

Response to the GD17 Draft Determination

May 2016

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Executive Summary

Firmus energy welcomes the opportunity to respond to the consultation on the Utility Regulator's GD17 Price Control Draft Determination and looks forward to continuing our productive dialogue in the run-up to the Final Determination in September 2016.

For GD17, we believe our Business Plan submission met the challenge of the Utility Regulator's primary objective: *"to promote the development and maintenance of an efficient, economic and coordinated gas industry in Northern Ireland"*. In responding to this challenge, our Business Plan set out an ambitious but deliverable business and network development proposal that aimed to meet the Utility Regulator's objectives while realising efficiencies in order to deliver significant real-terms reductions in costs for our customers.

We fully expected the Utility Regulator to conduct a detailed and critical examination of our proposals and looked forward to the process confident that our Business Plan delivered on all of the objectives that had been set for us. However, the Draft Determination proposals result in an unrealistic and unachievable commercial package containing the lowest ever cost of capital applied to a gas distribution network in the United Kingdom, against a background of significant cuts to our allowances and increases to our output targets.

We will always seek to meet the challenges that we are set, but we consider that the Draft Determination does not adequately balance the interests of all stakeholders. In particular, we are concerned that the unprecedentedly low cost of capital the Draft Determination proposes to allow; the lack of incentives built into our regulation and the effective elimination of all opportunity for outperformance, combine to produce an outcome in which we will be unable to attract the equity and debt financing we will need in order to continue to finance the development of the gas distribution network in Northern Ireland.

GD14 Review – A Tough Challenge

The Draft Determination follows a difficult experience in attempting to work within a tough GD14 price control in which over £7 million of unrecoverable expenditure has been incurred over the three year period from 2014-16. In our Business Plan we described the significant challenges we faced in the GD14 period, and asked that the Utility Regulator take account of them when proposing allowances for GD17. These challenges include:

Connection targets and incentives – due to a combination of factors, including the erosion of the cost advantage of gas over oil and the significant reduction in our Capex meterage allowance that was implemented at the beginning of 2015 (i.e. beginning of the second year of the GD14 period), we have struggled to meet our owner-occupied domestic connection targets in GD14. We anticipate ending GD14 approximately 10% behind target on owner-occupied connections.

In order to achieve these outcomes, we have had to spend, on average, £800 per connection (including sales, marketing, advertising costs and customer incentives). The GD14 allowance was £374 per connection (after non-additionality and re-allocations). This overspend was

compounded by the reduction in our allowances that results from falling short of our connections target. The cumulative effect has led to an overspend of £2.5-3.5 million on owner occupied Advertising and Market Development (more than 100% over allowances) over the GD14 period.

Capital expenditure - the GD14 allowances for domestic services and Industrial & Commercial (I&C) services and meters were significantly below contracted rates. In connecting more I&C customers than targeted (including several larger connections) and with domestic services costing on average £100 more than allowances, we have already invested between £2.5 million and £3.5 million in GD14 for which we will earn no return.

While the Capex challenge has been largely addressed in the GD17 Draft Determination by the application of an improved benchmarking technique and appropriate meterage allowance, we continue to have significant concerns as to the Utility Regulator's approach to setting our connections target. Indeed, the Utility Regulator's proposals for GD17 provide for a material (70%) increase in our connections target compared with our current GD14 target while simultaneously reducing (by 27%) the allowances available to us to make those connections.

Finding Common Ground

However difficult, the GD14 experience did provide us with the opportunity to carry out wide-ranging, substantial and detailed work to capture all relevant data relating to our network. This work was used in the preparation of our investment proposals and in the submission of our GD17 Business Plan.

The GD14 experience also encouraged us to identify, where possible, common ground between our own view and the Utility Regulator's perspective and to offer alternative solutions where areas of difference have arisen.

We broadly share the Utility Regulator's view on firmus energy's network development plan. The Draft Determination proposes a slightly higher target for properties passed, but it is one that we can accept. We have highlighted how the Utility Regulator's economic re-profiling of our investment projects could lead to certain customers never being able to connect to gas, but we are prepared to commit to delivering this revised plan for the GD17 period. We further accept the Utility Regulator's view that the average metres per (existing) properties passed is 8.92m for those properties included in the Utility Regulator's network rollout proposal in GD17.

Following the Utility Regulator signalling its intention to move firmus energy to a revenue cap form of regulation we have actively engaged with the Utility Regulator to facilitate the process. We compiled our Business Plan based on a revenue cap despite currently operating under a price cap model and have maintained a constructive dialogue with the Utility Regulator throughout the initial consultation process. We fully expect the constructive dialogue on this issue to extend through the licence modification process in order to facilitate the Final Determination.

We note the Utility Regulator's proposal in the Draft Determination to simplify the Sharing Mechanism for both Capex and Opex for the GD17 period. We welcome this proposal look forward to further engagement with the Utility Regulator around the detail.

Proposing Realistic Alternatives

The Draft Determination has significant implications for the Government and the Utility Regulator's joint ambition to develop the natural gas industry in Northern Ireland. We share this ambition. However, in many cases, the position adopted by the Utility Regulator will create significant challenges to the delivery of our development. While we may disagree with the approach adopted in many cases, we have sought where possible to propose credible means by which we can preserve our shared development goals while accommodating some of the Utility Regulator's concerns. These include:

- **Manpower** – despite the significant growth in network and customers that is planned over the GD17 period, the Draft Determination seeks to reduce firmus energy's overall staffing below its current operating level and maintain that headcount for the full six year period. There is no doubt we will need more staff in order to deliver this growth. However, we are willing to propose a glide-path towards a modest and gradual increase in manpower over the GD17 period. However, it should be noted that in determining its manpower figures, the Utility Regulator needs to ensure that it is starting from the correct base, which is discussed further in section 3 of this document.
- **Basket of works** – the rates used to derive the synthetic Capex rates in the Draft Determination do not take account of the 3.36% uplift in our period contract prices since March 2014. Provided that the Utility Regulator adjusts our synthetic Capex rates to reflect our current contracted costs, we believe that we can work within the overall approach to setting the Capex "basket of works". However, given our small scale, we will be unable to deliver the additional efficiency savings over and above this that the Draft Determination seeks.
- **Profile adjustment** – we welcome the Utility Regulator's proposal to consider whether the "profile adjustment" should be eliminated from our price control system, although would need to work together to establish the precise means by which this might be achieved, and the impact it might have on other areas of the GD17 price control. The profile adjustment adds significantly to the complexity of our regulation. In addition, the cash flow deferral implemented by the profile adjustment acts to compound the financeability threat we describe above. On the other hand, the profile adjustment's original purpose of smoothing customer charges in the early years of our network development has now been largely served, and it is no longer a significant factor in supporting growth.

The Remaining Challenges

We do not wish to be inflexible in any aspect of our response to the Utility Regulator's proposals, but we cannot shy away from certain critical aspects of the Draft Determination that will require the Utility Regulator to reassess if our shared goals for GD17 are to be achieved. The overriding central issue is financeability, but other fundamental challenges include:

- **Financeability** – this is the most immediate threat to delivery of our GD17 programme. The Draft Determination sets parameters under which our business will operate with negative pre-financing cash flows throughout GD17. The combined impact of a lower allowed return than

for any other gas distribution network in the UK, together with an overall price control in which opportunities for outperformance have been all but eliminated, calls into question our ability to raise further funding to support our growth. The Utility Regulator has undertaken a flawed and overly simplistic financeability analysis that has failed to recognise the significant cash flow shortfall created by the Draft Determination and the implications that this has for our ability to raise further financing. This issue is comprehensively addressed in our response and a number of reasoned solutions are proposed, although the preferred remedy is an upward revision of the proposed allowed rate of return. Ultimately, for the Final Determination we will need the Utility Regulator to conduct a full and detailed analysis of financeability that has regard for all of the factors relevant to whether we are able to secure and support the financing that we need to continue our network development.

- **Connections** - our GD17 Business Plan was based on a substantial increase in customer connections, focusing on the owner occupied sector. This was despite our having incurred significant unrecoverable expenditure in an attempt to meet our GD14 targets. Despite these challenges, the Utility Regulator has raised this target by a further 22% (to a total of 70% over our GD14 target) alongside a phased 27% cut to the allowances from which we fund our connections-related activity and an unsupported assumption that 25% of customer connections are non-additional (i.e. do not require any form of marketing to make the decision to connect).

While we understand that the Utility Regulator may wish to reduce the funding it makes available for connections, it is critical that it takes into account the knock-on impact that it will have in reducing the number of connections we are able to achieve. Alternatively, if the Utility Regulator wishes to prioritise the development of the natural gas industry then it must recognise that our ability to make connections is dependent on continuation of the current levels of support.

- **Capex Efficiencies** – the Draft Determination proposes a 1% year on year efficiency gain on Capex spend in GD17. This is on top of our Business Plan which contained a similar efficiency by assuming no increase in rates upon re-tendering of our period contract in March 2019. By assuming no increase in rates we are already exposed to the risk that our period contractor will seek to increase rates on contract renewal.

Very limited additional efficiency is practically achievable beyond this as the period contract, which was efficiently procured following a competitive tendering process, runs until March 2019 and contains the best available rates obtainable by the company. We continue to engage with our period contractors (McNicholas Construction Services Ltd, “McNicholas”) to ensure mutual understanding of cost pressures.

- **Opex & Maintenance** – the Draft Determination proposes a 26.5% Opex reduction compared with our request, representing a 13% real terms reduction to our current determined level of operating costs between 2016 and 2017. This is despite us emerging from a very demanding

GD14 settlement and entering into a period in which we are being asked to double our customer numbers and invest heavily to develop our network.

The Draft Determination materially reduces costs for maintenance activities (by 25% for variable costs) despite the fact that as the network matures beyond 10 years of age, certain planned maintenance activities become an unavoidable requirement.

- **Treatment of Accumulated Under-Recoveries** – We accept the Utility Regulator’s proposal that any future under-recoveries accumulated from 2017 under a revenue cap will earn a reduced rate of return of LIBOR plus 2%. However, we are strongly opposed to the retrospective application of such a rate to under-recoveries previously accumulated in reliance on the terms of our current licence, which permits us earn a rate of return consistent with our WACC.

Working Together to Achieve a Common Goal

The Utility Regulator and firmus energy have a shared goal to develop the natural gas industry in an efficient manner throughout the Ten Towns network area. The GD17 Review will determine how much progress we make towards this goal over the next six years and will have knock on impacts on future regulatory determinations, so it is vitally important to both organisations to strive to strike the right balance.

We wish to continue our engagement with the Utility Regulator on all aspects of the Draft Determination so that we can arrive at a common understanding that best serves the interests of natural gas customers, current and prospective, in the firmus energy Licensed Area.

1. Introduction

We have set out our response to the GD17 Draft Determination in detail below, focusing primarily on the significant challenges (and in some cases threats) it creates for the growth of the gas industry and delivering economic and environmental benefits for customers. We also deal with any divergent views from a regulatory perspective regarding our Business Plan submission and provide further evidence where we believe the Utility Regulator's proposals lack foundation.

The Utility Regulator's GD17 Draft Determination raises a number of fundamental issues for the future of natural gas in the firmus energy Licensed Area. The Draft Determination has implications for the optimal economic development of the natural gas network itself and for driving connections.

In addition, the Utility Regulator's proposals have implications for present and future customers including their ability to access the network to convert to gas and the extent to which this will be affordable, particularly for the fuel poor.

The Draft Determination is also important to other stakeholders including the Government and the Utility Regulator itself and their joint ambition to develop the natural gas industry in Northern Ireland and where economic to maximise customer connections.

1.1. Key Challenges

In setting out its Draft Determination, the Utility Regulator appeared to acknowledge the challenges we face and the central arguments outlined in our Business Plan. However, this acknowledgement does not appear to have been carried through into some of the detailed proposals put forward in the Draft Determination. Overall, we believe the Utility Regulator's proposals as a package represent an unsustainable approach to meeting our shared objective of developing the gas industry in Northern Ireland and bringing the benefits of gas to as many consumers as possible, including many in fuel poverty. The proposals also imperil our business by affording insufficient allowances to manage and safely operate our day to day business activities.

We had originally hoped that our response to the Draft Determination would need to focus only on a small number of key points. However, due to the Utility Regulator having implemented across-the-board changes to our Business Plan, we are compelled to address each area of difference in some detail. While acknowledging that there is a large gap remaining between what the Draft Determination allows and what firmus energy considers to be necessary for the business, we are ready to devote all the required resources to work with the Utility Regulator to find a solution. Given our professional relationship, we believe the Utility Regulator is prepared to adopt the same approach.

The key issues arising out of the Draft Determination - many of which are interrelated - are set out below. These are the matters upon which we wish to focus our future engagement with the Utility Regulator.

1.1.1. Connections and Volumes

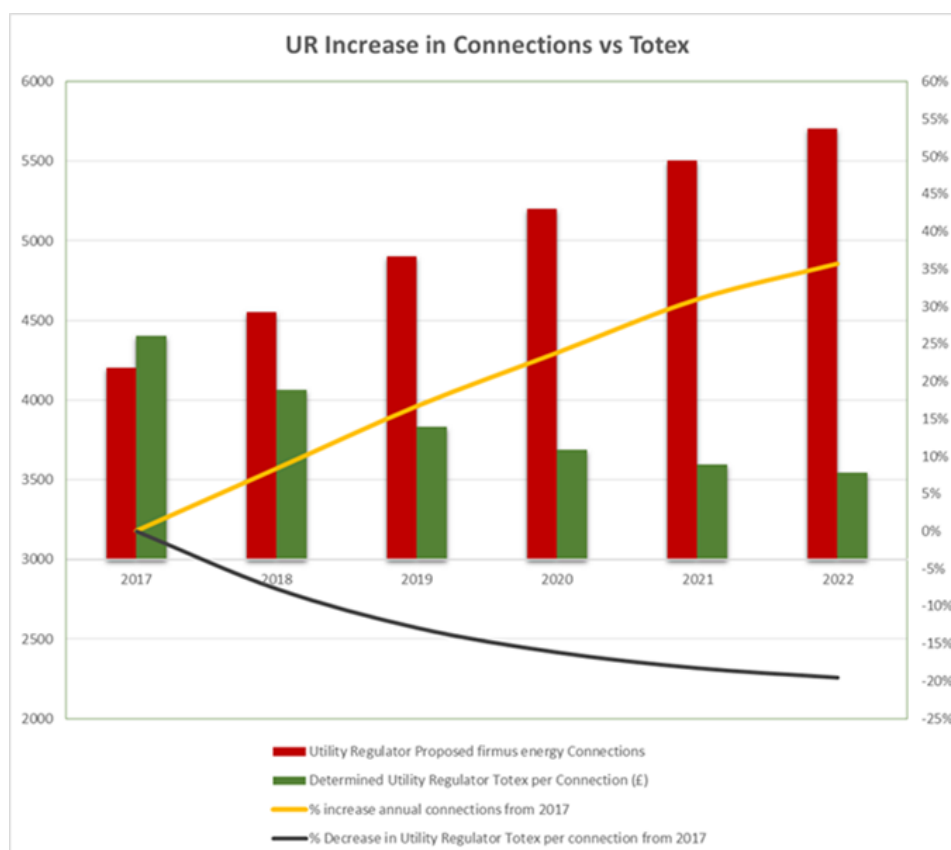
The firmus energy network development proposals submitted as part of the GD17 Business Plan were carefully put together to optimise the long term rollout of the network in the most efficient manner consistent with affording as many customers as possible the opportunity to connect to natural gas.

Our plans were built from the bottom up and driven by reliable, high quality data and measurement. The rigour with which our plans were prepared is described fully in our Business Plan submission.

The Utility Regulator has recognised the quality of this work. However, the Utility Regulator has significantly diluted our long term plans by front-loading only the most economically advantageous projects into the GD17 period. This will restrict the long term development of the network and leave many customers who would otherwise have had access to gas under firmus energy's plans in a position where they may never be connected. We calculate that as many as 11,500 prospective customers would be adversely impacted if such a scenario was to prevail. However, notwithstanding this aspect of the Utility Regulator's re-profiling of network rollout, firmus energy can and will deliver on the revised plan.

The Utility Regulator's Draft Determination also sets higher targets for owner-occupier connections (70% greater than our GD14 target and a 22% increase on our ambitious Business Plan targets), which are plainly inconsistent with the resources it proposes to allow (a 27% cut to the Connection Incentive allowance). Figure 1.1 shows the extent of this mismatch.

Figure 1.1



This increased connections target is accompanied by a Connection Incentive mechanism which is asymmetric in application in that it punishes underperformance much more heavily than it rewards outperformance.

It is a positive step that the Draft Determination has moved away from the Utility Regulator's original proposal to cut the Connection Incentive for owner occupiers by 50% from the beginning of GD17 although the current proposal of phasing a 27% reduction over the six years is still unhelpful.

It is now an essential requirement to encourage prospective customers to invest in converting to natural gas. Our Business Plan provided considerable evidence as to the sensitivity of prospective customers to the costs of conversion. It is firmus energy's considered view that any reduction in the Connection Incentive will make increased connections targets impossible to achieve, thereby presenting a further, and material downside risk to our business.

Ultimately, the Utility Regulator needs to consider its priorities for the GD17 price control and how those should flow through into the targets and allowances it sets for connections. If the Utility Regulator's priority continues to be to support the development of the gas industry then it must recognise that our ability to make connections is dependent on continuation of the current levels of support. Alternatively, if the desire is to reduce overall cost today by reducing the funding available to support new connections then the Utility Regulator must take into account the impact that will have in reducing the number of connections we are able to achieve.

Network development and connections are discussed further in Chapter 2.

1.1.2. Operating Costs (Opex)

The Draft Determination proposes to reduce firmus energy's planned Opex by £12.7million. This is a proposed cut of 27% compared with our Business Plan and a reduction of 13% in real terms compared with our current cost levels (2016 compared to 2017). If carried through to the Final Determination, these reductions create real risks to our ability to deliver the growth (i.e. a doubling of our customer base) and investment contemplated for GD17 while continuing to manage and maintain the gas network efficiently and safely.

Our fundamental belief is that the Utility Regulator in the Draft Determination should be allowing efficiently incurred costs. We see no evidence from benchmarking or from the comments of the Utility Regulator's GD17 consultants that would suggest firmus energy is either inefficient or planning to undertake activities deemed unnecessary. Therefore, any proposed reduction in Opex should be fully substantiated. In many instances the Draft Determination fails to meet this hurdle, instead relying on an approach of rolling forward our GD14 allowances without consideration of current cost levels or the material growth we are being asked to achieve.

The Utility Regulator's Draft Determination Annex 4 - GD17 Efficiency Advice, page 4, produced on their behalf by Deloitte notes:

"The main driver of cost variation over time and across GDNs is scale. The models estimate that a 1% increase in the scale of a GDN is expected to increase costs by 0.69%-0.81%."

Applying the same logic to the increase in outputs demanded by the Draft Determination (e.g. a doubling in our customer numbers and an c. 60% increase in network length) would imply a 60-70% real terms increase to the current level of our operating costs should be allowed over GD17. This is in stark contrast to the 13% decrease proposed by the Utility Regulator.

The Draft Determination proposes to disallow the small number of additional staff (7.25 FTE above current staffing level or 11.8 FTE above GD14 determined level) identified in our Business Plan who are required to meet the needs of a rapidly expanding network with a growing maintenance workload. These additional staff are also required to meet the growing workload that comes from a doubling of connections and increased maintenance requirements as network assets reach replacement age.

The Draft Determination dismisses substantial elements of firmus energy's planned Opex with little explanation or transparency. This is particularly true in relation to proposed insurance costs, professional and legal fees, at a cost to firmus energy of £1.7million over the GD17 period.

Opex is discussed further in Chapter 3.

1.1.3. Capital Investment (Capex)

The Draft Determination proposes to cut firmus energy's planned Capex by over £9.5 million over the GD17 period compared with our Business Plan. This is before account is taken of proposed reallocations into Capex from Opex totalling over £1 million.

The rates used to derive the synthetic Capex rates in the Draft Determination do not take account of the 3.36% uplift in our period contract prices since March 2014. Provided that the Utility Regulator adjusts our synthetic Capex rates to take account of our current contracted costs, we believe that we can work within the overall approach to setting the Capex "basket of works".

However, we will be unable to deliver the additional efficiency savings over and above this that the Draft Determination seeks. This is on top of our Business Plan which contained a similar efficiency by assuming no increase in rates upon re-tendering of our period contract in March 2019. By assuming no increase in rates we are already exposed to the risk that our period contractor will seek to increase rates on contract renewal. Very limited additional efficiency is practically achievable beyond this as the period contract, which was efficiently procured following a competitive tendering process, runs until March 2019 and contains the most efficiently achievable rates obtainable by the company.

It is important also that we secure adequate allowance to upgrade our IT system to deliver asset management efficiency and other productivity gains. We would stress that this requirement has no connection whatsoever with change of ownership considerations and the decoupling of our IT systems from BGE during GD14 (the full cost of which was borne by our shareholders). No matter what firmus energy's ownership structure was or is, the IT investment is required because the systems we have are outdated, no longer fit for purpose and need to be replaced.

Capex is discussed further in Chapter 4 of this document.

1.1.4. Financeability and Weighted Average Cost of Capital (WACC)

Firmus energy's business model and limited (negative) cash flow require network investment to be financed by a constant flow of new equity and debt financing. Based on the Draft Determination proposals as they currently stand, firmus energy will not be in a position to raise the required borrowing to deliver the investment. We strongly believe that we could not achieve an investment grade rating even assuming that we implement the Utility Regulator's implied capital structure. Unfortunately, this problem arises because the Utility Regulator's analysis of our financeability is flawed and overly simplistic. It does not take into account the need to finance our negative cash flows and undertakes limited stress-testing of our ability to withstand negative cost shocks during the six years of GD17.

The principal driver of this outcome is the Utility Regulator's proposed allowed cost of capital in the Draft Determination. The Utility Regulator proposes to grant us the lowest allowed return of any gas distribution network in the UK, based on an entirely hypothetical analysis that assumes that we have the same overall risk profile as a mature GB gas distribution network (GB GDN) without taking into account the unique factors contributing to the overall risk borne by our investors. The Utility Regulator benchmarks us against these significantly (sometimes 100 times) larger companies, but proposes to award us a significantly lower cost of equity (6.7% real post-tax for GB GDNs, against the GD17 Draft Determination proposal of 5.3% real post-tax for firmus energy).

Further, as noted in section 1.1.9 below, the GD17 price control contains none of the scope for outperformance or incentive arrangements enjoyed by our peers in GB, meaning that the prospect of firmus energy earning more than its allowed return on equity is very much diluted.

The resulting cost of equity allowance and lack of outperformance incentive fails to adequately compensate investors compared to GB GDNs, especially considering our negative cash flow profile and the deferral of reward implemented by the "profile adjustment". No rational investor would choose an investment in firmus energy (at a 5.3% real post-tax return on equity with no practical scope for outperformance, compounded by increased duration of investment return by virtue of the profile adjustment) over a GB GDN (at a 6.7% real post-tax return on equity with the prospect of achieving an outcome in double digits, supported by within-period cost recovery).

We have identified a number of possible solutions to the financeability problem including re-profiling Capex to improve cash flows or making a change to the way in which the profile adjustment operates. However, the recommended course is to revisit our allowed cost of capital. Ultimately, for the Final Determination we will need the Utility Regulator to conduct a full and detailed analysis of financeability that has regard for all of the factors relevant to whether we are able to secure and support the financing that we need to continue our network development.

Financeability and our cost of capital are discussed in detail in Chapter 5 of this document.

1.1.5. Profile Adjustment

We cautiously welcome the Utility Regulator's proposal to consider whether the "profile adjustment" should be eliminated from our price control system. The profile adjustment's original purpose of smoothing customer charges in the early years of our network development has now been largely served, and it is no longer a significant factor in supporting growth. Its removal has the potential to reduce the complexity associated with our price control system, as well as increase transparency and comparability with other regulated network operators. In addition, the cash flow deferral implemented by the profile adjustment acts to compound the financeability threat we describe above.

On the other hand, detailed consideration and consultation would be required on the precise means by which the profile adjustment would be eliminated in order to ensure it would be NPV neutral. For instance, we would expect the Utility Regulator to have regard for the slight impact on our tariffs that would result from removal of the profile adjustment in its overall consideration of the factors relevant to setting our connections targets. We would also need to understand the basis on which the profile adjustment would be rolled into our TRV¹ (or RCV²).

Our views on the profile adjustment are discussed further in Chapter 5 of this document.

1.1.6. Treatment of Under-recoveries

The Utility Regulator has proposed a more rapid unwinding of under-recoveries and suggests a very significant reduction, LIBOR plus 2% (67% lower than at present) in the allowed return. The Utility Regulator has indicated that this lower return should also apply retrospectively.

The Utility Regulator's proposed treatment of under-recoveries is in our view entirely inconsistent with the reasonable expectations of investors as well as the terms of our licence. It also casts further doubt on the future financeability of the business.

We note the Utility Regulator's consultants First Economics statement in Draft Determination Annex 7, page 21:

"what matters is whether investors can be reasonably confident that they will be able to collect the full value of the investment that they have made in the business... investors are likely to be far less concerned with the historical derivation of the FE RAB compared to the likelihood of being able to collect a full return of and on that capital going forward."

Firmus energy can accept the lower rate of return for future under-recoveries post 2017 but we are strongly opposed to any change that is retrospective in application.

Under-recoveries are discussed further in Chapter 6 of this document and firmus energy would welcome further meaningful engagement on this issue.

¹ 'Total Regulatory Value'

² 'Regulatory Capital Value'

1.1.7. Benchmarking

In our Business Plan we welcomed, in principle, the Utility Regulator's proposal that our requests for Opex and Capex allowances should be benchmarked against others as a qualitative check on whether our requests were reasonable. However, we cautioned against adopting a mechanistic approach to benchmarking given our business is significantly younger and smaller in scale than the companies against which we were compared. The scale of difference between the Greater Belfast and Ten Towns Network areas is illustrated by Figure 1.2, while Figure 1.3 compares firmus energy with Phoenix Natural Gas (Phoenix/PNGL) and Northern Gas Networks, one of the smallest of the GB GDNs.

Figure 1.2

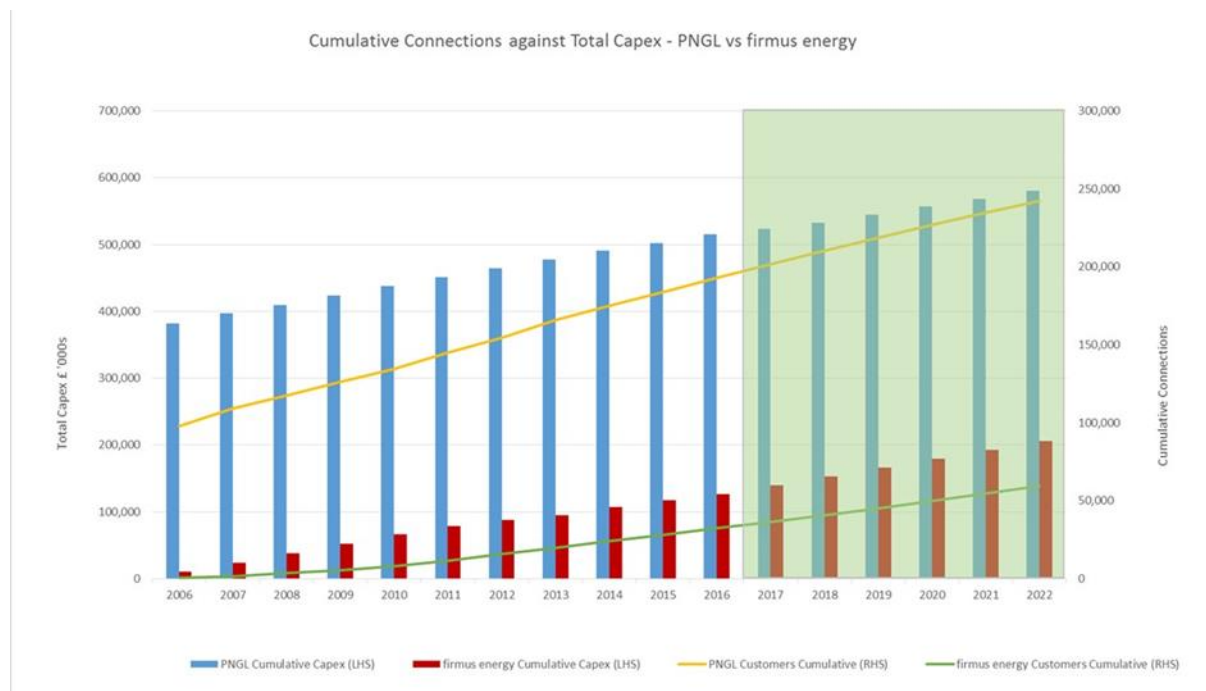
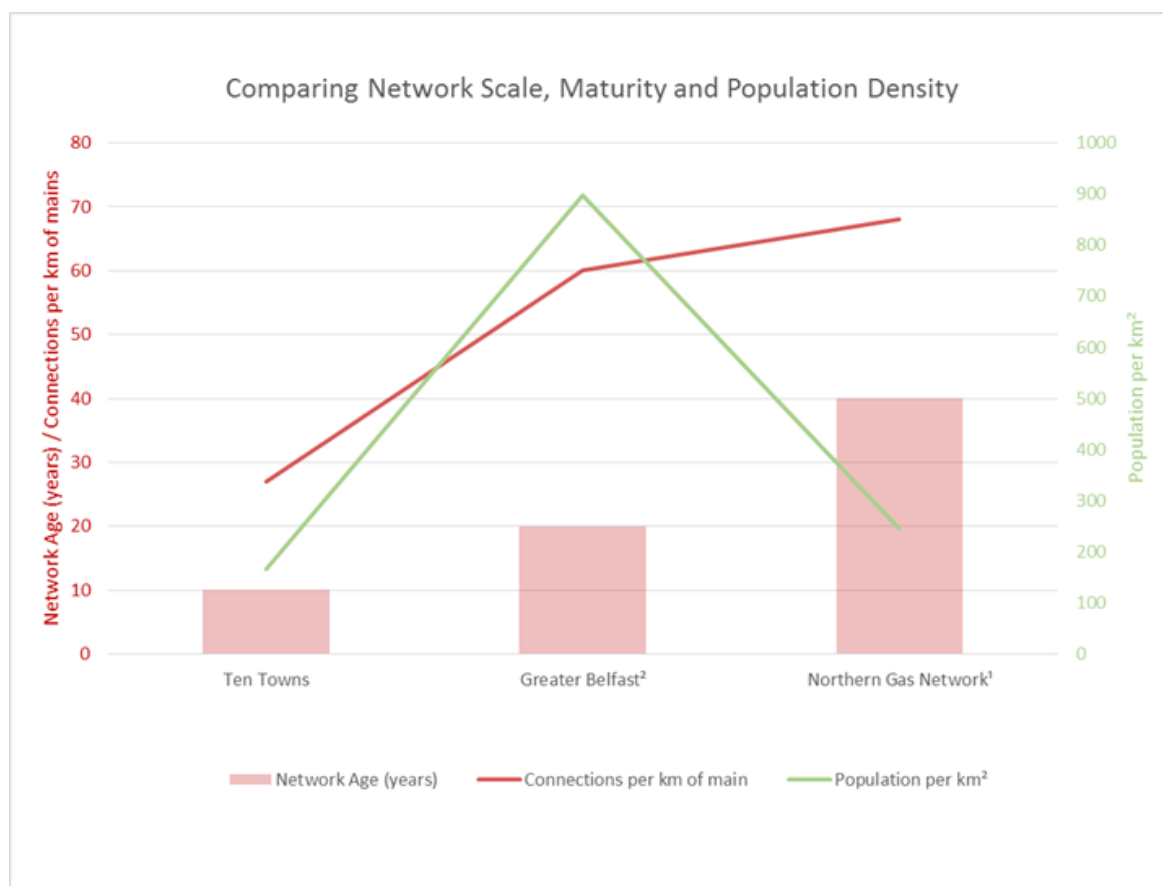


Figure 1.3

We submitted an analytical paper covering benchmarking, Real Price Effects (RPEs - costs that are likely to rise at a higher rate than inflation) and frontier shift to the Utility Regulator as part of our first GD17 submission in June 2015. It suggested that so many adjustments would be required to the GB GDN metrics in order to make them reasonably comparable with firmus energy that it possibly undermined the value of the entire exercise.

At that time (and since), the company and its advisors have made strenuous efforts to obtain relevant GB GDN performance data and primary data analysis undertaken by the Utility Regulator that would enable us to fully understand the approach taken. Unfortunately, the Utility Regulator has been unable to secure access to this data for us.

In conjunction with Oxera we have further assessed the benchmarking work undertaken by the Utility Regulator. As we have not had access to the primary data, Oxera's assessment is based upon back-calculating in an effort to replicate and derive the top-down Opex assumptions made by the Utility Regulator. The paper, titled *"Review of the Utility Regulator's top-down Opex benchmarking for GD17"* is appended to this document.

This problem was acknowledged by the Utility Regulator's consultants Deloitte in the executive summary of their report *"Relative efficiency of Northern Ireland Gas Distribution Networks"* appended to the Draft Determination. Deloitte state:

“FE has a significantly different profile to any of the other GDNs in terms of the ratios between network length, customer numbers and volume of gas supplies. This results in significant challenges in assessing the extent to which firmus energy costs are inefficient or are due to the characteristics of the business. As such, FE’s relative efficiency has been computed by estimating a model using the GB only or GB and PNGL data and fitting the model to the data. A detailed analysis of special factors driving cost differences between firmus energy and other GDNs, which is outside of the scope of this report, would be required to isolate these effects.”³[Emphasis added].

It is therefore our considered view that the Utility Regulator’s benchmarking approach falls short of any reasonableness test and does not adequately account for the real and tangible efficiencies already included in our GD17 Business Plan submission.

1.1.8. Consideration of Special Factors

*“In order to mitigate estimation uncertainty and the challenges associated with the comparability of the NI and GB GDNs, the efficiency determination should consider combining the econometric analysis with **special factor adjustments** (both positive and negative) and/or additional information such as the bottom-up model UR is developing”*⁴

In addition to differences in obligations imposed on firmus energy and GB GDNs, there are a number of structural differences and network characteristics that need to be properly considered when comparing firmus energy’s performance with others, particularly in terms of Capex and Opex activities.

The key differences between firmus energy, Phoenix and GB GDNs were outlined to the Utility Regulator by firmus energy in both its June 2015 submission, particularly in a benchmarking paper produced by Oxera and in our September 2015 Business Plan. The key special factors are:

- **Network Sparsity.** Firmus energy’s licence area is sparsely populated, with an average density of 166 people per km² compared to the Greater Belfast Licensed Area of 897 people per km² and most GB networks.
- **Scale.** Firmus energy’s customer base currently accounts for around 25,000 customers, around 10% of the scale of the Belfast licence area and 1% of the largest GB GDNs. We are unable to capture some of the economies of scale enjoyed by these significantly larger companies. The Utility Regulator’s consultants Deloitte recognise this in Draft Determination Annex 5, page 5, Paragraph 2.4 stating: *“FE has around 20,000 customers, which is approximately a hundredth of the GB GDNs’ customer base.”*

³ Page 4, Deloitte, “Annex 4 - GD17 Efficiency Advice Relative efficiency of Northern Ireland Gas Distribution Networks Final report” 11 March 2016

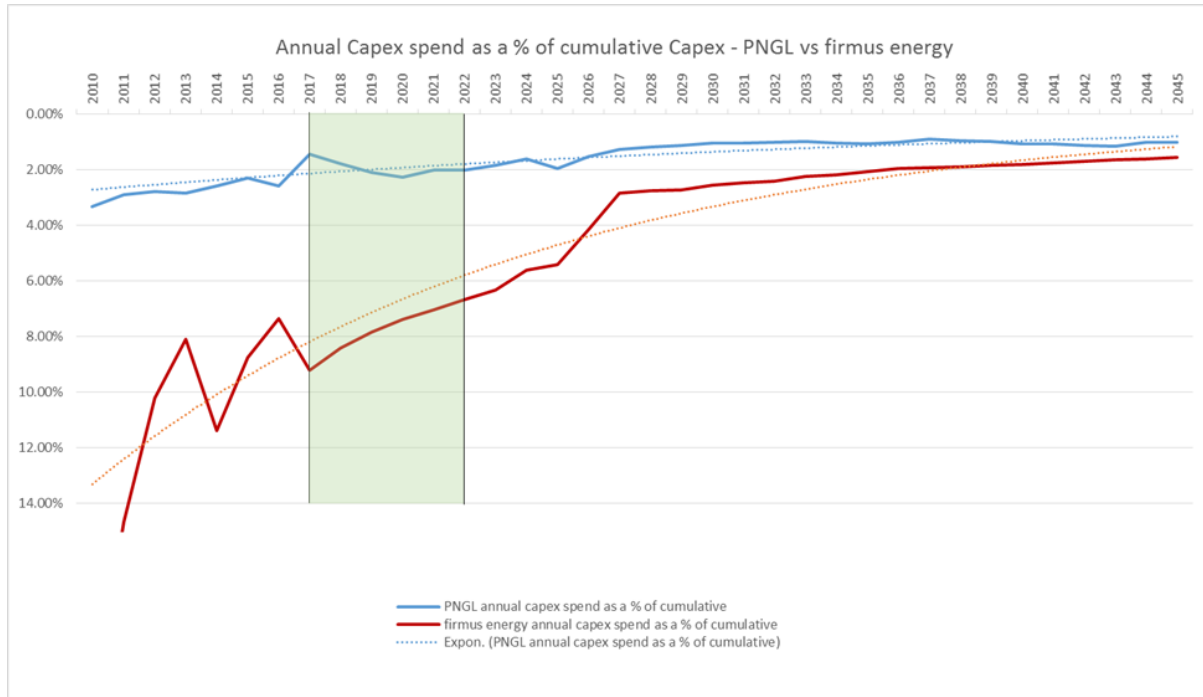
⁴ Ibid

- **Age and growth of the network.** Firmus energy indicated that its current network penetration rate (around 33%) is significantly lower than that of mature GB GDNs (around 82%) and Phoenix (around 58%). Our network is also still growing and not in the steady state of GB GDNs. As noted in Draft Determination Annex 5, page 5, Paragraph 2.4 *“One notable feature of the NI GDNs, is that they are growing much faster than the more mature GB GDNs, in terms of customers, volumes and network length.”*
- **Xoserve Costs.** The Utility Regulator has benchmarked firmus energy against GB GDNs with an arbitrary estimate of 75% of Xoserve costs removed. Such comparison is inappropriate given that the equivalent functions are undertaken in-house by firmus energy. These costs include the c.£300k pa costs for system control, £80k pa for switching system activities and additional costs for IT development and support, software and maintenance, customer switch support, other customer service and asset management functions

The combined impact of these special factors does not appear to have been adequately accounted for in the Draft Determination. We believe that if all factors had been fully considered, the benchmarking exercise would not have resulted in a Draft Determination proposing substantial reductions in allowed Opex and Capex at a time when such a significant capital intensive programme was being proposed. In addition, we consider there would have been less likelihood of an additional 1% efficiency gain per annum being proposed within the Draft Determination. We welcome the indication from the Utility Regulator that it is willing to further consider the impact of special factors on firmus energy's costs.

1.1.9. Level of Risk Associated with Underperformance

Figure 1.4



The Utility Regulator's Draft Determination raises some fundamental challenges for firmus energy in terms of the asymmetry of underperformance/outperformance mechanisms and the overall lack of outperformance incentives built in to the price control.

The Connections Incentive punishes underperformance much more harshly than it rewards outperformance. It also includes a largely unsupported assumption that 25% of customer connections are non-additional (i.e. not requiring any form of marketing to make the decision to connect) and therefore these properties do not count toward the Customer Incentive allowance.

Similarly there is an unbalanced approach to the performance mechanism governing network rollout where the penalty for each property short of the properties passed target is 2.5 times the reward for each property in excess of the target.

Opex and Capex outperformance is subject to the sharing mechanism, which serves to limit the extent to which we bear the risk or keep the benefit of any differences between actual and allowed Opex and Capex.

In addition, through its proposed 80/20 pain/gain sharing mechanism, the Utility Regulator now proposes to place a significant limit on the extent to which we are incentivised to achieve financing efficiencies through being able to arrange debt financing at a cost lower than our allowed debt cost.

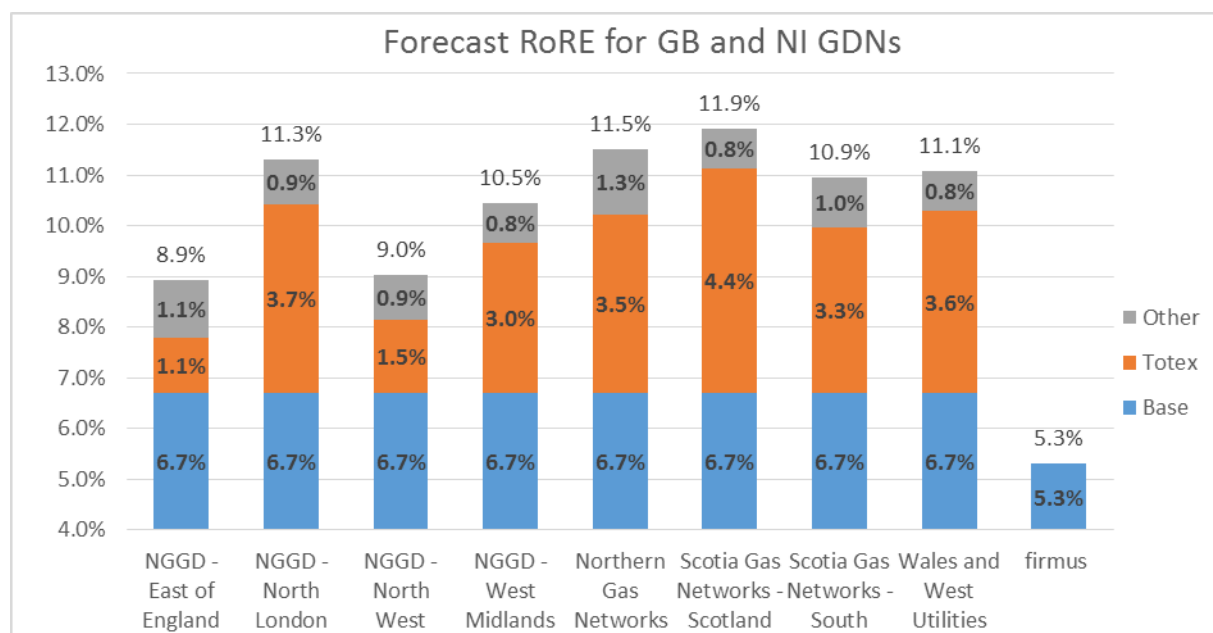
Overall, the GD17 regime creates an environment in which there are very few practical routes through which we will be incentivised to outperform our allowances. We must of course acknowledge that much of this is not a new feature of our regulation: the Connection Incentive and Properties Passed

Incentive have been lop-sided and limited in scope since their introduction. The concept of a sharing mechanism has existed for some time.

Given that the Utility Regulator appears to be committed to a low-incentive approach to regulation, our expectation of a change in view for GD17 is limited. However, we believe that the impact of this low-incentive approach should be reflected in the other aspects of the price control; particularly our overall allowed cost of capital. In particular:

- Since the Connections and Properties Passed Incentives are lop-sided, the downside risk that we face is greater than the prospect of upside, increasing the overall level of business risk that we face
- Our ability to “smooth” underperformance in one area of our business by outperforming on other incentive mechanisms is very limited, decreasing the extent to which our business is able to withstand cost shocks
- In comparing our allowed return on equity to other businesses (particularly the GB GDNs), the Utility Regulator needs to take into account the differences in scope for out- and under-performance that exist within the GB and Northern Ireland regulatory regimes. Thanks to the output-based incentive regime implemented by Ofgem for the RIIO (Revenue = Incentives + Innovation + Outputs) GD1 price control, the GB GDNs routinely earn a far higher RoRE than is achievable by firmus energy under the Draft Determination

Figure 1.4 Ofgem’s forecasted return on regulatory equity (RoRE) for GB GDNs, compared with firmus energy



Source: Ofgem/firmus energy analysis

2. Connections and Volumes

The Northern Ireland Government, the Utility Regulator and firmus energy share a common goal to extend the reach of the natural gas network in firmus energy's Ten Towns Licensed Area. From the outset, the Utility Regulator's stated primary objective for the GD17 review, as set out in its GD17 Guidance, has been to ***'promote the development and maintenance of an efficient, economic and coordinated gas industry in Northern Ireland'***.

Our GD17 Business Plan reflects this shared goal. Ultimately, our vision is to extend the benefits of natural gas to as many people and premises, and to achieve as many connections as economically possible. We aim to achieve this goal while maintaining the highest levels of safety, customer service and efficiency. We have set ambitious but realistic targets for customer connections based on our detailed data-driven plans for network roll out. Our Business Plan indicated an increase in overall connections in GD17 which is, on average, 45% higher than the average outturn per year in the GD14 period. We consider our GD17 connection targets particularly challenging, not least as a result of current market conditions.

Whilst we welcome the Utility Regulator's acceptance of our connection forecasts for the Northern Ireland Housing Executive (NIHE), New Build (NB), Industrial and Commercial (I&C) sectors, the GD17 Draft Determination sets a dramatically increased target for owner occupied connections (22% higher than firmus energy's Business Plan for GD17 and an average increase of 70% per annum compared to GD14 targets), while substantially reducing support for prospective customers from the Connection Incentive. This (27%) reduction in Connection Incentive over the GD17 period, along with asymmetric nature of the Connection Incentive poses a further and significant financial risk to firmus energy. This is discussed further in section 2.3.

We regard the Utility Regulator's proposals for owner occupied connections in GD17 as unrealistic and unachievable, as we consider the current proposals comprise a number of elements for which the Utility Regulator proposes the lowest cost option for an unduly onerous output.

2.1. Volumes

The Draft Determination forecasts the Utility Regulator's view of volume growth for the firmus energy Ten Towns network. It is worth noting that between the time of our GD17 submission and the publication of the Draft Determination our largest single customer, Michelin, announced a termination of its operations in the GD17 period.

This load loss, which follows the earlier Gallahers loss should of course be reflected in the Utility Regulator's volume projections.

The combined impact of the loss of Michelin and Gallahers is an 11% reduction to our overall volumes and illustrates the inherent risk within firmus energy's current load profile (i.e. c. 70% weighting of large I&C volumes), within the Ten Towns Licensed Area.

We acknowledge and agree with the Utility Regulator's volume forecasts for the domestic and SME sectors, and would ask that this update to the I&C volume forecast be incorporated accordingly.

We share the Utility Regulator's goal of ensuring optimal volume forecasts in an effort to limit any over/under corrections (i.e. the 'k' correction factor) within annual conveyance charges.

2.2. Properties Passed and Network Development

Given the nature of firmus energy's volume based price regulation since 2005, the focus in the early years of development was to prioritise large I&C customers and get them connected as early as possible. The next priorities were NIHE housing estates and NB housing. Network roll out allowances also resulted in a focus on lower demographic, lower gas burn areas across both the NIHE and owner occupied customer categories, with higher burn connections in the owner occupied sector having been deferred to GD17 and beyond.

As most of the large loads in the Licensed Area have already been connected, the focus in our GD17 Plan is on rolling out the network mains to a further 72,000 customers and for the first time targeting owner occupied residential customer connections in particular.

2.2.1. Network Development Plan - Utility Regulator's Re-profiling

The firmus energy network development plan was based on a detailed engineering and costing assessment of our Licensed Area, dividing the customer base into 'projects'. The projects, in turn, were analysed on the basis of several factors including demographics, property density and existing heating and inputs from installers, to determine the potential for connections, and the net present value (NPV) of connections for each project. The projects were then ranked by NPV to determine the optimal timing of the overall build programme.

The Utility Regulator has broadly accepted our network development plans, (proposing a 2.1% increase in the properties passed target) although the Draft Determination re-orders the 621 projects so that 28% of projects with the lowest economic return now fall outside the GD17 period.

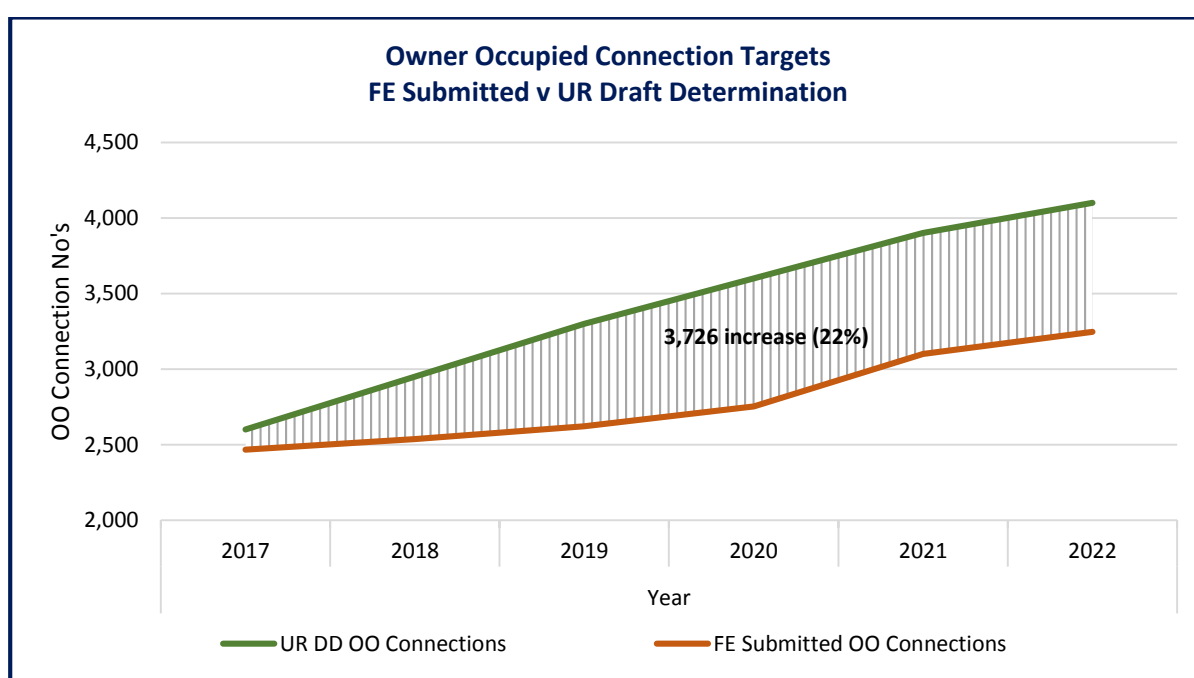
In terms of GD17 alone the Utility Regulator's re-profiled network development plan is rational and firmus energy can deliver this revision. The firmus energy Business Plan sought to optimise projects and maximise the availability of natural gas to customers by blending some properties, not necessarily economic on their own, into projects which were economically positive overall. The re-profiling means that many of the properties included in the lesser economic projects deferred beyond GD17 may never be connected. These are properties where the propensity to connect to natural gas is typically greater.

The Utility Regulator has acknowledged that the revised roll-out plan did not fully consider the associated gas burns for the properties in question (i.e. those now beyond GD17) and has invited firmus energy to provide additional historical burn analysis to establish the economic viability of passing all the properties planned. Firmus energy will continue to engage positively with the Utility Regulator in this regard.

2.3. Owner Occupier Connections Target

The Utility Regulator's Draft Determination on owner occupied connections targets imposes an unduly onerous obligation on firmus energy, which we do not consider achievable. The Draft Determination targets a 22% increase on our already ambitious plans for this customer sector, representing a 70% increase on average annual connection targets when compared to GD14. Figure 2.1 illustrates the annual profiling of this 22% increase from firmus energy's Business Plan targets for the GD17 period.

Figure 2.1



The Utility Regulator has also proposed a penetration rate (i.e. connections as a percentage of properties passed) of 85% by 2045. This is an increase to our GD17 Business Plan assumption of 65%, and the Utility Regulator's GD14 assumption for firmus energy of 45%.

Firmus energy believes there are two ways in which the Utility Regulator must consider the implications of their proposals for future development of the natural gas network;

Firstly, if the Utility Regulator chooses to apply an economic testing of the incentive mechanism (which reduces the incentive from the current rate of £573 to £420 per connection by 2022), then a 22% increase to firmus energy's Business Plan for owner occupied targets must be revised. Whilst we recognise the (future) potential merits of the Utility Regulator's economic testing, it is important to recognise the life cycle of our Business Plan, which for GD17 is focused primarily on the growth of owner occupied connections. As outlined previously, this is a new focus for firmus energy which follows our success in building the network to-date primarily upon I&C and NIHE connections, rather than attempting to align prices in the Northern Ireland Licenced Areas.

Secondly, if the Utility Regulator retains a 22% increase to firmus energy's targets, then further consideration must be given to the 27% reduction for funding this activity.

In line with option two, and given our shared goal to develop the natural gas industry, firmus energy has a desire to encourage connections to our network. However, this activity must be adequately funded. These items are further explored below.

2.3.1. Penetration Rate

As part of our GD17 Business Plan we established an overall goal of achieving a long-term penetration rate of 65% in the firmus energy Licensed Area by 2045. Our forecasts were peer-reviewed by economic consultants Oxera who, in comparing them with penetrations achieved by other GDNs, and taking account of the distinct characteristics of the Ten Towns Licensed Area, have found them to be reasonable.

Assessment of other GDNs penetration rates included assessment of the long-term Phoenix penetration rate extrapolated from its penetration of 58% in 2014, current GB penetration rates, and the Utility Regulator's own GD14 modelling which projected a 40 year penetration rate for firmus energy of 45%⁵. An Oxera paper detailing this assessment was submitted along with our September 2015 Business Plan.

This led to the development of a strong, evidence based forecast of a 5% run rate for owner occupied connections in new infill areas per year during GD17. From 2023 to 2030, with less growth forecast for the Network Area, the annual growth rate in connections will be less than 4%, falling to 2% per year by 2040.

Without providing detailed analysis within the Draft Determination, the Utility Regulator outlines the revised forecast applied for GD17, stating: *"We have assumed that 85% of properties will connect to the network in the long run at a rate of 5% per annum of properties passed but not connected. This is generally in line with the long term connection rate that we have seen to date. **It is higher than the connection rate assumed for GD14.**"*[Emphasis added].

The Utility Regulator's modelling does not appear to reflect the reduced network growth rate projected beyond the GD17 horizon. No explanation is provided for the very significant increase from the 45% penetration assumption set out in the Utility Regulator's revised GD14 Final Determination modelling. Benchmarking against other utility networks demonstrates that the annual growth rate is likely to be less than 5% (i.e. c.3%) in the post GD17 period when the majority of network rollout is complete.

Modelling by the Utility Regulator on the basis of an arbitrary 85% penetration figure is therefore unsupported, as is its application to backcast connection rates for the GD17 period. This has resulted in a connections target that we do not believe is achievable, particularly with the proposed funding available.

⁵ Utility Regulator's model shared with firmus energy, "FE infill cost per metre GD14 Review.xls"

We restate that the owner occupied connections forecast in the firmus energy Business Plan is based on reasonable assumptions and is sufficiently ambitious while being robust for the GD17 period.

2.4. Connections Incentive and Customer Support

The Connection Incentive element of the firmus energy price control is a vitally important allowance in terms of encouraging customers to switch to natural gas and assisting firmus energy in reaching its targets for customer connections. We provided strong evidence in our GD17 Business Plan that the Connection Incentive should be retained at its current value.

Firmus energy welcomes the decision by the Utility Regulator to set aside an earlier plan to reduce the Connection Incentive by 50% from the commencement of the GD17 period. We acknowledge that the Utility Regulator has listened to the GDNs on this point and moderated this proposal significantly.

However, the original 50% reduction has now been replaced by a Draft Determination proposal to cut the Connection Incentive progressively so that it is 27% lower by the end of GD17.

As outlined in section 2.3, development of the natural gas network must be adequately funded. We do not consider the results of the economic testing to be appropriate for this stage of our network development. Market momentum is not sufficiently developed within the Ten Towns network so as to validate the outputs of this standalone economic test.

We do not believe the 27% reduction per connection (by 2022) to be a reasonable reflection of funding required for owner occupied connection activity, and would ask that the Utility Regulator reinstate the level of allowance granted during GD14, (i.e. £573 per connection).

2.4.1. Connections Incentive – Asymmetry in how it Works

2.4.1.1. Underperformance/Outperformance Mechanism

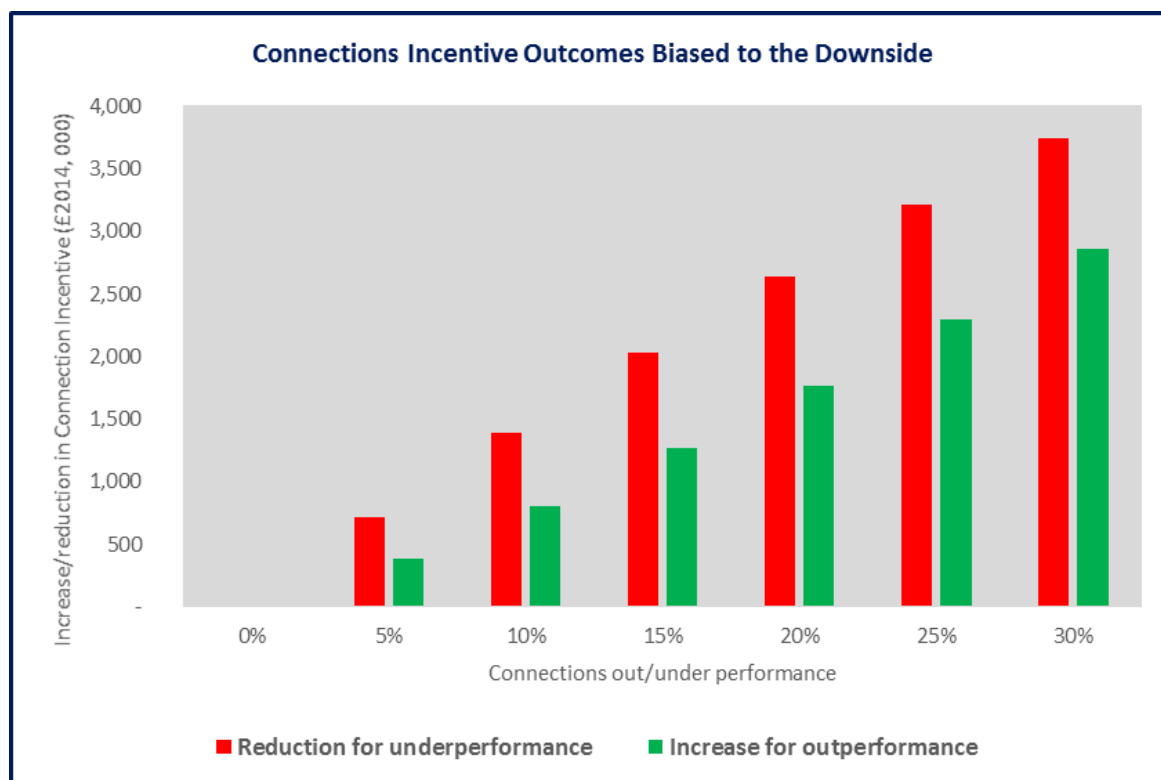
In the context of the Utility Regulator's substantially increased GD17 owner occupied connection targets there is a significant difficulty with the asymmetric risk presented by the proposed Connection Incentive underperformance/outperformance mechanism.

Current Utility Regulator proposals present a materially high risk of underperformance, in the context of very high and challenging targets, and reduced funding for owner occupied connection activities. The connection targets proposed by the Utility Regulator already effectively eliminate any possible upside – but even if outperformance were possible it would receive relatively modest reward. Firmus energy believes there is no justification for having such an imbalance between reward and penalty.

Figure 2.2 illustrates the asymmetric nature of the Connection Incentive for underperformance and outperformance to +/-30%. Given the Utility Regulator's proposed increase of 22% to firmus energy's Business Plan targets, this range captures the very real financial risk associated to such an increase. Over the GD17 horizon, an underperformance of 22% (i.e. achieving firmus energy's

Business Plan forecast connections) will incur a c. £3 million penalty. The graph clearly highlights the asymmetric nature of financial risk associated with underperformance (red bars), compared to the more modest reward for outperformance (green bars).

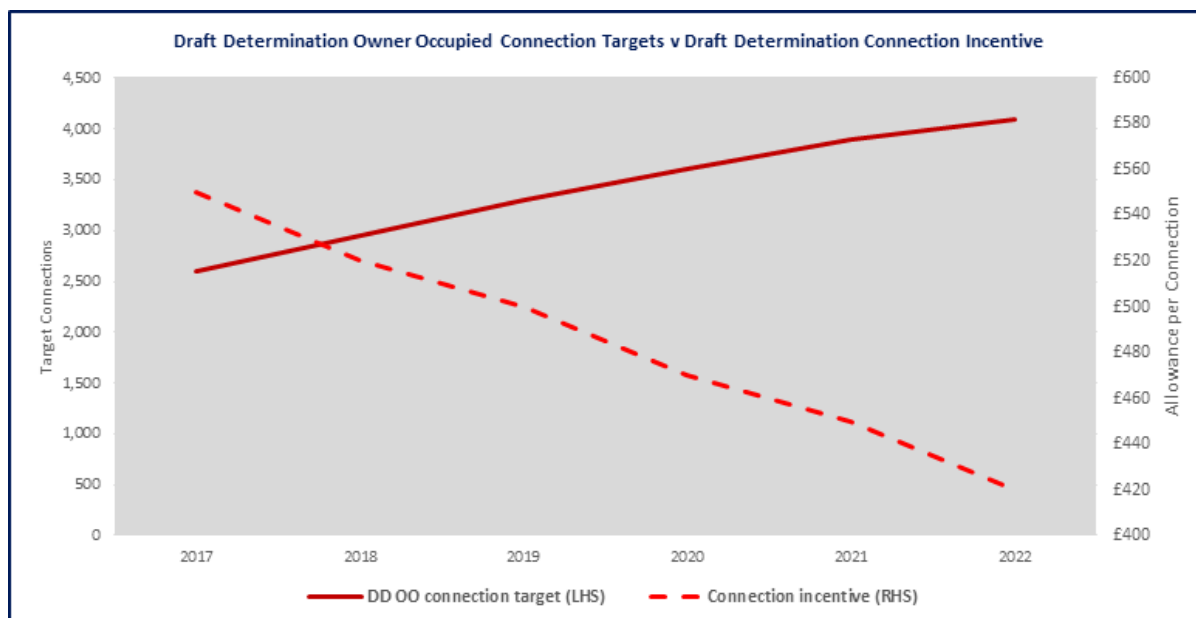
Figure 2.2



In addition to the asymmetric nature of the incentive mechanism, the decreasing value of the Connection Incentive over the GD17 period (by 27%) is juxtaposed to a doubling (105%) of owner occupied connection targets from GD14 to the end of the GD17 period, as detailed in Figure 2.3. This further exacerbates the potential financial risk to firmus energy, particularly as we progress through the GD17 period.

As outlined above, we do not consider it appropriate to implement a reduction in the Connection Incentive at this stage of our network development. We consider it incumbent upon the Utility Regulator to reconsider the impact that a reduction in the Connection Incentive would have on our ability to connect new customers, and would welcome further engagement in this regard.

Figure 2.3



2.4.1.2. Profile of Connections Incentive – Underperformance/Outperformance

We welcome that the Utility Regulator has requested our view on the benefits of calculating the Connection Incentive over the entire price control period rather than on an annual basis, as outlined in paragraph 6.453 of the Draft Determination.

As the financial risk to firmus energy of downside penalties resultant from annual underperformance in the connection mechanism significantly outweighs the annual outperformance incentives we believe this proposal merits consideration.

Under the current mechanism a GDN could find itself financially penalised for falling short of target in a single year despite meeting total connection targets for the GD17 period (i.e. outperforming in other years).

Calculation of the Connection Incentive over the full price control period may serve to marginally reduce this punitive aspect of the incentive's current application, and firmus energy is keen to engage with the Utility Regulator in further scoping this proposal and the detail of its application.

2.4.1.3. Non-Additionality

Within the Draft Determination the Utility Regulator has retained an assumption that 25% of all owner occupied connections will be "non-additional", i.e. that 25% of connections will occur without any direct marketing or selling to these customers. As a result, the Connections Incentive allowance is not applied to this proportion (25%) of connections.

As part of our September 2015 Business Plan submission to the Utility Regulator we acknowledged that there are indeed some customers who will connect without incentivisation, but that the number is closer to 5%.

We have not received any substantiation from the Utility Regulator regarding their estimate of 25%, and would welcome any supporting analysis which might be available.

Our 5% proposal for non-additionality recognises the extent to which firmus energy's network development plans are into new infill areas (as opposed to infill of our existing network).

Since our Business Plan submission in September 2015, and to test the Utility Regulator's contention of 25% non-additionality, we intentionally carried out our own test case in the village of Loughgall County Armagh. Having laid pipes and made gas live to 200 potential domestic connections in Loughgall in January 2016, we purposely, undertook no sales visits and no other advertising for the first 5 months of this year.

Despite our contractor being highly visible during the mains construction (six weeks) we received no sales enquiries and have secured no connections to-date, since gas went "live" in the area.

Whilst we recognise the limited time frame of this test and the necessity to begin appropriate marketing activities, the zero connections figure is completely at odds with the Utility Regulator's forecast of 25% non-additionality, and further helps to support the detailed evidence we put forward regarding the knowledge of gas in our immature network, and the infancy of our Business Plan life cycle.

These arguments were captured in our June 2015 GD17 Supplementary paper on the Connection Incentive, Part 5.6 of our September 2015 Business Plan and in the Millward Brown research paper regarding the Connection Incentive submitted as an annex to our September 2015 Business Plan.

We do not believe the Utility Regulator's assumption of 25% is substantiated and in the context of significant market development proposed for the GD17 period, we would strongly request that the Utility Regulator reconsider the unrealistic level at which the non-additionality threshold has been set, particularly given our connections underperformance forecast for GD14 of 10%.

2.4.1.4. Re-allocation of Fixed Costs to the Connections Incentive

In conjunction with a reduction to the Connections Incentive for the GD17 period the Utility Regulator has determined that significant additional fixed costs be reallocated to fund the Connection Incentive.

The removal of these cost lines from Opex allowances, reduces our overall Opex cost allowance very substantially, by £139k per annum or £834k over the GD17 period.

In some cases the reallocation has been simply applied incorrectly, for example, salary costs for our Director of Sales, Marketing & Customer Services have been removed from a cost line that never encompassed those costs to begin with. In other instances, the proposed reallocation is simply not reflective of the percentage of company resources utilised for owner occupied connections.

When fixed sales and marketing costs are fully accounted for against the Connections Incentive an average of around £200 per eligible connection remains to cover all other costs including a customer contribution to encourage connection.

2.4.2. Need for the Connections Incentive in firmus energy Area

2.4.2.1. Essential Contribution to Customer Costs

Although it has its origins in the requirement to raise **awareness** of natural gas (and was previously known as the Advertising Marketing and Public Relations (AMPR) allowance) the Connection Incentive is primarily used today to make a **contribution** to customer connection costs as part of encouraging them to switch to natural gas. Generally, firmus energy must make a direct contribution of £300 (sometimes £500) to assist the customer in meeting the up-front costs of c. £2,500, and ultimately secure a connection to the network.

There is now a general customer expectation that this contribution will be made in the overall context of a connection and we have provided evidence in our Business Plan submission that customers connecting to natural gas are extremely sensitive to cost.

The Connection Incentive payment is also needed to trigger other important funding which benefits customers and drives connections, such as a direct payment of £150 required to secure Northern Ireland Sustainable Energy Programme (NISEP) funding, granted to lower income customers to pay their overall connection costs.

It is essential to recognise the importance of Government funding to firmus energy customer connections. Some 66% of all owner occupied connections made in the Ten Towns network area in the last two years were dependent on NISEP or Boiler Replacement Scheme (BRS) funding.

However, the direct contribution is essential in assisting all natural gas customers to connect, and customers regularly enquire as to why the incentives offered now are less than those available previously.

2.4.2.2. Difficult Market Conditions for Natural Gas

The main competitor to natural gas in the firmus energy Licensed Area is home heating oil. The Utility Regulator's proposal to reduce the Connection Incentive comes at a time when the price of oil has fallen sharply in the market place and the relative competitive position of natural gas has deteriorated significantly.

Northern Ireland is still struggling to emerge from the economic downturn. It is not surprising that more and more households are less inclined to make a substantial investment (c. £2,500) to convert to gas when there is less grant-aid available and when there is currently no price advantage.

A downside to the Utility Regulator's re-profiling of firmus energy's network development plans means that the projects now deferred from the GD17 period are those with substantially higher income demographics, greater propensity to connect to natural gas, and greater ability to connect to natural gas.

2.4.2.3. Disposable Incomes

Office of National Statistics (ONS) figures demonstrate that the Gross Disposable Household Income (GDHI) per head in the North of Northern Ireland, an area that encompasses our network towns of Derry/Londonderry, Coleraine and Limavady, was only £12,910 in 2013. The area is ranked 168 of all 173 regions in the United Kingdom.

The GDHI is also significantly less than the two ONS areas that make up the Greater Belfast gas network area, 14% less than that of the Belfast region and 16% less than the Outer Belfast region.

Office of National Statistics (ONS) figures also demonstrate that GDHI per head in the North of Northern Ireland dropped by 2% from 2012 to 2013.

The impact of disposable income on connections was further evidenced by consumer research undertaken for firmus energy by Consumer Research specialists Millward Brown and submitted to the Utility Regulator alongside our September 2015 Business Plan. This GD17 specific research regarding customer connections was commissioned in order to highlight the opportunities and also challenges of network development in relation to delivering customer connections.

The research focused on customer feedback from infill domestic connection zones where marketing activity undertaken by firmus energy has been underway. The paper documents that 66% of customers who did not proceed with gas connections following initial contact with firmus energy had financial reasons for not doing so.

In proposing changes to the Connections Incentive and Basket of Works allowances (domestic services) we do not believe the Utility Regulator has adequately considered the greater financial impact on prospective natural gas consumers.

The need for such consideration becomes even more apparent when assessed against the significantly increased connection targets and extent to which customers in the firmus energy network depend on additional financial support.

2.4.2.4. Network Sparsity – Impact on Sales Costs

Because of the relative sparsity of the firmus energy network it costs more, on average, to reach customers with our sales and marketing activities. Even around the largest population centre of the Ten Towns area - Derry - the network area is semi-rural with a population density of 286 people per km² compared to 2,574 people per km² in Belfast City.

This increases the costs of reaching and engaging customers. On average our Energy Advisors cannot visit as many customers as they could if they were operating in Greater Belfast.

There is also a much smaller installer base in the Ten Towns network area reducing the concentration of installer activity. There are 55 registered installers in the Ten Towns compared to over 250 in Greater Belfast. Funding from the Connection Incentive is required in order to leverage the longer term economies of scale which the installer network can offer in raising awareness of natural gas, keeping natural gas ‘front of mind’ for prospective customers and ultimately supporting connections to the firmus energy network.

2.4.2.5. Network Sparsity – Impact on Marketing Costs

In marketing terms, firmus energy is significantly disadvantaged by its geographically dispersed market area. Our specialist media partners Genesis Advertising highlight the two key factors creating this disadvantage:

1. Firmus energy’s target audience is spread over a wide geographic area in the Ten Towns, by contrast the Greater Belfast audience is bound within a significantly smaller geographically defined market. This means that firmus energy must use more media formats (e.g. more radio stations and more press titles) to reach their audience.

While a single press title (The Belfast Telegraph) can be used to reach a wide percentage of target audience in Greater Belfast, firmus energy must use 7 different regional titles to attempt to reach the equivalent audience.

Similarly firmus energy must use multiple radio stations (e.g. Downtown, the entire Q Network of regional stations and Downtown Country), whereas the Greater Belfast Area can be reached using a single radio station (e.g. U105).

Both these factors add significantly extra cost for firmus energy: both in terms of the costs of purchasing the media space, but also in terms of producing more advertising formats as multiple versions of adverts attract additional artist/music and production studio buyout costs which are calculated on the basis of number of stations/titles/formats used.

2. Population density also disadvantages firmus energy in a second manner. As outdoor, radio and press advertising space is not priced directly proportionately on the basis of volumes of people coming into contact with them. This means it is significantly cheaper to develop effective marketing reach and frequency levels (which are the key currencies of media planning) within a more densely populated area such as Greater Belfast than in the Ten Towns.

Consequently firmus energy needs to pay much more for the ‘price of attention’ than Phoenix, and specifically in achieving ‘reach’ (the number of people that are exposed to the message) and ‘frequency’ (the number of times an audience is exposed to a message).

Successful marketing campaigns need to achieve both high reach and good frequency to ensure repeat exposure of the message. Clearly this is much easier and cheaper to do in a high density, geographically defined area such as Greater Belfast.

What this ultimately means is that firmus energy's *Cost per thousand* metric i.e. the cost of reaching 1,000 people within its target audience is significantly higher across all key channels when compared to Phoenix which results in firmus energy needing to spend much more just to match Phoenix's marketing efforts because of the differing dynamics within each market area.

Using analytical outputs from a number of advertising industry planning tools, including Target Group Index, Telmar (radio planning system) and JNOR (outdoor research planning tool) our Media partners Genesis Advertising has provided us the ratios in Figure 2.4 below.

Figure 2.4

Required Spend to Achieve Equal Marketing Impact (Indexed Ratio)		
Channel	Greater Belfast	Ten Towns
Outdoor	100	210
Radio	100	200
Press	100	250

2.4.2.6. Immaturity – Impact on Sales and Marketing Costs

Prospective customers in the sparse, rural firmus energy network area have little or no experience of gas and require education through intense sales and marketing activity. This is particularly so in relation to the issues of safety and desirability. Even in the towns where there was previous experience of town gas, the legacy is not particularly positive.

All of this impacts on the amount of effort, resource and cost that goes into securing a customer connection.

2.4.2.7. Fuel Poverty

A key feature of our September 2015 Business Plan was to ensure that natural gas contributes to the fight against fuel poverty. We note that the Utility Regulator has chosen not to replicate the RIIO-GD1 Discretionary Rewards Scheme undertaken in GB.

The Utility Regulator states: *“at this stage we see no requirement for such a policy change as we consider the key focus of the GDNs should be on achieving network growth.”* and *“the incentive mechanisms for GD17 should draw the focus of the GDNs to making connections and enhancing network infill, rather than on any other initiatives that might distract from such focus.”*

In the Ten Towns, addressing fuel poverty (see section 2.4.2.3) and making connections are inextricably linked and if a Discretionary Rewards Scheme is not to be implemented it is of even greater importance that the Connection Incentive is retained at its current level.

3. Opex

Firmus energy's Business Plan forecasts Opex costs which are necessary to fund our day-to-day business activities. Our forecasts are derived from actual, efficiently incurred, costs and are commensurate with the significant growth plans for our network during the GD17 period.

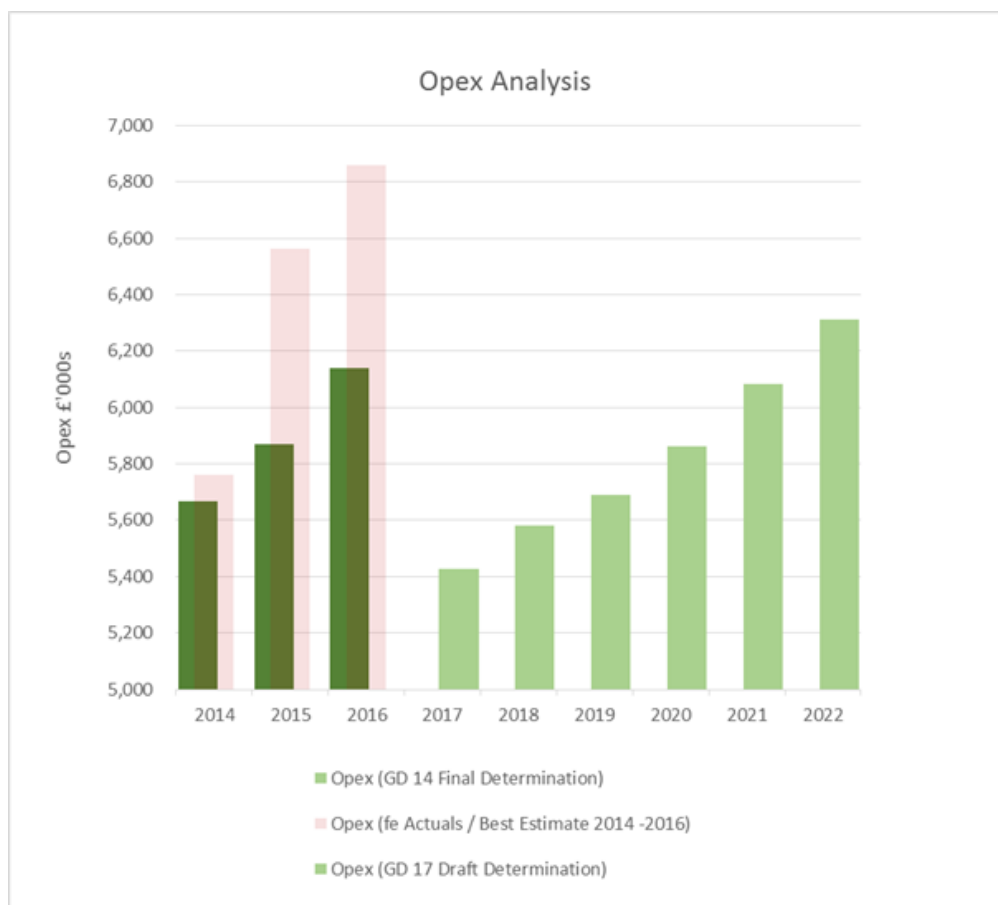
When commenting upon the maintenance element of our Opex costs the Utility Regulator has stated:

*"We asked our consultants to review the bottom up estimate of costs prepared by FE. **They concluded that the activities identified were reasonable and that the bottom up estimates of the unit costs was broadly reasonable with some exceptions.**"* [Emphasis added] (Draft Determination paragraph 6.119.)

Despite this assessment of part of our Opex costs the Utility Regulator's Draft Determination has proposed allowances which are 26.5% lower than our forecast costs during this period, including a c.3% reduction as a result of (RPE) efficiencies.

This amounts to a real terms reduction to our costs, meaning costs for GD17 would be below current costs, despite our significant network growth forecasts. This impact is illustrated by Figure 3.1 below.

Figure 3.1 Real-terms Opex Cut



As we believe our submitted costs to be efficient we consider the overall scale of cuts proposed by the Utility Regulator to be unwarranted especially for a rapidly growing business, in a new residential sector.

Our Business Plan Template was provided to the Utility Regulator with a substantial amount of information pertaining to the GD17 period and was more detailed than any previous price control requirement. However, this information does not appear to have been duly considered despite the focus on a bottom-up approach to benchmarking by the Utility Regulator as a result of the difficulties the Utility Regulator experienced in using top-down benchmarking approaches for the first time. (Further comment on top down benchmarking is included in Appendix 5 of this document.)

The potential impact and scale of the proposed disallowances adds to the downside risk for firmus energy, as discussed in Chapter 5 of this document.

In this chapter, we address the analytical approach undertaken by the Utility Regulator, before assessing the impact this approach has had on our specific costs lines. Where we can we propose alternative solutions in areas of potential difficulty.

3.1. Analytical Approach to Opex

The Draft Determination, as presented, does not appear to consider much of the extremely detailed data submitted by firmus energy, instead the Utility Regulator has relied on adopting the less analytical approach applied in GD14.

By rolling forward the approaches used in GD14 the Utility Regulator is not fully acknowledging the very significant network and market changes planned for GD17. Additionally, the Utility Regulator data analysis fails to engage at the same level of granularity and complexity as the very considerable information provided by firmus energy. This results in an inequitable outturn, particularly with regard to maintenance, as discussed in section 3.3, below.

3.1.1. Consideration of 2014 Actuals in Isolation

The guidance contained within the Utility Regulator's Regulatory Instructions and Guidance for Business Plan Submission confirmed that *"Financial values shall be input on a December 2014 basis and exclusive of real price effects unless explicitly stated otherwise in the template or guidance"* (3.19) and that *"The forecasts should be completed on the same basis as the annual/cost reporting for 2014 actual performance...If the basis for forecast is different, from cost reporting, it should be disclosed, with justification of why."* (Paragraph 3.15)

We recognise the necessity to consider an actualised base for forecast cost submissions, (2014 on this occasion), and we followed that approach. We highlighted within our Business Plan spending lines where forecast costs varied from 2014 and explained the rationale for these changes and trends in some detail.

Rather than undertaking in-depth analysis of the forecasts provided, the Utility Regulator relied almost exclusively on 2014 actuals. This practice of considering 2014 actuals or any single year in isolation is

questionable. It also fails to take due account of business growth or productivity increases already built into the Plan.

This lack of analytical rigour is evidenced by the incorrect suggestions within paragraphs 4.8, 4.9 and 6.34 of the Draft Determination that firmus energy failed to provide a full explanation of costs for 2014. Firmus energy's Business Plan clearly articulated the three principal reasons for the difference between the GD14 determined spend and the firmus energy actual spend for 2014; connection related activities, additional GD17 consultancy costs and IT transition costs. These were all addressed in section 2.2.6 of our GD17 Business Plan.

3.2. Manpower

Utility Regulator's Draft Determination proposals include:

- Increased connection targets; 96% increase (near doubling) of our customer base in GD17
- Increased properties to be passed; 82% increase in properties with gas availability
- Higher levels of efficiency savings; 1% per annum Opex and 1% per annum Capex
- No investment in obsolete IT infrastructure

The Draft Determination proposals consider that firmus energy can meet all of these challenges with only one additional staff member throughout the GD17 period, and implied reductions in pay for all staff.

The problems created by an over dependence on 2014 actuals are most striking in relation to manpower allowances, where it appears that the Utility Regulator has not considered the overall impact of network development and growth of the customer base on manpower resource requirements.

3.2.1. Detailed Data Provision

As discussed further below, the Utility Regulator has kept firmus energy's proposed full time equivalent (FTE) numbers flat from 2014 through to 2022, whilst increasing annual connection forecasts over the period.

As outlined previously, the level of data provided by firmus energy regarding manpower in particular was substantial and the granularity sought by (and provided to) the Utility Regulator was significantly more than any previous requirement.

We provided over 2,000 rows and 150 columns of manpower information, categorising all staff and their costs, including items such as salary, pensions and car allowance, across 22 business activities, 10 salary bands and the relevant Opex and Capex spending lines for 30 years.

The information was presented in this way at the request of the Utility Regulator (in line with the GD17 Business Plan Template) and followed the submission format used by Ofgem when requiring data from GB GDNs whose staff numbers are much (at least 20 times) greater than firmus energy.

The Draft Determination does not reflect due consideration of the data provided for the GD17 period, but rather relies unduly on the actuals recorded for firmus energy in 2014.

3.2.2. The Utility Regulator's Analysis

The Utility Regulator's approach fails to take account of the FTEs required to realise firmus energy's challenging network growth plans but also fails to recognise the appropriate salaries required during this period of development.

There are three fundamental issues with the Utility Regulator's analysis and use of 2014 actuals.

1. Firstly, the FTEs assumed by the Utility Regulator (53.7) is understated by 1.4 FTEs due to the average number of positions open, or furloughs caused by staff turnover, during 2014. This would re-base actual FTEs in 2014 to 55.1
2. Secondly, this approach fails to take account of the uplift required to move 2014's actual costs to December 2014 prices
3. Finally, the analysis does not account for the additional uplift of 2 FTEs allowed by the Utility Regulator in 2015 for system control as a result of market opening

In paragraph 6.51 of the Draft Determination, the Utility Regulator has stated;

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

Firmus energy entirely refutes this statement. We have made it clear to the Utility Regulator previously and restate again that no costs have been incorporated into our Business Plan as a result of a change in ownership of firmus energy in 2014. Some historic manpower increases are a function of reduced group recharges elsewhere. The increase in projected FTEs (and therefore manpower costs) for the GD17 period is consistent with our ambitious plans for network growth.

The Utility Regulator has determined manpower allowances throughout GD17 based on a headcount of 56.5, compared to firmus energy's submission of 67.2 FTEs for the period. Our Business Plan submission considers this level of manpower commensurate with the significant and efficient development required to deliver our planned network growth from 2017 to 2022.

As we are involved, on a daily basis, in the recruitment and remuneration of our staff, we believe we are uniquely placed to assess the current marketplace and the average manpower costs required for the business throughout GD17.

When we compare the average salary levels for operational staff in the Draft Determination, we note that the average is much less than our submission and is actually less than the actual average staff costs incurred by firmus energy in both 2013 and 2014 (when uplifted to the same price base).

The magnitude of the reduction in staff numbers, average costs and including assumed efficiencies, compared to our submission is outlined in Figure 3.2.

Figure 3.2

Staff & Agency Opex Costs (£,000)	2017	2018	2019	2020	2021	2022	Total
FE Submission	2,381	2,381	2,381	2,381	2,381	2,381	14,287
GD17 Draft Determination (post efficiencies)	1,866	1,850	1,835	1,824	1,812	1,800	10,986
Reduction	↓ -515	↓ -532	↓ -546	↓ -558	↓ -569	↓ -581	-3,301
Reduction per FTE	↓ -4	↓ -5	↓ -5	↓ -6	↓ -6	↓ -6	-32

In addition to the re-basing of firmus energy's FTE numbers and costs (notwithstanding the inconsistencies outlined above) to 2014, the Utility Regulator has applied further efficiencies to manpower costs (i.e. RPEs). This constitutes a double counting of efficiencies.

Manpower (FTEs) are a principle driver of other Opex cost elements, and the combined effect of the Utility Regulator's proposal for both headcount and cost disallowance has cut firmus energy's manpower costs by £3.3 million, including application of the further 1% per annum efficiencies (£2.6 million before efficiencies). These manpower cost disallowances are summarised in Figure 3.3 below.

Figure 3.3

Impact of GD17 vs firmus energy submission	Impact (£'000)	Impact (Staff No's)
Audit, Finance and Regulation	↓ -568	↓ -1.1
Customer Management	↓ -126	↓ -0.4
Property Management	↓ -14	→ 0.0
Trainee's & Apprentices	↓ -149	↓ -1.0
IT & Telecoms	↓ -329	↓ -1.2
Operations Management	↓ -586	↓ -0.5
HR & Non-Operational Training	↓ -144	↓ -0.6
Asset Management	↓ -309	↓ -0.6
System Control	↓ -281	↓ -1.3
AMPR (non-OO)	↓ -50	→ 0.0
Procurement	↓ -18	↓ -0.1
Total	↓ -2,574	↓ -6.8

3.2.2.1. Updates Required

Firmus energy has assessed the specific outcomes of the Draft Determination on each manpower line submitted in our GD17 Business Plan (as outlined in Figure 3.3).

Upon review of the Utility Regulator's analysis, we note that costs have not been provided for all of the determined FTEs (56.5), specifically 0.6 FTEs under HR and Non-Operational Training and 0.1 FTEs under Procurement.

Additionally, paragraph 6.94 of the GD14 Final Determination stated *"we have included 2 additional FTE in 2015 as requested by FE in order to assist with the extension of market opening to small I&C and residential customers"*.

By benchmarking total manpower to 2014 levels the Utility Regulator does not appear to acknowledge this allowed uplift in staff headcount that occurred later in the GD14 period.

For these reasons firmus energy believes the starting point for manpower assessment should be 2 FTEs higher than that acknowledged by the Utility Regulator, (in addition to the 1.4 FTEs following allowance for open positions in 2014.)

We have also undertaken specific assessments of each additional disallowed manpower element. Based on the specific assessments outlined below firmus energy believes the Utility Regulator could further uplift our Opex manpower allowances to 49 FTEs (i.e. excluding capitalised FTEs) by the end of the GD17 period, thereby alleviating our concerns regarding our ability to undertake appropriate management of the network and continue to provide the high levels of customer service.

3.2.2.2. Specific Considerations

Forecasts indicate a doubling of connection numbers across the GD17 period. Based on this connection growth we believe an uplift of 0.4 FTEs in addition to the 8.92 FTEs already in place is reasonable to provide the additional customer support that will be required.

Similarly based on the forecast growth in network length (660km in the period) we believe an uplift of 1.1 FTEs across asset management and operations management is reasonable to permit firmus energy to undertake appropriate stewardship of the network.

As our business grows, so does the level of central corporate services for procurement services, legal services, treasury/corporate finance and audit functions, payments/invoicing and secretariat services. In addition, there will be costs, also previously accounted for under group recharges, but required for corporate best practice, particularly those associated with establishing and running the Board of Directors, (i.e. firmus energy's Non-Executive Directors and Chairman). As noted elsewhere in this document, there has also been an increase in regulatory interaction and annual analysis requirements. Given all these considerations, we believe an uplift of 1.1 FTE's within audit, finance and regulation is reasonable to permit firmus energy to undertake these functions efficiently and to limit the use of external consultants.

The growth in all activities of firmus energy has placed significant strain on the IT and Telecoms function. Our Business Plan forecast the requirement for an extra 1.2 FTEs within this area to support the original FTE count of 0.75 FTEs. We would contend that a headcount of 2 FTEs is not unreasonable for managing, developing and administering the IT and Telecoms function within firmus energy.

We had included 2 FTEs (agency staff) for trainees and apprentices to provide engineering assistance, whilst also fulfilling our licence obligations and firmus energy values to promote training and development. The Draft Determination allows for only 1 trainee but we would welcome the opportunity to train and develop an additional trainee to support the growth of the industry in Northern Ireland.

3.3. Maintenance

After ten years of operation firmus energy now must begin a phased maintenance programme. Firmus energy's Business Plan submission for GD17 reflected that an increase in efficiently incurred costs was required to support the significant development of the network. Our Plan also outlined the introduction of new maintenance activities required on a 10 year cycle. As noted above the Utility Regulator's consultants found these unit costs "broadly reasonable" when subjected to bottom-up analysis. (Draft Determination paragraph 6.119)

Detail on the legislative requirements relating to firmus energy's network maintenance are provided in Appendix 3.

Subsequent to this bottom-up analysis the Utility Regulator undertook a benchmarking exercise the result of which proposes a 25% cut to firmus energy's variable costs in the GD17 period. On this basis we can only conclude that this cut results from flawed analysis which does not account for special factors.

The key consideration not accounted for by the Utility Regulator when undertaking this benchmarking is the impact of the level of sparsity in a GDN's operational area and how it affects costs.

The more sparsely populated the area is, the more expensive it is for a company to maintain its network on a per-customer basis and resource staff to attend to emergency calls.

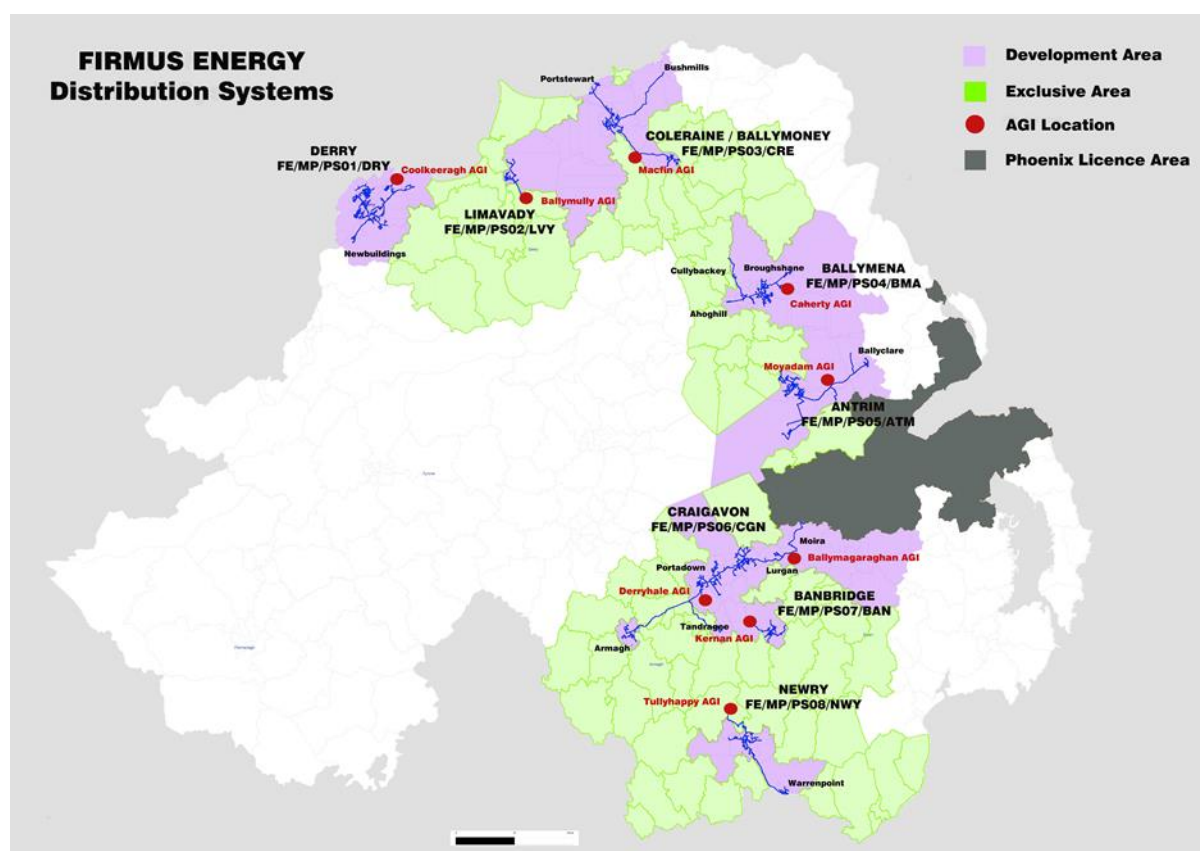
The requirement for such considerations when undertaking benchmarking was set out in detail in a Benchmarking paper produced on firmus energy's behalf by Oxera and submitted to the Utility Regulator as part of the GD17 Price Control in June 2015.

(In addition to this Oxera benchmarking paper we submitted a second Oxera benchmarking paper in September 2015 alongside our Business Plan Commentary and an appended commentary regarding sparsity impacts on the firmus energy period contract.)

This discrepancy was acknowledged in remarks made by Deloitte within Annex 4 (GD17 Efficiency Advice, Relative efficiency of NI Gas Distribution Networks (Deloitte LLP)) of the Utility Regulator's Draft Determination document:

*"FE has a significantly different profile to any of the other GDNs in terms of the ratios between network length, customer numbers and volume of gas supplies. This results in significant challenges in assessing the extent to which FE costs are inefficient or are due to the characteristics of the business. As such, FE's relative efficiency has been computed by estimating a model using the GB only or GB and PNGL data and fitting the model to the FE data. **A detailed analysis of special factors driving cost differences between FE and other GDNs, which is outside of the scope of this report, would be required to isolate these effects.**"*
[Emphasis added].

Map 1 outlines the dispersed nature of the eight distribution network areas operated by firmus energy.

Map 1. Firmus energy's Eight Separate Distribution Network Areas


Sparsity is further evidenced when population per km² is considered. As outlined in figure 3.4 Greater Belfast area has a population per km² of 897, Northern Gas Networks, one of the most rural of the GB GDNs has a population per km² of 246 and the Ten Towns development area has a population 166 per km².

As firmus energy also has the lowest customer numbers per km of mains it is clear that firmus energy is most impacted by sparsity. However, the Utility Regulator's failure to recognise these differences in their allowances undermines the benchmarking exercise undertaken, and therefore provides an unacceptable basis for the proposed allowances for firmus energy during GD17.

Figure 3.4

Network Sparsity				
Network Area	Customers	Network mains length	Customers per km of main	Population per km ²
Northern Gas Network	2,700,000	37,000km	68	246
Greater Belfast ¹	180,000	3,000km	60	897
Ten Towns ²	25,000	1,000km	27	166

The Utility Regulator's proposal is a general cut across all maintenance (variable cost) categories and does not seek to specify rationale for such a cut in any particular cost element.

As a responsible and prudent network operator, with an excellent safety record, firmus energy is wholly committed to continued good practice in the stewardship of our network. We are confident the current and proposed maintenance programme as submitted for GD17 is necessarily robust and reflective of the age and development of our Ten Towns network.

3.3.1. GB Precedent

As part of RIIO-GD1, Northern Gas Networks (NGN) highlighted regional factors that Ofgem needed to take into account for GDN's operating urban and rural networks of low customer density and how the rural areas increase operating costs. This has been reinforced by Ofgem's use of a "Sparsity Factor" to assess rural networks when benchmarking emergency costs.

Northern Gas Networks also highlighted their rurality in RIIO – GD1 submission, Annex 8 by assessing their km of mains per depots per km² against km² per First Call Operative (FCO). We have updated this table with information relating to firmus energy's four FCOs, in Figure 3.5.

Figure 3.5

Northern Gas Networks Depot Rurality Compared to firmus energy Rurality		
Depot / Area	Km mains per area km ²	Km ² Network Area per First Call Operative
Workington	0.66	171.22
Carlisle	0.32	445.43
Burradon	1.49	95.11
Hendon	4.11	51.43
Cannon Park	1.95	78.03
York	0.93	175.88
Scarborough	0.39	355.29
Hull	1.50	87.88
Heckmondwick	3.03	49.98
Pottery Fields	2.71	55.94
Firmus energy	0.49	525.75

The table demonstrates that firmus energy is currently subject to greater sparsity levels than even the most rural NGN depot area.

Given the network maturity of Northern Gas Networks it is also apparent that sparsity does not improve markedly with network maturity.

This is supported by the statement in the Utility Regulator's Annex 5 paragraph 2.8:

"In terms of customer density, both PNGL and FE have a lower number of customers per network main than the eight GB GDNs. As customers continue to connect to these new networks, these numbers have increased steadily and are expected to increase further into the medium term. Due to serving a more rural network, even once it reaches maturity, it is likely that FE will have a relatively low customer density."

We would request that the Utility Regulator recognise the impact of low customer density in relation to maintenance allowances and engage with firmus energy post draft determination responses to look in detail at the proposed maintenance activities, the special factors, benchmarking, and opportunities for synergies.

3.3.2. Independent Review of firmus energy's Regional Differences

Firmus energy has engaged the services of DNV-GL who provide expert advisory services to the gas industry to support the view of the material (regional) differences between firmus energy's network and other GDNs. The DNV-GL report is appended to this response as Appendix 7 and highlights:

The effect of sparsity with regards to unproductive time spent by our engineers. This "unproductive time" is quantified as 15%.

The report also considers the density of assets.

In combination these two special factors are assessed by DNV GL to have a 24% impact on firmus energy efficiency levels.

The report also provides:

- Explanation of firm-specific factors (sometimes known as regional differences) in utility network regulation and how it has been applied in UK regulation and other regimes
- Detailed independent assessment of the OPEX costs proposed by firmus energy
- Review of GDN costs to provide a basic comparative with the UK case (RIIO)
- Providing a view as to whether DNV-GL consider that the Utility Regulator has followed a reasonable approach in its assessment, has demonstrated transparency and has applied objective principles in line with their values of transparency, consistency, proportional, accountable and targeted

The material impact of the Utility Regulator's Draft Determination, and in particular the unjustified 25% proposed cut in variable network maintenance costs will significantly impact the network maintenance deemed appropriate to ensure firmus energy remain a responsible and prudent network operator. We believe it incumbent upon the Utility Regulator to review their benchmarking of these costs, in conjunction with the report prepared from DNG-VL.

3.4. Insurance

Firmus energy included insurance costs of £265k per annum as detailed below in Figure 3.6.

Figure 3.6 Annual Insurance Cost Forecast

Insurance Element	£
Property - buildings and contents	572
Crime and theft	9,445
Goods in transit	286
Business interruption	572
Terrorism and sabotage	1,322
Employer's liability	12,106
Public and product liability and professional indemnity	183,141
Motor vehicle liability	2,996
Personal accident and sickness insurance	32,676
Travel	286
Directors & officers	7,900
Broker fees	13,500
Total Insurance	264,803

The Draft Determination proposes a reduced allowance for these costs by applying the GD14 driver of 1.04% of turnover. Applying this metric leads to a reduction in costs in 2017 of £103k (39%) and £0.5 million over the GD17 period.

Whilst we would challenge the Utility Regulator's approach in this regard. A material weakness in application of this calculation is consideration of firmus energy's revenues when accounting for profile adjustment. Failure to account for profile adjustment results in an artificially low calculation of insurance requirements.

Further, as revenue is a function of items including Opex, Capex and WACC and the Draft Determination proposes reductions to each, there is a material impact upon any allowance calculated as a function of revenue.

The Utility Regulator appears to believe that firmus energy can negotiate lower premiums (as per 6.159 of the Draft Determination). The costs detailed above are based upon brokered rates, comparing several insurance providers, and we do not believe a reduction of almost 40% (in 2017) on current rates is justified or achievable.

In paragraph 6.336 of the Draft Determination, the Utility Regulator states the following when commenting on Phoenix's insurance cost allowance;

"It should be noted that in PNGL12, we adopted the approach used by Ofgem to base business insurance costs on 1.04% of turnover. We have decided not to use this approach to set allowances for Phoenix in the GD17 period as doing so would result in significantly lower allowances. OFGEM in RIIO GD1, moved away from the link in setting insurance to revenue, indicating that due to its specialist nature, a variety of factors can influence the premium paid".

This statement is inconsistent with the approach taken by Utility Regulator towards firmus energy's insurance allowances.

We have attached, as Appendix 8, a benchmarking report from our current brokers Marsh, which analyses our current levels of cover in comparison to other UK clients and confirms their adequacy and comparability.

3.5. Governance

As outlined in our manpower response, above, and in line with regulatory guidance, firmus energy has not requested allowances relating to change of ownership costs. While costs for our recent change of ownership were accounted for within our 2014 RIGs and BPT submissions, we clearly stated in our GD17 Business Plan submission that these transition costs are being borne by our new owners.

The Utility Regulator has chosen to disallow specific, material cost lines based upon the incorrect assumption that they result from our change of ownership. Of particular note is the impact on manpower, as outlined above.

In paragraph 4.8 of the Draft Determination, the Utility Regulator states;

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

...and further in paragraph 6.33 of the Draft Determination, the Utility Regulator states;

"We note that since the sale of the business, additional costs have been incurred, in respect of Professional, Legal and IT mainly. Our approach is not to make adjustments as a result of change of ownership and no additional allowances will be granted to fund these costs. Furthermore we have not provided for additional allowances within GD17 that were justified as a result of the change of ownership."

Our Opex overspend of 2014 cost allowances (by £0.4m) was entirely a result of having to uplift our marketing spend to support our challenging connection targets. It was not a consequence of our change in ownership.

Furthermore, whilst individual Opex cost lines may reflect the new structure of ownership (i.e. costs detailed within individual Opex items, as opposed to a rolled up parental charge), again, firmus energy has not requested any additional allowances associated with a change in ownership. Of note, in GD14 the Utility Regulator allowance for parental recharge (from our previous owners) was over £0.5m per annum. For GD17, these costs are now included within specific Opex line items.

3.6. Audit, Finance and Regulation

Firmus energy included professional and legal fees of £85k per annum to cover financial and regulatory consultancy and legal advice, audit and taxation fees and professional subscriptions.

Together with a reduction of 1.1 FTEs under this activity, the Draft Determination has reduced the allowance for these professional and legal fees to £20k per annum (a 77% reduction) – the figure in 2014.

Whilst the professional and legal fees have been reduced to their 2014 level, the stationery, communications and billing costs of £11k per annum have been accepted as presented (by the Utility Regulator) and not uplifted to the 2014 cost of £27k. The Utility Regulator's approach is therefore inconsistent.

Similar to HR & Non-Operational Training, financial and regulatory consultancy and legal advice can fluctuate year to year and to use a single year does not provide a true representation of average costs. This is borne out by the fact that Audit, Finance and Regulation professional and legal fees in 2013 were £76k.

The Utility Regulator has also allocated 15% of staff time (and cost) within this area to owner occupied connections, which equates to £62k per annum. Only a small proportion of time (<5%) for staff in Finance and Regulation is spent on owner occupied Advertising and Market Development. We therefore believe the Utility Regulator's assessment to be overstated (by a minimum of £40k per annum) and do not believe the proposal of £62k per annum is justified.

We would also note an error in figures under this activity within the Draft Determination, in that Table 39 (page 89) shows incorrect figures for Utility Regulator Draft Determination before re-allocation. This error is £34.2k per annum, or £205k for the GD17 period.

3.6.1. Price Control Consultancy Costs

In formulating some of these responses firmus energy required consultancy support. As a result of the level of detail required these professional and legal fees were higher than the costs allowed within the GD14 Price Control determination. Looking forward to the next price control period, we note the impact of price control related consultancy costs has not been acknowledged by the Utility Regulator in the Draft Determination.

3.7. Procurement

Firmus energy included professional and legal fees of £18k per annum to cover ongoing consultancy and legal advice. As a regulated utility, firmus energy is governed by the EU Utilities Directive with regard to how it awards contracts. As such, we continuously review procurement policies and procedures, as well as collating and evaluating tender documents for new and existing contracts.

The Draft Determination has reduced the allowance for these professional and legal fees to £11k per annum (a 38% reduction). The fees have been reduced to their 2014 level, thus reducing our opportunity to market test cost categories or to drive Opex savings.

Procurement consultancy and legal advice can fluctuate year to year, depending on contracts due for renewal or new contracts, and to use a single year does not provide a true representation of average costs. This is borne out by the fact that procurement professional and legal fees in 2013 were £20k.

3.8. Asset Management

Firmus energy included professional and legal fees of £12k per annum to cover Asset Management consultancy and legal advice.

The Utility Regulator has recognised and appears to allow these costs in their detailed calculations. Unfortunately, however, these costs do not appear to flow through to the final total allowed under Asset Management in the Draft Determination.

3.9. HR and Non-operational Training

Firmus energy included professional and legal fees of £67k per annum to cover recruitment and HR consultancy and legal advice.

Together with a reduction of 0.6 FTEs under this activity, the Draft Determination has proposed reducing the allowance for these professional and legal fees to £28k per annum (a 57% reduction). The fees have been reduced to their 2014 level.

HR consultancy and legal advice can fluctuate year to year, depending on employee relationship issues, and to use a single year does not provide a true representation of average costs. This is borne out by the fact that HR professional and legal fees in 2013 were £71k.

3.10. Trainees and Apprentices

Firmus energy included professional and legal fees of £88k per annum to cover the following costs:

- Cost of running training courses
- Fees paid to external training providers for provision of training
- Cost of externally advertising training and apprentice programmes
- Salary cost of apprentices or trainees whilst engaged on a training or apprentice programme; and
- Cost of ongoing professional development for operational staff

The Draft Determination has reduced the allowance for these professional and legal fees to £Nil per annum (a 100% reduction) stating *“We have not accepted the professional and legal fees into the GD17 period as we consider this expenditure was not justified within the FE GD17 Business Plan”*.

Annex 3, Part 3, Section 2 (General Development Plan, Company Structure) of the firmus energy Licence states:

“... The Licensee and its contractors will provide training to ensure that all required standards are properly met.”

Annex 3, Part 3, Section 5 (General Development Plan, Training) of the firmus energy Licence states:

“...To build a successful gas industry in Northern Ireland will require a highly skilled and competent work force. The Licensee will encourage the employment of local people and ensure that the necessary training and assessment is available. The company is in liaison with the Department of Education and Learning and using local training providers of Colleges of Further Education to provide the necessary skills training...”

Further Licence references to training requirements are made in the following sections:

- 2.7A.4 The Relevant Matters
- Annex 3, Part 3, Section 4 (General Development Plan, Organisation)

Aligned to our Licence requirements, we believe that the training of our staff is an invaluable ongoing investment for the organisation. Some elements of our training are also a legal requirement for our engineers who are on site and require continuing Health and Safety training. Further detail on the legislative requirements relating to firmus energy’s network maintenance provided in Appendix 3.

Firmus energy prides itself on having a highly skilled and trained workforce and we believe that this training hugely assists in our interactions with all stakeholders and consumers.

The Utility Regulator’s proposal to reduce our training allowances from £88k per annum to £Nil seems entirely inconsistent with our Licence obligations, as detailed above.

We would ask the Utility Regulator to reinstate our request for training, as per our GD17 Business Plan.

3.11. Emergency Costs

Safety is the principle priority for firmus energy. In order to fully assess the Utility Regulator’s view, we have requested, but are yet to receive the Utility Regulator’s modelling of emergency calls. Any disallowances in proposed, efficiently incurred forecasted costs are of particular importance. Our comments are made in this context, and we would welcome further engagement with the Utility Regulator in this regard. Further detail on the legislative requirements relating to firmus energy’s network maintenance provided in Appendix 3. Annex 8 (page 8, paragraph 1.59) of the Draft Determination states:

“We recognise that FE has to operate two separate operational areas for responding to emergencies, due to the nature of its distribution area and the rapid response times defined in its standards of performance. This explains at least in part why the variable cost unit rate might be higher than for Phoenix who operate a single, compact, response area.”

3.11.1. First Response Activities

In line with the Gas Safety (Management) Regulations and firmus energy’s Safety Case we are required to operate a 24/7 365 day per year emergency response service to manage reported gas escapes across our Licensed Area.

Firmus energy has in place a contract with the National Grid Emergency Control Centre (ECC), at Hinkley, England. Through the ECC all emergency calls are recorded and issued to the relevant competent engineer(s), supervisor(s) and where required, the standby manager on call.

Firmus energy’s management of emergency response includes:

- 24 Hour Emergency Response
- Emergency Phone Number (0800 002 001)
- On Call Duty Personnel (Engineers/Technicians/Supervisors/Manager)
- On Call Public Relations (PR) Personnel
- An Emergency Repair Response team & Support Resources, provided by McNicholas

The source of emergency reports may be from:

- Members of the public
- Police Service for Northern Ireland (PSNI) or Northern Ireland Fire and Rescue Service (NIFRS)
- firmus energy personnel
- Supply companies
- Other utilities, local authorities, building contractors and statutory bodies

Classifications of firmus energy’s emergency calls:

- A significant escape of gas, a localised pressure problem or a localised outage which requires manpower, equipment or expertise above that required for normal Leak Management. Any gas related incident where there is no perceived danger to life or property but which requires notification to Public Relations (including Marketing Manager and Regulatory Affairs Manager)
- A pressure incident which requires significant additional manpower, equipment or expertise
- Any report of a gas-related incident where fire, explosion, death, injury or property damage has occurred
- A Carbon Monoxide (CO) poisoning
- A problem in the Gas Networks Ireland (UK) Transmission system which adversely impacts supply to a firmus energy distribution system
- A problem in the Premier Transmission Pipeline System (PTPS) which adversely impacts supply to a firmus energy distribution system

During GD14 we have implemented a number of measures to mitigate the numbers of calls received that result in 'call outs' by response personnel and have therefore reduced costs, which are reflected in our GD17 Business Plan.

We have invested significant resources to expand the knowledge of our customer call handling staff who receive reports of PREs, with further training them in how to manage calls, deciding which calls should be transferred to our emergency call centre at Hinckley, and determining which calls can be managed internally by firmus energy staff.

We have also carried out extensive training with our Emergency Call Centre staff at Hinckley on our emergency processes and procedures to enable our Emergency Call Centre staff to close out perceived emergency calls over the phone, or re-direct customers to the responsible person, for example, a Gas Safe registered installer in the case of an issue downstream of the meter that is not an escape of gas, thereby further reducing the number of calls received requiring a First Response Operative.

The Utility Regulator has proposed a significant reduction in the first response allowance, notwithstanding a significant increase in connections to the network and has revised the methodology of modelled call numbers. This modelling is now based on mild (below average temperature) for the winter for years 2012, 2013 and 2014. We believe the actual average temperatures were: 2012; 9.17°, 2013; 9.61°, 2014; 10.09°. The seasonal norm temperature for 2013 was 9.22° and for 2014 was 9.38°. This provides an artificially low basis for deriving the Utility Regulator's assumptions.

In addition, the revised model makes a material change to the assumed mix of calls emanating from existing customers as compared to those emanating from new customers. This is of particular concern to firmus energy and we would ask the Utility Regulator to reinstate the assumptions applied as part of the GD14 review, particularly given the significant growth targets.

Figure 3.7 outlines the change in call assumptions, per 10,000 customers, highlighting the change in the modelled figure per 10,000 customers, used by the Utility Regulator to assess emergency call numbers, in 2014 (the first year of GD14) to the new modelled figure as proposed for 2017 (the first year of GD17) before any efficiency factors are applied.

Figure 3.7 Emergency Calls GD14 and GD17

Calls per 10,000 customer	2014	2017
Existing customer calls	1,951	1,643
New customer calls	3,813	4,404

This will have a significant impact on firmus energy due to the type of meters connected to our gas network. Over the past 10 years we have been connecting customers within the new build, NIHE and rented sectors. A high percentage of new build properties have been purchased by Housing Associations and landlords and due to the high turnover of tenants, or perceived risk to the landlords (regarding debt), pay-as-you-go (PAYG) meters have been fitted rather than credit meters. Firmus energy has a low level of owner occupied existing housing and credit meters compared to other GDNs. The percentage of prepayment meters in our domestic customer base is c. 90%.

As a result of this network profile, a high proportion of existing connected properties will continue to generate calls relating to the gas installation, regarding smells of gas, operation of the meter, and operation of boiler and appliances (i.e. calls typically associated with new customers).

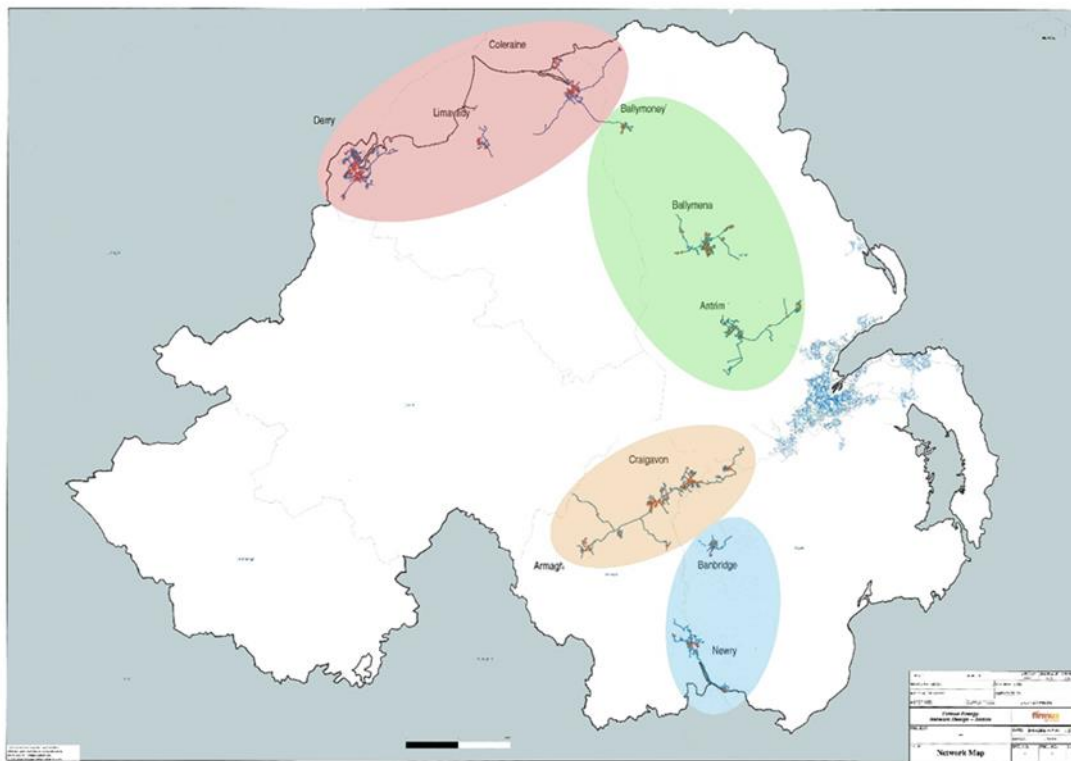
We believe the Utility Regulator's change in mix is not commensurate with firmus energy's network profile, and as these calls are paramount in terms of how firmus energy operates as a responsible and prudent network operator. These calls cannot be capped or indeed constrained (notwithstanding our efforts to mitigate their number) and these calls must be responded to.

We believe the Utility Regulator's proposals should be revisited.

3.11.2. Emergency Response Efficiencies

The Utility Regulator's Standards of Service and Performance (as introduced in 2014) have a material impact upon emergency costs. The Standards stipulate appointments for works and timescales for planned meter exchanges and for emergency response for PAYG meters and other gas emergencies. These timescales limit the scope to plan a more efficient programme of works and due to the sparsity of our network and the large distances and relatively low numbers of works, the contractor charges for any costs associated with the time taken to travel and fuel costs in their rates to complete the works.

Map 2. Activity Areas of Four firmus energy First Call Operatives (FCOs)



Distance (network sparsity, as outlined in Figure 3.5 and the map above) also impacts upon the supply of response engineers for emergency calls. The call levels experienced by firmus energy is small and are dealt with by 1–2 engineers in the summer and 2–3 engineers in the winter period. However, our

Licence and Standards of Performance regulations result in a requirement to have 4 engineers on standby at all times. These engineers remain within particular areas to ensure the Standards of Performance are met, or an unrecoverable penalty must be paid to the customer. The contractor will not complete any works at a loss and therefore all costs associated with providing this service are passed directly to firmus energy.

Furthermore, unlike the Greater Belfast Licensed Area, where the requirement for response engineers is driven primarily by the overall number of calls received, firmus energy's resourcing in this regard is particularly sensitive to the obligations of our Standards of Performance and subsequently this impacts upon our ability to avail of comparative economies of scale.

Therefore we would ask the Utility Regulator to review the scale of disallowance in this regard.

4. Capex

Firmus energy welcomes the fact that the Utility Regulator has accepted the central proposition in our GD17 Business Plan i.e. that in order to drive connections we must be allowed to invest in further extensive rollout of the network. The Utility Regulator has increased slightly the target for properties passed (against our GD17 Business Plan) and we believe the revised target can be delivered.

We have indicated our concern about how some potential customers may be disadvantaged by the Utility Regulator's proposed re-profiling of the network build to front load those projects delivering the highest economic return. Our own plan had been optimised to include as many properties as possible within projects that were overall positive and not just picking those individual properties that fitted with our meterage allowance. Nonetheless, with this qualification, we believe the Utility Regulator's revised plan can be delivered.

We also note some of the allowances in the Basket of Works are lower than in the GD14 period and lower than the fixed rates in our period contract. We are clearly bound by the rates in our fully tendered contract, not least until March 2019.

As regards connections we have already stated that we do not believe the Utility Regulator's sharply increased targets (a 22% increase on our own significantly increased owner occupied targets) are achievable. The position is exacerbated by the package of other proposals the Draft Determination makes regarding connections rather than by a particular problem with Capex.

We are concerned that the Utility Regulator is proposing year on year efficiencies on top of the efficiencies already built into our Plan and the lack of scope to make savings against a fixed rate period contract.

We are also seeking an appropriate allowance for essential investment in replacing obsolete IT systems. The Utility Regulator has confused this with other issues around change of ownership but it is a straightforward necessary replacement to drive productivity across the business with excellent payback.

4.1. Network Development

To underpin the GD17 submission firmus energy carried out a detailed analysis of all towns within our Development Area and produced a detailed construction programme for 2017–2022, with a high level programme for 2022–2045. We completed load surveys, network analysis, and designed the mains infrastructure for all towns. We zoned the towns to produce distinct infill projects which we subjected to NPV analysis and further assessed to produce forecast construction costs. The plan combines details of projected new connections and network extension across the Licensed Area with associated costs and investment requirements. We now have a detailed and costed network design of 621 projects which cover our entire Licensed Area. This includes a wealth of detailed quantitative and qualitative data to inform development planning and which represents our ability to demonstrate, in detail, the metrics around growing connections and extending the network.

The Utility Regulator notes in the Draft Determination paragraph 7.112 that *“The Company has prepared a detailed programme of work to provide a logical and efficient build.”*

Given the detailed nature of the firmus energy network rollout plan for the GD17, analysis of properties passed is a relatively straight-forward undertaking. It is forecasting the total number of additional properties that will stand within 50m of the firmus energy mains pipes at the end of the GD17 period.

The Utility Regulator’s Draft Determination recognised both the detail and integrity of this work, stating in paragraph 7.112:

“FE provided detailed plans for the development of gas mains in each town comprising 621 individual projects. Each project assessment included a detailed layout of mains, a schedule of works priced using current tendered rates and an economic assessment of the project. The company has prepared a detailed programme of work to provide a logical and efficient build.”

7.113 We reviewed a sample of the projects prepared by the company and concluded that the property counts and lengths of mains identified were reasonable and were able to confirm that the works identified were priced using current contract rates.”

Despite this acknowledgement of the reasonableness of our submission the Draft Determination proposes that firmus energy’s allowances, post efficiency, are reduced by 11% whilst output targets (i.e. connections and properties passed) have increased significantly.

Such reductions appear to result from an assessment of the firmus energy network rollout plan, then setting efficiency targets, calculating the average metres per properties passed and benchmarking.

Given the scale of this proposed cut to our forecast Capex spend we are concerned that in taking this approach the Utility Regulator has not fully accounted for key factors which differentiate firmus energy. Firmus energy submitted to the Utility Regulator an analytical paper addressing benchmarking, RPEs and frontier shift as part of our first GD17 submission in June 2015. It highlighted a number of major factors which differentiate the Ten Towns network area from the networks of the GB GDNs and Greater Belfast.

4.2. Efficiency Targets

In rolling out the network build across the Ten Towns since 2005, we have sought to optimise network design and to drive cost efficiencies through innovation, without compromising the safety or the quality of our network build.

In addition, we employ staff and contractors with extensive experience within the natural gas industry, allowing us to put in place efficient plans and processes, management of materials, construction methods and new technology to deliver benefits for customers and other stakeholders. We minimise costs where possible as well as disruption to the general public.

We have invested significantly to ensure that we build and operate the gas network professionally in line with all statutory, regulatory and legislative requirements. In 10 years of operation we have installed over 1,000km of mains and over 25,000 services and meters. In that time we have not received any DRD fines or HSENI enforcements.

In developing our GD17 Business Plan we factored in continuing best practice and adopted the resultant efficiencies into our forecasts.

We outlined that we had encompassed productivity improvements and efficiencies in section 10.2 of our September 2015 Business Plan submission. Therefore, we do not believe that there is scope for the additional 1% efficiency per annum proposed within the Draft Determination, which equates to a cut of £2.8million over the GD17 period (or a cut of 3% to our proposed Capex investment of £89.3million).

The period contract with McNicholas is based on a schedule of rates and there is limited, if any scope to gain additional efficiency on top of what we already have in place. Firmus energy is locked into the current contract (and therefore the tendered rates) with McNicholas until March 2019. We have not assumed any increase in contract rates post 2019 – a clear financial risk we are carrying in the GD17 Plan.

4.3. Properties Passed

Based on the calculation of the target numbers of properties passed it is then also a straight-forward calculation to assess the average distance between these properties. Based on this figure for the average distance between properties, it is then also possible to consider:

1. The overall economic efficiency of the project
2. An appropriate allowed cost per metre of mains laid to pass the properties

The following section addresses both these issues in turn and considers the impact of the assessments made by the Utility Regulator.

4.3.1. The Overall Economic Efficiency of the Project

The firmus energy rollout plan balanced connections activity for economically positive connections and economically negative connections over the GD17 period in order to maximise the number of customers who would be able to avail of a network connection, in line with the Utility Regulator's principle objective to promote the development of gas networks in Northern Ireland.

Throughout our engagement with the Utility Regulator in the period prior to our Business Plan submission the Utility Regulator indicated its support for this approach.

However, as part of the GD17 Draft Determination the Utility Regulator has restructured this plan by removing from the GD17 period the 28% least economically attractive connection projects (assessed by distance between properties of the 621 network rollout projects developed by firmus energy) and replacing them with more economically attractive connections we had planned to pass with our network in the GD23 period (i.e. post 2022.)

While this restructuring does not have a material impact on our ability to continue network rollout there does exist an important necessity to consider the potential consumer impact as the resultant

economics of the restricted Draft Determination rollout plan means those customers, who have been removed from the GD17 network rollout face the prospect of neither having the opportunity to connect to the natural gas network in the period 2017-2022 nor in all probability the opportunity to connect post GD17 unless significantly greater property passed allowances are granted in GD23.

We welcome that the Utility Regulator acknowledges this within the Draft Determination and has requested that firmus energy provides additional historical burn analysis to further prove the economic viability of passing all the properties planned. We will continue to work with the Utility Regulator to demonstrate the case to undertake future network rollout, beyond GD17.

4.3.2. Allowed Cost Per Metre of Mains Laid to Pass Properties

We acknowledge that two functions of this Capex re-profiling are, a slight uplift in the total number of properties passed proposed for the GD17 period and a reduction to the average weighted allowance provided per metre of mains laid. We would welcome further engagement with the Utility Regulator ahead of the Final Determination in order to best serve consumers within the Ten Towns as a result of the out-workings of any Capex re-profiling.

The Utility Regulator has also included a further retrospective adjustment that will be applied at the end of the GD17 period, which is outlined in paragraph 7.25 of the Draft Determination.

“Adjusting for the actual length of main delivered up to a length per property cap, removes the risk of estimated lengths for both consumers and the GDN and ensures that development is delivered within the parameters of the determination.” While we accept that this retrospective mechanism will act to ensure we lay mains as forecasted in our detailed network rollout plan, given the extensive work undertaken by our engineering department to develop our plans, we have no plan to do otherwise.

4.4. Benchmarking - Basket of Works Approach

We acknowledge that the intention of the ‘Basket of Works’ concept is to ensure company’s allowances are balanced across the full range of Capex costs and therefore reflective of total costs.

However, it is evident from our GD14 costs that, when the Basket of Works is applied to a small customer population, any customer outlier not predicted when the allowances were set has a major impact on the accuracy of the allowances.

The impact of the reapplication of the Basket of Works Approach for GD17 will produce further problems for domestic customers within the firmus energy network. While we acknowledge that the Industrial and Commercial service and meter allowances are more favourable in GD17 than in GD14 this is not the case for domestic customers.

Notably, the allowances for domestic services and meters are much less favourable than GD14 despite the GD17 period being focused on domestic growth. For example the reduction in domestic services allowances could require us to ask customers to contribute towards this element of the cost of a (domestic services) connection.

Firmus energy will be required to adhere to determined rates for GD17 while continuing to work to fixed rates that are included in the period contract with our subcontractor McNicholas until March 2019.

Firmus energy would therefore request that in the Final Determination the Utility Regulator reflect, as far as possible, the reality that we will be working to a fixed period contract to March 2019. Such consideration is important in order to reduce the prospect of customer contributions, particularly in the context of the proposed reduction to Connection Incentives.

4.4.1. Ten Towns Domestic Service Rates Compared to More Densely Populated Areas

In their assessment of the firmus energy network the Utility Regulator's consultants Deloitte state:

"FE has a significantly different profile to any of the other GDNs in terms of the ratios between network length, customer numbers and volume of gas supplies."

Despite these factors it is our understanding that the Utility Regulator primarily benchmarked firmus energy's service rates with those of the Greater Belfast Area. This approach does not appear to have accounted for a number of fundamental differentials between the Ten Towns and Greater Belfast most notably the impact of network sparsity upon costs to firmus energy.

In densely populated network areas service laying teams can share equipment and plant such as mini diggers and trailers, thereby reducing costs. In addition, in less sparsely populated areas travel times are reduced, limiting the additional costs paid in fuel costs and in staff wages for teams travelling between jobs.

Greater geographical spread of services also increases the costs associated with support services for service laying teams. Examples of these support functions include provision of grab lorries to transport material and equipment, reinstatement teams, pick up teams and supervisors.

The average length of a service in the Ten Towns network is 16 metres in length, significantly longer than the average service length of c. 10 metres in Belfast. This length differential will also impact upon the average cost of each service and the consequential build-up of rates.

In addition, the ground conditions in the Ten Towns, particularly in areas such as Newry which is a city built on basalt, are significantly less favourable than in Belfast, further increasing costs.

Rolling out our network in numerous town centres means contending with the additional cost of laying mains and services in many public realm areas. Areas where government has upgraded the street paving and furniture as part of public realm works result in significantly higher reinstatement costs compared to simple bitmac/asphalt reinstatement. If a Local Authority has a requirement that the company use the services of their own specialist contractor, the public realm reinstatement can cost up to £900 per square meter and there is also often a requirement to undertake reinstatement out of hours for which we incur a 65% uplift on our contract rates.

As a result of these factors the outputs from firmus energy's service laying teams across the ten Towns network are less than those of teams working in more density populated areas.

However, indicative benchmarking feedback we have received from the Utility Regulator demonstrates that firmus energy productivity compares favourably with the productivity of comparator GDNs involved in network rollout in more densely populated areas.

This feedback provides further evidence that firmus energy has accurately incorporated efficiencies into our network rollout plan and that the further efficiency targets applied by the Utility Regulator are not reasonable.

4.4.2. Utility Regulator's Calculation of firmus energy's Projected Costs

In the Utility Regulator's consideration of the Basket of Works, the proposed (synthetic) rates have been derived based upon firmus energy's historic costs from 2011 to 2014. This date range somewhat predates our current period contract, (which commenced in March 2014). The analysis therefore does not fully capture the impact of our updated tendered rates. Correcting the Utility Regulator's calculation uplifts firmus energy's projected costs by 3.36%, as detailed in Figure 4.1.

Figure 4.1

Element	Old Contract Rates			New Contract Rates		
	Activity	Rate	Cost	Activity	Rate	Cost
New Build Mains	10,579	29	305,104	10,579	25	260,233
Other Mains	62,499	71	4,447,592	62,499	73	4,580,679
Existing Housing Service	3,191	751	2,395,835	3,191	761	2,427,011
New Housing Service	779	307	239,332	779	322	250,783
I&C Services	292	1,182	345,064	292	1,346	392,978
Domestic Meters	3,759	169	634,519	3,759	174	653,765
I&C Meters	260	1,377	357,909	260	1,741	452,762
Total			8,725,355			9,018,212
					% increase	3.36%

We would ask the Utility Regulator to take this uplift into account in its calculation of synthetic rates.

4.5. Other Capex

4.5.1. Foyle River Crossing

Both the Utility Regulator and firmus energy recognise the importance of this security of supply project. We submitted an outline of the project as part of our GD17 supplementary papers in June 2015, and an update as part of our GD17 Business Plan submission in September 2015, in the shared knowledge that this project is intended to proceed during the GD14 period. We hope that following this submission discussions will continue in earnest on the project in order to confirm an allowable amount for the full project, and a date for the commencement of work. A start date is now critical if

this work is to be undertaken within the GD14 horizon. We would urge the Utility Regulator to progress the approval process with ourselves as a matter of urgency.

4.5.2. Telemetry

As noted in our September GD17 Business Plan submission, and appended supplementary paper, we are currently investigating new technology options with regard to telemetry proposals. To reduce costs it is proposed to use industrial and commercial (I&C) customers (where they are in close proximity to network extremities) for the location to monitor pressures within towns.

These costs were evidenced in our 30 June GD17 Supplementary Paper. However pending the outcome of discussions with the Utility Regulator on this issue we did not include these costs within the GD17 Business Plan Template.

We would welcome consideration by the Utility Regulator of the provision of allowances for these installations of new telemetry across the network, the cost for which is forecast as £191k over the GD17 period.

4.6. IT Capex

Firmus energy has a requirement to replace obsolete IT systems, costs for which were not allowed in the Draft Determination. The paragraphs below provide further detail, over and above that provided in our September 2015 Business Plan, to explain the essential nature of this investment.

We wish to state clearly that firmus energy's request for an allowance to replace the Integrated Utilities System (IUS) has not arisen as a result of our new ownership. This cost would still be requested had firmus energy remained a subsidiary of BGE or been owned by our current owners or indeed anyone else. Nevertheless, it should be noted that BGE, for whom IUS was written 20 years ago, has recognised IUS's restrictions and have themselves already transitioned to an IBM asset management system.

4.6.1. Rationale for New IT Platform to Host Replacement Asset Management System

As part of the GD14 final determination and engagement with the Utility Regulator, firmus energy confirmed its commitment to ensuring that its Assets Management System would be compliant with the PAS55 Asset management Standards by the end 2016. Since then PAS55 has been superseded by ISO 55000 as the International compliance benchmark and firmus energy continues to work towards the 2016 deadline. The GD14 final determination stated that neither firmus energy nor Phoenix would be granted an allowance by the Utility Regulator to ensure their asset management system was PAS55 compliant. The Utility Regulator stated that it was a requirement that should have been in place since 2006 and was not a cost that OFGEM had ever granted in Great Britain.

Firmus energy has commissioned The Woodhouse Partnership Ltd to audit the firmus energy asset management processes, project manage a restructuring of our internal procedures, and ensure ISO 55000 compliance by December 2016.

It is important to note that our request to implement a new IT asset management system, as part of the GD17 submission, is not associated with the aforementioned ISO 55000 compliance requirements. Instead this is an element relating to the replacement of our current 20 year old Integrated Utilities System (IUS). This is the character based software and database platform that facilitates firmus energy Supply's billing operations and firmus energy Distribution's Network assets information. Firmus energy has never requested, in any previous price controls, an allowance to replace its IT asset management platform.

Background

Until June 2014 firmus energy had been a subsidiary of Bord Gais Eireann (BGE) and its IT Corporate Systems were organised and operated on an integrated basis. Following the sale of firmus energy in 2014 it became apparent that, as a new separate entity, firmus energy had to detach from the BGE IT infrastructure. This IT transition project immediately became a main priority for firmus energy. Experienced IT consultants (Deloitte) were brought on board to project-manage and complete the process as expeditiously as possible. At the scoping and requirements stage, the need for replacing the current Integrated Utilities System (IUS) with a new separate billing system and separate asset management system was immediately recognised. However, given the additional time needed to implement this, there was no option other than to put it on hold until after the transition process.

In November 2015, firmus energy successfully migrated off the BGE IT platform. The transition process had a Capex cost of £600k, none of which will be paid under Price Controls or by customers.

Following the transition on to its own IT hardware infrastructure and support services, firmus energy intends now to seek further savings and benefits for customers by implementing the next requirements identified internally and by Deloitte. This is the replacement of the current IUS platform including an asset management system. The IUS Billing project (part of replacing IUS) is included as part of the firmus energy Supply Price control (SPC17) submission and the IUS replacement asset management system is part of the firmus energy Distribution (GD17) price control submission.

4.6.2. Integrated Utilities System

The Integrated Utilities System (IUS) application is a bespoke development which was originally developed by BGE over 20 years ago and sits on a Progress database. It was designed for the needs of BGE and not firmus energy. There are no system documents available for IUS, which means there are no instructions for a developer or systems administrator to follow in order to make standard changes. This means that any changes and fixes to the system, require a review of the coding and then a rewriting of the code. For this reason firmus energy is now reliant on two Progress developers rather than an internal systems administrator carrying out straight forward system changes. In addition the

asset management element of IUS is presently deemed inefficient and in need of replacement for a number of other reasons. These include:

- Reporting. IUS cannot report efficiently on network assets without labour intensive and time consuming data manipulation. Improved reporting, like any changes would require significant system development.
- IUS cannot communicate with firmus energy's online site works interface
- IUS cannot communicate with Main Contractor (McNicholas) IT systems. Job cards and handovers currently is a time consuming, manual and handwritten procedure. IUS cannot facilitate paper-less processes for this
- IUS cannot separate Distribution elements from IUS from Supply elements. i.e. separate asset management from billing

The asset management system could be maintained in its current state, with the operational cost of contracting 2 Progress developers to maintain the day to day running of IUS. Progress developers are a scarce resource and have a very niche skill set that few other database programmers have. At present each developer costs firmus energy £600 per day, which translates into nearly £300k per year for their services. Unfortunately, until such time as a new modern asset management system is in place, firmus energy has no option but to continue incurring disproportionate costs on this resource.

Phase One of firmus energy's transition away from IUS will be the new billing system and phase two will be the new asset management system. At present firmus energy is engaging with the Utility Regulator its external consultants Gemserv in reviewing Phase 1. Firmus energy is confident that through the provision of relevant information and significant engagement Gemserv will share our conclusion that IUS should be replaced.

5. Financial Aspects

Our business needs to secure significant amounts of new funding from both equity and debt investors during GD17 in order to finance the shortfall in cash flow arising from our capital expenditure programme. This cash shortfall is exacerbated by the operation of the “profile adjustment”. The Utility Regulator has failed to give due consideration to the combined impact of its Draft Determination on our ability to secure the financing we need. We therefore find ourselves in a position in which our ability to continue to operate our business safely and attract the financing we need to continue our network development is of notable concern.

5.1. Introduction

As the Utility Regulator states in the Draft Determination, “Article 14 of the Energy (Northern Ireland) Order 2003 requires us to carry out our functions in the manner we consider is best calculated to further our principal objective: having regard to the need to secure that licence holders are able to finance their licence obligations (amongst other things).”⁶

“Financeability” is generally interpreted in a UK regulatory context as the requirement that, in setting price controls, regulators should have regard to the ability of efficient companies to secure financing in a timely way and at a reasonable cost in order to facilitate the delivery of their regulatory obligations.⁷ In other words, the cash flows obtained by the utility from its regulated business must be sufficient to finance its (efficient – i.e. allowed) operating costs and its (efficient – i.e. allowed) capital expenditures. Where there is a shortfall, the utility must have a reasonable expectation of being able to source equity and/or debt financing in a timely way and at a reasonable cost in order to finance that shortfall.

To put this in context, the Draft Determination contemplates the following for firmus energy:

Figure 5.1 firmus energy’s cash shortfall in GD17 (based on Draft Determination)

GD17 Draft Determination	£m (nominal)
Determined revenues	117.2
Determined opex	(40.6)
Determined capex	(92.1)
Interest cost (at 55% gearing)	(36.1)
Net cash surplus/(shortfall)	(51.6)

Assuming that firmus energy is able to operate within its challenging allowances for Opex and Capex, the company will need to obtain an additional £51.6 million of new funding during GD17. This is primarily driven by the material capital investment programme contemplated for the period, in line

⁶ Draft Determination, paragraph 10.56

⁷ See, for example, Joint Regulators Group *Cost of Capital and Financeability* (March 2013), paragraph 3.16

with the objective we share with the Utility Regulator to support the development of the gas industry in Northern Ireland.

The new funding that we require will need to be sourced from a combination of equity investment and debt financing. In the sections that follow, we set out in detail our concern that the Utility Regulator has failed to give due consideration to all the factors relevant to our ability to finance our business in setting the parameters for its Draft Determination.

- The combination of a low rate of return, the deferral of cash flows as a result of the operation of the “profile adjustment” (see further section 5.7 below) and our significant capital expenditure programme for GD17 create a situation in which our cash flows are severely constrained and our ability to absorb any unforeseen cost shocks is limited
- The Utility Regulator’s assessment of our financeability is significantly less detailed than the exercise it undertook for GD14 and focuses solely on financial metrics that are specific to Phoenix. The methodology employed ignores the impact of capital expenditures and the profile adjustment on our overall funding requirement and limited sensitivity analysis appears to have been undertaken to test our ability to withstand unforeseen events
- The Draft Determination will place us at real risk of default under our existing debt financing arrangements (even assuming that we de-gear to 55% of TRV), placing in jeopardy our ability to raise further funding to meet our capital expenditure targets
- With our proposed allowed cost of equity being lower than that applied to the significantly less risky GB GDNs, our ability to raise further equity financing will be called into question. This is exacerbated by the profile adjustment meaning that our actual earnings during GD17 will be below our allowed return and the lack of meaningful incentives built into the GD17 period meaning that we have no reasonable expectation of outperformance

In order to avoid a risk of breaching the financeability requirement enshrined in the Energy (Northern Ireland) Order 2003, we need the Utility Regulator to take the following steps in preparing its Final Determination for GD17:

1. To increase our rate of return to a level at which we are able to attract new equity financing and cover the costs of our debt financing, having regard for the weak cash flows of our business.
2. To give serious consideration to the elimination of the profile adjustment.
3. To subject its final package of financial determinations to a detailed and complete assessment of financeability that has full regard to the unique characteristics of our business and the current terms of our banking covenants.

5.2. Standard Approaches to Assessing Financeability

Regulators and utilities generally utilise standard credit rating agency financial metrics as an indicator of a regulated company's ability to secure debt financing on reasonable terms. Phoenix has a licence condition to maintain an investment grade rating (i.e. a rating of BBB- (Fitch or Standard & Poor's) or Baa3 (Moody's) or above) and, according to the Utility Regulator, it is important that both Phoenix and firmus energy maintain investment grade credit quality.⁸

The financeability assessment undertaken by regulators will take into account a range of the credit ratios used by the various rating agencies, including:

- **FFO⁹/interest (FFO interest cover)** - a measure of the extent to which a company can fund its interest payments out of the cash flows obtained from its operations (before Capex and changes in working capital)
- **PMICR¹⁰** – a derivative of FFO interest cover that deducts regulatory depreciation from the operating cash flow used in the interest cover calculation
- **FFO/net debt** – a test of how highly levered a company is by reference to its operating cash flows
- **RCF¹¹/net debt** – a derivative of FFO/net debt in which dividend payments to shareholders are subtracted from the operating cash flow
- **RCF/Capex** – a measure of the extent to which cash flows from operations (after dividends) cover a company's capital expenditure requirements
- **Net debt/RAV (or RAB or RCV)** – a measure of the extent to which a company is geared against its regulated asset base. In the case of the Utility Regulator's financeability assessment, the gearing level is assumed to be 55%, consistent with the gearing it proposes to utilise in the calculation of weighted average cost of capital

These credit ratios are compared to the target ranges that the three major credit rating agencies state are consistent with credit ratings in the BBB-A range (Figure 5.2). However, it should be noted that, with the exception of RCF/Capex, none of these metrics take into account the cash capital expenditures of a regulated business in excess of regulatory depreciation. They are therefore imperfectly suited to the assessment of a rapidly growing business such as firmus energy.

⁸ Draft Determination, paragraph 10.60

⁹ FFO is 'funds from operations'

¹⁰ PMICR is 'post maintenance interest cover ratio'

¹¹ RCF is 'retained cash flow'

Figure 5.2 Credit metric ratios – using the example of regulated energy networks

Credit Metric Ratios	Fitch		Moody's		Standard & Poor's	
	A	BBB	A	Baa	A	BBB
Net debt / RAV (%)	50 – 65	>65	45 – 60	60 – 75	<70	>70
FFO interest cover (x)	4.0 – 5.0	<4.0	3.5 – 5.0	2.5 – 3.5	>3.5	2.5 – 3.5
PMICR (x)	>1.7	<1.7	2.0 – 4.0	1.4 – 2.0		
FFO / Net Debt (%)			12 – 20	8 – 12	>12	8 – 12
RCF / Capex (x) ^[1]			1.5 – 2.5	1.0 – 1.5		

5.3. The Utility Regulator's Analysis of Financeability

We consider that the financeability analysis undertaken by the Utility Regulator for the purposes of the GD17 is flawed in a number of respects, each of which overstate the financial health of our business.

5.3.1. The Utility Regulator's Financeability Assessment Focuses Solely on a Non-standard Financial Metric that is Specific to Phoenix

To date, the Utility Regulator's assessment of the GDNs' cash flows for the purposes of its financeability analysis has not focused on any of the "standard" credit metrics outlined in Figure 5.2 above. Instead, the Utility Regulator has adopted an adjusted version of the PMICR that matches the covenants embedded within Phoenix's existing debt financing package (the "**Phoenix PMICR**"). The Phoenix PMICR adjusts "standard" PMICR so as to deem that there is no deferral of revenues or cash flow as a result of the profile adjustment.

When we were arranging our own bank financing in 2014, our lenders did not believe that the Phoenix PMICR method represented an adequate method of testing our financial health, for two principal reasons.

- First, the Phoenix PMICR artificially overstates cash flows by deeming that there is no deferral of revenues or cash flow as a result of the profile adjustment. (Based on the Draft Determination, approximately £10million (in nominal terms) in cash flows will be deferred by operation of the profile adjustment during GD17)
- Second, the Phoenix PMICR pays no regard to the means by which our capital expenditures are to be funded to the extent that they exceed regulatory depreciation. (In firmus energy's case, the ratio of allowed Capex to regulatory depreciation over the GD17 period is over 2.5x in nominal terms)

As a result, our own financing covenant package utilises an alternative test of our financial health: the "**FE Adjusted PMICR**", which we describe further below.

While we understand the historical reasons for using the Phoenix PMICR as part of its analysis (not least because Moody's has adopted the definition in its rating of Phoenix), it is important that the Utility Regulator notes that the Phoenix PMICR provides an incomplete picture of financeability. In addition to the Phoenix PMICR, the Utility Regulator should also have regard for the "standard" credit ratios applied by credit rating agencies, as well as the FE Adjusted PMICR.

5.3.2. The Utility Regulator's Assessment is flawed on its Own Terms

As part of the Draft Determination, the Utility Regulator provided the following assessment of our financial metrics based on Draft Determination outputs:

Figure 5.3 Utility Regulator's GD17 Financeability Analysis for firmus energy¹²

UR GD17 Financeability Assessment	2017	2018	2019	2020	2021	2022
Adjusted interest cover	1.41	1.40	1.40	1.40	1.40	1.40
Gearing	56.6%	57.2%	57.2%	57.2%	57.2%	57.2%

As can be seen from Figure 5.3 above, the Utility Regulator has assessed that, under the outputs from the Draft Determination, firmus energy will have a Phoenix PMICR of 1.40x (although it should be noted that in the Utility Regulator's detailed calculations (provided post-Draft Determination) the ratio in 2018 actually drops below 1.40x). The smoothed 1.40x profile seen above has been achieved in part by the Utility Regulator's modelling assuming that dividend distributions are reduced or eliminated to the extent necessary to maintain a 1.40x Phoenix PMICR ratio.

However, in calculating the Phoenix PMICR, the Utility Regulator has applied a blended cost of debt throughout the GD17 period rather than applying the applicable allowed cost of debt for each year. Adjusting the cost of debt to determined values delivers the following Phoenix PMICR results (all other assumptions unchanged):

Figure 5.4 Utility Regulator's GD17 Financeability Analysis for firmus energy corrected for error in interest calculation

	2017	2018	2019	2020	2021	2022
Nominal interest rate	4.7%	4.7%	6.0%	6.0%	6.0%	6.0%
Adjusted interest cover	1.63x	1.63x	1.28x	1.27x	1.28x	1.28x

The above table highlights that, from 2019 onwards, firmus energy would be well below the Utility Regulator's own target for the Phoenix PMICR financial ratio.

¹² Table 183 of the GD17 Draft Determination

In addition, the Utility Regulator's modelling of Phoenix PMICR fails to take into account a number of factors that will or may result in a further deterioration of the ratio below the level stated above (after correcting for errors in the Utility Regulator's calculation of interest cost).

- **Working capital.** The Utility Regulator has assumed that there is no change in our working capital requirement throughout the GD17 period, despite forecasting material growth in connections and the size and scope of our network. Any increase in our working capital requirement will need to be funded with cash, in turn driving the Phoenix PMICR ratio down
- **Perfect mirroring of regulatory allowances.** The Utility Regulator has assumed that we are able to meet all of our operating cost allowances in each year of the GD17 period. While we accept that assessment against allowances (i.e. assuming no underperformance) is appropriate for the purposes of conducting a "pure" financeability assessment, we would note that the covenant levels shown above provide no margin for error in the form of underperformance. Accordingly, any underperformance will result in a material deterioration in our credit metrics from an already sub-investment grade level
- **No tax payable during GD17.** The Utility Regulator has assumed that we will not pay any cash tax during the GD17 period, presumably on the basis that our cash tax payments in prior years (and as disclosed by our Business Plan) have been limited due to the utilisation of brought forward taxable losses from other group companies. As the Utility Regulator noted in its GD14 financeability exercise *"a company needs to be able to finance its functions as a standalone business and hence the group structure should not be an issue in assessing financeability"*¹³. Therefore, the tax losses from firmus energy Supply should be ignored for the sake of the financeability exercise

5.3.3. The Utility Regulator's GD17 Financeability Assessment is Significantly Less Robust than its Approach in GD14

As part of the Final Determination for GD14, the Utility Regulator conducted a detailed long-term financeability modelling exercise that included sensitivity analysis in order to ensure that both firmus energy and Phoenix would remain on a financially sustainable trajectory over the forecast horizon.

The approach adopted for GD17 is significantly more high-level in nature, and therefore less robust. Key differences in the analysis are set out below.

- **Time horizon.** For GD14 the Utility Regulator modelled financeability through to the end of the "forecast horizon" (2035 in firmus energy's case), in order to understand the long-term

¹³ Page 149, Utility Regulator, "GD14 Price Control for Northern Ireland's Gas Distribution Networks for 2014-2016" 20 December 2013

trends in financeability of the GDNs. By contrast, the Utility Regulator's analysis for GD17 focuses solely on the six year price control period

- **More conservative assumptions on interest cost.** For GD14, the Utility Regulator modelled the GDNs' financeability assuming 65% gearing and a nominal cost of debt of 6.2%, which it expected would provide a conservative (i.e. over-) estimate of the cost of debt service. In GD17, the Utility Regulator has assessed financeability on the basis of a lower 55% gearing level and a lower blended nominal cost of debt of 5.48% (for firmus energy)
- **More conservative PMICR assumption.** In GD14, the Utility Regulator sought to ensure that the GDNs maintained a Phoenix PMICR of above 1.50x throughout the period to 2035 (allowing for occasions on which the covenant might dip below that level in the short term). In GD17, the Utility Regulator has reduced its target to 1.40x on the basis of the Competition Commission having adopted the same ratio in RP5¹⁴, but without explaining why it was appropriate to maintain a buffer over investment grade in GD14 but not in GD17
- **Inclusion of downside scenarios.** For GD14, the Utility Regulator tested the robustness of its financeability analysis by modelling downside scenarios in which the GDNs underperformed their Opex and Capex allowances by 15%. GD17 analysis is flawed in so far as no such scenario analysis has been undertaken
- **Standalone basis.** In GD14, the Utility Regulator sought to ensure that it had assessed the financeability of GDNs as standalone businesses, in other words ignoring the impact of the GDNs' interactions with parent and subsidiary companies. This is relevant in firmus energy's case where the Utility Regulator's GD17 modelling assumes that no tax is payable because we are able to utilise tax losses from elsewhere in our corporate group to reduce our cash tax payments

No explanation has been provided in the Draft Determination as to why the Utility Regulator considered it appropriate to alter its approach so significantly for its GD17 financeability assessment. We believe that had the Utility Regulator incorporated downside analysis alone it would have concluded that its financeability assessment was flawed on its own terms. Applying a 15% downside on Opex and Capex to the Utility Regulator's GD17 financeability model (and, for the avoidance of doubt, not correcting for interest calculation) indicates an average Phoenix PMICR for GD17 of 1.16x.

¹⁴ The fifth price control for NIE T&D. The control will apply from 1 January 2013 to 30 September 2017.

Figure 5.5 Utility Regulator's GD17 Financeability Analysis for firmus energy adjusted for 15% downside on Opex and Capex

	2017	2018	2019	2020	2021	2022
Adjusted interest cover	1.21x	1.18x	1.16x	1.15x	1.13x	1.12x
Dividends (£)	0	0	0	0	0	0

That the Utility Regulator should have failed to undertake this analysis is difficult to understand given the significantly lower WACC (and therefore revenues) contemplated for GD17, the challenging allowances proposed in the Draft Determination and the greater exposure that GDNs have to unanticipated costs and demand levels due to the longer price control period.

5.3.4. Consideration of Metrics other than Phoenix PMICR Presents a Different Picture of Financeability

As shown in the table below, the Draft Determination outputs leave firmus energy at well below investment grade level on all "standard" credit metrics assuming 55% notional gearing.

Figure 5.6 firmus energy's credit metrics based on the Draft Determination

Output	GD17 average	Investment Grade Requirement	Investment Grade?
Net debt / RAV (%)	56.4%	60 - 75%	Yes*
FFO interest cover (x)	1.12x	2.5x - 3.5x	No
FFO / Net Debt (%)	6.0%	8 - 12%	No
RCF / Capex (x)	0.36x	1.0 - 1.5x	No

*As a result of the Utility Regulator assuming that an equity investment is made to de-gear below our current actual level of gearing.

The low RCF/Capex ratio of 0.36x illustrates the significant incremental funding requirement associated with our capital expenditure programme.

5.3.5. How We Dealt with Financeability in our GD17 Business Plan

The following table provides credit metric ratios based on firmus energy's Business Plan Capex, Opex and WACC assumptions for the GD17 period.

Figure 5.7 Credit metric ratios – firmus energy's calculations based on submission

Credit Metric Ratios	2017	2018	2019	2020	2021	2022
Net debt / RAV (%)	56.7%	57.8%	58.3%	58.6%	58.8%	59.2%
FFO interest cover (x)	1.55x	1.43x	1.38x	1.32x	1.24x	1.18x
FE Adjusted PMICR ⁹ (x)	1.76x	1.71x	1.66x	1.61x	1.57x	1.54x
FFO / Net Debt (%)	8.3%	7.6%	7.4%	7.0%	6.6%	6.3%
RCF / Capex (x)	0.24x	0.25x	0.27x	0.28x	0.27x	0.26x

It will be apparent that, even on firmus energy's Business Plan assumptions, the company's operating cash flow generation is weak, with FFO interest cover at an average of 1.33x during GD17, compared with an investment grade requirement of at least 2.5x.

However, we considered our GD17 Business Plan to be financeable primarily because we assessed that we were able to continue to access incremental debt financing to finance the cash shortfall associated with capital expenditures not captured within the Phoenix PMICR or other "standard" credit metrics. This is because our current banking package was tailored specifically to accommodate network growth by adjusting the standard definition of PMICR by implementing the FE Adjusted PMICR.

The following table outlines the differences between how the Utility Regulator has calculated Phoenix PMICR and how the FE Adjusted PMICR is calculated:

Figure 5.8 Differences between Phoenix PMICR and firmus energy Adjusted PMICR

PNGL		firmus energy
Revenue	= PMICR =	Revenue
-		-
OPEX		OPEX
+/-		+/-
working capital		working capital
-		-
DAV depreciation		CAPEX
+		+
Profile Adjustment		CAPEX loan drawdowns

Application of the FE Adjusted PMICR calculation to the current GD17 Draft Determination proposals results in the following credit metrics:

Figure 5.9 Credit metric ratios – firmus energy’s Calculations based on Draft Determination

Credit Metric Ratios	2017	2018	2019	2020	2021	2022
Net debt / RAV (%)	56.4%	56.7%	56.4%	56.4%	56.4%	56.4%
FFO interest cover (x)	1.16x	1.12x	1.12x	1.12x	1.11x	1.11x
FE Adjusted PMICR (x)	1.35x	1.01x	1.06x	1.28x	1.14x	1.33x
FFO / Net Debt (%)	6.2%	6.0%	6.0%	6.0%	5.9%	5.9%
RCF / Capex (x)	0.28x	0.41x	0.41x	0.34x	0.40x	0.33x

It should be noted that the above outcomes are based entirely on the Utility Regulator’s financeability modelling methodology save for the application of the FE Adjusted PMICR rather than the Phoenix PMICR. In other words, none of the adjustments mentioned above in relation to the calculation of interest, working capital and tax have been made. Importantly, these outcomes are also expressed on the basis of a 55% gearing level (implying a material equity investment required to de-gear from current levels at the outset of GD17).

Assuming that the Draft Determination is implemented without change, our FE Adjusted PMICR would fall to an average of 1.2x throughout GD17 notwithstanding a de-gearing to 55%. This includes two years in which our FE Adjusted PMICR falls below the level at which an “Event of Default” would be triggered under our debt facilities (1.1x), leading to immediate solvency issues and the cessation of our ability to draw further debt financing to fund our capital expenditures.

In these circumstances, we would be wholly reliant on our ability secure new debt financing from an alternative source to support our licensed activities (specifically our capital expenditures) during GD17. Our ability to do so on attractive terms is very much in question based on the “standard” credit metrics implied by the Draft Determination (illustrated above), which describe a situation in which our credit metrics are considerably below investment grade level.

5.4. Potential Remedies to firmus energy’s Financeability Concerns

Our primary concern is to secure that we are able to finance our activities (including the growth of our network) throughout the GD17 period. As noted above, our ability to raise additional debt financing to fund the cash flow shortfall inherent in our business will be severely called into question if the Draft Determination is implemented without change. We may experience a default under our existing debt facilities, resulting in further funding being unavailable from our existing lenders. Our ability to source alternative funding would be significantly impeded by the fact that our credit metrics are considerably below investment grade level, including on the Phoenix PMICR once corrected for calculation of interest.

Having regard for the unique characteristics of our business and the regulatory system we are operating within (in particular, the impact of the profile adjustment), there are a limited number of ways in which our financeability concerns may be addressed by the Utility Regulator in the context of its Final Determination for GD17. While increased scope for outperformance during GD17 through the

introduction of genuine incentive mechanisms would be welcome (and good regulatory practice), it would have no impact on the base case financeability assessment described in this section.

1. Improve Short-term Cash Flow Profile by Deferring Capital Expenditure

This would require the Utility Regulator to re-profile our capital expenditure by moving a significant proportion of our network build-out from GD17 to later regulatory periods. This would not change the total Capex being invested over the recovery period to 2045, but would simply postpone it from the GD17 period to a future period (in order to avoid the profile adjustment operating to reduce tariffs and revenues during the GD17 price control period). Any such re-profiling would then need to be reflected in a reduction in our connections and properties passed targets (as well as determined volumes) for GD17, to take account of the reduced network growth.

Such an approach would, of course, not be consistent with the network growth aspirations we expressed in our Business Plan. Nor do we believe that it is likely to serve the interests of customers in Northern Ireland or meet the Utility Regulator's own stated objectives for GD17.

2. Removal or Reduction of the Profile Adjustment

A material reduction in the forecast horizon over which the profile adjustment solves to zero – or the elimination of the profile adjustment in its entirety – would serve to reduce or eliminate the extent to which our revenues and cash flows are deferred. This would result in increased tariffs to customers in the short term, but would also assist in increasing our cash flows over the GD17 price control, in turn improving our FE Adjusted PMICR ratio so as to avoid a default under our existing financing arrangements. Although such an approach would have no impact on the Phoenix PMICR, it would improve other standard credit metrics such as FFO interest cover, making it more likely that we are able to obtain replacement financing on attractive terms following maturity of our current debt facilities in 2019.

We acknowledge that our Business Plan was submitted on the basis of an increase in the forecast horizon to 40 years. However, this formed part of an overall package that we considered to be financeable *despite* the increased deferral of revenues associated with an extension in the forecast horizon. In view of the significant financeability issues generated by the other aspects of the Draft Determination we now need to consider all options available to us to ensure that we continue to be able to finance our activities. As such, we welcome the Utility Regulator's suggestion that it may be open to considering the removal of the profile adjustment as part of GD17.¹⁵

3. Increase the Weighted Average Cost of Capital (WACC)

The most straightforward way to address the financeability concerns raised above would be for the Utility Regulator to increase our allowed Weighted Average Cost of Capital (WACC) above the level contemplated by the Draft Determination. This would result in increased tariffs and therefore improved cash flow metrics.

Together with Oxera, we have identified in the following sections of this document and in Appendix 4 a number of areas in which the Utility Regulator's estimation of our WACC is understated on technical

¹⁵ Draft Determination, paragraphs 10.89 to 10.96

grounds. In addition, we describe the fact that the cost of capital of a business cannot be estimated in isolation from the risk implied by its underlying financial stability (as revealed by its credit metrics). As a company, we fall well short of all of the credit metrics generally accepted as indicating investment grade status. Accordingly:

- Our cost of debt is likely to be higher than that available to companies demonstrating investment grade characteristics (hence our request of a specific uplift to the cost of debt to reflect the spread between BB and BBB issuers).
- Our failure to achieve investment grade standards also indicates that firmus energy is a riskier business than the Utility Regulator is suggesting as part of its cost of capital analysis. Our asset beta should not be compared to the asset betas attributed to BBB (and higher) companies when our financial ratios imply a significantly riskier business risk profile.

5.4.1. Exclusion of Other Potential Factors to Improve Financeability

As outlined above, our primary concern is to secure that we are able to finance our activities throughout the GD17 period. In determining potential mitigating factors to our financeability concerns, due consideration was given to those elements highlighted by the Utility Regulator as part of its GD14 financeability exercise.

1. The Utilisation of Under-Recoveries

In the GD14 Final Determination the Utility Regulator noted that firmus energy could utilise some of its under-recoveries to mitigate financial impacts in the event of any downside shocks.

Any unwinding of the under-recoveries will marginally improve the financial position of firmus energy while they are outstanding. However, the impact would be temporary in nature and offset by the Utility Regulator's proposal to reduce the rate of return on accumulated under-recoveries to a level below our current cost of debt. Based on the Utility Regulator's own analysis the under-recoveries should be fully unwound by 2019/2020. As such, they will not help the financial position of the company beyond this point when the financial metrics are still consistently weak.

2. De-gearing

As noted above the FE Adjusted PMICR is a cash based metric and has been adjusted to enable firmus energy to benefit from the ability to make further drawdowns to fund capital investments. In addition to this the Draft Determination allowances imply that a cash shortfall of £51.6 million must be funded over the GD17 period. Given this, further restricting the gearing of the company below 55% will not improve the financial position of the business and will negatively impact our financial covenants.

3. Restricting Dividends

In GD14 the Utility Regulator highlighted that an immediate and straightforward method to conserve cash in the event of an unforeseen shock was to reduce dividend payments, noting that any unpaid dividends would be rolled forward, increased by the allowed WACC and the forecast RPI. The Utility Regulator utilised this method in GD14 to mitigate the negative impacts from the downside scenario

and in the Draft Determination to target a 1.40x Phoenix PMICR. Based on the current financeability analysis, in order to manage the financial position of the company firmus energy would not be in a position to distribute any dividends over the GD17 period regardless of any potential downside shocks and as such this cannot be used as a mitigating factor over the period.

As noted above, in the GD14 determination it was stated that any unpaid dividends would be rolled forward, increased by the allowed WACC and the forecast RPI. In the Draft Determination financeability modelling, allowed dividends are based on the opening 2017 TRV value as opposed to the average annual TRV and unpaid dividends are only rolled forward by RPI with no consideration paid to the WACC. It is unclear as to why this change has been made to the unpaid dividend profile.

5.5. Scope for Out/Under-performance to Influence Financeability

When regulators set price determinations, they generally build in certain financial incentives to encourage network operators in to achieve efficient outcomes in specific areas. Credit ratings agencies also value the scope for outperformance as this leads to the potential for greater headroom in financial ratios.

We have set out elsewhere in this document our general concern that the Draft Determination strays from good regulatory practice in providing very limited incentives for outperformance, with risks heavily weighted to the downside. Given the significant reductions in Opex and Capex allowances and the increase in our connections target compared with our Business Plan, the practical likelihood of outperformance on any of these metrics is also very low. Furthermore, as set out in the table below, the incentive mechanisms contemplated by the Draft Determination will have very limited practical influence on the financeability of our business during GD17.

Mechanism	Impact of outperformance on financeability	Impact of underperformance on financeability
Opex under/over spend	• Low probability • Short-term improvement in cash flow metrics • Outperformance subject to sharing mechanism, resulting in revenue correction at end of price control period	• High probability • Deterioration in cash flow metrics • Underperformance subject to sharing mechanism, resulting in revenue correction at end of price control period
Capex under/over spend	• Low probability • Improvement in FE Adjusted PMICR • No improvement in Phoenix PMICR or other cash flow metrics • Outperformance subject to sharing mechanism, resulting in TRV log-down at end of price control (limiting ability to draw down debt financing during the period, with countervailing negative impact on FE Adjusted PMICR)	• High probability • Deterioration in FE Adjusted PMICR • No change in Phoenix PMICR or other cash flow metrics • Underperformance subject to sharing mechanism, resulting in TRV increase at end of price control
Volume out/under performance	• Short term improvement in cash flow metrics in the year • Revenue cap exceeded, leading to reduction in tariffs in the following year – deterioration in cash flow metrics	• Short term deterioration in cash flow metrics in the year • Expected increase in tariffs in the following year – improvement in cash flow metrics
Connections out/under performance (Connections Incentive)	• Low probability • Incentive implemented through end of period TRV increase • No impact on cash flow metrics (other than that associated with increased volumes – see above)	• High probability • Incentive implemented through end of period TRV reduction (limiting ability to draw down debt financing during the period, resulting in negative impact on FE Adjusted PMICR) • No impact on cash flow metrics (other than that associated with reduced volumes – see above)
Properties passed incentive	• No impact on cash flow metrics (other than that associated with increased volumes/connections – see above) • Incentive implemented through end of period TRV adjustment	• No impact on cash flow metrics (other than that associated with reduced volumes/connections – see above) • Incentive implemented through end of period TRV adjustment (limiting ability to draw down debt financing during the period)

Mechanism	Impact of outperformance on financeability	Impact of underperformance on financeability
Cost of debt out/under-performance	• Low probability given Utility Regulator proposes to assess firmus energy against investment grade borrowing costs • Improvement in FE Adjusted PMICR and other interest cover ratios during the period • Pain/gain sharing mechanism limits upside • No detail provided on how pain/gain sharing mechanism to be implemented – outperformance anticipated to result in TRV log-down at end of period, (limiting ability to draw down debt financing during the period, with countervailing negative impact on FE Adjusted PMICR)	• High probability • Deterioration in FE Adjusted PMICR and other interest cover ratios throughout the period • Pain/gain sharing mechanism limits downside • No detail provided on how pain/gain sharing mechanism to be implemented - anticipated to result in TRV increase at end of period, therefore no benefit to interest cover ratios during the period

5.6. WACC

Summary of the Utility Regulator's Draft Determination

Our allowed cost of capital consists of a number of elements which combine to describe our overall weighted average cost of capital (WACC). Figure 5.10 below sets out the position we adopted in our Business Plan compared with the Utility Regulator's Draft Determination.

Figure 5.10

Parameter	FE Business Plan	UR Draft Determination
Cost of Debt Parameters		
Gearing	55%	55%
Cost of debt mechanism	Fixed ex-ante	Pain/gain sharing
Allowed cost of debt	3.1 – 3.3%	2.33%
Cost of Equity Parameters		
Risk free rate	1.25 – 1.50%	1.25%
Expected market return	6.5 – 7.0%	6.5%
Asset beta	0.4 – 0.5	0.4
Debt beta	0.1	0.1
Equity beta	0.77 – 0.99	0.77
Post-tax cost of equity	6.1%	5.3%
Method of adjusting to derive pre-tax cost of equity	Two-step	One-step
Pre-tax cost of equity	8.35% (mid-point)	6.3%
Overall WACC	5.5% (mid-point)	4.3%

As we have stated in a number of areas of this document we believe that the combined effect of the Utility Regulator having picked the bottom end of the range on every available input is to produce a proposed overall cost of capital allowance that is too low to provide us with the revenues we need to finance the growth of our network.

We consider that the Utility Regulator has made a number of technical and/or selection errors in its analysis and, furthermore, that in adopting a lowest-common-denominator approach it has underestimated the overall risk that we are faced with having regard for all other aspects of the GD17 price control. As part of our response to the Draft Determination, we have asked Oxera, our specialist economic consultants, to provide a separate submission containing a critical analysis of each element of the Utility Regulator's position (Appendix 4). We do not repeat that analysis in this section, but instead expand on a small number of key observations relating to the interaction between our allowed WACC and the overall regulatory and operational environment in which we are being asked to operate.

It is unclear why the Utility Regulator considers that the grant of a cost of equity that is so significantly below that of the GB GDNs on a like for like basis is sufficient to encourage further growth in the Northern Irish network when higher regulated returns are achievable in a more mature steady state gas distribution market. This is supported by the corporate finance theory that underpins the Capital

Asset Pricing Model (CAPM) which the Utility Regulator has used to determine the cost of equity for the NI GDNs. Two of the key underpinning assumptions of the CAPM are that investors seek to maximise returns, and they are rational and risk averse. As outlined in greater detail below, by setting a cost of equity so significantly below that of the GB GDNs no rational investor would invest in the network.

In order to ensure that the NI GDNs are able to access equity financing and are incentivised to grow the gas distribution network, we strongly encourage the Utility Regulator to reconsider its adoption of a lowest-common-denominator approach in setting the WACC.

Cost of Equity

The Utility Regulator has stated in the Draft Determination that the key focus of the GDNs should be on achieving network growth. However, the Utility Regulator's proposed allowed regulatory cost of equity of 6.3% real pre-tax (5.3% real post-tax) represents a c.24.5% reduction compared to the requested pre-tax return of 8.35% (representing the average of the proposed range outlined in Oxera's September 2015 rate of return submission) utilised in our Business Plan. As we illustrated in section 5.3, this simply does not provide us with sufficient revenues to meet our banking covenants and therefore to finance our network development plan. Nor do we consider that setting the allowed cost of equity at such a low level provides the right incentives to investors to support network growth.

In the Draft Determination, the Utility Regulator states that the allowed cost of equity for firmus energy is higher than the return that Ofgem factored into the RIIO-ED1 price control for GB electricity distribution networks but lower than that for GB GDNs under RIIO-GD1. This is misleading. The real post-tax cost of equity of 5.3% under the Draft Determination is lower than that for GB GDNs (6.0%), GB water companies (5.7%) and GB GDNs (6.7%). In attempting to compare our cost of equity on a "like-for-like" basis with these companies, the Utility Regulator has mechanistically increased the gearing applied to all companies including firmus energy to 65% without considering whether it is plausible to increase our gearing given that the results of its financeability analysis indicate that we are unable to support more debt than the 55% gearing assumed by the Utility Regulator.

We accept the Utility Regulator's approach to utilise the CAPM to determine the cost of equity, consistent with regulatory precedent. As noted above, two of the primary underpinning assumptions to the CAPM are that investors aim to maximise economic utility and are rational and risk averse. If we accepted the Utility Regulator's assertion that the NI GDNs face a similar overall level of risk as the GB GDNs (which we do not), then it would follow that no rational investor would invest in the NI GDNs given that they attract a lower return for a supposedly similar level of risk.

In addition to this, and as has been explained elsewhere in this response document, the significant reduction in firmus energy's cost allowances and increased targets combined with uncertainty and incentive mechanisms in which the risks are skewed to the downside leave the company with little prospect of meeting its regulatory allowances and targets, let alone outperforming them. This is at odds with the other GB regulatory regimes which offer regulated companies significant scope for outperformance and upside on their achievable RoRE.

As such, the company believes that the cost of equity is set at a level which is not commensurate with the risk profile of the GDNs, removes the ability of the companies to absorb any unforeseen risk (as is

outlined in further detail earlier in this document) and is not sufficient to attract further equity funding to support our network development programme.

Equity Return Parameters

The parameters contributing to the cost of equity consist of a combination of generic factors (i.e. observable metrics that apply to all companies irrespective of their characteristics), subjective factors (i.e. metrics that are less observable and require some judgment) and technical factors (the formulae by which the generic and specific factors are combined to generate the overall cost of equity allowance). Generic factors include the risk-free rate and the expected market return. Technical factors include the method by which the Utility Regulator grosses up its post-tax cost of equity estimate to arrive at our pre-tax cost of equity allowance. The principal subjective factors are the asset beta and the level of gearing.

Generic Parameters

In setting the generic parameters within the cost of equity the Utility Regulator has relied on a snapshot of recent market evidence with little consideration of the overall impact this may have on incentivising growth in an immature network.

For example, the Utility Regulator has allowed a total market return of 6.5% for firmus energy in line with recent allowances recommended by the Competition and Markets Authority (CMA). This rate is 0.75% lower than the total market return of 7.25% allowed for the GB GDNs leading to the counter-intuitive result that GB GDNs, which are much larger and mature than firmus energy, will have considerably higher cost of equity allowances up to 2021 (all else being equal).

Technical Parameters: Tax Gross-up

As outlined by Oxera, by utilising a simplistic one-step approach to grossing up the post-tax cost of equity to a pre-tax cost of equity the Utility Regulator has underestimated our pre-tax cost of equity allowance. The gross-up should utilise a two-step approach converting the real post-tax cost of equity to a nominal post-tax cost of equity as tax is calculated on a nominal basis. The conversion from post to pre-tax should then be done on a nominal basis and converted back to a real pre-tax return on equity to ensure that the tax impact is correctly accounted for. As shown in the appended Oxera paper (Appendix 4), this factor alone leads to an under-estimated WACC of 0.3%. The Utility Regulator's characterisation of this approach as "*an effective tax rate of 27%*" is unhelpful.

Subjective Parameters: Asset Beta

The Utility Regulator has noted that it has cautiously selected an asset beta on the top of the range for betas that regulators have judged appropriate for steady-state regulated utilities. However, in doing so the Utility Regulator has ignored recent market movements in listed asset betas. The Oxera paper appended to this document outlines how the analysis of betas of publicly listed UK utilities undertaken by First Economics provides an underestimate due to omissions in selection of the sample and selectivity in the time period analysed.

In any event, we do not consider that the business risks that we face are equivalent to those of the steady state regulated utilities to which we are being compared. We have made a number of previous

submissions to the Utility Regulator in this respect. However, in the Draft Determination the Utility Regulator has placed limited weight on these arguments on the basis that we had not quantified what our relative immaturity means in numerical terms. We do not accept the Utility Regulator's suggestion that an argument as to business risk is only valid to the extent that it is quantified. The only objectively "observable" data available on the difference between NI GDNs and GB GDNs is the interest premium over BBB bonds attracted by Phoenix's debt. The Utility Regulator's assessment ignores the fact that the Draft Determination is asking us to double the number of connections to our network over GD17 and that the Connection Incentive creates a one-sided regime, in which the penalty we face for failing to meet our targets is far greater than the reward we would receive for exceeding them.

In addition, as noted above in our review of the Utility Regulator's analysis of financeability, because our cash flow profile is comparatively weak by virtue of the impact of the profile adjustment and our capital expenditure profile, we are significantly more exposed to unexpected cost shocks than more mature businesses. We note that the Draft Determination disregards Phoenix's argument that the deferral of revenues under the profile adjustment creates incremental equity risk, based on Ofgem's consideration of the issue in RIIO-ED1 and the work undertaken by Europe Economics. It should be noted that this analysis focused on the depreciable lives of assets, i.e. the period over which Capex will be recovered. In Northern Ireland, the profile adjustment operates to defer recovery not only of Capex, but also of allowed return and Opex (which is typically a pass-through and classified as 'quick money'). In no other GB regulated utility are the cash flows in the current regulatory period impacted by assumptions made about future regulatory periods.

Additionally, Europe Economics' analysis questioned whether a net present value (NPV) neutral change in cash-flow duration should be expected to change the cost of capital. This ignores the potential impact under the profile adjustment of changes to the cost of equity and regulatory risk. This risk is heightened for NI GDNs due to the modelling of the profile adjustment, which means that long-term regulatory assumptions impact the cash flows that the NI GDNs are able to receive today. Indeed, if an NPV analysis was undertaken in respect of the post 2017 cash flows from the Utility Regulator's GD14 model by keeping all parameters the same and simply modifying the WACC from 2017 that was proposed in GD14 (4.83%) for the GD17 proposed WACC (4.3%) it shows that these cash flows are not NPV-neutral and that our investors will no longer achieve the return that they expected over the life of the project. In order to provide NPV neutrality on foregone dividends those dividends need to be rolled up at a return consistent with the expected return prevailing when the dividends were deferred. On the assumption that the Utility Regulator is unwilling to commit to a fixed equity return for the entire forecast horizon, what remains is a risk faced by NI GDNs that is not faced by any other regulated utility in the UK.

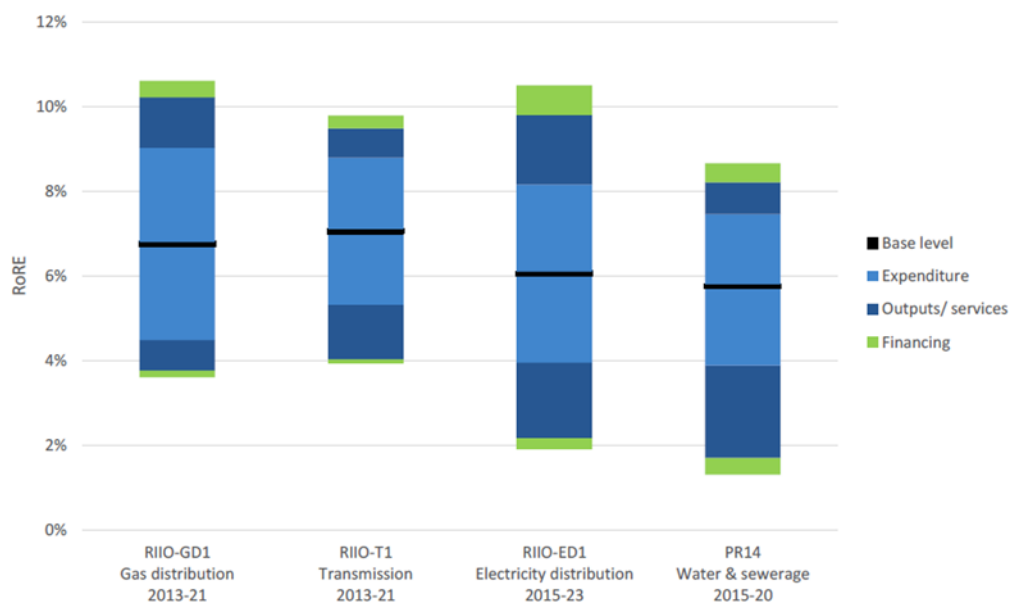
Additionally, it is not clear whether the Utility Regulator has fully considered the impact that selecting a high debt beta has on the equity beta analysis. By selecting a debt beta of 0.1 the underlying assumption is that firmus energy's debt is higher risk than that for comparable utilities (hence it warranting a high debt beta). The resulting equity beta from the Utility Regulator's analysis of 0.77 is considerably lower than for GB GDNs (0.9), electricity networks (0.9) and to a lesser extent water companies (0.8), all which attract no debt beta (excluding RIIO-ED1) and lower asset betas. It seems counter-intuitive to on one hand accept that the NI GDNs are higher risk through the selection of a

high debt beta and an asset beta on the upper end of what the Utility Regulator deems an appropriate scale, yet have an equity beta that implies that the equity portion of the TRV is at significantly lower risk than GB GDNs, electricity and water companies. This issue is borne out by the very constrained financeability metrics generated by the Draft Determination (see section 5.3) when compared with the financial health of the companies to which we are being compared.

Incentives

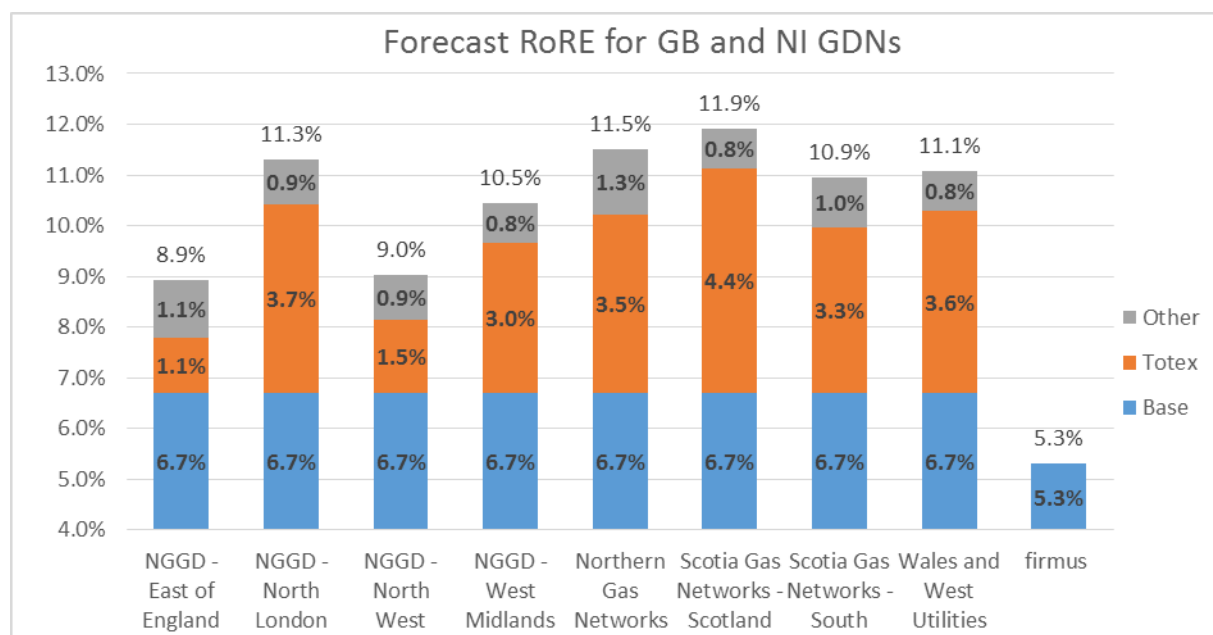
Over the last number of years allowed returns on regulated assets in the UK have trended down largely due to reductions in the risk free rate and corresponding drops in bond yields. At the same time regulators have moved more to output based regulations as is the case in Ofgem's RIIO-GD1 price determination. Cambridge Economic Policy Associates (CEPA), the economic and regulatory consultants have argued that moving to output based regulation, where companies have significant incentives to outperform their specified targets, has enabled companies to accept lower allowed headline RoREs. As can be seen from Figure 5.11, significant scope for outperformance exists in the primary GB utility regulatory regimes.

Figure 5.11 Estimated RoRE Ranges from Recent UK Price Controls



Source: CEPA analysis

It is clear from Ofgem's annual reports that each of the GB GDNs is significantly outperforming its base RoRE under the RIIO-GD1 framework. In its most recent annual report (published, 22 March 2016) Ofgem outlined its eight year forecast RoREs for each of the GB GDNs. These figures are presented in Figure 5.12 along with firmus energy's allowed RoRE.

Figure 5.12

Source: Ofgem

By including no meaningful incentives in the Draft Determination, setting extremely difficult cost allowances that have significantly reduced the requested amounts and difficult connection targets, the Utility Regulator has effectively removed the possibility of firmus energy outperforming its allowed RoRE which is already considerably below that of the GB GDNs, electricity companies and water companies. By removing the ability to outperform the RoRE, the Utility Regulator has also removed any ability for firmus energy to absorb any unforeseen shocks and reduced the resilience of the company to the effect of risk.

5.7. Profile Adjustment

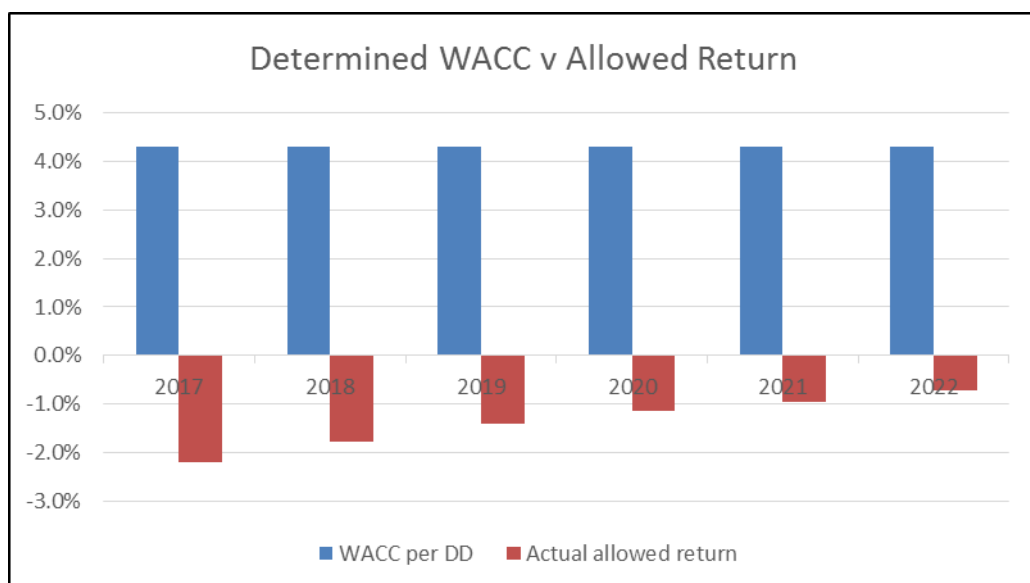
5.7.1. Background to the Profile Adjustment

Our licence conditions contain complex mathematical formulae designed to defer the recovery of part of our (otherwise) allowed revenue into the future, when our customer base is larger and therefore more able to support recovery of the sunk costs associated with the development of our network. The recovery of this deferred revenue is secured by way of an addition to our TRV via a mechanism known as the “profile adjustment”. The profile adjustment builds up over the course of each price control period, and then forms part of our asset base at the beginning of each price control review.

The existence of the profile adjustment represents a key difference between the regulatory regimes applying to the NI GDNs and the GB GDNs (in addition to a number of operational differences outlined elsewhere in this document). In simple terms, the profile adjustment means that:

- The NI GDNs' revenues are lower than might be expected based on the size of their asset base.
- The NI GDN's price controls are long-term in nature. This means that at each price control the Utility Regulator is required to make assumptions as to the number of customers we will have, the volumes of gas we will supply, and the operating and capital costs we will incur, not only for each year of the price control period but also for each subsequent year until the end of the "forecast horizon". In firmus energy's case the "forecast horizon" is until 2035 (30 years from licence grant), although both Phoenix and SGN have a longer period (50 years to 2045 and 40 years to 2057).
- The NI GDNs' revenues within a price control period therefore do not necessarily fully reflect the operating and capital costs that they incur in the period in the same way as is the case for GB GDNs. The assumptions that the Utility Regulator makes about our operating costs in 2030 will directly impact on the revenues we are allowed to earn today, despite the fact that future operating costs outside of the GD17 period are not under direct consideration in this price control.
- Similarly, changes that the Utility Regulator makes to our allowances within a regulatory price control do not necessarily impact on our allowed revenue for that price control period in an intuitive way. For example, if the Utility Regulator was to decide to award us a higher allowance for operating costs than is currently contemplated by the Draft Determination, the amount of revenue deferred by operation of the profile adjustment would also increase, such that £1 of increase in the building blocks of our tariffs will result in somewhat less than £1 of additional revenue.

Figure 5.13



- As a result, in any given year in which the profile adjustment operates to defer revenues, the allowed return on our TRV will *necessarily* be lower than the WACC determined by the Utility Regulator as part of its price controls. This situation is forecast to begin to reverse from 2024,

at which point – again as a result of the profile adjustment – the allowed return on our TRV will *necessarily* be higher than our determined WACC. The deferral we are currently experiencing is illustrated in Figure 5.13 by reference to the determined values utilised by the Utility Regulator in the Draft Determination.

5.7.2. Should the Profile Adjustment be Retained?

In its GD14 Final Determination the Utility Regulator stated, “We believe that both FE and PNGL now have a solid base of customers. Consequently, we intend to review the profile adjustment as part of GD17 to assess whether the profile adjustment is still required or whether moving to a model more in line with GB GDNs would provide benefits.”¹⁶

Accordingly, as part of the Draft Determination, the Utility Regulator has sought our views on whether the profile adjustment should be retained or whether NI is ready to move to a more conventional model, noting that:

- 10.92 *However there are disadvantages from the Profile Adjustment. It adds a certain level of complexity to the regulatory model and is not consistent with the standard regulatory model in the UK. While these disadvantages are clearly outweighed in the early years of a greenfield investment this becomes less obvious as the project progresses. At some point it is likely to make sense to move to a more standard model. UR considers it appropriate to set out the options for GD17.*
- 10.93 *If the profile adjustment was to be removed this would lead to higher prices today and lower prices at the end of the GDN revenue recovery periods...”*

5.7.3. Firmus energy’s View

We welcome the Utility Regulator’s suggestion that it may be open to considering the removal of the profile adjustment as part of GD17, for three principal reasons.

1. Removal would reduce complexity and increase transparency in the NI regulatory regime
2. Removal would serve to increase comparability between firmus energy and GB GDNs
3. Removal would assist significantly in the financeability of our business during GD17

However, if the profile adjustment were to be removed as part of the GD17 Final Determination then it is essential that the Utility Regulator take the impact on our tariffs into account when setting our owner occupied connections targets for the period. We would also require a better understanding of the Utility Regulator’s detailed proposals as to the basis on which “removal” would be implemented (for example, by addition of the profile adjustment balance to a vanilla RCV with a fixed depreciation period).

¹⁶ GD14 Final Determination, paragraph 16.20

Each of these factors is explored in further detail below.

Reduction in complexity and increase in transparency

The summary of the features of the profile adjustment that we set out above should serve as explanation of the complexity it introduces to our price control system. As a general principle of good regulation, complexity in itself is not an attractive feature unless it leads to significant advantages that are not available through simpler means. As the Utility Regulator notes in the Draft Determination, the advantages generated by the profile adjustment have become less obvious as firmus energy's customer base has increased. The short term tariff increases implied by removal of the profile adjustment are no longer so great as to prevent serious consideration of this simplifying step.

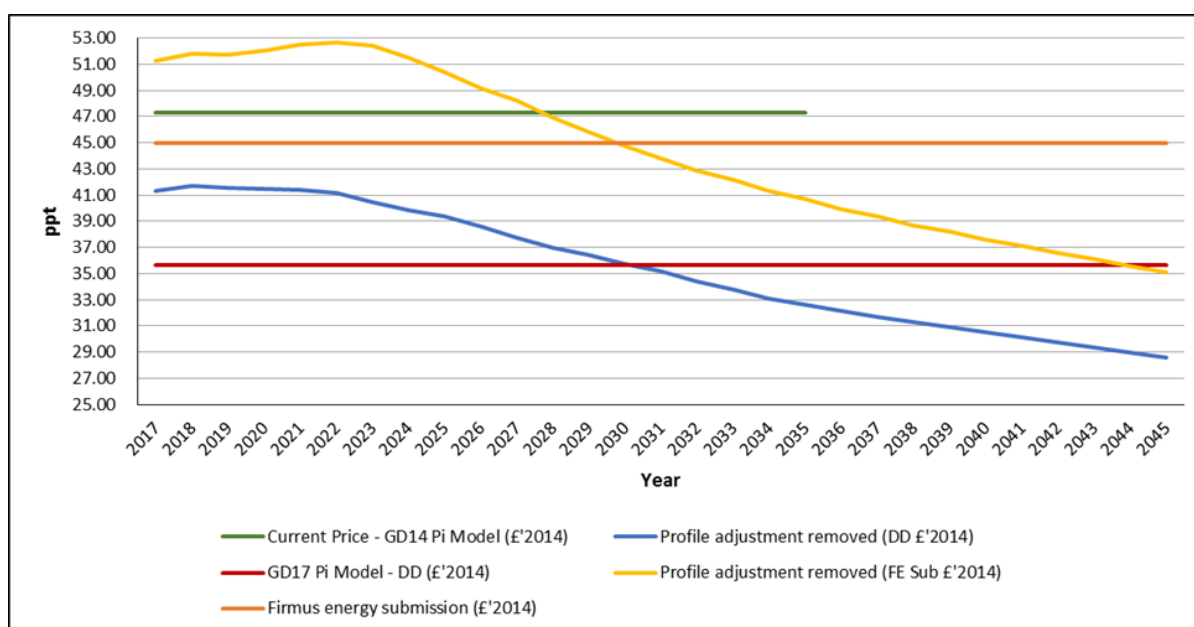
Increased comparability

Removal of the profile adjustment would enable a more direct comparison between the RCVs of the NI and GB GDNs, which should serve to improve like-for-like comparison between them for a number of purposes. For example, we note that debt finance providers and credit ratings agencies attribute an increased element of risk to non-standard elements of the TRV such as the profile adjustment

Improved financeability

Figure 5.14 below sets out our modelling of the impact on distribution tariffs of the removal of the profile adjustment.

Figure 5.14 Profile Adjustment Removal – Impact on Prices



From the outset, we should note that our GD17 Business Plan was submitted on the basis not only of retention of the profile adjustment, but also an *increase* in the “forecast horizon” to 40 years. However, this formed part of an overall package that we considered to be financeable *despite* the increased deferral of revenues associated with an extension in the forecast horizon. Put simply, the allowed WACC we had assumed as part of our Business Plan (5.5%) was set at a level that ensured that

the cash flows we would receive during GD17 would be sufficient to enable us to continue to finance our capital expenditure programme after taking account of the fact that we would not be able to earn that WACC in practice as a result of the profile adjustment.

In the Draft Determination, the Utility Regulator is proposing a substantial (25%) reduction in our allowed distribution tariff, based on significant reductions of our allowed Opex, Capex and WACC. We have provided our views on the appropriateness of these changes at length elsewhere in this document. However, in commenting on the profile adjustment itself it is relevant to note that the particularly low allowed WACC contemplated by the Draft Determination, combined with the impact of the profile adjustment (further reducing our actual returns to a level below the allowed WACC), generates a significant risk to our ability to finance our business during the GD17 period. In view of these issues, we now need to consider all options available to us to ensure that we continue to be able to finance our activities and removal of the profile adjustment could be of significant assistance in bridging the gap in this regard.

Impact on connections targets

In Chapter 2 of this document we have noted the significant challenges we are facing in encouraging customers to connect to our network. All other things being equal, a move to eliminate the profile adjustment will result in an increase in our tariffs of approximately 10%-15%. Given that our customers are price sensitive, it is essential that the impact of any such increase in tariffs on our ability to connect customers is taken into account by the Utility Regulator in setting its connection targets for GD17.

Further clarity required on mechanism for removal

Given that it's thought process is at an early stage, it is understandable that the Utility Regulator has provided no detail in the Draft Determination as to the precise mechanism by which the profile adjustment would be removed. We would expect this to be subject to a detailed formal and informal consultation process and look forward to engaging in further dialogue in this regard. For present purposes, we note that it will be absolutely critical to ensure that any proposal to remove the profile adjustment does not result in a reduction in the TRV (or RCV) – in other words, that the closing GD14 balance of the profile adjustment is rolled into a more standard GD17 opening RCV and then depreciated over a predetermined period. Given that we (and other GDNs) have borrowed against the full balance of our TRV (including the element attributable to the profile adjustment) any reduction in the TRV resulting from the removal of the profile adjustment would further compound the financeability issues created by other elements of the GD17 price control.

6. Outputs, Outcomes and Allowances

6.1. Under-recoveries

For the first 10 years of the development of our network, firmus energy has operated under a “price cap” system of regulation. Under this mechanism, the Utility Regulator sets an allowed tariff (as opposed to overall revenue levels), meaning that we bear the risk of any volume under-performance and keep the benefit of any volume out-performance. As part of this mechanism, our licence parameters currently permit us to set tariff levels below the allowed regulatory price cap (to “under-recover”) in order to encourage customers to switch to gas and connect to the network.

The under-recovery mechanism involves the company temporarily foregoing revenues that it would otherwise be entitled to recover from its customers. Accordingly, our licence stipulates that we should be remunerated for our foregone revenues by the balance of our under-recoveries being rolled up at our overall cost of capital (i.e. WACC). Our licence conditions also permit us to set tariffs at a level of up to 40% greater than our allowed tariffs so as to ensure that we are able to recoup our unrecovered revenues over time.

In the early years of our network development from 2006 to 2013, we accrued a balance of under-recovered revenues that the Utility Regulator estimates will amount to approximately £13 million at the start of GD17. The under-recovery of revenue was an important factor in our ability to achieve our early-years network development goals. As a result, we are now able to spread our costs over a larger volume base to the benefit of all of our customers. In this regard, the under-recovery mechanism has operated in a similar fashion to the profile adjustment.

However, it is critical to note that the accumulation of under-recoveries has necessarily led to a shortfall in our revenues that it was necessary to fund through a combination of debt (via bank financing) and equity (via foregone dividends). Our licence conditions recognise this funding requirement by specifically stipulating that there should be no difference between the rate of return on our under-recoveries and the rate of return applied by the Utility Regulator to the other elements of our TRV.¹⁷

6.1.1. Distinction between Under-recoveries under Price Cap and under Revenue Cap

Simultaneously with GD17, the Utility Regulator has determined that it wishes to move firmus energy away from price cap regulation towards revenue cap regulation, under which the Utility Regulator will set a cap on the overall amount of revenue that we are allowed to recover from our customers.

¹⁷ Firmus energy (Distribution) licence, Condition 4.10.4

It is important to distinguish between revenue under-recoveries arising under our current price cap mechanism (referred to within our licence as a 'Z' under-recovery) and a different category of under-recoveries that may arise under a revenue cap form of price control.

The intention of a revenue cap is that we will no longer keep the benefit or bear the risk of differences between the volumes of gas we convey and the volume targets set by the Utility Regulator as part of its price control. This means that our licence will need to contain provisions designed to "correct" for occasions on which our revenues are temporarily higher or lower than the revenue cap as a result of fluctuations in volumes compared with projections (referred to in Phoenix's licence as the 'K' correction factor). In this context, we noted in our Business Plan that further clarity was required on how the 'K' correction factor within the revenue cap would respond to a situation in which – for example - our revenues were higher than the allowed revenue cap as a result of our under-recoveries being unwound.

In view of the uncertainty created by the transition to revenue cap, we were required to make a number of assumptions as to the consequent changes to the price control provisions of our licence in constructing our GD17 Business Plan. In doing so, the Utility Regulator encouraged us to have regard to the price control conditions set out in Phoenix's licence. Phoenix's licence makes no reference to the treatment of pre-existing 'Z' under-recoveries and very limited public information is available that describes the precise means by which the transition from price cap to revenue cap was implemented. However, we believe that the following treatment was applied:

1. the balance of the 'Z' under-recoveries was moved into the "opening asset value" (OAV) and remunerated at the WACC; and
2. new under-recoveries under the revenue cap are dealt with through the 'K' correction factor and are remunerated at a base rate plus 1.5%, with any over-recovery charged at WACC.

We also infer that the balance of 'Z' under-recoveries that was moved into the OAV may have been discounted to reflect the present value difference between LIBOR plus 2% and the allowed WACC over a ten year period. We do not have any insight on the dialogue that may have taken place between Phoenix and the Utility Regulator on this aspect of the transition. However, we note that it appeared to form part of a wider negotiation in which Phoenix was able to secure a number of concessions including a 30 year licence extension and agreement that its allowed WACC would remain at 7.5% for years 10-20 of the Phoenix licence period.

Accordingly, our GD17 Business Plan was prepared on the basis that our 'Z' under-recoveries would be moved into our TRV and remunerated at our allowed WACC without discounting. We also assumed that we would cease to be able to over- or under-recover revenues under this mechanism going forward. We assumed that our revenues would equal our revenue cap, and that any unintended and temporary difference between actual and allowed revenues would be corrected for by the 'K' factor and remunerated on the same basis as set out in Phoenix's licence.

6.1.2. Utility Regulator's Proposal

As part of the Draft Determination, the Utility Regulator proposes that "the rate of return to be applied to firmus energy's under-recoveries will move to LIBOR plus 2%."¹⁸

This statement is capable of interpretation in a number of ways.

- (1) The new rate of LIBOR plus 2% will apply only to new 'K' correction factor under-recoveries accumulated under the revenue cap.*

For the avoidance of doubt, firmus energy has no objection in principle to the proposal that a rate of LIBOR plus 2% will apply to any new 'K' correction factor under-recoveries. Although the mechanics of the revenue cap are yet to be determined, typically any deviation from the allowed revenue should arise solely due to volume discrepancies and therefore be short-term in nature. As such firmus energy accepts that any such balance should be remunerated at a short-term rate.

AND/OR

- (2) The new rate of LIBOR plus 2% will apply to the equivalent of new 'Z' under-recoveries accumulated under the revenue cap as a result of firmus energy pricing below the allowed tariff implied by its revenue cap divided by allowed volumes.*

The Phoenix licence does not appear to distinguish between revenue differences that arise due to pricing decisions as opposed to volume variances and therefore it may technically be possible to reduce prices to attract connections under a revenue cap, although this is somewhat unclear.

Given the challenges we are currently experiencing in attracting connections to our network, there may conceivably be a benefit to retaining the facility to under-recover revenues in order to meet the Utility Regulator's connection targets. However, we did not assume that this would be the case in our Business Plan and the financeability constraints created by other aspects of the Draft Determination would mean that we would be unable to fund further under-recoveries in any event – particularly if we were to be remunerated at a level below our overall allowed cost of capital.

While we do not think that such a move would necessarily be in the interests of customers, we accept that the Utility Regulator may wish to disincentivise us from creating new under-recoveries and would therefore be prepared to accept a reduction in the rate of return on any 'Z'-equivalent under-recovery incurred after the start of GD17 (to the extent that any such under-recovery is possible).

¹⁸ Draft Determination, paragraph 11.79

AND/OR

- (3) The new rate of LIBOR plus 2% will apply to any future under-recoveries no matter how they are accrued as well as to the balance of existing 'Z' under-recoveries accrued in prior years.*

We would strongly object to any proposal to reduce the rate of return on pre-existing under-recovered revenues to a level below our allowed WACC. Any such decision would be entirely arbitrary, disproportionate, retrospective in effect, and not backed by principles of good economic regulation.

6.1.3. Retrospective Change to Existing Under-recoveries

In compiling our response to the Draft Determination we have commissioned Oxera to provide a paper outlining the potential ramifications of any proposal to change the rate of return on our previously accumulated 'Z' under-recoveries by reference best regulatory practice and regulatory precedent (see Appendix 6). The conclusions outlined in that paper are summarised below:

- **There is no justification for allowing differentiated returns on different elements of our capital structure.** To date our 'Z' under-recoveries have been remunerated at the same rate of return as the remainder of the TRV. This approach is consistent with the fact that the deferral of revenues needs to be funded in cash by the Company in the same way as the other elements of the capital employed in our business. The Utility Regulator's proposal would effectively treat the capital funding associated with accumulated 'Z' under-recoveries as lower risk than the rest of firmus energy's invested capital, including the profile adjustment (which is also a mechanism for the deferral of revenue).
- **The choice of return is arbitrary.** Even if a differentiated rate of return were to be appropriate, the Utility Regulator has not provided any justification for the selection of a rate of LIBOR plus 2% (and it is also not clear which LIBOR period is intended to be selected). Applying a rate of LIBOR plus 2% and taking into account the Utility Regulator's own inflation forecast of approximately 3% suggests a negative rate of return on 'Z' under-recoveries in real terms, compared with a proposed real WACC of 4.3%. The proposed rate of return of LIBOR plus 2% is likely to be below the Utility Regulator's real risk-free rate assumption of 1.25%, implying that there is (less than) zero risk attached to the financing and recovery of the under-recoveries.
- **Retrospective impact.** As noted by the Utility Regulator, Condition 4.10.4 of firmus energy's licence establishes that there should be zero differential between the rate of return on accumulated 'Z' under-recoveries and the licence WACC until 2034. We financed the deferral of revenues in reliance on that licence provision. In proposing to change the treatment applied to our existing 'Z' under-recoveries, the Utility Regulator would be seeking to implement a

change that would alter the basis on which we invested in revenue under-recovery at a time after the investment has been made. In that sense, any such proposal would be retrospective in its effect. Oxera make reference to the well-established principle of good economic regulation that regulators should not seek to implement retrospective change.

Furthermore, as noted by the Utility Regulator's consultants, First Economics, in Draft Determination Annex 7, page 21: *"what matters is whether investors can be reasonably confident that they will be able to collect the full value of the investment that they have made in the business... investors are likely to be far less concerned with the historical derivation of the FE RAB compared to the likelihood of being able to collect a full return of and on that capital going forward."*

6.1.4. The Utility Regulator's Case

In the Draft Determination, the Utility Regulator set out a number of arguments in support of a proposal to reduce the rate of return on our accumulated 'Z' under-recoveries.

- **Our licence contains provisions contemplating such a change.** The Utility Regulator states that Condition 4.2.17 of our licence "clearly foresees" the circumstances where it might be necessary to change the rate of return on 'Z' "in order to provide an incentive or disincentive (as the case may be) in respect of the accumulation of such under-recovery or over-recovery of revenue."¹⁹ We accept that this provision exists within our licence although it is in direct conflict with the provision stating that there will be no difference between the return on 'Z' and our allowed WACC until 2034. In any event, we do not accept the inference that Condition 4.2.17 anticipates a change to the return on previously under-recovered revenues. Instead, it contemplates that the Utility Regulator might seek to reduce the *incentive* for firmus energy to *create new 'Z' under-recoveries* by reducing the returns that they attract. By definition, a retrospective change to the return on previously accrued under-recoveries can have no impact on incentives, acting instead as a penalty for prior actions.
- **Our licence conditions are not "in the public interest".** In paragraph 11.73 of the Draft Determination the Utility Regulator states its belief that *"the current licence is not in the public interest"* because it provides a formula to change the rate of return on under-recoveries but also prevents this formula being applied. The Utility Regulator provides no further explanation as to what is meant by the "public interest" in this situation, and we note that the Utility Regulator has provided no justification as to why it is appropriate for different aspects of our capital funding to attract differentiated returns. In addition, as noted by Oxera, it is not clear that the existing approach to under-recoveries has worked against the public interest given the growth in volumes over the period in which they were accumulated and the benefit that this has had on spreading costs over a larger volume base.

¹⁹ Draft Determination, paragraph 11.64

- **Actual cost of capital lower than allowed cost of capital.** The Utility Regulator states that *“The current licence conditions provide customers with no protection from a situation where the licensees actual cost of capital is less than the licence allowed cost of capital”*²⁰. While the precise meaning of this statement is unclear, it is possible that the Utility Regulator may be arguing that our underlying cost of capital was lower than the 7.5% allowed to us over the first 10 years of our licence and therefore that it is justified in now taking action to reduce returns to a level below our actual cost of capital. This would appear to confirm that the Utility Regulator itself acknowledges that the proposed change is retrospective in nature. In any event, we do not see the relevance of the past allowed cost of capital to the question whether it is appropriate to award differentiated returns to different aspects of our capital structure.
- **Application is forward looking.** The Utility Regulator argues that the proposed change is forward looking only as it will only apply from 2017. This is true in the limited sense that the change in return on our ‘Z’ recoveries will only change with effect from a date in the future. However, as Oxera notes, changing the rate of return on our existing accumulated under-recoveries is effectively retrospective in nature because at the time the under-recoveries were incurred there was a legitimate expectation that a rate of return equal to the allowed WACC would be earned until 2034.
- **Sufficient notice granted.** The Utility Regulator notes that firmus energy has been given a *“number of years notice that this change was likely.”*²¹ In this regard, we would note that the vast majority of our ‘Z’ under-recoveries were accumulated over a seven year period up to the end of 2013. In its GD14 Final Determination, the Utility Regulator signalled its desire that we should unwind the under-recoveries we had accumulated up to that point. We had approximately three years to respond to this signal, and during that period we were successful in reducing our balance by £8 million (38%) to the end of 2016 while broadly maintaining our connections performance. In practical terms it would have been impossible to eliminate our under-recoveries completely over the three years of GD14 without creating significant risk to the development of the gas network as a result of having been required to set tariffs at the maximum level permitted by our licence (effectively 40% greater than our allowed tariff). In addition, certain features of our licence arrangements (in particular the “netback” arrangement) operated to slow the pace at which we were able to reduce our under-recoveries from 2014 to 2016.
- **Brings firmus energy in line with Phoenix and SGN.** All three of the GDNs have had under-recoveries treated differently within their licences. We do not consider the Phoenix precedent as capable of translation to our situation given that changes to the rate of return on its past ‘Z’ under-recoveries were subsumed within a wider non-public negotiation as a result of which Phoenix was permitted to earn a return of 7.5% on its entire TRV for an additional 10 years

²⁰ Draft Determination, paragraph 11.74

²¹ Draft Determination, paragraph 11.76

over and above what has been made available to firmus energy. As for SGN, the licence contains provisions under which 'Z' under-recoveries incurred in the future will be remunerated at LIBOR plus 2%. SGN has no existing balance of under-recoveries to which this rate of return is capable of applying. For the avoidance of doubt, as noted above, we would accept a proposal by the Utility Regulator to reduce the rate of return on any under-recoveries we incur in GD17 on the same basis as applied to SGN.

- **No additional complexity.** The Utility Regulator asserts that applying a differentiated rate of return to accumulated 'Z' under-recoveries would not add a layer of complexity to our price control regulation. To the extent that firmus energy continues to operate under its existing price cap regime we would agree with this statement: only limited licence changes would be required to implement the Utility Regulator's proposal. However, since the Utility Regulator intends to move firmus energy on to a revenue cap it is unclear how our licence should be drafted so as to differentiate between 'Z' under-recoveries and the 'K' correction factor under-recoveries, and how the licence will be crafted so as to ensure that the unwinding 'Z' will not be reflected in 'K'. We would note that Phoenix's licence contains no such differentiation and so in effect our licence would necessarily continue to be unique among the GDNs.
- **Minimal impact on firmus energy's return.** The Utility Regulator states that its decision to reduce the return on our accumulated 'Z' under-recoveries to a level below our allowed cost of capital *"is unlikely to impact on FE's return significantly"* on the basis that we are likely to have eliminated the remaining balance by 2020.²² Even if such a statement were true it is no basis on which to justify an arbitrary and retrospective decision. And, as we point out elsewhere in this document, given that we have borrowed from banks to part-fund our accumulated under-recoveries, the proposed reduction in return to a level below our actual interest cost will have an immediate negative impact on our financeability compared with the already challenging position we find ourselves in.

6.1.5. Treatment of the Under-recoveries Inside or Outside TRV

In paragraph 11.81 of the Draft Determination, the Utility Regulator asks the question whether our accumulated 'Z' under-recoveries should continue to be treated separately from the TRV or whether they should be rolled into the TRV²³.

This question is not necessarily connected with the Utility Regulator's consideration of whether to reduce the return on our 'Z' under-recoveries. Our view is that the Utility Regulator needs to consider the issue of the ongoing treatment of under-recoveries as part of the detailed implementation of our transition to a revenue cap in any event.

²² Draft Determination, paragraph 11.78

Our Business Plan assumed that our existing under-recoveries would be rolled into the TRV and remunerated at the allowed cost of capital (with no discount to their value attributable to a separate proposal to reduce the rate of return associated with them). However, this formed part of a package that we considered to be financeable in the round *despite* the associated increase in the period for which recovery of our foregone revenues would be deferred as a result of their inclusion in the TRV. In view of the significant financeability issues generated by the other aspects of the Draft Determination we now need to consider all options available to us to ensure that we continue to be able to finance our activities. Our ability to unwind accumulated under-recoveries over a shorter period than would be implied by their inclusion in the TRV will provide a small degree of temporary assistance in this regard. As such, we welcome the Utility Regulator's proposal that accumulated 'Z' under-recoveries should be retained outside the TRV.

As noted above, this is our position irrespective of the issue of the rate of return on 'Z' under-recoveries. This will become more critical still if the Utility Regulator in its Final Determination for GD17 decides to implement its proposal to reduce the rate of return on our previously accumulated 'Z' under-recoveries to a level below our allowed cost of capital. The alternative proposal of moving our balance into TRV at a discounted value would result in an immediate reduction in our TRV, further exacerbating our financeability constraints.

6.2. Utility Regulator's Top-Down Benchmarking Approach

We note the Utility Regulator's acknowledgement that in adopting a 'top down' approach for the first time, there have been practical difficulties in benchmarking the very different utilities to ensure like for like comparison and any meaningful outcomes. The Draft Determination concedes that in relation to benchmarking more work is necessary, i.e. that there are *"specific modelling concerns remaining, hence these results remain indicative at the present time"*.

There is a particular concern on the part of the Utility Regulator, which is shared by firmus energy, that further refinement is necessary to reflect special factors. The Utility Regulator has indicated therefore that it intends "refining further our indicative top down benchmarking through a process of further engagement upon how GDN special factor claims might be applied to the results of our benchmark modelling". Firmus energy welcomes and looks forward to this engagement.

6.3. Materiality Threshold

Firmus energy acknowledges the intention of the Utility Regulator to follow the approach within the GD14 price control to have a materiality threshold for costs not foreseen at the price control determination, but incurred as part of the GDN operations during the price control period.

However, firmus energy holds concerns as to the arbitrary nature of the proposed increase in the materiality threshold from £100,000 to £150,000 per project for the duration of the GD17 price control period.

Firmus energy accept the rationale for the inclusion of a materiality threshold. However, we note that the threshold has been raised to well above 1% of proposed annual GD17 operating costs.

The potential materiality of costs arising from projects such as the implementation of European Directives which firmus energy addressed in our GD17 Business Plan submission and which, while substantial, may fall below the proposed new materiality threshold.

The development of a customer switching system to enable market opening in the Ten Towns is an example of an essential project which cost greater than £100k, for which costs could not be covered under the increased materiality threshold.

This further example of the downside bias prevalent throughout the GD17 Draft Determination risks creating the scenario that essential projects, bringing benefit the industry and customers are placed in question because GDNs are not permitted to adequately fund them.

6.4. Stakeholder Engagement

Firmus energy has undertaken a comprehensive stakeholder engagement programme relating to GD17. In doing so, firmus energy has described our GD17 strategy and shown stakeholders the proposed detailed infill plans for their geographical areas. Alongside our Business Plan submission in September 2015 we were able to submit to the Utility Regulator a report evidencing the positive feedback we have received during our stakeholder interaction.

Firmus energy would welcome the opportunity to further scope the impact upon consumers of the Draft Determination proposals to reduce the Connections Incentive and re-profile network rollout with key stakeholders such as the Consumer Council for Northern Ireland, in conjunction with the Utility Regulator.

6.5. Consumer Research

Firmus energy has an excellent track record in delivering services for vulnerable customers and providing customer service responses to correspondence and complaints within 10 days, meaning we have continuously outperformed the target measures in our customer service standards. It is our intention to achieve further improvements.

To that end firmus energy recognises the opportunity for greater alignment of consumer research to improve customer service standards and to help with network growth planning.

As outlined in our GD17 Business Plan (Chapter 14, Customer Service) we already routinely undertake consumer research which provides the “actionable data” referenced by the Utility Regulator (Draft Determination paragraph 11.24) This research enables us to gain an assessment of our performance, areas for improvement and identify opportunities to connect more customers to the benefits of natural gas.

We welcome the proposed introduction of a customer service development objective outlined in Draft Determination paragraph 11.23. This will require delivery of new customer service metrics and customer satisfaction surveys and greater GDN partnership in the delivery of consumer research and stakeholder engagement. We note the importance of building on the strong work already being undertaken by GDNs.

Firmus energy recognise the potential for learning from the local water and electricity sectors when undertaking partnership work. However, it is also important to note that while further synergies can be developed between GDNs in relation to customer service research, there exists a significant challenge in the consideration of the needs of consumers not connected to the utility network. While unconnected consumers are a key focus in GD17 the very significant differences between the three Northern Ireland networks, in relation to network maturity, customer numbers, penetration rates and network sparsity would provide significant challenges in the design of any joint consumer research.

6.6. Innovation

The Utility Regulator set out clearly in paragraph 8.19 that they do not intend to incentivise innovation projects stating:

“To be clear, by saying this we do not mean that GDNs should not pursue innovation. On the contrary, we welcome innovation initiatives where reasonable and economically efficient. However, we consider that at this stage it is not appropriate to provide further incentives to further innovation.”

Firmus energy view this as an opportunity missed. Throughout this document we have highlighted the distinct nature of the gas market in each of the Northern Ireland distribution network areas and for that reason we understand that practices undertaken in GB should not always be applied directly to Northern Ireland.

However, by failing to provide any incentive for innovation of any type the Utility Regulator is restricting the prospect of innovative measures to address problems specific to Northern Ireland’s unique network areas.

Similarly while we recognise that the Utility Regulator welcomes our interest in developing the specific biomethane injection project proposal, submitted by firmus energy to the Utility Regulator in June 2015, we are concerned that the Utility Regulator’s repeated statements outlining their intention to set high hurdles for any such allowances could have the effect of discouraging innovation from the outset.

6.7. Supplier of Last Resort

Firmus energy continues to be actively engaged with the Utility Regulator and others in the industry to develop a Retail Market Procedure ('RMP') that would support a Supplier of Last Resort (SoLR) event in the Northern Ireland gas industry. The RMP outlines the processes that will be followed if the Utility Regulator intends to revoke a gas supply licence and initiate a SoLR event. The aim of the project is to ensure that arrangements are in place so that the supply of gas to customers can continue in such an event.

Firmus energy welcomes the recognition given to this project within the GD17 Draft Determination and the recognition that GDNs will incur costs as a result of this project. We also welcome the recognition that these costs will not be subject to the materiality threshold and believe that this should be the case regardless of the solution implemented.

We note that the Utility Regulator has outlined two options within the GD17 Draft Determination as to how the Utility Regulator could build SoLR costs into the GD17 price control, either interim measures, such as tariff adjustments or the use of an uncertainty mechanism at the time of the next price control.

During discussions between the Utility Regulator and the other GDNs ahead of publication of the Draft Determination a third option was proposed to the Utility Regulator and firmus energy is surprised that this has not been further explored within the Draft Determination.

This option, supported by the three GDNs, would allow for robust and transparent cost recovery arrangements to be clearly set out in all relevant Distribution and Supply Licences to ensure robust governance exists.

Provision for cost recovery through inclusion of a specific and limited special review within GDNs licences would prevent any potential detrimental cost impact on development of the network.

Firmus energy acknowledge that the Utility Regulator intends to further explore the issue. We believe that this engagement with the GDNs must be undertaken on the basis of the development of an appropriate licence modification as it is the only satisfactory option available. Given the number of licence modifications already proposed in order to facilitate the implementation of the GD17 price control we do not believe this is an unwarranted request.

7. Licence Implications

Annex 1 of the Draft Determination sets out the Utility Regulator's proposed licence modifications and a brief overview is provided in Chapter 12 of the Draft Determination.

At such an advanced stage of the price control process the Utility Regulator has provided little rationale for and detail regarding some of these key proposals and many of the key proposals within the Draft Determination are not captured in the Licence Modifications being consulted upon.

The following section outlines our views in relation to each proposed modification in turn. However it is important to note this in relation to the lack of detailed analysis as to the full effect of the proposed change from price cap to revenue cap, extension of forecasting horizon, treatment of under-recoveries and future treatment of profile adjustments in particular. All these issues will impact upon the price control but have not been adequately considered ahead of the introduction of the Licence Modifications discussed below, which include the parameter changes which are made to bring the Price Control into effect.

7.1. Parameter Changes

Firmus energy notes that the Designated Parameters to apply to the first Formula Year and subsequent Formula Years must be amended for the GD17 Price Control to take effect.

We also recognise that it is important that these changes are designated as a licence modification so that we have recourse to the Competition and Markets Authority (CMA) in the event of dispute.

Our Business Plan provides detailed proposals for growth in the Ten Towns network during the GD17 period and we set out the licence parameters to match. The table below reviews the parameters resultant from the Utility Regulator Draft Determination.

Figure 7.1 GD17 Parameter Assumptions

Designated parameter	Description	Current Value	Limitation to the application of redesignated values	UR Draft Determination Proposed value	Firmus energy proposed value	Rationale for firmus energy change
r_t	Rate of return	0.075	Shall be 0.075 until the end of Formula Year 2016, after which time it may be any number between 0 and 1	0.043	0.055	To reflect our proposed rate of return of between 5% and 6%. For further commentary please refer to Chapter 5 of this document and Oxera paper appended to document
n	Trigger for Price Control Reviews (as defined in Condition 4.4.2)	2016	A formula year	2017	2017	firmus energy agrees with the proposed modification to extend the price control review process from 12 months to 18 months
f_t	Averaging factor to reflect in year cashflow (as defined in Condition 4.6.5)	0.5	A number between 0 and 1	0.5	0.5	The current value reflects the cashflow profile over the reporting year
q	The forecasting horizon for review calculations (as defined in Condition 4.4.2)	2035	Shall be the Formula Year 2035 until 2028, after which time it may be the Formula Year 2035 or any Formula Year after 2035	2045	2045	The firmus energy submission is based upon a profile adjustment to 2045, however the out-workings of the Draft Determination impact upon the viability of this. For further commentary please refer to section 5.7 of this document
RPI	Retail Price Index	242.7	Shall be the average RPI for a given year	256.0	256.0	Firmus energy agrees with the basis upon which RPI has been calculated for GD17
w	Incentive period (as defined in Condition 4.6.10)	5	A number of formula years	6	6	Firmus energy believes this period should align with the length of the price control
g	A switch for the Operating Rolling Incentive	0	Either 0 or 1	0	0	Firmus energy accepts that the incentive is not currently required
h	A switch for the Capital Rolling Incentive	1	Either 0 or 1	1	1	Firmus energy accepts the continuation of the incentive in its current form
d	A switch for the depreciation component	1	Either 0 or 1	1	1	Firmus energy accepts the continuation of the incentive in its current form
l	Deemed asset life - Blended rate based on the depreciation of mains, services, meters and other.	33	None	33	33	This blended rate has not changed from the previous price control and is accepted by firmus energy
δt	A weighting factor to be used in the Primary Constraint	0	Between 0 and 1	0	0	Firmus energy supports the retention of the ability to offset over- and under-recoveries between customer categories
$X_{o,t}$	A rate of return adjustment which may be used to encourage or discourage accumulated over-recoveries (as defined in Condition 4.2.6)	0	None	0	0	For further commentary regarding the proposed treatment of under-recoveries please refer to section 6.1 of this document
$X_{u,t}$	A rate of return adjustment which may be used to encourage or discourage accumulated under-recoveries (as defined in Condition 4.2.6)	0	Shall be zero until Formula Year 2034, when it shall be $(rt=2033+1)$	on-going analysis	0	For further commentary regarding the proposed treatment of under-recoveries please refer to section 6.1 of this document
αt	A weighting factor used in the Supplemental Constraint	0.4	Greater than or equal to zero	0.4	0.4	For further commentary regarding the proposed treatment of under-recoveries please refer to section 6.1 of this document

7.2. GDNs Working Together – Common Branding

The Utility Regulator first proposed the development of greater synergies between the Northern Ireland GDNs during the GD14 process. The GD14 Draft Determination stated:

“We encourage both companies, where practically possible to work together to develop an efficient and growing gas industry.

16.42 We recognise that this occurs at some levels, but we believe further work is necessary to achieve a more co-ordinated approach.

16.43 We would especially encourage further work in the following areas:

- *Advertising and Marketing/ Consumer Research;*
- *Conveyance Charges;*
- *Connection Policies;*
- *Emergencies and Major Incidents.”*

Since the GD14 Determination the GDNs have continued to develop synergies where possible, particularly in relation to emergencies and major incidents and at the outset of the GD17 process firmus energy actively encouraged the Utility Regulator to facilitate engagement between the GDNs, CCNI and the Utility Regulator on consumer research. Additionally firmus energy submitted a GD17 supplementary paper in June 2015 detailing all aspects on which we work collectively with our GDN counterparts.

In relation to GDNs working together as a concept, and on common branding in particular, little guidance has been provided to the GDNs by the Utility Regulator beyond the following statement in the Draft Determination.

“The purpose of the proposed common branding licence condition is to further (and not hamper) the development of the natural gas industry in the firmus energy licensed area and in Northern Ireland as a whole, and to prevent consumers getting confused by the different brands. We consider that GDNs can achieve further efficiencies and improve recognition by consumers by aligning and/or sharing promotional material and/or activities, thus increasing the effect/reducing the cost for each GDN.”

The proposed licence modification builds upon this statement and outlines that GDNs shall, in conjunction and co-operation with other licence holders, develop, implement and comply with a common branding approach in relation to the promotion of gas in Northern Ireland.

This would involve a common approach to the promotion or use of any name, trade name, term, logo, sign, symbol, design or scheme for products or services relating to licensable activities or any other issue relating to the promotion of gas in Northern Ireland as specified in directions issued by the Utility Regulator following consultation.

Firmus energy have reviewed the EU and GB regimes to analyse whether there are any analogous provisions regarding common branding and have found no analogous obligations on GDNs in GB to

adopt a common branding approach in relation to the GB gas distribution network aside from promotion of the priority services register to protect vulnerable customers.

7.2.1. Legal Review

Following receipt of expert legal advice regarding the licence modification firmus energy request that the Utility Regulator provide detailed clarification regarding the practical outworking of this requirement for GDNs.

This clarification is necessary given the level of GDN co-operation that would be required as a result of this licence modification and the limited guidance provided by the Utility Regulator to date.

Provision of such clarification would enable the subsequent drafting of a licence modification that clearly sets out the obligations upon GDNs. Firmus energy would welcome the opportunity to input into such a development process.

7.3. Other Licence Modifications

7.3.1. Independence of the Licensed Business

Firmus energy welcome the change in wording as proposed by the Utility Regulator and it is our understanding that the purpose of this change is to provide greater clarity without effecting any change to the intent of the condition.

The proposal from the Utility Regulator to widen the scope of application of this Condition so that the Condition will apply if the Licensee or any Relevant Affiliate has (either individually or in aggregate) at least 100,000 premises connected to a low pressure conveyance network owned or operated by the Licensee or Relevant Affiliate.

We note a "Relevant Affiliate" is defined as any affiliate or related undertaking of the Licensee which is carrying on activities authorised under Article 6(1) of the Gas (Northern Ireland) Order 1996 (which includes a person who supplies gas to any other person or premises).

Firmus energy welcomes any opportunity to enhance Licence clarity and as such we welcome this change which merely clarifies the existing wording, and does not change the intent of the condition.

7.3.2. Regulatory Instructions and Guidance

Since inception firmus energy has submitted detailed business data to the Utility Regulator for compliance and price control purposes. In the last two years we have submitted this information in

significantly greater detail than before, following the Regulatory Instructions and Guidance ("RIGs") adopted by the Utility Regulator. This new condition sets out the scope, contents and common governance arrangements for these RIGs.

The condition also sets out the scope and content of the RIGs, as well as the process by which the Utility Regulator may develop and modify the RIGs.

The RIGs are the primary means by which Utility Regulator directs the Licensee to collect and provide the information required by Utility Regulator to administer the price control conditions.

The condition obliges firmus energy not only to request information, but to put in place and maintain appropriate systems, processes and procedures to enable it to estimate, measure and record information pursuant to the RIGs and provide such information to the Utility Regulator.

We must also keep separate accounting records for the licensed business and any business of any affiliates or related undertakings, and maintain such records for a period of eight years (or any shorter time period as set out in the RIGs).

Firmus energy agree with the statement contained within the Draft Determination that the new licence condition is desirable for both the Utility Regulator and firmus energy, as it clarifies the position in relation to the provision of information, as well as offering protection to licensees as new RIGs may only be issued following a consultation process and after due consideration of responses.

The Utility Regulator also suggest that they have sought alignment with the relevant Ofgem RIGs, and have added some NI-specific amendments.

While we support the idea of benchmarking in principle as a qualitative check on a utility's costs as efficient and reasonable, we are also aware of the significantly different scale of operations between firmus energy and comparators, particularly GB GDNs.

This significant scale differential, particularly with reference to manpower resources, creates a reporting and compliance burden on the firmus energy business that has not be adequately acknowledged by the Utility Regulator.

The Utility Regulator should undertake a deeper analysis of the relevant Ofgem templates to see whether the proposed modification is fit for purpose in a Northern Irish context.

This is of particular importance as despite our September 2015 Business Plan outlining the significantly greater level of workload resultant from Price Controls and RIGs and Retail Energy Market Monitoring framework (REMM) reporting the Draft Determination disallows our proposal for an addition 0.5 FTE staff member to assist with the collation and regulatory reporting of information.

7.3.3. Conveyance Charges

We understand that this modification clarifies, but does not alter, the dispute resolution process.

In the event of a dispute between the Licensee and any person over conveyance/connection charges and/or terms, any party to the dispute may make application to Utility Regulator to determine the terms of the agreement in dispute.

If the dispute has not been previously referred to CCNI (or the CCNI has not fully concluded its investigation), the Utility Regulator may refer the dispute to the CCNI. If the CCNI is unable to assist within three months, the matter is referred back to the Utility Regulator, and the parties will have one month to make further representations and the Utility Regulator may settle the terms in such manner as it deems reasonable.

If the disputing party wishes to enter into terms as set out by the Utility Regulator, then the Licensee shall enter into and implement such terms.

Firmus energy welcomes any opportunity to enhance Licence clarity and as such we welcome this change which provides more clarity to the process.

7.3.4. Connection Charges and Obligation to Permit a Connection

These modifications have been proposed to implement changes made necessary by the Gas (Individual Standards of Performance) Regulations (Northern Ireland) 2014.

The modifications require that:

(i) Any statement submitted by the Licensee to NIAUR under Condition 2.3.1 or Condition 2.3.7 be accompanied by a statement agreed with NIAUR which describes both complex and excluded connections; and

(ii) the Licensee shall also from time to time submit to NIAUR for its agreement an accuracy review scheme through which any customer can require the Licensee to review the accuracy of quotation provided to that customer for obtaining or renewing a connection and publish the agreed accuracy review scheme in such manner as will bring it to the attention of customers.

Whilst we agree with the Utility Regulator that these modifications may be necessary in order to properly implement the Gas (Individual Standards of Performance) Regulations (Northern Ireland) 2014, it may be necessary to define the frequency of the requirement to issue an accuracy review scheme. At present "from time to time" is too broadly drafted, and a specific timeframe should be set out.

Accordingly, we suggest an amendment to the proposed modification which would set an agreed timescale.

7.3.5. Complaints Handling Procedure

All firmus energy staff and contractors work to the Firmus Gas Distribution Complaints Handling Code which defines a complaint as "an expression of dissatisfaction made by any person or business in respect of the activities of firmus energy in the provision of its regulated activities". Therefore we welcome this modification to our Licence which widens its scope in line with our current practice.

7.3.6. Reasonable and Prudent Operator

This proposed modification will implement a licence obligation upon firmus energy to carry out the activities in a manner consistent with being a reasonable and prudent operator.

While our understanding is that this new condition merely formalises how we would expect any low pressure conveyance licence holder to run their business. We would welcome the opportunity to discuss the potential implications of this proposed modification for firmus energy in practice.

7.3.7. Trading with Associated Businesses

We understand that the proposed modification sets out that there should be no cross-subsidy between businesses operated by the Licensee or any of its affiliates or related undertakings.

Furthermore, any tenders or sub-contracts should state whether they are being submitted/entered into with an affiliate or related undertaking of the Licensee.

We note that similar provisions have been included in various electricity licences issued by the Utility Regulator.

While we do not believe that this will have any impact on firmus energy Distribution we would welcome the opportunity to discuss this proposed modification further with the Utility Regulator to understand if the Utility Regulator perceive any potential impact on our business activities.

7.3.8. Asset Management

Firmus energy is working to implement an asset management plan produced as part of the GD14 process. It is our understanding that this new condition 3.8A, formalises the requirement to carry out an initial assessment and prepare a plan to implement any necessary requirements, alongside a requirement to demonstrate that we have done so.

Given the work undertaken to implement an ISO 55001 accredited asset management system based on robust, evidence-based decisions in relation to the development, construction, operation and maintenance of the distribution network firmus energy welcomes the incorporation of asset management requirements into our Licence.

However, we note that our request for an adequate manpower allowance to undertake this work has been discounted in the GD17 Draft Determination.

7.3.9. Timeline for Periodic Review

Firmus energy accept the Utility Regulator's suggestion that 18 months is a more sensible period in which to implement a price control process from Business Plan submission to start of the new price control period and note that this proposed modification would affect that change.

At the beginning of 2015 firmus energy agreed to facilitate, in an informal manner such a change for the GD17 review.

At the Utility Regulator's request we agreed to bring forward by six months to June 2015 our initial GD17 reporting deadline as required by Licence. Subsequently we submitted our full Business Plan and Template in September 2015, three months ahead of Licence requirement.

Due to the significant additional resource requirement this last minute change placed upon the company we consider it imperative that timelines as stipulated by Licence are adhered to by the Utility Regulator in future price controls.

8. Outline of Appended documents

Appended to this response document are a number of supporting papers which serve to underpin our GD17 submission and the further evidence and analysis contained within this document. The appendices are:

1. Specific Requests and Comments from Utility Regulator

This appendix captures the Utility Regulator's specific requests for further information and comments and notes where they can be found within this response document.

2. Information Provided to Meet the Utility Regulator's requirements

Firmus energy has, to-date, made two substantive GD17 submissions to the Utility Regulator in June and September 2015. Details of these submissions are contained within Appendix 2.

3. A Paper Scoping Legislative Requirements Relating to Network Maintenance

This appendix further considers the impact of Legislative Requirements upon firmus energy's network maintenance costs.

4. An Oxera update paper on WACC

Oxera (economic consultancy) is advising firmus energy on its GD17 submissions. In doing so Oxera produced a paper for the Utility Regulator in June 2015 that provided an initial assessment of the weighted average cost of capital (WACC), as the allowed rate of return for firmus energy in the GD17 period. An updated paper was submitted in September 2015.

The paper appended to this document responds to the Utility Regulator's Draft Determination on the allowed rate of return for NI gas distribution networks (GDNs), including the allowance for taxation. It reflects further analysis, updated market evidence and provides evidence of the firm point estimate of the WACC rate for firmus energy in GD17 of 5.5% (pre-tax real).

5. An Oxera Review of the Utility Regulator's Top-down Approach to Opex Benchmarking

This appendix presents Oxera's review of Deloitte's analysis on behalf of the Utility Regulator. The review is limited, as access to any data by the Utility Regulator has not been made available; however, the paper identifies a number of significant concerns regarding the robustness of Deloitte's analysis in assessing firmus energy's efficiency.

6. An Oxera Paper on Under-Recoveries

Oxera has provided a view of the Utility Regulator's proposed licence modification regarding the rate of return on under-recoveries.

7. A DNV GL Paper Analysing the Impact of Special Factors on firmus energy

In this paper specialist engineering consultants DNV GL analyse the significant impact special factors, most notably sparsity and scale, have on firmus energy's network activities

8. Insurance Costs Benchmarking

In this paper our brokers Marsh, analyse our current levels of cover in comparison to other UK utility clients and confirm their adequacy and comparability.

Appendix 1. Specific Requests and Comments from Utility Regulator

The Utility Regulator's Draft Determination captured a number of specific requests for further information and specific comments on the firmus energy Business Plan submission which we have replied to in the relevant sections of this response document. The below table provides reference points where our comments and responses can be found.

Reference within Draft Determination		Reference within this Document
1.47	Review of, and potential removal of, the Profile Adjustment	1.1.6 5.4 and 5.7
6.242	Application of the owner occupied incentive mechanism and it's calculation over the entire price control period rather than on an annual basis	2.4.1.2
6.243		
6.454		
7.43	Basket of works	4.4
10.96	Impact of removal of the profile adjustment, along with the interlinked areas of depreciation and adjusting the Forecast Horizon.	1.1.6 5.4 and 5.7
11.62	SoLR processes	6.7
11.79	Reduction of firmus energy rate of return on under-recoveries to LIBOR plus 2%	6.1
11.80		
11.86	Retention of the current approach to 'Z' (under-recoveries) outside the TRV	7.1
12.1	The proposed licence modifications	7
Annex 5 – Benchmarking		
2.26	Input into further development of the Utility Regulator's top down benchmarking models	6.2
2.36	Detailed assessment of special factors	1.1.8, Appendices 5 and 7

Appendix 2. Information Provided to Meet the Utility Regulator's Requirements

Key Features of Our Initial Business Plan for GD17

On 30 September 2015, we submitted to the Utility Regulator our Business Plan for the GD17 regulatory price control in respect of the period from January 2017 to December 2022.

For GD17, the Utility Regulator challenged us to produce a Business Plan that would meet the primary objective of the price control: *"to promote the development and maintenance of an efficient, economic and coordinated gas industry in Northern Ireland"*. In responding to this challenge, our Business Plan set out an ambitious but deliverable business and network development proposal that aimed to meet the Utility Regulator's objectives while realising significant efficiencies in order to deliver significant real reductions in costs for our customers.

Figure A1.

Key Features of our Business Plan for GD17

Our plan will make the benefits of natural gas available to more members of our community

- increasing the number of properties with access to natural gas from 90,000 to c. 161,000
- doubling the number of connections to our network from 32,000 to nearly 60,000
- prioritising economically efficient growth and a greener, cleaner environment

Our plan will make gas cheaper for our customers

- a significant real reduction in customer tariffs for the entire GD17 period
- ensuring that natural gas contributes to the fight against fuel poverty
- helping businesses by lowering energy costs

Our plan will drive sustainable growth and employment in the Ten Towns

- over £80 million to be invested in the network over the GD17 period
- c. 360 employees/contractors directly involved in the development of our network
- competitiveness of local businesses and its ability to invest enhanced

Our plan has the support of our stakeholders

- supporting the primary network development objective of the Utility Regulator
- continuing to deliver high standards of customer service
- social housing sector (NIHE) and other key stakeholders committed to the plan

Our plan is deliverable

- the plan is soundly based on high quality information, data and evidence
- network development has been carefully planned zone by zone and over time
- contractors and agents are ready to "gear up"

The GD17 process itself represents a significant change compared with previous price controls in terms of the sheer quantity of data we were asked to provide. Despite our stated misgivings about the complexity and scale of the process relative to the small size of our business, we undertook to provide to the Utility Regulator all of the data it required (at considerable, unrecoverable financial cost to our business). Having taken up the Utility Regulator's challenge, we were pleased to present a Business Plan supported by significant amounts of data and analysis that took account of the specific characteristics of our business and the market in which we operate. In doing so, we made the Utility Regulator aware of a number of critical themes underpinning the approach we adopted in our Business Plan, including the following.

- **A more challenging marketplace.** We noted that reductions in oil prices in recent years have eroded the cost advantage of natural gas over oil and therefore that we are finding it ever harder to convince customers to connect to the gas network. We noted that it was critical that the GD17 price control provided us with allowances that would enable us to raise customer awareness around the benefits of gas and help our customers with the cost of conversion as much as possible.
- **Refocusing of connections growth.** Taking our lead from the Utility Regulator's guidance, we emphasised our desire to increase the reach of our network to enable large numbers of homes to connect to natural gas. We proposed to build over 700km of pipelines to pass over 70,000 new properties.
- **Critical link between connections target and Capex allowance.** We emphasised that we would only be able to deliver our ambitious connections targets if the Utility Regulator was prepared to allow us to invest to extend the reach of our network.
- **High quality data to support development plan.** We acknowledged that the Utility Regulator would need to be satisfied that our network development plan was economic. We provided a substantial amount of data and analysis to support our plan, including a full network design and economic appraisal, supported by 29 A4 ring binders of data and 621 detailed network development plans.
- **Cost of capital.** We noted that our ability to finance the development of our network was entirely reliant on a GD17 price control outcome that would allow us sufficient revenues to enable us to finance our business.
- **Comparisons with GB GDN's and Phoenix.** We welcomed in principle the Utility Regulator's proposal that our Opex and Capex allowances should be benchmarked against others as a qualitative check on whether our requests were reasonable. However, we cautioned against adopting a mechanistic approach to benchmarking given that our business is significantly different in size, network density and customer numbers from those against which we were to be compared.

Breakdown of firmus energy GD17 Submissions to Date

Firmus energy's GD17 Business Plan was submitted to the Utility Regulator in September 2015. This built upon our initial submission of supporting papers in June 2015. Subsequently these submissions were supplemented by numerous responses to Utility Regulator requests for information.

In developing a Business Plan submission that incorporated a level of detail directly comparable to that provided by GDNs in Great Britain despite having a fraction of the staffing available to these much larger corporations, firmus energy has committed a very high level of available time and resource to make GD17 a successful process.

While we have highlighted that the approach adopted was at odds with statements by the Utility Regulator about "light touch" and proportionate regulation, we nevertheless undertook to provide the information sought by the Utility Regulator in full and on time.

The figure below and overleaf indicates the extent of information provided by firmus energy to meet all regulatory requirements.

Figure A2.

Firmus energy GD17 Submissions to date	
Submission	Date and Comment
12 supporting papers 1. Rate of Return – produced on our behalf by Oxera 2. Security of Supply 3. Telemetry 4. GDNs Working Together 5. Benchmarking Assessment – produced on our behalf by Oxera 6. Connection Incentive 7. Infill Allowances Plan Methodology 8. Peer Review of firmus energy's Connection Assumptions – produced by Oxera 9. Draft Distribution Connection Policy 10. Innovation Business Plan 11. Smart Metering 12. Period Contract Overview	29 June 2015 On time – 6 months ahead of Licence requirement
Business Plan Template (BPT) c. 40 worksheets of detailed business data	30 September 2015
Business Plan 140 page document providing commentary on our Business Plan and detailed data template (BPT)	On time – 3 months ahead of Licence requirement
Business Plan Appendices 1. Calculation of Conveyance Charges with q=40 Years (used for determining financial outputs in the BPT)	31 December 2015

2. Calculation of Conveyance Charges with q=30 Years (used for determining financial outputs in the BPT) 3. Worksheet of firmus energy's energy Retrospective Adjustments for GD14 4. Millward Brown Research regarding Customer Connections 5. A Report on firmus energy GD17 Stakeholder Consultation Activity 6. The firmus energy Marketing Plan 7. An Update on Asset Maintenance – ISO 55001 8. An Oxera Update Paper on WACC 9. An Oxera Review of the Utility Regulator's Approach to 'Basket of Works' Benchmarking 10. An Oxera Peer Review of firmus energy Connection Rates and Penetration Profile 11. An Infill Plan Case Study 12. A paper detailing GD17 Proposed Maintenance Activities and • Resubmission of the Oxera paper: GD17 price control parameters: allowed rate of return • Resubmission of Oxera paper: Benchmarking/Efficiency Assessment	30 September 2015 On time – 3 months ahead of Licence requirement 31 December 2015
Capex Rollout Plan • 29 A4 ring binder files with 621 colour plans to detail our proposed network roll-out • An overall colour plan for each town and individual colour plans for zone/project which relate to the BPT • A list of each zone/project within each town file with total length of mains and total cost of project • A colour coded legend indicating proposed year of build • A polygon defining town limits and potential properties passed and connection numbers	30 September 2015 Additional information over and above that requested by the Utility Regulator
67 Information Request Responses All 67 information requests received and responded to on time, to provide the Utility Regulator with supplementary detail on aspects of our Business Plan	From October 2015 to January 2016

Appendix 3. Network Maintenance – Legislative and Safety Case Considerations

In order to meet the requirements of the Gas Safety (Management) Regulations firmus energy must submit a safety case to the Health and Safety Executive for Northern Ireland. All firmus energy operatives adhere to our Safety Case that was published in 2013 and on page 16 states *“Through maintenance schedules and inspections the risks are eliminated or reduced by continual assessment by competent persons, and maintenance carried out before failure occurs”*. Failure to adhere to these obligations result in a breach of the Gas Safety (Management) Regulations. The Utility Regulator’s proposals will challenge firmus energy’s ability to adhere to our obligations.

Given the generic nature of the Utility Regulator’s proposed disallowances and notwithstanding consideration of the benchmarking weaknesses outlined in our Draft Determination response, we consider it incumbent upon the Utility Regulator to review their proposals in light of the following legislative and safety case requirements for firmus energy:

- **Medium Pressure Regulator Testing & Replacement Programme**

As part of the development of our Asset Management system, firmus energy has instigated inspection and maintenance regimes for assets. In the case of medium pressure (MP) regulators this will be carried out by means of a 10 year inspection to confirm correct operation with a 20 year end of life replacement. As with all equipment it is forecast that some replacement will be required as a result of the 10 year inspection and functional testing. However, as some replacement may also be required subsequently, not all costs will be directly attributable to the inspection. Failure of a regulator could cause over pressurisation of downstream pipework and appliances, or the activation of the relief mechanism – this would contravene firmus energy’s duty to avoid or minimise the release of a dangerous substance as set out in the Dangerous Substance and Explosive Atmosphere regulations (DSEAR), Regulation 6.

- **Governor & Customer Rig Component Replacement**

The DSEAR Regulations place a duty on firmus energy to ensure that we avoid or minimise the release of a dangerous substance. Failure of components of this nature must be addressed as they create a situation which is either immediately dangerous or one with potential to lead to a dangerous situation, or a loss of gas supply.

- **Planned Maintenance Activities and Overhauls on CPRM’s & DPRM’s.**

It is a legal requirement under the Pressure Systems Safety Regulations, (PSSR) 2000 for firmus energy as a gas distribution system operator to demonstrate that we:

Have designed and constructed the pressure system to be safe with the appropriate protective devices where required (this is particularly relevant as the customer pressure reduction and metering module contains a safety device designed to protect the downstream pipework from being subjected to a pressure greater than that which it was designed to operate at – this is the slam shut device)

- **Have established the safe operating limits of pressure systems**
- **Have a written scheme of examination in place prior to the use of the system; and**
- **Maintain and repair the system to meet the required safety standards**

Firmus energy's written scheme of examination states that we will carry out annual safety device function checks on every Medium Pressure regulator with a flow rate ≥ 65 SCMH. Our approach to maintenance is to carry out a preventative maintenance programme consisting of minor remedial work at the same visit. The written scheme of examination certifies the pressure system (including all protective devices, pressure vessels and pipework) for use, and must be approved by a competent (independent) person. Examinations must be carried out by a competent person and must be reviewed at regular intervals as defined by the written scheme. The system must also be maintained properly to ensure that it is safe.

Firmus energy employ the services of an independent Competent Person who monitors our compliance with the written scheme by way of routine consultation and examination of our records. Our written scheme of examination, in line with all Gas Distribution Network Operators in GB, includes the annual function checking of each protective device installed on our networks. Any failure to carry out this annual inspection must be reported to the Health and Safety Executive (NI), they may then investigate the failure.

Firmus also follow a programme of non-routine maintenance which is largely an overhaul at set periods of between 5 and 7 years. This is aligned to manufacturer's guidelines and aimed at maintaining prolonged reliable operation of the regulators. As we have outlined previously, firmus energy has found this to be beneficial to reliability having experienced only 17 breakdowns in a 30 month period (January 2013 – June 2015) which constitutes a failure rate of 2.4%. We believe this demonstrates a superior level of reliability to our consumers.

As we must carry out the PSSR checks listed above, the impact of the Utility Regulator's 25% generic cut proposal will be a significant reduction or cessation in the routine maintenance activities. The implication is that as components age they will require more minor remedial work, and an inability to affect this will lead to increased incidences of gas escapes. This will be subject to discussion with HSENI as it constitutes a change to our network operations which are in line with the PSSR Regulations and our current safety case.

- **Inspection of Network Valves**

It is a legal requirement under the Pipeline Safety Regulations (NI), 1997 for firmus energy as a distribution system operator to consider maintenance and inspection requirements for the pipeline, this includes valves. Firmus energy submitted a proposal for network valve inspections to improve their accessibility in the event of a network emergency. Using a process of risk assessment we considered the criticality of valves and submitted a proposal to vary the frequency of inspection in line with this criticality.

Since our GD17 submissions of 2015, we have carried out a pilot programme of inspections on the most critical valves and found that the projected costs were approximately 33% insufficient. Resultantly, the proposed 25% generic cut will impact even further upon these activities. Furthermore, the difficulty in accessing valves due to lack of inspection and maintenance will have the potential

knock on effect of gas escapes and risk of loss of supply, or system outage for a longer period of time, while we have to dig and remove a frame and cover.

- **Replacement of Defective Valve & Pressure Point Covers**

It is a legal requirement under the Pipeline Safety Regulations (NI), 1997 for firmus energy as a distribution system operator to consider maintenance and inspection requirements for the pipeline, which includes 'valves and other primary attachments'.

Firmus regards the replacement of defective covers as a non-optional activity as surface covers in an unfit condition pose an immediate risk due to the restricted access for the maintenance and inspection activities under the Pipeline Safety Regulations, as described above.

- **Replacement of H25 & H40 DPRM's**

HSENI have expressed concern over the use of this type of district pressure reduction module which lacks a protective device (slam shut valve), leading to the risk of an incident of over pressurisation occurring should the device fail. The proposal to replace all of these units currently in service over the next six years was directly in response to the HSENI concerns, while applying a measured approach. The impact of the Utility Regulator's proposals will be discussed further with HSENI.

- **Bridge Inspections**

Following an incident in the Greater Belfast Gas Distribution Network at Ormeau Road, Belfast in November 2009 where a Medium Pressure Pipeline under a bridge was subjected to fire damage following vandalism, HSENI met with firmus energy and specifically requested that we carry out further risk assessment specifically focused on this type of interference damage. This in turn has led to a greater requirement for routine pipeline inspections where crossings are particularly exposed. The steel pipelines attached to existing bridges over rivers, roads or railways are a small but critical part of our asset base, most of these effectively constitute key parts of our single fed networks and their failure would lead to major network incident with potential loss of major parts of our networks. In line with Regulation 13 of the Pipelines Safety Regulations (NI) 1997, firmus had submitted a proposal for inspection after ten years in service, along with a re-application of pipe wrapping to ensure ongoing protection against degradation caused by exposure to the elements. Not carrying out the re-application of wrapping will ultimately lead to a reduced lifetime of the steel pipelines with an associated material replacement cost, which will arise sooner than firmus energy had intended due to the impact of the Utility Regulator's proposals on preventative maintenance.

- **Gas Samples**

The collection and analysis of gas samples is a legal requirement under the Gas Safety Management Regulations, Regulation 8(5). The purpose of this is to ensure that odorant levels are at a suitable level to enable prompt detection, and hence reporting of any network escape by the general public. Any implied reduction in expenditure will have to be discussed with HSENI, and our safety case revised accordingly to account for this change in our operational activities.

- **DSEAR Compliance**

It is a requirement of the DSEAR 2002 to ensure control measures are put in place which reduce the risks associated with the potentially explosive atmosphere which may occur in the vicinity of our pressure regulating equipment. Firmus energy's Business Plan has incorporated improvements to these measures including improved signage and relief venting systems. The proposed 25% impact to funding of this project would require further discussion with HSENI.

- **Leak Survey**

Regulation 13 of the Pipeline Safety Regulations (NI) 1997 deals with the requirement to ensure pipelines remain in a safe condition. Firmus energy's proposed network leak survey targets leakage from mechanical joints on below ground sections of the gas distribution network. The Utility Regulator's 25% proposed cut will challenge firmus energy's ability to ensure these activities are continued appropriately.



Response to the Utility Regulator's draft decision: allowed rate of return

For submission to the
Utility Regulator

Prepared for
firmus energy

31 May 2016

www.oxera.com

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Executive summary

Oxera is advising firmus energy (FE) on its submissions to the Northern Ireland Utility Regulator (the 'Utility Regulator') regarding the GD17 price control for gas distribution in Northern Ireland for the period 2017–22.

In March 2016, the Utility Regulator published its GD17 draft determination.¹ This report responds to the Utility Regulator's draft determination on the allowed rate of return for NI gas distribution networks (GDNs), including the adjustment from a post-tax to pre-tax WACC estimate. Having considered the allowed rate of return analysis that has been undertaken by the Utility Regulator and its adviser, First Economics,² Oxera's response to the draft determination focuses on the following issues.

Cost of equity

- The allowed total market returns for NI GDNs for 2017–22 are significantly lower than for GB GDNs over an overlapping time period (2013–21). This implies an inequitable outcome for Northern Ireland investors. To address this, the Utility Regulator may consider selection of a higher point estimate for the NI GDNs in its estimated weighted average cost of capital (WACC) range.
- The market analysis of the betas of publicly listed UK utilities undertaken by First Economics provides an underestimate due to the selection of the sample and the time period analysed. Regarding regulatory precedents within Northern Ireland itself, it is not clear that the Utility Regulator has appropriately calibrated its measure of the asset beta for GDNs against the allowed betas for other NI networks. On balance, the evidence supports the selection of an asset beta estimate for FE that is at the top end of the range assessed by Oxera (i.e. 0.5, rather than the bottom end of the range at 0.4 as assumed in the Utility Regulator's draft determination).
- The use of a relatively high debt beta has implications for the regulator's assessment of risk, and read-across to other WACC parameters. Combined with a low notional gearing assumption, a relatively high debt beta suggests that the Utility Regulator recognises that FE's debt is riskier than other regulated networks. However, the Utility Regulator does not allow for such higher risk in either its asset beta estimate or its assumed debt premium.
- Within the draft determination package, the cost of equity allowance for FE does not allow sufficient headroom for downside risk for FE in GD17. Since the Utility Regulator has suggested that the majority of debt financing costs in GD17 will be subject to a pass-through mechanism, the financeability analysis supports that the Utility Regulator selects a higher point estimate in its estimated cost of equity range. By its own analysis, the Utility Regulator has shown that FE's interest coverage ratio for the GD17 period is at the minimum necessary level for five years within the six-year control. This suggests that the Utility Regulator has not allowed sufficient headroom for volatility in its estimation of the allowed cost of equity, within the overall price control package.

Cost of debt

¹ Utility Regulator (2016), 'Price Control for Northern Ireland's Gas Distribution Networks GD17', Draft determination, 16 March.

² The Utility Regulator is being advised by First Economics, see: Utility Regulator (2016), 'Price Control for Northern Ireland's Gas Distribution Networks GD17', Draft determination, 16 March, para. 10.14.

- There is an inconsistency between the cost of debt approach used for FE and the regulatory disaggregated cost of debt approach used for the electricity System Operator for Northern Ireland (SONI). The 2.95% allowance for SONI, and its constituent estimates are broadly aligned with the allowed cost for FE in the September 2015 update, which assessed a reasonable range of 3.05–3.30%. It is therefore inconsistent within Northern Ireland that the allowed cost of debt for FE is much lower than for SONI. This arises due to the use of a different cost of debt estimation approach, and notwithstanding the fact that FE would have to offer a yield premium if it is perceived to have relatively high risk as a first-time bond issuer in GD17.
- The Utility Regulator has deflated embedded debt for the period 2017-19 using inflation forecasts for six years (i.e. average of 3.08% over 2017-22). Instead using an estimate of 2.68% inflation for the relevant 2017-19 period suggests that the real embedded debt cost allowance should be 40 basis points (bps) higher. Specifically, this leads to an increase in the embedded debt cost from 1.6% as assessed by the Utility Regulator, to 2.0%.
- To ensure that any 'pain-gain sharing' cost of debt approach appropriately allows for FE's specific financing constraints in GD17, Oxera recommends the following:
 - 60 bps allowance for transaction costs, rather than 40 bps as proposed by the Utility Regulator. This is based on an assessment of the notional quantum of debt to be raised by FE in GD17;
 - 1.3% additional allowance for 'credit uplift' within the debt premium. This should be added to the new cost of debt allowance inferred from BBB iBoxx yields if FE is unable to achieve an investment-grade rating;
 - inclusion of an RPI inflation 'true-up' to reflect any differentials in outturn inflation relative to the Utility Regulator's forecast, within the allowed cost of new debt;
 - cost pass-through with 80:20 pain-gain sharing should occur at the end of the period. This should allow for any pain-gain adjustments to the WACC to also be factored into 'logged-up' amounts for any other uncertainty mechanisms or revenue-reprofiling mechanisms.

Taxation

- The Utility Regulator has suggested that FE's submissions are underpinned by an effective tax rate of 27%. This is incorrect, as the submissions by Oxera on behalf of FE (i.e. the June 2015 report and the September 2015 update) consistently assume a statutory tax rate assumption of 20%.
 - By adjusting in one step from a real post-tax cost of equity estimate to a pre-tax cost of equity estimate, without allowing a tax wedge on the proportion of its return that is linked to inflation, the Utility Regulator has understated the allowed return for FE by around 30 bps.
-

1 Introduction

Oxera is advising firmus energy (FE) on its submissions to the Northern Ireland Utility Regulator (the 'Utility Regulator') regarding the GD17 price control for gas distribution in Northern Ireland for the period 2017–22.

In March 2016, the Utility Regulator published its GD17 draft determination.³ This report responds to the Utility Regulator's draft determination on the allowed rate of return for NI gas distribution networks (GDNs), including the adjustment from a post-tax WACC estimate to a pre-tax allowance.

This report is to be read in conjunction with earlier submissions by Oxera, relating to the allowed rate of return. First, in June 2015, Oxera submitted a report on the allowed rate of return for FE for the GD17 price control period (the 'June 2015 report').⁴ Second, in September 2015, Oxera submitted further evidence on the allowed rate of return for FE for the GD17 price control period (the 'September 2015 update').⁵ Third, in February 2016, Oxera responded to a query from the Utility Regulator relating to the adjustment for taxes (the 'tax note') included in the real pre-tax weighted average cost of capital (WACC) estimate for FE in the June 2015 report and the September 2015 update.⁶

This report is structured as follows:

- section 2 assesses issues relating to the estimation of the allowed cost of equity by the Utility Regulator, including its total market return estimate and the estimate of the asset beta;
- section 3 addresses issues relating to the allowed cost of debt estimate by the Utility Regulator, including the uncertainty surrounding its new 'pain-gain sharing' mechanisms;
- section 4 considers the Utility Regulator's assessment of the tax adjustment for FE in its estimate of the real pre-tax WACC;
- section 5 concludes.

³ Utility Regulator (2016), 'Price Control for Northern Ireland's Gas Distribution Networks GD17', Draft determination, 16 March.

⁴ Oxera (2015), 'GD17 price control parameters: allowed rate of return', for submission to the Utility Regulator, prepared for firmus energy, 30 June.

⁵ Oxera (2015), 'GD17 price control parameters: allowed rate of return', September update. Further submission, following Oxera's June 2015 report submission to the Utility Regulator, for submission to the Utility Regulator, prepared for firmus energy, September.

⁶ Oxera (2016), 'Tax adjustment in pre-tax cost of capital estimate', note for submission to the Utility Regulator, prepared for firmus energy, 19 February. The tax note is replicated in Appendix A1 of this report.

2 Cost of equity

This section assesses issues relating to the estimation of the allowed cost of equity by the Utility Regulator. Section 2.1 considers the Utility Regulator's total market return estimate, while section 2.2 assesses evidence relating to the Utility Regulator's estimate of the asset beta.

2.1 Total market return

In its estimation of the generic parameters within the cost of equity calculation—i.e. the risk-free rate and the equity risk premium, the Utility Regulator has relied on UK regulatory precedents, including the most recent precedent from the Competition and Markets Authority (CMA). The Utility Regulator has stated that its total market return estimate of 6.5%, as the sum of the risk-free rate and the equity risk premium, is based on the CMA precedent for Northern Ireland Electricity (NIE).⁷

The Ofgem decision for GB GDNs relates to the same sector, and for overlapping time periods relative to the Utility Regulator's GD17 decision.⁸ It is therefore relevant to compare the generic total market return allowed for GB and NI GDNs over the GD17 period. The differential in the total market return proposed by the Utility Regulator for NI GDNs (6.5%) relative to that allowed by Ofgem for GB GDNs (7.25%)⁹ is significant. This is because a timing difference—i.e. a decision in 2012 by Ofgem compared with a draft determination in 2016 by the Utility Regulator—implies a 0.75% reduction in the allowed total market return in Northern Ireland up to 2021. Therefore, while the 6.5% total market return assumption by the Utility Regulator is informed by recent market and regulatory precedents, the regulator should consider the following implications of its draft decision:

- whether the outcome—i.e. much lower allowed total market returns in Northern Ireland than in Great Britain over an overlapping time period, for the same industry, up to 2021—provides appropriate incentives for investors in the NI gas distribution sector;
- whether the resultant downward pressure on the overall allowed cost of capital for FE is appropriate by reference to the underlying risks faced by FE, or whether it should be offset by movements in other decisions based on market data (such as the asset beta).

The impact of the differing generic total market return assumptions has a significant effect on the overall cost of equity. The overall allowed cost of equity for NI GDNs is much lower, at 5.3%,¹⁰ compared with 6.7%¹¹ for GB GDNs.¹²

In other words, the Utility Regulator's estimate of generic equity parameters will imply an overall lower allowed return than GB networks for the same time period,

⁷ Utility Regulator (2016), 'Price Control for Northern Ireland's Gas Distribution Networks GD17', Draft determination, 16 March, paras 10.21–10.22.

⁸ In other words, RIIO-GD1 is in place until the end of March 2021 while the GD17 price control period extends up to December 2022.

⁹ Ofgem (2012), 'RIIO-GD1: Final proposals—finance and uncertainty supporting document', 17 December, para. 3.40.

¹⁰ Utility Regulator (2016), 'Price Control for Northern Ireland's Gas Distribution Networks GD17', Draft determination, 16 March, Table 178.

¹¹ Ofgem (2012), 'RIIO-GD1: Final proposals—finance and uncertainty supporting document', 17 December, Table 3.1.

¹² Both figures are reported on a post-tax, real basis. The asset beta assumption differs between the Ofgem and the Utility Regulator decisions, at 0.32 and 0.4, respectively.

unless the Utility Regulator selects a higher point estimate for the NI GDNs in its estimated WACC range.

2.2 Beta

In estimating an allowed beta for FE, the Utility Regulator and its advisers, First Economics, have considered evidence from the following sources: betas of UK listed utilities; recent UK regulatory precedents and the beta used by Scotia Gas Networks (SGN) in its application for the Gas to the West licence.

This sub-section considers the following issues, in relation to the Utility Regulator's estimation of the asset beta:

- the market analysis of the betas of publicly listed UK utilities undertaken by First Economics provides an underestimate due to the selection of the sample and the time period analysed;¹³
- regarding regulatory precedents within Northern Ireland itself, it is not clear that the Utility Regulator has appropriately calibrated its measure of the asset beta for GDNs against the allowed betas for other NI networks—i.e. the 0.4 assumption by the CMA for NIE,¹⁴ the Utility Regulator's 0.44 assumption for NI Water (2014)¹⁵ and the Utility Regulator's 0.6 assumption for the System Operator for Northern Ireland (SONI) (2016).¹⁶
- the use of a low notional gearing assumption and high debt beta suggests that the Utility Regulator recognises that FE's debt is riskier than other regulated networks. However, the Utility Regulator does not allow for such higher risk in either its asset beta estimate or its assumed debt premium.

2.2.1 Issues relating to market analysis of UK utility betas

Composition of sample

In analysing betas of UK utilities, First Economics presented beta estimates for a sample of UK listed 'network-dominated' companies—i.e. National Grid, Pennon Group, Severn Trent and United Utilities.¹⁷

First Economics suggested that its market beta analysis was designed to be consistent with recent Competition Commission (CC)/CMA practice.¹⁸ It is therefore not clear why SSE has been omitted from First Economics' sample of listed UK utilities; this omission runs counter to the CMA market beta analysis in recent decisions and leads to an underestimate of average market betas.

As explained with regard to the risk differentials analysis in Oxera's June 2015 report,¹⁹ there are no exact comparators for the NI GDNs. However, in

¹³ FE asked the Utility Regulator if calculations of asset betas as estimated by First Economics could be provided. However, the underlying calculations and data were not available.

¹⁴ Competition Commission (2014), 'Northern Ireland Electricity Limited price determination: A reference under Article 15 of the Electricity (Northern Ireland) Order 1992', Final determination, 26 March, Table 13.10.

¹⁵ Utility Regulator (2014), 'Water & Sewerage Services Price Control 2015–21, Final Determination—Annex A, Financing Investment', December, para. 3.3.13.

¹⁶ Utility Regulator (2016), 'Final Determination to the Price Control 2015–2020 for the Electricity System Operator for Northern Ireland (SONI)', 22 February, para. 359.

¹⁷ First Economics (2016), 'An Estimate of the GD17 Costs of Capital, Prepared for the Utility Regulator', 15 January, Table 1.

¹⁸ First Economics (2016), 'An Estimate of the GD17 Costs of Capital, Prepared for the Utility Regulator', 15 January, p. 3.

¹⁹ Oxera (2015), 'GD17 price control parameters: allowed rate of return', for submission to the Utility Regulator, prepared for firmus energy, 30 June, section 3.3.

undertaking any market analysis of UK utility betas, it does not appear reasonable to exclude SSE from the sample. For example:

- the CC/CMA, considered evidence on SSE's beta in its recent determinations on NIE;²⁰
- SSE is listed on the London Stock Exchange as being engaged in 'transmission, distribution and supply of electricity, in the production, storage, distribution and supply of gas and in other energy services'.²¹ Given that SSE is involved in gas distribution operations, this is relevant for NI gas distribution.

Including SSE in the sample of UK utilities, using a debt beta of 0.1 and a cut-off date that is in line with the First Economics' analysis,²² increases the five-year average range to 0.30–0.42 relative to the 0.31–0.37 range presented by First Economics.²³ Similarly, including SSE and using a cut-off date and debt beta that is consistent with First Economics' analysis, a range for the two-year average of betas is even higher, at 0.36–0.48.

Upward trend in betas

In considering market evidence on the range of UK utilities' asset betas, First Economics has only analysed five-year average asset betas.²⁴ Considering averages over a range of time horizons would provide an insight into trends for perceived asset risk. Consistent with this, in its most recent determination for Bristol Water, the CMA considered a range of averages, from one-year to five-year averaging periods.²⁵ A range of averages is shown in Table 2.1, including one-year and five-year averaging periods.

Table 2.1 Summary estimates of two-year daily rolling asset betas for UK utilities

	National Grid	United Utilities	Pennon Group	Severn Trent	SSE	Average
Spot estimate ¹	0.42	0.41	0.43	0.41	0.61	0.46
Average (one month)	0.43	0.42	0.43	0.41	0.61	0.46
Average (one year)	0.46	0.41	0.41	0.42	0.55	0.45
Average (two years)	0.42	0.35	0.38	0.38	0.49	0.40
Average (five years)	0.32	0.28	0.33	0.30	0.42	0.33

Note: The analysis shown in this table assumes a debt beta of 0.05 to replicate the CC's methodology as part of the NIE 2014 decision. See Competition Commission (2014), 'Northern Ireland Electricity Limited price determination: A reference under Article 15 of the Electricity (Northern Ireland) Order 1992', Final determination, 26 March, para. 13.176. ¹ The spot estimate is given as at 31 March 2016.

²⁰ Competition Commission (2014), 'Northern Ireland Electricity Limited price determination: A reference under Article 15 of the Electricity (Northern Ireland) Order 1992', Final determination, 26 March.

²¹ SSE website, 'What we do' (<http://sse.com/whatwedo/>) and 'About us' (<http://sse.com/aboutus/>), accessed 17 April 2016.

²² To facilitate comparison between the estimates of First Economics and those of Oxera, this range was calculated using a cut-off date of 31 December 2015 and assuming a debt beta of 0.1. See First Economics (2016), 'An Estimate of the GD17 Costs of Capital, Prepared for the Utility Regulator', 15 January, p. 3.

²³ First Economics (2016), 'An Estimate of the GD17 Costs of Capital, Prepared for the Utility Regulator', 15 January, Table 1.

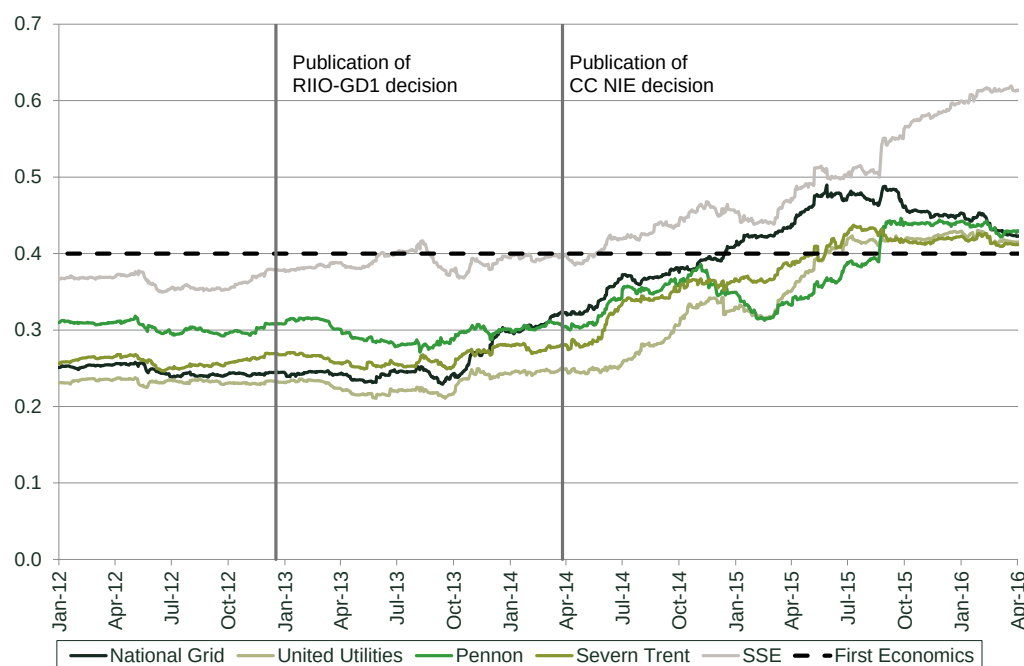
²⁴ First Economics (2016), 'An Estimate of the GD17 Costs of Capital, Prepared for the Utility Regulator', 15 January, Table 1.

²⁵ Competition and Markets Authority (2015), 'Bristol Water plc: A reference under section 12(3)(a) of the Water Industry Act 1991', Report, 6 October. Competition Commission (2014), 'Northern Ireland Electricity Limited price determination: A reference under Article 15 of the Electricity (Northern Ireland) Order 1992', Final determination, 26 March, Table 10.3.

Source: Oxera analysis, based on data from Bloomberg and Datastream.

By focusing on five-year averages only, First Economics has attributed little weight to the trend in asset betas. The market evidence suggests that the asset betas for UK utilities have been growing for a significant period and have, for some time, been in excess of the 0.4 mark selected by the Utility Regulator as an asset beta for FE (see Figure 2.1 below).

Figure 2.1 Asset betas of listed UK utilities



Note: The cut-off point is 31 March 2016.

Source: Oxera analysis, based on data from Bloomberg and Datastream.

This evidence suggests that a current allowed beta of 0.4 for FE would be understated relative to the current betas for listed UK utilities.

The Utility Regulator adopted a 6.5% total market return assumption, which is consistent with the latest CMA regulatory precedent from 2015. This decision gave weight to the downward trend in the risk-free rate. To be internally consistent, the regulator should also give weight to the upward trend in asset betas. For example, a one-year average of the asset betas shown in Table 2.1 implies a range of 0.41–0.55 and an average of 0.45. The recent market evidence supports a point estimate of the asset beta at the top end of the 0.4–0.5 range assessed by Oxera in the September 2015 update—i.e. 0.5, rather than 0.4.

2.2.2 Issues relating to regulatory precedents on betas

Risk differentials for FE relative to mature UK networks

First Economics has looked at regulatory precedents on the beta from Ofgem, Ofwat, the Commission for Energy Regulation (CER) and the CC/CMA.²⁶ Basing an asset beta for FE within a range of precedents for mature energy and water utilities in the UK and Ireland does not take into account FE's relatively high risk exposure. For example, the June 2015 report assessed why FE appears to have

²⁶ First Economics (2016), 'An Estimate of the GD17 Costs of Capital, Prepared for the Utility Regulator', 15 January, Table 2.

a higher risk profile than other UK GDNs and Phoenix Natural Gas Limited (PNGL), as summarised in the table below.

Table 2.2 Summary of FE risk differentials relative to comparators

	Description	Higher risk relative to GB GDNs?	Higher risk relative to PNGL?
FE risk differential 1: operational leverage	FE has higher operational leverage than its GB comparators, adjusting the Utility Regulator's TRV:TOTEX measure for differentials in the composition of the asset and cost base across the jurisdictions. While this analysis has not been undertaken for FE relative to PNGL, due to lack of data availability, it is likely that FE would also face higher operational leverage than PNGL, since the Utility Regulator has assessed that PNGL's unadjusted TRV:TOTEX ratio is more than double that of FE. ¹ In addition, there are a number of indicators that FE is not a steady-state network, as it has a young network, which is still in build-out phase with deferral of revenues, and a relatively low uptake of gas connections within its catchment.	Yes	Yes
FE risk differential 2: impact of profiling adjustment on risk	GB GDNs are not exposed to revenue profile adjustment mechanisms, as FE and PNGL are, which implies higher risk for the NI networks than their GB counterparts.	Yes	No
FE risk differential 3: accumulated under-recovery of revenues	FE is exposed to a higher risk of ex post recovery (of previously under-recovered revenues) than in Great Britain, where the comparable charges are recovered within the period. FE is arguably also exposed to more uncertainty regarding recovery of these revenues, as they are not included within its TRV (as in the case of PNGL).	Yes	Yes
FE risk differential 4: form of price control and volume risk	The Utility Regulator expects a nearly 100% increase in FE's connections over GD17, highlighting that the network remains in a high-growth stage. ² Connections growth risk is recognised by third parties for GDNs in Northern Ireland. For example, for PNGL, Moody's has commented: 'A key risk under this framework therefore is a shortfall in connection rates from the regulator's forecast'. ³ To the extent that FE has achieved a lower rate of connections than PNGL, its risk exposure is higher. Even when FE is moved to a revenue cap in GD17, it faces greater risk than PNGL and the GB GDNs because its long-term returns are tied to the demand for new connections.	Yes	Yes
FE risk differential 5: rolling incentive mechanisms and re-openers	OPEX and other reopeners are more broadly defined for FE than for its GB counterparts. This is to provide a greater degree of protection in insulating FE from cost shocks.	No	Not assessed

	Description	Higher risk relative to GB GDNs?	Higher risk relative to PNGL?
FE risk differential 6: third-party assessments of NI-specific factors	There is some evidence from debt capital markets, and credit rating agency assessments, which implies somewhat higher risk for NI utilities than GB utilities. For instance, Moody's writes that 'Stability and Predictability of Regulatory Regime' is assessed at... one notch lower than for gas distribution networks (GDNs) located in Great Britain (GB)', which is 'mostly explained by regulation being less established in Northern Ireland with a shorter track record of transparent decision making'. Moody's has also noted that 'the peculiarity of the regulatory framework in Northern Ireland under which the recovery of costs and investments incurred is deferred... [leads to] relatively weak cash flow generation'. ¹³	Yes	No

Note: ¹ See Utility Regulator (2013), 'GD14 Price Control for Northern Ireland's Gas Distribution Networks for 2014–2016', Final determination, 20 December, Figure 15. ² Utility Regulator (2016), 'Price Control for Northern Ireland's Gas Distribution Networks GD17', Draft determination, 16 March, para. 5.6 and data received from FE. ³ Moody's (2015), 'Credit opinion: Phoenix Natural Gas Finance PLC', 3 December, pp. 2 and 3.

Source: Summary of assessments in section 3.3 of Oxera (2015), 'GD17 price control parameters: allowed rate of return', for submission to the Utility Regulator, prepared for firmus energy, 30 June.

It is important to recognise that FE will face relatively high demand risk—which is a recognised driver of systematic risk as measured by the asset beta—even under a revenue cap form of control. FE has submitted a paper to the Utility Regulator, elaborating on its drivers of connections risk in GD17.²⁷ It is likely that FE would continue to face higher volume risk than more mature GDNs in Great Britain notwithstanding the introduction of a revenue cap in GD17, for the following reasons.

- The regulatory model for FE is underpinned by an assumption regarding the number of connections that are made over time. The operation of the Profile Adjustment requires a growth in connections over time so that deferred revenues can be recovered from a wider base of customers in the future. If FE fails to realise its connections targets, this may jeopardise the recovery of deferred revenues. The Utility Regulator has previously assessed that volume underperformance in the early years of operation, by PNGL, would have jeopardised the firm's ability to fully recover its revenues, and this led the Utility Regulator to increase the licence period for PNGL, from 20 to 50 years, in 2007.²⁸
- If FE were to fail to meet its connections targets in the early years, it might not be able to price up to the level consistent with the revenue cap in later periods, since an increase in price would deter further connections. FE is also exposed, within a price control period, to fluctuations in demand for new connections due to factors outside its control, such as changes in the price of oil relative to natural gas and the wider macroeconomic developments. The propensity for new customers to connect is likely to be more elastic (i.e. more sensitive to changes in price or household income) than demand from

²⁷ Firmus energy (2015), 'Connection incentive', GD17 Supplementary paper, 29 June.

²⁸ Utility Regulator (2012), 'Phoenix Natural Gas Limited Price Control Review 2012-2013, An Introduction to the Reference to the Competition Commission', March, pp. 10–11.

existing, connected customers (who are less likely to significantly reduce their gas demand in the short term).

- On a similar note, Moody's has suggested that there may be revenue shortfalls in GD17 if there is a 'drop-off' in connections due to a tariff increase (e.g. if the Profile Adjustment is unwound).²⁹ While Moody's comment is for PNGL (FE does not currently have credit-rated debt), it is reasonable to assume that similar reasoning would apply for FE:

the PA has historically resulted in very weak cash flow-based credit metrics (including funds from operations to net debt below 5%) compared with peers in GB. However, the change in approach [removal of the PA] could pose some risk to the company's growth trajectory if the resultant increase in tariffs resulted in revenue under-recovery resulting from a drop-off in connections. This could also have a negative impact on other areas of the price control, such as performance in relation to the Connection Incentive mechanism.

- The objective set by the Utility Regulator involves more than doubling the number of connections in GD17.³⁰ Achieving this objective is likely to be more challenging due to a decline in unit CAPEX allowances. Oxera understands from FE that the operation of the connections incentive mechanism could also lead to a TRV log-down if FE misses its connections target.
- The incentive mechanism proposed by the Utility Regulator implies downside risk while capping any potential outperformance. For example, the connections incentive operates to significantly reduce allowances if there is a shortfall in connections achieved relative to the regulator's assumptions. The costs of achieving connections are largely fixed, but the remuneration for these is variable depending on connections growth—especially to the extent that the connections incentive replaces fixed cost allowances. This implies significant downside cash-flow volatility.

In summary, FE's long-term returns are dependent on achieving growth in new connections, in contrast to GB GDNs that have already achieved a high customer penetration ratio in terms of connections. PNGL has also achieved higher penetration ratios than FE, having been in operation for a longer period of time in Northern Ireland. This implies higher volume risk, and thereby a higher asset beta for FE than for the GB GDNs and PNGL.

Calibrating asset beta for FE relative to other NI networks

It is unclear how the Utility Regulator has calibrated its 0.4 measure of the asset beta for FE against the allowed betas for other NI networks. For example, other regulated NI utilities have been allowed the following:

- 0.4 asset beta for NIE, based on the CMA's decision (2014);³¹

²⁹ Moody's Investor Service (2015), 'Evolution of regulatory framework will improve transparency but implementation challenges remain', 21 April.

³⁰ The GD17 connections target is 30,954 which is roughly equivalent to the total number of properties that FE expects to connect by the end of 2016 (i.e. FE expects that cumulative properties connected will be 32,328 by the end of 2016). See Utility Regulator (2016), 'Price Control for Northern Ireland's Gas Distribution Networks GD17', Draft determination, 16 March, p. 56 and data received from FE.

³¹ Competition Commission (2014), 'Northern Ireland Electricity Limited price determination: A reference under Article 15 of the Electricity (Northern Ireland) Order 1992', Final determination, 26 March, Table 13.10.

- 0.44 asset beta for NI Water, based on the Utility Regulator's decision (2014);³²
- 0.6 assumption for SONI, based on the Utility Regulator's decision (2016).³³

At the upper end of the 0.4–0.6 range for NI networks, SONI has a relatively high allowed asset beta because the Utility Regulator 'views SONI as facing greater risk than regulated network companies which do not face the [sic] operational gearing challenges as SONI but less risk than other companies which face significant volume risk in a competitive market.'³⁴ It is difficult to compare FE directly with SONI as the latter is a relatively asset-light business, rather than the asset-heavy nature of utility networks. However, it should be noted that the Utility Regulator's rationale for a high asset beta allowance for SONI (i.e. operational gearing and high volume risk) also applies to FE relative to the GB GDNs and PNGL. First, Oxera has submitted evidence in the June 2015 report showing that FE's operational leverage is higher than other GDNs in Great Britain and PNGL.³⁵ Second, FE faces significant volume risk, in particular due to uncertainty around future connections, as explained earlier.

A 0.4 allowed beta for FE is at the lower bound of the 0.4–0.6 range allowed for other NI networks. At the lower end of the 0.4–0.6 range for NI networks, NIE has an allowed beta of 0.4. It appears that FE has a relatively high systematic exposure compared with NIE. This is because as a relatively established energy network, NIE's financial stability is less dependent on securing a large number of new connections, as in the case for FE. Moreover, it should be noted that since the CC's NIE decision, market betas have increased significantly, as demonstrated in Figure 2.1. Both of these factors suggest that the asset beta estimate of 0.4 appears to be too low for FE.

2.3 Implications of debt beta assumption

First Economics has assumed a debt beta of 0.1 in its asset beta analysis, on the basis that this is consistent with previous inquiries by the CC.³⁶ In fact, the CMA does not use a 0.1 debt beta assumption indiscriminately. In the CMA's NIE decision, for example, it assumed a debt beta of 0.05 to reflect a relatively low level of gearing.³⁷ In its most recent price control decision, the Bristol Water (2015) redetermination, the CMA assumed a debt beta of zero.³⁸ Many regulatory decisions including Ofgem RIIO-GD1 and Ofwat PR14 have assumed zero debt betas in their analysis of allowed returns for UK utility networks.

First Economics states that 'a debt beta is similar to the equity beta, but rather than measuring the systematic risk taken by the company's shareholders, it represents such risk presented to the company's lenders.'³⁹ By assuming a positive debt beta, First Economics assumes that the systematic risk faced by

³² Utility Regulator (2014), 'Water & Sewerage Services Price Control 2015–21, Final Determination—Annex A, Financing Investment', December, para. 3.3.13.

³³ Utility Regulator (2016), 'Final Determination to the Price Control 2015–2020 for the Electricity System Operator for Northern Ireland (SONI)', 22 February, para. 359.

³⁴ Utility Regulator (2016), 'Final Determination to the Price Control 2015–2020 for the Electricity System Operator for Northern Ireland (SONI)', 22 February, para. 358.

³⁵ June 2015 report, section 3.3.

³⁶ First Economics (2016), 'An Estimate of the GD17 Costs of Capital, Prepared for the Utility Regulator', 15 January, p. 3.

³⁷ Competition Commission (2014), 'Northern Ireland Electricity Limited price determination: A reference under Article 15 of the Electricity (Northern Ireland) Order 1992', Final determination, 26 March, para. 13.175 (c).

³⁸ Competition and Markets Authority (2015), 'Bristol Water plc: A reference under section 12(3)(a) of the Water Industry Act 1991', Report, 6 October, para. 10.150.

³⁹ First Economics (2016), 'An Estimate of the GD17 Costs of Capital, Prepared for the Utility Regulator', 15 January, p. 3.

FE debt investors is non-negligible—e.g. because the company is excessively leveraged, or because its credit risk is relatively high. The assumption of a relatively high 0.1 debt beta for FE would tend to be associated with the following factors in the assessment of the WACC.

- First, the notional gearing assumption would tend to be lower than other utilities (with zero assumed debt betas), to reflect that the company has a lower ability to bear financial leverage due to its high systematic risk exposure.
- Second, the asset beta should be derived from comparator companies that also have relatively high systematic risk exposure.

Oxera's assumptions for the notional gearing, debt beta, debt premium and asset beta for FE have been internally consistent: we assume that FE will be perceived as a relatively high-risk network in GD17, compared with GB GDNs and other listed UK utilities. Therefore, we assess for FE:

- an asset beta that is higher than regulatory precedents, to reflect its relatively high risk exposure for equity investors;
- a cost of debt above that of BBB-rated networks, to reflect its relatively high risk exposure for debt investors;
- a debt beta of 0.1 to reflect the relatively high systematic risk exposure for FE's debt liabilities;
- a relatively low notional gearing assumption of 55% to reflect the firm's lower ability to bear debt, compared with utility networks in Great Britain.

Compared with Oxera's assumptions, the use of a low notional gearing assumption and high debt beta suggests that the Utility Regulator recognises that FE's debt is riskier than other regulated networks. However, the Utility Regulator does not allow for such higher risk in either its asset beta estimate or its assumed debt premium.

2.4 Overall cost of equity

The Utility Regulator has acknowledged the importance of the overall cost of equity allowance in determining FE's financeability:

The key determinant of the companies' ability to access equity finance is the allowed return on equity...we have built returns by considering the level of returns that investors are likely to be able to get from other equity investments and by positioning the return offered by PNGL and FE logically against these alternative investments.⁴⁰

We understand from discussion with iCON Infrastructure that its modelling suggests that FE will not be financeable in line with an investment-grade credit rating in GD17, for a number of reasons.

- Oxera understands that iCON has tested the Utility Regulator's financeability modelling and found that the regulator's approach to estimating interest coverage ratios is not aligned with FE's cash-based credit metrics and debt covenants. Adjusting the Utility Regulator's calculations to include working

⁴⁰ Utility Regulator (2016), 'Price Control for Northern Ireland's Gas Distribution Networks GD17', Draft determination, 16 March, para. 10.59.

capital and tax, iCON finds that PMICR drops well below 1.4x and that cash-based credit metrics drop significantly below investment-grade level.

- Specific revenue deferral arrangements for FE—for example, in the form of its Profile Adjustment mechanism—lead to a delay in cash inflows. Thus, for example, even if the company appears financeable on the basis of a standard regulatory PMICR covenant calculation, a lag in revenue recovery creates additional pressure on cash-based credit metrics.
- iCON has also undertaken modelling which demonstrates that the connections incentive confers asymmetric risk. (See also discussion on connections risk faced by FE in GD17, above.)

For FE, by its own analysis, the Utility Regulator has shown that the interest coverage ratio for the GD17 period is at the minimum necessary level for five years within the six-year control. Specifically, against the Utility Regulator's required threshold of at least 1.4x, FE's adjusted interest coverage ratio is 1.40 in five years, and 1.41 in the remaining year.⁴¹ This does not allow sufficient headroom for downside risk for FE in GD17. Since the Utility Regulator has suggested that the majority of debt financing costs in GD17 will be subject to a pass-through mechanism, the financeability analysis supports that the Utility Regulator should allow for sufficient headroom for volatility in its estimation of the allowed cost of equity for FE.

⁴¹ Utility Regulator (2016), 'Price Control for Northern Ireland's Gas Distribution Networks GD17', Draft determination, 16 March, Table 183.

3 Cost of debt

The Utility Regulator has estimated a real cost of debt allowance of 2.33% for FE in GD17. This is estimated based on the following approach and inputs:

- weight of embedded:forecast new debt of 40:60;
- nominal estimate of embedded debt of 4.7%, including transaction costs of 0.6%;
- nominal forecast cost of new debt of 6.0%, which is a build-up of current market rates (4.4%), expected increase in interest rates by mid-2019 (0.8%), illiquidity premium (0.4%) and transaction costs of 0.4%;
- an inflation assumption of 3.08%, to deflate the nominal overall cost of debt of 5.48% to an allowed rate of 2.33%.⁴²

The Utility Regulator has also proposed a pain-gain sharing mechanism whereby the allowed cost of debt will be revisited during the period, based on deviations from a target cost of debt.⁴³

In reviewing the Utility Regulator's proposed allowance for the cost of debt, there are some uncertainties, which are explored in this section. Specifically:

- there is an inconsistency between the cost of debt approach used for FE and the regulatory disaggregated cost of debt approach used for SONI;
- underestimate of allowed embedded debt costs, in real terms, due to an over-estimate of inflation for the period 2017–19;
- specific implementation issues relating to the proposed new cost of debt estimation approach.

These issues are discussed in turn below.

3.1 Cost of debt approach inconsistency

In the September 2015 update, Oxera proposed a regulatory disaggregated allowance for the cost of debt in GD17 as the preferred option, having considered multiple potential options to setting the allowed cost of debt.⁴⁴

This regulatory disaggregated approach comprised an allowed cost of debt based on a regulatory risk-free rate (consistent with that estimated for the cost of equity), with a debt premium based on BBB rated bonds as well as a regulatory transaction cost allowance of 20 basis points (bps). The debt premium and transaction cost allowance proposed for FE's allowed cost of debt were lower than would be consistent with an unknown issuer's risk profile.⁴⁵ However, the overall cost of debt that we proposed was still a reasonable estimate for FE's financing cost. This is because the risk-free rate assumption from regulatory precedents, in excess of current market yields, allowed sufficient headroom. Such a regulatory disaggregated approach to assessing the allowed cost of debt would have the following advantages:

⁴² Inflation assumption of 3.08% as stated in the Utility Regulator's model, 'Debt and Tax Mechanism.xls'.

⁴³ Utility Regulator (2016), 'Price Control for Northern Ireland's Gas Distribution Networks GD17', Draft determination, 16 March, para. 10.9.

⁴⁴ See June 2015 report (section 4) and the September 2015 update for details of all the potential options for estimating the allowed cost of debt that have been assessed.

⁴⁵ For example, BBB rated credit spread and 20 bps transaction costs.

- ease of implementation and known in advance;
- aligned with regulatory precedent (including the Utility Regulator's own subsequent allowance for SONI in February 2016);
- a fixed-rate allowance confers high-powered incentives for efficient financing of networks (i.e. to outperform the allowed cost of debt);
- achieved consistency between the risk-free rate assumptions for the cost of debt and the cost of equity;
- allowed for uncertainty around the future cost of debt in the form of headroom above spot yields, given that interest rates are expected to rise in GD17.

The Utility Regulator has proposed a new cost of debt estimation approach whereby the majority of the allowed cost of debt is to be based on the actual cost of new debt issuance with a pain-gain sharing proviso. This may have some practical difficulties relating to the design of the cost of debt mechanism, which are explored further in this section. There are also some high-level issues relating to regulatory incentives and consistency, which are explained below.

First, the Utility Regulator may dampen incentives for efficient financing if companies can retain only 20% of any outperformance.

Second, there is considerable uncertainty around the implementation of the new approach, and this uncertainty in itself may be of concern to ratings agencies and investors.

Third, it is not clear how the Utility Regulator has reconciled its approach to allowing for headroom and financing incentives across the networks it regulates. For example, the Utility Regulator has estimated a regulatory disaggregated cost of debt for SONI of 2.95%, which is estimated as real risk-free rate (1.25%) + corporate spreads for comparator companies (1.5%) and a transaction cost allowance (0.2%).⁴⁶ The 2.95% allowance for SONI, and its constituent estimates are broadly aligned with the allowed cost for FE in the September 2015 update, which assessed a reasonable range of 3.05–3.30%. It is therefore inconsistent within Northern Ireland that the allowed cost of debt for FE is much lower than for SONI due to the use of a different cost of debt estimation approach, and notwithstanding the fact that FE would have to offer a yield premium if it is perceived to have relatively high risk as a first-time bond issuer in GD17.

There is also an internal inconsistency in basing the allowed cost of debt on a much lower risk-free rate assumption than allowed within the cost of equity. Specifically, First Economics has observed yields on the iBoxx Non-Financials BBB (10-years+) Index as the basis for its market cost of debt. First Economics has assessed that the yields on this index will be 5.2% in mid-2019.⁴⁷ With an inflation assumption of 3.08%,⁴⁸ the real expected cost of debt is 2.1%.⁴⁹ If the debt premium for BBB bonds remains at around the 1.5% estimate allowed by the Utility Regulator for SONI,⁵⁰ this would imply a real risk-free rate allowance

⁴⁶ Utility Regulator (2016), 'Final Determination to the Price Control 2015-2020 for the Electricity System Operator for Northern Ireland (SONI)', 22 February, para. 346.

⁴⁷ Utility Regulator (2016), 'Price Control for Northern Ireland's Gas Distribution Networks GD17', Draft determination, 16 March, Table 179.

⁴⁸ Inflation assumption of 3.08% as stated in the Utility Regulator's model, 'Debt and Tax Mechanism.xls'.

⁴⁹ Using the Fisher equation to convert from nominal to real rates.

⁵⁰ Utility Regulator (2016), 'Final Determination to the Price Control 2015-2020 for the Electricity System Operator for Northern Ireland (SONI)', 22 February, para. 345.

within the cost of debt of 0.6%. This is considerably lower than the 1.25% risk-free allowance for the cost of equity.

3.2 Inflation assumption for embedded debt

The Utility Regulator has assessed that the embedded nominal cost of debt for FE in the period 2017–19 will be 4.7%.⁵¹ The embedded debt cost is a measure of the forecast nominal cost of FE's loan of £108.9m from its parent company, up to maturity in mid-2019.⁵²

The Utility Regulator has used an inflation assumption of 3.08% to derive a real embedded cost of debt for FE of 1.6%. This is an underestimate of the embedded debt cost in real terms because the Utility Regulator has assessed inflation on the basis of a six-year control, while the embedded debt matures in mid-2019. Inflation is projected to increase over the period of the control, so in estimating inflation as a six-year average rather than a 2.5-year average, the regulator has captured higher inflation forecasts beyond the relevant period. Specifically, the relevant measure of inflation in assessing the real cost of embedded debt for FE is forecast inflation for the period 2017 to mid-2019.

In estimating the relevant level of inflation for the period of FE's embedded debt, Oxera has derived estimates of forecast RPI from inflation-linked swaps. The advantages of using inflation swap rates in determining forward-looking inflation estimates have been recognised by the Bank of England.⁵³ For the purpose of deflating nominal embedded debt costs, Oxera has derived estimates from inflation-linked swaps for the following reasons.

- Compared with deriving breakeven inflation as the differential in index-linked gilt and nominal gilt yields, the analysis of swaps allows for near-term estimates. In the UK, the shortest maturity of index-linked gilt yields reported by the Bank of England is 2.5 years, which means that implied inflation from forward yields will be for 2.5-year forecast horizons, and beyond. By way of contrast, data on inflation-linked swaps covers a wider range of maturities, which allows for near-term inflation forecast estimates. In particular, data on one-year inflation-linked swaps is easily available. Oxera has therefore been able to derive inflation forecasts for each year of GD17, using data on inflation-linked swaps.
- Unlike government bonds, swaps are not directly affected by central bank market operations. This suggests that inflation forecasts derived from inflation-linked swaps may be more stable than breakeven inflation estimates from gilt yields.
- For the purpose of assessing inflation estimates that are relevant for forecast debt costs, capital market data is likely to be more informative than policymakers' inflation forecasts. In particular, one cannot disregard the possibility that inflation forecasts by policymakers, or authorities, in the long term may exhibit a mean reversion toward the inflation target.

⁵¹ Utility Regulator (2016), 'Price Control for Northern Ireland's Gas Distribution Networks GD17', Draft determination, 16 March, Table 179.

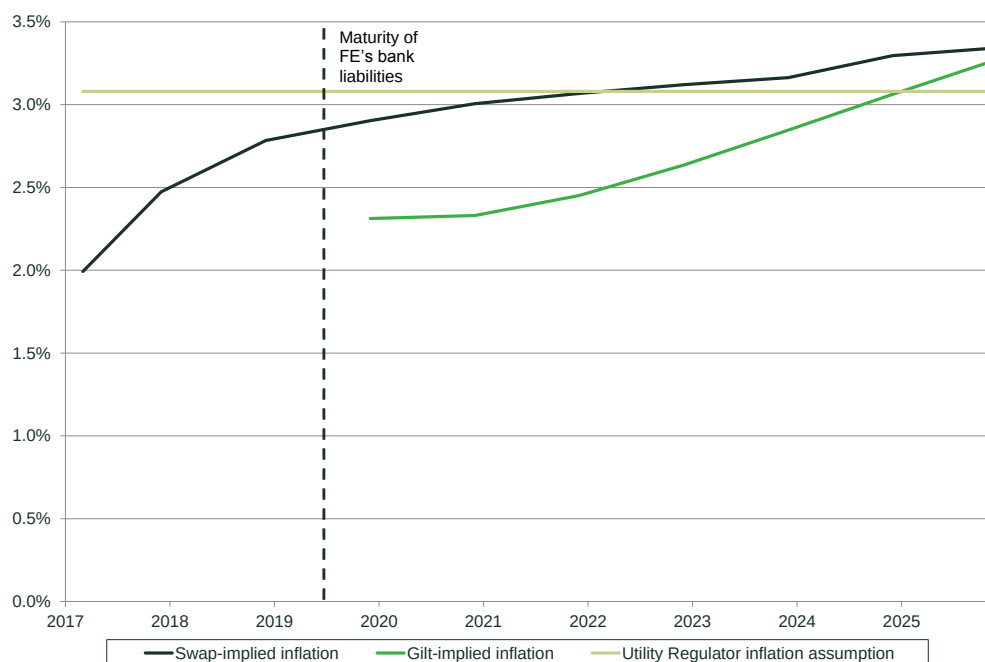
⁵² Reported as 'Amounts due to parent Company – subordinated loan' in Firmus Energy Distribution Ltd (2014), 'Financial statements for the year ended 31 December 2014', Note 12.

⁵³ Bank of England (2006), 'New information from inflation swaps and index-linked bonds', <http://www.bankofengland.co.uk/publications/documents/quarterlybulletin/qb060101.pdf>, p. 26, accessed 10 May 2016.

Using data on swaps with different maturities, it is possible to construct a forward-looking measure of inflation for each year in the GD17 control. The procedure is similar to that used to obtain forward interest rates.

For the benefit of comparison, Figure 3.1 also includes inflation inferred from government bonds. It can be seen that the two measures of inflation (i.e. implied from inflation-linked swaps and from forward evidence on gilts) are expected to converge over time. However, for the years where data is available, swap-implied inflation tends to be higher than the gilt-implied inflation. For the reasons described earlier (i.e. availability of near-term inflation forecasts and less likelihood of impact from monetary policy interventions), Oxera has obtained inflation forecasts from index-linked swaps. These imply that the inflation rate for the years 2017 to 2019 is expected to range from 2.5% to 2.9%. Assuming prices grow uniformly within a given year, the average inflation rate between 1 January 2017 and mid-2019 amounts to 2.68%.

Figure 3.1 Inflation expectation implied by inflation-linked swaps



Note: The breakeven inflation is calculated as at 31 March 2016. The swap-implied expected inflation rates were calendarised using liner interpolation.

Source: Oxera analysis, based on data from Datastream, the Bank of England and 'Debt and Tax Mechanism.xls'.

This data shows that the Utility Regulator's 3.08% assumption of inflation is an over-estimate up to mid-2019, at which point FE's loan from its parent company matures. Using an estimate of 2.68% for the relevant period, as derived from inflation-linked swaps suggests that the real embedded debt cost allowance should be 40 bps higher. Specifically, this leads to an increase in the embedded debt cost from 1.6%, as assessed by the Utility Regulator, to 2.0%.

3.3 Implementation issues for pain-gain sharing approach

For GD17, the Utility Regulator proposes to set an allowance for the new cost of debt that allows for cost pass-through of the majority of new issue costs, subject to a pain-gain sharing ratio. In relation to its proposed approach, the regulator has explained the following:

Given the level of uncertainty for FE in raising so much debt in GD17 we propose to include a pain gain adjustment to our cost of debt so that FE only takes 20% of the pain/gain if the actual cost of debt is over/under our allowance.⁵⁴

In order to avoid a situation in which the allowed cost of debt becomes a pass-through item, with the undesirable incentive properties that this brings, we propose to design the adjustment mechanism in such a way that 80% of any over- or under-forecast of the post-refinancing cost of debt passes through to prices and the remaining 20% is retained by PNGL's and FE's shareholders. Our intention is that this sharing rule will give the companies strong incentives to minimise the costs that they pay on their new borrowings, to the long-term benefit of customers in the GD23 period and beyond.⁵⁵

At the onset, note that the discussion in this section assumes that the regulator would implement a pain-gain sharing mechanism relative to a market benchmark.⁵⁶ Specifically, the pain-gain sharing would apply to the cost of new debt observed in the BBB market, with an additional allowance for transaction costs, illiquidity in the NI market, and a credit uplift for FE if it cannot price at investment grade in GD17. If, instead of using a market benchmark, the regulator assesses the cost of new debt by referring to FE's reported interest expense relative to total liabilities, then it will be important to ensure that the cost of debt allowance is an 'all-in' cost.⁵⁷ This would involve consideration of the following factors.

- The reported interest expense would have to be 'annualised', based on the time of issuance of each debt instrument. For example, if a bank loan is received at end-June, then a simple ratio of the reported interest expense for the year, divided by total liabilities as at year-end, would understate the annual cost of debt estimate by 50%.
- Transaction costs (e.g. legal advisory, financial advisory and underwriting costs) would have to be estimated and allowed separately for each debt issuance. Such costs would also have to be annualised.
- Hedging costs for variable debt instruments would have to be estimated and allowed separately. Again, these costs would have to be annualised.
- The estimate of the all-in cost would have to be repeated for each new debt issuance, as well as annually to allow for any changes to the cost of debt—for example, due to annual margin step-ups.

Relative to a market benchmark that is readily observable, the estimate of an all-in company-specific cost of debt involves detailed analysis on at least an annual basis. To the extent that this may also lead to annual ex post negotiations regarding the estimate of the all-in cost of debt, this would lead to uncertainty for investors regarding what will be allowed, and to the complexity of regulatory arrangements in implementing a pain-gain sharing mechanism. Owing to these practical difficulties, the discussion that follows assumes that the pain-gain sharing mechanism will be implemented using a market benchmark cost of debt rather than an annual estimate of the all-in actual cost of debt for FE.

⁵⁴ Utility Regulator (2016), 'Price Control for Northern Ireland's Gas Distribution Networks GD17', Draft determination, 16 March, para. 1.32.

⁵⁵ Utility Regulator (2016), 'Price Control for Northern Ireland's Gas Distribution Networks GD17', Draft determination, 16 March, para. 10.9.

⁵⁶ As per the Utility Regulator's current discussions with PNGL. See, for example, NERA (2016), 'GD17: Cost of Debt Mechanism', 21 April.

⁵⁷ An additional allowance for illiquidity or credit uplift for sub-investment-grade debt would not be separately required if the regulator is estimating all-in debt costs based on actual issuance by FE.

To ensure that any pain-gain sharing approach to the allowed cost of new debt for FE appropriately allows for its financing constraints in GD17, Oxera recommends the following.

- 60 bps allowance for transaction costs, rather than 40 bps as proposed by the Utility Regulator. This is based on an assessment of the notional quantum of debt to be raised by FE in GD17.
- 1.3% additional allowance for 'credit uplift' within the debt premium. This should be added to the new cost of debt allowance inferred from BBB iBoxx yields if FE is unable to achieve an investment-grade rating.
- Inclusion of an RPI inflation 'true-up' to reflect any differentials in outturn inflation relative to the Utility Regulator's forecast, within the allowed cost of new debt.
- Cost pass-through with 80:20 pain-gain sharing should occur at the end of the period. This should allow for any pain-gain adjustments to the WACC to also be factored into 'logged-up' amounts for any other uncertainty mechanisms or revenue-reprofiling mechanisms.

These issues are discussed in turn below.

3.3.1 Allowance for transaction costs

The Utility Regulator has suggested that it will allow transaction costs of 40 bps for FE for new debt issuance. Oxera's analysis suggests that it would be reasonable to allow higher transaction costs for FE of around 60 bps. This is based on the following reasons.

First, as submitted in the June 2015 report to the Utility Regulator, iCON's current estimate of annualised transaction costs, related to FE's bank loan via its parent company, is 60 bps. The Utility Regulator has subjected this 60 bps estimate to a 'small mark-down to reflect the benefit of raising slightly higher quantum of debt'.⁵⁸ However, notional estimates of the quantum of likely debt issuance by FE in GD17 suggest that this will be in the same region as the current £108.9m bank loan from its parent company. Specifically, if it is assumed that the TRV value for FE in 2019 will be around £186m,⁵⁹ then combined with a notional gearing assumption of 55%, this implies debt issuance in 2019 of £102.3m, which is broadly in line with the current quantum.

This analysis shows that the Utility Regulator should not reduce allowed transaction costs, based on an assumption that the quantum of debt issuance in 2019 will be higher than its notional gearing assumption implies. Instead of 40 bps, it may be appropriate for the Utility Regulator to allow transaction costs in GD17 of 60 bps, as per the current allowance for embedded debt.

3.3.2 Allowance for higher market debt premium

First Economics has observed yields on the iBoxx Non-Financials BBB (10-years+) Index as the basis for its market cost of debt estimate. This may not be an appropriate benchmark for FE's new debt costs in GD17. This is because FE

⁵⁸ Utility Regulator (2016), 'Price Control for Northern Ireland's Gas Distribution Networks GD17', Draft determination, 16 March, para. 10.44.

⁵⁹ Information received from FE.

plans to undertake its first bond issuance in GD17 and it may not achieve an investment-grade credit rating.⁶⁰

It is therefore necessary to specify an additional allowance to add to the market cost of debt as inferred from BBB yields, should FE price below investment-grade. This allowance should be incorporated within FE's allowed cost of new debt if it does not achieve investment-grade rating.

To quantify the extent to which FE's allowed cost of debt should be higher, if its issuance is BB rated rather than BBB rated, Oxera has estimated a 'credit uplift' over the cost of debt implied by the BBB iBoxx index. Since iBoxx does not publish an index for BB rated corporates, this credit uplift has been quantified by looking at the pricing of individual debt issues.

Specifically, to determine the value of this credit uplift, Oxera considered the yield to maturity at issuance for a sample of BBB rated⁶¹ and BB rated⁶² corporate bonds that satisfy the following criteria:

- issued over the last six years;⁶³
- issued in the UK and denominated in GBP;
- maturity of 5 to 15 years;
- the issuer operates in an industry that is broadly similar to that of FE, although the 'market' considered by the Utility Regulator in using the iBoxx index included all non-financial corporates.

On the basis of these criteria, focusing solely on the 'Utility & Energy' industry group resulted in a sample of 12 BBB rated and seven BB rated bonds. The average yield to maturity estimate for the two groups is 3.7% and 6.3%, respectively. This implies an estimated credit uplift of 2.6%. However, recognising the idiosyncrasy of pricing for bond issues, it is a valid concern that the sample size might not be large enough to cancel out possible biases in this data. Therefore, Oxera has widened the general industry group to include commodities, infrastructure and utilities.⁶⁴ This has resulted in a sample of 33 BBB rated securities and 16 BB rated securities.⁶⁵ The average yield to maturity at issuance is 4.7% for the BBB rated group and 6.0% for the BB rated group. The estimated credit uplift under this approach is 1.3%.

The credit uplift associated with using a market benchmark based on iBoxx BBB, recognising that FE may not achieve investment-grade rating, is therefore 1.3–2.6%. Recognising the idiosyncrasy of pricing for bond issues, the 1.3% estimate is recommended as a point estimate of the credit uplift, as it is derived from a larger sample size. This credit uplift should be incorporated within FE's allowed cost of new debt if it does not achieve investment-grade rating.

⁶⁰ Oxera understands from iCON that on the basis of the modelling it has undertaken, relating to the draft determination price control package, FE would not currently be able to achieve a BBB credit rating in GD17.

⁶¹ Includes BBB+, BBB and BBB-.

⁶² Includes BB+, BB and BB-.

⁶³ The deal pricing date was restricted to lie between 1 January 2010 and 31 March 2016.

⁶⁴ This group includes Agribusiness, Forestry and Paper, Metal & Steel, Mining, Oil & Gas, Telecommunications, Transportation and Utility & Energy.

⁶⁵ Applying the date, currency and maturity filtering criteria, this final sample is based on bonds from the Transportation, Telecommunications and Utility & Energy industry groups.

3.3.3 Adjustments for inflation

The Utility Regulator is proposing to anchor its estimate for the new cost of debt on nominal iBoxx yields.⁶⁶ To the extent that the regulator over- or underestimates inflation, this would lead to deviations in outperformance for new debt issuance. To avoid FE bearing the risk of inflation forecast errors within a mechanism that is intended to substantively pass through debt costs, the regulator should have a true-up mechanism for inflation in the allowed cost of new debt. To align with the basis on which FE's inflation-linked revenues are set, outturn RPI could be used in deflating new debt costs.

3.3.4 Logging up of pain-gain WACC adjustments

To avoid further complexity in requiring an annual re-set of the WACC allowance, the cost pass-through of new debt, with 80:20 pain-gain sharing should occur at the end of the period. Any amount of pain-gain sharing can be capitalised as a TRV adjustment at the start of each price control.

Note, however, that if the WACC had been subject to annual re-sets then this would have affected the capitalised values of uncertainty and revenue-reprofiling mechanisms. The pain-gain sharing mechanism should incorporate the feedback loop between the capitalised TRV sums relating to the WACC, and relating to other mechanisms.⁶⁷

⁶⁶ Utility Regulator (2016), 'Price Control for Northern Ireland's Gas Distribution Networks GD17', Draft determination, 16 March, para. 10.44.

⁶⁷ For example, by re-running the price control model at the end of the period with the adjusted end-of-period WACC assumption. The difference in the forecast TRV as per the model using the initial WACC assumption compared with the adjusted WACC assumption would show the TRV difference that is to be capitalised at the end of period.

4 Treatment of tax

In its draft determination the Utility Regulator states that 'an effective tax rate of approximately 27%' was used in FE's allowed return calculations.⁶⁸ The Utility Regulator is mistaken; the tax rate used in the allowed return calculations for FE by Oxera is assumed to be 20%, not 27%.⁶⁹

Contrary to the Utility Regulator's interpretation, Oxera has not used effective tax rates in estimating the pre-tax allowed WACC for FE. Instead, we have used a statutory tax rate assumption, which is consistent with the Utility Regulator's approach.⁷⁰

The reason that Oxera's estimate of the tax wedge varies from the Utility Regulator's assessment is that the Utility Regulator has not allowed for taxes that are payable on the proportion of FE's revenues that are index-linked. The Utility Regulator has therefore underestimated allowed returns for FE in applying its tax wedge within the WACC estimate.

Specifically, there is a difference in the 'one-step' tax estimation approach adopted by the Utility Regulator, and the 'multi-step' approach used by Oxera. Box 4.1 summarises the difference in approach taken by Oxera, relative to that of the Utility Regulator.

Box 4.1 Appropriate multi-step tax estimation approach

By adjusting from a real post-tax cost of equity estimate to a pre-tax cost of equity estimate (one-step approach) the regulator would understate the allowed return. The one-step approach would not allow a regulated firm to earn a sufficient tax wedge on the proportion of its revenues that are linked to inflation. The multi-step approach is appropriate for regulated utilities that receive pre-tax WACC allowances, as summarised below.

Multi-step approach (using statutory tax rate assumption of 20%)

To assess the allowed rate of return for FE in GD17, Oxera uses a multi-step approach. This converts the post-tax cost of equity allowance into pre-tax terms using the following steps.

1. Estimate the real post-tax cost of equity, using the capital asset pricing model (CAPM). For illustration, assume that a CAPM-derived estimate of the real post-tax cost of equity is 4%.
2. Convert the real post-tax cost of equity into a nominal post-tax cost of equity, using the Fisher equation.⁷¹ Assuming inflation of 3% and using a real post-tax cost of equity of 4%, the nominal post-tax cost of equity is estimated as: $[(1+4\%)(1+3\%)] - 1 = 7.1\%$.
3. Uplift the nominal post-tax cost of equity to a nominal pre-tax estimate by making a tax-wedge adjustment—i.e. divide the post-tax estimate by $(1-t)$, where 't' is the rate of corporate taxation. Assuming a taxation rate of 20%, and using a nominal post-tax cost of equity of 7.1%, the nominal pre-tax cost of equity is estimated as: $7.1\%/(1-20\%) = 8.9\%$.
4. Restate the nominal pre-tax estimate as a real pre-tax allowance by deducting inflation using the Fisher equation. Assuming inflation of 3%, and using a nominal pre-tax cost of equity of 8.9%, the real pre-tax cost of equity is estimated as: $[(1+8.9\%)/(1+3\%)] - 1 = 5.7\%$.

One-step approach (using the same statutory tax rate assumption of 20%)

Using the illustrative numbers above, a one-step approach to converting a real post-tax cost of equity to pre-tax terms would imply an allowance of 5% (i.e. $5\% = 4\%/(1-20\%)$), rather than 5.7%, as assessed using a multi-step conversion.

⁶⁸ Utility Regulator (2016), 'Price Control for Northern Ireland's Gas Distribution Networks GD17', Draft determination, 16 March, para. 10.41.

⁶⁹ Oxera (2016), 'Tax adjustment in pre-tax cost of capital', 19 February.

⁷⁰ Utility Regulator (2016), 'Price Control for Northern Ireland's Gas Distribution Networks GD17', Draft determination, 16 March, para. 10.39.

⁷¹ The Fisher equation is used to toggle between nominal and real rates, with the following equation: $(1+i) = (1+r) * (1+\pi)$, where 'i' refers to a nominal rate, 'r' refers to a real rate, and 'π' refers to the rate of inflation.

Source: Oxera.

We have submitted analysis to the Utility Regulator that shows that, in a regulatory setting, it is not appropriate to convert a real post-tax estimate to real pre-tax terms directly, as the tax wedge will then understate an allowance for corporate taxation, given that taxes are paid on nominal earnings (not real earnings).⁷² This tax note is appended in Appendix A1.

Indeed, in the case of the allowed WACC for FE, not applying the tax rate to the nominal estimate of the cost of equity has led to a significant understatement of the allowed return for FE by 34 bps.⁷³

⁷² Oxera (2016), 'Tax adjustment in pre-tax cost of capital', 19 February.

⁷³ Holding all else equal, as per the Utility Regulator's draft determination. This differential is calculated as follows: the regulator's one-step approach leads to a cost of equity allowance (real, pre-tax), which is assessed as the real post-tax cost of equity divided by the tax wedge, i.e. $5.3\% / (1 - 0.2) = 6.6\%$ (consistent with the estimate as reported in Utility Regulator (2016), 'Price Control for Northern Ireland's Gas Distribution Networks GD17', Draft determination, 16 March, para. 10.39). On the other hand, Oxera's multi-step approach using the regulator's draft decision estimates would involve the following steps. First, calculate nominal post-tax cost of equity, assuming inflation of 3.08% as: $((1 + 5.3\%) * (1 + 3.08\%)) - 1 = 8.5\%$. Second, apply the tax-wedge uplift as: $8.54\% / (1 - 0.2) = 10.7\%$. Third, convert the nominal pre-tax estimate to real terms as: $((1 + 10.7\%) / (1 + 3.08\%)) - 1 = 7.3\%$, allowing for rounding errors. The difference between the regulator's one-step estimate and Oxera's multi-step estimate is 0.75%, which assumes notional gearing of 55% translates to a 34 bps difference in the overall WACC. Note that these calculations compare the difference in allowed cost of equity on the basis of a 20% statutory tax rate assumption. If the statutory tax rate in Northern Ireland falls, the tax-wedge uplift for FE would decline. With a lower statutory tax rate assumption, the differential in cost of equity estimates under the one-step and multi-step approach would be lower.

5 Concluding remarks

Oxera's response to the GD17 draft determination is summarised in the table below.

Table 5.1 Summary of Oxera's response to GD17 draft determination

Parameter	Response
Cost of equity	
Total market return (risk-free rate + equity risk premium)	The allowed total market returns for NI GDNs for 2017–22 are significantly lower than for GB GDNs over an overlapping time period (2013–21). This estimate of generic parameters reduces the overall cost of equity allowance for FE, notwithstanding its higher risk compared to GB GDNs. To redress this inequitable outcome for Northern Ireland investors the Utility Regulator may select a higher point estimate for the NI GDNs in its estimated WACC range.
Asset beta	The evidence supports the selection of an asset beta estimate for FE that is at the top end of the range assessed by Oxera—i.e. 0.5, rather than the bottom end of the range at 0.4 as assumed in the draft determination.
Debt beta	The use of a relatively high debt beta has implications for the regulator's assessment of risk, and read-across to other WACC parameters. Combined with a low notional gearing assumption, a relatively high debt beta suggests that the Utility Regulator recognises that FE's debt is riskier than other regulated networks. The Utility Regulator should reflect this higher risk in its asset beta and debt premium assumptions.
Overall cost of equity	Within the draft determination package, the cost of equity allowance for FE does not allow sufficient headroom for downside risk for FE in GD17. Since the Utility Regulator has suggested that the majority of debt financing costs in GD17 will be subject to a pass-through mechanism, the financeability analysis supports that the Utility Regulator selects a higher point estimate in its estimated cost of equity range. By its own analysis, the Utility Regulator has shown that FE's interest coverage ratio for the GD17 period is at the minimum necessary level for five years within the six-year control. This suggests that the Utility Regulator has not allowed sufficient headroom for volatility in its estimation of the allowed cost of equity, within the overall price control package.
Cost of debt	
Approach	There is an inconsistency between the cost of debt approach used for FE and the regulatory disaggregated cost of debt approach used for SONI. The 2.95% allowance for SONI, and its constituent estimates are broadly aligned with the allowed cost for FE in the September 2015 update, which assessed a reasonable range of 3.05–3.30%. It is therefore inconsistent within Northern Ireland that the allowed cost of debt for FE is much lower than for SONI. This arises due to the use of a different cost of debt estimation approach, and notwithstanding the fact that FE would have to offer a yield premium if it is perceived to have relatively high risk as a first-time bond issuer in GD17.
Embedded debt	The Utility Regulator has deflated embedded debt for the period 2017–19 using inflation forecasts for six years (i.e. average of 3.08% over 2017–22). Instead, using an estimate of 2.68% inflation for the relevant 2017–19 period suggests that the real embedded debt cost allowance should be 40 bps higher. Specifically, this leads to an increase in the embedded debt cost from 1.6% as assessed by the Utility Regulator, to 2.0%.
New pain-gain sharing approach	To ensure that any new pain-gain sharing approach appropriately allows for FE's specific financing constraints, Oxera recommends the following. • 60 bps allowance for transaction costs, rather than 40 bps as proposed by the Utility Regulator. This is based on an assessment of the notional quantum of debt to be raised by FE in GD17.

Parameter	Response
	• 1.3% additional allowance for 'credit uplift' within the debt premium. This should be added to the new cost of debt allowance inferred from BBB iBoxx yields if FE is unable to achieve an investment-grade rating. • Inclusion of an RPI inflation 'true-up' to reflect any differentials in outturn inflation relative to the Utility Regulator's forecast, within the allowed cost of new debt. • Cost pass-through with 80:20 pain-gain sharing should occur at the end of the period. This should allow for any pain-gain adjustments to the WACC to also be factored into 'logged-up' amounts for any other uncertainty mechanisms or revenue-reprofiling mechanisms.

Taxation

Effective vs statutory tax rates	The Utility Regulator has suggested that FE's submissions are underpinned by an effective tax rate of 27%. This is incorrect, as the submissions by Oxera on behalf of FE consistently use a statutory tax rate assumption of 20%.
Taxes are payable on nominal basis	By adjusting in one step from a real post-tax cost of equity estimate to a pre-tax cost of equity estimate, without allowing a tax wedge on the proportion of its return that is linked to inflation, the Utility Regulator has understated the allowed return for FE by around 30 bps.

Source: Oxera.

A1 Appendix A1—Oxera tax note

Tax adjustment in pre-tax cost of capital estimate

Note prepared for firmus energy, to be submitted to the Utility Regulator

19 February 2016

Draft for comment: strictly confidential

1. Introduction

The Utility Regulator and First Economics have invited Oxera to comment on the tax allowance included in the real pre-tax weighted average cost of capital (WACC) estimate for firmus energy in Oxera's June and September submissions regarding the allowed rate of return for the GD17 period.⁷⁴

This short note provides an explanation of how Oxera has incorporated an allowance for tax within its estimate of the regulatory WACC, and why its methodology is appropriate in a regulatory setting. Specifically, Oxera has undertaken a multi-step approach that applies a tax uplift to a nominal estimate of the cost of equity; the Utility Regulator and its advisers have questioned whether the tax uplift could instead be applied in a one-step approach to a real estimate of the cost of equity. Oxera's analysis has shown that a multi-step approach appropriately remunerates investors where regulated firms' revenues, and thereby taxable profits, are derived from index-linked asset values, allowing for differences in the regulatory and accounting treatment of depreciation. It should also be noted that there is regulatory precedent from Ofcom supporting the multi-step approach.⁷⁵

The note is structured as follows:

- section 2 provides a description of how Oxera has incorporated the tax allowance for firmus energy in the GD17 allowed cost of capital;
- section 3 provides stylised regulatory allowed revenue modelling to illustrate why it is appropriate to allow for taxation on the basis of a nominal estimate of the cost of equity as Oxera has done, rather than by making a tax-wedge uplift to a real estimate of the cost of equity.

⁷⁴ See Oxera (2015), 'GD17 price control parameters: allowed rate of return', for submission to the Utility Regulator, prepared for firmus energy, 30 June; and Oxera (2015), 'GD17 price control parameters: allowed rate of return', September update, September.

⁷⁵ See, for example, Ofcom (2014), 'Fixed access market reviews: wholesale local access, wholesale fixed analogue exchange lines, ISDN2 and ISDN30 – Annexes', Non-confidential version, Table A14.1, June.

2. Tax uplift in pre-tax WACC estimation

The allowed cost of capital, or rate of return allowance, for firmus energy is assessed on a pre-tax real basis by the Utility Regulator.⁷⁶ To estimate the allowed pre-tax cost of capital for firmus energy in GD17, Oxera has undertaken the following adjustments.

- **No uplift for tax in cost of debt allowance.** Since capital market data, such as risk-free rate data and data on debt premia, which is used to infer an allowed cost of debt, is in effective pre-tax terms (given the tax shield of debt financing),⁷⁷ it is not necessary for Oxera to convert the cost of debt allowance that is estimated for firmus energy into pre-tax terms.
- **Uplift for tax in cost of equity allowance.** An estimate of the required return on equity, using the capital asset pricing model (CAPM), implies a cost of equity financing that is stated in post-tax terms. This is because equity returns are not exempt from corporate taxation, and investors are interested in returns that are net of taxation as inferred using the CAPM. Therefore, to derive a pre-tax WACC allowance, an estimate of the post-tax cost of equity using the CAPM model needs to be converted into pre-tax terms.

To assess the allowed rate of return for firmus energy in GD17, Oxera has converted the post-tax cost of equity allowance into pre-tax terms using the following steps.

1. Estimate the real post-tax cost of equity, using the CAPM. For illustration, assume that a CAPM-derived estimate of the real post-tax cost of equity is 4%.
2. Convert the real post-tax cost of equity into a nominal post-tax cost of equity, using the Fisher equation.⁷⁸ Assuming inflation of 3% and using a real post-tax cost of equity of 4%, the nominal post-tax cost of equity is estimated as: $[(1+4\%)(1+3\%)] - 1 = 7.1\%$.
3. Uplift the nominal post-tax cost of equity to a nominal pre-tax estimate by making a tax-wedge adjustment—i.e. divide the post-tax estimate by $(1-t)$, where 't' is the rate of corporate taxation. Assuming a taxation rate of 20%, and using a nominal post-tax cost of equity of 7.1%, the nominal pre-tax cost of equity is estimated as: $7.1\%/(1-20\%) = 8.9\%$.
4. Restate the nominal pre-tax estimate as a real pre-tax allowance by deducting inflation using the Fisher equation. Assuming inflation of 3%, and using a nominal pre-tax cost of equity of 8.9%, the real pre-tax cost of equity is estimated as: $[(1+8.9\%)/(1+3\%)] - 1 = 5.7\%$.

The Utility Regulator and its advisers have questioned why it is necessary to undertake this multi-stage process to incorporate an allowance for taxation within the cost of equity estimate. For example, it has been questioned whether it would be appropriate to instead uplift the real post-tax cost of equity estimate that is obtained by using the CAPM equation directly,⁷⁹ in order to obtain a real pre-tax estimate. Using the illustrative numbers above, a one-step approach to

⁷⁶ Currently 7.5% (pre-tax, real).

⁷⁷ In the UK and several other jurisdictions, debt financing is exempt from taxation. Effectively, paying a return to debt investors is seen as a cost of doing business, while paying a return to equity investors is seen as a distribution of profits.

⁷⁸ The Fisher equation is used to toggle between nominal and real rates, with the following equation: $(1+i) = (1+r) * (1+\pi)$, where 'i' refers to a nominal rate, 'r' refers to a real rate, and 'π' refers to the rate of inflation.

⁷⁹ That is, to convert from post-tax to pre-tax directly by dividing the post-tax estimate by the tax-wedge estimate $(1-t)$.

converting a real post-tax cost of equity to pre-tax terms would imply an allowance of 5% (i.e. $5\% = 4\% / (1 - 20\%)$), rather than 5.7% as assessed using a multi-step conversion.

Oxera has undertaken analysis that shows that, in a regulatory setting, it is not appropriate to convert a real post-tax estimate to real pre-tax terms directly, as the tax wedge will then understate an allowance for corporate taxation, given that taxes are paid on nominal earnings (not real earnings). This can be explained with some stylised allowed revenues modelling, as addressed in the next section.

3. Why is the tax adjustment made to the nominal cost of equity?

Oxera's tax-wedge adjustment applies to a nominal post-tax cost of equity rather than a real post-tax cost of equity, because the latter approach would lead to the regulated company receiving a lower than required rate of return because its taxes are paid on nominal earnings. To explore this concept, a numerical illustration is helpful.

Assume, as in the preceding section, that a regulator has used the CAPM to estimate that the (real, post-tax) required rate of return is 4%, while inflation is 3% and the statutory corporate tax rate is 20%. Assume further, for this example, that there is no debt financing. Estimating a pre-tax cost of equity directly (the 'one-step approach') may use the following calculation: $4\% / (1 - t) = 5\%$. Instead, allowing for taxation on a nominal basis (the 'multi-step approach') would lead to a real pre-tax estimate of 5.7% using the steps described in the preceding section.

To test whether the 5% (one-step approach) or 5.7% (multi-step approach) is appropriate, it is necessary to test the returns that the regulated firm would earn under each allowance scenario. Assume that, under both scenarios, the opening RAB is 100 and the investment is to be fully recovered within a five-year control period. The WACC allowance is in real terms, as investors are remunerated for inflation via annual RAB indexation.

Table 3.1 illustrates that using the 5% pre-tax one-step cost of equity allowance in a simplified price control model results in an internal rate of return on real post-tax cash flows of 3.4%, which is lower than the regulator's CAPM estimate of post-tax required returns of 4%. On the other hand, using the 5.7% pre-tax multi-step cost of equity allowance results in an internal rate of return of 4.0%, which is in line with the regulator's intended post-tax allowance of 4% (see Table 3.2).

Table 3.1 Returns realised in one-step cost of equity (5%) scenario

Year	0	1	2	3	4	5
<i>Allowed revenues</i>						
Opening RAB		100.0	82.4	63.7	43.7	22.5
RAB indexation (revaluation)		3.0	2.5	1.9	1.3	0.7
Depreciation		20.6	21.2	21.9	22.5	23.2
Closing RAB	100.0	82.4	63.7	43.7	22.5	0.0
Return on RAB @ 5.0% (pre-tax) ¹		5.1	4.2	3.2	2.2	1.1

Year	0	1	2	3	4	5
Allowed revenue (pre-tax)	-100.0	25.7	25.4	25.1	24.7	24.3
<i>Profit and loss statement</i>						
Allowed revenue (pre-tax)		25.7	25.4	25.1	24.7	24.3
Historic cost depreciation		-20.0	-20.0	-20.0	-20.0	-20.0
Taxable profit		5.7	5.4	5.1	4.7	4.3
Tax		-1.1	-1.1	-1.0	-0.9	-0.9
Post-tax profit		4.5	4.3	4.1	3.8	3.5
Post-tax cash flow	-100.0	24.5	24.3	24.1	23.8	23.5
Real post-tax cash flow	-100.0	23.8	22.9	22.0	21.1	20.2
Internal rate of return on post-tax cash flows						3.4%

Note: Figures rounded to 1 decimal place. ¹ Annual return on RAB is calculated as the rate of return * (opening RAB + 0.5 annual indexed increase in RAB), assuming mid-year valuation.

Source: Oxera analysis.

Table 3.2 Returns realised in multi-step cost of equity (5.7%) scenario

Year	0	1	2	3	4	5
<i>Allowed revenues</i>						
Opening RAB		100.0	82.4	63.7	43.7	22.5
RAB indexation (revaluation)		3.0	2.5	1.9	1.3	0.7
Depreciation		20.6	21.2	21.9	22.5	23.2
Closing RAB	100.0	82.4	63.7	43.7	22.5	0.0
Return on RAB @ 5.7% (pre-tax) ¹		5.8	4.8	3.7	2.5	1.3
Allowed revenue (pre-tax)	-100.0	26.4	26.0	25.6	25.1	24.5
<i>Profit and loss statement</i>						
Allowed revenue (pre-tax)		26.4	26.0	25.6	25.1	24.5
Historic cost depreciation		-20.0	-20.0	-20.0	-20.0	-20.0
Taxable profit		6.4	6.0	5.6	5.1	4.5
Tax		-1.3	-1.2	-1.1	-1.0	-0.9
Post-tax profit		5.1	4.8	4.4	4.0	3.6
Post-tax cash flow	-100.0	25.1	24.8	24.4	24.0	23.6
Real post-tax cash flow	-100.0	24.4	23.4	22.4	21.4	20.4
Internal rate of return on post-tax cash flows						4.0%

Note: For ease of comparison between scenarios, green text denotes figures that differ from the preceding scenario. Figures rounded to 1 decimal place. ¹ Annual return on RAB is calculated as the rate of return * (opening RAB + 0.5 annual indexed increase in RAB), assuming mid-year valuation.

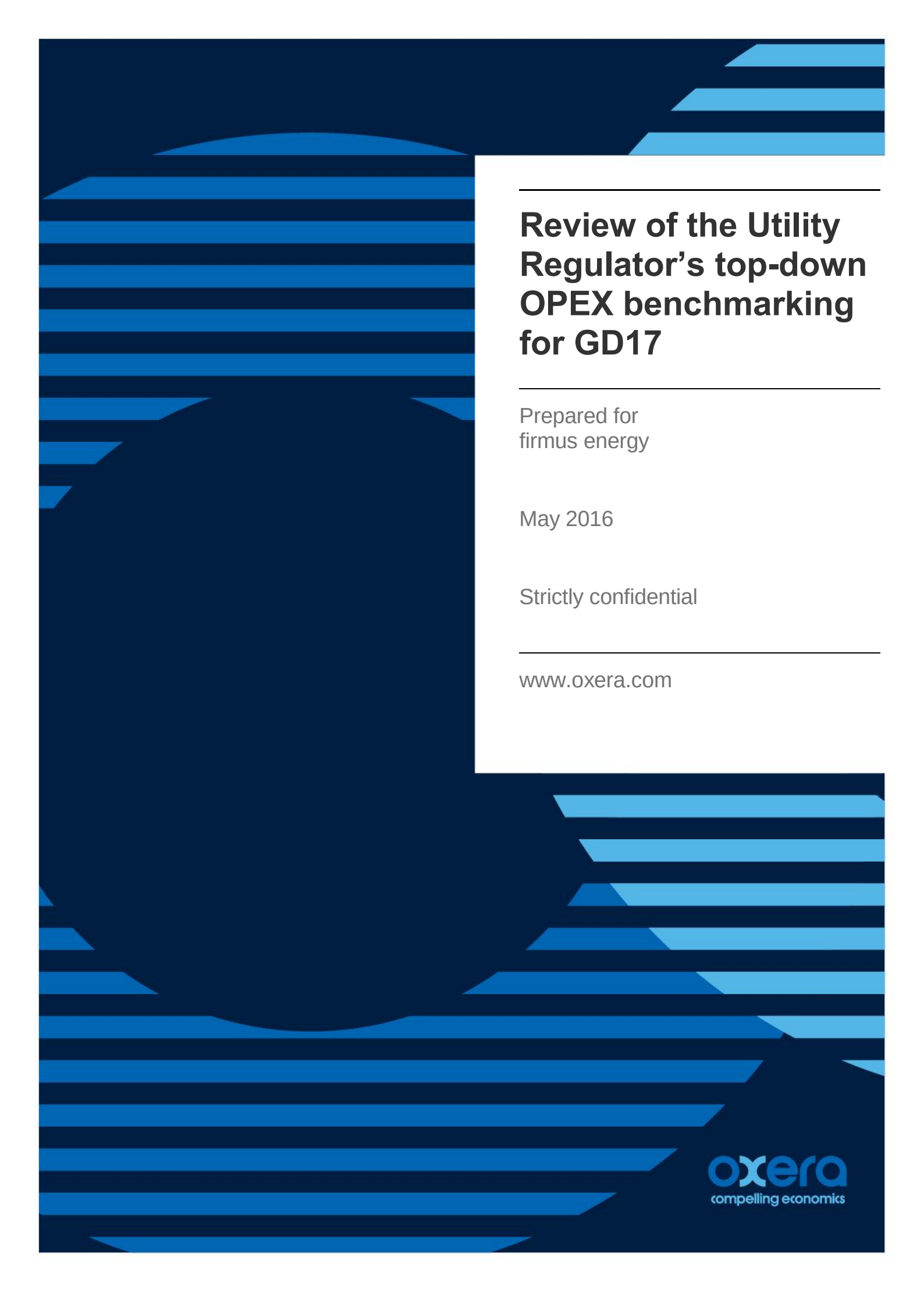
Source: Oxera analysis.

The multi-step approach to including taxes within the cost of equity therefore allows regulated firms to earn a realised return that is equivalent to the allowed

return in a regulatory setting, allowing for differences in the regulatory and accounting treatment of depreciation. The multi-step approach is consistent with UK regulatory precedent from Ofcom.⁸⁰ This approach recognises that regulated firms' revenues, and thereby taxable profits, are derived from index-linked asset values. By adjusting from a real post-tax cost of equity estimate to a pre-tax cost of equity estimate without allowing a regulated firm to earn a tax wedge on the proportion of its return that is linked to inflation, the regulator would understate the allowed return. In other words, taxes are paid on nominal, not real, earnings. It is therefore necessary to use a multi-step approach in adjusting for taxation by first converting from a real to a nominal post-tax cost of equity estimate, and then including an allowance for taxation.

⁸⁰ See, for example, Ofcom (2014), 'Fixed access market reviews: wholesale local access, wholesale fixed analogue exchange lines, ISDN2 and ISDN30 – Annexes', Non-confidential version, Table A14.1, June.

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Review of the Utility Regulator's top-down OPEX benchmarking for GD17

Prepared for
firmus energy

May 2016

Strictly confidential

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Executive summary

In its draft determination for GD17, the Utility Regulator has used results from econometric approaches to assess the OPEX efficiency of the NI GDNs, based on analysis undertaken by Deloitte.¹

This report presents Oxera's review of Deloitte's analysis based on available published material.² Our review is limited, as we have not been given access to any data by the Utility Regulator; however, we have identified a number of significant concerns regarding the robustness of Deloitte's analysis in assessing firmus energy's (FE) efficiency.

The Utility Regulator has noted that it is expecting companies to quantify the value of any special factors and atypical costs as part of their response to the draft determination.³ As we have not had access to the underlying data, it has not been possible to quantify these for FE relative (i.e. incremental) to the models developed by Deloitte and considered by the Utility Regulator. However, we have set out the directional impact of some of the key differences between FE and its GB and NI counterparts that are either not considered in Deloitte's models or considered inappropriately.

Based on the evidence available to us, our overall conclusion is that it is not possible to establish that FE is *not* on the efficiency frontier. Deloitte also flags this point, as below:

FE has a significantly different profile to any of the other GDNs in terms of the ratios between network length, customer numbers and volume of gas supplies. This results in significant challenges in assessing the extent to which FE costs are inefficient or are due to the characteristics of the business.⁴

Therefore, it is not possible to conclude that the models presented in the draft determination are a reflection of FE's actual efficiency. To that end, it would be inappropriate to determine allowed revenues for FE based on the analysis presented in the draft determination.

Key findings

Based on our review, the key findings and issues we have identified with Deloitte's analysis are presented below.

- The treatment of key economic/operational issues relating to economies of scale, network penetration, and age of network appear to be inappropriate, all of which significantly overestimate the inefficiency of FE.
- **Economies of scale.** The differences in scale of operations between FE and its GB counterparts is extreme, which cannot be captured robustly by Deloitte's econometric model with the use of a composite scale variable

¹ Deloitte (2016), 'Annex 4 - GD17 Efficiency Advice: Relative efficiency of Northern Ireland Gas Distribution Networks. Final report', 11 March, http://www.uregni.gov.uk/uploads/publications/GD17_Annex_4_-_GD17_Efficiency_Advice_Deloitte_LLP.pdf; Utility Regulator (2016), 'Annex 5 Indicative Findings from Top-Down Benchmarking GD17', Draft Determination, 15 March, http://www.uregni.gov.uk/uploads/publications/GD17_Annex_5_-_Indicative_Findings_from_Top-Down_Benchmarking.pdf.

² In particular, our review is limited to the draft determination and the Annexes 4 and 5 of it: Deloitte (2016), 'Annex 4 - GD17 Efficiency Advice: Relative efficiency of Northern Ireland Gas Distribution Networks. Final report', 11 March; Utility Regulator (2016), 'Annex 5 Indicative Findings from Top-Down Benchmarking GD17', Draft Determination, 15 March.

³ Utility Regulator (2016), 'Annex 5 Indicative Findings from Top-Down Benchmarking GD17', Draft Determination, 15 March, p. 19.

⁴ Deloitte (2016), 'Annex 4 - GD17 Efficiency Advice: Relative efficiency of Northern Ireland Gas Distribution Networks. Final report', 11 March, p. 4.

(referred to as a CSV⁵). Deloitte's functional form assumption relating OPEX and the CSV assumes the same scale economies across the sample dataset composed of the significantly bigger GB GDNs to be appropriate for FE, which is not aligned with underlying features of FE's business. Also, Deloitte's testing of varying scale economies in the sample, which is a key issue for FE, is limited. This issue is further exacerbated by the Utility Regulator's selection of preferred models that are least precise in estimating the scale elasticity.

- **Network penetration.** FE is a relatively new network with a naturally lower level of customer penetration at this stage in its development (and thus also relatively lower gas volumes transported). Deloitte has placed maximum weight on customer numbers (it has assumed a 50% weighting; and gas transported, which is also affected by penetration, is given a 25% weighting), which significantly biases FE's estimated inefficiency upwards as its scale (measured by the CSV) is underestimated relative to its OPEX. The Utility Regulator's view on the weighting appears to be based on Ofgem's 2007 analysis for GDPCR1; however, the Utility Regulator's view has not been substantiated by any engineering evidence and is inconsistent with the most recent regulatory precedent from Ofgem in the RIIO price controls.
- **Age of network.** We consider that the percentage of iron mains, which is used as a proxy for age of network, has a number of limitations in the way it is considered in the models. In particular, there are statistical issues in including the variable along with the time trend in the models as both variables are highly correlated with each other. This results in the coefficient being very inaccurately estimated, making it highly unreliable for inclusion in the model. Deloitte/the Utility Regulator has also not discussed whether the coefficient estimates are aligned with economic and engineering expectations. This is a critical issue, as the current treatment of this factor in Deloitte's analysis significantly biases FE's estimated inefficiency upwards, resulting in questionable outcomes (for example, FE—which is a new network—is assessed to be about 30% inefficient on the basis of models that include this factor, an increase of 20% over models without this factor,⁶ which does not appear credible).
- There are a number of issues regarding the detail of model specification, estimation approaches employed, diagnostic testing of models, and translation of results into OPEX targets.
- **Model specification.** Apart from considering alternative and more robust ways of treating the key economic issues described above, the inclusion of time trend in the model warrants further examination, as year-on-year fluctuations in OPEX can be better accommodated in more flexible ways, especially over a short time period. This inclusion may be particularly problematic, depending on how the Utility Regulator has used the models to forecast efficient OPEX levels up to 2022 (e.g. if the historical trend between -1.7% and -2.5% per annum is forecast to continue until 2022). As we have not received any data or details of the cost-prediction calculations, the exact mechanics underlying the Utility Regulator's forecast of efficient OPEX over GD17 is not clear. It would be helpful if the Utility Regulator provided this information.

⁵ Which is a geometric weighted combination of customers, network length and gas volume transported.

⁶ Under the GB only sample dataset.

- **Estimation approach.** The pooled Ordinary Least Squares (OLS) approach, which is the modelling approach considered in the Utility Regulator's preferred models, can produce biased and inconsistent parameter estimates if inefficiency changes over time, if there are company-specific effects, and if inefficiency depends on some exogenous variables (observed or unobserved). All of these contexts seem likely in the current application, and therefore the results from the pooled OLS approach cannot be deemed conclusive and need to be validated against operational and engineering expectations.
- **Translating model results into OPEX targets.** The wide range of results from the Utility Regulator's preferred models indicates that there is a high degree of uncertainty around FE's estimated gap, such that the upper-quartile efficiency benchmark is likely to be inappropriate for FE, or, the current models are not appropriate to be considered for FE (indeed, as noted above, the preferred models result in questionable outcomes for FE). In addition, there could be a degree of double counting in the Utility Regulator's efficiency estimates, depending on how the Utility Regulator has used the model results to forecast efficient OPEX up to 2022.⁷
- **Diagnostic testing of models.** The statistical properties of Deloitte's models, and the results of diagnostic testing applied to them, are not discussed in its report.⁸ Deloitte has noted that diagnostic tests would be considered in the final determination, but has not explained what testing it is intending to undertake. Given the small sample period, and significant differences between the operating profiles of FE and its comparators, we consider that the economic issues discussed above are far more important than the statistical diagnostics in this case.
- **Consideration of other FE special factors.** Apart from the structural factors discussed above, other cost adjustments are necessary for differences in regulatory obligations and network structure, to make the cost base between FE and its GB counterparts comparable.
- **Network sparsity.** This issue has not been considered or accounted for in any of Deloitte's or the Utility Regulator's preferred models. Only one of the (non-preferred) models considers a sparsity variable (network length over customer numbers), but not in the context of accounting for network sparsity. Based on the sparsity measure of customers per km of pipeline, FE's operational area is sparser than that of the most sparse GB GDN. In RIIO-GD1, Ofgem allowed a sparsity factor adjustment of £1.3m for Scotland GDN and £2.6m for Wales & West Utilities (WWU) (in 2009/10 prices)—i.e. two of the most sparse GB GDNs—based on a population served over district level area measure.⁹ While Ofgem's sparsity measure

⁷ This is because the time trend variable included in the regulator's preferred models captures the rate of the reduction in costs over the historical period for the average GDN, and over time, which (depending on how the Utility Regulator has derived the forecast OPEX figures) could have been projected to continue until 2022. In particular, the time trend (capturing catch-up, frontier shift and other effects) if extrapolated would result in cost reductions of between 8% and 12% over GD17. As the Utility Regulator treats frontier-shift and input price effects separately, overlaying a frontier-shift target to the model predictions (if it has done so) could account for this part of efficiency twice. It would be helpful if the Utility Regulator could clarify this point.

⁸ Deloitte has discussed a model fit measure in Bayesian Information Criterion (BIC) in comparing the statistical performance of models it has considered, but this is extremely limited compared with diagnostic testing undertaken by other regulators, including Ofgem. See, for example, the battery of tests considered by Ofgem in RIIO-GD1 apart from examining whether the model results are consistent with economic and operational expectations here. See Table A4.3 of Ofgem (2012), 'RIIO-GD1: Final Proposals - Supporting document - Cost efficiency', 17 December, <https://www.ofgem.gov.uk/ofgem-publications/48157/4-riiogd1fpcostefficiency.pdf>.

⁹ Ofgem (2012), 'RIIO-GD1: Final Proposals – Supporting document – Cost efficiency', 17 December, Table A4.2.

is also valid for quantifying a special factor for FE, it may be appropriate to consider the network penetration measure of sparsity in determining an adjustment for FE, as it is widely recognised that there are different valid ways of measuring network sparsity.¹⁰

- **Xoserve costs.** The Utility Regulator excludes 75% of Xoserve costs from the GB GDNs' cost base. However, the reasoning for this adjustment and the basis for 75% is unclear. As highlighted in our earlier report,¹¹ FE undertakes activities provided by Xoserve, but simply undertakes these in house; hence, it may be that no cost adjustment to the GB GDNs is necessary. Furthermore, the Utility Regulator and Deloitte do not take into account the huge economies of scale present on these costs—in particular, FE has 25,000 supply meter points when compared with Xoserve, which represents 21 million supply meter points. As such, one appropriate adjustment would be to adjust downwards FE's modelled costs rather than those of the GB GDNs.
- **Labour cost adjustment.** In adjusting the GDNs' OPEX for differences in regional labour costs, the Utility Regulator has used a single assumption on the labour component of OPEX across all GDNs (52%), which appears to be based on the notional structure assumed by Ofgem for the GB GDNs. However, given FE's different operational circumstances and stage of network development, the figure appears to be high—in particular, FE's business plan indicates that the share of labour costs in its OPEX will be decreasing from 46% to 37% over the period.¹² The higher percentage assumed by the Utility Regulator means that FE's costs will be uprated by a larger amount than they should be based on FE's actual cost structure. This would clearly disadvantage FE in the Utility Regulator's benchmarking analysis. Thus, this adjustment warrants further examination.

¹⁰ Oxera (2012), 'The impact of sparsity in benchmarking', prepared for Wales & West Utilities, April.

¹¹ Oxera (2015), 'Benchmarking and efficiency assessment', June.

¹² Firmus energy (2015), 'Business Plan Template Commentary GD17', September.

1 Introduction

As part of the price review for GD17, the Utility Regulator intends to determine the level of efficient OPEX for the NI GDNs based on top-down benchmarking of their cost performance against their GB counterparts and bottom-up assessment of their cost submissions. The Utility Regulator has noted that it is seeking to refine its top-down analysis and to continue working with the GDNs before concluding its modelling; as such, the OPEX efficiency targets and allowance in its draft determination¹³ reflect the results under the bottom-up approach.¹⁴

This report reviews the Utility Regulator's suggested top-down approach and assesses how much reliance can be placed on it in predicting FE's cost requirements over GD17.

The report is structured as follows:

- section 2 reviews the Utility Regulator's analysis and examines its suitability for predicting FE's cost requirements.
- section 3 discusses FE special factors that should be considered in the Utility Regulator's analysis to better reflect FE's operational characteristics. The section also reviews special factors already considered by the Utility Regulator;
- section 4 concludes;
- Appendix 1 summarises the Utility Regulator's top-down benchmarking approach proposed for GD17.

¹³ Utility Regulator (2016), 'Price Control for Northern Ireland's Gas Distribution Networks GD17', Draft Determination, 15 March, http://www.uregni.gov.uk/uploads/publications/2016-03-16_GD17_Draft_Determination_-_Final.pdf.

¹⁴ Utility Regulator (2016), 'Price Control for Northern Ireland's Gas Distribution Networks GD17', Draft Determination, 15 March, para. 3.1.

2 Review of the Utility Regulator's approach

An overview of Deloitte's analysis can be found in Appendix A1 of this report. In this section, we examine the following aspects of Deloitte's modelling:

- key economic/operational issues relating to treatment of economies of scale, network penetration, and age of network (sections 2.1–2.3);
- issues of detail regarding model specification, estimation approaches employed, diagnostic testing of models, and translation of results into OPEX targets (sections 2.4–2.5).

For both sets of issues, we highlight a number of significant concerns regarding the robustness of Deloitte's analysis in assessing FE's efficiency and discuss some options on how they can be mitigated.

2.1 Economies of scale

Given that companies' scale of operations is the principle cost driver (i.e. explanatory factor) in all the models and the differences in scale are extremely large, the way in which this issue is captured will have an overwhelming impact on the results. Since the core comparator set of the GB GDNs operate at a materially different scale to FE, the issue has to be robustly resolved for the model results to be reliable in assessing FE's efficiency.

FE has around 25,000 customers.¹⁵ In contrast, the smallest GB GDN has around 2 million customers, with the average number of customers for GB GDNs at about 2.7 million. Given the variance of about 1:100, FE is clearly operating at a materially different size compared with the GB GDNs. These differences can be captured only to a *very limited extent* by Deloitte's econometric model with the use of a composite scale variable (referred to as a CSV),¹⁶ where 50% of the weighting is given to customer numbers and 25% to volume. As customer numbers are a key driver for gas volume transported,¹⁷ the actual weight applied to customer numbers could be as high as 75% (in other words, about 75% of the weighting is applied to scale measures affected by penetration). In contrast, network length is only given 25% weighting in constructing the CSV, where smaller variance exists—i.e. while the average network length for GB GDNs is 33,000km, FE's corresponding figure is less than 1,000km (i.e. a ratio of 1:33).

2.1.1 FE's inefficiency is likely to be significantly overestimated in the models

Deloitte used a Cobb–Douglas model specification in its analysis,¹⁸ which assumes that economies of scale are the same for all companies, regardless of size. As noted in our report on benchmarking, submitted to the Utility Regulator in June 2015,¹⁹ the assumption that FE and its bigger and more mature GB counterparts have the same scale economies is unlikely to be the case, and, thus, as noted by Deloitte, 'the efficiency estimates will be biased':

Assume that a log-linear (i.e. Cobb–Douglas) specification is a good approximation of the underlying relationship. However, as discussed above, **if the**

¹⁵ While the Utility Regulator has noted FE's customer numbers to be about 20,000, we have used information provided by FE on this.

¹⁶ Which is a geometric weighted combination of customers, network length and gas volume transported.

¹⁷ Gas volumes may also depend on the customer mix (i.e. domestic versus non-domestic customers) and other factors such as leakage/shrinkage.

¹⁸ That is, the dependent variable (here, OPEX) and independent variables (here, cost drivers such as CSV) are expressed in natural logarithms and assumed to exhibit a linear relationship. Such modelling is assumed to exhibit constant elasticity with respect to the cost drivers across the sample.

¹⁹ Oxera (2015), 'Benchmarking and efficiency assessment', June.

approximation is invalid the efficiency estimates will be biased. [emphasis added]²⁰

The impact of scale on costs will differ for larger and for smaller companies, rather than be the same, as assumed in Deloitte's models. In addition, it is questionable as to whether FE can be compared with the GB GDNs at its current network maturity. FE is currently not at a steady stage of a network cycle, and is in the process of building its network, incurring higher fixed costs in the process, while PNGL and the GB GDNs are in more mature stages of development and maintenance of assets. Hence, the network needs of FE are rather different from those of PNGL and the GB GDNs, and this should be reflected in the analysis. Thus, with no GDNs in the sample dataset at FE's scale or level of maturity, it is difficult, if not impossible, for the models considered by Deloitte to represent this issue accurately.

With the sample set primarily based on GB GDNs, the economies of scale estimate will be biased towards the economies of scale appropriate for GB GDNs rather than FE. This issue has also been acknowledged by Deloitte:

The GB GDNs all operate on a scale materially greater than either FE or PNGL. **Whilst the econometric analysis seeks to allow for economies of scale the extent to which this is fully captured is challenging as the dataset is dominated by larger GDNs.** As a result the impact of scale on costs, and subsequently relative efficiency, may be over- or under-estimated. [emphasis added]²¹

The Utility Regulator has derived FE's inefficiency based on the gap between FE's actual cost and the third-most-efficient company from the models.²² If the scale elasticity estimated from the models is biased, which appears likely given the modelling assumptions, the estimated gap will also be biased and will not be a reliable indicator of FE's inefficiency.

2.1.2 Deloitte's testing of the issue appears to be inadequate

In its report, Deloitte suggests that one of the ways to test the impact of scale effects could be to examine the sensitivity of the results across alternative sub-samples. In particular, it notes that:

if the estimated scale coefficient is sensitive to the exclusion of the NI GDNs from the estimation sample, then this would provide some indication of differential scale effects. [emphasis added]²³

While Deloitte does not present any formal testing of the scale coefficient across the models, it notes that economies of scale may be more pronounced for NI GDNs, as the scale coefficient increases when either or both NI GDNs are excluded from the dataset. Despite noting the impact, on the data sample issue, Deloitte states:

FE has a significantly different profile to any of the other GDNs in terms of the ratios between network length, customer numbers and volume of gas supplies. This results in significant challenges in assessing the extent to which FE costs are inefficient or are due to the characteristics of the business. **As such, FEs relative**

²⁰ Deloitte (2016), 'Annex 4 - GD17 Efficiency Advice: Relative efficiency of Northern Ireland Gas Distribution Networks. Final report', 11 March, p. 10.

²¹ Deloitte (2016), 'Annex 4 - GD17 Efficiency Advice: Relative efficiency of Northern Ireland Gas Distribution Networks. Final report', 11 March, p. 4.

²² The gap is referred as to the 'corrected' OLS residuals.

²³ Deloitte (2016), 'Annex 4 - GD17 Efficiency Advice: Relative efficiency of Northern Ireland Gas Distribution Networks. Final report', 11 March, p. 10.

efficiency has been computed by estimating a model using the GB only or GB and PNGL data and fitting the model to the FE data. [emphasis added]²⁴

FE having very different characteristics from the other GDNs may well be a reason for dropping FE from the full sample size.²⁵ However, this does **not** mean that FE's efficiency can then be assessed by comparing it with the cost function estimated from a reduced sample set of GB GDNs, with or without PNGL. In fact, **it implies that FE has a different cost function and cannot be compared with the estimated cost function based on GB GDNs (with or without PNGL) only.**

Moreover, in illustrating the profiles of forecast modelled OPEX in its draft determination,²⁶ the Utility Regulator has presented the results from the GB GDNs only.

The reason for dropping the full dataset has not been justified; rather, the Utility Regulator has assessed FE's efficiency by imposing on it cost models developed for a more homogeneous²⁷ set of GB GDNs. This exacerbates the problem of differences in scale size. (We revisit the sample set issue in section 2.2.3).

Based on the results reported in the Deloitte report, we observe that the coefficients of CSV vary greatly across model specifications and samples. As noted above, Deloitte acknowledges this point:

there is an indication that economies of scale might be more pronounced for NI GDNs²⁸

Without access to the data, we have examined Deloitte's results by sample sets to illustrate the issue. Figure 2.1 shows that FE's catch-up efficiency in 2014 has been estimated at much lower levels by the models estimating larger economies of scale. (There is a similar relationship for the 2015 catch-up results for FE, which we do not report, as Deloitte has noted that the cost data in the year is not actual data.)

²⁴ Deloitte (2016), 'Annex 4 - GD17 Efficiency Advice: Relative efficiency of Northern Ireland Gas Distribution Networks. Final report', 11 March, p. 4.

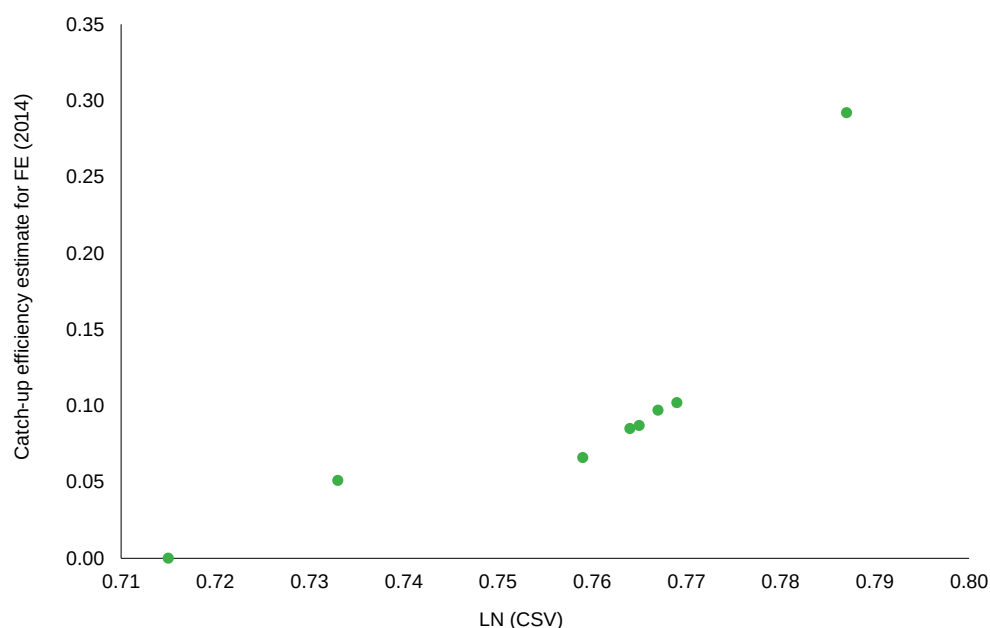
²⁵ Although this has not been adequately tested by Deloitte.

²⁶ See Figure 3 of Deloitte (2016), 'Annex 4 - GD17 Efficiency Advice: Relative efficiency of Northern Ireland Gas Distribution Networks. Final report', 11 March; Utility Regulator (2016), 'Annex 5 Indicative Findings from Top-Down Benchmarking GD17', Draft Determination, 15 March.

²⁷ That is, a set of GDNs with more similar characteristics to each other.

²⁸ Deloitte (2016), 'Annex 4 - GD17 Efficiency Advice: Relative efficiency of Northern Ireland Gas Distribution Networks. Final report', 11 March, p. 13.

Figure 2.1 Economies of scale versus 2014 catch-up efficiency estimates for FE



Source: Oxera analysis, based on Deloitte (2016), 'Annex 4 - GD17 Efficiency Advice: Relative efficiency of Northern Ireland Gas Distribution Networks. Final report', 11 March, tables 1-4.

While it should be noted that the pooled OLS method that Deloitte has employed cannot differentiate scale economies from other effects (see discussion of the issue in section 2.7), Figure 2.1 illustrates that the scale economies estimated in the models have a critical impact on FE's estimated catch-up efficiency. Figure 2.1 also shows that most of the models result in an efficiency gap for FE of between 5% and 10%, while two models (model 10, GB GDNs only sample, and model 5, GB GDNs plus PNGL sample) estimate a gap of 0–5%. Only one out of 11 models (model 5, GB GDNs only sample) results in a gap as large as 30%—this can be deemed as an outlier, as the results from this model do not seem credible (see section 2.3).

Deloitte has also suggested capturing varying scale effects by including a quadratic term of the CSV in the model (specifically, the logarithm of the quadratic term of CSV, i.e. $\ln(\text{CSV}^2)$ ²⁹ in model 9). However, from the model results Deloitte notes that the quadratic term is statistically insignificant, concluding that the relationship between OPEX and CSV is sufficiently described by a log-linear function. However, Deloitte does not mention that in model 9, both $\ln(\text{CSV})$ and $\ln(\text{CSV}^2)$ are insignificant, which may indicate that this is not an appropriate method to identify scale differentials in this case. Clearly, there are a number of ways to test and allow for scale economies in the models, which is a key issue for FE. As such, Deloitte's testing of the issue is limited.

2.1.3 The Utility Regulator's model selection exacerbates the problem

Despite being a clear outlier, the Utility Regulator has chosen model 5, GB GDNs only sample, as one of its two preferred models on the basis of 'economic

²⁹ While the quadratic term of $\ln(\text{CSV})$ is $\ln(\text{CSV})^2$, in Tables 1, 2, and 3 of its report, Deloitte has indicated that it has modelled $\ln(\text{CSV}^2)$ in model 9. It will be useful if Deloitte can clarify the specification of this model.

theory and statistical performance'.³⁰ It is not clear from the Utility Regulator's explanation, what economic theory reasoning has led to the choice of models 3 and 5.

In addition, while Deloitte has noted that model 3 (across different sample sets) has the best model fit in terms of the Bayesian Information Criterion (BIC),³¹ this criterion appears extremely limited compared with diagnostic testing undertaken by other regulators, including Ofgem.³² Clearly, the specific model that Deloitte has developed and the Utility Regulator uses for price-setting purposes must have adequate statistical properties such that the cost frontier and resultant efficiency are estimated with sufficient precision.³³ Deloitte has noted that diagnostic tests would be considered in the final determination, but has not explained what testing it is intending to undertake and has been considered in developing the current models and identifying preferred ones from these.

We noted above that the use of the samples excluding FE exacerbates the problem of economies of scale. The reliability of the results from the preferred models is further questionable given that the full sample models (i.e. including FE) result in smaller standard errors or tighter confidence intervals around the estimated coefficient of Ln(CSV), as illustrated in Table 2.1.

Table 2.1 Confidence intervals for the estimated coefficients of Ln(CSV)

Sample dataset	Model 2	Model 3	Model 5	Model 10
GB plus NI GDNs	0.66–0.83	0.66–0.83	0.57–0.86	0.63–0.84
GB GDNs plus PNGL	0.6–0.93	0.61–0.92	0.5–0.96	0.57–0.95
GB GDNs only	0.48–1.06	0.47–1.06	0.4–1.17	0.38–1.05

Source: Oxera analysis, based on Deloitte (2016), 'Annex 4 - GD17 Efficiency Advice: Relative efficiency of Northern Ireland Gas Distribution Networks. Final report', 11 March, tables 1-3.

The lower accuracy is clear in the GB GDNs only sample, which has the widest range of economies of scale estimates. This, therefore, results in the widest range of efficiency estimates (e.g. 0–29% for FE in 2014).

The full sample models produce lower Ln(CSV) coefficients (and, hence, account for higher economies of scale) in the range of 0.71–0.74. We note that, at RIIO-GD1, Ofgem estimated economies of scale for OPEX at 0.72,³⁴ which appears more aligned with the estimates produced based on Deloitte's full sample models.³⁵

While the efficiency estimates based on the full sample models are not reported, two models with similar coefficients (model 10, GB GDNs only sample, and

³⁰ Utility Regulator (2016), 'Annex 5 Indicative Findings from Top-Down Benchmarking GD17', Draft Determination, 15 March, p. 15.

³¹ Deloitte has noted that BIC measures model fit and is considered more powerful than other model fit statistics such as R-square, adjusted R-square and Akaike Information Criterion (AIC)

³² See, for example, the battery of tests considered by Ofgem in RIIO-GD1 apart from examining whether the model results are consistent with economic and operational expectations here. See Table A4.3 Ofgem (2012), 'RIIO-GD1: Final Proposals - Supporting document - Cost efficiency', 17 December, <https://www.ofgem.gov.uk/ofgem-publications/48157/4-riiogd1fpcostefficiency.pdf>.

³³ We note that statistical analysis should be balanced against assumptions underlying the statistical tests and other model selection statistical criteria, especially when considered on a small data sample. However, in all cases, results from the models must be consistent from an economic and operational perspective.

³⁴ Ofgem (2012), 'RIIO-GD1: Final Proposals - Supporting document - Cost efficiency', 17 December, Table A4.3.

³⁵ We note however that pooled OLS, which is the estimation approach used by Deloitte for models 3 and 5, cannot separate scale economies from other effects. See section 2.5, where this is discussed further.

model 5, GB GDNs plus PNGL sample) **estimate the efficiency gap for FE in the range of 0–5%.**³⁶

In conclusion, in contrast with the Utility Regulator's stated reasoning, based on the evidence available, we note that models 3 and 5 in the GB GDNs only or GB GDNs and PNGL samples:

- do not appear to be the best-performing models statistically; and, more importantly,
- are not aligned with economic and operational expectations.

2.1.4 How the bias with respect to scale economies can be mitigated

From the reasons discussed above, it is clear that FE's efficiency should be estimated at the level of economies of scale most appropriate to FE's scale size. To enable this, we discuss some options below.

- First, it should be tested whether FE is sufficiently comparable to the GB GDNs to have the same cost function estimated using the GB GDNs (with and without PNGL) and thus have its efficiency estimated against this. If it is deemed comparable enough, then the cost function based on the full sample set is appropriate. If it is not comparable, then it is not possible to estimate FE's efficiency as there are no comparable comparators from which it is possible to estimate its cost function. One could potentially estimate FE's efficiency under the scenario of similar network maturity as the GB GDNs.
- Second, other estimation approaches and model specifications should be examined in order to better account for FE's economies of scale, including examining appropriate definitions of scale given FE's lower network maturity (see section 2.2), linear econometric models, additional scale drivers to add flexibility, data envelopment analysis (DEA), etc. For example, if one were to use DEA to estimate FE's efficiency, the cost frontier might take into account more appropriately the varying levels of economies of scale. FE would, most likely, be estimated to be on the frontier. (Although, this would partly be due to a lack of comparators at its scale size).

2.2 Network penetration

The issue of economies of scale is exacerbated by FE being a relatively new network with a naturally lower level of customer penetration at this stage in its development; its customer and volume levels are significantly lower for its network size than GB GDNs that are at a more mature stage in their history. As such, FE's current number of customers and volumes materially underestimates its scale of operation, yet, as noted above, Deloitte places 75% weight on customer numbers and volume in its CSV measure.³⁷

FE has indicated that its current network penetration rate (around 33%) is significantly lower than that of mature GB GDNs (around 82%)³⁸ and PNGL (around 58%).³⁹ This results in some differences in FE's cost structure compared

³⁶ It should be noted that even if one were to consider the full dataset, given that the dataset is dominated by the larger GB GDNs, the scale economies will still be biased towards the GB GDNs if other structural differences between FE and the GB GDNs are not appropriately controlled for.

³⁷ Customers have a weight of 50% compared with 25% each for length and volume in Deloitte's CSV.

³⁸ Department of Energy & Climate Change (2013), 'National Energy Efficiency Data-Framework (NEED)', August.

³⁹ Phoenix Distribution Holdings Limited (2014), 'Unaudited condensed consolidated interim financial statements Half year ended 30 June 2014', October. The Phoenix report describes the figure of 58% as the number of potential customers connected. We take this to mean the number of connected customers as a share of properties passed.

with those of the GB GDNs, including higher fixed costs incurred by FE at the stage of building of its network. Therefore, FE will not be able to achieve the level of economies of scale relative to customer numbers enjoyed by the GB GDNs. In particular, FE's customer per length measure is about four to five times *smaller* than that of the average GB GDN.

Deloitte acknowledges the point by noting that:

FE has a significantly different profile to any of the other GDNs in terms of the ratios between network length, customer numbers and volume of gas supplies. This results in significant challenges in assessing the extent to which FE costs are inefficient or are due to the characteristics of the business. [emphasis added]⁴⁰

As noted by Deloitte, FE's network utilisation/penetration differs considerably from that of GB GDNs. As the models assume a single set of weights for all comparators, this poses a challenge as the estimated efficiency will fail to reflect FE's specific business characteristics—especially as FE's data is excluded from the sample dataset and the cost function estimated from the GB GDNs is imposed on it. In fact, it appears that the modelling results are sensitive to CSV composition. Deloitte examines this issue:

Finally, the sensitivity of relative efficiency was examined across a number of alternative weights which placed more weight on network length and volume. These models suggest that **the efficiency estimates are sensitive to the choice of weights, which was expected given the difference in the network utilisation between PNGL, FE and their GB counterparts** [emphasis added]⁴¹

2.2.1 The choice of weighting in the CSV could further bias FE's estimated efficiency

Despite these concerns, the Utility Regulator has decided to put more weight on customer numbers, based on its own judgement and without providing any reasons for its decision. Deloitte states:

The UR is of the **view** that customer numbers is a more important cost driver than network length and volume, and should have greater weight as reflected in the baseline weights. This is also consistent with precedence and other independent analysis [emphasis added]⁴²

The Utility Regulator's view does not appear to have been substantiated by any engineering evidence.

Moreover, it is **inconsistent** with the most recent regulatory precedent. While Ofgem placed 50% weight on customer numbers in its GDPCR1 models for OPEX, this is now out of date and Ofgem has subsequently developed, refined and improved its data collection, modelling and understanding of the drivers of the gas distribution costs. Indeed, at RIIO-GD1 Ofgem departed from this methodology. Specifically, **at RIIO-GD1, Ofgem only included customer numbers in the CSV for emergency OPEX model and for IT and telecom** (see Table 2.2).

⁴⁰ Deloitte (2016), 'Annex 4 - GD17 Efficiency Advice: Relative efficiency of Northern Ireland Gas Distribution Networks. Final report', 11 March, p. 4.

⁴¹ Deloitte (2016), 'Annex 4 - GD17 Efficiency Advice: Relative efficiency of Northern Ireland Gas Distribution Networks. Final report', 11 March, p. 20.

⁴² Deloitte (2016), 'Annex 4 - GD17 Efficiency Advice: Relative efficiency of Northern Ireland Gas Distribution Networks. Final report', 11 March, p. 20.

Table 2.2 Ofgem's OPEX models in RIIO-GD1

Expenditure modelled	Explanatory variables
Bottom-up regressions	
Emergency	CSV of external condition reports (20%) and number of customers (80%)
Repairs	Total mains and service condition external reports
Maintenance	Maintenance MEAV
Work management	MEAV
Business support	The bottom-up activity drivers are: • revenue (for finance, audit, and regulation; property management; CEO and group management) • end-users (for IT and telecom) • employees (for HR and non-operational training) • spend (for procurement)
Top-down regression	
OPEX	CSV of MEAV, emergency, repair and maintenance cost drivers

Note: MEAV, modern equivalent asset value. Work management excludes environmental costs and connections are modelled in net rather than gross values.

Source: Ofgem (2011), 'GDN Cost Workshop –presentation of preliminary 2010/11 GDN results', 27 September; Ofgem (2012), 'RIIO-GD1: Final Proposals - Supporting document - Cost efficiency', 17 December, <https://www.ofgem.gov.uk/ofgem-publications/48157/4-riiogd1fpcostefficiency.pdf>.

Given that, on average, emergency costs are likely to account for only a small proportion of OPEX (roughly 15% of the direct and indirect OPEX activities⁴³) and that customer numbers were given 80% weight in the CSV for emergency costs, this results in **customer numbers being a driver for only around 12–15% of the total OPEX**. Similarly, gas volumes were not considered by Ofgem to be a driver of any direct activities.⁴⁴

Deloitte goes on to say:

Ofgem in RIIO-GD1 used workload measures related to specific services (replex, connections, emergency services) which are mainly a function of number of customers.⁴⁵

However, we note that REPEX and connections are not part of OPEX and thus are not relevant to the current study. Only the emergency activities, and the impact of customers on this activity, as per Ofgem's RIIO-GD1 modelling, were discussed above.

Even then, we note that the emergency service is resourced on the basis of a requirement to meet a one-hour response standard. As such, the operational decision on how many resources are required is based on the level of expected reports in any year by area, and the ability of staff to reach the report within one hour. Thus, for a sparse region, this implies that relatively more resources are

⁴³ Based on ratio of emergency costs as a proportion of total direct and indirect OPEX for the GB GDNs from Ofgem's RIIO-GD1 determinations. See Appendix 8 (on RIIO-GD1 cost allowances and workload assumptions) of Ofgem (2012), 'RIIO-GD1 Final Proposals – Supporting document – Cost efficiency', December.

⁴⁴ Although other drivers such as revenues could be correlated with it.

⁴⁵ Deloitte (2016), 'Annex 4 - GD17 Efficiency Advice: Relative efficiency of Northern Ireland Gas Distribution Networks. Final report', 11 March, p. 20.

required. It also implies that the expected relationship between resources or costs and the number of actual reports is such that there is a relatively high fixed cost. This is because travel patterns, and resources within those travel patterns, are determined in order to meet the standards, while, as the number of reports increases, the resource requirement increases at a less than proportionate rate.

Furthermore, the Utility Regulator citing National Grid's 2007 response to Ofgem on the appropriateness of customer numbers is not sufficient justification for its decision, from either an academic-literature or an engineering point of view, given that Ofgem itself has refined its specification in the most recent price review. While it should be noted that there are no perfect cost drivers, Ofgem has employed MEAV as a key cost driver for various cost activities in the most recent price review (moving away from traditional scale drivers such as customer numbers and network length), as MEAV recognises size, asset base and complexity of a network relatively better.⁴⁶

2.2.2 How the bias with respect to network penetration can be mitigated

The sub-section above indicates that it could be argued that customers should have no more than about a 15% weight in CSV, and gas volumes minimal weight. Thus, one approach to mitigating FE's currently low penetration rate, due to it operating a relatively new network, would be to amend the weights used in the CSV. However, we note that this, in itself, would not be sufficient to reflect accurately FE's relative efficiency, since by comparing its cost performance to the GB GDNs, other structural differences would need to be evened out as well.⁴⁷

Alternatively, length of network, MEAV, or Ofgem's CSV of MEAV, emergency, repair and maintenance cost drivers could be used as the main cost driver. Also, modelling at the activity levels (e.g. maintenance) could be pursued, which would allow the capturing of specific scale, activity and structural cost drivers appropriate for that activity.

2.3 Age of network

The Utility Regulator's model 5 includes a proxy of network age—percentage of iron mains. The Utility Regulator notes that this variable has been included to capture higher workload levels that the GB GDNs may incur as a result of their less modern network. It also sights one regulatory precedent in Australia, where the variable has been considered as a proxy for average network age. However, we consider that the percentage of iron mains variable, in the way it has been considered in the models, has a number of limitations, as follows.

- The Utility Regulator has noted elsewhere⁴⁸ that the use of a CSV that captures scale and 'size' of the company could be somewhat 'fairer' to the NI GDNs than cost drivers based on a company's workload and activity levels. However, the percentage of iron mains could also capture the workload activities of the GB GDNs, which may not be appropriate for FE, which, as a relatively new and expanding network, is currently not in steady state.
- Deloitte states that:

⁴⁶ Ofgem (2011), 'Decision on strategy for the next gas distribution price control - RIIO-GD1 Tools for cost assessment', 31 March, <https://www.ofgem.gov.uk/ofgem-publications/48260/gd1decisioncosts.pdf>.

⁴⁷ For example, one can statistically test whether the cost function estimated from the GB GDNs with or without PNGL is appropriate for FE or if its fixed and variable cost elements are materially different.

⁴⁸ Utility Regulator (2016), 'Annex 5 Indicative Findings from Top-Down Benchmarking GD17', Draft Determination, 15 March, p. 13.

When percentage of iron mains is included in the model, the magnitude and significance of time effects diminishes [from -2.5% pa to -1.7% pa] potentially reflecting collinearity issues, i.e. time effects may primarily capture the change in the GB network composition, and/or degrees of freedom and statistical power issues rather than time-specific effects or efficiency improvements across the sector.⁴⁹

This indicates that the iron mains coefficient is not sufficiently reliable to be included in the model. Indeed, this is evident in that the coefficient, with a confidence interval of -1.91 to +3.01, is not significantly different from 0.

- Related to the previous point, it is not clear whether Deloitte/the Utility Regulator has considered if the estimated coefficient of 0.55, with a confidence interval of between -1.91 and +3.01, is aligned with economic and engineering expectations. In particular, iron mains would have an impact on only maintenance and repair activities, which make up at most 25% of the GB GDNs' direct and indirect OPEX.⁵⁰ Deloitte's model 5 implies that a 10% increase in iron mains results in a 5.5% increase in OPEX. This is high, given that a considerably lower proportion of the cost base is affected by iron mains. This will bias FE's estimated inefficiency upwards.
- In addition, Table 4 in Deloitte's report shows that under model 5, GB GDNs only sample, FE's efficiency score is a clear outlier. The inclusion of iron mains adds 20% to FE's estimated inefficiency (comparing model 3 results with model 5). This appears to be driven by both the inclusion of iron mains and an economies of scale estimate of 0.787. The inefficiency under this model is extreme to the extent that it is not credible for a relatively new network to be considered so inefficient.⁵¹

2.4 Model specification, estimation and testing

2.4.1 Model specification

Our review has identified a number of issues with the specifications of the Utility Regulator's preferred models, some of which have been discussed in earlier sections. While it has not been possible to test the impact of these without access to data, we note that the issues set out below will need to be robustly addressed in order for the analysis to reflect FE's relative efficiency.

- The appropriateness of the cost function estimated for FE using the GB GDNs, both with and without PNGL (section 2.1).
- The effect on FE's results of testing the appropriateness of other weightings to construct the CSV and the use of other cost drivers, e.g. MEAV (section 2.2).
- Using other proxies of network age and/or exploring alternative ways of distinguishing GB GDNs and their NI counterparts on this issue (section 2.3).
- Appropriate ways of capturing differences in the wage levels in the models (further discussed in section 3.2.1).

⁴⁹ Deloitte (2016), 'Annex 4 - GD17 Efficiency Advice: Relative efficiency of Northern Ireland Gas Distribution Networks. Final report', 11 March, p. 14.

⁵⁰ Derived as a ratio of repair and maintenance costs as a proportion of total direct and indirect OPEX for the GB GDNs from Ofgem's RIIO-GD1 determinations. See Appendix 8 (on RIIO-GD1 cost allowances and workload assumptions) of Ofgem (2012), 'RIIO-GD1 Final Proposals – Supporting document – Cost efficiency', December.

⁵¹ Deloitte (2016), 'Annex 4 - GD17 Efficiency Advice: Relative efficiency of Northern Ireland Gas Distribution Networks. Final report', 11 March, table 4.

- The inclusion of a time trend in the specification, which imposes strong assumptions on the profile of cost trend (either upward- or downward-sloping) especially over a short sample period. In contrast, year-on-year fluctuations in OPEX can be better accommodated in a more flexible way, using yearly dummies. Deloitte's specification of having a time trend may be particularly problematic, depending on how the Utility Regulator has used the models to forecast efficient OPEX (we have not received any information from the Utility Regulator on this point). The Utility Regulator will need to clarify this area.

2.4.2 Estimation approach

Deloitte's core modelling approaches have a number of limitations, including the following.

- Pooled OLS can produce biased and inconsistent parameter estimates if inefficiency changes over time, if there are company-specific effects, and if inefficiency depends on some exogenous variables (observed or unobserved), such that the inefficiency estimated from the model cannot be relied on. All these contexts seem likely, and therefore it seems likely that the results from the approach cannot be deemed conclusive and need to be validated against operational and engineering expectations. The pooled OLS approach, which is the modelling approach considered in models 3 and 5, is also likely to conflate the parameter estimates—for example, the scale, time trend, and iron mains estimates could be conflated with inefficiency, technological change and other effects.
- While Deloitte has considered a panel data model by using a random effects estimator to account for company-specific effects, it is not clear how it has treated the company-specific effects estimated from the model (it appears that it has considered only the coefficients of the explanatory variables included in the model to arrive at FE's catch-up efficiency and thereby efficient level of OPEX).
- Deloitte's use of random effects and time-invariant stochastic frontier analysis (SFA) also impose certain strong assumptions on the distribution of GDNs' inefficiency over time. In particular, its methodology assumes that the cost-efficiency frontier and the inefficient GDNs 'move in unison' over time. Deloitte could consider more flexible SFA models that control for company-specific effects and that capture time-varying inefficiency. While we acknowledge that the data sample is limited, it is important to understand the limitations of the estimation approaches considered so that the results from can be inferred appropriately.

2.4.3 Diagnostic testing of models

The general objective of cost modelling is to develop a specific model that uses a limited number of variables that explain the data and, at the same time, is consistent with economic and operational expectations. The specific model must have adequate statistical and economic properties such that the cost frontier and resultant efficiency are estimated with sufficient precision as to be useful in effective price setting.

The statistical properties of Deloitte's models, and the results of diagnostic testing applied to them, are not discussed in its report. Deloitte has noted that diagnostic tests would be considered in the final determination, but has not explained what testing it would seek to undertake.

We note that the tests we have considered relating to the economic issues discussed above indicate that there are issues with extrapolating the cost function primarily based on GB GDNs to predict FE's costs.

Nevertheless, given the small sample period, and significant differences in the operating profiles of FE and its comparators, we consider that the economic issues discussed above are far more important than the statistical diagnostics in this case.

2.5 Translating model results into OPEX targets

The wide range of results from the Utility Regulator's preferred models indicates that there is a high degree of uncertainty around FE's estimated gap to the efficient level of OPEX. This might be for a number of reasons, including those discussed above. Consequently, the gap might be capturing aspects other than inefficiency, and, to that extent, either the upper-quartile efficiency benchmark based on the current models is likely to be inappropriate for FE or the current models are not appropriate for estimating FE's efficiency (indeed, as noted above, the preferred models result in questionable outcomes for it). In contrast, Ofgem used an upper-quartile efficiency challenge for a group of relatively homogeneous GDNs, where issues such as those discussed in earlier sections did not exist.

In addition, there could be a degree of double counting in the Utility Regulator's efficiency gap estimates, depending on how the Utility Regulator has used the models to forecast efficient OPEX up to 2022. This is because the time trend variable included in models 3 and 5 captures the rate of the reduction in costs, on average, across GDNs and over time (controlling for the CSV and proportion of iron mains), which may be capturing elements of catch-up improvements, frontier shift and other effects. As the Utility Regulator treats frontier-shift and input price effects separately, there could be an element of double counting. It would be helpful if the Utility Regulator provided information on how it has projected FE's costs.

3 Consideration of other FE special factors

So far we have discussed FE's key characteristics that call into question the comparisons undertaken by Deloitte with respect to GB GDNs. When comparing FE's performance with that of other NI and GB GDNs, it is important to take into account other special factors that also affect the way in which FE operates compared with its counterparts.

Potentially, this could further explain the cost differentials, which, without necessary adjustments, would make the cost base non-comparable. Therefore, this section comments on the cost adjustments already made by the Utility Regulator where further clarification is required, and considers FE special factors that should be accounted for in the Utility Regulator's analysis. We first discuss the issue of sparsity (section 3.1), before moving on to review the special factors currently considered by the Utility Regulator (section 3.2).

3.1 Network sparsity

As explained in our previous report,⁵² the level of sparsity in a GDN's operational area affects its costs, and Ofgem has recognised this point by allowing for company-specific sparsity allowances—i.e. the more sparsely populated the area is, the more expensive it is for a company to maintain its network on a per-customer basis and resource staff to attend to emergency calls.⁵³ Given how sparse FE's area is,⁵⁴ it has a long network for a given customer base and it incurs higher unit costs to maintain its network and resource staff to attend to emergency calls. Its low penetration exacerbates this issue (if FE's penetration were at the same level as the average GB GDN—i.e. about 90 customers per length of network—its customer numbers could need to increase about four-fold to 90,000. Even then, while it would be comparable to the average GB GDN, it would still be more sparsely populated than sparse GB GDNs such as NGN and WWU).

Table 3.1 illustrates this point by comparing the number of customers per km of pipeline, as one of the possible sparsity measures. FE's operational area is sparser than the most sparse GB GDN (NGN).

Table 3.1 Sparsity measured as number of customers per km of pipeline

GDN	Number of customers (millions)	Pipeline length (in 1,000km)	Customers per km of pipeline
Firmus energy	0.025	1	25.0
NGN	2.7	35	77.1
WWU	2.5	32	78.1
SGN	5.9	71	83.1
NGGD (composed of four networks)	10.9	126	86.5
Average GB GDN	3	33	91

⁵² Oxera (2015), 'Benchmarking and efficiency assessment', June.

⁵³ Ofgem (2012), 'RIIO-GD1: Final Proposals – Supporting document – Cost efficiency', 17 December, Table A4.2.

⁵⁴ FE's licence area, which covers around 5,200km² with a network length of 902km, is quite sparsely populated, with an average population density of around 49.7 households per km². In contrast, the licence area of PNL covers around 570km², with a network length of about 3,000km. See Oxera (2015), 'Benchmarking and efficiency assessment', June.

Source: Data accessed from Ofgem's website here: <https://www.ofgem.gov.uk/network-regulation-riio-model/network-performance-under-riio/riio-gd1-performance-data>; Firmus energy (2015), 'Business Plan Template Commentary GD17', September, p. 17.

This feature has not been considered or accounted for in any of Deloitte's or the Utility Regulator's preferred models. Only model 7 controls for sparsity by including the $\ln(\text{network length}/\text{customer numbers})$ variable, but it has not been presented in the context of accounting for network sparsity or ultimately used by the Utility Regulator in predicting FE's efficiency cost level.

In RIIO-GD1, Ofgem allowed a sparsity factor adjustment of £1.3m for Scotland GDN and £2.6m for WWU (in 2009/10 prices), based on sparsity determined using population served over district level area measure. While Ofgem's sparsity measure is a valid measure for quantifying a special factor for FE, FE's network penetration should also be accounted for in the measure of sparsity when determining an adjustment for sparsity, unless penetration is accounted for elsewhere in the modelling.

3.2 Review of special factors adjusted for by the Utility Regulator

As described in Appendix A1, the Utility Regulator has excluded a number of items from the GDNs' cost base in order to facilitate the comparison. While most of these adjustments appear reasonable (for example, the Utility Regulator has adjusted for metering costs, as noted in our previous report⁵⁵), the basis of the following adjustments is less clear.

Xoserve costs

As highlighted in our earlier report,⁵⁶ in Great Britain, a separate entity (Xoserve) manages interactions with the gas transporters and supports the systems on a scale that is efficient for 21 million GB customers. There is no Xoserve equivalent in Northern Ireland, and **FE manages its own interactions**. Indeed, the Utility Regulator has acknowledged this point:

NI GDNs do not face xoserve costs. However, the UR is mindful that some of the activities undertaken by xoserve may be performed internally by the local GDNs.⁵⁷

Activities resultant from these interactions include:⁵⁸

- AQ determination;
- management of the new supplier accession process;
- facilitation of customer switching (including the management for the supply meter point register);
- management of data enquiries regarding supply meter points;
- invoicing.

As FE undertakes activities provided by Xoserve in house, the reasoning and basis for excluding 75% of Xoserve-specific cost from the GB GDNs' cost base by the Utility Regulator is unclear.

⁵⁵ Oxera (2015), 'Benchmarking and efficiency assessment', June.

⁵⁶ Oxera (2015), 'Benchmarking and efficiency assessment', June.

⁵⁷ Utility Regulator (2016), 'Annex 5 Indicative Findings from Top-Down Benchmarking GD17', Draft Determination, 15 March, p. 10.

⁵⁸ Based on information provided by FE.

Furthermore, the Utility Regulator and Deloitte do not take into account the huge economies of scale present on these costs—in particular, FE has 25,000 supply points, while Xoserve represents 21 million. In order to account for this more extreme difference in scale, one option would be to exclude both Xoserve costs and FE's costs for undertaking these activities. Alternatively, one appropriate adjustment could be to **reduce FE's costs** rather than those of GB GDNs.

3.2.1 Labour cost adjustment

In addition to a number of exclusions from the cost base, the Utility Regulator has adjusted OPEX for differences in regional labour costs. In doing so, the regulator has used a single assumption across all GDNs that around 52% of OPEX is related to labour costs. While this figure appears to be based on the notional structure assumed by Ofgem for the GB GDNs, given FE's different operational circumstances and stage of network development, the figure appears to be high—in particular, FE's business plan indicates that the share of labour costs in its OPEX will decrease from 46% to 37% over the period.⁵⁹ **The higher percentage assumed by the Utility Regulator means that FE's costs will be uprated by a larger amount than they should be based on FE's actual cost structure.** This would clearly disadvantage FE in the Utility Regulator's benchmarking analysis. Thus, this adjustment warrants further examination.

⁵⁹ Firmus energy (2015), 'Business Plan Template Commentary GD17', September.

4 Conclusions

In this submission, we have reviewed Deloitte's analysis based on the available published material, as well as the Utility Regulator's report discussing indicative findings from Deloitte's analysis.⁶⁰ While we have not been given access to any data by the Utility Regulator, we have identified a number of significant concerns regarding the robustness of Deloitte's analysis in assessing FE's efficiency.

Also, given no access to data, rather than quantify FE's special factors incremental to Deloitte's models, we have set out the directional impact of some of the key differences between FE and its GB and NI counterparts that are either not considered in Deloitte's models or considered inappropriately.

We conclude that, based on the evidence available to us, it is not possible to determine that FE is not on the efficiency frontier. The results that the Utility Regulator focuses on for FE appear to be driven by the assumptions used in the modelling and the particular models selected, and are not likely to reflect FE's actual efficiency. To that end, it would be inappropriate to determine allowed revenues for FE based on the analysis presented in the draft determination.

⁶⁰ Our review is limited to the draft determination and Annexes 4 and 5: Deloitte (2016), 'Annex 4 - GD17 Efficiency Advice: Relative efficiency of Northern Ireland Gas Distribution Networks. Final report', 11 March; Utility Regulator (2016), 'Annex 5 Indicative Findings from Top-Down Benchmarking GD17', Draft Determination, 15 March.

A1 Summary of the Utility Regulator's top-down OPEX benchmarking

This Appendix provides an overview of Deloitte's analysis and summarises how the Utility Regulator has used the results of this to determine the level of efficient OPEX for FE.

A1.1 Data

Deloitte's analysis used the data collected from the eight GB GDNs and two NI GDNs,⁶¹ covering the period from 2009 to 2015. However, because of data availability and quality concerns, only the last three and five years of data were considered for FE and PNGL, respectively.

Deloitte then used econometric modelling to explain differences in costs, primarily through a composite scale driver (a geometric weighted combination of customers, network length and gas volume transported). In total, Deloitte presented results for 11 alternative models based on a combination of different model specifications and estimation approaches, and using three sample datasets (i.e. with GB GDNs only; GB GDNs plus PNGL; GB plus NI GDNs). Deloitte then selected four preferred models and presented efficiency results from these over two sample datasets (i.e. with GB GDNs only; GB GDNs plus PNGL). From this subset of models, the Utility Regulator has selected two preferred models to establish its view of FE's efficiency. From the preferred models, the efficiency gaps of the NI GDNs are assessed relative to the third-most-efficient company. In addition, the Utility Regulator has presented the results of the historical and forecast cost profiles (actuals and model projections) of the NI GDNs from the two models but using only one of the sample datasets (i.e. using GB data only).⁶²

The Utility Regulator has made some pre-modelling adjustments to the GDNs' data, excluding several cost items, as shown in the table below.

⁶¹ The third NI GDN, SGN NI, was excluded from the top-down analysis as it does not have operational data as yet. See para 2.5 Utility Regulator (2016), 'Annex 5 Indicative Findings from Top-Down Benchmarking GD17', Draft Determination, 15 March.

⁶² See Figure 3 of Deloitte (2016), 'Annex 4 - GD17 Efficiency Advice: Relative efficiency of Northern Ireland Gas Distribution Networks. Final report', 11 March; Utility Regulator (2016), 'Annex 5 Indicative Findings from Top-Down Benchmarking GD17', Draft Determination, 15 March.

Table A1.1 Cost items excluded by the Utility Regulator

Cost item	Basis for exclusion	Affected GDNs
Metering costs	This activity is not included in the GB GDNs' licences	NI GDNs*
Independent networks	Applicable to Scotland only	GB GDNs*
75% of Xoserve costs	Represents the costs incurred by GB GDNs to manage their interactions with shippers and suppliers	GB GDNs*
Training and apprentices	There are differences in the approach to these activities in Northern Ireland and Great Britain	All GDNs*
Advertising and market development	These activities are not regulated in Great Britain, as opposed to Northern Ireland	All GDNs*
Gasholder decommissioning	The Utility Regulator considered that this would facilitate the comparison across the whole dataset, but no further detail is given	GB GDNs
Environmental costs		GB GDNs
Land remediation		GB GDNs
Smart metering		GB GDNs
Streetworks		GB GDNs
Physical Security Upgrade Programme (PSUP)		GB GDNs
Other uncertainties		GB GDNs
Non-controllable costs (licence fees, network rates, etc.)		GB GDNs

Note: * Not specified in the Utility Regulator's documents, but reflects Oxera's understanding.

Source: Utility Regulator (2016), 'Annex 5 Indicative Findings from Top-Down Benchmarking GD17', Draft Determination, 15 March.

In addition, the Utility Regulator has adjusted the GDNs' costs for differences in regional labour costs by comparing median wages of the private sector in the UK during the 2009–15 period. Based on this data, the Utility Regulator has concluded that wages in Northern Ireland have been around 18% lower than the UK average.⁶³

A1.2 Model specification

The key variables Deloitte considered include:

- customer numbers;
- volumes of gas distributed;
- network length;
- time trend/year dummies;
- percentage of iron mains.

Deloitte estimated efficient costs using:

⁶³ This translated into an adjustment of -9.2% to costs of NI GDNs, assuming that around 52% of OPEX relate to labour costs.

- models with combinations of the explanatory variables set out above;
- different sample sets (i.e. GB GDNs only, GB GDNs plus PNGL, or GB plus NI GDNs);
- different estimation approaches (see section A1.3).

The Utility Regulator currently regards two of Deloitte's models (models 3 and 5) as its preferred models and has used results from these to calculate the level of efficiency for FE (and PNGL). Both models use a composite scale variable (CSV) as the key explanatory variable. The CSV was created by calculating a weighted average of the cost drivers used in the models. Specifically, fixed weights of 50%, 25% and 25% were assigned to the CSV components (customer numbers, volumes of gas and network length). While the Utility Regulator gives a clear preference to customer numbers as the key cost driver for NI GDNs, Deloitte highlighted that FE's network utilisation (and the two NI GDNs in general) is considerably different from that of GB GDNs.

The difference between the two models is that model 5 includes an additional explanatory variable in percentage of iron mains. The Utility Regulator supports inclusion of this factor by arguing that older networks have a higher proportion of iron mains and, hence, higher maintenance costs due to more frequent leakages. It states that PNGL and FE have modern polyethylene mains and are therefore at a cost advantage since they should have lower workload levels relative to GB GDNs.

Both models assume a log-linear relationship between costs and scale variable (in this case proxied by CSV). The two models also use a time trend variable to capture industry-wide cost shocks over the period of analysis.

A1.3 Estimation approach

Deloitte performed the analysis based on the following econometric approaches:

- nine pooled OLS (POLS) models, using various explanatory variables and approaches to address yearly and scale effects;
- in two of the 11 models, random effects and time-invariant stochastic frontier analysis (SFA) models are considered, with CSV, percentage of iron mains and time trend as explanatory factors;
- the models were applied to three alternative samples: where all GB and NI GDNs are included; where FE is not included; where neither FE nor PNGL is included.

A1.4 Translating model results into OPEX targets

The Utility Regulator's analysis indicated that applying the results of the two models to PNGL's and FE's business plan data demonstrates that efficiency opportunities are between 12% (model 3) and 30% (model 5) over GD17.

These results reflect the Utility Regulator's preference for setting the efficient benchmark at the upper-quartile level as it used the third-most-efficient company from the sample as the benchmark. In addition, as the third-most-efficient company is chosen to represent the upper-quartile level, it appears that the estimation sample included nine companies (i.e. GB GDNs plus PNGL) in the analysis under the Utility Regulator's preferred models, although the regulator has presented results from using the GB sample only in presenting forecast modelled OPEX up to 2022.



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The Utility Regulator's proposed licence modification regarding the rate of return on under-recoveries

Note prepared for firmus energy

31 May 2016

Draft for comment: strictly confidential

1 Background—GD17 proposals

The Utility Regulator's principle objective in carrying out its gas functions is to promote the maintenance and development of the gas network in Northern Ireland. Firmus energy's (FE's) licence outlines two main mechanisms which are intended to promote the development of the gas network by deferring revenue recovery (and thus lowering prices) in the early years of network development.

- **The profile adjustment.** FE's price cap has historically been set below the level implied by the application of the buildings block approach in order to keep prices broadly level across a 30-year charging period. This has the effect of deferring the recovery of some allowed revenues into future price control periods.
- **Revenue under-recoveries.** FE is permitted to increase its tariffs in order to be remunerated for any accumulated under-recovery of revenues that has resulted from pricing below the regulatory price cap. Between 2006 and 2013 the company accrued under-recoveries, which the Utility Regulator states will amount to approximately £13m at the start of GD17.¹

These mechanisms have allowed FE to charge distribution tariffs below the allowed levels while the network has been developed, in order to encourage customers to switch to gas.

The licence specifies that FE should receive a rate of return on accumulated under-recoveries, which to date has been set equal to the allowed rate of return based on the regulator's assessment of the weighted average cost of capital

¹ Utility Regulator (2016), 'Price Control for Northern Ireland's Gas Distribution Networks GD17 Draft Determination', 16 March, p. 251, para. 11.71.

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(WACC). Condition 4.10.4 of FE's licence states that the return on under-recoveries should be equal to the licence WACC until 2034.² As part of the GD17 draft determination, the Utility Regulator has proposed changing the rate of return on 'Z' under-recoveries to the London Interbank Offered Rate (LIBOR) plus 2%. Consequently, the rate of return on under-recoveries is expected to be below the allowed GD17 WACC.

In its submission to the Utility Regulator on this issue, FE argued that:³

- in its view, the risk associated with under-recoveries (and thus the rate of return) should not be considered to be materially different from that associated with other invested capital;
- the proposed change would effectively renege on prior regulatory commitments to investors that under-recoveries would be rolled forward in line with the allowed WACC;
- this proposal would add complexity to the regulatory regime and would be inconsistent with previous decisions made by the Utility Regulator in relation to differentiated rates of return for different components of Phoenix Natural Gas' total regulatory value (TRV);
- FE would have to unwind accumulated under-recoveries at an accelerated rate, which would create significant short-term price volatility.

This note considers the Utility Regulator's proposed changes, and the potential ramifications in more detail.

2 Under-recoveries as invested capital

2.1 The principle of differentiated returns

The Utility Regulator's proposals effectively treat accumulated under-recoveries as lower risk than the rest of FE's invested capital. In its letter to the Utility Regulator, FE stated that £1 of deferred revenues should be treated in the same way as every other £1 of capital employed by the business given that revenue deferrals represent an upfront investment by the company, which carry the same financing requirement as investments in physical assets. Indeed, FE's historical under-recoveries have been financed with debt and equity capital (including foregone dividends during the initial high-growth period).

We note that the Utility Regulator has historically remunerated both under-recoveries and the profile adjustment at the same rate of return as the remainder of the TRV, and continues to apply this approach to the latter. As discussed above, the accumulated under-recoveries and the profile adjustment are both mechanisms by which the recovery of revenues has been deferred in order to generate additional volume that, in turn, is expected to allow it to realise economies of scale and levy lower prices to the benefit of consumers in the future.

We therefore consider that there is merit in setting the rate of return on under-recoveries to be commensurate with the average risk–return profile of the business, such that FE continues to earn a rate of return on under-recoveries that is equal to the allowed WACC.

² Firmus Energy (Distribution) Limited, Licence for the Conveyance of Gas in Northern Ireland, condition 4.10.4.

³ Firmus energy, Letter from Niall Martindale to Alan Craig, dated 19 February 2016.

2.2 The choice of return

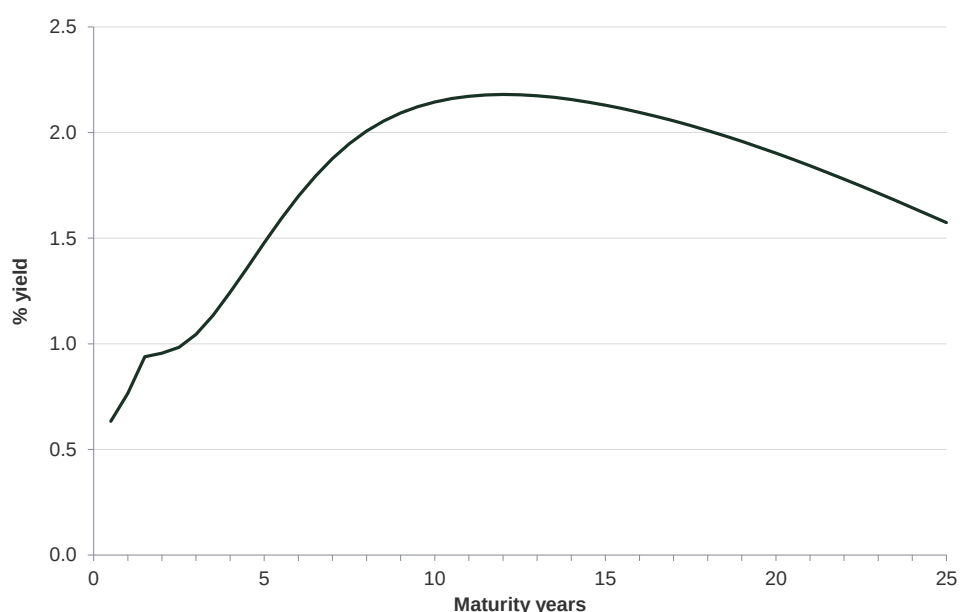
If a differentiated rate of return is to be used, it is not clear from the draft determination how the Utility Regulator has arrived at a rate of LIBOR+2%. It does not appear that any analysis has been undertaken, or evidence put forward, to suggest that this provides a risk-reflective return on under-recoveries.

We further note that the Utility Regulator has not specified the LIBOR rate that it refers to. The LIBOR is available in numerous maturities (from an overnight rate to 12 months) and the choice of maturity could have a material impact on the outturn rate of return. For example, the current 12-month LIBOR is approximately 0.5% greater than the overnight rate.⁴

Regardless of which maturity of LIBOR is chosen, current (and historical) market evidence suggests that a rate of return of LIBOR+2% will be significantly below the proposed real WACC of 4.3%, and could be close to zero real return over the GD17 period.

Figure 2.1 shows the (nominal) instantaneous LIBOR interest rates forward curve based on data produced by the Bank of England. The figure shows that, based on current market expectations, the LIBOR rate will be in the region of 1–2% over GD17.

Figure 2.1 GBP LIBOR instantaneous forward curve



Source: Oxera, based on Bank of England data.

Adding the proposed 2% premium, this would imply a **nominal** rate of return of 3–4% on under-recoveries. Analysis of inflation linked swaps suggests an inflation rate of 2.68% for the period from 2017 to mid-2019, while the latest medium-term macroeconomic forecasts published by HM Treasury predict that RPI inflation will be between 3.0% and 3.3% from 2017 to 2020.⁵

⁴ Based on Bank of England data on 'UK instantaneous commercial bank liability forward curve'.

⁵ These figures are based on the average of forecasts produced by independent bodies. HM Treasury (2016), 'Forecasts for the UK economy: a comparison of independent forecasts', February, p. 16.

This would suggest a rate of return of 1% or below (and potentially even negative) on under-recoveries in **real** terms, compared with a proposed **real** WACC of 4.3% to be applied to the TRV. Moreover, a rate of return of LIBOR+2% is likely to be below FE's actual nominal cost of debt over the GD17 period and could be below the Utility Regulator's real risk-free rate assumption of 1.25%, implying that there is (less than) zero risk attached to the financing and recovery of revenue under-recoveries.

In summary:

- the under-recovery of revenues by FE has played an important role in the development of the gas network in Northern Ireland;
- the associated deferral of revenues has been financed with a combination of equity and debt capital on the same basis as other elements of the TRV;
- it is inappropriate for the Utility Regulator to seek to apply a differential return to the balance of existing under-recovered revenues;
- the Utility Regulator's proposed rate of return has not been justified by analysis; is close to zero (or potentially even negative) in real terms; and is below the real risk free rate; and
- as such, FE is effectively being penalised for having historically under-recovered revenues, even though these revenue under-recoveries were allowed under the regulatory framework (and licence) and consistent with the development of the Northern Ireland gas network.

3 Regulatory commitment

Regulatory commitment and consistency are considered to be important tenets of incentive regulation. Once regulators have established the regulatory framework and the incentive mechanisms up front, they typically look to avoid ex post interventions that can be perceived to claw back any benefits accrued by the company from responding to these incentive mechanisms (see Box 3.1 below). The justification for this approach has been that retrospective adjustments have the potential to increase the perceived level of risk in a regulated industry and therefore potentially affect investors' willingness to invest in the future, which can be detrimental to users.

Box 3.1 Regulatory precedent for avoiding retrospective adjustments

There are numerous examples of regulators and competition authorities explicitly making decisions on the basis that to do otherwise could jeopardise a perceived regulatory commitment and thus undermine investors' confidence in the regulatory regime.

BIS's principles of economic regulation

The UK government outlined a set of 'Principles for Economic Regulation' in April 2011. These principles include predictability.

The framework for economic regulation should provide a stable and objective environment enabling all those affected to anticipate the context for future decisions and to make long term investment decisions with confidence.

The framework of economic regulation should not unreasonably unravel past decisions, and should allow efficient and necessary investments to receive a reasonable return, subject to the normal risks inherent in markets.⁶

Ofgem

As part of its RPI-X@20 review of network regulation, Ofgem stated its view that it should not take retrospective action regarding regulatory decisions made prior to the review, while also ensuring that future incentive mechanisms were forward-looking and would not allow for ex post interventions:

we will commit to not making retrospective adjustments to revenue in the event that costs turned out to be different to what was assumed in the price control itself, save through the application of the efficiency incentive rate. We will only consider using such ex post adjustments if outputs were not delivered or if we had a concern that a company had manifestly wasted money.⁷

Ofcom

In 2005, Ofcom changed the way it valued BT's copper access network assets, by replacing current-cost accounting measures with a regulatory asset value. It was noted that establishing access charges on the basis of current cost accounting values had allowed BT to more than recover its costs for the network assets that were deployed prior to August 1997 (when current-cost accounting had replaced historical-cost accounting). However, Ofcom chose not to claw back any of the associated over-recovery from BT, on the basis that this could set a precedent of ex post appropriation that could, in turn, affect investment incentives:

Ofcom remains of the view that it would be inappropriate to propose to 'clawback' any over-recovery that may have crystallised in the period up to the implementation of the results of this review. Ofcom believes that any attempt to do so would be retrospective, in contravention of Ofcom's regulatory principles, and could be perceived as opportunistic. Further, such retrospective action would set a precedent leading to investment uncertainty signalling the potential for ex-post expropriation of returns legitimately earned under the agreed regulatory framework.⁸

Office of Fair Trading (OFT)

As part of its 2010 review of UK infrastructure, the OFT (now part of the Competition and Markets Authority) found that the M6 toll benefited from pricing power but that revisiting the contract terms ex post had the potential to chill future investment. Consequently, the OFT chose not to intervene.

We found that the operator does have pricing power, in spite of clear alternative routes for drivers. This is likely to reflect inelastic demand of drivers with a high willingness to pay to avoid congestion on the alternative routes. The original contract for the M6 toll explicitly allowed the operator to raise charges, and we consider that ex post intervention would risk chilling future investment.⁹

Source: Oxera; Correia da Silva, L. (2013), 'The Future of Economic Regulation in Scotland: an outsider's view', David Hume Institute Research Paper No. 13/2013, May.

As noted by the Utility Regulator, Condition 4.10.4 of FE's licence establishes that there should be zero differential between the rate of return on accumulated

⁶ Department for Business, Innovation and Skills (2011), 'Principles for Economic Regulation', April, p. 5.

⁷ Ofgem (2010), 'Handbook for Implementing the RIIO Model', 4 October, p. 83.

⁸ Ofcom (2005), 'Valuing copper access – Final statement', 18 August, p. 17, para. 4.6.

⁹ Office of Fair Trading (2010), 'Infrastructure Ownership and Control Stock-take—Final report: Main findings', December, p. 8, para. 1.19.

under-recoveries and the licence WACC until 2034. The licence effectively provided a commitment to investors that any under-recoveries accrued by the company would earn a rate of return equal to the allowed WACC.

In its 2012 price control re-determination for PNGL, the UK Competition Commission (now part of the Competition and Markets Authority) emphasised the particular importance of regulatory consistency in the context of the Northern Ireland gas sector.

Regulatory stability is particularly important in the context of natural gas in Northern Ireland, given that this is not a fully mature industry, and that future investment in network expansion is expected and desired. If it is perceived that adjustments might be made after, for example, efficiencies have been achieved which then impact on investors' prior expectations, there is the possibility, if not more, that such incentives will be blunted in future.¹⁰

That is not to say that regulators should be fully constrained by their past decisions, but there are a number of best-practice principles that are usually applied to govern significant changes to the regulatory framework. In considering whether a licence modification is warranted, the Utility Regulator could apply the following three-part test.¹¹

- **Are the proposed changes retrospective or prospective?** Based on discussions between the Utility Regulator and FE, we understand that while the current value of under-recoveries will not be retrospectively reduced (i.e. a rate of return that is equal to the WACC will continue to apply to the end of GD14), the under-recoveries that have already been accumulated—as well as any future under-recoveries—will earn a return of LIBOR+2% from 2017 onwards. This is a retrospective adjustment in the sense that the rate of return that will be realised on the existing stock of under-recoveries will differ from what FE understood to apply at the time the under-recoveries were incurred (since, at the time the under-recoveries were incurred, investors had a reasonable expectation that they would earn a rate of return equal to the allowed WACC until 2034).¹² The Utility Regulator's proposals would not be retrospective if the LIBOR+2% were only to apply to new under-recoveries incurred by pricing below the cap from the start of GD17 onwards, while the existing stock of under-recoveries were to continue to earn a return equal to the WACC. Indeed, we understand that this would be commensurate with the approach taken with regard to PNGL's historical under-recoveries.
- **Has FE been given sufficient notice of the changes?** The Utility Regulator gave notice to FE in GD14 that it would assess the rate of return on under-recoveries at GD17. Following this notice, FE is expected to have reduced the stock of under-recoveries by around £9m in 2014 prices by the start of GD17 (based on the Utility Regulator's estimates). However, there are a number of reasons why this may not have provided sufficient notice for FE to alter its behaviour in such a way as to prevent it from being adversely affected by the changes (i.e. by fully unwinding the existing stock of under-recoveries).

¹⁰ Competition Commission (2012), 'Phoenix Natural Gas Limited price determination: A reference under Article 15 of the Gas (Northern Ireland) Order 1996', 28 November, p. 9-26, para. 9.114.

¹¹ We note that the Competition Commission's 2012 assessment of the Utility Regulator's proposed licence modifications for PNGL was based on similar criteria.

¹² We note that the Competition Commission took a similar view in assessing whether the Utility Regulator's proposal to remove historical outperformance from PNGL's TRV was purely prospective or would, in effect, be retrospective in nature. See Competition Commission (2012), 'Phoenix Natural Gas Limited price determination: A reference under Article 15 of the Gas (Northern Ireland) Order 1996', 28 November, p. 9-26, para. 5.67.

- This notice post-dated the time at which the majority of under-recoveries were accumulated (between 2006 and 2013).
- The netback arrangement between FE's distribution and supply businesses for customers using fewer than 25,000 therms per annum restricted the extent to which FE could unwind the under-recoveries until its expiration at the end of March 2015.
- The notice did not give sufficient time for FE to unwind the under-recoveries without creating a considerable price shock. Unwinding the under-recoveries fully over the three-year GD17 period would have implied increasing FE's allowed revenues by around 25–35% per year. This would necessarily have resulted in a significant tariff increase, which could have further jeopardised FE's connections performance and damaged customer relationships. This would have acted contrary to the Utility Regulator's objective of developing the gas network.

Moreover, The Utility Regulator did not specify in GD14 whether the review of the rate of return on under-recoveries would cover future under-recoveries only or whether the rate of return would also be modified for the existing stock of under-recoveries.

Finally, we note that the regulator's rejection of a 'dual pot' TRV approach for PNGL might have signalled to investors that the Utility Regulator was unlikely to adopt a differentiated return approach for FE.

- **Are the proposed changes in the public interest?** As acknowledged by the Utility Regulator, allowing FE to earn the full rate of return on under-recoveries may provide incentives to grow volumes (by pricing below the cap). The Utility Regulator references PCR02 volume outperformance of around 29.5m therms as evidence of this incentive. To the extent that volume outperformance in earlier price control periods is passed on in the form of lower prices in later periods, it is not clear that the existing approach to under-recoveries has worked against the public interest. Indeed, in this respect, under-recoveries are no different to the profile adjustment. An outcome of higher growth via pricing below the cap is also consistent with the Utility Regulator's principle objective in carrying out its gas functions of promoting the maintenance and development of the gas network in Northern Ireland. Moreover, we note that:
 - the Utility Regulator's own analysis shows that the adjusted interest cover metric (PMICR) is forecast to be on the boundary of the acceptable threshold throughout the control period and may even breach the minimum threshold for a BBB credit rating (1.40) in 2018.¹³ A return of LIBOR+2% is below FE's embedded cost of debt (as allowed for in the GD17 draft determination), implying a deterioration in the covenant position given the debt financing element. Consequently, the proposed approach to under-recoveries is likely to push the PMICR below the 1.40 threshold in GD17. Any changes that could further hamper the company's ability to finance its functions are unlikely to be in the public interest;

¹³ Table 183 of the draft determination shows the PMICR to be 1.40 in 2018, but the financeability spreadsheet provided by the Utility Regulator suggests that this number should be 1.39.

- the potential costs of chilling future investment are likely to significantly outweigh any costs to customers from FE continuing to earn the full WACC on historical under-recoveries.¹⁴

Based on this three-part test, there are robust reasons why imposing the proposed licence modification in its current form would be inconsistent with good regulatory practice and could be detrimental to the development of the gas network, and thus the interests of (current and prospective) users, in the long term.

4 Complexity

FE argued that the proposed approach would create additional complexity in an already complex regulatory model. In the draft determination, the Utility Regulator rejected this argument on the basis that the licence already contains the provisions for such an adjustment to be made to the rate of return on under-recoveries.

In addition to the fact that the licence currently prohibits such a rate of return adjustment prior to 2034, we consider that there could be unnecessary additional complexity if the accumulated under-recoveries are included in the TRV at a different rate of return to other assets. We would therefore agree with the regulator's proposal that under-recoveries should continue to be treated separately from the TRV if they are to earn a lower rate of return than the profile adjustment and depreciated asset value (DAV).

5 Unwinding

The Utility Regulator states in the GD17 draft determination that 'we think the history of the FE build up of 'Z' under-recoveries demonstrates the risk of perverse incentives.'¹⁵ This implies that the Utility Regulator does not consider that FE has sufficient incentives to unwind the accumulated under-recoveries under the existing framework. This does not appear to be borne out by the GD14 experience—the Utility Regulator's estimates suggest that FE will have unwound around 40% of under-recoveries between the peak in 2013 and the start of GD17. Moreover, FE's business plan does not contemplate the accumulation of any further under-recoveries in GD17.

FE noted in its letter to the Utility Regulator that it would be forced to accelerate the unwinding of under-recoveries if the rate of return applying to these under-recoveries were to be reduced. It argued that this would create a short-term increase in prices, followed by a 'cliff-edge' reduction once the under-recoveries had been fully recovered. In response, the Utility Regulator stated in its draft determination that:

We also disagree with FE's point about the need to unwind 'Z' under recoveries at a faster rate. We estimate that they will be eliminated by 2020 based on current tariffs therefore, the horizon for recovery currently is fairly short.¹⁶

¹⁴ Indeed, the Competition Commission's stated in its 2012 re-determination of PNGL's price control that the public interest includes striking a balance between protecting current customers and ensuring ongoing investment, and that 'creating a perception of regulatory instability... could impede future gas network development which could otherwise create substantial future benefits for future customers, and could increase costs for current and future gas consumers.' Competition Commission (2012), 'Phoenix Natural Gas Limited price determination: A reference under Article 15 of the Gas (Northern Ireland) Order 1996', p. 10, para 37.

¹⁵ Utility Regulator (2016), 'Price Control for Northern Ireland's Gas Distribution Networks GD17 Draft Determination', 16 March, p. 251, para. 11.74.

¹⁶ Utility Regulator (2016), 'Price Control for Northern Ireland's Gas Distribution Networks GD17 Draft Determination', 16 March, p. 252, para. 11.78.

The draft determination does not set out the Utility Regulator's forecasts for how the under-recoveries will be unwound by 2020. However, calculations provided by the Utility Regulator show the cumulative under-recovery to be £13.3m as of 2016. (We note that the Utility Regulator has stated that interest now accounts for 80% of the accumulated under-recoveries. This calculation is sensitive to assumptions made around the order in which historical under-recoveries and the return on these under-recoveries are paid off as the stock of under-recoveries is unwound. The Utility Regulator has assumed that no interest has been rolled off to date, which is one extreme of a range of potential assumptions. It would be more reasonable to assume that as under-recoveries are unwound, these would repay some proportion of both the principal amount of the under-recovery and the interest accrued.)

Assuming the stock of under-recoveries were to be rolled off evenly over the next five years, and given proposed allowed revenues of £15m in 2017, the revenue cap would need to be increased by around 15–20%. This suggests that the impact on prices, relative to the counterfactual in which the under-recoveries were unwound over the licence period, would indeed be significant in the short term. This also suggests that there would be a 'cliff-edge' reduction at the end of the period, when the revenue requirement including the under-recoveries roll-off would decline by around 15–20%. Such volatility in prices is unlikely to be in the best interests of consumers.

GD17 PRICE CONTROL

Response to Utility Regulator's Draft Determination on Price Control for GD17

firmus energy Distribution Limited

Report No.: PP158076-01, Rev. 1.0

Date: 27 May 2016

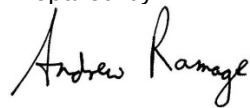


Project name: GD17 Price Control DNV GL Oil & Gas
Report title: Response to Utility Regulator's Draft Technical Advisory
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Project No.: 1-101UFDNW
Organisation unit: Pipelines
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Document No.: 1

Task and objective:

To provide an independent empirical assessment of firmus energy's network maintenance costs and form a view on whether or not they are reasonable. Also to provide a brief discussion of considerations around benchmarking and firm-specific factors in network regulation, as well as an assessment of the principles applied by UR in its assessment of firmus energy's operational expenses.

Prepared by:

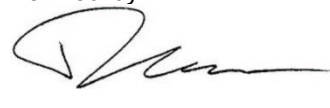


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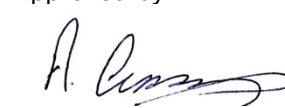
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Rev. No.	Date	Reason for Issue	Prepared by	Verified by	Approved by
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EXECUTIVE SUMMARY

Background

In the draft determination for GD17, the Utility Regulator (UR) explains that in determining the allowance for variable network maintenance costs for firmus energy, it has “applied a reduction of 25% to the variable costs estimated by firmus energy”¹ based on a benchmarking exercise involving a comparison with Phoenix Natural Gas Ltd (PNGL).

Firmus energy considers that UR has not given due regard to factors specific to firmus energy's network, that may justify differences in maintenance costs with other networks, including PNGL's, and which firmus energy has raised in its detailed submission. For this reason firmus energy is seeking the opportunity to explain to UR once more why its proposed costs are justified, as well as to understand what consideration UR has given firmus energy's specific circumstances, and more generally, to better understand the reasons behind UR's draft determination.

Firmus energy has asked DNV GL to lend support to its response and has requested that we carry out an independent empirical assessment of firmus energy's network maintenance costs and form a view on whether or not they are reasonable. In addition, firmus energy has asked us to provide a brief discussion of considerations around benchmarking and firm-specific factors in network regulation, as well as an assessment of the principles applied by UR in its assessment of firmus energy's operational expenses.

Our findings on each of these tasks are as follows:

Assessment of firmus energy's network maintenance costs

We consider that the maintenance philosophy adopted by firmus energy for its network assets is consistent with industry best practice and will enable continuous improvement as the data available for maintenance performance increases.

We have assessed firmus energy's proposed maintenance activities, frequencies and associated costs and we consider them to be appropriate for the type and age of its network assets and to be consistent with industry good practice.

From our review of the Utility Regulator's Draft Determination of network maintenance costs, we conclude that the Draft Determination does not adequately account for the dispersed nature of firmus energy's networks and the comparatively low asset concentrations within the networks.

We have also carried out impact assessments of longer travel time and comparatively low asset concentration and conclude that:

- the maintenance team travel time associated with firmus energy's dispersed networks will be 15% higher than for PNGL's urban network.
- the comparatively low asset concentration within firmus energy's networks result in unit maintenance costs that are 24% higher than PNGL's, inclusive of travel time effects.

UR's benchmarking of firmus energy's maintenance costs

Both UR's decision to benchmark firmus energy's variable maintenance costs, as well as its execution of this benchmarking exercise, raises questions as to whether the price control review process is robust and will lead to an efficient outcome.

¹ Utility Regulator, Price Control for Northern Ireland's Gas Distribution Networks GD17 - Draft Determination, 16 March 2016, para 6.125.



The decision itself overturns (without explanation) UR's own consultant's view that firmus energy's maintenance costs are reasonable, allegedly to gauge the scope for synergies, but UR does not explain what synergies or economies of scale might be realised, nor how a benchmarking exercise might generate insight into such synergies. Furthermore, UR's draft determination to cut firmus energy's variable maintenance costs by 25%, is not linked in any way to the potential for firmus energy to reduce its costs through synergies.

UR's execution of the benchmarking exercise is even more puzzling, since it does not give any consideration to "special factors" raised by firmus energy in its submission, even though UR has stated it interprets its duties to include having "due regard to all relevant factors,"² and even though consideration of special factors is a key element in the further development of the top-down benchmarking exercise and a next step in the price control review process.

By failing to consider firmus energy's "special factors," UR's proposed 25% cut is arbitrary and subjective, since it cannot be justified on the basis of objective principles or analysis. Such arbitrariness and subjectivity may be perceived as regulatory risk in the eyes of investors (not just for firmus energy but for all regulated networks in NI), since they reduce the certainty that investors will recover their costs (including a reasonable return on investment). As it stands, firmus energy is facing a cut in variable maintenance costs of £1.27m (25%) over the 6-year GD17 period, which has neither been explained nor justified by UR. Hence, unless UR provides greater transparency on its assessment, as well as justification for its decision based on objective principles, it is failing to deliver on its duty to *"ensure the gas distribution network operators can continue to finance the activities which are the subject of obligations placed on them."*³

UR's adherence to regulatory principles and price control duties

Our review of UR's assessment of firmus energy's maintenance costs identifies various points on which UR fails to apply regulatory principles, or carry out what UR considers its duties, particularly by failing to be transparent, consistent, and taking account of all relevant factors. We have also noted also that in various parts of its assessment, UR fails to remain objective in its assessment, a principle curiously absent in UR's values, yet vital to any regulator's mandate to provide investors a reasonable prospect of cost recovery.

We consider that UR's failure to apply regulatory principles and duties, particularly to be transparent, objective, and to take into account all factors relevant to firmus energy's network, jeopardises the ability of the price control review process to deliver an efficient outcome for both firmus energy, and its customers.

Our recommendation to firmus energy

Based on the findings of our assessment, we recommend that firmus energy seek to re-engage with UR with regard to the proposed allowance for network maintenance costs for GD17. The objectives of future discussions with UR should be as follows:

- 1) to seek further explanation on all areas of UR's assessment in which it has failed to be transparent, to gain a complete understanding of the basis for UR's draft determination;
- 2) to obtain UR's justification for those parts of its assessment where it has been inconsistent (with other areas of the price control or with the assessment for other GDNs) as well as where UR has based its assessment on subjective and/or unsubstantiated assertions; and

² Utility Regulator, Draft Determination, 16 March 2016, para 1.8.

³ Utility Regulator, Draft Determination, 16 March 2016, para 1.8.

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- 3) to ensure that UR has taken into account all (special) factors relevant to firmus energy's network, understand how UR has taken such factors into account, and resubmit any relevant information that UR has not taken into account (including our independent assessment of firmus energy's maintenance costs include in this document).

Successful collaboration on the points above should allow firmus energy and UR to come to a joint understanding of whether or not firmus energy's proposed maintenance costs are reasonable, and therefore determine the appropriate allowance for GD17.

1 INTRODUCTION

Firmus energy has asked DNV GL to lend support to its response and has requested that we carry out an independent empirical assessment of firmus energy's network maintenance costs and form a view on whether or not they are reasonable. In addition, firmus energy has asked us to provide a brief discussion of considerations around benchmarking and firm-specific factors in network regulation, as well as an assessment of the principles applied by UR in its assessment of firmus energy's operational expenses.

DNV GL is well qualified to provide support to firmus energy in this matter. Experts in our Oil and Gas (O&G) and Energy Advisory (EA) practices have decades of experience of independent assessment and verification of gas and electricity network costs, as well as assessments for regulators in the context of price control reviews. Most recently, our experts in O&G have advised Ofgem on the RIIO T1 price control review and advised CER for the BGN price control review, including independent assessment of investment levels proposed for new transmission assets and asset health. Our EA experts have in recent years advised Ofgem on the RIIO ED1 and GD1 price control reviews, including independent assessment of distribution companies' business plans, undertaken expert assessment of Strategic Wider Works (SWW) proposals in electricity transmission, and designed a framework for regulation of Competitively Appointed Transmission Owners (CATOs).

1.1 Background

On 16 March 2016 the Northern Ireland Utility Regulator ("UR") published its draft determination⁴ ("the draft determination") for GD 17, the price control for gas distribution network operators in Northern Ireland, including firmus energy, for 2017-2022. In the draft determination, UR sets out the proposed allowed revenues for the gas distributors at a level that is meant to allow recovery of efficiently incurred operational and capital expenses, as well as a reasonable return on investment.

UR writes in the draft determination that in determining the allowance for firmus energy's variable network maintenance costs, it has "applied a reduction of 25% to the variable costs estimated by firmus energy"⁵ based on a benchmarking exercise involving a comparison with Phoenix Natural Gas Ltd (PNGL). In the absence of a more detailed explanation or justification, firmus energy considers that UR has not given due regard to factors specific to firmus energy's network, that may justify differences in maintenance costs with other networks, including PNGL's, and which firmus energy has raised in its detailed submission.

Firmus energy is of the opinion that it should be allowed to recover the variable maintenance costs it has proposed in its submission, and that the reduction as adopted by UR in the draft determination will undermine its ability to operate an efficient, safe, and reliable network. For this reason firmus energy is seeking the opportunity to explain to UR once more why its proposed costs are justified, as well as to understand what consideration UR has given firmus energy's specific circumstances, and more generally, to better understand the reasons behind UR's draft determination.

1.2 UR assessment of firmus energy maintenance costs

UR's assessment of the firmus energy's maintenance cost proposals involves a bottom-up assessment by UR's consultants, RUNE Associates, as well as a bespoke benchmarking exercise, carried out by UR itself, in which firmus energy's variable maintenance costs are compared with those of PNGL. UR has not made available the full assessment by RUNE Associates with the draft determination, but instead reports RUNE's conclusions:

⁴ Utility Regulator, Price Control for Northern Ireland's Gas Distribution Networks GD17 - Draft Determination, 16 March 2016.

⁵ Utility Regulator, Draft Determination, 16 March 2016, para 6.125.

“They concluded that the activities identified were reasonable and that the bottom up estimates of the unit costs was broadly reasonable with some exceptions.”⁶

In addition, RUNE Associates highlighted in their assessment that there may be scope for synergies and efficiencies to reduce maintenance costs, which, according to UR, echoes statements made by firmus energy in its original submission. To determine the potential cost-savings through synergies in firmus energy’s maintenance costs, UR has carried out a benchmarking exercise in which it compares firmus energy’s variable maintenance costs⁷ with those of PNGL. UR reports the outcome of this exercise, and its decision for the draft determination, as follows:

“the estimated variable network maintenance costs determined for PNGL in GD17 were 27% lower than the benchmark calculated using unit rates derived from the firmus energy bottom up cost estimate for GD14 [sic]⁸. For our draft determination, we applied a reduction of 25% to the variable costs estimated by firmus energy to reflect this benchmarking exercise and added back the fixed and one-off costs proposed by the company.”⁹

Table 34 of the draft determination shows the impact of UR’s decision on firmus energy’s proposed variable maintenance costs, amounting to a reduction in firmus energy’s variable maintenance costs of £1.27m over the GD17 price control period. Table 1-1 below reproduces the results of UR’s draft assessment.

	2017	2018	2019	2020	2021	2022	Total
FE Business Plan total costs (£k)	869	925	898	1,013	1,176	1,441	6,322
FE Business Plan variable costs (£k)	624	686	692	806	1,003	1,269	5,080
<i>Draft determination - variable costs (£k)</i>	468	515	519	605	752	952	3,810
<i>One off costs (£k)</i>	79	73	41	41	7	7	248
<i>Fixed Costs (£k)</i>	165	165	165	165	165	165	992
Draft determination allowance (£k)	713	753	725	811	925	1,124	5,050

Table 1-1: Firmus energy maintenance costs allowance as per draft determination Table 34.

1.3 Document structure

The remainder of this note is organised as follows:

- Section 2 provides our independent assessment of firmus energy’s proposed variable maintenance costs for GD17;
 - detailed tables and figures underlying this assessment are provided in appendices a (travel time) and b (cost effect of asset concentration);
- Section 3 discusses issues with firm-specific factors in benchmarking for utility regulation; and
- Section 4 provides our assessment of the approach used by UR in its assessment of firmus energy’s maintenance costs.

⁶ Utility Regulator, Draft Determination, 16 March 2016, para 6.119.

⁷ Including, as per para 6.123, annually recurring costs (e.g. of routine meter maintenance and consumers requested works) as well as 10 year cycle costs covering periodic inspection and maintenance activities and meter calibration.

⁸ Presumably, UR means to refer to GD17 as opposed to GD14 here.

⁹ Utility Regulator, Draft Determination, 16 March 2016, para 6.125.

2 ASSESSMENT OF FIRMUS ENERGY O&M COSTS

2.1 General

This assessment concerns DNV GL's assessment of the firmus energy network maintenance costs as identified within the firmus energy GD17 Supplementary Paper¹⁰ which is contained within the firmus energy GD17 Business Plan Template Commentary.¹¹ One part of our assessment considers the Utility Regulator's Draft Determination.

2.2 Network Assets

Firmus energy operates eight separate gas distribution networks which are dispersed across Northern Ireland as shown in Figure 1.

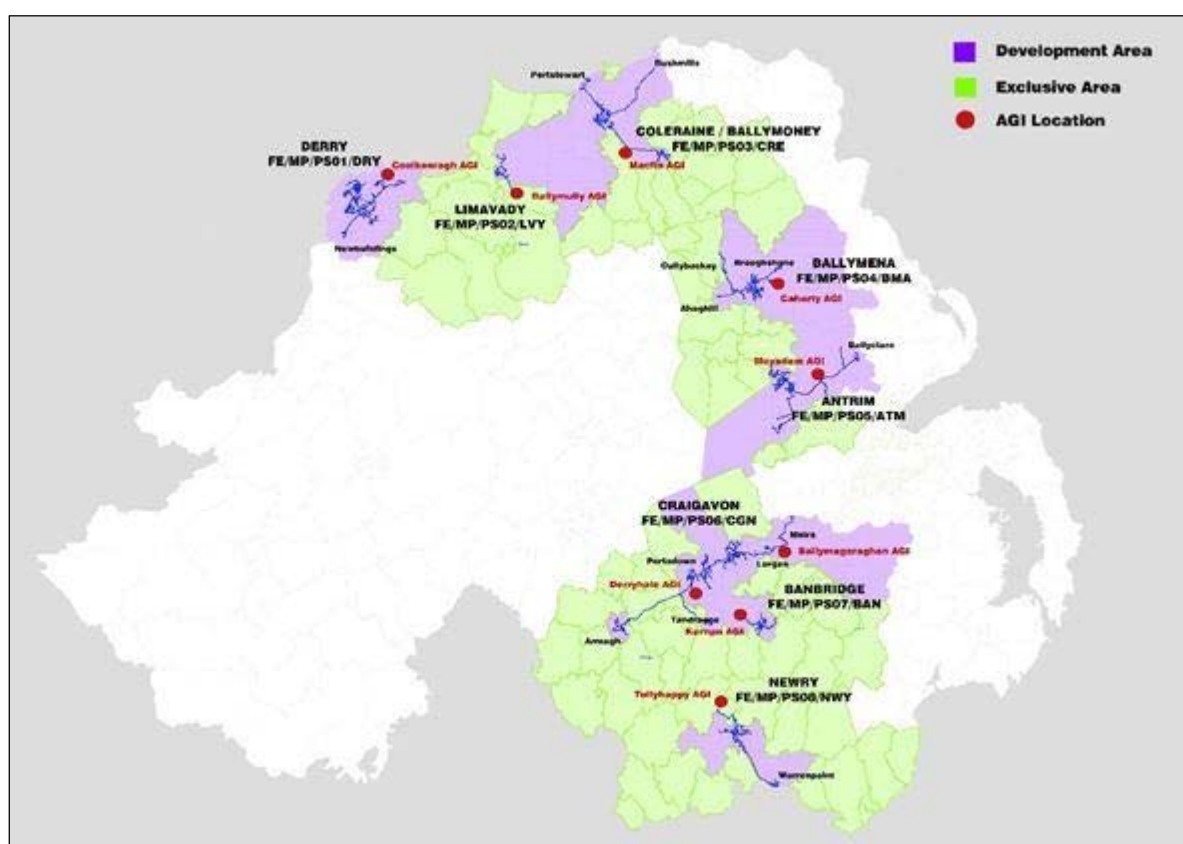


Figure 1 – Firmus energy distribution networks

The distribution networks are supplied via nine offtakes from the BGE (NI) North-West and South-North transmission pipelines which operate at 75bar. At each offtake the gas pressure is reduced to 4bar before entry to the firmus energy network.

At end of 2015 the distribution networks had c.1000km of mains and supplied c.28,000 domestic and industrial & commercial customers. New mains are projected to be laid at a rate of c.120km per annum and the number of new connections is projected to grow at an average rate of c.4,000 per annum throughout 2016-2022.

¹⁰ Firmus Energy Ltd, GD17 Supplementary Paper: Proposed Maintenance Activities, September 2015.

¹¹ Firmus Energy Ltd, GD17 Business Plan Template Commentary", September 201.



The categories of network assets operated by firmus energy, which are typical for gas distribution networks, are identified within the firmus energy Asset Management System, and comprise:

- Distribution mains
- Service pipes
- In-line valves
- Service isolation valves
- District pressure reduction modules
- Customer meters
- Steel bridge crossings
- Steel riser systems
- Telemetry systems

2.3 Maintenance Philosophy

Firmus energy has considered the use of reliability centred maintenance (RCM) and has determined that it would not be cost-effective for the firmus energy distribution networks.

The philosophy adopted by firmus energy uses calendar based maintenance at regular intervals for pressure reduction modules (DPRMs & CPRMs). Mostly breakdown maintenance is applied for domestic and small industrial & commercial meter installations although some regular inspections are conducted.

Due to the dispersed nature of firmus energy's networks and to minimise the required travelling time for its maintenance teams, firmus energy plans for all assets in a common location to be visited concurrently and for all the required activities for each asset to be completed simultaneously e.g. both the required maintenance activities and mandatory examinations are completed in a single visit.

Firmus energy intends to implement regular maintenance reviews in order to assure the continued effectiveness and efficiency of its maintenance activities. The reviews of maintenance performance will enable the identification of beneficial changes to maintenance practice. The reviews will rely upon the time-dependent growth of asset performance data in order to identify trends for particular types of asset along with asset synergies to enable performance improvements across the entire asset pool.

DNV GL considers that the maintenance philosophy adopted by firmus energy is consistent with industry best practice. In our opinion the use of time-based maintenance is correct for firmus energy's networks and firmus energy's methodology for the deployment of maintenance teams will maximise the efficient use of firmus energy resources. Also, we consider that firmus energy's regular maintenance reviews including condition trend analysis will enable improvements to maintenance practice to be quickly identified and implemented across all of firmus energy's networks.

2.4 Maintenance Activities

Each category of asset has its particular requirements for functional checking, inspection and maintenance. The particular requirements are specified within firmus energy's asset management system and they cover statutory examinations required by the Pressure Systems Safety Regulations¹² and industry recommendations as contained within various IGEM standards.

¹² HSE, Safety of pressure systems, Pressure Systems Safety Regulations 2000, Approved code of practice, L122, 2000.

Within each asset the particular maintenance requirements are identified on a parts basis. The requirements take full account of manufacturer recommendations and/or part condition, as appropriate.

DNV GL considers that the maintenance activities identified within firmus energy's asset management system are robust and are consistent with industry best practice.

2.5 Network Maintenance Costs

The network maintenance costs submitted by firmus energy are summarized in Table 1 and the trend is illustrated in Figure 2.

Network Maintenance Costs									
Year	2015	2016	2017	2018	2019	2020	2021	2022	Total
Maintenance Activities	548	657	949	1,007	958	1,074	1,240	1,510	7,942

Table 1 – Maintenance cost summary from firmus energy Business Plan template (Dec 2014 prices) commentary

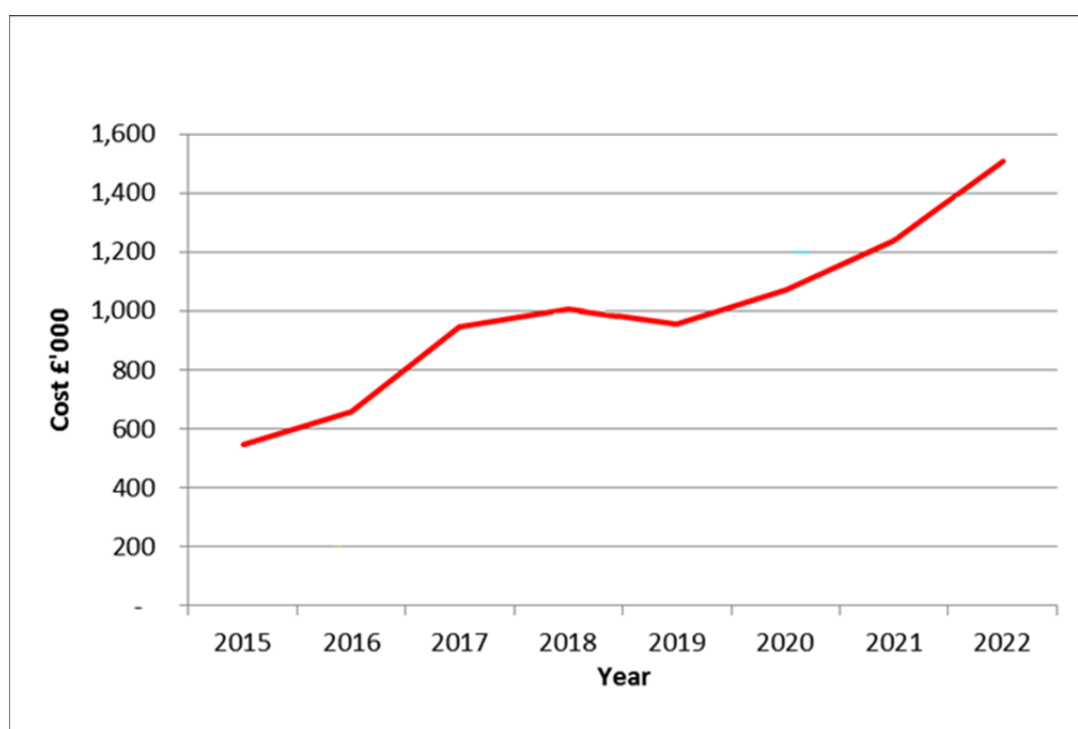


Figure 2 – Maintenance cost trend from firmus energy Business Plan template (Dec 2014 prices) commentary

Firmus energy's network maintenance costs are projected to rise steadily throughout the GD17 period. This is primarily a result of new maintenance activities being added as the network grows and as certain assets age to the point where inspection is necessary and in some cases replacement will be required.

Firmus energy identifies the main causes of rising maintenance costs to be new maintenance activities based around inspection and, where necessary, the refurbishment and/or replacement of certain equipment.

The work content of firmus energy's maintenance activities are identified within ¹⁰. In DNV GL's opinion the maintenance work contents and frequencies are consistent with UK industry practice. Also, in DNV GL's opinion the associated work requirements to ensure compliance with Pressure Systems Safety Regulations are consistent with UK industry practice.

The overall maintenance costs submitted by firmus energy for the GD17 period are identified in Table 2. The maintenance costs for network isolation and pressure control assets along with significant network structures are identified in Table 3. The detailed makeup of these costs is identified in ¹⁰.

	Cost (£)						
	2017	2018	2019	2020	2021	2022	Total
MP Regulator test & replace	75,909	141,644	127,908	168,514	227,110	279,395	1,020,481
Libra meter battery replace	33,404	63,859	62,346	83,939	133,913	245,434	622,894
Regulator replace	4,154	4,154	5,286	5,286	6,419	6,419	31,718
Meter replace	6,010	7,230	6,010	6,660	6,010	9,150	41,070
Component replace	0	0	0	0	8,225	30,245	38,470
Meter calibration	78,440	80,280	59,505	58,750	31,080	41,630	349,685
Routine & non-routine maint.	182,910	190,878	199,297	208,193	217,584	227,493	1,226,355
Regulator overhauls	47,403	45,487	35,347	25,195	20,407	20,290	194,129
Valve inspections	79,938	81,536	83,167	84,830	86,527	88,257	504,256
Below ground governor replace	11,050	22,100	16,575	22,100	33,150	33,150	138,124
Riser inspect & remediate	3,518	7,915	11,433	48,545	98,260	79,544	249,215
Bridge inspect & rewrap	76,942	6,032	0	0	0	62,000	144,974
Telemetry	49,431	43,279	41,416	41,416	7,452	7,452	190,446
Telemetry maintenance	14,868	17,228	19,352	21,476	22,600	25,724	121,248
Gas sampling	5,770	5,770	5,770	5,770	5,770	5,770	34,620
DSEAR compliance	8,500	8,500	8,500	0	0	0	25,500
Meter box maintenance	6,126	10,908	11,678	13,449	19,306	22,698	84,165
Instrument calibration	8,608	8,608	8,608	8,608	8,608	8,608	51,646
Instrument replace	3,894	3,894	3,894	3,894	3,894	3,894	23,364
Personal protective equipment	7,304	7,304	7,304	7,304	7,304	7,304	43,824
Tools	3,190	3,190	3,190	3,190	3,190	3,190	19,138
GIS	195,420	197,020	174,620	176,220	179,635	183,420	1,106,334
Total	902,787	956,815	891,204	993,338	1,126,444	1,391,066	6,261,654

Table 2 – Firmus energy Costs for Maintenance & Metering (all costs are nett of firmus energy manpower costs)

	Cost (£)						
	2017	2018	2019	2020	2021	2022	Total
Routine & non-routine maintenance	182,910	190,878	199,297	208,193	217,584	227,493	1,226,355
Regulator overhauls	47,403	45,487	35,347	25,195	20,407	20,290	194,129
Valve inspections	79,938	81,536	83,167	84,830	86,527	88,257	504,256
Below ground governor replacements	11,050	22,100	16,575	22,100	33,150	33,150	138,124
Riser inspect & remediate	3,518	7,915	11,433	48,545	98,260	79,544	249,215
Bridge inspect & re-wrap	76,942	6,032	0	0	0	62,000	144,974
Telemetry	49,431	43,279	41,416	41,416	7,452	7,452	190,446
Telemetry maintenance	14,868	17,228	19,352	21,476	22,600	25,724	121,248
Total	466,059	414,455	406,587	451,755	485,980	543,910	2,768,746

Table 3 – Firmus energy Maintenance Costs for Network Isolation, Pressure Control & Structures (all costs are nett of firmus energy manpower costs)

The drivers for the identified maintenance activities are in the form of network safety, reliability and legislative compliance and they are well understood by DNV GL. Our opinion is that firmus energy has adopted a robust approach to identify the maintenance requirements along with their associated costs and has complied with established good industry practice to enable an efficient level of investment in network maintenance.

2.6 Utility Regulator's Draft Determination

The Utility Regulator (UR) within its Draft Determination has benchmarked all three Northern Ireland Gas Distribution Networks (GDNs): firmus energy, PGNL (Phoenix) and SGN. UR identifies that the SGN Network is at an early stage of development and associated network maintenance costs are not yet available. Therefore, only firmus energy and PGNL are considered in the benchmarking of network maintenance.

UR has chosen to benchmark firmus energy against PGNL. Using PGNL's cost drivers UR has derived an estimated benchmark cost for PGNL to maintain firmus energy's distribution networks. From that comparison UR has determined that firmus energy's maintenance costs should be reduced by 25%.

There are two significant aspects affecting costs which in DNV GL's opinion are not adequately addressed by the UR benchmarking exercise. They concern: the dispersed nature of firmus energy's eight networks leading to higher travelling times, and the lower concentration of assets within firmus energy's networks leading to reduced economies of scale, when compared with PGNL's concentrated urban network. The effects of those aspects have been assessed by DNV GL as follows.

2.6.1 Travel Time

The dispersed nature of firmus energy's networks requires work teams to travel significant distances from the firmus energy office in order to conduct the required maintenance activities. DNV GL considers travel time to be non-productive and the associated costs to be an inherent overhead to network maintenance.

As required by the UR Cost Template, firmus energy's travel costs are not separately identified. Rather, they form a part of each maintenance activity cost. In order to assess the impact of these costs evaluation of relevant data was carried out by DNV GL, see Appendix A.

From Appendix A it is seen that the weighted average daily travel time for firmus energy maintenance teams is 1.9hrs i.e. 23% of each 8hr working day. For PNGL with assets concentrated in a single urban area the equivalent daily average travel time is 0.8hrs i.e. 10% of each 8hr working day. Comparing the two scenarios for dispersed & concentrated assets, due to less available working time DNV GL expects firmus energy's inherent maintenance productivity to be 15% lower than PNGL's before other factors are taken into account.

2.6.2 Asset Concentration

A further maintenance productivity consideration is the low concentration of assets within firmus energy's networks compared to more densely populated urban areas. The higher concentration of assets within urban networks leads to economies of scale and hence reduced unit maintenance costs. In order to assess the impact of the effect an evaluation of relevant data was carried out by DNV GL, see Appendix B.

From Appendix B it is seen that for firmus energy's network mains the average no. of assets per unit length is 37/km whereas for PNGL's concentrated urban network the ratio exceeds 60/km. DNV GL has compared the unit costs for firmus energy (low asset concentration) and PNGL (high asset concentration). Our comparison demonstrates that firmus energy's unit costs are expected to be 24% higher than PNGL's including the travel time effects identified in 2.6.1.

2.7 Summary of findings

We consider that the maintenance philosophy adopted by firmus energy for its network assets is consistent with industry best practice and will enable continuous improvement as the data available for maintenance performance increases.

We have assessed firmus energy's proposed maintenance activities, frequencies and associated costs and we consider them to be appropriate for its network assets and to be consistent with industry good practice.

From our review of the Utility Regulator's Draft Determination of network maintenance costs, we conclude that the Draft Determination does not adequately account for the dispersed nature of firmus energy's networks and the comparatively low asset concentrations within the networks.

We have also carried out impact assessments of longer travel time and comparatively low asset concentration and conclude that:

- the maintenance team travel time associated with firmus energy's dispersed networks will be 15% higher than for PNGL's urban network.
- the comparatively low asset concentration within firmus energy's networks result in unit maintenance costs that are 24% higher than PNGL's, inclusive of travel time effects.

3 BENCHMARKING AND FIRM-SPECIFIC FACTORS

UR's decision to carry out a benchmarking exercise to assess firmus energy's proposed variable maintenance activities goes curiously unexplained in the draft determination, except for a statement that the exercise serves to "address the opportunities for synergies"¹³ mentioned by RENE Associates (RENE).

We consider UR's decision to use benchmarking, as well as the way in which it has carried out the exercise, are both particularly curious:

- UR's decision to use benchmarking is strange because UR has explained that it has also undertaken a top-down benchmarking exercise that was not used to inform the draft determination, which instead draws on the results of a bottom-up assessment;
 - o this suggests that UR has no confidence in its bottom-up assessment and in any case requires that UR provide adequate justification for another benchmarking exercise;
- UR's execution of the benchmarking exercise is curious because despite various assertions throughout the draft determination that UR will give due regard to all relevant factors, including "special factors" (i.e. firm-specific factors), UR's analysis shows no evidence to support these assertions;
 - o failure to consider firmus energy's firm-specific factors is inconsistent with UR's principles, and without adequate justification, it comes across as a subjective exercise that undermines the stability of the regulatory method;
 - o failure to consider firmus energy's firm-specific factors is also inconsistent with other parts of the price control method, since consideration of "special factors" is a key element in the further development of the top-down benchmarking exercise and a next step in the price control review process.

It is worth noting that firmus energy has warned against overreliance on benchmarking to inform the cost assessment, as well as included discussion of "special factors" that it considers increase its network costs, in various places in its submission documents:

*"We welcome the idea of benchmarking for GD17 in principle as a qualitative check on whether there is a reason to doubt that a utility's costs are efficient and reasonable, but would caution against a purely quantitative process."*¹⁴

The "special factors" that firmus energy has raised in its submission include the comparatively early stage of network development, customer density, and the disposable income of clients in their network area.¹⁵

In addition, firmus energy engaged consultants Oxera to undertake a Benchmarking and Efficiency Assessment of the company in comparison with GB GDNs and with PNGL. The paper prepared by Oxera highlights the importance to take into account a number of major differences between the conditions under which firmus energy and its peers operate. Oxera identifies and explains the main differences in the obligations (e.g. metering, facilitation of customer switching and relationships with shippers/suppliers, controlled/uncontrolled gas escapes, pressure systems safety regulations), regulatory conditions and structural factors (e.g. network sparsity, geology,

¹³ Utility Regulator, Draft Determination, 16 March 2016, para 6.120.

¹⁴ Firmus energy, Business Plan Template Commentary GD17, September 2015, p14.

¹⁵ Firmus energy, Business Plan Template Commentary GD17, September 2015, p14 and p15.

scale, age of the network and regulatory treatment) between firmus energy and its GB and NI peers.

Moreover, even Deloitte, in a March 2016 report¹⁶ on the relative efficiency of NI gas distribution networks, included as Annex 4 to the draft determination, have noted that there are special factors that need to be considered in the assessment of firmus energy's network:

*"FE has a significantly different profile to any of the other GDNs in terms of the ratios between network length, customer numbers and volume of gas supplies. This results in significant challenges in assessing the extent to which FE costs are inefficient or are due to the characteristics of the business. As such, FE's relative efficiency has been computed by estimating a model using the GB only or GB and PNGL data and fitting the model to the FE data. A detailed analysis of special factors driving cost differences between FE and other GDNs, which is outside of the scope of this report, would be required to isolate these effects."*¹⁷

In the following sections we explore UR's decision to benchmark firmus energy's maintenance costs, as well as its execution of this exercise.

3.1 UR's decision to benchmark firmus energy's maintenance costs

UR discusses its assessment of the GDNs' opex proposals in chapter 6 of the draft determination. At the start of chapter 6, UR explains that although it has undertaken both a top-down benchmarking assessment as well as a bottom-up analysis of GDNs' opex, the draft determination is based on the latter:

*"...we have decided to apply the results of our bottom-up opex assessment in the figures used in the draft determination and this Chapter is largely focused on the bottom up analysis."*¹⁸

The bottom-up analysis is carried out by UR's consultants, RUNE Associates, whose work is not included with the draft determination. With regard to firmus energy's proposed maintenance costs, UR reports RUNE's conclusions as follows:

*"They concluded that the activities identified were reasonable and that the bottom up estimates of the unit costs was broadly reasonable with some exceptions."*¹⁹

This statement indicates that RUNE was mostly satisfied with firmus energy's proposed activities and the costs placed upon them. Why, then, does UR consider it is necessary to benchmark firmus energy's maintenance costs against PNGL's?

The reasoning that benchmarking allows UR to investigate possible synergies in firmus energy cost estimates invites considerably more explanation than UR provides in the draft determination:

- Firstly, since RUNE's analysis has not been made available, it is not possible to understand the context for this view or to obtain answers to reasonable questions, such as: *What aspects of firmus energy's maintenance costs might allow scope for synergies or economies of scale? How are they to be realised? Over what timeframe?*

¹⁶ Deloitte LLP, Relative efficiency of Northern Ireland Gas Distribution Networks – Annex 4 – GD17 Efficiency Advice – Final report, 11 march 2016.

¹⁷ Deloitte LLP, 11 March 2016, p4.

¹⁸ Utility Regulator, Draft Determination, 16 March 2016, para 6.1.

¹⁹ Utility Regulator, Draft Determination, 16 March 2016, para 6.119.

According to UR, RUNE's view that there is scope for synergies in maintenance costs mirrors comments made by firmus energy in its submission. However, it is not clear to which specific comments in firmus energy's submission UR refers.

- Secondly, even assuming the scope for synergies in maintenance costs exists, the draft determination fails to explain why benchmarking is the correct approach: *How, precisely, does the benchmarking exercise as carried out by UR generate insight into such synergies?*

We consider that the answer to this question is that benchmarking does not provide a meaningful insight into potential synergies for firmus energy, at least, not unless it is accompanied by a detailed consideration of firmus energy's costs and specific circumstances.

UR does not provide any explanation on these points. Moreover, we note that after paragraph 6.120, in which UR states that the purpose of the benchmarking exercise is to explore possible synergies, it does not refer to "synergies" or "economies of scale" again throughout the remainder of its discussion of firmus energy's maintenance costs. Hence, even UR cannot explain how its decision, to cut firmus energy's variable maintenance costs, captures in any way the potential for firmus energy to reduce its costs through synergies.

3.2 UR's benchmarking for firmus energy's variable maintenance costs

As we observed in section 3.1 above, we consider that cost benchmarking without a detailed investigation of costs, and without taking account of firmus energy's firm-specific factors (in the draft determination referred to as "special factors") is not a meaningful analysis. Oddly enough, UR's discussion of its top-down benchmarking analysis, the results of which it does not take into account in the draft determination, indicates that UR shares this view.

The discussion of top-down benchmarking in paragraphs 6.2 to 6.6 indicates that this exercise is not yet complete, with UR classing the results as "indicative" and citing "specific modelling concerns" that remain at this stage. Moreover, UR states an intention to "further refine" its top-down benchmarking:

*"... through a process of further engagement upon how GDN special factor claims might be applied to the results of our benchmark modelling. This will start with our draft determination consultation and extend beyond."*²⁰

UR's discussion of the top-down benchmarking exercise that has been carried out indicates a desire to ensure the modelling is sufficiently robust, and the analysis takes appropriate account of firm-specific factors, before it can be used to inform the price control review process. This desire is commendable, but it raises the question of why UR has not been consistent in adopting the same principles in its benchmarking of firmus energy's maintenance costs.

UR's failure to take into account firmus energy's specific factors undermines not only the entire exercise, in terms of its usefulness to inform UR's objective (to gauge potential synergies), but also the price control review process, since it is demonstrably inconsistent with other parts of the review process, it lacks transparency because it is not adequately explained, and since UR does not provide justification, it introduces subjectivity into the review process.

Issues with failure to account for firm-specific factors in the benchmarking of regulated utility networks have been well documented, particularly in a 2005 paper "Benchmarking of electricity networks:

²⁰ Utility Regulator, Draft Determination, 16 March 2016, para 6.6.

Practical problems with its use for regulation,”²¹ by Graham Shuttleworth²², published in Utilities Policy journal.

Mr. Shuttleworth describes the trend with regulators at the time to use a variety of benchmarking techniques, both statistical and non-statistical, as a way of defining the degree of inefficiency of a regulated network by reference to a notional efficient level, typically set by the network (or: group of networks) with the lowest cost. A key issue emerges when the benchmarking analysis assumes that any cost difference that cannot be explained by the variables in the model, can only be explained by inefficiency:

“...the analysis may identify factors with a significant impact on costs, but claims that any unexplained costs are due to inefficiency, as opposed to any other factor, would be no more than unsubstantiated assertions.”²³

Shuttleworth’s reasoning is that the costs of utility networks simply depend on too large a number of factors, many of which are specific to each individual network, to be captured in any one model:

“No benchmarking model can ever hope to capture all these factors in the model specification. Some of the omitted factors or unique factors explain part of the “residual”, i.e. the unexplained gap between observed costs and the estimated frontier. Until anyone can claim with certainty that a benchmarking model has capture every possible cost driver, it is incorrect and misleading to ascribe the residual to “inefficiency”, or to describe the benchmark as a measure of “efficient costs”. Instead, one must acknowledge that the residual measures no more than the element of observed costs that the model has failed to explain. On that basis, it provides no grounds for disallowing certain costs or anticipating rapid rates of cost reduction.”²⁴

Shuttleworth goes on to explain how the wrongful interpretation of benchmarking results undermines the regulatory process:

“Thus, when regulators use the results of benchmarking as a reason to disallow a proportion of total costs (or of a particular subset of costs), they are in fact acting on an arbitrary basis without proper evidence. Such administrative procedures are not usually desirable in utility regulation. They reduce the process of setting revenues to a series of subjective judgements, undermine the assurance of cost recovery, and thereby weaken any incentives offered by other aspects of the regulatory revenue formulae. This outcome is not consistent with the desire to provide regulatory incentives for efficient behaviour.”²⁵

We consider that the issue described by Shuttleworth is directly applicable to UR’s benchmarking of firmus energy’s maintenance costs. UR offers no evidence that it has considered firmus energy’s specific factors, and its approach to benchmarking implicitly assumes that PNGL’s maintenance costs are fully efficient, and that therefore any difference between firmus energy and PNGL can only be explained as inefficiency on the part of firmus energy. This outcome is wholly unsubstantiated, and completely disregards evidence provided by firmus energy (including in supporting documents provided by Oxera) that could have informed UR’s assessment and led to a consistent, transparent and objective outcome.

²¹ G. Shuttleworth, Benchmarking of Electricity Networks: Practical Problems with its Use for Regulation, January 2005, available at: <http://www.nera.com/publications/archive/2005/benchmarking-of-electricity-networks-practical-problems-with-it.html>

²² Graham Shuttleworth was at the time of writing this paper Director at NERA Economic Consulting in London (currently an affiliated consultant). He is an expert on the economics of network regulation, market rules, and contract design in the electricity and gas sectors, and helped design the Pool Rules for the new electricity market in England and Wales. A brief bio can be found here: <http://www.nera.com/experts/graham-shuttleworth.html>

²³ G. Shuttleworth, January 2005, p4.

²⁴ G. Shuttleworth, January 2005, p6.

²⁵ G. Shuttleworth, January 2005, p6.

3.3 Summary of findings

Both UR's decision to benchmark firmus energy's variable maintenance costs, as well as its execution of this benchmarking exercise, raises questions as to whether the price control review process is robust and will lead to an efficient outcome.

The decision itself overturns (without explanation) UR's own consultant's view that firmus energy's maintenance costs are reasonable, allegedly to gauge the scope for synergies, but UR does not explain what synergies or economies of scale might be realised, nor how a benchmarking exercise might generate insight into such synergies. Furthermore, UR's draft determination to cut firmus energy's variable maintenance costs by 25%, is not linked in any way to the potential for firmus energy to reduce its costs through synergies.

UR's execution of the benchmarking exercise is even more puzzling, since it does not give any consideration to "special factors" raised by firmus energy in its submission, even though UR has stated that it interprets its duties to include having "due regard to all relevant factors,"²⁶ and even though consideration of special factors is a key element in the further development of the top-down benchmarking exercise and a next step in the price control review process.

By failing to consider firmus energy's "special factors," UR's proposed 25% cut is arbitrary and subjective, since it cannot be justified on the basis of objective principles or analysis. Such arbitrariness and subjectivity may be perceived as regulatory risk in the eyes of investors (not just for firmus energy but for all regulated networks in NI), since they reduce the certainty that investors will recover their costs (including a reasonable return on investment). As it stands, firmus energy is facing a cut in variable maintenance costs of £1.27m (25%) over the 6-year GD17 period, which has neither been explained nor justified. Hence, unless UR provides greater transparency on its assessment, as well as justification for its decision based on objective principles, it is failing to deliver on its duty to *"ensure the gas distribution network operators can continue to finance the activities which are the subject of obligations placed on them."*²⁷

²⁶ Utility Regulator, Draft Determination, 16 March 2016, para 1.8.

²⁷ Utility Regulator, Draft Determination, 16 March 2016, para 1.8.

4 PRINCIPLES APPLIED IN UR'S ASSESSMENT

As brokers between consumers and network companies, utility regulators have to balance the interests of these two groups:

- on the one hand, regulators need to ensure that prices paid by consumer reflect the costs of the service, and that these costs are not excessive;
- on the other hand, regulators need to provide network companies a reasonable prospect of cost recovery, including the cost of capital, to ensure investor interest.

The only way regulators can realise an efficient outcome is if they follow a number of principles to ensure the regulatory process is unambiguous, predictable and fair. Like many regulatory authorities, UR posts some of these principles on its website, where they are incorporated in UR's value to be a "best practice regulator," meaning that UR endeavours to be "transparent, consistent, proportional, accountable, and targeted."²⁸ In addition, UR describes its interpretation of its duties in the context of price controls in the draft determination, listing the following:²⁹

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

In section 3 above, we review UR's decision to benchmark firmus energy's variable maintenance costs, as well as how it has carried out this benchmarking exercise. Our review identified various points on which the draft determination fails to apply the regulator's principles, or carry out what UR considers its duties, particularly by failing to be transparent, consistent, and taking account of all relevant factors. We have noted also that UR fails to remain objective in its assessment, a principle curiously absent in UR's values, yet vital to any regulator's mandate to provide investors a reasonable prospect of cost recovery.

In the table below, we provide a further list of specific aspects of UR's assessment of firmus energy's maintenance costs on which it is evident that UR fails to adhere to its values and/or deliver its duties.

DD Para.	Description	Principle / Duty
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²⁸ http://www.uregni.gov.uk/about_us/

²⁹ Utility Regulator, Draft Determination, 16 March 2016, para 1.8.

DD Para.	Description	Principle / Duty
6.119	UR refers to the bottom-up assessment by RUNE Associates, who “concluded that the activities identified were reasonable and that the bottom up estimates of the unit costs was broadly reasonable with some exceptions.” The assessment performed by Rune Associates has not been made available with the draft determination, so that it is not possible to understand the context of RUNE's assessment, its precise findings, and the "exceptions" referred to.	lack of transparency
6.119	The UR states that Rune Associates “highlighted opportunities for synergies and efficiencies which could be achieved between the proposed activities by combining work into single visits or general economies of scale. This reflected similar comments made by firmus energy in its own submission on opportunities to reduce costs through synergies between the activities.” As above, since RUNE's work is not available, it is not possible to understand the context of RUNE's assessment and the precise activities it refers to. Moreover, it is not clear to which comments in firmus energy's submission UR refers. Firmus energy informed us that a small percentage of cost saving synergies may be gained when, for example, a battery replacement on PAYG meters will be carried out at the same time as the regulator testing - but it is not clear that this is what UR (or RUNE) is referring to. UR does not mention the report “Benchmarking and efficiency assessment”, prepared for firmus energy by Oxera, which mentions on p.10 that “the difference in the scale of firmus energy’s operations relative to PNGL and GB GDNs can have a considerable effect on its ability to benefit from the economies of scale enjoyed by PNGL and GB GDNs”. Also, UR makes no mention of firmus energy's response of 10/02/2015 to the discussion document on the UR overall approach for the GD17 price control. In this document, firmus energy requests that UR takes full account of the differences in scale of the firmus energy business and the other UK GDNs, including PNGL, which would affect firmus energy's ability to realise economies of scale.	lack of transparency failure to consider all relevant factors lack of proportionality
6.120-6.125	UR fails to explain and justify why it has decided to carry out a benchmarking exercise, nor how this is meant to provide insights into potential synergies in maintenance costs for firmus energy. UR also fails to explain why it considers PNGL to be an appropriate benchmark for firmus energy, and does not consider (throughout 6.120-6.125) of firm-specific factors that apply to firmus energy's network.	lack of transparency failure to consider all relevant factors subjectivity
6.120-6.125	UR benchmarks firmus energy against PNGL using unit cost comparisons but does not take into account structural differences (except the proportion of LP mains) to enable a like for like comparison. Such structural differences (such as network sparsity, age of the network, scale, customer density, urbanity) are clearly explained in the report “Benchmarking and efficiency assessment” prepared by Oxera (pag. 9 and 10) and submitted to UR.	failure to consider all relevant factors

DD Para.	Description	Principle / Duty
6.120-6.125	UR does not follow the same approach to assess network maintenance costs for firmus energy and PGNL. For PGNL, UR compared the general level of expenditure proposed by PGNL against the determination for GD14 and the detailed information provided by the company. Thus, approaches like unit cost comparisons or performance indicators for benchmarking were not applied. Contrarily, the UR has benchmarked the cost of network maintenance for firmus energy against the costs for PGNL using cost drivers to determine unit rates. UR's use of benchmarking of firmus energy's maintenance costs contradicts earlier statements of approach in the draft determination (e.g. para 6.1) that is draft determination is based on a bottom-up analysis. UR mentions (in para 6.1-6.6) that it has also carried out top-down opex benchmarking using econometric analysis. UR reports the results of this analysis, but explains that the analysis is not yet complete and/or not yet fully robust, and that further work on this benchmarking will take place from the draft determination consultation. It is not clear what role the top-down benchmarking might play in the final GD17 determination and how this might affect the use of the bespoke benchmarking of firmus energy's maintenance costs.	inconsistency lack of transparency
6.125	UR reports that its benchmarking exercise shows that PGNL's variable maintenance costs are 27% lower than firmus energy's. UR then decides to apply a reduction of 25% to the variable maintenance costs estimated by firmus energy. UR does not explain why a reduction of 25% in firmus energy's variable maintenance costs is justified, how that is informed by its benchmarking analysis, or how this decision is meant to reflect potential synergies in maintenance costs that firmus energy may be able to realise.	lack of transparency subjectivity
1.30	Early on in the draft determination, in para 1.30, UR states: "While we have allowed increases in the area of maintenance and emergencies, the allowances are £1.8m less than firmus energy proposed as our analysis indicated the potential for significant efficiencies in this area" . It is not clear to which "significant efficiencies" UR is referring, as UR provides no discussion of <i>significant synergies</i> in its assessment of maintenance and emergency opex. It is possible that UR refers to its own benchmarking exercise, culminating in the arbitrary and subjective decision to apply a 25% reduction - this is a <i>significant</i> figure indeed, but as we have explained previously, it is not linked to the potential for firmus energy to realise synergies in maintenance costs.	lack of transparency subjectivity

APPENDIX A

Travel Time

Traveling times from firmus energy's operating base at Antrim to the centres of each of the networks have been identified from AA's "Routeplanner", see Table A1.

Network	Operating Base – Network Centre	
	Distance (Km)	Travel Time (Min)
Newry	77.1	67
Banbridge	56.0	53
Craigavon	51.0	42
Portadown	52.7	44
Armagh	69.0	60
Antrim	1.8	4
Ballymena	17.6	17
Ballymoney	50.0	41
Coleraine	64.2	54
Limavady	69.8	57
Londonderry	84.2	68
Sum of Travel Times		507

Table A1 – Travel Times

Then, each of the travel times has been weighted to reflect the volume of maintenance work within each of the networks. The weighting is based upon the proportion of firmus energy's total assets within each network, see Table A2. The weighted time total equals the un-weighted time total given in Table A1.

Towns	Valves	I&C meters	DPRMS	Risers	Domestic Meters	Total Asset No.	Weighted Travel Time (Min)	Mean Travel Time (Min)
Newry	699	198	15	74	2056	2968	41	56.3
Banbridge	277	79	11	17	868	1235	17	
Craigavon	1693	526	46	129	5722	7987	110	
Portadown								
Armagh								
Antrim	852	292	14	12	3475	4633	64	
Ballymena	864	317	30	54	2909	4120	57	
Ballymoney	947	297	30	49	2751	4025	56	
Coleraine								
Limavady	231	85	6	8	906	1228	17	
Londonderry	1861	617	35	301	8105	10618	145	
Total	7424	2411	187	644	26792	36814	507	

Table A2 – Weighted Travel Times using the data from firmus energy Network April 2016

From Table A2 the mean daily travel time for firmus energy's maintenance crews is 2x56.3 minutes i.e. 1.9hrs.

A similar exercise has been carried out for PNGL based upon a limited amount of available data, see Table A3.

Towns	Operating Base – Network Centre		
	Distance (Km)	Travel Time (Min)	Mean Travel Time (Min)
Larne	40.1	35	25
Belfast	7.9	15	
Sum of Travel Times		50	

Table A3 – PNGL Travel Data

There is insufficient asset distribution data available for PNGL therefore the travel time is set at a simple average of times from the operating base near City Airport to the main conurbations of Belfast and Larne i.e. 25 minutes that gives a mean daily travel time for its maintenance crews of 2*25 minutes i.e. 0.8hrs.

Note –The calculated PNGL mean travel time is conservatively high for the purpose of this assessment and it is considered that accurate asset data for PNGL's network would reduce it.

The daily travel times reduce the productive working day for both operators but the effect is not equal. The difference is quantified as follows:

Productive time = 8hr – Mean Daily Travel Time

Comparative firmus energy/PNGL productivity factor = $(8.0 - 1.9)/(8.0 - 0.8) = 6.1/7.2 = \underline{0.85}$

APPENDIX B

Cost Effect of Asset Concentration within Network

No relevant data for the cost effect of asset concentration has been identified in the public domain. Therefore, a comparison has been carried out using historic data for a large gas transmission pipeline network. Although the network duty differs from firmus energy's the principle of maintaining a distributed asset is the same and the data has been normalized to indicate cost trends versus asset concentration which can be applied to firmus energy's maintenance activities.

The network was maintained by 12 separate maintenance organizations which used common maintenance requirements. Asset and maintenance cost data from all 12 organizations using common criteria was compiled on an annual basis over several years.

The summary data is provided in Table B1. The "Normal Ratios" for asset concentration and asset unit costs show normalization against the mean values.

Maint. Org.	Length (km)	Asset Concentration			Asset Cost		
		No.	Asset / K m	Normal Ratio	Cost	Unit Cost	Normal Ratio
1	1529.3	15	0.01	0.50	17,171	1145	2.22
2	735.3	15	0.02	1.05	7,365	491	0.95
3	463.5	13	0.03	1.44	8,209	631	1.23
4	347.8	9	0.03	1.33	3,626	403	0.78
5	595.3	12	0.02	1.04	4,020	335	0.65
6	269.8	11	0.04	2.09	3,334	303	0.59
7	92.9	4	0.04	2.21	1,225	306	0.59
8	1091.9	10	0.01	0.47	5,484	548	1.07
9	88.2	5	0.06	2.91	2,486	497	0.97
10	78	4	0.05	2.63	1,502	376	0.73
11	318.1	6	0.02	0.97	1,952	325	0.63
12	397.3	13	0.03	1.68	3,853	296	0.58
Total	6007.4	117			60,227		
Mean			0.02	1.00		515	1.00

Table B1 – Asset Concentration & Asset Cost Ratios

Eliminating the outlying high and low asset concentrations the Normal Ratios for the remaining ten maintenance organizations are shown in Figure B1 along with the associated trend.

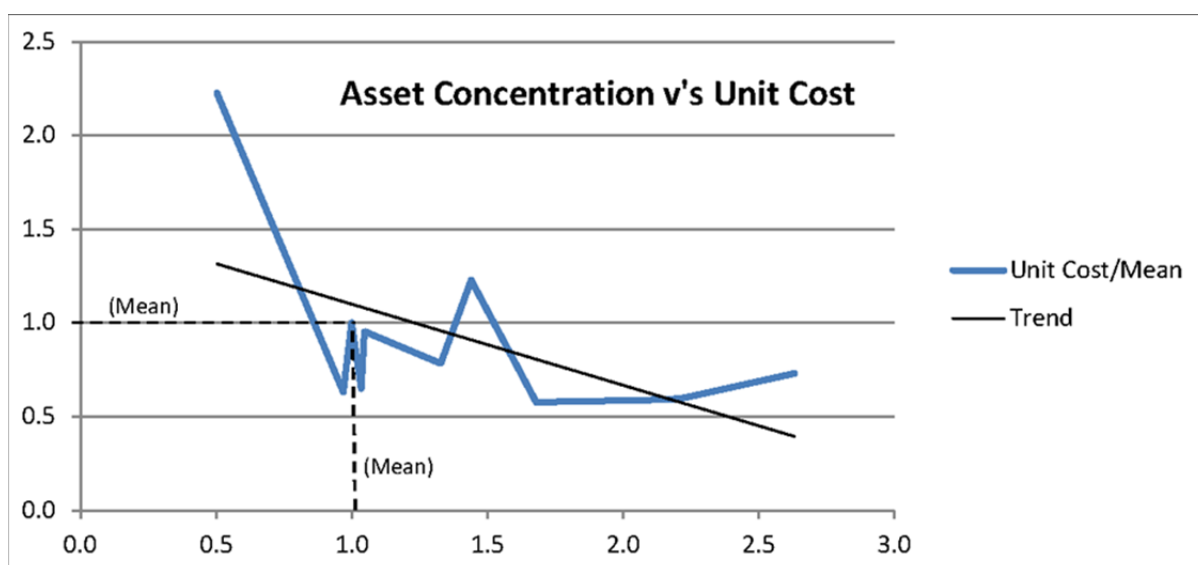


Figure B1 – Normalized Asset Concentration & Cost

The trend line in Figure B1 indicates the impact of asset concentration upon the unit maintenance cost, inclusive of travel time effects.

To compare firmus energy with PNGL there is insufficient asset data available for PNGL. Therefore, it is simply assumed that the number of customers can be used to represent asset volumes. The comparison data is provided in Table B2.

Maint. Org.	Length (km)	Asset Concentration		
		No.	Asset /K m	Normal Ratio
firmus energy	1038	36814	35.5	0.65
PNGL	3300	200000	60.6	1.11
Total	4338	236814		
Mean			54.6	1.00

Table B2 – Asset Concentration for firmus energy & PNGL

Using the trend line from Figure B1 it is expected that unit maintenance costs for firmus energy would be 1.3*Mean Unit Cost whereas for PNGL they would be 1.05*Mean Unit Cost. For comparison of unit maintenance costs between firmus energy and PNGL it is expected that the appropriate factor is:

Comparative firmus energy/PNGL unit cost factor = $1.30/1.05 = 1.24$





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FIRMUS ENERGY (SUPPLY) LTD & FIRMUS ENERGY (DISTRIBUTION) LTD

25 MAY 2016

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MARSH - BACKGROUND

Marsh is a global leader in insurance broking and risk management. In more than 130 countries, our experts help clients to anticipate, quantify, and more fully understand the range of risks they face. In today's increasingly uncertain global business environment, Marsh helps clients to thrive and survive.

We work with clients of all sizes to define, design, and deliver innovative solutions to better quantify and manage risk. To every client interaction we bring a powerful combination of deep intellectual capital, industry-specific expertise, global experience, and collaboration. We offer risk management, risk consulting, insurance broking, alternative risk financing, and insurance programme management services.

Since 1871 clients have relied on Marsh for trusted advice, to represent their interests in the marketplace, make sense of an increasingly complex world, and help turn risks into new opportunities for growth. Our more than 30,000 colleagues work on behalf of our clients, who are enterprises of all sizes in every industry, and include businesses, government entities, multinational organisations, and individuals around the world.

We are a wholly owned subsidiary of Marsh & McLennan Companies (NYSE: MMC), a global professional services firm offering clients advice and solutions in the areas of risk, strategy, and people. With 60,000 colleagues worldwide and annual revenue exceeding \$13 billion, Marsh & McLennan Companies also include global leaders Guy Carpenter, Mercer, and Oliver Wyman.

Marsh arranges cover for a wide range of Power & Energy companies – both globally and in the UK.

CURRENT FIRMUS PREMIUMS (30/06/15 – 29/06/16)

Policy Description	2015/16 GBP
Commercial Combined (inc Employers' Liability GBP 10m) *	21,500
Excess Employers Liability (GBP 10m in excess of GBP 10m)	2,150
Public Liability (Primary GBP 5m)	86,250
Excess Public Liability (GBP 20m in excess of GBP 5m)	44,000
Excess Public Liability (GBP 25m in excess of GBP 25m)	27,000
Excess Public Liability (GBP 50m in excess of GBP 50m)	15,000
Motor Fleet	5,215
Computer	2,310
Personal Accident/Travel	500
Motor Uninsured Loss Recovery	18
Crime (£5m)	16,500
Directors and Officers (Primary GBP 10m)	12,750
Excess Directors & Officers (GBP 15m in excess of GBP 10m)	7,125
Professional Indemnity (GBP 1m)	972
Broker Fee	25,000
TOTAL EXCLUDING IPT	266,290
Insurance Premium Tax **	14,477
TOTAL INCLUDING IPT	280,767

* Combined premium sub-splits Property/Business Interruption GBP 6,500 & Employers' Liability GBP 15,000.

** IPT was 6% at renewal 30/06/15 – but rate of 9.5% will apply to renewal 30/06/16.

LIABILITY COVERS IN COMPARISON TO PEERS

We have performed an analysis of Firmus' Liability covers in relation to other UK clients with our findings being as follows:

Employers' Liability (current cover GBP20M – split between primary GBP10M & top-up GBP 10M)

- Primary (GBP 10M) - Firmus' rate (i.e. primary policy premium of GBP 15,000 divided by Wages of GBP 4.419M) of 0.34% is lower than that applied to similar sized companies.
- Most of Firmus UK peers only carry GBP 10M or GBP 15M. However, the saving would only be GBP 2,150 plus IPT if Firmus was to drop the top up layer.
- Excess is Nil which is in line with other companies. (Nb. Given that Employers' Liability is required by law, the market norm is that Insurers don't offer an excess option.)

Public/Products Liability (current cover £100M – split between 4 policies)

- Primary (GBP 5M) – Firmus' rate (i.e. primary policy premium of GBP 86,250 plus IPT divided by Turnover of GBP 123M) of 0.07% is significantly lower than that applied to similar sized companies - most of your UK peers are paying approx. GBP 125,000 plus IPT.

Rates have reduced over the past year and we can confirm that Marsh have obtained an indication of GBP 72,500 plus IPT – which would reduce the rate down to 0.059%.

(As you are aware the current primary policy is not currently arranged via Marsh.)

- Top up layers (2 policies totaling GBP 45M over primary GBP 5M) – current total premium is GBP 71,000 plus IPT. Insurance rates for this class of cover have reduced over past year and an indication has been received of GBP 50,000 plus IPT.
- Top up layer (GBP 50M over GBP 50M) – premium GBP 15,000 plus IPT – this is in line with what Firmus' peers are paying.
- The total limit of £100M is in line with what other companies have.
- Excess - currently GB10K – most of your UK peers carry higher excess levels – but as commented above they are paying higher premiums. Given that you have an excellent claims history increasing the Excess isn't going to achieve any saving of note.



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Review of the Utility Regulator's analysis on frontier shift for GD17

Prepared for
firmus energy

May 2016

Strictly confidential

www.oxera.com

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Executive summary

In March 2016, the Utility Regulator published its draft determination for Northern Ireland's gas distribution networks (GDNs) for the GD17 period (2017–22).¹ As part of this, the Utility Regulator has set assumptions on frontier shift² that aim to 'take account of continuing efficiencies which the industry can achieve over the price control period'.³

Basis for the Utility Regulator's draft determination

The Utility Regulator has assumed a frontier shift of 1% per annum over GD17 on OPEX and CAPEX. In deriving this estimate, it has not undertaken an empirical analysis of frontier shift specific to the NI GDNs; instead, it has relied on:

- evidence on energy sector and economy-wide productivity growth from Ofgem's analysis for RIIO-T1/GD1;
- a selection of regulatory precedents from different sectors (transport, energy, water), which were considered by the UK Competition Commission (CC, now the Competition and Markets Authority, CMA) in the Northern Ireland Electricity (NIE) price control appeal inquiry.⁴

Key findings from Oxera's review

Having reviewed the Utility Regulator's use of Ofgem's productivity analysis for RIIO-T1/GD1, and its selection of regulatory precedents, we conclude as follows.

- The Utility Regulator has chosen Ofgem's evidence selectively by focusing on economy-wide evidence and not the targets that Ofgem actually set. Based on the wider set of results considered by Ofgem, and in particular the targets that Ofgem actually set the GDNs, we consider per annum frontier-shift targets of 1% (OPEX) and 0.7% (CAPEX) to be more consistent with the regulatory precedents chosen by the Utility Regulator.
- Among the regulatory precedents that the Utility Regulator has considered, Ofgem's RIIO-T1/GD1 determination is the most informative, since it is based on a comparable regulatory framework and pertains to the gas distribution sector.⁵
- There are a number of potential issues with the evidence presented by the Utility Regulator that require further consideration, as:
 - productivity estimates, such as those derived by Ofgem in RIIO-T1/GD1, provide a measure of productivity change, but they do not necessarily translate directly into frontier shift, as they may *encompass other effects* such as changes in catch-up efficiency and operational scale.⁶ For this

¹ Utility Regulator (2016), 'Price Control for Northern Ireland's Gas Distribution Networks GD17', draft determination, 16 March.

² Utility Regulator (2016), 'Annex 6 Real price Effects & Frontier Shift GD17', draft determination, March.

³ Utility Regulator (2016), 'Annex 6 Real price Effects & Frontier Shift GD17', draft determination, March, p. 14.

⁴ Competition Commission (2014), 'Northern Ireland Electricity Limited price determination. A reference under Article 15 of the Electricity (Northern Ireland) Order 1992', March.

⁵ Of relatively less relevance, but still informative, is Ofgem's determinations for the electricity distribution networks at DPCR5 and RIIO-ED1. However, it should be noted that while the comparator set of industries could be similar (or even the same) for electricity and gas distribution networks, the composite TFP benchmark (i.e. weighted TFP) could differ, since the weights attached to the comparator industries' TFPs are based on the cost composition of the two networks, which could be different.

⁶ Multi-factor productivity growth (including TFP growth) is calculated as a residual. As such, it may be driven by technology change as well as other factors, such as scale and catch-up efficiency change. For an

reason, it is necessary to consider an adjustment to such estimates in order to derive a frontier-shift target, especially as catch-up and scale issues are considered separately by the Utility Regulator. Typically, *downward adjustments* are applied to such productivity estimates to isolate catch-up (or scale) efficiency effects. For example, the Office of Rail Regulation (now the Office of Rail and Road, ORR) and the CC had considered a *25% downward adjustment* to translate empirical productivity estimates into appropriate frontier-shift targets.⁷ This issue is particularly important in the case of GD17, as the Utility Regulator has used *only* economy-wide evidence in informing its decision, wherein some of the sectors could have achieved (potentially significant) catch-up improvements that need to be isolated;

- the productivity analysis undertaken by Ofgem at RIIO-T1/GD1 in 2012 is based on a now *outdated EU KLEMS dataset*, which ends in 2007.⁸ A more recent version of that dataset is now available and includes two additional years of data: 2008 and 2009. The most recent EU KLEMS dataset benefits from improvements in the quality and accuracy of national accounts and makes use of the latest accounting standards.⁹ We would recommend the Utility Regulator considering the latest version of the EU KLEMS dataset¹⁰ and undertaking primary analysis of frontier-shift estimation for the NI GDNs. In addition to the extra years of productivity data and improved data quality, the recent industry classification allows for a more accurate mapping of GDN activities, thereby improving the overall relevance and robustness of the frontier-shift determination;¹¹
- the range of 0.5–1.5% that the Utility Regulator has relied on is based on *partial* productivity measures alone. These are *not comprehensive measures of productivity* as the productivity of any one input (e.g. labour) depends on the utilisation of other inputs (e.g. capital), which implies that such partial measures are not likely to truly reflect the productivity of any specific input set alone.¹² As such, any conclusions drawn from them should be treated with caution.¹³

The issues above are most likely to lead to an overestimate of the frontier-shift target proposed by the Utility Regulator. For instance, using the most recent version of EU KLEMS could result in a downward revision of Ofgem's productivity benchmarks, and accounting for catch-up may further reduce

overview, see Timmer, M., O'Mahony, M. and Van Ark, B. (2007), 'EU KLEMS Growth and Productivity Accounts: Overview', November, available at: http://www.euklems.net/data/overview_07ii.pdf, section 3. See also Oxera (2016), 'Study on ongoing efficiency for Dutch gas and electricity TSOs', prepared for Netherlands Authority for Consumers and Markets (ACM), April, pp. 40–1.

⁷ See Oxera (2008), 'Network Rail's scope for efficiency gains in CP4', prepared for Office of Rail Regulation, April; and Competition Commission (2010), 'Bristol Water plc: A reference under section 12(3)(a) of the Water Industry Act 1991', Appendix K, para. 51 (which refers to Oxera (2008)), para. 109 (which makes a net adjustment, implying at least a 10% adjustment for catch-up), and para. 112. Ofgem also acknowledged that there could be an element of catch-up in some industries of the economy, such as utilities. Ofgem (2012), 'RIIO-T1/GD1: Initial Proposals – Real price effects and ongoing efficiency appendix', September, p. 20.

⁸ ISIC revision 3. EU KLEMS (2011), 'EUKLEMS database. United Kingdom. Basic Tables', March, available at: http://www.euklems.net/data/09II/uk_output_09II.xls.

⁹ For a detailed review, see Oxera (2016), 'Study on ongoing efficiency for Dutch gas and electricity TSOs', prepared for Netherlands Authority for Consumers and Markets (ACM), April, section 5.

¹⁰ Ideally combining this with productivity data from other sources such as the ONS and the OECD to extend the dataset by including recent years of productivity data.

¹¹ For a detailed review, see Oxera (2016), 'Study on ongoing efficiency for Dutch gas and electricity TSOs', prepared for Netherlands Authority for Consumers and Markets (ACM), April, section 5.

¹² For a review, see Oxera (2016), 'Study on ongoing efficiency for Dutch gas and electricity TSOs', prepared for Netherlands Authority for Consumers and Markets (ACM), April.

¹³ For a review, see, for example, OECD (2001), 'Measuring productivity. OECD Manual. Measurement of aggregate and industry level productivity growth', July. See also Oxera (2013), 'The potential for frontier shift in electricity distribution', prepared for Electricity North West Limited', June, p. 8.

Ofgem's productivity benchmarks. And on the latter, for example, consistent with the CC and the ORR's treatment of catch-up conflation issue, a 25% downward adjustment to Ofgem's RIIO-T1/GD1 results would result in per annum targets of 0.75% on OPEX and 0.5% on CAPEX.¹⁴ These issues thus warrant further consideration.

¹⁴ This is derived in the following way: on OPEX, $(1-0.25)*1\%$ gives 0.75%, and on CAPEX, $(1-0.25)*0.7\%$ gives 0.5%.

1 Introduction

In March 2016, the Utility Regulator published its draft determination. In making a determination for the frontier-shift parameter, the Utility Regulator based its review on the CC's recent analysis in the NIE RP5 determination. By drawing on the CC's analysis, the Utility Regulator considered the following evidence.

1.1 Ofgem's productivity growth analysis for RIIO-T1/GD1

In RIIO-T1/GD1, Ofgem examined the productivity growth of the UK economy as a whole and a selection of sectors within it over the period 1970–2007. The evidence was used by the CC in its NIE RP5 determination and was part of a wider set of results presented by Ofgem in the context of the RIIO-T1/GD1 final determination.

The Utility Regulator reported average aggregate¹⁵ annual productivity growth rates using five productivity measures.¹⁶ The Utility Regulator's range (0.5–1.5%), from which it selected the midpoint (1%), was originally based on Ofgem's analysis for RIIO-T1/GD1.

1.2 Review of precedents on OPEX and CAPEX productivity assumptions

The Utility Regulator considered the following regulatory precedents based on the CC's review for the NIE RP5 determination.

Table 1.1 Regulatory precedents considered by the Utility Regulator (frontier-shift assumption, % per annum)

Precedent	OPEX target	CAPEX target
Utility Regulator: water and sewerage, PC13	0.9	-
PPP Arbiter: underground infrastructure companies, 2010 decision	0.7 (central costs) 0.9 (OPEX)	1.2
ORR: Network Rail, Periodic Review 2008	0.2 (OPEX) 0.7 (maintenance)	0.7
CMA: Bristol Water, PR14 ¹	1.0 ²	1.0 ²
Utility Regulator: GD14	1.0	1.0
CC: NIE RP5	1.0	1.0
Ofgem: GB electricity DNOs, DPCR5	1.0	1.0
Ofgem: Transmission & Gas Distribution, RIIO-T1/GD1	1.0	0.7

Note: ¹ For the other 17 companies that did not refer to the CMA, Ofwat implicitly assumed a frontier shift of +0.4% p.a., which is lower than the -1%p.a. target shown by the Utility Regulator. See Competition and Markets Authority (2015), 'Bristol Water plc price determination. Provisional findings', July, p. 96. For waste water, Ofwat implicitly assumed a frontier shift of +2% p.a. (i.e. deterioration of the frontier). ² Applied to TOTEX.

Sources: Utility Regulator (2012), 'Water and sewerage service price control 2013-2015 Northern Ireland Water. PC13 Final Determination Main Report', December. PPP Arbiter (2009), 'Draft directions on costs and related matters and initial thoughts on ISC setting and financing', December. Ofgem (2014), 'RIIO-T1/GD1: Real price effects and ongoing efficiency appendix. Final decision - appendix', December, pp. 15–16. Office of Rail Regulation (2008), 'Periodic review 2008. Determination of Network Rail's outputs and funding for 2009-14', October. Competition and Markets Authority (2015), 'Bristol Water plc price determination. Summary of report', October. Utility Regulator (2013), 'GD14 Price Control for Northern Ireland's Gas Distribution Networks for 2014-2016', December. Competition Commission (2014), 'Northern

¹⁵ Including all sectors of the economy except real estate, public administration, education, health and social services.

¹⁶ Value added (VA)-based TFP; VA-based labour and intermediate input productivity at constant capital; gross output (GO)-based TFP; GO-based labour and intermediate input productivity at constant capital; GO-based labour and intermediate input productivity.

Ireland Electricity Limited price determination. A reference under Article 15 of the Electricity (Northern Ireland) Order 1992', March.

For the NIE RP5 determination, the CC found Ofgem's decisions in respect of the GB DNOs, Transmission & Gas Distribution, to be the most relevant,¹⁷ and that the 'aggregate EU KLEMS data could support a range of estimates of productivity of between 0.5 and 1.5 per cent'.¹⁸

The Utility Regulator found the range of 0.5–1.5% derived by the CC to be reasonable for a regulated monopoly network company, and therefore made a productivity assumption of 1.0% per annum for the GD17 price control period.

¹⁷ Competition Commission (2014), 'Northern Ireland Electricity Limited price determination. A reference under Article 15 of the Electricity (Northern Ireland) Order 1992', March, pp. 11–14.

¹⁸ Competition Commission (2014), 'Northern Ireland Electricity Limited price determination. A reference under Article 15 of the Electricity (Northern Ireland) Order 1992', March, p. 15.

2 Review of the empirical analysis

The Utility Regulator has relied on Ofgem's (2012) RIIO-T1/GD1 analysis to derive a range for its productivity assumption. At RIIO-T1/GD1, Ofgem's analysis included estimates of productivity growth using sectoral evidence. The sectors were chosen according to their comparability with the activities carried out by transmission and gas distribution operators.

2.1 Utility Regulator's use of Ofgem's productivity analysis at RIIO-T1/GD1

Although the Utility Regulator relied on the evidence considered by Ofgem, it derived a more challenging productivity target on CAPEX.¹⁹

As can be seen in Table 3.1 below, the Utility Regulator has presented only some of the estimates shown by Ofgem, focusing on economy-wide (unweighted) average estimates from all industries in the economy. In addition, Ofgem has used a set of comparator industries to capture productivity growth for activities that are relevant to transmission and gas distribution companies.

Table 2.1 Productivity estimates considered by Ofgem and the Utility Regulator (average annual growth rate, 1970–2007, %)

Sector/target	Range	Ofgem		Utility Regulator
		OPEX target	CAPEX target	OPEX and CAPEX targets
Construction	0.3–0.7	×	✓	×
Unweighted average (comparators) ¹	0.9–2.8	✓	×	×
Unweighted average (comparators, excluding manufacturing)	0.5–1.2	✓	×	×
Unweighted average all industries ²	0.5–1.5	✓	×	✓
Weighted average all industries ²	0.5–1.1	✓	×	×
Determination		1.0	0.7	1.0

Note: Productivity estimates cover value-added (VA)-based total factor productivity (TFP); VA-based labour and intermediate input productivity at constant capital; gross output (GO)-based TFP; GO-based labour and intermediate input productivity at constant capital; GO-based labour and intermediate input productivity. ¹ Selected industries: Manufacture of Chemicals & Chemical Product, Manufacture of Electrical & Optical Equipment, Manufacture of Transport Equipment, Construction, Sale, Maintenance & Repair of Motor Vehicles/Motorcycles, Retail Sale of Fuel, Transport & Storage, Financial Intermediation. ² Ofgem excluded the following industries from this average: real estate (K), public admin (L), education (M), health (N) and social services (O).

Source: Oxera analysis; Ofgem (2014), 'RIIO-T1/GD1: Real price effects and ongoing efficiency appendix. Final decision - appendix', December, pp. 15–16.

It is not clear why the Utility Regulator has used economy-wide evidence only, as it did not provide a rationale for departing from Ofgem's determination. More specifically, a consistent use of Ofgem's RIIO-T1/GD1 analysis would imply per annum targets of 1% on OPEX and 0.7% on CAPEX.

¹⁹ Ofgem set an OPEX target of 1% per annum and a CAPEX target of 0.7% per annum. The OPEX target was based on the average industry estimates of partial factor productivity (0.5–2.8% range) using economy-wide evidence, as well as productivity growth estimates from a set of comparator industries. The CAPEX efficiency target was based on the construction industry TFP estimate.

2.2 Review of Ofgem's analysis at RIIO-T1/GD1

In the absence of a clear rationale for departing from the conclusion from which the original analysis was drawn, we consider that the 1% OPEX target and the 0.7% CAPEX target from Ofgem's RIIO-T1/GD1 are more consistent to the 1% target provisionally set by the Utility Regulator on both OPEX and CAPEX.

However, we have identified the following potential issues with using these estimates directly for determining a frontier-shift parameter for GD17.

Use of economy-wide estimates. Productivity estimates, such as those derived by Ofgem in RIIO-T1/GD1, provide a measure of productivity change, but they do not necessarily translate directly into frontier shift as they may encompass other effects such as changes in catch-up efficiency and operational scale. In particular, productivity change can be decomposed into:²⁰

- change in catch-up efficiency, which measures the degree to which performance has caught up to best practice;
- change in scale efficiency, relating to performance changes due to changes in a company's operational scale;
- change in technology, which captures how best practice has improved (or worsened) over the period of analysis (this is the only component that captures frontier shift improvements).

For this reason, it is necessary to consider whether an adjustment to such estimates is needed to derive a frontier-shift target, especially as catch-up and scale issues are considered separately by the Utility Regulator.

Typically, downward adjustments are applied to such productivity estimates to isolate catch-up (or scale) efficiency effects.²¹ For example, based on Oxera (2008), the ORR and the CC²² had applied a *25% downward adjustment* to translate empirical productivity estimates, similar to those examined by Ofgem, into appropriate frontier-shift targets. This issue could be particularly important in the case of GD17 as the Utility Regulator has used *only* economy-wide evidence in informing its decision, wherein some of sectors could have achieved (potentially significant) catch-up improvements that need to be isolated;²³

Outdated dataset. The productivity analysis undertaken by Ofgem at RIIO-T1/GD1 in 2012 is based on a now outdated dataset, ending in 2007.²⁴ A more recent version of the EU KLEMS dataset is now available, which would allow the Utility Regulator to consider the impact of two additional years of data (2008 and 2009).²⁵

²⁰ Oxera (2016), 'Study on ongoing efficiency for Dutch gas and electricity TSOs', prepared for Netherlands Authority for Consumers and Markets (ACM), April, p. 40–1.

²¹ Oxera (2008), 'Network Rail's scope for efficiency gains in CP4', prepared for Office of Rail Regulation, April; and Competition Commission (2010), 'Bristol Water plc: A reference under section 12(3)(a) of the Water Industry Act 1991', Appendix K, para. 51 (which refers to Oxera (2008)), para. 109 (which makes a net adjustment, implying at least a 10% adjustment for catch-up), and para. 112.

²² See Oxera (2008), 'Network Rail's scope for efficiency gains in CP4', prepared for Office of Rail Regulation, April; and Competition Commission (2010), 'Bristol Water plc: A reference under section 12(3)(a) of the Water Industry Act 1991', Appendix K, para. 51 (which refers to Oxera (2008)), para. 109 (which makes a net adjustment, implying at least a 10% adjustment for catch-up), and para. 112.

²³ For example, in RIIO-T1/GD1, Ofgem acknowledged that there could be an element of catch-up in some industries of the economy, such as utilities. Ofgem (2012), 'RIIO-T1/GD1: Initial Proposals – Real price effects and ongoing efficiency appendix', September, p. 20.

²⁴ ISIC revision 3. EU KLEMS (2011), 'EUKLEMS database. United Kingdom. Basic Tables', March, available at: http://www.euklems.net/data/09II/uk_output_09II.xls.

²⁵ Past Oxera analysis for a UK electricity distribution company showed that 2008 is the last year of a business cycle that started in 1992. Since business cycles tend to influence productivity trends, we

The latest version of the EU KLEMS dataset is likely to be less prone to measurement error than earlier versions. In addition, the latest EU KLEMS version uses the latest accounting standards used by statistical agencies.²⁶ Moreover, the recent industry classification can also allow for a more accurate mapping of GDN activities.

It is worth noting that Ofgem was not able to examine a complete business cycle, as 2008 was the end of the last business cycle. We note that UK output fell sharply from mid-2008.²⁷ Since productivity growth is expected to be positively correlated with output growth,²⁸ productivity should be examined over complete business cycles. These revised estimates, including the latest data, indicate a slowdown in productivity. Thus, Ofgem's productivity estimates are likely to be biased upwards. As such, we would recommend the Utility Regulator considering the latest version of the EU KLEMS dataset²⁹ and undertaking primary analysis of frontier-shift estimation for the NI GDNs in order to improve the overall relevance and robustness of the frontier-shift determination.

Partial productivity measures. The range of 0.5–1.5% that the Utility Regulator has relied on are based on *partial* productivity measures alone. These are not comprehensive measures of productivity as the productivity of any one input (e.g. labour) depends on the utilisation of other inputs (e.g. capital), which implies that such partial measures are not likely to truly reflect the productivity of any specific input set alone. As such, any conclusions drawn from them should be treated with caution.³⁰

suggested that full business cycles be covered in productivity analysis. Indeed, TFP growth comparisons over incomplete business cycles potentially misrepresent the impact of recessionary or growth periods. See Oxera (2013), 'The potential for frontier shift in electricity distribution', prepared for Electricity North West Limited', June, p. 10.

²⁶ For a review of revision 3 and revision 4 of EU KLEMS data, see Oxera (2016), 'Study on ongoing efficiency for Dutch gas and electricity TSOs', prepared for Netherlands Authority for Consumers and Markets (ACM), April, p. 32.

²⁷ See Bank of England (2010), 'The UK recession in context — what do three centuries of data tell us?', Quarterly Bulletin 2010 Q4, p. 285.

²⁸ For a review of the cyclical nature of TFP, see OECD (2001), 'Measuring productivity. OECD Manual. Measurement of aggregate and industry level productivity growth', July, p. 119.

²⁹ Ideally combining this with productivity data from other sources such as the ONS and the OECD to extend the dataset by including recent years of productivity data.

³⁰ Oxera (2013), 'The potential for frontier shift in electricity distribution', prepared for Electricity North West Limited', June, p. 8.

3 Review of regulatory precedents

In addition to the analysis used for RIIO-T1/GD1, the Utility Regulator has reviewed other determinations. The set of precedents considered relies on those reviewed by the CC in the context of the RP5 determination for NIE (i.e. electricity transmission and distribution). We consider it appropriate to select a relevant set of precedents on the basis of two criteria:

- **comparability of sectors**—the regulatory precedents need to be underpinned by empirical analysis that is relevant to the gas distribution sector;
- **comparability of regulatory framework**—the regulatory frameworks considered in the review must be comparable to the Utility Regulator's at GD17 (i.e. in which both an upper-quartile benchmark and a frontier-shift target are set separately);

We assess each of the precedents against these two criteria.

3.1 Comparability of sectors

The regulatory precedents need to be underpinned by empirical analysis that is relevant to the gas distribution sector.

- **Utility Regulator—water and sewerage, PC13.** For PC13, the Utility Regulator considered annual Total Factor Productivity (TFP)³¹ growth for a set of comparator sectors deemed relevant.³² The final estimates were calculated using the cost shares of water and sewerage companies, which may not reflect the cost structure of the GDNs.³³
- **PPP Arbiter—underground infrastructure companies, 2010 decision.** For the PPP Arbiter's 2010 determination, the analysis was based on a set of comparators to derive a TFP composite index aimed at reflecting a notional infrastructure company. Such comparators and cost structure may not be relevant for the GDNs.
- **ORR—Network Rail, 2010 decision.** Oxera's 2008 TFP analysis for the ORR considered evidence from a number of sectors of the economy.³⁴ While some of the sectors considered in the analysis could be appropriate for GDNs, the composite TFP benchmarks used weights based on total Network Rail projected CP4 costs, which may not be relevant.³⁵
- **Ofgem's RIIO-GD1 decision.** We consider the Ofgem RIIO-GD1 decision to be appropriate in terms of comparability to FE's activities, since this decision

³¹ TFP is a multi-factor productivity measure that takes into account all inputs (e.g. OPEX, CAPEX) that contribute to output growth. It is a standard measure of productivity that can be used for broad comparisons across companies as a static measure (undertaken in 'levels') and/or rate of change measure (undertaken over time)

³² Manufacturing; electricity, gas and water supply; sale, maintenance and repair of motor vehicles; retail sale of fuel; transport and storage; finance, insurance, real estate and business services.

³³ For example, the final estimate was driven by the high productivity growth of the manufacturing sector, which was given a 20% weight to reflect water and sewerage resource/treatment activities. These activities may not be relevant (or may be less relevant) for the GDNs.

³⁴ Electricity, gas and water supply, transport and storage, construction, post and telecommunications, rental of machinery and equipment and other business activities, financial intermediation. Some specific sectors within the ORR's comparator set, such as transport and storage, may not be relevant. This sector is also in Ofgem's comparator set at RIIO-T1/GD1.

³⁵ Oxera (2008), Oxera (2008), 'Network Rail's scope for efficiency gains in CP4', prepared for Office of Rail Regulation, April, p. 28.

was based on empirical analysis that aims to capture activities relevant to the GDNs.³⁶

- **Ofgem's DPCR5 decision.** DPCR5 is less relevant than RIIO-GD1, but still informative. However, it should be noted that while the comparator set of industries could be similar (or even the same) for electricity and gas distribution networks, the composite TFP benchmark (i.e. weighted TFP) could differ, since the weights attached to the comparator industries' TFPs are based on the cost composition of the two networks, which could be different.
- **CMA—Bristol Water, PR14.** In this case, the CMA did not consider any sectoral evidence, but made its decision based on Bristol Water's business-plan assumptions.³⁷
- **Utility Regulator—GD14 and CC—NIE RP5 inquiry.** These most recent decisions are based on some of the same precedents mentioned above, some of which are, in turn, based on analyses that may not be relevant for the GDNs.

3.2 Comparability of regulatory framework

The regulatory frameworks considered in the review must be comparable to the Utility Regulator's at GD17. The set of precedents considered by the Utility Regulator make different assumptions about the benchmark used to determine the scope for productivity improvements.

For the purposes of this review, we consider it more appropriate to select precedents in which regulators set frontier-shift targets that are achievable for an upper-quartile company (the benchmark that the Utility Regulator is considering in benchmarking the NI GDNs' OPEX).³⁸ In addition, the frontier-shift estimates from these decisions must exclude the impacts of catch-up and scale efficiency effects, as the Utility Regulator treats these effects separately for the NI GDNs.

- **PPP Arbiter—underground infrastructure companies, 2010 decision.** In 2010, the PPP Arbiter appeared to set a frontier-shift assumption only, without any catch-up targets.
- **CMA—Bristol Water, PR14.** In its price determination, the CMA set a frontier-shift target³⁹ of 1% per annum combined with an *average* efficiency benchmark. The CMA stated explicitly that a 1% per annum target was preferred because the precedents it had examined (Ofgem and NIE) were combined with catch-up efficiency benchmarks that were more demanding than an average benchmark.⁴⁰ In PR14, Ofwat did not set an explicit frontier-shift target, but implicitly determined a net frontier shift (i.e. frontier shift less

³⁶ For RIIO-ED1, Ofgem did not undertake any analysis for the electricity distribution networks, but considered the business-plan assumption made by the DNOs to be reasonable and in line with the independent information reviewed. See Ofgem (2014), 'RIIO-ED1: Final determinations for the slowtrack electricity distribution companies. Overview', November, p. 30.

³⁷ Competition and Markets Authority (2015), 'Bristol Water plc price determination. Summary of report', October. The CC NIE case and Ofgem were quoted in order to determine whether a 0.5% or 1% target was more appropriate.

³⁸ The Utility Regulator has noted that 'The analysis has compared the NI GDNs' historic and forecast opex costs to the 3rd best company in each regression sample. We regard this as being equivalent to the upper quartile benchmark'. See Utility Regulator (2016), 'Annex 5 Indicative findings from Top-down benchmarking GD17', March.

³⁹ The CMA referred to it as the cost trend on TOTEX.

⁴⁰ Competition and Markets Authority (2015), 'Bristol Water plc, A reference under section 12(3)(a) of the Water Industry Act 1991. Report', para. 4.24.

real price effects and other aspects) +0.4% per annum on water and around +2% per annum on sewerage for wholesale services.

- **Utility Regulator—GD14.** At GD14, the Utility Regulator did not set an explicit catch-up target.⁴¹

Apart from the three precedents above, all other precedents are compatible with a framework in which the scope for efficiency improvements is a combination of separate assessments of both catch-up and frontier shift.⁴²

3.3 Assessment of the relevance of OPEX and CAPEX targets from regulatory precedents

In Table 3.1, we summarise our review of the relevance of the regulatory precedents selected by the Utility Regulator.

Table 3.1 Relevance of regulatory precedents

Regulator	Relevant comparators?	Relevant framework?
Utility Regulator: water and sewerage, PC13	×	✓
PPP Arbiter: infrastructure companies, 2010 decision	×	×
ORR: Network Rail, Periodic Review 2008	×	✓
CC: NIE RP5	×	✓
CMA: Bristol Water PR14	Was based on Bristol Water's business-plan assumptions	×
Utility Regulator: GD14	×	×
Ofgem: GB electricity DNOs, DPCR5	(×)	✓
Ofgem: Transmission & Gas Distribution, RIIO-T1/GD1	✓	✓

Sources: Oxera analysis, based on various sources. The table includes OPEX and CAPEX productivity decisions considered by the Utility Regulator. Utility Regulator (2014), 'Water & Sewerage Services Price Control 2015-21', December. PPP Arbiter (2009), 'Draft directions on costs and related matters and initial thoughts on ISC setting and financing', December. Competition Commission (2014), 'Northern Ireland Electricity Limited price determination. Final determination', March. Competition and Markets Authority (2015), 'Bristol Water plc price determination. Summary of report', October. Utility Regulator (2013), 'GD14 Price Control for Northern Ireland's Gas Distribution Networks for 2014-2016', December. Office of Rail Regulation (2010), 'International cost efficiency benchmarking of Network Rail', September. Oxera (2008), 'Network Rail's scope for efficiency gains in CP4', prepared for Office of Rail Regulation, April.

Based on this review, we conclude that the most relevant precedent is Ofgem's RIIO-T1/GD1 determination, since it is based on a comparable regulatory framework and relates to the gas distribution sector. Of relatively less relevance, but still informative, are the Ofgem determinations for the electricity distribution networks at DPCR5 and RIIO-ED1.

⁴¹ '[The Utility Regulator has] chosen not to apply a separate catch-up efficiency challenge. In other words, [The Utility Regulator has] implicitly assumed in the absence of any evidence to the contrary that, with some specific adjustments to our allowances as a result of benchmarking analysis in selected areas, the GDNs allowance are reflective of a company at the frontier'. Utility Regulator (2013), 'GD14 Price Control for Northern Ireland's Gas Distribution Networks for 2014-2016. Final determination', December, p. 171.

⁴² For the CC RP5 case, the CC based the benchmark on the company ranked fifth out of a sample of 15 companies.

4 Conclusion

Having reviewed the Utility Regulator's draft determination on frontier shift, we conclude that there is most likely to be an upward bias with the current estimates, as

- a consistent use of Ofgem's RIIO-T1/GD1 analysis would imply per annum targets of 1% on OPEX and 0.7% on CAPEX;
- from the regulatory precedents that the Utility Regulator has considered, Ofgem's RIIO-GD1/T1 decision is most comparable, which again indicates that OPEX and CAPEX per annum targets of 1% and 0.7%, respectively, are in line with relevant regulatory precedents;
- there are a number of potential issues with using the estimates from Ofgem's analysis directly. In particular, the Ofgem TFP estimates that the Utility Regulator has relied on are likely to encompass other effects that will require downward adjustment to avoid overestimation of frontier-shift requirement. For example, consistent with the CC and the ORR's treatment of this issue, a 25% downward adjustment to Ofgem's RIIO-T1/GD1 results would result in per annum targets of 0.75% on OPEX and 0.5% on CAPEX.

To address some of the biases described above, we would recommend the Utility Regulator considering the latest version of the EU KLEMS dataset⁴³ and undertaking primary analysis of frontier-shift estimation for the NI GDNs, using comprehensive measures of productivity such as TFP growth measures.

⁴³ Ideally combining this with productivity data from other sources such as the ONS and the OECD to extend the dataset by including recent years of productivity data.



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