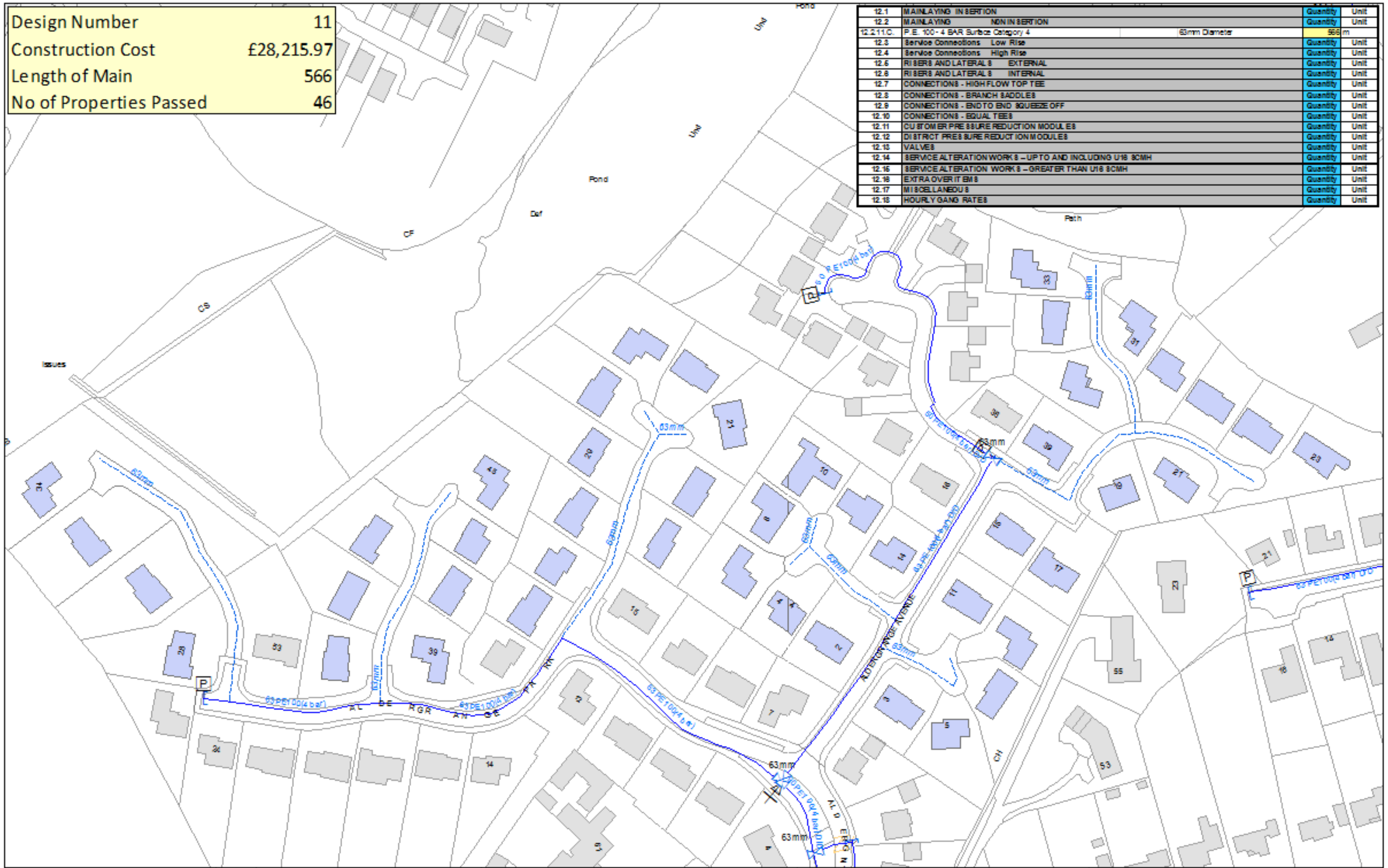

Aldergrange Park
Aldergrange Park
Aldergrange Park
Aldergrange Ave
Manse Rd

Design Number		11
OO	***NIHE***	***Total New Props Passed***
46		**46**
Total Length		**566**

Total Construction Cost
£28,216
Price Per Prop Passed
£613

Design Number	11
Construction Cost	£28,215.97
Length of Main	566
No of Properties Passed	46

12.1	MAINLAYING INSERTION			Quantity	Unit
12.2	MAINLAYING NON INSERTION			Quantity	Unit
12.2.11.C.	P.E. 100 - 4 BAR Surface Category 4		63mm Diameter	566	m
12.3	Service Connections Low Rise			Quantity	Unit
12.4	Service Connections High Rise			Quantity	Unit
12.5	RISERS AND LATERALS EXTERNAL			Quantity	Unit
12.6	RISERS AND LATERALS INTERNAL			Quantity	Unit
12.7	CONNECTIONS - HIGH FLOW TOP TEE			Quantity	Unit
12.8	CONNECTIONS - BRANCH SADDLES			Quantity	Unit
12.9	CONNECTIONS - END TO END SQUEEZE OFF			Quantity	Unit
12.10	CONNECTIONS - EQUAL TEES			Quantity	Unit
12.11	CUSTOMER PRESSURE REDUCTION MODULES			Quantity	Unit
12.12	DISTRICT PRESSURE REDUCTION MODULES			Quantity	Unit
12.13	VALVES			Quantity	Unit
12.14	SERVICE ALTERATION WORKS – UP TO AND INCLUDING U16 SCMH			Quantity	Unit
12.15	SERVICE ALTERATION WORKS – GREATER THAN U16 SCMH			Quantity	Unit
12.16	EXTRA OVER ITEMS			Quantity	Unit
12.17	MISCELLANEOUS			Quantity	Unit
12.18	HOURLY GANG RATES			Quantity	Unit



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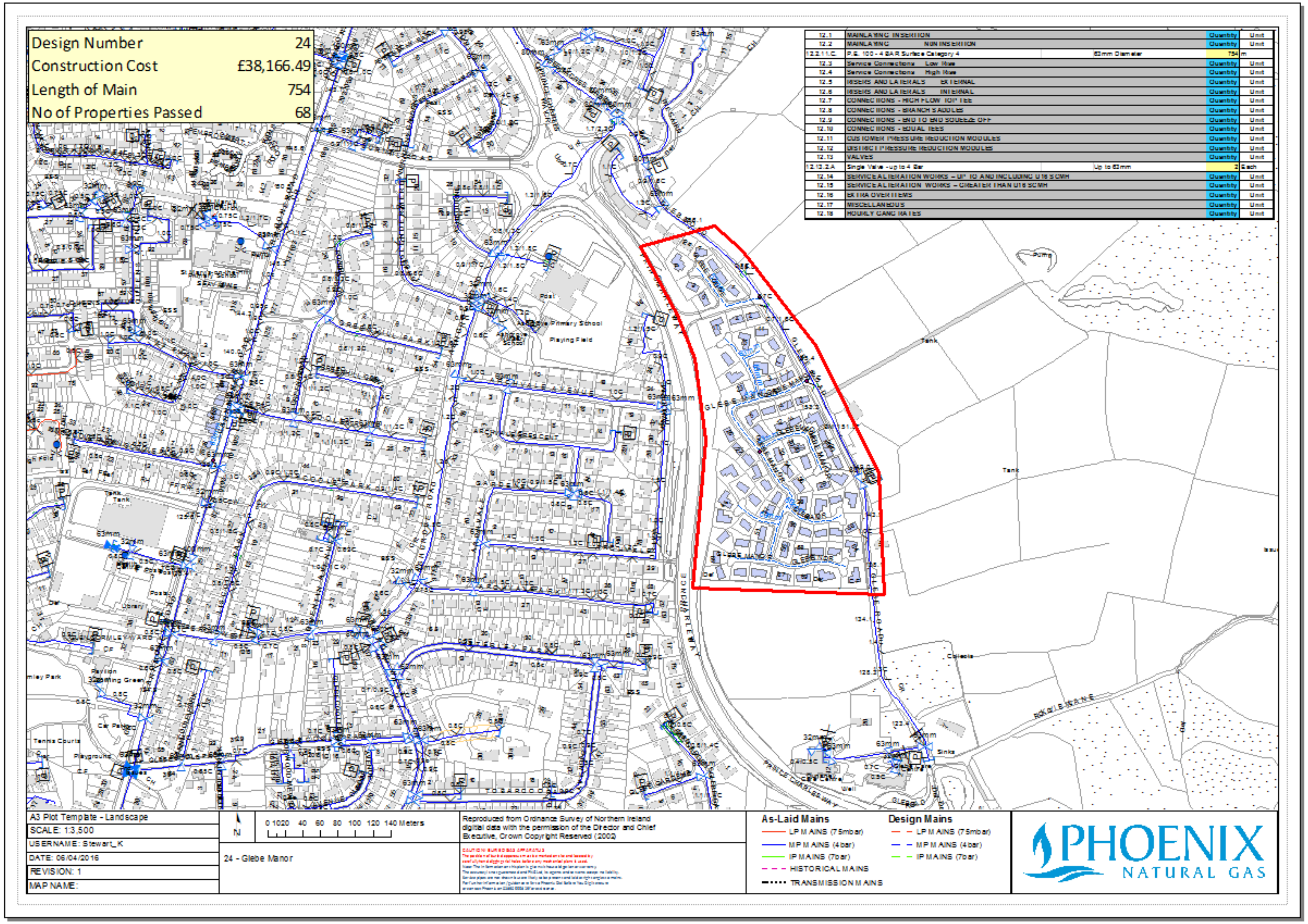
CAUTION! BURIED GAS APPARATUS

As-Laid Mains
- LP MAINS (75mbar)
- MP MAINS (4bar)
- IP MAINS (7bar)
- HISTORICAL MAINS
- TRANSMISSION MAINS

Design Mains
- LP MAINS (75mbar)
- MP MAINS (4bar)
- IP MAINS (7bar)

8. Glebe Manor, Newtownabbey




Glebe Rd
Prince Charles Way
Glebe Rd
Glebe Rd
Archvale Dr
Glebe Rd
Prince Charles Way
Glebe Manor
Archvale Dr
Glebe Rd
Archvale Dr
DELTA DISCO

Design Number		24
OO	**NIHE**	**Total New Props Passed**
68		**68**

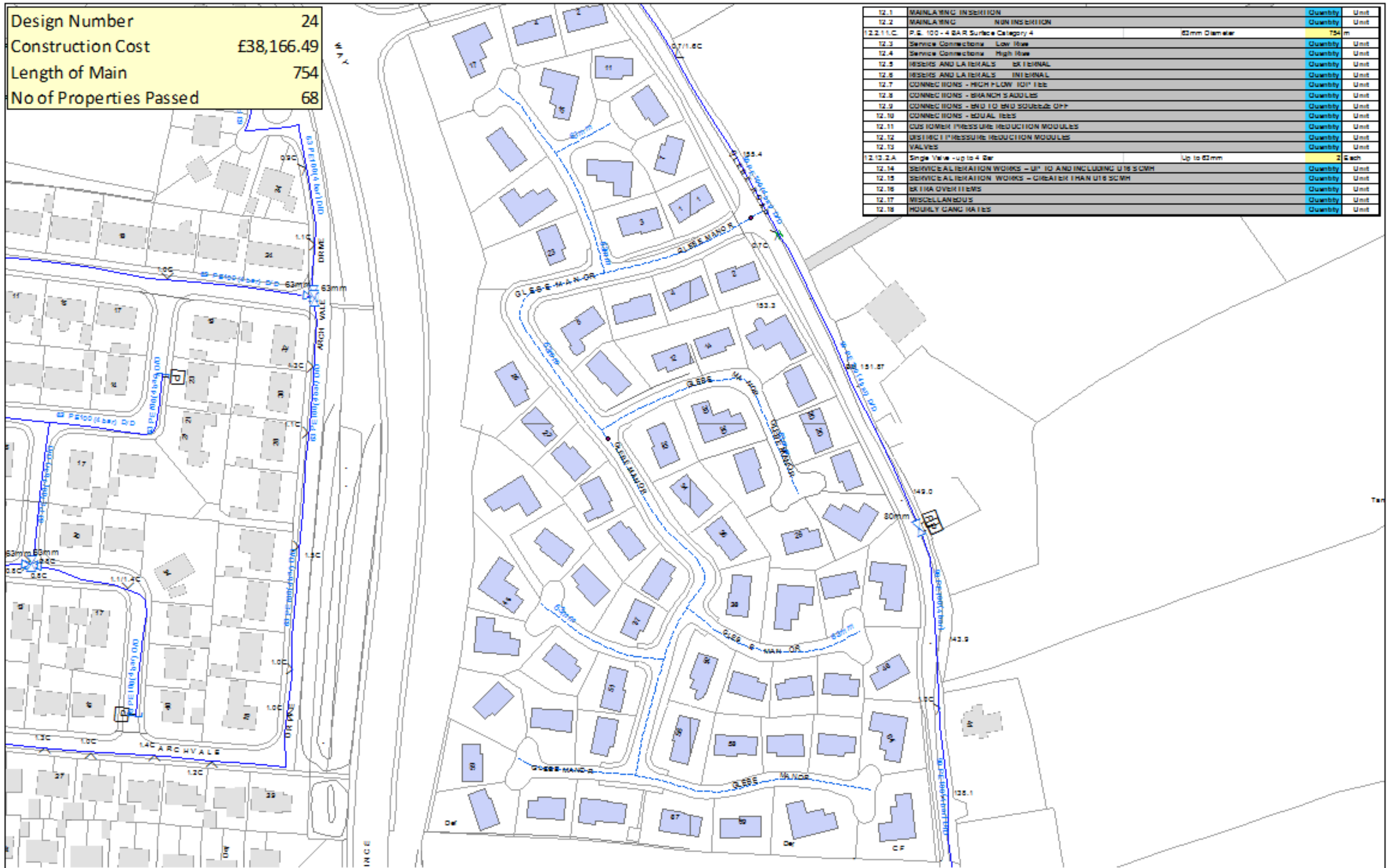
Total Length	**754**

Total Construction Cost
£38,166

Price Per Prop Passed
£561

Design Number	24
Construction Cost	£38,166.49
Length of Main	754
No of Properties Passed	68

12.1	MAINLAYING INSERTION			Quantity	Unit
12.2	MAINLAYING NON INSERTION			Quantity	Unit
12.2.11.C.	P.E. 100 - 4 BAR Surface Category 4		63mm Diameter	754	m
12.3	Service Connections Low Rise			Quantity	Unit
12.4	Service Connections High Rise			Quantity	Unit
12.5	RISERS AND LATERALS EXTERNAL			Quantity	Unit
12.6	RISERS AND LATERALS INTERNAL			Quantity	Unit
12.7	CONNECTIONS - HIGH FLOW TOP TEE			Quantity	Unit
12.8	CONNECTIONS - BRANCH SADDLES			Quantity	Unit
12.9	CONNECTIONS - END TO END SQUEEZE OFF			Quantity	Unit
12.10	CONNECTIONS - EQUAL TEES			Quantity	Unit
12.11	CUSTOMER PRESSURE REDUCTION MODULES			Quantity	Unit
12.12	DISTRICT PRESSURE REDUCTION MODULES			Quantity	Unit
12.13	VALVES			Quantity	Unit
12.13.2.A	Single Valve - up to 4 Bar		Up to 63mm	2	Each
12.14	SERVICE ALTERATION WORKS – UP TO AND INCLUDING U16 SCMH			Quantity	Unit
12.15	SERVICE ALTERATION WORKS – GREATER THAN U16 SCMH			Quantity	Unit
12.16	EXTRA OVER ITEMS			Quantity	Unit
12.17	MISCELLANEOUS			Quantity	Unit
12.18	HOURLY GANG RATES			Quantity	Unit



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DATE: 06/04/2016
REVISION: 1
MAP NAME:

N

0 10 20 40 Meters

24 - Glebe Manor

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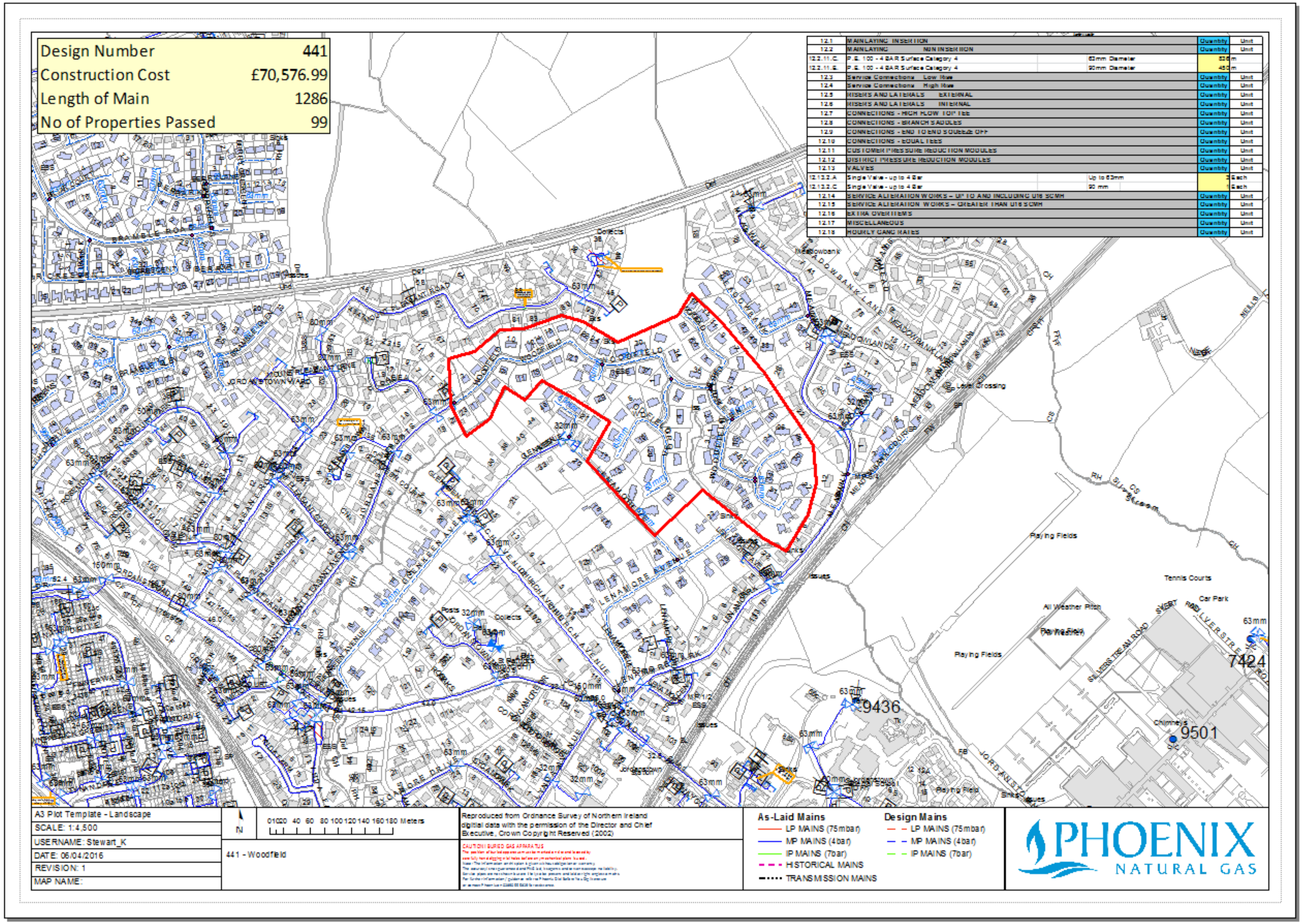
As-Laid Mains
- LP MAINS (75mbar)
- MP MAINS (4bar)
- IP MAINS (7bar)
- HISTORICAL MAINS
- TRANSMISSION MAINS

Design Mains
- LP MAINS (75mbar)
- MP MAINS (4bar)
- IP MAINS (7bar)

9. Woodfield, Newtownabbey (not in 2,500 properties for GD17)



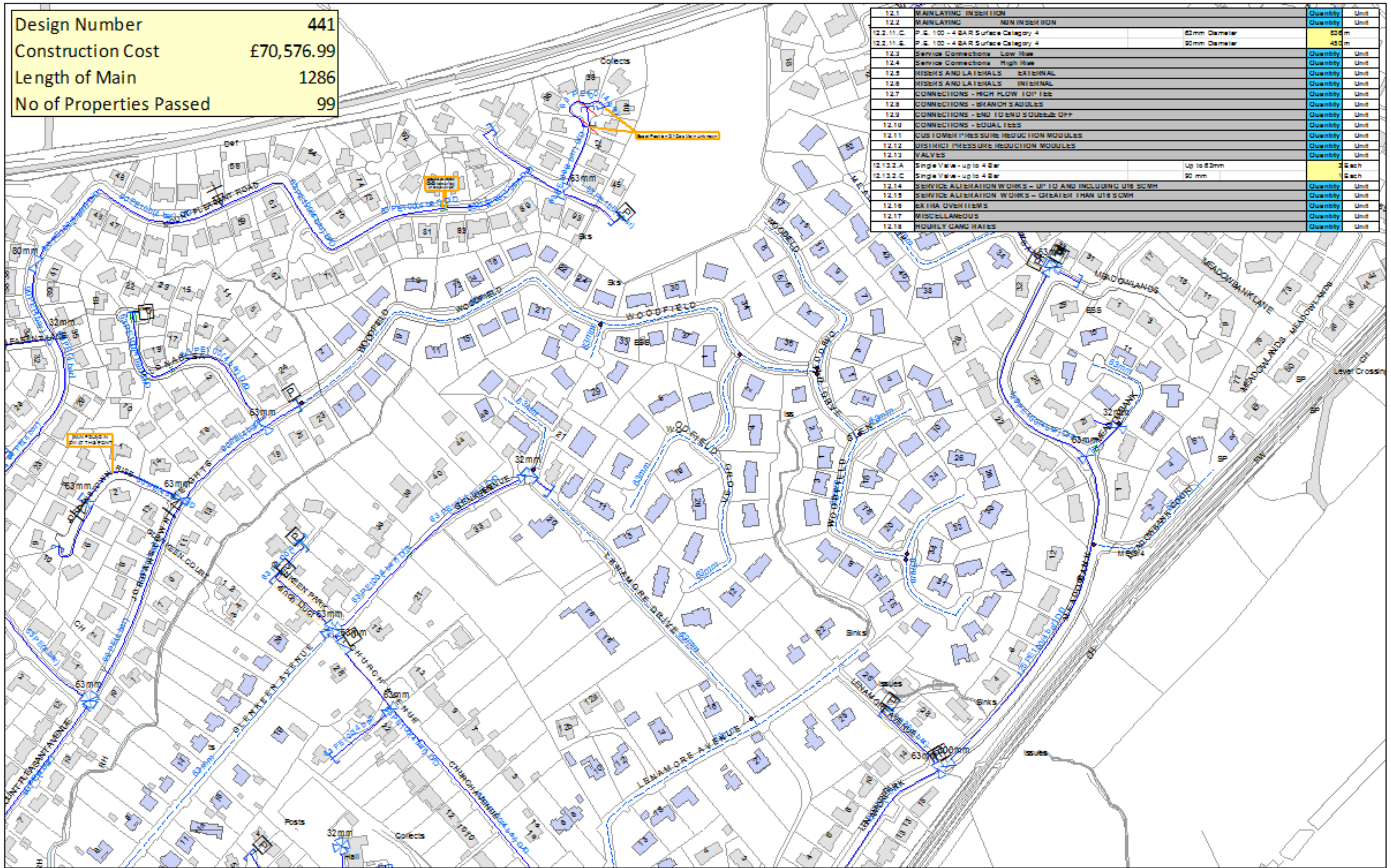
Mount Pleasant Rd
Woodfield
Jordanstown Heights
Woodfield
Meadowbank
Meadowbank
Meadowbank
Modern Mum
Woodfield Grove
Woodfield Grove
Glenkeen Ave
Lenamore Dr
Lenamore Dr
Woodfield Dr
Glenkeen Ave
Church Ave

Design Number		441
OO	***NIHE***	***Total New Props Passed***
99		**99**
Total Length		**1,286**

Total Construction Cost
£70,577
Price Per Prop Passed
£713

Design Number	441
Construction Cost	£70,576.99
Length of Main	1286
No of Properties Passed	99

12.1	MAINLAYING INSERTION		Quantity	Unit
12.2	MAINLAYING NON INSERTION		Quantity	Unit
12.2.11.C.	P.E. 100 - 4 BAR Surface Category 4	63mm Diameter	536	m
12.2.11.E.	P.E. 100 - 4 BAR Surface Category 4	90mm Diameter	450	m
12.3	Service Connections Low Rise		Quantity	Unit
12.4	Service Connections High Rise		Quantity	Unit
12.5	RISERS AND LATERALS EXTERNAL		Quantity	Unit
12.6	RISERS AND LATERALS INTERNAL		Quantity	Unit
12.7	CONNECTIONS - HIGH FLOW TOP TEE		Quantity	Unit
12.8	CONNECTIONS - BRANCH SADDLES		Quantity	Unit
12.9	CONNECTIONS - END TO END SQUEEZE OFF		Quantity	Unit
12.10	CONNECTIONS - EQUAL TEES		Quantity	Unit
12.11	CUSTOMER PRESSURE REDUCTION MODULES		Quantity	Unit
12.12	DISTRICT PRESSURE REDUCTION MODULES		Quantity	Unit
12.13	VALVES		Quantity	Unit
12.13.2.A	Single Valve - up to 4 Bar	Up to 63mm	3	Each
12.13.2.C	Single Valve - up to 4 Bar	90 mm	1	Each
12.14	SERVICE ALTERATION WORKS – UP TO AND INCLUDING U16 SCMH		Quantity	Unit
12.15	SERVICE ALTERATION WORKS – GREATER THAN U16 SCMH		Quantity	Unit
12.16	EXTRA OVER ITEMS		Quantity	Unit
12.17	MISCELLANEOUS		Quantity	Unit
12.18	HOURLY GANG RATES		Quantity	Unit



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USERNAME: Stewart_K	441 - Woodfield
DATE: 06/04/2016	
REVISION: 1	
MAP NAME:	

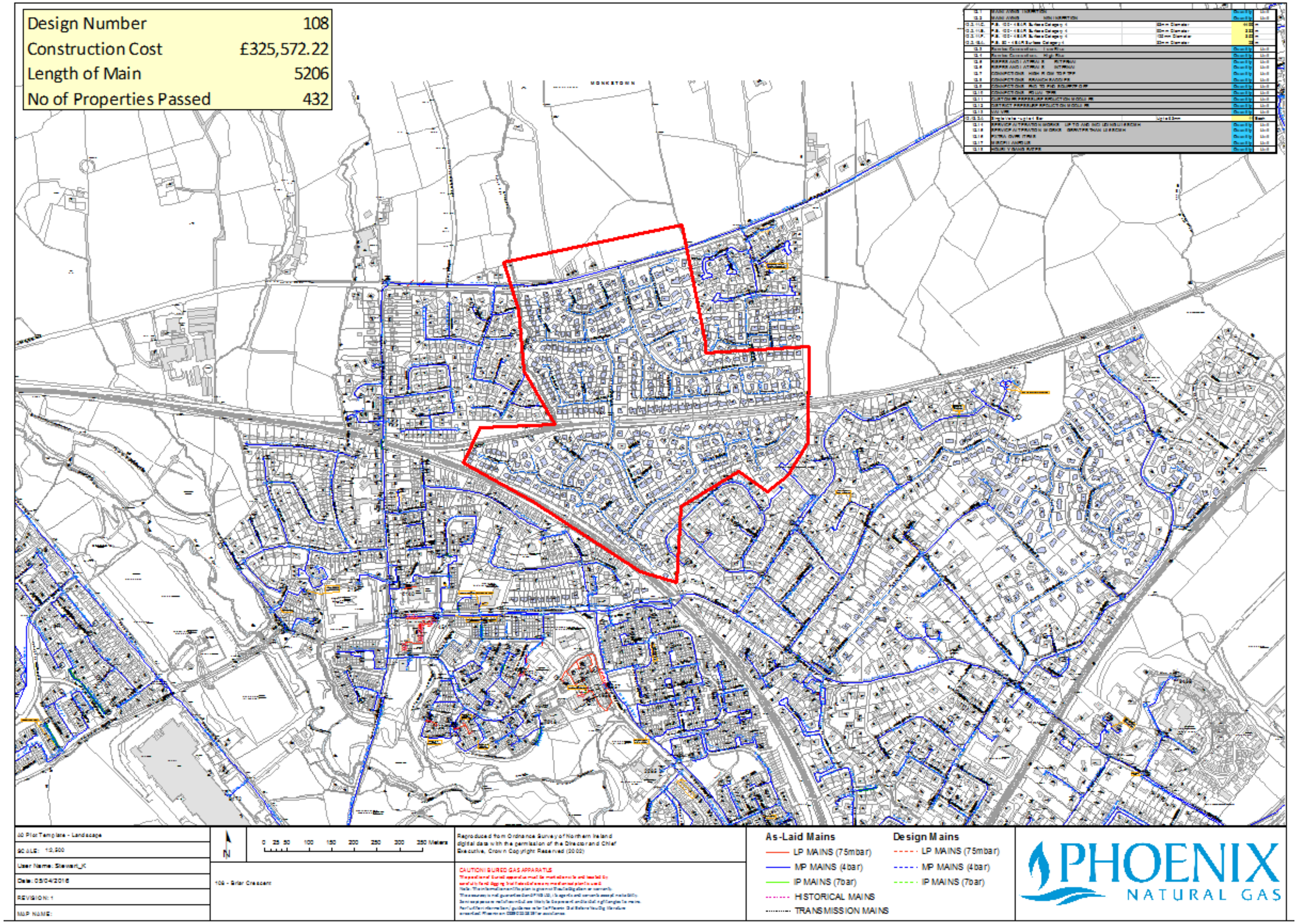
CAUTION! BURIED GAS APPARATUS

As-Laid Mains
- LP MAINS (75mbar)
- MP MAINS (4bar)
- IP MAINS (7bar)
- HISTORICAL MAINS
- TRANSMISSION MAINS

Design Mains
- LP MAINS (75mbar)
- MP MAINS (4bar)
- IP MAINS (7bar)

10. Brambles, Newtownabbey (not in 2,500 properties for GD17)

Design Number	108
Construction Cost	£325,572.22
Length of Main	5206
No of Properties Passed	432




Nick Bonar Cars
B90
B90
Oaklands Dr
Bramble Ave
Bramble Ave
Bramble Ave
Berryfields Rd
Burnet Cl
Burnet Ave
Burnet Dr
Briar Cres
Mulberry Cres
Lisbane Dr
Blackthorn Dr
Blackthorn Rd
Rosemount Park
Mount Pleasant Rd
Jennings Dr
Rosemount Cres

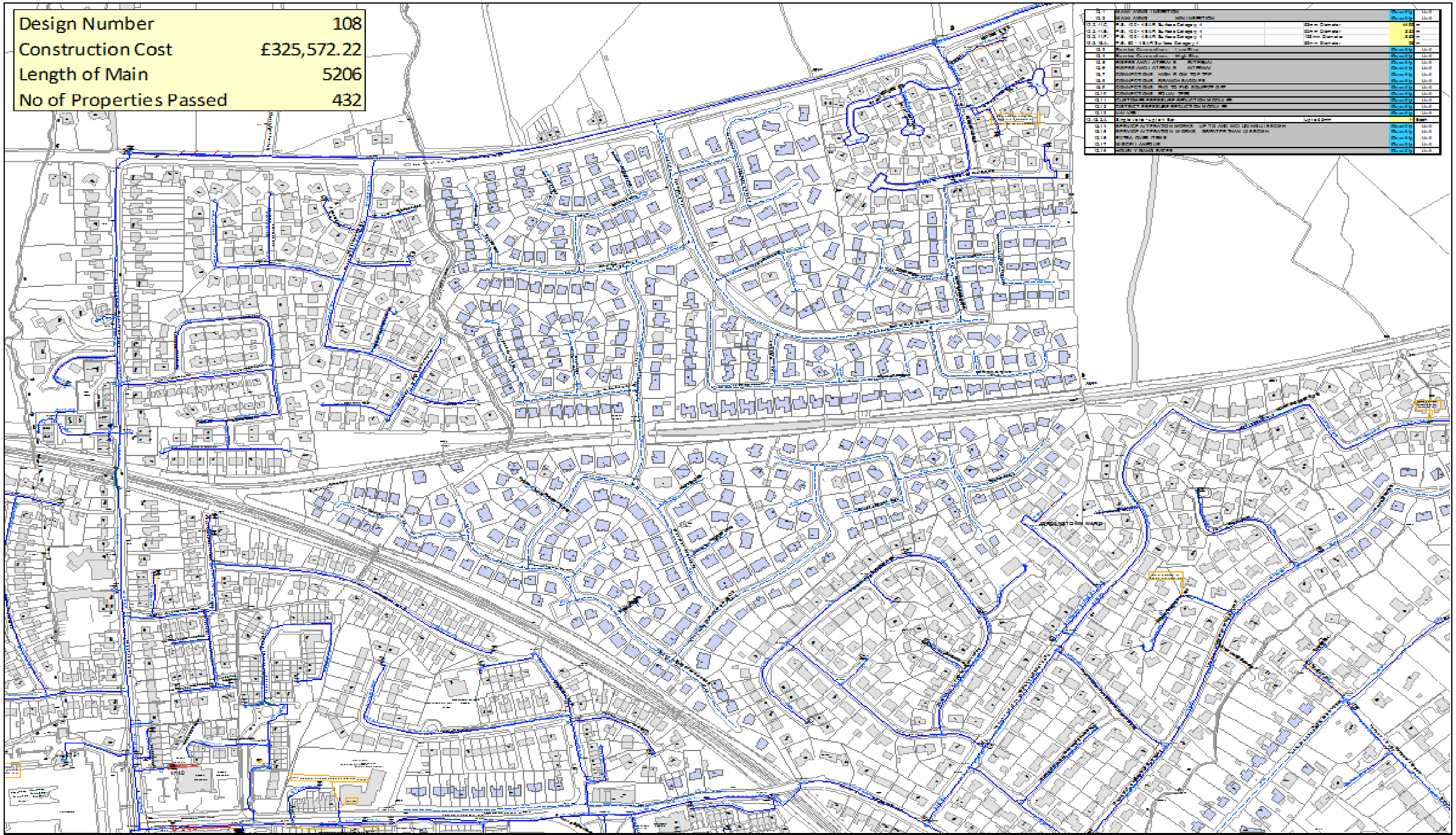
Design Number		455
OO	***NIHE***	***Total New Props Passed***
432		**432**

Total Length	**5,206**

Total Construction Cost
£325,572

Price Per Prop Passed
£754

Design Number	108
Construction Cost	£325,572.22
Length of Main	5206
No of Properties Passed	432



A0 Plot Template - Landscape
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User Name: Stewart_K
Date: 05/04/2016
REVISION: 1
MAP NAME:

N

0 25 50 100 150 Meters

109 - Briar Crescent

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As-Laid Mains
- LP MAINS (75mbar)
- MP MAINS (4bar)
- IP MAINS (7bar)
- HISTORICAL MAINS
- TRANSMISSION MAINS

Design Mains
- LP MAINS (75mbar)
- MP MAINS (4bar)
- IP MAINS (7bar)

NERA
ECONOMIC CONSULTING

Response to UR’s Draft Determination on Real Price Effects and Productivity Growth for GD17

Prepared for Phoenix Natural Gas Ltd

28 April 2016

Project Team

James Grayburn

Richard Druce

Soren Christian

Leen Dickx

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United Kingdom
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Contents

Executive Summary

On 16 March 2016, the Utility Regulator released its Draft Decision (DD) for the gas distribution networks' price control, GD17. In calculating draft opex and capex allowances, UR has included a frontier shift element, which is the sum of input price growth (or real price effects) less the expected improvement in productivity.[1,2] This report summarises our response to the UR's DD proposals.

UR's overall approach fails to take account that input prices will return to trend

With the exception of labour, where UR draws on Office of Budget Responsibility's (OBRs) wage forecasts, UR forecasts input prices by extrapolating historical averages based on a time-trend. The approach fails to take into account that input price levels, namely labour and materials are below trend, and are expected to return to trend as the UK economy continues to emerge from the global financial crisis.

By contrast, our approach based on a so-called ARIMA process, takes into the cyclicality of input prices, and notably the expected return of labour and material price levels to their long-run levels over the GD17 period.

UR's approach is inconsistent with regulatory practice

Notwithstanding our concerns with UR's overall approach, we also have some concerns with the UR's application of its preferred approach.

For labour, where UR relies on OBR's forecasts, we have identified two main problems, which if corrected, would increase the RPE for labour from 0.8% p.a. on average over GD17 to 1.2% p.a., much closer to our own estimate of 1.5% p.a. The problems we have identified are as follows:

- UR used OBR's forecast for economy-wide average-earnings growth, while it should use private sector earnings, given PNG faces private sector wage growth pressure
- UR draws on weekly wage changes whereas the correct approach is to use hourly earnings growth, as this measure is unaffected by changes in hours worked

For materials, UR assumes that material prices will grow at a below trend growth rate before achieving the UR's assumed long-term average of 0.3% p.a. towards the end of GD17. Despite recognising that the price levels are below trend, UR ignores the tendency of price indices to grow more quickly. By contrast, Ofgem assumed that material prices would revert immediately to their long-term growth rates, as its practical approach to accommodating reversion to mean. Using UR's proposed indices and long term average but applying Ofgem's practical approach, implies an RPE of 0.3% p.a. on average over GD17 as opposed to UR's DD assumption of *minus* 0.3% p.a.

1 UR (2016): *Price Control for Northern Ireland's Gas Distribution Networks GD17*, Draft Determination, 16 March 2016.

2 UR (2016): *Annex 6 Real Price Effects & Frontier Shift GD17*, Draft Determination, 15 March 2016.

For plant and equipment, UR relies only on one index (ONS PPI Machinery and Equipment index). This is in contrast to standard regulatory precedent, including previous UR decisions. For example, the UR at GD14 considered along with the ONS index also the BCIS Plant and Road Vehicles, as did the CMA for NIE and Ofgem at RIIO-ED1 and RIIO-GD1. Taking into account both indices would lead to an average RPE of *minus* 0.3% p.a. on average over 2015-2022, compared to the current UR average estimate of *minus* 0.7% p.a. over the same period.

Overall, our preferred approach is to draw on a methodology that takes into account the cyclicality of input prices, as per PNG's submission. However, if UR does not adopt such an approach, we have identified a number of changes to the application of its proposed approach to bring it in line with standard regulatory practice (as indicated by the final column "UR Corrected").

Table 1
Comparison of RPE Forecasts by Category (Real),
Average RPE p.a. over 2015-2022

	PNG Submission	UR DD GD17	UR Corrected
Labour	1.5%	0.8%	1.2%
Materials	0.8%	-0.3%	0.3%
Plant & Equipment	-0.4%	-0.7%	-0.3%
Transport/Other	0.0%	0.0%	0.0%

For productivity, UR selects an upper bound estimate although the evidence supports a lower bound estimate

UR assumes a productivity shift of 1% per annum for both opex and capex, higher than our estimates of 0.6 p.a. for capex and 0.8% p.a. for opex. UR's DD estimates are at the upper-end of regulatory evidence, whereas the PNG specific factors would suggest a value at the lower end:

- UR cites 17 productivity decisions with an average productivity improvement of 0.8% and 0.9% for opex and capex respectively (yet the UR assumes values above the average).
- PNG is a new utility which would support a value towards the low end of productivity improvements, as it has less scope to reduce costs relative to incumbent former publically owned utilities. NIE – the UR's principal comparator – is not a reasonable comparison.

Overall, we consider that UR is wrong to draw on evidence at the top end of the plausible range, when PNG specific factors would support values towards the lower end. Overall, we consider that our submission of 0.6% p.a. and 0.8% p.a. for capex and opex respectively is supported by the empirical evidence.

1. Summary

On 16 March 2016, the Utility Regulator released its Draft Decision (DD) for the gas distribution networks' price control, GD17. In calculating draft opex and capex allowances, UR has included a frontier shift element, which is the sum of input price growth (or real price effects) less the expected improvement in productivity.[3,4]

This report summarises our views on UR's approach to setting real price effects (RPE) and productivity improvements in the PNG DD.

2. Real Price Effects

Table 2 below compares PNG's business plan RPE forecasts with those of the UR, by category.[5]

Table 2
RPE Forecasts by Category (Real)

Opex Weights	Capex Weights			2015	2016	2017	2018	2019	2020	2021	2022	Avg
52%	56%	Labour	PNG	0.9%	1.6%	1.8%	1.8%	1.9%	1.6%	1.4%	1.1%	**1.5%**
			UR	1.6%	1.4%	0.8%	0.4%	0.5%	0.7%	0.7%	0.7%	**0.8%**
6%	19%	Materials	PNG	0.5%	0.5%	0.7%	0.8%	0.9%	0.9%	0.9%	1.0%	**0.8%**
			UR	0.5%	-1.5%	-1.3%	-1.2%	-0.2%	0.3%	0.3%	0.3%	**-0.3%**
1%	4%	Plant & Equipment	PNG	-0.3%	-0.1%	-0.6%	-0.3%	-0.1%	-0.7%	-0.8%	-0.6%	**-0.4%**
			UR	0.0%	-0.3%	-0.6%	-0.9%	-0.9%	-0.9%	-0.9%	-0.9%	**-0.7%**
41%	21%	Transport/Other	PNG	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	**0.0%**
			UR	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	**0.0%**
		Combined Opex	PNG	0.5%	0.9%	1.0%	1.0%	1.0%	0.9%	0.8%	0.6%	**0.8%**
			UR	0.9%	0.6%	0.3%	0.1%	0.2%	0.4%	0.4%	0.4%	**0.4%**
		Combined Capex	PNG	0.6%	1.0%	1.1%	1.2%	1.2%	1.1%	0.9%	0.8%	**1.0%**
			UR	1.0%	0.5%	0.2%	0.0%	0.2%	0.4%	0.4%	0.4%	**0.4%**

With the exception of "transport/other" category (where UR assumes no real price effect, in line with PNG's submission), UR has proposed a lower RPE for all expenditure categories.

Overall, UR's forecast a RPE of 0.4% per annum for both combined opex and combined capex over GD17, compared to PNG's forecasts of 0.8% and 1.0% per annum for opex and capex respectively.

---

3 UR (2016): *Price Control for Northern Ireland's Gas Distribution Networks GD17*, Draft Determination, 16 March 2016.

4 UR (2016): *Annex 6 Real Price Effects & Frontier Shift GD17*, Draft Determination, 15 March 2016.

5 UR defines four cost categories: Labour (direct and contracted); Materials; Plant/Equipment; and Other. The weights differ for opex and capex, but both are dominated (>50%) by the labour index.

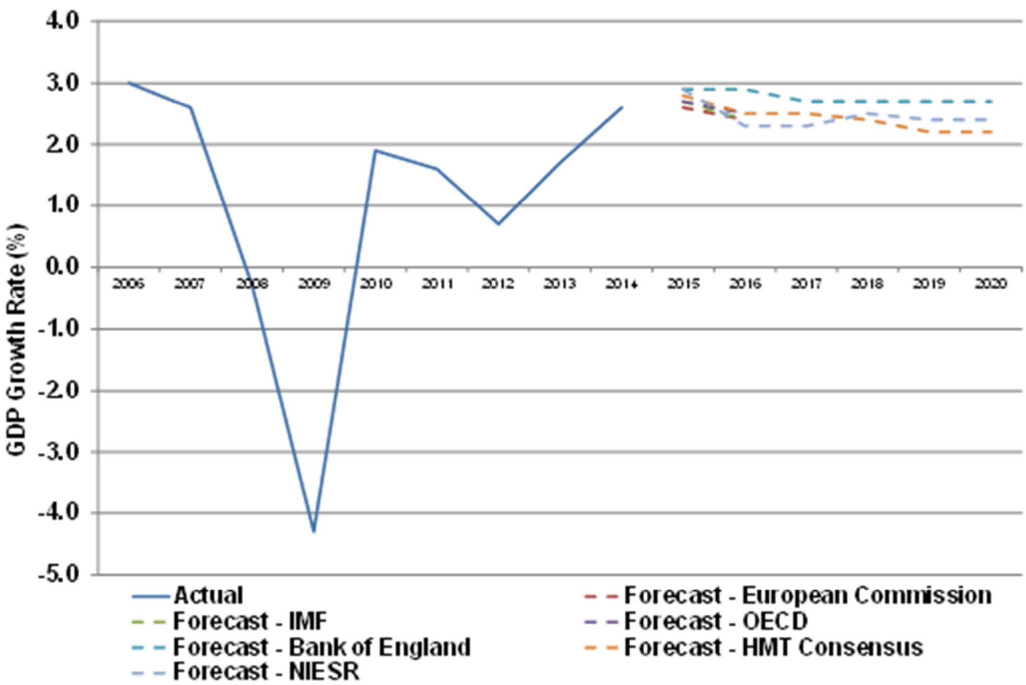
2.1. UR's Approach Fails to Take into Account Cyclicality of Input Prices

As set out in our report to UR, we described two main techniques to extrapolate historical trends based on: (i) a simple long-term average growth rate using an OLS trend line (as per UR's approach at DD); and (ii) a statistical model ("ARIMA model") that accounts for both the long-term average growth rate and any "mean-reverting" features.[6]

Of these two approaches, we adopted the ARIMA process for forecasting RPEs for GD17. UR noted that our modelling approach has "advantages" but did not use it for forecasting RPEs.[7] Instead, UR relies on the extrapolation of long run trends based on historical growth rates of underlying indices for materials, plants and equipment costs while it uses third party forecasts to predict real growth in labour costs.

The major problem with the long-term average growth rate technique, adopted by UR, is that it ignores cyclicality in the underlying data. The technique adopted by UR is particularly ill-suited to forecasting RPEs over GD17, given the UK economy is in a state of recovery from the global financial crisis, which means that we expect input prices to grow faster than they otherwise would if the economy were at its "steady state" level.

Figure 1
The Expected Recovery in the UK Economy Implies Higher Input Price Growth than the Historical Average



Source: European Commission, IMF, OECD, Bank of England, HMT, NIESR and analysis of Bloomberg data

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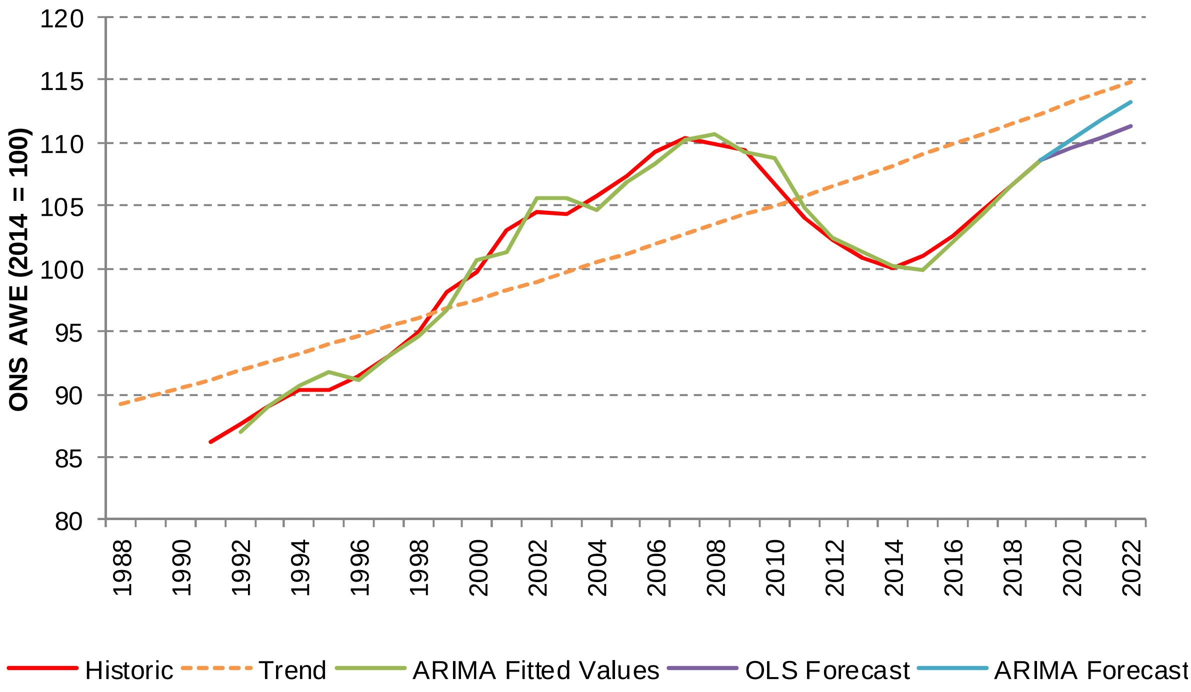
6 NERA (2015): *Forecasting Real Price Effects and Productivity Growth for GD17*, Prepared for Phoenix Natural Gas Ltd, 10 September 2015, p.14, section 2.3.4.

7 UR (2016): *Annex 6 Real Price Effects & Frontier Shift GD17*, Draft Determination, 15 March 2016, p.7, para. 2.24.

By contrast, our proposed approach allows for a cyclical pattern. It takes into account the current variation in the index value relative to its expected trend value, and assumes that the gap between the current and trend value is closed over a period of time based on the historically observed time it has taken to revert to trend. In the context of GD17, the ARIMA process allows for the expected higher growth rate in some input prices (e.g. labour and materials) from their below trend values as the UK emerges from recession.

For example, as set out in Figure 2, it is clear that historical labour costs are cyclical, and currently below trend values. Our ARIMA based forecast allows for the expected return to trend values, whereas the historical time trend analysis does not.

Figure 2
Our Preferred ARIMA Forecast Accounts for Cyclical Nature of Input Prices
(Labour Cost Forecast: ARIMA vs OLS time-trend)



Source: NERA analysis on data from the ONS and OBR

As we explain below for each individual series, the UR's approach of ignoring cyclical trends results in downward bias estimate of RPEs. The impact is particularly notable for materials costs, given the inherent cyclicality of material input costs.

2.2. Labour

UR has drawn on wage forecasts by the Office of Budget Responsibility (OBR) published in November 2015 as the basis for its labour RPE for the period 2016 to 2020. Beyond this period, it appears that UR assumes that the growth rate will be equal to the 2020 growth rate of the ONS private sector wage series. [8] We have two main concerns with the UR's use of OBR:

- UR used OBR's forecast for economy-wide average-earnings growth, while it should use private sector earnings (which is more comparable to PNG, as a private sector organisation). Based on November 2015 OBR data, use of private earnings data as opposed to whole economy (as UR uses) would have the effect of increasing UR's estimate of labour growth to 1.1% p.a. on average over 2015-2022, i.e. by around 0.3% p.a.[9]
- UR draws on weekly wage changes whereas the correct approach is to use hourly earnings growth, as this measure is unaffected by hours worked. Using hourly earnings would have the effect of increasing UR's estimate of labour growth by a further 0.1% p.a. on average over 2015-2022.[10]

Overall, correcting for these faults in UR's approach results in a forecast for wage growth of 1.2% p.a. on average based on November 2015 OBR data, or 0.4% higher than the UR's DD forecast.[11]

In addition, beyond the OBR forecast period (which ends 2020), UR assumes the same wage growth rate as per 2020 for the remainder of the period. This approach ignores the cyclical nature of labour costs. As set out above, we consider that UR should adopt a process that allows for well-established tendency for labour cost to mean revert.

2.3. Materials

We believe that the materials RPE is a particularly strong candidate for using our modelling approach ("ARIMA") given the marked tendency for materials prices to revert to trend.

The failure to adjust for cyclicality or mean reversion means that UR is out of line with GB regulators. For example, UR's approach is more conservative than Ofgem's RIIO-ED1 approach in this respect:

- Ofgem assumed that indices would revert immediately to their long-term growth rates (even if current outturn data is below the trend line).[12]

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8 UR (2016): *Annex 6 Real Price Effects & Frontier Shift GD17*, Draft Determination, 15 March 2016, p.17, Table 5 and Table 6.

9 We expect the UR to update its estimates based on the latest available OBR data. This is confirmed by the UR in its DD: "[we] are minded to update for any more recent forecast available by the time of [its] final determination". Based on the latest March 2016 OBR data, the use of private earnings data as opposed to whole economy (as UR uses) would have the effect of increasing UR's estimate of labour growth to 0.8% p.a. over 2015-2022, i.e. by around 0.2% p.a.

10 Assuming that the UR were to use the latest March 2016 OBR data, using hourly earnings would have the effect of increasing UR's estimate of labour growth by a further 0.1% over 2015-2022.

11 Assuming that the UR were to use the latest March 2016 OBR data, correcting for both flaws in UR's approach results in a forecast for wage growth of 1.0% p.a., or 0.3% higher than the DD.

12 Ofgem (2014): *RIIO-ED1: Final determinations for the slow-track electricity distribution companies*, 28 November 2014, p.150, para. 12.6.

- Instead, the UR assumes that under "medium growth scenario" material prices will grow at a more moderate rate in the short and medium term before achieving the long-term average towards the end of GD17.[13,14] In fact, while the UR implicitly recognises that material growth rates are currently below trend due to "current market conditions", UR ignores the tendency of price indices to grow faster when they are below trend. As a result it underestimates the scope of real price growth of material inputs for PNG.

Overall, UR's RPE estimate of *minus* 0.4% p.a. on average over GD17 is markedly below the estimates used by Ofgem at both RIIO-GD1 and RIIO-ED1 for material costs:[15]

- At RIIO-GD1 Ofgem estimates real growth rate of materials costs between 1.2% and 2.2% according to the selected index.[16] At the aggregate level it expects opex and capex materials for real input prices for GDNs to increase on average over the price control period at a rate of 1.6% and 1.2% p.a., respectively.[17]
- At RIIO-ED1, Ofgem estimates real growth rate of materials costs between 0.3% and 1.7% according to the selected price index. At the aggregate level, Ofgem expects opex and capex materials real input prices to increase at rate of 1.3% and 0.8% p.a.[18]

To conclude, we consider that the ARIMA approach is the most accurate and best suited methodology to estimate materials real price growth rates, especially given the cyclical nature of material's prices. As an alternative, we consider that UR should *as a minimum* adopt Ofgem's rule that materials prices grow at the long-term trend over the GD17 period as a whole. Using UR's proposed indices and long term average but applying Ofgem's practical approach, implies an RPE of 0.3% p.a. on average over GD17 as opposed to the current assumption of *minus* 0.3% p.a. on average.

2.4. Plant and Equipment

UR's has drawn on the long-term average machinery and equipment Producer Price Index (PPI) published by ONS as basis for its plant & equipment RPE estimate, assuming that the current trend towards the long term average rate will continue throughout the upcoming price control.[19] We have two concerns with this estimate:

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13 UR's methodology to estimate materials RPEs is somewhat opaque, but involves the following steps: (i) first, UR takes "*the "current "snapshot" of inflationary indications"* provided by the interim construction Output Price Indices ("I-OPI"), then (ii) it "*forecast possible 'high' 'medium' and 'low' growth trends that all increase toward the long term average of the NOCOS and FOCOS indices*", and finally (iii) opts to adopt the "*medium growth scenario*" based on the "*current market conditions*" which suggest "*downward pressure on cost inputs*".

14 UR (2016): *Annex 6 Real Price Effects & Frontier Shift GD17*, Draft Determination, 15 March 2016, p.11, para. 2.36.

15 Ofgem (2014): *RIIO-ED1: Final determinations for the slow-track electricity distribution companies*, 28 November 2014, p.152, Table 12.3.

16 Ofgem (2012): *RIIO-T1/GD1: Real price effects and ongoing efficiency appendix, Final decision – appendix*, 17 December 2012, p.12, Table 1.5.

17 Ofgem (2012): *RIIO-T1/GD1: Real price effects and ongoing efficiency appendix, Final decision – appendix*, 17 December 2012, p.13, Table 1.6.

18 Ofgem (2014): *RIIO-ED1: Final determinations for the slow-track electricity distribution companies*, 28 November 2014, p.151, Table 12.2.

19 UR (2016): *Annex 6 Real Price Effects & Frontier Shift GD17*, Draft Determination, 15 March 2016, p.11, para. 2.40.

- As argued for labour and materials input costs, by taking the average of long-run data UR fails to account for the cyclicality of the considered index, therefore underestimating the real growth rate of plant and equipment input costs for PNG.
- UR relies only on one index (ONS PPI Machinery and Equipment index) to forecast plant & equipment RPEs, disregarding the relevance of other indices and regulatory precedent. For instance, at GD14 the UR considered along with the ONS index also the BCIS Plant and Road Vehicles as relevant for the purpose of forecasting plant and equipment RPEs.[20] This approach is consistent with the CC final decision at RP5 for NIE and Ofgem's approach at RIIO-ED1 and RIIO-GD1.[21,22,23]

If UR continues with its approach, it should at least take into account the BCIS Plant and Road Vehicles index that is typically used by regulators to estimate real growth rates of plant and equipment inputs. Taking into account both indices would lead to an average RPE of -0.3% p.a. over 2015-2022, compared to the current UR average estimate of *minus* 0.7% p.a. over the same period.

2.5. Overall UR's Allowance is Lower than Recent Decisions

UR's overall RPE is low compared to recent regulatory decisions, which re-enforces the fact that UR needs to correct for the issues identified in this report.

At a high-level, compared to recent decisions, UR's overall RPE forecast of 0.4% p.a. on average is lower than forecasts used by both the CMA in its final determination for Bristol Water's PR14, which assumes an RPE factor equal to 0.6% p.a., and Ofgem's RIIO ED1 determination which assumes 0.6% p.a.[24,25]

The high-level comparison supports the need for UR to correct for the issues we have identified above.

3. Productivity Improvement

Our submission on productivity drew on an empirical dataset of productivity growth rates (the EU KLEMS dataset). Using a range of different sector-specific and economy-wide long-term total factor productivity levels, we estimated productivity growth of 0.6% for capex and 0.8% for opex.

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20 UR (2013): *GD14 Price Control for Northern Ireland's Gas Distribution Networks for 2014-2016*, Final Determination 20 December 2013, p.167, para. 14.22.

21 CC (2014): *Northern Ireland Electricity Limited price determination - Final Determination*, presented on 26 March 2014, Appendix 11.1, p.5, para. 17, Table 17.

22 Ofgem (2014): *RIIO-ED1: Final determinations for the slow-track electricity distribution companies*, 28 November 2014, p.151, Table 12.2.

23 Ofgem (2012): *RIIO-T1/GD1: Real price effects and ongoing efficiency appendix, Final decision – appendix*, 17 December 2012, p. 12, Table 1.5 and p.13, Table 1.6.

24 CMA (2015): *Bristol Water plc - A reference under section 12(3)(a) of the Water Industry Act 1991*, 10 July 2015 - *Report*, 6 October 2015, para. 5.72.

25 Ofgem (2014): *RIIO-ED1: Final determinations for the slow-track electricity distribution companies Business plan expenditure assessment*, 28 November 2014, p.152, para.12.12, Table 12.5.

UR's approach is to rely heavily on regulatory precedence, particularly the CMA's determination for NIE in 2014. The CMA applied a productivity shift of 1% per annum for both opex and capex, and this is number UR uses in GD17.

UR also cites a range of other regulatory decisions. Its GD17 DD is on the upper end of this range. The most relevant other decision is RIIO-GD1, which uses 0.7% for capex and 1% for opex.

UR's DD estimates are at the upper-end of regulatory evidence, whereas the PNG specific factors would suggest a value at the lower end:

- UR DD is on the upper end of regulatory precedent. UR cites 17 productivity decisions (listing opex and capex separately). Nine use 1.0%, seven use less than 1.0% (usually 0.7% but as low as 0.2%), and only one uses higher than 1.0% (1.2%). Taking an average of the decisions would give productivity improvements of 0.8% and 0.9% for opex and capex, respectively.
- PNG is a new utility which would support a value towards the low end of productivity improvements, as it has less scope to reduce costs relative to incumbent former publically owned utilities. In other words, NIE is not a reasonable comparison.

There are also technical issues around the interpretation of data that support a figure at the lower end of the range (as described in our original report) around the use of Gross Output vs Value Added measures of productivity. [26]

Our submission cited reservations by Ofgem (RIIO-GD1) and the CC (NIE) in using VA productivity, so we relied on GO productivity, which, by definition improves more slowly than VA productivity. We believe that GO productivity is more relevant than VA productivity.

Overall, we consider that UR is wrong to draw on evidence at the top end of the plausible range, when PNG specific factors would support values towards the lower end. Overall, we consider that our submission of 0.6% p.a. and 0.8% p.a. for capex and opex respectively are well-justified.

[26] NERA (2015): *Forecasting Real Price Effects and Productivity Growth for GD17*, Prepared for Phoenix Natural Gas Ltd, 10 September 2015, p. 28.

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An Analysis of UR's Regional Labour Adjustments at GD17

Prepared for Phoenix Natural Gas

April 2016

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Contents

Executive Summary

As part of its top-down benchmarking analysis of PNG for GD17, the Utility Regulator (UR) makes a regional wage adjustment to NI and GB GDNs' labour costs. UR stated that it does this to ensure that NI GDNs "*are not unfairly advantaged by being situated in a low cost region*".[1]

Drawing on Office of National Statistics (ONS) Average Survey of Hours and Earnings (ASHE) data, UR calculates that NI wages levels are 82% of the GB average. The UR applies the regional wage adjustment to its estimate of 52% of opex that relates to labour, and as a result, UR concludes that PNG's efficient level of costs should be around 9% lower than GB GDNs to account for PNG's apparent lower wage costs.

UR's real labour adjustment (RLA) of 9% explains in its entirety UR's assessed top-down efficiency gap for PNG of 7-8%, as set out in UR's preferred model.[2]

UR's derivation of an RLA of around 9% is out of line with GB regulators' approaches

There are a number of areas where UR does not follow established principles for estimating RLAs, and established regulatory practice. First, the UR compares median private sector wages across all regions. By comparing median wages across regions, it is very likely that UR is comparing wages for occupations which are not the same across GB regions, given the different composition of regional workforces. In addition, the approach is very likely to involve comparisons of wages for occupations which are not relevant to a GDN's workforce. By contrast, all other GB regulators who have estimated RLAs in a comparative efficiency context (e.g. CMA, Ofgem, Ofwat) compare wages for occupations relevant to the network in question, drawing on ONS Standard Occupational Codes (SOCs).

Second, UR compares weekly earnings which does not control for differences in the hours worked per week across different regions. The average working week in NI is on average lower than in GB, and the shorter working week will in part explain NI lower earnings. Under UR's approach, PNG is penalised for the shorter NI working week. However, if PNG's employees actually worked shorter working weeks than the GB GDN peers (for which there is no evidence), PNG would have to employ more staff in order to perform the same tasks as its British peers, entirely offsetting the apparent lower weekly wage. Instead of using weekly wages, the correct comparison is hourly wages.

Finally, the UR's approach ignores the fact that the market for much of GDNs' labour costs is national, and therefore should not be subject to a regional labour adjustment.

[1] UR (15 March 2016) Indicative Findings from Top-Down Benchmarking – GD17, p. 11.

[2] UR (15 March 2016) op. cit., p.15

Adopting established approach, we calculate a much lower RLA adjustment of around 2-3%

We have calculated an RLA drawing on sound economic principles and established regulatory practice. Principally, we have undertaken a comparison of mean hourly real wages for occupations relevant to GDNs, drawing on the ONS occupational wage data ("SOC codes") used by the CMA in its 2014 NIE decision. Where necessary, we substitute the CMA SOC codes which are specific to electricity distribution for occupations relevant to gas networks. Using relevant occupations, we calculate that real wages for PNG are around 91-93% of the GB average – far closer to the average than UR's approach (based on entirely irrelevant occupations) of 82%.

This figure then needs to be applied to the share of opex that relates to labour, and specifically labour employed within the GDNs' regions. In order to calculate the relevant proportion, we draw on UR's assumption of the labour share of opex of 52%. Of this, we assume that around 50% of labour is employed from outside of GDNs' regions and therefore should not be subject to RLAs, e.g. GDNs locate some functions outside the network region, and/or employ contracted labour drawn from a wider geographic region.

Overall, we conclude that the RLA should apply to 26% of opex (=52%*50%) compared to UR's assumption of 52%.

Correcting for UR's faults, UR's own top-down models show that PNG's costs are efficient

Under its preferred model (model 3), UR acknowledges that PNG is "*reasonably close to being an upper quartile performer, but an efficiency gap does exist (estimated to be around 7% to 8% in 2014*".[3,4]

However, these results are based on an upward adjustment of 9% to PNG's costs for the UR's estimated RLA. As we have shown, the adjustment should be in the region of 2-3%. If we were to correct for UR's errors, and adjust PNG's costs by only 2-3% to account for RLAs, it is very likely that the top-down benchmarking analysis would show that PNG's costs are efficient based on UR's own preferred efficiency models.[5]

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3 UR (2016) Indicative Findings from Top-Down Benchmarking, GD17, p. 15

4 UR also identifies a further model (model 5), which is distinguished by its inclusion of a variable for iron mains. The results vary according to the sample used to estimate the model. Using GB and PNG as the sample, UR determines an efficiency gap of 7% (as per model 3). However, if PNG is omitted from the model estimation process, UR estimates an efficiency gap of 29%. However, the UR acknowledges itself that the co-efficient on iron mains is not statistically significant, and the modelling result of 29% is clearly an outlying result. See: UR (2016) Indicative Findings from Top-Down Benchmarking, GD17, p. 15, and Deloitte (March 2016) Annex – GD17 Efficiency Advice – Relative efficiency of NI GDNs.

5 Ideally, we would re-run UR's preferred econometric model(s) using our estimate of the regional wage adjustment in order to recalculate PNG's efficiency gap. However, UR has not provided PNG with access to the dataset.

1. Introduction

1.1. The Role of Top-down Modelling and RLAs at GD17

On 16 March 2016, the Utility Regulator of Northern Ireland (UR) released its draft determinations for the GD17 price control of the three gas distribution networks in Northern Ireland. In assessing companies' opex costs, the UR has relied on two approaches: a bottom-up assessment of costs; and a top-down econometric benchmarking approach which compares the Northern Irish GDNs' historical and future opex costs to their counterparts in Great Britain.

At this draft stage, the UR places no weight on the results of the top-down models, acknowledging that it still has work to do before the models are properly specified (especially with respect to special factor claims). However, the UR indicates that it will continue to develop its analysis with the GDNs.[6] Although UR has not used the results of this analysis in its draft determination, the UR's intention to further develop and apply these models means it is important that the GDNs scrutinise these models to assess their economic and statistical robustness.

This report focusses on one particular aspect of the UR's methodology: the Regional Labour Adjustment (RLA). The UR makes a pre-modelling adjustment to GDNs' opex costs "*to ensure that companies are not unfairly advantaged by being situated in a low-cost region for labour*".[7] In other words, the UR contends that since labour costs are generally lower in Northern Ireland than in Great Britain, GDNs in Northern Ireland can operate more cheaply simply by virtue of being located in Northern Ireland. In order to compare companies on a like-for-like basis, the UR inflates the costs of companies in low-wage regions and deflates the costs of companies in high-wage regions. The UR then reverses that adjustment after the modelling process to ensure that companies are not over- or under-compensated for their opex costs.

The use of RLAs in benchmarking models is common in similar comparisons of utilities' costs conducted in other periodic reviews, and there is a sound economic rationale for making RLAs. However, the UR's methods for calculating RLAs make a number of methodological errors that cause it to exaggerate the difference between the labour costs faced by GDNs in Northern Ireland compared to Great Britain, as we demonstrate in this report.

1.2. Structure of this Report

Chapter 2 of this report highlights the components of the UR's RLA methodology which are incorrect and explains why they result in an RLA that unfairly disadvantages GDNs in Northern Ireland. Chapter 3 draws on recent regulatory precedent to derive a more sensible RLA for Northern Irish GDNs, and Chapter 4 concludes. In Appendix A, we describe the range of approaches taken by other regulators in greater detail.

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6 UR (2016): *Price Control for Northern Ireland's Gas Distribution Networks GD17*, 16 March 2016, para. 6.1

7 UR (2016): *Annex 5: Indicative Findings from Top-Down Benchmarking GD17*, 16 March 2016, para. 2.37

2. UR’s Approach in the GD17 Draft Determinations

This chapter describes the UR’s approach to calculating an RLA for its top-down econometric benchmarking models for opex and highlights flaws in its approach. This chapter proceeds as follows:

- Section 2.1 outlines the UR’s GD17 approach to calculating and applying RLAs;
- Section 2.2 discusses the granularity of wage data the UR uses;
- Section 2.3 discusses the UR’s measure of wages;
- Section 2.4 discusses the share of costs that the RLA is applied to; and
- Section 2.5 concludes.

2.1. Summary of the UR’s Approach

The UR gives a brief description of its approach to adjusting for regional labour differences prior to performing econometric benchmarking of the GDNs’ opex costs.[8] The key components are as follows:

- UR uses wage data from the Annual Survey of Hours and Earnings (ASHE) from 2009 to 2015. In GB, this data is collected by the Office of National Statistics (ONS). In Northern Ireland, the Department of Enterprise, Trade and Investment publishes equivalent data sets.
- For each year of data, the UR compares the median weekly wage of full-time private sector employees in Northern Ireland to the UK average. It also performs the same comparison for the 11 statistical regions in Great Britain, and maps these regions to the network regions of British GDNs.
- It finds that the median weekly wage of full-time private sector employees in Northern Ireland over the seven-year period is 82% that of average employees across the whole of the UK.
- The UR applies this adjustment to the labour component of GDNs’ opex costs, which it assumes to be 52% of opex. The UR inflates 52% of opex by 22% (1.00/0.82 – 1) before benchmarking to ensure that PNG is not unfairly advantaged by its low wage environment (as the UR contends) in its comparative efficiency assessment. The UR then makes a corresponding reverse adjustment after benchmarking to ensure that companies in lower cost labour regions are not over-remunerated.

2.2. Granularity of the UR’s Data

The ONS classifies types of workers in the ASHE dataset using an index of Standard Occupational Classifications, or “SOC codes”. SOC codes identify a range of occupational classifications, with an increasing level of granularity as the number of “digits” in the SOC code increases. For instance:

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8 UR (2016): *Annex 5: Indicative Findings from Top-Down Benchmarking GD17*, 16 March 2016, page 11.

- The 1-digit SOC codes group workers by the level of responsibility and skill, ranging from SOC Code 1 “Managers and Senior Officials” to SOC Code 9 “Elementary Occupations”, with no differentiation by industrial sector;
- Adding digits to the SOC code makes the classification (and hence the associated estimates of average wages) progressively more specific to a particular type of worker. For example:
  - The “2-digit” SOC Code 21 corresponds with “Science, research, engineering and technology professionals” and is a subset of the “1-digit” SOC Code 2, “Professional occupations”;
  - The “3-digit” SOC Code 212 (a subset of the “2-digit” SOC Code 21) corresponds with “Engineering professionals”; and
  - The “4-digit” SOC Code 2121 (a subset of the “3-digit” SOC Code 212) corresponds with “Civil engineers”.

As described in Appendix A, all the regulatory decisions we have surveyed (excluding those from the UR) have used SOC codes to identify occupation-specific variation in wages across regions. That is, GB regulators consider, for example, how the market wage for a civil engineer varies around the country, as these are the cost pressures that impact the labour costs companies actually face. However, in a departure from this regulatory precedent, the UR has not used SOC codes at all in the GD17 draft determination. Instead it has compared private-sector wages across all industries and occupations.

2.2.1. UR’s approach uses wage information for irrelevant occupations

UR’s approach compares the median private-sector employee in each region (by gross weekly earnings) to one another. This comparison is not relevant to the cost pressures faced by GDNs around the UK for two reasons: first, the median employee in each region may be employed in different occupations (with different pay levels); and second, even in the unlikely event that the median employees were employed in the same occupation, the regional wage differential in that occupation may not match the regional wage differential in occupations relevant to GDNs.

The first of these issues is known as “composition bias”, as the composition of the overall private-sector workforce differs between Northern Ireland and the UK (and the other regions within the UK). The UR’s approach fails to compare similar employees to each other across different regions, which overstates the regional wage differential between Northern Ireland and the UK. If, for example, the economy in Northern Ireland is more heavily skewed towards lower-income industries than London, then the median employee will probably be in a lower-paying occupation than the median employee in London, holding constant any regional variations.

The UR is out of step with GB regulators and the Competition and Markets Authority (CMA) in failing to control for these issues by identifying wages for segments of the labour market that are relevant to the utilities being benchmarked. For example, Ofgem used regional wage data for a range of 2-digit SOC codes, as opposed to average wages across all parts of the private sector. Additionally, in the appeal of Ofgem’s RIIO-ED1 decision by Northern

Powergrid, the CMA concluded that "*compositional bias is a relevant issue in the calculation of RLCAs*".[9]

The UR's approach unduly penalises the NI GDNs for being located in a region whose overall private-sector workforce is composed differently than that of the UK as a whole.

Moreover, even if composition of NI and GB workforces were identical, and the UR were indeed comparing equivalent occupations in taking the median wage, there are many reasons why regional wage differentials are not the same across occupations or sectors. Local supply and demand dynamics, income inequality and occupation-specific labour mobility are all possible explanations.

As explained in Appendix A, British regulators have sought to avoid these problems by comparing wages only for *relevant* occupations. For example, Ofgem used 2-digit SOC codes "*in order to strike a balance between using data which contained relevant occupations on the one hand and avoiding small sample sizes on the other*".[10] By contrast, the UR's approach factors in wages of occupations that have nothing to do with the gas distribution industry.

The UR has sought to defend its failure to control for regional wage variation using data for relevant sectors of the labour market by highlighting the distinction between private- and public-sector employees. ONS publishes regional wage data that distinguishes between private- and public-sector employees, and that distinguishes between occupations, but not jointly between those dimensions. UR notes that "[p]*rivate sector median wages have been preferred over all employee jobs due to the fact that the firms are private enterprises*".[11] In other words, the UR has chosen to distinguish between private- and public-sector employees while accepting that the data includes employees in other occupations.

Other regulators, as explained in Appendix A, have decided it is more important to use wage data for relevant occupations/sectors rather than focusing on private sector wages specifically. Furthermore, most occupations relevant to GDNs' costs are likely to be dominated by private-sector employees. For example, the engineering-related SOC-codes which are relevant to the regulated networks are likely dominated by private-sector employees. Therefore, the approach used by other regulators is not heavily biased by the inclusion of some public-sector employees.

For this reason, the RLAs we derive in Chapter 3 rely on this approach, using wages for particular SOC codes to compute RLAs.

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9 Northern Powergrid (NPg) argued that Ofgem's 2-digit SOC codes were susceptible to composition bias. The CMA did not sustain this ground of appeal, on the basis that NPg did not prove Ofgem to be "wrong" in its approach, but it agreed that compositional bias is a relevant issue. Composition bias becomes more egregious when data granularity decreases, so, whilst it was not clear that Ofgem's 2-digit approach suffered from significant composition bias issues as compared to NPg's proposed alternative of using 3- or 4-digit SOC codes, UR's economy-wide approach is more likely to suffer from this compositional bias. Source: CMA (2015): Northern Powergrid v GEMA,29 September 2015, para. 6.61

10 Ofgem (2015): *Response to Notice of Appeal – Energy License Modification,* 22 April 2015, para. 207(c)

11 UR (2016): *Annex 5: Indicative Findings from Top-Down Benchmarking GD17*, 16 March 2016, page 11-12.

2.3. UR's Measure of Wages

2.3.1. Weekly vs hourly wages

UR's compares weekly wages among full-time earners in each region. It does not justify why it uses weekly rather than hourly wages

We consider this approach is incorrect and underestimates the wage pressures faced by NI GDNs. We expect that the same task would take the same number of hours in Northern Ireland as it would in Great Britain (as we assume labour productivity is the same[12]). Therefore, a company in a region with shorter working hours would need either more weeks or more employees to complete the task, offsetting the lower weekly salary it pays due to shorter working hours. Alternatively, it may be the case that GDNs have similar working practices around the UK, such that engineers employed by PNG work longer than non-GDN engineers in Northern Ireland, whilst National Grid's engineers work the same amount as non-GDN engineers in its network regions. In any case, GDNs in Northern Ireland do not benefit from the component of lower weekly wages in Northern Ireland that comes from shorter working hours.

The UR could control for this regional difference in hours worked by using an hourly measure of wages. Instead, its approach unfairly penalises PNG either for being located in a region with shorter working hours (regardless of whether PNG's employees work less than their British counterparts), or for having a more productive workforce.

2.3.2. Median vs mean wages

The UR uses median earnings "*as they are less liable to be skewed than using the mean*".[13] This is statement is theoretically correct: mean measures can be skewed by outliers, whereas median measures are not. Whilst no full-time employee can earn less than minimum wage, some employees earn many times more than the average employee, especially if we look at the private sector as a whole. Furthermore, the extent of this skew varies by region. The top decile of 2015 weekly earnings in London (across the private sector as a whole) is 139% higher than median earnings in London. By comparison, the top decile earner in the UK as a whole earns 111% more than the median UK earner, and the top decile earner in Northern Ireland earns 93% more than the median Northern Irish earner,[14] as shown in Figure 2.1.

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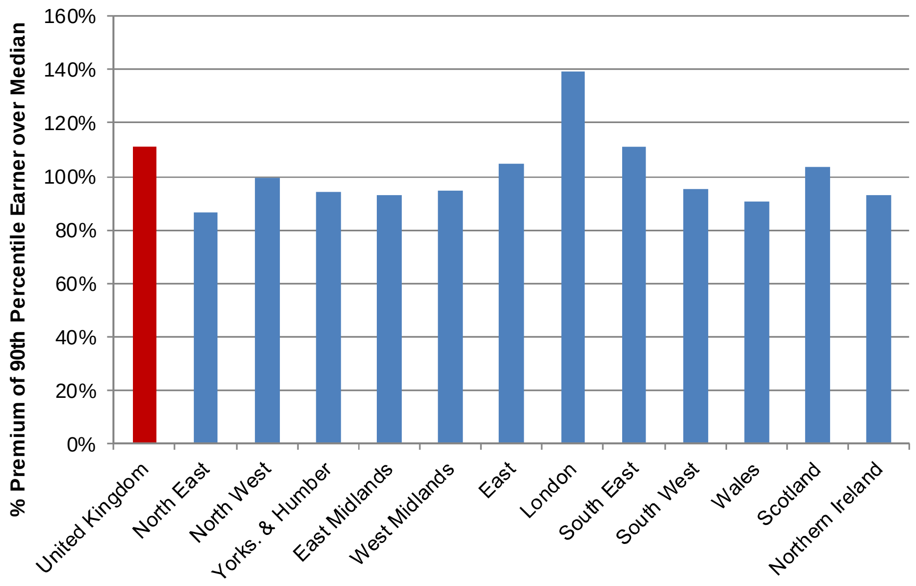
[12] In order to carry out the same tasks with the same amount of labour in one week but with shorter working hours, PNG's employees would have to be more productive than employees of British GDNs. There is no evidence to suggest that this is case, and it is unlikely given the relatively standardised education and qualifications engineers receive around the country, such as from the Institute of Civil Engineers. However, if PNG's employees were more productive (and PNG could perform the same tasks with fewer man-hours), the UR's approach would effectively be punishing PNG for having a more efficient workforce. This is at odds with the wider objective of regulatory benchmarking, which is to encourage efficient behaviour by regulated networks.

[13] UR (2016): *Annex 5: Indicative Findings from Top-Down Benchmarking GD17*, 16 March 2016, page 11.

[14] Using 2015 data on weekly gross earnings for full-time private sector employees, we compare the 90th percentile earner to the median earner in each region. Data for Great Britain comes from ONS ASHE Table 25, whilst Northern Ireland data comes from the Department of Enterprise, Trade and Investment – Northern Ireland, ASHE Table 13.

Figure 2.1
Income Disparities Vary Substantially by Region



Source: NERA analysis on ONS data

Given the clear issues around income distribution at the private-sector-wide level, the UR was correct to use a median rather than the mean, taking as given the other aspects of its approach. It is less clear which is more appropriate if we use more granular SOC-codes, as we discuss in Section 3.1.2.

2.4. Share of Opex Costs Driven by Labour

UR assumes "*that only 52% of opex relates to labour*", and therefore applies this adjustment to 52% of GDNs' opex costs.[15] However, unlike Ofgem's decisions at RIIO-ED1 and RIIO-GD1, the UR has not accounted for the fact that not all labour needs to be co-located with the network. At RIIO-ED1, Ofgem "*considered the proportion of work that is done in these areas and elsewhere*" and did "*not make regional labour adjustments for business support costs in line with our view that these can be procured on a national basis*".[16] In other words, Ofgem considered that in principle (and indeed in practice) networks can choose to locate some staff in whatever region of the country it is most efficient for them to be, accounting for regional labour cost variation (amongst other factors).

The UR's failure to adjust for the share of labour that needs to be co-located with network services will tend to exaggerate the cost advantage enjoyed by companies, such as the NI GDNs, operating in regions with relatively low wages.

15 UR (2016): *Annex 5: Indicative Findings from Top-Down Benchmarking GD17*, 16 March 2016, page 12.

16 Ofgem (2014): *RIIO-ED1 Final Determinations – Expenditure Assessment*, 28 November 2014, paras. 4.12 & 4.16.

2.5. Conclusions

The UR estimates that the labour prices Northern Irish GDNs face are 82% of the UK average. The methodology exaggerates the cost advantage that Norther Irish utilities experience due to relatively low regional wages due to a series of flaws in the UR's methods:

- The UR includes many irrelevant occupations by using wages for the whole of the private-sector to compute RLAs. This comparison is not relevant to the cost pressures faced by GDNs around the UK for two reasons: the median employee in each region may be employed in different occupations (with different pay levels) – a problem referred to as "compositional bias". The way to address this is to draw on occupations relevant to GDNs;
- The UR compares weekly wages, which fails to account for the lower average weekly working hours in Northern Ireland than in the rest of the UK. This means that Northern Irish employers must either hire more employees or take more weeks to complete the same task, offsetting some of the savings from lower weekly wages; and
- It does not consider that some portion of companies' labour comes from a national market and are therefore unaffected by regional variations in pay.

As a result of these methodological failings, the UR's proposed 18% adjustment to Northern Irish GDNs' costs to account for regional wage variation is exaggerated.

We provide a more robust estimate of the required regional wage cost adjustment for PNG and FE in Chapter 3.

3. Deriving a Regional Labour Adjustment for PNG

Following a review of recent regulatory precedent in the UK, we have developed our own approach to deriving and RLA for PNG using occupation-specific data from the ASHE dataset. This chapter describes our approach to deriving this adjustment and sets out a more appropriate adjustment to PNG's costs. This chapter proceeds as follows:

- Section 3.1 outlines our methodology;
- Section 3.2 calculates a regional wage adjustment applicable to the NI GDNs;
- Section 3.3 suggests the share of PNG's opex costs that should be adjusted for regional labour cost differences; and
- Section 3.4 concludes.

3.1. Methodology for Deriving a Regional Labour Adjustment

This section sets out our methodological choices in deriving RLAs, drawing on both regulatory precedent and our own economic judgement.

3.1.1. Data window

In line with most regulatory precedent, we derive RLAs using the five most recent years of data (2011-2015) from the ONS ASHE dataset, as well as the equivalent ASHE dataset from Northern Ireland. Our use of five years of data accommodates any volatility in annual data.

In the GD17 decision, the UR used seven years of data. There is a trade-off in this respect: a longer window reduces volatility, but data from 2009 may not be relevant to a price control period that begins eight years later, especially if there are underlying trends in the data. In this case, we have relied on recent regulatory precedent which suggests that five years of data is sufficient.[17]

3.1.2. Wage measure

We use data on gross hourly wages including overtime, as weekly wages do not control for regional differences in working hours, and overtime is an important component of the market price for labour. This is consistent with Ofgem's approach at RIIO-ED1 and GD1.[18]

We use mean wages rather than median wages, which is consistent with Ofgem's approach at RIIO-ED1 as well as the CMA's approach in the NIE decision, and is more reflective of

[17] We take the five-year average of the regional premium of each occupational category before applying occupational weights. We do this because the ASHE dataset does not an average wage for every occupational category in every year in every region. This is especially true at the 4-digit level of granularity. This approach deals with occasional gaps in the data without changing the weighted placed on each occupational classification.

[18] There are few specifics in the public domain on Ofgem's RLA approach at RIIO-GD1. However, there are numerous references to the fact that the ED1 process, which we know well, was consistent with the GD1 process. See, for example: Ofgem (2014): *RIIO-ED1 Final Determinations – Expenditure Assessment*, 28 November 2014, para. 4.15

GDNs' costs than the median, assuming that GDNs have to buy a mix of labour that reflects the spectrum of workers included in each SOC code.[19]

3.1.3. Data granularity

As described in Chapter 2, the UR's approach ignores specific occupations in its RLA, leading to material biases in the results. All other regulators have sought to identify occupation-specific effects by using SOC-code data, but have used different levels of granularity.

For example, Ofgem's ED1 decision used exclusively 2-digit SOC codes "*in order to strike a balance between using data which contained relevant occupations on the one hand and avoiding small sample sizes on the other*".[20] On the other hand, the CMA's[21] 2014 decision for NIE used both 3- and 4-digit SOC codes. The 3-digit adjustment "*strikes a balance between including occupational categories that are relevant to the activities of NIE and GB DNOs and avoiding the risks of data error from a small sample size*". On the other hand, the 4-digit adjustment "*is more closely aligned than [the 3-digit adjustment] with the occupations relevant to NIE's activities, even if it does suffer from a smaller sample size*".[22]

We have decided to use an average of RLAs based on 2-, 3- and 4-digit SOC codes which broadly reflects the approach used by CMA at NIE.

3.1.4. SOC codes used

Our starting point is to consider the SOC codes used by the CMA, which are publically available.[23] Table 3.1 presents the CMA 3- and 4-digit SOC codes and weights it used for NIE in 2014, and the 2-digit codes that sit above the CMA's 3- and 4-digit codes.[24]

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19 Note, the UR used a median measure in its GD17 draft determination, which was more appropriate given the methodological errors present in its overall approach. In light of the UR's approach, we will test the sensitivity of our results to the use of a median measure in Section 3.2.

20 Ofgem (2015): *Response to Notice of Appeal – Energy License Modification,* 22 April 2015, para. 207(c)

21 Then known as the Competition Commission (CC)

22 CC (2014): *Northern Ireland Electricity Ltd Price Determination, Final Determination,* 26 March 2014, para 8.203.

23 Ideally we would also like to have considered the SOC codes used in RIIO-GD1, but to our knowledge Ofgem did not publish these.

24 Note that all three approaches include SOC-codes that are less granular than others, for example SOC-code 1 (Managers, directors and senior officials).

Table 3.1
SOC Codes in Electricity Distribution

SOC code	Description	2-digit approach	3-digit approach	4-digit approach
1	Managers, directors and senior officials	6%	6%	6%
21	Science, research, engineering and technology professionals	18%	0%	0%
212	Engineering professionals	0%	18%	0%
2123	Electrical engineers	0%	0%	18%
31	Science, engineering and technology associate professionals	16%	0%	0%
311	Science, engineering and production technicians	0%	16%	0%
3112	Electrical and electronics technicians	0%	0%	16%
41	Administrative occupations	5%	5%	5%
52	Skilled metal, electrical and electronic trades	29%	0%	0%
524	Electrical and electronic trades	0%	29%	25%
5241	Electricians and electrical fitters	0%	0%	4%
71	Sales occupations	3%	0%	0%
712	Sales related occupations	0%	3%	0%
7122	Debt, rent and other cash collectors	0%	0%	3%
82	Transport and mobile machine drivers and operatives	1%	0%	0%
821	Road transport drivers	0%	1%	0%
8211	Large goods vehicle drivers	0%	0%	1%
91	Elementary trades and related occupations	21%	0%	0%
913	Elementary process plant occupations	0%	21%	0%
9139	Elementary process plant occupations n.e.c.	0%	0%	21%
92	Elementary administration and service occupations	1%	0%	0%
926	Elementary storage occupations	0%	1%	1%
Total		**100%**	**100%**	**100%**

Source: Ofgem, CC. Note: SOC-code definitions were updated in 2011. The CMA used some SOC codes that no longer exist in the ASHE dataset. We have replaced these with their equivalents under the new definitions.

These weights all relate to the electricity distribution industry, and we use them as a starting point for determining weights for PNG's RLA. In particular, we retain the same SOC code and weighting for those functional areas/occupations that are common to energy networks (e.g. administrative occupations) but make changes to SOC codes for their respective technical occupations. For example, the CMA applies 5% weight to SOC code 41 (Administrative occupations), and we assume that GDNs employ a similar share of administrative staff. On the other hand, GDNs do not require many, if any, electrical engineers. We therefore reassign the weights on electricity-specific codes to codes more appropriate to the gas industry, without changing the weights from what the CMA used.

We give our reassigned weights in Table 3.2 below, with the highlighted rows representing codes we have changed.

Table 3.2
SOC Codes in Gas Distribution

SOC code	Description	2-digit approach	3-digit approach	4-digit approach
1	Managers, directors and senior officials	6%	6%	6%
21	Science, research, engineering and technology professionals	18%	0%	0%
212	Engineering professionals	0%	18%	0%
2121	Civil engineers	0%	0%	18%
31	Science, engineering and technology associate professionals	16%	0%	0%
311	Science, engineering and production technicians	0%	16%	16%
41	Administrative occupations	5%	5%	5%
52	Skilled metal, electrical and electronic trades	29%	0%	0%
521	Metal forming, welding and related trades	0%	29%	29%
53	Skilled construction and building trades	0%	0%	0%
71	Sales occupations	3%	0%	0%
712	Sales related occupations	0%	3%	0%
7122	Debt, rent and other cash collectors	0%	0%	3%
81	Process, plant and machine operatives	0%	0%	0%
82	Transport and mobile machine drivers and operatives	1%	0%	0%
821	Road transport drivers	0%	1%	0%
8211	Large goods vehicle drivers	0%	0%	1%
91	Elementary trades and related occupations	21%	0%	0%
913	Elementary process plant occupations	0%	21%	0%
9139	Elementary process plant occupations n.e.c.	0%	0%	21%
92	Elementary administration and service occupations	1%	0%	0%
926	Elementary storage occupations	0%	1%	1%
Total		**100%**	**100%**	**100%**

Source: ONS, Ofgem and CC. Note: We have had to drop two of our preferred 4-digit SOC codes due to data unavailability in Northern Ireland: 3114 (Building and civil engineering technicians) and 5216 (Pipe fitters). In both cases, we have assigned more weight to the parent 3-digit code.

3.2. PNG's Regional Labour Cost Differential

Using the assumptions set out in Section 3.1, we can now calculate an appropriate regional labour cost differential for PNG's opex costs. We calculate three different levels for each region under the three sets of weights given in Table 3.2. Ultimately, we take an unweighted average of these numbers. We present our results in Table 3.3.

Table 3.3
Labour Cost Differential by Region

Region	2-digit approach	3-digit approach	4-digit approach	**Average**
London	1.189	1.113	1.105	**1.136**
South East	1.050	1.043	1.054	**1.049**
North East	0.985	1.017	0.999	**1.000**
North West	0.980	0.996	0.981	**0.986**
Yorks. & Humber	0.963	0.979	0.990	**0.977**
East Midlands	0.967	0.968	0.987	**0.974**
West Midlands	0.956	0.953	0.944	**0.951**
East	1.014	0.978	0.974	**0.989**
South West	0.983	0.974	0.956	**0.971**
Scotland	1.051	1.114	1.131	**1.098**
Wales	0.960	0.957	0.963	**0.960**
Northern Ireland	0.903	0.908	0.916	**0.909**

Source: NERA analysis on data from ONS, Ofgem and CC

This table shows that, of the labour costs relevant to GDNs, networks in Northern Ireland face labour costs which are 90.9% of the UK average. This is substantially higher than the 82% figure the UR used in the GD17 draft determinations.

As mentioned in Sections 2.3.2 and 3.1.2, the UR based its approach on median earnings rather than mean earnings. Given the other aspects of our approach, it is theoretically preferable to use mean earnings. However, as we show in Table 3.4 below, the results are not very sensitive to this aspect. In fact, a comparison of median wages actually makes the regional wage differential between Northern Ireland and the UK appear smaller than a mean comparison does.

Table 3.4
Labour Cost Differential by Region – Median Sensitivity

Region	2-digit approach	3-digit approach	4-digit approach	Average
London	1.165	1.099	1.092	**1.119**
South East	1.048	1.047	1.056	**1.050**
North East	0.991	1.025	1.003	**1.006**
North West	0.968	0.986	0.976	**0.977**
Yorks. & Humber	0.972	0.980	0.995	**0.982**
East Midlands	0.963	0.959	0.967	**0.963**
West Midlands	0.957	0.942	0.927	**0.942**
East	1.011	0.989	0.994	**0.998**
South West	0.983	0.982	0.977	**0.981**
Scotland	1.049	1.101	1.124	**1.091**
Wales	0.972	0.965	0.963	**0.966**
Northern Ireland	0.921	0.925	0.928	**0.925**

Source: NERA analysis on data from ONS, Ofgem and CC

In Ofgem's RIIO-ED1 calculation, it then mapped regional indices onto network regions by population. PNG and FE are located exclusively in Northern Ireland, so their costs should be adjusted by the index level for Northern Ireland (subject to other scalings which we discuss in Section 3.3). As the UR benchmarks PNG's and FE's opex to British GDNs, however, the UR would need to map these regional indices onto the GDNs' network regions, especially in England and Wales where network regions do not line up neatly with ONS's statistical regions.

3.3. Proportion of Costs Affected

Having estimated the difference in wages in Northern Ireland as compared to the rest of the UK, the next step is to calculate the share of PNG's opex costs to which wage adjustments should be applied. The adjustments should only be applied to the labour component of PNG's opex, and within that, they should only be applied to the component which needs to be co-located with the network, as described above.

3.3.1. Proportion of opex that is driven by labour

First, the adjustment should only apply to PNG's share of labour in opex, or to the share of labour for an average network.[25] The UR's GD17 draft determination "assume[s] that only 52% of opex relates to labour".[26] It therefore applies the adjustment to 52% of each GDN's opex costs. This matches the labour share assumption the UR uses for real price effects, which we use here to approximate PNG's labour share of opex.

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[25] At ED1, Ofgem applied the adjustment to the labour share of an average company, presumably to avoid incentivising companies to manipulate their cost structure to benefit from RLAs.

[26] UR (2016): *Annex 5: Indicative Findings from Top-Down Benchmarking GD17*, 16 March 2016, page 12.

3.3.2. Proportion of labour that must be co-located with network

Secondly, as described in Section 2.4, the RLA should only be applied to the share of labour which must be co-located with the network.

At RIIO-ED1, Ofgem did not apply the RLA to business support costs, and suggested that that it sought to identify the share of labour that must be local within other opex cost areas.[27,28] For example, much of the cost area called "closely associated indirects" (CAIs), which includes project management, could be located anywhere in the country. At RIIO-GD1, Ofgem assumed that only"*40 per cent of work management will be carried out locally*".[29]

Business support costs comprise 20% of DNOs' total opex and CAIs comprise 39%.[30] If we assume that each cost category is equally labour intensive, that 40% of CAI labour needs to be co-located with the network, and that 100% of labour in other opex categories needs to be co-located with the network, this means that only 57% of DNOs' opex was subject to an RLA. On balance, this is likely an overestimate, as some portion of labour costs in other cost areas can be located anywhere. Therefore, we assume that 50% is a closer approximation of the proportion of labour Ofgem deemed to be local.

Due to the similar nature of gas and electricity networks, we assume that this is a reasonable assumption for GDNs as well, and we apply our RLA to 50% of Northern Irish GDNs' opex labour costs.

3.4. Conclusions

Using a range of assumptions derived from regulatory precedent and our own judgement, we have calculated an RLA for PNG's opex costs at GD17. Based on 2-, 3- and 4-digit SOC codes from the ONS ASHE dataset, we compute an RLA for PNG of 90.9%. This adjustment is only relevant to PNG's labour share of opex (which the UR assumes to be 52%), and only to the labour costs that must be located within a networks' region (which we assume to be 50%). Therefore, this adjustment should only be made to 26% of PNG's opex costs.

Thus, in order to make PNG's opex costs comparable for benchmarking to British GDNs' opex costs, the UR should multiply opex costs (including the non-labour component) by 1.0249.[31] It should perform equivalent adjustments to British GDNs after mapping pay data by statistical region onto network region.

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27 Ofgem (2014): *RIIO-ED1 Final Determinations – Expenditure Assessment*, 28 November 2014, paras. 4.12 & 4.16.

28 We refer to the following cost areas as "opex": Trouble Call, Occurrences Not Incentivised (ONIs), Tree Cutting, Severe Weather 1-20, Inspections & Maintenance (I&M), Network Operating Costs Other (NOCs other), Smart Metres, Business Support and Closely Associated Indirects.

29 Ofgem (2012): *RIIO-GD1: Initial Proposals – Supporting document – Cost efficiency*, 27 July 2012, Appendix 5, para. 1.5.

30 Ofgem (2014): *RIIO-ED1 Final Determinations – Expenditure Assessment*, 28 November 2014, tables 9.1, 9.2, 9.4-9.8, 10.1 & 10.3.

31 $1.0249 = \left[(52\% * 50\%) * \left(\frac{1}{0.908}\right)\right] + [(1 - 52\% * 50\%) * (1)]$

4. Conclusion

In this report, we have examined and critiqued the UR's methodology for calculating an RLA for PNG's opex costs, and we have drawn on regulatory precedent and our own judgement to calculate a better RLA.

As described in this report, the UR's approach to computing an RLA for the NI GDNs is flawed for several reasons.

- First, it compares median private sector earnings across all regions, irrespective of occupation. This ignores the fact that regional premia vary by occupation and the mix of occupations will vary by region, Together, these mean that the UR makes a comparison that is virtually meaningless to the cost pressures faced by PNG, FE and British GDNs.
- Second, it compares weekly earnings, which do not control differences in hours worked per week across different regions. PNG's labour costs appear lower by this metric, but if PNG's employees actually worked shorter weeks along with the average Northern Irish employee, PNG would have to employ more staff in order to perform the same tasks as its British peers. This would offset some of the savings it receives through shorter working hours.[32]
- Finally, the UR's approach ignores the fact that the market for much of GDNs' labour costs is national, and therefore should not be subject to a regional labour adjustment.

The UR finds that labour costs in Northern Ireland are 82% as high as they are in the UK, and that this should be applied to the labour share of Northern Irish GDNs' opex (52%). This means that the UR scales up PNG's total opex costs by 11.4% before benchmarking with British GDNs. This is outside the bounds suggested by regulatory precedent and is not a robust basis for adjusting PNG's opex costs for the reasons set out above.

We have therefore calculated an alternative regional labour adjustment based on regulatory precedent and our own economic judgement. In particular, we have:

- Used data on mean gross hourly earnings from the ONS ASHE dataset (and its Northern Irish equivalent) from 2011 to 2015;
- Used 2-, 3- and 4-digit SOC codes derived from the 2014 NIE decision, adjusted to be more appropriate to the gas distribution network; and
- Applied the resulting adjustment to the share of opex that relates to locally-based labour, using the UR's assumption on the labour share of opex and Ofgem's assumptions on the local share of opex labour.

Ultimately, we have calculated an index level of 90.9% to 92.5% which should be applied to 26% (ie. 52% x 50%) of PNG's opex costs. When we write out the algebra, we find that the UR should scale up PNG's total opex costs by around 2.5% before benchmarking to GB GDNs.

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32 This would not be the case if PNG's staff were more productive than their British counterparts, but there is no evidence to suggest this is true. Furthermore, the UR would then be penalising PNG for employing more efficient staff.

Appendix A. Regulatory Precedent

In this appendix, we review the approaches regulators have used in adjusting for regional labour cost differences in recent decisions. In particular, we review the following decisions:

- Ofgem’s 2014 RIIO-ED1 decision, which set allowed revenues for 14 electricity distribution companies in Great Britain;
- Ofgem’s 2012 RIIO-GD1 decision, which set allowed revenues for eight gas distribution companies in Great Britain;
- Ofwat’s 2014 PR14 decision, which set allowed revenues for ten water and sewerage companies and eight water-only companies in England and Wales;
- UR’s 2015 PC15 decision, which set allowed revenues for Northern Ireland Water Ltd.;
- UR’s 2012 RP5 decision, which would have set allowed revenues for NIE had NIE not sought a referral of the decision to the CMA (then the CC). However, we were unable to find any detail in published documents on how the UR treated regional labour cost differences, so this decision ultimately does not inform our assessment;
- UR’s 2014 GD14 decision, which set allowed revenues for the two gas distribution companies in Northern Ireland. However, we were unable to find any detail in published documents on how the UR treated regional labour cost differences, so this decision ultimately does not inform our assessment;
- The CMA’s 2014 decision on NIE’s referral of RP5 (then the CC); and
- The CMA’s 2015 decisions on appeals by Northern Powergrid (RIIO-ED1) and Bristol Water (PR14), in which the CMA upheld the approaches used by Ofgem and Ofwat, respectively, despite those approaches being substantially different from each other.

We have focussed on the following aspects of each of the above decisions:

- The sources of data used to calculate regional wage differences, including the granularity of the data;
- The number of regions which regulators treated as separate labour cost regions;
- The approach used to incorporate the labour cost adjustment; and
- The portion of costs to which a labour cost adjustment was applied.

A.1. Data Sources

All of decisions we have reviewed have used data from the ASHE dataset, though regulators have used different data within that broad dataset.

A.1.1. Time frame

In most of the decisions we reviewed, regulators used several years of data to make adjustments for regional wage variations. For example, Ofgem used four years of data (2009-

2012, inclusive) in RIIO-GD1[33] and five years of data (2008-2012, inclusive) in RIIO-ED1.[34] As Ofwat included regional labour costs as a driver in its econometric model (see Section A.3), it used data from its full estimation period, which was five and seven years for water and sewerage companies, respectively.[35] The CMA used five years (2007-2011, inclusive) in its 2014 NIE decision.[36] In PC15 (NI Water), however, the UR used data from just 2013.[37]

The CMA justified its choice by explaining that "a five-year period […] helps to reduce concerns about small sample sizes in the ASHE regional wage data".[38] We were otherwise unable to find justification in any of these decisions for the use of several years' data, but the breadth of regulatory decisions in support of using several years' data shows that regulators have a preference for reducing the volatility of the measure. Given the inter-year volatility of the ASHE dataset, this approach is likely theoretically better than relying on just one year.

A.1.2. Wage measurement

Not all regulators published enough detail about their regional labour approach to identify the specific measure of pay (ie. which ASHE table) they used. We identified three measures that regulators used. In RIIO-ED1, Ofgem used data on gross hourly pay.[39] The two water decisions (PR14 and PC15) used data on gross hourly pay excluding overtime. Ofwat argued that "[w]eekly pay may be capturing differences in company policies and in efficiency. For example, if employees in one company work 40 hours a week while employees in another company work 35 hours a week, doing the same job, this would mean that the weekly wages would allow for that inefficiency".[40]

The CMA used *weekly* data, which it believed "were more relevant to the type of salaried occupations that are relevant to the workforce of NIE and NIE Powerteam".[41] NIE disagreed with this approach, and argued that "working hours are higher in GB than NI for the most relevant occupations, by 2.5 per cent"[42], which would tend to overstate the negative differential between Northern Ireland and Great Britain.

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33 Ofgem (2012): *RIIO-GD1 Final Proposals – Cost Efficiency*, 17 December 2012, Table A4.2

34 NPg (2015): *Notice of Appeal Energy Licence Modification – Sensitive Information Redacted*, para. 2.22

35 CEPA (2014): *Cost Assessment – Advanced Econometric Models*, 20 March 2014, page 12

36 CC (2014): *Northern Ireland Electricity Ltd Price Determination, Final Determination - Appendix 8.4*, 26 March 2014, para 6(d).

37 UR (2014): *Water & Sewerage Services Price Control 2015-21 Final Determination - Annex P*, December 2014, para. 5.3.2

38 CC (2014): *Northern Ireland Electricity Ltd Price Determination, Final Determination*, 26 March 2014, para 8.69.

39 NPg (2015): *Notice of Appeal Energy Licence Modification – Sensitive Information Redacted*, para. 8.13

40 CEPA (2014): *Cost Assessment – Advanced Econometric Models*, 20 March 2014, page 56

41 CC (2014): *Northern Ireland Electricity Ltd Price Determination, Final Determination*, 26 March 2014, para 8.72.

42 CC (2014): *Northern Ireland Electricity Ltd Price Determination, Final Determination*, 26 March 2014, para 8.73.

A.1.3. Data Granularity

The ONS classifies types of workers in the ASHE dataset using an index of Standard Occupational Classifications, or "SOC codes". SOC codes identify a range of occupational classifications, with an increasing level of granularity as the number of "digits" in the SOC code increases. For instance:

- The 1-digit SOC codes group workers by the level of responsibility and skill, ranging from SOC Code 1 "Managers and Senior Officials" to SOC Code 9 "Elementary Occupations", with no differentiation by industrial sector;
- Adding digits to the SOC code makes the classification (and hence the associated estimates of average wages) progressively more specific to a particular type of worker. For example:
  - The "2-digit" SOC Code 52 corresponds with "Skilled metal, electrical and electronic trades", and is a subset of the "1-digit" SOC Code 5, "Skilled trades occupations";
  - The "3-digit" SOC Code 524 (a subset of the "2-digit" SOC Code 52) corresponds with "Electrical and electronic trades"; and
  - The "4-digit" SOC Code 5241 (a sub-set of the "3-digit" SOC Code 524) corresponds with "Electricians and electrical fitters".

There has been substantial debate around the granularity of data used in calculating regional labour cost differences, as the more granular codes more directly measure labour costs associated with particular roles or occupations in individual industries, but are more susceptible to data issues as the sample sizes are smaller.

In RIIO-ED1, Ofgem based its regional labour cost adjustment (RLCA) on 2-digit SOC codes, without providing any justification for this approach. Not all DNOs agreed with this approach, however, and Northern Powergrid (NPg) appealed the decision on this ground as well as two others.

NPg argued that "[t]hese broad categories will not isolate differences in labour costs faced by DNOs between regions, because of compositional bias or mix issues".[43] NPg argued instead for the use of 4-digit codes. Ofgem then justified its approach by clarifying that it used 2-digit SOC codes "in order to strike a balance between using data which contained relevant occupations on the one hand and avoiding small sample sizes on the other. [Ofgem] did not use 4-digit SOC codes because that would have given rise to problems deriving from data with small sample sizes and industry bias (i.e. samples which contain a disproportionately high ratio of DNOs' own employees)".[44]

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43 NPg (2015): *Notice of Appeal Energy Licence Modification – Sensitive Information Redacted*, para. 8.18

44 Ofgem (2015): *Response to Notice of Appeal – Energy License Modification,* 22 April 2015, para. 207(c)

Ultimately, the CMA dismissed NPG’s appeal on this ground. In doing so, it noted that “analysis of the four-digit ASHE data demonstrates that it is also at risk of error and is unstable, which suggests it may not be reliable for estimating RLCAs over RIIO-ED1”.[45] Although the CMA did not endorse 2-digit SOC codes as the “correct” method, it did find that “NPg did not demonstrate that [Ofgem]’s approach was wrong by reference to any of the grounds of appeal advanced by NPg”.[46]

Ofwat also used 2-digit SOC codes in PR14. In particular, it used just two SOC codes: SOC code 21 (Science, research, engineering and technology professionals) and SOC code 53 (Skilled construction and building trades), with a 40% weight on the former and a 60% weight on the former, drawing on precedent from Ofgem’s DPCR5.[47] In selecting the use of 2-digit codes, Ofwat chose not to use 1-digit codes because they include “occupations that are not applicable to the water and sewerage industry”, and did not use 3- and 4-digit codes as they “are less robust because they rely on smaller sample sizes and may also create industry bias”.[48]

The most granular approach in the decisions we have reviewed was adopted by the CMA in the 2014 NIE decision. The CMA used two different wage adjustments: one based on 3-digit codes and one based on 4-digit codes. The 3-digit adjustment “strikes a balance between including occupational categories that are relevant to the activities of NIE and GB DNOs and avoiding the risks of data error from a small sample size”. On the other hand, the 4-digit adjustment “is more closely aligned than [the 3-digit adjustment] with the occupations relevant to NIE’s activities, even if it does suffer from a smaller sample size”.[49] At the time, NIE argued for the full reliance on 4-digit codes, stating that the 3-digit approach is “based on an analysis of types of labour that are completely irrelevant to NIE and the GB DNOs”.[50] We list the weights below in Table A.1, which were based on the labour breakdown in NIE’s submission to the CC:[51]

45 CMA (2015): *Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc v the Gas and Electricity Markets Authority—Final determination*, 19 September 2015, para. 6.73

46 CMA (2015): *Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc v the Gas and Electricity Markets Authority—Final determination*, 19 September 2015, para. 6.77

47 CEPA (2014): *Cost Assessment – Advanced Econometric Models*, 20 March 2014, page 57

48 CEPA (2014): *Cost Assessment – Advanced Econometric Models*, 20 March 2014, page 57

49 CC (2014): *Northern Ireland Electricity Ltd Price Determination, Final Determination*, 26 March 2014, para 8.203.

50 CC (2014): *Northern Ireland Electricity Ltd Price Determination, Final Determination*, 26 March 2014, para 8.214.

51 CC (2014): *Northern Ireland Electricity Ltd Price Determination, Final Determination*, 26 March 2014, Appendix 8.4, pages A8(4)-2 – A8(4)-3.

Table A.1
NIE Wage Adjustment Weights

SOC code	3-digit approach	4-digit approach
1	6%	6%
212	18%	0%
2123	0%	18%
311	16%	0%
3112	0%	16%
41	5%	5%
524	29%	0%
5241	0%	4%
5243	0%	25%
712	3%	0%
7122	0%	3%
821	1%	0%
8211	0%	1%
913	21%	0%
9139	0%	21%
914	1%	0%
9149	0%	1%
Total	**100%**	**100%**

Source: CMA NIE decision, Appendix 8.4, Table 2.

Conversely, the least granular approach was taken by the UR at PC15. The UR did not use wage data by SOC codes, but instead used the economy-wide median wage across the entire region. The UR then compared the Northern Irish average wage to the regions where the "econometric frontier" companies are located, namely the South West and Yorkshire and the Humber.[52]

UR's approach of using is economy-wide data is a less relevant measure of the wages that NI Water pays its employees than a more precise measure using SOC-codes and may be susceptible to compositional bias, as discussed in the body of this report.

A.2. Definition of Separate Labour Markets

The ASHE dataset divides Great Britain into 11 regions (not including Northern Ireland). The Northern Ireland provides its own equivalent ASHE dataset. There has not been consensus amongst regulators regarding how many regions to treat as separate labour markets. The two approaches have been to measure each region separately or to assume that regional wage differences do not exist outside of London and the South East.

52 UR (2014): *Water & Sewerage Services Price Control 2015-21 Final Determination - Annex P*, December 2014, Chapter 5

In Northern Irish regulation, regulators have not grouped Northern Ireland together with the rest of the UK (outside of London/South East). [12]

Ofwat did not specify whether they aggregated data outside of London and the South East, but we take this omission to mean that they did not. Conversely, Ofgem aggregated regions outside of London and the South East in both RIIO-ED1 and RIIO-GD1. In its RIIO-ED1 decision, Ofgem decided that there was not "sufficient and compelling new evidence to support applying regional wage differentials for each region of GB given the mobility in the labour market".[53] Ofgem also used a 3-region approach in RIIO-GD1.[54]

A.3. Econometric Approach

After identifying a method for measuring regional labour cost differences, the next step is to incorporate the calculated differences into benchmarking and cost assessment methodologies. In the regulatory decisions we have reviewed, this has taken two forms: regulators have either made an off-model adjustment to companies' costs or they have included regional wages as an explanatory variable in their econometric models.

The first of these approaches is the most common. Under this approach, regulators scale up or down companies' submitted costs before conducting cost benchmarking in order to improve the comparability across companies. For example, if a company's regional wage were 95% of the country average, that company's submitted costs would be scaled up by 1.0/0.95 (1.053) before model estimation. After regulators estimate companies' efficient costs (such as through an econometric benchmarking model), they then scale the company's allowed costs down by 95% to reflect the fact that labour costs are lower than in the rest of the country. It is this reverse RLA that reduces allowances for companies in regions with below-average labour costs. This was the approach adopted by Ofgem in RIIO-ED1[55] and RIIO-GD1,[56] by the UR in PC15[57] and by the CMA in the 2014 NIE decision.[58]

Ofwat used a different approach at PR14, including a regional wage variable in its econometric models.[59] As described in Section A.1.1, Ofwat calculated a different regional wage level for each year of the historic estimation period. Thus, each company's total expenditure (totex) in each year was a function of that company's wage variable in that year, among many other explanatory variables.

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53 Ofgem (2014): *RIIO-ED1 Final determinations for the slow-track electricity distribution companies - Business plan expenditure assessment*, 28 November 2014, para. 4.1

54 Ofgem (2012): *RIIO-GD1: Final Proposals – Supporting document – Cost efficiency*, 17 December 2012, para. 2.1

55 Ofgem (2014): *RIIO-ED1 Final determinations for the slow-track electricity distribution companies - Business plan expenditure assessment*, 28 November 2014, para. 4.1

56 Ofgem (2012): *RIIO-GD1: Final Proposals – Supporting document – Cost efficiency*, 17 December 2012, para. 2.1

57 UR (2014): *Water & Sewerage Services Price Control 2015-21 Final Determination - Annex P*, December 2014, para. 5.1.2.

58 CC (2014): *Northern Ireland Electricity Ltd Price Determination, Final Determination*, 26 March 2014, para 8.67.

59 CEPA (2014): *Cost Assessment – Advanced Econometric Models*, 20 March 2014, page 56

Bristol Water appealed the PR14 decision to the CMA. The CMA applied its own totex benchmarking model using a different set of explanatory variables. It accepted Ofwat's use of a regional wage variable in its models, albeit with some adjustments:[60]

> "Our econometric models used a regional wage variable calculated by Ofwat, which was intended to take account of regional differences between water companies in the wage levels that they face. We agreed with the logic of seeking to include a measure of relative wages in the models, but there were a number of concerns, particularly in relation to the treatment of Bristol Water. We considered whether a special cost factor adjustment would be appropriate to address the concerns we identified with the econometric model estimation results for Bristol Water."

A.4. Portion of Costs Affected

Regulators have typically not applied RLAs to the entirety of companies' costs, as there is a national market for some of companies' inputs – particularly materials. Rather, regulators have sought to apply adjustments to the proportion of costs that are driven by labour costs, and in some cases only to the subset of labour costs that need to be located in the company's service region.

At RIIO-ED1, Ofgem calculated a DNO-average labour cost component to each cost area as well as to totex.[61] It also "considered the proportion of work that is done in these areas and elsewhere" and did "not make regional labour adjustments for business support costs in line with our view that these can be procured on a national basis".[62] It then adjusted those proportions of costs before modelling. At RIIO-GD1, Ofgem used "the labour component of opex, capex and repex costs to calculate the percentage of work required to be done locally" and assumed that "40 per cent of work management will be carried out locally".[63] At PC15, the UR applied the adjustment to all labour costs excluding capitalised salaries, atypical VER/VS costs and sundry items, which works out to about 77% of NI Water's labour costs.[64] In the NIE decision, the CMA applied its labour adjustment to the DNO-average labour share of total indirect, inspections & maintenance, faults and tree cutting (Indirect and IMF&T) costs.[65]

On the other hand, Ofwat's methodology at PR14 involved including a regional labour variable in its totex models (see above). In essence, Ofwat let a statistical model decide the scale of adjustment that should be made across the companies for variation in regional labour costs.

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60 CMA (2015): *Bristol Water plc – Report*, 6 October 2015, para. 4.255(e)

61 Ofgem (2014): *RIIO-ED1 Final determinations for the slow-track electricity distribution companies - Business plan expenditure assessment*, 28 November 2014, Table 3.1

62 Ofgem (2014): *RIIO-ED1 Final Determinations – Expenditure Assessment*, 28 November 2014, paras. 4.12 & 4.16.

63 Ofgem (2012): *RIIO-GD1: Initial Proposals – Supporting document – Cost efficiency*, 27 July 2012, Appendix 5, para. 1.5.

64 UR (2014): *Water & Sewerage Services Price Control 2015-21 Final Determination - Annex P*, December 2014, Table 5.4.

65 CC (2014): *Northern Ireland Electricity Ltd Price Determination, Final Determination*, 26 March 2014, para 8.67.

A.5. Conclusions

To the extent that detailed information is available, we have reviewed regulators' recent approaches to RLAs. We have identified the following patterns:

- All regulators have relied on variations of the ONS ASHE data set (or its NI equivalent).
- Regulators have typically used five years of data. Regulators who have only used one year have not justified that approach, which would likely not stand up to scrutiny in light of the data volatility.
- Most regulatory decisions have used hourly wages, save for the CMA's decision on NIE and the UR's decision on PC15. We consider that hourly wage data is probably more appropriate than weekly data as it controls for regional differences in average hours worked per week:
- We consider that it also appropriate to include overtime in measures of wages. This is because overtime is an important component of the market wage for some occupations and/or companies. A particular position may be more attractive to an employee if the prospects of receiving overtime pay are greater. Therefore, overtime pay is an external component of the market labour price and should be accounted for in determining regional labour cost differences.
- Ofwat's approach treats the UK as many different regional labour markets, whereas Ofgem only adjusts for differences in wages between London and the South East and the rest of the country. However, all of the decisions we have reviewed that relate to Northern Ireland have treated Northern Ireland as a separate labour market from the rest of the UK. Moreover, from an economic perspective, it is probably most defensible to disaggregate wages into all the regions for which data is available.
- With the exception of Ofwat at PR14, all regulators treated the regional labour cost differential as an off-model adjustment. Ofwat's approach is arguably more theoretically robust, as it allows the model to choose the scale of adjustment required, which obviates the need to form an assumption on the share of cost to which the adjustment should be applied. However, the challenge in this case, which is less acute in the England & Wales water industry, is the lack of data on comparators and the shorter time series of historic cost and volume data. This constrains the number of explanatory variables that can be used for benchmarking electricity distributors. Also, this method of adjusting for regional labour costs is only possible in regression-based modelling approaches. It cannot readily be applied in simple unit cost benchmarking analyses.
- All regulators (except for Ofwat, for the reasons described above) have sought to identify and apply the costs to just the proportion of costs attributable to labour. Some regulators have set this labour share of total costs based on an average labour share across companies (the CMA and Ofgem) or the company's own labour cost share, as the UR did at PC15.
- Regulators have used a range of different SOC-codes, from the UR's use of economy-wide wages to the CC's use of 3- and 4-digit codes. We discuss this choice in the main body of this report.

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GD17 REINFORCEMENT PROJECT

Objective

1. To determine the impact of removing the Interruptible Customer load from the PNGL strategic reinforcement model (see "*Strategic Reinforcement Modelling*" below);

2. Analyse pressure graph during Peak Hour to determine if/when West Circular Road output performance is affected (see "*Pressure Monitoring*" below).

Analysis based on PNGL's coldest gas day 21 December 2010, Peak Hour 18.00hrs. Total Gas flow in system 112,539 scmh

Background

The PNGL Greater Belfast Area is fed via an intermediate pressure ("**IP**") network of c.95km of 7bar main. This IP network has three supply points:

1. Torytown Above Ground Installation ("**AGI**") – gas flows from Torytown towards Belfast;

2. Knocknagoney AGI – gas flows in two directions: towards Belfast and towards Bangor; and

3. Lisburn AGI – gas flows from the outskirts of Lisburn towards Belfast

Figure 1 shows the outline of the IP network and the direction of gas flow:

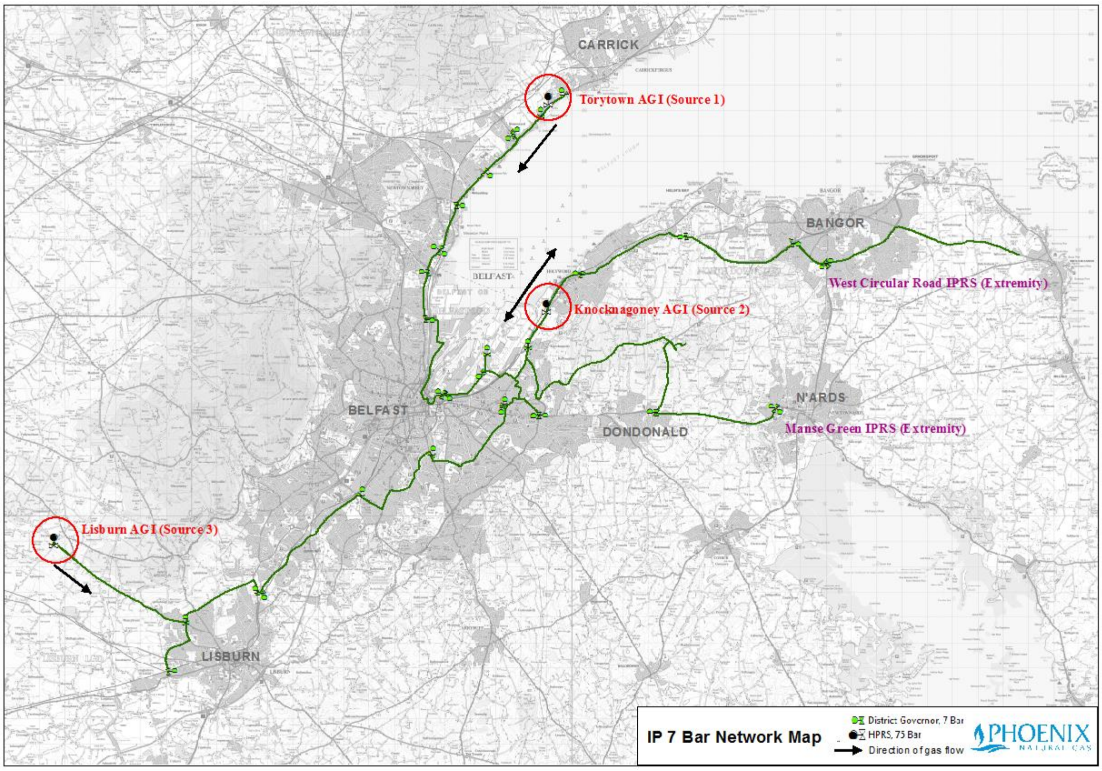

Figure 1 - PNGL Intermediate Pressure (7 Bar) Network

The majority of the IP network is back fed except for two legs:

1. Knocknagoney AGI towards Bangor to West Circular Road Intermediate Pressure Reduction Station ("**IPRS**"); and

2. Holywood Road/Parkway junction towards Newtownards to Manse Green IPRS.

These two locations are single fed legs and are classified as IP extremity points. As extremity points, it is critical that the two IPRS stations i.e. West Circular Road and Manse Green, are monitored daily to give visibility of the performance of the IP network.

West Circular Road IPRS

The West Circular Road IPRS predominantly feeds the towns of Bangor, Donaghadee and Millisle:

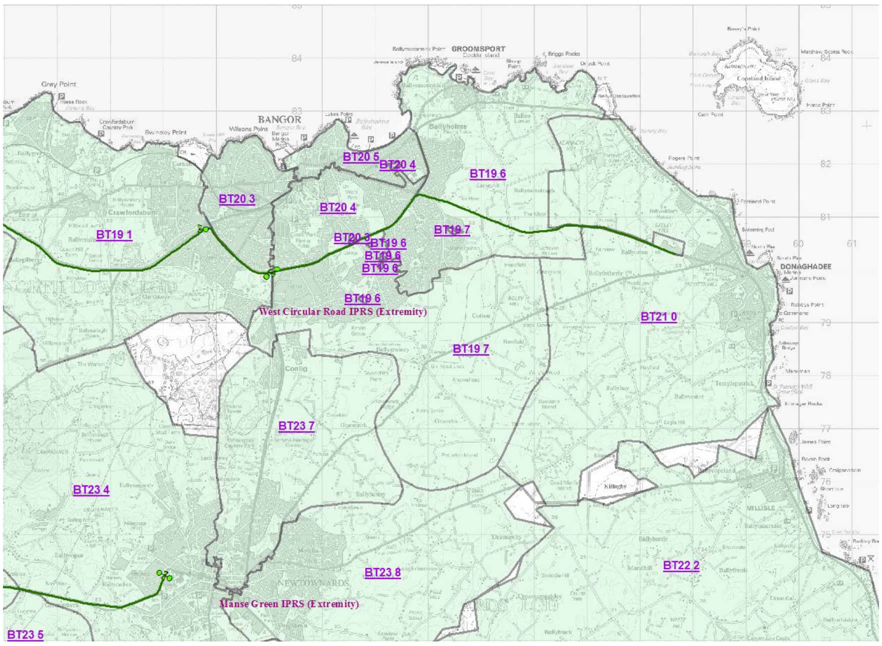

Figure 2 - Postcodes around West Circular Road

PNGL has undertaken two methods i.e. Strategic Reinforcement Modelling and Pressure Monitoring, to determine the requirement for an IP reinforcement at West Circular Road.

Strategic Reinforcement Modelling

A list of all interruptible customers within the PNGL network was compiled. The gas usage for each Interruptible Customer during the Peak Hour was obtained. The location of each Interruptible Customer was also established to determine if its usage has an impact on the West Circular Road IPRS.

Interruptible Customers - Overall Network	
Number of Interruptible Customers	38
Total Interruptible Customer gas usage in Peak Hour (scmh)	7,160
% of overall Interruptible Customer gas usage in Peak Hour	6%

Interruptible Customers affecting West Circular Road	
Gas flow through West Circular Road in Peak Hour	6,573
Total Interruptible Customer gas usage within West Circular Road postcodes in Peak Hour (scmh)	91
% of overall Interruptible Customer gas usage within West Circular Road postcodes in Peak Hour	1%

This analysis shows that by switching off the Interruptible Customers a load reduction of 91scmh or 1% would be obtained on the Knocknagoney AGI to West Circular IPRS line. This reduction would have little to no effect on the IP network pressure. The inlet pressure to West Circular Road IPRS would remain the same.

Pressure Monitoring

In conjunction with the PNGL strategic reinforcement model, pressure monitoring procedures are also present within PNGL. Critical key sites have been identified and are monitored daily and pressures logged. To investigate the performance of West Circular Road IPRS, data analysis was completed over a six year period, from January 2010 to March 2016. Figure 3 shows the mean daily pressures during the peak hour of 18.00 -19.00:

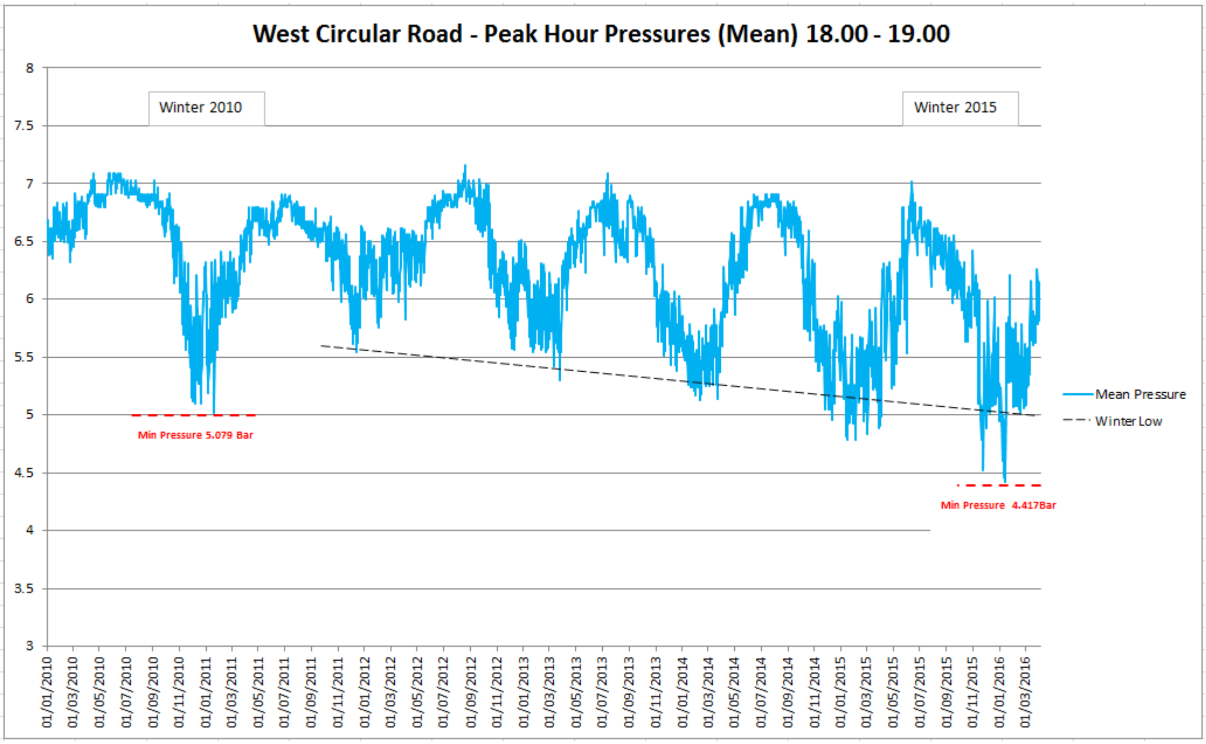

Figure 3 - West Circular Road Daily Mean Pressure during peak hour – 18.00hrs to 19.00hrs

From Figure 3, the summer and winter profiles are clearly identifiable. What is also evident is the winter trend line – the 2015 and 2016 winters, although mild, have seen the pressure drop below 5 bar. Similar pressures were recorded during the 2010 winter and are attributed to the increased load on the PNGL network.

Pressures below 5 bar start to have an operational impact on an IPRS. The pressure reduction station cannot maintain the same gas throughput as the pressure drops below 5 bar. Therefore this could potentially cause a shortfall of gas to the Bangor / Donaghadee / Millisle areas, increasing the risk of loss of supply.

Conclusion

Both of these methods i.e. Strategic Reinforcement Modelling and Pressure Monitoring, support the requirement for an IP reinforcement at West Circular Road between 2017 and 2020.