

## UR's notice of reference to the CC

### Notice under Article 15 of the Gas (Northern Ireland) Order 1996

#### Reference to the Competition Commission

The Northern Ireland Authority for Utility Regulation (the **Authority**), pursuant to Article 15(1) of the Gas (Northern Ireland) Order 1996 (the **Order**), gives notice as follows.

#### WHEREAS –

- (A) Phoenix Natural Gas Limited (**PNGL**) is the holder of a licence for the conveyance of gas in Northern Ireland under Article 8 of the Order (the **Licence**).
- (B) Conditions 2.3.8 to 2.3.26 (inclusive) of the Licence – the **Price Control Conditions** – establish a restriction on the charges that may be made by PNGL for the conveyance of gas.
- (C) On 10 January 2012 the Authority, in accordance with Condition 2.3.13(c) of the Licence, gave notice to PNGL of its determination of certain values and parameters to have effect for the purposes of the Price Control Conditions (the **Determination**).
- (D) On 10 January 2012 the Authority, under Article 14(3) of the Order, published the Authority's directly related proposal to modify Condition 2.3.18 of the Licence (the **Modification**).
- (E) On 6 February 2012, PNGL –
  - (i) under Condition 2.3.13(d)(i) of the Licence, gave to the Authority a 'Review Disapplication Notice' requesting the Authority not to establish the values and parameters set out in the Determination, and
  - (ii) notified the Authority that it did not consent to the Modification.

#### NOW –

- (1) In accordance with Article 15(1) of the Order, the Authority by this reference to the Competition Commission (the **Commission**) requires the Commission to investigate and report on the questions –
  - (a) whether the Price Control Conditions operate or may be expected to operate against the public interest, and
  - (b) if so, whether the effects adverse to the public interest which those matters have or may be expected to have could be remedied or prevented by modifications of the conditions of the Licence.
- (2) In accordance with Article 15(4) of the Order, and for the purpose of assisting the Commission, in the opinion of the Authority –
  - (a) the effects adverse to the public interest which the matters specified in paragraph (1)(a) may be expected to have will include the payment by gas consumers in Northern Ireland of higher prices for the conveyance of gas by PNGL than are necessary or appropriate, to the detriment of:

- (i) the interests of those consumers; and
    - (ii) the development and maintenance of an efficient, economic and co-ordinated gas industry in Northern Ireland, and
  - (b) those adverse effects can be remedied or prevented by modifications of the Price Control Conditions designed to implement the Modification and apply the values and parameters set out in the Determination.
- (3) In accordance with Article 15A(1) of the Order, the Authority specifies that the Commission makes a report on this reference within six months of the date of this notice.

**SHANE LYNCH**

Authorised on behalf of the Authority

28 March 2012

## UR's statutory duties

1. As noted in paragraph 2.6, UR's principal objective in carrying out its gas functions, as set out in Article 14(1) of the Energy Order, is to promote the development and maintenance of an efficient, economic and coordinated gas industry in Northern Ireland, and to do so consistently with fulfilment of the objectives set out in Article 40 of the Gas Directive. The article says:

**14.—(1)** The principal objective of the Department [DETI] and the Authority [NIAUR] in carrying out their respective gas functions is to promote the development and maintenance of an efficient, economic and co-ordinated gas industry in Northern Ireland, and to do so in a way that is consistent with the fulfilment by the Authority, pursuant to Article 40 of the Gas Directive, of the objectives set out in paragraphs (a) to (h) of that Article.

2. Article 40 of the Gas Directive reads as follows:

### General objectives of the regulatory authority

In carrying out the regulatory tasks specified in this Directive, the regulatory authority shall take all reasonable measures in pursuit of the following objectives within the framework of their duties and powers as laid down in Article 41, in close consultation with other relevant national authorities, including competition authorities, as appropriate, and without prejudice to their competencies:

- (a) promoting, in close cooperation with the Agency, regulatory authorities of other Member States and the Commission, a competitive, secure and environmentally sustainable internal market in natural gas within the Community, and effective market opening for all customers and suppliers in the Community, and ensuring appropriate conditions for the effective and reliable operation of gas networks, taking into account long-term objectives;
- (b) developing competitive and properly functioning regional markets within the Community in view of the achievement of the objectives referred to in point (a);
- (c) eliminating restrictions on trade in natural gas between Member States, including developing appropriate cross-border transmission capacities to meet demand and enhancing the integration of national markets which may facilitate natural gas flow across the Community;
- (d) helping to achieve, in the most cost-effective way, the development of secure, reliable and efficient non-discriminatory systems that are consumer oriented, and promoting system adequacy and, in line with general energy policy objectives, energy efficiency as well as the integration of large and small scale production of gas from renewable energy sources and distributed production in both transmission and distribution networks;

- (e) facilitating access to the network for new production capacity, in particular removing barriers that could prevent access for new market entrants and of gas from renewable energy sources;
- (f) ensuring that system operators and system users are granted appropriate incentives, in both the short and the long term, to increase efficiencies in system performance and foster market integration;
- (g) ensuring that customers benefit through the efficient functioning of their national market, promoting effective competition and helping to ensure consumer protection;
- (h) helping to achieve high standards of public service for natural gas, contributing to the protection of vulnerable customers and contributing to the compatibility of necessary data exchange processes for customer switching.

3. The UR is also required to have regard to a number of other considerations, as set out in Article 14 of the Energy Order. The text below, an extract from Article 14, sets these out:

(2) The Department and the Authority shall carry out those functions in the manner which it considers is best calculated to further the principal objective, having regard to—

- (a) the need to ensure a high level of protection of the interests of consumers of gas;
- (b) the need to secure that licence holders are able to finance the activities which are the subject of obligations imposed by or under Part II of the Gas Order or this Order;
- (c) the need to secure that the prices charged in connection with the conveyance of gas through designated pipe-lines (within the meaning of Article 59) are in accordance with a common tariff which does not distinguish (whether directly or indirectly) between different parts of Northern Ireland or the extent of use of any pipe-line; and
- (d) the need to protect the interests of gas licence holders in respect of the prices at which, and the other terms on which, any services are provided by one gas licence holder to another.

(3) In performing that duty, the Department or the Authority shall have regard to the interests of—

- (a) individuals who are disabled or chronically sick;
- (b) individuals of pensionable age; and
- (c) individuals with low incomes;

but that is not to be taken as implying that regard may not be had to the interests of other descriptions of consumer.

(4) The Department and the Authority may, in carrying out any gas functions, have regard to the interests of consumers in relation to electricity [and in relation to water or sewerage services].

(5) Subject to paragraph (2), the Department and the Authority shall carry out their respective gas functions in the manner which it considers is best calculated—

- (a) to promote the efficient use of gas;
- (b) to protect the public from dangers arising from the conveyance, storage, supply or use of gas;
- (c) to secure a diverse, viable and environmentally sustainable long-term energy supply; and
- (d) to facilitate competition between persons whose activities consist of or include storing, supplying or participating in the conveyance of gas;

and shall have regard, in carrying out those functions, to the effect on the environment of activities connected with the conveyance, storage or supply of gas.

(5A) In carrying out their respective gas functions the Department or the Authority shall not discriminate between persons whose activities consist of or include storing, supplying or participating in the conveyance of gas as regards either rights or obligations.

(6) In this Article “gas functions” means—

- (a) functions under Part II of the Gas Order; and
- (b) functions under this Order relating to gas.

(7) For the purposes of paragraph (5)(c) environmental sustainability includes the need to guard against climate change.

4. Article 2 of the Energy Order provides that in the Order: “consumers” includes both existing consumers and future consumers.’

## Evidence on outperformance from submissions

### Introduction

1. In this appendix we set out some of UR's and PNGL's submissions in relation to issues relating to outperformance. These are quotes and summaries, drawn largely from the initial submissions, intended to support the preceding discussion rather than representing a complete reflection of all their submissions. We follow the structure of issues set out in paragraph 5.47.

### Points drawn from the parties' submissions

#### ***The 2012 TRV adjustment is retrospective and not best regulatory practice***

2. In this section we set out some of PNGL's views that the TRV adjustment is retrospective and not consistent with ex ante regulatory practice, and are not consistent with regulatory precedent. We then set out some of UR's views on these issues.

#### *PNGL's views*

##### *Retrospectivity and ex ante regulation*

3. PNGL said that the underlying principles of incentive regulation were embodied in the original licence operated by PNGL. It said that effective incentive-based regulation required that incentive mechanisms under which regulated companies operated were not revisited ex post. Setting incentive mechanisms ex ante allowed the company to respond to the incentives being provided. If the regulator retrospectively changed the rules, any incentive mechanism employed would lose the credibility that was crucial in order for it to function effectively.<sup>1</sup>
4. PNGL said that effective incentive-based regulation required clear rules set in advance and not subject to retrospective review for the valuation and recovery of the expenditures made to create and maintain the asset base of the business. This clarity provided comfort to investors and operators that investments would not be unreasonably stranded, enabling them to raise finance efficiently and encouraging them to seek operational efficiency improvements.<sup>2</sup>
5. PNGL said that the 2007 determination stated that PNGL should receive the same quantum of benefit for outperformance that it would have earned under a continuation of the 1996 licence, less some adjustments that led to PNGL giving up some value relative to the licence. This quantum had not been recovered by 2006 because of the profiling of revenues and it therefore had to be included in the 2007 TRV.<sup>3</sup> PNGL said that it was allowed under the licence (which applied to outperformance accumulated before 2007) to retain the entire benefit of any outperformance achieved for the duration of the price control period. In other words, PNGL's incentive strength was 100 per cent.<sup>4</sup> PNGL said that it would only receive the agreed

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<sup>1</sup> PNGL [statement of case](#), paragraph 3.21.

<sup>2</sup> PNGL [statement of case](#), paragraph 3.20.

<sup>3</sup> PNGL [statement of case](#), paragraph 1.46.

<sup>4</sup> PNGL [statement of case](#), paragraph 3.10.

quantum of benefit if the value of outperformance in the 2006 TRV was fully depreciated, ie if it remained in TRV to be recovered over 40 years.<sup>5</sup>

6. PNGL said that UR had never mentioned its intention to make the 2012 TRV adjustment previously (and its intention to do so was not transparent in 2006). Therefore it considered that it had no ex ante notice of this action. It considered that this action was retrospective in that it reduced the TRV which had been previously determined and removed the return to outperformance which had applied at the time the out-performance occurred.
7. PNGL said that it was not regulatory best practice to apply a new outperformance sharing mechanism ex post as UR did.<sup>6</sup> PNGL said that changes to the regulatory framework and methodology should only be applied on a forward-looking basis so that the company had an opportunity to respond to the incentives being provided.
8. PNGL said that applying changes retrospectively removed this opportunity and allowed for opportunistic behaviour on the part of the regulator which, if pursued by the regulator, damaged the credibility of the regulatory regime. Utilities had an incentive to outperform regulatory assumptions to promote efficiency and economy, in the expectation that they would keep a proportion of that outperformance. If regulators retrospectively removed the value of any outperformance, the concept of incentive regulation was undermined,<sup>7</sup> to the long-term detriment of both customers and the company.<sup>8</sup> Therefore, PNGL said that it was not standard regulatory practice to revisit the asset base that had been agreed in respect of a period prior to start of the previous charge control.<sup>9</sup> Rather it was expected that a regulator would review the asset base value in the light of what had occurred within the most recent control period, based on the principles that were set out at the time the control was set.<sup>10</sup> PNGL said that the confidence that the operator could recover a pre-agreed asset value was a cornerstone of the UK system of incentive-based regulation. That confidence was the basis for investment in regulated assets, and gave the regulator the credibility necessary to create effective incentives for the company.<sup>11</sup>
9. PNGL said that UR itself aspired to be 'a Best Practice Regulator: transparent, consistent, proportional, accountable, and targeted'. The 2012 TRV adjustment breached these principles and risked cutting across the objectives of the Energy (Northern Ireland) Order 2003, which were designed to promote certainty in the efficient development of a Northern Ireland gas market.<sup>12</sup>
10. PNGL said that transparency and accountability were also recognized as key values of best practice regulation elsewhere, for example the set of Principles for Economic Regulation (published by BIS in April 2011)<sup>13</sup> which highlighted the importance of predictability and stability in economic regulation, stating:<sup>14</sup>
  - (a) '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

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<sup>5</sup> PNGL statement of case, paragraph 1.46.

<sup>6</sup> PNGL statement of case, paragraph 4.39b.

<sup>7</sup> PNGL statement of case, Paragraph 6.7.

<sup>8</sup> PNGL statement of case, paragraph 3.21.

<sup>9</sup> PNGL statement of case, paragraphs 4.39b & 4.39c.

<sup>10</sup> PNGL statement of case, paragraph 6.6

<sup>11</sup> PNGL statement of case, paragraph 1.6,

<sup>12</sup> PNGL statement of case, paragraph 6.12,

<sup>13</sup> BIS, [Principles of Economic Regulation](#).

<sup>14</sup> PNGL statement of case, paragraph 6.12.

(b) '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.'

### *Regulatory best practice*

11. PNGL said that the 'ratcheting' adjustment had been applied to opex outperformance fairly commonly in Great Britain. It was sometimes referred to as a 100 per cent sharing factor, because the company retained the entire benefit of outperformance for the duration of the price control period, even though the company did not receive 100 per cent of the total benefit of outperformance over time.<sup>15</sup> For opex outperformance a Great-Britain-style sharing mechanism (ie used the ratcheting adjustment)<sup>16</sup> was embodied in the original licence and applied in the price control reviews in 1999 and 2002. However, it said that the sharing mechanism in the price controls covering the period of 1996 to 2006 for opex outperformance was in line with Great Britain precedent and if anything was less generous as UR did not apply a rolling retention of opex outperformance.<sup>17</sup>
12. PNGL said that it was UR's proposal to allow PNGL to retain five years' worth of return and depreciation earned on the value of outperformance that entered the TRV as part of the 2006 'agreement' and that UR considered that this was consistent with regulatory precedent.<sup>18</sup> UR said that it was normal practice in incentive regulation that the benefits of outperformance were shared between regulated companies and their customers. For example, a regulated company may be allowed to retain the benefits for a period (say, five years as in the five-year rolling capex mechanisms used by some regulators), after which time the benefits were shared with customers.<sup>19</sup>
13. PNGL said that the precedent cited by UR (Ofgem and Ofwat) was different from UR's proposal:<sup>20</sup>
  - (a) PNGL said that these precedents were not applied ex post (without an agreed ex ante mechanism) and were not introduced after a prior agreed mechanism had already been applied.<sup>21</sup>
  - (b) PNGL said that these precedents were set up ex ante and as a result the rules of how outperformance would be shared were known in advance.<sup>22</sup> It said that the ex ante mechanism set up by PNGL was different from those cited by UR as regulatory precedent.<sup>23</sup>
  - (c) PNGL said that the precedents cited by UR were not examples where changes were made to the asset base for outperformance already included in the asset base at the start of the prior charge control (but only for outperformance since the start of the previous charge control).<sup>24</sup>

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<sup>15</sup> PNGL statement of case, paragraph 3.9.

<sup>16</sup> PNGL statement of case, paragraph 3.10.

<sup>17</sup> PNGL statement of case, paragraph 4.41a.

<sup>18</sup> PNGL statement of case, paragraph 4.38.

<sup>19</sup> UR [initial submission](#), paragraph 2.29.

<sup>20</sup> PNGL statement of case, paragraph 4.39.

<sup>21</sup> PNGL statement of case, paragraph 4.39a.

<sup>22</sup> PNGL statement of case, paragraph 4.39b.

<sup>23</sup> PNGL statement of case, paragraph 4.39b.

<sup>24</sup> PNGL statement of case, paragraph 4.39c.

14. PNGL said that Ofgem, as part of its RPI-X@20 review of network regulation, confirmed its view that there should be no retrospective action and no change in the treatment of assets already in the asset base. This was done to provide certainty for investors. PNGL said that Ofgem also stressed that there would be no retrospective action taken with the benefit of hindsight, as long as outputs were delivered. Any adjustments and incentive mechanisms that were to be developed would be consulted on and would be forward looking only.<sup>25</sup> PNGL quoted Ofwat as saying 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'.<sup>26</sup>
15. PNGL said that the CC, in a previous decision, had been very cautious before sanctioning any adjustment in respect of the past that could amount to ex post clawback of value.<sup>27</sup>
16. PNGL said that UR's statement that one of the key tenets of economic regulation was to mimic competitive outcomes (see paragraph 21) was an unrealistic standard which seemed to misunderstand the basis of economic regulation. No regulated company would ever be able to benefit from efficiency savings if its regulator had in mind a benchmark of a perfectly competitive market. Rather, the basis of a price control framework was to provide regulated utilities with an incentive to deliver efficiency savings, and to share this benefit with customers. The strength of this incentive, and the mechanism for passing the benefit to customers, were variables that were to be determined ex ante as part of the regulatory framework. PNGL said that it managed its investment spend efficiently while meeting all of its output targets ahead of the timetable required in its licence and shared these benefits with customers through the ratchet mechanism. It said that UR should not change the incentive strength and sharing mechanism that were established ex ante under the original licence, and under which outperformance was achieved.<sup>28</sup>

### *UR's views*

17. UR said that given the nature of the PNGL licence and history, it was not possible to have identical treatment with standard regulation.<sup>29</sup> UR said that its decision for historical outperformance related only to whether benefits that PNGL received during the period 2007 to 2011 should continue from 2012, and did not involve revisiting price control periods before 2007. This was consistent with standard regulatory practice.<sup>30</sup> UR said that the actions were not retrospective as it did not claw back any value which had previously been received (except deferred capex); the £35 million value of return and depreciation allowed in the 2007 to 2011 period would be retained as a reward for historical outperformance. The changes proposed were prospective in nature.<sup>31</sup>
18. UR said that those sums were always subject to review and amendment in accordance with the licence conditions and/or UR's powers to modify those conditions under the Gas Order. This process of review and revision was entirely normative in regulatory practice across all economic regulators. UR acknowledged that the powers this gave regulators must be used carefully and with good reason to ensure

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<sup>25</sup> PNGL statement of case, paragraphs 6.9 & 6.10.

<sup>26</sup> PNGL statement of case, paragraph 6.11.

<sup>27</sup> PNGL statement of case, paragraph 6.5.

<sup>28</sup> PNGL response, Annex 1, p29.

<sup>29</sup> UR comprehensive response to comments on draft proposal (2012 decision), p12.

<sup>30</sup> *ibid*, p12.

<sup>31</sup> UR supplementary submission, paragraphs 2.54–2.56.

that investors had confidence that a regulator would not act in an arbitrary fashion. UR said the detail in its papers explained the unique circumstances which warranted its decisions.<sup>32</sup>

19. UR said that the term outperformance in a regulatory context always meant the ex post sharing of differences between the allowed and actual expenditure between the regulated company and the consumers. The ratcheting mechanism was a different concept from this.<sup>33</sup> UR said that when outperformance was defined in this way, no outperformance had been shared between PNGL and customers at the time of the 2007 determination (ie the customer share of outperformance would be zero). Furthermore, Great Britain precedent indicated that regulators generally simultaneously applied the ratcheting mechanism and the sharing of outperformance (often by removing capitalized outperformance after five years).<sup>34</sup>
20. UR said that in order that the benefits from PNGL's outperformance were shared between the company and customers, it was necessary to remove the outperformance addition from the asset base at the end of the five-year period 2007 to 2011, so as to reflect regulatory practice elsewhere.<sup>35</sup>
21. UR also stated that retention of outperformance:

... would run counter to one of the key tenets of economic regulation to mimic competitive outcomes (it would not be possible in a competitive industry for companies to charge customers for assets which were not provided, or were provided late, as competitors, who did not charge their customers in this way, would take customers away from them).<sup>36</sup>
22. UR said that such action was consistent with best regulatory practice elsewhere, and with the intentions of the 2007 licence modifications. To illustrate the point, UR provided the following examples of how some Great Britain regulators had treated outperformance.<sup>37</sup>
  - (a) Ofgem's five-year rolling mechanism for gas distribution networks allowed capex outperformance to remain in the asset base for a period of five years, during which time the company received depreciation and return as normal. After five years, however, the outperformance was removed from the asset base. The net gain to the company would depend on the rate of return and depreciation period applied, but was typically in the region of 40 per cent of the outperformance.
  - (b) In Ofwat's most recent price control, capex outperformance was shared between the company and customers on a 30/70 basis (on average).
23. UR noted that all PNGL expenditure was capitalized so it sought to apply the principles of sharing capitalized outperformance to all of PNGL's outperformance. UR said that its decision to remove the outperformance from the asset base in 2012 was consistent with the approach taken by Ofgem (and the five-year period UR chose was consistent with best regulatory practice and with UR's statutory duties).<sup>38</sup>
24. Other examples of sharing of outperformance identified by UR included:

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<sup>32</sup> UR comprehensive response to comments on draft proposal (2012 decision), p12.

<sup>33</sup> UR supplementary submission, paragraph 2.32.

<sup>34</sup> UR supplementary submission, paragraphs 2.33 & 2.34.

<sup>35</sup> UR [PNGL12 determination](#), paragraph 7.59.

<sup>36</sup> UR initial submission, paragraph 3.46.

<sup>37</sup> UR [PNGL12 determination](#), paragraph 7.60.

<sup>38</sup> UR [PNGL12 determination](#), paragraph 7.61.

- (a) UR, NIE electricity transmission and distribution: under- and overspending against UR's allowances for capitalized expenditure were split 38.9:61.1 between the company and its customers.
- (b) Ofgem, electricity and gas transmission: under- and overspending against Ofgem's allowances for capitalized expenditure were split 25:75 between the company and its customers.
- (c) Ofgem, electricity distribution: under- and overspending against Ofgem's allowances for total expenditure were split roughly 50:50 between the company and its customers, with the precise shares differing from company to company according to their position in Ofgem's Information Quality Incentive matrix.
- (d) Ofgem, gas distribution: under- and overspending against Ofgem's allowances for capitalized expenditure were split roughly 40:60 between the company and its customers, with the precise shares differing from company to company according to their position in Ofgem's Information Quality Incentive matrix.
- (e) ORR, Network Rail: under- and overspending against ORR's allowances for capitalized expenditure were split 25:75 between the company and its customers.
- (f) CAA, airports: under- and overspending against the CAA's allowances for capitalized expenditure were retained in the regulatory asset base until the next reset of the price control when the under- or overspending was removed and benefit or cost was passed on to customers.

### ***The 2012 TRV adjustment is not consistent with expectations***

#### ***PNGL's views***

- 25. PNGL said that the 2006 'agreement' had been presented to it by UR as agreed upon on the understanding that the 2006 TRV was a once and for all settlement that, when viewed within the context of the other concessions that PNGL was making, reflected on balance a fair sharing of value for the period 1996 to 2006.<sup>39</sup> PNGL said that UR's proposal removed this value of outperformance from TRV before it had been fully depreciated. In effect, this proposal therefore nullified the agreed sharing of value that was established in 2006.<sup>40</sup>
- 26. PNGL said that it had good reasons for its legitimate expectation that the 2006 TRV was intended by UR to be recovered in full and to represent the starting point for future price controls.<sup>41</sup> PNGL said that its understanding of the discussions of 2006/07, the contemporaneous documentary evidence from that time and UR's own actions during and since the 2006 'agreement' did not support UR's view that the 2012 TRV adjustment resulted from the 2006 'agreement', but was rather a retrospective reopening of the outperformance prior to 2006.<sup>42</sup> PNGL said that such retrospective reopening of the 2006 'agreement' was in violation of the fundamental principles of incentive-based regulation.<sup>43</sup>

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<sup>39</sup> PNGL statement of case, paragraph 1.37.

<sup>40</sup> PNGL statement of case, paragraph 1.38.

<sup>41</sup> PNGL statement of case, paragraph 4.4b.

<sup>42</sup> PNGL statement of case, paragraphs 4.1–4.3.

<sup>43</sup> PNGL statement of case, p9.

27. PNGL said that UR's public and private statements in 2006 and 2007 were clear that the agreed TRV was part of a package of measures that properly shared value with customers and was not to be reopened.<sup>44</sup>
- (a) UR had not at any time intimated, publicly or privately, that it would seek to reopen the treatment of outperformance included in the 2006 TRV.<sup>45</sup>
  - (b) UR said in its 2007 consultation paper that the 'proposed modifications make explicit the regulatory asset value and how this is determined at each price control review', and that 'The DAV at the beginning of each control period is calculated as the DAV at the start of the previous control period (OAV in 2007) net of depreciation plus capex over the previous control period net of depreciation'.<sup>46</sup>
  - (c) UR said in its 2007 consultation paper that the 2006 TRV was 'a function of ... a sharing of cost out performance for the period 1996–2006' and that 'out performance for the period 1996–2006 is shared between customers and Phoenix based on regulatory practice elsewhere'.<sup>47</sup>
  - (d) UR said in its PC03 determination that '... key aspects of [the 2006] agreement were to agree the RAV (including historic out performance, deferred capex and under-recovery) ...'.<sup>48</sup>
  - (e) UR's press release announcing the 2006 'agreement' referred to the 'agreement' as a 'package' and 'a fair deal' and said that 2006 'agreement' 'creates a stable basis for future investment and growth'.<sup>49</sup>
  - (f) UR's statements in 2006 and 2007 that the agreements benefited customers between £25 million and £35 million.<sup>50</sup> PNGL said that the size of these numbers could not have included the (around £75 million) of the 2012 TRV adjustment and had UR anticipated that further value could be shared with customers at that time, it was very strange that this was not mentioned.<sup>51</sup>
  - (g) UR's email, signed by Iain Osbourne, from 8 October 2007 to PNGL (in relation to PC03 in the context of the treatment of outperformance in the second price control (2002–2006)) stated that:

There is certainly no intention to claw back past out-performance. Our ambition is to set a control that delivers the lowest possible cost to consumers for the coming years, consistent with being financeable by an efficient co-ordinated development of the gas industry. **Nor do we plan to reopen the November 06 agreement as part of our price control determination** (although we can give no such assurance were a Competition Commission reference to be necessary). [Emphasis added by PNGL.]<sup>52</sup>

28. PNGL said that if UR had always intended to make the adjustment to TRV that it was now proposing, then there was no reason why it should have waited until 2012 to

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<sup>44</sup> PNGL statement of case, paragraphs 1.41a & 4.6a.

<sup>45</sup> PNGL statement of case, paragraph 4.8.

<sup>46</sup> PNGL statement of case, paragraphs 4.8ai & 4.8aiv.

<sup>47</sup> PNGL statement of case, paragraphs 4.8aii & 4.8aiii.

<sup>48</sup> PNGL statement of case, paragraph 4.8b.

<sup>49</sup> PNGL statement of case, paragraphs 4.9ai, 4.9aii & 4.9c.

<sup>50</sup> PNGL statement of case, paragraphs 4.9aii, 4.9b & 4.9c.

<sup>51</sup> PNGL statement of case, paragraph 4.10.

<sup>52</sup> PNGL statement of case, paragraphs 4.11 & 4.12.

make this adjustment. UR could have included a lower value for outperformance within the 2006 TRV. PNGL said that the 2012 TRV adjustment was based on the same information as was available at the time of the 2006 'agreement' and that no new relevant information had come to light since then.<sup>53</sup> It said that the adjustment was not done at the time of the 2006 'agreement' because UR did not have the intention at the time to revisit the value of the TRV in the manner it now had done.<sup>54</sup>

29. PNGL said that UR's conduct in 2006 and 2007 showed that UR took a very conscious decision to conclude a once and for all package sharing past outperformance. This was because UR had taken the highly unusual step (compared with Great Britain practice) of embodying the 2006 TRV in PNGL's licence, together with a set of formulae that provided for it to be recovered in full over the 40-year period:<sup>55</sup>

(a) PNGL said that because the 2006 TRV was included in the licence, it could only be changed if PNGL agreed. PNGL considered it implausible that UR would have done this had it expected that the 2006 TRV value was to be revisited in the future.<sup>56</sup> It said that because the roll forward of the 2006 TRV in future price controls was designed without the need for a licence modification, it created a legitimate expectation for PNGL and its investors that this mechanism would be followed in the future.<sup>57</sup>

(b) PNGL said that its licence was drafted so that no modification would have been required had UR not made the 2012 TRV adjustment.<sup>58</sup>

(c) PNGL said that the 2006 'agreement' explicitly did not finalize the 2006 TRV until audited actual out-turn date was available (as a result the final 2006 TRV was only included in the licence in 2009), at which time forecasts were replaced with actuals (using the same calculation method). PNGL said that such a process would not have been necessary had UR intended to revisit TRV in 2012. PNGL said it was obvious that this actualized number was included within the licence to provide additional certainty that the value was agreed and was not intended to be revisited subsequently.<sup>59</sup>

30. PNGL said that UR's PC03 financial models showed that UR was working on the basis that there was to be no further sharing of historic outperformance:<sup>60</sup>

(a) PNGL said that the financial model calculated the allowed revenues on the basis of expected revenues over the period of the 40-year licence period. It said that despite the significant impact on revenues from the 2012 TRV adjustment, no adjustment was made in the PC03 model to reflect such a potential adjustment.<sup>61</sup>

(b) PNGL also said that its view was supported by the fact that the PC03 model did not have the capability to make such an adjustment.<sup>62</sup>

(c) PNGL said that prices in PC03 would have been around 7 per cent lower had the 2012 TRV adjustment been included in the modelling at that time. It said that given the size of this impact, it would be difficult for UR to justify not taking it into

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<sup>53</sup> PNGL statement of case, paragraph 4.19.

<sup>54</sup> PNGL statement of case, paragraph 4.20.

<sup>55</sup> PNGL statement of case, paragraphs 1.41b, 4.6b, 4.21 & 4.22.

<sup>56</sup> PNGL statement of case, paragraph 4.23.

<sup>57</sup> PNGL statement of case, paragraph 2.55.

<sup>58</sup> PNGL statement of case, paragraph 4.24.

<sup>59</sup> PNGL statement of case, paragraph 4.26.

<sup>60</sup> PNGL statement of case, paragraphs 1.41c & 4.6c.

<sup>61</sup> PNGL statement of case, paragraph 4.27.

<sup>62</sup> PNGL statement of case, paragraph 4.28.

account if it had known at the start of PC03 that its intention was to make the 2012 TRV adjustment.<sup>63</sup>

31. PNGL said that this created a legitimate expectation (not only at PNGL but at its investors and at the rating agencies) that this mechanism would be followed by UR in the future. PNGL said that this was particularly important given the requirements for investor certainty following a period of regulatory instability since 2002.<sup>64</sup>
32. PNGL said that UR's conduct since 2006/07 was entirely inconsistent with its claimed intention that it always intended to revisit past outperformance. PNGL said that at no stage during the 2006/07 discussions, nor during the PC03 review, nor during the months of discussions surrounding the PNGL12 price control review (including the extracts provided to PNGL by UR from its Consultation Paper), did UR indicate any intention to revisit the value of outperformance contained in the 2006 TRV. PNGL said that no such suggestions had appeared in any version of PNGL's licence or any financial modelling prepared by UR that was shared with PNGL.<sup>65</sup> It said that UR allowed PNGL, its investors, the market and the rating agencies to operate as though the 2006 TRV was fixed and did not indicate any change in approach until the final stages of the PNGL12 price control (which was four to five years after the value of the TRV was first embedded in PNGL's licence).<sup>66</sup>
33. PNGL said that the first time that PNGL and Terra Firma learned of UR's intention to make the 2012 TRV adjustment was at the time of the publication of the 2011 consultation paper, despite months of discussions about the roll forward of the TRV in PNGL12 between PNGL and UR prior to this date.<sup>67</sup>
34. PNGL said that despite UR's statement in the 2012 determination that 'there could have been greater detail in the 2007 licence modifications public consultation on exactly how the sharing of historical outperformance would be implemented', the 2007 consultation said nothing about any future sharing of historical outperformance.<sup>68</sup>
35. PNGL said that UR did not mention its intention to make a 2012 TRV adjustment during the two refinancing actions PNGL did since 2006. PNGL said that the 2012 TRV adjustment would have had a material impact on the terms for the 2011 refinancing.<sup>69</sup> It said that it also made a number of its decisions on the understanding that the 2006 TRV would not be changed, including obtaining a BBB+ credit rating, issuing £275 million of bonds and further investments in the network, and that UR had not suggested in the context of any of these actions that it was intending to make the 2012 TRV adjustment.<sup>70</sup>
36. PNGL said that the 2006 'agreement' confirmed how much of the benefit of out-performance achieved between 1996 and 2006 it was allowed to receive. In order for PNGL to actually recover this agreed share of the benefit of outperformance, it was necessary that the value embedded in the 2006 TRV was depreciated fully (ie that it remained in the asset base for 40 years).<sup>71</sup>

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<sup>63</sup> PNGL statement of case, paragraph 4.29.

<sup>64</sup> PNGL statement of case, paragraph 4.25.

<sup>65</sup> PNGL statement of case, paragraph 2.61.

<sup>66</sup> PNGL statement of case, paragraphs 1.41d & 4.6d.

<sup>67</sup> PNGL statement of case, paragraph 4.30.

<sup>68</sup> PNGL statement of case, paragraphs 4.31 & 4.32.

<sup>69</sup> PNGL statement of case, paragraph 4.33.

<sup>70</sup> PNGL statement of case, paragraphs 4.34 & 4.35.

<sup>71</sup> PNGL statement of case, paragraph 1.38.

37. PNGL said that it did not agree with UR's statement that the 2012 TRV adjustment was consistent with the intentions of the discussions related to the 2006 'agreement' and that PNGL did not have any objective basis for believing that it could fully recover the share of historic outperformance allowed it in the 2006 'agreement'.<sup>72</sup>
38. PNGL said that UR appeared to be relying on Great Britain regulatory precedent as the basis for the 2012 TRV adjustment and that PNGL should have, on the basis of this precedent, expected UR's approach.<sup>73</sup> PNGL said that this was erroneous.<sup>74</sup> It said that as UR's approach was neither analogous to the precedent cited by UR nor was it in line with regulatory best practice, UR was incorrect to conclude that there was an objective basis on which PNGL could have anticipated UR's 2012 TRV adjustment.<sup>75</sup>

### *UR's views*

39. UR said that the April 2007 consultation paper showed the importance UR put on sharing of outperformance based on regulatory practice elsewhere.<sup>76</sup> UR quoted:
- (a) 'The agreed OAV is a function of actual investment (opex and capex), under-recovered revenue and a sharing of cost outperformance for the period 1996–2006' (paragraph 11).
  - (b) 'Outperformance for the period 1996–2006 is shared between customers and Phoenix based on regulatory practice elsewhere while the net cash flow over the period established the base for the OAV' (paragraph 13).
  - (c) 'The depreciated asset value (DAV) at the beginning of each control period is calculated as the DAV at the start of the previous control period (OAV in 2007) net of depreciation plus capex over the previous control period net of depreciation. The discounted cash flow methodology in the original licence is based on forecast costs at the previous review and as such makes no allowance for passing on outperformance in capex to customers. The modified conditions allow the Licensee to retain the benefit (financing and depreciation) of capex out performance against agreed capex forecasts (for a given output) for the period from the year of outperformance to the start of the following control period. This continues to provide the Licensee with an incentive to make efficiency savings over a control period which are passed to customers at the beginning of the subsequent control period.' (Paragraphs 21 to 24.)<sup>77</sup>
40. UR also said that in June 2006 it had set out its principles in relation to gas regulation, and PNGL in particular, in a public consultation. This included the statement that PNGL's '... Opening regulatory asset value [is] to be based on actual investment in developing the industry plus a fair reward for efficiency savings'.
41. UR said that these statements were clearly not consistent with any suggestion that it had determined that PNGL would enjoy a cash-flow benefit from unspent allowances for 40 years.<sup>78</sup>

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<sup>72</sup> PNGL statement of case, paragraph 1.39.

<sup>73</sup> PNGL statement of case, paragraphs 1.44 & 4.36.

<sup>74</sup> PNGL statement of case, paragraph 4.36.

<sup>75</sup> PNGL statement of case, paragraph 4.4.

<sup>76</sup> UR [PNGL12 determination](#), paragraph 7.56.

<sup>77</sup> UR [PNGL12 determination](#), paragraph 7.57.

<sup>78</sup> UR supplementary submission, paragraph 2.84.

42. UR accepted that it could have set out in greater detail the mechanism for sharing outperformance based on regulatory practice elsewhere.<sup>79</sup> It said that in 2007 it did not have a well-developed view of how it would deal with the sharing of historic outperformance in future price controls.<sup>80</sup>
43. However, it said that there was nothing which committed UR to allowing the historical outperformance to be retained until 2046. It said:

We accepted that on introducing the concept of a TRV in 2007 we could have explained more clearly how it was intended to roll forward the asset base at subsequent price control reviews. There was a lack of clarity, for consumer representatives and the industry as well as the company and investors. However, having reviewed the history of the matter, we were satisfied that there had been no commitment in 2007 that all aspects of the TRV were fixed and binding and (as PNGL has argued) would remain so until 2046.<sup>81</sup>

UR said that it informed PNGL about the proposed adjustment to TRV as soon as it had completed its initial analysis on the issue and was ready to present its proposals. The analysis was carried out in 2011 as part of PNGL12.

44. UR said that PNGL did not have any legitimate expectation of a continuation of the value of TRV as set in 2006, and it was appropriate, and in line with established regulatory precedent elsewhere, for the benefits of previous outperformance to be shared with consumers.<sup>82</sup> UR said that it found nothing in either the 2007 licence modifications, or the discussions surrounding them, which was designed to, or did in practice, offer any assurance to PNGL that the retention of deferred capex and outperformance in its asset base would not be revisited during future price control reviews.<sup>83</sup> It said that if it had meant to give that assurance it would have stated it clearly.<sup>84</sup> It would not have offered such an assurance, and in any event would have considered such an approach to be inconsistent with and overridden by the statutory duties and the inconsistency with regulatory practice elsewhere.<sup>85</sup> UR said that the email from Iain Osborne mentioned in paragraph 27(g) followed a review of previous outperformance and how it was achieved, and was prompted by concern from PNGL that UR would claw this back due to inefficiency. It said that the email confirmed it had no plans to do such a review but interpreting it as a statement on allowing a 40 years reward for outperformance was wrong.<sup>86</sup>
45. UR said that it was true, as PNGL stated, that UR considered the 2007 amendments to the licence as being compatible with UR's statutory duties, and therefore in the interests of consumers, at that time (eg see paragraphs 27(e) and 5.47). But this did not mean that they were set in stone.<sup>87</sup>
46. UR said that it did not agree, as PNGL had suggested (see paragraph 29(c)), that the fact that the calculation for the 2006 TRV was postponed to allow audited numbers to

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<sup>79</sup> UR comprehensive response to comments on draft proposal (2012 decision), p4.

<sup>80</sup> UR supplementary submission, paragraph 2.81.

<sup>81</sup> UR initial submission, paragraph 1.11.

<sup>82</sup> UR comprehensive response to comments on draft proposal (2012 decision), p4.

<sup>83</sup> *ibid*, p8.

<sup>84</sup> *ibid*, p8.

<sup>85</sup> *ibid*, p8.

<sup>86</sup> UR [response to the provisional determination](#), paragraph 5.16.

<sup>87</sup> UR comprehensive response to comments on draft proposal (2012 decision), p9.

be used indicated that it was not to be reviewed in the future as one thing did not follow from the other.<sup>88</sup>

47. UR said that it had also taken into account the decisions made by PNGL since 2006 which, PNGL suggested, were taken on the basis that the value for TRV was unchangeably fixed at the 2006 rate. UR did not accept that the taking of these actions, nor UR's failure to comment on them at the time, established that there was any expectation in this regard.<sup>89</sup>
48. UR said that although there was no convincing evidence to support PNGL's claim of a legitimate expectation that the 2006 value for TRV would not be revisited, and noting that UR's statutory duties in any event led it to change the TRV figure in the licence conditions, UR had in the interests of fairness fully considered PNGL's arguments for allowing the company to retain the value of previous outperformance and deferred capex.<sup>90</sup>
49. UR said that it was correct that the formulae contained in Condition 2.3 of the licence provided a mechanism for recovering TRV and acknowledged that the existing licence conditions did not contain a mechanism for the adjustment of the 2006 value of TRV.<sup>91</sup> It did not agree that the value to be recovered was intended to be, expressed to be, or was as a matter of fact, unchangeable at the 2006 level. The licence did not state that the 2006 value for TRV could not be adjusted.<sup>92</sup> Even though the existing licence did not contain a mechanism for the adjustment of the 2006 value of TRV (see paragraph 29(a) and (b)), this did not mean that the value could not be adjusted in line with UR's statutory powers.<sup>93</sup> The fact that the 2006 value for TRV was incorporated into the licence in 2007 did not either say or imply that the value for TRV would not be changed in future reviews. UR said that the mechanism for change came from UR's powers under the Gas Order, and nowhere in the licence, or in the discussions surrounding it, was it ever stated or implied that this power would not be used to modify the value for TRV. Indeed it would have been extremely unusual for UR to give such an assurance, as its fulfilment could conceivably conflict with UR's statutory duties at some future point, as indeed it would have done now had it been given.<sup>94</sup>
50. UR said that it therefore did not agree with PNGL's view that the inclusion of the value for 2006 TRV in the 2007 licence indicated that it was to be fixed and binding on UR in future reviews. It said that where it wished to set a provision for a specific time period, this had been expressly stated on the face of the licence, as was the case with the fixing of the rate of return at 7.5 per cent until 2016. UR said that even that would have been capable of being modified through the normal licence modification processes had UR considered it appropriate to do so in the light of our statutory duties, but it indicated that where UR intended in 2007 that an element of the price control would not be changed for a period of time, UR said so clearly. The provisions concerning the rate of return were set at the same time as those relating to the retention of deferred capex and outperformance. If, therefore, UR had wished to indicate that the latter would also not be reviewed for a period of time, UR would have expressly provided for it in the licence in the same way.<sup>95</sup>

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<sup>88</sup> *ibid*, p9.

<sup>89</sup> *ibid*, p10.

<sup>90</sup> *ibid*, p10.

<sup>91</sup> *ibid*, p8.

<sup>92</sup> *ibid*, p8.

<sup>93</sup> *ibid*, p4.

<sup>94</sup> *ibid*, p8.

<sup>95</sup> *ibid*, pp8&9.

51. UR said that the TRV was clearly not locked down, as it had indicated that it would review deferred capex.<sup>96</sup> UR said that exchanges in 2007 indicated that there were differences of opinion on whether the TRV would be reopened, showing that PNGL understood UR's intentions. UR said:

Following our proposals to review deferred capex in October 2007, PNGL responded by claiming that—'Ureg's draft "determined to" with respect to deferred capex is unchanged since the 30th October draft and continues to disallow a significant element of required capex going forward. Phoenix considers this as an unacceptable reopening of the OAV determined as part of the November 2006 Agreement and thus, it should be withdrawn.'

Our response makes it very clear that we had a different interpretation of the November 2006 'Agreement' and the August 2007 licence modifications. Iain Osborne, the then Chief Executive of UR, responded on 30 November stating—'I am of the view that, after many meetings and much correspondence between us, what remains is a difference of opinion rather than a misunderstanding. Should Phoenix continue to feel that the Determination is not justified, then there is a clear process through which this can be considered.'<sup>97</sup>

### ***The 2006 'agreement' was a package***

#### *PNGL views*

52. As noted in paragraph 5.43, PNGL indicated that it believed there had already been some implicit sharing of outperformance in the 2007 determination through concessions it said it made elsewhere.
53. PNGL said that in addition to moving to a longer-term recovery period, there were a number of other issues that UR wished to revisit at the time of the 2006 'agreement'. The 2006 'agreement' was therefore a comprehensive package covering many aspects of PNGL's business.<sup>98</sup> These included:
- (a) a reduction in PNGL's allowed pre-tax WACC from 8.5 to 7.5 per cent. PNGL said that this represented a significant transfer of value to customers relative to the 1996 licence;
  - (b) UR's ambitions to see PNGL sell its transmission business to a mutual company. PNGL said that the premium to RAV allowed by UR for the sale of the transmission business, designed to compensate PNGL for forgoing a stream of revenues from that transmission business, was set by UR at a level significantly below the level of premiums being earned in the sale of other regulated assets at the time; and
  - (c) the 'agreement' required a write-off of value on legacy supply contracts.<sup>99</sup>
54. Additionally UR reduced the outperformance associated with working capital allowances and removed the outperformance against grants.<sup>100</sup>

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<sup>96</sup> UR supplementary submission, paragraph 2.72.

<sup>97</sup> UR supplementary submission, paragraphs 2.73 & 2.74.

<sup>98</sup> PNGL statement of case, paragraph 2.39.

<sup>99</sup> PNGL statement of case, paragraph 1.29.

<sup>100</sup> PNGL statement of case, paragraph 2.46.

55. PNGL said that it (and third parties) were given to understand that the 2006 ‘agreement’, and the subsequent licence modification (which included the 2006 TRV), was a once and for all package that reflected a fair sharing of value for the period 1996 to 2006<sup>101</sup> between PNGL’s customers and its shareholders while facilitating and incentivizing the continued effective roll-out of a natural gas infrastructure.<sup>102</sup>
56. PNGL said that in some cases PNGL kept the value associated with its 1996 licence (such as in respect of cost outperformance), while in other cases value passed to customers (such as in respect of the reduction in the WACC). PNGL said that UR was clear at the time that it considered the package a win-win for customers and PNGL because the total amount payable by customers had been reduced, and the package created a stable and predictable basis for future investment and growth for the company.<sup>103</sup>
57. PNGL said that each element of the package represented a change to PNGL’s original licence and that the calculation of each element was subject to a detailed and thorough discussion and negotiation between PNGL and UR. PNGL said that this was undertaken in an open, transparent and constructive manner. Each element of the package had a value to both PNGL and customers, relative to the licence that was already in force, and overall value was shared in a way that was regarded at the time as fair.<sup>104</sup>
58. PNGL said that UR said at the time that:<sup>105</sup>
- (a) UR estimated ‘the value of benefits of the agreement to consumers to be in the region of £25m in 2006 present value terms’;<sup>106</sup> and
- (b) PNGL benefited:
- from reduced uncertainty of recovering investment and return. The agreement should ensure that the market for the supply of gas continues to develop robustly as those premises not already connected switch to natural gas and costs are spread over a wider customer base to the benefit of all customers and the Licensee;<sup>107</sup>
- (c) ‘this package will save customers £25m’;<sup>108</sup>
- (d) the 1 per cent reduction in PNGL’s cost of capital implemented in the 2007 licence modifications was determined ‘as part of the overall licence package’;<sup>109</sup> and
- (e) ‘the Utility Regulator and PNGL finalised a regulatory agreement to facilitate a stable future for the growing gas industry’.<sup>110</sup>
59. PNGL said that UR also generally referred to its determinations as a package (for example, PNGL12).<sup>111</sup>

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<sup>101</sup> PNGL statement of case, paragraph 4.4a.

<sup>102</sup> PNGL statement of case, paragraphs 1.30, 2.40 & 2.49.

<sup>103</sup> PNGL statement of case, paragraphs 1.30, 2.49 & 2.51.

<sup>104</sup> PNGL statement of case, paragraph 2.50.

<sup>105</sup> PNGL statement of case, paragraphs 1.31 & 2.51.

<sup>106</sup> PNGL statement of case, paragraphs 1.31 & 2.51.

<sup>107</sup> PNGL statement of case, paragraphs 1.31 & 2.51.

<sup>108</sup> PNGL statement of case, Annex 9, p7.

<sup>109</sup> PNGL statement of case, Annex 9, p7.

<sup>110</sup> PNGL statement of case, Annex 9, p7.

<sup>111</sup> PNGL statement of case, Annex 9, p7.

60. PNGL said that had UR given any indication that its package was a temporary sharing of past value that it would subsequently revisit, PNGL and Terra Firma would have rejected the licence modification in 2007.<sup>112</sup> However, the TRV and the way in which it was to be recovered were explicitly included in the 2007 licence.<sup>113</sup>
61. PNGL said that UR's decision effectively sought to unpick a specific, key aspect of the 2006 'agreement' by requiring PNGL to concede a significant element of further value. These proposals came at a time when the business had only recently begun to generate positive cash flows, after years of significant cash outlays. It described this action as opportunistic and retrospective.<sup>114</sup>
62. PNGL also detailed some discussions it had had with UR prior to the 2007 determination on the sharing of historic outperformance.<sup>115</sup> PNGL provided the following evidence in support of this:
- (a) PNGL said that at the time of the 2006 'agreement' UR initially suggested that only a proportion of outperformance should be retained by PNGL based on an efficiency assessment and where it could be demonstrated that efficiencies benefited customers in the past or the future. UR suggested that PNGL should only retain the time value of savings for a specific time period. PNGL said that UR made a number of proposed calculations for capex outperformance in this respect.<sup>116</sup>
  - (b) PNGL said that it told UR at the time that if UR allowed five years rate of return and five years depreciation on capex outperformance, this meant that 50 per cent of the capex would be kept if assets were depreciated over 20 years.<sup>117</sup>
  - (c) PNGL said that as part of the ensuing discussions, UR put forward options where PNGL did not retain the 1996 licence value of outperformance but where other aspects of the 2006 'agreement' would have been treated in a way where PNGL retained more value (such as a higher rate of return or the inclusion of an environmental grant). For example, UR's letter of 1 September 2006 setting out on a provisional basis 'the terms that Ofreg [was] prepared to offer to conclude our re-negotiation of the Phoenix Natural Gas licence' proposed a value of £44.6 million for outperformance which reduced the retention of capex outperformance to 50 per cent of the value. PNGL said that UR recognized that this package was difficult for PNGL and that UR therefore proposed an additional allowance of £15 million as a social/environmental allowance at the time, noting that the inclusion of such an allowance was preferable to UR compromising over the appropriate treatment of capex outperformance.<sup>118</sup>
  - (d) PNGL said that the 2006 'agreement' nevertheless did not include such a sharing of capex outperformance (ie outperformance was treated in line with the 1996 licence, which meant that outperformance was retained by PNGL except for the ratcheting effect).<sup>119</sup>

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<sup>112</sup> PNGL statement of case, paragraph 4.5.

<sup>113</sup> PNGL statement of case, paragraph 4.21.

<sup>114</sup> PNGL statement of case, paragraph 1.50.

<sup>115</sup> PNGL statement of case, paragraphs 1.41b, 4.6b & 4.14.

<sup>116</sup> PNGL statement of case, paragraph 4.15.

<sup>117</sup> PNGL statement of case, paragraph 4.16.

<sup>118</sup> PNGL statement of case, paragraph 4.17.

<sup>119</sup> PNGL statement of case, paragraph 4.18.

- (e) PNGL said that, given that the 2006 ‘agreement’ did not include a social/environment allowance, this demonstrated that UR had made a compromise in respect of the treatment of outperformance.<sup>120</sup>

### *UR’s views*

63. UR disagreed that as part of the 2006 discussions and subsequent 2007 licence modifications PNGL had to make a number of concessions on particular items which corresponded to a more favourable treatment of outperformance. UR said that PNGL argued that in return for these, the value of TRV which was established as part of the 2006 discussions and subsequent 2007 licence modifications should remain fixed in the licence since PNGL could not now withdraw what it had previously done.
64. UR said that the first of the claimed concessions was the sale of PNGL’s transmission business, thereby denying PNGL’s investors the opportunity to earn either a return on this investment or to realize its potential value on the open market.<sup>121</sup> In response, UR said:
- (a) PNGL received the full value of the business *plus* a significant premium for the sale of its transmission business. For this reason, this could not be considered a ‘concession’ that caused a detriment to PNGL.<sup>122</sup>
  - (b) When the PNGL transmission business was ‘mutualized’, this did lead to customer ‘benefits’ in the region of £25 million (2007 prices). UR said that these ‘benefits’ reflected a transfer of risk to customers and should not be portrayed as a concession by the selling party.<sup>123</sup>
  - (c) The mutualization of the PTL transmission business which delivered customer benefits of about £41.5 million (2005 prices) was not a concession by the seller.<sup>124</sup>
  - (d) Taking a view from 1996 to 2006, when the transmission asset was owned by PNGL, the regulatory treatment was supportive of shareholders in reducing risk while allowing healthy rates of return.<sup>125</sup>
65. UR said that the reduction in the rate of return was not a concession by PNGL. This reduction in the rate of return did provide a reduction in prices to customers and this was reflected in the UR setting out of the benefit at £25 million (2006 prices). However, the 2007 licence modifications fundamentally changed the nature of the risks facing the company and the balance of risks between the company and its customers. The reduction in the rate of return was fully justified based on the reduction of risk alone, not as a concession from the company as part of the 2006 discussions and subsequent 2007 licence modifications.<sup>126</sup> It also said that the one percentage point reduction in the rate of return in any case did little more than track the downward reduction in the cost of capital that had been observed across the regulated sectors in the UK between 1996 and 2007.

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<sup>120</sup> PNGL statement of case, paragraph 4.18.

<sup>121</sup> UR comprehensive response to comments on draft proposal (2012 decision), p11.

<sup>122</sup> *ibid*, p11.

<sup>123</sup> *ibid*, p11.

<sup>124</sup> *ibid*, p11.

<sup>125</sup> *ibid*, p11.

<sup>126</sup> *ibid*, p11.

66. UR said that the write-off of a loss to the supply business relating to the legacy contract issue was not a concession.<sup>127</sup> It said that as a result of long-term contracts entered into by the Phoenix supply business, it suffered a loss of £9.7 million. PNGL had proposed that it manipulate distribution charges in order to offset the loss. UR considered that this proposal would be in breach of the licence and consulted on enforcement action in May 2006. It said that it was content that this issue could be resolved by ensuring that appropriate revenues were paid by Phoenix's supply business to PNGL and thus reduce the PNGL under-recoveries. On this basis, UR agreed not to proceed with legal enforcement and a possible fine. This did not cause any kind of detriment to PNGL.<sup>128</sup>
67. It said that writing off these losses relating to the supply business was not in any way a concession in relation to the transmission business.
68. UR said that PNGL had also argued that it made a large concession in agreeing to the treatment of under-recoveries given that it could not raise prices due to regulatory pressure. However, UR said that it had no power to prevent PNGL from increasing prices and PNGL's commercial decision not to do so underlined the difficulties with this option and the overall risk inherent in the original licence before UR agreed to the licence modification. Furthermore, the treatment of under-recoveries in the 2007 licence modifications was more generous than that which would have been allowed under the 1996 licence.<sup>129</sup>
69. UR also said that PNGL argued that the treatment of under-recovery represented some kind of transfer of value from PNGL to consumers. In UR's view, this under-recovery was directly attributable to the failure of the PNGL business model. It did not think PNGL's description of this as a transfer of value was credible.<sup>130</sup>
70. UR said that the only adjustments made in 2007 to unspent allowances were to reflect the treatment of working capital allowances and grant.<sup>131</sup>
71. UR said that PNGL stated that it was unfair to review individual amendments to the 2007 licence as PNGL could not reopen other elements of the 2006 review such as selling off its transmission business. UR said that it did not accept that PNGL had been disadvantaged in any way regarding the other elements.<sup>132</sup>
72. UR said that in support of PNGL's view that there was an agreed package, PNGL pointed out that all the proposed modifications to the existing licence were presented in a single letter of 27 October 2006, and that Terra Firma's reply of 8 November 2006 stated that 'the overall package that is being offered is acceptable'. UR said that the letter of 27 October 2006 did not state that the elements of the price control were to be treated in such a way, and it also did not use a term such as 'agreement' to describe them. It referred instead to 'proposals', 'amendments' and 'modifications', and made clear that everything set out in it was subject to public consultation. Likewise, the setting out of the proposals in a single letter did not mean that they were indivisible. Instead it was simply a matter of convenience and common sense, the alternative being separate correspondence on each individual issue.<sup>133</sup>

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<sup>127</sup> *ibid*, p11.

<sup>128</sup> *ibid*, p11.

<sup>129</sup> *ibid*, p11.

<sup>130</sup> UR supplementary submission, paragraph 1.27.

<sup>131</sup> UR supplementary submission, paragraph 2.88.

<sup>132</sup> UR comprehensive response to comments on draft proposal (2012 decision), p9; UR initial submission, paragraph 3.30f.

<sup>133</sup> *ibid*, p9.

## **No exceptional circumstances apply to justify the 2012 TRV adjustment**

73. PNGL said that agreements determining value, incentives and returns should be revisited only under exceptional circumstances.<sup>134</sup> PNGL said that retrospective action such as the 2012 TRV adjustment could only be justified in such exceptional circumstances, for example if the 2006 'agreement' had resulted in a perverse outcome, leading to the regulated business earning excessive and windfall profits or if the 2006 'agreement' had turned out to have resulted in a sharing of value that could be said to have been manifestly wrong or unfair. PNGL said that there were no such exceptional circumstances and that the 2006 'agreement' was fair.<sup>135</sup>
74. PNGL said that both it and UR supported the 2006 'agreement' (and the resulting licence modifications) on the basis that it resulted in a fair deal for both customers and PNGL's shareholders.<sup>136</sup> PNGL said that UR said in April 2007 that customers benefited by not having a substantial increase in distribution charges which would otherwise be necessary in the absence of the 2006 'agreement' and a reduced rate of return and that PNGL benefited from reduced uncertainty of recovering investment and return and that the market for the supply of gas continued to develop robustly.<sup>137</sup>
75. PNGL said that the only exceptions for reopening decisions made in prior charge controls were:<sup>138</sup>
- (a) if significant new information came to light, for example if the regulator had been misled by the company in terms of the information it originally provided; and
  - (b) a company failed to meet its core output measures due to insufficient investment.
76. PNGL said that there was no new information relating to the calculation of the 2006 TRV. PNGL said that it had always met its licence obligations in respect of coverage of the network and that PNGL had consistently met its service standards, even during the extremely challenging 2010/11 winter period.<sup>139</sup>
77. PNGL said that one indication that a previous determination might have been inappropriate might arise if it was shown that a regulated company was making excessive returns. PNGL said that an analysis of the returns earned by PNGL to date showed that there was no justification for making the 2012 TRV adjustment.<sup>140</sup>
78. PNGL provided calculations that showed that the IRR (without the 2012 TRV adjustment) achieved by the distribution business was around 7.9 per cent which was just below the average rate of return it had been allowed of around 8.2 per cent.<sup>141</sup> PNGL said that as the IRR was below the allowed rate of return, the analysis showed that PNGL had not earned excess returns.<sup>142</sup> It said that this showed that there was no justification for claiming that PNGL had been earning excess returns that would justify a retrospective adjustment to the TRV.<sup>143</sup>
79. PNGL said that this analysis fully captured the impact of value sharing that was ratified in 2006, including, for example, the losses PNGL faced on WCA outperform-

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<sup>134</sup> PNGL statement of case, paragraph 1.9.

<sup>135</sup> PNGL statement of case, paragraphs 5.3, 5.4, 5.8, 5.80, 6.4 & 6.42.

<sup>136</sup> PNGL statement of case, paragraph 5.5.

<sup>137</sup> PNGL statement of case, paragraphs 5.6 & 5.7.

<sup>138</sup> PNGL statement of case, paragraph 6.13.

<sup>139</sup> PNGL statement of case, paragraph 6.13.

<sup>140</sup> PNGL statement of case, paragraph 5.11.

<sup>141</sup> PNGL statement of case, paragraph 5.84.

<sup>142</sup> PNGL statement of case, paragraph 5.86.

<sup>143</sup> PNGL statement of case, paragraph 5.87.

ance, grants outperformance and legacy contracts.<sup>144</sup> PNGL said that its concessions it made as part of the 2006 'agreement', together with the benefits customers received from outperformance under the ratchet mechanism (as included in the 1999 licence), showed that there were no grounds for concern about how value had been shared with customers in the 2006 'agreement'.<sup>145</sup>

## **Efficient outperformance**

### **PNGL**

80. PNGL said that at the time of the 2006 'agreement', UR initially suggested that only a proportion of outperformance should be retained by PNGL based on an efficiency assessment and where it could be demonstrated that efficiencies benefited customers in the past or the future.<sup>146</sup>
81. PNGL said that opex outperformance amounted to 17 per cent of opex allowances over the period 1996 to 2006.<sup>147</sup> It said that the main drivers for outperformance were its partnership with McNicholas, successful marketing campaigns to attract new customers, outperformance on office costs, outperformance on network operations and successful rating valuation negotiations.<sup>148</sup>
82. PNGL gave some further explanation of how outperformance was achieved. For example, there was outperformance on manpower between 2002 and 2005. At this time, PNGL experienced a heavy loss of staff and replaced them with new staff, who needed training, with a consequent reduction in average salary levels. Meanwhile, PNGL streamlined its operations and consolidated them on one site. It said that management resources were shared between PNGL and McNicholas with no duplication or man marking of staff. Control room staff were required to undertake a variety of other processes in quiet periods other than 'core control room activities'. There were increased manpower efficiencies in the sales operations, and market development process and consolidation of marketing and PR agencies. In relation to office costs, PNGL also referred to savings arising from the consolidation at a single out-of-town site, including co-location with the contractors' management staff, savings on telephone costs, IT licensing, maintenance and support, etc. It said that these savings were not known when these forecasts were being prepared for the PC02 price control review in October 2000.
83. PNGL said that opex outperformance of £14.7 million (undiscounted at 1996 prices) over the period 1996 to 2006 was largely driven by savings in manpower (£5.7 million), rates (£5.0 million), office costs (£2.4 million) and network operation and maintenance (£1.3 million).
84. In relation to manpower, PNGL said that whilst it outperformed in manpower, it also incurred additional counterbalancing costs under other cost lines, for example in external services from BG and higher costs under the McNicholas contracts.
85. In relation to rates, PNGL said that its outperformance on rates was due to successful negotiations with the Valuation and Land agency (VLA), and partly due to lower-than-expected revenues, particularly in the period 2003 to 2006. PNGL said that the effect of its lower revenues on rates did not mean that it was not entitled to the

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<sup>144</sup> PNGL statement of case, paragraph 5.86.

<sup>145</sup> PNGL statement of case, paragraph 5.21.

<sup>146</sup> PNGL statement of case, paragraph 4.15.

<sup>147</sup> PNGL statement of case, Annex 6, paragraph 3.

<sup>148</sup> PNGL statement of case, Annex 6, paragraph 4.

outperformance on rates, as PNGL received penalties for volume underperformance, as there was a penal interest rate associated with revenue under-recoveries, and as it had to give up value in relation to the treatment of revenue under-recovery in the 2006 'agreement'.

86. PNGL said that it estimated that around 60 per cent of the outperformance on business rates over PC02 was due to turnover being lower than assumed in the PC02 determination (which in part was due to revenue under-recoveries and in part due to volume underperformance).
87. PNGL said that it did not have as much information on how the business rates allowance in PC01 was calculated as it did for PC02 and that it was not aware of what the actual level of rates were that went into the business rates calculation in the PC01 price control, and as such it could not provide an estimate of the percentage of business rates outperformance that was associated with revenue under-recoveries for PC01. However, we note that UR's consultants, PKF, in its 1999 opex report stated that business rates in PC01 would be determined as being equivalent to 9 per cent of conveyance income.
88. PNGL also said that its business rates allowance from 2007 onwards was linked to turnover.
89. PNGL also said that business rates allowances in PC01 and PC02 were determined at these price controls on the basis of expected annual conveyance revenues over the period. PNGL said that expected revenues were calculated on the basis of the expected revenues of the supply business, rather than relating directly to the expected conveyance charge.
90. PNGL said that its outperformance on business rates was partially related to negotiations with the Valuation Lands Agency (VLA), in particular two sets of discussions:
  - (a) In discussions soon after PNGL commenced operations, the VLA accepted that rates for PNGL could not be established in line with standard formulae for regulated utilities in light of the fledgling nature of the natural gas industry in Northern Ireland, which involved significant upfront costs and revenues profiled over time. The VLA therefore agreed a methodology whereby rateable value would be determined as being equivalent to 9 per cent of conveyance income in the previous year. This approach was implemented by PNGL following the PC01 determination in 1999 and resulted in an adjustment to accrued charges in the 1999 accounts. This new approach was taken into account in the PC02 cost forecasts.<sup>149</sup>
  - (b) In 2002, PNGL entered into further discussions with the VLA ahead of the 2003 rating revaluation in Northern Ireland. As part of these discussions, PNGL and the VLA agreed that the basis of rates assessment should continue to be the corrected measure of transportation revenue, in line with the methodology that had been established in 1999. In addition, the VLA agreed to adjust the percentage rate to reflect the fact that part of the transportation income related to market development costs. Based on these agreed adjustments, the VLA established that rateable value should be based on a reduced percentage of around 6 per cent of nominal corrected transportation revenue.

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<sup>149</sup> PNGL's 1999 resubmission, paragraph 3.2.3, states that the methodology recently agreed with the VLA has been used to calculate forecasted PC01 rate expenditure.

91. PNGL said that the level of business rates it negotiated with the VLA benefited consumers in Northern Ireland in each and every year. There was no re-profiling of rates from the period of 1996 to 2006 into later charge control periods (ie PNGL did not make an agreement to pay higher business rates in the future in order to achieve outperformance on business rates in the period of 1996 to 2006). PNGL said that the traditional methodology for utilities would lead to business rates of about £5 million a year compared with around £1.4 million currently.
92. PNGL said that business rates outperformance in PC02 was, apart from revenue under-recoveries and the negotiations with the VLA (as set out in paragraph 90), due to the ability to deduct rates payable on office costs, due to changes of rates charges payable across the districts in PNGL's Licensed Area and due to adjustments for accruals.
93. In response to our provisional determination PNGL provided an estimate of around 30 per cent for the amount of business rates outperformance that was related to PNGL's revenue under-recoveries in PC02. PNGL said this took into account that some revenue under-recoveries in PC02 were related to the transmission business, that business rates were set by reference to forecast revenues which were lower than allowed revenues and that the timing of revenue under-recoveries was towards the end of the charge control period (which reduced the capitalized financing element of the adjustment).
94. PNGL also said that all value in the 2006 TRV related solely to the distribution business (and that no outperformance associated with the transmission business was included in the 2006 TRV).
95. In response to our provisional determination PNGL said that our proposed adjustment for business rates did not take into account the overall risk and reward framework that was in operation when the outperformance occurred.<sup>150</sup>
- (a) PNGL said that as revenues used for the calculation of the business rates allowance in PC02 were lower than the allowed revenues in the PC02 determination this meant that PNGL was at risk of underperforming on business rates had it recovered the allowed revenues in full.
- (b) PNGL said that the PC02 determination implied that its penalties on under-performance from revenue under-recoveries would be (partially) offset by out-performance in business rates and that its business rates outperformance was therefore part of the overall risk and return framework applying to PNGL at that time.
- (c) The business rates outperformance was the result of inaccurate forecasts and the risk/benefit with inaccurate forecasts were retained by the regulated company. Making an adjustment now effectively made business rates subject to a retrospective adjustment mechanism, even though this was not signalled ex ante. PNGL also said that it was known at the time of the 2006 'agreement' that including past outperformance in the 2006 TRV would effectively result in PNGL being funded twice for business rates relating to revenue under-recoveries and that the 2006 'agreement' should not be reopened, because this would be retrospective.

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<sup>150</sup> PNGL [response to provisional determination](#), paragraph 4.14.

96. PNGL said that savings in office costs were due to a number of initiatives delivered by PNGL as part of the consolidation of activities at a single site and ongoing successful negotiation of commercial agreements at preferential rates. This included savings on items such as lower telephone costs, mobile phone costs, licensing, IT services, rental arrangements etc. In 2001, BG constructed a purpose-built office on the outskirts of Belfast, which also reduced costs.
97. In relation to network operation and maintenance, PNGL said that there were many initiatives aimed at delivering improvements and efficiency gains, including reducing the costs of service contracts and bringing outsourced activities in-house.
98. As noted in paragraph 5.25, PNGL said that outperformance on manpower largely accrued over PC02, specifically between 2002 and 2005. This was because PNGL experienced a heavy loss of staff which PNGL replaced with lower-cost staff, as a high proportion of the new staff needed to be formally trained. PNGL said that it also successfully streamlined operations and consolidated its operations at one site. Examples of savings included:
- (a) sharing of staff between McNicholas and PNGL;
  - (b) efficient use of staff in the 24-hour control room;
  - (c) reduction of sales costs by upskilling the installer network;
  - (d) reduction in the cost of connecting new customers to gas; and
  - (e) reducing costs by asking PR agencies to undertake some of the tasks PNGL was doing.
99. PNGL said that outperformance on incentives largely accrued over PC01. It said that the costs of market development manpower (and the associated overheads) were included within the overall market development allowance for PC01. While the level of incentives paid by PNGL to consumers were in line with the level of allowable incentive payments within the PC01 determination, PNGL was able to deliver cost savings against the costs of market development manpower (and the associated overheads), as described in the previous paragraph.
100. PNGL said that another opex efficiency was the reduced risks of gas leakage as the result of the pre-assembled meter installation.
101. PNGL said that actual tender rates of the second McNicholas contract were not available at the time of the PC02 submission, but the contract philosophy and contract approach were shared and discussed with UR and its consultants.
102. PNGL said that it was able to provide to UR and its consultants the full tender rates and the distribution contract document for the third McNicholas contract, which commenced in July 2006.
103. PNGL said that for both PC02 and PC03, the actual out-turn costs which incorporated the innovations and efficiencies delivered by PNGL during PC01 and PC02 were used to forecast and agree allowable unit costs going forward for PC02 and PC03 respectively, and these benefits were passed to customers through the ratchet mechanism.
104. PNGL said that In PC01, capex outperformance attributable to take-up and connections being below forecast accounted for less than 2 per cent of total capex out-

performance in the period 1996 to 2006 (which was around £46 million in 2006 prices, ie around £1 million).

105. PNGL said that none of the PC02 capex outperformance was due to connections by domestic consumers being below forecast in PC02 as a retrospective mechanism applied in PC02 in relation to connections. This mechanism ensured that only the actual number of connections (multiplied by the determined unit costs per connection) were included in allowed revenues.
106. PNGL said that none of the opex outperformance in 1996 to 2006 was due to underspend on marketing and other market development-related expenditure.
107. In relation to capex outperformance, PNGL said that capex outperformance was 7 per cent of the capex allowances over the 1996 to 2006 period.<sup>151</sup> It said that this outperformance of £15.8 million (1996 prices, undiscounted) was due to:
  - (a) the alliance partnership with McNicholas, in particular the renegotiation of the terms of the contract in November 1999 (which delivered £6.5 million savings);
  - (b) a higher-than-expected proportion of non-dig mains laying, for example through a higher-than-expected percentage of pipes having been laid using the old towns' gas network (which delivered around £5.5 million in savings);
  - (c) pre-assembled meter installation (£0.9 million) and the development of a new PAYG meter (£0.7 million); and
  - (d) other improvements (£0.4 million).
108. PNGL said that the costs for 1996 to 1998 in the PC01 determination for capex were target costs derived from the contract payments to McNicholas during the period 1996 to 1998 (ie the tendered rates), and the actual level of activity rather than the forecast level of activity. It said that this was clear from the related consultant reports and from this it was clear that UR set the PC01 allowances to mimic how it might have set the allowances had it had the opportunity to do so in 1996 (ie UR used the unit rates derived from the McNicholas contract combined with the actual level of activity undertaken to derive the target level of costs, and applied an efficiency factor for a five-year period). PNGL said that the target cost level against which outperformance was measured therefore had a clear and objective basis.
109. In relation to opex outperformance, PNGL said that Pannell Kerr Forster Corporate Finance (PKF), consultants to UR, confirmed the efficiency level of projected costs for 1996 to 1998 in PC01. PKF's methodology included comparing projected information with actual results in 1996 to 1998, to identify areas of cost estimation requiring, in its view, amendment and areas for efficiency savings.
110. PNGL said that in the absence of any new information to suggest that a mistake was made, it was not appropriate retrospectively to reopen tests and measurements of the outperformance achieved between 1996 and 1998.
111. PNGL said that its 1999 submission was made in March 1999. UR made its determination in September 1999. Therefore it was clear that allowances for 1999 were being set on forecasts for 1999 as 1999 could not have been actualized given that the determination was issued part-way through 1999.

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<sup>151</sup> PNGL statement of case, Annex 6, paragraph 5.

112. PNGL said that outperformance in 1999 and 2000 was made up of the following categories:
- (a) PNGL further outperforming tendered rates (which formed the basis for the PC01 determination). This included, for example, use of higher levels of non-dig (as opposed to open-cut mainslaying) than forecast; greater use of 4 bar MP than forecast (resulting in a greater amount of small diameter pipe, which reduced costs); use of bespoke diameters such as 75mm and 50mm, which was cheaper than the traditional sizes of 90mm and 63mm).
  - (b) Some deferrals. The scale of deferral was small in the context of the wider roll-out of the network that was taking place in the late 1990s. The bulk projects deferred made up only two weeks' worth of work in 1999. Projects were deferred in order to implement PNGL's dynamic strategy to get gas to prospective customers at the right time. Identifying and responding to prospective customer demand was what allowed PNGL to deliver the output targets specified in the licence, and was consistent with the regulatory objective to ensure the efficient development of gas in Northern Ireland. Monthly development meetings reviewed the requirements of each of the four main customer groups (industrial and commercial (I&C), Northern Ireland Housing Executive (NIHE), new-build homes (New Build) and owner occupied (OO)) and considered which construction should be prioritised to maximize connections, and thus ensure that those customers who wanted gas were connected to the network as soon as possible. Regular meetings assessing demand were critical to achieving this objective as NIHE determines when and where network was required on a rolling four- week basis. To miss these connections would have been to miss the opportunity to connect these households for a further 15 years (ie until the next heating replacement scheme commenced), reducing the company's ability to meet its output targets. Confirmed visibility of demand from New Build was a maximum of three months and mainly only one month. To miss these customers would be to miss the opportunity to get 100 per cent customer take-up on day 1 for that phase of the development and for all subsequent phases of that development, again reducing the company's ability to meet output targets. I&C demand reflected the timing of individual companies' decisions whether and when to move to gas. The loads demanded by these customers were often large. For this reason, the sooner PNGL provided a network for them, the better for all customers. OO was built according to 'register of interest surveys' prepared by PNGL, which prioritized areas in line with the level of interest shown (and proximity to existing networks) in order to maximize connections to the benefit of all consumers. Responding to demand identified in the register facilitated the company in meeting its output targets.
  - (c) Outperformance arising from renegotiation of the tender rates in the McNicholas contract in November 1999, which delivered unit cost reductions. This involved a review of the additional quantity of work that McNicholas was getting through the contract because of the accelerated build programme. This contract review delivered approximately £3–£4 million of outperformance in 1999.
113. PNGL also said that it met its targets set out in the 1996 licence.
114. PNGL said that even though UR said that it did not specifically carry out an assessment of efficiency of outperformance at the time of the 2006 'agreement', it was quite clear that during each of the price control reviews, UR very carefully analysed and determined appropriate levels of allowable capex and opex. PNGL said that there were numerous reviews, information exchanges and meetings with UR and its consultants over a number of years. This was not surprising given that a detailed under-

standing of the efficiencies achieved was necessary for the operation of the ratchet mechanism in PC02 and PC03. By way of example, UR undertook a substantial review of capex and opex as part of PC03 over an extended period using external consultants to challenge PNGL forecasts. In line with previous experience, this review incorporated substantial analysis of historic costs and the relevance of such costs for future forecasting. Against this background, it was extraordinary for UR to argue that it had not reviewed the efficiency of historic outperformance.

115. PNGL said that the efficiencies achieved at PC01 were reviewed by UR and its consultants as part of the PC02 price control review process. The efficiencies achieved at PC02 were similarly reviewed at PC03. PNGL said that the PC02 and PC03 determination notices and related consultants' reports contained further detail on these efficiency savings and demonstrated clearly that PNGL's historic cost performance against regulatory allowances had been scrutinized closely. PNGL provided the following quotes:
- (a) In relation to the PC02 capex review: 'To summarise 1999 performance, the total output was much less than planned for most asset categories. There were some efficiency savings, due primarily to unit cost reduction, and rather less unit cost increases.'
  - (b) In relation to the PC02 capex review: 'The Regulatory Agreement was to build 562km at a total cost of £13.894m. In the event Phoenix fulfilled the output requirement by laying a little less than 562km at a cost of £12.772m ie a unit cost reduction of around 8%.'
  - (c) In relation to the PC02 opex review: 'some improvements have been made that will have contributed to the efficiency improvements seen in Phoenix over the last number of years'.
  - (d) In the PC03 determination: 'the cost associated with pressure reduction has been consistently driven down from a cost of £39k in 2002 to £26K in 2005. This would suggest efficiency savings have been achieved in the cost associated with this type of work'.
  - (e) In the PC03 determination: '30km of feeder were not constructed due to efficiency improvements in laying feeder mains'.
  - (f) In the PC03 determination: 'PNG ... outperformed unit rates by 15%. ... Consequently the Utility Regulator has passed these efficiency savings on to customers.'
116. PNGL said that the evidence confirmed a mutual understanding between PNGL and UR as to the extent of the outperformance, which was thoroughly scrutinized by UR and its consultants over a considerable period of time and that UR had examined the outperformance during the period 1996 to 1998 (ie in 1999, 2004 and 2006), confirming that this treatment of outperformance was correct.
117. PNGL also said that it was not required to collect unit cost data under the 1996 licence. The 1996 licence granted a single aggregate capex and opex cost allowance which PNGL worked to. Under standard incentive regulation, and in accordance with the principle of avoiding micro-management, PNGL was able to optimize its expenditure within the overall allowances determined. PNGL said that given the passage of time since these efficiencies were achieved, it was difficult to look back at the available data and assess now the drivers and causes of variance to forecasts.

118. PNGL said that the question of efficiency was not relevant to our determination, as the 1996 licence prescribed that PNGL was to retain the benefit of all outperformance, as it would undermine incentive and because reassessment today of the efficiency of PNGL's outperformance many years ago was not possible. Even if it was possible to reach some tentative views, there would be grave doubt that those views could be more reliable than the assessment that took place at PC01 when the information was freshly available. That assessment had now formed part of the analysis in three price controls; and it had been checked and audited by UR's accountants and consultants.
119. PNGL said that against this background, reassessment would be appropriate—if at all—only if it became clear that there had been an error or new facts emerged that justified retrospective intervention (and even then only if a reliable reassessment were possible).
120. PNGL said that Great Britain practice was to set efficiency challenges prospectively with, in some cases, a formula for sharing outperformance at the end of the regulatory period. It was not normal regulatory practice to review retrospectively at the end of a regulatory period whether out-turn outperformance has been efficient. Rather, any assessment of efficiency at that point informed the targets for the next review.
121. PNGL said that to perform an efficiency assessment now was retrospective as it would be performed long after the price control period in which the outperformance was originally achieved and five years after the outperformance was allowed into 2006 TRV and included in the licence.

## UR

122. UR said that it discussed with PNGL implementing the concept of sharing through an adjustment to this number on the basis of carrying out a review to ensure that only efficient costs were allowed, but instead included 100 per cent of outperformance in the asset base.<sup>152</sup> UR said that the paper from 2006 cited by PNGL referred to the *intention* to carry out such an assessment. It said that PNGL should be aware that no such review occurred, since any review would have had to involve PNGL. The fact that no review took place and all of the historical outperformance was treated as efficient was clearly a favourable outcome for PNGL.<sup>153</sup>
123. UR said that it did not carry out an ex-post review of outperformance over the period 1996 to 2006 and, as such, it did not know the extent to which the outperformance that currently sat within PNGL's TRV was driven by efficiencies.
124. UR said that it never reviewed outperformance for efficiency and had not done so in making its PNGL12 proposals. It said that for the purpose of calculating the 2006 TRV, it treated the whole amount of outperformance as if it was normal efficient outperformance earned against ex-ante forecasts and that PNGL had earned five years' reward against this during PC03. UR said that it decided not to carry out a review when setting the 2006 TRV, because an outperformance efficiency review would be more diverse and complex and because, in moving to a new licence regime as a result of the failure of the old one, UR had to make decisions in drawing a line under the past (achieving an overall balanced approach in its decisions).

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<sup>152</sup> UR supplementary submission, paragraph 2.91.

<sup>153</sup> UR supplementary submission, paragraphs 2.95 & 2.96.

125. UR said that its 2012 TRV adjustment ensured that consumers did not over-reward PNGL for outperformance. Maintaining network costs at a lower level than would otherwise be the case ensured that gas remained competitive as a fuel and, therefore, the resulting lower prices contributed to the continued development of the gas industry. UR said that it had no robust evidence that its decision would have a negative impact on the gas industry, having seen continuing investment across all industry sectors since its proposals were published. It said that the 2012 TRV adjustment in no way jeopardized PNGL's ongoing ability to fund its activities (even under pessimistic out-turn scenarios) and that PNGL continued to earn an attractive rate of return. UR said that its decision protected the short- and long-term interests of existing and potential customers, as it resulted in lower prices than would otherwise be the case.
126. UR said that it did not think that the outperformance in the 2006 TRV was attributable solely to efficiency.
127. UR said that PNGL did not provide details of the outperformance for 2000 and 2001 during PC03, claiming that it was not possible because of an update to the cost management system in 2002.
128. UR indicated that outperformance directly attributable to take-up and connections being below forecast was limited to the effects on service pipes and meters involved in making connections (it termed this as a 'narrow view'). It said that PNGL benefited by £0.5 million (2006 prices) from failing to deliver I&C (ie business customer) meters in PC02. UR said that for PC01, it did not have the details to make a similar estimate.
129. UR said that in PC02 it subjected domestic meter costs to retrospective adjustments, correcting for differences between forecast and actual connections, therefore there was no scope for capex outperformance to arise in this cost area from connections being below forecast. UR said that in PC01 it indicated that a mechanism would be agreed to compensate PNGL for unforeseen connections above the baseline numbers assumed for the PC01 period, but it was not clear whether any such adjustments were necessary.
130. UR said that the lack of detailed information made it difficult to establish with certainty how much outperformance was efficient. However, there were readily identifiable areas where it would be improbable that the outperformance could be considered efficient. UR said that it seemed clear now that the sums relating to outperformance in 1996 to 2000 represented something other than efficient performance against appropriate ex-ante targets. Examples included:
  - (a) Outperformance as a result of deferrals amounted to around half the outperformance that went into the 2007 TRV. It was not clear that consumers had benefited from these deferrals.
  - (b) The period 1996 to 1999, which accounted for around £36 million of the amount attributed to outperformance, was based on 'targets' that were not set until 1999, based on information provided in 1999, ie these were 'ex-post forecasts'. The information provided to the regulator, and therefore the 'targets' that were set, ought to have been based on actual out-turn costs and therefore to have allowed no room for outperformance. Given the licence obligation on the company to use reasonable endeavours to provide best estimates, it not clear why they were not. The same doubts also applied to 2000 where outperformance amounted to £38 million, even though this was immediately after the price control determination, raising questions about the quality and validity of information provided to UR. That PNGL might have outperformed so greatly, in so short a time, in circum-

stances in which there were no historic efficiencies to drive out, did raise questions. That it should be rewarded as if it were receiving an incentive payment when there were no ex-ante targets against which it could have been incentivized had no sound basis in regulatory theory or practice.

131. It also said that it seemed clear now that the sums relating to outperformance in 1996 to 2000 represented something other than efficient performance against appropriate ex-ante targets.
132. UR said that when taking a wider view, outperformance in 1996 to 2006 did include savings from not delivering the level of capex and opex that was allowed to meet a growing market. This would include outperformance on lower-pressure upstream pipes (infill and feeder mains) that transported gas around housing estates and down residential streets. This amounted to around £14 million (2006 prices).
133. UR said that there would also have been a level of opex outperformance associated with the reduced network build and take-up being below forecast. One area would be business rates which were calculated using revenues and these would have been significantly below forecast due to pricing below the price cap. It also said that from 2007 onwards business rates were included in its determinations on the basis of allowed revenues.
134. UR said in response to our provisional determination that the scale of under-recovered revenues over the course of PC01 was greater as a proportion of allowed revenues than in PC02 (63 per cent for PC01 compared with 44 per cent over PC02). Given that the under-recovery in PC01 was proportionately greater, it would be reasonable to assume the proportion of the outperformance on business rates attributable to revenue under-recoveries was higher than the 60 per cent assumption used by us in our provisional determination for the PC02 period.
135. UR also said that outperformance on business rates arising from the VLA's agreement to exclude market development costs from rateable revenues did not suggest outperformance arising from efficiencies. The inclusion of market development costs was an attempt by the regulator to improve connection rates. It was not meant to lead to outperformance by PNGL and PNGL should not be allowed to retain it. UR said that PNGL's submissions indicated that, as a result of this renegotiation, the rateable value reduced from 9 to 6 per cent of conveyance income. UR estimated this as an equivalent overall reduction of 33 per cent to the eventual 'rates bill', given the multiplicative nature of the ratings formulae.
136. UR said that PNGL's outperformance on business rates following its negotiations with the VLA led to higher business rates in the future and was therefore effectively a deferral of business rates payments, rather than outperformance, because lower rates in earlier periods were traded off against higher rates in future periods.
137. UR also said that outperformance attributable to the transmission business should not be retained by the distribution business.
138. UR said that prior to 2005, both PNGL's transmission and distribution businesses had revenue under-recoveries. In October 2004, however, UR introduced a postalized transmission tariffing system throughout Northern Ireland, which ensured that all transmission companies received their allowed revenues in full each year. This was of significant benefit to PNGL, as evidenced by the marked increase in its transmission revenues from 2005.

139. UR said in relation to PNGL's comment that under-recoveries were to be offset by outperformance on business rates that:
- (a) The 1996 licence set out how under-recoveries were treated (the 'Z factor') and how outperformance was treated. The two were not directly, or otherwise, linked in the licence formulae. It followed then that revenue under-recoveries were not meant to be offset by outperformance on business rates.
  - (b) By the time the 1996 licence was modified in 2007, PNGL had under-recovered to such an extent that it was not technically possible for it to recover it all by 2016. Yet the regulator allowed all of it to be capitalized into the OAV as part of the 2007 modifications. If, as PNGL claimed, under-recoveries and business rates outperformance were intended to be offset, then in granting PNGL its full under-recovery it followed that business rates outperformance should not have been capitalized into the OAV.
  - (c) The 1996 licence did not envisage under-recoveries and as such it was not clear whether outperformance on business rates was intended as an offset to the penal rates applied to revenue under-recoveries.
140. UR said that PNGL had outperformed significantly in manpower and some of this would have related to market development costs.
141. UR said that it incorporated actual volumes provided by PNGL for 1996 to 1999 in making its PC01 determination (and not the 1997 forecasts). This saved PNGL £22.7 million in 2006 prices (the 2006 TRV would have been reduced by this amount). UR also said that it explicitly described the capex numbers for 1996 to 1998 as actuals in the PC01 determination. It said that it appeared from the 1999 determination that PNGL continued to argue for a reduced efficiency level until well into 1999. This resulted in considerable increases in allowances over the period 1996 to 1999 compared with the regulator's 'minded to' May letter preceding the determination.
142. UR said that the most rational conclusion was that the 1996 to 1999 numbers in the PC01 determination were intended to be actual. It said that the PC01 determination was made when PNGL was a greenfield project, meaning that an initial period of investment and/or operation was necessary to obtain a meaningful basis for preparing cost and demand forecasts.
143. UR said that capex for the period 1996 to 1998 was labelled as actuals in the PC01 determination and the spreadsheet used by PNGL. UR said that it assumed that capex and opex allowances for 1999 were set on the basis of a mixture of actuals and forecasts, and would have been informed by out-turn costs in the period (almost three full quarters) leading up to the determination.
144. UR said that PNGL had a licence obligation to use reasonable endeavours to provide best estimates in its submission and that it appeared that PC01 included the costs submitted by PNGL on the understanding that they were based on actual figures.
145. UR said that there was no economic rationale for rewarding outperformance that had not resulted from normal ex-ante forecasts. UR said that the history of PNGL had many unique features and that in making its decisions it had tried to draw a line under the past in order to facilitate the move to the new TRV model based on more normal regulatory practice. In doing so, with a view to delivering the benefits to be obtained from that transition, UR tried to strike a balance between different considerations and had sometimes decided not to revisit issues that, in other circumstances, would certainly have merited greater scrutiny.

146. UR said in respect of the 2012 TRV adjustment that it acknowledged that, in hindsight, it would have been better if UR, in 2007, had been clearer as to the treatment of TRV at all future price controls and not just focused on the immediate price control period. The decision to deal with outperformance in PNG12 was consistent with the principle of sharing based on regulatory practice elsewhere, as PNG1 had now earned five years' reward by retaining outperformance in the TRV between 2007 and 2011, and therefore it was appropriate to implement sharing now. This was consistent with what would happen in a competitive market and was necessary to ensure that PNG1 was not overcompensated.
147. UR said that the treatment of outperformance in the 2012 TRV adjustment was in line with its treatment of outperformance since 2007 for PNG1 and how it treated firmus. UR said that it was also in line with how Ofgem, Ofwat, the ORR and the CAA treated capex overspend and in some cases opex overspend.
148. UR said that the new licence regime from 2007 onwards did not seek to reconcile all elements of the 1996 regime with the 2007 licence modifications and that the 2007 regime included the sharing of outperformance.
149. UR said that the difference between the capex forecast in 1999 and actuals was 31 per cent of the forecast. PNG1 continued discussing its submission and the price determination with the regulator into August 1999, including using actual figures to argue its case, eg incentives. Given PNG1's licence obligation to provide best estimates, it was not clear why PNG1 did not take the opportunity to provide accurate capex data for the period and why it was selective in the areas to which it provided actual figures. Almost certainly, PNG1 must have had monthly management accounts and detailed information on what projects it had already completed in 1999 and what projects it had planned to progress in the following 18-month period.
150. UR said that the main area of outperformance in 2000 was very similar to that in 1999 and stemmed from the very large increases in capex provided for in PC01 for PNG1 to deliver its accelerated network build program. It was clear now that PNG1 did not deliver this and much of this capex had been deferred.
151. UR said that the PC01 price control determination process was prolonged partly as a natural consequence of it being the first decision and its coming at the outset of a greenfield investment, but was also due to significant delays and slow response times on the part of PNG1.
152. UR said that the scale of the deferrals in 1999 and 2000 highlighted the concerns raised in the PC01 determination on PNG1's strategic planning ability. It was now apparent that PNG1 had benefited greatly from this lack of strategic planning.
153. UR said that as PNG1 was in a growth phase of development, it was difficult to argue that the deferral of capex activity was due to efficiency. This was very clear for large specific projects, although the analysis became more complex when considering smaller infill and feeder mains. UR said that it had, for example, accepted PNG1's argument that some of the deferral of infill and feeder capex was due to efficiency.
154. UR also said that the special reforecasting review section of the licence did not suggest that this could be applied retrospectively. Given that PNG1 supplied its reforecast in March 1999, this meant that the new numbers would only have applied from January 2000. If UR had used PNG1's 1999 submission only prospectively, PNG1 would have suffered significant losses, but in the event UR did not do so.

155. UR said that in PC02 PNGL was granted an allowance of £1.5 million (1996 prices) for the cost of purchasing the old towns' gas pipeline system that existed in some parts of Belfast. The acquisition of this network would potentially facilitate the roll-out of PNGL's network using the insertion method (ie inserting new pipe into the old existing pipe), thereby avoiding significant surface digging which in turn would lead to lower costs. However, PNGL did not require these costs for purchasing the towns' gas network, and therefore outperformed by the full £1.5 million allowance (which added £2.3 million (2006 prices) to the outperformance element of the 2006 TRV). UR said that it was not sure why PNGL did not require these costs and why it was not aware of this in 2002. However, PNGL said that UR's account was incorrect. It said that in fact PNGL paid DETI £3 million for the old towns' gas network, a payment which was spread over ten years with £1.5 million in PC01 and the same in PC02. Therefore it indicated no such outperformance arose.
156. In respect of opex outperformance, UR said that much of opex outperformance in PC02 seemed to relate to recharges of opex to capex (through the management fee). The total amount of recharges was £3.8 million (in 2006 prices over the period of 2002 to 2006). UR said that there may have been double counting when setting the allowances for the management fee and opex allowances in PC02. However, PNGL said that UR's account was also incorrect. It said that there was no double-counting allowance. PNGL's PC02 submission was based on a bottom-up analysis of management fee and opex manpower, in line with the approach established at PC01. It said each cost line was justified by PNGL on its own merit and scrutinized by UR during the PC02 price control review.
157. UR said that in striking a balance in moving to a TRV-based model and drawing a line under historic issues, it had given the benefit of the doubt in some areas to PNGL.

### Third party comments

158. Several parties made submissions supportive of UR's proposals for resetting the RAV both at the start of our investigation and in response to the provisional determination (these later submissions are covered in Appendix I).<sup>154</sup> Some submissions draw attention to adverse consequences arising from the proposals. Here, we review comments relating to the treatment of historic outperformance specifically.
159. CCNI said that where a natural monopoly existed, it was the role of the regulator to act as a proxy for competition. In a competitive environment the need to keep the cost to the customer as low as possible would have driven the value of these non-existent assets out of the TRV and PNG would not have been able to retain the value over the 40-year period now envisaged. CCNI said that in retrospect it appeared that UR agreed to 2007 Licence Modifications (as a result of the 2006 'agreement') that provided a long-term benefit to PNGL, to the detriment of consumers.<sup>155</sup>
160. Bryson Energy said that it was well established within regulatory practice that in order to protect the long-run interests of customers through driving down costs to the minimum possible economic level, companies might be incentivized to make additional returns within a price control period. However, this incentive mechanism only worked for customers if the benefits of the lower cost base were afforded to

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<sup>154</sup> See CC website: [www.competition-commission.org.uk/our-work/phoenix-natural-gas-limited-price-determination/evidence/initial-submissions](http://www.competition-commission.org.uk/our-work/phoenix-natural-gas-limited-price-determination/evidence/initial-submissions). For example, Manufacturing Northern Ireland and John Thompson and Sons. Age Concern said that 'we consider that the UR has struck the right balance between the consumer and the company and would support the adjustment to be made as part of the review'.

<sup>155</sup> CCNI submission.

customers in subsequent price control periods. Moreover where the excess returns in one period were not even the result of efficiency but of underspend through change of circumstances or plans, then it was both unjust and contrary to any principle of incentive regulation to permit the company to enjoy such returns into the future. To permit the retention of such returns would perversely be to incentivize companies to deliberately mislead the regulator.<sup>156</sup>

161. firmus said:

If regulation is not stable and predictable, investors will be uncertain as to the level of future returns. ... However, this is not to say that regulatory frameworks cannot change. They should respond to evolving market conditions. ... However, they should change in a way which is objective (and therefore which investors could anticipate if they asked themselves 'what if ...' before making an investment) and which appropriately balances short and long term interests. Changes which look to undermine the confidence of investors in securing a return on a regulatory asset value agreed by a regulator are particularly important, as they undermine a concept which is key to efficient long term financing. Customers may benefit in the short term as a result of lower prices. However, they will undoubtedly be worse off in the longer term as investors increase the premium which they require to make investments within certain sectors/countries.<sup>157</sup>

162. Northern Ireland Electricity (NIE) made similar points. It said:

Our concerns arise because the integrity of a company's regulatory asset value (whether it relates to gas, water or electricity) is critical to the integrity of the entire regulatory regime. Retrospective adjustments like this conflict with good regulatory practice which promotes consistency, predictability and transparency in regulatory decision making.<sup>158</sup>

163. Fitch said:

Given the retrospective TRV adjustment that includes a clawback of £59.6m of operating and capital expenditure outperformance, which is inconsistent with PNG's existing licence, Fitch could change its view on predictability and supportiveness of the regulatory regime in Northern Ireland.<sup>159</sup>

164. Martin Falkner said:

The Authority's core argument appears to be either that its duty to customers means that it has an obligation to revisit decisions it has previously made, or that the Authority's intention was always to 'move the regulation of Phoenix to a more standard regime', but unfortunately, if the latter, the Authority failed to adequately disclose that to Phoenix or investors. Either argument is fatal to any concept of regulatory certainty

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<sup>156</sup> Bryson Energy submission.

<sup>157</sup> firmus energy submission.

<sup>158</sup> NIE submission.

<sup>159</sup> Fitch ratings, PNGL Update, August 2011.

and is not consistent with good regulatory practice as applied by the GB regulators.<sup>160</sup>

165. NIIRTA recognized that any adverse consequences for long-term natural gas developments could have adverse impacts for customers. It said:

NIIRTA also has concerns that if Phoenix's cost of borrowing increases in the future as a result of the proposed price control actions, then consumers and businesses may ultimately pay for this in the longer term. Whilst the proposed savings stated by NIAUR are of course welcome, it is important the Commission balances this plus against a longer-term, more strategic view of the potential negative implications that have been flagged up.<sup>161</sup>

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<sup>160</sup> Mr M N M Falkner submission.

<sup>161</sup> NIIRTA submission.

## Deferred capex

### Detailed summary of submissions on deferred capex and other relevant information

1. We set out below, in respect of the 1999/2000 capex deferrals, first a summary of PNGL's initial submissions (including PNGL's responses to UR's pleadings), then UR's PNGL12 decision and response to PNGL's pleadings, then additional information we looked at, followed by comments from third parties.

### ***PNGL's detailed pleadings—deferred capex***

#### *Introduction*

2. PNGL said that it and UR agreed that the value of deferred capex within the 2006 TRV was £5.257 million.<sup>1</sup>
3. PNGL said that the 1999/2000 capex deferrals were only 2 per cent of the total delivered capital expenditure up to 2006 of over £290 million (in 2010 prices) and covered approximately 40 km of network out of a total construction build during this period of around 2,000 km.<sup>2</sup>
4. PNGL said that it was because of an accelerated build programme (in the first charge control period—PC01) that the 1999/2000 capex deferrals were deferred to a future date.<sup>3</sup>
5. PNGL said that in total UR removed £17.3 million from the 2012 opening TRV for the 1999/2000 capex deferrals (consisting of the deferrals set out in paragraph 2), plus a management fee of 20 per cent plus capitalized financing (returns) from the date of the original deferral to 2011 for both the original deferral and the management fee.<sup>4</sup>
6. PNGL said that the £17.3 million adjustment consisted of:
  - (a) projects that were not yet completed;
  - (b) projects that were not necessary any more (ie projects that would never be completed); and
  - (c) projects that were completed later than originally envisaged.<sup>5</sup>
7. PNGL said that for projects that were completed later than originally envisaged, UR (in the 2012 TRV adjustment) removed the capitalized financing (ie the return) and added an uplift of 20 per cent to this for the management fee saved by not completing the projects earlier.<sup>6</sup>

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<sup>1</sup> PNGL [statement of case](#), paragraph 2.48.

<sup>2</sup> PNGL statement of case, paragraph 2.48.

<sup>3</sup> PNGL statement of case, paragraph 2.22.

<sup>4</sup> PNGL statement of case, Annex 7, paragraph 2.

<sup>5</sup> PNGL statement of case, Annex 7, paragraph 3.

<sup>6</sup> PNGL statement of case, Annex 7, paragraph 3b.

8. PNGL said that for projects that were not necessary any more or were still to be completed, UR, as part of the 2012 TRV adjustment, removed the original amount including capitalized financing (ie the returns) and added an uplift of 20 per cent to both elements for the management fee saved by not completing the projects.<sup>7</sup>

### *PNGL's disagreement with UR*

9. PNGL said that it accepted that UR had previously signalled its intention to consider further the treatment of deferred capex included in the 2006 TRV.<sup>8</sup> However, PNGL said that UR's methodology for calculating the 2012 TRV adjustment for deferred capex was wrong, because:<sup>9</sup>
- (a) PNGL said that there was no separate provision in the 1996 licence for the treatment of deferred capex. It said that both UR and investors therefore knew that, under the terms of the 1996 licence, deferred capex would be treated in the same way as any other capex efficiency.<sup>10</sup> It also said that it was a feature of the 1996 licence that outperformance and deferral of capex spend should be treated in the same way as the actual investments in infrastructure.<sup>11</sup> See paragraphs 23 to 25.
  - (b) PNGL said that UR's 2012 TRV adjustment for deferred capex would transfer 100 per cent of the benefit of deferral to customers. PNGL said that this was inconsistent with the treatment of deferred capex that it could reasonably have expected given the terms of the 1996 licence, the 2006 'agreement', the precedent established by the PC03 determination and other public statements by UR.<sup>12</sup> PNGL also said that the magnitude of the adjustment for the 1999/2000 capex deferrals was entirely unexpected, since it was inconsistent with the 2006 'agreement'; the precedent established at PC03; and regulatory best practice.<sup>13</sup> See paragraphs 27 to 34.
  - (c) UR's proposal for deferred capex undermined any incentive on PNGL to optimize the timing of capital expenditure going forward,<sup>14</sup> and was not in line with regulatory precedent in Great Britain (which would not apply a 100 per cent clawback on an efficiency benefit).<sup>15</sup> See paragraphs 35 to 42.
  - (d) PNGL also disagreed with UR's 20 per cent uplift to the deferred capex calculations for the management fee. See paragraphs 43 to 50.
  - (e) PNGL's 1999/2000 capex deferrals were efficient. See paragraphs 51 to 70.
10. PNGL provided more detailed comments on these points which are set out further below. Before doing so, we set out some details on the specific projects that were subject to the 1999/2000 capex deferrals.

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<sup>7</sup> PNGL statement of case, Annex 7, paragraph 3.

<sup>8</sup> PNGL statement of case, paragraph 1.49 and Annex 7, paragraphs 10 & 11.

<sup>9</sup> PNGL statement of case, Annex 7, paragraph 4.

<sup>10</sup> PNGL statement of case, paragraph 3.13.

<sup>11</sup> PNGL response, paragraph 7.1a (footnote 67).

<sup>12</sup> Paragraphs 1.49, 1.49b, p4, Annex 9; paragraph 4b, 12, Annex 7, PNGL statement of case; paragraphs 10, 11, Annex 7, PNGL statement of case.

<sup>13</sup> PNGL response, paragraph 1.6b.

<sup>14</sup> PNGL statement of case, paragraphs 1.49 & 1.49b and Annex 7, paragraphs 10 & 11.

<sup>15</sup> PNGL statement of case, paragraph 4.41c.

### *Details on 1999/2000 capex deferral projects*

11. PNGL said that in 1998 it decided to accelerate its network build programme compared with the Mandatory Development Plan in its licence. However, it said that its strategy had always been based on the clearly-defined output objective in its licence—to meet and beat the Mandatory Development Plan in the licence and to maximize the customer base as quickly as possible to keep costs to individual customers down.
12. PNGL said that it built part of its network by inserting polyethylene (PE) pipes into the old towns' gas network (which consisted of cast iron pipes).<sup>16</sup> It said that although the insertion technique provided an initial lower-cost solution to get gas to areas quickly, it was always understood that this approach might not provide sufficient capacity to serve the expected longer-term needs of the customer base, and that reinforcement of some strategic legs may be necessary as customer penetrations increased over time. PNGL said that the original strategy was that the reinforcement would be undertaken at the same time as the original construction of that part of the network.<sup>17</sup> In other words, its initial build strategy was to build all networks that would ever be required in each area at one time ('build it and they will come' strategy), before moving on to the next area (PNGL said that this approach was based on the fact that it was essential to have network in the ground before premises could switch to natural gas). It said that the capital expenditure for PC01 was forecast on this basis, and in agreeing to this forecast, UR recognized that the plan reflected an efficient, best practice approach.<sup>18</sup>
13. PNGL said that whilst the 'build it and they will come' approach ensured a thorough and complete programme of construction, ensuring that gas was made available to all properties within a given area regardless of intention on the part of the customer to immediately connect, it did not cater for gas demands driven by expansion of the housing market in other parts of PNGL's licensed area. Consequently, the decision was made to accelerate the network build by switching to a 'build to meet customers' needs' approach to accelerate the wider roll-out of the network, which involved constructing mains at a faster rate than originally allowed for in the business plan in order to make gas available earlier than required by the original licence, and to lay gas mains after having obtained commitments from key target markets that they would make the switch to natural gas as and when it became available.<sup>19</sup> PNGL said that maximizing the number of connections would bring benefits for all customers through lower network charges in future control periods.<sup>20</sup>
14. PNGL said that the move to the 'build to meet customers' requirements' strategy was motivated both by the success of PNGL's commercial strategy and to take advantage of technical developments. It said that it managed to secure demand from different groups of customers (eg new-build sites) and therefore the need arose to meet this demand. PNGL said that the 1999/2000 capex deferrals were not associated with lower connections, but rather allowed PNGL to focus on connecting customers who were willing to take up gas in a wider area, faster than contemplated by the Mandatory Development Plan. For example, in the case of new builds, PNGL had to meet demand at the time of construction, or else developers may have utilized another fuel option (which would introduce switching costs for customers); and in the case of NIHE, its 12 district offices planned their own refurbishment programmes on

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<sup>16</sup> PNGL statement of case, Annex 3, paragraphs 7–10.

<sup>17</sup> PNGL statement of case, Annex 3, paragraph 11.

<sup>18</sup> PNGL statement of case, Annex 3, paragraphs 4, 5 & 15.

<sup>19</sup> PNGL statement of case, Annex 3, paragraphs 5, 12, 13 & 30.

<sup>20</sup> PNGL statement of case, Annex 3, paragraphs 5 & 18.

a rolling four-week basis, and the consequence of missing any connection would be that those customers would miss out on gas for around 15 years (at which time heating replacement would take place).

15. PNGL also said that due to the completion of the second phase of the transmission network and the construction of the Knocknagoney HPRS in 1998, a source of natural gas became available on the south side of PNGL's Licensed Area. This additionally enabled PNGL to adopt its new forward-looking strategy by allowing gas to be taken to new areas to meet customer needs.
16. It said that the accelerated roll-out strategy adopted in 1999 was factored in to the allowed costs determined by UR at the first price control review (PC01), and that this effectively endorsed PNGL's revised strategy.<sup>21</sup>
17. PNGL said that this led to a rapid expansion of the gas network well beyond the development targets contained within its licence, with approximately £20 million additional investment by the end of the first price control period compared with the development plan envisaged at the time of the 1996 licence (about 20 per cent of PNGL's network was constructed in 1999 alone, making gas available to over 55,000 properties constructing over 600 km of network).<sup>22</sup> Feeder mains were constructed on a prioritized basis to outlying areas of the network (with only the mains required to make gas immediately available being constructed at the time) ensuring that all new-build developments, NIHE and large industrial and commercial customers in these areas were supplied with natural gas, minimizing the loss of potential customers to alternative fuels.<sup>23</sup> In line with the design philosophy from the beginning of the project, maximum use was made of the existing old towns' gas system as a conduit for insertion.<sup>24</sup>
18. PNGL said that its revised strategy for the network construction, together with the acceleration of the roll-out programme, meant that there was great demand on a very limited number of resources within both PNGL and its construction contractor, McNicholas. PNGL said that this meant resources (and capital) were focused on delivering the identified key requirements of customers. At that time, PNGL was developing and training its own engineering staff, as was McNicholas, because it was not possible to recruit the required number of employees from Great Britain.
19. PNGL said that accordingly, network that was not an absolute necessity—such as network that provided increased security of supply or increased capacity in an area—was constructed only as and when the need arose.<sup>25</sup>
20. PNGL said that the 1999/2000 capex deferrals (and additional deferrals of feeder mains) were made because they related to security of supply and reinforcement projects, which were by their nature disproportionately more complex and time consuming and because priority was given to increasing connections. PNGL said that the level of deferrals was moderate (a total of approximately 40 km out of a total construction build during this period of approximately 2,000 km) and by no means undermined PNGL achieving the output targets contained in the Mandatory Development Plan. On the contrary, deferral of certain capex was critical to imple-

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<sup>21</sup> PNGL statement of case, Annex 3, paragraphs 5 & 18.

<sup>22</sup> PNGL statement of case, Annex 3, paragraphs 5 & 18.

<sup>23</sup> PNGL statement of case, Annex 3, paragraphs 5, 18, 19 & 31.

<sup>24</sup> PNGL statement of case, Annex 3, paragraph 32.

<sup>25</sup> PNGL statement of case, Annex 3, paragraphs 1, 6, 15, 20 & 32.

menting PNGL's network construction strategy and delivering a successful natural gas industry for Northern Ireland.<sup>26</sup>

21. PNGL said that many of the 1999/2000 capex deferral projects had been redesigned on the basis that the network that was now available would deliver a better long-term network solution to the benefit of customers. Such improvements included increased security of supply and the opportunity to extend the licensed area to new towns than would otherwise have been the case.

22. Whilst PNGL made more detailed comments on all of the 1999/2000 capex deferral projects, we summarize below only the comment on the four largest projects (using the names set out in UR's decision), which together accounted for more than 70 per cent of the 1999/2000 capex deferrals:

(a) *Bangor Reinforcement*. PNGL said that this area was initially supplied using the roll-down technique to lay new PE pipe inside the old towns' gas network. However, this pipe would not provide sufficient capacity for the whole of the Bangor area and a second pipe would be needed by 2020. It was this second pipe that was subject to the deferral. PNGL said that it would have been extremely costly (and disruptive to the public) to construct this second pipe.<sup>27</sup> PNGL said that this project would not be needed if the N'ards–Bangor IP and Newtownards 7bar projects went ahead.<sup>28</sup> PNGL later clarified that this project would be replaced by the combination of a revised N'ards–Bangor IP and Newtownards 7bar project. PNGL also said that its connection of a quarry at Craigtantlet via a newly-constructed 7-bar IP main provided an alternative solution to reinforce Bangor. It said that it received no additional allowance for the Craigtantlet project (but did so for all other 1999/2000 capex deferrals where alternative projects supported a deferral decision), which it completed at a cost of £1.5 million (25 per cent higher than the original allowance for Bangor Reinforcement). PNGL said that it decided to do this in the customer interest.

(b) *N'ards–Bangor IP and Newtownards 7bar*. The need of this project was now projected to be for 2023.<sup>29</sup>

(i) PNGL said that the N'ards–Bangor IP project was originally designed to connect the 7-bar IP networks that separately supplied Bangor and Newtownards. PNGL said that its analysis at the time revealed that there would be a greater benefit to customers if the Newtownards and Bangor 4-bar systems were connected via this route, because using 4-bar systems would enable small conurbations along the route of the pipeline to access gas (which would not be economical with a 7-bar pipeline). This benefited those additional customers who were able to access the gas network.

(ii) PNGL said that Newtownards 7bar project was initially delayed by a 12-month embargo due to the local Road Authority just having resurfaced the road. When the embargo was lifted, PNGL identified a better medium-term solution via the 7-bar pipeline at a quarry at Craigtantlet.

(c) *Bangor 250mm duplicate*. PNGL said that this was deferred as it was not immediately required to supply the Bangor area and also for resource rationing

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<sup>26</sup> PNGL statement of case, Annex 3, paragraphs 1, 6, 15, 20, 21 & 32.

<sup>27</sup> PNGL statement of case, Annex 3, paragraphs 36–40.

<sup>28</sup> PNGL statement of case, Annex 3, paragraph 45.

<sup>29</sup> PNGL statement of case, Annex 3, paragraphs 43–45.

reasons. It said that it would be required by 2021.<sup>30</sup> It also said that this project would have caused a significant amount of disruption to road users on the main A2 road and the local Road Authority discouraged PNGL from undertaking this work. PNGL redesigned this project and named it Bangor Dual 7 bar Main.

(d) *East Reinforcement.* PNGL said that this project would be extremely complex and would present some considerable engineering challenges. The project would be required by 2020.<sup>31</sup> PNGL said that the original reinforcement project was delayed as an alternative option was identified, which would provide the additional required capacity to Greater Belfast in the medium term.

#### *The provisions of the 1996 licence*

23. PNGL said that the 1996 licence did not distinguish between deferred capex and other outperformance. Since both represented efficient investment decisions, both were treated equivalently under the licence (which was that all capex and opex outperformance were to be retained by PNGL, with efficiencies being shared with customers through lower cost assumptions in future price control periods), meaning that PNGL had incentives to do both. In response to these incentives, PNGL had ensured that projects were carried out at the most appropriate time.
24. PNGL said that the 1996 licence did not distinguish avoiding inefficient capex from any other type of efficiency. However, there was no incentive under the 1996 licence for PNGL to defer expenditure indiscriminately, since the licence also provided a specific set of output measures which PNGL was required to deliver (as set out in the Mandatory Development Plan), as well as the incentive to meet the regulatory target for volumes within the price control.
25. PNGL said that the 1996 licence did not make any provisions for dealing with additional capex projects that were not included in the price control determination. All capex overspend within a price control period was at the risk of PNGL.
26. PNGL also said that the 1996 licence set the framework for the sharing of benefits between PNGL and customers until the 2006 'agreement', while UR's determinations established the expectations about how the deferred capex that had been identified as part of the 2006 'agreement' would be unwound over time.

#### *Inconsistency with 2006 'agreement' and PC03*

27. PNGL said that the issue of deferred capex was discussed both in the 2006 'agreement' and at the PC03 review. UR's decisions at those points established expectations as to the quantum of value associated with deferred capex, and a methodological precedent for the treatment of this value. However, contrary to good regulatory practice, UR's treatment of deferred capex in the 2012 TRV adjustment was entirely out of line with the expectations established at these points, without any indication to PNGL that these expectations would be contradicted until the publication of the August 2011 Consultation Paper.<sup>32</sup>
28. PNGL said that the 2006 'agreement' led to the inclusion of £5.3 million of deferred capex in the 2006 TRV.<sup>33</sup> It said that UR at the time stated that this amount 'will have

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<sup>30</sup> PNGL statement of case, Annex 3, paragraphs 46 & 47.

<sup>31</sup> PNGL statement of case, Annex 3, paragraphs 48–50.

<sup>32</sup> PNGL statement of case, paragraph 5.24; Annex 7, paragraph 4a.

<sup>33</sup> PNGL statement of case, Annex 7, paragraphs 6 & 7.

to be profiled over the forecast period for PCR 03 and netted out of forecast capex to avoid double counting'.<sup>34</sup> PNGL said that this statement created an expectation about the maximum value of deferred capex to which a regulatory mechanism might be applied at future price control reviews.<sup>35</sup>

29. PNGL said that whilst it was clear that the treatment of the value for deferred capex would be reconsidered at future reviews, this was with important limitations set by UR's treatment of other capex deferrals (ie deferred feeder and infill mains capex projects).<sup>36</sup> PNGL said that as part of PC03, UR established the methodology used for deferred feeder and infill mains capex projects (which were deferred in PC02), stating that whilst PNGL would still be required to deliver some of these projects, it would not provide a capex allowance during PC03 for these projects as they had already been funded in PC02, ie PNGL was still required to complete these projects, but no cost allowances were granted for the period 2007 to 2011.<sup>37</sup> The methodology involved subtracting the value of deferred feeder and infill capex from the corresponding PC03 allowed capital expenditure (ie netting deferred capex off future capex allowances).<sup>38</sup> PNGL said that no adjustment was made to the value of the 2006 TRV itself to account for this. Rather, in accordance with the expectations of PNGL, the 2006 TRV remained fixed in the 2006 'agreement' (ie it continued to include the allowance made for deferred feeder and infill mains capital projects), with the value to be depreciated fully over 40 years.<sup>39</sup>
30. PNGL said that UR, during the PC03 price control review, also referred to the 1999/2000 capex deferrals as:
- most of these projects have been planned for post PC03 and the activity/forecast cost associated with these works has been removed from the PNGL forecast revenue requirement [in PC03]. Consequently no revenue has been allowed going forward to take account of this activity and it will be up to PNGL 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.<sup>40</sup>
31. PNGL said that UR's indications at PC03 were therefore that if projects were no longer needed, UR would consider transferring the allowances to other projects by netting it off future capex allowances (ie PNGL was still required to complete these projects, but no additional cost allowances were granted).<sup>41</sup>
32. PNGL said that UR did not indicate that it would depart from this methodology in subsequent price control reviews (and make the 2012 TRV adjustment). PNGL said that UR's precedent for deferred capex was therefore consistent with the position that the value of the 2006 TRV was a fixed once and for all settlement. PNGL said that it did not follow from the statements made by UR in 2007, nor from PNGL's decision not to reject the third price control determination (PC03), that PNGL could reasonably have anticipated the 2012 TRV adjustment for deferred capex.<sup>42</sup> PNGL said that it

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<sup>34</sup> PNGL statement of case, Annex 7, paragraph 7.

<sup>35</sup> PNGL statement of case, Annex 7, paragraph 8.

<sup>36</sup> PNGL statement of case, paragraphs 4.13 & 2.56d.

<sup>37</sup> PNGL statement of case, Annex 7, paragraph 9.

<sup>38</sup> PNGL statement of case, paragraph 2.56d.

<sup>39</sup> PNGL statement of case, paragraph 2.56d.

<sup>40</sup> PNGL statement of case, Annex 7, paragraph 9.

<sup>41</sup> PNGL statement of case, Annex 7, paragraphs 10 & 11.

<sup>42</sup> PNGL response, paragraph 7.1(e)(ii).

certainly did not expect to have this value expropriated through an adjustment to the TRV.<sup>43</sup>

33. PNGL also said that it reasonably expected that having consulted and finally settled on a methodology for treatment of deferred capex (in PC03), this methodology would be applied in PNGL12. While clear that UR would look at deferred capex in PNGL12, there was never any discussion, nor any expectation, that the amount attributable to deferred capex should or would be removed from the TRV. Rather, there was every reason to believe that a methodology developed by the Authority and accepted by PNGL would be followed.<sup>44</sup>
34. PNGL said that UR's planned review of the 1999/2000 capex deferrals that UR announced at the PC03 determination was intended to focus on ascertaining whether or not the deferred projects were still needed and, if not, whether to use the allowed costs in PNGL's asset base for other purposes. UR's decision in PNGL12, by contrast, expanded the scope, the value, and the nature of the review of the 1999/2000 capex deferrals (compared with what was set out in the PC03 decision).

#### *Regulatory precedent and incentives*

35. PNGL said that UR's 2012 TRV adjustment transferred 100 per cent of the benefits of the deferral to customers.<sup>45</sup> It said that this was out of line with Great Britain regulatory precedent. This was because Great Britain precedent would not apply this adjustment retrospectively and would instead seek to harmonize incentives across all investment choices to avoid promoting distortionary, inefficient behaviour.<sup>46</sup>
36. PNGL said that UR's methodology for calculating the 2012 TRV adjustment was inconsistent with the principles of incentive regulation, and would undermine the incentive regime going forward, resulting in significantly worse outcomes for consumers in the future. This was because the 2012 TRV adjustment retrospectively removed the entire benefit from deferral from PNGL, even though this deferral was efficient (which risked establishing a precedent that PNGL would never be rewarded for deferring projects, and in so doing undermined entirely any incentive on PNGL to efficiently defer projects). PNGL said that in order to incentivize regulated companies to deliver efficiency savings (for example, delivering a project at a lower cost than planned or delaying projects without impacting outputs), the regulator needed to allow the regulated company to retain some of these savings. It was this reward which encouraged a company to seek ways to reduce costs, which ultimately benefited consumers through lower prices. PNGL said that doing otherwise would incentivize regulated companies always to meet their investment plans, even if better ways of delivering them were identified later, and PNGL would have no incentive to seek to optimize the timing of capex in a way that was beneficial to customers (PNGL said that this would be likely to lead to the construction of some assets before they were actually needed).<sup>47</sup>
37. PNGL said that the realization of the Government's objectives of making gas available to 70 per cent of the population of Northern Ireland would require a doubling of investment made in gas to date, and UR's 2012 TRV adjustment reduced incentives to invest efficiently during these further phases of expansion.

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<sup>43</sup> PNGL response, paragraphs 1.6b & 7.1(e)(ii).

<sup>44</sup> PNGL response, Annex 1, p32.

<sup>45</sup> PNGL statement of case, paragraph 5.22 and Annex 7, paragraph 2.

<sup>46</sup> PNGL statement of case, paragraphs 4.41c & 5.23.

<sup>47</sup> PNGL statement of case, Annex 7, paragraph 14.

38. PNGL also said that UR's treatment of deferred capex in the 2012 TRV adjustment was different from the rules applying to deferred capex in the 1996 licence. The 2012 TRV adjustment was therefore retrospective and changed, ex post, the incentives applying to PNGL in relation to deferred capex (in particular, considering that it was accepted that those projects were efficient at the point those projects were originally proposed by PNGL and were assessed by UR's consultants).<sup>48</sup> PNGL said that incentive-based regulation could not be effective and credible if all benefits to the company were removed ex post.<sup>49</sup> Such ex-post changes had the potential to undermine any incentive mechanism UR might wish to employ in future.<sup>50</sup> PNGL said that it made its decision to defer capex at the time in response to the incentive framework at the time.<sup>51</sup> It said that had it known at the time it made the deferral decisions that the treatment currently proposed would be applied, it would have been in its interest to continue with its existing construction strategy, instead of accelerating the network roll-out in 1999. This would have been to the detriment of customers.<sup>52</sup>
39. PNGL said that UR considered a similar proposal to the 2012 TRV adjustment for deferred capex during the PC02 review, but the proposal was withdrawn when PNGL explained that such a proposal would undermine PNGL's incentive to undertake efficient deferral.<sup>53</sup>
40. PNGL said that by removing the entire benefit of capex deferrals through a full adjustment of capitalized financing, any incentive for PNGL to time capital expenditure efficiently in future would be undermined and PNGL would be incentivized not to undertake efficient deferrals in the future, but to spend the allowances regardless. It also said that it would lose its incentive to be responsive to dynamic customer requirements.
41. PNGL noted that the incentives for capex deferrals applying from 2007 onwards were put in place at a time when most capex spend was complete for the first phase of the natural gas project in Northern Ireland, but that a higher-powered incentive may become appropriate again at future price controls, for example when replacement capex within the existing licensed area began to ramp up.
42. In response to UR's statement that its approach to the 1999/2000 capex deferrals was consistent with the CC's approach to the delay to expenditure at Heathrow Terminal 5 (see paragraph 96), PNGL said:
- (a) PNGL said that BAA's T5 investment deferrals (2002) were very different from PNGL's case. BAA's case related to delayed expenditure on one major project for which a specific adjustment to charges was made, where the cause of the delay was exogenous to the company (ie a failure to get planning permission in the expected timescales). The CC also stated that there was no presumption that lower expenditure due to capital efficiency would ever be treated in such a way. This was in recognition of the dynamic incentive properties of making such adjustments, which would effectively undermine incentives to ever seek efficient deferrals.<sup>54</sup> PNGL said that its 1999/2000 capex deferrals were the result of efficient investment decisions (ie they were made to allow the efficient and

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<sup>48</sup> PNGL statement of case, Annex 7, paragraphs 13b & 16.

<sup>49</sup> PNGL statement of case, Annex 7, paragraph 16.

<sup>50</sup> PNGL statement of case, Annex 7, paragraph 13b.

<sup>51</sup> PNGL statement of case, Annex 7, paragraph 13b.

<sup>52</sup> PNGL statement of case, Annex 7, paragraph 14.

<sup>53</sup> PNGL statement of case, Annex 7, paragraph 15.

<sup>54</sup> PNGL response, paragraph 6.2c.

effective construction of a new natural gas network in Northern Ireland), unlike the BAA delayed expenditure for T5.<sup>55</sup>

- (b) PNGL also said that the BAA case was not a case of a company looking at the optimal capital investment strategy and deciding that it needed to be revised for efficiency reasons, rather BAA deferred capital investment on T5 because it did not get the planning permission in the expected timescales. As noted by the CC itself in its 2002 decision, it would not expect such an approach to be used where underspend related to capital efficiencies. Indeed, both the CAA and the CC recognized the potential detrimental implications for investment incentives of correcting for 100 per cent of underspend, which is what UR was currently proposing for PNGL.<sup>56</sup>

#### *Treatment of management fee*

43. PNGL said that not only did UR remove the deferred capex, but it also removed UR's estimate of the management costs that were associated with deferral, which UR claimed were avoided as a result of that deferral.<sup>57</sup>
44. PNGL said that the individual assumptions on which the proposed adjustment in relation to the management fee was based were inconsistent with the historic treatment of the management fee.<sup>58</sup>
45. It said that the management fee was largely fixed as part of the McNicholas contract, and should be treated as such.<sup>59</sup> It said that UR recognized this in the PC03 final determination where it stated that 'it has been decided to disallow the management fee associated with these projects given PNGL's arguments that management fee is not directly linked to activity. Therefore the marginal nature of these projects should not incur any additional mgt fee.'<sup>60</sup>
46. PNGL said that UR estimated the management fee (ex post) as being 20 per cent for the purpose of attributing allowances for deferred capex projects between 1996 and 2006. PNGL said that this assumed that the management fee was marginally dependent on the number of projects PNGL undertook, or on the size of the capital programme.<sup>61</sup>
47. PNGL said that the ex-post estimate of the size of the management fee was initially used as an aid to benchmarking PNGL's capital costs against other organizations. It was used simply as a way of apportioning this cost across the capital programme, such that PNGL's cost could be accounted for on a comparable basis. This apportionment exercise in no way reflected the nature of the costs incurred, nor the way in which those costs were allowed.<sup>62</sup>
48. PNGL said that the deferred projects represented only a very small part of PNGL's overall capital programme undertaken in conjunction with McNicholas. PNGL said that it did not avoid 20 per cent of the value of the deferred projects as a result of

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<sup>55</sup> PNGL response, paragraph 6.2c.

<sup>56</sup> PNGL response, paragraph 4.6.

<sup>57</sup> PNGL statement of case, Annex 7, paragraph 2.

<sup>58</sup> PNGL statement of case, Annex 7, paragraph 5.

<sup>59</sup> PNGL statement of case, Annex 7, paragraph 20.

<sup>60</sup> PNGL statement of case, Annex 7, paragraph 21.

<sup>61</sup> PNGL statement of case, Annex 7, paragraph 18.

<sup>62</sup> PNGL statement of case, Annex 7, paragraph 19.

deferral, since the deferral of these projects did not result in a reduction in the overall capital programme sufficient to trigger such a reduction in the management fee.<sup>63</sup>

49. It said that the PC01 determination calculated the management fee as 51 per cent fixed and 49 per cent variable dependant on the forecast workload. The PC01 management fee estimate included all capex expenditure, including the management of the accelerated network build projects.
50. PNGL said that it did not agree with the variable/fixed methodology, but accepted the overall allowance it produced. It said that despite having deferred projects in 1999 and 2000, PNGL underperformed (ie overspent) against its management fee allowance for these years, indicating that the management fee did not flex marginally to the number or size of projects.

#### *Efficiency of deferral*

51. PNGL said that the 1996 licence did not distinguish between efficient outperformance and deferral and inefficient outperformance and deferral, and it was for this reason that an efficiency assessment now was not necessary or appropriate.
52. PNGL said that any attempt to try to retake decisions whether it would have been inefficient to build certain projects, long after the event and with the benefit of hindsight and after UR (with the support of its consultants) must have taken the view, in line with its statutory duties, that these projects were necessary and efficient to build at the time, would be unreliable and inappropriate.
53. PNGL said that it was reasonable for a regulated company to expect that the understood ex-ante incentive framework setting levels of efficiency on a prospective basis would apply to it, in line with good regulatory practice, rather than ex-post changes being made that judged efficiency with the benefit of hindsight.
54. PNGL said that should an efficiency test be performed, then the following criteria should apply:
  - (a) whether regulatory outputs had been delivered; and
  - (b) whether the underspend was material and therefore required a detailed investigation.
55. PNGL said that the 1999/2000 capex deferrals resulting from the strategic shift in 1999 on part of PNGL in its construction strategy represented efficient investment decisions, because PNGL continued to meet all its output targets and because the accelerated roll-out strategy focused resources on construction that would increase connections earlier than anticipated, and thereby reduce unit costs, to the direct benefit of customers.<sup>64</sup>
56. PNGL said that at the time of the 1999 submission (March 1999), it could not have foreseen that it would become efficient to make the deferrals later on in the year.
57. It said that when deferrals were efficient, it was legitimate that deferrals were treated like any other outperformance, with the benefit being shared between shareholders and customers according to the established incentive regime under which the com-

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<sup>63</sup> PNGL statement of case, Annex 7, paragraph 22.

<sup>64</sup> PNGL statement of case, paragraph 5.17 and Annex 3, paragraph 6.

pany operated. PNGL said that under the RIIO framework, Ofgem had reiterated that, if a company underspent on capex relative to its allowances, then it could benefit from that underspend as long as outputs were delivered. PNGL said that the CC in 1997 also recognized that outputs were important for determining whether the deferral of capital expenditure was efficient (and not whether the envisaged inputs in terms of capital expenditure had been spent).

58. PNGL said that the deferrals were efficient and in the best interest of customers and that it was never asked for evidence demonstrating the efficiency of deferrals that occurred at PC01 and PC02.<sup>65</sup>
59. It said that the 1999/2000 capex deferral projects were not deferred because they were inefficient at the time they were first planned. At the time it submitted its March 1999 PC01 forecasts, it had no reason to believe that it should not complete the projects that were subsequently deferred. At the point of planning, those projects were carefully assessed by PNGL and proposed only where they were considered both necessary and efficient. The 1999 submission was based on a fundamental analysis of each of the specific projects to assess, first, whether they were still required; and second, whether the proposed solution was the most appropriate based on information available at that time. It determined following this review that the deferred projects would still be built in line with the PC01 forecasts. It said that this was also consistent with the switch in strategy to accelerate the wider roll-out.
60. PNGL said that its initial 'build it and they will come' construction strategy was considered to be the most efficient strategy at the time. This strategy was adopted in the early years of the construction process at a time when there was no natural gas in Northern Ireland. In line with the Mandatory Development Plan, PNGL focused on developing the network in the areas in the north of PNGL's Licensed Area via the Torytown High Pressure Reduction System (HPRS). Starting from there, it aimed to expand into one area at a time. It said that as no reinforcements were planned in the early period of its network rollout, all networks that were constructed at that time were needed to enable customers to connect to natural gas. All costs of network construction during this period were therefore efficiently incurred.
61. PNGL said that the 1999/2000 capex deferral projects were also vetted carefully at the time by UR's consultants who reviewed, analysed and challenged the projects and efficiencies delivered. PNGL said that UR's consultants confirmed the efficiency of the 1999/2000 capex deferral projects following rigorous review and challenge of the projects' costs.
62. PNGL said that its deferrals were efficient and this was confirmed by UR's consultants and was accepted over three price controls by UR. PNGL said that the efficiencies achieved at PC01 were reviewed by UR and its consultants as part of the PC02 price control review process. The efficiencies achieved at PC02 were similarly reviewed at PC03. PNGL said that the PC02 and PC03 determination notices and consultants' reports demonstrated clearly that PNGL's historic cost performance against regulatory allowances had been scrutinized closely.
63. It said that the assessment that projects that were the subject of the 1999/2000 capex deferrals were not needed, and that certain of those projects may still not be needed today, could be reached only later in the price control period after PNGL had learned from its experience of undertaking the accelerated programme and the related projects (for example, the specific innovations PNGL had delivered) and had

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<sup>65</sup> PNGL statement of case, Annex 3, paragraph 3.

assessed any capacity constraints arising out of customer demand, which allowed it to optimize the timing of capital spend.

64. PNGL said that its comment that ‘the roll-out strategy imposed some strain on the resources of PNGL and its contractor, McNicholas’ should not be interpreted as PNGL being capacity constrained. PNGL said that it had demonstrated in this period that it could significantly increase its construction activity (in 1999 about 600 km was constructed): if PNGL had decided that it was in the interest of consumers to construct the deferred projects at this time, then it would have been capable of undertaking the necessary construction. PNGL was not forced to defer capex projects by capacity constraints. However, it later said that the 1999/2000 deferrals allowed it to focus its resource on delivering gas to customers at the right times.
65. In response to UR’s statement that it ‘is difficult to understand how deferring works because they were unnecessary, and/or because PNGL had insufficient resources to deliver the capex outputs for which it had requested allowances, can constitute a form of efficiency saving’, PNGL said that it had always delivered against the output targets set in its licence. Deferring certain projects until the need for construction arose, and prioritizing resources to deliver connections and to maximize the utilization of the existing infrastructure, was exactly the type of efficiency that good economic regulation should and did incentivize. A core part of the regulatory incentive regime should be to encourage the company to optimize the timing of expenditure to benefit customers, rather than simply spending according to the plan.<sup>66</sup>
66. PNGL also said that its business plan was a high-level business plan rather than a detailed one, akin to a strategy. Actual network build decisions were done with a planning horizon of one to three months. Its overall strategic decision was clear and guided by the output objective in the licence, and its plan was responsive to customer requirements and aimed at maximizing customer connections. It did not therefore produce detailed week-by-week, street-by-street network development plans months or years in advance as UR might have wished. It would have been inefficient to produce and follow such predetermined plans, as this would not have allowed PNGL to react to customer demand for connections which arrived with a much shorter lead time.
67. PNGL said that in 1999 it only deferred 30 km of capex out of a total of 600 km, which was equivalent to two weeks’ work. It said customers benefited from these deferrals as they allowed alternative pipes to be laid that allowed more customer connections.
68. It said that the reason UR did not adjust the 2012 TRV for feeder and infill deferred capex was because their deferral never prevented PNGL from achieving its connections targets, and the same was true for the 1999/2000 capex deferrals (which related to bulk projects and were therefore even less related to connections than infill and feeder deferred capex).
69. PNGL provided examples of how customers had benefited from the 1999/2000 capex deferrals:
  - (a) *Bangor Reinforcement*. In 2003, PNGL built an alternative pipeline to connect a quarry at Craigtantlet (for £1.5 million<sup>67</sup>) without further allowances being granted for this alternative pipeline (this customer generated £0.1 million revenue a year, using 0.4 million therms a year).

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<sup>66</sup> PNGL response, Annex 1, p31.

<sup>67</sup> See paragraph 22(a).

(b) *East Reinforcement*. By not completing the East Belfast reinforcement, but instead undertaking the alternative medium-term reinforcement from the North–South transmission pipeline, PNGL was able to supply a large customer in the Lisburn area (Contour Global) who was using around 4 million therms a year and contributed around £1 million of distribution income. This alternative project also supplied additional capacity and security to the Greater Belfast area as a whole. If PNGL had proceeded with the East Belfast reinforcement, the additional reinforcement from the North–South transmission pipeline would still have been required to service Contour Global. PNGL’s decision also opened up the possibility of extending gas to other areas outside PNGL’s existing Licensed Area (East Down) which had been presented to UR and was under consideration by DETI.

70. PNGL also said that because UR, in its determinations, set explicit output targets, the efficiency of deferrals (and of underspend generally) should be judged by reference to whether these output targets were achieved. This was supported by the MMC decision with regard to NIE (1997). However, PNGL also said that the MMC ultimately allowed a partial adjustment for underspend because there were no output targets set and due to the scale of the underspend (two-thirds of the projected capex over that period). PNGL said that neither of these difficulties applied to PNGL: there were clear output targets in PNGL’s licence; and the scale of the deferral was small (approximately 40 km out of a total construction build of approximately 2,000 km during PC01 or two weeks’ work in 1999). Since PNGL had met and beaten the output targets it was set, it was not relevant to look back to the inputs or the means by which those outputs were achieved.

#### *Symmetry of the treatment of deferred capex and unforeseen capex*

71. PNGL said, in response to UR’s statement that its treatment of deferred capex was symmetric with its treatment of additional capex allowances, that it had every reason to expect that the 1999/2000 capex deferrals would be treated in the same way as in PC03 (ie no further allowances would be made for the deferred projects or it would be required to apply the allowances to alternative projects in PNGL12) and that it had no reason to suspect that UR would now depart from that methodology.<sup>68</sup>
72. PNGL also said that UR’s argument about symmetry was misplaced because no unexpected capex was retrospectively allowed as additional allowances at PC01 and PC02 (at which time the relevant deferrals occurred).
73. PNGL said in respect of UR’s statement that UR’s treatment of PAYG meters was symmetric to the treatment of the 1999/2000 capex deferrals that PNGL only installed prepayment meters in line with customer demand. Customers were used to paying for coal on a weekly basis and there was demand for the same payment method to be available for gas. It was incorrect to imply that PNGL was not permitted to install more than 13 per cent of meters as prepayment. Conditions 2.6.1 and 2.6.2 of the original 1996 licence explicitly envisaged that PNGL may be asked by gas suppliers to install more than 13 per cent of meters as prepayment and provided that, in this scenario, it could charge for those extra meters in accordance with the principles and methodologies which UR had approved. However, UR only determined this methodology at the point it produced the licence modification that allowed the level of prepayment meters to increase to the level of customer demand. PNGL said that the

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<sup>68</sup> PNGL response, Annex 1, pp31&32.

attempt to draw an analogy to the treatment of deferred capex did not hold, and therefore this example did not support UR's position.<sup>69</sup>

### *Suitability of the substitution method*

74. PNGL said that there was a sufficient number of alternative projects against which UR could have offset the 1999/2000 capex deferrals. PNGL said that since the 2006 'agreement' was concluded, a total of £77 million of further capex had been determined by UR (compared with a value of £5.3 million for deferred capex).
75. PNGL said that UR's usual treatment for deferred capex was to net the activity levels off the total capex forecasts in the subsequent charge control period. This had the effect that only additional capex received an allowance. The resulting allowances, net of deferrals, were then multiplied by unit costs allowed for the corresponding price control in order to set the £ allowances for that period.
76. PNGL said that its licence did not require it to seek permission to substitute projects. This was because UR's price control determination set the total capex figure for the price control period and not on a project by project basis, and PNGL therefore had discretion as to how to spend that money so long as it met the targets set out in its licence.

### *Management fee*

77. PNGL said that the total allowance for management fee over PC01 amounted to 11 per cent of forecast capex. On this basis, if the variable element of the management fee was 49 per cent of this allowance, the variable component of management fee amounted to 5.5 per cent of the total distribution capex allowances during PC01.
78. PNGL said that in PC02, UR used a percentage to determine an allowance for the management fee that was fixed at an absolute level. PNGL said that it accepted this methodology for determining allowances on the basis that the overall allowances it produced were acceptable.
79. PNGL said that the retrospective mechanism in PC02 included an adjustment for the management fee and capitalized financing.
80. It said that in PC03 the management fee was a fixed allowance, which was retrospectively adjusted based on the actual number of connections constructed.
81. PNGL said that from 2007 onwards any large load projects which were included in the determination but did not go ahead would be removed from the asset base. This mechanism foresaw adjustments for capitalized financing, but not for the management fee. Infill and feeder mains now formed part of the retrospective mechanism. Allowances for this expenditure were therefore adjusted ex post to reflect actual properties passed. This adjustment therefore removed any financing benefit PNGL would receive from deferral. There was no associated ex-post adjustment to PNGL's management fee. PNGL said that the retrospective capex adjustments relating to the number of connections achieved (ie service and meter costs) did, however, include a component for management fee.

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<sup>69</sup> PNGL response, Annex 1, p43.

82. PNGL said that the treatment of deferred capex from 2007 onwards was not equivalent to UR's proposed treatment of the 1999/2000 capex deferrals in the 2012 TRV adjustment as it did not include an adjustment for the management fee.
83. PNGL said that it did overspend on its allowance for management fee in 1999 and 2000. This was due to a challenging management fee allowance that was accepted by PNGL as part of the overall PC01 determination and because the management fee incurred did not vary as a result of the capex deferrals. The scale of deferrals was small in relation to the overall capex plan in 1999 and 2000, meaning that the reduced network build effectively had no impact on the management fee, which was largely a fixed cost. In addition, management resource increased in this period to deal with an increase in civil disturbances (there were a number of major disturbances throughout Northern Ireland over a period of years related to issues such as the Drumcree dispute). These disturbances meant that additional supervision was required both during the day and out of hours to minimize interference with construction operations, and that additional security measures were required at store facilities.

### ***UR's PNGL12 decision and response to PNGL's pleadings—deferred capex***

#### *Introduction*

84. UR said that as part of the 2012 price control exercise, PNGL submitted updated information on the 1999/2000 capex deferrals. UR said that its analysis of this information indicated that PNGL was originally remunerated for these projects in 1999 or 2000, by way of an addition to its asset base. All the projects were deferred from their original date and were now either: no longer required; completed; still to be completed; or substituted for other projects.<sup>70</sup> As a result, PNGL's asset base had increased by more than it would have otherwise if capex was included only at the time of actual spend.<sup>71</sup>
85. UR said that its analysis further indicated that PNGL had benefited from the early receipt of allowances into its asset base versus when the work actually took place. The make-up of the gain varied depending on the status of the project, namely: for projects no longer required, PNGL had received an allowance and had been earning a return on that allowance for investments that it had never made; for projects deferred but subsequently completed, PNGL received a return on the allowance for a number of years before the projects were actually completed; for projects still to be completed, PNGL already had the allowance in its asset base and had been earning a return on this allowance before the projects were completed.<sup>72,73</sup> UR said it concluded that the PNGL asset base had been unduly inflated as a result;<sup>74</sup> and that the company should not retain the benefit of a failure to deliver assets or the delivery of assets later than originally scheduled;<sup>75</sup> and that gas customers should not have to pay (until 2046) for assets before they were built.<sup>76</sup>

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<sup>70</sup> UR [PNGL12 determination](#), paragraph 7.40.

<sup>71</sup> UR [PNGL12 determination](#), paragraph 7.38.

<sup>72</sup> UR [PNGL12 determination](#), paragraph 7.41.

<sup>73</sup> UR said that for projects no longer required but that had been substituted for other projects, there had been no obvious benefit to PNGL. UR had therefore not made any adjustment to the 2012 opening TRV for such projects (see paragraph 7.41, UR [PNGL12 determination](#)).

<sup>74</sup> UR [PNGL12 determination](#), paragraph 7.42.

<sup>75</sup> UR [initial submission](#), paragraph 3.16.

<sup>76</sup> UR [PNGL12 determination](#), paragraph 7.38; UR [initial submission](#), paragraph 3.46.

86. UR said that its plan to review the treatment of the 1999/2000 capex deferrals was identified and highlighted at the time of developing PC03. It said that in its final determination for PC03, UR stated:<sup>77</sup>

The Utility Regulator wishes to consider the appropriateness of deferred capex (**4/7 bar and Governors**) that is planned for future construction, and will review the planned activity to ascertain when/if it will be carried out and if it would be in the customer interest to use the 'deferred' cash within the asset base for other construction activities. This analysis will form one of the reviews to be conducted during PC03.<sup>78</sup>

87. UR said that it made a deduction of £17.3 million to the 2012 opening TRV for the 1999/2000 capex deferrals. This figure represented the removal of any return earned prior to a project being completed, and in addition to that the original allowance that entered the asset base if the project was not yet completed.<sup>79,80</sup>
88. Table 1 shows the composition of the £17.3 million 2012 TRV adjustment for the 1999/2000 capex deferrals.<sup>81</sup>

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<sup>77</sup> UR PNG12 determination, paragraph 7.39.

<sup>78</sup> See also UR PNG12 determination, Appendix 5, paragraph 10:

During the PC03 price control review PNG advised that all deferred capex contained within its asset base will eventually be constructed. The Utility Regulator removed such deferred activity from PNG's future forecasts in setting its determination for PC03. The determination also stated that the Utility Regulator wished to consider the appropriateness of deferred capex (4/7bar and governors) planned for future construction, and would review the planned activity to ascertain when/if it will be carried out and if it would be in the customers interests to use the 'deferred' cash within the asset base for other construction activities. It is anticipated that this analysis will be considered as part of PNG12.

<sup>79</sup> UR PNG12 determination, paragraphs 7.38, 7.43 & 7.44 and Appendix 4, p93.

<sup>80</sup> UR clarified that for projects still to be completed, PNG12 could request the monies again and, if granted, these would re-enter the asset base in future price controls. Allowances for such projects had been included as part of UR's PNG12 determination.

<sup>81</sup> UR PNG12 determination, Annex 4.

TABLE 1 UR's information set which formed the basis for the 1999/2000 capex deferral adjustment in the 2012 TRV

Project name	Project status	Revised date of completion	Treatment	All monies in £2010			Total
				Original allowance	Management fee @ 20%	Return to end 2011	
O'Neill Road	No longer required	N/A	Remove capex + return	275,556	55,111	443,816	774,484
Legoneil MPRS	Done	2010	Remove surplus return	39,365	7,873	59,859	59,859
Botanic Gardens MPRS	Done	2007	Remove surplus return	32,804	6,561	47,466	47,466
Carrick MPRS	To be done	2010	Assume will be done, remove surplus return	32,804	6,561	57,720	57,720
Donegall Road	Done	2008	Remove surplus return	183,704	36,741	242,464	242,464
Dee Street extension	Done	2008	Remove surplus return	98,413	19,683	129,892	129,892
Duncrue backup	Done	2010	Remove surplus return	196,826	39,365	299,297	299,297
Duncrue IPRS	To be done	2014	Remove capex + return	39,365	7,873	72,807	120,045
Upper Road Carrick	Done	2009	Remove surplus return	196,826	39,365	327,276	327,276
Upper Road G'Island	To be done	2012	Remove capex + return	131,217	26,243	242,689	400,150
Bangor & N'ards MPRS	To be done	2015	Remove capex + return	275,556	55,111	509,647	840,315
Albetbridge MPRS	To be done	2015	Remove capex + return	32,804	6,561	60,672	100,037
Inverary Avenue IPRS	No longer required	N/A	No action required since allowances have been used for Harbour reinforcement works	N/A	N/A	N/A	N/A
Lisburn Road MPRS	No longer required	N/A		N/A	N/A	N/A	N/A
Shankhill Road MPRS	To be done	2014	Remove capex + return	32,804	6,561	60,672	100,037
Stream 3 Lambeg	To be done	2011	Assume will be done, remove surplus return	26,243	5,249	48,538	48,538
Stream 3 F'William	To be done	2015	Remove capex + return	26,243	5,249	48,538	80,030
N'ards-Bangor IP	To be done	2020	Remove capex + return	1,279,368	255,874	2,060,575	3,595,816
Newtownards 7bar	To be done	2020	Remove capex + return	393,652	78,730	634,023	1,106,405
Bangor 250mm duplicate	To be done	2021	Remove capex + return	787,303	157,461	1,268,046	2,212,810
East Reinforcement	To be done	2022	Remove capex + return	1,180,955	236,191	1,902,069	3,319,215
Bangor Reinforcement	To be done	2023	Remove capex + return	1,197,489	239,498	1,928,697	3,365,684
Cutts IPRS	To be done	2016	Remove capex + return	39,365	7,873	72,807	120,045
Total				<b>6,498,662</b>	<b>1,299,734</b>	<b>10,517,572</b>	<b>17,347,587</b>

Source: UR.

89. UR said that it did not agree with PNGL that its 2012 decision covered a wider or broader set of deferred capex projects than that determined in the 2007 determination. At the time of establishing the 2006 TRV, UR had not yet undertaken a review of deferred capex and therefore had not made any determination on the treatment of deferred capex.
90. UR said that one of the key tenets of economic regulation was to mimic competitive outcomes. Its 2012 TRV adjustment for deferred capex was designed to reflect the position of competitive markets, where companies would not be able to recover money for investments that were never made since if they tried to do so, competitors would undercut them and they would lose market share.<sup>82</sup>
91. UR said that PNGL disagreed with the way UR calculated the 2012 TRV adjustment for deferred capex, but that:<sup>83</sup>
- (a) UR had always said that deferred capex would be subject to a review during the control period that followed the 2006 discussions and subsequent 2007 licence modifications (ie during PC03). UR said that PNGL's own response acknowledged this to be the case.<sup>84</sup>
  - (b) UR did not agree that it made any statements that committed it to any particular approach to deal with deferred capex.<sup>85</sup>
  - (c) UR's approach was equivalent, in principle, to PNGL's expectations since UR could now substitute the deferred cash amount in the asset base against total future capex which would produce the same revenues for PNGL (ie UR's proposed treatment of deferred capex was equivalent to netting deferred capex off against future capex<sup>86</sup>).<sup>87</sup>
  - (d) This treatment was consistent with how some other regulators had treated deferred capex in the past (and was therefore consistent with best practice).<sup>88</sup>
  - (e) This treatment was symmetrical with how UR had treated additional unforeseen capex that UR considered was necessary for PNGL to incur, for example through 'logging up' and 'logging down' in PC03.<sup>89</sup>
92. UR said that PNGL's approach would treat investments and unspent allowances in the same way. However, they were different in that unspent allowances represented money that was not spent whereas investments were money that was spent and there could therefore be no basis for treating them as the equivalent.<sup>90</sup>

### *The provisions of the 1996 licence*

93. UR said that under the 1996 licence, it was apparent from the formulae that charges were based solely on allowed expenditures, ie at no point was the concept of actual expenditures introduced (although forecasts were subject to periodic review by the

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<sup>82</sup> PNGL12 determination, paragraph 7.38 and Appendix 4, p93. UR initial submission, paragraph 3.46.

<sup>83</sup> PNGL12 determination, paragraphs 7.48 & 7.49.

<sup>84</sup> PNGL12 determination, paragraph 7.48.

<sup>85</sup> PNGL12 determination, paragraph 7.50.

<sup>86</sup> UR [supplementary submission](#), paragraph 2.41.

<sup>87</sup> UR PNGL12 determination, paragraph 7.52.

<sup>88</sup> UR [initial submission](#), paragraphs 3.17 & 3.46; UR PNGL12 determination, paragraph 7.3; UR [comprehensive response to comments on draft proposal \(2012 determination\)](#), p7.

<sup>89</sup> Paragraph 3.17, UR initial submission; paragraph 7.3, PNGL12 determination; p7, UR's comprehensive response to comments on draft proposal (2012 determination).

<sup>90</sup> UR [supplementary submission](#), paragraphs 2.77 & 2.78.

regulator, the effect of the licence was that PNGL would be able to recover the difference between the allowed and out-turn costs for any given regulatory control period). It was therefore a correct observation that under the 1996 licence, all past out-performance was fully retained by the regulated company.

94. UR said that deferred capex was not explicitly dealt with in the 1996 licence. Issues of both deferred capex and unforeseen capex had been dealt with through the price controls.
95. UR said that there was no provision for the treatment of inefficient capex in the licence.

### *Regulatory precedent and incentives*

96. UR said that its approach to the 1999/2000 capex deferrals was consistent with the CC's approach to the delay to expenditure at Heathrow Terminal 5.<sup>91</sup>
97. UR said that PNGL had accepted the approach for deferred capex from 2007 onwards and had not indicated that this would create disincentives for the company to undertake efficient deferrals. It also said that PNGL had argued for this approach in PC02.
98. It said that if it was considered that a project was not deferred for efficiency reasons, it was not clear why financing charges for such projects should be retained by the regulated company and how this would create incentives for efficiency.
99. UR said that retaining financing charges could potentially create the 'wrong' incentives for the regulated company, such as postponing projects even though they might be needed and/or presenting to the regulator 'inflated' capital expenditure programmes that were subsequently cancelled or postponed.

### *Efficiency of deferral*

100. UR said that PNGL's 'build it and they will come' strategy was not efficient as optimal network development required that it be constructed as and when required. UR said that it would not be efficient to build pipelines that were not required for over 20 years.<sup>92</sup>
101. UR said that the 1999/2000 capex deferrals were not deferred for reasons of efficiency. It said that PNGL should not be rewarded for the fact that it did not have the resources to carry out the capex it requested.<sup>93</sup>
102. UR said that it was for the reasons set out in paragraphs 100 and 101 that the 1999/2000 capex deferrals did not benefit consumers.
103. UR said that the *accelerated* network build programme was PNGL's response to the low customer connections and volumes in the early period and was intended to make gas available to a *greater* proportion of the licence area at an earlier stage than previously planned. UR said that it understood that this expenditure was additional to (rather than a substitute for) existing capital works. At the time of the PC01 decision, UR was not in a position to discern that an element of PNGL's capital expenditure

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<sup>91</sup> UR supplementary submission, paragraph 2.39; UR initial submission, paragraph 3.17, footnote 6.

<sup>92</sup> UR supplementary submission, paragraph 2.38.

<sup>93</sup> UR supplementary submission, paragraph 2.38.

programme would be postponed and subsequently be characterized as 'deferred capex'. A significant amount of reliance would have been put on the fact that PNGL provided the capex numbers in the middle of 1999 and had a licence obligation to provide best estimates.

104. UR also said that PNGL should have known before UR's PC01 decision in September 1999 that it would not execute the large capex projects as envisaged in the 1999 submission. UR said that, for example, the big 7-bar projects would require a lot of traffic management and preparation. It also said that PNGL only spent about 5 per cent of its allowance on 7-bar projects in 1999.
105. UR said that it would have been inefficient for PNGL to build the 1999/2000 capex deferral projects at the time envisaged in the 1999 submission as they were not needed at the time.
106. UR said that PNGL said that it was going to build all the projects financed by the 1999 and 2000 capex allowances, but it now turned out that a lot of this capex was reinforcement which was not needed at the time because of the lower-than-expected demand.
107. UR said that it performed little detailed scrutiny on a year-by-year basis on what PNGL was doing and why it was doing it before 2009.
108. It said that it had (in the PC01 determination) focused on encouraging PNGL to adopt modern and best practice network planning and management systems and procedures, which it found to be wanting, and had called into question the soundness of PNGL's network development plan.
109. UR said that in PC01 it expressed concern about the lack of transparency and robust justification for PNGL's proposed accelerated network build programme. The associated capital expenditure was allowed in the end, but on the condition that PNGL would adopt a series of capex-related recommendations, including:
  - (a) the development of an explicit (and written) strategy for the roll-out of the gas distribution system with medium- and long-term forecasts based on detailed market surveys and experience to date—this was in recognition of the fact that the distribution system was being developed on a reactive basis, as evidenced (among other things) by the lack of any linkages between PNGL's June 1997 and March 1999 submissions;
  - (b) the establishment of a formal outputs and investment reporting system that would permit the active and effective monitoring of outputs, activities and expenditure and thereby contribute to the achievement of capital efficiency savings; and
  - (c) the preparation of a sound and comprehensive asset management plan for the gas distribution network, which was completely lacking.
110. UR said that some of these issues continued in PNGL12 with PNGL questioning whether it should adopt a PAS55 asset management system in line with Great Britain norms, arguing that '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'.
111. UR said that no price control ever used the mandatory development plan as a basis for setting allowances.

112. It said that the following criteria should apply for the assessment of the efficiency of all outperformance (including deferred capex):
- (a) Cost savings that arose because activities were not undertaken were not efficient.
  - (b) Efficient outperformance should not consist of misrepresented, unrealistic or otherwise in appropriate initial cost targets.
  - (c) The efficiencies/deferrals must lie within management control, ie they must result from deliberate decisions/actions.
  - (d) The efficiencies/deferrals must be legitimately earned, ie no benefit from deferrals should be allowed where equivalent funding was provided for alternative projects, where there was obvious double counting, where projects were obviously not needed or where it would have been clearly inefficient to build the projects in the first place.
  - (e) The regulated company must meet the criteria required in the regulatory framework in order to earn the reward envisaged in the regulatory framework; and efficiencies should not result from short cuts that reduced standards to consumers.
  - (f) Efficiencies should benefit consumers in such a way that they could be repeated over time and therefore lower the cost of provision in future, rather than simply resulting from postponing or cancelling activities that were not necessary or did not deliver any additional consumer benefit.
  - (g) Efficiencies should be similar to efficiencies that would be rewarded in a competitive market—in economic theory terms, this meant that for ‘outperformance’ to be treated as such, it should improve the technical/productive efficiency of the regulated company or reduce ‘X-inefficiency’.
  - (h) The onus should be on the company to substantiate its claim of efficiencies.

#### *Symmetry of the treatment of deferred capex and unforeseen capex*

113. UR said that consumers should not have to pay fully for projects that were originally not foreseen but were needed (and therefore retrospectively added to the TRV) and also pay for projects (ie to leave projects on the TRV) that were originally foreseen but not needed (ie the 1999/2000 capex deferrals).
114. UR said that the 1996 licence did not contain any provisions for capital expenditure incurred above that allowed as part of the price control determinations. However, there were some examples of capex and opex items where allowances had been made outside the price control mechanism. It said that for unforeseen capex it allowed additions to the TRV going back many years, and provided the following examples:<sup>94</sup>
- (a) In the case of prepayment meters, PNGL in PC02 exceeded the limit of the more expensive prepayment meters that it installed by £2.3 million (2006 prices). In spite of this, UR decided in 2009/10 to retrospectively allow all the additional costs that could have otherwise been disallowed into the asset base. This

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<sup>94</sup> UR supplementary submission, paragraph 2.39; UR initial submission, paragraph 3.17, footnote 6.

demonstrated that where there were benefits for consumers, UR had rewarded PNGL retrospectively. Where there were no benefits, UR removed such items, ie deferred capex.<sup>95</sup>

- (b) Over the course of PC03, to facilitate unforeseen connections and network reinforcement, UR agreed to increase PNGL's allowances, and these were retrospectively added to its asset base at the time of spend as part of PNGL12.<sup>96</sup>
- (c) The PC02 determination retrospectively included expenditure on market incentive costs incurred during the first price control period equal to £1.1 million (in 1996 prices).
- (d) The Lisburn tie-in was a transmission connection to the South–North (transmission) pipeline in 2006 and was added to the transmission TRV outside the licence conditions and price control determination.

115. UR said that as part of its review it could not establish a very good reason why it should not treat the 1999/2000 deferred capex symmetrically with unforeseen capex. It said that it did not identify any efficiency in the 1999/2000 deferrals.

#### *Suitability of the substitution method*

116. UR said that it did not commit itself to the substitution method (ie to net the deferred capex allowances off future capex allowances—see also paragraphs 29 and 31).
117. UR acknowledged that the substitution method was suggested as a possibility for the treatment of the 1999/2000 capex deferrals (ie to substitute the deferred capex projects for other capex projects). However, after more detailed consideration it did not believe there were enough sizeable projects left in the PNGL licence area for substitution to provide a realistic solution (UR said that the amount of the 1999/2000 capex deferrals was much larger than ongoing capex). It found it highly unlikely that PNGL would agree to develop its network outside its licence area with no additional allowances granted for such extensions. UR said, therefore, that it decided it would be more practical and realistic to remove the amount from the 2012 TRV.<sup>97</sup> However, it later said that the substitution method could have been applied with equivalent financial effect.

#### *Management fee*

118. UR said that the 20 per cent assumption for the 1999/2000 deferrals was based on what the actual management fee had been for PNGL over the years and UR's treatment of it as all variable in the retrospective mechanism.
119. UR said that PNGL had historically reported the management fee as a separate cost line with this fee encompassing the costs incurred by its third-party contractor (McNicholas) and PNGL itself in managing construction activity. Most GDNs had this cost embedded within their unit rates. Accordingly, it was appropriate that a proportion of the management fee be apportioned to capex activities and therefore a corresponding uplift be applied when adjusting the TRV for deferred capex.

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<sup>95</sup> UR supplementary submission, paragraph 2.133.

<sup>96</sup> UR initial submission, paragraph 3.17, footnote 6.

<sup>97</sup> UR supplementary submission, paragraph 2.41; UR PNGL12 determination, paragraph 7.51.

120. UR said that in PC01 and PC02, the management fee was included in a capex item called 'Engineering Other'. This cost item amounted to between around 10 and 20 per cent of total capex in each year. It said that it therefore estimated that the variable element of the management fee would have been in the region of 5 to 10 per cent of total capex.
121. UR said that the treatment of deferred capex from 2007 onwards consisted of adjustments for capitalized financing and the management fee (as well as a removal of the original allowance), which was equivalent to the treatment of the 1999/2000 capex deferrals.
122. It said that the management fee was treated as variable in PC03. The management fee assumption for capex deferrals in PC03 was between 20 and 24 per cent (the fee assumption differing from year to year in PC03). UR said that these percentages were calculated based on the total allowance for the management fee in each year divided by the total capex allowance in that year.
123. It said that in PC02 the determined management fee was treated as variable (ie the allowance was treated as variable) and was calculated as a percentage of allowed capex (retrospectively corrected for actual connections) and net of deferrals.
124. For connections, UR included a retrospective adjustment mechanism from PC02 onwards, which included an adjustment for capitalized financing and the management fee.
125. UR said that from PNG12 onwards all retrospective adjustments included an adjustment for the management fee, because from PNG12 onwards UR had included the management fee in the capex unit cost calculations with no separately identified allowance for the management fee.

### ***Additional material that we reviewed in our decision***

#### ***Relevant extracts from UR's 1999 (PC01) determination***

##### ***PNG1***

126. PNG1 said that the fact that UR chose to delay until 1999 formalizing the opex and capex allowances on which outperformance for the period 1996 to 1998 was to be measured did not mean that there was no clear expectation in 1996 as to the manner in which the opex and capex allowances would be determined (which is what happened in 1999).
127. PNG1 said that it was clear that the approach UR took in 1999 was to mimic how it might have set the allowances had it had the opportunity to do so in 1996.
128. PNG1 said that UR, in the 1999 decision, retrospectively adjusted PNG1's activity levels for the period 1996 to 1998 so as to reflect actuals rather than previous forecasts of activity, which showed that not all adjustments made as a result of PNG1's 1999 submission were in its favour.
129. PNG1 said that in PC01 it had provided all the information in its possession requested by UR and its consultants. The information which PNG1 was unable to provide in the format specified by UR was information that PNG1 did not use or maintain in its day-to-day operations, such as the cost per metre of constructing a 180mm pipe. PNG1 said that instead it was challenging and improving upon the measures it monitored operationally that delivered its efficiency improvements.

130. PNGL said that if it was true that it did not fully cooperate in providing the necessary information for the PC01 charge control process, it would have been incumbent on UR to identify exactly what information was missing and its effect before reaching any conclusion on inefficiency. In any event, PNGL had fully cooperated with UR's process to the best of its ability, but PNGL did not produce detailed week-by-week, street-by-street network development plans months or years in advance as UR might have wished as this would not have allowed PNGL to react to customer demand for connections which arrived with a much shorter lead time.
131. PNGL said that the relevant recommendations from PC01 had now been implemented, either through normal operational management processes or when the alliance partnership contract was retendered in 2001 and 2006. The only recommendation which (according to UR) was outstanding related to asset management as PNGL had not obtained PAS55 accreditation.

*UR*

132. UR said that PNGL's first price control decision was made on 20 September 1999 (covering the period 1997 to 2001). UR said that the 1999 price control determination process was prolonged partly as a natural consequence of it being the first decision and its coming at the outset of a greenfield investment, but was also due to significant delays and slow response times on the part of PNGL.
133. UR said that PNGL provided two forecasts as part of the PC01 charge control process:<sup>98</sup>
- (a) the 1997 initial base value submission in June 1997 (the 1997 submission); and
  - (b) a revised base value submission in March 1999 (the 1999 submission).
134. UR said that following PNGL's 1997 submission, UR employed consultants (W S Atkins and Pannell Kerr Foster) to review respectively capex and opex, and they issued position papers and initial conclusions in August 1998. UR said that PNGL resubmitted its proposals (for all parameters) in March 1999, as a result both of the consultants' findings and because gas throughput volumes were significantly lower than forecast in 1997 (as provided for under the 1996 licence).
135. UR said that the 1999 submission was necessary because PNGL's licence allowed for a special reforecast review of the conveyance charges if in any formula year total throughput differed from forecasts by more than 15 per cent. UR said that actual throughput in 1997 was significantly less than forecast in the 1997 submission (due to lower take-up of connections and lower unit volume usage compared with the forecast assumptions and due to a time lag between sale and gas burn<sup>99</sup>).<sup>100</sup> It said that PNGL conceded that this produced a much slower projected build-up of load over the 20-year period to 2016.<sup>101</sup>
136. UR said that the special reforecasting review section of the licence did not suggest that this could be applied retrospectively. Given that the information was supplied in March 1999, this would mean the new numbers would only have applied from January 2000. If the review had only applied prospectively, PNGL would have suffered significant losses. However, the circumstances were unusual as UR had not

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<sup>98</sup> PC01 determination, 20 September 1999, paragraph 2.2.

<sup>99</sup> PC01 determination, paragraph 3.1.

<sup>100</sup> PC01 determination, paragraph 2.2.

<sup>101</sup> PC01 determination, paragraph 3.3.

yet set the determined values, and it could be argued that this was not a reforecast under the licence. The decision to accept the reforecasts and to apply them retrospectively removed significant risk from PNGL and was another example of the supportive regulatory regime put in place to develop the gas industry.

137. UR said that in response to the lower-than-expected throughput, PNGL decided to accelerate the network build programme to make gas available to a greater proportion of the licence area at an earlier stage than previously planned. UR said that it was anticipated that this would in part make up for the lower-than-expected rate of take-up in exiting areas.<sup>102</sup>
138. UR said that the 1999 submission indicated a significant acceleration of mains activities over that envisaged in the 1997 submission. It said that the 1999 submission envisaged that the 7-bar system would be completed by the end of 2000 and the majority of the 4-bar system and feeder mains by 2001.<sup>103</sup>
139. UR accepted (in the PC01 determination), with some adjustments (eg for reprofiling of the take-up of new connections and an assumption on efficiency gains), PNGL's capex proposals in the 1999 submission (ie the accelerated network build programme was incorporated in setting the allowed levels of capital expenditure in PC01).<sup>104</sup>
140. UR said that it (then called Ofreg) then issued a preliminary view on 18 May 1999 and following the finalization of the consultants' reports and the receipt of PNGL's comments, it issued its final decision in September 1999.
141. UR welcomed the accelerated network built, but was concerned about the lack of related documentation. It said that (in its 'minded to' letter from 18 May 1999) it was prepared to accept the accelerated network build, provided that the specific capex-related recommendations were adopted.<sup>105</sup> These specific capex-related recommendations appeared to include: improved strategic planning;<sup>106</sup> monitoring of expenditure and output;<sup>107</sup> asset management;<sup>108</sup> providing more clarity on the McNicholas contracts;<sup>109</sup> and benchmarking.<sup>110</sup>
142. UR also said that the 1997 and 1999 submissions fell short of best practice and that there was a lack of transparency in the preparation of the 1999 submission.<sup>111</sup>
143. UR said that the process of determining conveyance charges in PC01 were delayed by occasional difficulties in obtaining the information required from PNGL (eg PNGL, in certain instances, did not provide timely or sufficient information to UR's consultants<sup>112</sup>). Whilst recognizing that PNGL was at that time a small organization, UR nevertheless thought that PNGL (and the parent company, BG plc) could have allocated more resources to the charge-control-setting process considering the importance of this process.<sup>113</sup>

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<sup>102</sup> PC01 determination, paragraph 3.3.

<sup>103</sup> PC01 determination, paragraph 4.1.

<sup>104</sup> PC01 determination, paragraph 4.6.

<sup>105</sup> PC01 determination, paragraphs 4.2 & 6.1.

<sup>106</sup> PC01 determination, paragraphs 6.2 & 6.3.

<sup>107</sup> PC01 determination, paragraph 6.5.

<sup>108</sup> PC01 determination, paragraph 6.6.

<sup>109</sup> PC01 determination, paragraphs 6.7–6.11.

<sup>110</sup> PC01 determination, paragraph 6.12.

<sup>111</sup> PC01 determination, paragraphs 6.3 & 6.4.

<sup>112</sup> PC01 determination, paragraph 6.4.

<sup>113</sup> PC01 determination, paragraph 1.

144. UR said that PNGL had an apparent lack of strategic planning as the overall strategic direction of the roll-out of the distribution network appeared to be unclear, as there seemed to be no clear written strategy and as the distribution system was developed on a reactive basis.<sup>114</sup>
145. UR estimated that 49 per cent of the management fee (recorded as 'Engineering other' expenses) was variable until 2006, with the rest being fixed.<sup>115</sup>
146. It said that in its PC01 determination it indicated that a mechanism would be agreed to compensate PNGL for unforeseen connections above the baseline numbers assumed for the PC01 period, but it was not that any such adjustments were necessary.

*Relevant extracts from UR's 2001 determination (PC02)*

*PNGL*

147. PNGL said that a retrospective mechanism applied for domestic connections in PC02, ie the PC02 determination established a mechanism which ensured that no capex outperformance could be achieved as a result of below-forecast domestic connections.

*UR*

148. UR said that in PC02 domestic meter costs were subject to retrospective adjustments, correcting for differences between forecast and actual connections, therefore there was no scope for capex outperformance to arise in this cost area from connections being below forecast.
149. It said that PNGL displayed a cooperative attitude in the PC02 charge control process.<sup>116</sup>
150. UR's consultant's view was that although some of the PC01 proposals for improved capex reporting had been implemented (see paragraph 141), many of the key proposals had not been taken up by PNGL. UR said that it would appear vital that PNGL improved its strategic and business planning (and UR's consultants said that the standard of PNGL's planning had not improved significantly in 2001 compared with 1999).<sup>117</sup>
151. In its 'minded to' letter in relation to the PC02 determination on 20 November 2001 (the final PC02 determination was issued in April 2002), UR made the following statements:
- (a) Price controlling PNGL was unlike price controlling other utilities. This was because PNGL was a new utility seeking to establish its presence in a market where other fuels were entrenched.
- (b) Price controls for established utilities consisted of incentivizing the managers to reduce the inefficiencies which had kept prices higher than they needed to be. The regulatory bargain consisted of an understanding that outperformance

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<sup>114</sup> PC01 determination, paragraph 6.2.

<sup>115</sup> PC01 determination, paragraph 4.11.

<sup>116</sup> UR PC02 decision, April 2002, p3.

<sup>117</sup> UR PC02 decision, April 2002, p26.

against agreed expenditure targets over a five-year period were retained by shareholders but were subsequently passed over to customers thereafter as the utility's costs were rebased on the new lower cost base revealed by the efficiency gains in the preceding period.

- (c) The regulatory bargain with PNGL was a price formula set over a 20-year period allowing the company to recover 8.5 per cent pre-tax real on their expenditure over the 20-year period including their negative cash flows. UR said that it was this regulatory bargain which it was totally committed to honouring, subject only to appropriate levels of protection for customers. It regarded these two commitments as inextricably intertwined since without a growing and satisfied customer base PNG had little prospect of recovering its allowed revenue.
- (d) The first major milestone would occur around 2006, when according to PNGL's estimates, for the first time, PNGL should move from being cash negative to cash positive, after which there would then be the climb to full profitability while the company recovered the expenditure on infrastructure and paid its shareholders the allowed return on their investment.
- (e) There was in the normal regulated utility price control a conflict of interest between customers and shareholders. Shareholders were driven by the logic of the price control methodology to seek to maximize the allowed revenue from capital investment and operating costs. This maximized the scope for gains from efficiency or underspend. Regulators, on behalf of customers, sought to minimize allowed revenue to keep prices down. So far regulation had not been terribly clever at aligning the interests of customers and shareholders by giving incentives which worked for both.
- (f) The PNGL price control was less likely a zero sum game than the conventional price control. This was because if PNGL's costs were too high, it would never be able to recover them from gas sales and would fail to secure its target rate of return. This logically placed an upper limit on what PNGL would spend if it operated in an unregulated environment. PNGL also needed to have a large capex programme since it started from a zero asset base. This was in sharp contrast with existing network utilities where customers had an interest in minimizing capex and possibly reducing the size of the regulatory asset base.
- (g) However, there were still conflicts of interest between customers and shareholders in the PNGL price control. Both had an interest in driving costs out of the business but the customer interest was absolute—the lower the cost, the lower the price. The shareholder interest was more complex and differed from the customers' in two ways. First, the shareholder had an interest in expenditure being at the limit of what the market would bear and give the 8.5 per cent pre-tax return. Thus the shareholder had no logical objection to 'gold plating' provided that it kept within the limit of market sustainability. The problem for shareholders on this front was that they could not know *ex ante* what this limit was and in any event it was not within their control. Shareholders had therefore an incentive to create a space between allowed expenditure and actual expenditure. The uncertainty about realizing all of the allowed revenues return made it rational for the company to seek windfall gains.
- (h) Conversely UR had a duty to ensure that, as far as possible, actual expenditure and allowed expenditure were well matched and that this was done by holding allowed expenditure to as low a level as was necessary to achieve the development of the network.

- (i) In order to honour the regulatory undertaking given to PNGL, it was UR's intention to seek to ensure that actual expenditure equalled allowed/deemed expenditure by thoroughly challenging and minimizing allowed expenditure. However, where PNGL had succeeded in reducing actual expenditure below allowed expenditure in any price control period, there would be no clawback of that gain in subsequent periods. Thus the allowed expenditure would be the recognized expenditure for the purpose of calculating PNGL's rate of return.
- (j) UR said that it hoped this clear statement of regulatory commitment would be accepted by PNGL as being in the interest of establishing a firm long-term basis for price control regulation. In return, Ofreg would ask of PNGL:
  - (i) its cooperation in seeking to minimize allowed/deemed expenditure; and
  - (ii) its cooperation in looking at ways in which the interests of both customers and shareholders might be better secured in the future by changes to the regulatory formula.

### *The PC03 determination*

#### *UR*

- 152. UR said that the treatment of deferred capex from 2007 onwards was not set out in the licence. Instead, UR applied a retrospective mechanism, which was formalized in 2010. This mechanism in essence replaced the value of forecast spend with the value of actual spent.
- 153. UR said that since PC03 infill, feeder and meters were part of the retrospective mechanism and PNGL could no longer benefit from deferring or cancelling such capex. Likewise PNGL would be fully rewarded for any additional capex it carried out above forecasts.
- 154. UR said that the treatment of deferred capex from the PC03 review onwards was chosen as it was symmetrical with the treatment of unforeseen capex. This was also symmetrical with how UR treated all deferred capex since the retrospective mechanism was put in place.

### *Other capex deferrals*

#### *PNGL*

- 155. PNGL said that the 1999/2000 capex deferrals (as per Appendix 4 in UR's PNGL12 decision document) were not the only examples of deferred capex projects in the period from 1996 to 2006.
- 156. PNGL said that there were a total of 35 bulk projects that had been planned and were deferred from the first price control (PC01, 1996–2001), of which 12 were completed by the end of 2006 and 23 were yet to be completed at the time of the 2006 'agreement'. These 23 projects were the 1999/2000 capex deferrals. PNGL said that the original allowances for the 12 projects that had been completed by the end of 2006 represented £4.9 million (1996 prices) and the original allowances for the 1999/2000 capex deferrals amounted to £4.5 million (1996 prices).

157. PNGL said that in addition to these bulk projects, some infill mains were deferred from PC01 and completed in PC02; and some feeder and infill mains were deferred from PC02 and completed in PC03.
158. PNGL said that as part of the PC03 determination, UR treated feeder and infill mains that had been deferred in PC02 and were subsequently planned to be completed in PC03, and bulk and infill projects that had been deferred from PC01 and were planned to be undertaken in PC03, as follows:
- (a) When these projects were undertaken, PNGL would not be granted new allowances for these costs. Accordingly, in the PC03 determination, capex corresponding to these projects was deducted from the total forecast costs for the period.
  - (b) To calculate this deduction to forecast capex, UR multiplied the length of bulk, feeder and infill mains that had been deferred to PC03 by the determined allowable unit cost for this type of activity as determined at PC03.
159. PNGL said that this methodology was agreed upon by both PNGL and UR. The primary objective was to avoid PNGL being given allowances twice for the same projects, while encouraging PNGL to manage its investment programme efficiently. Since the original allowances had been rolled up in the 2006 TRV, PNGL would finance these projects when they occurred through its asset base. Therefore, in order to avoid double counting, it was appropriate to net off the cost of these projects against future allowances.
160. PNGL said that as part of the PC03 determination, UR removed the forecast costs associated with deferred bulk projects (ie the 1999/2000 capex deferrals) from cost allowances. This approach meant that PNGL would have to fund the deferred bulk projects out of its existing asset base as and when they arose, in order to avoid any double counting of allowances. For example, any capex that was deferred from, say, PC01 into PC03 and subsequent controls reduced allowances in the price control period that the deferred project was planned to take place, ie if 10 km was deferred from 1999 and reforecast at the PC03 price control review to be constructed as 6 km in 2009 and 4 km in 2020, then capex allowances in 2009 would be reduced by 6 km and capex allowances in 2020 would be reduced by 4 km.

*UR*

161. UR said that the 1999/2000 capex deferrals (per Appendix 4 of UR's 2012 decision) included details of all large, discrete and hence easily identifiable projects that were deferred. All these projects related to 7-bar or 4-bar mainslaying projects, or the construction of pressure reduction stations (sometimes called 'governors').
162. UR said that there had also been significant deferred capex in other capex categories relating to 'infill' and 'feeder' mains (these were smaller, lower-pressure pipes that took gas from the higher 4/7-bar pipes down residential streets and around housing developments).
163. UR said that capex deferrals in the period 1996 to 2006 of lower-pressure mains (ie infill and feeder mains) contributed in the region of £14 million (2006 prices) to the outperformance element of the 2006 TRV. UR said that the following deferrals for infill and feeder mains occurred in PC01 and PC02:
- (a) For infill mains:

- (i) A total of 658 km of infill mains had been scheduled during PC01 but were deferred. In PC02, allowances for these deferrals, which were granted in PC01, were netted off the 886 km of scheduled infill mainslaying during PC02, ie an allowance for only 228 km of new infill mains was granted in PC02.
  - (ii) In PC02, only around 660 km of infill mains were constructed, thereby deferring a further 226 km of infill mains beyond 2006.
  - (iii) In PC03, whilst PNGL had deferred 226 km of infill mains, only 93 km were deducted from the PC03 capex allowance. This was because UR accepted PNGL's justification for deferring the balance of 133 km as a result of efficiency improvements.
- (b) For feeder mains:
- (i) There were no deferrals in PC01.
  - (ii) In PC02, 136 km of feeder mainslaying was planned but only 93 km was laid. Similar to the review of infill mains carried out in 2006, UR also reviewed feeder mains deferrals. UR concluded that whilst PNGL had deferred 43 km of feeder mains, it had only been overcompensated for 13 km, for similar reasons as for infill, ie efficiency improvements. The 13 km was netted off planned feeder mainslaying during PC03.
164. UR said that the reasons for allowing PNGL to retain 133 km of infill mains and 30 km of feeder mains was because of arguments put forward by PNGL that the deferrals were due to efficiency and because of spreadsheet analysis on the cost per property passed, which showed that the quantity of infill/feeder meters per property passed was less than forecast (UR said in its PC03 decision that it allowed PNGL to retain these capex allowances because PNGL passed proportionally more properties than implied by the total amount of deferred capex<sup>118</sup>). The reasons PNGL provided to show that the deferrals were efficient included that PNGL was able to pass each property using a lower average quantity of metres per property passed than forecast; better zoning in NIHE areas; use of a single main down some streets, instead of a double main; and use of smaller diameter feeder pipe. UR said that when allowing PNGL to retain these benefits, no account was taken of the previous finding of a lack of strategic planning on behalf of PNGL.
165. UR said that allowing PNGL to retain 133 km of infill mains and 30 km of feeder mains capex added around £5.8 million to the 2006 TRV (in 2006 prices).
166. UR said that in its PC02 decision it netted an amount of around £22 million (in 1996 prices, undiscounted) of capex deferrals off future allowances for capex. UR said that this value related to all deferred capex projects, and not just the 1999/2000 capex deferrals.
167. UR said that in its PC03 decision, it netted £4.3 million (in 2006 prices) of infill and feeder capex volumes off infill or feeder mainslaying planned during PC03.
168. UR said that given that PNGL was operating in a new market with no replacement capex issues, this meant that PNGL had been rewarded for not delivering infill and feeder mains that could have provided the opportunity to connect more consumers.

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<sup>118</sup> UR PC03 decision (Annex 2), Section 6.3.

However, the reasons for delaying infill and feeder were likely to be more complex and difficult to scrutinize (than the 4-bar/7-bar/governors deferrals, ie the 1999/2000 deferrals) and UR wanted to limit the scope of its review and therefore did not make any further adjustments for these capex deferrals.

169. UR said that the 2006 TRV also included deferred capex that was subsequently (in PC03) substituted for other projects. UR said that permission to substitute deferred capex projects was not requested by PNGL before they took place, so the substitutions were not 'agreed' up front. However, after learning of these, UR decided that it was not necessary to take any action.
170. UR said that the substitutions related to two pressure reduction stations (at Inverary Avenue and Lisburn Road). These were originally planned for completion in 1999 and PNGL was granted appropriate allowances for their construction. The projects were then subsequently deferred. At the time of the discussions in 2006/07 when the value of the TRV was established, the estimated completion date of these projects was 2010. In 2010, when PNGL made its submission for the 2012 price control, it informed UR that these pressure reduction stations were no longer required and it had opted to use the allowances already granted to complete a reinforcement of the Belfast Harbour Estate (an unforeseen project for which UR had not previously granted an allowance). UR considered that PNGL's use of its allowances in this manner did not overcompensate it. UR said that it therefore effectively netted the project costs off each other and excluded them from its review of the 1999/2000 capex deferrals (and no allowance was granted for the reinforcement of the Harbour Estate).
171. UR said that prior to the review of deferred capex carried out as part of PNGL12, it had previously treated deferred capex in a number of ways. This may have involved both reducing future (cash) allowances for deferred projects, and/or reducing output assumptions. For example, in PC02, some capex adjustments were made on the basis of cash allowances (eg connections) and others on a volume/outputs basis (eg infill and feeder). Since 2007, adjustments for deferred capex had been made on the basis of cash allowances.
172. UR said that the treatment of deferred capex originating in 1996 to 2006 was that future capex allowances were reduced by the amount of deferred capex that was planned for each future year (ie the PC03 determination capex allowances were reduced for deferred capex that was planned to be spent in PC03).

### ***Comments from third parties—deferred capex***

173. Fitch said that UR (in its August 2011 consultation document) proposed a £21.2 million (in September 2010 prices) retrospective adjustment for deferred capex. It said that while it anticipated a log-down of the TRV of GBP3.5m–GBP5.0m, it generally took the view that deferred capex should not be included in the asset base. Fitch also said that the retrospective adjustment for deferred capex needed to be substantiated.<sup>119</sup>
174. Moody's said that UR's wording in its previous publications was sufficiently vague that it did not prohibit any form of retrospective adjustment for deferred capex. However, any significant adjustment to the value of the regulatory asset base should be articulated in advance with sufficient opportunity for all relevant stakeholders to

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<sup>119</sup> [Fitch press release, 12 October 2011.](#)

engage. In addition, such a change should be well justified in order to increase transparency in the regulatory framework.

175. firmus said that the regulatory framework should only change in a way which was objective (and therefore which investors could anticipate if they asked themselves ‘what if ...’ before making an investment) and which appropriately balanced short- and long-term interests. firmus said that changes to regulatory frameworks which looked to alter previous regulatory decisions in ways which could not reasonably be anticipated by investors did not meet the ‘predictability’ or ‘objectivity’ criteria.<sup>120</sup>
176. NIE said that the integrity of a company’s regulatory asset value was critical to the integrity of the entire regulatory regime. Retrospective adjustments like the 2012 TRV adjustment conflicted with good regulatory practice which promoted consistency, predictability and transparency in regulatory decision making (and would be a fundamental departure from Great Britain precedent). Such adjustments were contrary to the interests of customers because they increased investors’ perceptions of regulatory risk, thereby increasing the cost of capital. NIE said that bonds issued by both NIE and PNGL were yielding 150–175bps more than bonds issued by Great Britain gas and electricity utilities and that this was evidence that the capital markets already perceived a higher risk of investing in Northern Ireland, a situation which would be exacerbated if UR’s decision was upheld.<sup>121</sup>
177. Manufacturing Northern Ireland said that gas consumers should not have to pay for pipes before they were built and that it supported UR’s 2012 TRV adjustment for deferred capex.<sup>122</sup>
178. Bryson Energy said that it was well established within regulatory practice that in order to drive down costs to the minimum possible economic level, companies may need to be incentivized through the opportunity to make additional returns within a price control period. However, this incentive mechanism only worked for customers if the benefits of the lower cost base accrued to customers in subsequent price control periods. Moreover where the excess returns in one period were not even the result of efficiency but of underspend through change of circumstances or plans, then it was both unjust and contrary to any principle of incentive regulation to permit the company to enjoy such returns into the future. To permit the retention of such returns would perversely be to incentivize companies deliberately to mislead the regulator.<sup>123</sup>
179. With reference to deferred capex, CCNI said that it was an established principle that consumers should not pay for something that did not exist and from which they derived no benefit.<sup>124</sup>

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<sup>120</sup> firmus [initial submission](#).

<sup>121</sup> NIE [initial submission](#).

<sup>122</sup> Manufacturing Northern Ireland [initial submission](#).

<sup>123</sup> Bryson Energy [initial submission](#).

<sup>124</sup> CCNI [initial submission](#).

## Arguments by PNGL and UR regarding the risks faced by PNGL in 1996

1. PNGL has submitted the following arguments regarding the risks it faced in 1996.<sup>1</sup>

5.49 PNGL represented an unusual project at the time in the UK, being the only recent example of which PNGL is aware when a gas distribution network was retrofitted in a major city. Accordingly, the regulatory settlement had to be tailored to the specifics of the investment. To reflect the time profile of risks it was necessary to fix the allowed rate of return for significantly longer than the five years that is standard regulatory practice for GB gas distribution networks.

5.50 PNGL faced a number of specific challenges, which were not experienced by the mature privatised utilities:

- (a) PNGL required a significant initial investment, primarily in laying the gas transmission pipeline from Larne to Belfast, including crossing the Belfast Lough. In addition, PNGL had to lay the primary distribution network throughout the city. This investment was made before sales could be secured, or assured in future. The scale and complexity of this investment, and the financing risks that are associated with it, go beyond the level of risk faced by a mature utility;
- (b) PNGL's investment risk extended beyond the direct risks of building the network. There was no established wider gas industry in Northern Ireland, and PNGL therefore had to develop one. This entailed:
  - (i) establishing a network of installers and retailers, so that householders could confidently buy gas appliances and have them safely installed and maintained;
  - (ii) establishing training programmes so that gas industry operatives could obtain the required skills and qualifications, for example qualifying for CORGI/GasSafe certification; and
  - (iii) bringing in gas construction contractors from outside Belfast to construct the network, as there were none in Northern Ireland; and
- (c) while natural gas was the default option for heating homes in GB, builders and architects in Northern Ireland did not automatically select natural gas. PNGL had to persuade householders of the benefits of natural gas when its unit cost was often higher than oil. Similarly, PNGL had to convince the NIHE, which owns and manages some 40% of the housing stock in Northern Ireland, to install natural gas routinely as

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<sup>1</sup> PNGL [statement of case](#), pp64–66. The footnotes in the text are not reproduced here.

part of its refurbishment programme. The oil industry was well established in Northern Ireland and remains the main heating fuel, with about 80% of the total market.

- 5.51 A key feature of the PNGL business model was to re-use the abandoned town gas networks, using the old pipes as sleeves for the new natural gas pipes in order to reduce construction costs and minimise disruption to road users. To this end PNGL acquired the abandoned town gas networks in Belfast, Bangor and Newtownards. At the outset, there was no guarantee that this approach would be effective. In particular, there was significant uncertainty about the accuracy of the recorded location of the old pipes, and whether they would still be in sufficiently good condition to use as sleeves.
- 5.52 Another major risk factor for PNGL's investors was the political and social instability in Northern Ireland at the time. Although the security situation in Northern Ireland was improving, the 1996 licence pre-dated the Good Friday Agreement of 1998. There was uncertainty about how the security situation might develop, and whether it might adversely affect the development of the business or the costs that it incurred. Political and social instability was reflected in the fact that contractors' prices were initially higher than expected. Further, a culture of 'non-payment' of utility bills had been established, which affected the level of 'bad debts'.
- 5.53 In addition, the regulatory structure that PNGL was operating under was immature compared to the regulatory structures in GB. Ofreg had been established in 1992 and Northern Ireland Electricity (NIE) was privatised in 1993. By 1996, NIE had not yet been subject to a price control review and there had therefore been little opportunity to establish a consistency of regulatory approach. In addition, the trade sale of the electricity generating units in 1992 was considered to have been flawed and was criticised by the Northern Ireland Audit Office and the House of Commons Public Accounts Committee.
- 5.54 Within this context, PNGL had to establish a reputation as a credible, efficient and reliable fuel supplier to gain the trust and confidence of potential customers. This situation was markedly different to that faced by the GB utilities that were privatised during the 1980-90s. Unlike those utilities, where the priority has been to improve operating efficiency to reduce costs, the commercial imperative for PNGL has been (and continues to be) to build the customer base to an efficient, economically optimal level. This objective was (and continues to be) shared with the Authority, and with Northern Ireland politicians.
- 5.55 A further facet of the greenfield nature of the PNGL investment was that there was no pre-existing accumulation of inefficiency or 'fat' in the business. Unlike the privatised GB utilities, which were able to achieve some 'easy wins' as a result of the extent of inefficiency that had been built up under public ownership, there was little obvious scope for PNGL to outperform its plan and achieve returns above the allowed rate.

5.56 Given the challenges outlined above, the risks faced by PNGL were significantly higher than those faced by a mature GB network utility at that time. The additional risks merited an allowed return above the allowed cost of capital for mature GB utilities. This risk environment provides the context for the decision to set an allowed pre-tax WACC of 8.5% for a period of 20 years. Indeed, the risks faced by PNGL in the early years of the original licence were significantly higher than those implied by this WACC. Further, there is no reason to believe, retrospectively, that any other investor would have taken on the challenge of starting up the gas market in Northern Ireland for a lower return.

2. UR has submitted the following arguments regarding the risks faced by PNGL in 1996.

1.18 We see the original risk allocation facing PNGL as having two defining features:

- first, PNGL faced the risk of under- and over-spending against the opex and capex allowances that were to be set by the regulator at each five-year periodic review; and
- second, PNGL faced uncertainty as to the business's ability to recover by 2016 the revenues that were needed to pay for this investment. (The Commission refers to this as revenue risk and stranding risk, but in reality these amount to the same thing).

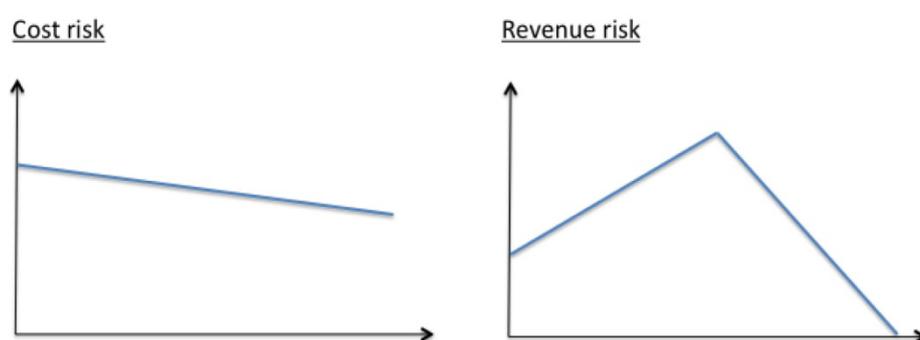
1.19 The first of these risks is largely idiosyncratic or company-specific in nature. The second has a large systematic component to it and may also exhibit the sort of asymmetries that the Commission refers to in its paper.

1.20 Figure 1 is a stylized representation of how these risks were expected to develop over a 20-year period.

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Figure 1 – Cost Risk and Revenue Risk

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Source: The Utility Regulator

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1.21 The left-hand side of Figure 1 shows cost risk gradually diminishing over time as PNGL moved through the construction of the network. The right-hand side shows that revenue risk was initially unimportant for a business with no customers. However, as time went on, it became more and more critical that the

business was generating sufficient revenues and a sufficient customer base.

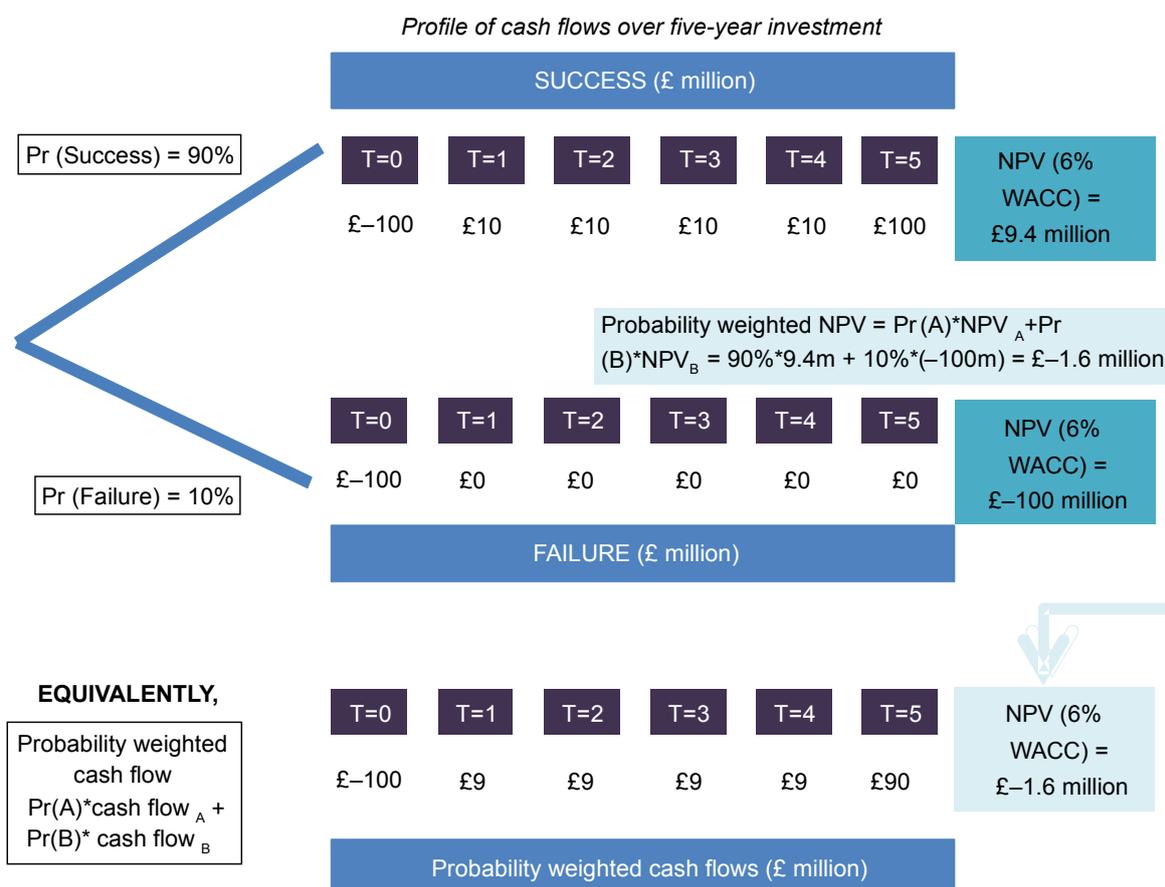
- 1.22 The uncertainty around revenue/stranding should have peaked perhaps midway through the 20 years – i.e. at the point where the business would start having to price up to its price cap in order to have any chance of recovering its full revenue entitlement – after which revenue/stranding risk would diminish as it would start to become more and more apparent to investors how much of their investment they would be able to recover.
- 1.23 Taking these two things together, we think it is reasonable to say that investors' perceptions of PNGL's premium to GB utilities under the terms of its original licence would have been fairly stable throughout the 1996 to 2006 period. Or to put it another way, we do not see that PNGL's (risk) premium in 2006 would have been any lower than its premium in 1996 had the Utility Regulator not agreed to changes to the 1996 licence.
- 1.24 This is evidenced by the fact that PNGL was sold by British Gas to East Surrey Holdings at a discount to notional RAB in December 2003. If the risk profile proposed by PNGL was correct, the business would have been sold at a significant premium as British Gas had financed the business through the early years when it was supposedly very risky.

### Stylized illustration of asymmetric risk

- Figure 1 provides a stylized illustration of asymmetric risk. In this illustration, there is a 10 per cent probability that investors will wholly fail to recoup their initial investment. The consequential loss may include sums related to the building of the assets as well as initial start-up and operating costs.
- For simplicity, the stylized illustration in Figure 1 only considers two scenarios, one where the investment succeeds, and the other where it wholly fails. However, we do not consider complete failure of demand to be the only relevant scenario. In the context of PNGL’s greenfield investment, we have considered that asymmetric risk may have arisen due to project-specific factors that gave rise to a possibility that PNGL might fail to generate sufficient revenues within the licence period to compensate for the sunk costs of initial investment and operation.

FIGURE 1

#### A stylized illustration of asset stranding risk



Source: CC analysis.

- The implications of this stylized illustration are:
  - The cash flows of the ‘success’ outcome must be increased to make the probability-weighted NPV positive, in order to induce investment.

- (b) One possible way of doing this in a price control would be to increase the rate of return on the RAB (ie an increase in the rate of return over and the above the cost of capital).
  - (c) The NPV of the successful outcome will be positive, ie ex post the firm could be earning what looks like an excessive return. This is because the ex ante investment appraisal takes into account the probability of failure in the cash flows.
4. We note that in the context of regulated access to next generation access networks in the telecommunications sector, the EC has allowed for an exceptional premium above the cost of capital, to reflect investment risk related to asset stranding, such as uncertainty regarding technological progress.<sup>1</sup>

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<sup>1</sup> European Commission (2010), '[Commission Recommendation of 20 September 2010 on regulated access to Next Generation Access Networks \(NGA\)](#)', *Official Journal of the European Union*, L 251/45.

## PNGL's arguments on the cost of capital allowed to mature Great Britain utilities and potential comparators in 2006

1. PNGL has submitted evidence on the cost of capital allowed in regulatory determinations between 1991 and 2006, as shown in Table 1.

TABLE 1 Cost of capital allowed by regulators and the MMC from 1991 to 2006 (real, pre-tax)\*

	<i>Water</i>	<i>Airports</i>	<i>Electricity distribution</i>	<i>Electricity transmission</i>	<i>Gas transmission</i>
1991		8			
1993					6.5–7.5†
1994	Post-tax WACC 5-6% Rate of return falling from 13% to 6–7%‡ over 10 years		7		
1995	6–8		7		
1996		6.3–8.3		7	7
1997				6.5–7.5	7
1999	4.75‡		6.50		
2000	5.90‡			5.50–6.25	
2001					6.00–6.25
2004	5.1‡		6.91		
2005		6.75			
2006				6.25	6.25

Source: PNGL [response](#), p88.

\*Where there are numbers in two subsequent years, the earlier number is the regulator's determination and the later one is the MMC's ruling on the determination reference.

†Gas and British Gas (1993) included both distribution and transmission.

‡Post-tax cost of capital for the water sector, except in 1995.

2. PNGL also argued that '(in) addition to the treatment of mature regulated utilities, it is also relevant to consider the allowed returns and WACCs of other potentially more comparable utility and greenfield network investments over this period'.<sup>1</sup>
3. The evidence presented by PNGL on other potential comparators is set out below.<sup>2</sup>

### Firmus

2.21 In March 2005, firmus energy was awarded a gas distribution licence in 10 development areas in Northern Ireland. The cost of capital for firmus energy was set in the licence at 7.5% (real, pre-tax) for a period of at least 10 years...

<sup>1</sup> PNGL [response](#), p89.

<sup>2</sup> PNGL [response](#), pp89&90.

## **IGTs**

- 2.22 Independent Gas Transporters (IGTs) own and operate small gas distribution networks in GB. These networks cover areas not served by the existing regulated gas distribution networks. IGTs are subject to less detailed regulatory controls than the larger gas networks, although regulations are imposed to prevent the IGTs from earning more than a reasonable level of profits.
- 2.23 There are some similarities in business profile between IGTs and PNL, both are developing new gas networks and connecting customers that were not previously served by a gas network. At the same time there are some important differences between IGTs and PNL that result in IGTs having a lower risk profile. In particular, IGTs are able to be more selective about the areas that they serve and are able to ensure a higher and more certain level of customer take-up prior to the construction of the network.
- 2.24 In 2002 Ofgem...reviewed the appropriate cost of capital for IGTs and analysed the risks that they faced compared to a fully regulated gas network (Transco at that time). Ofgem determined that the appropriate cost of capital for IGTs was 8.5% (pre-tax real). This figure was reaffirmed in 2006 and in 2011 was reduced to 7.6%. Ofgem concluded that the premium in this WACC compared to the regulated gas networks in GB reflected the relative small size of IGTs and the potential impact of revenue profile on debt financing costs.

## **Telecoms - BT**

- 2.25 In 1992 Oftel published an assessment of the cost of capital for BT... This assessment was subsequently adopted into later decisions. The paper estimated that the nominal pre-tax WACC of BT was in the range 17% to 20%. The estimate of the nominal risk-free rate 9% - 11% would have incorporated an expectation of inflation that was relatively high. To make this comparable with the real WACC figures in the previous section PNL has converted using a real risk-free rate of 3.5%. This was a typical figure for the real risk-free rate in decisions at that time, for example it was the lower end of the range (3.5% to 3.8%) employed by the MMC in Scottish Hydroelectric in 1995.
- 2.26 On this basis the real pre-tax WACC for BT was in the range 11% - 12%. This was significantly higher than the allowed WACC for other regulated networks at that time. This, presumably, reflected the fact that although it was a mature regulated network activity BT faced higher risks than other mature regulated industries.

## **Financeability**

### **Overview**

1. One of UR's duties is to ensure that PNGL is financeable. UR, in its PNGL12 determination has performed a financeability assessment for PNGL and UR's financial model includes the relevant calculations.
2. Some of our decisions impact on the revenues PNGL will be able to earn over the charge control period (2012/13). It is therefore necessary for us to adapt the regulator's financial model to reflect these decisions in order to calculate a revised revenue cap for PNGL. As for UR, it is also necessary for us to ensure that PNGL remains financeable following our decision.
3. This section provides a description of UR's financeability assessment in the PNGL12 determination and PNGL's criticism thereof (see paragraph 5), a summary of third party submissions (see paragraphs 29 to 36) and our provisional determination of PNGL's financeability (see paragraphs 45 to 53).

### ***The financial model for PNGL12***

4. PNGL said that the financial model for PNGL12 was a model initially developed by PNGL and provided to UR as part of the discussions of PNGL12. UR then incorporated its own determination values in the model and added various worksheets which performed a financeability analysis for PNGL's operations.

### ***Financeability***

5. We set out below the key points raised by PNGL in relation to the modelling of financeability. We think that PNGL's submissions can be grouped under the following headings.
  - (a) UR's overall financeability assessment; and
  - (b) UR's dividend assumptions.

### ***Financeability assessment***

#### ***PNGL***

6. PNGL said that while poor metrics emerging from a financeability assessment could identify a situation requiring regulatory intervention or indicate a flaw in the regulatory price proposals, an acceptable financeability position did not demonstrate that the price control proposals were correct. Financeability assessments were particularly ill-equipped to validate a price control in the case of a greenfield investment such as PNGL's gas network. This was because in the later phase of a project, largely positive cash flows would almost mechanically generate a good performance with respect to credit metrics. If this good financeability performance was perceived as a justification to impose tough rulings on greenfield investments at that point in their life cycle, investors would be stripped of any incentives to commit to such projects in the

earlier phases when high costs were incurred and no return was provided to shareholders.<sup>1</sup> PNGL said that it therefore did not need to demonstrate that the financeability position was not acceptable in order to show that the 2012 TRV adjustment was inappropriate.<sup>2</sup>

7. PNGL said that under established regulatory practice a financeability assessment was applied as an additional test and that under most circumstances, allowing a reasonable return on investments would ensure that the company could finance its activities. However, under certain circumstances, a company might find it difficult to finance its activities even when the allowed return on investment was reasonable. A financeability assessment was aimed at identifying these circumstances and allowing the regulator to respond to the situation in an appropriate way.<sup>3</sup>
8. PNGL said that, in general, the regulatory duty to secure a regulated network's ability to finance its activities should be implemented by allowing a reasonable rate of return on the investments required for the licence holder to operate under its licence. PNGL said that this was not the same as a financeability test that focused only on testing for adequate metrics for debt investors, as UR's financeability analysis did.<sup>4</sup> PNGL said that UR itself said that its financeability assessment only served to show that PNGL would be able to repay its debt. PNGL said that this fell short of UR's duty to secure that PNGL was able to finance its activities, which covered both equity as well as debt finance.<sup>5</sup>
9. PNGL said that UR's ratio analysis did not include fund from operations (FFO) to net debt or the ratio of retained cash flows (RCF) to capex even though these two credit metrics were highlighted in Moody's published methodology for assessing financeability of regulated electricity and gas networks. However, PNGL noted that Ofgem had placed less emphasis on them in its RIIO model.
10. PNGL also said that UR had not calculated any equity metrics in its financeability analysis. This was contrary to the approach of Ofgem under the RIIO model, which highlighted the notional 'RAV/EBITDA' and 'Regulated Equity/Earnings' ratio for the regulated company.
11. PNGL said that, because UR's financeability assessment was based on assuming that dividends were only paid from 2019, this highlighted the risks taken by PNGL's equity investors compared with a utility with a stable dividend stream.<sup>6</sup> In PNGL's view, the assumptions underpinning the financeability assessment confirmed that PNGL was not a typical mature utility, and that its equity investors faced materially higher risks than other utilities. PNGL said that this fact was not recognized by UR in the financeability section of its Final Decisions document.<sup>7</sup>

## *UR*

12. UR said that it must take account of issues relating to the financeability of PNGL in discharging its duties.<sup>8</sup> UR said that it had carried out a thorough and robust

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<sup>1</sup> PNGL [response](#), paragraph 8.1(b) and Annex 5, paragraphs 3.4 & 3.7.

<sup>2</sup> PNGL [response](#), Annex 5, paragraph 3.6.

<sup>3</sup> PNGL [response](#), Annex 5, paragraph 3.4.

<sup>4</sup> PNGL [response](#), Annex 5, paragraph 3.3.

<sup>5</sup> PNGL [response](#), Annex 5, paragraph 2.6.

<sup>6</sup> PNGL [statement of case](#), paragraph 5.61.

<sup>7</sup> PNGL [statement of case](#), paragraph 5.62.

<sup>8</sup> UR [comprehensive response to comments on draft proposal \(2012 determination\)](#), p10.

assessment of PNGL's financeability in the PNGL12 decision to satisfy itself that the company could continue to raise capital at a reasonable rate.<sup>9</sup>

13. UR said that as part of its financeability analysis it modelled two key financial ratios (gearing (debt/TRV) and debt interest cover (post-maintenance interest cover ratio (PMICR))) with a focus on 2012 and 2013.<sup>10</sup> However, UR said that it had also considered the longer-term ability of PNGL to finance its activities.<sup>11</sup>
14. UR said that it assessed PNGL's financeability using three sets of criteria, namely the financial ratios required to satisfy:<sup>12</sup>
  - (a) an investment-grade credit rating (as per the requirement in the licence) of at least BBB- (Fitch). UR said that under Fitch's rating criteria this would imply (under normal circumstances) gearing of 80 per cent or less, and a PMICR of around 1.4x or better;
  - (b) the specific bond covenants in PNGL's existing debt (which state gearing of 77.5 per cent or less, and a PMICR of 1.4x or better for dividend lock-up); and
  - (c) PNGL's existing credit rating by Fitch which was BBB (which was one notch above investment grade) and implied a gearing of 70 per cent or less, and a PMICR of 1.5x or better.
15. UR said that for the purposes of financeability modelling it applied the most conservative criteria (ie the toughest) and therefore performed the financeability analysis on the basis of a BBB credit rating.<sup>13</sup>
16. UR said that its financeability analysis was based on PNGL's accounts for 2010 and, following discussions with Fitch, UR had adopted assumptions for working capital movements in order to align its net debt forecast for 2011 with that of Fitch's of £280.3 million.<sup>14</sup> UR said that Fitch's net debt assumption included a provision of £12 million described by Fitch as an assumption on PSL's working capital requirement (Fitch said to UR that it included this because these were assumptions provided by PNGL). UR later said that this was a loan facility that PNGL extended to PSL.<sup>15</sup> UR said that this should not in any way be considered a liability for PNGL for the purpose of this regulatory calculation. However, UR said that for prudence it retained this provision in its modelling but that if it were excluded it would result in a lower gearing in 2012.<sup>16,17</sup>
17. UR said that in its financeability assessment it assumed that PNGL would not reasonably declare dividends that would trigger a default of its licence obligation to maintain an investment-grade credit rating, and/or breach any covenants of existing debts. For modelling purposes UR assumed that this was proxied by the ratio guidelines of for a BBB (Fitch) credit rating.<sup>18</sup> UR said it therefore assumed that

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<sup>9</sup> UR [comprehensive response to comments on draft proposal \(2012 determination\)](#), p12.

<sup>10</sup> UR [PNGL12 determination](#), paragraph 1.51.

<sup>11</sup> UR [PNGL12 determination](#), paragraph 9.8.

<sup>12</sup> UR [PNGL12 determination](#), paragraphs 1.51 & 9.6.

<sup>13</sup> UR [PNGL12 determination](#), paragraph 9.7.

<sup>14</sup> UR [PNGL12 determination](#), paragraph 9.10.

<sup>15</sup> UR [initial submission](#), footnote 11, p24.

<sup>16</sup> UR [PNGL12 determination](#), footnote 39.

<sup>17</sup> UR later said that PNGL had now sold the supply business and that this would improve PNGL's financial position as the disposal had reduced PNGL's debt by £17 million and PNGL said that following the sale of PSL, PNGL no longer made loans to PSL.

<sup>18</sup> UR [PNGL12 determination](#), paragraph 9.13.

dividends would only be paid in any year to the extent that there was headroom over the ratio guidelines in the previous year.<sup>19</sup>

18. UR said that it had also assumed that the deferred tax provision made in the 2010 accounts would reverse by 2022 (increasing tax payments over that period).<sup>20</sup>
19. UR said that it used actual gearing (rather than notional gearing) in its financeability analysis.
20. UR said that at periodic reviews, the price control was reset to take into account new information. This meant that PNGL's exposure to unanticipated levels of costs or demand was limited and that, in due course, customers shared in the financial benefit or pain.<sup>21</sup> UR said that in general, PNGL was exposed for a period of up to five years, with five years being the default period of price controls specified in the licence. The current review was, however, only for a period of two years to the end of 2013.<sup>22</sup>
21. UR said that the financial model allowed it to consider the financial prospects for PNGL under a range of downside scenarios.<sup>23</sup> UR said that its downside scenario analysis assumed that allowances were not reset in future price controls.<sup>24</sup> UR modelled the following downside scenarios:<sup>25</sup>
  - (a) reductions in the level of new connections—a 50 per cent reduction in the rate of new connections from 2012 onwards; and
  - (b) Increases in costs—a 15 per cent increase in both opex and capex from 2012 onwards.
22. UR said that the risk of these variances occurring was small. This was because PNGL had a very good record of performance against regulatory allowances; because UR was allowing PNGL an increase in opex of more than 10 per cent from the last audited figures in 2009; because capex was based on contract rates with efficiencies set at 1 per cent and because connections had performed well in a difficult climate recently and it was not obvious what would lead to a 50 per cent reduction.<sup>26</sup>
23. UR said that under its central case scenario (ie assuming that PNGL's actual performance would be in line with the assumptions used in PNGL12—or, in other words assuming no out-turn variances to the regulatory allowances), debt interest cover in 2012 and 2013 was comfortably satisfied under all three sets of criteria, and remained so in all years to 2046, even after assuming the commencement of substantial dividend payments in the medium to long term.<sup>27</sup>
24. UR provided the following graph (Figure 1) that showed the result of its financeability analysis using its central case scenario.<sup>28</sup> UR said that gearing in 2012 was calculated to be 70.5 per cent (marginally above the guideline level of 70 per cent, but would be 67.5 per cent when PSL's working capital was excluded<sup>29</sup>) and in 2013 it

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<sup>19</sup> UR PNGL12 determination, paragraphs 9.14 & 9.47.

<sup>20</sup> UR PNGL12 determination, paragraph 9.11.

<sup>21</sup> UR PNGL12 determination, paragraph 9.37.

<sup>22</sup> UR PNGL12 determination, paragraph 9.38.

<sup>23</sup> UR PNGL12 determination, paragraphs 1.54 & 9.12.

<sup>24</sup> UR PNGL12 determination, paragraph 9.38.

<sup>25</sup> UR PNGL12 determination, paragraph 9.39.

<sup>26</sup> UR PNGL12 determination, paragraph 9.40.

<sup>27</sup> UR PNGL12 determination, paragraph 1.52.

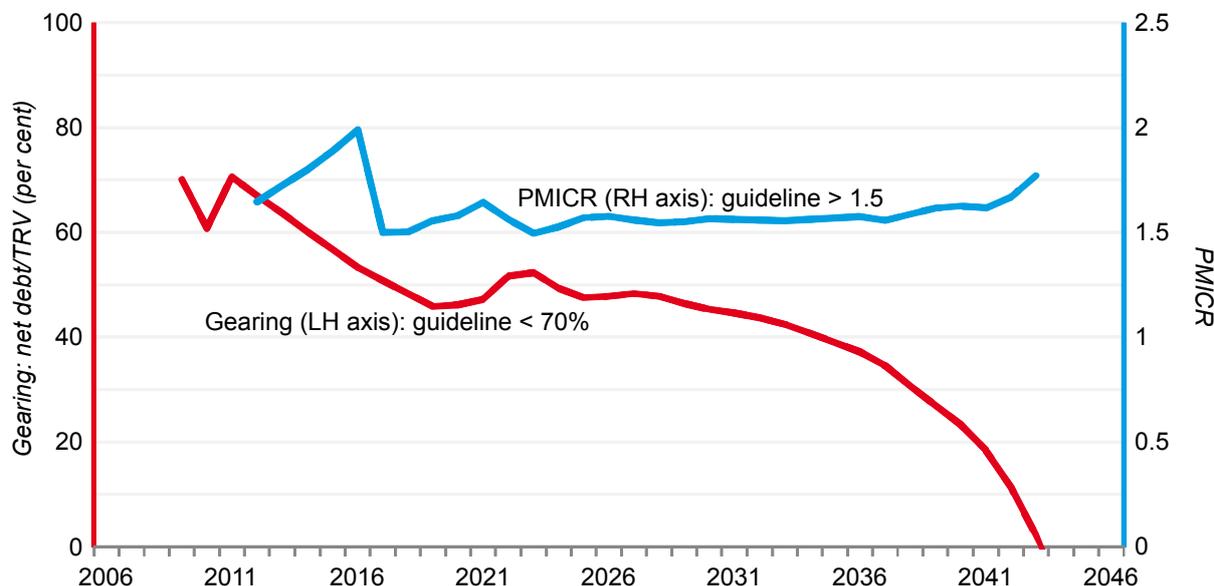
<sup>28</sup> UR PNGL12 determination, Diagram 3.

<sup>29</sup> UR PNGL12 determination, footnote 38.

was 69.5 per cent, which satisfied the requirements for an investment-grade credit rating and the bond covenants. UR said that its modelling further indicated that gearing would fall progressively from 2012.<sup>30</sup>

FIGURE 1

### Result of UR financeability analysis



Source: UR.

25. UR said that, in its central case scenario, the PMICR in 2012 was 1.6x which was above the BBB guideline level.<sup>31</sup> UR said that in 2013 the PMICR would be 1.7x.<sup>32</sup> See also figure 1.
26. UR said that the results of its downside scenario modelling demonstrated that there was no significant pressure on the ratios in 2012 or 2013. Looking over the longer term and even assuming allowances were not reset at future price controls, gearing remained well below Fitch guidelines. UR said that the PMICR ratio (under the downside scenario) was projected to dip below the BBB guidelines when the cost of capital allowance fell to its new level in 2017. However, the ratios never breached the BBB-guidelines nor the bond covenants and the PMICR was restored to Fitch's BBB guideline through a delay in dividend payments. UR said that even under the downside scenario PNGL would be able to pay significant dividends in later years and would earn a healthy return on equity.<sup>33</sup> UR said that PNGL remained financeable in the downside scenario assuming it adopted a prudent dividend policy.<sup>34</sup>
27. UR said that its financeability analysis therefore indicated that the revenues that PNGL would generate after the 2012 TRV adjustment would be sufficient to secure that PNGL's debt could be repaid.<sup>35</sup>

<sup>30</sup> UR [PNGL12 determination](#), paragraphs 1.53 & 9.29.

<sup>31</sup> UR [PNGL12 determination](#), paragraph 9.29.

<sup>32</sup> UR [PNGL12 determination](#), paragraph 9.30.

<sup>33</sup> UR [PNGL12 determination](#), paragraphs 9.44 & 9.49.

<sup>34</sup> UR [PNGL12 determination](#), paragraph 1.54.

<sup>35</sup> UR [supplementary submission](#), paragraph 2.143.

28. UR said that the underlying financial resilience in the short, medium and longer term meant that PNGL was inherently robust and it was satisfied that its final decisions would leave PNGL on a financially sustainable trajectory and that PNGL would be able to raise finance at an appropriate cost of capital.<sup>36</sup>

#### *Third party views*

29. Northern Ireland Electricity (NIE) said that it had concerns in relation to the approach UR had adopted to assessing PNGL's financeability. Contrary to Great Britain regulatory practice UR's analysis ignored dividends, short-term financial metrics and the adverse impact its proposals would have on PNGL's ratings and cost of debt.<sup>37</sup>
30. Fitch said on 2 May 2012 that it affirmed the £275 million bond issued by PNGL at BBB+. Fitch said that the affirmation reflected Fitch's expectation that PNGL could maintain a financial profile commensurate with existing ratio guidelines of net debt to TRV below 70 per cent and a PMICR above 1.5x for during 2012 and 2013. This was based on the preliminary financials for 2011 and UR's January 2012 decision, which now indicated a gearing close to 70 per cent for 2012 and lower thereafter. This lower than expected (preliminary) outcome was driven by slightly better cash flow generation than previously forecast by Fitch, higher out-turn retail price inflation and PNGL not paying any dividends as well as a slightly lower TRV adjustment in the final PNGL12 decision compared with the draft decision. Fitch's analysis included in full UR's 2012 TRV adjustment of £74.4 million (in 2010 prices).<sup>38</sup>
31. Fitch said that given the 2012 TRV adjustment included a retrospective clawback of £59.6 million of opex and capex outperformance, which was inconsistent with PNGL's existing licence, Fitch could change its view on predictability and supportiveness of the regulatory regime in Northern Ireland. However, Fitch said that it would not do so before our decision and before the next price control settlement for 2014 to 2018. Fitch said that a revision of financial guidelines for the regulatory regime in Northern Ireland might lead to a ratings downgrade.<sup>39</sup>
32. Fitch said that it maintained a negative outlook for PNGL pending the outcome of our proceedings, and/or further evidence related to the development of the regulatory regime (including the assumptions and scope for dividends) for gas distribution networks in Northern Ireland, expected by the end of 2013 through the outcome of the price control review for the period 2014 to 2018.<sup>40</sup>
33. Fitch said that it would look to resolve the outlook and rating for PNGL either after our decision or in the third quarter of 2013 together with the next price control settlement, taking into account the impact of any TRV adjustment on quantitative ratios as well as its qualitative criteria and regulatory assessment for PNGL.
34. Fitch said that when it placed PNGL on negative rating watch in October 2011 it had assumed that PNGL's gearing would increase to a range of 75 to 80 per cent at December 2011 following the 2012 TRV adjustment.<sup>41</sup>
35. Moody's said that given the long-dated nature of PNGL's asset base and of the regulatory model for earning a return, UR's adjustment to TRV had only a minimal

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<sup>36</sup> UR PNGL12 determination, paragraph 1.55; UR comprehensive response to comments on draft proposal (2012 determination), p10.

<sup>37</sup> NIE initial submission.

<sup>38</sup> Fitch Ratings 2 May 2012.

<sup>39</sup> Fitch Ratings 2 May 2012.

<sup>40</sup> Fitch Ratings 2 May 2012.

<sup>41</sup> Fitch Ratings 2 May 2012.

impact on near-term revenue and cash flow. Therefore, most cash-flow ratios, including FFO/interest, FFO/net debt and RCF/capex were only slightly affected by the 2012 TRV adjustment. For net debt/TRV, while the adjustment was more significant (the ratio increased to the mid-60s in percentage terms from the mid-50s), PNGL's current rating of Baa2 was based on the expectation that leverage would remain no higher than the low 70s in percentage terms, and was thus unaffected.

36. Moody's said that while ratios might not be materially affected, regulatory risk for PNGL could increase following UR's actions. Moody's said that it would await our re-determination before making any reassessment of the transparency and predictability of the regulatory framework in Northern Ireland. Moody's said that in the event that we ruled against PNGL, Moody's could not exclude the possibility that PNGL's credit rating could be affected. However, the rating agency's approach would be to balance any perceived deterioration in the regulatory environment in Northern Ireland against the headroom established by PNGL in its financial metrics at the current rating level.

## *Dividends*

### *PNGL*

37. PNGL said that UR's financeability assessment was based on inappropriate and unrealistic assumptions:<sup>42</sup>
- (a) PNGL said that UR assumed that PNGL would not pay any dividends before 2018. PNGL said that this assumption was not explained nor justified.
  - (b) PNGL said that UR's financial model adjusted the dividend payments immediately downwards if the financial metrics came under stress (ie dividends were only paid if the net debt to TRV ratio was less than 70 per cent and the PMICR was above 1.5x). This was contrary to standard regulatory practice which allowed for a reasonable level of dividends in each year. As a consequence, there was a real risk that the analysis would conclude that the financial metrics were acceptable even when the utility was not, in fact, financeable.<sup>43</sup> This was because this assumption automatically generated an outcome where the financial ratios remained above the thresholds regardless of whether UR's determination figures would cause financeability problems. This undermined the purpose of the financeability test (which was to assess whether both debt and equity investment continued to be attracted in light of UR's determination).<sup>44</sup> This also resulted in a more volatile profile of earnings for equity investors than would be typically expected for a utility.<sup>45</sup>
  - (c) PNGL said that adjustments to the dividend profile might be considered as a possible solution to a financeability problem when it occurred. However, it was not appropriate to assume that dividends were just varied altogether for whatever time necessary when assessing if there was a financeability problem.<sup>46</sup>
  - (d) PNGL said that UR did not perform any further analysis of the sustainability of the assumed dividend policy, for instance through assessing the RCF to capex ratio.

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<sup>42</sup> PNGL [response](#), paragraph 8.1(a) and Annex 5, paragraphs 2.1 & 2.4.

<sup>43</sup> PNGL [response](#), paragraph 8.1(a) and Annex 5, paragraphs 2.1 & 2.4.

<sup>44</sup> PNGL [response](#), Annex 5, paragraph 2.2.

<sup>45</sup> PNGL [statement of case](#), paragraph 5.60.

<sup>46</sup> PNGL [response](#), Annex 5, paragraph 2.3.

38. PNGL said that UR should assume a steady payment of dividends to shareholders in each year. In the specific case of PNGL, this stream must start in the short term as PNGL had now gone 16 years without paying a dividend during the investment phase of the network.<sup>47</sup>
39. PNGL said that it was standard practice for regulators, when making a financeability assessment, to allow for a reasonable level of dividends in each year. PNGL said that typically, regulators assumed a starting point dividend yield and applied a dividend growth rate in subsequent years.
- (a) PNGL suggested using an assumption of a 5 per cent starting dividend yield; and
- (b) a dividend growth of 1 to 5 per cent a year (in line with regulatory equity growth rates).

#### *UR*

40. UR said that its analysis showed that PNGL was substantially cash-flow positive in the medium to long term, allowing PNGL to pay substantial dividends to its investors, in particular in the final two decades or so of the licence period. UR was therefore content that the business remained inherently financeable under UR's PNGL12 decision.<sup>48</sup>
41. UR said that PNGL was never likely to pay a dividend in 2012 and 2013 and that PNGL itself had stated this in its response to the draft proposals consultation for PNGL12. With no dividend payments planned in these years, PNGL's gearing and PMICR during this price control would comfortably be within the guideline levels needed for an investment-grade credit rating.<sup>49</sup>
42. UR said that the sharp return of value over the last 20 years or so of the licence period provided a natural starting point for shareholder dividends (ie dividend flows would naturally be weighted towards the back end of the licence period<sup>50</sup>).<sup>51</sup> UR said that this was always the intention and was fully understood by all parties at the outset of PNGL's operations in 1996. For 2012 and 2013 it was clear that it would not be appropriate to assume dividends.<sup>52</sup> UR said that there was adequate headroom in the ratios for PNGL to begin paying dividends averaging £12.4 million in 2019.<sup>53</sup> UR said that the key assumption driving this assessment was that the cost of capital allowance would reduce from 2017 (UR said it assumed an allowance at 7.5 per cent until 2016 and an allowance of 5.866 per cent in 2017 and beyond in line with Ofgem's initial cost of capital assessment for the GDNs in its last price control review) and that this meant that the constraining financial indicator for dividends was the PMICR, Fitch's guideline level for which was 1.5x or better (for a BBB credit rating).<sup>54</sup>
43. UR also said that assumptions for dividends needed to take into account that PNGL was still deferring revenues under the profile adjustment.

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<sup>47</sup> PNGL response, Annex 5, paragraph 2.5.

<sup>48</sup> UR PNGL12 determination, paragraphs 9.35 & 9.48.

<sup>49</sup> UR PNGL12 determination, paragraphs 9.24, 9.31 & 9.34.

<sup>50</sup> UR PNGL12 determination, paragraph 9.24.

<sup>51</sup> UR PNGL12 determination, paragraph 9.23.

<sup>52</sup> UR PNGL12 determination, paragraphs 9.24 & 9.31.

<sup>53</sup> UR PNGL12 determination, paragraphs 9.25 & 9.32.

<sup>54</sup> UR PNGL12 determination, paragraph 9.26.

44. UR also said that Ofgem's RIIO model did foresee that regulated companies would address financeability issues by (among other actions) reducing dividends.

### *Assessment*

45. We do not think that we necessarily need to re-perform the financeability analysis for our redetermination. This is because our determined adjustment to the 2012 opening TRV is much smaller than the 2012 TRV adjustment in UR's PNGL12 decision. We therefore first assess whether UR's financeability analysis in its PNGL12 charge control decision sufficiently demonstrates that PNGL is financeable.
46. We note that under UR's analysis (which included the full 2012 TRV adjustment of £74.4 million) PNGL's net debt/RAV ratio is at or below the 70 per cent threshold for 2012 and 2013 (and below 70 per cent if the loan to the supply business is excluded in the calculation for gearing) and that the PIMCR ratio is well above the 1.5x threshold for both 2012 and 2013.
47. We do not agree with PNGL that UR made inappropriate assumptions on PNGL's dividend payments for the duration of the PNGL12 charge control (ie for 2012 and 2013), given that PNGL itself indicated that it was not intending to pay dividends in 2012 and 2013.
48. We also note that whilst PNGL suggested that we should look at ratios other than the net debt/TRV and PMICR ratio, it has not provided any evidence indicating that these ratios would demonstrate that it would not be financeable under UR's PNGL12 decision. We therefore did not look at other financial ratios.
49. We do not think that looking at PNGL's financeability beyond PNGL12 (ie beyond the time frame of 2012 and 2013), other than at a very high level, is necessary given that UR is under a duty to ensure that PNGL is able to finance itself when it makes the next charge control decision.
50. We also do not think that UR's assumptions on PNGL's dividends beyond 2013 was necessarily inappropriate. This is because we think that it is, in principle, for PNGL to decide how best to finance itself and that the payment of dividends is part of PNGL's financing decisions and because no more than a high-level assessment was needed for the period beyond 2013 for the reasons set out in paragraph 49.
51. We also note that both Fitch's and Moody's assessment in May and April 2012 respectively, indicate that PNGL's financial ratios (even including UR's full 2012 TRV adjustment of £74.4 million) are sufficient to sustain PNGL's investment-grade credit rating.
52. We set out in Section 8 that we were very aware of the risks to PNGL's credit rating stemming from regulatory uncertainty and took this into consideration when deciding on the appropriate adjustment to the TRV. We do think that the TRV adjustments in our decision are transparent, well justified and in line with regulatory best practice and do therefore not think that our decision is likely to weaken the regulatory system in Northern Ireland and we therefore do not think that our decision would lead to a downgrade in PNGL's credit rating because of a revised assessment by the ratings agencies of the regulatory framework for Northern Ireland.
53. We therefore think that the analysis that UR performed at the time of its PNGL12 decision sufficiently demonstrates that PNGL is financeable for the duration of the PNGL12 charge control even if UR's 2012 TRV adjustment is made in full. It follows that, as the adjustment to the 2012 opening TRV in our redetermination is less than

the adjustment that UR made to the 2012 opening TRV, PNGL is also financeable for the duration of the PNGL12 charge control in our decision.

## Third party submissions in response to our provisional decision

### CCNI

1. CCNI submitted that it was difficult to comprehend the impact of regulatory uncertainty on future gas consumers, in relation to the expansion of the network. It argued that if gas was extended to the West, it would only bring gas to a maximum consumer base of approximately 30,000 homes. Therefore, CCNI argued that it was mainly the existing and future consumers in the licence areas for PNGL and firmus who would be affected by our decision. It noted that there was very little information to quantify the benefit to Northern Ireland consumers of our decision.<sup>1</sup>

### Bombardier Aerospace<sup>2</sup>

2. Bombardier submitted that it appreciated and supported a drive towards a sustainable, reliable and competitive future energy supply mix but stated that the pursuit of this long-term ideal could not jeopardize fairness nor the short-term profitability and sustainability of Northern Ireland businesses. Bombardier urged us to consider the importance of competitive energy costs for large industrial and commercial customers. It also proposed that it was not fair that current gas consumers should face higher costs to fund further development of the gas network because each extension of the gas network must be economically viable in its own right.

### Bryson Energy

3. Bryson Energy indicated that UR's PNGL12 decision would not prevent new investment as gas companies were seeking to extend their network. It suggested that PNGL earned a return which was higher than that required to supply gas at the minimum economic cost, as originally intended by Parliament. Bryson Energy did not believe that uncertainty would be created if the return were 'more realistically' aligned to the risk.<sup>3</sup>

### Manufacturing NI

4. Manufacturing NI urged us to consider that competitive energy costs were vital to the survival of the manufacturing sector in Northern Ireland.<sup>4</sup>
5. Manufacturing NI argued that there had been no evidence since UR's PNGL12 decision of lack of investor confidence—Manufacturing NI pointed to firmus' plan to extend its network to the town of Bushmills, and indicated that both firmus and PNGL continued to connect customers within their existing areas.<sup>5</sup>

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<sup>1</sup> CCNI [response to the provisional determination](#).

<sup>2</sup> Bombardier [response to the provisional determination](#).

<sup>3</sup> Bryson Energy [response to the provisional determination](#).

<sup>4</sup> Manufacturing NI [response to the provisional determination](#).

<sup>5</sup> Manufacturing NI [response to the provisional determination](#).

## Age NI

6. Age NI said that it supported UR's PNGL12 decision.<sup>6</sup> It supported the view that the PNGL12 decision should not damage the investment climate in Northern Ireland. As counter-evidence of the investment climate having been damaged by UR's PNGL12 decision, Age NI argued that both PNGL and firmus were continuing to connect new gas customers and extending into new areas.<sup>7</sup>

## Centre for Progressive Economics<sup>8</sup>

7. The Centre for Progressive Economics' (CPE's) submission suggested that the PNGL12 decision might introduce regulatory uncertainty to the detriment of customers if shareholders had an unchallenged right to excess profits in perpetuity. CPE indicated that there was a dearth of evidence regarding the extent to which investment in Northern Ireland had been, or would be, deterred due to regulatory uncertainty. CPE argued that the future cost of capital was uncertain, therefore 'any shocks to the system [can be] managed if and when they arise'.

## ContourGlobal<sup>9</sup>

8. ContourGlobal supported UR's PNGL12 decision. It said that the Northern Ireland gas market was not competitive, or transparent, and that our PNGL12 provisional determination had not given a clear message of regulatory certainty which was required for a long-term investment decision. ContourGlobal argued that the (lack of) transparency and competitiveness in the gas market adversely impacted on its investment decisions and commitment to Northern Ireland.

## Green Party Northern Ireland<sup>10</sup>

9. The Green Party questioned the extent to which UR's PNGL12 decision would increase the cost of capital for PNGL. It argued that if the financing costs of PNGL, or any utility company, were to increase there would be mechanisms available to UR to reopen the price control and ensure access to finance.
10. The Green Party also questioned the extent to which there was a likelihood of expansion of the gas network in Northern Ireland. It highlighted evidence from Lord Whitty which suggested that proposals to extend the gas network were uneconomic. The party also highlighted that the Energy Saving Trust & Action Renewables group had asserted that the proposals for expansion of the gas network were not cost-effective and ought to be reconsidered.
11. The Green Party argued that a ruling in favour of UR would send a positive signal to the investment community which would demonstrate that investors should not expect to get away with earning excessive and unjustified profits.

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<sup>6</sup> Age NI [response to the provisional determination](#).

<sup>7</sup> Age NI [response to the provisional determination](#).

<sup>8</sup> CPE [response to the provisional determination](#).

<sup>9</sup> ContourGlobal [response to the provisional determination](#).

<sup>10</sup> Green Party [response to the provisional determination](#).

## **Mutual Energy<sup>11</sup>**

12. Mutual Energy submitted that it was difficult to substantiate that there had been a reduction in investor appetite due to UR's PNG12 decision, given substantial industry interest in the Gas to the West project. Mutual Energy also suggested that rating agencies might have a short-term reaction to an adverse decision for PNG12 but this would not raise the cost of investment in the long term.

## **National Energy Action Northern Ireland<sup>12</sup>**

13. National Energy Action Northern Ireland (NEA) noted that firmus had applied for an extension in its network and therefore submitted that the perceived risk to potential investors following the PNG12 decision was minimal. It urged us to prioritize the needs of current gas customers in Northern Ireland, many of whom were experiencing fuel poverty.

## **Patsy McGlone<sup>13</sup>**

14. Patsy McGlone is a member of the NI Assembly and sits on the Committee for Enterprise, Trade & Investment. She urged us to consider recent developments in the gas market, specifically the sale of Phoenix's gas supply business to Airtricity in June 2012, and firmus' application to build beyond its licensed area into Bushmills. She also emphasized that the Gas to West project had interest from several companies. She suggested that these examples of investment and expansion provided counter-evidence against 'unquantifiable warnings' which had been submitted to us with regards to investor confidence in NI.

## **John Thompsons & Sons Limited<sup>14</sup>**

15. John Thompsons & Sons submitted that the cost of 'perceived' regulatory uncertainty might actually be cheaper than the penalty for seeking to avoid it, given the uncertainty surrounding potential expansion of the gas network and the extent of the savings which accrued to households that switched to gas from oil. It suggested that the public interest would be better served by allowing a 'regulatory risk premium' to be factored into gas customers' bills should there be any detrimental impact of our upholding UR's PNG12 decision.

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<sup>11</sup> Mutual Energy [response to the provisional determination](#).

<sup>12</sup> NEA [response to the provisional determination](#).

<sup>13</sup> Patsy McGlone [response to the provisional determination](#).

<sup>14</sup> John Thompsons & Sons [response to the provisional determination](#).

## Glossary

<b>1996 licence</b>	<b>PNGL</b> 's original licence, before the amendments following the 2007 revisions.
<b>1999/2000 capex deferrals</b>	A subset of <b>PNGL</b> 's overall capex deferrals. <b>PNGL</b> identified a list of larger projects, as part of the <b>PC03</b> and <b>PC2012</b> determinations, that were subject to deferral, and where the initial allowances for these larger projects were included in <b>UR</b> 's <b>PC01</b> determination in the years 1999 and 2000. The 1999/2000 capex deferrals are set out in Appendix 4 of <b>UR</b> 's <a href="#">2012 determination</a> .
<b>2006 TRV/TRV<sub>F,2006</sub></b>	The <b>OAV</b> which is incorporated in <b>PNGL</b> 's current licence.
<b>2007 determination</b>	Used throughout this report to refer to the <a href="#">PC03</a> price determination and licence modifications together. While separate, and enacted at different times—see paragraphs 2.49 to 2.59, we have found it useful to have a term to refer to the effect of the package of measures together.
<b>2011 consultation paper</b>	<b>UR</b> 's August 2011 <a href="#">consultation paper</a> on the 2012 price determination.
<b>Actualization</b>	The process of replacing forecast input data (for example, in the <b>OAV</b> calculation) with audited out-turn data.
<b>Airtricity</b>	A <b>gas supply business</b> . <b>PSL</b> was sold to SSE plc (Airtricity) in June 2012.
<b>Allowed revenue</b>	The revenue for the conveyance of gas determined by <b>UR</b> which <b>PNGL</b> is entitled to recover under its conveyance charging methodology.
<b>BG</b>	British Gas plc.
<b>Bord Gáis Éireann</b>	A major energy provider, owned by the Republic of Ireland state, supplying both gas and electricity to homes and businesses throughout the Republic of Ireland, and through its subsidiary, firmus energy, also in Northern Ireland.
<b>Capex</b>	Capital expenditure.
<b>CAPM</b>	Capital asset pricing model. This is used to determine the theoretically appropriate rate of return on an asset. In utility regulation, the CAPM is widely used to estimate the cost of equity for a company.
<b>CCNI</b>	The Consumer Council for Northern Ireland.
<b>Combined licence</b>	A combined licence for the conveyance and supply of gas.
<b>DAV</b>	Depreciated asset value. DAV captures the <b>OAV</b> and the asset value of the investments undertaken by <b>PNGL</b> since 2007 (net of depreciation).

<b>Deferred capex</b>	<b>Capex</b> for which <b>PNGL</b> has been provided an allowance, but where the investment has not yet taken place or took place at a date later than originally forecast.
<b>DETI</b>	The Department of Enterprise, Trade and Investment Northern Ireland.
<b>DFP</b>	Department of Finance and Personnel, Northern Ireland.
<b>Distribution</b>	Refers to the gas networks that take gas from the high-pressure transmission system, and distribute it locally to households or industrial and commercial customers, including supplying the meter at the customer's premises.
<b>Energy Order</b>	Energy (Northern Ireland) Order 2003. One of the Orders that regulate the carriage of natural gas in Northern Ireland.
<b>ESH</b>	East Surrey Holdings plc.
<b>firmus</b>	firmus energy. Distributes and supplies gas in Northern Ireland.
<b>Fitch Ratings</b>	A global credit rating agency.
<b>Gas Directive</b>	<a href="#">Directive 2009/73/EC</a> of the European Parliament and the Council of 13 July concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC.
<b>Gas Order</b>	Gas (Northern Ireland) Order 1996.
<b>Gas supply businesses</b>	Gas supply businesses sell gas to customers. The customer contract is with the supply business, which pays for use of the distribution network.
<b>GDN</b>	Gas distribution network. There are eight gas distribution networks in Great Britain, which each cover a separate geographical region of Great Britain.
<b>Good Friday agreement</b>	This refers to a major political development in the Northern Ireland peace process in April 1998.
<b>Greenfield</b>	Greenfield investment relates to previously undeveloped sites for commercial development or exploitation.
<b>I&amp;C</b>	Industrial and commercial gas customers
<b>IGT</b>	Independent Gas Transporter.
<b>Kellen Acquisitions Limited</b>	An acquisition vehicle for <b>Terra Firma</b> .
<b>Legacy contracts</b>	<b>PNGL</b> 's contracts for the supply of gas to large customers that were agreed before there was effective competition in the supply of gas.
<b>Licensed Area</b>	The designated area for which <b>PNGL</b> can convey gas under its licence.

<b>Licence recovery period</b>	The term over which <b>PNGL</b> was able to recover its investment.
<b>LPG</b>	Liquid propane gas.
<b>Management fee</b>	An allowance granted by <b>UR</b> to <b>PNGL</b> to cover the costs of managing <b>PNGL</b> 's <b>capex</b> programme (including the management costs associated with the <b>McNicholas</b> contract).
<b>Mandatory development plan</b>	Contained in the 1996 licence and requiring <b>PNGL</b> to develop a sustainable network through which natural gas would be available to no less than 81 per cent of all properties within the <b>Licensed Area</b> within a fixed rolling timescale.
<b>MAR</b>	Market to asset ratio: the rate of a company's market value to the value of its assets.
<b>McNicholas</b>	McNicholas Construction Services Limited— <b>PNGL</b> 's contractor for roll-out of the gas <b>distribution</b> network.
<b>MMC</b>	Monopolies and Mergers Commission. The CC replaced the MMC on 1 April 1999.
<b>Moody's</b>	A global credit rating agency.
<b>Mutual Energy</b>	A company which owns and operates the Moyle Interconnector which links the electricity systems of Northern Ireland and Scotland, and the Premier Transmission Pipeline System, which consists of the Scotland to Northern Ireland natural gas transmission pipeline and the Belfast Gas Transmission Pipeline.
<b>Mutualization</b>	Conversion from an equity-based ownership model to a 100 per cent debt-financed ownership model where customers carry all risks (ie a 'mutual' model).
<b>Network roll-out</b>	The building of the gas <b>distribution</b> network by <b>PNGL</b> .
<b>NPV</b>	Net present value. When applied to a sequence of net cash flows, the NPV is the discounted sum of that sequence at a given discount rate.
<b>NIE</b>	Northern Ireland Electricity Limited.
<b>NIEH</b>	Northern Ireland Energy Holdings.
<b>NIHE</b>	Northern Ireland Housing Executive.
<b>NRAs</b>	National regulatory authorities.
<b>OAV</b>	Opening asset value. This is the initial value of <b>PNGL</b> 's <b>TRV</b> as determined in <b>UR</b> 's <b>2007 determination</b> .
<b>Ofcom</b>	Independent regulator and competition authority for the UK communications industries.

<b>Ofgem</b>	The Office of the Gas and Electricity Markets. Its responsibilities include protecting consumers, promoting competition and regulating the monopoly companies which distribute and supply the gas and electricity within Great Britain.
<b>Ofwat</b>	The Water Services Regulation Authority, economic regulator of the water and sewerage sectors in England and Wales.
<b>Opex</b>	Operating expenditure.
<b>Outperformance</b>	Cost (or volume) performance below (or above) the target level set at a price control review.
<b>PAYG metering</b>	Pay-as-you-go metering.
<b>PC01</b>	First <b>PNGL</b> price control covering the period 1996 to 2001.
<b>PC02</b>	Second <b>PNGL</b> price control covering the period 2002 to 2006.
<b>PC03</b>	Third <b>PNGL</b> price control covering the period 2007 to 2011.
<b>PNGL12/PC</b>	Fourth <b>PNGL</b> price control covering the period 2012/13.
<b>PNGL</b>	Phoenix Natural Gas Limited.
<b>Postalized</b>	To structure rates or prices so that they are not distance-sensitive, but depend on other factors, such as level of usage, type of service and time of day.
<b>Profile adjustment</b>	Component of <b>PNGL's TRV</b> that 'logs up' revenue recoveries that are deferred to later in the licence period (which lasts until 2046).
<b>PSL</b>	Phoenix Supply Limited. <b>PNGL's</b> gas supply business, which separated from <b>PNGL</b> in January 2007. PSL is selling gas to customers but has now been sold to <b>Airtricity</b> in June 2012.
<b>RAB</b>	Regulatory asset base.
<b>Ratchet mechanism</b>	At periodic price control reviews, future allowances are 'ratcheted' down to reflect historic efficiencies. This means that customers can benefit in future charge controls from efficiencies achieved within a price control period (and also allowing increased profit during the control period for the regulated company).
<b>Rate of return</b>	The return (or profit) made on an investment.
<b>RAV</b>	Regulatory asset value.
<b>Revenue reprofiling</b>	In <b>PNGL's</b> case, this refers to the deferral of revenue to later in the licence period (to reflect an increase in expected volumes over time as new customers connect to the network).
<b>Risk-free rate</b>	The theoretical <b>rate of return</b> of an investment with no risk of financial loss.

<b>Rolling retention mechanism</b>	Mechanism that allows for the regulated company to retain the benefit of <b>outperformance</b> for a given number of years (typically five years) regardless of when the <b>outperformance</b> is achieved.
<b>Second EU Gas Directive 2003/55/EC</b>	This <a href="#">directive</a> concerns common rules for the EU internal market in natural gas.
<b>Terra Firma</b>	Terra Firma Capital Partners Limited.
<b>Therms</b>	A unit of heat equal to 100,000 British thermal units ( $1.054 \times 10^8$ joules) and is used to measure amounts of gas.
<b>Transmission</b>	The transmission network refers to the high-pressure major gas pipeline network.
<b>TRV</b>	Total regulatory value of <b>PNGL</b> . This represents the value of the <b>RAB</b> at any given point in time. <b>PNGL</b> 's initial 2006 <b>TRV</b> for 2007 was also called the <b>OAV</b> .
<b>Underperformance</b>	Cost (or volume) performance above (or below) the target level set at a price control review, ie costs above target.
<b>UR</b>	The Northern Ireland Authority for Utility Regulation.
<b>WACC</b>	Weighted average cost of capital. It reflects a blended rate of the company's cost of debt and the cost of equity.
<b>WCA</b>	Working capital allowances.
<b>Working capital</b>	The cash required to cover financing shortfalls arising from day-to-day operations.
<b>Z</b>	Unrecovered revenue resulting from <b>PNGL</b> setting prices below the levels allowed price control in the period 1996 to 2006.