Terms of reference and conduct of the inquiry

On 30 April 2013 the Northern Ireland Authority for Utility Regulation made the following reference to the CC:

Notice under Article 15 of the Electricity (Northern Ireland) Order 1992

The Northern Ireland Authority for Utility Regulation (the **Authority**), pursuant to Article 15(1) of the Electricity (Northern Ireland) Order 1992 (the **Order**), gives notice as follows.

WHEREAS—

(A) Northern Ireland Electricity Limited (**NIE**) is under Article 10 of the Order:

(a) the holder of a licence authorising it to participate in the transmission of electricity; and

(b) the holder of a licence authorising it to distribute electricity,

(each a **Licence**).

(B) Condition 42 and Annex 2 in each Licence—the **Price Control Conditions**—establish a restriction on the charges that may be made by NIE for the transmission and distribution of electricity.

(C) On 23 October 2012 the Authority, in accordance with Article 14 (2) of the Order, gave notice to NIE that it proposed to modify each Licence in order to implement new price control arrangements for the period 1 January 2013–30 September 2017 (the **RP5 Price Control**).

(D) The Authority proposed to—

(a) modify the Price Control Conditions in each Licence by deleting current Annex 2 and replacing it with a new Annex 2;

(b) make a consequential modification to Condition 1 of each Licence; and

(c) introduce a new condition in each Licence setting out requirements in respect of a new “Reporter” function being introduced in the RP5 Price Control period,

(the **Modification**).

(E) In accordance with Article 14(1)(a) of the Order, the Authority may only make the Modification if NIE consents to it.

(F) On 20 November 2012, NIE notified the Authority that it did not consent to the Modification in either Licence.

NOW—

(1) In accordance with Article 15(1) of the Order, the Authority, by reference to the Competition Commission (the **Commission**) in respect of each Licence, requires the Commission to investigate and report on the questions—

(a) whether the Price Control Conditions in each Licence operate or may be expected to operate against the public interest,

(b) whether the continuation of each Licence operates or may be expected to operate against the public interest absent the inclusion of further conditions designed to improve the recording, reporting, monitoring and verification of information related to the Price Control Conditions and related conditions of the Licences, and

(c) 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 each Licence.

(2) In accordance with Article 15A(1) of the Order, the Authority specifies that the Commission makes a report on each reference within six months of the date of this notice.

SHANE LYNCH

Authorised on behalf of the Authority 30 April 2013

Description of network

Changing role of NIE

1. NIE used to be the only company operating in the electricity industry in Northern Ireland. Since the early 1990s, government and regulatory decisions have introduced competition to some parts of the industry.

2. Generators, such as power stations and wind farms, are now owned and operated by private companies and compete to sell electricity into the SEM. This is an all-Ireland mandatory pool. Similarly electricity suppliers (companies that issue the bills for electricity usage) compete for customers. Homes and businesses can choose their electricity supplier as a result of the competition afforded by the SEM and customers are able to switch suppliers if they wish. The process of switching suppliers was assisted by NIE's Enduring Solution programme.[1]

3. NIE is the network owner. The company owns the T&D networks. It is not permitted to generate or supply electricity. Although NIE owns the transmission network it is operated by SONI Ltd. As a natural monopoly NIE is the only electricity network company in Northern Ireland, and is therefore regulated by the UR.

Electricity generation

4. Electricity is generated by large thermal generators operated by AES and ESB and renewable energy sources for sale to the SEM. These can be large power plants that use coal, oil or gas or can be other types of electricity generators like wind farms.

5. The electricity current generated by power stations is sent through transformers which increase the voltage to levels necessary to transmit the power efficiently over long distances. The major fossil fuel power stations in Northern Ireland are located at Ballylumford, Kilroot and Coolkeeragh.

6. More wind farms are being built to connect to the grid and generate electricity. Currently there are 29 large wind farms and multiple one-off small wind turbines in Northern Ireland producing approximately 11 per cent of electricity consumed.

Electricity transmission

7. Electric-power transmission is the bulk transfer of electrical energy from generating power plants to electrical substations located near demand centres. Electricity is transmitted at very high voltages (110 kV or above) to minimize the energy lost when transported over long distances. In Northern Ireland electricity is transmitted at 275 kV or 110 kV.

8. There are over 400 km of 275 kV transmission lines and over 900 km of 110 kV transmission lines across Northern Ireland. These are mainly carried on steel pylons although some wood pole construction is used at 110 kV. There is also around 90 km of 110 kV underground cable. NIE owns and maintains these transmission lines and cables in Northern Ireland.

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[1] An IT project undertaken by NIE to meet legislative and regulatory requirements for a competitive retail electricity market—including full separation of the customer billing processes—which assisted customers' ability to change electricity supplier.

9. When transmission lines reach substations which are located close to major load centres, the voltage is lowered so that it can be sent through smaller power lines or cables.

10. The Northern Ireland network is connected to the Scottish network via the Moyle Interconnector, which runs from Islandmagee to Ayrshire. There is a 275 kV double circuit interconnector between Tandragee and Louth in the Republic of Ireland, and there are two smaller 110 kV connections at Enniskillen and Strabane.

Electricity distribution

11. The distribution network carries electricity from the transmission system and delivers it through high-voltage and low-voltage networks of wood-pole lines and cables to consumers' premises. The distribution system begins as the electricity circuit leaves the substation and ends as it enters the customer's meter. Most distribution lines connect to another substation or transformer that reduces the voltage again to take the power safely into customers' houses.

12. Conductors for distribution may be overhead lines carried on wood poles, or in urban areas they can also be cables buried underground.

13. Houses connect to the distribution network through a service cable (overhead lines or underground cable) to where the meter is located. The service cable is supplied from an 11 kV/LV transformer which transforms the voltage to 230 V, the standard voltage for domestic wiring, lighting and appliances.

14. The transformer may be pole-mounted or set on the ground in a protective enclosure. In rural areas a pole-mounted transformer often serves only one customer. In higher populated areas multiple customers may be connected through one transformer, mini-pillar or underground box.

15. The meter measures how much electricity a customer uses. NIE owns the network up to and including the electricity meters.

Electricity suppliers

16. Electricity suppliers, including ESB, power ni, energia, Airtricity and firmus among others, buy and then sell electricity to customers. The electricity supplier bills customers and deals with billing enquiries. Customers pay for the units of electricity they use and their bills are made up of network, generation and other costs (including Public Service Obligation[2]).

17. Some large businesses connect to the network at high voltage as they have a high power usage. These businesses connect directly to the distribution network at 33 kV, 11 kV or 6.6 kV.

Main components of electricity network

18. The electricity network is made of a number of key components.

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[2] See NIE Statement of Case, Annex 1A.1, paragraph 5.17, fn 30.

Overhead lines

19. Overhead lines are a set of electricity conductors used to transport electricity around Northern Ireland. Depending on the size of the conductor and the voltage it carries, overhead lines can be used for either the transmission or distribution of electricity.

20. Overhead lines are the cheapest and most efficient means of connecting rural areas of Northern Ireland to the network.

Underground cables

21. In Northern Ireland, town and city dwellers generally receive electricity transported by means of underground cables which run underneath roads and footpaths. Underground cables can be used for either the transmission or the distribution of electricity.

Substations

22. Electricity substations convert electricity from one voltage level to another through transformers. Another function performed by substations is ‘switching’, which is the connecting and disconnecting of lines or other components to and from the system. Switching is essential for a number of operations, for instance configuring the network for efficient operation; configuring following a fault to restore supplies and carrying out essential maintenance.

23. Substations also contain important protection and control equipment which operates as a result of a fault to isolate the faulty component and prevent damage ensuring safe operation of the network.

24. There are four main types of substations:

(a) 10 275 kV/110 kV grid substations each supplying around 100,000 customers;

(b) 32 110/33 kV main substations each supplying around 25,000 customers;

(c) 230 33/11 kV primary substations each supplying between 4,000 and 12,000 customers; and

(d) 78,000 11 kV or 6.6 V/LV secondary substations, the type found in housing developments, each supplying up to 500 customers.

Transformers

25. Transformers are devices that can change the voltage. Transformers range from small pole-mounted transformers to huge units weighing up to hundreds of tonnes used in grid substations.

26. Transformers are essential for high-voltage power transmission, which makes long-distance transmission economically practical by reducing the current and hence the losses in a transmission line.

Meters

27. Electricity meters are devices that measure the amount of electricity used by customers and measures calibrated billing units, ie kWh. There are a number of different types of meters:

    (a) *standard meters*—count the number of revolutions on an aluminium disc to measure energy consumed;

    (b) *digital meters*—measure energy use and gives digital readings;

    (c) *Economy 7 meters*—clock-type measurement as there are different tariffs for night and daytime use;

    (d) *prepayment meter*—customer pays for electricity in advance of use; and

    (e) *smart meters*—use a wireless transmitter and enable remote meter readings to be taken.

28. NIE owns the meters and reads meters to enable customers to be billed.

The Electricity Supply Board and its relationship to NIE

The Electricity Supply Board's structure and operations

1. The ESB was established as a statutory corporation in the Republic of Ireland in 1927 (originally to control and develop Ireland's electricity network). ESB operates under the Electricity (Supply) Acts 1927 to 2004 of Ireland.

2. It is majority owned by the Government of the Republic of Ireland through:

   (a) the Minister for Public Expenditure and Reform of Ireland (who holds 85 per cent of its issued capital stock); and

   (b) the Minister for Communications, Energy and Natural Resources of Ireland (who holds 10 per cent of its issued capital stock).

3. The remaining 5 per cent of the issued capital stock of ESB is held by employees (through an Employee Share Ownership Trust).

4. ESB describes itself as a vertically integrated utility under state control, as such:

   > [ESB] Group's strategy, business operations, capital structure, corporate and environmental policies, profitability, dividend policy and level of retained profit are directly and indirectly influenced by decisions of the Government of Ireland over which the Group has no control. In particular, the Group's actions and policies may be influenced by political imperatives. In addition, under its governing legislation, ESB is required to obtain the consent of the Minister for Communications, Energy and Natural Resources of Ireland, the Minister for Finance and/or the Minister for Public Expenditure and Reform of Ireland in order to engage in a variety of commercial transactions. There can be no assurance that such consents will be forthcoming when requested by the management of ESB. Political developments and considerations, therefore, have the ability to materially and adversely impact upon the Group's business, results of operations, operating costs, prospects and/or financial condition.[1]

5. The primary activities of ESB are the:

   (a) operation and ownership of electricity distribution and transmission networks in the Republic of Ireland and Northern Ireland; and

   (b) generation and supply of electricity in the Republic of Ireland and other countries.

6. A significant part of the business activities of ESB and its subsidiaries are carried on in regulated markets and are therefore subject to regulation.[2]

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[1] ESB Finance Limited Prospectus dated 20 November 2012, p7.

[2] ibid, p6. This document listed the principal regulatory risks to the ESB Group, which included those originating from licence compliance, ring-fencing requirements, the impact of price control reviews in markets where the prices charged by the Group are regulated and changes to market mechanisms such as the SEM.

7. ESB has around 8,000 employees and reported an operating profit of €415 million in 2012.

8. The board of ESB comprises a non-executive Chairman and ten other members. Six members (including the Chairman) have been appointed by the Government of Ireland for terms of up to five years. Four employees of ESB have been appointed to the board by the Minister for Communications, Energy and Natural Resources of Ireland for a four-year term under the Worker Participation (State Enterprises) Act 1977. The Chief Executive is also a member of the board.

9. Having previously announced its intention to sell a minority stake in ESB, in February 2012, the Government of Ireland announced that following detailed analysis and further consideration, it had decided *(a)* not to proceed with a sale of a minority stake in ESB, *(b)* that ESB would remain as a vertically integrated utility in Irish State ownership, and *(c)* that it would only consider the sale of some of ESB's non-strategic generation assets. On 24 October 2012, the Government of Ireland requested ESB to develop proposals for the sale of some non-strategic generation capacity, with the specific objective of delivering special dividends to the Government targeted at up to €400 million by the end of 2014. In making this request, the Government of Ireland reaffirmed its commitment that ESB will:[3]

(a) remain as a vertically integrated utility in State ownership;

(b) maintain its strong credit rating to ensure access to funding in order to deliver its investment in key infrastructure; and

(c) retain significant scale in generation to compete in the All-Islands (Republic of Ireland and UK) market, while continuing to move to an appropriate market share in the Republic of Ireland.

Relationship with NIE

10. NIE is a wholly-owned subsidiary of ESB. ESB acquired NIE from Viridian in 2010.[4]

11. NIE constitutes approximately 15 per cent of the ESB Group in terms of asset value and EBITDA.

12. There are no ESB representatives on the board of NIE,[5] although Joe O'Mahony, NIE's Managing Director (appointed to this position in July 2011) and ESB board member, is on secondment to NIE from ESB and previously held a number of senior management positions in ESB including Head of the Wind Development business and Head of Network Projects.[6]

13. In its submissions to the CC, NIE stated that although the UR believed that there would be synergies arising from the acquisition of NIE by ESB, no such synergies were possible given:[7]

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[3] ESB Finance Limited Prospectus dated 20 November 2012, p23, and ESB Annual Report and Accounts 2012, pp11 & 126.
[4] In July 2010, ESB and Viridian reached conditional agreement for the sale of NIE to ESB. NIE was reregistered as a private company in November 2010 and acquired by an ESB subsidiary, ESBNI Limited, in December 2010.
[5] Licence Condition 3A requires NIE's board to comprise a majority of independent non-executive directors (meaning a person who has not been employed by NIE, its ultimate controllers or any affiliate or related undertaking of NIE within the last five years).
[6] www.nie.co.uk/Corporate-Information/Our-team/Joe-O-Mahoney.
[7] NIE Statement of Case, pp174 & 191.

(a) the stringent licence provisions that ring-fenced NIE from ESB (currently being demanded by the UR)—see below; and

(b) the European Commission's decision of 12 April 2013 in respect of the certification of the transmission arrangements in Northern Ireland under the Third Energy Package, which would prohibit the provision of any corporate services by ESB to NIE. For example, ESB currently provided two services to NIE in relation to insurance and the management of cash/treasury. However, these services would be prohibited in future.

Relevant licence conditions[8]

14. NIE operates as a ring-fenced business within the ESB Group. This is due to restrictions in NIE's transmission and distribution licences. The relevant licence conditions are summarized below.

15. The ring-fencing obligations on NIE are primarily set out in Licence Condition 14:

(a) Paragraph 1 provides that no core business[9] of NIE (the transmission and distribution businesses) must be held by or carried on through any affiliate[10] or related undertaking[11] of NIE.

(b) Paragraph 2 provides that NIE must procure that all businesses of NIE other than the core business must be held by or through affiliates or related undertakings of NIE.

(c) Save as permitted in Licence Condition 9, NIE must not guarantee the obligations of any subsidiary of NIE carrying on a non-core activity nor create any encumbrance in favour of any other person over any asset used or to be used in carrying on any core business to secure any obligation of any other person or of NIE in relation to any non-core activity.

(d) Save as set out in paragraphs 8 and 9 (see below), NIE must not conduct any business or carry on any activity other than those falling within the definition of 'core businesses'.[12]

(e) Paragraph 7 provides that NIE must not, without the consent of the UR, acquire shares in any affiliate or related undertaking (there are some limited exceptions).

(f) Paragraph 8 provides that NIE may continue to conduct any business or carry on any activity otherwise prohibited by this Condition which it was conducting as at 8 February 1998 but must transfer any such business to an affiliate or related undertaking or cease conducting that business or activity.

(g) Paragraph 9 sets out what Licence Condition 14 does not prevent NIE from doing. This includes, for example, NIE holding shares as, or performing the supervisory or management functions of, an investor in respect of any body

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[8] The relevant conditions are the same in each Licence.
[9] Defined in the Licences as NIE's Transmission Business, Distribution Business and the Land Bank Business (which covers land acquired by NIE by virtue of any requirement that a generator must transfer to NIE a freehold interest in any land).
[10] Defined in the Licences as any holding company of NIE or subsidiary of NIE or any subsidiary of a holding company of NIE.
[11] In relation to any person means any undertaking in which that person has a participating interest within the meaning of section 421A of the Financial Services and Markets Act 2000 (section 421A provides, for example, that a holding of 20 per cent or more is presumed to be a participating interest).
[12] Defined in the Licences as NIE's Transmission Business, Distribution Business and the Land Bank Business.

corporate in which it holds an interest consistently with the provisions of this licence.

16. Under Licence Condition 9 (Disposal of relevant assets and indebtedness), NIE must obtain the UR's consent before disposing of or relinquishing control over any relevant asset. There are some exceptions to this requirement such as, for example, where the UR has issued a direction containing a general consent for specified transactions.

17. Other relevant conditions include:

(a) Licence Condition 2: NIE is required to prepare separate accounts for each of the Transmission and Distribution businesses.

(b) Licence Condition 3:

(i) each year the board of NIE must certify that the company has sufficient resources to enable it to carry out the core business for the next 12 months; and

(ii) NIE must procure that any ultimate controller of NIE (ie ESB) sign a legally enforceable undertaking in favour of NIE that it will refrain from any action which would be likely to cause NIE to breach any of its statutory or licence obligations.

(c) Licence Condition 5: NIE is prohibited from giving any cross-subsidy to, or receive any cross-subsidy from, any other business of NIE or of an affiliate or related undertaking of NIE.

(d) Licence Condition 12: NIE must maintain full managerial and operational independence of the Transmission Owner Business and Distribution Business from any Associated Business.[13] This includes the requirement to comply with NIE's Compliance Plan, which sets out the practices, procedures, systems and rules of conduct that NIE adopts to ensure its compliance with Condition 12.

(e) Licence Condition 13: covers restrictions on NIE's ability to acquire and generate electricity.

[13] Means any business of NIE (or of any affiliate or related undertaking of NIE) other than a 'relevant holding', the Distribution Business, the Transmission Owner Business, the Land Bank Business and Powerteam.

Principles of agreement between NIE and SONI

1. NIE and SONI management told us that they had agreed the principles of how functions should be arranged to give effect to the transfer of transmission investment planning to SONI. The agreement between SONI and NIE would be subject to regulatory approval. A summary of some of the relevant proposed principles is set out below:

- There will be no change to the System operation.
- SONI will maintain and develop transmission planning standards while NIE will prepare an annual report identifying those aspects of the transmission network it considers should be considered in TSO plans.
- NIE will identify its asset replacement decisions, and will feed these into the Transmission Network Annual Report (TNAR). SONI will prepare the TNAR, Transmission Development Plan (TDP) and Transmission Investment Plan (TIP).
- NIE will feed its cost and programme information into SONI's preparation of the TIP and NIE will have regard to SONI's comments in the definition of its programme.
- NIE and SONI will seek jointly to agree the TNAR, TDP and TIP but SONI will have the final responsibility. SONI will coordinate the TIP with the Republic of Ireland. Planning and feasibility studies will be carried out by SONI.
- There will be a two-way exchange of information between SONI and NIE to allow each party to carry out its duties in accordance with its licences and the TIA.
- SONI will be responsible for high-level functional design. NIE will be responsible for developing and maintaining technical policies, detailed design and equipment specifications.
- SONI will be responsible for all planning and consenting activities. This includes survey, wayleaving, EIAs, planning and all other consents, publicity and stakeholder interaction.
- SONI has sole right to offer terms for connection to the transmission system and SONI will specify the method of connection. Provision will be made for contracts with any applicants in relation to contestable build.
- Procurement will normally be carried out by NIE. Third party procurement may be a feature in the event of contestable build. Construction will be the responsibility of NIE except in the case of contestable build.
- NIE (TO) will be responsible for physical maintenance activities and will carry out all condition monitoring and assessment in keeping with policies and standards.
- NIE will be responsible for all maintenance policies and standards.
- Following input from SONI, NIE(TO) will submit a five-year rolling maintenance plan to SONI for agreement. NIE (TO)/SONI will agree the annual maintenance plan and the outputs of the annual plan will be jointly reported upon.

- In principle, where one party has responsibility for an activity, there will also be a right of review by the other party, and a subsequent escalation mechanism should that be required.

Article 36 of the Electricity Directive 2009/72/EC

1. The text below sets out the objectives set out in Article 36*(a)* to *(h)* of Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009[1] (the Electricity Directive):

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 37, 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 electricity 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 electricity 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 electricity between Member States, including developing appropriate cross-border transmission capacities to meet demand and enhancing the integration of national markets which may facilitate electricity flows 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 electricity from renewable energy sources and distributed generation in both transmission and distribution networks;

(e) facilitating access to the network for new generation capacity, in particular removing barriers that could prevent access for new market entrants and of electricity 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;

[1] OJ L211/55, 14 August 2009.

(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 universal and public service in electricity supply, contributing to the protection of vulnerable customers and contributing to the compatibility of necessary data exchange processes for customer switching.

The UR's RP5 proposals, NIE's rejection of UR final determination and post-RP4 arrangements

1. In this appendix, we first summarize at high level the UR's final determination for RP5, which NIE rejected, with the UR's reasoning for its proposals as set out in the determination document. We then set out NIE's reasons for rejecting the UR's final determination. Finally, we describe the arrangements that have been in place following the initial expiry date of RP4.

The UR's RP5 proposals

Opex

2. The UR's proposed determination drew a distinction between controllable and uncontrollable opex.

3. In respect of uncontrollable opex, the UR proposed a pass-through approach, protecting NIE from any risk. The items proposed as 'uncontrollable' and the amounts that NIE T&D expected to spend over the course of RP5 in respect of those items are identified in Table 1.

TABLE 1 **NIE uncontrollable opex submission, 2009/10 prices**

£ million

	NIE submission	*UR final determination*
Rates	69	
Wayleaves	21.2	
Licence fees	5.7	
Reporter	0	
Injurious affection	11.4	
Total uncontrollable opex	107.3	88.8

Source: UR Statement of Case, Table 3; UR final determination, Table 6.2.

4. In respect of controllable opex, the UR proposed an overall allowance based on the opex that an efficient operator of the network would incur, with NIE bearing the risk of any over- or underperformance against that benchmark. NIE's opex was divided into 'business as usual' controllable expenditure (ie those items of controllable opex during RP5 that reflect or continue items of controllable opex that NIE T&D incurred during RP4 as well), and 'new' controllable opex (ie items of controllable opex that are new in RP5).

5. In respect of 'business as usual' expenditure, the UR constructed a baseline level of expenditure based on NIE T&D's total opex in the year 2009/10, after adjusting for exceptional items. A benchmarking exercise determined the extent of a 'catch-up' efficiency adjustment that needed to be made to that baseline to reflect the expenditure NIE would require if it operated at a high level of efficiency (as benchmarked against GB DNOs). The UR determined a catch-up efficiency adjustment of 7.0 per cent to be achieved over the course of the first two years of RP5, ie 2012/13 and 2013/14. It also proposed a 1 per cent annual ongoing efficiency adjustment for all business as usual opex starting from 2012/13.

6. The principal items relating to new controllable expenditure were (i) workforce renewal; (ii) renewables baseline opex; (iii) RPEs; and (iv) its new, 'Enduring Solution' IT system. The UR rejected NIE's claims in relation to the costs of recruiting and retaining labour. The second category relates to baseline opex costs associated with the preliminary development phases of the renewable energy transmission projects that it has identified—largely the cost of staff planning the development of those projects. In the first category, the UR rejected a proportion of the claims in so far as they were based on such staff being paid above-average salaries. The third category relates to the extent to which NIE faces input price inflation above (or below) that captured by RPI. The UR determined that there was perhaps an overall negative effect given falls in relative prices since the 09/10 base year. The final category relates to a large, market opening IT project, where the UR disallowed 26 per cent of NIE's claimed costs.

7. The proposed allowances for controllable opex are set out in Table 2 alongside NIE T&D's initial request.

TABLE 2 **Controllable opex summary, 2009/10 prices**

£ million

	NIE RP5 total requested allowance	*UR 5-year total proposed allowance*
Base level controllable opex	174.1	167.5
7% 'catch-up' efficiency adjustment		–10.6
Legislative and regulatory requirements	3.7	0.5
Workforce renewal	7.4	0.0
Storm costs	1.6	1.6
AGU		0.3
Credit rating process		0.4
PAS55		0.1
Enduring Solution/Market Opening	28.9	21.4
Renewables baseline	19.3	9.8
New controllable opex	54.6	34.1
1% ongoing efficiency adjustment		–5.6
RPEs	8.8	–3.3
Total controllable opex	237.4	182.2

Source: UR Statement of Case, Table 2.

8. In addition to the opex costs set out in Table 2, NIE requested £15.2 million for non-network capex investment during RP5. Historically, the regulatory allowance for non-network capex forms part of the opex allowance. The UR rejected 50 per cent of the NIE claim.

Capex

9. NIE's submissions for capital spending for RP5 represented a substantial increase over RP4. The UR said that NIE's proposals for business-as-usual capex of £776 million over the five years of RP5 was more than twice what it spent over the course of RP4.[1] The UR expressed concerns over the necessity of this scale of capex, and also over the transparency and accountability in NIE's accounting practices.[2] The UR proposed a three-fund structure for capex in order to deal with these concerns. It said that each of these three categories would be financed by a separate fund using distinct mechanisms and risk allocations reflecting the degree of control

[1] UR Statement of Case, paragraph 33.
[2] ibid, paragraph 5.

that NIE T&D had over the activities covered by the three funds and the degree of certainty as to their costs.[3]

10. Fund 1 covers capex activities that are largely within NIE T&D's control. It consists of two components, each of which is governed by a different mechanism.

11. First, Fund 1 includes planned asset replacement and refurbishment work where NIE can easily identify the volumes of assets that it actually replaces or refurbishes within that category. Investments would only be added to the RAB where it was shown assets had been replaced or refurbished. An overall cap would apply to such investments (a penalty would apply to the return earned on additional investments), with the limits reflecting benchmarking of asset management practice in GB. The amount by which the RAB increases will vary with the volume of asset replacement that NIE does, and NIE can allocate and prioritize the volumes of work of different types that it does within that cap.[4] The UR said that unit cost risk for this category of work would be shared between customers and NIE, in that NIE would retain the benefit or penalty for a five-year period, ie if NIE T&D spent more than the predetermined allowed unit cost for a particular piece of work, it would pay a penalty for that inefficiency for a period of five years. If it spent less than the predetermined allowed unit cost, it would be rewarded for that efficiency for a period of five years.[5] Clearly then a crucial aspect of this system is that the UR should be able to determine in advance representative, generally applicable efficient costs for each category of investment.

12. The second category refers to capex for which NIE cannot identify any outputs (ie assets replaced or refurbished). Such investments include: fault and emergency work; additional costs associated with replacing assets in storm conditions; reactive work; capitalized overheads; additional overheads associated with the new roads and street works legislation; real price effects; and the implementation of the Electricity Safety Quality & Continuity Regulations (Northern Ireland) 2012 (ESQCR).[6] The UR proposed that NIE be allocated a fixed sum of money without needing to account for what it achieves by spending it.[7]

13. Fund 2 is intended to cover work that is less predictable than Fund 1 and is largely in respect of work that is necessary because of changes in customers' needs, such as increases in demand in particular local areas that call for an increase in capacity. It consists of three categories, each of which is dealt with differently: *(a)* specific load-related projects; *(b)* metering; and *(c)* connections.[8]

14. Category (i), funding for specific projects required because of an increase in demand in local areas, is the main element of Fund 2. The UR said that it had accepted some proposed projects whereas others were not accepted because NIE did not produce the evidence required to justify them. However, it said that in light of the inherent uncertainty in respect of demand for electricity in Northern Ireland, it proposed an annual reporting system in which NIE could present evidence to a 'reporter' (see paragraphs 37 and 38) to justify the projects that it considered necessary for the following year. The reporter would then make a recommendation to the UR, which would issue an updated allowance for that year.[9] The UR said that this removed volume risk because NIE could obtain pre-approval for its projects. If it undertook

[3] ibid, paragraph 11.
[4] ibid, paragraph 13.
[5] ibid, paragraph 14.
[6] ibid, paragraph 17.
[7] ibid, paragraph 18.
[8] ibid, paragraph 20.
[9] ibid, paragraphs 21 & 22.

projects without first obtaining the UR's approval, then those projects would be approved on an ex-post basis if they met the thresholds for necessity set out in NIE T&D's planning standards in force at the time.[10] Unit cost risk would be dealt with in the same way as Fund 1 (the UR said that these projects involved replacement of the same assets with the same unit costs as Fund 1).[11]

15. The UR proposed an allowance for metering activities in Fund 2. This would work in a similar way to Fund 1. These activities were included in Fund 2 because it remained uncertain as to when smart metering would be introduced.[12]

16. The UR said that Fund 3 was intended to cover large projects for which there was even greater uncertainty than in Fund 2, both as to timing and cost, such as smart metering and investments in the network required to accommodate the expansion of renewable energy. It said that there were no pre-set allowances, but NIE was able to present proposals for projects at any stage in RP5 and these would be approved by the UR to the extent that they were necessary and efficient.[13]

17. Having set out the structure of its proposed mechanism for dealing with capex, the UR also set out its proposals for NIE's allowances on costs and volumes of work.

18. The UR believed that NIE was relatively inefficient compared with GB DNOs in relation to indirect costs. It therefore proposed an efficiency adjustment (reduction) of 10 per cent for those costs. No ongoing year-on-year efficiency adjustment was proposed.[14]

19. In respect of the general asset replacement and refurbishment activities in the output measurable part of Fund 1, the UR benchmarked asset replacement requirements against GB DNOs. It expressed concern that NIE's data on the age of its assets was biased upwards by virtue of the fact that it had not updated its asset register in respect of the unplanned capitalized replacement and refurbishment work that it had done on the network over the years. Therefore the UR felt that this was likely to favour a finding that replacement was necessary.[15]

20. In respect of specific named projects in Funds 1 and 2, the UR carried out a modelling exercise to give an allowance based on each project in turn. In many cases, the UR concluded that NIE had failed to produce sufficient evidence to justify the investment. In respect of the 'input driven items' in Fund 1, the UR proposed that NIE T&D should be given an allowance based on its historic run-rate for those items, adjusted for the 10 per cent indirect cost inefficiency finding.[16]

21. Table 3 below shows the UR's final RP5 determination for Funds 1 and 2 capex (but excluding Fund 3). This compares with NIE's initial submission for £776.0 million of funding.

[10] ibid, paragraph 23.
[11] ibid, paragraph 24.
[12] ibid, paragraph 25.
[13] ibid, paragraph 27.
[14] Ibid, paragraphs 31 & 32.
[15] ibid, paragraph 34.
[16] ibid.

TABLE 3 **Funds 1 and 2 capex summary**

Fund	*Spend area*	*Transmission £m*	*Distribution £m*
1	Asset replacement (output measurable)	85.3	157.6
1	Input-driven items	7.1	44.8
1	Subtotal	92.4	202.4
1		294.8	
2	Load-related capex network IT; network performance; non-network IT	11.6	31.3
2	Metering	0.0	20.5
2	Connections	0.0	37.3
2	Subtotal	11.6	89.1
		100.7	
1 & 2	Total	104.0	291.5
1 & 2		395.5	

Source: UR Statement of Case, Table 1.

Pensions

22. In its pension submission, NIE T&D requested £10.5 million of ongoing costs and £66.7 million of deficit repair costs to be allowed.[17] In its determination, the UR adopted a different approach to risk allocation than that which it had taken in previous price controls. The UR said that its determination in RP5 essentially allocated the unavoidable risk of pension deficit costs to consumers rather than NIE T&D shareholders, with the exception of a proportion of ERDC's.

23. The UR said that 99.26 per cent of the deficit would be attributed to NIE. This included NIE Ltd and NIE Powerteam Ltd but excluded Powerteam Electrical Services Ltd and Capital Pensions Management Ltd, which did not provide services exclusively to the regulated business.[18]

24. The UR said that it would redetermine deficit recovery costs on the basis of the deficit at each triennial formal valuation (the next formal valuation being 31 March 2014), although it may be appropriate to bring this forward in some circumstances. Any pension revenue in the tariff related to deficit repair would therefore be adjusted (from October 2015 at the latest) to reflect the deficit as at the 31 March 2014 valuation. This would be done on an NPV-neutral basis.[19]

25. Although it proposed basing the deficit repair on the most recent formal actuarial valuation, it decided to base the allowances for RP5 on the deficit amount quoted at 31 March 2012 (£156.4 million) in order to reduce potential tariff volatility in the period following the next formal review.[20] The UR determined that a 15-year deficit recovery period was appropriate, from 31 March 2012 to 31 March 2027.[21]

26. The UR also determined that NIE would be allowed to recover nearly all the pension scheme deficit, covering NIE Ltd and NIE Powerteam Ltd (and excluding Powerteam Electrical Services Ltd and Capital Pensions Management Ltd).[22]

27. NIE had in the past allowed early retirement on generous terms. The costs of these early retirements had now contributed to the overall pension deficit. In its final determination, the UR said that it had decided to apply a 30 per cent disallowance of these

[17] UR RP5 final determination, paragraph 7.6.
[18] ibid, paragraphs 7.37–7.44.
[19] ibid, paragraphs 7.29 & 7.30 & fn 28.
[20] ibid, paragraphs 7.31 & 7.32.
[21] ibid, paragraphs 7.35 & 7.36.
[22] ibid, paragraphs 7.37–7.44.

costs, in that some of the benefit of early retirement represented a benefit to the company in reduced operating costs.[23] The adjustment amounted to –£41.2 million in total over 15 years and –£14.7 million in RP5.

28. The UR said that its assessment of NIE's ongoing pension costs over a five-year allowance was £10.5 million, which amounted to £10 million for a four-year nine-month price control.[24]

29. Table 4 summarizes the RP5 determination.

TABLE 4 **Summary of RP5 pension allowances**

2009/10 prices	*Final determination (5 years)*	*Final determination (4 yrs 9 months)*
Scheme deficit (£m)	156.4	156.4
Regulated fraction (%)	99.26	99.26
Recovery period (years)	15	15
Relevant NIE T&D deficit (£m)	155.2	155.2
Recovery in RP5 (£m)	63.1	58.4
Total ERDC's (£m)	–41.2	–41.2
ERDC's in RP5 (£m)	–15.2	–14.7
Deficit recovery in RP5 (£m)	47.9	43.7
Ongoing costs in RP5 (£m)	10.5	10.0

Source: UR RP5 determination.

Capitalization practices

30. The UR explained that for the RP4 price control, NIE T&D was given an opex allowance. Under the principles and rules, if NIE T&D actually incurred smaller operating costs, it was entitled to keep the difference in full. This is known as outperformance. NIE T&D was also allowed full recovery of its actual capex.[25]

31. The UR believed that during the last two years of RP3, NIE changed its capitalization practice with regard to a number of cost items (for example, NIE moved some of its reactive tree cutting, treated as opex, to an organized programme of regular tree cutting which is treated as capex). It said that the change in practice meant that some cost items or their apportionments that were previously treated as opex could now be treated as capex.[26] In summary, the UR said that it was concerned that the RP4 mechanism meant that consumers could in effect pay twice for certain services. NIE had received an opex allowance based on historic expenditure, so that if that opex was not actually incurred the company would retain the difference as outperformance, while at the same time it would accept volume risk so that if more opex was incurred than had been allowed the difference would be treated as underperformance. However, if the expenditure was treated as capex instead, then this could be added to the RAB, remunerating the company in respect of expenditure which either had already been allowed, or would have been treated as underperformance, were it treated as opex. The UR said that NIE T&D had claimed extensive outperformance for the RP4 period, some of which, upon investigation, appeared to be affected by the changes in capitalization practices. Following investigation and consultation, the UR determined that a RAB adjustment of a decrease of £31.7 million should be made at the start of RP5 to correct for the change in capitalization practice adjustments.

[23] ibid, paragraphs 7.52 & 7.53.
[24] ibid, paragraph 7.54.
[25] UR RP5 determination, Executive Summary, paragraph 4.2.
[26] ibid, paragraphs 4.4 & 4.5.

32. The UR did not claim that NIE had changed its accounting policy in relation to the capitalization of costs over the period under review, nor did it believe that any accounting rules had been broken. However, it considered that its analysis demonstrated that there were changes in accounting estimates and formal guidance to its staff that had had a material impact on the allocation of costs between opex and capex.[27]

Cost of capital and financeability

33. The real cost of debt used by the UR in the RP5 WACC calculation is 3.39 per cent.[28] The UR determined that the gearing level to be applied in the final determination was 50 per cent.[29] It said that this level was closer (than the 60 per cent gearing proposed in the draft determination) to NIE's actual gearing figure at the start of RP5, and it considered that a lower level of gearing was more appropriate during a growth phase and when there was some investment uncertainty (timing and quantum) associated with Funds 2 and 3. It thought that this level of gearing would allow NIE T&D to maintain a solid investment-grade credit rating.[30]

34. The UR determined NIE's cost of equity (post-tax real) at 5.7 per cent. The equity risk premium was set at 5 per cent and the asset beta was set at 0.42. The UR rejected NIE's arguments that its cost of equity should be set to be comparable to the returns that Ofgem provided for in its 2009 determination for GB electricity distribution companies for DPCR5, partly because it said those returns included rewards from incentive mechanisms that were not in place for NIE.[31]

35. The UR had at one point contemplated a lower WACC to be applied for Fund 3 investments as these would be subject to lower systematic risk, but in the end it decided to allow the same rate of return.[32]

36. The UR determined the final vanilla WACC (real) to be applied for RP5 at 4.55 per cent.[33]

Transparency and accountability

37. In its determination, the UR concluded that a reporter should be introduced for RP5. A reporter is an independent professional who periodically audits, certifies and comments on submissions that are made by regulated companies to their regulators over a price control period.[34] It said that the reporter's role would be threefold:

(a) a technical role, auditing the outputs and unit costs of NIE T&D's capex for the purposes of implementing the RP5 capex proposal, and advising the UR in relation to NIE T&D's annual submissions for approval of further projects under capex Funds 2 and 3 in the following years;

(b) a financial role, reviewing NIE T&D's accounting practices and advising us in relation to the same, so as to identify potential problems such as the capitalization practices issue referred to above before they arose; and

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[27] ibid, paragraph 4.10.
[28] ibid, paragraph 12.10.
[29] ibid, paragraph 12.14.
[30] ibid, paragraph 12.13.
[31] ibid, paragraphs 12.15–12.17.
[32] ibid, paragraph 12.18.
[33] ibid, paragraph 12.20.
[34] ibid, paragraph 3.4.

(c) a general ad hoc role, investigating and reporting on any particular issues that we consider give rise to concern from time to time.[35]

38. The UR said it believed that, historically, the quality and quantity of reporting from NIE on its regulated activities had not been adequate. It said that there was an asymmetry of information between the UR and NIE. Second, it said that in light of NIE's proposed substantial increase in capex for RP5 compared with RP4, there was a greater need for high-quality reporting. It said that it was essential for the success of economic regulation that the regulator should be able to measure with confidence what customers had funded with their money, but it had time and time again found that to be impossible.[36]

Connections, innovation and incentives

39. The UR instructed NIE to remove the subsidy for domestic connections, so that new connections after October 2012 would have to pay the full cost.[37]

40. Under the RP5 proposals, NIE has incentives covering customer interruptions and customer minutes lost. Planned outages and transmission outages were excluded from these measures. A penalty is applied if customer minutes lost or interruptions exceed 10 per cent over a target rate. An incentive for revenue protection (ie to prevent illegal extraction) was retained, and a number of other incentive schemes were under evaluation with a view to possible introduction in the future.[38]

41. Three formal innovation schemes which applied during RP4 were dropped. NIE requested monies to fund smart technology. Funding for online monitoring for transmission transformers was approved but other plans were considered to be insufficiently developed and so were moved to the capex Fund 3.[39]

Revenue entitlement and impact on electricity tariffs

42. In its final determination document, the UR calculated that NIE would be allowed a revenue of £0.92 billion, compared with its submission of £1.11 billion over four years and nine months. When Fund 3 capex is included, the revenue allowance in the final determination is £0.96 billion—see Table 5.

TABLE 5 **RP5 revenue allowances**

£ million

	Financial year				
	2012/13	*2013/14*	*2014/15*	*2015/16*	*2016/17*
Without Fund 3	152	200	186	191	191
With Fund 3 (interconnection and renewables)	153	204	193	202	206

Source: UR final determination Executive Summary, Tables 15.1 & 15.2.

43. In its determination, the UR reported the impact of the determination on representative tariffs as calculated by NIE—see Table 6. The figures in the table, after current average cost, refer to the cumulative impact on the total charge over five years

[35] UR Statement of Case, paragraph 10.
[36] ibid, paragraphs 4–6.
[37] UR RP5 final determination, Executive Summary, paragraph 8.1.
[38] ibid, paragraphs 9.1–9.10.
[39] ibid, paragraphs 10.1–10.6.

excluding Fund 3 costs. For example, NIE's proposals would imply an annual domestic charge of £165 in year 5 (2016/17) whereas the UR determination implies a fall in charges from current levels (with a domestic charge of £129 in 2016/17).

TABLE 6 **Impact of determination on network charges**

£/customer

		Change in total cost over five years		
	Current average cost	*NIE request*	*UR determination*	*Potential additional cost for Fund 3*
Domestic	132	106	–1	18
Small Business (Quarterly Billing)	497	399	–5	66
Half hourly Metered MV	1,107	889	–9	136
Half hourly Metered MV	7,652	6,149	–55	895
Half hourly Metered HV	39,163	30,988	–987	9,274
Half hourly Metered eHV	124,927	96,142	–7,095	55,892

Source: UR final determination, Executive Summary, Tables 16.1 & 16.2.

NIE reasons for rejecting UR's final determination

44. NIE told us that it had been compelled to reject the final determination because it would allow insufficient revenues to finance the activities which were necessary to enable it, in the short term, to provide a safe and reliable electricity transmission and distribution service to today's electricity customers, and in the longer term, to invest in the maintenance and development of the skills and assets required to provide such a service to future electricity customers.

45. It said that the UR's proposed price control would therefore leave NIE unable adequately to finance its regulated functions and would not serve the interests of electricity customers.[40] It identified five key alleged deficiencies it saw in the final determination:[41]

(a) The structure of the proposed price control departed from established principles of incentive-based regulation in favour of a system of regulation by micro-management and ex-post revision.

(b) The proposed price control provided insufficient allowed revenues to meet the needs of NIE's business.

(c) The proposed arrangements for regulating network capex incorporated a rigid investment plan that would unduly constrain many of NIE's network investment decisions. Other parts of the capex arrangements involved an ex-post review of operational decisions and/or a requirement to agree, ex ante, changes to capex plans. This exposed NIE to an unacceptable risk of ex-post clawbacks.These deficiencies would result in adverse consequences for customers because:

(i) they risked underinvestment in NIE's network with consequential reductions in network resilience and performance; and

(ii) (ii) they substantially diminished incentives to innovate and achieve new sources of efficiency or improvements in the delivery of services to customers.

[40] ibid, Chapter 1, paragraph 2.1.
[41] ibid, Chapter 1, paragraph 2.2.

(d) NIE would be compelled to expend more than the price control proposals envisaged, with resultant unfair detriment to NIE's investors, and detriment to NIE's financial position and credit rating.

Arrangements after the expiry of RP4

46. The RP4 price control continued after 1 April 2012 (when it was due to expire) to 31 December 2012. The UR said that the delay arose because of the need for further consultation with NIE over capex proposals and also to allow an investigation into changes in capitalization practices.[42] The draft determination was not published for consultation until 19 April 2012, and following further consultation the final determination was published on 23 October 2012, with the proposed licence changes due to apply from 1 January 2013.

47. The UR said that the paragraph setting out the maximum core revenue (Annex 2, paragraph 2.3) was not limited to specific years. It said this meant that the RP4 price control did not come to an end at March 2012 but continued. It said that this was made even clearer by paragraph 7.1 of Annex 2, which read: 'The transmission and distribution charge restriction conditions shall apply so long as the Licence continues in force but shall cease to have effect … if [ ] delivers to the Authority a disapplication request made in accordance with paragraph 7.2 and … [one of two circumstances apply].'

48. It said that as NIE had not delivered a disapplication request to the UR, the licence conditions therefore continued in force.

49. In its final determination, the UR said that NIE raised concerns with the UR about the continuation of RP4 beyond 31 March 2012, saying it would have preferred formal licence modifications to reflect the calculation of allowed revenues in the interim period before RP5 was in place, and flagging up that a number of cost items previously approved under the D_t term (see paragraph 3.21) of NIE T&D's licence would require an additional allowance to cover the period 1 April to 31 December 2012.[43]

50. The UR acknowledged that the continuation of RP4 raised some difficulties. For example, it noted that some elements used in determining the maximum core revenue (eg forecast units transmitted and distributed, and forecast level of uncontrollable operating costs) were defined in a reference table that did not extend past March 2012 and did not state how forecast values for other periods would be derived.[44] It said that the formulae in NIE's licence were generally capable of being applied beyond RP4. It used the RP4 formulae to determine the tariff amounts required for 2012/13, and it included allowances for approvals under the D_t term of NIE T&D's licence within the tariffs (while two terms could not be populated, but these did not impact on the calculation of the tariffs).[45]

51. The UR said that it had taken a pragmatic approach to continuing the application of the licence formulae for RP4 until they were replaced by RP5.[46] It said that this approach had been facilitated through the UR's approval of NIE's regulated tariffs. NIE sets its tariffs on an annual basis taking into account the applicable price control for the relevant year, including its allowed revenue under the licence. The UR said

[42] UR final determination, paragraphs 3.3 & 3.4.
[43] ibid, paragraph 3.8.
[44] ibid, paragraph 13.
[45] ibid, paragraph 3.9.
[46] ibid, paragraph 3.10.

that, in the present circumstances, NIE filled in the 'gaps' by either extrapolating the required values from the last year for which the relevant value was available or by using the most appropriate and up-to-date data available for determining/calculating the relevant values. The UR said that it then assessed whether the values extrapolated or otherwise proposed by NIE were suitable and/or appropriate given the circumstances of the case and the data available. It said that there was therefore an iterative process whereby the parties engaged in discussions and ultimately agreed on the relevant values—hence the pragmatic approach. The UR said that although it and NIE 'agreed' on the figures/values that should be used to set the regulated tariffs in the absence of a clear price control, the agreement was purely for the purposes of implementing a short-term pragmatic solution.

52. The UR said that it saw no practical solution other than to permit the continuation of RP4 and use the existing price control formulae, as consulting on alternatives for the period beyond 31 March 2012 would have resulted in the prolongation of RP4.[47] It noted that capex allowances were stated in the RP4 final determination, and so in order to allow NIE to continue capital investment, the UR's board approved a further capex budget for the six-month period of 1 October 2012 to 31 March 2013.[48]

53. In contrast to the UR's position, NIE said that as it was not possible to apply the price control formulae, it submitted that it had not been subject to any charge control conditions since 31 March 2012. It said that the way in which the UR had sought to extend the RP4 price control did not accord with the ways permitted under the Electricity Order (with NIE consent following consultation or following reference to the CC). It said that it had not given consent to these extensions, and the UR had not conducted any statutory consultation on them, or attempted formally to adopt them in exercise of its statutory powers to modify the conditions of NIE's licence.[49] Therefore NIE considered that the UR's extensions of RP4 did not modify the charge control as the actions did not accord with the UR's power of modification specified in the statutory framework, and there was nothing in RP4 to indicate whether or how values for terms should be determined in the absence of a valid modification of the charge restriction condition.

54. However, NIE had, in practice, set its tariffs and constrained its capex as if it were bound by the price control conditions, as modified by the new values for certain key terms proposed by the UR for the two extension periods up to 30 September 2012 and then to 31 December 2012. It said that as the UR has not proposed new values for key terms or taken any action with respect to the status of NIE's charge restriction condition for the period from 1 January 2013, it had prudently maintained its expenditure since 1 January 2013 at the minimum level consistent with compliance with its statutory and licence obligations. It said that it had done this on the basis that any under-recovery, relative to what was later determined to be an appropriate revenue allowance for the period, may be recovered in future tariff periods (via a correction factor) in the normal way.

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[47] ibid, paragraph 3.10.
[48] ibid, paragraph 3.11.
[49] ibid, paragraphs 6.5–6.7.

The UR's RP5 proposals for capital expenditure

1. This appendix provides further information on the UR's proposed approach for the price control design or, in the UR's terminology, 'structure' for capex. It is based on: the UR's draft and final determinations for RP5; the UR's initial submissions to our inquiry; a presentation by the UR to our team on 21 May 2013; and subsequent clarifications from the UR.

2. There were some differences between the description of the approach to Fund 2 in the UR's final determination and the description of the approach to Fund 2 in the UR's initial submissions to our inquiry. We focused in this appendix on the UR's more recent explanations of Fund 2, which we labelled the 'updated Fund 2 approach' to distinguish it from the description of Fund 2 in the final determination. This terminology is not intended to reflect any definitive view on whether the description of Fund 2 that the UR put to us represents a revision to, or a refined explanation of, the approach that the UR envisaged it published in final determinations.

3. In addition to its distinction between Fund 1, Fund 2 and Fund 3, the UR proposed a materially different treatment of different expenditure categories within these funds. We take the UR's proposed approach to each of these expenditure categories within each fund separately. This appendix is organized as follows:

   (a) the UR's proposed approach to 'output-measurable capital expenditure' part of Fund 1;

   (b) the UR's proposed approach to the 'input-driven items' part of Fund 1;

   (c) the UR's updated approach for specific load-related projects under Fund 2;

   (d) the UR's updated approach for metering work under Fund 2; and

   (e) the UR's updated approach for connections work under Fund 2.

4. This appendix does not cover the UR's proposals for Fund 3 or the UR's proposals in relation to opex.

Fund 1: output-measurable capital expenditure

5. The UR proposed a specific mechanism for 'Output measurable' capex in Fund 1. The scope of capex included within output-measurable capex in Fund 1 comprises asset replacement, asset refurbishment and capitalized tree-cutting. It covers work on the transmission system and distribution system.

6. The UR proposed an overall 'allowance' for each of transmission and distribution for the expenditure on the type of work falling in this category. The allowance was around £200 million for distribution and £90 million for transmission. The UR told us that the separation of allowances for transmission and distribution was due to licence separation. The calculation of these allowances is built up from the UR's assessment for the following:

   (a) a number of specific named transmission projects (eg replacement of the of the Kells 110 kV substation), for which the UR has made an upfront cost assessment; and

(b) specified volumes (or workloads) for a number of specified types of capex activities (eg replacement of Z km of 11 kV overhead lines). For each of these types of activity, an upfront cost assessment is made by multiplying the specified volumes by the UR's assessment of the unit costs of the activity (eg the UR's assessment of the average unit cost per km of replacing 11 kV overhead lines if NIE acts efficiently).

7. If NIE were to spend more than the overall allowance over the five-year period, the UR proposed a form of financial penalty which is intended to expose NIE to an amount equivalent to the allowed rate of return and depreciation that NIE would otherwise earn in the first five years following that expenditure. Subject to that intended penalty, any over-spend would be reflected in NIE's RAB after five years (minus the depreciation that would have applied had it been added to the RAB immediately) and NIE would be able to recover part of the value of that over-spend in subsequent price control periods.

8. The rule on under-spends is more complicated. Neither the UR's final determination nor its initial submissions in our inquiry provide a detailed explanation of what would happen if NIE spends less than its allowance for transmission, or distribution or both. Our interpretation is that it would need to work as follows:

(a) At the end of the price control period, the value of the allowance would be recalculated by taking information on which projects NIE has actually completed over the price control period, and the volumes of work it has done, and combining this information with the upfront project cost and unit cost figures that the UR had used to calculate the original allowance. If the total value from this recalculation is above the value of the original allowance, no change is made and the original allowance stands: the original allowance is a form of budget (though not a strict one, because of the adjustments under *(b)* below). If the total value from this recalculation is below the value of the original allowance, financial adjustments would be made as part of the next price control determination which are intended to deny NIE any financial benefits from this amount being lower than the original allowance. The financial adjustments would include deductions to NIE's RAB. To take an extreme example for illustration, if NIE does none of the named projects and none of the volumes of work included within the allowance, the allowance would be recalculated as zero and financial adjustments would be made as part of the subsequent price control to ensure that NIE does not profit from cancelling or deferring the projects and volumes of work that were included in the original allowance.

(b) NIE's RAB would subsequently be revised to reflect the actual costs that it has incurred to carry out the projects and volumes of work it has done. Further financial adjustments would then be made as part of the next price control determination with the aim that, combined with the RAB adjustments, NIE is financially exposed to an amount of money considered by the UR to be equivalent to the allowed rate of return and depreciation for the first five years on the difference between these actual costs and the value of the recalculated allowance from *(a)* above. The intention is that NIE would gain some financial benefits from delivering projects and volumes of work at a lower (unit) cost than the UR's upfront assessment for those projects and volumes, and that NIE would experience some financial detriment from delivering projects and volumes of work at a higher (unit) cost than the UR's upfront assessment.

9. In addition to the above—and regardless of whether there is an under-spend or over-spend against the original allowance—the UR proposed that all expenditure within Fund 1 would be subject to an 'efficient spend clause', such that only efficient spend

on capex is added to NIE's RAB. This clause means that some of the projects or volumes of work that NIE carries out during the price control period may be considered to be inefficient by the UR (perhaps on advice from the reporter) and NIE may be denied the opportunity to earn any depreciation or rate of return on the costs of those projects or on the element of them deemed inefficient.

Fund 1: input-driven items

10. The UR proposed a different regulatory treatment for a category of expenditure that it refers to as 'input-driven' items. It describes these as areas where it cannot measure the physical output in terms of network assets replaced. The input-driven items include: 'fault and emergency work', 'reactive work', 'capitalized overheads', 'additional overheads associated with new roads and street works legislation', and 'RPEs'.

11. The UR proposed an allowance of around £7 million for transmission and around £45 million for distribution for input-driven items.

12. The UR's proposed treatment of any under- or over-spend against these allowances would be different to that for output-measurable capex in Fund 1. In its initial submissions, the UR said that NIE's RAB would increase by the allowed sum irrespective of whether NIE spent this amount.[1] This would mean that any over- or under-spend in this category would have no impact on the RAB—ie there would be no RAB adjustments in light of actual expenditure in this category. There would not be any adjustments to pass through some of the difference between what NIE actually spends on input-driven items within Fund 1 and the upfront allowances. In its final determinations the UR said that it only planned to consider NIE's expenditure on input-driven items within Fund 1 when it set a new price control for the RP6 period.[2]

13. The UR told us that its proposed treatment of input-driven items in Fund 1 was an area in which it was generous in its final determinations and that we may find that this was not in the public interest. The UR identified a downside of its proposal, which is the risk of 'double (or even triple) funding some items of work'.[3] This risk arises from the potential overlaps between the work falling under input-driven items within Fund 1 and *(a)* output-measureable capex under Fund 1 and *(b)* the UR's proposed allowance for controllable opex.

14. The 'efficient spend clause' referred to above would also apply to input-driven items. NIE might be subject to the potential impacts of this clause as described for output-measurable expenditure under Fund 1.

Updated Fund 2 approach for specific load-related projects

15. For the remainder of this appendix we focus on the presentation of Fund 2 contained in the UR's submissions, in particular UR-4. The UR said in UR-4 that the main element of Fund 2 was funding for specific projects required because of an increase in demand in local areas. The UR proposed a separate approach within Fund 2 for the treatment of 'specific load-related projects'. Our interpretation of the updated Fund 2 approach for specific load-related projects is as follows:

[1] UR Statement of Case, paragraph 18.
[2] UR RP5 final determination, paragraph 5.62.
[3] UR Statement of Case, paragraph 19.

(a) There would be an upfront allowance for some load-related projects included as part of the RP5 price control. These projects are not intended to cover all of the load-related work that NIE would be reasonably expected to do over the price control period.

(b) During the price control period, NIE would have the opportunity to gain approval for further load-related projects before carrying these out. The UR would determine an additional allowance for any newly approved projects.

16. The additional allowance for projects under *(b)* would be based on the upfront assessment of unit costs that the UR used in the calculation of the upfront allowance for Fund 1. The UR said that 'there is no real uncertainty as to [the] unit cost [of projects within Fund 2] because they are essentially the same activities as those covered by Fund 1 (i.e. installing network infrastructure)'.[4]

17. Any additional allowances approved as part of the process under *(b)* above would not affect NIE's revenues or prices during the RP5 price control period. Instead, these would feed through to NIE's allowed revenues (in an NPV neutral manner) in the RP6 price control period.

18. NIE's RAB will be updated in light of its actual expenditure in each year of the price control period with a five-year lag. The intention is that NIE would be exposed financially to some of the difference between its actual expenditure and the upfront allowance for Fund 2 (which includes projects under both *(a)* and *(b)* above). The way that this financial exposure is calculated would be consistent with the calculations to expose NIE to unit cost risk under Fund 1.

19. For other projects or volumes of work that NIE carried out which were not approved in advance under *(a)* or *(b)* above, there is a potential for NIE to be fully compensated for the efficient costs of those projects after they have been carried out, if they meet thresholds for necessity set out in NIE's applicable network planning standards (provided these are approved by the UR in advance). On the other hand, it is possible that some of those projects or volumes of work are subsequently considered not to be necessary by the UR (on advice from the reporter) and NIE may be denied the opportunity to earn any depreciation or profit on the costs of those projects (this possibility does not apply to projects approved in advance by the UR under *(a)* or *(b)* above). The UR would determine in advance the standards, assumptions and processes that are to be used to make assessments of whether work carried out by NIE was necessary. The UR (drawing on input from the reporter) would also provide annual feedback to NIE on its planned investments.

20. In relation to any projects (or parts of projects) that fall under *(e)* and which the UR has agreed were necessary, changes would be made to NIE's RAB, alongside other financial adjustments at the next price control determination, with the aim that NIE is financially exposed to an amount of money considered by the UR to be equivalent to the first five years' allowed return and depreciation on the difference between NIE's actual expenditure on those projects and what it would have spent had it delivered those projects at the same unit costs as those from the UR's upfront assessment of unit costs (referred to in *(c)* above).

Updated Fund 2 approach for metering

21. For metering, the UR's Fund 2 proposal was that:

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[4] UR Statement of Case, paragraph 24.

(a) The UR determines a set of upfront unit cost allowances for work falling within the metering capex category. This category excludes smart metering, the costs of which would be dealt with through Fund 3 if they arise.

(b) There is an upfront allowance for metering as part of Fund 2, which is based on estimated volumes of metering work. This allowance would be used as an input to the calculation of the price control for RP5.

(c) The upfront allowance is recalculated in light of the actual volumes of metering work that NIE carries out (this could be annually or at the end of the price control period). Changes would then be made to NIE's RAB, alongside other financial adjustments to subsequent price controls, with the aim that NIE is financially exposed to an amount of money considered by the UR to be equivalent to the first five years' allowed return and depreciation on the difference between NIE's actual expenditure on metering and what it would have spent had it delivered metering projects at the unit cost from *(a)* above.

22. The intention is that *(a)* NIE is financially exposed to differences between its actual costs of metering work and those costs that would arise if it carried out metering work at the same unit costs as those determined upfront by the UR; and *(b)* NIE is not financially exposed to any differences between the volumes of metering work anticipated when the price control was set and the actual volumes carried out during the price control period.

23. The UR confirmed to us that the efficient spend clause discussed above in relation to Fund 1 output-measurable expenditure would apply to all capex, including meter work.

Updated Fund 2 approach for connections

24. Since 1 October 2012, customers that made requests for a new connection to NIE's system have been required to pay a one-off charge based on the full costs of the work to make that new connection. For connections agreed prior to this date, certain customers faced a one-off charge based on 60 per cent of those costs. The remainder of these costs was funded through use of system charges and was provided for in the revenue covered by NIE's price control.

25. NIE expected to do some work on new connections in relation to requests that were made before 1 October 2012 and which qualify for the charge based on 60 per cent of costs.

26. The UR proposed a provision in the price control to allow NIE to recover the element of the costs of these new connections which is not covered the 60 per cent upfront charge for the customer. NIE would be able to recover these costs subject to an 'efficient spend clause' as proposed for Fund 1. This means that it would be possible that NIE may not recover some of the costs it incurs in making these connections if they are deemed inefficient by the UR (perhaps on advice of the proposed reporter). the UR's proposals for NIE to recover the costs incurred of work on new connections in relation to requests that were made before 1 October 2012 and which qualify for the charge based on 60 per cent of costs are limited to costs that NIE incurs before 1 October 2014.

The UR's concerns on approach to cost risk-sharing

1. This appendix provides further information on the concerns about our approach to cost risk-sharing raised by the UR in submissions before the publication of our provisional determination. It then provides our assessment of those submissions.

2. The UR's submissions included a short paper by First Economics that set out a number of worked examples relating to the financial incentives for opex and capex under alternative possible approaches to cost risk-sharing. In particular, First Economics sought to compare the proposals from the UR's final determinations with the type of approach envisaged above in which a single, fixed percentage for cost risk-sharing is applied to both opex and capex. In relation to capex, First Economics said that the single, fixed percentage for cost risk-sharing was very similar to the approach proposed by the UR (this leaves aside the choice of percentage).

3. First Economics identified more significant differences in relation to opex. It claimed that, compared with the proposals in the UR's final determinations, an approach involving a single, fixed percentage for cost risk-sharing applied to both opex and capex would: *(a)* reduce the strength of incentives in relation to opex and *(b)* mean that a cost saving made in year 1 of the price control period could give NIE five times as much reward as a saving made in year 5.

4. We were not persuaded by the UR's submissions on the defects in our proposed approach. The claims made by the UR rest on worked examples presented in First Economics' paper. The results from these worked examples rest, in turn, on an assumption about the way in which NIE's costs would be taken into account when a new price control is set at the subsequent price control review. The stated assumption is that an opex allowance for each year of the subsequent price control period is set to match the level of NIE's opex at the start of that period. We do not consider such an assumption to be appropriate:

   (a) That assumption is not compatible with the approach to cost assessment that we took (see Sections 7 to 10), in which we gave significant weight to cost benchmarks from electricity distribution companies in GB rather than NIE's historical costs: we have not set an expenditure allowance for NIE using the level of NIE's historical expenditure.

   (b) Further, the assumption underpinning the worked examples is not compatible with the UR's approach to cost assessment in its RP5 proposals. The UR did not propose an expenditure allowance for NIE using NIE's historical expenditure, but rather made a series of adjustments including significant adjustments to NIE's historical costs in light of benchmarking analysis. Nor is the assumption compatible with the way that Ofgem sets price controls for electricity distribution companies in GB.

5. The UR also argued that the paper by First Economics showed that it was important that we should be aware that the 'apparently consistent incentive rates' under the approach of a single percentage cost risk-sharing 'would not make NIE T&D indifferent to the type of expenditure it incurs in many real-life situations' and that this was 'particularly the case where NIE T&D is choosing between (one-off) capex solutions and recurring) opex solutions to the problems that it encounters on its network'.

6. We reviewed the analysis in the paper by First Economics in relation to this aspect of the UR's submissions. It rests on worked examples that involve the same assumption as discussed above about the impact of NIE's expenditure on the way that the price control is set at the next price control review. The paper argues that 'a reasonable assumption might be that the regulator will reset the opex allowance at the next periodic review to match NIE T&D's expenditure'. We did not agree that this assumption is reasonable for operating expenditure, for the reasons set out above in relation to the use of benchmarking analysis. Further, the paper ignored the potential for elements of capex to be seen as 'recurring', with forecast capex based on historical costs, unit costs and volumes.

7. We accepted that for some of NIE's activities we were not able to use benchmarking analysis as part of our inquiry (eg metering and meter reading activities). In these cases we sought to avoid any unnecessary differences in our approach to cost assessment between opex and capex and to use forecasts and information other than NIE's historical costs where possible. Where we used data from NIE's historical costs we sought to take data across several years. Further, in areas of activity such as meter reading, the possibility of future regulatory reform to enhance the role of competition may place some additional discipline on NIE's costs which can reduce concerns about the incentive effects of using NIE's historical cost data to calculate its price control. Taken together these features of our approach help tackle the concerns raised by the UR.

Price control design options for investment deferral risk

1. This appendix provides further information on options we considered (but rejected) in relation to the risk of NIE deferring planned investment to the detriment of consumers and further information on our evaluation of these options. It takes the following options in turn:

   (a) Option D3(a): volume adjustment mechanism with volume cap.

   (b) Option D3(b): Ofgem outputs and secondary deliverables.

   (c) Option D3(c): NIE's proposed cap and collar mechanism.

   (d) Option D3(d): pass-through of network investment costs subject to a cap.

   (e) Option D3(e): capex allowance reflecting investment deferral risk.

   (f) Option D3(f): compliance with asset management documentation.

2. This appendix does not discuss our chosen approach, option D3(g): 'no double-funding of deferred network investment'. This is considered in detail in Section 5.

Option D3(a): volume adjustment mechanism with volume cap

3. We use the term 'volume adjustment mechanism' to refer to the type of mechanism proposed by the UR for output-measureable capex under Fund 1 (see Appendix 5.1 for more information). We treat a volume adjustment mechanism as a regulatory arrangement under which financial adjustments are made to NIE's regulated revenues and RAB, in a relatively mechanistic way, according to differences between the volumes of network investment assumed for the purposes of setting the price control and out-turn volumes.

NIE's proposals for a narrower application of a volume adjustment mechanism

4. NIE argued that the scope of asset replacement expenditure falling under the UR's proposals for output-measurable capex in Fund 1 was too wide. Indeed, elements of the UR's proposals for Fund 1 reflect NIE's antecedent proposals for a similar mechanism which would apply to a subset of its asset replacement expenditure. We consider below the potential scope of a volume adjustment mechanism.

5. NIE proposed in its Statement of Case a narrower 'Fund 1' approach, under which only 'high-volume rolling programmes' under which each project is relatively low value, rather than all asset replacement, would be subject to a form of volume adjustment. NIE argued that the high volume of similar projects undertaken meant that the risk of individual unit costs being higher or lower than the unit cost forecasts underpinning the price control would be diversified. NIE's view was that a narrower version of Fund 1 would expose it to lower financial risk in relation to the unit costs of delivering investment projects than the UR's proposals.

6. As discussed further below, the problems that we saw with the UR's Fund 1 approach included *(a)* the risk of perverse incentives for NIE to choose an inefficient mix of projects; *(b)* the risk of consumers paying charges that provide NIE with

excessive remuneration for the investment volumes it carries out; and *(c)* complexity and novelty. NIE's proposals for a narrower Fund 1 did not tackle these concerns; they only mitigate them by reducing the scope of the volume adjustment mechanism. And, by reducing its scope, NIE's proposals reduced the effectiveness of the volume adjustment mechanism in meeting the purposes of the mechanism.

7. NIE made some further criticisms of the UR's Fund 1 as part of its Statement of Case, but these were criticisms of the Fund 1 proposal overall, and did not justify the introduction of a narrow Fund 1.

8. NIE did not demonstrate that the UR's proposed scope of Fund 1 would expose it to excessive or disproportionate financial risk.

9. Overall, we saw no merit in NIE's proposal for a narrow Fund 1. It did much less to address the UR's concerns about investment deferral whilst still retaining the short-comings of the UR's Fund 1 proposals where these apply. If a volume adjustment mechanism were to be introduced, we considered that the UR's proposed scope was preferable to NIE's proposed scope.

How a volume adjustment mechanism (with volume cap) could work

10. The UR's draft and final determinations, and its submissions to the CC, did not provide a fully-specified volume adjustment mechanism.

11. In addition, aspects of the UR's proposals for the volume adjustment mechanism might require refinement before implementation. For instance, the UR's proposals treated real price effects as an ex ante allowance under 'Fund 1 input-driven items'. The allowance for RPEs would be completely separate from the volume adjustment mechanism for what the UR calls output-measurable capex in Fund 2. This approach seemed to mis-characterize real price effects as an item of costs or expenditure. Instead, the role of real price effects within a price control is to make adjustments to a cost (or unit cost) estimate in one year to help produce a cost (or unit cost) estimate in the subsequent year by taking account of forecast changes in input prices relative to the RPI inflation index. For the purposes of a volume adjustment mechanism, RPE adjustment factors would more naturally be used as adjustments to produce unit cost figures for each year of the price control period. It would not make sense to assume real price effects in one part of the price control and then ignore these and assume that unit costs grow by RPI (or remain flat in nominal terms) for the purposes of the volume mechanism.

12. We gave more consideration to how a volume adjustment mechanism of the nature envisaged by the UR could work. We also tried to separate that mechanism from the cost risk-sharing mechanism that we proposed.

13. If a volume adjustment mechanism is considered desirable, we envisage that it would have the following features:

    (a) The volume adjustment mechanism would require a full set of unit costs for a specified base year (eg 2009/10) for all aspects of NIE's asset replacement programmes across transmission and distribution.

    (b) These unit costs would apply to the specific components specified for each of the investment projects identified by NIE. For instance, within the NIE project '11 kV Overhead Lines' (code D08) we would include the unit cost for the '11 kV Line Re-engineer' component of that project (eg a unit cost of £17,000 per km). We

expect that this would require around 100 different project components to be specified in the mechanism.

(c) Regulatory assumptions on RPEs and productivity growth would be applied to adjust the base year unit costs to produce forecasts of unit costs for each of year of the price control.

(d) The volume adjustment mechanism would require a regulatory forecast of volumes of activity for each project component for each year of the price control. For instance, for the project component of '11 kV Line re-engineer', the regulatory forecast might be that NIE would re-engineer 300 km of lines in each year of the price control period. In some cases, the project may be a one-off project that is not broken down into volumes of activity or sub-components; if so, the volume forecast for that project would be one unit and the unit cost would be the total project cost.

(e) For each year of the price control we would calculate the total value of asset replacement investment forecast for NIE by first multiplying the volume forecast for each project component for that year from *(d)* with the unit cost forecast for that project component for that year from *(c)* and then taking the sum across all projects.

(f) A regulatory cap on the total volume of network investment over the price control period would be calculated by adding together the measure of the volume of asset replacement investment forecast for NIE for each year of the price control.

(g) During the price control period, information would need to be collected on the volume of work done in each year for every single project component used in the steps above.

(h) The information on out-turn volumes for each project component under *(g)* would be multiplied by the regulatory forecasts of unit costs from *(c)* and then aggregated across all project components. This produces a measure of the volume of network investment that NIE has carried out in a year: we can see this as a measure of the value *at constant prices* of the asset replacement or refurbishment work done in the financial year.

(i) Over the course of the price control period, a comparison would be made between the regulatory cap on the total volume of network investment under *(f)* and the out-turn volume of network investment under *(h)*. If out-turn volume is higher, no adjustment for volume differences is made. If out-turn volume is lower, adjustments would be made to NIE's RAB to deny NIE financial benefits from delivery of a lower volume of network investment.

14. If a cost risk-sharing mechanism applied it would also be necessary to calculate an updated regulatory allowance for each year of the price control for the purposes of implementing this mechanism, in addition to making the adjustment under *(i)*. The updated allowance for each financial year would be based on the total value of asset replacement investment forecast under *(e)* above, adjusted for any cumulative underspend against the volume cap to date.

Risk of perverse financial incentives for inefficient expenditure

15. A volume adjustment mechanism as proposed by the UR and outlined above may provide NIE with perverse financial incentives in relation to asset replacement work.

16. A large part of NIE's revenues would be linked directly to the volumes of asset replacement work it does on the network. In effect, NIE would be remunerated for the network investment it chooses to carry out, according to a 'price list' of unit costs established at the price control review. The unit costs are unlikely to be precise estimates of NIE's actual unit costs for network investment. These are difficult to forecast accurately and, in any event, will vary across different parts of NIE's network (eg costs may vary according to location and topography). For some potential investment projects, the unit costs could be much higher than NIE's actual unit costs and for others they could be much lower.

17. In these circumstances, NIE may face a financial incentive to carry out excessively high volumes of a particular category of asset replacement work, or to carry out unnecessary asset replacement projects, in cases where its costs of doing that work are lower than the (unit) cost allowance for that category of work. NIE may receive substantial remuneration from consumers for carrying out volumes of network investments that are not necessary or useful for consumers but which NIE does because it is 'well paid' to do them under the volume adjustment mechanism.

18. NIE's financial incentives would not be aligned with the asset replacement work that is highest priority on the network. NIE may be financially motivated to carry out more replacement work than is necessary or efficient for some categories of network investment.

19. There would be some limitations on NIE's willingness and ability to exploit a volume adjustment mechanism. Apart from its statutory duties to maintain and operate an efficient network, NIE would be aware that skewing its investment towards categories of asset replacement with attractive unit cost allowances under the mechanism could lead to underinvestment in other parts of its network which tend to increase the costs it would face over the longer term.

20. Further, the UR's proposals for an embedded reporter within NIE, combined with its proposals for a review of whether NIE's expenditure investment decisions were efficient, would provide some way to tackle the concern that NIE would act inefficiently in response to the financial incentives of the volume adjustment mechanism. But this brought the concerns about regulatory micromanagement and risks of blurred responsibilities that NIE emphasized in its criticisms of the UR. A reporter may not be effective at fully addressing the risks from perverse financial incentives above as it may be difficult to establish what investment was inefficient.

Limitations to the effectiveness of volume adjustment mechanism

21. A volume adjustment mechanism did not seem likely to be fully effective in addressing risks relating to investment deferral to the detriment of consumers.

22. Under the scheme, NIE may have financial incentives to defer worthwhile network investment projects in cases where it considers the unit cost allowance for that investment to be too low.

23. If such deferral were offset by additional volumes of other categories of network investment (eg for which the unit cost allowance is more attractive to NIE) consumers would not experience any subsequent reduction in charges arising from the investment deferral or any share of the cost savings that NIE enjoyed from that deferral.

Implementation issues

24. A volume adjustment mechanism would rely on calculations comparing forecast and actual volumes of network investment across a large number of project categories (probably around 100).

25. Whilst considerable information on out-turn volumes for specific components of investment projects would be required to implement the mechanism, such information may already be required for other purposes, in particular to provide a relevant information base for cost assessment at the next price control review (see Section 17 of our final determination for our proposals on regulatory reporting).

26. We identified some concerns that there was not a sufficiently comprehensive and granular set of unit costs and volumes forecasts to implement the scheme across all areas of asset replacement expenditure; it could nonetheless be applied to the majority of it.

Option D3(b): Ofgem outputs and secondary deliverables

27. As an alternative to the UR's proposals, we considered whether it would be possible to apply to NIE the type of output-based approach developed by Ofgem for energy network companies in GB.

28. Ofgem has developed its own approach to address the risks relating to deferral of planned capex projects to the detriment of consumers. Ofgem's price control framework (which it calls RIIO) involves the specification of a comprehensive set of 'outputs' and 'secondary deliverables' which the regulated company is required to meet or deliver over the price control period. The upfront cost assessment is intended to estimate the amount of money that the company needs in order to deliver those outputs and deliverables. The expenditure allowance used to calculate the price control is linked to the outputs and deliverables as the regulated company may face a financial penalty—or an adjustment that is intended to ensure that consumers do not pay twice if outputs and deliverables have not been delivered.

29. In relation to network asset management, Ofgem has worked with companies to develop a set of 'secondary deliverables' which concern the health and condition of a company's electricity distribution network. For the next electricity distribution price control (which Ofgem calls RIIO ED1), Ofgem's proposal is that there will be health and 'criticality' indices (or scores) for assets on each company's network and that these will be combined into a composite risk index.

30. Under the outputs-based approach, the price control would be set to provide a regulated company with the expenditure necessary to achieve specified outcomes in terms of those secondary deliverables (eg avoiding any deterioration in the health of network assets). A regulated company's opportunity to defer or abandon forecast investment projects is constrained by the risk that doing so may cause it to fail to deliver, by the end of the price control period, the anticipated outcomes in terms of secondary deliverables; the company could then face adverse financial consequences for that shortfall in performance.

31. It should be recognized that elements of Ofgem's output-based approach have not been tested over a full price control period. Whether they work as intended is yet to be revealed.

32. To apply Ofgem's approach to NIE would require the development of a range of measures of outputs and deliverables and the assessment of NIE's current network

against reliable measures of asset heath and load factors. Both parties told us that it would not be feasible to develop these measures for the purposes of our inquiry. NIE indicated at the hearing in July 2013 that it did not expect to be able to report the relevant measures until around 2016 or 2017.

33. Although the UR's proposed approach for RP5 did not implement Ofgem's approach to outputs and secondary deliverables, the UR proposed in its final determination to work closely with NIE during RP5 to develop the reporting for load and health indices which could then be used as part of the next price control period (RP6). Both parties said that they do plan to develop the necessary reporting arrangements.

Option D3(c): NIE's proposed cap and collar mechanism

34. NIE made various submissions on possible ways to mitigate the risk of investment deferral under a simple ex ante allowance. NIE put forward a cap and collar mechanism that could provide an alternative to the type of volume adjustment mechanism for asset replacement expenditure proposed by the UR.

35. Under NIE's proposed cap and collar mechanism, its financial exposure to the upfront regulatory expenditure allowance would only apply between a lower limit (the 'collar') and an upper limit (the 'cap'). Any expenditure that NIE incurred that was outside the range of the cap and collar would be subject to full pass-through to consumers. If NIE were to spend substantially less than the lower limit (collar)—perhaps through deferral or abandonment of forecast investment projects—the savings in expenditure below the cap would feed through to lower charges to consumers and NIE would not profit from those savings. This feature of the proposal would reduce the extent to which NIE would profit from deferral or abandonment of forecast investment projects and it would reduce consumers' financial exposure to the risks of such deferral or abandonment. Conversely, if NIE were to spend more than the cap, charges to consumers would subsequently rise to fully compensate NIE for the costs it has incurred in excess of the cap.

36. The cap and collar arrangement could apply to the overall capex allowance used to set the price control or to specific categories of its expenditure. NIE proposed the application of a cap and collar arrangement to a single capex fund as part of its proposed 'RPI–X with safeguards' approach, which NIE submitted after the hearing on 9 July 2013.

37. We did not think a cap and collar approach, or NIE's proposed variation on it, provided an effective way to address the UR's concerns about investment deferral. This is for several reasons which we set out below.

38. NIE's proposals would only tackle the deferral risk by converting the price control to one of full cost pass-through under certain conditions. This was undesirable because *(a)* the deferral risk is not addressed if those conditions are not met; and *(b)* if those conditions are met, the price control is based on full cost pass-through of capex which is, in itself, undesirable.

39. The introduction of a lower limit or collar, below which any further reduction in NIE's actual expenditure (compared with regulatory forecasts) is passed through to consumers, did not seem to provide an effective way to address risks relating to investment deferral. By construction, for levels of expenditure above the collar, there would not be protection for consumers against the risks of investment deferral. If the collar is reached, there would be full pass-through to consumers of variations in NIE's expenditure. This presents a risk of consumers being exposed to charges that reflect inefficient or unnecessary expenditure by NIE.

40. The cap would also present problems. As NIE recognized, if there was complete pass-through of capex to NIE's RAB in the event that it exceeded the cap, NIE may have no effective incentive to control its expenditure if it found itself in the situation of exceeding the cap. We would be concerned that NIE would be in a position to spend money unnecessarily to the detriment of consumers.

41. In light of concerns about complete pass-through of capex in excess of the proposed cap, NIE proposed a variant on the cap and collar approach, under which it would face financial exposure to any expenditure it incurs beyond the cap, but its financial exposure to such expenditure would be less than its financial exposure to expenditure between the cap and the collar. Under this variant, the intention was that NIE would not be fully compensated for any expenditure it incurs in excess of the cap, but for expenditure in excess of the cap there would be a greater degree of cost pass-through than for expenditure between the cap and the collar. We did not consider this kind of incentive structure likely to provide an effective way to deal with concerns about the proposed cap. This was for the following reasons:

(a) If relatively weak incentives are in place for any expenditure that NIE incurs in excess of the cap, there is a risk that NIE's financial exposure to such expenditure is insufficient to encourage it to control its costs effectively once it reaches—or anticipates reaching—the cap. Even if the financial exposure to NIE is ostensibly not a cost pass-through arrangement, NIE may still have insufficient financial exposure to costs in excess of the cap to avoid inefficiency or unnecessary investment.

(b) Alternatively, if we were to choose an incentive rate to be applied to any expenditure in excess of the cap which we are confident provides NIE with sufficient incentives to control its expenditure, the question would arise as to why we should not also apply the same incentive rate in situations in which NIE's expenditure is below the cap. Applying a uniform incentive rate would be simpler. It would provide greater protection to consumers against the risks of investment deferral. It would also provide greater protection to both consumers and NIE against the inaccuracy of regulatory cost forecasts.

Option D3(d): pass-through of network investment costs subject to a cap

42. The RP4 price control agreed between the UR and NIE in 2006 provided another conceivable way to tackle concerns about investment deferral and, more generally, the uncertainty faced in forecasting NIE's capex.

43. Under this approach, we would take our forecast of NIE's expenditure requirements over the price control period and use this to set a cap on its investment over the period. If NIE's actual expenditure on network investment exceeded the cap, our proposed cost risk-sharing mechanism would apply. If NIE spent less than the cap, that cost risk-sharing mechanism would not apply: instead adjustments to NIE's maximum revenues and RAB would be made to pass through the full value of any underspend to consumers and to deny NIE financial benefits from spending less than the cap.

44. On its own, this approach would mean that NIE would not have an ability to benefit financially from an underspend against the upfront regulatory forecast of its expenditure requirements. There would be several concerns:

(a) NIE would not have profit opportunities from improving the efficiency of its capex programme.

(b) The approach could frustrate the competitive process for commercial control of NIE. Potential investors would be denied the opportunity to make money from taking over NIE and improving the efficiency of its capex programme.

(c) NIE would not suffer financial consequences from carrying out network investment that is unnecessary or unduly costly. Instead, consumers would bear those costs.

45. There would also be concerns about distortions of working practices and accounting information in favour of capex if NIE were to be exposed financially to its opex but not to its capex (below the cap).

46. To reduce these concerns, the approach might be combined with a special incentive scheme to provide NIE with some financial benefits for measurable efficiency gains. A capex incentive scheme based on measures of labour productivity and procurement efficiency was used as part of the RP4 price control. Such a scheme was unlikely to be fully effective, not least because we were concerned not just with NIE's unit costs of delivery but also with its decisions on what investments to carry out.

47. Neither party advocated an approach based on the RP4 treatment of capex. The UR identified concerns that such an approach would not provide sufficient transparency and accountability and would lack financial incentives for NIE to achieve capex efficiencies.

Option D3(e): capex allowance reflecting investment deferral risk

48. It might be possible to limit the risks to consumers from investment deferral in the following way. We could anticipate the opportunity for deferral and abandonment of forecast investment projects by setting the price control on the basis of a relatively low forecast of NIE's capex, which reflects an expectation that, in response to the financial incentives of the price control, it would be likely to defer some of the investment projects that were included in its business plan.

49. Such an approach would probably exclude some expenditure that could be justified as efficient on a whole-life cost basis but which was not strictly necessary during the price control period and which NIE could defer without intolerable consequences. This would not be an ideal long-term regulatory approach. It would almost certainly mean that NIE would miss opportunities for investments that could help reduce costs over the long term. However, the relevant comparison was not against an ideal approach but rather against other feasible approaches which are also imperfect.

Option D3(f):compliance with asset management documentation

50. We identified a potential option under which we would require NIE to comply with asset management documentation that specified how it would make decisions in relation to asset replacement and refurbishment. NIE's opportunities for investment deferral would be constrained to the extent that deferral or abandonment of planned investment may not be compatible with the asset management documentation.

51. The documentation would need to refer to observable and verifiable information and it would need to be consistent with the network investment forecasts used to calculate the price control.

52. For instance, the asset management documentation could specify the criteria in terms of asset age, condition monitoring test results, consequences of failure and

other factors that would lead to the replacement of a 33 kV/11 kV transformer. There could be financial penalties, or requirements to make up for any shortfalls at no additional cost to consumers, if NIE then failed to carry out replacement of 33 kV/ 11 kV transformers that ought to be replaced according to the criteria in its asset management documentation.

53. This option would be contingent on NIE developing detailed asset management documentation as part of our inquiry.

54. NIE submitted some documents on its asset management policies to the CC, but these were not detailed explanations of how NIE takes asset management decisions. NIE provided more information on the decision-making processes behind its network investment proposals in its Statement of Case and the strategy papers it had prepared as part of the UR's price control review. But these too seemed insufficient for the purposes envisaged here.

55. For instance, NIE's strategy paper C11 in relation to 11 kV and 6.6 kV four-pole substations proposes the gradual replacement of these substations with more modern alternatives on safety grounds. It identifies 190 of these substations for replacement during the planned RP5 price control period and says that these were the substations that were identified as highest risk. But the strategy paper does not set out observable criteria that would enable an objective assessment of the degree of safety risk posed by each substation—in particular whether it meets the threshold of 'high risk' or whether its replacement can reasonably be deferred until the next price control period.

56. We were concerned that, given the many different types of assets on NIE's network, it would be difficult in the time available for our inquiry to establish the type of asset management documentation needed for the approach above to be effective.

57. Furthermore, in its submission to us, NIE said that it was 'simply not possible to produce documentation that would be suitable for the CC's purposes' and that there were 'simply too many variables and importance of engineering judgment too pivotal to the assessment process'.

58. There were also difficulties in seeking to retrofit the type of approach set out above to an expenditure plan that had already been produced and reviewed by other parties. Ideally, if this approach were to be applied, the detailed asset management documentation would predate the forecast of expenditure requirements and regulatory assessments of expenditure forecasts would go hand in hand with assessment of the detailed asset management documentation.

Regulation of quality of service and revenue protection income

1. This appendix provides further information on the parties' submissions, and our assessment, in relation to the treatment within NIE's price control of several aspects of its quality of service as well as NIE's revenue protection activities (eg recovery of money in cases of illegal abstraction of electricity). It takes the following topics in turn:

   (a) guaranteed standards;

   (b) customer interruptions incentive scheme;

   (c) electrical losses;

   (d) revenue protection;

   (e) NIE's transmission network availability and quality of service to SONI;

   (f) customer service incentives; and

   (g) connection of renewable generation incentive.

Guaranteed standards

2. There are currently a series of standards that NIE is required to meet that concern aspects of its service to customers. These standards are specified in a determination that the UR made under Article 43 of the Electricity (NI) Order 1992 and in Regulations made under Article 42 of the same Order.

3. Some of the standards give customers experiencing shortfalls against the standards a right to specified compensation. For instance, according to Table 13.3 of the UR's draft determination, if NIE takes more than 24 hours to restore electricity to a domestic customer following a fault, it must pay the customer £50, and an additional £25 for every 12 hours that the electricity stays off after the first 24 hours.

4. In its draft determination, the UR proposed changes to the standards and compensation entitlements. This would require changes to legislation. These standards are specified under legislation rather than under Annex 2 of NIE's licence conditions.

5. In its final determination, the UR said that it had proposed introducing new standards but that, after considering further evidence on the practicality and cost of the standards, it did not propose to make changes at present. It said that it would consider them further during the RP5 price control period.

6. In its Statement of Case, NIE raised concerns that the UR may introduce new standards during the RP5 price control period which added materially to NIE's operating and capital costs. NIE also raised a concern with the lack of a formal definition of the criteria for 'exceptional weather events' under which it has been practice for NIE to receive an exemption from compensation payments under one of the standards. NIE told us that it was concerned that any formal or de facto change in the standards to be met during the next price control period would not be adequately reflected in the RP5 allowed revenues.

7. NIE made two specific requests in relation to guaranteed standards:[1]

(a) to confirm that the criteria for 'exceptional weather events' to be applied to exemptions from the network performance incentive and GS2 should be consistent with historical data and precedent (ie the criteria should have the effect of granting an exemption for events where the number of faults affecting the high voltage distribution network exceeds 13 times the daily mean); and

(b) to specify how the UR should approach the introduction of any changes to the GSs (or Overall Standards 14) during RP5 and, in particular, to require the UR to discuss and agree with NIE the need for any increments to the price control allowances for additional opex or capex arising from the changes.

8. The UR said that these requests were both outside the scope of our reference.

9. We did not find any reason why we should meet these requests from NIE.

10. On the first point, the interpretation of exemptions from the guaranteed standards does not seem part of the price control licence conditions referred to us. The standards themselves are not part of the price control conditions or the charge restriction in Annex 2 to NIE's Licence. And the UR told us that it was committed to a future consultation on the definition of exemptions from guaranteed standards.

11. On the second point, we did not see any concrete plans from the UR to change the standards before the end of the new price control period that we envisage (ie before 30 September 2017). The UR's final determinations suggest that this might happen, but leave this open. We do not know at this stage how the UR would approach such a change.

12. If the UR decides to make changes (or seek changes to legislation) that become effective before the end of September 2017, it will be for the UR to decide whether it is appropriate to propose modifications to NIE's licence conditions to allow it additional revenue in respect of any additional costs that it may be exposed to as a result of the change. We would expect the UR to take account of the methods we have used for cost assessment as part of our calculation of a new price control for NIE, including our use of estimates from benchmarking analysis across DNOs in the UK; the UR pointed out that the DNOs in GB currently make higher payments than NIE under guaranteed standards as well as significant non-mandatory payments. We would also expect the UR to consider whether to delay the implementation of any change in guaranteed standards if there are legitimate concerns that such a change could deny NIE adequate revenue under the price control that we have determined as part of our inquiry.

13. It did not seem necessary or appropriate for us to make any price control licence modifications in order to address a hypothetical risk that the UR will make a bad or unfair decision in the future in relation to guaranteed standards.

14. NIE also argued that whilst it did not form part of our task to provide a definitive interpretation of guaranteed standards, we must nonetheless form a view as to what standards are implied by the wording of the guaranteed standards. NIE said that its concern was that if the UR reinterpreted the guaranteed standard so as to narrow the range of circumstances in which NIE was excused from performance by virtue of 'exceptional weather events', then NIE would need to spend more money to ensure

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[1] NIE Statement of Case, p249.

that it could perform to the standard as more strictly interpreted. NIE argued that we would then need to take account of the de facto rising of the standard in deciding on an appropriate level of allowed revenue. We did not accept that argument. It would not be feasible for us to form a precise view of the obligation imposed on NIE by every aspect of regulation and legislation. Nor did it seem appropriate to take into account in our assessment of NIE's expenditure requirements the impact of a possible future change in standards, the nature and timing of which is unknown.

Customer interruptions incentive scheme

UR's proposals for RP5

15. NIE currently measures certain aspects of the quality of service that it provides to energy consumers connected to its network. It reports information on two measures that relate to interruptions to consumers' electricity supplies:

(a) The number of customer minutes lost (CML). This is a measure of the aggregate number of minutes of electricity supply interruption experienced in a year by all connected customers divided by the total number of connected customers.

(b) The number of customer interruptions (CI). This is a measure of the average number of customer interruptions in a year per 100 connected customers.

16. In its draft determination,[2] the UR reported that NIE had proposed the introduction of a financial incentive scheme relating to its performance against these measures:

> NIE proposes a network performance incentive based on customer minutes lost (CML) and customer interruptions (CI) as a result of unplanned outages on the distribution network. NIE T&D proposes to exclude planned outages, outages resulting from transmission faults and the levels of service received by their worst served customers. An incentive would be based on performance (excluding weather-related events) against annual targets for CML and CI resulting from faults affecting NIE's distribution network.

17. In its RP5 final determination, the UR proposed the introduction of a financial incentive scheme for customer interruptions and customer minutes lost that was based on the scheme set by Ofgem as part of the price controls for GB DNOs in the five-year period from April 2010. The scheme in the UR's final determination built on that proposed by the UR in its draft determination, but with changes to address some of the criticisms made by NIE. The scheme proposed by the UR had the following features:

(a) *Exclusions.* The scheme would exclude interruptions attributed to planned outages (eg where consumers' electricity supply is cut off to allow NIE to carry out planned refurbishment work on the network). The scheme would exclude interruptions attributed to outages on NIE's transmission system. The scheme would also exclude interruptions attributed to 'exceptional weather events'. By the stage of its final proposals, the UR had not reached a position on how such interruptions would be defined, and proposed to consult on the criteria to use during RP5.

[2] UR draft determination, paragraph 13.45.

(b) *Baseline (or target).* Subject to these exclusions, a baseline (or target) would be set for NIE's performance on the CML and CI measures for each year of the price control.

(c) *Deadband.* The UR proposed a 'deadband' of plus or minus 10 per cent around the baselines. NIE would face no financial exposure for variations in its performance against the CML and CI measures that lie within the deadband.

(d) *Incentive rate.* NIE would face a symmetrical financial incentive for variations in its actual performance on the CML and CI measures that are outside the deadband.

(e) *Cap and collar.* The UR proposed annual caps on the maximum of money that NIE can receive under the incentive scheme in each year. It also proposed an annual lower bound (or 'collar') on the financial downside that NIE faces under the scheme, for each of the CML and CI performance measures.

18. The scheme would apply in addition to the guaranteed standards, which include requirements for NIE to pay compensation to customers for interruptions that last over a specified time period (eg 24 hours).

19. In response to the UR's final determination, NIE supported the introduction of the incentive scheme, but raised concerns with specific aspects of its design and calibration. Table 2 sets out the design and calibration of the scheme proposed by the UR, by reference to the features of the scheme highlighted above. The table indicates NIE's concerns and NIE's proposals against the features to which they apply. The subsections that follow discuss in more detail the submissions of the parties on each feature.

TABLE 1 **Calibration of CML and CI incentive scheme (values in 2009/10 prices)**

Feature of incentive scheme	*UR proposal*	*NIE submission to the CC*
Exclusions	Exclusions for planned outages, transmission outages and exceptional weather events	NIE asked us to confirm the definition of 'exceptional weather events' for the purposes of the exemption
Baseline	CML (average minutes lost per connected customer per year): 56 CI (average interruption per customer): 61.	NIE said that CML and CI baseline based on the best annual CML performance during RP4 period, which it says is too demanding NIE proposed baselines based on average performance during RP4
Deadband	Set at +/– 10 per cent of the baseline: CML: 50.4–61.6 CI: 54.5–67.2	NIE proposed removal of deadband to address concern that it erodes the incentive to improve network performance
Incentive rate	£180,000 per CML £30,000 per CI	NIE said that UR proposals limit potential gains and losses to around £1m per year, which is equivalent to around 0.5% of what NIE thinks regulated revenue should be. NIE said that its exposure should be +/– 1.5% of regulated revenue. This would comprise an exposure of 0.9% of regulated revenue for the CML incentive and 0.6% of for the CI incentive Incentive rate would be calculated to achieve this upside and downside financial exposure given the cap and collar below
Cap and collar	Annual cap or collar set at five times the annual incentive rate: For CML: +/– £900,000 For CI: +/– £150,000	Cap and collar specified by reference to CML and CI performance measures: For CML: +/– 15% For CI: +/– 10% Incentive rate calibrated so that maximum annual exposure for the CML incentive would be 0.9% of regulated revenue and for 0.6% of for the CI incentive

Source: CC.

The deadband

20. The UR said in its final determination that the deadband would 'provide flexibility for NIE T&D, permitting the company to achieve targets while allowing for any "natural fluctuations" that may occur' (paragraph 9.13).

21. NIE had itself made some comments about 'natural fluctuations' in its response to the UR's draft determinations. But these comments were made as part of a complaint about the asymmetric nature of the incentive scheme proposed by the UR in its draft determinations, which would have meant that NIE suffered penalties for worse performance than specified in the baseline but did not receive financial rewards for better performance than the baseline level. In its final determination, the scheme proposed by the UR did not have this asymmetric feature. NIE did not consider the existence of natural fluctuations a reason to support a deadband.

22. NIE considered that a deadband would harm the effectiveness of the scheme. In particular, NIE considered that a deadband would undermine the incentive properties of the scheme because, in practice, it would be difficult to improve performance sufficiently during the RP5 price control period to exceed the deadband and trigger any additional revenue entitlement.

23. NIE said that its position that there should be no deadband was consistent with Ofgem's approach for DPCR5.

24. The UR subsequently told us that whilst it had proposed a deadband to reduce the risk to NIE in relation to natural fluctuations in performance, it would be content for no deadband to be applied if NIE saw no value in it.

Baselines (or targets)

25. NIE was concerned that the UR's baseline was not representative of its current performance and included an implied improvement target from the outset. NIE said that it would be more consistent with Ofgem's DPCR5 methodology for the baseline to be set on the basis that it had proposed (average performance during RP4) so that NIE was rewarded for any improvement and penalized for any worsening of performance. NIE said that if it was required to improve in order to avoid penalties under the scheme, then this needed to be reflected in our determination of its allowed revenues.

26. From NIE's Statement of Case,[3] the UR's proposed baseline for CML seems close to the best level of performance that NIE experienced in RP4. In its supplementary submission, the UR said the following in response to NIE's concerns about the baseline (or target):

> NIE T&D also criticises our proposed network performance incentives in relation to customer minutes lost ('CML') and customer interruptions ('CIs') as being too challenging because they are based on the best annual performance achieved by NIE T&D during RP4. But in our view it is appropriate to set NIE T&D's target by reference to the best performance that it achieved in RP4 because its performance in recent years show that the CML and CI metrics are on a downward (i.e. improving) trend. That trend has continued in 2012/2013. In any event,

[3] NIE's Statement of Case, paragraphs 2.6–2.9.

our proposal of a dead band and penalty/reward cap and collar provide a safety net that protects NIE T&D from excessive penalties.

27. In its supplementary submission, NIE considered that the UR had not responded in detail to the deficiencies it highlighted in its Statement of Case. NIE told us that its concern was that setting a target based on best annual performance took no account of natural fluctuations in annual performance resulting from the random nature of network failures and external influences such as weather. Rather than using a deadband, NIE said that natural fluctuations could be catered for by setting a target based on average performance during RP4, in a similar way to the approach taken by Ofgem for DPCR5.

28. The UR's argument that there was a downward trend in NIE's CML and CI metrics seems plausible from the charts contained in NIE and UR documents. It does not seem appropriate to set baselines on NIE's average performance during RP4. That average performance includes a particularly poor performance in 2007/08 which may not be representative of plausible outcomes for the period in question.

29. Because there is some volatility in year-on-year performance, the UR's proposed approach of using the lowest figures for CML and CI did not seem the best available. To set an appropriate baseline, we would need to look at the available data in more detail in light of the risk that NIE historical performance in any one year is unrepresentative of the average level of performance that one can reasonably expect from NIE in the future.

30. In setting a baseline, it also seemed relevant to consider whether NIE's recent and anticipated network investment would lead to continuation, over the price control period, of any apparent improvement of NIE's performance in terms of the CI and CML measures. It might be appropriate to set a baseline at a more demanding level of performance than NIE had achieved in the past. Under the incentive scheme NIE would receive financial rewards for performance in excess of the baseline (or deadband, if applicable) and there would be a risk of it being remunerated twice if it would receive such payments for performance improvements that arise from investment that had been funded as part of price control calculations.

Incentive rate and cap and collar

31. NIE's position on the cap and collar and the incentive rate were closely related. Indeed under NIE's proposal the incentive rate would be set by reference to the intended maximum financial exposure relative to annual regulated revenue. NIE said that its proposed calibration of the incentive scheme was consistent with that used by Ofgem for its DPCR4 price control review. NIE did not advocate the use of Ofgem's DPCR5 methodology in relation to the incentive rate and cap and collar because Ofgem's DPCR5 scheme related to a more mature regulatory incentive model.

32. The UR considered NIE's proposals to be inappropriate. The UR argued that NIE's proposals would mean that the penalty or reward per CML would be linked to NIE's total revenue which the UR expected to increase over the price control period (eg to cover network investments to accommodate renewable generation), whereas the value to consumers per CML avoided would not change.

33. The UR proposed incentive rates that were set by Ofgem in 2009 for one of the Scottish distribution companies, SSE Hydro (SHEPD). The UR told us that NIE regularly referred to SSE Hydro as its closest comparator. The UR said the following about its choice of incentive rate in its draft determinations (paragraph 13.5):

Given the lack of information on the willingness to pay of NIE T&D's customers the most appropriate data to use is the data Ofgem used to set incentive rates at its DPCR5 review. Ofgem's final incentive rates were based on the product of each customer type's willingness to pay and the DNO's number of customers.

34. We were not confident that Ofgem's 2009 figures would be appropriate to use without any review of our own. Ofgem itself proposed to use revised values for the next price electricity distribution price control which starts on 1 April 2015, reflecting different estimates and calculation methods, but Ofgem had not confirmed its figures at the time of our assessment.[4]

35. NIE said that the UR's proposed incentives were too weak but did not provide a good explanation of why this was the case.

36. The cap and collar defines points at which the incentive scheme would cease to apply. NIE argued in relation to the deadband that it eroded the incentive to improve network performance. The same argument can be made about the cap and collar: once NIE's performance for a year is predicted to exceed the cap or be below the collar, NIE faces no further incentive. This feature of the cap and collar would not mean that the scheme would be ineffective, but may reduce its effectiveness.

37. NIE argued that in practice the performance improvements necessary to reach the cap would likely be unachievable during RP5 so the cap was not relevant. However, in its submission above on the baseline, NIE emphasised that annual performance was affected by random nature of network failures and external influences such as weather. A cap may limit the effectiveness of the scheme in circumstances in which the random nature of network failures and the weather created conditions in which NIE's measured performance was abnormally good. Similarly, a collar may limit the effectiveness of the scheme in circumstances in which the random nature of network failures and the weather created conditions in which NIE's measured performance was abnormally bad.

38. The UR said that the cap was intended to protect customers as it limited the financial exposure of consumers to the incentive scheme, and argued that Ofgem now considered it good practice to apply cap and collar regimes. Similarly, NIE argued that a cap and collar mechanism limited the exposure of consumers and the regulated company to extreme unintended outcomes which would otherwise generate windfall gains or losses.

39. By their nature, caps and collars limit the financial exposure of consumers and the regulated company to an incentive scheme. But they also limit the effectiveness of the scheme. The choice of approach is not straightforward.

40. Finally, the application of a cap and collar may also reflect a concern that an incentive scheme—particularly a new one—may not work as well as hoped: a cap and collar would limit the impact of the scheme on consumers and the regulated company.

[4] Ofgem 'Strategy decision for the RIIO-ED1 electricity distribution price control: outputs, incentives and innovation', March 2013, p33.

Planned outages

41. If we were to introduce an incentive scheme, there are some further issues that we might consider beyond those discussed above. In particular, we might reconsider the exclusion of planned outages from the scheme.

42. Following the UR's draft determination, the UR decided to remove planned outages from the scope of the incentive scheme. The UR told us that this change was due to strong representations from NIE and the UR no longer supported it: the UR believed that both planned and unplanned outages should be included in an interruptions incentive scheme.

43. There seemed no reason in principle why NIE should face financial incentives to limit unplanned outages but not to limit planned outages. Ofgem intends to include planned outages within its interruptions incentive scheme for the electricity distribution price controls which start in 2015.[5]

44. However, there were some further considerations which mean that this aspect of scheme design was not straightforward.

45. NIE told us that one reason for excluding planned outages was because it would introduce significant forecasting uncertainty into the development of appropriate baselines for the incentive scheme. NIE said that this presented a material risk because the nature of NIE's network meant that planned outages had a much greater impact on measures of CML and CI than would be the case for a distribution company in GB. NIE said that this was a particularly important concern in light of significant increase in planned network investment during the RP5 price control period and uncertainty about its impact on planned outages.

46. We also identified that an incentive scheme covering planned outages may bring a risk of perverse incentives (eg NIE may seek to avoid or minimize asset management activities where these would contribute to its planned outages).

The public interest arguments relating to current price control conditions

47. In their original submissions, neither the UR nor NIE provided explicit arguments that the current price control licence conditions operated against the public interest because they did not contain a financial incentive scheme relating to customer interruptions. We asked the parties to provide further submissions on the question of how the current licence conditions may operate against the public interest.

48. The UR's submission did not make any specific arguments about the public interest in relation to the need for a customer interruptions incentive scheme.

49. The UR emphasized to us that, even in the absence of a strong financial incentive, NIE's quality of service in relation to customer interruptions had improved over the RP4 price control period and thereafter.

50. Nonetheless, the UR said that an incentive scheme was appropriate because it was important that NIE's performance in relation to customer interruptions did not deteriorate.

[5] ibid, p34.

51. NIE told us that Annex 2 of its licence operated against the public interest for reasons that include (paragraph 1.7): 'It fails to provide NIE with effective incentives to provide an appropriate quality of T&D services, in terms of the achievement of certain output standards (e.g. in relation to network performance)'. NIE's submissions did not explain this concern beyond the claim that there was a 'risk that NIE will fail to provide T&D services to an appropriate standard' because the price control mechanisms in the current licence are limited in scope and no longer apt. NIE's submission did not provide any evidence that this risk had materialized in practice in relation to customer interruptions on NIE's network.

52. NIE's submissions on the public interest took the position that the most appropriate price control framework for NIE would involve an interruptions incentive scheme and that, as a result, the current licence conditions are deficient in the sense that they lack such a scheme. We did not accept this argument.

53. The submissions to us from the Consumer Council did not make the case that an interruptions incentive scheme is necessary or emphasize problems relating to NIE's performance in terms of customer interruptions.[6]

Potential risks to the effectiveness of an incentive scheme

54. The theoretical aim of the type of regulatory scheme envisaged above is to reflect estimates of customers' willingness to pay for shorter interruptions or fewer interruptions in the incentive rate, so that the regulated company will make efficient (or sensible) trade-offs between the harm customers experience from interruptions and the costs of action to reduce interruptions. Such action could be network investment or operational measures that reduce the duration of interruptions.

55. However, the ability of the type of regulatory scheme envisaged above to achieve the theoretical aim is impeded by some practical considerations, including the following:

(a) uncertainty as to consumers' valuation of the harm they experience from interruptions; and

(b) the fact that that valuation will vary substantially by type of electricity consumer (eg domestic consumers versus a large business) and by the circumstances of the interruption (eg time of day and duration).

56. An impact of *(a)* and *(b)* is a risk that in some circumstances a financial incentive scheme would provide NIE with financial incentives to take action that would not be economic and efficient (eg expenditure that is not justified by the value to consumers of that expenditure).

57. These considerations do not mean that it would necessarily be inappropriate to introduce an incentive scheme. But they contributed to our view that to introduce a fair and effective scheme is not a straightforward matter.

Our assessment

58. We decided not to introduce an interruptions incentive scheme for NIE.

[6] CCNI initial submission.

59. Instead, we decided that NIE should publish its annual performance in terms of measures of customer interruptions and customer minutes lost. We also decided that NIE should publish a forecast of its performance in terms of these measures over the period to 30 September 2017, in light of its recent and planned network investment, and explain any shortfalls in performance against its forecasts.

60. We found that the need for a financial incentive scheme had not been established. For instance, the UR did not argue that the extent of interruptions on NIE's network was unsatisfactory and that an incentive scheme was needed to improve performance. NIE's submissions identify a hypothetical risk of poor service quality in relation to customer interruptions but did not demonstrate the need for a scheme to address that risk.

61. NIE identified that the introduction of a financial incentive scheme could bring improvements for consumers, encouraging it to act in a more 'optimal' way. We recognized the basis for NIE's argument but found that there were also some practical considerations relevant to our inquiry and risks of unintended adverse consequences.

62. The specification of a new interruptions incentive scheme is a complex matter: a poorly designed scheme could be worse than no scheme at all and could impose unnecessary costs on consumers. The parties disputed several important aspects of the design and calibration of such a scheme, including the setting of the baseline, the incentive rate and the treatment of planned outages. These disputes reflect the difficulties faced in the specification of an appropriate scheme.

63. To take an example, NIE and the UR proposed different methods to set the baseline. The UR proposed using the best performance of NIE during the RP4 period whilst NIE proposed average performance. The UR said that NIE's approach would not allow for the upward trend in NIE's historical performance. NIE said that the UR's approach was inappropriate in light of the variability in annual performance due to random events and external conditions (eg weather). The concerns raised by NIE and the UR are valid and some alternative approach would seem necessary.

64. Further, the proposals of the parties seemed to overlook other considerations that are relevant to the specification of a fair and effective scheme. To return to the example of the baseline, neither party's proposals take account of the possibility that, even in the absence of a response by NIE to financial incentives, NIE's performance will improve over the price control period due to the network investment it has recently made and the network investment anticipated over the next price control period. And neither party's proposed approach recognized that the incentive properties of the scheme may be undermined if the established method to set baselines is to use NIE's historical performance (NIE might refrain from improving performance if this means it will face a more demanding baseline in the next price control period).

Electrical losses

65. As electricity is transmitted through electricity transmission and distribution systems some energy is lost (eg as heat in system components). Network companies take decisions that affect the scale of these losses. The cost of the electricity that is lost will tend to be borne by consumers through their electricity bills; it contributes to the wholesale charges per unit of electricity that suppliers face. Action to reduce losses can have a benefit to consumers by reducing the total costs of losses. Such action may also entail costs. For example, purchasing system components that give rise to fewer losses may increase network investment costs.

66. The group of consumers affected by losses differs across NIE's transmission and distribution networks. The costs arising from losses on NIE's distribution network are experienced by Northern Ireland consumers. The costs arising from losses on NIE's transmission network are experienced by consumers in both Northern Ireland and the Republic of Ireland as part of the treatment of transmission losses in the single electricity market.

Ofgem's distribution losses incentive scheme

67. At its review to set price controls for the five-year period from April 2005, which it refers to as DPCP4, Ofgem introduced an incentive scheme intended to provide electricity distribution companies in GB with explicit financial incentive to manage the level of losses on their networks in an efficient way.

68. Ofgem's losses incentive scheme has not been successful. One of the main problems with the scheme is that it is difficult to measure the scale of losses on a GB DNO's network. There is the potential for DNOs to have received substantial financial benefits from the scheme due to measurement and estimation issues rather than the performance improvements that the scheme was intended to achieve. The scheme also contributes to tariff uncertainty and volatility and has also been a time-consuming process: by July 2013, Ofgem was still not close to having worked out the final payments the DNOs were due under the DPCR4 incentive scheme that ran to March 2010.[7] Ofgem has abandoned the losses incentive scheme and does not plan to have any similar financial incentive scheme in relation to measures of losses on the GB DNOs networks as part of its next price control.[8]

UR's RP5 proposals and NIE's response

69. The current licence conditions (under the RP4 price control) do not contain any kind of losses incentive scheme for NIE.

70. The UR expressed enthusiasm for the introduction of such a scheme. It told us that requirements under Article 15 of the Energy Efficiency Directive required it to consider this type of incentive scheme. It referred us to the following part of Article 15 of that directive: 'Member States shall ensure that national energy regulatory authorities pay due regard to energy efficiency in carrying out the regulatory tasks specified in Directives 2009/72/EC and 2009/73/EC regarding their decisions on the operation of the gas and electricity infrastructure.'

71. In its final determination, the UR said the following in relation to losses (paragraph 9.2):

> We are keen to introduce new incentives, such as a distribution loss incentive and health and load indices. However, to do so we need detailed measurements and base line information. We encourage NIE T&D to develop these areas during the RP5 period so that we are in a position to consider additional incentives later in RP5 or in RP6.

72. The UR did not seek to introduce any form of losses incentive scheme through agreement of the RP5 price controls proposals with NIE, but indicated that it might seek to introduce such a scheme at some future point, perhaps at a later point in the

[7] Ofgem 'Decision on the process to follow for closing out the losses incentive mechanism for the fourth distribution price control', July 2013.
[8] Ofgem 'Strategy decision for the RIIO-ED1 electricity distribution price control: overview', March 2013, p26.

RP5 price control period or in the RP6 price control period. The UR said that this would be subject to public consultation and licence modifications.

73. The UR said the following about the problem that it would like to address through a losses incentive scheme:[9]

> Losses impose a cost on consumers as additional energy has to be generated and transported to replace the lost energy. Losses are effectively funded by consumers; we consider this to be unreasonable. It is estimated that 7.1% (worth around £70 million per year) of the electricity entering the distribution system in NI is lost before it reaches customers. NIE T&D can influence this cost, but at present has no incentive to do so.

74. Whilst the UR said that NIE could influence the costs arising from losses, it did not explain the extent of that influence in relation to the estimate of £70 million per year.

75. Given Ofgem's bad experiences with its distribution losses scheme, it is open to question as to whether an effective financial incentive scheme can be developed to address the UR's concerns. Neither the UR's draft or final determinations address that point directly; instead they recognized the need for measurement systems and reporting structures to underpin any new incentive scheme and acknowledge uncertainty as to if and when these will be available.

76. It is possible that the issues relating to estimation of losses that have been problematic in GB would not be as severe in Northern Ireland. In GB, it is suppliers rather than DNOs that carry out meter reading, whereas in Northern Ireland NIE carries out meter reading.

77. The UR told us that besides Ofgem's experience, there were other EU models that could be considered for electrical losses. The UR said that other regulators in the EU had introduced losses incentive schemes that had appeared more effective than the Ofgem scheme and that further consideration of the potential for such a scheme in Northern Ireland was appropriate. The UR did not provide—and we did not ask for—any further information on the models applied in other EU member states.

78. NIE's Statement of Case only provided a brief response in relation to a potential distribution losses incentive scheme. NIE highlighted that the UR recognized the need to obtain historical data first. NIE told us that it intended to work with the UR to establish a viable distribution losses incentive scheme. NIE also reiterated the limitations of such a scheme and the need to design the scheme to reflect the extent to which NIE could influence network losses and the potential impact of measurement error.

79. NIE told us that it did not expect us to be able, in the time available, to devise any workable losses incentive scheme but urged us not to pass judgement on the workability of such schemes generally.

Our assessment

80. We decided not to introduce a financial incentive scheme in relation to electrical losses on NIE's distribution or transmission systems. Neither party suggested that we should seek to do so as part of our inquiry.

[9] UR draft final determination, paragraph 13.27.

81. Energy efficiency on NIE's network is relevant to our public interest considerations. We did not find that the absence from NIE's price control licence conditions of a financial incentive scheme in relation to electrical losses operated against the public interest.

82. NIE has statutory duties under the Electricity (Northern Ireland) Order 1992 in relation to the efficiency of the electricity distribution and transmission systems in Northern Ireland. We would expect that, in light of its duties, NIE will need to take account of the impact of losses on the efficiency of its transmission and distribution systems as part of its asset management decision-making and procurement policies. For instance, when taking decisions on the purchase of new transformers, NIE may need to consider not only the purchase price of alternative options but also any differences in terms of the electrical losses they give rise to (at least to the extent that they are material and conducive to estimation).

83. At the first hearing with NIE, we asked it why a specific financial incentive scheme for losses was necessary given NIE's existing statutory duties. During the discussion that followed that question, NIE made the argument that a financial incentive scheme could encourage NIE to purchase a more efficient transformer (in terms of electrical losses) even if it was more expensive to purchase than an alternative, less efficient transformer. NIE said that if NIE were neutral to the cost of a transformer or if there was a financial incentive scheme, it would generally choose the most efficient transformer. The implication of NIE's argument is that if NIE is exposed financially to the purchase price of the transformer, but no financial incentive applies in relation to electrical losses, NIE would not necessarily choose the most efficient transformer.

84. Taken on its own, these comments might suggest concerns about electrical losses and energy efficiency that may be relevant to the public interest. However, we did not see how NIE could comply with its statutory duties if it took decisions on which transformers to purchase without regard to the impact on losses and energy efficiency. Furthermore, NIE told us that we should not infer from the comments made at the hearing with NIE that NIE was neglectful of efficiency considerations in its network configuration. NIE said that it procured low-loss transformers based on lifetime costs in line with industry practice.

85. The UR also highlighted that NIE has obligations to reduce the energy consumed by its network under the Energy Efficiency Directive.

86. Finally, in relation to purchasing of transformers, the UR also told us that it had concerns that NIE's procurement policy might not comply with its legal duties and suggested that this might need further exploration by the UR or the CC. We did not seek to consider this point: it did not relate to NIE's price control licence conditions which were the subject of our inquiry.

Revenue protection

87. The illegal abstraction of electricity from NIE's electricity system imposes costs on other electricity consumers who are consuming lawfully. The act of consuming electricity illegally does not directly impose a cost on NIE, though NIE may incur costs investigating and dealing with instances of illegal abstraction.

88. The term 'revenue protection' is used in the electricity industry to describe activities to detect and deter cases of illegal abstraction of electricity (and electricity theft) and to collect money owed in relation to that illegal abstraction.

UR's RP5 proposals and NIE's Statement of Case

89. The UR proposed in its final determinations to continue with a scheme it called the Revenue Protection Programme. The UR's draft determination[10] said:

> The Revenue Protection Programme, which we introduced during RP4, incentivises NIE T&D to recover as much revenue as possible from illegal electricity abstraction at de-energised non-domestic sites. The scheme provides an incentive to NIE T&D by allowing the benefits of recovered revenue to be shared equally between NIE T&D and customers. The scheme therefore recognises that the ultimate cost of illegal abstraction is borne by customers. It requires NIE T&D to split the recovered amount on a 50:50 basis. Over a 3 year period, this mechanism has cost consumers £162,000 (funding for NIE T&D to set up the scheme and allocate resources). However, the return to consumers has been £570,000. This is a net benefit of £408,000.

90. The UR's draft determination[11] said the following:

> The [revenue protection] incentive allowed NIE T&D to retain 50% of any recovered amount that is in excess of the allowed additional costs of providing the service. As well as sharing the recovered monies, customers also benefit in full from the prevention of any further illegal abstraction that would otherwise have occurred but for the intervention of the Revenue Protection Service.
>
> Our draft determination noted that the revenue protection unit service has provided a net benefit for consumers during RP4. We believe that this work should be resourced to ensure that illegal extraction is kept to a minimum and we have decided that it should continue in RP5 on the same basis as it did in RP4, i.e. any recovered amount will be shared 50:50 between NIE T&D and consumers. We will require regular reporting of this area during RP5.

91. The first extract from the UR's draft determinations quoted above said that the current revenue protection scheme was introduced during RP4. In contrast, NIE told us that the scheme was approved by the UR in October 2005 and pre-dated the RP4 price control. The exact timing of the introduction of the scheme was not important to our inquiry. What was more relevant is the wider lack of transparency about the scheme. There is no reference to the Revenue Protection Programme in NIE's licence conditions. Nor are there any formulae or rules that would give rise to the intended effect described above in the calculation of the restriction on NIE's maximum regulated revenue in Annex 2 to NIE's Licence.

92. NIE proposed changes to the current revenue protection scheme and the introduction of a new scheme for domestic properties. In its Statement of Case, NIE said that the UR did not address the substance of its proposals for changes to revenue protection incentives. NIE's Statement of Case referred to its business plan questionnaire (BPQ) submission on incentives, which it included as Appendix 9.1 to its Statement of Case. About two pages of this appendix concerns NIE's proposals in relation to revenue protection or 'reduction in theft'. NIE said that the UR's RP5 proposals represented a missed opportunity to benefit consumers.

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[10] UR draft final determination, paragraph 13.13.
[11] ibid, paragraphs 9.20 & 9.21.

NIE's proposals for revenue protection in its statement of case

93. In its Statement of Case, NIE proposed the following:

(a) A substantial change to the current incentive scheme for non-domestic vacant premises. Under the change, NIE would retain 100 per cent of the revenue it recovered in relation to past illegal abstraction of electricity at such premises. Consumers would not receive any share of these revenues. NIE would bear some costs for revenue protection activities that had previously been funded through an allowance as part of the price control; the allowance had been around £54,000 per year in the past.[12]

(b) The introduction of a new incentive scheme relating to illegal abstraction at domestic properties. This would involve: (i) a target being set for the number of units of electricity that NIE recovered money in relation to, based on historical information, and (ii) NIE being entitled to 7p for every unit of electricity recovered in excess of the target. NIE said that 7p represented around 50 per cent of the cost of electricity for domestic customers.[13]

94. Besides these proposals, NIE did not seek to establish how the current licence conditions operate against the public interest in relation to revenue protection or the illegal abstraction of electricity.

Our assessment of the proposals in NIE's statement of case

95. This subsection considers the proposals made by NIE in its Statement of Case, which we considered as part of our provisional determination. Section 6 of our final determination considers NIE's subsequent proposals in its response to our provisional determination.

96. NIE claimed that its proposed changes in relation to non-domestic vacant premises would benefit both customers and NIE.[14] We were not persuaded of this.

97. NIE correctly identified that where it recovered money for past illegal abstraction, consumers might benefit from a reduction in the amount of illegal abstraction in the future. The detection of illegal abstraction at premises, and recovery of money due, may reduce future illegal abstraction at those premises. But that does not in itself mean that consumers would benefit overall from the change proposed by NIE. The most direct and clear impact of the change proposed by NIE is the elimination of the benefit to consumers from 50 per cent of the money recovered by NIE from illegal abstraction.

98. NIE did not provide any analysis to explain why the proposed change would be better for consumers, taking account of the various sources of benefit to consumers from activities to tackle illegal abstraction of electricity and the costs of those activities. NIE argued that its proposal was designed to strengthen the current incentive and to provide NIE with greater flexibility, but NIE has not explained why the incentive properties of the current scheme need strengthening or how NIE lacks flexibility.

99. NIE's proposals for a revenue protection incentive in relation to domestic customers would be heavily dependent on data and estimates of illegal consumption.

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[12] NIE Statement of Case, Appendix 9.1, p22.
[13] ibid, Appendix 9.1, p23.
[14] ibid, p247.

Considerable work would be required to ensure that the data and reporting arrangements were fit for purpose.

100. We also considered NIE's proposals in light of publications by Ofgem in relation to illegal abstraction of electricity. In GB, Ofgem has been considering potential incentive schemes that could be applied to GB electricity suppliers to encourage them to take action to detect and deter illegal abstraction electricity. Ofgem published a consultation paper 'Tackling electricity theft' published in July 2013 alongside a draft impact assessment. There are differences between GB and Northern Ireland. For instance, in GB it is suppliers rather than the distribution companies which are responsible for meter readings. But Ofgem's work is still relevant. In light of Ofgem's work and our own analysis, the following points seemed relevant to the inquiry:

(a) There may be substantial benefits to consumers from efforts to tackle illegal abstraction of electricity that arise from the prevention of future cases of electricity theft (eg illegal abstraction of electricity at a particular premises may end following detection, saving honest consumers the costs of the electricity that would otherwise be stolen).

(b) The design of an incentive scheme to encourage a company to tackle electricity theft in a way that is likely to provide net benefits to consumers is not a straightforward task. The effectiveness of the scheme will depend on its calibration. And there are risks of perverse effects and unintended consequences.

(c) There are other ways for a regulator to address concerns about illegal abstraction of electricity beyond the introduction of incentive schemes. For instance, one possible option is to place obligations on regulated companies to take actions to tackle illegal abstraction or to require them to explain how they comply with their obligations.

101. The point under *(c)* seemed particularly relevant to our inquiry. The UR told us that it obliged NIE to read all meters, including keypad meters, annually and that this had led to a substantial increase in the detection of cases of illegal abstraction of electricity. The UR reported that the number of people caught stealing electricity rose from 400 in 2007 to 2,000 in 2012 and that in the last five years the number of people prosecuted rose from 19 to 200. This casts doubt on the need to introduce special incentive schemes as part of NIE's price control licence conditions in order to tackle concerns about the illegal abstraction of electricity.

102. We decided not to implement the proposals for revenue protection incentives from NIE's Statement of Case.

NIE's transmission network availability and quality of service to SONI

103. Another aspect of NIE's service quality is its 'service' to SONI in relation to the electricity transmission network that NIE owns and maintains and which SONI operates. For instance, in GB Ofgem's work on electricity transmission price controls has sought to tackle concerns that transmission network companies may take too long to carry out planned work on the network that leaves some transmission capacity unavailable (planned outages).

104. The UR told us that this aspect of NIE's service was a concern for the UR but that it did not seek to address this as part of its RP5 proposals because of changes relating to TSO certification.

105. We thought that any such concerns, if verified, could be dealt with through modification of the ‘transmission interface agreement’ between SONI and NIE, rather than through changes to the charge restriction in NIE’s licence. NIE agreed with our view that any concerns with NIE’s services to SONI (were they to arise) could be dealt with through the transmission interface agreement.

106. We decided not to make modifications to NIE’s price control licence conditions in relation to any aspect of NIE’s quality of service to SONI.

Customer service incentives

107. In its Statement of Case,[15] NIE said that the UR’s final determination proposed no incentive for improving customer services. It said that this was based on the UR’s judgement that customers were generally satisfied with existing service levels. It said that because of the UR’s position on the matter the engagement that would be necessary to develop incentive measures had not taken place. NIE did not propose that we consider the potential introduction of a customer service incentive scheme.

108. We decided not to introduce any incentive schemes for customer service.

Connection of renewable generation incentive

109. NIE said that it proposed incentives for connection of renewable generation to the distribution network.[16] These proposals were probably influenced by a distributed generation incentive scheme that Ofgem introduced for the GB DNOs in 2010. NIE said that the UR made no reference to NIE’s proposal in either its draft or final proposals. NIE said that it had envisaged working with the UR to develop a renewable generation incentive scheme, which would be informed by public consultation, but the necessary engagement had not taken place. NIE did not propose that we consider potential introduction of a renewable generation incentive scheme.

110. We decided not to introduce any incentive schemes for connection of renewable generation to the distribution system.

[15] ibid, p245.
[16] ibid, pp245–246.

Why use benchmarking?

1. One potential approach to setting a price control for NIE would be to base this on NIE's actual costs (including an allowance for profit), with potential to revise the price control or revenue restriction each year (or as needed) in light of updated information on NIE's actual expenditure. This would be a form of 'cost pass-through' or 'cost plus' regulation. It would be relatively simple to implement. It would not involve any cost comparisons or benchmarking analysis.

2. However, there are (at least) two reasons why it may be appropriate to use cost comparisons or benchmarking analysis:

   (a) *Accuracy objective.* Using benchmarking analysis may provide a more accurate estimate of a regulated company's expenditure requirements (if it were to operate efficiently) over a price control period than information on its historical expenditure. A company's historical expenditure may reflect historical inefficiency and overlook opportunities for future cost savings.

   (b) *Efficiency objective.* If expenditure allowances used to calculate price controls are (expected to be) based on the regulated company's actual costs in a previous financial year, this may provide it with perverse financial incentives to incur more expenditure than necessary in that year (and other years). It may also mean that the regulated company has no direct financial incentives to operate more efficiently. In short, using a regulated company's historical costs to set its future price control allowances brings risks to the efficiency of the regulated company, which may then feed through to the level of charges that consumers pay. Calculating the price control for a regulated company on the basis of information on the costs of *other* companies provides a way to address these risks.

3. It is important not to overlook the second reason above. Even if we have some concerns over the contribution of benchmarking analysis to the accuracy objective (eg because of the difficulties of fully accounting for differences between companies that affect their expenditure requirements), benchmarking analysis may also make an important contribution to the efficiency objective.

4. If the price control arrangement involves some form of explicit sharing of differences between regulatory expenditure allowances and out-turn expenditure, this will reduce the regulated company's exposure to any inaccuracy from the use of benchmarking data. The maximum revenues that the company can raise from customers would reflect a mix of: *(a)* estimates of the regulated company's expenditure requirements based on the results of benchmarking analysis and *(b)* the regulated company's actual costs.

5. An emphasis on cost benchmarking is not the only way to try to tackle the risks relating to efficiency incentives. For instance, the rolling operating expenditure mechanism that formed part of the NIE's RP4 price control is a possible method that does not rely on benchmarking, although we have some doubts over its effectiveness—especially in periods of relatively high RPI inflation relative to interest rates. Furthermore, a long-term commitment to an RP4-style rolling mechanism is not compatible with the use of benchmarking analysis to make adjustments to historic spend at price control reviews—such adjustments break the incentive properties of the rolling scheme. We are not aware of UK precedent for an incentive mechanism that addresses the concerns about using a regulated company's past spend to set its

future expenditure allowance in a way that is *(a)* effective and *(b)* does not give rise to risks of severe perverse incentives.

6. An alternative type of approach altogether would be to set a price control for NIE by reference to an estimate of the costs of a hypothetical efficient network operator that provides the same services as NIE (including in terms of the number, location and consumption of electricity customers using a bottom-up cost model). This would represent a substantial change to the type of price control regulation that NIE is subject to. We have not sought to implement such a change as part of this inquiry.

The UR's approach to controllable operating expenditure

1. This appendix provides a summary of the UR's approach to the calculation of proposed allowances for NIE's 'controllable' opex. We have drawn on the UR's draft and final determinations, the UR's submission UR-3 and the Excel file the UR provided to show how it had calculated its opex allowances (UR-33 'Breakdown of opex allowances'). This appendix gives particular attention to the benchmarking analysis that the UR relied on.

Summary of the UR's proposals

2. The UR's final proposals involved a 4.75-year price control running from 1 January 2013 to 30 September 2017. Its original plan had been to set a five-year price control running from 1 October 2012 to 30 September 2017 but a shorter period was proposed for the final determinations in light of delays in the process. For ease of explanation, we first describe how the UR calculated a five-year allowance for controllable opex from 1 October 2012. We then describe how the UR calculated controllable opex allowances for the 4.75-year period from January 2013.

TABLE 1 **The UR calculations for controllable opex: five-year basis**

		Financial year ending				
	Mar 10	*Sep 13*	*Sep 14*	*Sep 15*	*Sep 16*	*Sep 17*
(a) Base year costs	31.39					
(b) Calculation of adjusted base year costs	33.51					
(c) Roll-forward of adjusted base year costs		33.51	33.51	33.51	33.51	33.51
(d) Adjustment for estimated inefficiency		–1.19	–2.35	–2.35	–2.35	–2.35
(e) Allowance for new cost items		6.94	7.06	6.84	6.65	6.61
(f) 1% annual productivity improvement		–0.39	–0.76	–1.13	–1.49	–1.85
(g) Adjustment for RPEs		–1.66	–1.09	–0.50	–0.16	0.14
Allowance for controllable opex		**37.20**	**36.38**	**36.38**	**36.17**	**36.06**

Source: CC analysis of UR-33.

3. Table 1 above provides an overview of the UR's calculation of the five-year allowance, which we have separated into steps *(a)* to *(g)* for presentational purposes. The steps taken by the UR can be summarized as follows:

   (a) Start with the measure of NIE's controllable opex for the base year (2009/10) reported in NIE's BPQ response.

   (b) Make a series of adjustments to the figure from *(a)* to produce a value for adjusted base year opex. These adjustments comprise: (i) including some additional operating costs not captured under the definition of controllable opex in NIE's BPQ response (eg meter reading costs); (ii) deducting opex incurred in 2009/10 for regulatory schemes not being continued (eg certain innovation schemes); (iii) removing the impact of some exceptional costs experienced by NIE in 2009/10 (eg excess overtime due to certain storms); and (iv) adjusting for some accounting provisions.

   (c) Take the adjusted value of controllable opex in the base year, calculated in step *(b)*, and roll this forward to provide the starting point for a controllable opex allowance for each of the five financial years of the price control, from 1 October 2012 to 30 September 2017.

(d) Calculate deductions to the amounts from step *(c)* for an estimate of the extent of inefficient costs reflected in NIE's controllable opex in the base year. The deductions are calculated to reduce NIE's controllable opex by 7 per cent. This reduction is phased in over a two-year period, so the deduction in the first 12-month period is only 3.6 per cent; after that it is 7 per cent. The 7 per cent reduction is based on the results from cost comparisons between NIE and distribution network companies in GB (GB DNOs) carried out by the consultancy firm CEPA.

(e) Make additions to the allowances from step *(c)* for items of controllable opex that the UR treats as 'new' in RP5. These additions are based on the UR's review of a series of claims for additional costs by NIE. In some cases the UR only allowed part of the costs sought by NIE and in other cases the UR did not allow any.

(f) Calculate the cumulative impact of an assumed 1 per cent annual productivity improvement on the cost allowances for each year obtained from steps *(b)* to *(e)*. The 1 per cent improvement starts from the year ended September 2013.[1]

(g) Make adjustments for the cost allowances for each year for the impact of RPEs, which reflect estimates of the extent to which the input prices (eg wages and materials prices) that affect NIE's controllable opex grow faster or slower than the RPI.

4. The UR's total allowance for controllable opex was calculated as the roll-forward values for each financial year from step *(c)* for each financial year, plus the net value of the additions and adjustments from steps *(d)*, *(e)*, *(f)* and *(g)*.

5. In its final determination, the UR's proposals included a 4.75-year allowance running from January 2013 to September 2017. This comprised a 0.75-year allowance in the period January 2013 to December 2013 and annual allowances for the remaining four financial years. The UR calculated this price control by modifying the calculation of the five-year control summarized above in two ways:

(a) The efficiency adjustment for opex is phased in over a 24-month period from January 2013 rather than a 24-month period from October 2012.

(b) All expenditure allowances for the 0.75-year period from January 2013 to December 2013 are based on the allowance for the first year of the five-year control multiplied by 0.75.

6. We provide more information below on the adjustments that the UR makes as part of the calculation of adjusted base year costs in step *(b)* above and on the benchmarking analysis used by the UR to support the adjustments under step *(d)*. This appendix does not deal with assumptions on ongoing productivity improvements or real price effects.

The UR's calculation of adjusted base year costs

7. Table 2 provides more information on the adjustments made as part of the calculation of adjusted base year costs under what we have labelled as the UR's step *(a)* above.

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[1] The UR told us that the calculations under step *(f)* included an error: the annual productivity adjustment factor should be applied from the base year.

TABLE 2 **The UR calculation of adjusted base year costs, 2009/10**

	£m
Base year costs	
Controllable opex 2009/10	31.39
Additional items for roll-forward	
Keypad assets for opex costs	0.15
Rathlin opex costs	0.03
Adjustments for exceptional items	
Excess overtime	–0.70
Demolition provision	0.40
Billing charges	0.00
Innovation	–0.60
Other opex	0.15
Price review costs	–0.03
Adjust meter-reading costs	2.72
Adjusted base year costs	**33.51**

Source: CC analysis.

8. The adjustments for keypad asset costs and Rathlin costs relate to areas of expenditure for which NIE did incur costs in 2009/10 but which are not included within the definition of 'controllable operating expenditure' reported by NIE. Indeed, NIE's regulatory accounts for the year to 31 March 2010 include a substantial amount of additional costs that are not recorded under the definition of controllable opex used for the purposes of the RP4 price control, but which NIE was able to recover through charges to customers under the D_t term in its licence. The UR took account of some but not all of these costs in its calculation of adjusted base year costs. Some of the other costs falling under the D_t term in 2009/10 are considered by the UR as part of its separate assessment of claims by NIE for 'new' costs.

The UR's adjustment for opex inefficiency in light of benchmarking analysis

9. In its final determination, the UR proposed a 7 per cent downward adjustment, phased in over the first two years of the proposed new price control period, as part of the calculation of an allowance for NIE's controllable opex. The impacts of this adjustment are shown in Table 1 above, under what we label as step *(d)*. The UR's 7 per cent adjustment was based on the results from comparisons of NIE's costs against those of GB DNO's carried out by CEPA.

10. CEPA produced a report for the UR entitled *Efficiency assessment of NIE's operating expenditure*, dated October 2011. This report was published by the UR as part of its draft determinations. The approach taken by CEPA for this report can be summarized at a very high level as follows:

(a) CEPA took data on NIE's controllable opex in 2007/08 and 2008/09 and made a series of adjustments to make it comparable with certain cost categories that the GB DNOs reported their costs against. The net effect of these adjustments is substantial.

(b) CEPA did not use data for 2009/10. The publicly available data for GB DNOs for 2009/10 involved GB DNO's cost forecasts for that year rather than out-turn cost data. CEPA did not consider the forecast cost data suitable for its benchmarking analysis.

(c) CEPA made adjustments to the cost data for NIE and for the GB DNOs for estimates of the impact on costs of regional wage differences across different

parts of the UK. Northern Ireland has relatively low wages, and the effect of the adjustment is to increase the costs attributed to NIE.

(d) CEPA used a series of relatively simple econometric models, estimated using the ordinary least squares (OLS) technique, to produce estimates of the costs that NIE would have faced in 2008/09 if it was averagely-efficient among the companies included in the sample (after regional wage adjustments). CEPA used the results from these models to produce estimates of how much, in percentage terms, NIE would need to reduce its costs in order to have a level of efficiency that would be at the upper quartile of efficiency within the sample. The UR used these estimates of the cost reductions that would be required of NIE to produce the efficiency adjustments in its draft and final determinations.

11. The UR provided us with a short update to CEPA's analysis, prepared by CEPA in June 2013. This provided some additional analysis including results using data for 2009/10. The 2009/10 data relate to GB DNO forecast costs rather than actual costs; CEPA preferred the 2008/09 data.

Scope of costs covered by CEPA benchmarking analysis

12. The CEPA report relied on by the UR for its final determinations is described as 'an econometric top down efficiency assessment of NIE's operating expenditure (opex)'.[2] The UR refers to the analysis as benchmarking of 'indirect opex costs (ie total controllable opex less network repairs and maintenance (R&M) costs)'.[3] The CEPA benchmarking analysis that the UR relies on is not a comparison of NIE's opex—or controllable opex—against the opex of GB DNOs.

13. CEPA's benchmarking analysis of NIE's costs against the costs of GB DNOs is based on estimates of the costs that NIE would report, for its electricity distribution network activities, against the category of costs defined by Ofgem as 'indirect costs' (using the definition prevailing in 2008/09). This is a special cost category developed by Ofgem for the specific purposes of its work on energy network price controls.

14. Ofgem has defined indirect costs as the costs of those activities which do not involve physical contact with system assets. These activities include network design, project management, engineering management and clerical support; control centre; human resources; IT and telecoms; and regulation and finance.[4] Within the category of indirect costs there are two subcategories: business support costs and closely associated indirect costs.

15. It is not appropriate to equate this category with the concept of opex used by the UR in the calculations for its draft and final determinations.

16. What CEPA and the UR describe as 'indirect opex costs' should instead simply be described as 'indirect costs'. These costs include not only opex (as defined by NIE and the UR) but also costs that it is reasonable or necessary to capitalize for accounting purposes. Ofgem's concept of indirect costs includes costs that are capitalized by GB DNOs. And it includes costs that are capitalized by NIE. Figures

[2] CEPA 2011, p1.
[3] UR Statement of Case, p2.
[4] www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR5/Documents1/DPCR5_Glossary_Master1.pdf, p75.

from Ofgem's published DPCR5 financial model suggest that high proportions of indirect costs are capitalized by some GB DNOs.[5]

17. The estimate of NIE's indirect costs used in CEPA's analysis is calculated by taking data on NIE's reported controllable opex and then making a series of substantial adjustments. These adjustments have the effect of including a large amount of costs that NIE capitalizes within the measure of NIE's indirect costs which is compared against the indirect costs of GB DNOs.

18. In addition to benchmarking analysis of NIE against GB DNOs on a measure of NIE's indirect costs, CEPA's report provides benchmarking analysis of NIE against GB DNOs on a measure described as 'total opex' or 'total distribution opex'. Again, these labels are potentially misleading. This measure is the sum of the estimate of NIE's indirect costs for its distribution network activities plus the element of NIE's repairs and maintenance costs allocated to distribution. A substantial part of these costs are capitalized.

19. Two main points stand out:

(a) A large part of NIE's reported controllable opex is repairs and maintenance costs that fall outside the Ofgem definition of indirect costs.

(b) A large part of the costs included in the CEPA's estimate of NIE's indirect costs do not fall under the definition of NIE's controllable opex. These comprise some elements of NIE's opex which were not reported as 'controllable' opex (for example, wayleaves costs are reported as 'uncontrollable' opex) and a substantial element of costs that NIE capitalizes (for example, capitalized overheads of NIE and indirect costs of NIE Powerteam that are capitalized).

20. The UR recognized that the benchmarking carried out by CEPA relates also to NIE's capex. The CEPA analysis of NIE's indirect costs has fed into the UR's proposals for the level of NIE's capex requirements. The UR's final determination in relation to capex says the following:[6]

> Benchmarking by SKM has shown that the direct costs associated with NIE T&D's capex plan are efficient. However, the indirect cost benchmarking that was undertaken for us by Cambridge Economic Policy Associates (CEPA) identified room for further improvement in this area. SKM has proposed a reduction in the amount that NIE T&D can recover for indirect costs of 10%, to remove this inefficiency. This is reflected in our recommended allowance for indirect cost projects.

21. As highlighted above, repairs and maintenance costs represent a large part of NIE's controllable opex. The UR did not use benchmarking analysis of NIE's repairs and maintenance costs when calculating the efficiency adjustments for NIE's controllable opex. CEPA (2011) did include results from econometric models that took NIE's indirect costs together with its repairs and maintenance costs (CEPA labelled this 'total opex' or 'total distribution opex') and compared these against the costs of GB DNOS. But CEPA downplays the results from these models:[7]

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[5] For example, see figure for '% of Engineering Indirects capitalised' in worksheet 'NEDL' of Ofgem's published DPCR5 financial model.
[6] UR final determination, paragraph 5.54.
[7] CEPA 2011, p18.

> Based on the results of the total opex and indirect benchmarking, we consider that NIE's total opex performance appears to be enhanced by its relatively low spend on R&M. In other words, as NIE's relative performance increases as we are using the same cost drivers for both indirect costs and total opex we can assume that NIE is spending relatively less on R&M. However, we do not consider that the drivers we have available are suitable for benchmarking R&M costs alone. Without appropriate cost drivers for R&M costs (e.g. spans of trees cut) the total opex benchmarking analysis provides more insight into NIE relative expenditure levels rather than efficiency. We are therefore more confident in the efficiency results produced by the indirect costs' models.

22. The UR only used the results from the benchmarking of indirect costs for the calculation of the efficiency adjustment in its draft and final determinations. The UR explains as follows:[8]

> The consequence of that lack of data is that we were only able to produce a robust benchmarking of NIE T&D's indirect opex costs (i.e. total controllable opex less network repairs and maintenance (R&M) costs). In other words, our Final Determination (FD) proposal implicitly assumes that NIE T&D's network costs for R&M are already efficient.

23. To calculate an inefficiency adjustment for NIE's controllable opex, the UR's approach is, in effect, to produce a weighted average adjustment based on two components:

(a) a downward adjustment of around 10 per cent based on benchmarking of NIE's indirect costs; and

(b) a 0 per cent adjustment in relation to repairs and maintenance expenditure.

24. The weight attached to the first component is around 72 per cent. This is calculated in the CEPA model as the value of the measure of NIE's indirect costs (labelled by CEPA as indirect opex) divided by the sum of the measure of its indirect costs and repairs and maintenance costs (labelled as total opex). This calculation seems to neglect the fact that CEPA's measures of 'indirect opex' and 'total opex' include a large element of NIE's capitalized expenditure. If we wished to rely on these figures from CEPA and the UR we would need to examine them in more detail, to consider whether a weighting of 72 per cent to the adjustment under *(a)* above is appropriate. However, we have taken a different approach to cost assessment which is not reliant on the 72 per cent weighting.

[8] UR Statement of Case, pp2 & 3.

NIE's submissions on controllable operating expenditure

1. This appendix provides a summary of NIE's submissions on controllable opex from its Statement of Case. It does not include the UR's response to these submissions or our assessment of them. We have taken account of relevant aspects of NIE's submissions and the UR's submissions in our cost assessment.

2. In its Statement of Case, NIE provided a forecast of £235.9 million over the RP5 period for 'controllable opex'. NIE identified a shortfall, compared with the UR's final determination, of £53.7 million. In addition, NIE forecast £95.3 million over the RP5 period for 'uncontrollable costs' which covered rates, wayleaves, licence fees, injurious affection and the UR's proposed reporter.

3. NIE said that its forecast for opex was based on a robust bottom-up assessment of the needs of the business in respect of ongoing activities and a range of new activities arising for the first time in RP5.[1] It said that it was confident that its baseline costs reflected a high level of efficiency which had been confirmed by independent benchmarking (the benchmarking analysis carried out for NIE by Frontier). NIE said that the main objective in preparing its opex plan for RP5 was to ensure that future costs associated with existing and ongoing activities were controlled at prevailing efficient levels and that new activities were undertaken with the same high level of efficiency.

4. In light of its own forecasts, NIE made submissions to us in relation to the following aspects of its opex requirements and the UR's proposals, which we take in turn below:

   (a) the UR's calculation of adjusted base year costs;

   (b) NIE's relative efficiency compared with GB DNOs and the UR's proposals for a 7 per cent adjustment to NIE's adjusted base year costs in light of the CEPA benchmarking analysis; and

   (c) costs to be added to the baseline.

Calculation of adjusted base year costs

5. As part of its calculation of adjusted base year costs, the UR made adjustments for Rathlin costs, keypad opex and meter reading costs. NIE said that the allowances for keypad opex and Rathlin costs were not high enough and identified a £0.3 million shortfall on keypads and another £0.3 million shortfall on Rathlin costs (in respect of periodic cable inspections) compared with its cost forecasts.

6. NIE disputed the allowance that the UR provided for meter reading costs. NIE's Statement of Case identified a shortfall of £4.3 million for 'meter reading' and a shortfall of £0.3 million for 'keypad meter opex' over the RP5 period.

[1] NIE Statement of Case, p108.

NIE's relative efficiency compared with GB DNOs

7. NIE referred to analysis by Frontier Economics in support of its contention that it was efficient and that it was not appropriate to make any downward adjustment to its historical costs for the purposes of setting a new price control.

8. CEPA's benchmarking analysis for the UR was based, in part, on benchmarking analysis that Frontier had previously carried out for NIE. CEPA built on large parts of the method and data sources used by Frontier, but also made some significant changes.

9. NIE said the following in its Statement of Case:[2]

> Prior to CEPA's involvement, NIE had commissioned its own analysis of its efficiency on the set of costs benchmarked by CEPA. A report summarising this analysis, which was undertaken by Frontier Economics, was submitted to the Utility Regulator as part of NIE's Business Plan Questionnaire submission. The cost mapping exercise undertaken by Frontier … was relied upon by CEPA in their analysis.
>
> Frontier's conclusion was that NIE's performance was consistent with the leading GB DNOs and that NIE should be regarded as efficient.

10. Subsequent to the initial Frontier analysis that NIE submitted to the UR, Frontier produced a number of further reports. The most recent report was submitted to us in August 2013 (Indirect cost benchmarking update). This included a critique of CEPA's analysis and revisions to Frontier's own analysis. This report estimated that, for a cost measure comprising NIE's indirect costs and network operating costs (referred to as 'total opex'), NIE ranked second in terms of efficiency in 2009/10 among 15 DNOs and had an efficiency score of 84 per cent. The result of 84 per cent represents an estimate that NIE's costs were only 84 per cent of the estimate of the costs that NIE would incur if it was averagely-efficient among the companies in the econometric analysis.

11. In its Statement of Case, NIE raised the following flaws in the analysis carried out by CEPA:[3]

   (a) an overstatement of the element of NIE's reported 'market opening' costs which should be included in the benchmarking analysis to support a like-for-like comparison with GB DNOs;

   (b) the inclusion within the benchmarking analysis of costs incurred in the past by NIE but which the UR proposed not to include in the allowance for operating expenditure (eg the profit margin element of charges from NIE Powerteam to NIE). NIE identifies an inconsistency between the NIE costs for the UR's extrapolation of controllable opex and the NIE costs used for benchmarking;

   (c) CEPA's analysis made regional wage adjustments which had the effect of making NIE look higher-cost relative to GB DNOs than in the absence of such an adjustment (ie it worsened NIE's apparent position in the benchmarking analysis). NIE argued that it was not appropriate to make such an adjustment for regional wages without making adjustments for other significant differences between regions. NIE said that previous work commissioned by NIE and evidence in the

[2] ibid, p189.
[3] NIE Statement of Case, pp188–199.

public domain from other regulatory reviews indicated that the spare dispersion of NIE's customers tended to increase its costs significantly and that taking account of sparsity was likely to offset the effect of a regional wage adjustment; and

(d) NIE also objected to the method used by CEPA to calculate the regional wage adjustment on the basis that CEPA relied on regional data for two very high level occupational codes, which do not accurately reflect the nature of NIE's workforce. NIE said that when a more reasonable adjustment was calculated, making use of more relevant occupational codes, the effect of the regional wage adjustment observed by CEPA was greatly reduced.

12. Subsequent to the submission of its Statement of Case, NIE made a series of further submissions on cost benchmarking analysis, including further reports and updated analysis by Frontier. These submissions claim that there are further flaws in CEPA's analysis in addition to those identified above. They also involve significant revisions to Frontier's previous analysis. We have taken account of these submissions in our own benchmarking analysis.

Costs to be added to the baseline

13. The UR's approach to the calculation of an allowance for controllable opex for NIE involved an extrapolation of NIE's historical expenditure (following positive and negative adjustments) combined with allowances for a number of specific cost items that the UR treated as new for the purposes of its RP5 calculations. This approach reflects the UR's review of a series of claims by NIE for additional allowances beyond the level of adjusted base year opex.

14. NIE's Statement of Case provided the following explanation of these claims, which it described as 'costs to be added to the baseline':[4] 'Over the course of RP5 a number of additional demands will be placed upon the business giving rise to costs over and above those incurred in the 2009/10 base year.'

15. One of the cost categories that NIE referred to as 'new' was real price effects ('the need to pay above the cost of living pay rises to retain specialist labour').[5] Leaving aside real price effects, NIE asked us to allow it an additional £57.9 million over the RP5 price control period in relation to costs to be added to the baseline. Table 6 sets out NIE's claims and compares them with the allowance provided by the UR in its RP5 proposals.

[4] ibid, p124.
[5] ibid, p124.

TABLE 1 **NIE claims for costs to be added to the baseline (five-year period from 1 Oct 2012 to 30 Sept 2017)**

Cost category	*NIE forecast*	*UR RP5 allowance*
Enduring solution	28.90	21.40
Workforce renewal	4.90	-
Road and steelworks legislation	2.10	0.50
Regulatory reporting requirements	1.50	-
ESQR regulations	0.20	-
R&D relating to smart technologies	2.50	-
Renewables baseline	12.30	9.80
RP6 price control review	2.00	-
Storm costs	1.60	1.60
Distribution service centre	0.80	-
Credit rating	0.60	0.40
Distribution code	0.10	-
PAS 55	0.10	0.10
Aggregated generator units	0.30	0.30
	57.90	34.10

Source: NIE Statement of Case, pp111 & 124–173.

16. Some of the costs listed in the table above are not, in fact, costs arising from 'additional demands that will be placed upon the business giving rise to costs over and above those incurred in the 2009/10 base year'. For instance, in 2009/10 NIE incurred costs related to the activities envisaged under 'renewable baseline', Enduring Solution, distribution code and aggregated generator units and was reimbursed for these via the D_t term of the current licence provisions. Nonetheless, other elements do reflect changes over time in the nature of the activities carried out by NIE and the services it provides.

Further information on calculation of NIE indirect costs

1. This appendix provides further information on a number of detailed aspects of our calculation of NIE's indirect costs for the purposes of benchmarking against GB DNOs. In particular, it addresses a number of points about the calculation of NIE's cost for benchmarking purposes that were raised in NIE's Statement of Case or subsequent submissions by NIE and the UR.

2. We have drawn on data from NIE's BPQ opex response and its BPQ financial questionnaire response as well as further information and analysis provided to us by NIE (including analysis from its consultants, Frontier Economics).

3. Many of the issues covered in this appendix were originally raised by NIE or the UR in the context of the benchmarking analysis we carried out ahead of our provisional determination, for which the cost data we used for NIE was for 2009/10 only. As a consequence, this appendix contains a number of references to costs or issues in 2009/10. Following our provisional determination NIE provided additional data that allowed us to include cost data for NIE for 2010/11 and 2011/12 in our analysis. Unless otherwise stated, the approach we took for NIE's indirect and IMF&T costs in 2010/11 and 2011/12 was consistent with that which we took for 2009/10. In particular, we made use of additional data for 2010/11 and 2011/12 that NIE provided following our provisional determination which was prepared on a basis consistent with the approach we had used for 2009/10.

Pensions costs

4. The original benchmarking analysis by Frontier and CEPA used cost data for GB DNOs that did not include pension costs.

5. In our benchmarking analysis we have used data on 'total gross costs' for categories such as business support costs that are reported under the Ofgem RIGS reporting rules. The measure of total gross costs includes pension costs. These pension costs are on a cash basis.

6. In the cost assessment paper published as part of its March 2013 strategy decision on its current price control review for electricity distribution companies, Ofgem said the following:[1]

> Under our pension methodology (set out in appendix 6 of the 'Supplementary annex—Financial issues') pension costs attributable to the licensee, but which relate to pensionable service on or after 1 April 2010, are considered as a constituent part of labour costs/totex for price control purposes, which we benchmark. This includes costs relating to any deficit that accrues in relation to such service; this is termed the incremental deficit. We do not set specific allowances for ongoing (defined benefit or defined contribution) pension service costs, pension scheme administration and PPF levy costs; and the annual funding costs of the incremental deficit. We do set a specific allowance to fund the established deficit, i.e. the deficit relating to pensionable service before 1 April 2010.

[1] www.ofgem.gov.uk/ofgem-publications/47072/riioed1deccostassessment.pdf, p8.

7. To allow for like-for-like comparisons, we include in the estimation of indirect costs and network operating costs the cash pension contributions of NIE that are associated with ongoing service.

8. NIE provided data on its pensions cash costs and we used these instead of NIE's accounting pension charges in our calculation of indirect costs. NIE also provided us with an update to the Frontier estimate of NIE Powerteam's indirect costs which included NIE Powerteam's pensions costs.

9. We did not include pension deficit repair contributions in our benchmarking analysis (or at least those pension deficit repair contributions relating to service before April 2010). These are not part of the costs of ongoing activities but rather liabilities arising from activities carried out—and decisions made—in the past. Ofgem's data on activity costs do not include costs reported for 'Pensions Deficit Repair Payments' (see, for example, the definition of 'Non-activity-based costs' under the definition of pensions in the RIGS glossary).[2]

Recharge from NIE to NIE Powerteam

10. Frontier said the following in relation to recharges from NIE to NIE Powerteam:

> NIE T&D provides support services to NIEPT (all of which would be classified as indirect by Ofgem and all of which fall within the regulated business ring fence). NIEPT is charged for these services by T&D. The cost of this recharge is included in NIEPT's cost base and has been captured in full by the Frontier/NIE cost mapping (and therefore included in the indirect costs to be benchmarked). Consequently, in order to avoid a double count, it is necessary to exclude from T&D's costs the amount of the recharge (£0.4m in 2009/10), otherwise this set of costs would be included once within the mapped costs of NIEPT and again within the mapped costs of T&D. While such an adjustment was made in the cost mapping supplied to CEPA, it appears that CEPA has not excluded this recharge from T&D's costs in its benchmarking and is therefore overstating NIE's total indirect cost base by £0.4m.

11. The value of the recharge from NIE reported by Frontier was £436,000 in 2009/10.

12. That figure of 436,000 is close to the figure of £433,000 reported as the 'T&D recharge' for 2009/10 from NIE's BPQ response for financial questionnaire in the sheet 'Charged to Separate Businesses'. The BPQ reports that the charge is made on a 'cost recovery' basis.

13. We accepted that it would be double counting to include in the benchmarked costs an estimate of NIE Powerteam costs that includes the NIE T&D recharge and also to include the NIE T&D costs that are the basis for that recharge.

14. Whether we needed to make a deduction as part of our calculation of NIE indirect costs depended on the reporting basis of the data from NIE's BPQ response on operating expenditure response which we used in that calculation:

    (a) If the NIE T&D cost data include all costs incurred by NIE T&D, including costs of activities that it attributes (or partially attributes) to NIE Powerteam, then a deduction is needed.

[2] www.ofgem.gov.uk/ofgem-publications/46658/glossary-termsv2.pdf.

(b) If the NIE T&D cost data are net of the costs (eg overheads) that NIE attributes to other businesses (eg NIE Powerteam) then a deduction is not needed.

15. Following a request for clarification, NIE confirmed that the costs reported in its BPQ response on opex:

- exclude costs relating to rechargeable work carried out by the Connections Business. These costs are included within the work-sheet titled 'Cost of Sales';
- include costs which are subsequently recharged to other businesses in respect of the provision of administrative support services, for example human resources and property management; and
- include costs associated with third party damage to the network which may be recovered from external parties through tort claims.

16. In light of this confirmation, we deducted from our calculation of indirect cost the figures for 'T&D recharge' referred to above from the NIE BPQ response for the financial questionnaire.

Recharge from NIE T&D to 'other businesses' and other income

17. In its calculation of indirect costs, Frontier made a series of adjustments relating to recharges to other businesses. We agreed that it was appropriate to make adjustments to remove any costs included in the costs data we have used from NIE's BPQ response on opex which are attributable to businesses and external parties other than NIE's regulated distribution and transmission activities.

18. Similarly, for the measures of GB DNO indirect costs we use in the benchmarking, we deducted costs recorded as 'Indirect Activity Allocations to Non distribution (exc connections)'.

19. We reviewed the adjustments made by Frontier against data from NIE's BPQ response for the financial questionnaire. The adjustments made by Frontier seemed to be deductions for revenues collected from 'separate businesses' and 'external parties'. These revenues were mostly reported as revenues from charges levied on a cost-recovery basis so we considered it reasonable to treat these revenues as an estimate of the costs that should be excluded.

20. We made deductions to remove from our calculation of NIE's indirect cost for benchmarking purposes the following revenues:

(a) management charges recovered on cost recovery basis from separate businesses (excluding recharge to NIE Powerteam);

(b) amount charged to other businesses under 'miscellaneous';

(c) amount charged to external parties under 'miscellaneous';

(d) rental income from external parties; and

(e) rental income from other businesses.

21. These amounts lead to a deduction of around £0.7 million in 2009/10.

22. We did not seek to deduct income that NIE receives from connection charges. Instead we set an allowance for NIE that is based on benchmarking analysis for indirect costs excluding costs attributed to connections.

Administrative costs relating to metering activities and market opening

23. NIE incurs expenditure in relation to metering capex and meter reading activities. The GB DNOs that we use for our benchmarking analysis do not provide similar metering and meter-reading services. For our calculation of NIE's indirect costs for benchmarking purposes, we considered to appropriate to exclude costs that NIE incurs as part of its metering and meter-reading activities.

24. The original benchmarking analysis carried out by Frontier for NIE used an allocation of NIE Powerteam costs which sought to exclude the costs attributable to metering and meter-reading activities. The spreadsheets developed by Frontier separated NIE Powerteam's costs between a number of different categories of work, and excluded costs reported under metering and meter-reading activities from the calculation of NIE's indirect costs. In its benchmarking analysis for the UR, CEPA drew on these estimates of NIE's indirect costs.

25. In its updated benchmarking report, submitted by NIE on 2 August 2013, Frontier identified an error in CEPA's benchmarking analysis. Frontier said that NIE T&D's administrative costs associated with metering should also be excluded from its benchmarked cost base, as they related to activities that were not undertaken by the GB DNOs. Frontier said that, by not excluding these administrative costs, CEPA had overstated NIE's total indirect cost base by around £0.1 million. The Excel model accompanying that Frontier report had included a deduction of £56,000 for 2009/10 to remove NIE administrative costs relating to metering.

26. In a subsequent submission, NIE said that 'it has become apparent that the process through which NIE and Frontier have removed metering from the benchmarking analysis is in need of revision'.

27. NIE proposed substantial changes to the calculation of NIE's indirect costs for benchmarking purposes, which involved much greater deductions for the administrative costs and other overheads attributable to meter reading. Prompted in part by concerns raised by the UR on NIE's proposed changes to the calculation of indirect costs, and partly by concerns we had identified, we asked NIE to revise aspects of its analysis.

28. NIE provided a revised submission on the administrative costs relating to metering and meter reading in September 2013. In its analysis, NIE distinguished between metering (which refers to meter certification and metering investment) and meter reading costs. NIE's submission and analysis can be summarized as follows:

(a) The original 'cost mapping' analysis for NIE Powerteam costs that was developed by Frontier and NIE did not exclude enough costs in relation to metering. The revised calculations prepared by Frontier proposes that for the calculation of NIE's indirect costs for benchmarking against GB DNOs, a further £439,000 of NIE Powerteam costs should be deducted. These costs reflect a reallocation to metering activities of a proportion, varying between 6 and 10 per cent, of several other categories of NIE Powerteam indirect costs (reported under headings such as safety, procurement and stores).

(b) The original 'cost mapping' analysis of NIE Powerteam costs used by Frontier was appropriate for meter reading. That exercise had excluded all the NIE

Powerteam costs reported under the heading of ‘meter reading’. NIE said that the figures reported under that heading of meter reading already incorporated an allocation of managerial resources from metering and an allocation of Powerteam internal support costs (£462,000 in total in 2009/10).

(c) NIE proposed that an additional £849,000 of costs should be excluded from the calculation of NIE’s indirect costs in 2009/10, based on an allocation to metering of some administrative costs incurred by NIE T&D. The allocation was calculated by taking a figure for NIE T&D administrative costs of £14.2 million in 2009/10 and multiplying this by the proportion of total NIE Powerteam costs that are attributed to metering (6 per cent). As far as we understood, the NIE T&D administrative costs of £14.2 million did not include any costs already excluded by the proposed adjustment under *(a)* above.

(d) Similarly, NIE proposed that a further £779,000 of costs should be excluded from the calculation of NIE’s indirect costs in 2009/10, based on an allocation to meter reading of some administrative costs incurred by NIE T&D. The allocation was calculated by taking the figure for NIE T&D administrative costs of £14.2 million in 2009/10 and multiplying this by the proportion of total NIE Powerteam costs that are attributed to meter reading (5.9 per cent). As far as we understood, the NIE T&D administrative costs of £14.2 million did not include any NIE Powerteam cost costs already excluded under the heading of *(b)*.

29. We worked through the Frontier analysis used to calculate NIE’s proposed adjustments. In relation to the allocation of NIE Powerteam costs under *(a)*, we found that the allocation method seemed reasonable (though we did not have opportunity to carry out a detailed review of NIE’s cost allocation methodology: as with other elements of our indirect cost calculation, we used cost allocations provided by Frontier and NIE).

30. We had more concerns with Frontier’s proposed allocation of NIE T&D costs to metering and meter-reading activities. Frontier’s proposed approach was to allocate NIE overheads between metering activities and other activities according to the relative shares of NIE Powerteam’s total costs that are attributed to metering activities and other activities. However, Frontier did not provide a logical explanation or rationale for using the share of NIE Powerteam costs as the allocation factor.

31. Frontier’s proposed approach might make sense if NIE T&D was a service provider which provides administrative and back office functions to NIE Powerteam and if NIE Powerteam was responsible for NIE’s network and metering activities. But this characterization did not fit with the way that NIE runs its business or with the nature and scope of NIE Powerteam.

32. NIE Powerteam provides services to NIE, but NIE Powerteam’s costs form only part of the overall costs incurred by NIE to provide services to customers. Using NIE Powerteam costs as an allocation factor risks an unduly high allocation of NIE’s overheads to those services provided by NIE for which a relatively high proportion of costs are incurred by NIE Powerteam (eg meter reading).

33. NIE’s revised cost allocations did not arise directly from NIE’s accounting systems or its established cost allocation practices. Furthermore, the approach proposed by

Frontier, which placed emphasis of NIE Powerteam's costs, did not seem compatible with NIE's approach to allocation of overheads between opex and capex.[3]

34. Given the more limited information available to us, we were reluctant to override NIE's own cost allocations. However, in this instance we considered NIE's figures and methods to be unacceptable.

35. We made an alternative cost allocation that we considered more appropriate, although admittedly approximate.

36. We first distinguished NIE's core 'services' into four main categories:

(a) distribution and transmission use of system services and network connections services, for which NIE incurs costs in relation to operation, maintenance and investment in its transmission and distribution systems;

(b) metering capex;

(c) metering-reading services; and

(d) market-opening services.

37. We then made an approximate estimate of the total value of NIE's costs identified with each of these categories. We used data from NIE's regulatory accounts for the value of property plant and equipment additions, data from NIE's BPQ opex response for meter-reading costs and market opening costs and data from NIE's regulatory accounts and RP5 strategy papers on metering capex. This gave a total value which averaged £121 million over the period 2009/10 to 2011/12.

38. We then calculated allocation factors for metering capex, meter reading and market opening by taking the percentage of the cost base above that we had identified with each of these activities. This produced percentages of which averaged 3.4 per cent, 2.5 per cent and 2.0 per cent respectively over the period 2009/10 to 2011/12.

39. We then applied those allocation factors to the value of NIE T&D administrative costs and overheads that Frontier method had sought to allocate (these administrative costs and overheads were £13.9 million on average between 2009/10 and 2011/12). We calculated separate allocations for each financial year. The average allocation between 2009/10 and 2011/12 were:

(a) an allocation of £0.47 million of NIE administrative costs to metering capex;

(b) an allocation of £0.36 million of NIE administrative costs to meter reading; and

(c) an allocation of £0.29 million of NIE administrative costs to market opening.

40. We deducted the allocations to metering, meter reading and market opening from our calculation of NIE's indirect costs for the purposes of our benchmarking analysis.

41. In Section 10 of our final determination, we considered NIE's metering, meter reading costs and market opening costs (Enduring Solution). We included in our cost assessment annual allowances for relating to the administrative costs and overheads that we had deduced for the purposes of our benchmarking analysis.

[3] NIE Statement of Case, p201.

Costs associated with Rathlin Island cable

42. We included indirect costs associated with the Rathlin Island cable in our calculation of NIE's indirect costs. In NIE's BPQ response on opex, these costs are not reported as part of controllable opex but they are nonetheless relevant.

43. NIE's BPQ reported costs relating to the Rathlin cable separately from NIE's 'controllable' opex. It reported opex for the cable as £34,000 in 2009/10.

44. NIE described[4] the historical Rathlin opex as comprising permissions for the cable on the seabed, salary costs for islanders who provide a range of services and overheads such as electricity and servicing. These costs might fall between the Ofgem's definition of indirect costs and network operating costs. In the absence of other information, and given the small scale of costs, we included them in indirect costs.

Wayleave costs

45. The Ofgem definition of indirect costs includes the costs of wayleave payments and the administrative costs of wayleaves. We included wayleave costs in our benchmarking analysis.

46. NIE reported on the costs it incurred in relation to wayleave costs in its BPQ opex response. We included these costs in our calculation of NIE's indirect costs.

47. NIE confirmed to us that the wayleave costs in its opex BPQ response included the administrative costs of NIE Powerteam. Since we included NIE Powerteam costs separately in our calculation of NIE's indirect costs, we made an adjustment to exclude these administrative costs to avoid double counting. For this adjustment we used data from the Frontier cost allocation for NIE Powerteam which reported costs for 'wayleaves admin' under the NIE Powerteam indirect costs. The total costs for wayleaves administration was £0.12 million in 2009/10 (including pension costs and depreciation).

Distribution Code costs

48. The Distribution Code sets out the operating procedures and principles which govern NIE's relationship with all users of the distribution system. A new Distribution Code came into force in May 2010.[5]

49. In 2009/10, NIE incurred £0.160 million under the heading of 'Distribution Code' costs. Recovery of these costs was approved by the UR during RP4 under the D_t term. In its draft determination,[6] the UR said that for the RP4 period the total cost approved for the Distribution Code was £0.5 million and that the reason for the approval of distribution costs was 'change in law'.

50. NIE's forecast costs for the Distribution Code were £0.1 million over a five-year price control period, which it said reflected past experience with costs of this nature.

51. We include the reported historical costs for distribution code over the period 2009/10 to 2011/12 within NIE's opex BPQ within the NIE indirect cost measure we used for

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[4] ibid, p124.
[5] ibid, p170.
[6] UR draft determination, p51.

benchmarking. These are a type of cost that GB DNOs might incur and which would be included as part of indirect costs (eg business support costs).

52. This did not mean that we considered that these costs will necessarily be the same in the future as they were in the past. Rather we were seeking to apply an approach which *(a)* avoids a very detailed bottom-up analysis for individual operating cost activities carried out by NIE and *(b)* makes use of cost comparisons with GB DNOs.

Review of generator connections policy

53. Consistent with our approach for the Distribution Code above, we include reported costs relating to the review of generator connections policy as part of our calculation of NIE's indirect costs. We used data from NIE's BPQ response on opex.

Short- and medium-term projects and renewable integration development programme

54. We considered the inclusion in our calculation of NIE's indirect costs the costs reported under 'Dt costs' under the following headings:

(a) Short and Medium Term projects.

(b) Renewable Integration Development Programme.

55. Both sets of costs are for opex related to measures to facilitate renewable generation.[7] DNOs in GB also experience costs to facilitate renewable generation.

56. Frontier reported that the costs for the Renewable Integration Development Programme were 'very predominantly focused on 275kV projects' and should not be included in the benchmarking analysis. Frontier said that NIE considered it reasonable to include the costs of the Short and Medium Term projects in the calculation of NIE's indirect costs.

57. We included the costs reported for Short and Medium Term projects in our calculation of NIE's indirect costs. These were £0.2 million in 2009/10. We did not include costs reported under the Renewable Integration Development Programme.

North–South interconnector site costs and routing studies

58. We also identified costs in NIE's BPQ response on opex under the heading 'N/S Interconnector Costs of Site & Routing Studies'. These costs were £1.2 million in 2009/10. These costs relate to a potential 400 kV interconnector between Northern Ireland and the Republic of Ireland. Costs associated with this project did not seem comparable with GB DNOs and we did not include these in our indirect cost figure.

Excess overtime related to extreme weather event

59. Frontier reported that NIE believed that £813,000 of costs in 2009/10 related to excess overtime which should be excluded from the benchmarking analysis against GB DNOs, explaining as follows:

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[7] NIE Statement of Case, p162.

These excess overtime costs were incurred by NIE in responding to a single extreme weather event, i.e. the ice storm of March 2010, addressing the resulting network issues. In GB, these costs would be reported as Network Operating Costs, but since they relate to extreme weather events would not be included in the coverage of the CC's analysis (i.e. IMF&T).

60. Following further clarification from NIE, we have accepted this point and made an adjustment to remove £813,000 from our calculation of indirect costs in 2009/10. We did not make any similar adjustment for 2010/11 or 2011/12.

Price review costs

61. NIE sought a separate allowance for its price control review costs. However, we considered it more appropriate to use the GB DNO benchmarking analysis to provide an (implicit) allowance for NIE's price control review costs than to make a separate allowance. It would be difficult to determine what an appropriate allowance should be without using cost benchmarks from other companies.

62. Under Ofgem's regulatory reporting rules, costs relating to 'finance and regulation' are included as part of business support costs, which are a category of indirect costs. The GB DNO data we use for benchmarking will reflect costs that DNOs incur as part of price control reviews and other regulatory processes. We did not have data on the costs of GB DNOs that would allow us to separately identify costs related to price control reviews.

63. As part of our calculation of NIE's indirect costs we included a figure for NIE's historical costs for the price review process. In the light of substantial year-to-year fluctuations in NIE's price review costs due to the timing of price control review processes, and the more detailed data we had available for NIE, we used an average over the planned RP4 price control period running from 1 April 2007 to 31 March 2012.

64. Based on the data provided in NIE's Statement of Case[8] and its BPQ response on opex, we calculated that NIE's costs reported for 'price review' to be £1,129,290 over the five-year RP4 period from 2007/08 to 2011/12 inclusive. This implied an average cost for the RP4 period of around £225,000. In the calculation of NIE's indirect costs for benchmarking purposes, we replaced the figures reported for NIE under the heading 'Other—Price Review' with a figure of £225,000 and applied this to the financial years 2009/10, 2010/11 and 2011/12.

Powerteam profit margin

65. As part of our calculation of indirect costs for NIE, we did not seek to include NIE Powerteam's historical profit margin in our measure of NIE's indirect costs. This was in contrast to the approach taken by CEPA in its analysis for the UR.

66. We considered it inappropriate to include such a profit margin in the costs used for the purposes of our benchmarking analysis. We were not seeking to assess whether NIE's costs (including and costs to NIE that reflect NIE Powerteam profits) were in any sense too high in the period 2009/10 to 2011/12. Instead, our aim was to use data on NIE's costs, and comparable data on other DNOs' costs, to determine an

[8] NIE Statement of Case, p166.

expenditure allowance for NIE for the period from 1 April 2012 to 30 September 2017.

67. We investigated whether it was necessary to make an adjustment to the figures that we used to calculate NIE's indirect costs to exclude any NIE Powerteam profit margin that may be embedded in those figures and thereby inadvertently included in our analysis. We did not make such an adjustment because any embedded profit element seemed likely to be small.

68. Following a series of questions to NIE and the UR in relation to the treatment of the NIE Powerteam profit margin, NIE carried out further analysis of the extent to which any amount of NIE Powerteam profit might appear in the benchmarking and opex figures used by the UR to calculate a proposed allowance for the RP5 price control period. NIE provided a submission that reported the following:

> Of the line items that comprise T&D's controllable opex baseline of £31.390m (as specified in the UR's FD), only two are related to activities carried out by NIEPT which may potentially contain any PT profit. These are:
>
> - The Powerteam labour element of "Repairs & Maintenance" (R&M); and
>
> - "Powerteam managed service and supply chain charges".

69. NIE's submission estimated that around £19,000 of NIE Powerteam profit might be included in the 2009/10 cost figures relating to the Powerteam labour element of repairs and maintenance expenditure. It also estimated a loss (costs to Powerteam in excess of charges) in relation to the Powerteam managed service and supply chain and attributed £8,000 of this loss to opex. On this basis, NIE estimated that around £11,000 of NIE Powerteam profit margin for 2009/10 was reflected in the figure of £31.39 million for NIE's controllable opex on 2009/10.

70. We reviewed NIE's estimates against the Excel model accompanying Frontier's updated analysis and NIE's estimates did not seem unreasonable. A slightly higher profit margin might be attributable to NIE's total indirect costs (rather than opex) but the amount did not seem large.

Accounting for provisions

71. No adjustments for provisions and accruals were made in the original cost benchmarking analysis carried out by Frontier or CEPA.

72. Frontier reconsidered the treatment of provisions:

73. In the course of revisiting the cost mapping work in detail, NIE identified costs related to certain provisions (or the release of previously made provisions back to the P&L) that were included in NIE T&D's accounts for the base year. These provisions were included in the benchmarked cost set of both Frontier and CEPA. Actual cash costs incurred against these provisions are excluded NIE T&D's accounts for the base year, and were excluded from the benchmarked cost set of both Frontier and CEPA.

> Frontier has now clarified that Ofgem requires the DNOs to report costs on a cash basis and consequently these provisions should be excluded from the benchmarked cost set to ensure comparability with GB. However, where a provision account has been created for certain heads

of costs, and that provision is deducted from the benchmarked costs, it is necessary to bring back in the actual cash costs incurred in the relevant period. With NIE's support Frontier has made this correction in its latest update.

74. Frontier reported that Ofgem's RIGS stated that all costs should be entered on a cash basis, excluding all provisions and all accruals and prepayments that were not incurred as part of the ordinary level of business.

75. Frontier proposed a net upwards adjustment of £0.29 million to NIE's reported costs for 2009/10 for the purposes of benchmarking with GB DNOs. This reflected the net impact of three elements:

(a) a deduction of £0.35 million to remove the impact of provisions that are reflected in NIE's reported costs for 2009/10, which relate to stock provision and severance;

(b) the addition of £0.21 million to add in the cash costs of a payment of severance costs in 2009/10; and

(c) the addition of £0.43 million to remove the impact of the release of provisions made in earlier years relating to substation demolition, security and R&D.

76. We did not review the underlying accounting data behind Frontier's proposed adjustments. NIE's BPQ response was not on a cash basis and did not provide such data. Given the relatively small scale of the net adjustments, and the fact that we used information from Frontier and NIE for much larger elements of the estimation of NIE's indirect costs, we used Frontier's figures in our calculations.

77. For the purposes of our calculation of the benchmarked indirect costs for NIE for 2009/10, we *(a)* started with NIE's reported costs on a basis which reflects provisions and the release of provisions and which excludes cash payments against provisions and *(b)* made an upward adjustment of £0.29 million with the aim of converting the reported costs to a cash basis consistent with the data for GB DNOs.

Legal claim provision

78. Frontier said that its updated analysis excluded from indirect costs an amount described as 'legal claim provision for connections' which relates to a legal case brought in relation to NIE's connections activities. The value of this provision was £250,000 for 2009/10. This matches the figure reported as 'Other—Legal Claim Provision' for 2009/10 in NIE's BPQ response on opex.

79. Frontier said that the provision should be excluded because it is related to connection activities and because it would not be reported as a regulated indirect cost by GB DNOs. In line with the approach for other provisions above, we excluded the legal claim provision of £250,000 from our measure of NIE's indirect costs for benchmarking.

Bad debt provision

80. The Frontier benchmarking update (2013, p9) said that: 'Bad debts are not recorded as an indirect under Ofgem's accounting policies and should therefore be excluded.'

81. As highlighted above, Ofgem's regulatory reporting for DNO indirect costs is on a cash basis, so provisions should not be included. Furthermore, any expenses in relation to bad debt (eg write off) are treated as non-activity costs. In contrast the costs of debt recovery activities are included under the category of finance and regulation costs, which fall under business support costs and hence indirect costs.

82. We excluded the provisions reported under 'Other—Bad Debt Provision' in NIE's BPQ response on opex from the measure of indirect costs we use for benchmarking.

Provision for legal costs relating to IME3 regulations

83. The Frontier benchmarking update identifies a provision relating to the legal costs in relation to compliance with the IME3 regulations (the Gas and Electricity (Internal Markets) Regulations (Northern Ireland) 2011). Frontier excludes this provision from its benchmarking on the basis that the no GB DNO would incur such costs.

84. The value of the accrual for IME3 in the Excel model accompanying Frontier's updated analysis was £109,000 in 2009/10. The accrual is reversed by a deduction of that amount in 2010/11. The detailed figures in that Excel model indicated that the accrual of £109,000 forms part of the £323,000 reported for NIE's 'professional services' costs for 2009/10 in NIE's BQP response on controllable opex.

85. As highlighted above, Ofgem's regulatory reporting for DNO indirect costs is on a cash basis, so provisions should not be included in our benchmarking analysis.

86. We deducted £109,000 from the reported figure for NIE's 'professional services' costs for 2009/10 in our calculation of NIE's indirect costs.

Accrual relating to legal costs in relation to complaint by Quinn Group

87. The Frontier benchmarking update identified a provision relating to the legal costs in relation to a complaint raised by the Quinn Group requesting a rebate of connection charges.

88. As highlighted above, Ofgem's regulatory reporting for DNO indirect costs is on a cash basis, so provisions and accruals should not be included in our benchmarking analysis. The value of the accrual for the Quinn Group legal costs in the Excel model accompanying Frontier's updated analysis was £138,000 in 2009/10. There is a deduction from costs of £169,000 in 2010/11 which reflects the allocation of costs to 2009/10 and to previous financial years.

89. We deducted £138,000 from the reported figure for NIE's 'professional services' costs for 2009/10 in our calculation of NIE's indirect costs.

Billing charges

90. In its draft proposals the UR had proposed a deduction of £600,000 from adjusted base year costs in relation to certain billing costs. Following submissions from NIE, the UR proposed no such deduction in its final determinations. We included in the calculation of NIE's indirect costs the costs reported under the heading 'NIE Other—Billing System Charges (BSC)' in NIE's BPQ response on opex. These costs were £575,500 in 2009/10.

Innovation scheme costs

91. The UR made a deduction of £601,000 from reported controllable operating expenditure as part of the calculation of adjusted base year costs for its final determinations. The figure of £601,000 was consistent with the figure reported for 'Innovation Schemes Costs' in the data reported in NIE's BPQ response on opex. Of these costs £400,000 was attributed to the 'Vulnerable Customer Fund'.

92. The innovation scheme costs reported by NIE reflect schemes included as part of the RP4 price control which are not expected to continue. We excluded the costs reported under the heading of 'innovation schemes' from the calculation of NIE's indirect costs that we use for benchmarking analysis.

Credit rating costs

93. We included in our method for the calculation of NIE's indirect costs the historical credit rating costs reported by NIE in its BPQ response on opex.

Market opening costs

94. The benchmarking analysis in the October 2011 CEPA report for the UR included in the calculation of NIE indirect costs a line of costs described as 'Market opening costs'. These were £2.5 million in 2009/10. The CEPA report said that these costs were included 'to ensure comparability with Ofgem's reporting' (p19). The figures used for market opening costs by CEPA are the costs reported by NIE under 'market opening costs' under the 'Dt costs' sheet of NIE's opex submission.

95. In its final determination, the UR used revised benchmarking analysis. It said that the analysis used for its draft report (the CEPA February 2011 report) included 'the full cost of market opening systems' but that NIE had provided additional evidence to show that the responsibilities and costs of the GB DNOs were lower, so an adjustment was required.[9]

96. The revised benchmarking analysis used a figure of £0.5 million for market opening costs for each of the financial years from 2007/08 to 2009/10 inclusive.

97. NIE said the following about market-opening costs:[10]

> In order to ensure consistency with the GB peer group, it is appropriate to add only a small proportion of NIE's market-opening costs to its cost base, consistent with the relatively narrow role of GB DNOs in the electricity retail market in GB. NIE estimated that the relevant costs it incurred in undertaking similar activities to those undertaken by GB DNOs were £0.13 million in 2009/10 and £0.185 million in 2010/11. However, NIE understands that CEPA's analysis for the Final Determination adds £0.5 million to NIE's costs in respect of these activities. No details on the basis of this estimate have been provided to NIE.

98. The UR responded as follows in its supplementary submission:[11]

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[9] UR final determination, p51.
[10] NIE Statement of Case, p188.
[11] UR Supplementary Submission, paragraph 31.

> In respect of the overstatement of market opening costs, NIE T&D claims that instead of including market opening costs of £500k for NIE T&D, we should have included only £130k, reflecting the narrower range of market opening activities that GB DNOs engage in. Our figure of £500k was already significantly narrowed from the full extent of market opening costs actually incurred by NIE T&D, and we considered it to be conservative. NIE T&D has failed to produce a detailed break-down of its relevant costs to demonstrate that our figure is inappropriate.

99. Neither the UR nor NIE provided any explanation of how their proposed figures of £500,000 and £130–£185,000 were derived. Both parties recognize that the majority of market opening costs are not comparable with the costs incurred by GB DNOs, but have struggled to provide a well-founded estimate of the element of costs reported under the D_t term that should be included in the benchmarking analysis.

100. We did not include any of the D_t costs incurred by NIE in relation to market opening in our calculation of NIE's indirect costs for the benchmarking analysis. These costs predominantly relate to activities not carried out by GB DNOs. We did not identify a reasonable basis to determine the value of an adjustment.

Pension and depreciation elements of corporate charge

101. Frontier reported that in 2009/10, NIE received 'support services from Viridian (e.g. Board, Group Finance, Treasury, Legal & Company services)' and was charged a cost-reflective amount. Frontier argued that an element of the charge from Viridian to NIE was associated with recovery of depreciation costs and that this element should be excluded from the cost benchmarking. Frontier had originally proposed another adjustment to remove Viridian pension charges, but this was in a context where NIE was compared against GB DNO data excluding pension costs and the proposed pension adjustment was no longer relevant as we include pension costs.

102. The total cost to NIE reported under 'Viridian corporate' for 2009/10 was £3.1 million in NIE's BPQ response on controllable opex. The value of the proposed adjustment for Viridian depreciation charges in the Excel model accompanying Frontier's analysis was £54,000 in 2009/10.

103. Neither NIE nor Frontier refer to an explicit part of Ofgem's cost reporting guidelines that confirm that any depreciation charges incurred by a parent company should be deducted from the corporate costs charged to NIE by Viridian. In view of the small scale of the adjustment proposed by Frontier, and the lack of confirmation that an adjustment is appropriate, we made no such adjustment for Viridian depreciation charges.

Further information on wage adjustments for benchmarking analysis

1. As part of our benchmarking analysis to compare the costs of NIE against GB DNOs we made adjustments to the costs of each company using estimates of the impacts of wage differences between regions within the UK. This appendix provides further information on the wage adjustments we have used.

Overview of alternative wage adjustment factors considered

2. We considered a range of different wage adjustment methods and factors. This appendix presents the calculation method for eight of these which are described in the table below and explained in more detail in the sections that follow. Of these, we used three wage adjustment methods for the econometric results that we present in our final determination (WA1 to WA3 in the table).

TABLE 1 **Summary of wage adjustments**

Reference	*Overview of features*
WA1	Uses NIE labour breakdown (including contractors) provided by Frontier Economics. Calculation uses Methodology B. Uses weekly mean wages.
WA2	Uses NIE labour breakdown (including contractors), with four digit code categories aggregated up into three digit code categories. Calculation uses Methodology A. Uses weekly mean wages.
WA3	Uses regional mean wages. Calculation uses Methodology A. Uses weekly mean wages.
WA4	Uses weightings based on those provided by CEPA. Calculation uses Methodology A. Uses weekly mean wages.
WA5	Same as WA1, but uses hourly mean wages.
WA6	Same as WA2, but uses hourly mean wages.
WA7	Same as WA3, but uses hourly mean wages.
WA8	Same as WA4, but uses hourly mean wages.

Source: CC.

3. We describe the methods we used in three separate steps:

   (a) step (1): calculating the wage adjustment factors;

   (b) step (2): calculating labour percentages; and

   (c) step (3): application of the adjustment factor.

Step (1): Calculating wage adjustment factors

4. There were two basic methodologies employed to calculate the wage adjustment factors. Methodology A was used to calculate the majority of wage adjustment factors ($WA2_R$, $WA3_R$, $WA4_R$, $WA6_R$, $WA7_R$ and $WA8_R$). It involves calculating a weighted mean wage for each year based on mean wage data for different SOC 2000

categories from the Annual Survey of Hours and Earnings (ASHE). The ratio of the weighted mean wage calculated for the UK as a whole (WMW_{UKt}) to that calculated for each region (WMW_{Rt}) is taken for each year T=t1-ti, and its average across these years is calculated. This is shown below:

$$WMW_{Rti} = W_1 * MW_{1Rti} + W_2 * MW_{2Rti} + \cdots W_j * MW_{jRti}$$
$$WMW_{UKti} = W_1 * MW_{1UKti} + W_2 * MW_{2UKti} + \cdots W_j * MW_{jUKti}$$
$$WA_R = \frac{\frac{WMW_{UK\mathrm{t1}}}{WMW_{R\mathrm{t1}}} + \frac{WMW_{UK\mathrm{t2}}}{WMW_{R\mathrm{t2}}} + \cdots + \frac{WMW_{UK\mathrm{ti}}}{WMW_{R\mathrm{ti}}}}{\mathrm{ti} - \mathrm{t1}}$$

where W_j represents the weight on the j[th] ASHE category, MW_{jRti} represents the mean wage of the corresponding ASHE category in region R at time ti and MW_{jUKti} represents the mean wage of that ASHE category in the UK at time ti. The details of the weights used for each of these wage adjustments and their other distinguishing features are described below. The same weights were applied to both NIE and the GB DNOs.

5. Methodology B was used to calculate WA1 and WA5, and is based on the process used by Frontier. Instead of calculating separately the ratio of the weighted UK mean wage to the weighted regional mean wage for each year and then averaging all these ratios, Methodology B begins by averaging the wage for each category across time and only then applying the weighting to these time-averaged wages. The wage adjustment is then the ratio of the UK weighted mean wage calculated by this method to each regional weighted mean wage. As before, the same weightings were applied to both NIE and the GB DNOs. The calculation process for Methodology B is shown below:

$$\overline{MW_{\mathrm{j}R}} = \frac{MW_{\mathrm{j}Rt1} + MW_{\mathrm{j}Rt2} + \cdots + MW_{\mathrm{j}Rti}}{ti - t1}$$
$$\overline{MW_{\mathrm{j}UK}} = \frac{MW_{jUKt1} + MW_{jUKt2} + \cdots + MW_{\mathrm{j}UKti}}{ti - t1}$$
$$\overline{WMW_R} = W_1 * \overline{MW_{1R}} + W_2 * \overline{MW_{2R}} + \cdots W_j * \overline{MW_{JR}}$$
$$\overline{WMW_{UK}} = W_1 * \overline{MW_{1UK}} + W_2 * \overline{MW_{2UK}} + \cdots W_j * \overline{MW_{JUK}}$$
$$WA_R = \frac{\overline{WMW_{UK}}}{\overline{WMW_R}}$$

6. WA1 to WA4 use ASHE weekly wage data to estimate the wage adjustments. Their different labour categories and weightings are described below:

(a) WA1: The SOC categories and weightings used when estimating the weighted mean wage for each year were based on the breakdown of NIE's labour (including contractors) into SOC 2000 categories which was provided in submissions from NIE.

(b) WA2: The categories and weightings were again based on the labour breakdown submitted by Frontier. However, wherever this breakdown gave the most dis-aggregated ASHE category, ie the four-digit SOC code, they were aggregated up a category into three-digit SOC codes.

(c) WA3: This wage adjustment did not use weightings and instead simply applied the regional mean wage for each year.

(d) WA4: The weightings for this wage adjustment are based on the general labour and specialist labour categories used by Ofgem for its RPE weightings and

provided to the CC by CEPA. For both closely associated indirects (CAI) and business support costs (BSC) general labour makes up approximately 67 per cent of total labour and specialist labour makes up the other 33 per cent. CEPA applied these weightings to the ASHE categories ‘Professional occupations’ and ‘Skilled trades occupations’, although we believe that CEPA may have applied the weightings incorrectly. We gave ‘Professional occupations’ a weight of 1/3 and ‘Skilled trades occupations’ a weight of 2/3. A key difference to the other wage adjustments is that WA4 only used data from 2007–2010, whereas all other wage adjustments used ASHE data from 2007–2011. WA4 uses the shorter time frame to improve comparability with the wage adjustment calculated by CEPA.

7. WA5 to WA8 are replications of WA1 to WA4, but are calculated using ASHE hourly wage data instead of weekly wage data. Hourly data was used by Frontier in its calculation of the wage adjustment.

8. Using hourly rather than weekly data does not tend to change the resulting wage adjustments greatly. The main exception is when the most disaggregated four-digit SOC codes are used to calculate the wage adjustment (ie WA1 and WA5). In this case using hourly wage data rather than weekly wage data results in a lower wage adjustment calculated for Northern Ireland.

9. Note that because there is missing wage data for some four-digit SOC categories in certain regions and years, the average mean wage for each category in each region is only the average over the years that the data exists. In each instance that an average mean wage is calculated for a category in a region, an average mean wage is also calculated for that category in the UK, averaging only over the years which were used in the corresponding regional calculation. This allows the UK figure to be comparable with the regional figure.

10. Where there is no data at all on wages in any year for a particular category in a region, the average of the values calculated for all other regions is taken.

11. Table 2 gives the weightings used for each SOC category for WA1, WA2, WA5 and WA6.

TABLE 2 **Wage adjustment weightings**

per cent

SOC code	*Weights used for WA1 and WA5*	*Weights used for WA2 and WA6*
1	6	6
212	0	18
2123	18	0
311	0	16
3112	16	0
41	5	5
524	0	29
5241	4	0
5243	25	0
712	0	3
7122	3	0
821	0	1
8211	1	0
913	0	21
9139	21	0
914	0	1
9149	1	0
Total	100	100

Source: CC.

12. Table 3 gives a full list of the wage adjustments resulting from the above calculations.

TABLE 3 **Comparison of wage adjustments**

per cent

Company	*Region*	*WA1*	*WA2*	*WA3*	*WA4*	*WA5*	*WA6*	*WA7*	*WA8*
CN West	West Midlands	109	106	110	104	111	107	110	104
CN East	East Midlands	104	105	110	103	103	105	111	104
ENW	North-West	105	104	108	103	106	103	108	102
CE NEDL	North-East	100	105	115	104	102	105	114	103
CE YEDL	Yorkshire and the Humber	96	106	112	102	95	107	112	103
WPD Wales	Wales	102	108	117	106	101	107	115	103
WPD West	South-West	99	106	111	107	99	105	109	106
EDFE LPN	London	92	87	71	86	91	86	73	87
EDFE SPN	East	106	98	105	101	108	99	104	101
EDFE EPN	South-East	96	97	96	97	96	97	96	98
SP Distribution	Scotland	102	99	106	100	97	98	106	101
SP Manweb	Wales	102	108	117	106	101	107	115	103
SSE Hydro	Scotland	102	99	106	100	97	98	106	101
SSE Southern	South-East	96	97	96	97	96	97	96	98
NIE	Northern Ireland	108	111	116	112	102	111	116	110

Source: CC.

Step (2): Calculating labour percentages

13. The proportion of labour in indirect costs for each of the Ofgem DNOs in each year ($\%LI_{ct}$), where c represents each DNO and t represents the year) was calculated by multiplying the per cent of labour in BSC ($\%LBSC_{ct}$) by the per cent of BSC in total indirect costs ($\%BSC_{ct}$) and adding it to the per cent of labour in CAI ($\%LCAI_{ct}$) multiplied by the per cent of CAI in indirect costs ($\%CAI_{ct}$). Because the proportion that BSC and CAI make up of indirect costs varied between DNOs and across time, this figure also varied. Given the broad labour assumptions, we do not believe that this variation is informative, and therefore take a flat average of this figure to be the labour percentage for all DNOs across time ($\overline{\%LI}$). This percentage was applied to NIE as well. The calculation of the average labour percentage is shown below:

$$\%LI_{ct} = \%LBSC_{ct} * \%BSC_{ct} + \%LCAI_{ct} * (1 - \%BSC_{ct})$$
$$\overline{\%LI} = \frac{\%LI_{ct}}{c * t}$$

Step (3): application of the adjustment factor

14. Adjusted indirect cost for each company ($AdjI_C$) is calculated by multiplying the labour percentage by the indirect costs of that company (I_C) to give the size of that company's indirect labour costs, then multiplying this by the wage adjustment factor. The company's non-labour indirect costs are left unadjusted and are added on to the adjusted labour cost to give the total adjusted indirect cost. This is shown below.

$$AdjI_C = \overline{\%LI} * I_C * WA + (1 - \overline{\%LI}) * I_C$$

Further information on econometric models, GB DNO data and results

1. This appendix provides further information on the econometric model specifications used for benchmarking analysis, the data used for the GB DNOs and the results.

Model specification

2. In each econometric model that we use, the relationship between the explanatory variable and the dependent variable is assumed to take one of two forms:

$$y_{Ct} = \beta_0 + \beta_1 x_{Ct} + t_1 + t_2 + \varepsilon_{Ct}$$

$$\ln(y_{Ct}) = \beta_0 + \beta_1 \ln(x_{Ct}) + t_1 + t_2 + \varepsilon_{Ct}$$

where y_{Ct} is the dependent variable (cost or cost per customer), x_{Ct} the explanatory variable, ε_{Ct} is a random error term, β_1 is the coefficient of the explanatory variable, β_0 is the constant and t_1 and t_2 are time dummies. Ln represents the natural log. Regressing y_{Ct} on x_{Ct}, time dummies and a constant gives predicted values of β_0, β_1 t_1 and t_2, which can then be used with each company's explanatory variable to calculate the cost that an averagely efficient company with that explanatory variable would be expected to have ($\widehat{y_{Ct}}$). For log equations, this cost takes the form $\widehat{y_{Ct}} = e^{\widehat{\ln(y_{Ct})}}$.

3. Table 1 below provides a brief description of each regression model used. CSV(1) is a composite scale variable made up of network length (NL), number of customers (C) and TWh distributed (TWh), with network length having a 50 per cent weight, and the other two having weights of 25 per cent. CSV(2) is a composite scale variable made up of modern equivalent asset value (MEAV) with a weight of 63 per cent and load and non-load related expenditure (LDNL) with a weight of 37 per cent.[1] These are defined formally as follows:

$$\text{CSV}(1) = \text{NL}^{0.5} * \text{C}^{0.25} * \text{TWh}^{0.25}$$

$$\text{CSV}(2) = \text{MEAV}^{0.63} * \text{LDNL}^{0.37}$$

TABLE 1 **Model descriptions**

Model	*Description*
M1	Regression of cost on CSV(1) and time dummies
M2	Regression of cost on CSV(2) and time dummies
M3	Regression of cost per customer on time dummies
M4	Regression of ln(cost) on ln(CSV(1)) and time dummies
M5	Regression of ln(cost) on ln(CSV(2)) and time dummies
M6	Regression of ln(cost per customer) on ln(network length per customer) and time dummies

Source: CC.

[1] For NIE, the LDNL and MEAV are based on figures calculated by CEPA. We are not convinced of the precision of the LDNL variable, given that an assumption seems to have been made that 10 per cent of the load and non-load investment cost was indirect cost. As discussed in Section 8 of our final determination, we have not placed weight on the models using this explanatory factor but have included its results because they were used in CEPA's analysis for the UR.

Calculation of the cost benchmark

4. We explain below our method to calculate the cost benchmark and the efficiency score reported in Section 8 of our final determination. In the description we use the term efficiency in a hypothetical sense that ignores the limitations of these models; our focus here is on the calculations we make using results from the econometric analysis and not their interpretation.

5. The estimated parameters of each regression model can be used to calculate an 'estimated cost' for each company. This is the level of costs that the regression results imply that the company would have if it were averagely efficient within the sample of 15 DNOs.

6. The actual cost of each company is divided by its estimated cost. This serves to normalize the costs of different companies to a comparable scale. The value derived at this stage (which, for simplicity, we dub 'efficiency') shows the percentage above or below average that each company is. Its formal calculation is shown below:

$$E_{Comp} = \frac{C_{Comp}}{\hat{C}_{Comp}}$$

where E_{Comp} is the 'efficiency', C_{Comp} is the company's actual cost and $\hat{C}_{Comp}$ is the company's estimated cost.

7. The companies are ranked based on the efficiencies calculated in step 2 above, and the fifth-ranked company is selected as the benchmark for NIE. This is a different benchmark to that used by CEPA, which compared NIE's efficiency with the efficiency it would have to be to reach the first quartile. This first quartile was calculated to be equivalent to a rank of 4.5. However, when dealing with discrete distributions of numbers there are a number of different possible approaches to calculating quartiles, which will give different results. For instance, the preferred quartile calculation of the statistical software Stata has the first quartile of 15 observations equal to the fourth observation. We decided not to use the upper quartile concept and instead to set a benchmark using results for the fifth-ranked company.

8. The rank variable should be interpreted with some care because it gives no indication of the scale of the distance to the benchmark. If results are clumped together, two companies may be ranked quite differently and yet both be close the benchmark; alternatively one company may be much further from the benchmark than another which is close to it in rank.

9. Each company's efficiency is divided by the efficiency of the fifth-ranked company to derive the 'score'. This score is equivalent to the ratio of the company's actual cost to what its cost would be if it were ranked fifth. Therefore this score gives a measure of the cost improvement that would bring the company's costs up to the fifth rank. So if a company's score is 110 per cent then $1 - {}^{1}/_{110\%} = 1 - 90.9\% = 9.1\%$ is the reduction in cost that would bring the company up to the level of the fifth-ranked company. The calculation for the score is shown below:

$$S_{Comp} = \frac{E_{Comp}}{E_5}$$

where S_{Comp} is the company's score and E_5 is the efficiency of the fifth-ranked company.

10. The cost benchmark for NIE is then taken to be NIE's actual cost divided by its score. This gives the cost that NIE would be expected to have if it were the fifth-ranked company.

Data for indirect costs for GB DNOs

11. We used Ofgem data for GB DNOs to calculate cost measures that include and exclude costs attributed to connections. In both cases we remove costs attributed to non-distribution activities (or excluded services) other than connections.

12. More formally, our measure of indirect cost including connections was calculated as the sum of the following elements for closely associated indirect costs and for business support costs:

    Total Gross Costs – Indirect Activity Allocations to Non distribution (exc connections)

13. Our measure of indirect costs excluding connections was calculated as the sum of following elements for closely associated indirect costs and for business support costs:

    Total Gross Costs

    – Indirect Activity Allocations to connections outside RAV

    – Indirect Activity Allocations to connections (RAV related)

    – Indirect Activity Allocations to Non distribution (exc connections)

Adjustment to GB DNO data to remove disallowed related party margins

14. Further to the calculations above, we made an adjustment to the data on GB DNO's indirect and IMF&T costs to remove 'disallowed related party margins'.

15. Following our provisional determination, we obtained data from Ofgem on disallowed related party margins by DNO for 'network operating costs', 'closely associated indirects' and 'business support,' for each of the 2009/10, 2010/11, and 2011/12 reporting years.

16. The data on 'disallowed related party margins' are defined as 'The portion of the related party margins which will not be included within the RAV Additions calculation for the year in accordance with the relevant price control settlement.'[2]

17. We made a deduction from the GB DNOs' indirect costs for the disallowed related party margins that were reported under 'closely associated indirects' and under 'business support' costs. We excluded from this deduction an element of the disallowed related party margins that we attributed to connections and non-distribution activities. We calculated this element in proportion to the costs attributed to connections and non-distribution activities out of total indirect costs.

18. We made a deduction from the GB DNOs' IMF&T costs for the disallowed related party margins that were reported under 'network operating costs'. We excluded from

[2] Ofgem (2012) 'Electricity Distribution (DPCR5): Glossary of Terms - Regulatory Instructions and Guidance: Version 3'

this deduction an element of the disallowed margins that we attributed to activities falling under network operating costs but outside IMF&T. We calculated this element in proportion to the costs falling under network operating costs but outside IMF&T compared to total network operating costs.

Data for explanatory factors

19. For the GB DNOs we used data provided by Ofgem on network length (km), customer numbers and units distributed (GWh) for each of 2009/10, 2010/11 and 2011/12.

20. For NIE, we used the data from NIE's BPQ response for our measures of number of customers and units distributed in 2009/10 but used the network length for 2009/10 reported in Frontier's model submitted in August 2013, which makes use of updated data available from NIE. We understand that the network length figures for 2009/10 from NIE's BPQ response were not the most up-to-date data available. For 2010/11 we used data on network length, number of customers and units distributed submitted by Frontier in August 2013 and for 2011/12 we used data from the model Frontier submitted in December 2013. Our network length data excluded the 275 km network.

21. The explanatory factor in our models M2 and M5 are based on data on MEAV and LDNL from the CEPA model (UR-67). We found an apparent error in the conversion of the LDNL data from 2007/08 prices to 2009/10 prices. Aside from making this RPI-related adjustment, our explanatory factor data for models M2 and M5 are taken from the CEPA data in UR-67 for NIE and the GB DNOs. For the GB DNOs we used the same explanatory factor data for 2010/11 and 2011/12 as for 2009/10. Updating the MEAV and LDNL data for 2010/11 and 2011/12 would have required far more data to be provided by Ofgem and the work to update the figure did not seem proportionate for this proxy measure of relative scale which is only used in models M2 and M5.

Results from model estimation

22. In Section 8 of our final determination we provide results for the efficiency score and rank for NIE. We provide further model estimation results below.

Regression results for indirect costs excluding connections

TABLE 1 **No wage adjustment***

	M1	*M2*	*M3*	*M4*	*M5*	*M6*
Coefficient	2.545	0.032	-	0.866	0.734	0.609
	(0.206)	(0.003)	-	(0.060)	(0.062)	(0.058)
Constant	10.472	15.982	31.489	1.527	-1.206	1.354
	(4.180)	(4.580)	(2.295)	(0.178)	(0.451)	(0.210)
R^2	0.71	0.664	0	0.726	0.677	0.561

Source: CC analysis.

*Standard errors in parentheses.

TABLE 2 **Wage adjustment WA1***

	M1	*M2*	*M3*	*M4*	*M5*	*M6*
Coefficient	2.476	0.031	-	0.841	0.71	0.651
	(0.234)	(0.003)	-	(0.066)	(0.064)	(0.056)
Constant	12.36	17.91	31.922	1.609	-1.028	1.221
	(4.542)	(4.778)	(2.444)	(0.191)	(0.463)	(0.208)
R^2	0.64	0.593	0	0.674	0.625	0.556

Source: CC analysis.

*Standard errors in parentheses.

TABLE 3 **Wage adjustment WA2***

	M1	*M2*	*M3*	*M4*	*M5*	*M6*
Coefficient	2.424	0.03	-	0.816	0.685	0.669
	(0.227)	(0.003)	-	(0.064)	(0.065)	(0.052)
Constant	13.577	19.167	32.172	1.687	-0.844	1.168
	(4.612)	(4.879)	(2.509)	(0.190)	(0.472)	(0.187)
R^2	0.652	0.599	0	0.686	0.629	0.598

Source: CC analysis.

*Standard errors in parentheses.

TABLE 4 **Wage adjustment WA3***

	M1	*M2*	*M3*	*M4*	*M5*	*M6*
Coefficient	2.37	0.029	-	0.78	0.646	0.745
	(0.244)	(0.003)	-	(0.066)	(0.066)	(0.055)
Constant	16.175	22.069	33.253	1.818	-0.538	0.936
	(5.069)	(5.224)	(2.758)	(0.194)	(0.479)	(0.198)
R^2	0.596	0.536	0	0.637	0.568	0.64

Source: CC analysis.

*Standard errors in parentheses.

Regression results for indirect and IMF&T costs excluding connections

TABLE 5 **No wage adjustment***

	M1	*M2*	*M3*	*M4*	*M5*	*M6*
Coefficient	4.649	0.059	-	0.949	0.818	0.468
	(0.322)	(0.005)	-	(0.052)	(0.064)	(0.044)
Constant	7.461	15.986	50.506	1.773	–1.322	2.313
	(6.213)	(7.246)	(3.126)	(0.154)	(0.461)	(0.155)
R^2	0.847	0.824	0.003	0.862	0.833	0.599

Source: CC analysis.

*Standard errors in parentheses.

TABLE 6 **Wage adjustment WA1***

	M1	*M2*	*M3*	*M4*	*M5*	*M6*
Coefficient	4.506	0.057	-	0.921	0.792	0.514
	(0.329)	(0.005)	-	(0.055)	(0.063)	(0.040)
Constant	10.987	19.52	51.182	1.862	–1.129	2.169
	(6.252)	(7.187)	(3.369)	(0.158)	(0.454)	(0.147)
R^2	0.797	0.77	0.003	0.829	0.797	0.6

Source: CC analysis.

*Standard errors in parentheses.

TABLE 7 **Wage adjustment WA2***

	M1	*M2*	*M3*	*M4*	*M5*	*M6*
Coefficient	4.426	0.056	-	0.895	0.765	0.533
	(0.332)	(0.005)	-	(0.056)	(0.066)	(0.036)
Constant	12.951	21.607	51.617	1.945	–0.93	2.112
	(6.521)	(7.493)	(3.458)	(0.165)	(0.480)	(0.128)
R^2	0.81	0.777	0.003	0.834	0.792	0.638

Source: CC analysis.

*Standard errors in parentheses.

TABLE 8 **Wage adjustment WA3***

	M1	*M2*	*M3*	*M4*	*M5*	*M6*
Coefficient	4.332	0.054	-	0.856	0.723	0.616
	(0.348)	(0.006)	-	(0.058)	(0.068)	(0.050)
Constant	17.395	26.522	53.444	2.087	–0.6	1.857
	(7.130)	(7.951)	(3.886)	(0.171)	(0.490)	(0.178)
R^2	0.761	0.717	0.002	0.783	0.727	0.671

Source: CC analysis.

*Standard errors in parentheses.

Regression results for indirect costs including connections

TABLE 9 **No wage adjustment***

	M1	*M2*	*M3*	*M4*	*M5*	*M6*
Coefficient	3.1	0.039	-	0.866	0.751	0.559
	(0.261)	(0.004)	-	(0.059)	(0.057)	(0.074)
Constant	11.605	17.402	37.708	1.714	–1.141	1.705
	(4.916)	(5.376)	(2.647)	(0.167)	(0.405)	(0.261)
R^2	0.742	0.718	0.004	0.76	0.743	0.549

Source: CC analysis.

*Standard errors in parentheses.

TABLE 10 **Wage adjustment WA1***

	M1	*M2*	*M3*	*M4*	*M5*	*M6*
Coefficient	3.012	0.038	-	0.84	0.727	0.601
	(0.281)	(0.004)	-	(0.065)	(0.060)	(0.069)
Constant	13.918	19.754	38.215	1.796	–0.963	1.572
	(5.131)	(5.503)	(2.834)	(0.182)	(0.425)	(0.248)
R^2	0.686	0.659	0.004	0.716	0.697	0.551

Source: CC analysis.

*Standard errors in parentheses.

TABLE 11 **Wage adjustment WA2***

	M1	*M2*	*M3*	*M4*	*M5*	*M6*
Coefficient	2.955	0.037	-	0.816	0.702	0.619
	(0.276)	(0.004)	-	(0.063)	(0.060)	(0.061)
Constant	15.259	21.182	38.501	1.873	–0.779	1.519
	(5.179)	(5.578)	(2.889)	(0.179)	(0.428)	(0.216)
R^2	0.709	0.676	0.004	0.738	0.71	0.602

Source: CC analysis.

*Standard errors in parentheses.

TABLE 12 **Wage adjustment WA3***

	M1	*M2*	*M3*	*M4*	*M5*	*M6*
Coefficient	2.895	0.036	-	0.779	0.663	0.696
	(0.289)	(0.004)	-	(0.063)	(0.061)	(0.047)
Constant	18.238	24.548	39.768	2.005	–0.472	1.286
	(5.519)	(5.865)	(3.173)	(0.179)	(0.431)	(0.170)
R^2	0.673	0.628	0.004	0.712	0.67	0.668

Source: CC analysis.

*Standard errors in parentheses.

Regression results for indirect and IMF&T costs including connections

TABLE 13 **No wage adjustment***

	M1	*M2*	*M3*	*M4*	*M5*	*M6*
Coefficient	5.204	0.067	-	0.938	0.819	0.453
	(0.397)	(0.006)	-	(0.051)	(0.058)	(0.056)
Constant	8.595	17.406	56.726	1.922	–1.21	2.483
	(7.339)	(8.239)	(3.495)	(0.146)	(0.417)	(0.195)
R^2	0.834	0.825	0.009	0.856	0.849	0.573

Source: CC analysis.

*Standard errors in parentheses.

TABLE 14 **Wage adjustment WA1***

	M1	*M2*	*M3*	*M4*	*M5*	*M6*
Coefficient	5.042	0.065	-	0.91	0.793	0.498
	(0.395)	(0.006)	-	(0.055)	(0.059)	(0.050)
Constant	12.545	21.364	57.475	2.011	–1.018	2.34
	(7.182)	(8.087)	(3.774)	(0.153)	(0.417)	(0.178)
R^2	0.795	0.781	0.008	0.828	0.817	0.584

Source: CC analysis.

*Standard errors in parentheses.

TABLE 15 **Wage adjustment WA2***

	M1	*M2*	*M3*	*M4*	*M5*	*M6*
Coefficient	4.957	0.063	-	0.884	0.767	0.517
	(0.399)	(0.006)	-	(0.055)	(0.061)	(0.042)
Constant	14.633	23.623	57.947	2.093	–0.821	2.284
	(7.419)	(8.363)	(3.851)	(0.158)	(0.439)	(0.146)
R^2	0.814	0.794	0.008	0.84	0.82	0.63

Source: CC analysis.

*Standard errors in parentheses.

TABLE 16 **Wage adjustment WA3***

	M1	*M2*	*M3*	*M4*	*M5*	*M6*
Coefficient	4.857	0.062	-	0.845	0.724	0.599
	(0.410)	(0.007)	-	(0.056)	(0.063)	(0.038)
Constant	19.458	29.001	59.958	2.234	–0.493	2.033
	(7.863)	(8.748)	(4.311)	(0.161)	(0.446)	(0.139)
R^2	0.781	0.749	0.008	0.81	0.774	0.689

Source: CC analysis.

*Standard errors in parentheses.

BPI’s comments on NIE’s response to our provisional determination

BPI Comments on NIE's response to the Competition Commission's Provisional Determination

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1. Introduction

We have reviewed the comments made by NIE in response to the Competition's Provisional Determination set out in its paper dated 29 November 2013, in particular Chapter 3 of the paper which covers Direct Capex. This paper sets out our response to the specific comments on BPI's report or specific points on which the Competition Commission has asked us to provide comment.

For convenience we have structured our response to follow the points made in NIE's paper with the Chapter and Section references relating to the relevant sections of that paper. We have produced parts of NIE's comments (in italics) followed by our specific response.

2. The Consequences of Not Providing Finance for Certain Projects (Chapter 3, Section 2)

11kV Network performance

"In relation to network performance (for which NIE requested £9 million), the CC's determination will mean that network performance in NI will fall further behind that of peer companies in GB which continue to make improvements because of the effective incentive mechanisms that were put in place in DPCR5. The direct consequence is that finance will not be made available to improve network performance for worst served customers. This will impact almost exclusively on rural customers."

It is worth repeating UR's response to this request, namely:

NIE has not provided any evidence to show that customers are unhappy with the current standard of network performance or that customers would be willing to fund improvements to network performance. Our own experience of customers contacting our office is that they are significantly more concerned about the cost of electricity than quality of their current supply.

We have therefore not included any funds here, however we have incentivised NIE to maintain the current level of performance by including an incentive for customer minutes lost and customer interruptions based on the values identified for GB.

In its response to the provisional determination NIE infer that its network performance currently lags behind that of the peer companies in GB although we believe that that is not the case. For instance, for the period 2012/2013, NIE's Customer Minutes Lost (CML) performance was 53.1 for unplanned outages comparing with an average of 59.5 for the DNOs within Great Britain for the year 2010/2011. We would have expected the DNOs to have made some improvements since 2011 but this would not materially affect this comparison. The CMLs range from 32.4 to 89.5 but there is a mixed picture when comparisons are made. Some companies in the upper quartile (high CML indices) have invested highly in automation whilst there are better performing companies which have limited automation but rely more on staff and organisation.

NIE has not presented any further justification for network automation but merely states that:

The direct consequence is that finance will not be available to improve network performance for worst served customers. This will impact almost exclusively on rural customers.

As we stated in our report we believe this really comes down to a policy decision by the Regulator and its perception that customers would rather pay less for their electricity than enjoy a marginal improvement in overall network performance We accept that for some customers in rural areas any improvement could be substantial, however, the worst served customers will generally also be subject to more interruptions in supply and as NIE itself points out this investment will bring about an improvement in response times to restore supply only with no improvement in the numbers of Customer Interruptions (CIs).

We recognise that automation can have significant benefits when utilised on poorly performing circuits, and hence worst served customers, but in any case it would seem likely that these will be targeted as priority in the on-going overhead line refurbishment programme. This should then subsequently reduce the number of damage faults affecting those particular lines and the circumstances for which remote control of switches provide a useful method for reducing the interruption period for some customers. Additionally, and as evidenced from the DNOs, efficient processes for organising fault response teams can also have a major impact on CML indices.

Notwithstanding the above, we do recognise that automation and remote control of strategically placed switches and sectionalisers will reduce customer minutes lost on a typical distribution network. However, NIE's current network performance compares reasonably favourably with the DNOs in GB and at a level that is apparently acceptable to the Regulator. Consequently, and unless the Regulator wishes to pursue future performance improvements using the better performing GB DNOs as a benchmark, then we believe our original recommendations are still valid and without any further analysis supporting NIE's case recommend that there should be no change to the Provisional Determination.

25mm2 Conductor Ice Accretion

"In relation to 11kV network resilience (for which NIE requested £35 million), there will be no reduction of the risk from widespread failure of the rural 11kV networks resulting from extreme ice accretion. This risk will instead rise over the course of RP5 as the network continues to age and deteriorate. As we explained in the Statement of Case and previously, there is a significant risk of extended outages arising from the effects of severe weather on the overhead line networks. Customers located in Great Britain and the RoI are not exposed to this risk to the same extent because the networks in those locations have already had very significant investment to reduce the risk."

Our initial report contained the following comment:

Although it was no doubt recognised by NIE that small cross sectional area conductors were more prone to damage from ice accretion than larger types, it seems to have been the three snow events between 2001 and 2010 that focused NIE's attention on its sizeable 25mm2 SCA overhead line network.

However, following the publication of our report we subsequently learnt that NIE had installed 25mm conductor as recently as 2008, albeit for some spur lines only, but nonetheless, given the known problems with ice accretion and 25mm conductor, this appears somewhat at odds with NIE's concerns about the resilience of the 11kV network that it expressed within its Statement of Case and supporting documentation.

We have had long discussions in this process on the impact of ice accretion and the need to replace 25mm conductor. NIE's proposal to spend £35m on a pilot study in order to accurately quantify the costs for replacing this conductor was questionable at best given that the work involved is essentially 11kV overhead line refurbishment and a repetitive everyday activity. In its latest response, NIE does not mention the requirement to quantify costs but reiterates its perceived risk of extreme and widespread ice accretion to the network. We note that the company has not provided any further evidence in order to quantify the level of performance improvement that would result from such a large capital programme or indeed anything to support its belief that future extreme weather events resulting in ice accretion are likely to become more common place.

Consequently we are not moved to change our view that this allowance should not be allowed and would reiterate our view that the generous allowances for 11kV OHL refurbishment will allow NIE sufficient funds to replace critical sections of small section conductor.

3. Implications of extending the control period by six months (Chapter 3, Section 3)

"NIE prepared its RP5 capex submission on the basis of a five year period from 1 April to 31 March 2017. The CC has instead proceeded on the basis of a 5.5 year price control. Despite this, the CC makes on minimal addition to the capex allowance to cover the longer period on the presumption that NIE will be challenged to deliver the volume of work sought.

The final six months of RP5 will coincide with the preparation of the network for the following winter peak……….these problems can be addressed only during periods of lighter loads on the network, normally spring to autumn..."

"…a significant portion of the work can be described as 'rolling programmes' of the more repetitive day-to-day work on the network which NIE has been carrying out for a number of years, the delivery of which during RP5 will neither stress the organisation nor will it involve any significant ramp up of resources. Such rolling programmes include virtually all the work on the secondary network (the 11kV and lower voltage network) and 33kV overhead line work."

NIE claims that the problems associated with unacceptable circuit and plant overloads and voltage problems at all voltages "can be addressed only during periods of lighter load on the network", and that because of this, all load related reinforcement for the year will need to be completed during April to September i.e. by the end of the 6 month extension, and that an additional full year's expenditure should therefore be allowed.

We do not fully accept this argument. Whilst it is generally true that the majority of load related reinforcement will need to be carried out between April and September (particularly at the higher voltages where outages are of a longer duration and the risk of loss of supply during the works is therefore higher) some reinforcement work can usually safely take place outside of this period. This is particularly true at the lower distribution voltages where, for example, 11kV transformer changes can often be safely carried out in late autumn or early winter, outside of the 6 month extension period.

We would consider it a reasonable assumption that 75% of the overall annual load related network expenditure would generally be spent during April to September, which includes the six month extension period, and the remaining 25% over the rest of the year or, in this case. in the following regulatory period.

We propose that 75% of the annual amount be allowed for the six months extension period. This equates to £3.1 million from the £4.1 million requested by NIE.

We do accept NIE's reasoning on the continuation of routine "rolling programmes" of day to day work on the secondary network, and we believe that it would be inefficient and impractical for them to interrupt this type of work. If such programmes of work had to be interrupted they would need to demobilise either their own direct staff and/or contractors, and would then face considerable difficulty in re-recruiting the skilled resources once theses programmes re-started. Furthermore we accept NIE's point that interrupting certain renewal programmes could compromise the safety at, for example, customers' premises.

Therefore we propose that six months at the forecast run-rate is allowed for NIE to continue the rolling programme of work without interruption or rescheduling. This allowance will be an additional £9.3 million based on the five year plan and average annual run rate of £18.6 million.

4. The CC Allowance for ESQR (Chapter 3, Section 5)

"A further £5 million of direct costs (in addition to the £10.38 million already allowed) would permit approximately one quarter of the estimated non-compliances to be addressed during RP%, approximately twice as much as would otherwise be possible and which would go some way towards complying with DETI guidelines."

The Competition Commission awarded £8.0million above our proposed allowance in its Provisional Determination. We do not believe that an additional £5.0million can be justified until all the survey and planning work we recommended has been completed and a full gap analysis has demonstrated what needs to be done In terms of compliance. We also have similar concerns to UR in that there may be "double counting" with other projects, particularly for tree-cutting costs.

We do not recommend that the Determination is increased in line with NIE's request.

5. The BPI Rationale for Disallowing Certain Asset Replacement Volumes (Chapter 3, Section 6)

Project T14 – 110/33kV Transformers (Chapter 3, Sections 6.4 to 6.10)

"We are unable to find any rational explanation as to why five transformers should be replaced during the period rather than the eight [proposed by NIE. Neither has any evidence been presented supporting BPI's view that the strategy proposed will not increase network risk"

In our report we discussed the merits of condition monitoring against predictive asset modelling and, in general, favoured the condition monitoring approach for these assets because of smaller population and site specific issues. However, the risk and impact model used by NIE to take these critical decisions is weak and unsupported with detailed background information. Importantly, there is no stated threshold above which assets should be replaced nor has NIE reported any change in condition of the assets or additional faults since the strategy paper was presented over 2 years ago. We also agreed with the UR that £1.5million should be added to these projects for better condition monitoring and we would expect to see some results from that at least before revising our proposal. The information provided by NIE in the table presented at 6.9 shows a risk ranking of the highest priority transformers. This may be used to rank the assets in order of priority but we do not believe that NIE has provided any evidence to show that the assets it claims should be replaced are at particular risk of failure during the regulatory period, just that they are more at risk than others. We believe that the probability numbers are simply a score based on a number of factors rather than an assessment of the probability of the asset failing during a specified period.

Importantly it was never our intention to constrain NIE to applying engineering judgement in terms of selecting sequence and the sites for replacements. Indeed it is likely that the priority listing will change over a 5 year period as further diagnostic data is obtained.

We believe that we proposed a reasonable and practical approach on the basis of all the evidence that was provided by NIE, accepting that a degree of engineering judgement must be applied. Although we believe that an allowance for the replacement of six transformers is reasonable, we also believe that it is likely that NIE will wish to retain one of the units as a spare for the duration of RP5 given its concerns. We do not therefore recommend that the Determination is increased in line with NIE's request.

Project T15 – 22kV Reactors (Chapter 3, Sections 6.11 to 6.15)

"NIE cannot understand how BPI can arrive at its conclusion based on NIE's risk scoring as set out in the table"

As we explained in the report, this is a very similar case to that for transformers. We do not believe that there is sufficient evidence to justify replacing the number claimed by NIE. Although the table setting out risk ranking may be useful for demonstrating the order of priority, we do not believe that sufficient evidence has been provided to s demonstrate that there is sufficient justification to change four reactors. The same comments we made above regarding the application of engineering judgement to finalise the replacement sequence also applies here.

Therefore, we do not recommend that the Determination is increased in line with NIE's request.

Project D15 – Secondary Substations (Chapter 3, Sections 6.16 to 6.20)

"It is irrational for CC/BPI to consider maintaining these 145 transformers in service without providing an allowance for re-cabling."

NIE makes the point that no allowance has been made for the additional cabling and suggest that non-standard terminations will be required. However, we note that NIE have not taken the opportunity to quantify the costs for the cabling requirements and further, on the basis of the additional costs, provided a cost benefit analysis in order to demonstrate its reasoning.

We would also make reference to the statement in our original report, and mentioned again by NIE in its response to the PD, in relation to secondary substations:

"BPI does not consider this approach to follow GB DNO engineering practice. In reality substations of the age profile concerned are more economically scrapped or could be potentially stored for spares."

Although it is often the case that DNO's do replace secondary substations in their entirety because it is economic to do so, that does not in our view negate the need for NIE to provide evidence that it is similarly economic to do so on its network whilst recognising the age of its transformer population.

Therefore, we do not recommend that the Determination is increased in line with NIE's request. However, we do agree that an allowance should be made for any additional cabling works but are unable to make an allowance because no costs have been provided.

Distribution investment

Project	*Project name*	*Asset name/further information*	*Planned investment*	*Total cost basis*	*CC direct allowance*	*Comments*
D06	D06 Distribution Tower Lines	Refurbishment 26km Tower Lines Condition Monitoring Vegetation Management	Specified number of units, as per BPQ N/A N/A	£1.5m	£1.4m	
D07	D07 33kV Overhead Lines	33kV Line Re-engineer 33kV Line Refurb 33kV Line TAR	Specified number of units, as per BPQ Specified number of units, as per BPQ N/A	£11.6m	£6.2m	Includes additional allowance for rolling programmes
D08	D08 11kV Overhead Lines	11kV Line Re-engineer 11kV Line Refurb 11kV Line TAR	Specified number of units, as per BPQ Specified number of units, as per BPQ N/A	£68.3m	£36.4m	Includes additional allowance for rolling programmes
D09	D09 LV Lines	Line Undergrounding (Land locked) Refurbishment - Urban and rural Associated tree cutting LV Line TAR LV Line Undergrounding (Direct Access)	Specified number of units, as per BPQ Specified number of units, as per BPQ N/A N/A Specified number of units, as per BPQ	£21.4m	£11.4m	Includes additional allowance for rolling programmes
D10	D10 Undereaves	0.4 services (undereaves)	Specified number of units, as per BPQ	£11.9m	£9.5m	Includes additional allowance for rolling programmes
D11	LV cut-outs	Replace house service cut-outs at 8000 properties	Specified number of units	£1.8m	£1.9m	Includes additional allowance for rolling programmes
D13	D13 Primary Plant	Primary switchgear (11kV & 6.6kV) Outdoor switchgear - Circuit Breaker (33kV) Associated civils costs Associated cable costs Outdoor switchgear - replacement of comlete Mesh (with indoor switchboard) Associated civils costs Associated cable costs Outdoor switchgear - removal of back stays Outdoor switchgear - replacement of Mesh equipment (33kV) Associated civils costs Associated cable costs Indoor Switchgear (33kV)	Specified number of units Specified number of units Linked to associated deliverable Linked to associated deliverable Specified number of units Linked to associated deliverable Linked to associated deliverable Specified number of units Specified number of units Linked to associated deliverable Linked to associated deliverable Specified number of units	£31.2m	£29.7m	

Project	Project name	Asset name/further information	Planned investment	Total cost basis	CC direct allowance	Comments
		Associated civils costs Associated cable costs Primary substation DC system Primary substation AC rewiring Building refurbishment Civil works to primary substations Primary transformer painting Primary substation lease renewal	Linked to associated deliverable Linked to associated deliverable Specified number of units Specified number of units Specified number of units N/A N/A N/A			
D14	D14 Primary Transformers	33/11kV Tranformer (upto 6.25MVA) 33/11kV Transformer (upto 12.5MVA) 33/11kV Transformer (upto 18.75MVA) 33/6.6kV Transformer (upto 18.75MVA) 33/6.6kV Transformer (upto 20/25MVA) Cable	Specified number of units Specified number of units Specified number of units Specified number of units Specified number of units Linked to associated deliverable	£10.1m	£9.6m	
D15	D15 Secondary Substations	Replace RMU Replace complete S/S Replace complete S/S and temp Replace switchboard Replace OH fed GMT Replace H pole H pole TX change only H pole replace LV cab 4 pole replacement 4 pole defects Replace sectionlisers Minipillars LV wall mounted Ancillary systems Inspection programme	Specified number of units Specified number of units Specified number of units Specified number of units Specified number of units Specified number of units Specified number of units Specified number of units Specified number of units Specified number of units Specified number of units Specified number of units Specified number of units N/A N/A	£36.7m	£38.4m	Includes additional allowance for rolling programmes
D16	D16 Distribution Cables	Refurbishment of 4 x 33kV fluid filled circuits Refurbishment of hydraulic systems Sheath renewal Replacement of oil sections OL147 & 148 Purchase of hydraulic leak detection equipment Replacement of L42T connections Purchase and installation of on-line condition monitoring equipment Refurbishment/replacement outdoor terminations Replace 15km of HV cable Replace 14.5km of LV cable Replace 6km of VB main cable	Specified number of units N/A N/A Specified improvement at specified location(s) N/A Specified number of units Specified improvement at specified location(s) N/A Specified number of units Specified number of units Specified number of units	£4.9m	£4.7m	
D49	Smart Grid	Condition monitoring	Specified number of units	£3.0m	£2.9m	No allowance for Smart Technologies

Project	*Project name*	*Asset name/further information*	*Planned investment*	*Total cost basis*	*CC direct allowance*	*Comments*
D39 /41	SCADA / Operational Telecoms network		N/A	£3.7m	£3.5m	
D50	Substation Flooding Enforcement (D)	Permanent protection several distribution substations	Specified number of units	£0.9m	£0.8m	
D51	Public Realms	Replacement / urban regeneration	N/A	£0.9m	£0.8m	
	ESQCR - Distribution	Full survey and asset register, additional reporting as outlined in Section 9	Reporting as per Section 9		£9.5m	Based on CC split between T/D
	Non-recoverable alterations		N/A		£14.6m	Based on 5.5 years
	Distribution load related allowance		N/A		£24.5m	Per FD - additional allowance for summer work included
	Total Distribution investment				**£205.9m**	

Source: CC analysis.

Transmission investment

Project	*Project name*	*Asset name/further information*	*Planned investment*	*Total cost basis*	*CC direct allowance*	*Comments*
T6	Transmission Plant Switch Houses	Refurb two 275kV substation buildings and associated works	Specified improvement at specified location(s), as per BPQ	£2.5m	£2.4m	
T7	Kells 110kV substation	Refurbishment to standard specified in BPQ C3 (28.1.2011). To a fault rating of 40kA	Specified improvement at specified location(s), as per BPQ	£8.1m	£7.8m	
T8	Tandragee 110kV Substation	Refurbishment to standard specified in BPQ C3 (28.1.2011). To a fault rating of 40kA	Specified improvement at specified location(s), as per BPQ	£3.2m	£3.1m	
T9	Castlereagh 110kV substation	Refurbishment to standard specified in BPQ C3 (28.1.2011). To a fault rating of 40kA	Specified improvement at specified location(s), as per BPQ	£3.0m	£2.9m	
T10	110kV switchgear at 3 substations	Replacement 110kV circuit breakers (Ballyvallagh, Dungannon, Lisburn)	Specified number of units	£6.4m	£6.0m	
		Cabling	Linked to associated deliverable			
T11	275kV Plant Ancillaries	Replacement 275kV switchgear and other equipment. As specified in BPQ C2; Cladding is included in project T6	As per BPQ	£5.6m	£5.3m	
		Catenaries	N/A			
		Cladding replacement	Specified improvement at specified location(s)			
		Protection	Specified improvement at specified location(s)			
		Asbestos removal	Specified improvement at specified location(s)			
		Concrete structure refurbishment	N/A			
		Transformer Bunding	Specified improvement at specified location(s)			
		Holthum	N/A			
		Security systems	Specified improvement at specified location(s)			
		Generator	Replace 5 standby generators			
		DC Standby systems	Specified improvement at specified location(s)			
		FMJL & Reyrolle Hairpin CTs	N/A			
		Earthing	Specified improvement at specified location(s)			
		AC rewire	Specified improvement at specified location(s)			
		Control room refurb	Specified improvement at specified location(s)			
		Drainage	N/A			
T12	110kV Plant ancillaries	Replacement 110kV switchgear and other equipment. As specified in BPQ C2, Table 5, p7	As per BPQ	£7.0m	£6.7m	
		Protection	Specified improvement at specified location(s)			
		Cable ducts	N/A			
		Structure refurb	N/A			
		Tx Bunding	Specified improvement at specified location(s)			

Project	*Project name*	*Asset name/further information*	*Planned investment*	*Total cost basis*	*CC direct allowance*	*Comments*
		Holthum	N/A			
		Generator	Replace 2 standby generators			
		External lighting	N/A			
		DC standby systems	Specified improvement at specified location(s)			
		AC system rewire	Specified improvement at specified location(s)			
		Busbars, isolators and VTs	N/A			
		Security	Specified improvement at specified location(s)			
		CO2 refurb	N/A			
		Eathing	N/A			
		Civil	N/A			
		Strabane Main transformer refurbishment	Specified improvement at specified location(s)			
T13	T13 275kV/110kV Transformer Replacement	Transformers (275/110 kV)	Specified number of units	£7.8m	£7.4m	
T14	T14 110/33kV Transformers Replacement	110 transformers (110/33 kV)	Specified number of units	£6.9m	£6.6m	
		Installation	Linked to associated deliverable			
		Cables	Linked to associated deliverable			
T15	T15 22kV Reactor replacement	22kV Reactor	Specified number of units	£1.4m	£1.3m	
		Installation cost	Linked to associated deliverable			
T16	T16 Transmission Transformer Refurbishment	275kV Buching Refurbishment	Specified number of units	£1.2m	£1.1m	
		275kV Plant Painting	Specified number of units			
		275kV disconnector Refurnishment and spares	Specified improvement at specified location(s)			
		275/110kV TX Tap changer refurbishment	Specified number of units			
		110kV Cooler replacements	Specified number of units			
		110kV Bushings replacements	Specified number of units			
		110kV Plant Painting	Specified number of units			
		110kV Disconnector Refurbishment	Specified improvement at specified location(s)			
		110/33kV TX Tap changer refurbishment	Specified number of units			
T17	T17 275kV Overhead Line Asset Replacement	275kV Colour and Number Plates	Specified number of units	£9.0m	£6.5m	
		275kV Spacers	Specified number of units			
		275kV Suspension Insulator	Specified number of units			
		275kV Tension Insulator	Specified number of units			
		275kV Tower Painting	Specified number of units			
		Foundation assessment (towers)	N/A			
		Condition assessment	N/A			
		Vegetation	N/A			
T19	T19 110kV Overhead Line Asset Replacement	110kV Conductor replacement	Specified number of units	£9.4m	£6.8m	
		110kV Colour and Number Plates	Specified number of units			
		110kV Suspension Insulator	Specified number of units			
		110kV Tension Damper	Specified number of units			
		110kV Tension Insulator	Specified number of units			

Project	*Project name*	*Asset name/further information*	*Planned investment*	*Total cost basis*	*CC direct allowance*	*Comments*
		110kV Tower Painting 110kV Wood Poles replacement Foundation assessment Condition assessment Vegetation Management	Specified number of units Specified number of units N/A N/A N/A			
T20	T20 Transmission Cables	Requirements defined BPQ E1, p4, table 2 Refurbishment of cable tunnels & installation of permanent pumps Replacement of 110kV double circuit (2.6km) Replacement of Sheath Voltage Limiters Refurbishment cost of double circuit Donegal Main – Whitla Street Replacement of existing mineral oil with modern DDB fluid Refurbishment of 110kV sealing ends Refurbishment of hydraulic ancillary systems Sheath testing programme and refurbishment	As per BPQ Specified improvement at specified location(s) Specified number of units Specified improvement at specified location(s) Specified improvement at specified location(s) Specified number of units N/A Specified improvement at specified location(s) N/A	£4.7m	£4.5m	
T36	T36 Belfast North Main 110/33kV Bulk Supply Substation	110 transformers (110/33 kV)	Specified number of units	£1.6m	£1.5m	Only transmission load related project included
	ESQCR - Transmission	Full survey and asset register, additional reporting as outlined in Section 9	Reporting as per Section 9		£0.8m	Based on CC split T/D
T42	Substation Flooding Enforcement (T)	Permanent protection to at risk substations	Specified improvement at specified location(s)	£0.6m	£0.6m	
	Total Transmission investment				**£71.3m**	

Source: CC analysis.

Provisional allowances for transmission load-related projects

This appendix sets out those projects for which NIE may apply to the UR for funding under our D5 mechanism and for which we determined a provisional allowance. This list is not exhaustive: there may be other projects for which NIE may apply to the UR for funding in the same way.

Project	*Project name*	*Total cost, before RPEs and productivity £m*	*Direct cost, before RPEs and productivity £m*
T26	Ballyumford 110 kV switchboard replacement	15.3	14.5
T27	Airport Road 110/33 kV substation	4.0	3.8
T30	4th transformer at Castlereagh 275/110 kV substation	2.2	2.1
T31	Armagh Main 110/33 kV substation	2.0	1.9
T33	Castlereagh–Knock 110 kV partial cable replacement	1.6	1.5
T34	Tandragee 275 kV substation 2nd bus coupler	1.3	1.2
T38	Creagagh 110 kV substation isolators and earth switches	0.4	0.4
T39	Hannahstown & Kells 275 kV substation	0.2	0.2

Enduring Solution

Introduction

1. In this appendix we set out summaries of some of the submissions and supporting evidence provided by the UR (and its consultants, Gemserv) and NIE in relation to Enduring Solution.

Concerns over process

2. As noted in paragraph 10.187, both the UR and NIE expressed concerns about the processes followed in reaching the UR's final determination.

3. The UR highlighted revisions to cost estimates by NIE and concerns over the supporting information provided. The UR said:

> The information provided by NIE in relation to those costs was a cause of serious concern for us during the price control process, and we would welcome any further investigation that the Commission is able to conduct in this inquiry. NIE initially claimed the substantial sum of £22.4m. This increased to £29.4m in NIE's response to the draft determination after a number of other submissions for various cost categories. That is an unsatisfactory way to approach the setting of an allowance for such a substantial opex item.[1]

4. In contrast, NIE said that given the nature of the programme, it was inevitable that revisions to opex forecasts would be made as more information became available and that this had been explained to the UR. It submitted that its cost projections had been developed from a detailed, bottom-up analysis of the new processes and systems required, that the projections had been validated through activity analysis in the period since go-live and external best practice information had been used to confirm that the operating costs were being incurred in an efficient manner (for example, see paragraph 31).[2] NIE said that the costs that had been allowed were inadequate. It said that the UR had failed to demonstrate the basis on which it considered NIE's costs to be inefficient.[3] It also said the UR's lack of open and detailed engagement over the subsequent months significantly impacted its ability to understand properly the data provided by NIE.[4] It noted that it had not had sight of any of the Gemserv reports prior to the CC process.

5. NIE told us:

> NIE submits that it was unreasonable to expect it to present a fully detailed and evidenced submission of opex costs at an early stage of an extremely complex IT and business change programme. However, whatever the difficulties experienced in arriving at a final submission, these operating costs are being incurred efficiently as demonstrated by the IT market benchmark information referred to above and therefore should be fully recoverable. To date, the UR has failed to demonstrate

[1] UR Statement of Case, paragraph 18.
[2] NIE Statement of Case, paragraph 5.11, p126.
[3] NIE Supplementary Submission, Annex 3, paragraph 2.10.
[4] ibid, Annex 3, paragraph 2.9.

the basis upon which it considers these costs to be inefficient. The detailed rationale used and the benchmarking underpinning the disallowance has not been shared with NIE.[5]

UR and NIE submissions in relation to Enduring Solution cost categories

6. We now set out some material from submissions received from NIE and the UR (including Gemserv) in relation to three of the cost categories for Enduring Solution.

Applications Support Resources—SAP

7. NIE's Investment Case for Enduring Solution was submitted to the UR for approval in the late spring of 2010 and proposed the retention of the Oracle CC&B systems, then in use by both Power NI and NIE for the interim market systems. However, with the sale of NIE, plans changed to use SAP, which was the same platform used by ESB. The UR approved the commencement of delivery activities but, to safeguard the customers' interests, inserted several additional conditions in the approval letter sent to NIE.

8. NIE said it initially contemplated implementing an Oracle-based solution for Enduring Solution, as this represented, at the outset, the 'least risk' option to meet the target market-opening timescales. It said that although SAP IS-U provided more relevant distribution-related functionality as standard than the Oracle product (which is more targeted as a retail billing engine), Oracle was the technology already in place to support the interim Northern Ireland market arrangements and the appropriate skills and resources were available to NIE to deliver the project.[6] NIE said that an SAP IS-U solution was considered at that time but was rejected due to the quality of the bid and NIE's lack of confidence in the bidder's ability to deliver successfully within the required timescales rather than any concern about the product set.[7]

9. NIE said the acquisition of NIE by the ESB Group created the opportunity to access ESB Intellectual Property Rights in its SAP solution, as well as its experience and resources, which allowed NIE to implement a superior SAP solution within the expected timescales.[8] It said that it made the decision to switch to SAP because it was a better solution for the Northern Ireland retail market. NIE said that it had confidence in the ability of an SAP-based solution effectively to support the demands of the Northern Ireland market going forward because the SAP-based solution employed by ESB had been successfully supporting a similar market with high volumes of switching for a number of years. It said that it did not believe SAP increased support costs compared with an Oracle solution, as it considered it would have needed to take Oracle 'out of its comfort zone' as a retail billing engine to achieve similar functionality and this would have required greater support. It also said that a bidder for the Systems Integrator role which had submitted both CC&B (Oracle) and SAP-based bids had not indicated any difference in the ongoing support requirements for the different solutions.

10. In contrast, Gemserv noted that SAP-ISU systems had been discarded at two points before and during the open procurement process, suggesting that ESB had initiated the change. NIE said that at the time of the switch, NIE gave assurances to the UR that the project would be managed effectively and no additional risk would result for

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[5] ibid, Annex 3, paragraph 2.10.
[6] NIE Statement of Case, paragraph 5.22, p128.
[7] NIE Supplementary Submission, Annex 3, paragraph 4.26.
[8] ibid, Annex 3, paragraph 4.26.

the Northern Ireland customers. It said that the UR's additional conditions in the approval letter did not include any instruction to NIE that the change to SAP must result in a change to the procurement strategy with regard to ongoing operational support and the need to retender the existing services.[9]

11. In relation to Enduring Solution support and maintenance services, a Gemserv report stated that:

> At the start of the initiative the UR provided NIE with the high level regulatory requirements for the Enduring Solution project. One of those requirements was that the system selection should be based on the whole life costs and not just the capital costs. Ongoing operational costs were considered to be an important feature in any system selection process … During the summer of 2011, during the discussion on ITC Opex costs, the UR reminded NIE of their obligation to procure efficiently using a competitive selection processes. NIE indicated that the five year managed services contract met this condition and they had no intention of embarking on a further competitive procurement. … NIE have also stated on more than one occasion that their managed services contractor has the necessary skills to fully support the SAP IS-U systems … It would seem that eventually NIE realised that NMS would not, in isolation, be able to support the new arrangements and started to enter into negotiations with Wipro (the Systems Integrator) to provide SAP IS-U support alongside NMS. It is not clear to Gemserv how negotiations at this late stage could result in an efficient and competitive procurement.

12. It also stated:

> With hindsight Gemserv considers it debateable if NIE gave enough attention to the changes imposed by SAP on ultimate capital costs and on the five year managed services contract that had already been concluded with Northgate Managed Services. Gemserv believes the Oracle CC&B systems were already incorporated in the previous managed services contract but SAP IS-U requires a completely different skill set that was not previously required. This would lead Gemserv to the supposition that NIE would have never signed the existing managed services contract if SAP was then their preferred solution.

13. NIE told us that it had competitively tendered its managed service contract for a minimum five-year term in 2009. It said it was understood in that process that the new Enduring Solution services would be incorporated into the managed service contract via change control. It said that this was the most cost-effective and low-risk way to achieve the go-live date and support the market during the bedding-in period. It said that the managed service re-procurement in 2009 established a competitive resource cost base for use in future change control throughout the life of the agreement.[10] It said that due to the integrated nature of the Enduring Solution and NIE legacy applications, it was considered appropriate that one organization would continue to provide an end-to-end service, and that the service desk arrangements would best be delivered by one organization, whereas the introduction of a second major outsourced IT provider would give rise to additional costs and greater risk for the market as ownership of specific system issues could become blurred and

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[9] ibid, Annex 3, paragraph 4.23.
[10] NIE Statement of Case, paragraphs 5.40 & 5.41, p132.

restoration processes extended. NIE said that the introduction of a new technology suite to an ongoing managed service contract was common practice (and gave examples of where it had previously done this).[11] It said that it was not currently resourced to manage two ICT outsourced providers.[12]

14. NIE also told us that the contract with Capita meant that separately tendering for SAP support would require early termination of the entire contract with breakage charges. It said that the costs for just terminating these services were likely to include redundancy and pension costs for several staff as well as compensation to Capita for loss of profit and payment for exit management. It provisionally estimated the costs of early termination of this element of the contract at around £2 million.

15. NIE told us that Capita had considered various means to provide support for SAP, as it did not have suitable existing resources. Capita had expanded its own support team and retrained some of its staff. But it had decided that it would be most cost-effective to bring in additional resources from outside. Therefore Capita had contacted three organizations to provide resources (though not through a formal tender). NIE said the costs of each option were similar and Capita chose to take advantage of the experience of Wipro employees previously involved in the project by engaging Wipro as a subcontractor to provide resources in some key areas where specific skills were more difficult (and costly) to obtain.[13] NIE said it did not itself undertake any of these exercises; it had, however, signed off this agreement between Capita and Wipro and so was confident that the costs were reasonable.

16. In its resubmission of cost estimates dated 6 July 2012, NIE identified increased ICT support costs of approximately £3.75 million, including additional costs for the Wipro SAP applications support. Gemserv identified the breakdown as 'some cost reductions but also new cost lines of £4,330k for additional Wipro SAP applications support, an additional £383k for additional NMS SAP applications, additional software support costs of £303k and a further cost for basic operational support of £375k'.

17. Gemserv said:

> The new cost line for Wipro was not in the November 2011 submission and represents the majority of increased costs in the NIE July submission. The cost of £4,237k,[14] based on the NIE information, represents approximately 47 man years and, assuming 220 days are worked per annum, provides an average daily cost of £[✂]. For an offshore model this seems expensive based on 2009/10 prices and is substantially more than the Gemserv benchmarking carried out last year where the base year costs were calculated to be around £[✂] per day for a 60:40 onshore/offshore split. The Wipro team seem to be used as an extended, and nearly permanent, transitional support team. Gemserv can only conclude that the main underlying reason for this is NIE have had to negotiate with both organisations who have collectively, for different reasons, found themselves in strong negotiating position that could be described as predatory.

18. NIE said that while the contractual framework with Capita allowed it to gain access to additional offshore resources as required for future development projects, it did not

[11] NIE Supplementary Submission, Annex 3, paragraph 4.25.
[12] NIE Statement of Case, paragraph 5.44, p132.
[13] NIE Supplementary Submission, Annex 3, paragraph 4.14.
[14] NIE said that its submission figure was £4,327,000.

believe that significant offshoring of these support services was appropriate, particularly in the early days of operation. Therefore 50 per cent of the steady state Wipro resources were operating onshore. It said that the average daily rate for the Wipro team (onshore and offshore) was £[✂].[15]

19. The UR told us that Gemserv progressively reviewed and carried out an assessment of all the Enduring Solution material supplied to the UR by NIE including the 6 July 2012 submission. It said that the agreed approach between Gemserv and the UR was to review all new evidence against any previous opinions and conclusions; Gemserv did not change its original opinion with every subsequent change in the NIE cost projections unless the changes were supported by an objective rationale and were, in Gemserv opinion, justified. To ensure this approach and the related opinions would be balanced Gemserv did not recommend either reductions or additional allowances where there was inadequate supporting evidence to support the changes.

20. The breakdown of the allowance for SAP application support that was allowed in the UR's final determination, showing how this was adjusted from the provisional determination, and compared to NIE's submission, is set out in Table 1.

TABLE 1 **NIE's submission and the UR's final determination of SAP application support allowances**

£ million, 2009/10 prices

	2012/13	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*Total*
NIE submission for SAP Applications support (including market driven developments)	2.892	2.691	2.442	2.218	2.218	12.459
UR provisional determination	1.133	1.158	1.018	0.896	0.836	5.041
Additional SAP application support allowance	0.473	0.164	0.009	–0.130	–0.130	0.385
Adjustment to neutralize effect of RPI-X	0.050	0.101	0.151	0.202	0.252	0.756
Final determination	1.656	1.423	1.178	0.967	0.958	6.182
Additional term for market-driven developments	0.200	0.200	0.200	0.200	0.200	1.000
Total allowance in the UR's final determination	1.856	1.623	1.378	1.167	1.158	7.182

Source: CC based on data from NIE and the UR, and Gemserv report.

21. The UR said that Gemserv recommended an increase in the SAP IS-U support costs in its final report but not of the magnitude proposed by NIE. In assessing whether cost increases were justified it appears to have perceived the procurement process as flawed, with the consequence that projections did not reflect efficiently incurred costs. Gemserv said that while the increase in SAP application support costs was 59.5 per cent, the increase in resources proposed was less than 40 per cent overall. It said it did not manage to resolve this dichotomy and so treated this difference as being increases in day rates, whereas it only allowed additional costs where objectively justified.

22. However, the UR also said that rather than applying the same 1 per cent efficiency factor as was applied to business as usual opex, an additional sum of £0.756 million was added to offset this, because the assessment of support costs was considered challenging. It also allowed a revision to Capita's daily rate costs (worth £0.383 million).

23. The allowance also includes an additional term for market-driven developments. Gemserv said in its assessment the additional sum of £200,000 a year for variable work was based on changes to the systems based on new or changed requirements from the market. It assumed that these were approved by the UR and were additional

[15] NIE Supplementary Submission, Annex 3, paragraph 4.18.

to any capacity the new applications maintenance teams would have to support market-driven changes.

24. Gemserv continued to rely on its initial benchmarking work (undertaken before NIE revised and increased its cost estimates), and its conclusions table did not set out an explicit allowance for Wipro resources. It said:

> Gemserv believes it is reasonable to expect organisations such as NIE to procure expert resources efficiently and competitively. In the absence of a competitive tender process that tests the market, it is not possible to confirm the NIE ICT operational proposals are based on efficient and competitive cost and there is much evidence to support a conclusion that operational costs could be much lower than are presently projected.
>
> As requested by the UR, Gemserv's advice assumes a well considered competitively procured service and has used this information in the opinions and recommendations provided to date. We realise that this has to be somewhat subjective and accept there is always room for error in providing assurance advice in such complex situations. However, we believe the recommended costs in this report are achievable and could be further reduced in the long term by effective procurement processes and good expert management.

25. Gemserv, in its report to the UR, said to part compensate for not making any allowance for Wipro resources, it had not reduced its recommended costs lines where the revised NIE proposals were now below its July recommendations.

26. In that report, it briefly outlined its benchmarking of NIE's proposals. It acknowledged that the complexity of the SAP system would mean additional resources would be required over legacy systems.

27. Gemserv said that finding analogous SAP IS-U systems which could be used for benchmarking proved difficult. It carried out what it called some 'rudimentary' benchmarking exercise with the Enduring Solution Systems Integrator and a major large utility which used the system. Gemserv said that it also sourced some general opinion from experts in SAP environments regarding SAP support structures, off-shoring arrangements and how resources changed as systems matured. It concluded that NIE's initial manpower proposals were reasonable for the end of year 1. It assumed steady state conditions for 12 months with further resource reductions at the end of years 2, 3 and 4, as the systems and support team matured. It said that these projections excluded any transitional costs during the first year of operation, and it assumed that a lower-cost offshore support team would be used with the percentage of offshore resources being increased over the five-year period. Therefore it concluded that support costs would decline over the five years, in contrast to NIE's initial proposals. It also said it would expect a reduction in the overall numbers of resources over the five years as the systems matured. The annual reductions in resources and the offshore rates were the main reasons why Gemserv's recommendations in its benchmarking assessment were considerably lower than NIE's proposals in its initial submissions.

28. NIE said that its July 2012 submission accepted that SAP support costs would be expected to decline over time for efficiency reasons and it said its final estimates incorporated a 10 per cent cost reduction in the third and fourth years.

29. Gemserv also questioned whether any future changes and developments to the system would be applied by both ESB and NIE and so whether such costs would be shared, as they were both using similar SAP systems. The UR also noted that NIE would have to (and ESB might have to) re-procure their support services during the RP5 period. It said even allowing for licence restrictions, there were potential economies of scale along with many common changes that would be required by the market's single schema. NIE told us that the Enduring Solution costs included in its Statement of Case included all the savings to be achieved by the sharing of the system between NIE and ESB. It said that the only synergies related to the sharing of the TIBCO messaging system with ESB Networks; although both NIE and ESB Networks used SAP systems to support core market activities, they were very different applications supporting different market and business processes, and with very different IT support models in place.[16] It said that only 30 per cent of the NIE SAP IS-U implementation reused code developed by ESB. This relatively small reuse was due to the differences in legislation, market rules and business processes in place in Northern Ireland and the Republic of Ireland.[17] It said that NIE's purchase of SAP was separate from ESB's and so there had been no discount linked to the size of the combined group. However, NIE said that following the change to an SAP-based solution for NIE, the overall licence purchase costs for the project reduced by £1.26 million (when compared with the CC&B licence costs) and that this resulted in lower ongoing licence charges to NIE.

30. NIE expressed concern that a large proportion of its SAP support costs were disallowed on the basis of Gemserv's 'rudimentary' benchmarking exercise.[18] It also noted the initial headcount estimates (which had accorded with Gemserv's assessment) had been heavily caveated and later submissions, with greater staffing requirements (the SAP support number increased from 21 to 28 staff), had been updated on the basis of more information.

31. NIE said it had not itself benchmarked its opex costs because the applications support process had been competitively tendered. It said that it was not possible to undertake a simple benchmark to establish support team size. It had said (based on an initial attempt to undertake comparisons) in its October 2011 submission to the UR: 'Completely independent benchmark information for SAP IS-U is difficult to obtain as the technology is relatively limited in its customer base (when compared to generic SAP implementations) and the functionality implemented and the service provided varies enormously from one installation to the next.' NIE said that its initial attempt to undertake comparisons had identified support teams varying in size from 8 FTE to 75 FTE. NIE said that one relevant benchmark was that ongoing IT support costs would be around 20 per cent of the implementation costs of a project, and Gartner[19] benchmarking information suggested that numbers were often higher than that. It said that the number for Enduring Solution was around 13 per cent, giving comfort that these costs were efficient. It said that it was confident the resourcing behind those costs, and the rates being paid, were efficient. Gartner's opening statement in that paper was 'There is no "rule of thumb" to correlate the total cost of

[16] NIE also said that ESB used an internal corporate IT department to support and develop its SAP system while NIE used an outsourced managed service provider. It said that the European Commission's decision of 12 April 2013 in respect of the certification of the transmission arrangements in Northern Ireland under IME3 prohibited the provision of any corporate service (such as IT services) by ESB to NIE.
[17] NIE Supplementary Submission, Annex 3, paragraph 4.30.
[18] ibid, Annex 3, paragraph 4.8. It said that the use of such informal information was inappropriate to assess if NIE's SAP support costs were being incurred efficiently. It said that a proper benchmark was a detailed assessment of services, ensuring a like-for-like comparison which would give confidence that the benchmark was robust and had value and that its review of the various Gemserv reports identified no evidence that this was the case.
[19] Gartner research note: The Four Laws of Application Total Cost of Ownership, 3 April 2012. Gartner is an information technology research and advisory company.

ownership (TCO) for an application with the initial capital investment in the application.' However, NIE explained that Gartner's comment reflected that there could be a very wide range of total costs in relation to these projects and it said its projected (steady state) operating costs for Enduring Solution substantially beat Gartner's 'best case scenario' for future opex.

32. NIE also told us that its parent, ESB, had undertaken a recent IT benchmarking exercise with Gartner, which included SAP support services. The study identified that ESB Group's SAP support costs were 16 per cent lower than its peer group of companies and the projected NIE costs sit well within this framework of benchmarked costs.

33. NIE said that it had had no opportunity to review and comment upon Gemserv's benchmark data, and it was still unclear how Gemserv reached its conclusions with respect to appropriate support resourcing.

34. In its 28 November 2011 report Gemserv said the new applications software support should be market tested via a competitive procurement process as soon as possible. It said there would still be benefits in going out to tender soon after go live.

35. [✂][20]

36. NIE said that it was currently assuming that it would be able to hold its IT costs at the current level. It considered that incorporating SAP support in the overall managed services contract was the most cost-effective solution, for example there would be no additional corporate overheads or desktop support costs from having separate contracts. The UR, however, expressed concern at the delay in retendering given NIE's obligations to procure efficiently.

Outsourced business process staff

37. In its 28 November 2011 report on the impact of the Enduring Solution project on NIE's costs, Gemserv reviewed the number additional resources requested by NIE. It understood that the SAP systems were largely automated and so the BPO resources were required mainly to deal with queries and data inconsistencies.

38. On reviewing NIE's submission requesting cost recovery for 17 FTEs, Gemserv identified six of these as being temporary BPO resources previously identified (and approved to work with the interim system) as required to carry out the manual migration routines between the legacy systems when a change of supplier process took place. Gemserv said that with Enduring Solution, these manual transfers would no longer be required. NIE agreed that these staff would not need to be retained and so were dropped from the requests. However, it told us that the staff were in fact retained until December 2012 to deal with bedding-in issues.

39. In evaluating NIE's estimates, Gemserv said:

> it would be expected in a steady state situation that a new modern unified system would provide economies of scale and a reduction in the number of operators. As a counter to that improvement it could be argued that more market activity will impose a heavier work load and the sharing of the legacy system with Power NI had some implicit

[20] [✂]

> efficiencies. Inevitable in a business as usual situation the answer is somewhere in between.

Gemserv disallowed around £0.5 million of NIE's estimated costs, however, as noted by NIE,[21] no detailed rationale for the disallowance was provided. We note that Gemserv's recommendation assumes no reduction in costs over the five years.

Internal costs to support market processes

40. In its update report of July 2012, Gemserv reviewed its assessment of NIE's employee resource costs. Its original assessment had been set out in a 29 November 2011 paper. Gemserv had taken views on the requirements for additional staffing in relation to Enduring Solution, and in the update report it considered those resources currently employed that would continue to have a role to support ongoing operations. NIE noted that Gemserv had disallowed a total of seven FTEs, and it argued that Gemserv's evaluation was flawed because it failed to provide any robust analysis to support that opinion. It said that, in contrast, NIE's submission was based on a detailed resource model, developed specifically to assess the number of additional resources required.[22] It submitted that in the absence of a robust analysis supporting Gemserv's opinion, there were strong grounds to prefer NIE's reasoned submission as to its requirement for additional resources.[23]

41. Gemserv, in justification for its recommendation to reduce the number of existing staff, commented in relation to call centre staff:

> Gemserv does not believe that NIE, as a distribution business, has the role or responsibility to advise electricity customers on competitive market activities. Any telephone callers should therefore be referred to relevant organisations or websites. On this basis we cannot recommend the continuation of the DT funding for 3 FTEs.

42. The UR told us that there was a problem with people in Northern Ireland understanding that the distribution business was not the supplier. It said this confusion meant that resolving issues and complaints was confusing and could take longer. It said that in its view NIE should refer all such customer queries to the suppliers.

43. In response, regarding the need for call centre staff, NIE argued that it was not comparable with a typical GB DNO, given its role as common services provider to the Northern Ireland market. NIE's services extended to include meter reading, meter changes and data aggregation, activities all undertaken by suppliers in the GB market. It said that therefore it was reasonable to expect a volume of customer enquiries relating to these services that would be addressed by suppliers in the GB market. It said that it would be wrong for NIE, from the customer service point of view, to refer the customer back on every occasion to the supplier. It provided an example of meter works appointments where a supplier's view of NIE appointment information was not at a detailed enough level to allow it to respond to customer queries relating to appointments scheduled for the same day, and customers were therefore required to contact NIE. In relation to two metering electricians required to attend quickly to any SEM metering faults, Gemserv rejected these as such meters were normally reliable and any faults could be dealt with by other metering electricians without recourse to specialists. NIE told us that the requirement had been

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[21] NIE Statement of Case, paragraph 5.104, p142.
[22] NIE Supplementary Submission, Annex 3, paragraph 3.26.
[23] ibid, Annex 3, paragraph 3.27.

identified to service wholesale market requirements in 2007, had been approved by the UR and the requirement had not changed. In relation to three FTE staff employed to support Keypad change of supplier processes for interim systems, Gemserv determined that the costs should be discontinued on Enduring Solution going live as NIE did not provide any objective foundation for funding, given that its role would then be discontinued. However, it appears that NIE had accepted that these roles should not be funded.

RPEs and productivity

Introduction

1. This appendix is structured as follows. We provide:

   (a) a summary of the EU KLEMS data and reports on productivity which we considered;

   (b) additional data relating to our RPE estimate for:

      (i) labour;

      (ii) general materials;

      (iii) specialist materials;

      (iv) plant & equipment;

      (v) other; and

      (vi) overall RPE forecast; and

   (c) a summary of the evidence provided by the parties in this area.

Productivity

2. In this section we provide a summary of the EU KLEMS data and reports on productivity which we considered.

3. We considered that EU KLEMS was a useful source of information covering a long period, albeit that it has the disadvantage of ending in 2007 and being backward-looking. In considering this data we had regard to a number of sources which made extensive use of the EU KLEMS data set:

   (a) Ofgem's initial and final proposals for transmission and gas distribution (in 2012);[1]

   (b) Reckon's review of productivity and unit cost change for ORR (in 2011);[2]

   (c) First Economics report on productivity prepared for Northern Gas Networks (in 2011);[3] and

   (d) CEPA's report on efficiency, productivity and unit cost change for ORR (in 2012).[4]

[1] www.ofgem.gov.uk/ofgem-publications/53713/riio-t1-initial-proposals-nggt-and-nget-overview-2707212.pdf; and www.ofgem.gov.uk/ofgem-publications/53599/1riiot1fpoverviewdec12.pdf.
[2] Productivity and unit cost change in UK regulated network industries and other UK sectors: initial analysis for Network Rail's periodic review, May 2011: www.rail-reg.gov.uk/upload/pdf/reckon_200511.pdf.
[3] www.northerngasnetworks.co.uk/documents/a7.pdf.
[4] www.rail-reg.gov.uk/pr13/PDF/cepa-orr-om-productivity-over-cp5.pdf.

4. We noted that the result of any analysis using EU KLEMS data was sensitive to: the choice of value-added (VA) or gross output (GO) as a measure of total factor productivity (TFP); the time period chosen; and the choice of relevant industries.

5. The VA and GO methods of measuring industry output are different and therefore produce different results: VA measures gross output minus intermediate inputs; GO measures gross output. In our view both measures are useful, but neither measure perfectly captures the productivity changes that could be expected in a company's cost base.

6. GO is a closer approximation of a company's cost base. This is because it contains labour, capital and intermediate inputs (as a company's cost base does) rather than just labour and capital. However, the GO method is also acknowledged to be more prone to measurement errors[5] and is also impacted by changes in the vertical structure of industries.[6] Changes in GO have been systematically smaller than changes in VA.

7. The choice of time period is also an important influence on the results of any analysis. By way of example, Table 1 shows annual TFP using one measure (GO) for several different industry groupings over different time periods.

TABLE 1 **Average annual percentage growth rates in TFP (VA) in various sectors (EU KLEMS)**

UK sector	*1970–2007*	*1990–2007*
Electricity, gas and water supply	2.2	0.9
Sale, maintenance & repair of motor vehicles and retail sale of fuel	2.0	2.6
Transport and storage	2.1	1.7
Finance, insurance, real estate and business services	–0.9	0.3
Construction	0.7	0.6

Source: www.northerngasnetworks.co.uk/documents/a7.pdf, Table 4.1 using EU KLEMS data.

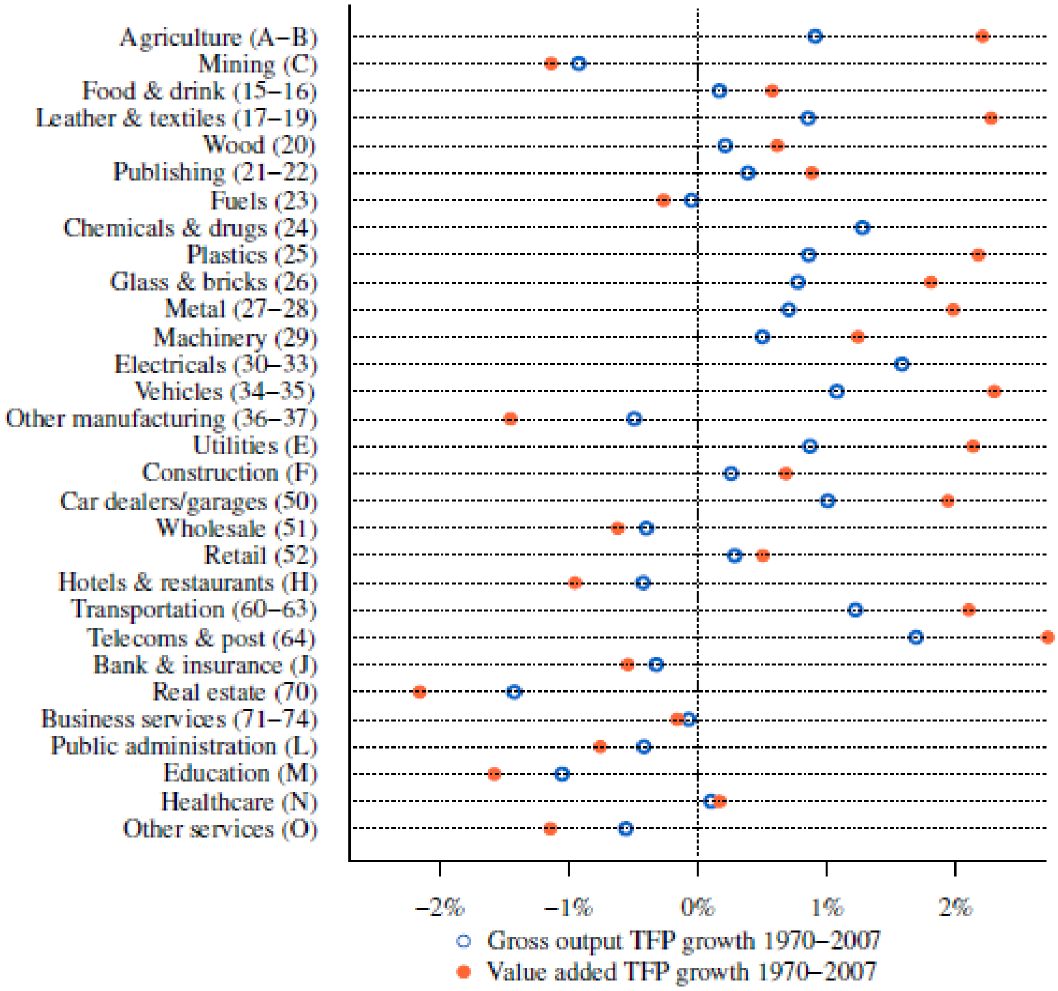
8. It can be seen from Table 1 that in some sectors the choice of time period will make a material difference to level of productivity. This also applies (although to a lesser extent) to the data at an aggregate level.

9. Figure 1 shows the annual TFP growth for different sectors for the period 1970 to 2007.

[5] As evidenced by the scale of the revisions—www.northerngasnetworks.co.uk/documents/a7.pdf.
[6] ie vertical separation or integration of industries.

FIGURE 1

TFP growth for different sectors of the UK economy, 1970 to 2007



Source: Reckon.

10. It can be seen from Figure 1 that, depending on the choice of sector and measure of TFP, a wide range of estimates for productivity is possible. In our judgement, the range of productivity implied by this data for NIE could be from less than 0.5 per cent to 2.0 per cent.[7]

Our RPE estimate

11. In this section we provide the underlying data relating to our RPE estimate.

Labour

12. Combining the historic estimate and the forward-looking estimate produces the labour RPEs shown in Table 2.

[7] For example: TFP (GO) construction is about 0.3 per cent; Utilities (VA) and Transportation (VA) are both close to 2.0 per cent.

TABLE 2 **Labour RPE, 2009/10 to September 2017**

	2010/11	*2011/12*	*2012/13*	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*6m to Sept 2017*
Labour inflation	3.3	3.3	3.3	2.0	2.8	3.7	4.3	2.2
RPI	4.5	5.4	3.2	2.6	3.0	3.5	3.5	2.5
Labour RPE	–1.2	–2.0	0.1	–0.6	–0.2	0.2	0.7	–0.3

Source: OBR/CC analysis.

Note: Figures may not sum due to rounding.

General materials

13. Table 3 shows our nominal estimate for general materials inflation.

TABLE 3 **BIS data on general materials costs**

per cent

	2010/11	*2011/12*	*2012/13*	*Average annual change 1996–2012*
Resource cost of building materials (non-housing) (NOCOS)	8.7	5.8	0.3	3.3
Resource cost of infrastructure materials (FOCOS)	8.6	7.7	1.7	5.1
Average	8.6	6.7	1.0	4.2

Source: BIS construction resource data.

Note: The Q12013 data point used for 2012/13 calculation is provisional.

14. Applying the average of the two data points and deducting RPI produces the general materials RPE shown below in Table 4.

TABLE 4 **General materials RPE, 2009/10 to September 2017**

	2010/11	*2011/12*	*2012/13*	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*6m to Sept 2017*
General materials	8.6	6.7	1.0	4.2	4.2	4.2	4.2	2.1
RPI	4.5	5.4	3.2	2.6	3.0	3.5	3.5	2.5
General materials RPE	3.9	1.3	-2.1	1.6	1.2	0.7	0.7	-0.4

Source: OBR/ONS/CC analysis.

Specialist materials

15. Table 5 shows our nominal estimate for specialist materials inflation.

TABLE 5 **ONS producer price inflation**

per cent

	2010/11	*2011/12*	*2012/13*	*Average annual change 1996–2012*
ONS: Electric motors, generators and transformers; electricity distribution and control equipment (JV6R)	1.5	–0.1	0.3	0.7
ONS: Electricity distribution and control apparatus (JV72)	5.2	4.8	2.1	2.0
ONS: Other electronic and electric wires and cables (K32F)	27.1	3.7	–4.9	4.9
ONS: Cold Drawn Wire (JV2C)	10.6	10.6	–5.4	5.0
BEAMA: Materials in electrical engineering	11.7	10.7	0.0	3.7
Average	11.2	5.9	-1.6	3.3

Source: ONS/CC analysis.

16. Applying the average of the four data series and deducting RPI produces the specialist materials RPE shown in Table 6.

TABLE 6 **Specialist materials RPE, 2009/10 to September 2017**

	2010/11	*2011/12*	*2012/13*	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*6m to Sept 2017*
Specialist materials	11.2	5.9	-1.6	3.3	3.3	3.3	3.3	1.6
RPI	4.5	5.4	3.2	2.6	3.0	3.5	3.5	2.5
Specialist materials RPE	6.4	0.5	–4.6	0.7	0.2	–0.2	–0.2	–0.9

Source: OBR/ONS/CC analysis.

Plant & equipment

17. Table 7 shows our nominal estimate for plant and equipment inflation.

TABLE 7 **ONS producer price inflation**

per cent

	2010/11	*2011/12*	*2012/13*	*Average annual change 1996–2012*
ONS: Machinery and equipment output PPI	1.1	3.2	1.5	1.8
BCIS: Plant and Road Vehicles (90/2)	1.9	1.9	0.9	2.9
Average	1.5	2.6	1.2	2.4

Source: ONS/BCIS/CC analysis.

18. Applying the average of the two data series and deducting RPI produces the general materials RPE shown in Table 8.

TABLE 8 **Plant & equipment RPE, 2009/10 to September 2017**

	2010/11	*2011/12*	*2012/13*	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*6m to Sept 2017*
Plant & equipment	1.5	2.6	1.2	2.4	2.4	2.4	2.4	1.2
RPI	4.5	5.4	3.2	2.6	3.0	3.5	3.5	2.5
Plant & equipment RPE	–2.9	–2.7	–2.0	–0.2	–0.6	–1.1	–1.1	–1.3

Source: OBR/ONS/CC analysis.

Other

19. In response to our provisional determination, the UR said that we should split out IT weightings from this category to reflect NIE's considerable future spend in this area.[8]

20. In our view there are likely to be elements of this category which exhibit rate of inflation which are both above and below RPI. We therefore decided to continue to assume that this category of input inflation would, on average, be the same as RPI over the period.

Summary of our RPE estimate

21. Putting together the RPEs for each of the input categories discussed above, together with the input weightings for capex and opex, results in the overall level of RPE over the period shown in Table 9.

TABLE 9 **RPE, 2009/10 to 2016/17**

	Capex weight %	*Opex weight %*	*2010/11*	*2011/12*	*2012/13*	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*6m to Sept 2017*
Labour RPE	53	77	–1.2	–2.0	0.1	–0.6	–0.2	0.2	0.7	–0.3
General materials RPE	12	8	3.9	1.3	–2.1	1.6	1.2	0.7	0.7	–0.4
Specialist materials RPE	19	0	6.4	0.5	–4.6	0.7	0.2	–0.2	–0.2	–0.9
Plant & equipment RPE	6	0	–2.9	–2.7	–2.0	–0.2	–0.6	–1.1	–1.1	–1.3
Other RPE	11	15	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Overall capex RPE			0.8	–1.0	–1.2	0.0	0.1	0.1	0.4	–0.4
Overall opex RPE			N/A	N/A	–0.1	–0.3	0.0	0.2	0.6	–0.2

Source: CC analysis.

N/A = not applicable.

Summary of the evidence provided by the parties

Calculating RPEs

22. In its final determination the UR took the following steps to calculate RPEs:

(a) measure RPI in the years 2010/11 and 2011/12 and make a forecast for the period 2012/13 to 2016/17;

(b) measure inflation for inputs:

(i) for the historic years 2010/11 and 2011/12 (for labour RPEs out-turn data is also available for 2012/13); and

[8] UR response to the provisional determination, paragraphs 101–103.

(ii) by making an estimate for the forecast period 2012/13 to 2016/17 for each input;

(c) calculate RPEs for individual inputs (comparing input inflation to RPI);

(d) determine input weights, including:

(i) the relative weight of labour and different material inputs; and

(ii) the relative weights of the components of labour and materials;

(e) calculate a weighted average RPE for opex and capex using *(c)* and *(d)*; and

(f) apply to NIE's cost base.[9]

The UR's final determination and position on productivity

23. The UR's decisions on productivity incorporated the application of a 1 per cent a year cumulative improvement to controllable opex. The UR said that this was applied to the RP5 charge control period only and its application to the 'historic forecast' period (between the 2009/10 baseline and March 2012) was a notable omission from the final decision, excluding two years' potential for productivity improvement in 2010/11 and 2011/12.

24. Further, the UR's final decision applied no ongoing productivity forecast to capex, neither in the 'historic' nor 'forward-looking' periods, despite the sizeable and material additional capex examined in RP5.[10]

The UR's final determination and position on RPEs (including recent precedent)

25. In this section we summarize the UR's decision on RPEs.

26. In its analysis, the UR followed Ofgem's approach, including weights for labour and materials.[11] The UR allowed £0.6 million for capex RPEs and –£3.3 million for opex RPEs. This was significantly less than the amount which NIE had requested (£58 million for capex RPEs and £8.8 million for opex RPEs).[12]

27. The key reason for this difference between the UR and NIE is with regard to the real price of labour and construction during the period from 2009/10 to 2011/12 (that is, for the years to March 2010/11 and March 2011/12).

28. The UR commissioned First Economics to produce a forecast of electricity industry RPEs for the price control period as well as a backcast for the period from 2009/10 to 2011/12.

29. For this forecast First Economics used OBR projections for general wage inflation (with a premium added to this for specialist labour) and for other inputs it allowed for a gradual return following the effects of recession, to what it judged to be 'equilibrium'

[9] www.competition-commission.org.uk/assets/competitioncommission/docs/2013/northern-ireland-electricity-price-determination/130510_nie_statement_of_case.pdf, Ch 8, paragraph 3.27.
[10] ibid.
[11] www.uregni.gov.uk/publications/rp5_final_determination_main_paper, paragraphs 5.49 & 6.40.
[12] ibid, paragraphs 5.48 & 6.39; UR Statement of Case, paragraph 16.

levels of cost inflation. For its backcast it used ONS average weekly earnings for general labour and series of indices for specialist labour and equipment.[13]

30. Table 10 shows the RPE estimates for the forecast period 2012/13 to 2016/17 and Table 11 shows the backcast RPE estimates for the years 2010/11 and 2011/12.

TABLE 10 **First Economics RPEs used by the UR**

	2012/13	*2013/14*	*2014/15*	*2015/16*	*2016/17*
Labour—general	–0.5	1.3	1.5	0.7	0.6
Labour—specialist	0.75	2.55	2.75	1.95	1.85
Materials—general	–0.9	1.3	1.6	0.7	0.5
Materials—electrical	–0.9	1.8	2.1	1.2	1.0
Plant & equipment	–0.9	0.8	1.1	0.2	0.0
RPI used* (%)	2.9	2.2	2.9	3.8	4.0

Source: The UR.

*OBR forecast is March 2012.
Note: RPI forecast is that from the OBR forecast from March 2012.

TABLE 11 **First Economics backcast RPEs used by the UR**

	2010/11	*2011/12*
Labour—general	–3.4	–2.8
Labour—specialist	–1.6	–3.4
Materials—general	1.5	2.5
Materials—electrical	6.7	5.9
Plant & equipment	–3.2	–3.1
RPI (actual) (%)	5.0	4.8

Source: The UR.

Note: Chosen indices used are:
General wages—ONS, average weekly earnings (including bonuses).
Specialist wages—BEAMA, electrical engineering labour cost index.
General materials—BCIS, resource cost of infrastructure materials cost index.
Specialist materials—BEAMA, basic electrical materials index.
Plant & equipment—BCIS, plant and road vehicles cost index.

31. First Economics prepared a subsequent additional paper on RPEs and productivity. Its view was that RPEs should be considered in conjunction with productivity. It said that estimates of RPEs varied according to sector-specific factors and/or the economic outlook at the time of the regulators' determinations, and that it was noticeable that regulators' estimates of forecast RPEs have declined markedly since 2010.

32. First Economics said that when conducting this analysis the focus should be on RPEs affecting the frontier firm and the productivity improvement that the frontier firm could achieve. In its view it was not necessary to investigate NIE's company-specific input mix or NIE's company-specific wage pressures, materials price pressures because such analysis focused on the wrong entity (ie NIE rather than the frontier firm).

33. First Economics highlighted the recent RPE and productivity decision by Ofgem with regard to Gas Distribution Networks (GDNs) and Transmission owners/operators. Table 12 shows the results of this decision.

[13] ibid.

TABLE 12 **Ofgem's final RPE and productivity proposals for GDNs and Transmission owners/operators**

per cent

	Opex	*Capex*	*Totex*
GDNs	0.4	0.5	0.5
NGET TO	0.5	0.8	0.8
NGGT TO	0.6	0.4	0.4
NGET SO	0.4	0	0.3
NGGT SO	0.4	0	0.2
Productivity assumption	1.0	0.7	

Source: www.ofgem.gov.uk/ofgem-publications/48159/5riiogd1fprpedec12.pdf, Table 1.1 and Chapter 3.

Note: NGET = National Grid Electricity Transmission; NGGT = National Grid Gas Transmission; SO = System operator; TO = Transmission owner; Totex = Total expenditure.

34. It also highlighted a number of regulatory decisions on RPEs and productivity, which are summarized in Table 13.

TABLE 13 **Opex and capex RPE/productivity assumptions in other price control reviews**

per cent

	RPE	*Productivity*	*'Frontier shift'*
Opex			
UR—Water and sewerage	RPI+0.7	–0.9	RPI–0.2
PPP Arbiter—underground	RPI+1.5	–0.7	RPI+0.8
infracos, central costs		–0.9	RPI+0.3
PPP Arbiter—underground infracos, opex	RPI+1.2		
Ofgem—DNOs	RPI+1.4	–1.0	RPI+0.4
ORR—Network Rail, opex	RPI+1.4	–0.2	RPI+1.2
ORR—Network Rail, maint	RPI+1.3	–0.7	RPI+0.6
Capex			
PPP Arbiter—underground infracos	RPI+1.2	–1.2	RPI+0
Ofgem—electricity distribution	RPI+1.1	–1.0	RPI+0.1
ORR—Network Rail	RPI+0.7	–0.7	RPI+0

Source: The UR.

Notes:
1. UR's Water and Sewerage determination relates to 2012.
2. PPP Arbiter's decision for underground infrastructure companies (infracos) relates to 2010.
3. Ofgem's decision for DNOs relates to 2009.
4. ORR's decision for Network Rail relates to 2008.

35. First Economics said that there were clear similarities in the judgements that had been made with regard to the ongoing productivity side of the analysis. This apparent consensus around the expected rate of productivity improvement for a mature network business is 1 per cent a year.

36. For completeness, we would note that in Bristol Water the CC decided on an opex RPE of 0.4 per cent a year and a productivity assumption of 0.9 per cent a year which resulted in a combined 'efficiency challenge' relative to RPI of 0.5 per cent a year.

NIE submission

37. NIE's updated assessment of RPE's for RP5 was £47.9 million, comprising £37.5 million in capex and £10.4 million in opex. It had previously estimated RPEs at £66.8 million.[14]

38. NIE said that there were three key areas where it disagreed with the UR's assumptions:

   (a) In respect of labour RPEs in 2010/11 to 2011/12 (and 2012/13, for which out-turn information was now available). The impact of this was £39.1 million.

   (b) The choice of material weights in capex. The impact of this was £7.1 million.

   (c) The proportion of NIE's workforce that the UR regarded as general, rather than specialist. The impact of this was £5.1 million.[15]

39. In addition it said that:

   (a) a new EU directive for transformer performance would give rise to an additional price-related cost increase for which £5.0 million was necessary (this was included in its overall updated RPE of £47.9 million);

   (b) updating for the latest Office for Budget Responsibility (OBR) forecasts reduced NIE's request by £9.6 million. It now used OBR forecasts for December 2012 forecasts rather than March 2012 (note: new forecasts for March 2013 are now available); and

   (c) it did not accept the overall scale of opex and capex feeding into the calculation.[16]

NIE's view on RPEs

40. Table 14 shows NIE's view on RPEs. The emboldened figures show where NIE disagrees with the view taken by the UR.

TABLE 14 **NIE view on RPEs highlighting areas of dispute**

	Capex weight	*Opex weight*	*2010/11*	*2011/12*	*2012/13*	*2013/14*	*2014/15*	*2015/16*	*2016/17*
Labour—general	**19.7**	**23.3**	**0.55**	**1.24**	**1.82**	–0.6	0.2	0.7	0.5
Labour—specialist	**33.1**	**54.0**	**0.55**	**1.24**	**1.82**	0.6	1.4	1.9	1.7
Materials—general	**11.6**	7.7	1.5	2.5	–1.1	0.7	1.7	1.3	1.0
Materials—specialist	**18.6**	0	6.7	5.9	–1.1	1.1	2.1	1.8	1.5
Plant & equipment	**5.9**	0	–3.2	–3.1	–1.1	0.2	1.2	0.8	0.8
Other	**11.0**	15.0	0	0	0	0	0	0	0
Capex RPEs (%)			1.5	1.9	0.6	0.4	1.2	1.3	1.1
Opex RPEs (%)			0.5	1.1	1.3	0.3	1.0	1.3	1.1

Source: www.competition-commission.org.uk/assets/competitioncommission/docs/2013/northern-ireland-electricity-price-determination/130510_nie_statement_of_case.pdf, p218.

[14] www.competition-commission.org.uk/assets/competitioncommission/docs/2013/northern-ireland-electricity-price-determination/130510_nie_statement_of_case.pdf, Ch 8, p211.
[15] ibid, Ch 8, p211 & paragraph 2.4.
[16] ibid, Ch 8, p211 & paragraph 2.5. The updated OBR forecast is December 2012. The previously used forecast was March 2012.

41. We consider below each of the areas in which NIE disputes the UR's RPEs.

Labour RPEs in 2010/11 to 2012/13

42. NIE said that it disagreed with the UR's assumptions in respect of labour RPEs from 2010/11 to 2012/13. The differences are summarized in Table 15.

TABLE 15 **Labour RPEs, 2010/11 to 2012/13**

			per cent
	2010/11	*2011/12*	*2012/13*
UR view			
Labour—general	–3.4	–2.8	–0.5
Labour—specialist	–1.6	–3.4	0.8
NIE view			
Labour—general and specialist	0.55	1.24	1.82

Source: www.competition-commission.org.uk/assets/competitioncommission/docs/2013/northern-ireland-electricity-price-determination/130510_nie_statement_of_case.pdf, p218.

43. NIE said that it did not benefit from the real wage reductions in the general economy. Rather, it experienced the above-inflation wage settlements, which can be seen in Table 16.

TABLE 16 **Labour RPEs, 2010/11 to 2012/13**

					per cent
	NIE settlement	*Other increases (grade progression)*	*Total nominal pay*	*RPI (ex post)*	*RPE*
2010/11	[✂]	[✂]	[✂]	5.0	[✂]
2011/12	[✂]	[✂]	[✂]	4.8	[✂]
2012/13	[✂]	[✂]	[✂]	3.1	[✂]

Source: www.competition-commission.org.uk/assets/competitioncommission/docs/2013/northern-ireland-electricity-price-determination/130510_nie_statement_of_case.pdf, p218.

44. NIE said that its settlements had been appropriate, necessary and efficient. They also needed to be considered in light of terms and conditions which it considered to be market leading.[17]

45. It said that in negotiating its pay settlements it was mindful of wider developments in the renewable sector and the electricity networks industry. The increases in expenditure in these sectors had created strong demand for skilled and experienced electrical engineers which NIE was not immune from. For example, the number of people leaving to take up employment in the UK had trebled and GB TSOs and DNOs were recruiting aggressively.[18]

46. Table 17 shows NIE pay settlements compared with an average of GB peers.

[17] ibid, Ch 8, paragraphs 3.5–3.7.
[18] ibid, Ch 8, paragraphs 3.8 & 3.24.

TABLE 17 **Nominal labour cost increases compared with GB peers**

	Years				*per cent*
	6	*5*	*4*	*3*	*2*
NIE weighted average	[✂]	[✂]	[✂]	[✂]	[✂]
GB average	[✂]	[✂]	[✂]	[✂]	[✂]
Difference	[✂]	[✂]	[✂]	[✂]	[✂]

Source: www.competition-commission.org.uk/assets/competitioncommission/docs/2013/northern-ireland-electricity-price-determination/130510_nie_statement_of_case.pdf, p222.

47. NIE said that its pay settlements had differed only slightly from GB peer settlements and that the recent rises needed to be seen in the context of the pay freeze for all staff it implemented in 2009.[19]

48. It said that despite the real increases in labour costs, its salaries were competitive within benchmarks for comparable roles across the sector. This was supported by a comparison of NIE average pay for roles with Croner, IDS and XpertHR averages as well as NIE's own benchmarking.[20]

49. In NIE's view, netting off past wage reductions that did not have any impact on its cost base was unreasonable and it considered that setting RPEs at levels which reflected its actual experience over 2010/11 to 2012/13 was appropriate.[21]

Capex material weights

50. Table 18 shows how NIE's view of the appropriate materials weighting for capex differs from the UR's view.

TABLE 18 **Material weights for capex**

		per cent
	UR view	*NIE view*
General materials	10.0	11.6
Electrical materials	9.7	18.6
Plant & equipment	6.3	5.9
Total	26.0	36.2

Source: www.competition-commission.org.uk/assets/competitioncommission/docs/2013/northern-ireland-electricity-price-determination/130510_nie_statement_of_case.pdf, p226.

51. NIE said that the UR had chosen to use the estimates made by Ofgem for DPCR5. In its view this was unreasonable because:

(a) NIE was also the transmission owner (unlike GB DNOs) so its materials weight would be higher.

(b) NIE regulatory accounting rules were different from those that applied in GB and the UR had not verified whether the splits derived from GB cost estimates were applicable.

[19] ibid, Ch 8, paragraphs 3.13–3.16.
[20] ibid, Ch 8, paragraphs 3.21 & 3.22, Table 8.8.
[21] ibid, Ch 8, paragraph 3.27.

(c) The UR had used a simple arithmetic average of Ofgem's weights for different categories of cost when a weighted average, reflecting the size of each category, would be more appropriate.[22]

52. NIE said that its estimate of the material content of its capex proposals was a verifiable fact. It had analysed data on its last three years' capex spend to form its view on the relevant materials weights.[23] It had also determined that during this period 52.8 per cent of capex spend was for labour. For opex it accepted the UR's assessment of aggregate spend allocated to labour.[24]

53. In its view, these estimated input weights should be used to derive a more accurate estimate of the necessary level of RPE funding.[25]

Labour weights

54. Table 19 shows NIE's view on the appropriate weights for general/specialist labour compared with those used by the UR.

TABLE 19 **Weights for general and specialist labour**

per cent

	UR view		*NIE view*	
	Capex	*Opex*	*Capex*	*Opex*
General labour	57	67	37	30
Specialist labour	44	33	63	70
Total	100	100	100	100

Source: www.competition-commission.org.uk/assets/competitioncommission/docs/2013/northern-ireland-electricity-price-determination/130510_nie_statement_of_case.pdf, p228.

55. NIE said that the UR's labour weights had been informed by Ofgem's decisions in DPCR5. Its weights had been derived following a detailed review of its own employees and an assessment of the labour contained in its agreements with subcontractors. The UR had underestimated the mix of specialist labour because:

(a) It had not taken account of NIE's operating model which it had been necessary to adopt to efficiently serve a sparsely populated region (more employees needed to be able to work without supervision, leading to a higher percentage of skilled staff).

(b) It had not evaluated the up-skilling model adopted by NIE in order to reduce its workforce significantly.

(c) It had not assessed whether a recruit from the general labour market would be an adequate substitute for an existing member of its workforce (NIE needed to invest significantly in order to bring the skills of new recruits up to an acceptable level).[26]

[22] ibid, Ch 8, paragraph 4.5.
[23] ibid, Ch 8, paragraph 4.8.
[24] ibid, Ch 8, paragraph 4.9.
[25] ibid, Ch 8, paragraph 4.10.
[26] ibid, Ch 8, paragraphs 5.4–5.13.

56. NIE said that it considered that specialist labour included managerial, professional engineering and technical staff, as well as a majority of its craftspersons and specialist administrative staff as each of these would receive years of bespoke training and could not be replaced without significant cost.[27]

The UR's supplementary submission

57. In its supplementary submission, the UR said that it was common ground that *(a)* real labour costs in the economy were falling; but that *(b)* NIE's real labour costs did not fall. The UR said that its position was that opex and capex allowances should increase by no more than the cost of inflation that an efficient company would have experienced during these three years. To do otherwise would negate the purpose of the separate benchmarking of NIE's costs and of requiring it to eliminate the efficiency gap between its own costs and the efficiency frontier at the start of RP5. This effect alone (labour RPEs 2010/11 to 2012/13) accounted for £39.1 million (77 per cent) of the gap between the UR's determination on this issue and NIE's submission.[28]

58. In the UR's view, rather than focus on its own costs—past and future—NIE should have been concerned with estimating the RPEs for a frontier firm. It could not therefore legitimately claim monies from customers to pay for above-market pay increases between 2010/11 and 2012/13, nor could it atypically deem vast quantities of its workforce to be 'specialist labour', commanding premium pay increases.[29]

NIE supplementary submission

59. NIE said that it maintained that the ongoing productivity target should be considered jointly with RPEs and that it was standard GB regulatory practice to do so.[30]

60. NIE said that it considered that there was strong evidence to demonstrate that the effect of RPEs would exceed future productivity savings. This was evident from the recent regulatory settlements summarized by First Economics and also emerged as a trend in the draft business plans presently made available by the GB DNOs as part of the RIIO-ED1 review.[31]

61. It said that no justification had been provided to support the UR's assumption that 1 per cent productivity for opex was reasonable.[32]

62. NIE said that Ofgem was currently undertaking its ED1 price control for the GB DNOs and two of the GB DBOs had published relevant information on RPEs and efficiency assumptions:

    (a) WPD was projecting a net uplift of about 2.85 per cent for RPEs net of productivity over the eight-year period of the price control. Within this it had assumed an annual productivity of 1 per cent a year.

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[27] ibid, Ch 8, paragraph 5.15.
[28] www.competition-commission.org.uk/assets/competitioncommission/docs/2013/northern-ireland-electricity-price-determination/130530_ur_supplementary_submission.pdf, paragraph 17.
[29] ibid, paragraph 36.
[30] www.competition-commission.org.uk/assets/competitioncommission/docs/2013/northern-ireland-electricity-price-determination/130620_northern_ireland_electricity_supplementary_submission.pdf, paragraph 3.47, & Annex 6, paragraph 2.5.
[31] ibid, paragraph 3.47.
[32] ibid, Annex 6, paragraph 2.4.

(b) UKPN was projecting a net uplift of approximately 2.8 per cent over the eight-year price control with annual RPEs of 1 per cent for network investment and 1.2 per cent for operational activities. Productivity gains offset, in part, the effect of these RPEs.[33]

63. NIE said that it was Ofgem's practice to apply productivity from the base year (ie to 2010/11 to 2011/12) as well as to the charge control. It was also Ofgem's practice to apply a productivity target to capex. In its view, if such a target was applied to capex it should be smaller in scale than the target applied to capex, given the challenging nature of NIE's capex programme.[34]

64. NIE said that in respect of input weights, there were obvious difficulties with adopting First Economics' prescription that it should analyse the input structure of a notional, frontier firm, since this would require a real or hypothetical firm with known input structure to be found and analysed. A more practical solution would be to assess the reasonableness of NIE's input mix, in the light of its service region and its role as combined transmission and distribution operator and then to use that as a basis for estimating RPEs going forward.[35]

Additional points raised at the hearings (9/10 July 2013)

65. In this section, we summarize the additional points made by each party at the hearings (ie those points which had not previously been raised by the parties in their other submissions).

The UR

66. The UR told us that it had been a mistake not to apply a productivity assumption annually from 2009/10 onwards in respect of both opex and capex. In its view, we should apply its productivity assumption from the 2009/10 base year and apply it to both capex and opex.

67. The UR told us that the forecast level of infrastructure investment was the main reason why a specialist labour premium might continue to apply in the future. It said that any productivity assumption should apply annually from the base year (2009/10) and that it looked like it was an error in the determination not to do that.

68. The UR said that a rule of thumb for opex productivity improvements would be 1 per cent productivity growth a year; for capex it might be something like 0.7 per cent. It also told us that RPEs should be updated to reflect the latest OBR forecasts.

NIE

69. NIE told us that productivity should be considered together with RPEs and that should be applied from 2009/10 onwards. It told us that a study which had been conducted for Ofgem suggested that productivity growth in the sector had slowed significantly in recent years. It also said that the 7 per cent efficiency benchmarking reduction to opex which the UR had applied concerned it more than the annual productivity assumption.

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[33] ibid, Annex 6, paragraph 2.12.
[34] ibid, Annex 6, paragraph 2.14.
[35] ibid, Annex 6, paragraph 3.10.

70. NIE told us that the productivity assumptions of the GB DNOs would be potentially informative evidence for us to draw upon, but that they might be being somewhat softer in the baseline level in order to be able to demonstrate an impressive level of ongoing productivity.

71. NIE said that it agreed with the methodology and assumptions used by First Economics to calculate RPEs, although it said that there would be a need to update some of the work.

72. With regard to labour, NIE explained that the utility industry was experiencing very different conditions from the rest of the economy, which was resulting in a demand pull on wages to attract people into the profession. It told us that significant training was required for new recruits, even if they were well qualified; it also told us that it was expecting to lose three times as many staff in RP5 compared with RP4 and referred us to the extensive information available on this matter in its Statement of Case appendix.

Pensions

1. This appendix sets out:

    (a) pensions treatment in RP4;

    (b) the UR's position on pensions in its final determination for RP5;

    (c) submission of Northern Ireland Electricity Pension Scheme;

    (d) the UR's submission to the CC on pensions;

    (e) NIE's submission to the CC on pensions;

    (f) the UR's response to NIE's submission;

    (g) NIE's supplementary submission;

    (h) additional points raised at the main party hearings;

    (i) the parties response to our Provisional Determination; and

    (j) pensions treatment by other regulators:

        (i) Ofgem;

        (ii) CC—Bristol Water;

        (iii) CC—Wholesale Broadband Access (WBA) appeal; and

        (iv) other.

Pensions treatment in RP4

2. In RP4, pension costs were treated as a separate category of operating costs and NIE's pension allowance was set through a rolling mechanism. This rolling mechanism differed from that used to create the opex allowance in that it was based on cash payments to the pension scheme rather than the costs accrued in any one year. This approach meant that the cost associated with pensions was not analysed by the UR, but an annual allowance was instead set using actual cash payments made in the preceding five years, rolled forward each year with RPI.[1]

3. In a given year, NIE's pension allowance was therefore set as equal to the actual cash pension contribution made five years ago, adjusted upwards for cumulative RPI inflation since that date.

4. RP4 used a 30:70 split between shareholders and customers for funding the liability associated with ERDCs, which the UR said was consistent with Ofgem's practice at the time.[2]

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[1] UR Statement of Case.
[2] ibid, paragraph 15.

5. As a result, an adjustment was made to NIE's pensions allowance to exclude 30 per cent of the portion of the cash contribution to the scheme which was related to ERDCs (this amounted to £225,000 in 2004/05 prices, adjusted upwards for RPI inflation).[3]

6. The pension allowance in any given year in RP4 was therefore equal to the cash costs incurred five years earlier in RP3, adjusted for RPI inflation and for ERDCs.

7. We note that in reality in RP4 there was a technical error which meant that the size of the ERDC reduction was substantially reduced. This error was not corrected for or clawed back in the UER's RP5 final determination.[4]

The UR's final determination on pensions in RP5

8. In this section we summarize the UR's final determination on pensions for RP5.

9. The UR proposed a different approach to pensions to that which it had taken in previous price controls. It also introduced a set of 'pension principles'. These were:

   (a) NIE can recover the efficient ongoing costs for employees who are members of both the DB and DC schemes.

   (b) NIE can recover deficit repair costs relating to the DB scheme which it cannot legally avoid.

   (c) Assuming the pension trustees comply with their legal obligations, there is little opportunity for NIE to achieve efficiencies in managing the DB scheme, other than closing it to new members.

   (d) Deficits that occur in any period may have been influenced by avoidable or inefficient actions in previous price control periods. To ensure that customers do not pay twice, it is important to take account of these effects.

   (e) Deficits should be based in the most recent formal actuarial valuation.[5]

Deficit recovery

10. The UR said that it would redetermine deficit recovery costs on the basis of the deficit at each triennial formal valuation (the next formal valuation being 31 March 2014), although it might be appropriate to bring this forward in some circumstances. Any pension revenue in the tariff related to deficit repair would therefore be adjusted (from October 2015 at the latest) to reflect the deficit as at the 31 March 2014 valuation. This would be done on an NPV-neutral basis.[6]

11. The UR said that this approach reduced the cash-flow risk to NIE and maintained consumer tariffs more in line with current costs.[7]

12. Although the UR proposed basing its deficit repair allowance on the most recent formal actuarial valuation, it decided to base the allowances for RP5 on the deficit

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[3] UR Licence Modifications for RP4, pp11 & 12.
[4] UR Statement of Case, fn 7.
[5] UR final determination, paragraph 7.7.
[6] ibid, paragraphs 7.29–7.30 & fn 28.
[7] ibid, paragraph 7.30.

amount quoted at the funding update of 31 March 2012 (£156.4 million) in order to reduce potential tariff volatility in the period following the next formal review.[8]

13. The UR said that a 15-year deficit recovery period was appropriate because its pension principles provided a strong covenant and was consistent with the period adopted by other regulators (Ofgem applied a 15-year recovery period in DPCR4/5). This period would apply from 31 March 2012 to 31 March 2027.[9]

The regulated fraction

14. The UR said that 99.26 per cent of the deficit would be attributed to NIE. This included NIE Ltd and NIE Powerteam Ltd and excluded Powerteam Electrical Services Ltd and Capital Pensions Management Ltd (see Figure 12.1).[10]

15. The UR said that it would ignore the effect of historical legally avoidable actions with the exception of ERDCs. It said that it would also ignore the effect of special or extra contributions the company had paid. This was to maintain consistency with the approach that had been adopted for RP4.[11]

16. With regard to the ERDCs, the UR said in its draft determination that the likely split of benefits from early retirement schemes (which created the ERDC liability) was 50:50 between consumers and the company. This was because the age profile of retirees was 50 to 60 and consumers would have therefore benefited anyway from reduced opex after ten years due to natural retirements occurring. Under an opex allowance, the company would keep the benefit for five years and then consumers would receive subsequent benefits. In this case, the consumers would benefit for five years, so the benefit share would be 50:50.[12]

17. In its final determination, the UR said that it had decided to continue to apply a 30 per cent disallowance for ERDCs (rather than 50 or 100 per cent) to remain consistent with RP4 and Ofgem precedent.[13]

18. However, the calculation methodology for this adjustment was revised to bring it into line with the methodology used by Ofgem.[14] The adjustment based on the deficit at 31 March 2012 amounted to –£41.2 million in total over 15 years and £14.7 million in RP5.

Ongoing costs

19. The UR said that its assessment of NIE's ongoing pension costs over a five-year period was £10.5 million, which amounted to £10 million when adjusted for a four-year nine-month price control.[15]

Summary

20. The UR said that its determination in RP5 essentially allocated the unavoidable risk of pension deficit costs to consumers rather than NIE T&D shareholders, with the

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[8] ibid, paragraphs 7.31 & 7.32.
[9] ibid, paragraphs 7.35 & 7.36.
[10] ibid, paragraphs 7.37–7.44.
[11] ibid, paragraphs 7.45–7.49.
[12] UR draft determination, paragraph 11.68.
[13] UR final determination. paragraphs 7.52 & 7.53.
[14] ibid, paragraph 7.25.
[15] ibid, paragraph 7.54.

exception of a proportion of ERDCs. It said that this approach was now more consistent with the Ofgem approach (with the introduction of the 'true-up mechanism'). The adjustment for ERDCs was also consistent with what had been signalled in RP4.[16]

21. Table 1 summarizes the RP5 determination.

TABLE 1 **Summary of RP5 pension allowances, 2009/10 prices**

	Final determination (5 years)	*Final determination (4 years 9 months)*
Scheme deficit (£m)	156.4	156.4
Regulated fraction (%)	99.26	99.26
Recovery period (years)	15	15
Relevant NIE T&D deficit (£m)	155.2	155.2
Recovery in RP5 (£m)	63.1	58.4
Total ERDCs (£m)	–41.2	–41.2
ERDCs in RP5 (£m)	–15.2	–14.7
Deficit recovery in RP5 (£m)	**47.9**	**43.7**
Ongoing costs in RP5 (£m)	**10.5**	**10.0**

Source: UR final determination, Table 7.2, p72.

Submission of Northern Ireland Electricity Pension Scheme

22. Northern Ireland Electricity Pension Scheme (NIEPS) said that it agreed with the UR's RP5 pensions principles, which considerably removed uncertainties that had previously existed. It asked the CC to confirm and build on these principles. Regarding the final determination, it said that:

(a) not allowing NIE to recover its RP4 costs fully would result in a weaker sponsor covenant and more difficult negotiations regarding deficit repair going forward;

(b) NIEPS supported NIE's position in respect of ERDCs and previous shareholder contributions;

(c) there should be a mechanism to allow NIE to recover any overpayments on an NPV-neutral basis; and

(d) any materially adverse impact on NIE's covenant strength would cause it to take a more prudent view of managing the scheme's risk.[17]

The UR's submission on pensions

23. In this section we summarize the main additional points made on pensions in the UR's initial and subsequent submissions to the CC.

24. The UR said that the CC should give fresh consideration to the appropriate allocation of costs between shareholders and consumers in respect of ERDCs.[18] This was because:

(a) The 30:70 split was adopted for RP4 on the basis that the five years of benefit that a company could take from opex efficiency savings equated to around 30 per

[16] ibid, paragraph 7.55.
[17] NIEPS initial submission.
[18] UR Statement of Case, paragraph 18.

cent of the net present value of the perpetual cost saving that the business enjoys under the RPI–X system of regulation.

(b) However, in the case of early retirement, because the age profile of NIE's early retirees was approximately 50 to 60 years, it could be said that the average efficiency saving lasted no more than ten years in total (ie before the retiring employee would have left the workforce naturally). It follows that customers might have received no more than five years or 50 per cent of the total of the approximately ten years of benefit arising from NIE's early retirements.

(c) In principle, customers should therefore bear no more than 50 per cent of the costs of meeting early retirement liabilities.[19]

25. The UR said that it did not follow this approach (a 50:50 split) in its final determination because it wanted to maintain continuity with the approach that it had taken in RP4.[20] However, it thought that the CC might reasonably come to a different view and invited the CC to look at this matter closely as part of its inquiry.

26. The UR said that NIE had indicated that it could accept a period of 15 years, so long as it was allowed to earn its allowed regulatory rate of return on the cost of capital on the excess contributions made by it in meeting its obligation to repair the deficit in the shorter period of 11 years. It said that this would produce an artificial profit for NIE. It considered that the approach it took in the final determination, using the scheme's own discount rate (2.08 per cent real) to produce the profile of contribution allowances over 15 years, was appropriate.[21]

27. The UR also said that its proposed approach (other than for RP5) was to base the ex ante pension revenue allowance on the deficit value at the most recent triennial review. In order to reduce cash-flow risk even further, it had proposed that the pension revenue allowed should be adjusted during the price control period to reflect the deficit valuation at any triennial review that occurred during the price control period. It said that this proposal significantly reduced the risk that NIE faced with respect to its pensions obligations.[22]

NIE's submission on pensions

28. In this section we summarize the main points on pensions submitted by NIE.

29. NIE said that since pension costs were not within the control of NIE, the appropriate regulatory treatment was cost pass-through.[23] It agreed with the principles introduced by the UR in RP5. However, it said that it had two significant concerns about the RP5 determination:

(a) the UR had not provided for £24 million of stranded pension costs which had occurred due to contributions it had paid in RP4 which were in excess of allowances; and

[19] ibid, paragraph 18.
[20] ibid, paragraph 18.
[21] ibid, paragraph 21.
[22] ibid, paragraph 23.
[23] NIE Statement of Case, Chapter 10, paragraph 3.6.

(b) the UR had not recognized the special shareholder contributions made in 2005/06 and 2006/07. These reduced the deficit by £71.4 million and more than offset its share of ERDCs.[24]

30. NIE also said that there was a requirement to 'true up' for timing differences in respect of actual contributions paid by NIE under the deficit repair plan compared with the amounts allowed under the price control.[25]

31. We summarize each of the points raised below.

Stranded pension costs

32. NIE said that if the UR had adopted the same mechanism in RP5 as in RP4, then it would recover all its relevant costs with a five-year time lag. NIE would bear financing costs beyond RPI (or vice versa if costs were falling). It said that it took comfort that it would recover its actual pension costs (but not the financing costs), albeit with a five-year lag.[26]

33. NIE said that its actual pension costs in RP4 were £57 million, which was £24 million higher than the RP4 allowance amount of £33 million (which was based on the actual pension costs incurred in RP3, adjusted for RPI). However, because a new mechanism had been introduced (which did not account for this shortfall of £24 million), a one-off adjustment was required to take account of this.[27]

34. In NIE's view, it would never have chosen to accept the risk that RP4 pension contributions exceeded those of RP3. This was because it had very little control over the quantum of pension deficit repair payments, and the principle if such costs should be recovered was common to both RP4 and RP5.[28]

ERDCs have already been funded

35. NIE said that it was content in principle to bear 30 per cent of the cost of ERDCs, which was consistent with Ofgem's approach to the Great Britain DNOs and the UR in RP4. However, it said that it had already funded these costs through two special shareholder contributions made in 2005/06 and 2006/07, totalling £75 million.[29]

36. NIE said that, if one were to adopt the UR's approach for valuing the impact of ERDCs, these contributions would have reduced the deficit by £71.4 million and would therefore have been more than sufficient to discharge the £41.2 million to be borne by NIE's shareholders for 30 per cent of past ERDCs.[30]

37. NIE submitted that the allowance for previous shareholder contributions should be up to, but no greater than, the amount of ERDCs payable by NIE shareholders. The

[24] ibid, Chapter 10, p255.
[25] ibid, Chapter 10, p255.
[26] ibid, Chapter 10, paragraphs 4.3 & 4.4.
[27] ibid, Chapter 10, paragraphs 4.5–4.7.
[28] ibid, Chapter 10, paragraph 4.11.
[29] ibid, Chapter 10, paragraph 5.3. These were: *(a)* £2.7 million paid by NIE and included in the £24 million under-recovery of pension costs in RP4; *(b)* £63.3 million paid by NIE Powerteam: of this, £12 million was accounted for as a prepayment of its costs for 2007/08–2009/10, and the remaining £51.3 million was funded by shareholders; *(c)* £9 million paid by other Viridian Group PLC entities. NIE Statement of Case, Chapter 10, paragraphs 5.5–5.7.
[30] ibid, Chapter 10, paragraph 5.8.

proposed adjustment for ERDCs in RP5 amounted to £15.2 million (and £41.2 million over the 15-year deficit recovery period proposed by the UR).[31]

Other points raised by NIE

38. NIE said that its projection for ongoing pension costs had increased by £0.6 million to £11.1 million since making its business plan submission. This reflected an increase in the cost following completion of the 31 March 2011 actuarial valuation.[32]

39. NIE also said that the UR was basing its deficit repair allowance on a 15-year repair period (March 2012 to March 2027) rather than the 13-year period (March 2009 to March 2022) which it actually agreed with trustees. As a result, there was a projected £2.7 million financing cost shortfall in RP5 due to timing differences. NIE said that these costs should be 'trued up'.[33]

40. NIE said that, in addition, it should be made whole on an NPV-neutral basis for any differences between the actual ex-post cost of pensions and the ex-ante allowance (this might occur due to a change in the deficit repair plan being agreed with the trustees during a price control period).[34]

The UR's response to NIE's submission

41. In this section we briefly summarize the UR's responses to NIE's submissions.

42. The UR said that NIE had accepted all of its RP5 'pensions principles', which was not surprising as they were very accommodating to NIE. In its view, NIE had proposed two substantial exceptions, neither of which withstood scrutiny.

43. First, the £24 million in stranded pension costs from RP4. The UR said that this was an attempt to revise retrospectively the risk allocation which NIE signed up for in RP4 and cherry pick between approaches. In its view, the new principles applied going forward and there was no basis on which NIE could properly have expected the rolling approach to continue from RP4 into RP5. The UR provided evidence in support of its view that NIE had accepted the full risk of underperformance against the pensions allowance (and not just financing risk). In the UR's view, the new principles, and in particular 'truing up', applied going forward and there was no basis on which NIE could properly have expected it to be applied retrospectively.

44. Second, to offset special shareholder contributions against ERDC costs. It said that this was an attempt to rewrite history and that no link existed between these contributions and ERDCs.[35] It said that the 2007 shareholder payment was made in the context of and motivated by the acquisition of Viridian Group (then NIE T&D's parent company) by Arcapita Bank. It had nothing to do with early retirement costs. In addition, NIE had conveniently ignored all other past actions (including pension holidays and improved benefits) which had contributed to the present day deficit.

45. The UR's view was that in RP5 it sought to change the historic risk allocation for pensions on a prospective basis only and NIE had no basis for a retrospective claim on stranded costs. It said that the actual NPV impact of the discontinuation of the

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[31] ibid, Chapter 10, paragraphs 5.8–5.9 & 5.12.
[32] ibid, Chapter 10, paragraphs 1.2 & 6.3
[33] ibid, Chapter 10, paragraph 6.4.
[34] ibid, Chapter 10, paragraph 6.6.
[35] UR Supplementary Submission, 24 May 2013, paragraphs 19, 55 and 58–60.

rolling mechanism from RP4 was around £10 million (rather than the £24 million suggested by NIE); this amount was more than offset by the gains from the end of the rolling opex mechanism.

46. In the UR's view, the key pensions question was whether it was fair to customers to ask them to bear 70 per cent of ERDCs. NIE enjoyed closer to 50 per cent of the benefits of early retirements and the only argument against that approach was Ofgem's and the UR's previous regulatory precedent.[36]

NIE's supplementary submissions

47. NIE said that the UR's submission needed to be understood within a context where the UR had accepted that NIE's pension costs were uncontrollable, and 97 per cent of the scheme's members were protected persons, so NIE was precluded from reducing their benefits, even on a forward-looking basis.[37] It noted that this inability to take further steps to manage its liability was an important difference between Bristol Water and NIE.[38]

48. NIE said that seeking a 'true up' for stranded pension was not a case of cherry picking: it was a direct and necessary consequence of the switch from one approach to another between RP4 and RP5. The rolling allowance of RP4 recognized that customers would pay the full costs of NIE's pension deficit repair costs, albeit that NIE would need to wait until the next price control period to recover these costs.[39] It said that the UR/First Economics analysis of the cost of stranded pension costs was flawed and irrelevant.

49. NIE also said that because the UR was assuming a different deficit repair period from that agreed between the company and the scheme's trustees, any financing cost borne by NIE as a result of making actual contributions in advance should be recoverable and attract the regulatory rate of return. It disagreed with the UR that this would amount to an artificial profit. NIE said that NIEPS was a separate legal entity from NIE and the discount rate used to discount pension scheme liabilities for actuarial purposes was not the same as NIE's cost of capital.[40]

50. NIE provided a calculation which it said showed that the specific circumstances of this case warranted a 23 per cent allocation of ERDCs to shareholders. It also said that some of the UR's alternative calculations in respect of ERDCs contained errors.

51. With regard to its special shareholder contributions, NIE said that it was sufficient to know that these eliminated the deficit in 2007 and were today sufficient to cover NIE's share of ERDCs. It said that the 2007 special shareholder contribution was successful in its stated objective of clearing the deficit at the time. In its view, the UR's proposals would mean that shareholders were being asked to fund ERDC costs twice.[41]

[36] ibid, 24 May 2013, paragraph 61.
[37] NIE's Supplementary Submission, 10 June 2012, paragraph 3.59.
[38] ibid, Annex 8, paragraphs 2.8 & 2.9.
[39] ibid, paragraphs 1.18–1.20.
[40] ibid, Annex 8, paragraphs 2.14–2.16.
[41] ibid, Annex 8, paragraphs 3.1–3.8.

Additional points raised at the main party hearings (9/10 July 2013)

52. In this section, we summarize the additional points made by the parties at the hearings (ie those points which were not already covered in the parties' various written submissions).

The UR

53. The UR told us that 30 per cent of early retirement pensions costs attributed to shareholders was actually an Ofgem number—it was not a calculation which was carried out by the office in Belfast by itself. It said that not much thought had gone into the calculation of 30 per cent in the UR's office and that there was a perfectly respectable argument that the number was more like 50 per cent.

54. The UR told us that for its RP5 determination it did do analysis on ERDCs based on the data for NIE employees in Northern Ireland and landed at a 50:50 split. It said that in its final determination it decided to revert to what it had signalled in RP4. It told us that this was an area where the CC should check if this was the right deal for customers.[42]

55. The UR told us that the reason why there were notional repayment profiles in other regulated sectors was that regulators did not want to impose undue burden on today's customers for something they were not actually responsible for.[43]

56. The UR said that it was only with RP5, and not before, that it signalled that the risk allocation on pensions had changed. It said that the risk allocation in RP4 was not the same—all that existed in RP4 was a pensions opex allowance. It said that it had never indicated that this rolling allowance would continue.[44]

NIE

57. With regard to ERDCs, NIE told us that it accepted 30 per cent because the precedent was established by Ofgem and it had been used in RP4. It told us that apart from those major interventions made in early retirements (which caused the ERDC liability), pension costs were uncontrollable costs. It also told us that benefit improvements for members were a matter for RP2 and RP3.

58. NIE told us that it did not know what the pension regulator was going to say in March 2014 at the next triennial valuation. It has agreed a deficit repair plan in March 2009 which would last until March 2022; but the pensions regulator saw that as potentially a long period and he recommended seven to ten years. Whilst NIE had sought to push out the deficit plan as far as possible, the trustees were bound by their own duties as trustees, pensions legislation and the oversight of the pensions regulator.[45]

59. NIE told us that, whilst the rolling mechanism (from RP4) was not its preference, it could still work for pensions and NIE could possibly fund the timing differences.

60. NIE told us that it was not claiming that, in case law, it had a legitimate expectation to recover stranded costs. Rather, its case was that: pensions were treated differently from other opex items and all pensions costs would be recovered with a five-year lag

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[42] ibid, p110.
[43] ibid, p114.
[44] ibid, pp116–118.
[45] ibid, pp125&126.

under the rolling mechanism; and because the regulator had characterized pensions costs as uncontrollable internal, coherence required that the shortfall was made up.[46]

61. NIE told us that the price control should be based on what was agreed between the company and the trustees because that was a legally binding agreement and represented the cash costs being incurred by the company.[47]

The parties response to our provisional determination

62. In this subsection we summarize the main points made by the parties in response to our provisional determination.

The UR

63. The UR said that much of our approach to pension costs mirrored its own approach. It had no objections to one of the key differences proposed in the provisional determination: that in future pension contributions (other than deficit repair) should be benchmarked rather than passed through to consumers.[48]

64. The UR disagreed with two aspects of our approach in the provisional determination, in respect of: *(a)* NIE's stranded pension costs from RP4; and *(b)* ERDCs.[49]

65. With regard to stranded pension costs, the UR said that our provisional determination amounted to a backdating of our decision to 1 April 2007, which was an arbitrary date and at odds with our strict rules against reopening previous price controls other than in exceptional circumstances.[50]

66. The UR also said that even if the rolling mechanism had been allowed to continue indefinitely the maximum possible loss that NIE could claim to suffer was £11 million, not £24 million.[51]

67. With regard to ERDCs the UR reiterated its position and asked that 45 per cent of ERDCs, rather than 30 per cent, be attributed to shareholders.[52]

68. The UR also raised concerns about the in-period adjustment mechanism which had been proposed in the provisional determination. It was concerned about how the mechanism would work in practice and the fact that the 15-year notional deficit recovery period was intended to protect consumers from bearing too high a burden from deficit repair.[53]

NIE

69. NIE said that it was generally content with our analysis and approach to pensions in so far as it related to deficit repair. It said that the clarity and transparency created by

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[46] ibid, p127.
[47] ibid, p129.
[48] UR response to the provisional determination, paragraph 109.
[49] ibid, paragraphs 110–112.
[50] ibid, paragraphs 116–118.
[51] ibid, paragraphs 119–122.
[52] ibid, paragraphs 123–126.
[53] ibid, paragraphs 127–129.

the alignment of approach between NI and GB would provide significant comfort to investors in respect of the treatment of pensions now and going forward.[54]

70. NIE disagreed with our approach to past shareholder contributions and ERDCs. It provided further detail on the background to these contributions. It said that our conclusion on this matter was impliedly based on an erroneous assumption that it was for NIE to prove that the shareholder contributions were or should now be hypothecated towards meeting the shareholders' liability for ERDCs.[55]

71. NIE said that it had discussed this issue with the Scheme Actuary at Aon Hewitt, who confirmed that, even if the additional contributions had been paid to offset a weakening of the employers' covenant, nevertheless the money was wholly employed to reduce the scheme deficit. It also provided copies of contemporaneous documents which it submitted should be sufficient to satisfy the CC that there was no reason not to treat the shareholder contributions as having had the effect of discharging NIE's shareholders' obligations to fund 30 per cent of the ERDCs.[56]

72. NIE outlined a proposed approach to the treatment of the special contributions which it said was consistent with the overall rationale of the CC's approach.[57] It said that we made no comment about the timing of shareholder contributions in our provisional determination; in its view since NIE's liability for ERDCs arose as a result of early retirements that took place prior to 2003, it was only right to take account of shareholder contributions that were made after that date. It would be entirely one-sided for us to take account of liabilities arising from earlier periods but to ignore shareholder contributions made in more recent years.[58]

73. NIE outlined a calculation method for implementing our decisions. It also requested clarification with regard to how the three-year review cycle would work and that the 15-year notional deficit repair period in the provisional determination was not a 'stop dead' date.[59]

Pensions treatment by other regulators

74. In this subsection, we summarize the treatment of pensions in some recent regulatory decisions. The purpose of this section is to explain of how other regulators have dealt with pensions issues.

Ofgem

75. Ofgem updated its Pensions Principles in June 2010.[60] We consider below some relevant aspects of Ofgem's guidance.

Split between historic and incremental deficits

76. Ofgem funds historic pension scheme deficits but not incremental deficits. The historic deficit is the difference between assets and liabilities attributable to pensionable service up to a defined cut-off date. The cut-off dates for the historic deficit are:

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[54] NIE response to the provisional determination, Chapter 4, paragraphs 1.2–1.4.
[55] ibid, Chapter 4, paragraphs 1.6–1.16.
[56] ibid, Chapter 4, paragraphs 1.23–1.27.
[57] ibid, Chapter 4, paragraphs 1.28.
[58] ibid, Chapter 4, paragraphs 1.29.
[59] ibid, Chapter 4, paragraphs 1.34.
[60] www.ofgem.gov.uk/ofgem-publications/42784/pricecontroltreatmentofpensioncostsfinal.pdf. Ofgem's first Pensions Principles were first set out in 2003.

for the DNOs, the end of DPCR4 (March 2010); for the GDNs, March 2013; for Transmission Operators, March 2012.[61]

77. Following a significant consultation period, Ofgem has also recently established and agreed a methodology for attributing a scheme deficit between historic and incremental deficits.[62] This now forms a part of Ofgem's Pension RIGS.[63]

Deficit repair period

78. Ofgem said that a 15-year deficit repair period was appropriate, balancing the duties of regulated companies and pension trustees with affordability for customers.[64] For the Great Britain DNOs, Ofgem used the pension scheme pre-retirement discount rate, not the WACC, to discount the allowance over a notional period.[65]

Under/overfunding during a charge control period

79. This occurs when funding rates change during a charge control and therefore contributions differ from the ex-ante forecast. For example, this would occur when a triennial valuation takes place during a charge control and the scheme contributions increase/decrease.

80. Ofgem said that it would log up the cumulative effect of under/overfunding liabilities accrued up until March 2012 and pass the impact through to consumers when setting the subsequent price control. This would be done on an NPV-neutral basis.[66]

ERDCs

81. Ofgem said that post-March 2004 ERDCs were entirely a matter for shareholders.[67] However, ERDCs before this date were borne 30 per cent by shareholders and 70 per cent by customers.[68]

82. Ofgem's rationale for the 30:70 split was that the companies retained the benefit of early retirements (through lower opex) for five years, whereas customers received the remainder (from year 6 into perpetuity). It also recognized that: there was merit in the companies' argument that they retained the benefit for less than five years on average; it could be argued that early retirement only brought forward lower costs rather than creating a permanent reduction (as staff would have retired anyway); and therefore it was also possible to sustain an argument for a 50:50 split.[69]

83. In adopting a 30:70 split, Ofgem noted that the companies were generally low risk but that pensions was one area where they did bear risk that was related to market performance. By giving the companies extra protection in this area, Ofgem considered that it was reinforcing the low-risk characteristics of the business and reducing the case for a higher cost of capital based on pension fund risk.[70]

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[61] ibid, p11.
[62] www.ofgem.gov.uk/ofgem-publications/42762/pdam-decision-letter-final-12apr2013.pdf.
[63] www.ofgem.gov.uk/Networks/Documents1/NWO%20Triennial%20Pension%20RIGS%20supplements%20v1.0%2012Apr13.pdf.
[64] www.ofgem.gov.uk/ofgem-publications/42784/pricecontroltreatmentofpensioncostsfinal.pdf, p13.
[65] ibid, paragraph 3.33.
[66] ibid, pp26&27.
[67] ibid.
[68] www.ofgem.gov.uk/ofgem-publications/46270/8425-22204dpcrsepupdate.pdf, paragraphs 5.12–5.17.
[69] A 48:52 split would be based on a four-year saving over a ten-year total saving. Ofgem: Electricity Distribution Price Control Review, Update Paper, September 2004, paragraphs 5.12–5.17.
[70] ibid, paragraphs 5.16 & 5.17.

Commitment to benchmarking ongoing pension service costs

84. Ofgem is committed to benchmarking ongoing pension service costs (including incremental deficits) and setting an ex-ante allowance rather than using a cost pass-through mechanism.[71]

CC inquiry: Bristol Water PLC price determination

85. This report was presented to Ofwat on 4 August 2010. Bristol Water operated two DB schemes which had been closed to new members since 2002 and which were both in deficit. It argued that it should be entitled to an additional opex allowance in respect of four pension items.[72]

86. With regard to deficit repair payments the CC determined three key variables:

(a) the proportion of the deficit which should be passed through to consumers;

(b) the size of the deficit (ie which valuation to use); and

(c) the deficit recovery period.[73]

87. We summarize the decision on each as well its recommendation in respect of ongoing contributions.

Proportion of the deficit which should be passed through to consumers

88. Ofwat decided on 50 per cent in its determination. The CC proposed 100 per cent in its provisional findings, having particular regard to the extent to which the deficit was within Bristol Water's control and the steps it had taken to control liabilities.[74]

89. In the final decision, the CC reduced this to 90 per cent pass through to reflect: first, that Bristol Water had some limited options to control scheme liabilities; and secondly, that it wished to retain some incentive for Bristol Water to manage its liabilities.[75]

90. The CC said that its decision reflected the specific circumstances of Bristol Water and its pension scheme and should not unduly influence Ofwat in future determinations.[76]

The size of the deficit

91. The CC used the most recent available valuation date rather than the last triennial review date. It preferred to rely on slightly less rigorous but more up-to-date data.[77]

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[71] www.ofgem.gov.uk/ofgem-publications/42784/pricecontroltreatmentofpensioncostsfinal.pdf, p5.
[72] *Bristol Water plc: A reference under section 12(3)(a) of the Water Industry Act 1991*, presented to Ofwat on 4 August 2010, paragraphs 6.24 & 6.25.
[73] ibid, paragraphs 6.26 & 6.27.
[74] ibid, paragraph 6.28.
[75] ibid, paragraphs 6.29–6.31.
[76] ibid, paragraph 6.32.
[77] ibid, paragraph 6.33.

The deficit recovery period

92. Both Ofwat and Bristol Water had assumed a ten-year recovery period. The CC determined that 15 years was more appropriate. This was consistent with Ofwat's treatment of other companies and smoothed the effect of the intergenerational transfer arising from the deficit.[78]

Ongoing contributions

93. Bristol Water argued that, in the absence of additional lump-sum payments which it had agreed with the trustee in 2005, its employer contributions would have been 24 per cent rather than 18 per cent. It further argued that the most recent valuation would imply an employer contribution of 27 per cent.[79]

94. The CC found that for 2010/11 the actual cash paid (ie 18 per cent) was the appropriate allowance. For the remainder of the charge control, the CC found that 24 per cent was appropriate (that is, the underlying ongoing contributions from the last triennial review).[80]

CC telecommunications appeal: Wholesale Broadband Access

95. This decision was made on 11 June 2012. This was an appeal by BT against Ofcom and one of the questions referred to the CC concerned BT's pension deficit. The legal framework in this telecommunications appeal is different from a redetermination —in the WBA appeal the CC did not have investigatory powers and was asked to determine only if Ofcom had erred because of the reasons outlined by the appellant (in this case BT).

96. BT argued that Ofcom had erred in the WBA price control by not allowing it to recover the cost of its pension deficit repair payments. There was a significant amount of evidence presented by the parties in this appeal and below we summarize the (at a very high level) views of BT, Ofcom as well as the CC's final determination.

97. Ofcom's view was that:

(a) It had outlined its approach in its 2010 Pensions Review and had concluded that deficit repair was not a forward-looking efficiently-incurred cost.[81] Sunk costs might be included as an exception when it was necessary to incentivize investment in sunk assets and where this was consistent with the regulatory framework and dynamic efficiency.[82]

(b) In Ofcom's view, deficit repair payments were not forward looking and it was not persuaded to make an exception to its general rule.[83] It said that just because a liability was inherently difficult to forecast, it did not make any increase in that liability a forward-looking efficiently-incurred cost.[84]

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[78] ibid, paragraph 6.34. The intergenerational transfer occurs because a pension deficit reflects, with hindsight, that past employment costs have been understated.
[79] ibid, paragraph 6.36.
[80] ibid, paragraph 6.37.
[81] *British Telecommunications plc v Office of Communications supported by British Sky Broadcasting Limited TalkTalk Telecom Group plc*, 11 June 2012, paragraphs 1.37–1.39.
[82] ibid, paragraph 1.138.
[83] ibid, paragraphs 1.150 & 1.151.
[84] ibid, paragraph 1.154.

(c) In Bristol Water, PDR was not in dispute as Ofwat had originally decided to allow a proportion of payments. It said that the dispute was centred on whether a greater percentage of payments should be allowed.[85]

(d) Ofcom said that BT and Bristol Water performed different functions in different sectors. Also, Ofwat (and the CC on appeal) had a statutory duty to ensure that Bristol Water was able to finance its functions: Ofcom did not have this duty. Bristol Water was also required to maintain an investment grade credit rating: this duty did not apply to BT (and by extension Ofcom).[86]

98. Some of the points raised by BT were:

(a) In its view, RPI–X regulation allowed a company to recover its efficiently-incurred costs—there was no point in trying to incentivize a company to minimize costs that were uncontrollable.[87]

(b) The economic principles which underlay the CC's Bristol Water decision were appropriate in this case—and Ofcom's decision was inconsistent with these principles.[88]

(c) Other regulators and the CC had recognized that movements in pension deficit costs did not represent a lack of efficiency in a regulated business. Ofcom was the only UK regulator to disallow PDR payments in full.[89]

(d) Ofcom had placed too much weight on regulatory consistency and trying to defend it.[90] Its application of its six principles of pricing and cost recovery was also flawed.[91]

(e) Ofcom's principal argument rested on the suggestion that it allowed only efficiently-incurred forward-looking costs, because allowing other costs would reduce allocative efficiency. BT argued that this mischaracterized the way Ofcom actually regulated BT and that in reality a wide range of sunk costs which were forward looking had been allowed. It said that this was inevitable in a capital-intensive industry.[92]

99. In response to the argument that the pension deficit was a 'fair bet', BT said that there 'was nothing fair about that bet' and that it had exposed it to highly material uncontrollable losses.[93]

100. The CC decided that:

(a) BT's pension costs were different from some of its other costs because of: their unpredictability and uncontrollability; the scale of the risk; and that the forecast errors were made in successive charge controls and did not become apparent for many years. This provided a reason for considering exceptional treatment, but it did not indicate who should bear the costs.[94]

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[85] ibid, paragraph 1.154.
[86] ibid, paragraph 1.160.
[87] ibid, paragraphs 1.20 & 1.21.
[88] ibid, paragraph 1.12.
[89] ibid, paragraphs 1.14 & 1.31.
[90] ibid, paragraph 1.60.
[91] ibid, paragraphs 1.66–1.104.
[92] ibid, paragraph 1.105.
[93] ibid, paragraphs 1.127–1.129.
[94] ibid, paragraph 1.404.

(b) Ofcom had a policy of 'no retrospection', and given that PDRs were retrospective corrective payments, Ofcom's choice to disallow them was not inappropriate (for the reasons alleged by BT).[95]

(c) It was not persuaded that the fact that other regulators, in different markets, operating under different regimes, on its own constituted sufficient reason to show that Ofcom erred in the exercise of its regulatory judgement in adopting the approach that it did.[96]

(d) The arguments about the principles of RPI–X regulation did not provide a reason to justify the exceptional treatment of PDRs.[97]

(e) Allowing PDRs would not materially impact BT's incentives to minimize costs.[98]

(f) The CC was not persuaded that the uncontrollable nature of the costs and the scale of the out-turn were such that Ofcom was wrong in deciding that PDR payments should not be borne by current customers (at least in part) and that they should be borne by BT and its shareholders.[99]

(g) There were important differences between the facts underlying the Bristol Water determination and the decisions of other regulators relied upon by BT in support of its case, and the case before us. The CC did not consider that those other decisions, or the criteria which BT drew from Bristol Water, should have led Ofcom to a different decision in this case from the one that it reached.[100]

Other regulators

101. The Office of Rail Regulation had no specific policy on deficit repair and Network Rail's deficit was not substantial in the consultation period before the PR12 control (April 2009 to March 2014).[101]

102. The Postal Services Commission previously allowed recovery of the postal services pension deficit over 17 years. In June 2011 the Postal Services Act provided for, among other things, the privatization of Royal Mail, the transfer of the pension deficit to the Government and transfer of regulatory responsibility to Ofcom.[102]

103. CAA (NATS) had a pension fund surplus before entering its current charge control (this had turned into a deficit in 2012).[103]

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[95] ibid, paragraph 1.304.
[96] ibid, paragraph 1.398.
[97] ibid, paragraph 1.405.
[98] ibid, paragraph 1.408.
[99] ibid, paragraph 1.412.
[100] ibid, paragraph 1.413.
[101] http://stakeholders.ofcom.org.uk/binaries/consultations/751766/summary/pensionscondoc.pdf, Table 2, p81.
[102] http://stakeholders.ofcom.org.uk/binaries/post/postal-service-annual-report.pdf, and http://stakeholders.ofcom.org.uk/binaries/consultations/751766/summary/pensionscondoc.pdf, Table 2, p81.
[103] www.nats.aero/wp-content/uploads/2012/07/NATS-AnnualReport2012.pdf, p42. The 2012 deficit was £37.8 million.

Contribution of different components to the difference between the UR's and NIE's projected cost of capital

1. In this appendix, we calculate the contribution of different components to the difference between the UR's and NIE's projected cost of capital. As shown in Table 13.1 in Section 13, the UR's projected WACC was 4.6 per cent and NIE's was 5.2 per cent. NIE assumes higher gearing than the UR: our calculations take into account the impact of gearing on beta and the cost of equity but we do not attempt to quantify any impact of higher gearing on the cost of debt.[1]

2. We reworked the two WACC computations on the same gearing basis of 50 per cent. This also involved adjusting NIE's equity beta assumption. In Table 1 we show two alternative calculations using an equity beta assumption based on a debt beta of either 0 and 0.1.

TABLE 1 **Regeared projected real cost of equity**

	Gearing of 50% and debt beta of 0.0		*Gearing of 50% and debt beta of 0.1*	
	UR	*NIE*	*UR*	*NIE*
Gearing (%)	50	50	50	50
Cost of debt (pre-tax) (%)	3.4	3.6	3.4	3.6
Cost of equity (post-tax) (%)	5.7	6.78	5.7	6.89
WACC (%)	4.55	5.19	4.55	5.24
Cost of equity calculation				
Debt beta assumption	0	0	0.1	0.1
Asset beta*	0.37	0.36	0.42	0.42
RFR (%)	2	2	2	2
ERP (%)	5	5.25	5	5.25
Equity beta*	0.74	0.72	0.74	0.74
Northern Ireland premium	0	1	0	1
Cost of equity (post-tax) (%)	5.7	6.78	5.7	6.89

Source: CC calculations.

*Asset beta and equity beta are calculated using Miller formula (asset beta = (equity beta) x (1-g)+(debt beta) x g).

[1] Any such effect would most likely be small but, as higher gearing increases the riskiness and hence the cost of debt, it would reduce slightly the contribution of differences in the cost of debt and increase the contribution of the difference in gearing.

Approach to measuring historical returns of a market index

1. Under the assumptions that expected returns are constant over time, and that returns in each period are independent of each other, the arithmetic average of realized returns is an unbiased measure of the constant expected return. A simple approach to measuring historical returns is therefore to calculate an arithmetic average of historical returns.

2. The length of the period over which the return to be averaged is measured is a complex issue. The relevant period would seem to be the period for which investors expect to be invested in the market (we describe this as the holding period). It seems very unlikely that this is as short as one year. Because of their price variability, equities are usually regarded as a long-term investment. The FSA, for instance, advises consumers that 'it is important to stress that you need to be looking to the medium to long term when investing in shares—at least five years but preferably longer'.[1]

3. Blume has shown that, if the holding period is longer than one year, the arithmetic mean of one-year returns is an upwards-biased measure of the true expected return (assuming that returns are independently and identically distributed around the true expected return).[2] Blume suggested a number of unbiased measures if the holding period is longer than one year. Assuming a holding period of h years, expressed as equivalent annual returns, these included:

   (a) The arithmetic mean of returns for all non-overlapping periods of h years.[3] We describe this as the 'simple' estimator of the average return for a holding period of h years. The DMS and Barclays data covers 110 years and if we wish to use all of this data we are limited to values of h which are factors of 110: that is 2, 5, 10, 11, 22 and 55. However, the number of non-overlapping observations drops off rapidly as the holding period increases—there are only 11 observations for a holding period of ten years and two for a holding period of 55 years.

   (b) The arithmetic mean of returns for all overlapping periods of h years.[4] This greatly increases the number of observations (the data gives 101 such observations for a ten-year holding period): intuitively, we might expect accuracy to be increased by extending the observations even though these observations are not independent of each other, but Blume's simulations tended to suggest that the overlapping mean tends to be a less efficient estimator than the non-overlapping mean.

   (c) A weighted average of the arithmetic and geometric means[5] where the weight on the arithmetic mean is (110–h)/(t–1) and the weight on the geometric mean (h–1)/(t–1) where t is the length of time for which we have data. We describe this as the Blume estimator. For a holding period of one year, this is the arithmetic mean which, as noted above, is unbiased for a holding period of one year; and for a holding period equal to t (110 years for our data), this is equal to the geometric

[1] www.moneymadeclear.org.uk/products/investments/types/asset_classes/shares.html.
[2] Blume, M, 'Unbiased estimators of long-run expected rates of return', *Journal of the American Statistical Association*, 1979.
[3] The mean is calculated from the formula $(\sum(R_{t+h}/R_t)/(110–h))^{1/h}$ where h is holding period, R_t is value of returns index at the end of year t and the expression is summed for (110/h) values of t for which non-overlapping data is available.
[4] The mean is calculated from the formula $(\sum(R_{t+h}/R_t)/(110–h))^{1/h}$ where h is holding period, R_t is value of returns index at the end of year t and the expression is summed for (110–h+1) values of t for which overlapping data is available.
[5] The geometric mean of annual return indices is equal to the compound annual growth rate in returns over the period.

mean which is an unbiased estimator for this length of holding period (albeit one based on a single observation of the expected return over 110 years).

4. Jacquier, Kane and Marcus[6] (JKM) extended Blume's work under the assumption that returns were lognormally distributed.[7] JKM proposed a general class of estimators of annualized returns taking the form: $e^{(m + 0.5vk)}$ where m is the arithmetic mean and v is the variance of annual returns; and k is a parameter depending on h and t. In particular, JKM proposed:

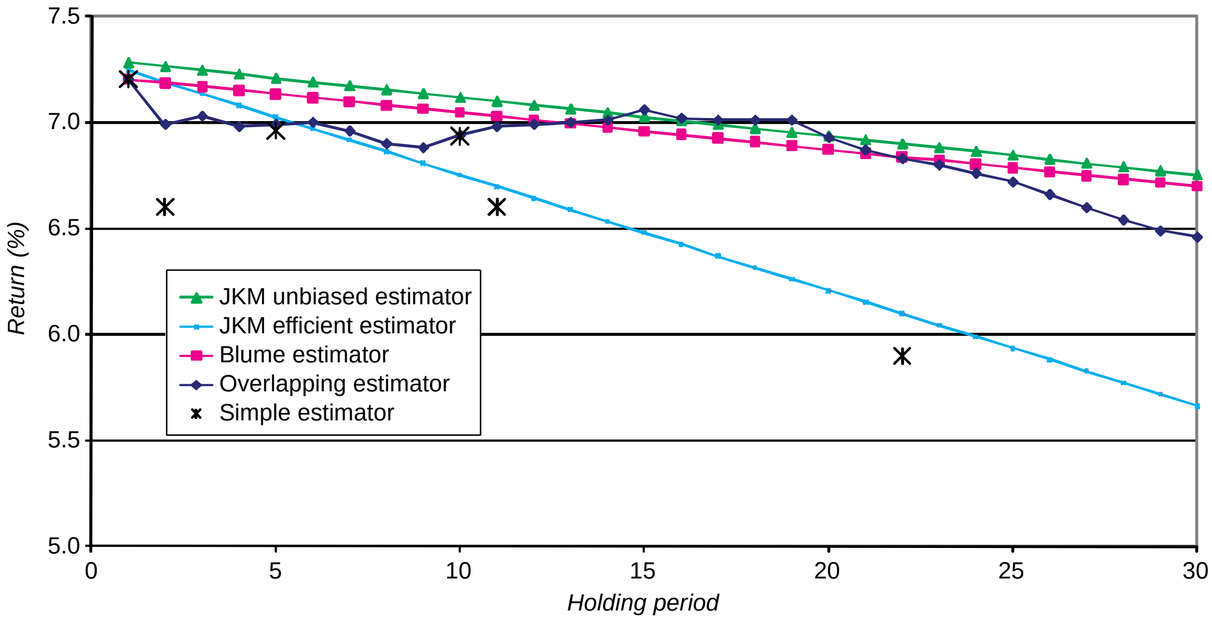
   (a) an unbiased estimator, where k = (1–h/t); and

   (b) a further estimator, where k = (1–3h/t). JKM show that this minimizes the difference between the estimate and the true value in small samples (is small sample efficient), even though it is not unbiased.[8] This is useful because our sample of independent observations becomes small as h increases.

5. Figures 1 and 2 show values of these estimators for holding periods of up to 30 years for DMS and Barclays data respectively.

FIGURE 1

Mean return on UK market for different holding periods (DMS data)

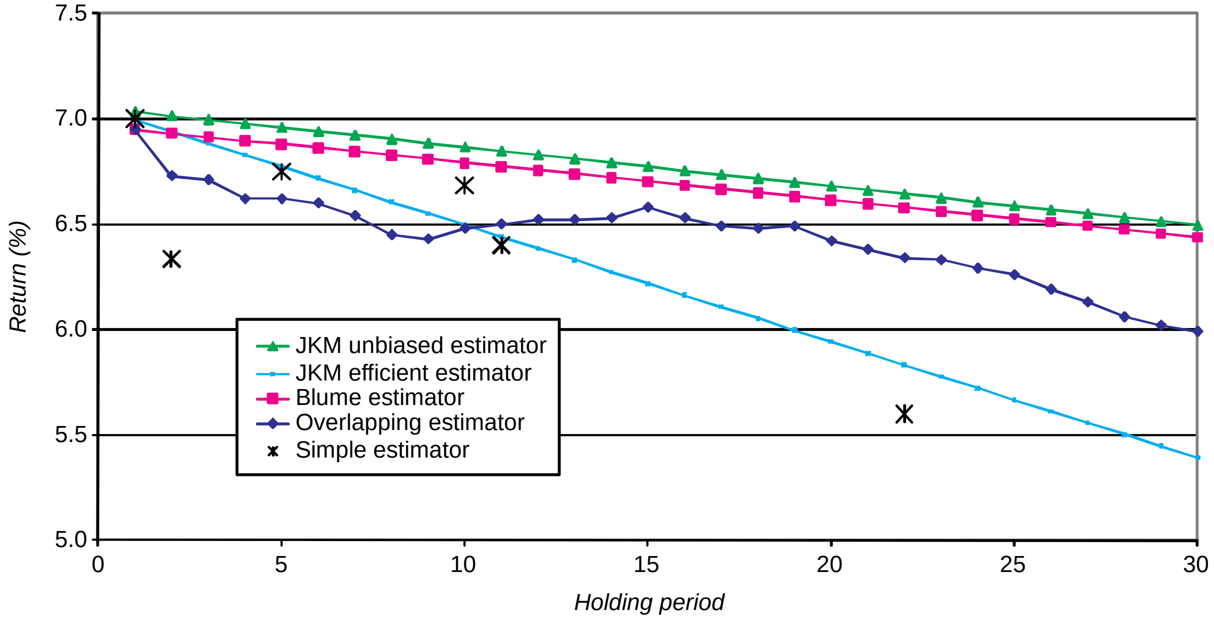


Source: CC calculations based on DMS data.

[6] Jacquier, E, Kane, A and Marcus, A J, 'Optimal estimation of the risk premium for the long run and asset allocation: a case of compounded estimation risk', *Journal of Financial Econometrics*, 2005.
[7] Blume assumed that returns were normally distributed, implying that the return index can take a negative value; the lognormal assumption avoids this implication and is more analytically tractable.
[8] JKM show that this estimator minimizes the squared deviation of the estimator from the true value (mean square error).

FIGURE 2

Mean return on UK market for different holding periods (Barclays data)



Source: CC calculations based on Barclays data.

6. It seems likely that different investors have different holding periods, and so it is desirable to look at a range of holding periods. For holding periods of 2 to 30 years, the mean return on the UK market is around 6 to 7 per cent. The estimated equity return declines as the holding period increases, most noticeably for JKM's small sample efficient estimator which declines below 6 per cent for holding periods longer than about 20 years. The Blume estimator and the unbiased JKM estimator are very similar and in Table 13.4 we only show the Blume estimator. In that table, we also show similarly derived estimates of the ERP. The simple estimator fluctuates depending on the pattern of autocorrelation in returns—in particular, average returns for a holding period of two years are about 0.6 per cent less than for a one-year holding period, reflecting a number of periods when large negative returns were followed by large positive returns (1919/20, 1931/32, 1973/75, 2008/09).

7. An alternative approach to estimating expected returns can be made under the assumption that the dividend-price ratio (dividend yield) is stationary. Under this assumption, the expected return can be estimated as the sum of the average dividend yield and the average annual dividend growth rate. Academic literature using this approach includes Fama and French (2002)[9] for the USA, and Vivian[10] and Gregory[11] for the UK. We report UK estimates using Barclays data for the period to 2009 in the main text (dividends for the DMS data set are currently not available to us).

8. The dividend yield approach tends to lead to a lower estimate of the market return (5.5 per cent) than the total return approach (7.0 per cent for a one-year holding period using the same data). Part of this can be explained by dividend growth being

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[9] Fama, E F and French, K R, 'The Equity Premium', *Journal of Finance*, April 2002.
[10] Vivian, A, 'The UK Equity Premium: 1901–2004', *Journal of Business Finance and Accounting*, 2007.
[11] Gregory, A, 'The Expected Cost of Equity and the Expected Risk Premium in the UK', *Review of Behavioral Finance*, Volume 3, Issue 1, pp1–26, June 2011.

less volatile than equity price index growth.[12] Fama and French (2002) suggest that the effect is approximately half the difference between the variance of the two growth rates. On this basis, the lower volatility of dividend growth explains about half the 1.5 per cent difference between estimated market return under the dividend yield approach (5.5 per cent) and the total return approach for a one-year holding period (7.0 per cent using Barclays data).

9. A main motivation for the dividend yield approach in the academic literature is to estimate the expected market return and ERP for shorter time periods (neither the market return nor the ERP might be constant for the full 110 years of the DMS and Barclays data). Fama and French (2002) found that the evidence suggested that the high US average return for 1951 to 2000 was due to a decline in expected returns that produced unexpectedly large capital gains. There is evidence of a similar but smaller effect for the UK (see Table 1). This appears to explain the remaining difference between the two approaches (the part not accounted for by the lower volatility of dividend than capital growth—see previous paragraph).

TABLE 1 **Average market returns, 1901 to 2009**

per cent

	1901–1950	*1951–2009*	*Total period*
Total return approach*	4.3	9.1	7.0
Dividend yield approach	5.1	5.8	5.5

Source: CC calculations based on Barclays Equity Gilt Study.

*One-year holding period.

[12] Under the dividend yield approach, the mean return is the sum of mean dividend yield and mean dividend growth. Under the total return approach with a one-year holding period, the mean return is approximately the sum of mean dividend yield and mean equity price index growth (since total return is approximately equal to the dividend yield plus equity price index growth). Hence the difference between the two is approximately the difference between average dividend growth and average equity price index growth.

CC estimates of beta

Analysis of equity and asset betas

1. We estimated the equity beta for listed GB utility comparators for periods of two years using daily data from Bloomberg. We used daily total return indices for each company and on the FTSE All Share Index as a proxy for the market portfolio. We excluded from our data set those days for which there was no reported price.

2. A summary of the basic statistics is shown in Table 1.

TABLE 1 **Summary of basic statistics: equity beta—two-year daily data**

Variable	*Estimate (average)*	*Newey-West standard error (average)*	*95% interval**	
SSE	0.54	0.06	0.30	0.73
National Grid	0.56	0.06	0.40	0.74
UU	0.54	0.06	0.34	0.71
Severn Trent	0.52	0.06	0.14	0.74
Pennon	0.42	0.06	–0.01	0.74
Portfolio	0.54	0.05	0.37	0.71

Source: CC calculations using Bloomberg data. Calculations use all two-year windows ending between 1 April 2002 and 31 December 2013.

*Over the period, 95 per cent of the estimates fell within this range.

The portfolio approach to the calculation of raw beta

3. We estimated a raw beta for the utility industry by reference to an industry portfolio, where each utility company stock is weighted by the value of the company's market capitalization at each date. The formula for the return at date t on this utility industry portfolio has been computed in the following way:

$$r_{wt} = \sum_{i=1}^{4} \alpha_{it} r_{it} \quad \text{where} \quad \alpha_{it} = \frac{market\ capitalization\ firm\ i\ at\ date\ t}{\sum_{i=1}^{4} market\ capitalization\ firm\ i\ at\ date\ t}$$

So the return on the industry portfolio is the following:

$$R_{wt} = \ln(r_{wt}) - \ln(r_{wt-1}) \tag{3}$$

where r_{it} is the daily total return index. The econometric model that we estimate is the following:

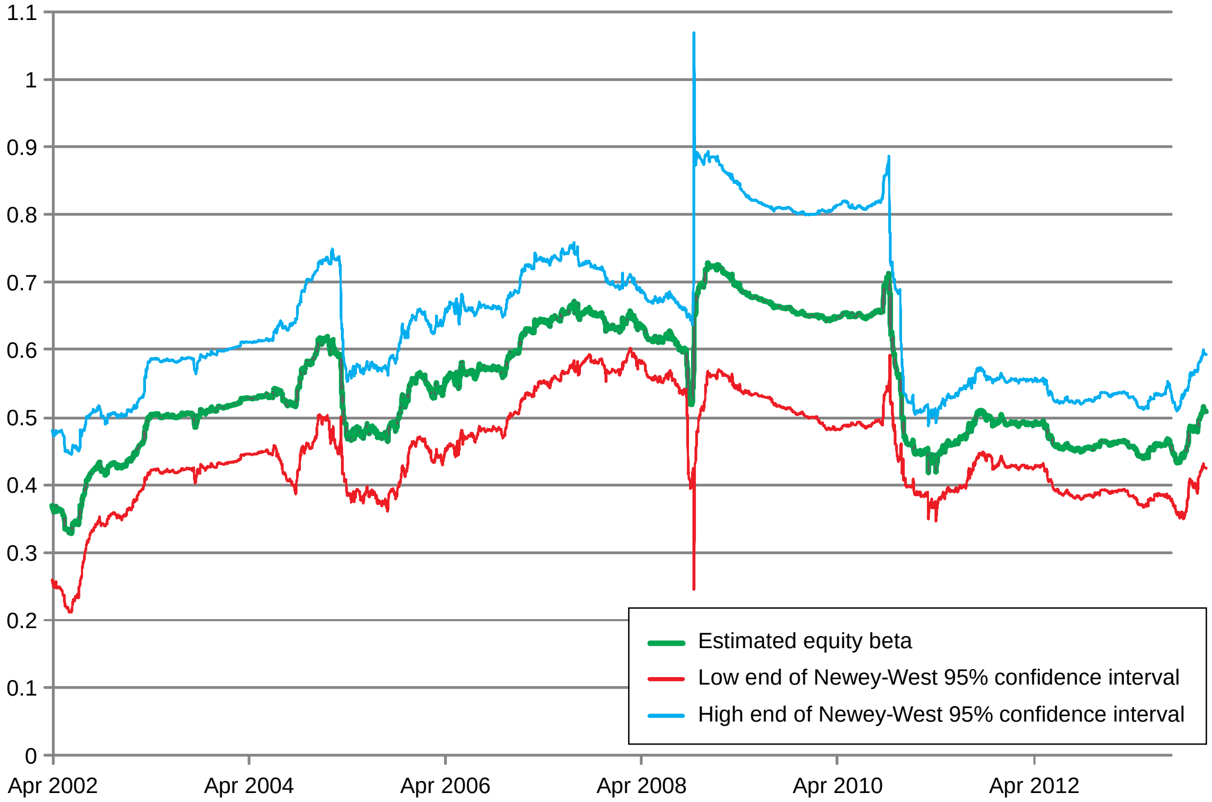
$$R_{wt} = \alpha_w + \beta_w R_{mt} + \varepsilon_{wt} \tag{4}$$

where ε_{wt} is an error term exhibiting heteroskedasticity and autocorrelation.

4. We estimated Model (4) by OLS and compute the Newey-West standard errors. We plot the results using daily data and a two-year moving window in Figure 1.

FIGURE 1

Equity beta based on two-year daily data—utility portfolio



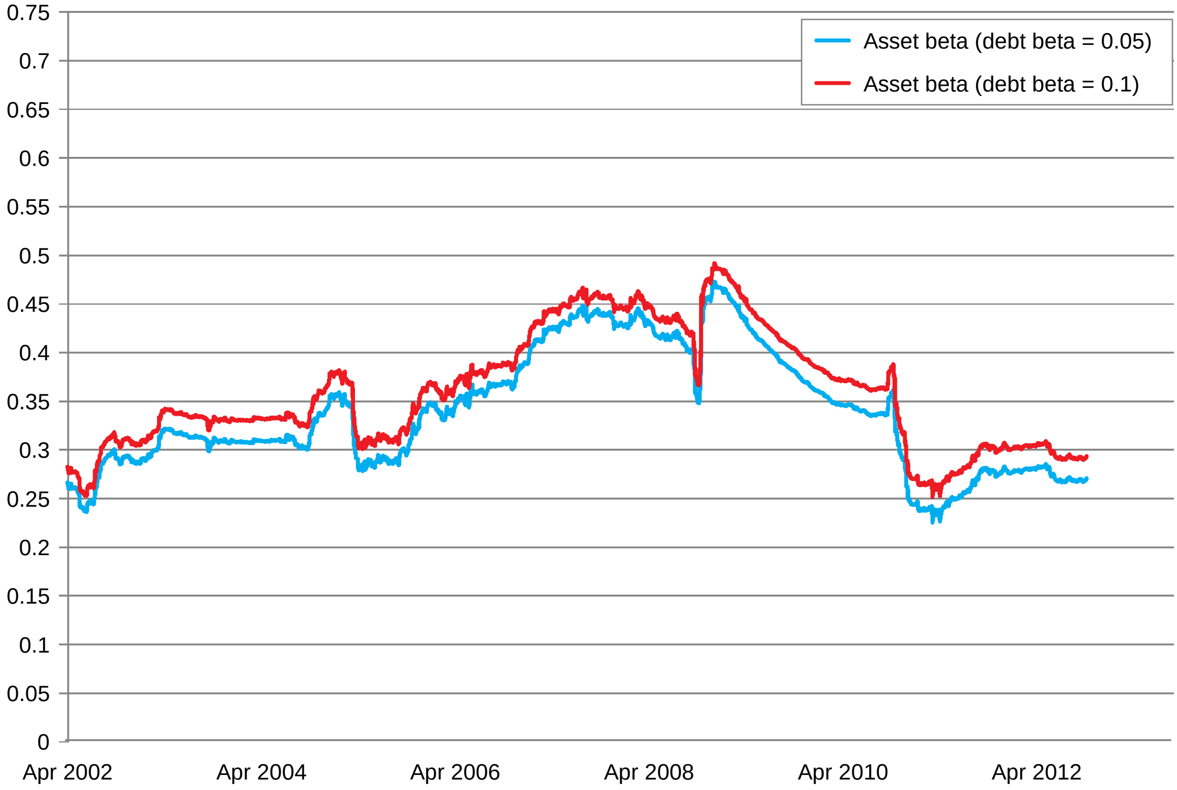
Source: CC calculations using Bloomberg data.

Asset betas for the portfolio

5. Figure 2 shows the evolution of the estimated asset beta for the portfolio of utility companies. The asset betas are shown using assumptions for debt beta of 0.05 and 0.1. Gearing is calculated using net debt figures calculated from Bloomberg.

FIGURE 2

Two-year asset beta for utility portfolio



Source: CC calculations using Bloomberg data.

6. Table 2 shows relevant statistics for two-year daily equity and asset betas for the portfolio.

TABLE 2 **Statistics for two-year daily betas**

	Equity beta	*Debt beta 0.1*	*Debt beta 0.05*	*Newey-West SE on equity beta*	*Trailing average gearing*
Average	0.54	0.35	0.33	0.05	0.43
Min	0.33	0.25	0.23	0.03	0.32
2.5 percentile	0.37	0.26	0.24	0.03	0.34
Median	0.53	0.33	0.31	0.04	0.44
97.5 percentile	0.71	0.47	0.45	0.08	0.53
Max	0.73	0.49	0.47	0.21	0.53

Source: CC calculations using Bloomberg data.

NIE's capitalization practices: review of costs

1. In this appendix we look at the costs in relation to the three activities referred to us, namely tree cutting, repairs and maintenance and capitalized overheads in order to gain an understanding about what has happened in these areas. We also review what both the UR and NIE told us about in relation to each of these activities.

Tree cutting

2. When a new overhead line is constructed it is often necessary to remove any existing vegetation in the way first. Once the overhead line has been created it is also necessary for NIE to periodically cut down trees and other vegetation alongside overhead lines for safety and network resilience reasons. It is the treatment of costs associated with this latter activity which are in dispute between the UR and NIE.

3. Periodic tree cutting can be managed on a reactive basis responding to known or imminent problems that have been identified locally or an element of a planned programme of work on overhead lines. The latter activity falls within NIE's capital programmes, all expenditure in respect of which NIE capitalizes.

4. The following table shows expenditure on tree cutting carried out as part of NIE's overhead line refurbishment programmes (capitalized) and (reactive) tree cutting which is treated as opex.

TABLE 1 **NIE's expenditure on tree cutting between 2000/01 and 2011/12**

£ million in 2009/10 prices

	RP2		*RP3*					*RP4*				
	00/01	*01/02*	*02/03*	*03/04*	*04/05*	*05/06*	*06/07*	*07/08*	*08/09*	*09/10*	*10/11*	*11/12*
Capex	1.3	0.4	0.3	0.4	0.8	1.7	1.5	2.4	3.5	3.9	5.2	6.5
Opex	0.1	0.8	0.9	0.7	1.5	0.9	0.7	0.4	0.4	0.6	0.5	0.3
Total	**1.4**	**1.2**	**1.2**	**1.1**	**2.3**	**2.6**	**2.2**	**2.8**	**4.0**	**4.5**	**5.8**	**6.8**
Capex as a percentage of total (%)	91	30	25	40	34	65	67	86	89	87	91	96

Source: NIE.

The UR's view

5. The UR told us that there was no justification for the increase in proportion of tree cutting that had been capitalized. This proportion had risen from 34 per cent of total tree-cutting expenditure in 2004/05 to 91 per cent in 2010/11 whilst at the same time the absolute level of expenditure on tree cutting had increased from £2.3 million to £5.8 million per year over the same period. The UR argued that all that had happened was that trees had been cut to keep them away from power lines. NIE had not performed different activities subsequent to it increasing the proportion of its total tree-cutting expenditure that it capitalized: all that it had been doing was cutting trees.

6. The UR said that NIE's assertion that it had consistently made a distinction for accounting purposes between reactive (treated as opex) tree cutting and strategic tree cutting (ie tree cutting carried out with other activities on overhead lines on a five-year cycle was treated as capex) was not borne out by a close examination of the facts. Previously regular, planned tree cutting along the overhead lines to

maintain clearance levels in between the 15-year refurbishment programmes had not been capitalized. What changed in 2005 was that what had previously been called 'other tree cutting carried out on the 33 kV and 11 kV lines', and accounted for as opex, had become an integral element of NIE's every-five-years overhead line programme (namely the targeted asset replacement (TAR) programme) the expenditure on which had been capitalized in its entirety.[1] This view was supported by the limited amount of contemporaneous documentation which set out NIE's accounting policies towards the capitalization of expenditure relating to tangible fixed assets. The UR added that in any case, the distinction that NIE sought to draw between proactive and reactive tree cutting was artificial.

7. As mentioned in paragraph 15.37, the UR said in response to our provisional determination that we had misread the factual evidence on tree cutting. It said that NIE had always cut trees on a five-yearly programmatic basis, and that historically the costs involved in that programme had been expensed.[2]

NIE's response

8. NIE argued that for accounting purposes it had always made a distinction between reactive and strategic tree cutting. NIE had not changed its capitalization practices as it had always treated tree cutting as part of a planned overhead line refurbishment programme as capex. The UR was aware of this as its own consulting engineers, Mott MacDonald in May 2006, when reviewing the overhead line programme element of NIE's planned capital investment programme for RP3 and RP4, had drawn the UR's attention to this fact. Mott MacDonald had noted that this expenditure might need to be transferred to opex because it could be considered to be maintenance expenditure. However, the UR had not subsequently requested NIE to change the accounting treatment of this planned expenditure.[3]

Our analysis and interpretation of events

9. Based on the analysis set out in Table 1 the most significant development over the period presented was the dramatic increase in programmatic tree cutting. The increase in spend on capitalized tree cutting started in 2004/05 with the introduction of NIE's five-year TAR overhead line rolling programmes, a development which was the culmination in NIE's change in approach to managing tree cutting as explained below. The change in the proportion of total spend on tree cutting that had been capitalized primarily results from this increased programmatic tree cutting adding to total expenditure, and less so due to reductions in opex.

Developments in NIE's approach to tree cutting

10. After privatization in 1992 NIE operated a policy of maintaining its overhead lines high-voltage distribution network by carrying out a full refurbishment programme every 15 years. If there is otherwise a problem with the overhead lines, NIE repaired it usually by replacing the failed component with a new one.[4]

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[1] The UR also explained that NIE's LV programme also included capitalized tree cutting.
[2] UR response to provisional determination, paragraphs 164 & 192.
[3] NIE Statement of Case, Chapter 11, paragraph 4.35.
[4] See paragraph 18.

11. In conjunction with this programme, NIE cut trees. There had been some other programmatic tree-cutting but otherwise NIE cut trees on a reactive basis, ie when either a customer identified or NIE otherwise identified[5] an imminent problem.

12. On Boxing Day 1998 Northern Ireland was affected by storms. There were over a 1,000 broken poles and a lot of the 33 kV network fell over with a lot of tree issues. As a result NIE instigated a light refurbishment programme every five years.

13. Even more significant for NIE's asset management practices were the storms in October 2002 affecting England, in particular East Anglia, with some customers cut off for up to ten days. The then UK energy minster commissioned a report from BPI to investigate the variation in response by the various GB DNOs. The December 2002 report notes that vast majority of service disruptions were caused by the lack of effective implementation of vegetation management policies on the part of some DNOs.

14. There was a general push on the part of the UK government to get the DNOs to make their overhead line networks more storm resilient. In response to this general desire NIE specified and then implemented from 2004/05 onwards three revamped overhead line rolling programmes including the introduction of an every-five-years targeted asset replacement programme which addressed urgent defects as well as tree cutting.

15. These programmes have continued since. As a result there has been a significant development in NIE's asset management practices over the period of review in relation to overhead lines and tree cutting. One aspect of this revised approach was that trees were cut on a per-circuit (ie from substation to substation) basis rather than on a per-span (from pole to pole) basis.

Interaction between reactive and programmatic tree cutting

16. We considered that there was likely to have been a reduction in reactive tree cutting following the dramatic increase in expenditure on programmatic tree cutting, and therefore there to be scope for operational cost savings as a result of the increase in capex spend. NIE explained that it had estimated that there had been a small saving in the costs of reactive tree cutting of around £2.0 million over the five years of RP4 since the introduction of the five-year rolling programmes.

UR's claim that five-yearly tree cutting had been treated as opex

17. We investigated the UR's claim that five-yearly tree cutting had historically been treated as opex. We found that NIE had started its Light Refurbishment programme, an element of which had comprised the five-year cycle for tree cutting, in 1999. All of the Light Refurbishment programme expenditure had been capitalized. We therefore considered that NIE had adopted a consistent approach to the treatment of this tree-cutting expenditure ever since, including in particular during the RP3 period (2002/03 to 2006/07). Under the rolling opex mechanism, this period had been the comparator period for the setting of the opex allowances that had applied in RP4.

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[5] NIE describes the element of reactive tree cutting that it, rather than a customer identifies, as 'hotspot' activity.

Repairs and maintenance

18. Broadly speaking, repairs and maintenance activity relates to the day-to-day servicing of items of property, plant and equipment like NIE's network assets. Costs of day-to-day servicing are primarily the costs of labour and consumables, and may include the cost of small parts. As these costs relate to day-to-day rather than the replacement of an asset (or a component of an asset) these costs are recognized as an operating cost in the profit or loss account as incurred.[6]

'Repairs and maintenance' in relation to composite assets[7]

19. Many of NIE's network assets such as its overhead lines are composite assets. For example, overhead lines are built from components with quite different characteristics, maintenance requirements, potential failure rates and life expectancy, erected on site to form the overhead line asset. Components of this composite asset include the overhead line supports, which themselves will range from naturally grown wood poles through to fabricated steel, current carrying conductors made generally from aluminium, copper and alloys and several items of ancillary equipment plus connected plant.

20. Each component has quite different maintenance requirements usually amounting to replacement of all or part of that component. Overhead line inspections identify the condition of components, and from experience and previous performance the companies develop their asset maintenance and replacement programmes in accordance with their own asset management policies.

21. It therefore can be the case that expenditure on some interventions undertaken as part of, or in consequence to, routine maintenance activity comprise of replacing failed or expected-to-fail components of an existing asset. As a result, this expenditure, if incurred as part of repairs and maintenance activity, would need to be reclassified as capex. This expenditure is referred to as 'capitalized repairs and maintenance'. It is also the case that replacing failed or expected-to-fail components of an existing asset can also be carried out as part of a planned capital programme, in which case the expenditure would not be captured under the banner of 'repairs and maintenance' at all.

22. Therefore three of the four categories of subsequent expenditure on existing assets[8] illustrated in Table 2 would fall within the broad category of repairs and maintenance in the first instance. Those categories which are classed by NIE as repairs and maintenance have been italicized. The reactive capex shown in the bottom left-hand corner of the table is the element of repairs and maintenance which NIE initially records in repairs and maintenance and subsequently capitalizes.[9]

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[6] This definition of repairs and maintenance is based on IAS16 (International Accounting Standard 16: Property, Plant and Equipment), paragraph 12.
[7] The following two paragraphs are based on descriptions contained in section 5.2 of Department of Trade and Industry: October 2002 Power System Emergency Post Event Investigation, Overview Report, Version 1.0, dated 16 December 2002, prepared by BPI.
[8] See Section 15 paragraph 15.13 for a definition of subsequent expenditure on existing assets.
[9] NIE told us that the element of repairs and maintenance which NIE initially records in repairs and maintenance and subsequently capitalizes is not confined to the reactive capex as shown in Table 2.

TABLE 2 **Classification of subsequent expenditure on existing assets between capex and opex, 'repairs and maintenance' categories italicized (current situation)**

	Capex ie asset replacement or refurbishment	**Opex** ie other expenditure not classified as asset replacement or refurbishment
Planned	Asset Replacement Programme as defined in NIE's asset strategy papers as: • assessed asset replacement; and • refurbishment assets (selected major component replacement at transmission eg bushings).	*Routine maintenance performed in accordance with NIE's ISO certified plant maintenance procedures.*
Reactive	*Unplanned asset replacement.* *Addresses asset replacement not included in the planned programme or capitalized asset replacement as a result of faults*	*Repairs to an existing asset. Can involve similar activities to routine maintenance but selective to address specific failure or defect*

Source: NIE.

23. In Table 3 we set out the trends that the UR observed in NIE's combined opex and capex repairs and which formed the starting point for its concerns.[10]

TABLE 3 **NIE's expenditure on repairs and maintenance between 2000/01 and 2011/12**

£ million in 2009/10 prices

	RP2		*RP3*					*RP4*				
	00/01	*01/02*	*02/03*	*03/04*	*04/05*	*05/06*	*06/07*	*07/08*	*08/09*	*09/10*	*10/11*	*11/12*
Opex	18.2	16.1	13.8	13.7	13.4	11.0	10.0	9.8	10.0	9.1	9.6	10.5
Capex	1.6	3.0	3.5	3.7	5.8	5.7	7.6	6.4	7.5	6.7	10.2	8.1
Total	19.8	19.1	17.3	17.4	19.2	16.7	17.6	16.2	17.5	15.8	19.8	18.6
Capex as a percentage of total (%)	8	16	20	21	30	34	43	40	43	42	52	44

Source: NIE.

The UR's view

24. The UR's view was that the higher proportion of other repairs and maintenance expenditure that had been capitalized (whilst total expenditure had remained broadly flat over the period) had been the result of two factors:

(a) NIE had substituted activities carried out under an opex programme for the same activities carried out under a capex programme. The UR also referred to metering cabinet and street pillar replacement programmes here as further examples. The UR described this as 'capital programme substitution'.

(b) NIE had set up processes over the period of review to identify activities that, although for accounting purposes had initially been treated as opex, NIE had subsequently been able to ascertain that these activities had in fact been incorrectly classified as opex. As a result NIE had transferred the costs for these activities from opex to capex. The UR described this as 'direct capitalization'.

25. As mentioned in paragraphs 15.38, the UR asked us following our provisional determination to investigate further a number of activities that fell within repairs and

[10] Reactive tree cutting is one element of routine maintenance activities that NIE undertakes in connection with its overhead lines. As we analyse this element separately, the costs presented exclude those relating to reactive tree cutting.

maintenance, namely non-recoverable alterations and certain routine maintenance activities.[11]

NIE's response

26. NIE argued that it was not possible to infer that any transfers to capex from expenditure initially recorded as opex were inappropriate or evidence of any change in capitalization practice ('direct capitalization'). Further, the 'capital programme substitution' effect that the UR had identified amounted to the UR attempting to match an increase in capex in one accounting category to a fall in opex in another accounting category where the UR deemed that both categories covered broadly the same type of work.[12] The UR, however, had failed to recognize important changes in the mix of NIE's activities between RP3 and RP4 which had legitimately given rise to an increase in capex and a decrease in opex.[13]

Our analysis and interpretation of events

27. From the overview analysis of the development of repairs and maintenance expenditure set out in Table 3 it is noticeable that opex has declined as capex has grown. One possible explanation for this situation out of many possible explanations could be that some expenditure previously classified as opex was now being classified as capex. Another possible explanation could be that NIE, having previously invested in new assets with lower ongoing maintenance requirements, had been able to reduce the level of its ongoing maintenance activity. A further possible contributory explanation could be that NIE had replaced more assets on a proactive basis in later periods than it had in earlier periods. We also noted that this analysis did not give a complete picture of subsequent expenditure on existing assets as some of such expenditure would be captured within NIE's (planned) capital programmes, ie 'planned capex' as shown in the top left hand corner of Table 2.

28. We obtained a better understanding of the nature and extent of the principal categories of activity captured under the umbrella term 'repairs and maintenance'. In the tables below we provide breakdowns of these categories as identified by NIE, split between opex and capex, and give a description of what each activity encompasses.

TABLE 4 **Analysis of the principal categories of activity within NIE's expenditure on repairs and maintenance (opex element only) between 2000/01 and 2011/12**

£ million in 2009/10 prices

	RP2		*RP3*					*RP4*				
	00/01	*01/02*	*02/03*	*03/04*	*04/05*	*05/06*	*06/07*	*07/08*	*08/09*	*09/10*	*10/11*	*11/12*
Fault & emergency	6.5	7.3	6.4	5.8	6.1	5.4	5.7	5.0	5.3	5.0	5.1	5.9
Routine maintenance	8.6	5.1	5.0	6.0	5.4	3.8	2.9	3.6	3.3	2.9	3.3	3.6
Customer Driven (To do)	0.6	1.9	1.4	1.1	0.8	1.0	0.9	0.7	0.9	0.7	0.8	0.6
Non-recoverable alterations	1.4	0.8	0.8	0.6	0.8	0.6	0.4	0.3	0.3	0.3	0.3	0.3
Metering	1.1	1.0	0.2	0.3	0.4	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total	**18.2**	**16.1**	**13.8**	**13.8**	**13.5**	**11.0**	**10.1**	**9.8**	**10.0**	**9.1**	**9.7**	**10.5**

Source: NIE.

[11] , The UR referred to the provisional determination, Appendix 15.1, paragraphs 35 & 36 (non-recoverable alterations) and paragraphs 31–34 (routine maintenance).
[12] NIE Statement of Case, Chapter 11, paragraph 4.31.
[13] ibid, Chapter 11, paragraph 4.32.

TABLE 5 **Analysis of the principal categories of activity within NIE's expenditure on repairs and maintenance (capex element only) between 2000/01 and 2011/12**

£ million in 2009/10 prices

	RP2		*RP3*					*RP4*				
	00/01	*01/02*	*02/03*	*03/04*	*04/05*	*05/06*	*06/07*	*07/08*	*08/09*	*09/10*	*10/11*	*11/12*
Fault & emergency	0.7	1.3	1.1	1.6	2.9	2.6	4.4	2.7	3.3	2.9	6.5	4.1
Routine maintenance	0.6	0.4	0.7	0.5	0.9	0.8	1.0	1.4	1.4	1.4	1.0	1.4
Customer Driven (To do)	0.3	0.1	-	-	0.4	0.3	0.1	0.1	0.1	0.1	0.1	0.2
Non-recoverable alterations	-	1.1	1.6	1.6	1.6	2.1	2.1	2.1	2.7	2.4	2.7	2.4
Metering	-	-	-	-	-	-	-	-	-	-	-	-
Total	**1.6**	**2.9**	**3.4**	**3.7**	**5.8**	**5.8**	**7.6**	**6.3**	**7.5**	**6.8**	**10.3**	**8.1**

Source: NIE.

TABLE 6 **Description of the principal activities within repairs and maintenance**

Category	*NIE description*
Fault and emergency	Work required immediately after a fault occurs on the system. This will be initiated by either a fault on the system affecting customer supply or an incident or fault having the potential to compromise public safety or system security. This can involve repairs to the overhead network, underground network and plant and equipment following faults or as a result of storms.
Routine maintenance	A number of activities were captured under this category including: • cyclic maintenance (inspections/patrol/testing etc) • clearing defects resulting from inspections • grounds maintenance (both cyclic and reactive) • clearance of Apparatus Operational Restriction (AOR) applied to plant and switchgear for safety reasons • maintenance to overhead plant items—sectionalisers and reclosers • testing of cables and cable oil pumping • one-off exceptional items • plant workshop (eg re-calibration of overhead line test equipment, steelwork fabrication (either in house or outsourced))
Customer Driven (To do)	Network defects reported to NIE by customer which give rise to inconvenience and/or concern to customers and which could through time result in safety or performance matters. This type of reactive work would include: • Environmental—such as bird fouling • Maintenance—including encasing services, stays, substation defects • Dangerous situations • Third party tree cutting • Defective poles, services or equipment k
Non recoverable alterations	This is a particular category of customer-driven activity which can arise in those situations where NIE has needed to obtain a wayleave, cable easement or lease (excluding service equipment) in order to install its equipment on third party property. Under the terms of, for example, the standard Wayleave Agreement, NIE is required to alter or move that equipment at no charge to the specific customer. In these cases NIE is required to do the minimum work to meet statutory safety obligations. Capex relates to alteration activity, for example: • where electricity infrastructure is impeding a bona fide development • to provide statutory overhead line clearances to remove unsafe or dangerous situations Opex (repairs and maintenance element) relates solely to the activity of unclip/reclip of LV mains and services.
Metering	This comprises two categories of R&M expenditure: *Service Order Scheduling and Appointments (SOSA)* This is domestic metering work that is largely driven by the electricity market, for example new connections, replacement of faulty meters, replacement of house service cut-outs, and meter changes required to facilitate a change in tariff. The portion of SOSA expenditure associated with high-volume meter changes is allocated to capex. The remaining expenditure is allocated to opex for work that does not result in changing or installing a meter, for example, supply energizations (required when customers move into previously vacant premises) and de-energizations (required when properties are left vacant). *Revenue protection* Revenue protection services relate to work engaged with the detection and prevention of the illegal abstraction of electricity, and associated unbilled electricity consumption. This involves visits to both energized and de-energized domestic and commercial properties. The service includes the administration of theft recovery.

Source: NIE.

29. We noted from Table 4 that a relatively small amount of opex had been incurred both on Customer Driven and Metering. In addition there had been very limited capitalized expenditure on Customer Driven and no recent capitalized expenditure on metering. This suggested that, if there had been any reclassification between opex and capex, its impact would have been very limited in terms of NIE's outperformance of its controllable opex.

30. We therefore examined more closely the three main categories of repairs and maintenance expenditure where there appeared to have been an increase in capex potentially through a reduction in opex.

Fault and emergency

31. NIE provided an analysis of its expenditure falling within this category in which it separately identified costs capitalized in relation to repair work following storms.

TABLE 7 **NIE's expenditure on fault and emergency between 2000/01 and 2011/12**

£ million (2009/10 constant prices)

	Annual expenditure											
	00/01	*01/02*	*02/03*	*03/04*	*04/05*	*05/06*	*06/07*	*07/08*	*08/09*	*09/10*	*10/11*	*11/12*
Capex (not storms)	0.7	1.3	1.1	1.5	1.8	2.6	2.8	2.5	2.6	2.8	2.8	2.9
Opex (not storms)	6.5	7.3	6.4	5.7	5.1	5.3	5.4	4.7	5.1	4.3	4.9	4.9
Total excluding storms	7.2	8.6	7.5	7.2	6.9	7.9	8.2	7.2	7.7	7.1	7.7	7.8
Storms (capex)	-	-	-	0.1	1.0	-	1.6	0.3	0.6	0.1	3.7	1.2
Storms (opex)	-	-	-	0.1	0.9	0.1	0.3	0.3	0.3	0.7	0.2	1.0
Total including storms	7.2	8.6	7.5	7.4	8.8	8.0	10.1	7.8	8.6	7.9	11.6	10.0
Capex as a percentage of total (%)	10	15	15	21	26	33	34	35	34	39	36	37

(Excluding storms in both the numerator and denominator)

Source: NIE.

32. This category of expenditure comprises almost half of total repairs and maintenance expenditure (ie both opex and capex). Storm costs vary significantly from one year to the next but otherwise total fault & emergency costs, as shown in Table 7, appear to have been relatively stable over the period. Non-storm capex has grown as non-storm opex costs have fallen somewhat over the period analysed.

33. NIE commented that it had been experiencing more cable faults as its underground network aged. As fixing cable faults typically consisted of it replacing the faulty cable, a procedure which was relatively expensive compared with fixing overhead faults, this would in part explain the increase in fault and emergency repairs being capitalized. NIE also referred to its ongoing review and development of its reporting systems (timings refer to 2006/07 onwards), which enabled better identification of capex.

Routine maintenance

34. NIE also provided an analysis of its expenditure falling within this category. We deducted the costs for reactive tree cutting provided by the UR from the amounts identified as opex as we analysed that element of cost separately.

TABLE 8 **NIE's expenditure on routine maintenance between 2000/01 and 2011/12**

£ million (2009/10 constant prices)

	Annual expenditure											
	00/01	*01/02*	*02/03*	*03/04*	*04/05*	*05/06*	*06/07*	*07/08*	*08/09*	*09/10*	*10/11*	*11/12*
Capex	0.6	0.4	0.7	0.5	0.9	0.8	1.0	1.4	1.4	1.4	1.0	1.4
Opex	8.6	5.1	5.0	5.9	5.4	3.8	2.9	3.5	3.3	2.9	3.3	3.6
Total	**9.2**	**5.5**	**5.7**	**6.4**	**6.3**	**4.6**	**3.9**	**4.9**	**4.7**	**4.3**	**4.3**	**5.0**
Capex as a percentage of total (%)	7	7	12	8	14	17	26	29	30	33	23	28

Source: NIE.

35. We observed that the drop in opex spend was very marked over the period. NIE provided a number of reasons for this drop including replacement of aged assets with their modern equivalents, reduction in the numbers of offices reducing the need for building and grounds maintenance and the subsequent outsourcing of grounds maintenance as well as revised maintenance strategies such as 'reliability centred maintenance'[14] and 'cost risk optimization'.[15]

36. NIE also referred to improvements it had been able to make to its asset register since 2003/04 which had led to improved classification of spend on clearing defects that had been identified as a result of routine maintenance. The implication was that some of this expenditure that previously may have remained as opex was now being capitalized as it related to the replacement of a component of an existing asset.

37. NIE also provided some examples of maintenance activities which had previously been accounted for as routine maintenance. However, these activities had been subsumed into capital programmes. These related to inspection[16] and patrol[17] activities, miscellaneous plant maintenance,[18] rectifying defects,[19] transmission fault and emergency[20] and maintenance.[21]

38. At the UR's request, we further investigated a number of routine maintenance activities that have been subsumed into capital programmes as outlined in the previous paragraph. We requested that NIE explain what had occurred in relation to the following activities:

(a) mini pillar and underground disconnection box (UDB) inspections;

(b) Condition Monitoring Patrol;

[14] Reliability centred maintenance is where the network operator first seeks to understand the causes and effects of different types of network failure in order to determine which type of maintenance task would address each failure mode and when that task should be applied.

[15] Cost risk optimization happens when the correct (ie optimal) frequency of a maintenance task is applied following analysis of actual costs and potential costs of a risk.

[16] Mini pillar and underground disconnection box (UDB) inspection activity, which involved the gathering of condition data, had from 2003 been incorporated into a new capex program which focused on effecting asset inspection, refurbishment and replacement.

[17] Condition monitoring, line patrol (both transmission & distribution). Previously the collection of data for Grade 1 asset systems had fallen under routine maintenance, but now this data (from 2005/06 and 2007/08 respectively) was being captured either as part of the capital patrol survey or as part of organising the wayleaving ahead of refurbishing overhead lines.

[18] Maintenance of 33kV air break disconnectors since 2007/08 had been combined with the overhead line refurbishment programme.

[19] The mini-pillar refurbishment project had from 2006/07 subsumed any previous activity undertaken under routine maintenance or defect clearance associated with LV mini-pillar and feeder pillars.

[20] From 2003/04 routine maintenance on transmission assets, which is capital in nature as it generally involves replacement of assets, was capitalized.

[21] The use of helicopter to facilitate repairs to the distribution line network was from 2007/08 subsumed into the (capex) overhead line programme.

(c) Distribution Line Patrol;

(d) Transmission Line Patrol;

(e) 33 kV Air Break Disconnectors maintenance;

(f) LV Minipillar and feeder pillar Defects;

(g) Transmission Fault & Emergency; and

(h) Distribution Repairs re Helicopter overheads;

39. We reviewed NIE's responses in each case. We were not satisfied that any of these examples represented cases of reclassification of opex as capex.

Non-recoverable alterations[22]

40. The final area we looked at in more detail was non-recoverable alterations. Although total expenditure is not large, there has been a very marked switch of spend being categorized as capex, rather than opex.

TABLE 9 **NIE's expenditure on non-recoverable alterations between 2000/01 and 2011/12**

£ million (2009/10 constant prices)

	Annual expenditure											
	00/01	*01/02*	*02/03*	*03/04*	*04/05*	*05/06*	*06/07*	*07/08*	*08/09*	*09/10*	*10/11*	*11/12*
Capex	-	1.1	1.6	1.6	1.6	2.1	2.1	2.1	2.7	2.4	2.7	2.4
Opex	1.4	0.8	0.8	0.6	0.8	0.6	0.4	0.3	0.3	0.3	0.3	0.3
Total	1.4	1.9	2.4	2.2	2.4	2.7	2.5	2.4	3.0	2.7	3.0	2.7
Capex as a percentage of total (%)	-	58	67	73	67	78	84	88	90	89	90	89

Source: NIE.

41. NIE explained that the underlying nature of its activities had not changed in this area and the overall level of spend had increased generally in line with construction activity in the wider economy in Northern Ireland. It mentioned that it was incurring higher excavation and reinstatement costs associated with diversionary work in areas where 'high amenity' paving had been laid. It also referred to the fact that it transferred this activity to its job management system (JMS) since 2005/06, which improved visibility and management of costs in this area. The implication was therefore that since this point it has been better able to identify that element of total spend that related to replacing existing assets, resulting in a higher level of capitalized expenditure in this area.

42. At the UR's request, we further investigated non-recoverable alterations. NIE explained to us that prior to 2001/02, all non-recoverable alterations work had been classified for accounting purposes as opex—hence the zero figure for capex in 2000/01. However, the element of it which related to the diversion of existing lines should have been treated as capex. As explained in paragraph 41, NIE had been able, through the deployment of a JMS system over time, to identify fully all its capital expenditure, in this case from a zero base.

[22] This category of activity is also explained and discussed in paragraphs 9.68–9.73.

Capitalized overheads

43. A business will need to undertake, or pay someone else to provide, a wide range of activities in support of its primary activities, in NIE's case the supply of electricity to Northern Ireland consumers. These costs are often described as indirect costs or overheads. Under accounting standards overheads should be capitalized when they form part of the directly attributable costs of bringing an asset into its present location and condition etc. Whether such costs are being appropriately capitalized cannot be judged in isolation from whether the expenditure on the 'assets' is appropriately capitalized in the first place.

The UR's view

44. The UR observed that there had been a large increase in the allocation of overhead costs from opex to capex (up from 65 per cent of total overhead expenditure to 80 per cent in some cases) without any evidence of an efficiency gain to explain the reduction in opex costs.[23,24]

NIE's response

45. Capitalized overheads, whilst not directly relating to the purchase of or construction by NIE of a tangible fixed asset, relate to any related expenditure which is directly attributable to the capital project being undertaken. The types of expenditure that fall into this category would relate to asset management and planning, procurement and stores, outage management, the installation and commissioning of technical equipment, safety and IT.[25]

46. NIE is required by condition 2[26] of its licences to comply with relevant accounting standards in deciding how much of its overheads to capitalize. Those obligations have the effect to require NIE to keep its capitalization rates under review, with a view to ensuring that an appropriate proportion of overheads are capitalized.[27] As an increased proportion of recent expenditure was now classified as capex, therefore an increased proportion of these types of costs were now being capitalized.

Our analysis and interpretation of events

47. We note that the information provided to us related to the amounts of overheads capitalized over the period as set out in Table 15.2 of Section 15 and the UR's comments about the proportions of total overheads capitalized. We note that the level of overhead costs capitalized in real terms remained broadly flat whilst at the same time all of NIE's other costs within controllable opex including all overhead costs had fallen significantly over the period.

48. In its submission, the UR did not argue that NIE had been inappropriately capitalizing certain indirect costs, rather than the proportion of the total indirect costs that NIE had been capitalizing had grown above historical levels of capitalization. Were we to

[23] UR Draft Determination, 30 August 2012, paragraph 6.3.
[24] UR Statement of case, paragraph 6(b)(c).
[25] NIE's Supplementary Submission to the CC, Annex 9, 10 June 2013, paragraph 3.1.
[26] The current Condition 2 of NIE's licence, Preparation of Accounts, requires, amongst other things, the accounts to conform to the best commercial accounting practices including International Accounting Standards and International Financial Reporting Standards issued by the International Accounting Standards Board and adopted for use in the European Union: www.uregni.gov.uk/uploads/publications/NIE_-_Successor_Distribution_Licence_Document_-_11_March_2013.pdf, paragraph 6a).
[27] NIE's Supplementary Submission to the CC, 10 June 2013, Annex 9, paragraph 3.2.

judge that an adjustment would be warranted in relation to the reclassification of expenditure between opex and capex on tree cutting and/or in relation to repairs and maintenance, then a natural consequence would be to revisit the calculation of the amount of overheads capitalized.

49. We note that some overhead costs may be capitalized because they relate to NIE's planned capex programmes, and as a result the absolute amount capitalized may vary to some degree with the extent of these programmes, particularly if the support activities associated with these projects were not provided as part of the project itself and therefore were either provided in-house by NIE or procured separately.

Trends in NIE controllable opex

50. Finally, we also looked at the trends in NIE's controllable opex over the period to see if there were any other factors that would explain NIE's substantial outperformance of its controllable opex forecasts. It appeared from this analysis that substantial savings had been made by NIE in many other areas, such as payroll and IT and telecoms, costs which one would expect to be primarily opex, rather than capex, in nature.

TABLE 10 **NIE's breakdown of its controllable opex between 2000/01 and 2011/12**

£ million in 2009/10 prices

	RP2		*RP3*					*RP4*				
	00/01	*01/02*	*02/03*	*03/04*	*04/05*	*05/06*	*06/07*	*07/08*	*08/09*	*09/10*	*10/11*	*11/12*
Payroll	21.2	18.0	15.0	17.6	15.6	10.9	11.1	10.1	10.6	10.9	10.4	11.1
Repairs & maintenance (including opex tree cutting)	19.1	17.3	14.8	14.7	15.2	12.0	10.8	10.3	10.5	10.0	10.2	10.9
Powerteam (not repairs & maintenance)	8.3	9.0	8.8	8.6	7.2	6.8	6.4	6.0	5.7	5.6	5.8	6.1
IT & telecoms	10.3	9.0	9.0	7.6	7.0	5.0	4.6	4.1	4.0	4.6	4.6	4.6
Corporate	3.9	3.9	3.5	5.5	5.3	5.2	4.8	3.7	2.9	3.1	3.5	2.6
General controllable opex	8.0	8.7	6.7	4.1	4.2	4.1	3.5	3.6	3.9	2.7	2.8	2.7
Insurance	3.9	2.7	2.7	2.5	2.1	1.6	1.3	1.2	1.1	1.4	1.3	1.0
Property	1.9	1.9	1.8	1.0	0.7	0.8	0.6	0.6	0.6	0.7	0.5	0.7
Innovation schemes	-	-	-	-	-	-	0.0	0.4	0.4	0.6	0.3	0.1
Professional services	0.6	0.4	0.4	0.3	0.2	(0.0)	0.1	0.1	0.2	0.3	(0.1)	0.2
Severance/redundancy/ restructuring	0.8	0.6	1.2	0.7	1.6	0.1	(0.1)	0.2	0.3	0.3	-	-
Capitalization of overheads	(6.2)	(8.1)	(9.1)	(10.6)	(9.1)	(9.2)	(9.9)	(9.3)	(9.1)	(8.7)	(9.0)	(8.9)
Controllable opex (BPQ view)	71.8	63.4	54.8	52.0	49.9	37.1	33.3	30.9	31.1	31.4	30.3	31.1
Costs excluding tree cutting, R&M and capitalized OHs	58.9	54.2	49.1	47.9	43.9	34.3	32.4	29.9	29.7	30.2	29.1	29.1

Source: NIE.

Note: The analysis of controllable opex ('BPQ view') differs from actual controllable opex (ACO), the term defined in NIE's licence conditions and required to be reported in the unpublished version of NIE's regulatory accounts, and analysed in Tables 1 and 2 of Section 15. Controllable opex (BPQ view) is greater than ACO. The former includes costs and revenues (treated as negative costs) in relation to items which are recovered through separate charges to the main transmission and distribution charges. Examples of these other items are rechargeable income, tort income, recharges to other businesses.

Capitalization practices and the accounting framework for NIE

Introduction

1. In this appendix we set out different approaches to accounting and how NIE accounted for opex and capex costs, and how this changed for the items under consideration in recent years.

2. Regulators of UK network industries invariably require regulated firms to prepare, publish and have audited regulatory accounting statements (often referred to as regulatory accounts). This is an additional requirement on these firms above the general requirement that applies to all incorporated entities to prepare annual statutory accounting statements.

3. One of the purposes of regulatory accounting statements is to assist the regulator in setting future charge controls. Such statements allow the focus to be squarely on the regulated activities of the firm and allow the possibility, among other things, for the regulator to specify the application of accounting policies that differ from those applying to statutory accounting statements.

4. Condition 2 of NIE's Licences (Preparation of Accounts) requires NIE to produce such regulatory accounting statements annually. The Licence states that these statements should conform to the best commercial accounting practices including recognized accounting standards,[1] that they should be consistently prepared from one period to the next[2] and that the accounting policies should be stated.[3] This Licence condition does not set any further requirements regarding the basis on which NIE should prepare its regulatory accounts. NIE adopts the same accounting policies in its statutory and its regulatory accounts.

5. Best commercial accounting practice would include adhering to the accounting standards in force at the time. Up to and including 2004/05 NIE, in common with all UK listed firms, followed UK accounting standards and from 2005/06, following an EU directive, followed international accounting standards, IFRS.

6. While it is the case that the treatment of costs in NIE's regulatory accounts will not necessarily be the same as those reflected in any price control settlement, under RP4 costs treated as fixed asset additions (in other words, capex) in any one period are the starting point for additions to NIE's RAB.

Accounting standards in relation to subsequent expenditure on existing fixed assets

7. As discussed in Section 15 (paragraph 15.6), much of NIE's expenditure relates to subsequent expenditure on existing fixed assets, and that the bulk of NIE's fixed assets are composite assets. There appears to be two broad approaches to classifying subsequent expenditure on composite fixed assets, as set out below.

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[1] The current version (dated 13 March 2013) of the Licence for NIE's distribution business stipulates International Accounting Standards and International Financial Reporting Standards issued by the International Accounting Standards Board and adopted for use in the European Union:
www.uregni.gov.uk/uploads/publications/NIE_-_Successor_Distribution_Licence_Document_-_11_March_2013.pdf.
[2] Paragraph 3b of Condition 2 of the Licence.
[3] Paragraph 6a of Condition 2 of the Licence.

UK accounting standards

8. If the asset has been given a single asset life, then any further expenditure[4] on the asset subsequent to its creation but before the wider asset has come to the end of its expected useful economic life, should be expensed. In other words all such expenditure should be written off in the profit and loss account as repairs and maintenance. Under this approach replacement of components of a wider composite asset before that wider asset has come to its useful life would be expensed.

International accounting standards

9. Alternatively, that element of such expenditure relating to the replacement of components of the wider asset should be capitalized and at the same time the carrying values associated with the replaced components, to the extent that they are not already fully depreciated, must at the same time be written off to the profit and loss account.

Our analysis of the relevance of these different approaches

10. The difference in these approaches can be illustrated by way of an analogy with a car. If major parts of a car such as the engine or gearbox needed to be replaced before the end of the period of intended use of the car, then under UK accounting standards the cost of the replacement engine or gearbox would be written off as incurred as opex. Most individuals in relation to their own cars would describe such expenditure as 'repairs and maintenance' rather than an investment in a replacement component of their car.

11. Under international accounting standards the cost of the replacement engine or gearbox would be capitalized on the grounds that the engine and gearbox are major parts of the car and in themselves are assets which can be expected to bring future benefits to their owner.

12. What is particularly difficult in relation to perpetual composite assets (see paragraph 15.7), precisely the type of assets that NIE operates, is that there is not necessarily any clear cut-off point when the originally constructed assets have been replaced. This contrasts sharply with the example of a car, which at some point its owner will either decide to sell inclusive of its replacement engine or gearbox or sell/give away for scrap.

13. The implication is that in the case of perpetual composite assets under UK accounting standards there will not necessarily be a sharp distinction between expenditure on replacement components of an asset at the end of their intended useful life (capitalized) and replacement of components on an asset before the end of their intended useful life (expensed as an operating cost). Under international accounting standards this distinction does not apply, so that all such replacement expenditure on components of a wider asset should be capitalized.

Materiality

14. Another consideration that might have been taken into account by NIE when deciding to what level of disaggregation it would implement its chosen accounting policy is the concept of materiality.

[4] However, expenditure which in effect creates an enhanced asset would be capitalized.

15. An item of information is material if its misstatement or omission might reasonably be expected to influence the economic decisions of users of that information. Whether information is material will depend on the size and nature of the item in question judged in the particular circumstances of the case. In the case of statutory financial statements the users are taken to be the (potential) investors in that firm. As investors are primarily interested in the returns generated by the firm as a whole, the level of disaggregation at which an accounting policy is implemented is not a major concern so long as the statements at an overall level provide a fair view.

16. However, the information we reviewed in order to investigate NIE's capitalization practices has been at a much more disaggregated level. At this level of disaggregation, a change in classification of a particular activity might be considered material, but at the level of the overall financial statements, such a change might not. In these circumstances a change in classification at the disaggregated level would not necessarily have led to the recognition of a change in accounting policy at the level of the statutory or regulatory accounts.

17. It might therefore have been the case that for materiality reasons (operating at the level of the statutory and regulatory accounts) that NIE did not need to restate its prior period tangible fixed asset figures when it switched from UK to international accounting standards.

Accounting treatment of subsequent tree cutting

18. During the course of our review the UR also raised the issue whether subsequent tree cutting, which 'represented nothing more than the removal of trees that could damage the existing network', should be considered to be a valid asset. The UR further pointed out that there had been a dramatic increase in the scale of capitalized empty space with no physical improvement or change to the network.

19. While cut trees may not represent a typical example of an item of tangible fixed assets, it is nevertheless an asset for accounting purposes. This is because, while the clearance provided by the cut trees may not of itself provide the physical medium over which electricity is delivered to the consumers of Northern Ireland, without the trees and other vegetation being regularly cleared, no electricity would be able to be supplied to Northern Ireland consumers in a safe and storm-resilient manner. Therefore it was appropriate to account for expenditure on tree cutting like any other item of spending on measures which are essential for safety or which enhance the desired characteristics of the network. And as this expenditure provided several years of future economic benefits, it was appropriate (under international accounting standards as described above) that it should be capitalized.

20. The UR also questioned the depreciation over 40 years of this expenditure, the regulatory asset life assigned to all the expenditure on its overhead lines which NIE capitalizes. NIE, however, typically cut trees in the proximity of overhead lines between every three to five years. This question therefore relates to the period of time over which it is appropriate for the cost of tree cutting (capitalized element) to be recovered in customers' prices.

21. NIE explained to us that the policy was to depreciate all network assets over 40 years for regulatory purposes, and therefore it did not distinguish between the various components of the network.[5] Some components like underground cables and overhead conductor may last 50 years; other components may have shorter asset lives.

[5] NIE also adopts an 'up to 40 years' asset life for infrastructure assets in both its statutory and regulatory accounts.

However, NIE's policy was to treat all these assets as part of a single network that is depreciated over 40 years. As tree cutting accounted for only a very small percentage of the overall value of NIE's network, it was not necessary under the relevant accounting standard[6] for NIE to ascribe a separate asset life to this expenditure.

22. The appropriate regulatory asset life for this expenditure is related to, but distinct from, the assessment of the implications of NIE's alleged changes in its capitalization practices (see paragraphs 15.96 to 15.101).

NIE's documentation regarding its capitalization practices

23. The UR told us that it had had difficulty in getting a clear picture of NIE's capitalization policies from the information NIE had provided it, and whether there had been any changes in these policies, over the period. The UR had ascertained that NIE had in the past relatively detailed guidance (dated June 2000) on what expenditure should be treated as capex and what should be treated as opex.[7] In the following year there had been an NIE Group Finance paper to update NIE's accounting policies to be in line with the latest UK accounting standard on tangible fixed assets.[8] The next development had been the NIE Executive's approval of an updated version of NIE's Networks Capital Expenditure Procedures manual in 2005. This included half a page of summary guidance regarding 'capital v revenue classification'.

24. We reviewed all of this documentation, noting that none of the guidance set out clearly articulated principles of the distinction between opex and capex expenditure that could be easily and consistently followed in practice. The 2000 guidance was the most specific and prescriptive and suggested that UK accounting standards had informed its thinking. For example, expenditure on cable replacement with a like-for-like capacity where the cable was under 35 years of age and expenditure on tower replacement where towers were less than 55 years were both accounted for as opex.

25. The 2005 documentation simply stated that all asset replacement should be classed as capital, an approach clearly consistent with international accounting standards.

26. Finally, there appears to have been a long-standing lack of clarity about the distinction between capex and opex. As noted in paragraph 15.12, footnote 10, NIE had billed its Composite Proposal, which eventually was reflected in the design of RP4, as a solution which would remove ambiguity around the allocation of costs between opex and capex. This lack of clarity dates back to at least the last time an NIE price control was referred to us in 1997. When the MMC published its final report, it included as an appendix NIE's then classification between opex and capex.[9]

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[6] IAS16 (International Accounting Standard 16: Property, Plant and Equipment).
[7] NIE had issued version 1.0 of Networks Capital Expenditure Procedures manual. This included three pages of illustrative guidance regarding 'capital v revenue classification'.
[8] 'Accounting for Fixed Assets and Depreciation: implications of Financial Reporting Standard 15'. www.frc.org.uk/Our-Work/Publications/ASB/FRS-15-Tangible-Fixed-Assets/FRS-15-Tangible-Fixed-Assets.aspx. NIE's paper set out the criteria to be applied when deciding whether expenditure was either capital or revenue in nature.
[9] http://webarchive.nationalarchives.gov.uk/20111202195250/http:/competition-commission.org.uk/rep_pub/reports/1997/fulltext/397a7.2.pdf.

Assessment of the possible effect of the RP5 price control on consumer prices

1. This appendix sets out how our determination might affect consumers. We used the financial model provided to us by the UR to produce an estimate of the maximum regulated revenues that NIE would be allowed to levy for each period of RP5 following our final determination on the premise that NIE neither under- or outperformed its RP5 cost allowances.[1] The specification in NIE's Licences of the calculation of maximum regulated revenues is the principal mechanism through which the price control affects the charges NIE can levy for distribution and transmission services.

2. In Table 1 we set out the profile of the expected billing of the maximum regulated revenues for RP5 based on our upfront cost allowances profiled over the tariff years beginning 1 October 2012. This table demonstrates that most of the revenue raised relates to distribution, rather than transmission charges.

TABLE 1 **Billed revenues excluding impact of any one-off refund***

£ million (nominal)

	Actual	*Forecast*			
Year beginning 1 October	*2012*	*2013*	*2014*	*2015*	*2016*
Distribution	177	178	177	180	185
Transmission	40	44	43	49	54
Combined	217	222	220	229	239

Source: CC analysis using a spreadsheet model provided by the UR.

*See paragraph 7 for further information about the any one-off refund.

3. The restriction on NIE's revenues takes the form of a revenue rather than a price control, ie any increases or falls in the volume of electricity transmitted and distributed during RP5 would mean that unit prices would fall or increase accordingly. In other words, consumers in aggregate do not actually have to pay more for transmission and distribution when they consume more, so that NIE's transmission and distribution revenues remain unchanged.

4. We therefore took account of the effect of expected changes in the volume of electricity to be transmitted and distributed over RP5 to convert our estimate of maximum regulated revenues arising from our final determination into an estimate of the effect on consumer prices. For this purpose we used the estimate of the annual increase in volumes of electricity NIE expected to deliver to consumers over RP5 of just under 1 per cent per year, almost all of which was forecast to be accounted for by growth in the number of customers, rather than by greater usage by these customers. For the purposes of this analysis we also assumed that any changes in maximum regulated revenues would flow directly into NIE wholesale revenues and these in turn would directly flow through to revenues raised at the retail level from consumers.[2] We therefore were able to generate an estimate of the effect on the prices charged to consumers of our final determination for each billing year from 1 October 2012 through to the end of RP5 on 30 September 2017.

[1] Maximum regulated revenues will also depend on whether NIE seeks, and the UR approves, allowances for additional D5 investment projects and the extent of NIE's expenditure on certain items outside core allowances, for example legacy Dt items.
[2] We cannot, however, estimate the impact on the individual charges that NIE levies to its customers (which are not the end consumers) as these are subject to separate approval by the UR.

5. We set out in Tables 2 and 3 the possible effect on consumer prices. We do this both relative to (forecast) movements in the RPI index[3] and in nominal terms. Actual maximum regulated revenues, and therefore the impact on consumer prices, may differ in practice depending on NIE's out-turn performance over RP5 (see paragraph 1) and, for the effect on consumer prices expressed in nominal terms, also on out-turn RPI inflation.

6. Table 2 sets outs the possible effect on consumer prices on a tariff-year-by-tariff-year basis, whereas Table 3 shows this information expressed in terms of its cumulative impact on prices compared with the base year for this analysis, namely 1 October 2012 to 30 September 2013.

7. Both tables exclude the effect on consumers of any over-recovery of transmission and distribution charges by NIE up to the end of the period before revised prices take effect for the tariff year beginning on 1 October 2014. As explained in Section 19, any over-recovery of charges will be reimbursed through a refund, to be passed on to consumers.

TABLE 2 **Change in prices excluding impact of any one-off refund: year-on-year change (per cent per year)**

		Announced	*Forecast*		
	Increase at 1 October each year	*2013*	*2014*	*2015*	*2016*
Distribution	Change in prices relative to RPI	(3.3)	(4.5)	(2.4)	(1.4)
	RPI increase	3.0	3.2	3.6	3.7
	Nominal change in prices	(0.4)	(1.5)	1.1	2.3
Transmission	Change in prices relative to RPI	5.7	(5.5)	9.7	4.5
	RPI increase	3.0	3.2	3.6	3.7
	Nominal change in prices	8.9	(2.5)	13.7	8.4
Combined	Change in prices relative to RPI	(1.6)	(4.7)	(0.0)	(0.1)
	RPI increase	3.0	3.2	3.6	3.7
	Nominal change in prices	1.3	(1.7)	3.6	3.6

Source: CC analysis using a spreadsheet model provided by the UR.

TABLE 3 **Change in prices excluding impact of any one-off refund: cumulative change over year beginning 1 October 2012 (per cent per year)**

		Announced	*Forecast*		
	Increase at 1 October each year	*2013*	*2014*	*2015*	*2016*
Distribution	Change in prices relative to RPI	(3.3)	(7.7)	(9.9)	(11.1)
	RPI increase	3.0	6.3	10.1	14.2
	Nominal change in prices	(0.4)	(1.9)	(0.8)	1.5
Transmission	Change in prices relative to RPI	5.7	(0.1)	9.6	14.6
	RPI increase	3.0	6.3	10.1	14.2
	Nominal change in prices	8.9	6.2	20.7	30.9
Combined	Change in prices relative to RPI	(1.6)	(6.3)	(6.3)	(6.4)
	RPI increase	3.0	6.3	10.1	14.2
	Nominal change in prices	1.3	(0.4)	3.2	6.9

Source: CC analysis using a spreadsheet model provided by the UR.

[3] Movements in the RPI index are calculated with reference to April RPI figures, approximately in the middle of each tariff year which runs from 1 October to 30 September. For example, the movement in the RPI index relevant for the increase at 1 October 2013 is calculated using April 2013 (actual) and April 2014 (forecast) RPI index values. RPI figures are as reported by the ONS up to October 2013, and thereafter estimated on the basis of the December 2013 OBR forecasts for RPI inflation.

8. For a representative domestic customer consuming 4,000 kWh a year over the period 1 October 2012 to 30 September 2013, the electricity charges include approximately £130 a year for distribution charges payable by the supplier to NIE.[4] An additional cost of the order of £22 might be attributable to NIE's element of the transmission charges payable by the supplier and by generators to SONI.[5] The total contribution of an average domestic customer to transmission and distribution charges considered in this inquiry is therefore about £152 a year.

9. Applying the cumulative price impacts measured relative to RPI, and assuming that SONI, generators and retailers pass through the changes in NIE's distribution and transmission charges in proportion to their current charges, we estimate that prices for consumers will overall reduce relative to the RPI over the course of RP5[6] by 6 per cent, and increase in nominal terms over the same period by 7 per cent (see Table 3). The significant above-RPI increases in transmission prices offset part of the reductions relative to RPI in distribution prices. As transmission charges form a relatively small proportion of the overall charge (see Table 1), the overall effect is still a reduction in charges relative to RPI. The representative domestic customer's bill is forecast to reduce by approximately £10 by the end of the four years to September 2017 from £152 per year to around £142 per year in 2012/13 prices (ie relative to RPI). Consumers may in addition receive a refund relating to any over-recovery of transmission and distribution charges by NIE relating to the period up to 30 September 2014.

[4] Based on 4,000 kWh and a distribution tariff of £10.39 a quarter plus 2.070p/kWh plus 5 per cent VAT.
[5] Based on an average transmission cost of 0.525p/kWh, from a transmission service charge of £42 million and total consumption of 8 billion kWh, applied to 4,000 kWh, plus 5 per cent VAT.
[6] We estimate the effect on prices against the prices in force for the tariff year beginning 1 October 2013.

The reporter and information transparency

Introduction

1. In this appendix:

   (a) We summarize how other regulators have made use of a reporter (or similarly-named function).

   (b) We summarize third party submissions we received on the subject of the reporter and information transparency.

   (c) We briefly review the Ofgem DNO RIGs.

How other regulators have used a reporter

2. This section briefly summarizes how Ofwat, ORR and Ofgem have made use of a reporter. We also reference how the UR has made use of a reporter for Northern Ireland Water.

Ofwat

3. Ofwat has recently changed its approach to regulatory compliance. Before this change took place it had used reporters for three main purposes:

   (a) to scrutinize the 'June returns': until 2010/11 Ofwat required the water companies to submit an extensive data set (covering areas such as operational performance and efficiency) on an annual basis;

   (b) to analyse the forecast data presented by companies in their charge control submissions; and

   (c) to carry out special investigations on specific aspects of individual water company performance, for example leakages.

4. The role of reporter was performed by consulting engineers. In addition, auditors were employed to examine the financial elements of the information submitted to Ofwat. Ofwat estimated that the total cost (across the 21 companies in the regulated water industry) was £1.5 million a year in a non-price-control year and £6 million a year in a price-control year.

5. Following a review of the sector by David Gray,[1] which highlighted the regulatory burden being imposed on the sector, Ofwat changed its policy on regulatory compliance. For the 2011/12 reporting year, it abolished the June returns. Instead, companies now take responsibility for assurance of their data and systems; they publish at least annually a risk and compliance statement and a series of key indicators. These statements coincide with the publication of company regulatory accounts.

[1] www.gov.uk/government/uploads/system/uploads/attachment_data/file/69442/ofwat-review-2011.pdf.

6. As a consequence of this change, the role of the reporter has reduced very significantly in the water industry (although the licences still seem to allow for the appointment of a reporter, presumably for ad-hoc special investigations).

ORR

7. Since April 2001 Network Rail's licence has included a condition providing for reporters to be appointed.[2] The purpose of the role is to provide ORR with an independent review of Network Rail's performance and stewardship of the network (as stipulated in its licence) via a rolling programme of data audits.[3] For example, in the current charge control reporters have assessed the accuracy and reliability of information; they have also monitored Network Rail's enhancement projects.

8. The data reporter spends approximately one FTE a year reviewing the reliability, quality, completeness and accuracy of reported information.[4]

Ofgem

9. Ofgem requires extensive asset data and performance and financial reporting from the regulated gas and electricity utilities (Ofgem has provided the DNOs with RIGs for this purpose). The licences of these companies provide that these values can be required to be verified by an 'independent examiner'.

10. Ofgem appoints an independent examiner to verify this data; there is a particular focus on verification in areas which are either high risk or technically complex. The examiner therefore has a remit which is confined to auditing/validating a particular piece of data.

11. It also has a technical assessor role relating to renewable investments brought forward which are similar to the proposed 'Fund 3' investments in Northern Ireland. Ofgem uses consultants for this work (in RP5 the UR saw this as being carried out by the reporter).

UR—Northern Ireland Water

12. In Northern Ireland the UR has established a reporter for the Water Utility sector (Northern Ireland Water). The UR said that the experience had been positive and that its decision to include a reporter for RP5 followed on from the positive contributions it had seen through the reporter role in water regulation in Northern Ireland Water. It said that this role was now well established.[5]

Water Industry Commission for Scotland—Scottish Water

13. From 2003 until 2010 the Water Industry Commission for Scotland (WICS) and Scottish Water engaged an independent 'Regulatory Reporter' whose remit was to audit and verify Scottish Water's information submissions. This involved the auditing of Scottish Water's Business Plans, along with audits of Scottish Water's Annual 'June Returns' and a range of targeted audits in areas such as the quarterly Capital

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[2] www.rail-reg.gov.uk/.
[3] ibid.
[4] www.ofgem.gov.uk/ofgem-publications/42781/network-licensee-data-compliance-report-final.pdf, Appendix 6, April 2011.
[5] www.uregni.gov.uk/publications/air12_reporters_submission/ &
www.uregni.gov.uk/uploads/publications/1_NIW_AIR12_Reporters_Overview_PD_final.pdf.

Investment Returns, Output Reporting, and Customer Service Reporting. The reporter was also involved in carrying out independent technical and cost-benefit assessments of specific areas of interest to WICS such as large projects and major study outputs.

14. In 2010, WICS reassessed the role, and requirement for, a regulatory reporter. It decided to replace it with the role of 'Independent Technical Assessor'. WICS considered that the role of regulatory reporter had delivered significant benefits but that a change in the format and extent of Scottish Water's information submission had become necessary (with a likely substantial reduction in content). The detailed information provided in previous submissions was replaced by a small number of high-level performance measures. The Independent Technical Assessor's role is to ensure that the information, processes and systems which will underpin these high-level measures are being properly handled within Scottish Water's business.

Third party submissions on the reporter

ESB (NIE's parent company)

15. Professor Littlechild (on behalf of ESB) submitted a detailed critique of the proposed use of a reporter in RP5. His points included: the regulatory burden that a reporter would impose; whether the UR had the resources to monitor and respond to the information which would be provided; that the role had not worked well where it had been tried and that the trend was clearly now away from using this role in GB regulation; the possibility that a reporter would reduce a company's own sense of responsibility for its data; that the UR had proposed a reporter because it had made less use of technical consultants than GB regulators; and that the reporter role would create an ambiguity about responsibility and increase uncertainty.[6]

16. The UR's response included: that Professor Littlechild had not disputed that the volume of and detail information it wanted to collect was less than Ofgem's RIGs; that the account of other regulators' experience of reporters was misleading with Professor Littlechild stating that Ofwat's use of reporters 'had now become a problem in itself' as a conclusion from a document where Ofwat actually stated that companies would remain free to choose to use reporters as part of their own assurance processes and in earlier documentation had supported their use for both Ofwat and the companies (hence they had continued to use reporters); that a step change in the quality of NIE's reporting was required and that a reporter was a good way to achieve this; and that it appeared to be common ground that a reporter would be necessary with the UR's proposed RP5 capex mechanism.

Commissioner for Older People for Northern Ireland

17. The Commissioner said that there was a need for improved reporting and agreed with the appointment of a reporter.[7]

Consumer Council of Northern Ireland

18. The Consumer Council of Northern Ireland advocated the use of a reporter as a useful control and a source of transparency.[8]

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[6] Stephen Littlechild, 'The Utility Regulator's approach', 16 July 2012.
[7] Submission from Commissioner for Older People.

National Energy Action Northern Ireland

19. National Energy Action Northern Ireland advocated the use of a reporter.[9]

Phoenix Natural Gas

20. Phoenix Natural Gas said that the proposals for a reporter indicated a trend towards micro-management and that this would undermine the proven benefits of an incentive-based model of regulation.[10]

SONI

21. SONI said that a relatively light-touch incentive-based approach to regulation should be adopted. With regard to the use of a reporter, it said that it did not disagree with this in principle but that the terms of reference of the reporter would need to be understood and its use would need to be proportionate.[11]

The Ofgem RIGs

22. We reviewed the full Ofgem RIGs[12] and additionally a sample of RIGs workbooks (for example, the 'Cost and Volumes' workbook). We believe that, because the GB DNOs are NIE's closest comparators, the RIGs are the obvious starting point for any proposal on increased regulatory reporting.

23. Our view is that some of the data contained in the RIGs would be particularly useful to the UR and other stakeholders. For example, within the Cost and Volume workbook the following worksheets would be particularly useful:

    (a) Worksheets C1 to C37, which collect costs by high-level activity: for example, 'Indirects' is a high-level category which would be broken down into around 15 different sub-areas, such as Project Management or Finance & Regulation;[13] and

    (b) Worksheets CV1 to CV18, which collect volumes, costs and unit costs by category and also at an individual asset level: for example, 'asset replacement' is a category within which direct costs, volumes and unit costs are reported for different types of asset (eg various cables, switchgear and transformers).

24. These worksheets would provide the UR with granular cost, direct unit cost and volume data on a basis which is directly comparable with the GB DNOs. This should improve transparency and enable easier comparison of NIE's performance to the GB DNOs in these areas.

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[8] Submission from The Consumer Council of Northern Ireland, p8.
[9] www.competition-commission.org.uk/assets/competitioncommission/docs/2013/northern-ireland-electricity-price-determination/130604_national_energy_action_northern_ireland.pdf.
[10] www.competition-commission.org.uk/assets/competitioncommission/docs/2013/northern-ireland-electricity-price-determination/130604_phoenix_natural_gas.pdf.
[11] www.competition-commission.org.uk/assets/competitioncommission/docs/2013/northern-ireland-electricity-price-determination/130611_soni.pdf.
[12] www.ofgem.gov.uk/ofgem-publications/46537/nadprrigv3clean.pdf, paragraph 1.3. For completeness, the full RIGs reporting comprises: Cost and Volumes; Memo and disaggregated costs; Network asset data and performance reporting; Connections; Customer Service.
[13] Project Management is an example of a closely associated indirect cost; Finance & Regulation is an example of a business support cost.

Glossary

2003 Order	Valuation (Electricity) Order (Northern Ireland) 2003.
2006 Direction	Direction issued by the Utility Regulator in 2006 for the implementation of **RP4**.
ADAS	Agricultural Development Advisory Service.
Aon Hewitt	Actuary to the **NIE** pension scheme.
ASHE	Annual Survey of Household Expenditure.
BAU	Business as usual.
BERR	Department of Business, Enterprise and Regulatory Reform, Northern Ireland.
Beta	(Comes within **CAPM**.) Refers to the additional return needed to reflect the risk profile of the organization compared with the industry as a whole.
BPO	Outsourced business process.
BPQ	Business Plan, Investment and Efficiency Questionnaire.
Bristol Water	The **CC** conducted price control determination in respect of Bristol Water PLC in 2010.
BSP	Bulk supply point (110/33 kV substation).
CAI	Closely associated indirects (a cost category used by Ofgem).
Capex	Capital expenditure.
Capita	Capita Managed IT Solutions (previously known as Northgate Managed Services Limited)—contracted to **NIE** to provide managed **IT** and business process services.
Capital Pensions Management Ltd	**NIE** Pension Scheme administrators.
CAPM	Capital asset pricing model.
CC	Competition Commission.
CCNI	Consumer Council for Northern Ireland.
CEPA	Cambridge Economic Policy Associates provided consultancy support for the **UR**.
CI	Customer interruptions.
CML	Customer minutes lost.

Cover ratio	Used by credit rating agencies. Compares earnings to interest payable on debt.
CPI	Consumer prices index.
CSV	Composite scale variable.
DB	Defined benefits.
DETI	Department of Enterprise, Trade and Investment for Northern Ireland.
Direct costs	A category of costs for regulated electricity network companies which is defined by **Ofgem** and intended to cover the costs of activities that do involve physical contact with system assets. It is distinguished from the **Ofgem** category of indirect costs.
Distribution	33 kV and lower voltage networks. The networks forming part of the distribution system, including (in each case) any electrical plant and/or meters used in connection with distribution
DNO	Electricity distribution network operator.
DPCR3	Electricity distribution price control review set by **Ofgem** in effect 1 April 2000–31 March 2005.
DPCR4	Electricity distribution price control review set by **Ofgem** in effect 1 April 2005–31 March 2010.
DPCR5	Electricity distribution price control review set by **Ofgem** in effect 1 April 2010–31 March 2015.
DUoS	Distribution use of system charge.
Dt	A term used in setting **NIE**'s revenue allowance comprising of eight different elements in **RP4**. It includes provision for the UR to approve additional costs to be recovered by NIE..
EIA	Environmental Impact Assessment.
EirGrid	EirGrid is the electricity Transmission System Operator and Market Operator in the Republic of Ireland and also in Northern Ireland (through **SONI**). The Single Electricity Market Operator is part of the EirGrid Group, and operates the **SEM** on the island of Ireland.
Electricity Directive	European Parliament and Council Directive 2009/72/EC or Third European Internal Market Directive EC Directive 2009/72/EC.
Electricity Order	Electricity (Northern Ireland) Order 1992.
Enduring Solution	An **NIE IT** project directed at facilitating the competitive supply market and customer switching.
Energy Order	Energy (Northern Ireland) Order 2003.

ERDC	Early retirement deficiency contributions. An early retirement liability arose because companies ran early retirement schemes which allowed retiring workers to access pension benefits immediately (rather than at their retirement date). At the time no additional funding was provided by the company to the scheme for these early retirement benefits. In GB and Northern Ireland this liability has subsequently been apportioned between shareholders and consumers. ERDC payments represent the shareholders' payments which arise from this early retirement liability.
ERP	Equity risk premium.
ESB	Electricity Supply Board, licensed transmission system owner and distribution system operator in the Republic of Ireland.
ESBNI	ESBNI Limited. NIE is a subsidiary of ESBNI Limited.
ESQCR	Electricity Safety Quality Continuity Regulations.
EU Transformer Directive	EU Transformer Directive (ECO-Directive 2009/125/EC). This EU Directive requires that transformers up to 36 kV should be designed and constructed to meet new higher standards.
FFO	Funds from operations.
Fitch	Fitch Ratings, a credit rating agency.
Frontier	Frontier Economics (providing consultancy support for **NIE**).
FTE	Full-time equivalent.
Fund 1	Part of the **UR**'s proposals for **capex** in its **RP5** determination, covering asset replacement and refurbishment.
Fund 2	Part of the **UR**'s proposals for **capex** in its **RP5** determination, covering less predictable investments, including load-related investments, metering and connections.
Fund 3	Part of the **UR**'s proposals for **capex** in its **RP5** determination, including uncertain large projects relates to renewable generation.
GAD	Government Actuary's Department.
GB DNO	Distribution Network Owner operating in GB.
GSS	Guaranteed Standards Scheme.
HMRC	HM Revenue and Customs.
HV	High voltage (electric lines of 110 kV and above).
IAS	International Accounting Standard.
IAS 19	International Accounting Standard Nineteen is an accounting rule concerning employee benefits under the IFRS rules.

iBoxx	Markit iBoxx indices.
I&C	Industrial and commercial.
ICT	Information and communication technology.
Indirect costs	A category of costs for regulated electricity network companies which is defined by **Ofgem** and intended to cover the costs of activities that do involve physical contact with system assets. For example, it includes costs in areas such as network design, project management, network control centre, human resources, finance and regulation.
IME3	European Parliament and Council Directive 2009/72/EC.
IMF&T	A cost category that we have defined and used for the purposes of our cost assessment in this inquiry. It includes the direct costs of inspections, maintenance, faults and tree-cutting activities.
IFI	Innovation funding incentive: an incentive scheme for innovation applied by **Ofgem** as part of its regulation of electricity network companies in GB.
Injurious affection	The diminution in value to a property caused by the existence and/or use of public works carried out under, or in the shadow of, compulsory powers.
Interconnection	The physical linking of two or more electricity networks via their transmission systems.
IT	Information technology.
Keypad	Brand of prepay/pay-as-you-go meter used in Northern Ireland.
KPI	Key performance indicator.
KPMG	KPMG LLP UK (provided consultancy support to **NIE**).
kV	Kilovolt.
Licences	Held by NIE for the transmission and distribution of electricity.
LPN	London Power Networks—DNO.
LV	Low voltage (electricity lines less than 110 kV).
MEAV	Modern equivalent asset value.
Mott Macdonald	**RP4** consultants commissioned by the **UR**.
MMC	Monopolies and Mergers Commission, the predecessor to the **CC**.
Moody's	Moody's Investment Services Ltd, a credit rating agency.
Moyle Interconnector	Links the electricity grids of Northern Ireland and Scotland through submarine cables. The link has a capacity of 500 MW.

MTP	Medium-term plan. Part of **NIE**’s coordinated network plan, incorporating term measures designed to increase the capacity of the network to accommodate wind power over the coming years.
NIAER	Northern Ireland Authority for Energy Regulation—now **NIAUR**.
NIAUR	Northern Ireland Authority for Utility Regulation (the **UR**).
NIE	Northern Ireland Electricity Ltd.
NIE Powerteam	NIE Powerteam Ltd, part of the **NIE** organization, the only function of which is to undertake activities forming part of **NIE**’s business. NIE Powerteam was renamed NIE Networks Services in December 2013. Any reference in this report to NIE Powerteam may also relate to NIE Networks Services.
NIEPS	**NIE** Pension Scheme.
NIRIG	Northern Ireland Renewables Industry Group.
NOC	Network operating costs. A category of costs for regulated electricity network companies which is defined by **Ofgem** and includes the direct costs of activities including inspections and maintenance, resolution of trouble calls, and tree cutting.
Northgate	Northgate Managed Services (now acquired by Capita), an **IT** provider contracted to **NIE** to provide managed services.
NPV	Net present value.
O&M	Operation and maintenance.
Ofcom	Independent regulator and competition authority for the UK communication industries.
Ofgem	Office of the Gas and Electricity Markets in GB.
Ofwat	Economic regulator of the water and sewerage sectors in England and Wales.
OHL	Overhead line.
OLS	Ordinary least squares, a form of statistical analysis.
ONS	Office for National Statistics.
Opex	Operating expenditure.
ORR	Office of Rail Regulation.
P&L	Profit and loss.
PAS55	British Standards Institution’s Publicly Available Specification for the optimized management of physical assets.
PB	Parsons Brinkerhoff (provided consultancy support to **NIE**).

PDR	Pension deficit repair.
PKF	Provided consultancy support to the **UR**.
PMICR	Post-maintenance interest cover ratio.
PNGL	Phoenix Natural Gas Ltd.
Power NI	Power NI Energy Ltd, owned by **Viridian Group**. Regulated supply company formally known as **NIE** Energy Supply.
PSO	Public Service Obligation.
Price control conditions	Establish a restriction on the charges that may be made by NIE for the transmission and distribution of electricity.
R&D	Research and development.
R&M	Repair and maintenance.
RAB	Regulatory asset base—same as RAV.
RASW	Road and Streetworks legislation.
RAV	Regulatory asset value—same as RAB.
Renewables Integration	Projects relating to the reinforcement of the **T&D** network to accommodate new renewable generation.
RFR	Risk-free rate.
RIDP	Renewable Integration Development Project. A joint venture between **NIE**, **EirGrid** and **SONI** whose aim is to identify the optimum reinforcement of the electricity transmission grid in the north and north-west of the island to cater for expected power output and renewable energy sources.
RIGs	Regulatory Instructions and Guidance—for Ofgem's reporting requirements.
RIIO	Ofgem's price control framework for energy network companies in GB. Revenue = Incentives + Innovation + Outputs.
RIIO-T1	The first transmission price control review in GB to reflect the new regulatory framework resulting from the RPI–X@20 review.
RIIO-ED1	Will be the first electricity distribution price control review in GB to reflect the new regulatory framework resulting from the RPI–X@20 review.
RP	The price control periods applying to **NIE**.
RP1	Regulatory Period 1 in effect from 1 April 1992 to 31 March 1997.
RP2	Regulatory Period 2 in effect from 1 April 1997 to 31 March 2002.

RP3	Regulatory Period 3 in effect from 1 April 2002 to 31 March 2007.
RP4	Regulatory Period 4, originally planned to be in effect from 1 April 2007 to 31 March 2012.
RP5	Regulatory Period 5 that follows after **RP4**.
RPE	Real price effects.
RPI	Retail prices index.
RPI–X	A type of incentive-based price control regulation where X represents annual cost reductions relative to the **RPI**.
SAP	Accounting system used by **NIE T&D**.
SAP IS-U	A customer registration and billing **IT** system used by **NIE T&D**.
SCADA	Supervisory control and data acquisition.
SEF	Strategic Energy Framework.
SEM	Single Electricity Market.
SEM Committee	Single Electricity Market Committee and the decision-making authority on all **SEM** matters.
SFA	Stochastic frontier analysis: a form of statistical analysis.
SKM	Sinclair Knight Merz provided consultancy support for the **UR**.
SLA	Service level agreement.
SMART	Sustainable Management of Assets and Renewables Technologies.
Smart meters	Uses a wireless transmitter to transfer information to a wireless display which indicates how much energy is being used. Smart meters also enable a meter reading to be taken remotely.
SoC	Statement of Case.
SONI	System Operator for Northern Ireland and the Transmission System Operator for Northern Ireland.
SSE	Formerly Scottish and Southern Energy.
Standard and Poor's	Standard and Poor's Ratings Services, a credit rating agency.
SWW	Strategic wider works.
T&D	Transmission and distribution.
T&D Business	**NIE**'s licensed transmission and distribution business.
TAR	Targeted asset replacement.

TDP	Transmission Development Plan.
TIA	Transmission Interface Agreement between **NIE** and **SONI**.
TIP	Transmission Investment Plan.
TNAR	Transmission Network Annual Report.
TO	Transmission owner.
Totex	Total expenditure (**capex** and **opex**).
Transmission	In Northern Ireland, 110 kV and above. High-voltage electric lines and cables operated by a **TSO** for the purposes of transmission of electricity from one power station to a substation or to another power station or between substations or to or from any inter-connector including any plant and apparatus and meters owned or operated by the **TSO** or **TO** in connection with the transmission of electricity.
TSC	Transmission Service Charge. Transmission services charges, regulated by NIE's Licence, which are levied on **SONI**.
TSO	Transmission system operator.
TUoS	Transmission use of system charges, which are levied by **SONI** on suppliers and generators.
Tx	Transmission.
UFU	Ulster Farmers' Union.
UR	Utility Regulator (Northern Ireland Authority for Utility Regulation).
Vanilla WACC	A measure of the **WACC** combining a post-tax return on equity and a pre-tax return on debt.
Viridian Group	Owner of **NIE** until December 2010.
VSS	Voluntary severance scheme.
WACC	Weighted average cost of capital.
Wayleaves	Provides rights for an electricity company to install and retain their apparatus; either underground cables or overhead lines across land with annual payments being made to the landowner and occupier.
WPD	Western Power Distribution.