

Phoenix Natural Gas Limited

Response to the Utility Regulator consultation on the Phoenix Natural Gas Limited price control draft proposals 2012-13

October 2011

1. INTRODUCTION

Phoenix Natural Gas Limited (**PNG**) welcomes the opportunity to respond to the Utility Regulator's (**UR**) Price Control Draft Proposals 2012-2013 Consultation Paper (the **Consultation Paper**) for the fourth price control period imposed by UR since natural gas was first introduced to Northern Ireland in 1996. For the avoidance of doubt, this fourth price control covers the calendar years 2012 and 2013 and is referred to as "PNGL12" hereon.

PNG has grave concerns that the proposals put forward by UR in its Consultation Paper, in particular UR's stated intention to retrospectively adjust the Total Regulatory Value (**TRV**) agreed in 2006 and implemented via modifications to PNG's licence in 2007, are entirely inconsistent with UR's duties under the Energy (Northern Ireland) Order 2003, and with regulatory best practice. The implementation of such proposals is likely to erode investor confidence and thus increase the cost of capital for both PNG and other utilities in Northern Ireland, to the ultimate detriment of Northern Ireland consumers.

The Energy (Northern Ireland) Order 2003 established an overarching principal objective for UR, defining the purpose of UR's activities as promoting the development and maintenance of an efficient, economic and co-ordinated gas industry in Northern Ireland.¹ UR's duties require UR to consider a number of issues in furthering its primary objective, including having regard to, *inter alia*, the need to protect the interests of consumers of gas² and the need to secure that licence holders are able to finance their activities.³

In making its day to day decisions, UR should also have regard to regulatory best practice and guidance from Government. As recognised by the UK Department for Business Innovation and Skills (**BIS**) in its "Principles for Economic Regulation",⁴ successful economic regulation requires that the framework of 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. Economic regulation plays a significant role in establishing the terms under which investment is made; and efficient investment is an important part of promoting the long-term interests of consumers. It is consumers who will ultimately bear the costs of regulatory failures that prevent efficient delivery of investment. It is therefore crucial that regulatory frameworks avoid adding undue uncertainty to the business environment.

UR notes at paragraph 1.6 of the Consultation Paper that it interprets its duties, in the context of carrying out price controls, as "*a mandate to secure the most cost efficient outcome for the consumer that also allows the company to continue financing its activities.*" UR goes on to state at paragraph 9.1 of the Consultation Paper that "*any decisions we make*

¹ The Energy (Northern Ireland) Order 2003, Article 14(1).

² The Energy (Northern Ireland) Order 2003, Article 14(2)(a).

³ The Energy (Northern Ireland) Order 2003, Article 14(2)(b).

⁴ BIS Principles for Economic Regulation, April 2011

in our price control reviews should not compromise the ability of a regulated company to finance its licensed activities."

This formulation does not, however, match up to the statutory requirement, which imposes a duty upon UR to secure an adequate financing of PNG's functions, not a mere passive requirement not to compromise such financing. This point is significant. To comply with its duty, UR must secure finance that is adequate to finance PNG's functions (as well as the need to promote the gas industry in Northern Ireland) taking into account all relevant circumstances – including the commercial and regulatory risk profile facing PNG; and the factors that influence the cost of equity (and debt).

In formulating its proposals, UR seems completely to have overlooked the need to consider how the regulatory uncertainty created by UR's interventions may impact on the credit rating of PNG and in turn on PNG's ability to finance its functions. UR must look at such issues if it is to fulfil its statutory duty to ensure that PNG is able to finance its activities. UR's reopening of the 2006 TRV creates uncertainty and significantly increases the risk of a downgrade to PNG's credit rating, which is likely to increase PNG's cost of debt and equity.

This risk is not hypothetical. The rating agencies have indicated their concern to PNG (and no doubt to UR) in conversations over recent days and weeks. In the last few days, the dangerous effect of UR's failure to consider the impact of regulatory uncertainty has become very clear.

On 12 October 2011, Fitch reacted to the mere announcement of UR's intentions in the Consultation Paper by placing PNG on negative watch. Fitch, in underlining that it considers transparency and predictability of the regulatory regime to be a key rating driver for gas distribution networks, has warned that the outcome of the Consultation Paper could have further implications for how Fitch views the regulatory framework for gas distribution in Northern Ireland. UR will need to take clear and decisive action (not least by abandoning its current proposal to revisit old agreements) if it is not to be the catalyst for regulatory uncertainty, for damage to PNG's (and indeed to other Northern Ireland utilities') ability to attract finance, and for a costlier gas regime in Northern Ireland resulting from increased financing costs.

In addition to being wholly inconsistent with UR's duties, UR's proposal to re-open TRV_{F,2006}, is entirely at odds with standard regulatory practice and, in particular, with the principle that the framework of economic regulation should not unreasonably unravel past decisions. UR's failure to engage in consistent and transparent decision-making - and in deviating from standard regulatory practice - is likely to have a chilling effect on investment in Northern Ireland. The setting of such a regulatory precedent, which so deviates from best practice principles of economic regulation, risks also having an unwelcome knock-on effect across other regulated industries in Northern Ireland and potentially beyond.

PNG is unable to accept a set of proposals which introduce such a high level of risk and uncertainty to the regulatory regime and which undermine PNG's ability to finance its licensed activities going forward. PNG would therefore urge UR to reconsider its proposals in light of UR's duties and regulatory best practice.

PNG would reiterate, in responding to the Consultation Paper, the concerns that PNG has already articulated with respect to the inadequacies of the consultation procedure related to PNGL12. Most importantly (see further the letter from PNG's lawyers of 6 October 2011), PNG has pointed out the grave difficulty it has (and no doubt other respondents will have) in responding to UR's price control proposals when those proposals are expected to be followed by a licence modification significantly affecting prices without knowledge of the exact licence modification proposed. PNG is disappointed that UR has failed to provide a coherent explanation of how the proposed price control and licence modifications fit together and reserves its rights to provide further comments as and when UR provides an explanation on the cumulative effect of the price determination procedure and the licence modification.

The response which follows summarises PNG's key points on the various proposals put forward by UR in its Consultation Paper. Only the most significant points have been addressed in this response as PNG is confident that less significant points and/or more practical points can be addressed and agreed with UR through working level discussions.

PNG's response is structured as follows:

- Section 2 addresses UR's proposal to remove certain outperformance from the opening Total Regulatory Value (TRV) for 2012.
- Section 3 addresses UR's proposal to remove certain deferred capex from the opening Total Regulatory Value for 2012.
- Section 4 represents PNG's response to Section 9 of UR's Consultation Paper on financeability.
- Section 5 represents PNG's response to all elements of UR's Consultation Paper other than those discussed in previous sections.
- Section 6 represents PNG's response to Appendix 1 of UR's Consultation Paper.

2. REGULATORY MODEL

Introduction

This Section 2 addresses UR's proposal to remove certain outperformance from the opening Total Regulatory Value (TRV) for 2012 as set out in Section 7 of UR's Consultation Paper⁵.

At Section 7, UR proposes to *"review the value of [PNG's] asset base"*. It proposes to do so by *"consider[ing] the value of the PNG asset base ... at the opening of the previous price control, PC03 [and] the adjustments that need to be made to reach an opening TRV position in this price control"*.

As explained briefly in this introduction and in more detail below, this approach:

- operates in a manner inconsistent with PNG's licence, which expressly sets out both the value for $TRV_{F,2006}$ ⁶ and the formulae for future price controls, taking this total regulatory value (**TRV**) into account;
- runs contrary to principles of good regulation adopted by other industry regulators and the Competition Commission in that it seeks to re-open the opening asset value agreed in the price control for a previous period;
- as a result, causes regulatory uncertainty that risks stifling investment in, and/or increasing the cost of capital for, both PNG and other utilities in Northern Ireland, to the ultimate detriment of Northern Ireland consumers.

For these reasons (and on the basis of the more detailed reasoning set out below) PNG cannot accept the price control (and/or licence modifications) proposed by UR.

UR's approach is inconsistent with the terms of PNG's licence

UR claims that its approach is consistent with the intentions of the 2006 discussions and with its 2007 licence modifications. There was never, however, any suggestion in 2006 or 2007 that UR would seek to re-open the agreement on the treatment of historic outperformance that was achieved during the periods which predated the 2006 Agreement.

The value of $TRV_{F,2006}$ was agreed between UR and PNG following detailed negotiations in 2006 on the appropriate regulatory regime for PNG going forward (the **2006 Agreement**). The licence was modified specifically in 2007 so as to include the value of $TRV_{F,2006}$ agreed in negotiations between UR and PNG as part of the 2006 Agreement at Condition 2.3.18,

⁵ PNG's response to UR's deferred capex proposals are detailed in Section 3 below.

⁶ $TRV_{F,2006}$ refers to the value of £312.8m as stated in Condition 2.3.18 of PNG's licence. This is the value agreed by UR and PNG as part of the 2006 Agreement and subsequent 2007 licence modifications, and is occasionally referred to as the Opening Asset Value (OAV) in this response.

effectively “locking in” the $TRV_{F,2006}$ value for future price control reviews and with an understanding between UR and PNG that inclusion of the provision in the licence was designed to have this effect. That the $TRV_{F,2006}$ value was intended to form a base for future price controls is confirmed by the fact that the licence was amended to include an agreed mechanism for recovery of this value in future price control review periods. This mechanism is incorporated in the licence through the set of equations set out in Condition 2.3. UR’s action in seeking to re-open $TRV_{F,2006}$, which was regarded by PNG and any reasonable observer as fixed and binding on UR, is inconsistent with the terms of PNG’s licence.

Moreover, prior to the publication of the Consultation Paper, the prospect of a retrospective adjustment to $TRV_{F,2006}$ to remove the 1996-2006 outperformance addition from the asset base was never once mentioned by UR in any discussions or interactions with PNG or its shareholder, or indeed with the rating agencies. To say such action is consistent with the intentions of the 2006 discussions and the resulting 2007 licence modification is extremely misleading. PNG comments further on UR’s selective representation of history as set out in Appendix 1 of the Consultation Paper (which it uses to suggest that its approach now is consistent with the 2007 licence modifications) at Section 6 of this response.

UR’s approach is inconsistent with principles of good regulation

UR’s assertion that it is “standard regulatory practice to re-open the value of a regulated company’s asset base at each price control⁷” is entirely misleading. It is not standard practice, as UR states, for a regulator to revisit and re-open agreements previously reached on matters relating to periods preceding the current control period i.e. pre 2007. In fact, it is standard regulatory practice, outside Northern Ireland (and as summarised below), to avoid revisiting such values given the very real risk that a re-opening of the regulatory “contract” would damage regulatory credibility and threaten investor confidence.

Moreover, the examples from Ofgem and Ofwat cited by UR in its Consultation Paper as evidence that there is regulatory precedent for UR’s proposal to revisit the opening asset value agreed at the start of a previous price control⁸ are not relevant and referring to these examples is misleading⁹. The examples referred to relate to regulatory mechanisms to make adjustments to the previously agreed opening TRV for capital expenditure that has occurred **since the last review**. They are not examples of regulators re-visiting the opening asset value agreed at the start of the previous control period. As such, they cannot provide any support for UR’s contention that its approach is in accordance with standard regulatory practice.

⁷ UR (2011) para 7.9.

⁸ i.e. $TRV_{F,2006}$ in this case.

⁹ UR (2011) p.51

UR's approach causes unnecessary and inappropriate regulatory uncertainty

Industry regulators do not revisit old price controls or seek to revisit historic valuations locked into a licence for a very good reason. They understand that such retrospective acts undermine regulatory credibility, denying investors - including here PNG's bankers, PNG's bond holders and PNG's shareholders - the confidence to invest.

The uncertainty over the methodology for determining TRV that UR's draft proposals have created completely undermines this confidence (see further Section 4 of this submission, reporting on the fact that Fitch, reflecting the uncertainty resulting from the steps UR has proposed in its Consultation Paper, has placed PNG on negative watch). UR has created a situation where PNG's investors cannot place any reliance on licence provisions in general, or the agreed value for $TRV_{F,2006}$ and price control formulae in particular. If UR is prepared to reduce $TRV_{F,2006}$, a term specifically laid out in the licence, what comfort do PNG's investors have that UR will not repeat the process at each and every periodic review?

UR's proposals destroy the regulatory certainty that was achieved through the 2006 Agreement. The natural consequence of this is to increase regulatory risk for investors, and with that, the cost of gas and other utilities for consumers in Northern Ireland. This will make future financing of utilities difficult and more costly to secure.

A price control that suffers the defects and carries the risks of regulatory uncertainty summarised above (and described in more detail below) could never be justified as operating in the manner best calculated to allow PNG to finance its licensed activities. Accordingly, PNG cannot accept UR's proposal to re-open this value or the mechanism for future recovery.

PNG also notes that UR's calculations contain fundamental mistakes in understanding both how $TRV_{F,2006}$ was calculated and how "standard" GB regimes work. However, since PNG does not accept that the proposed adjustment to $TRV_{F,2006}$ and the TRV valuation methodology is legitimate, PNG does not consider that such calculation errors are relevant at this present time and therefore does not elaborate on such errors in this response. PNG is nonetheless willing to go through these errors separately with UR if UR would find it helpful.

UR's approach operates in a manner inconsistent with PNG's licence

PNG's licence is both clear and explicit as to how a price control review should be conducted. Specifically, and crucially, it specifies precisely the TRV for 2006; sets out how $TRV_{F,2006}$ is to be adjusted to reflect additional capital expenditure between regulatory periods; sets out how allowable costs and hence total revenues are to be determined; and identifies the return that PNG's investors are entitled to make on their investment.

By proposing a new TRV methodology that revisits the value for $TRV_{F,2006}$ agreed as part of the 2006 agreement, UR deviates from the requirements of the licence. UR puts forward two explanations for deviating in this way.

First, UR alleges that such a form of deviation is “*consistent with regulatory practice elsewhere*”¹⁰. As addressed in detail in the next section of this submission, UR’s assertion is incorrect.

Second, UR alleges that such a form of deviation is consistent with the “*intentions of the 2006 discussions and the resulting 2007 licence modifications*”¹¹. Regrettably, UR’s recollections of the discussions and the agreement underpinning the 2007 licence modifications are very far from accurate. A detailed look at the history demonstrates this beyond doubt: and shows that a re-opening of $TRV_{F,2006}$ to reconsider past outperformance is wholly inconsistent with the 2006 Agreement and 2007 licence modifications. PNG is particularly disappointed that UR’s recollection of the history so deviates from events. PNG would urge UR, in the light of the summary below, to interrogate its files – and to share the contents of those files with PNG – as PNG is confident that such files should confirm the facts as set out below by PNG.

This section looks at that history in an attempt to assist UR in reaching a proposal that is consistent with understandings and legitimate expectations from past reviews; and in the hope that this will be sufficiently clear to enable UR to abandon the proposal to revisit the issue of past outperformance.

The historical analysis is broken down into the following stages:

- the prelude to the 2006 Agreement;
- the 2006 Agreement process; and
- the licence modification and implementation of PC03.

There are two important points to note from the history:

- first, that UR sought and agreed in 2006 (and implemented by way of licence modifications in 2007) a *package* whereby a *number of components of price control were fixed* for specific periods. In its Consultation Paper, UR acts in a manner inconsistent with the 2006/7 position by treating elements of the package in isolation; and by seeking to amend elements that were deliberately fixed (and noted as fixed in the licence);
- second, that UR has from 2006/7 until the publication of the Consultation Paper behaved in a manner entirely consistent with there being a package with fixed

¹⁰ UR (2011) para 7.28
¹¹ UR (2011) para 7.28

elements. Indeed, it is hugely surprising that UR would never have alerted PNG to the fact that some or all elements of the package were suitable for re-examination over the five year period when it had multiple opportunities to do so.

Pre-2006 Agreement

Section 6 below provides a comprehensive response to Appendix 1 of the Consultation Paper. The following facts are particularly important:

- The original 1996 licence, as UR acknowledges, reflected the *“high level of risks associated with developing an entirely new market from a zero base”*¹². An 8.5% return was originally allowed for an original period of 20 years on the basis that it was an *average* over those 20 years. The 20 year agreement was to allay investors’ fear that UR would seek to reduce the return once they had made the large initial investment.
- With the need for a ‘new build’ network, revenue recovery was profiled over the 20 year licence period to reflect the fact that it would take time for the volumes to grow to a sustainable level enabling the original investment to be recovered. This was entirely appropriate and consistent with the aim of delivering stability to long term prices. However, it meant that the TRV (when created) would necessarily have to allow for recovery of incentives for outperformance later in the licence period. In a “standard” GB price control they would have been recovered as enhanced profit within the price control period. The economic value of PNG’s outperformance (and underperformance in respect of volumes) therefore had to be included in the calculation of $TRV_{F,2006}$ because they could not be recovered at the time that they occurred. This is distinct from the issue of under-recovered revenue (i.e. where PNG set tariffs below the cap set by UR and with UR’s knowledge and support). The drafting in Appendix 1 of UR’s Consultation Paper does not make a clear distinction between these issues.
- Within this 20-year cashflow calculation, there were periodic price control reviews that allowed UR to reflect past efficiencies in the forward looking forecasts, thus allowing customers to share in these benefits going forward. Therefore the substance of the GB model of sharing outperformance was honoured in the PNG licence, except that PNG’s share was ‘rolled up’ in the TRV because they could not be realised at the time they were made.
- UR makes no mention in Appendix 1 of the Consultation Paper to the events of 2002 to 2006. UR first began to support the need to move to a longer-term recovery

¹² UR (2011) p58.

period in 2002. This new arrangement allowed customers to benefit from having prices reflect the expected economic life of the assets, rather than the original control period of 20 years. From 2002, PNG faced intense regulatory pressure not to increase prices to the level of its price cap. By responding to this regulatory pressure from UR, PNG under-recovered against its price cap to a greater extent than expected. This had a significant adverse effect on the cash flow of the business.

- PNG believed it had reached agreement with UR on this issue in August 2004. UR engaged with PNG in detailed drafting reflecting this agreement, but chose to withdraw its support for the agreement at a very late stage (when drafting was at an advanced stage), the prompt for withdrawing support being apparently the takeover in 2005 of East Surrey Holdings plc (ESH) (and indirectly PNG) by Kellen Acquisitions Limited (Kellen). As a consequence, a significant build-up of under-recovered revenue occurred as PNG, in response to pressure from UR, held prices down, in the expectation that the recovery period issue would be resolved and the development of the gas industry maintained. PNG did not want to put prices up to the maximum allowed under its original price control only to have to reduce them when UR finally agreed to the new model, as PNG felt that this would give the wrong price signals to potential new customers.

2006 Agreement

As UR notes, an agreement was finally reached in 2006. The 2006 Agreement was comprehensive, a package covering many aspects of PNG's business. In terms of the price control, UR had decided it wanted to move from the cashflow approach (set out in the original licence condition) to one that reflected what (at the time) was a more standard GB regulatory approach; namely that based allowable revenue on expected values for operating expenditures plus a return on, and depreciation of, a regulated asset value (i.e. TRV). This required an opening value for this TRV to be determined (which became $TRV_{F,2006}$).

There were a number of components in the determination of the closing TRV in 2006, one of which comprised the treatment of historic out (and under) performance. The calculation of each component was subject to a detailed and thorough deliberation between PNG and UR. This was undertaken in an open, transparent and constructive manner. There are many papers from both sides debating the calculation, including detailed consideration of the treatment of outperformance, which UR now seeks to re-open. Indeed, the calculations that UR describes in the Consultation Paper were considered at the time as an alternative means of calculating TRV but were not pursued by UR. Instead it adopted a different methodology and was satisfied that its final calculation of the $TRV_{F,2006}$ meant "*out performance for the*

*period 1996-2006 is shared between customers and Phoenix based on regulatory practice elsewhere*¹³.

This debate on the calculation of the opening TRV also covered other elements, including the penal treatment of accrued under recovered revenue that had arisen due to UR's failure to agree to a longer recovery period in a timely manner (an approach PNG considered at the time as falling well short of regulatory best practice).

Further, as part of the package (incorporating the approach to outperformance), PNG was persuaded to give up value in relation to a number of significant components. These included:

- PNG having to sell its transmission business to a mutualised vehicle at a value determined by UR, thereby denying PNG's investors the opportunity to either earn a return on such an investment by operating in an efficient manner itself; or to realise its potential open market value through an arm's length sale of the asset alongside its licence to operate;
- PNG having to accept a reduced rate of return on both its transmission business (for the period up to sale) and distribution business, compared with that set out in the original licence; and
- PNG also having to agree to a write-off to PNG's Supply business from a loss on the Legacy Contract issue, among other elements.

The 2006 Agreement therefore comprised a number of different components. All of these different elements were, and were seen at the time, as part of a single agreement, part of a total package.

PNG and its investors always made their view of the elements as a package clear to UR. For example, in a letter setting out Terra Firma's response to the provisional proposals it said:

*"Subject to reaching agreement on the issues raised in the attachment to this letter, I would be minded to recommend to these boards that they should approve these proposals. For the avoidance of doubt, this does not mean that we necessarily agree with the methodologies or policies that underlie individual aspects of your proposals. However, I would be inclined to take the view that the overall package that is being offered is acceptable."*¹⁴

It is clear from this statement that the 2006 Agreement was seen by PNG's investors as an all-inclusive agreement. It is wholly inappropriate to unwind this agreement by revisiting and re-opening one component of this package in isolation. This is not an option available to

¹³ "Phoenix Natural Gas Licence Restructuring: Proposed Price Control Licence Modifications", UReg (6 April 2007), p 4 para 13.

¹⁴ Letter from TF to UR 8 November 2006

PNG – it cannot, for example, “un-sell” its former transmission business. It is not an option which should be available to UR.

It was not just PNG and Terra Firma that saw the components as part of a single package. It was apparent throughout the negotiation process that led to the 2006 Agreement that UR also recognised the interrelationship of the various components of the agreement. It too treated these components as part of an overall package, as reflected in the fact that it presented the elements of the package to Terra Firma in a single letter setting out the terms that it was minded to offer to conclude its renegotiation of the PNG licence. It was also clear that, at the time, UR regarded the overall package as being in customers’ best interests, commenting:

“Customers benefit in two ways from the agreement; no substantial increase in distribution charges which would otherwise be necessary in the absence of agreement and a reduced rate of return. The Authority estimates the value of benefits of the agreement to consumers to be in the region of £25m in 2006 present value terms”.¹⁵

When UR proposed the revised licence, PNG was given to understand that UR judged the new licence conditions to be those best calculated to promote the development of the network in PNG’s licensed area in an economic and efficient manner, and to provide investors with a secure framework for them to underpin PNG’s continued growth.

Licence modification

PNG consented to the 2007 licence modification on the basis of the understanding that was reached under the 2006 Agreement. Central to the 2007 licence modification was the introduction of a price control which contained a mechanism which allowed future price controls to be implemented **without** the need for a formal licence modification. The extensive negotiation of an opening TRV, of a mechanism that allowed future price controls without licence modification, and the embodying of these terms within the licence created a legitimate expectation (not only at PNG, but at its investors and at the rating agencies) that this mechanism would be followed by UR in the future. At the time PNG agreed to the licence modifications, there was no indication from UR that the treatment of outperformance would change or that the regulatory treatment of outperformance predating the 2007 price control period would be revisited. Rather, UR’s behaviour at the time gave every indication that the extensively discussed opening TRV and mechanism would be applied in the future.

UR never raised with PNG the prospect of a retrospective adjustment to the treatment of outperformance. It was not mentioned in the consultation to the licence modification; the licence modification itself does not make provision for such a treatment; and the prospect of

¹⁵ UR (April 2007) p5 para 17.

such an adjustment was not discussed before the current Consultation Paper was published. Most importantly, it was not referred to during discussions with PNG and the rating agencies when PNG was acquiring an investment grade credit rating in the autumn of 2009 and subsequently refinancing its business in the summer of 2011, when clearly such an issue would have been particularly relevant to such discussions. It was also not mentioned in UR's January 2010 Consultation Paper on aligning the price control reviews of Northern Ireland's Gas Distribution Networks, nor throughout the discussions which have occurred subsequently during this PNG12 price control process.

UR has itself recognised in the Consultation Paper that its proposals do not comply with the licence, by stating that:

*"We will also need to make some amendments to the PNGL licence to implement the price control."*¹⁶

UR's proposals are therefore not consistent with the 2007 licence modifications and the procedure established in Condition 2.3.13.

It should be noted that the calculation of $TRV_{F,2006}$ for inclusion into the licence was held up until PNG's 2006 Regulatory Accounts were issued. The reason for the delay was to enable the number to be finalised based on audited numbers, because it was not intended to be subject to change. Any reasonable person would understand (as did PNG) that this number was included within the licence to provide additional certainty that the value was agreed between UR and PNG and would not be revisited subsequently.

As noted above, prior to the receipt of the Consultation Paper, PNG was not made aware that UR would seek to re-open the treatment of outperformance earned before the start of the current control period that is captured in $TRV_{F,2006}$. Indeed, when UR published the third price control determination (PC03) covering the five-year period from 2007 to 2011 it stated:

"In November 2006 the Utility Regulatory and PNG finalised a regulatory agreement to facilitate a stable future for the growing gas industry in Belfast allowing the recovery of revenues over the next 40 years. Key aspects of this agreement were to agree the RAV [i.e. $TRV - PNGL$ clarification] (including historic out performance, deferred capex and under-recovery), extend the recovery period from 20 years to 40 years and reduce the rate of return from 8.5% to 7.5%"

If UR was aware of its intention to re-open $TRV_{F,2006}$ earlier then we would question why UR did not make this clear to PNG, particularly given its relevance in the context of the two refinancing actions that PNG has undertaken since 2006 and which PNG discussed with UR as recently as August 2011. UR cannot have been unaware that its proposals would have a

¹⁶ UR (2011) para 10.4.

material impact on the terms for the proposed 2011 refinancing, and accordingly PNG could have reasonably expected to have been informed of UR's intentions at that time.

Since 2006, a number of decisions have been made by both PNG's investors and by PNG's board which were consequent on PNG's understanding that the $TRV_{F,2006}$ recorded in licence Condition 2.3.18 was fixed. These include:

- Obtaining a credit rating of BBB+ by Fitch and Baa2 by Moody's and maintaining it
- Issue of £275m of Bonds in 2009 due 2017 at rate of 5.5% by Phoenix Natural Gas Finance plc, guaranteed by PNG and Phoenix Distribution Holdings Limited
- Continued investment of c.£60m in developing the network over the five years and connecting c.40,000 additional properties
- Approval by the Board of certificates in accordance with licence condition 1.22.6(d) where gearing is calculated by the ratio of Net Debt/TRV
- Approval by the Board of projections of the TRV to bond holders in accordance with the covenants in the bond

UR has been aware of all of these transactions and at no time has suggested or drawn attention to the fact that it was minded to re-open the way in which the licence envisages TRV being calculated.

It should be noted that since this 2006 Agreement was reached, PNG has entered into licence amendments on the basis of the Agreement and accepted the application of UR's third price control (PC03), which, contrary to UR's assertions, did not follow "*shortly after the 2006 deal was concluded*". Instead, it was only partially completed after the first year of the control period had ended with UR setting allowances for that first year that meant that PNG was unable to cover the costs it had incurred during that period while it waited for UR to complete the process.

Further, PNG has continued to invest in its business over the subsequent 5 years on the basis of the 2006 Agreement and subsequent price controls, restructured its business to facilitate sale of transmission, refinanced its business on the basis of the 2006 Agreement and in support of ring fencing obligations, and operated the business in good faith in compliance with fiduciary requirements on the basis of the fact that $TRV_{F,2006}$ was and is not retrospectively changeable. UR's proposal to retrospectively adjust the treatment of historic outperformance represents a failure by UR to provide a stable regulatory framework for PNG to operate within and substantially increases the risk to both PNG and indeed other related utility infrastructure investment. As a consequence of UR's proposals, there are significant concerns about PNG's ability to meet future financing requirements at a level consistent with comparable investments in GB (this is discussed further in Section 4).

UR's approach is inconsistent with principles of good regulation

UR's justification for removing outperformance is premised on the basis that its proposed course of *"action is consistent with regulatory practice elsewhere"*. This justification is misguided – and wrong. UR's proposals are not in line with regulatory precedent and are inconsistent with established best practice principles of regulation.

The standard regulatory approach is to review the asset base value in the light of what has occurred **within the most recent control period**, based on the principles that were set out at the time the control was set. It is most certainly not standard regulatory practice to revisit the calculation of the asset base that had been agreed prior to the commencement of the previous control period.

This is for good reason. Changes to the regulatory framework and methodology are only applied on a forward-looking basis so that the company has an opportunity to respond to the incentives being provided. Applying changes retrospectively removes this opportunity and allows for opportunistic behaviour on the part of the regulator which, if pursued by the regulator, damages the credibility of the regulatory regime. Utilities have an incentive to out-perform regulatory assumptions to promote efficiency and economy, in the expectation that they will keep a proportion of that outperformance. If regulators retrospectively remove the value of any outperformance, the concept of incentive regulation is completely undermined.

Furthermore, it is unreasonable to expect a regulated company and its investors to have to second-guess the regulator's future retrospective actions when making their investment decisions. A regime which allows for this type of behaviour only serves to promote regulatory uncertainty and risk to the business and investors, which cannot be considered as best calculated to promote efficiency and economy and enable PNG to secure the required finance.

Regulators and the Competition Commission have recognised the poor incentive properties associated with writing off value from the TRV, and have sought to avoid doing so. For example, as part of its RPI-X@20 review of network regulation, Ofgem confirmed its view that there should be no retrospective action and no change in the treatment of assets already in the TRV. This was done to provide certainty for investors.

*"No retrospective action: We understand the importance of maintaining regulatory certainty and therefore are keen to make clear that RPI-X@20 will be focussed upon the framework for future regulation of energy networks."*¹⁷

¹⁷ Ofgem (2009), RPI-X@20:Principles, Process and Issues, p12
(http://www.ofgem.gov.uk/Networks/rpix20/ConsultDocs/Documents1/Principles%20Processes%20and%20Issues%20con%20doc_final%20-%20270209.pdf)

Ofgem also stressed that there would be no retrospective action taken ‘with the benefit of hindsight’, as long as outputs are delivered. Any adjustments and incentive mechanisms that were to be developed would be consulted on and would be forward looking only. For example:

“we would 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 would 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.”¹⁸

Similarly, Ofwat’s key criteria for setting capex incentive mechanisms includes that *“each company needs to know in advance how the mechanisms will be applied as this will reduce uncertainty in its decision making”* and *“wherever possible we should avoid retrospective changes to the agreed mechanisms.”¹⁹*

UR itself strives to *“be a Best Practice Regulator: transparent, consistent, proportional, accountable, and targeted.”²⁰* UR’s proposals therefore represent a breach of UR’s own principles and risk cutting across the objectives of the Energy (Northern Ireland) Order 2003 which are designed to promote certainty in the efficient development of a Northern Ireland gas market. Transparency and accountability are upheld as key values of best practice regulation elsewhere. For example, the Government recently published an overarching set of Principles for Economic Regulation²¹ which highlights the importance of predictability and stability in economic regulation, stating that:

“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”

and

“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”

¹⁸ Ofgem (2010), Handbook for Implementing the RIIO model, p84

¹⁹ Ofwat, Further consultation on incentive mechanisms: rewarding future out-performance and handling under-performance of regulatory expectations - a consultation paper, Jun 2003.
http://www.ofwat.gov.uk/pricereview/pr04/pr04phase1/pap_con_outperform.pdf?download=Download#

²⁰ UR values statement. http://www.uregni.gov.uk/about_us/ These are in turn based on DETI’s Better Regulation Strategy for Northern Ireland DETI, Northern Ireland Better Regulation Strategy, Annual Report 2009/10. http://www.detini.gov.uk/better_regulation_annual_report_2009-10_pdf.pdf

²¹ “Principles for Economic Regulation”, BIS (April 2011)

UR explicitly recognises that it is unravelling past decisions by stating that *“In our review, we have considered the value of the PNGL asset base ... at the opening of the previous price control, PC03.”*²² By doing so, UR’s proposals will destabilise the investment environment, and lead to a significant loss of credibility, in contrast to the best practice principles set out above.

Further, the examples cited by UR from Ofgem and Ofwat are misleadingly presented as evidence that there is regulatory precedent for UR’s proposals²³. These mechanisms allow for adjustments to the previously agreed opening TRV for capital expenditure that has occurred **since the last review**. They are not examples of regulators re-visiting the opening asset value agreed at the start of the previous control period. As such, these mechanisms do not provide support for UR’s proposals.

Instead it is extremely unusual for a regulator to change elements of price control that relate to periods before the last price control review. The only exceptions to this are the following, both of which have a very limited application:

- **Significant new information comes to light:** If the Regulator has been misled by the company in terms of the information it originally provided, there may be a case for making a subsequent change to rectify any resulting error. There is no new information relating to the calculation of the TRV in this case. Indeed, the calculations that UR has undertaken are based on the same information that was available at the time the 2006 Agreement was reached.
- **A company fails to meet its core output measures:** There may also be a case for making a retrospective adjustment if the company manifestly fails to meet its core output measures because it has failed properly to invest the revenue it has received. Again this is not the case for PNG. PNG has always met its licence obligations in respect of coverage of the network and at the end of 2010 c.280,000 properties have natural gas available to them, c.140,000 customers are already connected and it has met its service standards, even during the extremely challenging 2010/11 winter period.

Since PNG has neither misled UR nor failed to meet its output targets, UR has no justification in claiming that regulatory precedent allows it to make such a retrospective change to PNG’s asset value.

²² UR (2011) para. 7.9.

²³ UR (2011) p.51

UR's approach causes inappropriate regulatory uncertainty

As set out in the previous two sections, UR's approach in proposing a retrospective adjustment to the treatment of historic outperformance is wholly inconsistent with regulatory best practice and inconsistent with previous regulatory agreements. No advance warning or consultation (e.g. through working level discussions) preceded the announcement of such a radical approach. As a result, UR's proposals give rise to the following consequences.

- UR has introduced a significant degree of uncertainty into an element of PNG's price regulation which PNG and investors reasonably understood to be fixed. UR is re-opening one aspect of the 2006 Agreement without recognising the fact that the 2006 Agreement was only accepted by both parties when all the components are considered 'in the round'. Other aspects of that package, such as the sale of PNG's transmission business, cannot be undone. Such behaviour therefore increases the perception of regulatory risk and damages the credibility of the utility regulation regime in Northern Ireland (see further Section 4 on the attitude of the rating agencies and in particular to the fact that Fitch, concerned about regulatory risk, has very recently placed PNG on negative watch).
- UR's behaviour will also undermine investor confidence in the regulatory process, with serious consequences for future incentives to invest in utilities in Northern Ireland. Firms will not invest if they believe there is a likelihood of inconsistent regulatory behaviour (e.g. through retrospective adjustments) which might undermine the value of their investment (and Fitch's recent warning confirms to investors that they may be right to be cautious on investing).
- The required relative rate of return will rise as a direct consequence of such a decision. The TRV is central to the value of the business and key to facilitating and encouraging investment. A stable TRV allows the networks to secure financing on reasonable terms and at an efficient cost. Revisiting the TRV creates significant uncertainty about future remuneration for investments previously committed and irrevocable investment, and it will have the knock-on effect of raising the required return or causing investors to avoid investing at all. This will impact not only PNG, but all regulated entities in Northern Ireland, to the long term detriment of customers. The potential impact that UR's proposals could have on PNG's ability to attract finance should not be downplayed. In the case of Bristol Water in 2010, the Competition Commission recognised the potential impact that ex post adjustments to the TRV could have on the cost of capital.

"Water companies are capital-intensive businesses. In principle, a regulator could try to develop a view of a company's efficient level of capital-related costs in a similar way to that for opex, using inter-company comparisons. However, this has not

*happened in the water industry, nor in the utilities sector more generally or for airports. This is for two main reasons. First, it is very difficult to calculate an efficient level of capital-related costs given the geographical and historical differences between companies. Second, given the uncertainties, any attempt to use such techniques would expose the companies to significant regulatory risk (ie of tough future regulatory decisions leaving companies with 'stranded' assets). This risk would be costly because it would cause investors to require a higher return on their investments, resulting in a higher cost of capital."*²⁴

Summary

In summary, PNG is of the view that UR's proposals in Section 7 of the Consultation Paper would be subjected to the most intense criticism on any review by the Competition Commission. First, they deviate from UR's past decisions in relation to PNG and in relation to outperformance, with UR choosing to revisit its position in 2006 but doing so in a manner that can best be described as "cherry picking", i.e. UR has chosen to revisit parts of a package that would if adjusted reduce prices but not the other parts of the package from that time. Second, they deviate from good regulatory practice. Third, they will have the effect of creating significant regulatory uncertainty, deterring efficient investment and ultimately raising the required rate of return, to the detriment of Northern Ireland consumers. If investors cannot rely on figures clearly stated in a licence when they are making decisions to finance PNG's licensed activities, then there is no reliable basis upon which they can make those decisions. Therefore UR's proposals undermine PNG's ability to finance its licensed activities going into the future. Investors will always have to factor into their analysis the risk that UR will arbitrarily reduce the TRV at the next review.

²⁴ Competition Commission, Bristol Water plc Price Limits Determination, Appendix B, September 2010. http://www.competition-commission.org.uk/rep_pub/reports/2010/558Bristol.htm

3. DEFERRED CAPEX

Introduction

This Section 3 represents PNG's response to UR's deferred capex draft proposals within Section 7 of the Consultation Paper.

UR's proposals for deferred capex are flawed in three substantial respects, in terms of the scope of UR's review and the individual assumptions that underlie the proposed adjustment. In particular:

- as with the proposals for treatment of outperformance described in Section 2, the methodology proposed by UR for deferred capex fails to recognise the facts of the 2006 Agreement, and the treatment of deferred capex that was established within that Agreement;
- the methodology proposed by UR is inconsistent with the treatment of deferred capex established in the PC03 determination, and with PNG's understanding of how deferred capex would be treated at this review; and
- the proposals run directly counter to the principles of incentive regulation, which is likely to result in significantly worse outcomes for consumers in future.

In addition to these primary concerns, there are a number of mistakes in the calculations made by UR to reach the figure of a £21.2m reduction to TRV. However, since PNG does not accept that the proposed adjustment is legitimate, PNG does not consider that such calculation errors are relevant at this present time and therefore does not elaborate on such errors in this response. PNG is nonetheless willing to go through these errors separately with UR if UR would find it helpful.

The proposed treatment of deferred capex has not been subject to discussion between UR and PNG as part of the PNG12 review. PNG was not given an opportunity to discuss the appropriateness of UR's draft proposals within Section 7 of the Consultation Paper in advance of publication. It is unacceptable as a matter of regulatory practice for UR to raise a substantial issue in the Consultation Paper that has not been explored at working level discussions during the PNG12 review. This is inconsistent with UR's commitment to transparency, and with best practice principles of regulation. There is a mechanism to deal with deferred capex. Had there been discussions with UR, a sensible resolution would likely have been reached as to the appropriate treatment and number for deferred capex. We are very willing to engage constructively with UR on this issue and would welcome engagement at the earliest opportunity.

We discuss our primary concerns with UR's current approach in turn below. PNG urges UR to take note of these concerns, and to engage in an open and constructive discussion regarding the appropriate treatment of deferred capex for PNG12.

Inconsistency with 2006 Agreement

As discussed in Section 2, UR's proposals in Section 7 of the Consultation Paper run contrary to the decisions made in the 2006 Agreement and subsequently embedded in the 2007 licence modifications. For deferred capex, as with outperformance, UR's proposals change that decision, and effectively re-open the discussions that were held at the time. Deferred capex was subject to considerable discussion between UR and PNG at the time of PNG's second price control review (PC02) and as part of the 2006 Agreement. The 2006 Agreement set the agreed level of deferred capex at the end of PC02. This was confirmed in UR's published third price control determination (PC03) of 20th February 2008.

*"In November 2006 the Utility Regulator and PNG finalised a regulatory agreement to facilitate a stable future for the growing gas industry in Belfast allowing the recovery of revenues over the next 40 years. Key aspects of this agreement were to agree the RAV (including historic out performance, deferred capex and under-recovery), extend the recovery period from 20 years to 40 years and reduce the rate of return from 8.5% to 7.5%."*²⁵

The level of deferred capex out-performance included within the agreed 2006 TRV of £312.8m was £5.257m. This was calculated as the difference between the allowed expenditure for projects deferred since before PC02 and due to be completed within the PC02 period, and actual expenditure on deferred projects.

The valuation of deferred capex arrived at in 2006 set a level of expectation, both with regard to the magnitude and scope of subsequent reviews of deferred capex, which is totally inconsistent with proposals included in this Consultation Paper. In the same way as for its proposals on outperformance discussed in Section 2, UR's proposals for deferred capex run completely contrary to the principles used in deriving TRV_{F,2006}, which is embedded in PNG's licence.

In particular, it is inappropriate that an adjustment to TRV should be made now to reflect the value of deferred capex achieved before 2007. UR's proposal to claw back value before that time ignores the fact that this was already debated at length in 2006. UR's current proposals are tantamount to a rejection of the conclusions reached at that time, and effectively amount to re-opening the 2006 Agreement. Furthermore, as discussed in Section 2, they amount to an unacceptable attempt to unravel elements of that Agreement in isolation, without acknowledging that the Agreement was only acceptable to both parties as a whole package.

²⁵ Information relating to the Phoenix Distribution Price Control Review 2007 – 2011 Final Determination UR 20th February 2008 – page 3

As discussed in Section 2 above, these proposals can only lead to an increased perception of regulatory risk, uncertainty, and instability in the regime, and as such are likely to cast doubt on the credibility of any decision or commitment made by UR at this and future reviews.

Inconsistency with treatment of deferred capex at PC03

It is clear from the discussion above that UR's proposals relating to the period before the 2006 Agreement and subsequent licence modifications contradict that Agreement. UR signalled that the treatment of deferred capex in the period following the 2007 licence modifications and the PC03 determination would be up for review at subsequent price controls. However, the proposals now are, notwithstanding earlier signalling, inappropriate in that they are not consistent with the methodology for the treatment of deferred capex for feeder and infill mains that was established during PC03, or with UR's stated intentions for the treatment of deferred capex at PNGL12. Had UR thought there was a justification for a sudden shift in the established and agreed approach to deferred capex, it has had many months to discuss it with PNG: raising the issue so late in the process without explanation of the reason for a change in strategy calls into question whether there is or can be any meaningful justification.

UR's published PC03 determination describes the approach adopted with regard to how the remaining deferred capex would be treated in future control periods:

"During PC01 PNG received an allowance for capital projects that were subsequently deferred to a future date. Most of these projects have been planned for post PC03 and the activity/forecast cost associated with these works has been removed from the PNG forecast revenue requirement. Consequently no revenue has been allowed going forward to take account of this activity and it will be up to PNG to finance these construction packages out of its own asset base, as it has already been given an allowance for this work at previous price controls.

*During PC02 PNG significantly outperformed in relation to forecast quantities of feeder and infill mains. Although some of this out performance relates to efficiency savings, it has been determined that 96km of infill mains and 13km of feeder mains has actually been deferred to a future date. Consequently these amounts of mains have been deducted from the PNG allowance for the period 2007 – 2011 and once again it will be up to PNG to construct these mains using previously allowed revenue from its own asset base."*²⁶

This methodology fully unwound deferred feeder and infill capex by subtracting the deferred quantities in PC02 from the corresponding PC03 forecasts. PNG was required to construct these mains but no cost allowances were granted for the period 2007 - 2011.

²⁶ Information relating to the Phoenix Distribution Price Control Review 2007 – 2011 Final Determination UR 20th February 2008 – page 7

PNG accepted the terms of the PC03 proposals on the basis that the remaining deferred projects would be treated in a consistent manner to this. It is not appropriate to revisit the methodology as part of the PNGL12 review.

Since deferred feeder and infill projects have been fully unwound, the remaining deferred projects are bulk projects (i.e. 7 bar mains, 4 bar mains and governors/Pressure Reduction Stations deferred along with the main laying that was originally planned). While it was common ground that UR would review the treatment of the remaining level of deferred capex as part of PNGL12, it was clear at the time that the purpose of the review was to ascertain whether or not the projects were still needed and, if not, to use the cost for other purposes. UR's published PC03 determination implicitly confirmed this approach, commenting that:

*"The Utility Regulator plans to further consider the appropriateness of deferred capex that has been planned for future construction and will review planned activity to ascertain when/if it will be carried out and if it would be in customers interests to use the allowances contained within the asset base for other construction activities."*²⁷

and reiterated this approach to deferred capex in Section 1.6 on 'Future Reviews':

*" **Deferred Capex** – A proportion of the current PNG RAV is made up of deferred capex for projects that had been forecast at previous price controls. It is intended that these projects will be reviewed to ascertain whether or not they are actually needed and it may be decided to use the costs associated with these projects for other purposes."*²⁸

So, while clear that UR intended to review the treatment of the remaining bulk projects as part of the PNGL12 review process, this cannot justify a review beyond that contemplated at the time, establishing whether costs associated with pre-identified projects could be used for other purposes. PNG has been open and fully transparent in identifying deferred capex and has been happy to discuss this as part of the PNGL12 review process.

Management fee

A specific component of UR's proposed approach which is inconsistent with previous treatment of deferred capex is the inclusion of a 20% uplift to the value of projects to reflect the management fee.

UR and PNG already have a template for monitoring outstanding deferred capex activity at the time of each price control review. This template does not include a management fee. This approach is correct as PNG does not allocate management fee to individual projects.

²⁷ Information relating to the Phoenix Distribution Price Control Review 2007 – 2011 Final Determination UR 20th February 2008 – page 7

²⁸ Information relating to the Phoenix Distribution Price Control Review 2007 – 2011 Final Determination UR 20th February 2008 – page 8

The concept of uplifting the cost of projects to account for the costs of managing them was only introduced by UR to allow benchmarking with other organisations.

Indeed, while UR granted PNG an allowance to take gas to Comber, Temple Quarry and McQuillan Quarry, UR did not allow PNG any additional costs to manage the projects. For example, in Section 6.10.2 of Annex 2 of UR's final determination for PNG for PC03, UR states in relation to the costs for the Temple Quarry and Comber projects:

"It has been decided to disallow the mgt fee associated with these projects given PNG's arguments that mgt fee is not directly linked to activity. Therefore the marginal nature of these projects should not incur any additional mgt fee."

The fact that UR's decision took no account of management fee indicates that UR recognises that the management fee incurred by PNG each year is largely fixed and independent of such additional projects, given the resources required to meet the volume of activity already being delivered by PNG in developing the natural gas network across its Licensed Area. It would be assumed that UR would adopt the same approach when PNG undertakes the deferred capex at a later date. PNG would not expect UR to grant an additional allowance for managing deferred capex projects when these are delivered.

As such, whilst a management fee uplift may be appropriate for benchmarking analysis in order to account for fixed overheads, it is entirely inappropriate to inflate the cost allowed for individual projects to include the management fee.

Inconsistency with principles of incentive regulation

Had PNG been notified that UR's intended treatment of deferred capex going forward would change so significantly, PNG would have warned UR about the poor incentive properties associated with its new proposals. UR's proposed regime starkly contradicts best practice principles of incentive regulation. As a result, these proposals will have a detrimental impact on both PNG and customers in Northern Ireland.

The capital projects that are the subject of UR's deferred capex review were deferred either because reinforcement was not yet needed, or because work was postponed until demand increased. In other words, this was an efficient investment decision made by a business operating under what it assumed was a standard regulatory incentive regime.

UR's proposals amount to an attempt to remove all benefit from deferral of capital programmes. The incentive properties of this 'claw back' of benefits are clear. UR's proposals would create a regime where it would never be in PNG's interest to defer construction activity. This cannot be in customers' interests, as it would result in an incentive for the company simply to spend according to its business plan, without having regard to new information or previously unknowable outcomes that come to light during a regulatory period. There would be no benefit to uncovering efficiencies, using new information, and

improving performance for the benefit of customers. Ultimately, this would lead to inefficient timing of capital expenditure.

The arguments that UR is making are not new. As part of PC02, UR made a similar proposal to remove the value to PNG of the efficient deferral of its capex projects. PNG provided a paper to UR which set out both UR's and PNG's views on the treatment of deferred capex in September 2001 (see Appendix C). PNG's view was that UR's proposal was not compatible with the licence or the principles of incentive regulation. Further, it would have removed the incentive from PNG to deliver savings through efficient deferral of capex, which ultimately benefits consumers.

UR accepted PNG's argument at that time. It is unclear why this position has now been reversed, to the point that UR's proposals now run directly counter to these established best practice principles.

Summary

1. UR's proposal on historic deferred capex is inconsistent with the 2006 Agreement. The value to be recovered for deferred capex going forward, and the treatment of deferred capex projects already completed, were discussed and debated at length, and subsequently embedded in the resulting TRV of £312.8m set out in PNG's current licence. To make adjustments to the TRV for returns earned before 2007 fails to recognise the facts of the Agreement, and is therefore inappropriate.
2. PNG acknowledges that, as agreed at PC03, UR intended to review the treatment of **future** deferred capex projects. However, UR's proposed approach is inconsistent with the approach established for the treatment of feeder and infill mains at PC03, including the uplift to costs to include a management fee.
3. Going forward, if UR were to make such a radical shift in its approach to treatment of deferred capex, UR should have regard to the incentive properties of doing so. These proposals would have implications for PNG's incentive to uncover efficiencies in the timing of capital projects as and when new information arises. Incentive-based regulation cannot be effective and credible if all benefits to the company are removed ex post.

4. FINANCEABILITY

Introduction

This Section 4 represents PNG's response to Section 9 of UR's Consultation Paper.

In proposing a price control, UR is required under the Energy (Northern Ireland) Order 2003 to secure that PNG is able to finance its activities. UR's statement recognises this statutory requirement, commenting that *"any decisions we make in our price control reviews should not compromise the ability of a regulated company to finance its licensed activities."* This formulation does not, however, quite match up to the statutory requirement which imposes a duty to secure an adequate financing of functions, not a mere passive requirement not to compromise such financing.

This point is significant. To comply with its duty, UR must secure finance that is adequate to finance PNG's functions taking into account all relevant circumstances – including the commercial and regulatory risk profile facing PNG; and the factors that influence the cost of equity (and debt).

UR's approach to financeability fails to take into account three critical factors:

- First, it fails to consider how regulatory risk created by UR's interventions may impact on the credit rating of PNG and in turn on PNG's ability to finance its functions. UR's reopening of the opening TRV agreed in 2006, as described in Sections 2 and 3 above, results in an increased risk of a downgrade as rating agencies reassess the extent of regulatory risk and uncertainty. This is highlighted by the recent decision by Fitch Ratings to place PNG on Negative Watch (see Appendix D). The increase in assessed regulatory risk undermines the future financeability of PNG, and would materially increase both the cost of debt and cost of equity. UR's financeability analysis has a very short term focus, only assessing the immediate impact of its decisions given current investor expectations, and failing to recognise the dynamic effect of its proposals over the longer term. UR must ensure that the assessment of financeability is consistent with the degree of regulatory risk implied by its proposals.
- Second, UR's approach, in assuming no dividends will be paid by PNG until 2030 is inconsistent with other regulators' practices and with equity investors' legitimate expectations. UR's conclusions that PNG is able to finance its functions under its proposals cannot be sustained under an assumption of no dividends and must instead be tested against some reasonable dividend assumption.
- Third, it fails to look at a sufficient range of rating targets, and as a result takes an unrealistic and short-term approach to its assessment of whether PNG will be able

to finance its functions. UR should consider a wider range of ratings and financial indicators (an approach adopted by GB industry regulators) in assessing whether PNG is able to finance its activities.

Only by taking into account regulatory risk (and its impact on the cost of debt) and equity investors' reasonable expectations for a return on the risk they take can UR reach a decision that secures an ability to finance regulatory functions.

We discuss each of the three issues summarised above in turn.

Treatment of regulatory risk

The framework that UR is proposing in Section 9 of the Consultation Paper suggests that rating agencies rely only on the financial ratio metrics in their assessments. However, rating agencies emphasize the importance of other factors.

For example, Standard & Poor's recognises that the regulatory relationship is critical to its assessments, particularly in the case of utilities, where *"it is a factor in all assessments of business risk"*. Standard & Poor's notes that regulatory treatment must be transparent, timely and should allow for consistent performance if it is to be viewed positively in the ratings context: to support credit quality, a utility must be assured of earning a fair – and consistent – return.²⁹

Fitch states that its corporate ratings reflect both qualitative and quantitative factors incorporating the business and financial risks of issuers and their individual debt issues. Fitch's Corporate Rating Methodology makes clear that Fitch's assessments explore *"the possible risks and opportunities in an issuer's operating environment resulting from social, demographic, regulatory and technological changes."*³⁰

The **predictability of the regulatory regime and the timing of investment recovery** also play a key part in other rating agencies' assessments. This is clearly illustrated in the Figure below which summarises the rating methodology employed by Moody's.

²⁹ Standard & Poor's Corporate Ratings Criteria, p. 44.

³⁰ Fitch Corporate Ratings Methodology, 12 August 2011, p.1.

Figure: Moody's rating methodology

Rating Factor/Sub-Factor Weighting			
Broad Rating Factors	Broad Rating Factor Weighting	Rating Sub-Factor	Sub-Factor Weighting
Regulatory Environment and Asset Ownership Model	40%	Stability and Predictability of Regulatory Regime	15.00%
		Asset Ownership Model	10.00%
		Cost and Investment Recovery	10.00%
		Revenue Risk	5.00%
Efficiency and Execution Risk	10%	Cost Efficiency	6.00%
		Scale and Complexity of Capital Programme	4.00%
Stability of Business Model and Financial Structure	10%	Ability and Willingness to Pursue Opportunistic Corporate Activity	3.33%
		Ability and Willingness to Increase Leverage	3.33%
		Targeted Proportion of Operating Profit Outside Core Regulated Activities	3.33%
Key Credit Metrics	40%	Adjusted ICR (or FFO Interest Cover)	15.00%
		Net Debt/RAV (or Fixed Assets)	15.00%
		FFO/Net Debt	5.00%
		RCF/Capex	5.00%
Total	100%		100.0%

Source: Moody's Global Infrastructure Finance, Rating Methodology, August 2009, p.5

In its rating methodology Moody's explains the importance of these factors (emphasis added):

*"In addition to tariff-setting, there are numerous ways that regulatory decisions can affect a network's business position, including a regulator's ability to agree on a capital expenditure programme ex-ante or to set efficiency targets (i.e. achievable cost savings). Finally, the ability to recover prudently incurred costs in a timely manner is one of the most important credit considerations for regulated electric and gas networks, as the lack of timely recovery of such costs may cause financial stress. **Therefore, the predictability and supportiveness of the regulatory framework in which a network operates is a key credit consideration and the one that differentiates this sector from most other corporate sectors.**"*

"c) Cost and Investment Recovery (Ability and Timeliness)

This sub-factor focuses on the supportiveness of the regulatory framework, i.e. the extent to which the regulatory formula is conducive to supporting cost recovery."

*"Where there is tendency for a regulator to challenge cost recovery or some history of disallowance or delays in some costs, a network would likely receive a "Baa" rating for this factor. **Where there is a history of unfavorable price reviews or a highly uncertain cost recovery environment, lower scores for this factor would apply.**"*

The evidence is that the credit rating agencies monitor closely the issue of regulatory certainty in Northern Ireland – and apparently more closely than GB, on the basis that they see the Northern Ireland regime as carrying greater potential risk than more established regimes such as GB.

Thus, for example, Moody's drew some comfort from the apparently stable regulatory settlement in 2007, although even then only a Baa2 rating was considered appropriate in respect of PNG:

"the assigned (P)Baa2 rating is based upon the stable and predictable nature of the company's cash flows stemming from its regulated gas distribution activities under a transparent – albeit fairly recent – regulatory framework" Moody's, Pre-Sale Report, October 2009.

At the same point in time, Moody's noted that the regime in relation to PNG is:

"less established than the most sophisticated regimes in Europe such as that of GB, which scores Aaa under the regulatory environment sub-factor, the regulatory framework applying to PNG follows closely the GB approach and precedents. Reflecting the characteristics of this regulatory framework, PNG maps to the Aa rating category under the "asset ownership model" sub-factor." Moody's, Pre-Sale Report, October 2009, and Moody's, Credit Opinion, November 2009.

Significantly, though, Moody's point out that:

"[t]he rating could come under downward pressure in the event of (i) adverse regulatory determinations or material changes in the regulatory framework, (ii) serious underperformance in operating and capital expenditure or (iii) negative funding conditions". Moody's, Pre-Sale Report, October 2009.

In effect Moody's had 'upgraded' the rating of PNG based on an assumption that the regulatory regime would follow the best practice and level of stability of the GB approach. Without this positive assessment of the regulatory regime at the time, the financial ratios would have pointed to a lower rating. This is illustrated in the figure below.

Figure 1. Moody's assessment of PNG (2009)

Model Rating Grid						
Regulated Electric and Gas Networks						
	Aaa	Aa	A	Baa	Ba	B
Factor 1: Regulatory Environment and Asset Ownership Model (40%)						
a) Stability and Predictability of Regulatory Regime		X				
b) Asset Ownership Model		X				
c) Cost and Investment Recovery				X		
d) Revenue Risk				X		
Factor 2: Efficiency and Execution Risk (10%)						
a) Cost Efficiency			X			
b) Scale and Complexity of Capital Programme	X					
Factor 3: Stability of Business Model and Financial Structure (10%)						
a) Ability & Willingness to Pursue Opportunistic Corporate Activity			X			
b) Ability & Willingness to Increase Leverage			X			
c) Targeted Proportion of Operating Profit Outside Core Regulated Activities		X				
Factor 4: Key Credit Metrics* (40%)						
a) Adjusted ICR				X		
b) Net Debt / TRV				X		
c) FFO / Net Debt						X
d) RCF / Capex						X
Rating:						
a) Indicated Rating from Methodology				Baa2		
b) Actual Rating Assigned				(P)Baa2		

* 3-year forward-looking average
NB: X denotes Moody's estimate.

Source: Moody's Global Infrastructure Finance, Pre-Sale Report on Phoenix Natural Gas Finance PLC, October 2009, p.15

UR's proposal to reopen the calculation of the opening TRV will fundamentally undermine the predictability and stability of the regulatory regime. This is exactly the type of issue that Moody's indicates (see above) should be kept under review and exactly the type of issue that may be expected to impact on the credit rating that PNG will attract. Both will adversely impact PNG's ability to finance its activities.

This is much more than a theoretic risk. On 12 October 2011, Fitch put PNG on Rating Watch Negative (indicating an increased likelihood of a downgrade) confirming that it, like Moody's, is anxious about the level of regulatory uncertainty caused by UR's proposals (see Appendix D). Fitch stated that:

"the agency considers transparency and predictability of the regulatory regime to be a key rating driver for gas distribution networks, the outcome of the draft proposals could have further implications for how Fitch views the regulatory framework for gas distribution in Northern Ireland."

This highlights that investors are as much concerned about the stability and transparency of the regulatory process as they are about the specific financial metrics. This is not surprising given the long-term nature of the investments being made.

PNG's understanding is that there is a real risk of a downgrade in the event that the ultimate price control decision and proposed licence modification do not establish a secure regulatory footing for future years.

PNG believes that a reduction of one grade by the debt rating agencies would inevitably increase the cost of debt, and this increased regulatory risk would likely be reflected across all utilities in Northern Ireland. There would be a similar adverse impact on the cost of equity. In fact, given that they are taking the full risk of the investment, equity investors are even more sensitive to regulatory uncertainty than providers of debt finance: in the event of regulatory instability, equity investors would inevitably demand a higher return on their investment given the more high risk environment. The increased costs of debt and equity resulting from regulatory uncertainty would in the long term ultimately be passed on to consumers because a higher rate of return would be required in the future.

UR has made no attempt, in the assessment of financeability, to consider the impact of its proposals (and specifically the write-off of previously agreed regulatory value) on regulatory risk. The assessment assumes that investors will continue to treat the regulatory environment as essentially on a par with GB. The evidence demonstrates that this is not the case. The Consultation Paper does not address the risk of a downgrade, let alone its effect on PNG and its ability to finance its functions. With the company on Negative Watch, UR cannot properly ignore this issue. And unless UR addresses this issue, it inevitably risks failing to discharge its statutory duties.

Ignoring returns for equity investors

As UR notes, in Section 9.4 of the Consultation Paper, financeability should be assessed in terms of both debt and equity. However, the regulatory model applied by UR assumes no dividends – and finds that none would be payable before 2030. UR assumes that equity holders will not begin to receive a dividend until the some 34 years after the licence was issued. This conflicts with assumptions made by other regulators as well as investors' expectations.

Dividends are the return received on the capital invested by shareholders and for the risks taken by shareholders. In their assessments of financeability both Ofwat and Ofgem assume that shareholders receive a reasonable dividend stream. The calculations of the financial metrics (PMICR etc) are made after taking account of dividend payments. For example, in the 2009 price review Ofwat assumed that dividends were paid equivalent to a yield of 5% (on the equity portion of the RAB) with real growth of 2.1% per year.

Ofgem adopted a similar approach at DPCR5 and this was supported by investors. Investors were asked whether they thought “Ofgem’s assumption on dividend yield (5%) is too high, about right, too low, don’t know or not applicable?” Of the ten that offered a view, six thought Ofgem’s dividend assumption was about right and four that it was too low. None of the responses thought the Ofgem yield assumption was too high³¹.

Because the cashflow profile of PNG is different to GB regulated networks and PNG needs to retain cash to finance its continued growth, PNG is not currently paying a dividend. However, this is not to say that PNG’s investors do not expect to see a return on their investment in the near future. To the contrary, PNG’s investors’ expectations before this Consultation Paper were that dividends would be payable in a few years time along the lines of the rating agencies’ expectations. However, the implication of UR’s proposals and the reduction to the TRV is to push-back significantly the timescale for distribution to equity investors. In its assessment UR has failed to consider the impact that this has on the degree of risk for equity investors and the impact on required returns.

We are not arguing that UR should assume in its modelling that PNG is currently paying a dividend. However, UR’s duty is to ensure that PNG can finance its functions and attract the necessary investment (including necessary equity investment) and an efficient cost of equity. To ignore normal and reasonable expectations of investors is inappropriate and dangerous. It risks disincentivising investment and undermining the financial stability of PNG, contrary to UR’s regulatory duty. For a sustainable price control, reasonable estimates of dividends over the 30 period must be made that would be sufficient to allow the necessary investment at the appropriate cost of finance.

Choice of rating targets

UR presents the financial metric criteria from the rating agencies for both A and Baa ratings. Without explicitly stating its position UR appears to then focus its assessment on the Baa rating.

Although PNG’s current rating is Baa, good regulatory practice requires a price control to be based on an assessment of a range of rating levels. GB regulators and investors routinely consider that appropriate credit rating embraces both A and Baa ratings.

For example, Ofwat targeted an A- rating for the water industry:

“In its FD09, Ofwat said that it had targeted financial ratios that were consistent with an A- /A3 credit rating, though Ofwat added that if one particular indicator (and in a small minority of cases, two key indicators for one rating agency) did not meet its required

³¹ Indepen, “Investor Survey: Ofgem’s DPCR5 Initial Proposals”, 9 October 2009, Q17

threshold, it ensured that the ratio met the criteria for a strong BBB+/Baa1 credit rating as a minimum.”³²

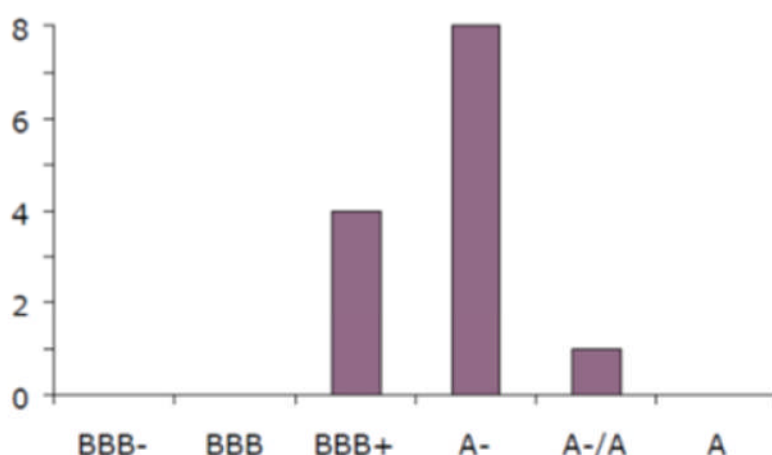
This is consistent with the findings from a survey of investors in the electricity sector³³:

“The majority of responses suggested that Ofgem should target a rating in the A- to BBB+ range”

“An equity response suggested that as regulated utilities had always targeted a strong investment grade rating (A-/A3) and that this allowed them greater access to the capital markets (at reasonable rates) then Ofgem should target ratios commensurate with A-/A3.”

“We received 13 responses from debt and equity to what credit rating Ofgem should target in setting prices ranging from BBB+ to A-/A.”

Figure: Investors’ views on appropriate rating for financeability



Source: Indepen, “Investor Survey: Ofgem’s DPCR5 Initial Proposals”, 9 October 2009, Q23

In focussing (or appearing to focus) exclusively on achieving only a Baa rating, UR has not undertaken its financeability assessment on an appropriate basis. It has focussed too narrowly on the current position of PNG’s credit ratings and not taken a sufficiently long-term view of the ratings required for utility businesses to be able to finance their activities. By doing so its assessment of investors’ willingness to finance PNG is unacceptably risky. UR should undertake the financeability assessment on the basis that PNG is able to secure an A-rating over the longer term.

Moreover, in carrying out its financeability assessment, UR has given limited consideration to working capital and other short term constraints on PNG going forward. For example, UR’s assessment fails to take into account the two £30 million facilities currently available to

³² Competition Commission, Bristol Water, 2010, Appendix O.

³³ Indepen, “Investor Survey: Ofgem’s DPCR5 Initial Proposals”, 9 October 2009

PNG (a capex facility and a working capital facility) which, although undrawn at present, may well be drawn in the near future. UR's financeability assessment should therefore be undertaken on the reasonable assumption that PNG will make drawings on its undrawn facilities in the near term thereby increasing its overall level of debt and impacting upon the gearing ratio.

5. PROPOSED PNGL12 ALLOWANCES AND OTHER ELEMENTS OF THE CONTROL

Introduction

This Section 5 represents PNG's response to all elements of UR's Consultation Paper other than those discussed in previous sections. In particular, we focus here on UR's proposals for operating expenditure (opex) and capital expenditure (capex) allowances for PNGL12 detailed within Sections 5 and 6 of UR's Consultation Paper.

PNG is pleased that UR and its engineering consultants, PB Rune, have recognised the efficiency inherent in PNG's business. PNG has worked hard over the course of the last review period to uncover efficiencies, adopt best practice approaches, and deliver the outputs valued by customers. These principles will continue to drive our business over the upcoming control period and beyond, and were reflected in the business plan submitted for this review.

Compared to that plan, UR has proposed a reduction of £5.2m for opex and £0.1m for capex. On a like-for-like basis, the difference between PNG's plan and UR's allowances is greater than this. As noted in Section 1.23 of UR's Consultation Paper, UR's proposals are based on a higher connection target for domestic owner occupiers (4,200 per year instead of the 3,700 proposed by PNG). The effect of using a higher target is to grant a higher allowance, particularly for capex, since allowance levels for certain cost items are driven by forecast connections. UR acknowledges that had it used PNG's target, the overall allowances would be around £1-2 million lower.

PNG considers that UR's methodology in determining the allowances fails in certain respects (detailed below) to reflect PNG's costs drivers; and is flawed in a number of respects:

- UR's proposals 'double count' efficiency savings, determining the efficient cost of specified items and then applying an efficiency factor to the identified efficient cost (see below on indexation);
- UR's benchmarking by comparison to other utilities is inconsistent in approach and risks producing inappropriate allowances. For example, in some cases, UR compares PNG to larger and mature utilities in Great Britain (e.g. in relation to insurance) proposing savings that are unachievable by smaller, less mature businesses. In other places, UR does not seek to benchmark PNG, again producing unreliable results (e.g. in relation to network maintenance);
- UR's proposals, where there are uncertainties in relation to future expenditure, propose adjustments which do not appear to be quantified or justified – and which as a result appear arbitrary (see for example in relation to advertising/marketing and network maintenance);

- UR's proposals take insufficient account of costs that might reasonably be expected to be allowed on a pass-through basis and of costs or cost trends which are outside PNG's ability to control (see for example in relation to fleet costs or rates).

A number of these points have been made previously: and PNG is disappointed that many of its representations during the 12 month PNGL12 review process, which appeared to have been understood by UR at an operational level during representations on these matters, now seem to have been disregarded in the proposals within the Consultation Paper as approved by UR's Board.

We have provided PNG's view of these particular aspects of UR's proposals below. We first discuss UR's proposal for a 1% efficiency factor, before discussing UR's proposals for specific items of opex and capex allowances in detail. We would welcome the opportunity for further engagement with UR to discuss any detail on these issues, should further clarification be required.

Indexation

UR is proposing an unadjusted "X" factor of one per cent for PNGL12. The application of a blanket efficiency factor is inappropriate for two reasons.

First, applying a blanket efficiency factor across all of PNG's cost allowances effectively amounts to 'double counting' of efficiency.

As part of its bottom-up assessment of opex, UR is proposing to reduce allowances for many cost items to levels lower than those forecast by PNG and experienced historically. This includes, but is not limited to, office costs; IT costs; insurance; and maintenance costs. The proposed cost allowances also require that PNG delivers efficiency savings on licence fees, despite the fact that it has already been established that these costs are outside of PNG's control.

As such, the proposed opex allowances already embed challenging, and in some instances unfeasible, efficiency targets. Applying an "X" factor in addition to these targets is arbitrary, and represents unjustified double counting of efficiency targets.

On capex allowances, UR has recognised the efficiency built in to PNG's plans, stating that:

"PB Rune compared PNGL with the GDNs in GB, and concluded that PNGL is generally efficient at undertaking and delivering capital projects. Implicit in this is that the unit rates for the various capex activities, as proposed by PNGL, do not seem unreasonable."

UR's explicit recognition that PNG is starting from an efficient base undermines the validity of any proposal to apply a further efficiency reduction.

Second, UR's proposal appears inconsistent with its determinations elsewhere in Northern Ireland. As outlined in PNG's PNGL12 submission paper "**RPI-X Efficiency**", provided to UR on 24th February 2011 (see Appendix A), PNG's forecasts already account for potential efficiencies arising as the business grows and develops. At the recent SONI price control consultation³⁴, SONI, like PNG, used a bottom-up analysis to forecast its costs to ensure that efficiencies for consumers were captured within each individual cost-line. UR recognised this and determined an X factor of zero on the basis that efficiencies for customers were already captured within the proposed allowance:

"The Utility Regulator has carried out a bottom up analysis of all Opex to ensure that past efficiencies are captured within the allowance. The Utility Regulator has decided that an X factor equal to zero is appropriate given the level of rigour applied to the assessment of costs."

PNG understood that this principle would also be adopted by UR in relation to PNG's PNGL12 submission. This understanding was based on discussions with UR during the PNGL12 review, where UR confirmed that this was its position. UR has put forward no explanation as to the reason for changing its position: and it is very unclear what reason there could be for adopting inconsistent approaches across the different utilities it regulates in Northern Ireland.

In short, UR's proposal to introduce a blanket 1% X-factor is inappropriate in that it is applied as an efficiency incentive after each item has already been tested for efficiency. Since the first exercise of testing efficiency item by item is thorough, the scope for an additional efficiency target is much more limited. On many cost items UR accepted the view of its consultants that PNG operates efficiently, and for other individual cost items UR has built challenging efficiency targets in to the allowance. The application of the efficiency incentive must be moderated to avoid double counting. The 1% efficiency factor appears to represent an arbitrary addition, which was unexpected given UR's recent determination for SONI, and the discussions held over the course of this review.

PNG would urge UR to moderate the application of the efficiency "X" factor in order to avoid double-counting, inconsistency of regulatory approach and in order to secure a sustainable and justifiable price control.

Operating Expenditure

PNG provided UR with further detail on a number of operating expenditure cost lines as part of the PNGL12 review process. PNG would ask UR to review its proposals of the following cost lines:

³⁴

SONI Price Control 2010 – 2015 Decision Paper April 2011

Advertising Marketing and PR

UR proposes to move away from its past practice of granting fixed allowances for sales-related costs and instead plans to remunerate PNG with a per connection allowance. PNG has already expressed its reservations in respect of UR's new approach to market development costs in a paper provided to UR on 22nd June 2011 as part of the PNG12 review process. In addition to the points made in that paper, PNG would like to emphasise the following points.

First, the level of cost attributed to the owner occupied sector as part of UR's analysis appears unjustified. As highlighted to UR, a high proportion of the costs included within the corporate overheads cost line are neither marginal in nature nor are they directly attributable to market development. PNG will incur these fixed corporate overheads irrespective of whether owner occupied connections arise. Setting allowances for these cost items on the basis of the volume of connections cannot therefore be justified.

UR's proposal to reduce the allowance to 50 per cent from 2017 onwards would serve only to magnify the flaw in UR's treatment of corporate overheads described above. This proposal appears to be an arbitrary reduction, as demonstrated by the fact that it is being considered some 5 years in advance of its implementation. There seems little reason to try to estimate what reduction of allowance is appropriate from 2017 when this can properly be addressed – and with greater accuracy – at the next price control review.

Second, it is far from clear why UR should propose that no allowance be given for the first 1,050 Owner Occupied connections. The cost of market development varies by consumer. The historical allowances for sales-related costs reflected the required average cost per customer across all of the customers that switched to natural gas (i.e. those who required a higher stimulus and those who would still have switched with a lower incentive). If UR proposes to disallow costs for customers who need less incentive to switch, it must recognise that the average cost required to attract the remaining customers is higher.

As UR is aware the Greater Belfast area accounts for more than half of the potential for gas sales in Northern Ireland. Currently about half of the customers who could switch to natural gas have chosen to do so in the 15 years since PNG started to develop its gas network. There still remain around 140,000 customers in PNG's licensed area who could switch to gas but have chosen not to. Based on PNG's experience to date, it will, contrary to what UR's proposal implies, get progressively harder to persuade the remaining potential customers to switch rather than easier.

However, under UR's current proposals, PNG faces a significant reduction in sales-related costs over a very short timeframe. The implication of such proposals is that PNG will have an allowance for 2012 which is c.£500k below the 2011 allowance (using like-for-like connections) at a time when the level of potential connections from areas where gas has just been made available is actually falling by c.500 connections each year. Such reduction will

make it all the more challenging for PNG to continue to increase its customer base by c.8,000 new customers each year as PNG will have to encourage more consumers within existing gas licensed areas to convert to gas. As each of these areas becomes more mature, the early adopters who were persuaded to convert to natural gas have already connected. In many cases those who are still to convert have not yet been convinced of the benefits and require significantly more time and effort to educate and persuade them to make the switch. PNG would urge UR to reconsider its proposals in light of its primary objective to promote the development and maintenance of an efficient, economic and co-ordinated gas industry in Northern Ireland. Appropriate levels of investment in advertising, marketing and PR are fundamental to PNG's ability to deliver further growth in the Northern Ireland gas market.

Billing

PNG notes that UR adjusted PNG's allowance request downwards in order to reflect UR's own views of the level of switching activity the market is likely to experience as a result of supply competition in the domestic market. However, should competition turn out to be more successful than envisaged by UR, it seems unfair that PNG should have to bear the higher billing costs that have arisen solely due to the fact that a higher level of switching activity is observed than that estimated by UR in determining PNG's allowance. UR may therefore wish to consider introducing an uncertainty mechanism to reflect the level of switching actually observed, in order that PNG's incentives are properly aligned with the objective of greater competition.

Emergencies

The provision of a 24 hour/365 days per year emergency response service to reports by members of the public (classified as Public Reported Escapes (PREs)) is an essential operation that PNG must undertake to ensure safe and reliable operation of its gas distribution network. PNG's reputation as a reliable operator when tested in extreme conditions also influences the attractiveness of gas as a fuel of choice and hence has a direct impact on market growth. This is also a licence requirement and a key operational requirement of PNG's safety case. Any action being considered by UR that would jeopardise PNG's ability to provide a fully effective emergency service should be reconsidered. It cannot be in the public interest that PNG's ability to respond to extreme conditions should in any way be placed at risk.

UR has proposed to provide PNG with a reduced allowance, to the level of c.£250k per annum, equivalent to an 11% reduction compared to the allowance requested by PNG. UR's stated rationale is that in the period 2007-2009, PNG experienced a downward trend in the number of calls received through its call centre. However, the table below shows the total

numbers of calls that PNG responded to during the period 2007-2010, which contradicts UR's assertion that the trend for the period 2007-2009 was downwards.

	2007	2008	2009	2010
Number of PREs	12,125	12,993	12,694	14,791

As can be seen by the table, PNG in fact experienced a clear upward trend, amounting to 7% on average per year over the period. It is therefore not clear why UR believes there has been a downward trend.

On average, PNG also increases its customer base by approximately 8,000 new customers or c.6% per year as well as increasing the length of its network by approximately 2% per annum. To date in 2011, PNG has experienced an increase of c.17% in the number of PREs received compared to the same period last year.

UR has also ignored the fact that its proposals are based on a higher connection target for domestic owner occupiers, 4,200 per year, instead of the 3,700 domestic owner occupiers proposed by PNG, which would have an upward impact on the emergencies cost line.

UR's case for reducing emergency allowances is difficult to understand, and appears to be based on a factual inaccuracy. Contrary to UR's suggestion, PNG's proposals reflect the cost of providing an essential emergency service to the members of the public within its licensed area. Reinstatement of the level of allowances as requested by PNG is therefore required and appropriate.

Entertainment

The allowance proposed by UR for entertainment excludes costs associated with client and corporate entertainment. PNG recognises that it would be more appropriate for UR to consider these costs in the context of market development and requests that UR either allows or disallows the costs of client and corporate entertainment in that context.

Fleet Costs

PNG has successfully driven down unit fleet costs over the years through re-tendering and actively managing costs of operation.

The increase in costs relative to 2007-2009 has been driven by the following:

- an increase in mobile resources

- an increase in unit fuel costs – we apply HMRC approved rates and these are 20-30% higher than those experienced in the period 2007-2009 as a result of increasing average fuel costs at the pumps.

In addition, there was a rebate from a previous provider for disputed amounts relating to a previous price control period amounting to £130k within the period 2007-2009, which therefore cannot be regarded as representative. UR states in its Consultation Paper that cost forecasts cannot be based on trends which are calculated on the basis of a short period of historical data, since an abnormal year can distort the forecast. PNG notes that abnormal years equally impact average costs calculated over short time periods, and that care must therefore be taken when using average costs so that exceptional cost items are reflected as such in any estimate of future costs.

It should also be noted that cost pressures due to rising cost of vehicles currently being experienced, together with rises in employer's National Insurance Contributions associated with the benefit-in-kind of fleet costs (which are included within this cost category), will also have an adverse effect on fleet costs going forward. Rising fuel costs/HMRC approved rates and increased National Insurance Contributions are exogenous costs that should be fully reflected in UR'S projections.

Information Technology

PNG submitted a "**Key Principles Document**" on 8th November 2010 as part of the PNG12 review. In the section on Common Arrangements for Gas (CAG), this paper clearly stated that:

"PNG has based its price control submission on the regulatory requirements prevailing at the time of its submission and therefore no consideration has been given to the costs which PNG would require to fulfil any requirements of CAG.

For the avoidance of doubt, PNG has engaged in discussions with UR on the potential requirements of a CAG transmission interface with the Greater Belfast distribution system. At this stage changes to PNG's systems have not been finalised nor a specification drafted hence PNG has not attempted to forecast such costs within its PNG12 submission.

PNG will however prepare a separate submission of its forecast costs as PNG's role becomes clear and system changes identified over the coming months and, depending on timing, UR will either be required to issue a supplemental determination of allowable costs or include these within the PNG12 determination."

We note UR's statement that it is unlikely to grant any additional allowances for unexpected IT expenditure during the control period, including any costs that may arise in respect of the CAG project. We understand that it is UR's position that PNG's rate of return is sufficient to

manage the risk associated with delivering the requirements of CAG. However, as CAG is still not defined, it is hard to see how UR can with any confidence assume that the rate of return is sufficient to manage the risk. Moreover, as the specific requirements of CAG are not under the control of PNG or indeed essential for PNG to provide services within its licensed area, it is difficult to see why PNG should bear the risks associated with delivering its elements of CAG with no possibility of allowance to mitigate risk. Such risks include the manpower resources needed to develop, implement and undertake the ongoing operation of CAG when it is up and running. If UR considers that CAG is beneficial for gas consumers as a whole, then the cost of provision should be funded.

Under the heading “Treatment of Unforeseeable/Unpredictable Costs” in Section 8, UR comments that any additional allowance it considers appropriate to grant may include a net reduction of outperformance achieved “on say, the general IT budget (for IT projects)”. This would suggest that UR may consider granting an additional allowance for IT in some instances.

PNG would welcome clarification of UR’s position on IT costs, and those associated with CAG in particular.

Insurance

UR makes the following statement in the Consultation Paper:

‘Historic actual costs in 2007, 2008 and 2009 are £749k, £734k and £662k respectively. This would indicate a clear downward trend even as the network has been expanding, which suggests PNGL has some ability to manage this cost downwards’

PNG has already provided information to UR with regard to the rationale for this downward movement in cost during the PNGL12 price control process - the cost reduction in 2007, 2008 and 2009 being driven by a reduced sum insured associated with Business Interruption Insurance.

This reduced sum insured arose primarily as a result of the reinforcement to the PNG network following connection of the South-North pipeline in 2007, coupled with distribution reinforcement at Lisburn in order to maximum the capacity benefits therefrom in 2008. The effects of the lower potential maximum loss resulting from this reinforcement were only fully experienced in 2009 premiums, thus offsetting the effect of increasing distribution income which otherwise arose in this year.

Therefore, the reduction in insurance costs during the period 2007 to 2009 was driven by a one-off structural event affecting the most significant item within this cost category. Without a further such event, the sum insured will be driven by the rising distribution

income within the distribution model, with the premium paid impacted by general market conditions within the insurance market sector where such insurance is sought. This is evidenced by the forecast for 2010 included within the PNG12 submission of £703k which is in line with the actual cost incurred for that year in the 2010 accounts and clearly substantially higher, even before taking account of further rises in distribution income, than the £533k and £548k proposed by UR for the price control years 2012 and 2013.

UR's approach therefore rests on a false premise – that insurance costs have been declining, when that is not (after addressing an exceptional event) the case. For this reason alone the approach needs revision.

When revisiting insurance costs, and when trying to assess future costs, UR will need also to take into account general market conditions in 2011 and anticipated further changes. 2011 has seen further rises in premiums being paid with worldwide market effects adversely affecting this cost item.

UR's proposed approach also relies on the benchmark applied by Ofgem for the GB gas distribution networks in the existing GDPCR. Specifically, UR proposes to apply Ofgem's benchmark that insurance allowances are set at 1.04% of turnover. However, PNG faces a set of risks significantly different to those faced by GDNs in Great Britain. In particular, a significant risk is concentrated in the potential failure of a single pipeline, which would impact a large portion of PNG's network. Moreover, this pipeline is not under the ownership of PNG and contains a marine insurance risk which impacts on the premium payable and curtails PNG's ability to access the appropriate cover. It is therefore inappropriate for UR to simply lift the value applied in GB and describe it as a benchmark.

UR will be aware moreover that beyond the specific risks associated with PNG's network relative to GB, insurance premiums in general in Northern Ireland tend to be relatively higher than elsewhere in GB. For example public liability insurance and car insurance are higher in Northern Ireland given Northern Ireland's claim history. Whilst the relative sum assured has reduced as a result of completion of the South-North pipeline, the residual risk remaining is the basis on which annual premiums are payable with limited options available for placing this insurance.

For these reasons, reliance on Ofgem's benchmark is misplaced. If UR intends to use GDPCR as a benchmark, it should have to identify, as a minimum, the differences between PNG's network and those in Great Britain, and account for this difference in allowances. A direct, unadjusted "read across" from GB cannot produce any reliable evidential base for an adjustment for PNG. A more reliable and appropriate approach would be to focus on what the insurance industry will charge for the insurance being sought (as contained in PNG forecasts).

It should be further noted that PNG's ability to influence premiums paid through performance is limited. Insurance premiums payable by PNG, with the exception of car

insurance³⁵, are based on an excellent claims track record. As a result, PNG has little scope to reduce its premiums through its own improved operational performance. Future premiums will be driven by changes to the sum insured and by the relevant underlying market conditions within the insurance market. Our advisers believe that, due to general pressures in the market in relation to claims experience, a significant increase to premiums will be likely from 2011 onwards.

For these reasons, we would urge UR to review its proposed allowances for insurance in PNG12. Allowances based on an incorrect analysis of PNG's past premia and on an attempt to compare two unlike insurance situations cannot provide any meaningful basis for UR's determination.

Manpower

UR has sought to disallow significant costs associated with executives within PNG. Despite our requests to seek clarification on this matter throughout the price control process, the issue was only finalised once UR had received a benchmarking report immediately prior to publication of its Consultation Paper. PNG is therefore responding to this issue for the first time.

With regard to the specific issue of remuneration, it is PNG's belief that its remuneration packages are appropriately benchmarked throughout the organisation, not least at the executive level. Average remuneration has remained relatively consistent year on year and is below the level of its comparators. PNG therefore has difficulty understanding UR's rationale for targeting this area of cost.

As UR is aware, the availability of appropriate benchmark data in a market as small as Northern Ireland makes comparisons difficult, not least because of the existence of relatively few independent private companies of a comparable structure to PNG. As a private equity owned business, PNG operates within a robust corporate governance framework. Within that framework, executive compensation is dealt with by the Remuneration and Nominations Committee, a sub-committee of the Kellen Investments Limited board. Details of the remit of this committee as contained within the Kellen 2010 Annual Report are provided below:-

³⁵ With regard to car insurance, our premiums have risen significantly since Phoenix no longer benefitted from being part of a larger group (initially BG plc and laterally ESH). Since that time Phoenix Group claims experience has been fully transparent to insurers and despite the very proactive approach we have taken to managing these risks year on year, actual claims experience (including those suffered as a result of 3rd party losses) has resulted in premiums being lower than claims suffered by insurers which is clearly an unsustainable position. Phoenix will continue to actively manage this activity to try and reduce the liabilities incurred but the operational nature of our drivers and the potential risks associated with such a fleet will make the risk of claims much greater than average.

"The Remuneration and Nominations Committee is chaired by Lorenzo Levi and consists of three non-executive directors. This committee meets at least once a year and at such other times as the Kellen Board requires.

The committee's specific duties and responsibilities are as follows:

- *establish the criteria to be used in selecting directors and ensure the remuneration package is designed to attract, motivate and retain staff of the highest calibre;*
- *approve the remuneration of the executive directors and management to provide independent and objective assessment of any benefits granted to directors and management;*
- *ensure that the pension arrangements throughout the Group are appropriate, well supervised and conform to applicable law.*

The committee also reviews the design of incentive and performance related pay plans for approval by the board, together with remuneration policies as a whole and trends across the Group."

This committee determines the salary and benefits package applicable to senior executives using relevant benchmark data. It is this committee's view that the relevant benchmark is data available for CEO/CFO positions within a comparable business in GB (see latest publicly available report from Deloitte³⁶), as this is the pool within which, if a replacement senior executive is required, the company is likely to seek such a replacement.

It should also be noted that following the previous price control determination for PNG, PC03, PNG undertook a significant rationalisation of its business. This included reducing the number of directorates by 25%, and redistributing responsibilities amongst the other executives in the business, with salary adjusted to accommodate such changes. PNG's forecasts for 2012 and 2013 were adjusted to benefit from this resource saving. However, UR has proposed to disallow the associated cost on top of the reduction that was built in to our plan.

Further, UR has proposed to reduce allowances to a level below that allowed in PC03. Average salary costs for senior executives have been cut by 20% in real terms in UR's proposals, compared to the base salary that UR determined in PC03. This is before taking account of the rationalisation at a senior level that occurred following PC03.

Finally, the application of new mechanisms such as the Advertising, Marketing and PR mechanism, together with the implications of potentially stranded costs through the

³⁶

Deloitte (September 2010) Your guide: Executive directors' remuneration

proposal to charge a proportion of the time of the CEO/CFO to Phoenix Supply Ltd., creates further risk on this cost item. This has not been recognised in any way. The matter is magnified as UR is seeking to disallow costs which the company is already bearing.

PNG would therefore urge UR to reconsider its current manpower proposal.

Network Maintenance (including PAS 55)

Asset risk management systems and associated efficiencies

In Section 5.91 of UR's Consultation Paper, UR states that it has been its opinion for some time that PNG should develop and implement an asset risk management system. UR also states in Section 5.92 that it had reduced PNG's allowance request in PC03 to reflect its view that the company was unlikely to be operating to the most efficient maintenance schedule. UR states that in PNG12 it is also proposing a reduction of 10% on the costs submitted by PNG for network and meter maintenance. In addition UR is not allowing any allowance to deliver an asset risk management system such as PAS 55.

The approach being adopted by UR is hard to interpret and lacking in transparency. Under "Meter Maintenance" within Section 5.90 UR states:

"PB Rune also compared PNGL's meter maintenance unit costs with that of National Grid Metering, who undertake similar work in Great Britain. PB advised that PNGL's unit costs were reasonable in comparison"

In addition, in May 2011 PNG received a draft report detailing UR's indicative opex allowances for 2012 and 2013. Under "Network Maintenance" in this earlier version of the report UR states:

"PB Rune found no significant issues in the cost build-up as presented by PNGL. We (UR) propose therefore to grant PNGL its full allowance request for network related maintenance, and for the development of PAS 55."

In meetings between UR and PNG between the issuing of the draft report in May and the publication of the final Consultation Paper in August, PNG asked whether UR needed any further information to support the position already taken by UR in the May draft report. PNG was informed that no further information was required, as UR was content with the position stated in the draft May report. PNG, therefore, does not understand UR's rationale for changing its position so dramatically between the May draft report and its August Consultation Paper, particularly since this issue was not discussed with PNG.

In addition, we believe that UR is not being consistent in its approach to the regulatory treatment of PNG, compared to the regulatory treatment of GDNs in GB. PNG understands

that at the time that GB network operators were instructed by Ofgem to implement an asset risk management system such as PAS 55, the reason GDNs were not allowed additional allowances was because GDNs were allowed to retain any benefits that were derived during the five year price control period from implementing such a system. As such the cost of developing and implementing the asset risk management system could be offset by any potential benefits that were derived as a result. This provided GB network operators with a potential risk and reward situation.

UR has already decided that there will be benefits associated with implementing such a system and has as a result already reduced PNG's allowance in PC03 and is proposing a similar reduction in PNG12. UR's approach means that not only does PNG have to absorb the costs of delivering an asset risk management system, but it has also had any potential benefits derived therefrom within the price control period deducted from its cost allowances over the last five years (PC03) and the next two years (PNG12).

UR has also proposed an apparently arbitrary reduction in allowances of 10% for PNG12 for which a credible rationale has not been provided. The effect of UR's proposal is that UR is introducing asymmetric risk into its cost estimates, where PNG is faced with downside risks but no commensurate upside opportunities. This approach is not consistent with the principles of incentive regulation since PNG is best placed to decide whether such a system would result in efficiencies going forward.

UR has also proposed that if information on asset condition is not available at the time of the next price control it may commission its consultants to carry out actual site visits and physically inspect a sample of PNG's assets. The intention is that UR's consultants can advise on a maintenance schedule and associated costs based on need and reliability, rather than manufacturers' instructions. The current price control review process has been ongoing for 12 months and therefore PNG would question why UR did not undertake such a review for PNG12. PNG believes such an inspection would have revealed that our maintenance programme and associated costs are efficient. In addition, as the next price control process starts in less than a year (information has to be submitted by PNG to UR in September 2012) and the timetable proposed to UR by PNG for implementation of an asset risk management system is approximately 24 months, which is in line with GB GDNs, UR is already aware that information on asset condition may not be available at the time of the next price control.

In the absence of any justification for disregarding manufacturers' instructions, PNG does not agree that there should be a change to the current policy of maintaining apparatus to the manufacturers' schedule. We assume that the manufacturers have prepared this schedule on the basis of their experience and knowledge of the reliability and 'wear and tear' on their equipment. PNG has no reason to believe that it is unduly cautious or indeed that there is any material benefit to manufacturers from recommending more than the minimum essential level of maintenance. The general philosophy of the Health and Safety Executive for Northern Ireland (HSENI) is one of continuous improvement. If PNG changed

to a reliability centred programme, HSENI would require PNG to prove that there was no increase in risk to consumers.

PNG would therefore request that UR adopts the position proposed in its May draft report and (a) allows the cost of implementing an asset risk management system such as PAS 55 and (b) removes the arbitrary reduction of 10% in its August Consultation Paper.

In light of UR's comments in its Consultation Paper indicating that PNG has not made progress in this area, Appendix B provides further information on the steps PNG has already taken in the process of implementing an asset risk management system.

Rates

Northern Ireland and GB precedent is to treat rates on a pass-through basis:

1. Ofgem's 2010-2015 electricity distribution price control review classifies business rates as non-controllable opex and therefore treated as pass-through
2. UR's 2007-2012 NIE transmission and distribution price control review classifies rates as uncontrollable opex and therefore recoverable on a pass-through basis
3. Ofgem's 2008-2013 gas distribution price control review classifies rates as a non-controllable cost and therefore allowed on a pass-through basis
4. UR's 2008/09, 2009/10 and 2010/11 opex review for PTL and BGT considers rates as an uncontrollable cost and therefore treated as pass-through

The Annual Cost Reporting template which UR issued to PNG for completion in 2010 also classifies rates as a non-controllable activity. Further, PNG's rates will be considered on a pass-through basis at the next price control review, since it would be unreasonable for UR to align the price controls of the two gas distribution network operators in Northern Ireland while treating rates differently for PNG and for firmus.

It is impossible, against this background, to discern a legitimate reason to treat rates as anything other than a pass-through cost. PNG accordingly would ask UR to allow a pass-through (failing which in the interests of transparency UR should as a minimum detail its rationale for treating PNG differently from other utilities in Northern Ireland and GB and explain how it expects PNG to moderate costs beyond its control).

Telephone and Postage

2008 telephone costs included a credit negotiated with our telephone provider with regard to prior and current year costs of using a local call platform for incoming calls hence the movement year on year.

More recently, call costs appear to have reached a plateau with providers now seeking cost increases in order to deliver the same service going forward.

Furthermore, call and postage volumes within PNG are increasing in line with a rise in the number of live connections and the number of customers switching in response to new supply competition. It is therefore imperative that these considerations are factored into future forecasts.

The application by UR of an allowance based on three year average cost for 2007 to 2009 without taking account of these factors is not appropriate and we would ask UR to review this matter further.

Travel and Subsistence

Travel activity increased in 2009 as a result of an increase in activity associated with travel outside of Northern Ireland (for example the rating process and related financing implications, and attendance at industry and supply chain meetings and forums as the complexity of the industry develops such as CAG). Additional travel associated with specialist training, skills accreditation and legislative update courses in GB is also impacting on these costs.

Furthermore, the unit cost of travel is rising with prior benefits experienced by utilisation of wider options supplied by low cost carriers being offset in 2009 and beyond by rising fares driven by increased fuel costs, transport taxes and landing costs and more recently through the reduction in options available.

Despite these factors being highlighted to UR during the price control process, UR proposes granting PNG an allowance based on the three year average cost for 2007 to 2009. PNG does not believe UR has adequately accounted for the additional costs PNG will incur during the period and would urge UR to reconsider its position.

Capital Expenditure

PNG has always aimed to deliver an efficient and effective construction activity which minimises costs to consumers and maximises the standard of service that customers receive from PNG. Although PNG does not have the scale of operation that GDNs in GB have, PNG has worked diligently over the last 15 years to innovate and re-engineer traditional methods of working to enhance the experience being delivered to consumers. These include operation of an Alliance contract, implementation of an integrated supply chain, delivery of a one stop service and meter installation process, and development of a pre-assembled meter/meter box installation to name but a few. Moreover, PNG's alliance contract provides

a strong incentive for the contractor to reduce costs with the benefits shared between the contractor and PNG, and hence customers within PNG's licensed area.

PNG welcomes the fact that both UR and its engineering consultants, PB Rune, have recognised the efficiency inherent in PNG's business and that UR and PNG broadly agree on the overall level of capital expenditure required by the business throughout the PNGL12 review.

"PB Rune compared PNGL with the GDNs in GB, and concluded that PNGL is generally efficient at undertaking and delivering capital projects. Implicit in this is that the unit rates for the various capex activities, as proposed by PNGL, do not seem unreasonable."

PNG strives to adopt best practice approaches, uncover efficiencies, and deliver a service customers value. These objectives will be maintained over the next control period, as reflected in our business plan. However, in evaluating PNG allowances, PNG has concerns about UR's approach in apportioning what UR considers to be an efficient allowance for the management fee across the various capex activities undertaken by PNG. UR believes that this facilitates a more direct comparison of PNG's unit costs with other GDNs.

PNG remains of the view that this approach should only be adopted for the purpose of benchmarking as, in practical terms, PNG's management fee is predominantly fixed. Hence this proposal increases the risk faced by the business as cost recovery of fixed overhead is not certain, i.e. PNG incurs upfront costs for stores, supply chain, manpower, etc., whereas the allowance proposed by UR is only available if PNG delivers the numbers of connections.

PNG has also noted a transposition error in UR's apportionment of the c.£2.4m management fee allowance across the various capex activities as highlighted in recent discussions with UR.

Treatment of Unforeseeable/Unpredictable Costs

PNG welcomes UR's proposal to continue using the current mechanism as the vehicle for dealing with unforeseeable and/or unpredictable costs over PNGL12. However UR's proposal to introduce a de minimus threshold of £100k below which additional allowances will not be considered, is misguided. The proposed de minimus threshold is not appropriate to the size of PNG's operations and should be removed [or at least reduced].

To put this threshold into context, the cost of developing the semi-automated IT system which facilitated the introduction of supply competition within PNG's Licensed Area was less than £100k. Under UR's de minimus proposal, PNG would have had to fund fully development of the switching system, which benefits suppliers and consumers, for the Greater Belfast area but which is of no direct benefit to PNG.

The application of such a de minimus threshold over a cost category such as IT, where UR's proposed allowance is on average only c.£240k per annum, further demonstrates the inappropriateness of this threshold. Given the replacement cost of PNG's current IT infrastructure, PNG's IT allowance is already fully committed and therefore there would be no margin for absorbing any such de minimus expenditure.

This is another example of UR's proposals effectively 'double counting' efficiency.

6. A BRIEF HISTORY OF PHOENIX

Introduction

This Section 6 represents PNG's response to Appendix 1 of UR's Consultation Paper.

In Appendix 1, UR provides its view of the history of PNG and the changing risks faced by PNG since 1996.

PNG consider UR's description of PNG's regulatory history and the changing risks faced by the business to be extremely selective and, at times, misleading. PNG therefore wishes to correct what has been written through the provision of this Section of PNG's formal response.

1996 to 2006

In 1996 Phoenix was granted a combined licence to undertake conveyance activities (at both transmission and distribution levels) and supply activities. There was no natural gas network in Northern Ireland: the 'Towns Gas' industry had ceased in the early 1970s and the infrastructure had been decommissioned by the late 1970s/early 1980s. As a consequence, PNG's task was not limited to carrying out the traditional roles of a network operator and gas supply business: PNG also had to develop a network and create a market for natural gas from scratch. This included establishing an installer and appliance retail network where none existed and ensuring that technical training and certification was readily available for those wishing to work in the gas industry.

This task was made harder by the fact that the trend across the UK for homes to move to central heating from the mid-1970s and into the early 1980s was evidenced in Northern Ireland by the increased use of home heating oil and electricity. This was in sharp contrast to GB where the conversion from 'Towns Gas' to natural gas occurred at the same time as demand for domestic central heating was increasing. While GB had a willing market for natural gas, consumers in Northern Ireland had to be convinced to move away from their traditional central heating sources to natural gas and, in so doing, to meet the additional cost of converting to gas and investing in new gas appliances.

Between 1996 and 2002 PNG had to create the infrastructure to physically make natural gas available to, initially, a limited number of homes and businesses in Northern Ireland. The next step was to educate people about natural gas, both in terms of what it was, its benefits and how it could be utilised. In parallel, the skill base to specify, design and install natural gas in homes and businesses had to be developed amongst private sector companies willing to invest in the potential of this industry. Products and alliances with the required distribution channels and support activity had to be developed as no gas products were

manufactured in Northern Ireland at that time. Natural gas had to be actively sold to customers, on a “door-to-door” basis, to create the required levels of demand to establish the market for natural gas and its related markets in Northern Ireland.

One important element of the licence issued to PNG was the inclusion of a mandatory Development Plan. This required PNG to make gas available to 81% of all the properties within the PNG licensed area and to the districts within that licensed area within a fixed rolling-timescale. This was to avoid ‘cherry picking’ of areas and was enshrined in the licence in order to commit both the investor and the regulatory bodies to a sustainable long-term development plan. The plan would allow customers early access to natural gas with investor reward coming later once PNG had delivered on its investment commitments and met the licence conditions applied to the upfront investment.

In addition to the ‘green field’ development of the industry, another key aspect of the licence was that PNG would be subject to regulatory price control reviews on a 5 year basis. As investors were concerned that UR might seek to reduce their return once they had made the initial investment or might seek to remove any benefit of out-performance, the initial licence set the return for the first 20 years at 8.5% real pre-tax. Moreover, at each review, UR was restricted to reviewing forward looking data only.

Following a significant consultation exercise, UR issued PNG with its first price control determination in 1999 (3 years into the initial 20 year recovery period). This determined that, although PNG’s licence established deadlines for making gas available to districts, it did not prevent the construction of networks in advance of the original timetable. PNG and UR agreed that in order to stimulate the market and to sell gas to customers in meaningful numbers and on a sustainable basis, gas must first be ‘on the doorstep’ of homes and businesses. The 1999 price control determination confirmed that PNG should accelerate the build of the network and make gas available to consumers sooner than was originally planned. On this basis, investors significantly increased their early capital commitment by bringing forward investment to facilitate the ‘accelerated’ build programme. This led to a situation where the level of investment was significantly greater than anticipated at the time the original development plan was agreed.

At this stage, the full conveyance charge for recovery of this investment, and other earlier investment, was not being passed on to customers. Across the first half of this period to 2001 and in the early development of the market, this facilitated lower gas costs for customers; it always being understood and agreed that this under-recovered income would be recovered in later years, by either increasing conveyance charges or through recovery within the residual value of the investment determined at the end of the initial 20 year period.

It was also understood that the original licence did not adequately reflect the new accelerated investment scenario, and that investors would be made whole over time. Because PNG kept prices below the level that was allowed by the original 1996 licence, this

generated under-recovered revenue (the “Z” factor), which was subject to a penal rate of interest. The Z factor mechanism was designed to provide an incentive to set prices at a level to match the level of allowed prices rather than as a mechanism to defer revenue recovery. In these early years, the level of under-recovery was such that the penalty for rolling forward Z was relatively modest. However, following on from the second price control review, it had reached the point when investors either needed to increase prices to fully reflect the way the licence was supposed to operate or to reach agreement to move to a longer term cost recovery model. This longer term model would more closely reflect the expected economic life of the assets, but would require further deferral of cost recovery by the investors. Moving to a longer recovery period was thought appropriate and more helpful to the development of the gas industry in Northern Ireland compared with the alternative of raising prices so that the investment could be recovered within the original 20 year control period. Consequently, in 2003 PNG and UR entered into dialogue on the move to a longer term recovery period.

Following detailed discussions between UR and PNG in 2003 and 2004, which were aimed at facilitating an agreement that would ensure that the unit price charged to consumers was minimised while still enabling PNG to recover its investment in full, the two parties reached the following conclusion:

“Phoenix and the Authority are both agreed that our objective must be to create the conditions which will allow Phoenix to grow rapidly to at least the extent envisaged when it was established in 1996 and preferably to surpass those expectations by winning more customers than then anticipated in the licence area and by extending its activities into adjacent areas. We are also agreed that the key to success must be affordability and long-term price stability being so effectively enshrined in the new arrangements as to remove any grounds that may exist for scepticism on the part of existing or potential customers.”³⁷

The key aspects of the 2004 Agreement were a move to a 40 year regulatory recovery period, the retaining of a rate of return of 8.5% and the divestment by PNG of its transmission assets.

In 2005 the ownership of PNG changed after Terra Firma (the current owners) acquired the company as part of their acquisition of East Surrey Holdings plc. As the 2004 Agreement had been agreed but had not been reflected in PNG’s licence, UR took the opportunity to withdraw its agreement to an extended recovery period during the acquisition process. The acquisition was ultimately completed in November 2005. Following the completion of Terra Firma’s acquisition of PNG, Terra Firma and PNG entered into new discussions with UR to try and reach agreement along the lines first agreed in 2004.

³⁷ Final Offer letter from Ofreg August 2004

2006 to 2011

These discussions resulted in an agreement between UR and PNG towards the end of 2006. The main elements of this 2006 Agreement were as follows.

- 1) The licence recovery period (the period over which PNG's costs were to be recovered) was extended from the original 20 years (i.e. 1996 to 2016) to a 40 year period from 2006 (more closely reflecting the economic life of the asset base).
- 2) PNG agreed to sell off its transmission business to a mutualised vehicle such as Mutual Energy at an agreed value³⁸.
- 3) PNG agreed to a reduction in the rate of return it was allowed on its network business from 8.5% to 7.5% on its distribution business (fixed to the end of 2016), and 6.25% on its transmission asset (up to the date of its sale).
- 4) UR and PNG agreed a regulated asset value for the distribution business and the transmission business (to facilitate its sale). This is discussed further in Section 2 of this document.

The 2006 Agreement necessitated changes to the licence and these were introduced through the 2007 licence modifications. As part of this process UR issued a consultation document³⁹ and a decision paper⁴⁰ that stated:

*"This meant that, in order to encourage connections to the network, prices had to be set so as to be competitive with alternative fuels after accounting for customers switching costs.If Phoenix was to achieve the original rate of return of 8.5% (pre-tax real) it would have to increase the distribution charge substantially above current levels. The effect of such a strategy on the return on investment depends on the response of connections and volume to this price increase. This situation was not, in the opinion of the Authority, in the best interests of customers or the Licensee....In addition, as the risk profile for the Licensee was altered it was also necessary to establish the appropriate rate of return for this risk and the period over which it should apply. That is, what was the appropriate sharing of the benefits of restructuring between Phoenix and customers (existing and future)? ...**Customers benefit in two ways from the agreement; no substantial increase in distribution***

³⁸ PNG completed the sale of its transmission asset following a complicated reorganisation of its business on 31st March 2007

³⁹ Phoenix Natural Gas Licence Restructuring ; Proposed Price Control Licence Modifications April 2007

⁴⁰ Phoenix Natural Gas Licence Restructuring; Proposed Price Control Licence Modifications 27 June 2007

charges which would otherwise be necessary in the absence of agreement and a reduced rate of return. The Authority estimates the value of benefits of the agreement to consumers to be in the region of £25m in 2006 present value terms."

In addition, in UR's decision paper⁴¹ on the sale of Phoenix's transmission asset to Northern Ireland Energy Holdings Limited, UR stated:

"If we examine the benefits from a gas industry perspective which compares the opening asset value of £98m financed at 7.26% over 17 years compared to £106m at 1.84% over 40 years the NPV of the benefit of the transaction equals approx £31m. As a sensitivity analysis, if we assume the market rate achieved by the bond is 2.5% this still results in NPV savings of approx £19.7m and if we assume 3% then NPV savings would be approx £10.5m.

The current operating expenditure for Phoenix Transmission amounts to £1.2m, although some of this is made up of uncontrollable costs such as rates and licence fees. If we assume that savings from lower operating costs amount to £300,000 per annum this would equate to NPV savings to transmission consumers of £6m. The reduced size of the Phoenix group as a result of the sale of the transmission asset may partially offset some of this gain through reduced economies of scale feeding through to higher unit prices in the distribution business. However we feel that this will be significantly less than £300,000 per annum, and any such increase is offset by the inclusion of Phoenix 7 bar pipelines in the transmission Regulatory Asset Base."

The above evidences UR's view that the 2006 Agreement and subsequent 2007 licence modifications delivered significant benefits to consumers. However, UR's selective summary of the developments between 2006 and 2011 makes no reference to these benefits.

PNG's third price control review, PC03, (for the period 2007-2011 inclusive) was subject to a long delay and was not issued until 30th November 2007 (11 months after the start of the control period). As part of this determination, UR disallowed significant costs that PNG had already incurred in 2007 and had no ability to recover. However, in the context of a five year price control and the need for continued focus on development of the market, PNG accepted the terms of the price control and set about operating within these terms. Again, UR's summary of the regulatory history fails to make reference to this fact.

UR states in the Consultation Paper that additional elements were agreed following the issuing of the 2007 price control determination by UR which significantly benefitted PNG. UR states that:

⁴¹ Proposed Acquisition of Phoenix Transmission by Northern Ireland Energy Holdings Limited
Utility Regulator Decision Paper October 2007

“The third price control of PNGL (PC03) followed shortly after the 2006 deal was concluded. Some further changes were made in that price control that also benefited PNGL, the key ones being:

- PNGL was moved from a price control to a revenue control, removing volume risk from PNGL.*
- PC03 saw the introduction of an extensive retrospective adjustment mechanism, which sees much of PNGL’s allowances (for both opex and capex) adjusted up or down depending on outturn events, significantly reducing activity based risks for PNGL.”*

PNG believes that UR has again been selective/misleading in its representation of the benefits to PNG of these reforms.

First, it should be noted that the ‘further changes’ that are referred to were not embedded within PNG’s licence until almost two and a half years after the start of PC03 when, in June 2009, UR implemented, via a further licence modification, a change from the inherent incentive on PNG to maximize volumes of gas to an incentive to maximize connections. The rationale for this change was to more directly align price control incentives to an area in which PNG had the ability to influence the outcome. The previous volume of gas incentive had become more heavily influenced by factors outside of PNG’s control, i.e. mainly actual temperatures experienced in any year, meaning that the performance outcome was likely to be driven by climate rather than PNG’s actual performance and making the setting of appropriate forecasts difficult as part of a price control. It is worth noting that a volume incentive was both an opportunity for PNG as well as a risk and on the basis of volume performance in 2010, PNG would have benefitted by c.12m therms/c.£4m purely because temperatures were colder than average.

Second, the Consultation Paper implies that the move to revenue control from price control was particularly advantageous for PNG in that it removed volume risk. The following extracts from the PC03 Price Control Determination⁴² and UR’s licence modification decision paper⁴³ in 2009 evidence UR’s view at the time of the impact of the changes to incentives on PNG’s risk profile. It is clear from these extracts that UR was of the view that the changes to the regime would result in PNG facing an equivalent risk to the volume risk that it had previously faced.

⁴² Phoenix Natural Gas Price Control Review 2007 – 201, Distribution Expenditure Final Determination, November 2007

⁴³ Phoenix Natural Gas Licence Further Restructuring; Licence Modifications to Replace the Volume Revenue Driver with a Part Fixed, Part Connections Revenue Driver A DECISION PAPER June 2009

*"We also intend to introduce an incentive regime for connections and will consult in 2008 on how this should be designed. In designing an incentive regime we are minded to take into account current connection projections and marketing and incentive allowances in determining an appropriate connections target with the reward or penalty increasing depending on how far PNG are from the target. **The regime will reflect a similar risk to the volume risk currently faced by PNG.**"*

and

"The Authority considers that a volume revenue driver in the distribution business is not appropriate and does not necessarily deliver the optimum outcome for customers. The Authority also considers that a connections driver in the sectors where further significant levels of connections are required to reach the ultimate forecast penetration levels is more appropriate in developing the market with benefits for customers via a larger customer base."

Third, UR's summary of the regulatory history fails to give adequate regard to the significant risks that the PNG business continues to face. The connection incentive developed by UR requires PNG to grow connections in the incentivised sectors by 45% over the PC03 review period. The risk associated with this level of targeted growth is significant and therefore the challenge that PNG faces under the connection incentive remains material. In addition, the methodology of the connection incentive was to put at risk three things:

- 1) The marginal revenue of each incentivised connection foregone over the price control period due to a shortfall in connections must be passed back to consumers in following years.
- 2) Costs associated with the incentivised connection are not allowed as part of the price control if that incentivised connection is not delivered.
- 3) Part of PNG's advertising and marketing allowance is disallowed for each incentivised connection not delivered.

Therefore, unlike the previous volume incentive regime which only put at risk allowable revenue, the connection incentive regime not only puts at risk allowable revenue but also a level of costs that was not previously at risk under the volume incentive regime.

By the end of the current PC03 price control in 2011 PNG will have connected c.148,000 customers to its network. PNG's current network makes gas available to over 290,000 premises. By the start of 2012 there will still be c.50% of the available premises not yet connected to natural gas. PNG has planned to spend a further £25m in capex constructing new network, making natural gas available to these homes and businesses for the first time, and connecting those customers who are convinced to move to natural gas by PNG energy advisors, during 2012 and 2013. The targeted number of incentivised connections proposed by UR remains at the same level as during PC03 notwithstanding: worsening economic conditions; the significant reduction in new first time gas areas where initial penetrations

are higher than the long run average; and the lack of availability of funding for 'fuel poor' homes to convert to natural gas. It is therefore misleading for UR to imply that PNG's business faces lower levels of risk as a result of the PC03 reforms.

Fourth, although UR is correct that PNG saw the introduction of a retrospective adjustment mechanism during PC03, UR has again been misleading in its comment about "*significantly reducing activity-based risks for PNGL.*"

The following is an extract from the PC03 public determination document⁴⁴:

Retrospective Adjustments:

- 1. Rates*** – Rates are currently calculated using a formula based on PNG's turnover. Our decision on Rates is to set the allowance based on the current formula and any variation in turnover will be accounted for retrospectively.
- 2. Licence fees*** – Licence fees will be treated on a pass through basis and any variation from allowances will be retrospectively adjusted.
- 3. Advertising, Marketing, PR and incentives*** – A retrospective adjustment will take account of any difference between actual and forecast costs (which have been capped) for 2007 & 2008. The appropriateness of the current allowance for 2009 – 2012 will be reviewed and may be adjusted accordingly.
- 4. Traffic Mgt Act*** – Costs have been included within the determination to take account of the potential impact of the Traffic Management Act. Any difference between this allowance and what the Utility Regulator considers appropriate will result in a retrospective adjustment at the next review.
- 5. Numbers of Properties Passed*** – The forecast number of properties passed within the determination has formed the basis for forecasting the quantity of feeder and infill mains to be laid. If the actual number of properties passed is less than forecast, the associated reduction in infill and feeder mains will result in a reduction to the current allowance.
- 6. Connections*** – The cost of connections above or below that forecast will result in a retrospective adjustment to allowed costs at the next review. In addition, a connections incentive mechanism is to be designed that will incentivise PNG to connect more customers than currently forecast.

As can be seen from the items listed above, the majority of the retrospective items allow UR to ensure that PNG is not given any allowance which exceeds actual costs.

⁴⁴ Information relating to the Phoenix Distribution Price Control Review 2007 – 2011 Final Determination

In addition we note:

- The mechanism for rates ensures that if the allowed revenue of PNG is reduced during the price control period due to other mechanisms such as the connection incentive mechanism, then the allowance provided by UR for rates is also reduced.
- Licence fee is a direct cost from UR and as such PNG has no control over these costs.
- Advertising, Marketing, PR and incentives is part of the connection incentive mechanism which, as described above, means that if PNG does not hit the incentivised connection targets, it also loses some of the associated allowances.
- The Traffic Management Act is a new form of legislation. The responsible government department in Northern Ireland has not yet decided the exact scope and nature of how it will be implemented in practice. The retrospective mechanism in this case allows the estimate that UR has made for this cost to be adjusted accordingly to reflect actual costs incurred.
- The retrospective adjustment for properties passed allows PNG to make gas available to as many customers as possible, in line with the requirements of its licence and the agreement with UR, where it is economic to do so. This mechanism does not remove PNG's risk in managing the unit costs associated with carrying out this activity but enables a different number of properties to be passed to the number forecast at the start of the price control, as it is driven by customer demand. The key areas that drive the requirement for this mechanism are the construction of new build properties and the conversion of public sector housing from more polluting fuels to natural gas. The level of each of these activities is beyond PNG's control but it is clearly beneficial, where economic to do so, to make gas available to these sectors as and when required as it delivers benefits to all customer sectors.
- 'Connections' is similar to properties passed. Again this mechanism does not remove PNG's risk in managing the unit costs associated with carrying out this activity but enables a different number of customers to be connected to the network than is forecast at the start of the price control. Again, where economic to do so, it makes absolute sense for PNG not to be restricted in meeting customer demand as greater demand benefits all consumers.

It is clear from the mechanisms described above that UR's statement in the Consultation Paper *"which sees much of PNG's allowances (for both opex and capex) adjusted up or down depending on outturn events, significantly reducing activity based risks for PNG"* is both inaccurate and misleading.

Customers over the past 5 years have accrued significant benefits resulting from the PC03 regulatory efficiency targets and the 2007 licence modifications resulting from the 2006 Agreement i.e. sale of PNG's transmission assets to a mutualised vehicle, the reduction in the rate of return, the negotiated reduced OAV and the continued roll-up of under-recovery going forward, all of which have resulted in lower gas prices.

PNG has worked in a committed and diligent manner over the last 5 years using its professionalism, experience and ability to innovate in order to meet the incentivised connection targets set by UR. The reason that UR decided to, retrospectively, incentivise connection targets was to ensure that PNG was sufficiently incentivised to deliver those targets. This is exactly what has been done and therefore it appears rather disingenuous for UR to make the statement that *"customer connections have not suffered during the recession and that there seems to be a good constant flow of customers."* This statement ignores the active steps taken by PNG in ensuring a good flow of customers despite the recession and instead implies that the good flow of customers is inherent in the business and would have occurred without PNG's proactive measures. The fact that PNG has successfully managed the risk that UR placed on it and delivered against the incentive regulation devised by UR does not mean that the original risk was any smaller than previously thought. It begs the question whether UR expected PNG to fail to meet the incentivised targets that were set in PC03.

2012 onwards

15 years into the rolling 40 year regulatory investment model, PNG has delivered significant benefits to consumers and the establishment of fuel choice to energy users in the Greater Belfast area. However, PNG cannot agree with UR's assertion that PNG's business has been significantly de-risked in this time period. Oil remains the dominant fuel of choice across Northern Ireland with c.20% of homes and businesses utilising natural gas compared to c.90% in GB. In the Greater Belfast area 50% of homes still prefer home heating oil as their central heating fuel; with around 80% of these properties having had gas on their 'doorstep' for around 10 years. Despite the option to move to natural gas, these homes and businesses are yet to make the switch. It remains to be seen whether these potential properties can be converted to natural gas. An additional cause for concern is that over half of this potential is, by the Government's own calculations, in fuel poverty and it is difficult to see how these properties will find the funding to meet the conversion costs required to take advantage of fuel choice.

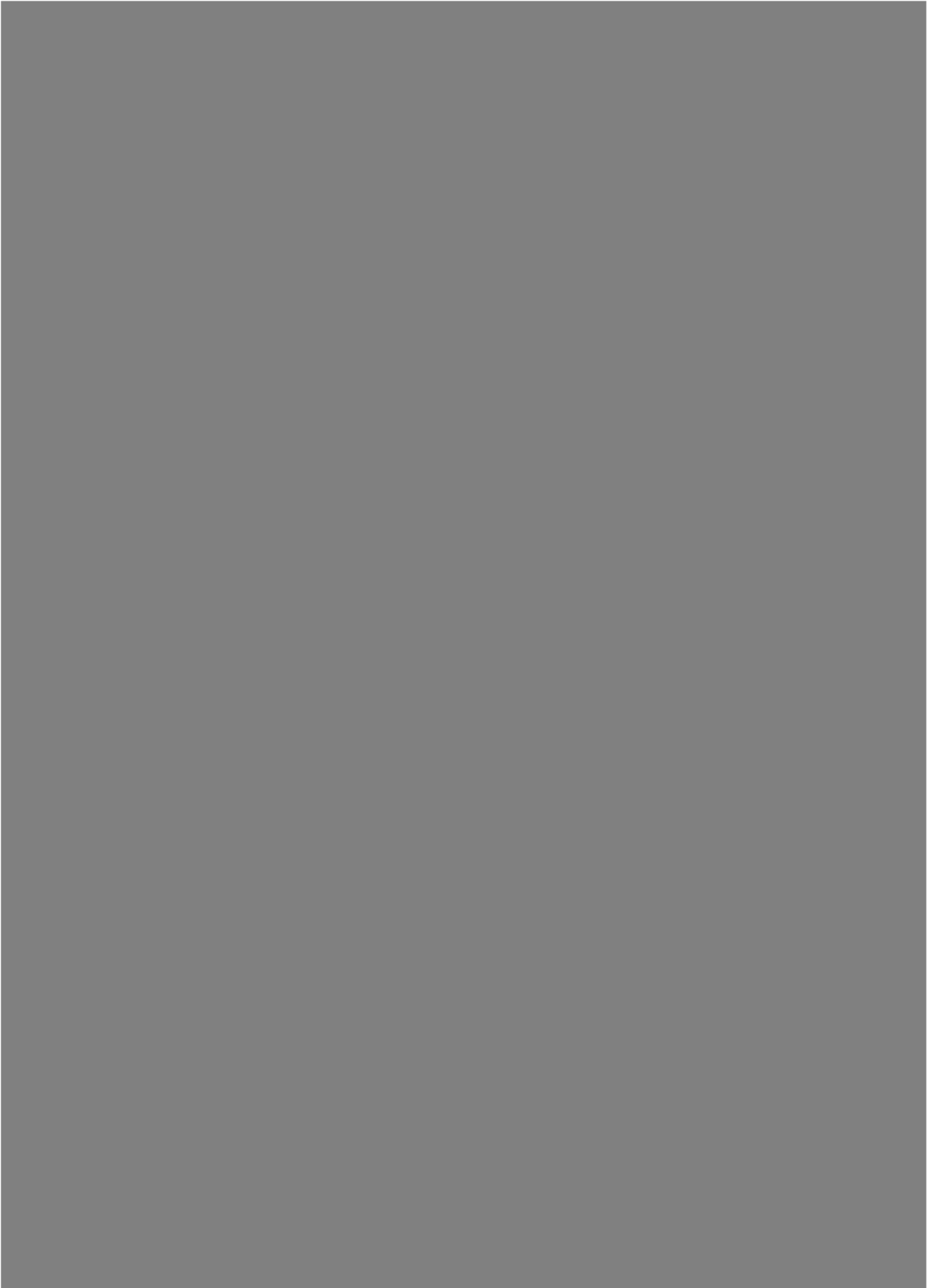
There are also more obvious immediate challenges facing PNG from the wider economy and the significant efficiencies being sought by UR as part of the PNG12 period. Natural gas in Northern Ireland is no longer just competing with well established fuels such as oil and electricity but is also having to deal with the huge publicity and support, including financial support, being provided to renewable energy - this is another significant risk factor that was

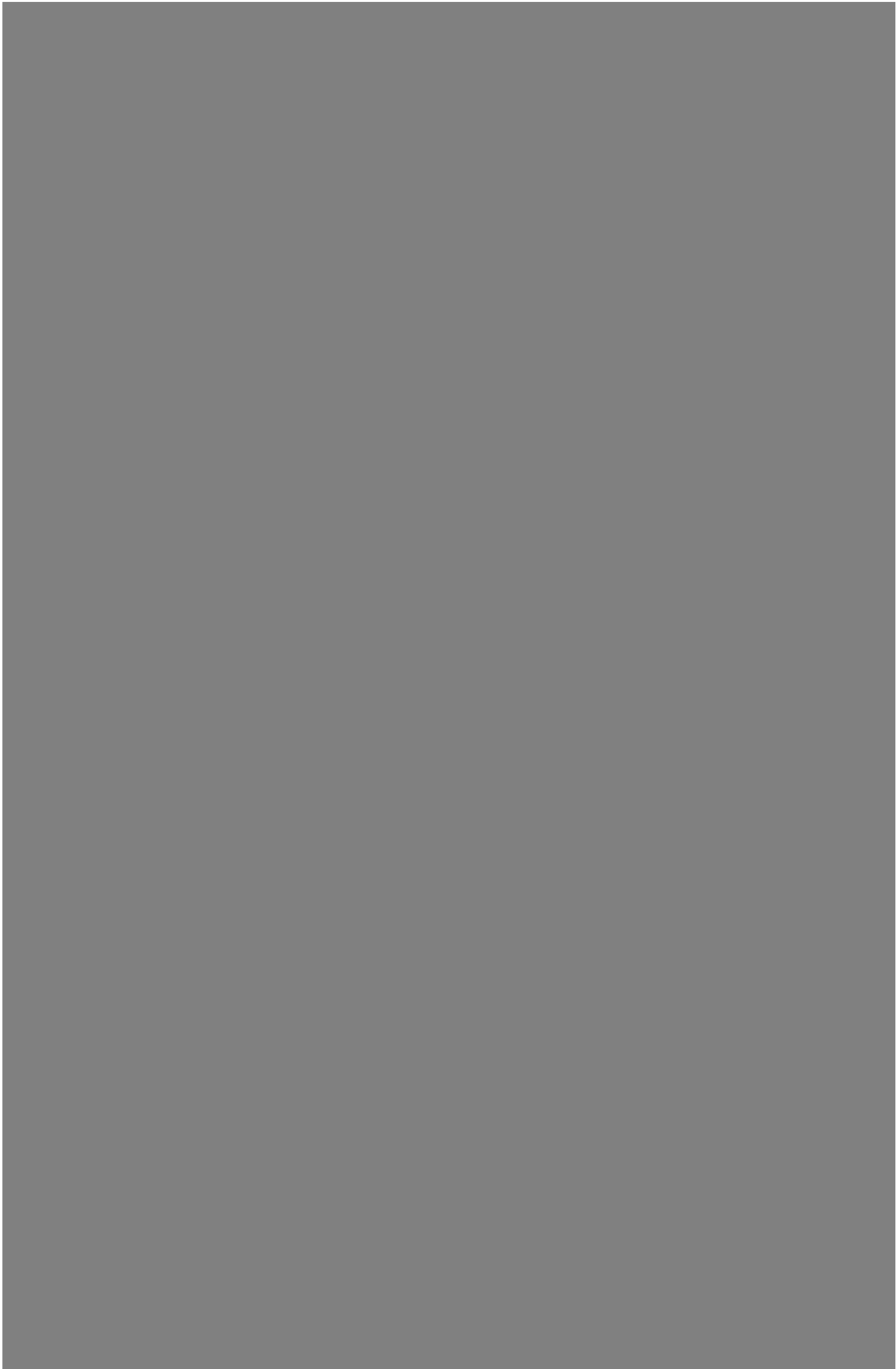
not present in GB when natural gas was first introduced. In omitting to make reference to this risk, UR's summary of the risks that PNG faces is incomplete.

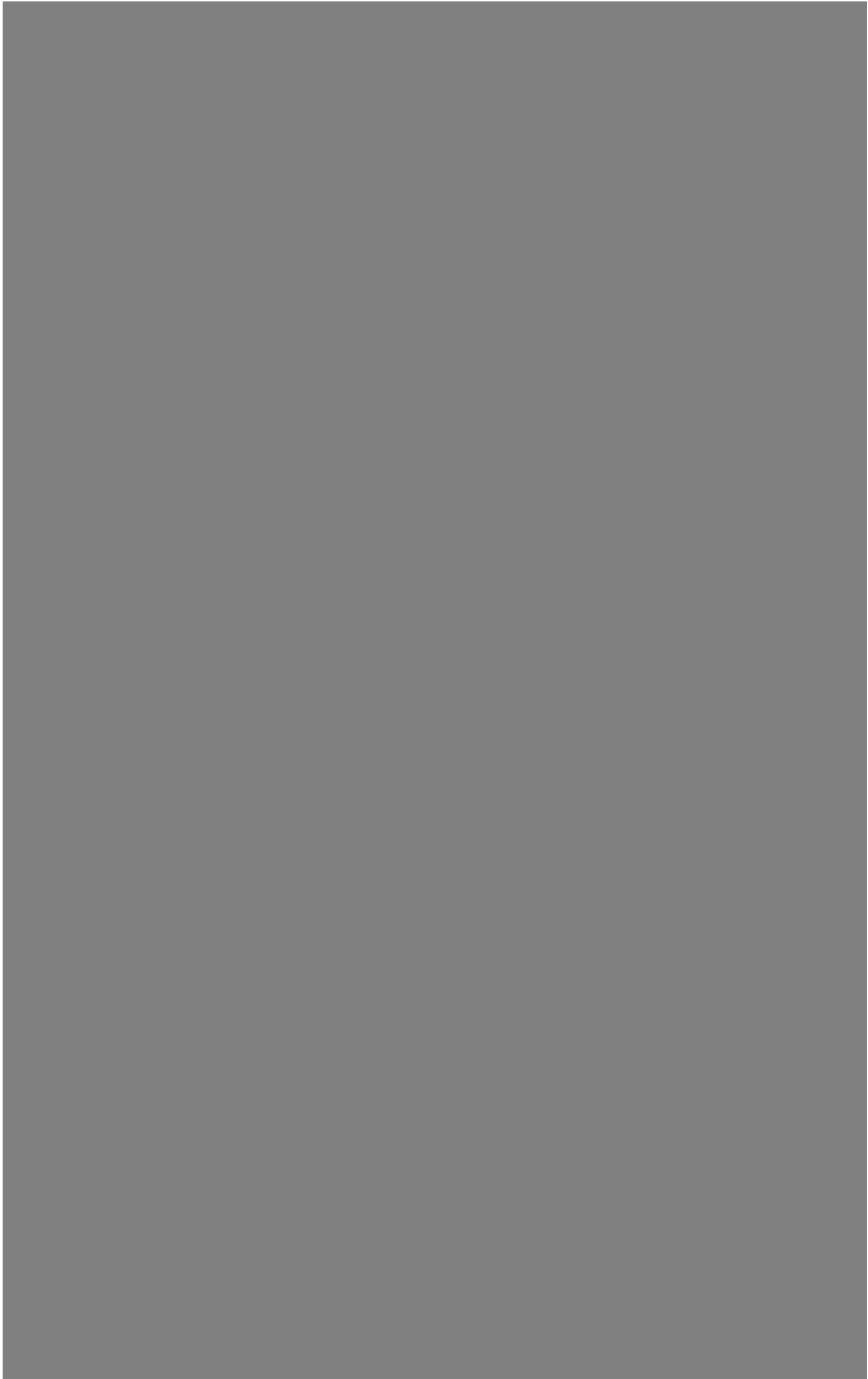
To summarise PNG believes that the level of risk it faces now and in the future is still high when compared to other mature utilities. Developing a gas industry over a short period of time when growth is dependent on new customers self funding the switch to natural gas remains very challenging.

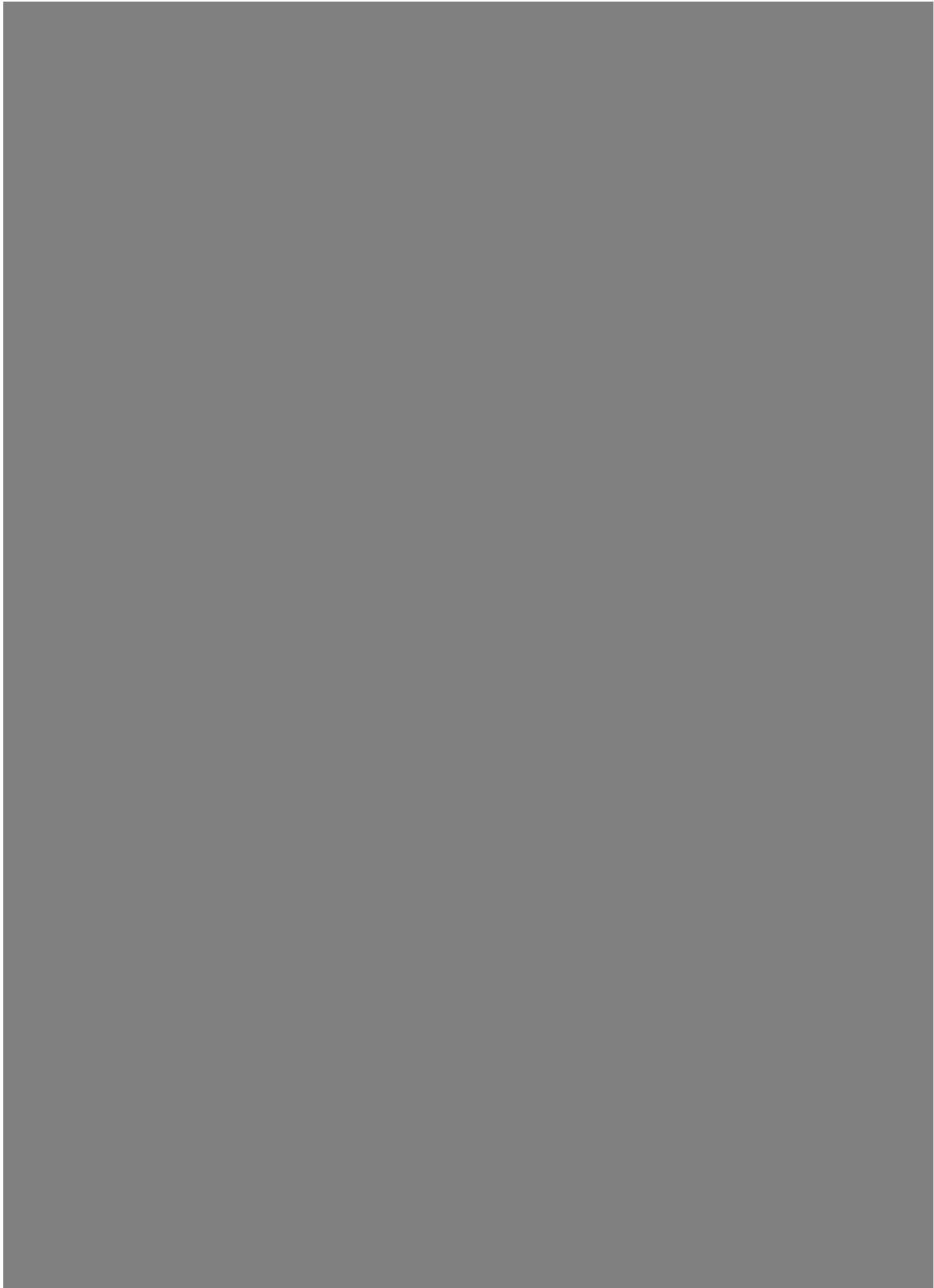
APPENDIX A – CONFIDENTIAL



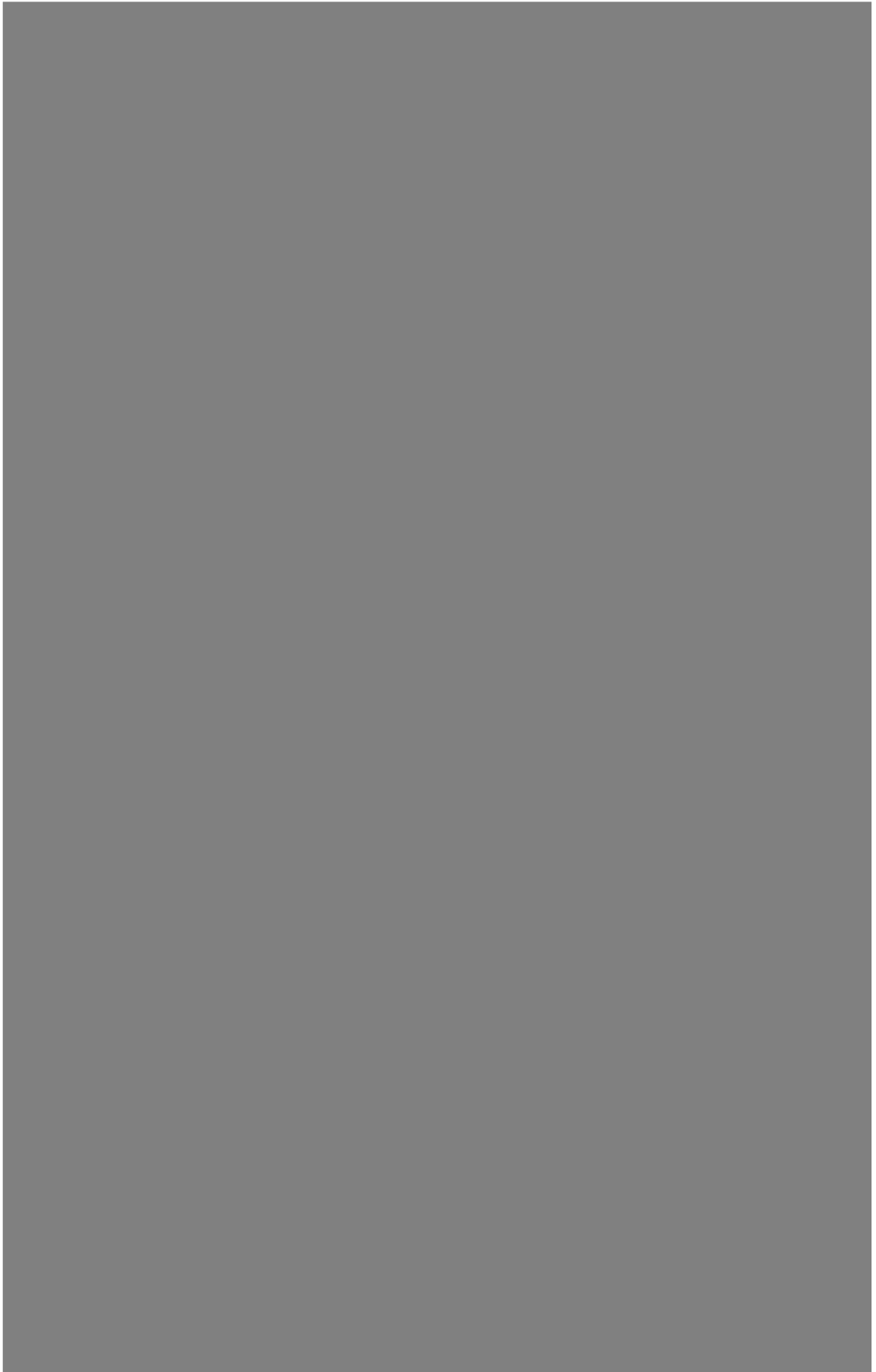


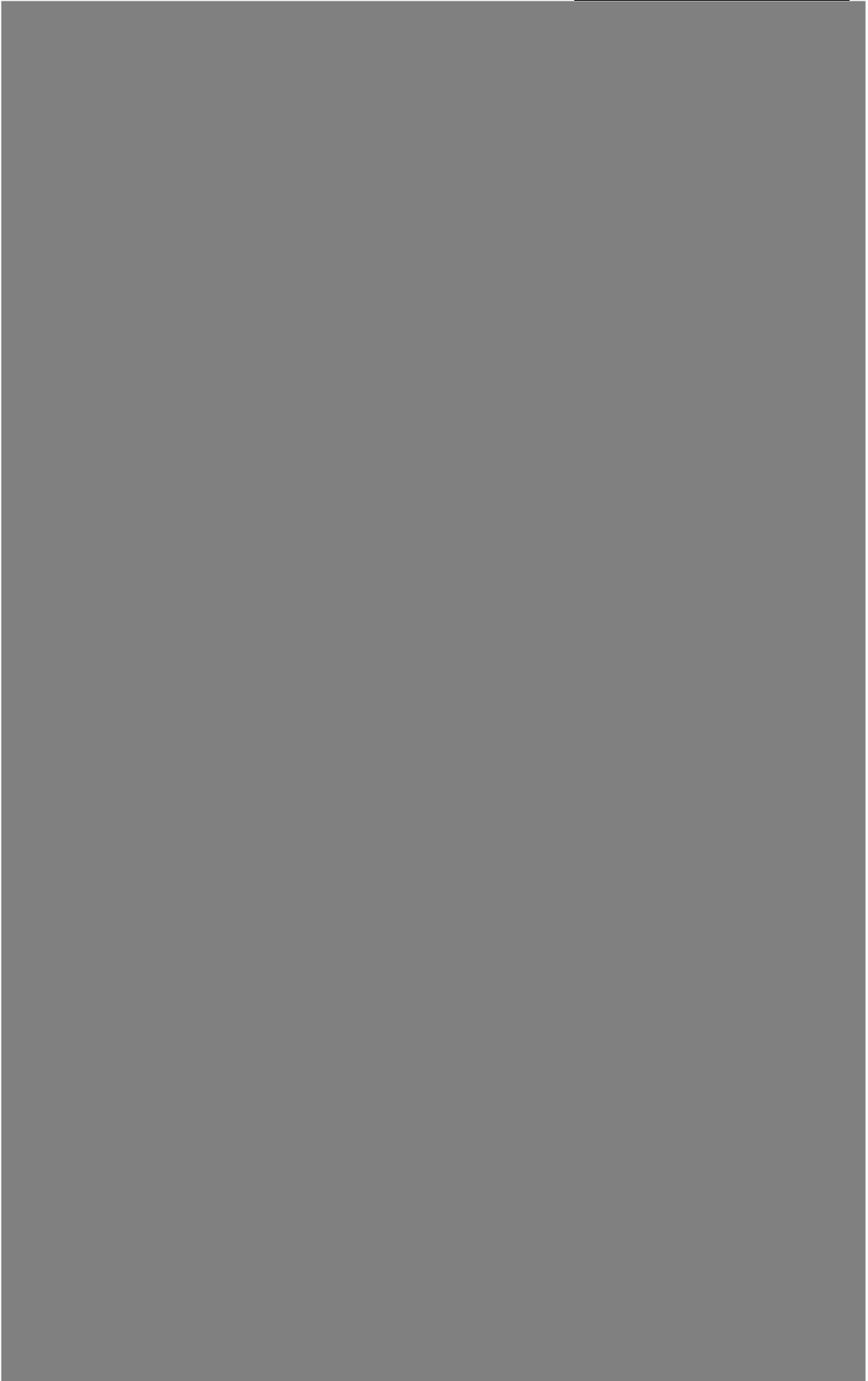


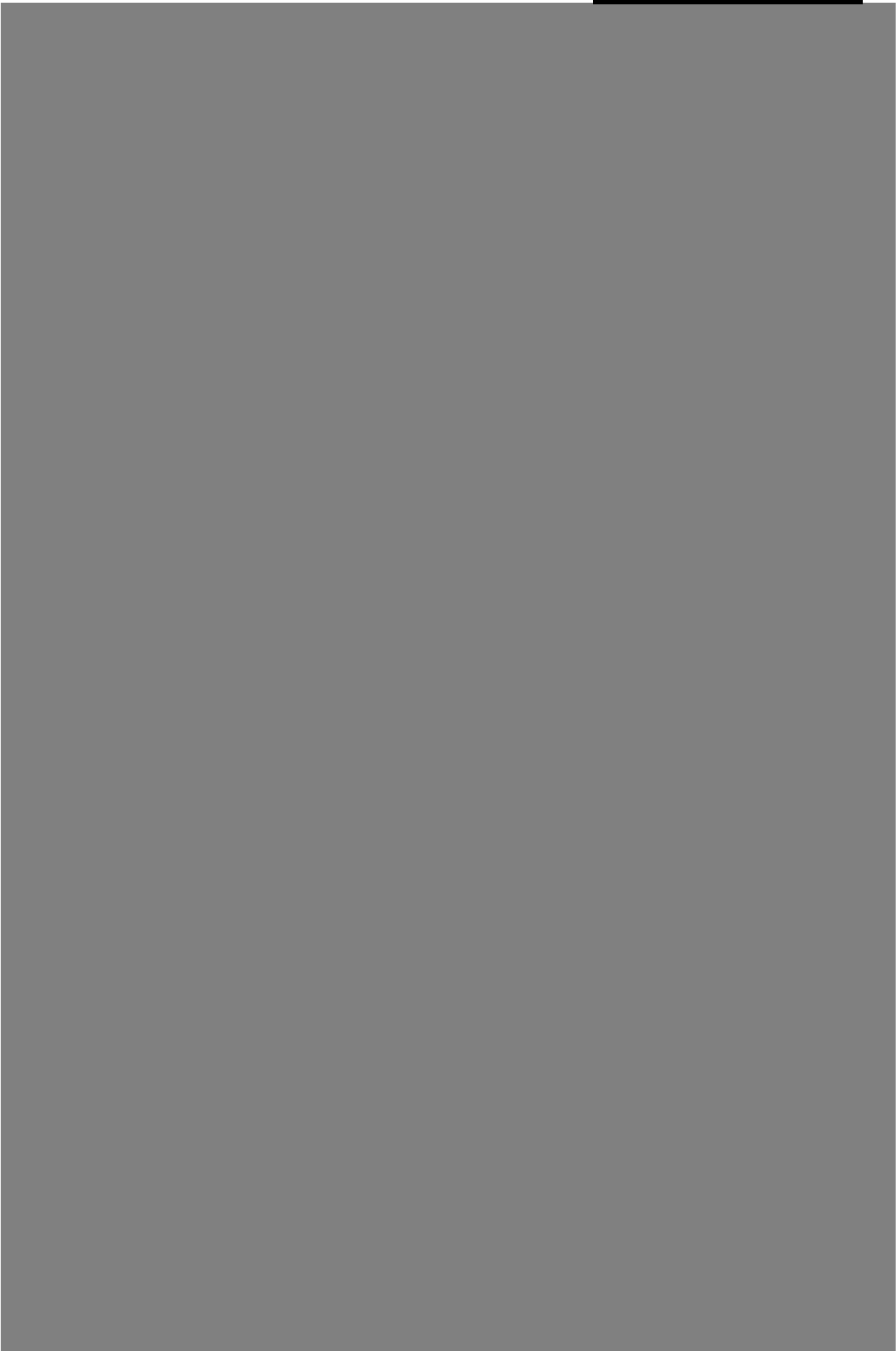


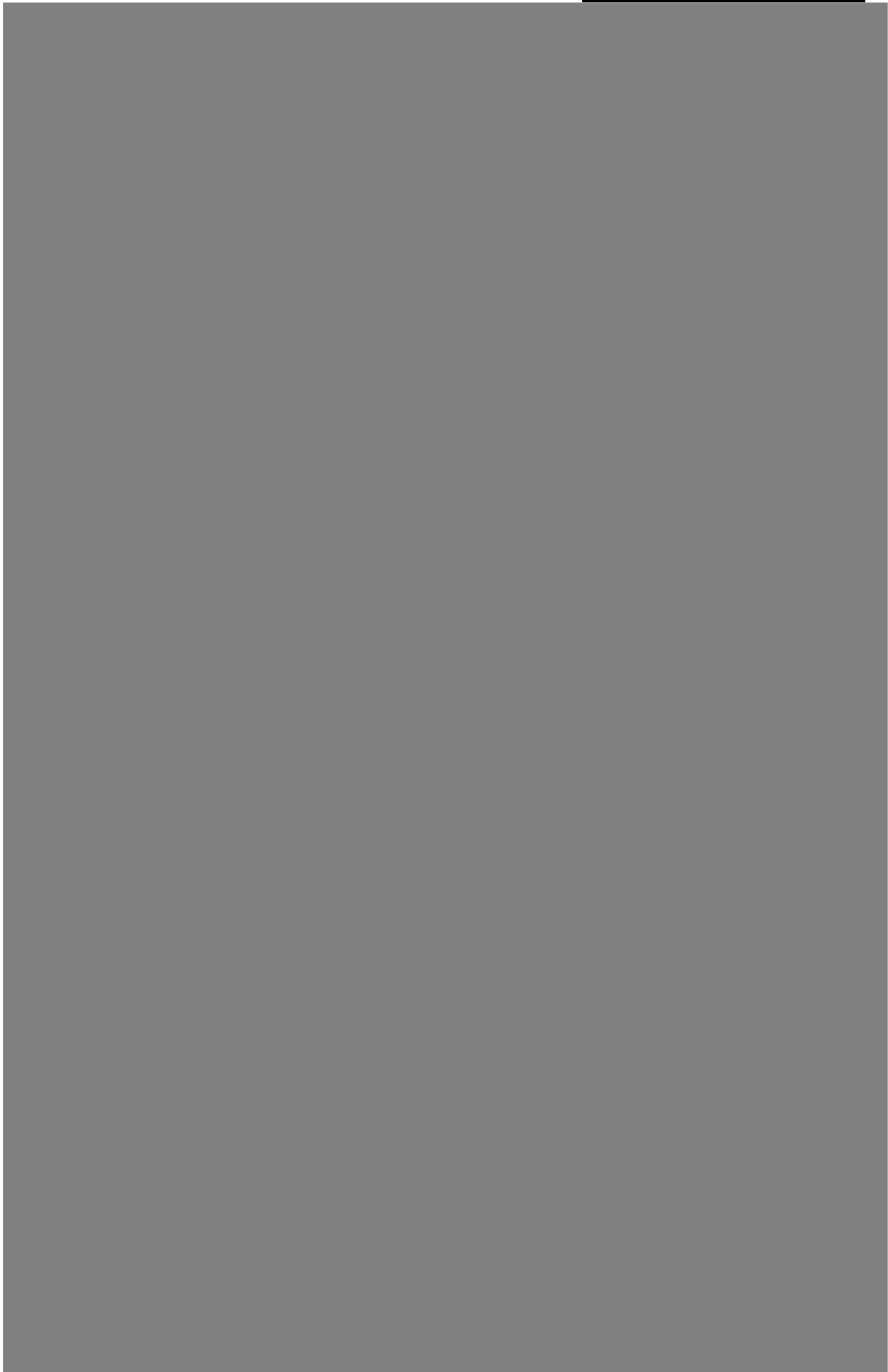


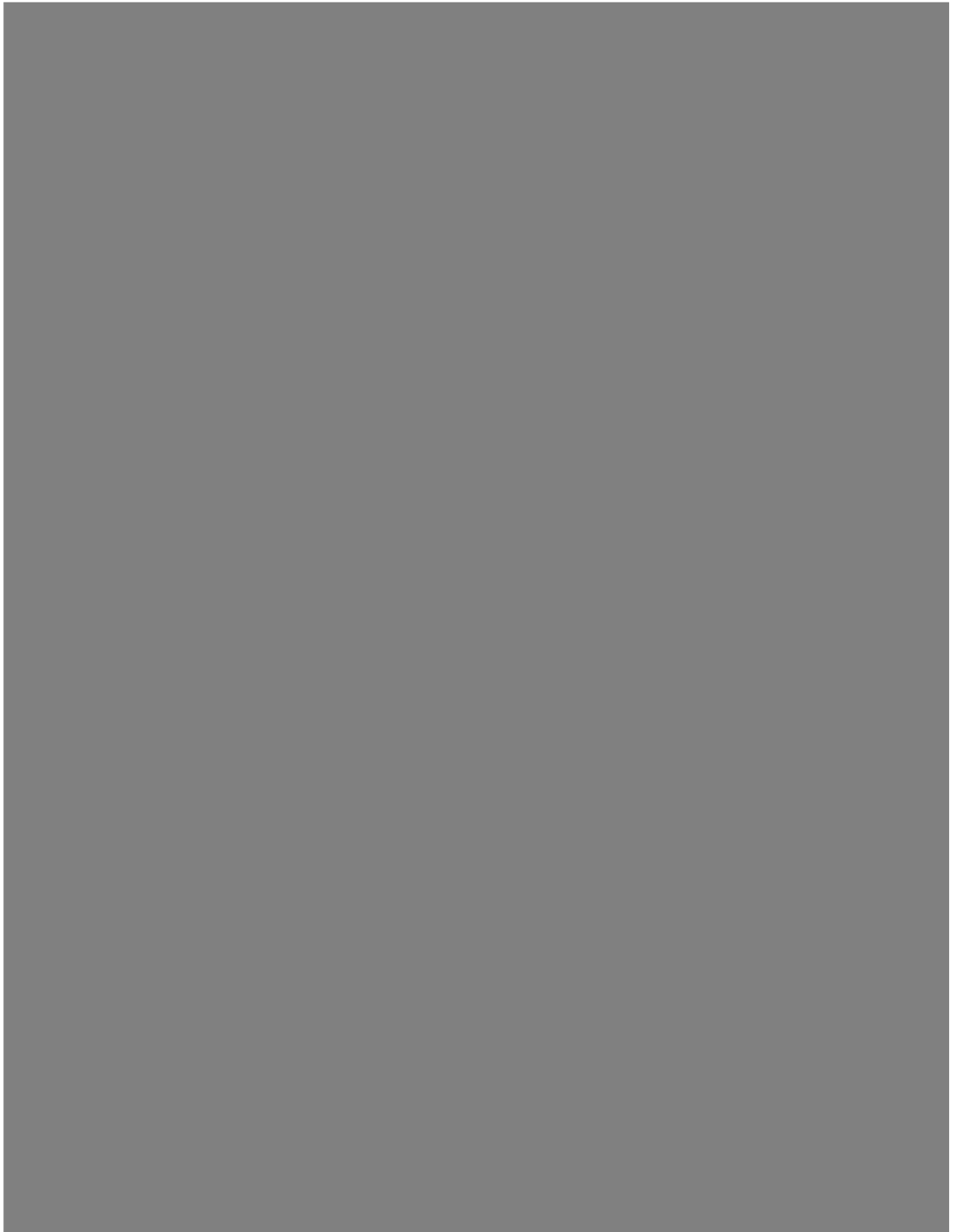




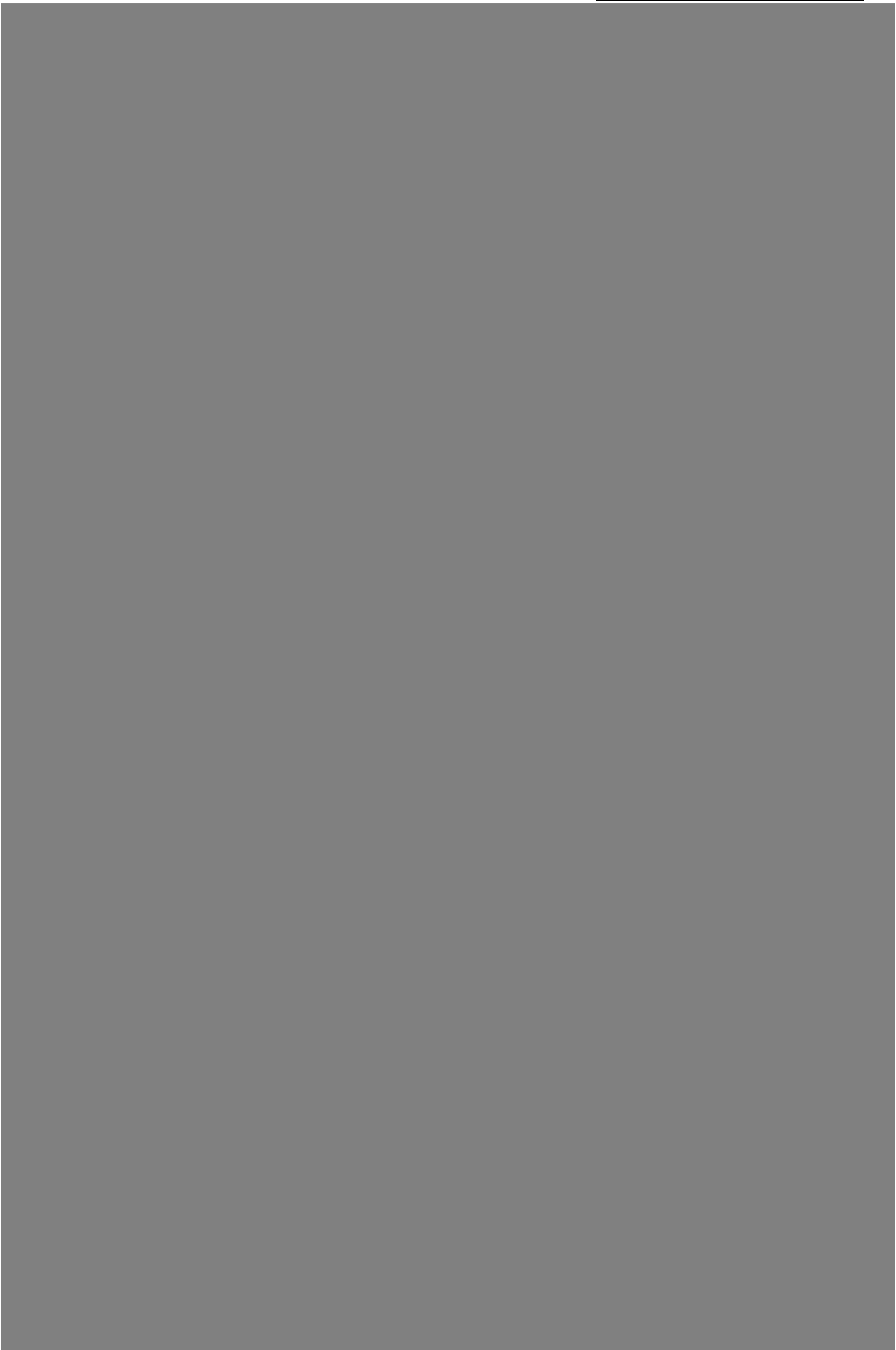


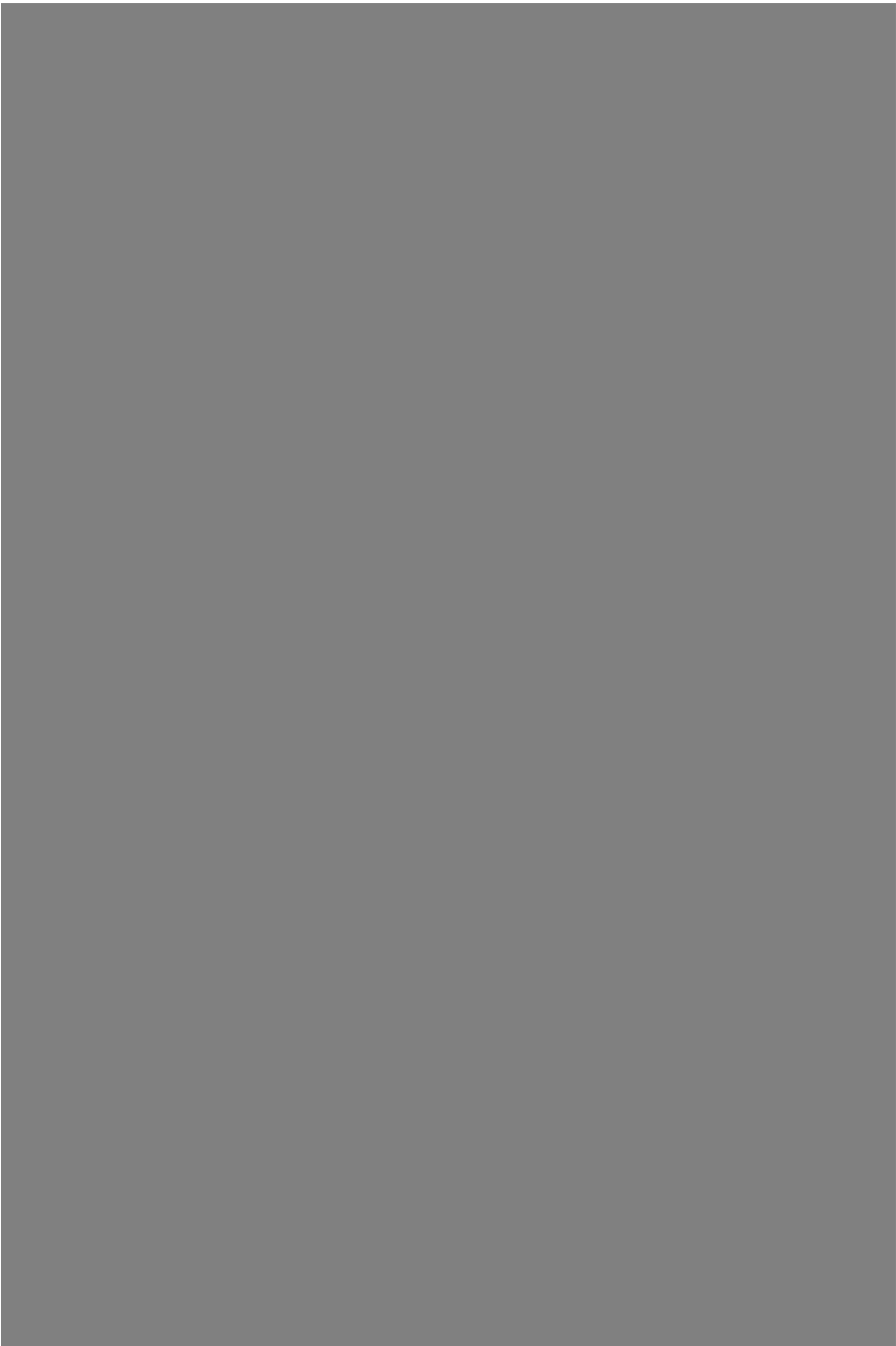


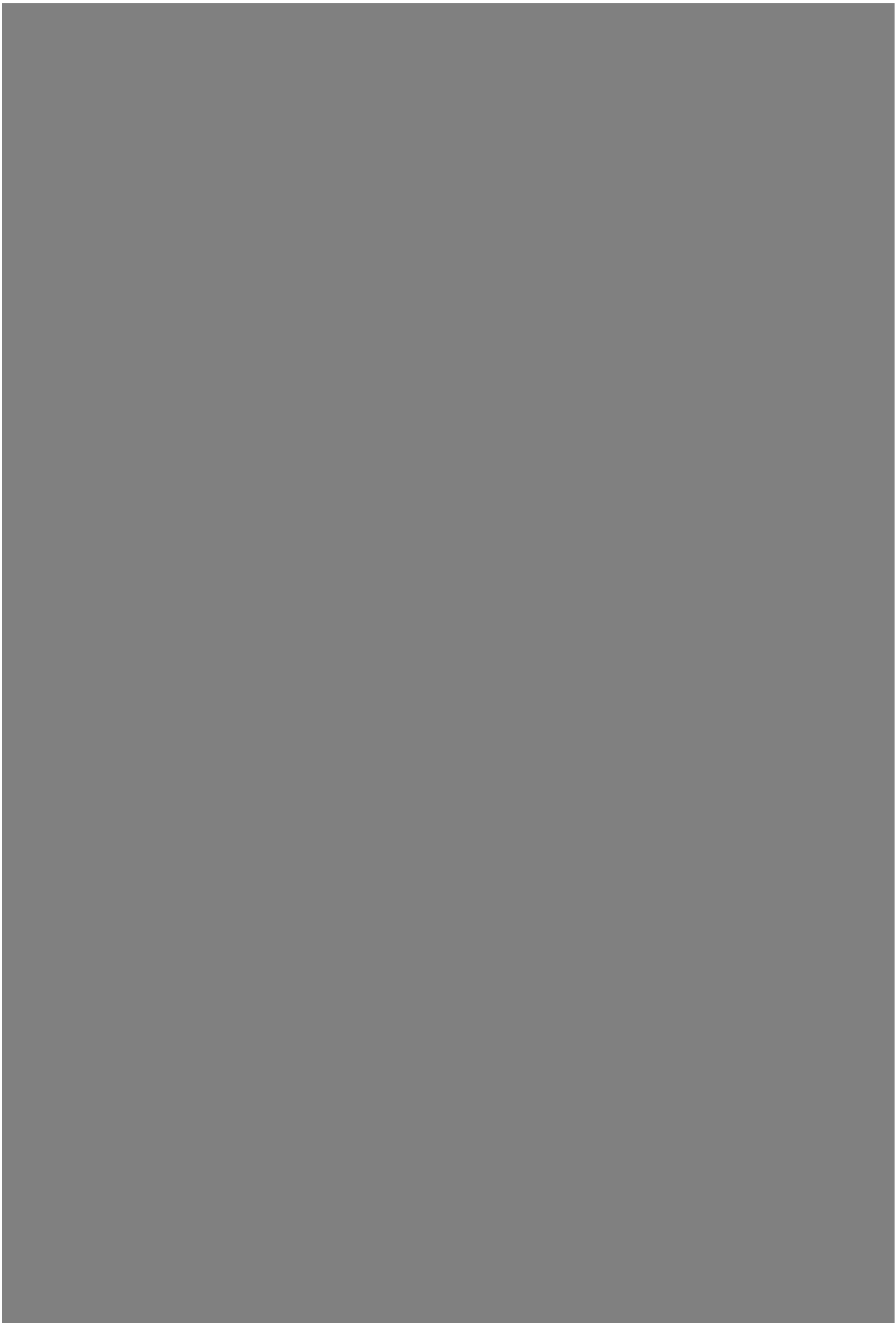




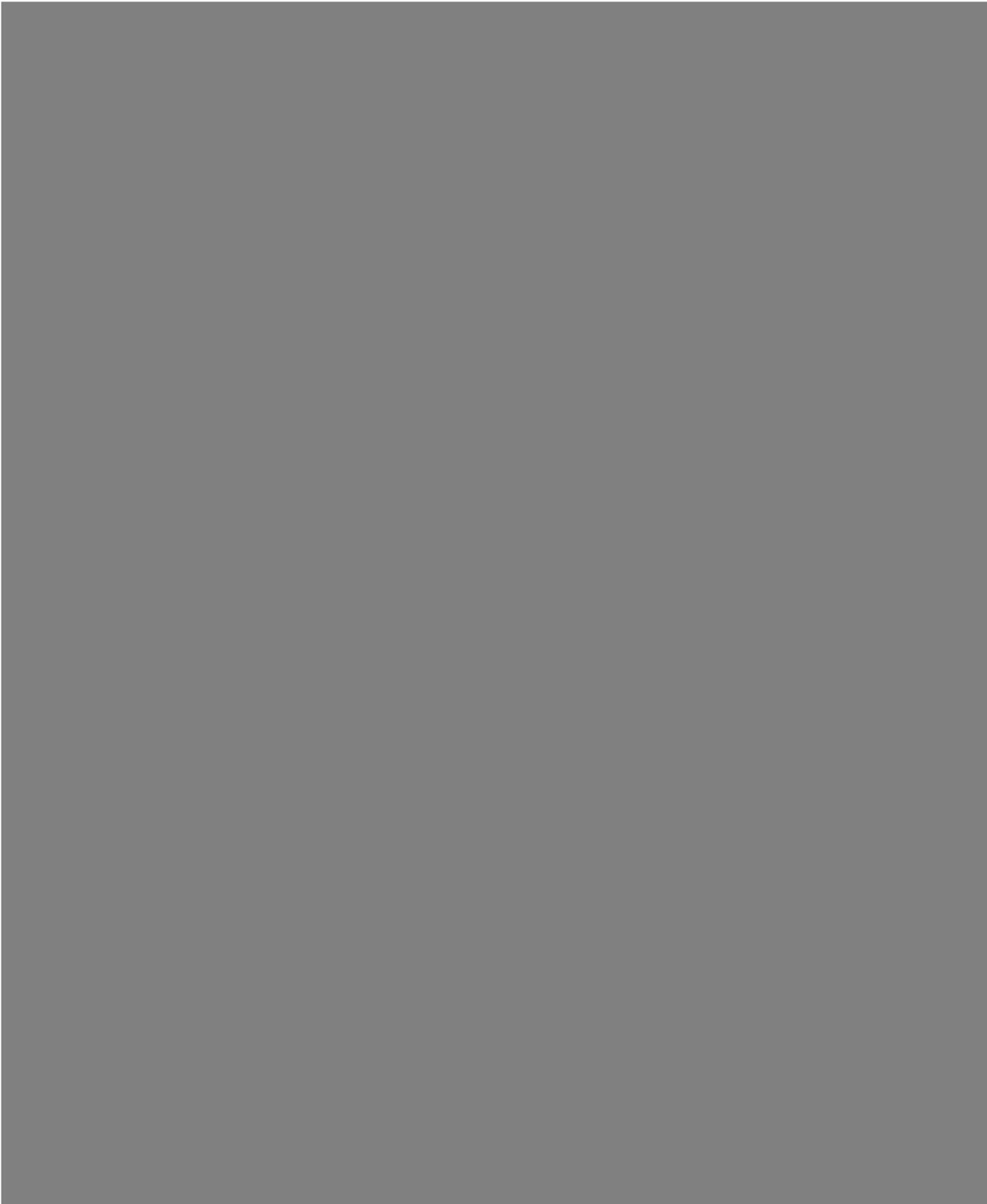
APPENDIX B - CONFIDENTIAL

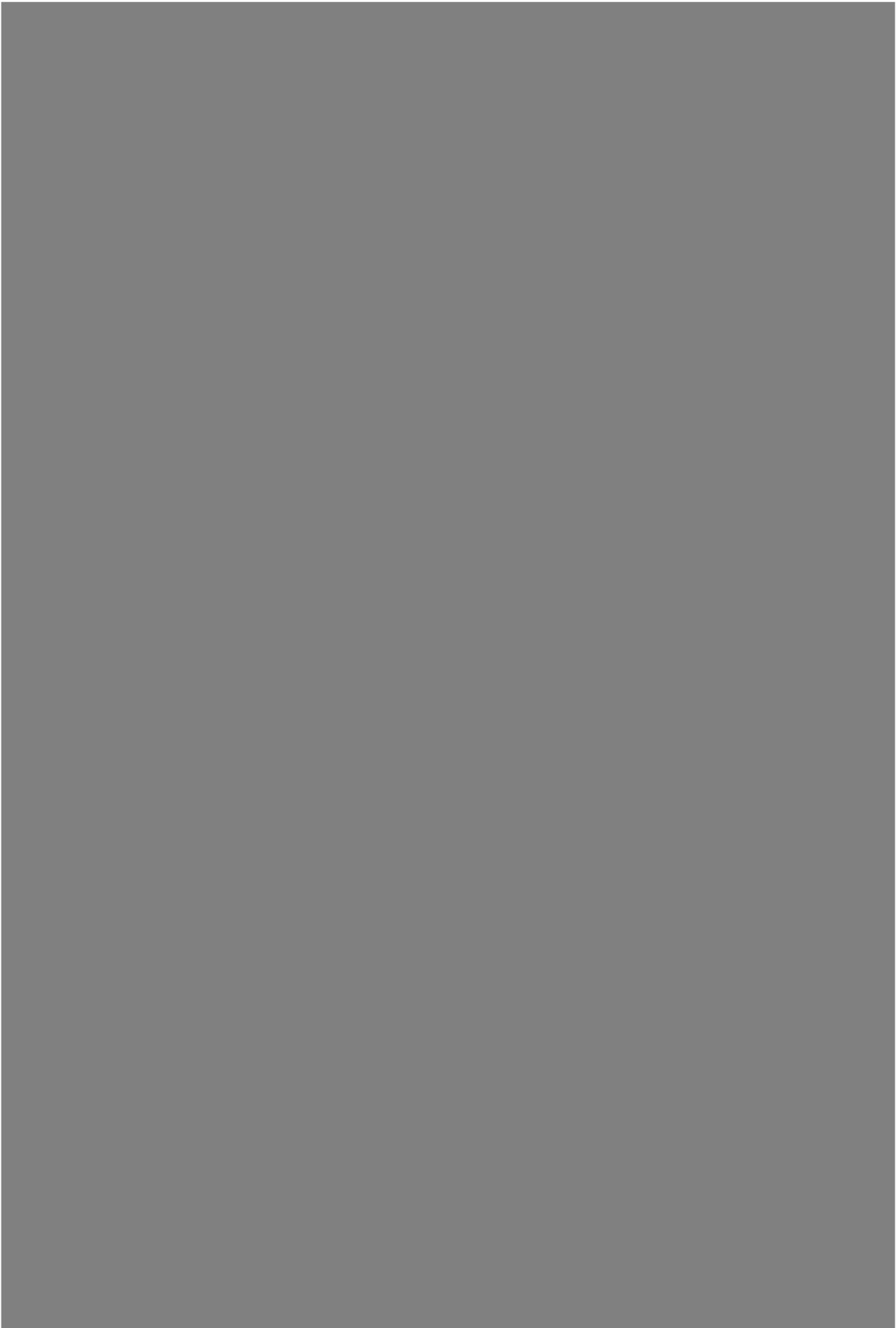






APPENDIX C - CONFIDENTIAL





APPENDIX D - FITCH PRESS RELEASE



FITCH PLACES PHOENIX NATURAL GAS' RATINGS ON RATING WATCH NEGATIVE

Fitch Ratings-London-12 October 2011: Fitch Ratings has placed Phoenix Natural Gas Limited's (PNG) Long-term Issuer Default Rating (IDR) of 'BBB' and senior unsecured rating of 'BBB+' on Rating Watch Negative (RWN). The agency has also placed the GBP275m bond issued by Phoenix Natural Gas Finance PLC, rated 'BBB+', on RWN. The bond is guaranteed by PNG. PNG's Short-term IDR is affirmed at 'F3'.

The RWN is pending the outcome of the open consultation "Phoenix Natural Gas Limited Price Control Draft Proposals 2012-2013" published by the utility regulator in Northern Ireland, Ureg, on 26 August 2011. Importantly, proposals include a GBP80.8m (in September 2010 prices) reduction in the opening Total Regulatory Value (TRV) for 2012. This is considered by Fitch to be material in the context of the previously forecasted 2012 TRV of GBP463m. If implemented, the agency estimates that PNG's actual net debt/TRV would increase to within a range of 75% to 80% compared with 60% at YE10, depending on dividends paid by the company. This leverage is substantially higher than a range of 60%-70% deemed appropriate for PNG's 'BBB' IDR.

Of the proposed GBP80.8m reduction in the opening TRV for 2012, GBP59.6m (in September 2010 prices) reflects proposed retrospective adjustments for capex and opex outperformance. Fitch understands that the retrospective clawing back of value for the benefit of customers is inconsistent with PNG's existing license dated 26 June 2009 and represents an unexpected change in Ureg's communicated regulatory approach. The regulator's move to propose a retrospective TRV adjustment relating to outperformance dating from the years 1996-2006 is not considered by the agency to be good regulatory practice.

The GBP80.8m reduction in the opening TRV for 2012 also includes a GBP21.2m (in September 2010 prices) proposed retrospective adjustment for deferred capex. While Fitch anticipated a log-down of the TRV of GBP3.5m-GBP5.0m and the calculation of the retrospective adjustment for deferred capex needs to be substantiated, the agency generally takes the view that deferred capex should not be included in the asset base.

As the agency considers transparency and predictability of the regulatory regime to be a key rating driver for gas distribution networks, the outcome of the draft proposals could have further implications for how Fitch views the regulatory framework for gas distribution in Northern Ireland.

Whilst part of the consultation paper, Fitch believes that it is more likely than not that the regulator will go ahead with an adjustment of TRV of material magnitude, following discussions with the regulator. If implemented, PNG could appeal to the Competition Commission but this process will take time to reach its conclusion and its outcome is not certain.

Fitch anticipates a one notch downgrade of PNG's IDR and senior unsecured rating would be the most likely outcome in a scenario of material TRV adjustment.

PNG's existing rating reflects a regulatory environment, which follows the relatively transparent, predictable and consultative stakeholder approach pursued by England and Wales utility regulators, albeit it at an early stage of development since the build-out of natural gas infrastructure in Northern Ireland only began in 1996.

The open consultation for "Phoenix Natural Gas Limited Price Control Draft Proposals 2012-2013" closes on 21 October 2011. Implementation of the proposals is anticipated for 1 January 2012.

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Additional information is available at www.fitchratings.com.

The ratings above were solicited by, or on behalf of, the issuer, and therefore, Fitch has been compensated for the provision of the ratings.

Applicable criteria, 'Corporate Ratings Criteria', dated 12 August 2011, are available at www.fitchratings.com.

Applicable Criteria and Related Research:

Corporate Rating Methodology

http://www.fitchratings.com/creditdesk/reports/report_frame.cfm?rpt_id=647229

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