COMPETITION COMMISSION

Northern Ireland Electricity Limited price determination

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

Final determination

Presented to the Northern Ireland Authority for Utility Regulation
26 March 2014

Website: www.competition-commission.org.uk

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Background

1. The Northern Ireland Authority for Utility Regulation (the Utility Regulator (UR)) issued a price control determination (final determination) for Northern Ireland Electricity Limited (NIE) on 23 October 2012 in respect of NIE's licences for transmission and distribution (each, a Licence, together, the Licences), together with proposed draft Licence modifications. NIE rejected the licence modifications. On 30 April 2013, the UR made a reference to the Competition Commission (CC) in accordance with Article 15(1) of the Electricity (Northern Ireland) Order 1992 (Electricity Order).

2. NIE is the owner of the electricity transmission network in Northern Ireland and the owner and operator of the distribution network. NIE's transmission and distribution network contains several interconnected networks of overhead lines and underground cables which are used for the transfer of electricity to approximately 840,000 consumers (of which nearly 780,000 are domestic customers) via a number of substations. NIE derives its revenue principally through use of distribution system charges levied on electricity suppliers; and transmission services charges levied on the System Operator for Northern Ireland (SONI). These charges are ultimately recovered from final consumers. Network charges typically make up around 20 to 25 per cent of the final consumer's electricity bill. NIE is no longer involved in the generation of electricity, nor in the purchase and supply of electricity to customers.

3. NIE was acquired by ESBNI Limited (ESBNI), a subsidiary of the Electricity Supply Board (ESB, the licensed transmission asset owner, distribution system operator and meter operator in the Republic of Ireland), in December 2010.

4. The UR has controlled charges for transmission and distribution by setting the revenues that NIE is allowed to raise during the following price control period. The price control determination sets these allowed revenues and proposes amendments to NIE's Licences to implement this. The UR also approves NIE's tariffs, but that process is not the subject of this redetermination.

5. In its 'RP5' (revenue period 5) final determination, the UR set out NIE's allowed revenues for transmission and distribution, for the period 1 January 2013 to 30 September 2017. It said that the revenue was set at a level to allow the company to recover operating costs, depreciation and a reasonable return on investment.

6. NIE said that it rejected 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.

7. We were therefore required to undertake a redetermination in accordance with the terms of reference. Our starting point was to assess whether the existing RP4 (revenue period 4) price controls operated in the public interest. The RP4 price control ran, originally, from 1 April 2007 to 31 March 2012. However, in 2011 the UR announced delays in the implementation of the RP5 price control, and it sought to extend the RP4 price control.

Questions referred and determination

8. We first summarize the most important aspects of our determination of the three questions referred to us, which were:

   (a) whether the Price Control Conditions in each Licence operate or may be expected to operate against the public interest (paragraphs 9 to 14);

   (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 (paragraphs 15 to 17); 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 (paragraphs 18 to 57).

   We then summarize:

   (d) the timing and duration of the price control that we determined (paragraphs 58 to 59);

   (e) implementation issues (paragraphs 60 and 61);

   (f) the overall allowances in our determination (paragraphs 63 to 65)

   (g) the financial modelling and the ability of an efficient licence holder to finance the RP5 price control that we undertook (paragraphs 66 to 68); and

   (h) the overall effect of the modifications that we have proposed in order to remedy or prevent the effects adverse to the public interest (paragraphs 69 to 78).

Whether the Price Control Conditions in each Licence operate or may be expected to operate against the public interest

Parties' views

9. In relation to the UR's first question, both the UR and NIE said that the existing RP4 price control conditions now operated against the public interest, principally on the basis that they were only intended to operate until 31 March 2012. The UR told us that the RP4 price control was not a good one, that continuation of the adapted RP4 approach under its 'pragmatic approach' was an interim solution without adequate legal certainty, and that continuation would not promote efficiency and economy on the part of NIE and consequently would not adequately protect the interests of consumers in respect of services provided and prices charged. NIE said that the existing price control conditions could no longer function effectively at all, and it argued that the interests of consumers required that a fresh assessment was made of the regulatory mechanisms and other tools that formed the basis of the price control going forward.

Our view of the 'public interest'

10. In making our redetermination of whether any particular matter operated against the public interest, we were required by Article 15(7) of the Electricity Order to have

regard to the duties imposed on the UR. The public interest scheme in its entirety as set out in the Energy (Northern Ireland) Order 2003 (the Energy Order), the Electricity Order and Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 (the EU Electricity Directive) is extensive (see paragraphs 2.42 to 2.53). It provides, in addition to the principal objective of protecting the interests of consumers (where this includes both current and future consumers including business as well as domestic users), for a detailed set of more specific objectives and further considerations to which we must have regard. These objectives include the need to secure that all reasonable demands for electricity are met, that licence holders are able to finance their activities, and the need to protect the interests of vulnerable consumer groups.

11. At least some of these additional objectives and considerations may, properly understood and in terms of their substance, be part and parcel of an overall objective to further the interests of consumers. We balanced and attached appropriate weight to specific public interest factors where the particular facts and evidence before us have given us reason to do so. In addition, we took account of other factors where relevant to the particular issue, which included (among other considerations) the Northern Ireland Government's aspiration to have 40 per cent of electricity generated from renewable sources by 2020.

12. The approach we adopted was to consider for each aspect of the price control conditions whether it operated against the public interest and, if so, which was the best alternative available (if any) that would address the adverse effect, and best serve the public interest. This included the determination of appropriate allowances and any consequent adjustments arising from redesign of the price control. We then considered whether the overall effect of our determination operated in the public interest or whether any aspects or the overall package should be modified.

13. For our redetermination, we used the best data available to us, which meant that in some cases we used data that had been updated since the UR reached its determination. We also engaged consultant engineers, BPI, to advise us on NIE's capital expenditure (capex) proposals, and a consultancy, Pelicam Project Assurance, to help us investigate issues relating to the Enduring Solution project and non-network capex.

Our determination

14. We determined that the Price Control Conditions in each Licence operate or may be expected to operate against the public interest in particular because:

   (a) the application of the current price control conditions is uncertain. In particular the UR and NIE disagree over whether the Price Control Conditions continue to have legal effect. Moreover, some terms in the current Licence conditions are not defined for the period after 31 March 2012.

   (b) aspects of the price control design are not sufficient to protect the interests of consumers, in particular:

      (i) the calculation of NIE's maximum regulated revenue according to the level of capex that NIE incurs may expose consumers to excessively high charges that reflect capex that was inefficiently or unnecessarily incurred by NIE—or missed opportunities for efficiency and innovation in relation to network investment;

(ii) RP4 set a rolling mechanism, by which the operating expenditure (opex) allowance was set by the actual costs incurred by NIE five years previously, adjusted for inflation. We found that this operated against the public interest as it may give NIE insufficient incentives to be efficient;

(iii) the incentive rates for outperformance differ between opex and capex, which can create distortions in how NIE would organize its activities that could increase inefficiencies;

(iv) the UR's ability to approve, on a case-by-case basis, additional cost to be recovered through NIE's revenue control (under the Dt term of the price formula) operated against the public interest. The scope for approval of such costs is limited to a cost pass-through basis, which would give NIE insufficient incentives to be efficient and so exposed consumers to the risk of excessive costs;

(v) NIE's price control licence conditions were deficient in respect of the treatment of income from revenue protection activities;

(vi) the treatment of pensions costs in the current price control licence conditions may provide NIE with insufficient incentives to be efficient;

(vii) adding all transmission and distribution investments to a RAB depreciated over 40 years operates against the public interest where this includes significant expenditure on assets which have a much shorter life;

(viii) the current price control conditions specify a single maximum regulated revenue for NIE across its distribution and transmission services. We found that this operated against the public interest as it missed opportunities, now that there are separate Licences for NIE's transmission and distribution systems, to better align charges with costs and to reduce the risk that distribution charges reflect transmission costs (and vice versa);

(ix) the current price control does not allow for NIE's historical capital costs for projects linked to the development of retail competition through distribution use of system charges (these costs are instead recovered through PSO charges). This may lead to an inconsistent treatment of costs between distribution charges and the PSO charges and potentially inappropriate PSO charges;

(x) the misalignment between the regulatory year and the tariff year created unnecessary tariff volatility; and

(xi) the UR received insufficient reliable information in order for it to regulate NIE in a fully effective manner and that other stakeholders (such as consumer representatives) may also benefit from greater transparency.

(c) they contain formulae with parameters that are out of date. In particular, we found that the cost of capital specified was now too high, and the formulae for calculation corporation tax allowances used assumptions on the corporation tax rate and NIE's interest payments that were out of date.

The inclusion of further conditions designed to improve the recording, reporting, monitoring and verification of information related to the Price Control Conditions

15. In answer to the UR's second question, we found that the continuation of each Licence operated 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: see paragraph 14*(b)*(xi). However, we determined that the introduction of a reporter function was not the best way to achieve this.

16. Instead, we determined that a licence condition should be added to:

(a) oblige NIE to report to the RIGs in 2014/15 and 2015/16 for the purpose of facilitating benchmarking against the GB DNOs and to give the information required for the UR to assess NIE's performance;

(b) give the UR the ability to make directions to NIE setting out which elements of the RIGs are exempt on the grounds of being unnecessary due to differences in the Northern Ireland network compared with GB; and

(c) require NIE to report using a confidence grading system, which would set out its confidence in the data it would be reporting. This would allow NIE and the UR to identify those aspects of the RIGs which would need greatest focus and development.

17. We could not confidently forecast NIE's costs of establishing the systems necessary to allow it to report against the Ofgem GB DNO RIGs. We therefore set an initial allowance for implementation costs of £1 million, with the ability for NIE to apply to the UR to for a further allowance that should be granted if the UR is able to satisfy itself that any additional implementation costs are efficient and in the public interest.

Whether the effects adverse to the public interest could be remedied or prevented by modifications of the Licence conditions

18. With regard to the UR's third question, we found that 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. We summarize our key findings in relation to aspects of the price control and our determination of modifications to the Licence conditions. The overall allowed revenues are set out in Table 1, and opex and capex allowances are set out in Tables 2 and 3.

Design of price control

19. For the reasons set out in Section 5 of this report, we determined that significant changes to the design of the price control would address the effects adverse to the public interest. Our determination for alterations to the licence conditions, while still an example of RAB-based incentive regulation, also differs substantially in several respects from the arrangements proposed by the UR in its RP5 determination document. Our determination with regard to the price control design is set out in paragraphs 21 to 37.

20. We also determined that there should be separate revenue controls for transmission and distribution, in line with the separate Licences. Apart from consistency with the

separation of Licences, separate revenue controls can help better align transmission charges with transmission costs and distribution charges with distribution costs.

Cost risk-sharing mechanism

21. We determined a new price control for NIE calculated by reference to our assessment of NIE's expenditure requirements (if it were to operate efficiently) in the period from 1 April 2012 to 30 September 2017. We determined that the price control should include arrangements that have the effect of sharing between NIE's investors and consumers any differences between our assessment of NIE's expenditure requirements and NIE's out-turn expenditure.

22. More specifically, we specified a cost risk-sharing mechanism under which 50 per cent of any difference between our assessment of NIE's expenditure requirements and NIE's out-turn expenditure in a particular financial year is passed through to consumers through adjustments to NIE's maximum regulated revenue. The rate of 50 per cent will apply to NIE's opex and capex. In determining this mechanism we sought to ensure that NIE would face clear and strong financial incentives to operate and invest efficiently and to avoid unnecessary expenditure. We also sought to reduce the risk that the regulatory framework gives NIE financial incentives to favour unduly working practices and capitalization practices that inefficiently enhance NIE's capex relative to its opex.

23. We decided that some categories of costs would be excluded from the cost risk-sharing mechanism (for example, costs subject to full cost pass-through (see Section 19).

Inefficient spend clause

24. We included a provision within NIE's Licence conditions that the UR can determine to make adjustments to NIE's revenues or RAB to protect consumers from exposure to any costs that the UR finds to be demonstrably inefficient or wasteful.

Measures to tackle risks from deferral of planned network investment projects

25. Under conventional RAB-based incentive regulation, there is a risk that a regulated company may defer investment projects (and so capex) for which it has received an allowance and in subsequent price control periods seek further allowances for similar projects, or projects designed to have the same effect as those deferred.

26. Our approach aims to ensure that there should be no double funding of any such deferred network investment. Therefore, in subsequent price controls, we expect that NIE would be required to identify any aspects of its forecast network investment which arise as a result of deferment or abandonment of investment that was included in the calculations we have used to set a this price control for NIE. These would be netted off its expenditure allowances for the subsequent price control period. This is intended to protect customers from the risk of facing charges for further work which have already been funded.

27. We are mindful that NIE's investment requirements and priorities can develop over the course of a price control period. We are satisfied that our approach provides NIE with sufficient financial incentives to defer planned projects where it is efficient to do so and to abandon planned projects that are no longer necessary.

Investment projects for distribution network-load-related expenditure

28. We considered possible mechanisms or provisions in the price control framework to allow some flexibility to reflect changes in requirements for distribution network-load-related expenditure in the period to 30 September 2017.

29. In view of the relative scale of capex envisaged by NIE and the drawbacks we identified with the possible mechanisms we considered (and that we have determined allowances for certain core network investments, see paragraphs 43 and 44), we determined to set an upfront allowance in relation to distribution-load-related expenditure, with the same cost risk-sharing arrangements as for other areas of NIE's expenditure.

Investment projects to increase transmission system capacity

30. We determined that there should be provisions within NIE's Licence conditions to allow the UR to make within-period adjustment to NIE's revenue restriction and RAB calculations, to allow for the costs of new investment projects that are needed to increase the capacity and capabilities of the transmission network. NIE will be able to apply to the UR on a project-by-project basis for an adjustment to its revenue restriction and RAB during the price control period, without having to wait for the UR's next price control review. If the UR considers an adjustment necessary, it will determine an upfront cost allowance based on its estimates of the efficient costs of the investment project. The same cost risk-sharing arrangements will apply as for NIE's other expenditure.

Electricity meter investment and smart meter programme

31. Our determination is that a form of volume-driver mechanism is appropriate for NIE's capex in relation to electricity meters. In addition to upfront forecasts of NIE's capex on electricity meters, the revenue restriction in NIE's Licence conditions will adjust mechanistically according to the out-turn volumes of metering investments that NIE carries out. The adjustment will be calculated by reference to unit cost allowances for different categories of metering capex. This mechanism helps address substantial uncertainty about the volumes of metering investment that NIE will need to carry out.

32. The mechanism we determined for metering capex is focused on conventional electricity meters (including keypad meters) and is not intended to accommodate a potential future transition to smart meters. If the smart meter programme in Northern Ireland means that changes are needed to NIE's maximum regulated revenue before 30 September 2017, we expect the UR and NIE to make use of either the change of law provision in the existing licence conditions (which we propose to retain) or a licence modification.

Pass-through of specified connection costs

33. NIE imposes charges for new connections to its network (also known as customer contributions). These are subject to price regulation outside of the NIE revenue control that is the main subject of our inquiry. At present, there is an arrangement by which an element of certain connection charges is 'subsidized' through NIE's RAB and revenue control, rather than falling entirely on the party seeking the new connection. Our determination is that costs relating to this subsidy from NIE's RAB should be recovered on a cost pass-through basis. This will be a temporary arrangement until 1 October 2015, as the UR has made a regulatory policy decision to terminate

the current subsidy from the RAB from that date. Any costs incurred after that date will not be recoverable through NIE's RAB.

Pass-through of specified operating costs

34. Under RP4, certain operating costs that NIE incurred were passed through, in full, to consumers. These relate to: the regulatory licence fees that NIE pays; wayleave costs; and rates (forms of taxation on NIE's premises and assets).

35. Our determination is that licence fees should continue to be treated as a cost pass-through item. However, rates and wayleaves should not be subject to cost pass-through. Instead an upfront allowance and the cost risk-sharing mechanism described above will apply.

36. We determined that there would be no upfront allowance for costs relating to injurious affection but there should be a provision for the UR to make an allowance in the future. This would be informed by the results of forthcoming Lands Tribunal determinations.

Other terms to remove from current licence conditions

37. We determined to remove from the Price Control Conditions of various elements which we consider to be redundant following changes to the Licences under the other modifications we determined.

Quality of service and other incentives

38. We considered various proposals from the parties relating to the regulation of NIE's quality of service or output through NIE's price control conditions, covering: guaranteed standards; customer interruptions; and electrical losses incentives (see Section 6).

39. We found that a poorly designed scheme could be worse than no scheme and could impose unnecessary costs on consumers. Instead, we decided that NIE should publish its annual performance in terms of measures of customer interruptions and explain any shortfalls in performance against its forecasts.

40. We decided on changes to the treatment of income that NIE receives as part of revenue protection activities (for example, revenue recovered in cases of illegal abstraction of electricity). We decided that 50 per cent of the revenues that NIE receives each year should be shared with consumers by offsetting them against NIE's maximum regulated revenue. This widens the scope of a similar arrangement applying to money recovered by NIE in relation to vacant non-domestic premises.

Allowance for indirect costs, inspection, maintenance, faults and tree-cutting

41. We made a determination of an annual allowance for NIE's indirect costs and costs for inspection, maintenance, faults and tree cutting (IMF&T) using the results from benchmarking analysis of the costs of NIE and 14 GB DNOs (see Section 8).

42. These categories include both costs that are capitalized and costs that are not capitalized. Our benchmarking analysis therefore cuts across NIE's capex and its opex. Since we maintain the approach of including forecast capex in NIE's RAB, we need to separate our allowance for indirect and IMF&T costs between opex and

capex. We did this by applying an allocation based on the separation of NIE's historic indirect and IMF&T costs between opex and capex.

Core network investment

43. We made an allowance for NIE's core network investment expenditure (see Section 9). Our determination therefore included all projects which, in our judgement, it would be in the public interest for NIE to complete by 30 September 2017.

44. We gave additional review to three projects which we considered required additional scrutiny. We concluded that some additional provision should be made for work to ensure NIE's compliance with ESQCR requirements. We decided that a large-scale pilot to accelerate network resilience work to deal with ice accretion was not justified or demonstrably cost effective; nor was an 11 kV network performance project to install remote control facilities.

45. We made an allowance for non-recoverable alterations and we removed a project relating to Road and Street Works legislation which is not currently predicted to have any impact in the relevant period. We made an allowance to cover distribution-load-related expenditure which NIE will undertake in the period 1 April 2012 to 30 September 2017.

46. We removed from our allowance all transmission-load-related projects which had not already begun; we did this because of the changing role which SONI will have in transmission investment planning from April 2014. Our D5 mechanism (see Section 5) will allow these projects to be proposed during the price control. We also made an adjustment to remove indirect costs to enable us to set a direct-only core network investment allowance. Finally, we adjusted our forecast to allow for the length we determined for the price control period.

Other elements of cost assessments

47. We determined allowances for a variety of other specific items (see Section 10). Items for which we made specific separate allowances include the cost of the Enduring Solution market opening project; non-network or non-operational capex; metering capex; additional opex costs relating to ESQCR; storm costs relating to atypical severe weather; meter reading and operating costs related to keypad meters; rates; injurious affection; and others.

RPEs and productivity

48. We estimated how NIE's costs may compare with expected changes in general inflation (measured by the RPI) over the period. This is because NIE's allowed revenues are indexed to increases in RPI but the costs of an efficient firm might be expected to follow a different path due to the combined effects of productivity and RPEs. We adapted our allowances accordingly. We estimated productivity improvements at 1 per cent a year for each of opex and capex. We estimated RPEs for the period. Our analysis is set out in Section 11.

Pensions

49. We examined a variety of issues around pensions (see Section 12). We determined that only the pension schemes which provide for employees exclusively of the regulated business of NIE should be included in our revenue control. We also

determined that the deficits in the included schemes should be split into historic (up to 31 March 2012) and incremental deficits. The historic deficit will be funded 100 per cent by consumers: our allowance for this deficit in RP5 is based on the cash deficit repair payments which NIE is forecast to make in the period. Any incremental deficit arising will be funded 100 per cent by NIE. We determined that NIE should not be given an additional allowance for pension payments which it made in RP4 which exceeded its RP4 allowance. We determined that no adjustment to NIE's ERDC liability should be made for previous shareholder contributions. We made provision for an adjustment to be made at the end of RP5 if NIE's deficit repair payments to the pension scheme were to change during the price control period. We did this to ensure that neither NIE (nor consumers) would be worse off in NPV terms if the historic deficit repair payments changed during RP5.

50. NIE's ongoing pension service costs were included in our indirect benchmarking and therefore we included no additional allowance for this item.

Allowed rate of return

51. We examined the return that NIE should be allowed to earn on the RAB (see Section 13). We considered that this should be set equal to the expected cost of capital for NIE as if it were a stand-alone company. We determined that NIE's real WACC for RP5 is 4.1 per cent.

Unresolved RP4 issues

52. NIE drew our attention to certain outstanding issues with respect to the RP4 period. Since these were aspects relating to the implementation of RP4, we determined that these did not call for further investigation or for any adjustments for the purpose of the next price control. See Section 14.

Capitalization practices

53. The UR asked us to investigate whether changes in NIE's capitalization practices meant that, in effect, customers had paid twice for certain activities in RP4. It suggested this might have arisen because the activities had been funded through both an opex allowance and capex allowance, when NIE had changed its accounting treatment of certain activities from opex to capex.

54. Our consideration is set out in Section 15. We concluded that the design of the RP4 price control could give NIE incentives to recategorize opex as capex in this way, because opex allowances were based on historic opex levels whereas capex was remunerated on a pass-through basis. We found that this aspect of the RP4 price control design was against the public interest because it could distort NIE's choices between opex and capex and lead to NIE receiving inappropriate opex allowances.

55. However, on examining the facts, we were not convinced that NIE had engaged in reclassification of activities in this way to a significant extent. Changes in the balance of opex and capex activities reflected a mix of causes, including genuinely additional capex activities, the replacement of reactive opex with planned programmes of capitalizable activities, and improvements in information allowing replacement of assets to be better planned and better recorded. In addition, NIE will have achieved genuine opex efficiency improvements. We noted that the opex allowance in RP4 was never explicitly allocated to particular expenditures. We also thought that absent good cause any intervention to correct for such effects after the period in which the

regulatory design applied could be harmful to investors' perceptions of regulatory stability. We therefore made no adjustment to the RAB.

Allowances for corporation tax

56. NIE's current price control licence conditions include allowances for NIE's corporation tax payments in the calculation of NIE's maximum regulated revenue. We found that the formulae and definitions used in the current calculations required modification. We determined a revised approach for calculating allowances for NIE's corporation tax payments. This takes account of updated information on the corporation tax rate, revised assumptions on NIE's interest payments and a revised definition of the capital allowances term in the calculation. See Section 16.

RAB for short-lived assets

57. We determined that a new five-year RAB should be adopted for all new capitalized tree cutting undertaken from the start of the RP5 period. We also found that investments in certain IT under the non-network capex category should similarly now be put into a five-year RAB.

Timing and duration of price control

58. For the reasons set out in Section 4, we decided that the new price control governs the calculation of NIE's tariffs applicable from 1 October 2014 onwards. However, we determined that the price control should have the effect of setting NIE's maximum regulated revenue in the period between 1 April 2012 and 30 September 2017.

59. We decided to put arrangements in place to ensure that some form of price control would apply to NIE after the planned end date, in case of a failure to implement a new price control in time. We specified licence modifications with the effect that, in the period from 1 October 2017 until such time as the next price control commences, the restriction on NIE's maximum regulated revenue is replaced with a restriction of no increases from the tariffs set from 1 October 2016.

Implementation issues

60. We specified a number of detailed points with regard to how to implement our determination most effectively. See Section 19.

61. The revenues that NIE has collected (and will collect) in the period from 1 April 2012 to 30 September 2014 may be greater than the maximum regulated revenue that we have determined for that period. In the event of such an over-recovery in distribution service revenues, NIE should provide a refund which should be passed on to consumers by electricity suppliers. NIE should also make a refund in relation to its PSO charges since April 2012, following our decision that some historical capex should be transferred from NIE's PSO charge control to its distribution price control.

62. We expect NIE, the UR and suppliers to work through the detailed implementation of any refund, bearing in mind the reasonable costs of its administration and so the extent to which the refund is in the public interest.

Overall allowances in our determination

63. Under our determination, the maximum regulated revenues for NIE's transmission and distribution activities will depend on the upfront cost allowances that we have determined and other factors that become known during the price control period (such as NIE's out-turn opex and capex and the volumes of electricity meter replacement it carries out).

64. In Table 1 below 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. We have presented our revenue allowances separately in respect of transmission and distribution, reflecting our decision that each should be subject to separate revenue control.

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 61.

65. In Tables 2 and 3, we set out our determination on upfront allowances for capex and opex to be used as part of the calculation for the additions to NIE's RAB and its opex allowances. The figures in Tables 2 and 3 below are calculated after the application of adjustments for productivity and RPEs (see Section 11). Total capex allowances in our decision for the period from April 2012 to September 2017 are £459.1 million. The total opex allowances for the same period are £259.1 million. A detailed breakdown of these allowances and a forecast of additional expenditure outside these allowances which may occur during RP5 is included in Section 7, Tables 7.3 to 7.12.

TABLE 2 **Overall assessment: capex after RPEs and productivity split allocated by RAB**

£m, 2009/10 prices

	2012/13	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*2017/18 (6 months)*
Total RAB additions: distribution RAB	41.62	44.10	58.01	57.48	57.13	28.32
Total RAB additions: transmission RAB	5.65	9.48	23.17	22.96	22.82	11.31
Total RAB additions: metering RAB*	3.84	3.80	7.80	7.40	7.35	3.64
Total RAB additions: new 5-year RAB—distribution	7.03	8.70	6.94	6.87	6.83	3.39
Total RAB additions: new 5-year RAB—transmission	0.30	0.72	0.70	0.70	0.69	0.34
Total RAB additions	58.44	66.80	96.62	95.40	94.83	47.00

Source: CC analysis.

*Subject to a volume adjustment mechanism.

TABLE 3 **Overall assessment: opex after RPEs and productivity allocated to transmission and distribution**

£m, 2009/10 prices

	2012/13	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*2017/18 (6 months)*
Opex allocated to transmission	5.73	6.02	5.65	5.64	5.63	2.80
Opex allocated to distribution	42.19	43.62	41.04	40.48	40.25	20.02
Total opex after productivity and RPEs	47.92	49.65	46.69	46.12	45.88	22.82

Source: CC analysis.

Financial modelling and the ability of an efficient licence holder to finance the RP5 price control

66. The UR (and we) must have regard to the need to secure that licence holders are able to finance the activities which are the subject of obligations imposed under statute. We set the level of allowances for RP5, including that for allowed return on the RAB, at a level at which we considered that an efficient licence holder would be able to provide the transmission and distribution services envisaged under RP5. We likewise assessed the ability of an efficient licence holder to finance the RP5 price control independently of the particular identity of the licence holder. Based on our financial modelling (see Section 17), our view is that our determination is consistent with an efficient licence holder maintaining an investment grade credit rating, as NIE is obliged to do under the terms of its Licences.

67. However, we recognize that the efficient licence holder's interest cover ratios were a potential source of concern. In particular, the efficient licence holder realizes profits in cash based on a 'real' return on its RAB during the RP5 price control. However, the element of the total return which compensates its investors for the impact of changes in the purchasing power of money over the period on the value of their investment is only returned to the licence holder in the form of cash over the 40-year period following any investment's addition to the RAB, and in large part after the end of the period with which we are concerned. This can lead to a mismatch between the levels of cash that are generated from profits on the efficient licence holder's capital investments (ie 4.1 per cent per year WACC specified in 'real' terms) and the interest charges on debt payable during the RP5 price control period (ie 6.45 per cent per year specified in nominal terms).

68. This phenomenon is often described as a 'real/nominal mismatch'. This mismatch is currently exacerbated by the fact that forecast RPI inflation at 3.25 per cent per year is relatively high in relation to the real WACC. We considered possible actions to address this concern, and found that the efficient licence holder had some options, including limiting dividend payments.

The overall effect of the modifications that we proposed in order to remedy or prevent the effects adverse to the public interest

69. We examined the overall effect of the modifications that we proposed in order to remedy or prevent the effects adverse to the public interest. Table 4 shows preliminary estimates of possible effects on prices, according to the Utility Regulator's financial model. These approximate estimates are not a substitute for the work that NIE and the Utility Regulator will need to do in order to develop tariffs that will implement our determination.

TABLE 4 **Change in prices excluding impact of any one-off refund: year on year change across transmission and distribution (per cent per year)**

	Announced	*Forecast*		
Increase at 1 October each year	*2013*	*2014*	*2015*	*2016*
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.

70. We forecast that the transmission and distribution component of the representative domestic customer's annual bill will reduce by approximately £10 relative to RPI by the end of the four years to September 2017 from £152 per year to around £142 per year in 2012/13 prices, excluding the effect of any one-off refund (see paragraph 61).

71. Our view is that our determination will operate in the public interest. We are required to have regard to the interests of specified consumer groups. For example, increases will have a greater impact on any customers who purchase relatively large amounts of electricity, for example the small number of domestic customers who rely on electric heating. However, we do not consider that driving charges to their lowest possible level, excluding all other public interest considerations, would be in the overall interests of consumers. Concerns relating to vulnerable, very low income groups might not best be addressed solely through electricity charges and may also require other Government measures.

72. A key aspect is ensuring that the transmission and distribution networks are capable of meeting all reasonable demands for electricity. We equate this with ensuring that NIE is able properly to maintain its network, with minimal interruptions to supply, and that all reasonable increases in demand for electricity are met (through ensuring adequate transmission and distribution networks). Our determination of capex allowances is intended to facilitate all investment projects necessary to maintain services to customers, projects which comply with applicable network design and meet other obligations, and also projects complying with applicable network design and planning standards, and/or which meet any other obligation, and have been sufficiently justified. In addition, we allowed within our capex and opex allowances provision for repairs, maintenance, tree cutting and other items necessary to maintain supplies and to meet new demands for electricity, on the basis that such work is done efficiently. However, we were not convinced of the need for some projects and did not include in our capex allowance funding for them.

73. We did not include in our capex allowance funding for some projects proposed by NIE, for example to tackle risks of ice accretion and to install remote control facilities to improve 11 kV network performance. While these projects may have contributed to a reduction in supply disruption risks for some individuals residing in rural areas, we found that they would provide poor value for money.

74. The development of renewable energy sources is facilitated by some network reinforcement projects and a provision for NIE to apply to the UR for approval to reinforce transmission networks as and when necessary in response to developments in renewable energy generation.

75. We considered the determination overall and found it to be compatible with other aspects of the public interest test, for example development of the all-Ireland electricity market, or prevent the efficient use of electricity.

76. Our determination is also intended to allow the licence holder to recover relevant costs and earn an appropriate return. We consider that it provides incentives to invest appropriately and operate efficiently, and that it is able to finance the activities required by its obligations, but does not impose unnecessary costs on consumers.

77. Ultimately it is a matter of judgement to balance the various aspects of the public interest in light of all the relevant evidence. As we consider that our determination strikes an appropriate balance, we conclude that our proposed modifications will, overall, remedy or prevent the effects adverse to the public interest that we identified.

78. We are grateful for the cooperation of the UR and NIE in particular during our investigation, and also to Ofgem, the GB DNOs and others who made submissions and responded to our information requests. We noted that the relationship between the UR and NIE showed signs of stress. While this was to an extent inevitable given the importance of the issues and the duration of the process, we consider that effective communication and understanding were prerequisites of an effective process. There remains significant work to be done in finalizing and implementing the Licence modifications we specified, and in setting tariffs for consumers. We hope that the UR and NIE will engage with this report and each other in a constructive manner: this will ensure that the public interest is best served.

Final determination

1. Introduction

The reference

1.1 The UR issued a Price Control Determination for NIE on 23 October 2012 in respect of NIE's licences for transmission and distribution (each a 'Licence', together the 'Licences'), together with proposed draft Licence modifications. On 20 November 2012, NIE responded with a letter rejecting the Licence modifications and suggested that a reference should be made to the CC. On 30 April 2013, the UR made a reference to the CC. The UR's notice of reference to the CC was published on our website on 30 April 2013 and is at Appendix 1.1 to this report. The specific matters which the UR required the CC to investigate are 'the Price Control Conditions'. This term is defined in Recital B to the reference and refers to Condition 42 and Annex 2 in each Licence which deal with the restrictions on the charges that may be made by NIE for the transmission and distribution of electricity.[1]

1.2 In accordance with Article 15(1) of the Electricity Order, the reference provided six months[2] for us to consider:

(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.

1.3 Our task was to consider the questions that the UR referred to us, and we note that these relate to the Licences in their current form, ie not modified as proposed by the UR in its Price Control Determination for NIE on 23 October 2012. Our conclusions on the first two questions bind both NIE and the UR.[3] Before making modifications, the UR must 'have regard' to the modifications we specify in response to the third question,[4] although there is a process under the Electricity Order to ensure that we are satisfied that any licence modifications that the UR proposes to put in place address the public interest findings we made in response to the first two questions.[5]

1.4 On 12 November 2013, we published our provisional determination regarding the questions referred. We received submissions from NIE and the UR, and held hearings with both. We also received submissions from: Powerline Compensation Ltd, Ulster Farmers Union, Hastings, Phoenix Natural Gas, Unite the Union, NIRIG,

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[1] Annex 2 to each licence is the transmission and distribution charge restriction condition which caps the revenue NIE can earn from its levied distribution and transmission charges. Annex 2 is identical in each Licence. Regulation 90(3) of the 2011 Regulations provides that Annex 2 to each licence shall be taken as relating to the activities authorized by both licences taken together.
[2] On 20 August 2013, the UR extended the period for making the report to 29 April 2014.
[3] Electricity Order, Article 17.
[4] Electricity Order, Article 17(2).
[5] Electricity Order, Article 17A.

Prospect, CCNI, SONI, MNI, Smart Grid Ireland, Simple Power, and Anglian Water Services. These submissions are available on the CC website.[6]

1.5 This document and its appendices comprise our final determination on the questions which the UR required us to consider. Non-commercially-sensitive versions of written submissions from the main and third parties and a summary of hearings with third parties are published on our website[7] along with other relevant documents. We cross-refer to them where appropriate.

Our approach to the reference

1.6 Since NIE rejected the UR's final determination, the UR's proposals for RP5 fell away. We were therefore required to consider whether the current Price Control Conditions operated, or may be expected to operate, against the public interest. Only if we answered that question 'yes' were we required to consider whether the effects adverse to the public interest can be remedied or prevented by licence modifications. The starting point for our work was therefore the current Licences.

1.7 In considering the reference questions, the differences between the UR and NIE, and between their respective proposals and submissions, informed our thinking. However, we did not confine ourselves to considering the UR's proposals in its determination, or NIE's objections to them, but with the current Licence conditions. In the interests of proportionality, we gave appropriate weight to issues bearing in mind their likely effect on the price determination.

1.8 We engaged consultant engineers, BPI, to advise us on NIE's capex proposals. We also engaged a consultancy, Pelicam Project Assurance, to help us investigate issues relating to non-network capex (see paragraphs 10.43 to 10.105) and the Enduring Solution Project (see paragraphs 10.184 to 10.268).

1.9 We also used the best data available to us, which meant that in some cases we used data that had been updated since the UR reached its determination.

1.10 Article 15(7) of the Electricity Order provides that, in determining whether any particular matter operates, or may be expected to operate, against the public interest, the CC must have regard to the matters as respects which duties are imposed on the UR by Article 12 of the Energy Order[8] or Article 9 of the Electricity (Single Wholesale Market) (Northern Ireland) Order 2007 (SEM Order).[9] This meant that, in making our determination, we were required to have regard to the duties of the UR as set out in paragraphs 2.41 to 2.53. This included determining whether any particular matter operated or may be expected to operate against the public interest.[10]

1.11 In doing so, we had regard to the UR's principal objective which, in accordance with Article 12 of the Energy Order, is the protection of the interests of consumers of electricity supplied by authorized suppliers, wherever appropriate by promoting effective competition between those engaged in the relevant commercial activity

[6] www.competition-commission.org.uk/our-work/directory-of-all-inquiries/northern-ireland-electricity-price-determination/evidence/responses-to-the-provisional-determination.
[7] www.competition-commission.org.uk/our-work/directory-of-all-inquiries/northern-ireland-electricity-price-determination/evidence.
[8] SI 2003 No. 419 (N.I.6).
[9] These Articles apply in the alternative, such that Article 12 of the Energy Order does not apply in relation to the carrying out of functions of the UR to which Article 9 of the SEM Order applies (Article 13(1A) of the Energy Order). Given that Article 9 of the SEM Order relates to the UR's duties in giving effect to any decision of the Single Electricity Market Committee, which is not the subject of the reference, the relevant Article for the purposes of the CC's investigation is Article 12 of the Energy Order. Therefore, Article 9 of the SEM Order does not apply.
[10] Article 15(7) of the Electricity Order.

associated with the generation, transmission, distribution or supply of electricity. The public interest scheme, as set out in the Energy Order, the Electricity Order and the EU Electricity Directive,[11] is extensive. It provides, in addition to the principal objective of protecting the interests of consumers, for a detailed set of more specific objectives and further considerations to which the CC must have regard. At least some of these additional objectives and considerations may, properly understood and in terms of their substance, be part and parcel of an overall objective to further the interests of consumers.

1.12 Overall, in making our determination we sought to set a price control that gave sufficient weight to a range of considerations. For example, as well as the need to ensure fair consumer prices (including current and future consumers, and business as well as domestic users), it included consideration of the requirement to secure that all reasonable demands for electricity in Northern Ireland are met (see paragraph 2.47), as well as a level of service quality that ensured that supply interruptions are kept to a reasonable level—that is, in other words, to ensure that 'lights are kept on'. Therefore protecting the interests of consumers may not be a matter of keeping prices for consumers, or individual groups of consumers (some of which may be particularly vulnerable) as low as possible. A licence holder must be able to finance its activities to fulfil its obligations under the Licence, which means that these various objectives and considerations should be seen not just in the short term.

1.13 The extent to which specific elements of the public interest test may be engaged was determined by the relevant evidence. We believe that it would be difficult to demonstrate how the interests of consumers overall could be furthered if, for example, disproportionate weight were to be given to any of the various limbs of the public interest test, at the expense of one or more of the others. Consumers should properly benefit from, for example, both fair prices and the satisfaction of all reasonable demands. We took care that disproportionate weight was not given to any of the limbs of the public interest test. We balanced and attached appropriate weight to specific public interest factors where the particular facts and evidence gave us reason to do so. The requirement to have regard to the duties of the UR did not mean that we would be required to follow the same approach that the UR adopted or adopt the same methodologies.

1.14 In addition, we took account of other factors where relevant to the particular issue, which included the Northern Ireland Government's aspiration to have 40 per cent of electricity generated from renewable sources by 2020, and the need to facilitate a single electricity market in the island of Ireland. While the 40 per cent renewable target is not a statutory obligation as such, we note that it is nonetheless a relevant policy target to combat climate change. Both NIE and the UR have referred to it in various submissions to us.

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

2. Background

2.1 In this section we describe:

(a) NIE's current business, its history and current structure, and its Licences;

(b) developments in the electricity market in Northern Ireland;

(c) government energy policy;

(d) the UR and its duties;

(e) the process of price control reviews;

(f) NIE's network charges and how they compare with other UK electricity distribution companies; and

(g) NIE's consumers of electricity and certain issues relating to the interests of 'consumers'. Note we refer to consumers to identify domestic and industrial and commercial consumers of electricity. These consumers are not direct customers of NIE, rather their contracts are with electricity suppliers. NIE's direct customers are electricity suppliers (principally through use of distribution system charges) and SONI (through transmission services charges), albeit that the charges to customers will be based on categories of final consumer and their consumption.

NIE

2.2 In this subsection we describe NIE's: *(a)* current business; *(b)* history and current structure; and *(c)* Licences.

NIE's current business

2.3 NIE is the owner of the electricity transmission network in Northern Ireland and the owner and operator of the distribution network.[12] The transmission and distribution networks convey electricity between generating stations, interconnectors (ie the lines and cables connecting the Northern Ireland transmission system to those in the Republic of Ireland and Scotland) and consumers' premises.[13]

2.4 NIE's transmission and distribution network contains several interconnected networks of overhead lines and underground cables which are used for the transfer of electricity to approximately 840,000 consumers via a number of substations. There are approximately 2,200 km (circuit length) of transmission system, 43,500 km of distribution system and 250 major substations throughout the NIE network.[14]

2.5 NIE derives its revenue principally through:

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[12] 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. When transmission lines reach substations which are located close to major load centres, the voltage is lowered so it can be sent through smaller power lines or cables. 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. Distribution lines and cables in Northern Ireland distribute electricity at voltages of 33 kV, 11 kV and 6.6 kV. (NIE Statement of Case, Annex 5.A.1.)

[13] NIE Statement of Case, Annex 1A.1, paragraph 4.1.

[14] NIE Statement of Case, Annex 1A.1, paragraph 4.3. Further detail on the structure of the Northern Ireland electricity system and market is given in Appendix 2.1.

(a) use of distribution system charges levied on electricity suppliers; and

(b) transmission services charges levied on SONI—see paragraphs 2.28 to 2.31.[15]

2.6 These revenues are set out in more detail in Table 2.1. This shows that in the year to March 2013, about 65 per cent of NIE's income came from distribution charges. Of that 65 per cent, 56 per cent came from domestic consumers and 44 per cent from industrial and commercial users. The other 35 per cent of NIE's income came from Transmission charges paid by SONI Ltd (16 per cent), the Public Service Obligation (PSO)[16] (12 per cent) and other income (8 per cent).

TABLE 2.1 **NIE income, year ended 31 March 2013**

	£	%	%
Domestic	100,478,732	57	38
Extra high voltage	1,349,486	1	1
High voltage	11,615,291	7	4
Larger business low voltage	37,278,707	21	14
Small business	23,560,585	13	9
Unmetered Supplies	1,966,784	1	1
Distribution total	176,249,584	100	66
Transmission (charged to SONI)	41,621,570		16
PSO	31,765,000		12
Other income	16,060,000		6
Total	265,696,154		100

Source: NIE regulatory accounts and detailed breakdown of income provided by NIE.

2.7 In addition to the maintenance and development of the transmission and distribution network, NIE told us that its other areas of transmission and distribution activities included:

(a) development of the network to accommodate the connection of renewable generation in accordance with the Government's renewable energy integration targets for 2020 (see paragraph 2.37);

(b) increasing interconnection transfer capacity between the electricity networks in Northern Ireland and the Republic of Ireland (see paragraph 2.35); and

(c) wider market services.[17]

2.8 NIE's transmission system is connected to that of the Republic of Ireland through 275 kV and 110 kV interconnectors and to that in Scotland via the Moyle Interconnector. NIE owns and maintains these transmission circuits within Northern Ireland. There are also plans to strengthen further the interconnection of the electricity networks of Northern Ireland and the Republic of Ireland via a 400 kV North–South interconnector. This is currently subject to a public inquiry.[18] The Moyle Interconnector is owned by Moyle Interconnector Limited (part of the Mutual Energy group of companies).

[15] NIE Statement of Case, Annex 1A.1, paragraph 4.4
[16] PSO charges relate to matters which benefit all electricity consumers in Northern Ireland. They arise from costs approved by the UR incurred by Power NI's power procurement and supply businesses, the Northern Ireland Sustainable Energy Programme, and NIE's costs associated with market opening and the Land Bank business. (NIE Statement of Case, Annex 1A.1, paragraph 5.17, fn 30.)
[17] NIE Statement of Case, Annex 1A.1, paragraph 4.2.
[18] NIE Statement of Case, Annex 1A.1, paragraph 4.6.

2.9 NIE told us that in its role as 'common service provider', it operated the market registration service and the market data service,[19] and acted as meter data provider to facilitate the operation of the Single Electricity Market (SEM—see paragraph 2.24) and the downstream retail market. NIE also told us that in support of this it had recently implemented a new IT system (the Enduring Solution project) to: provide full business separation between NIE and Power NI's systems; allow for consumers to switch electricity supplier; and to accommodate potential future changes to market requirements. [20]

2.10 NIE is no longer involved in the generation of electricity, nor in the purchase and supply of electricity to customers. The overall structure of the electricity industry in Northern Ireland is set out in Appendix 2.1.

NIE's history and its current structure

2.11 NIE was incorporated on 25 October 1991 as a public limited company. In March 1992, it was granted Licences to transmit electricity and to act as a public electricity supplier. Conditions of its Licences regulated its activities in relation to: power procurement (including transmission system operation); electricity transmission and distribution; and electricity supply.

2.12 The generating operations of Northern Ireland Electricity Service (the legacy electricity public utility) were separated from NIE and sold to third parties in April 1992, removing electricity generation from the scope of NIE's regulated business activities.[21] NIE was floated on the London Stock Exchange in June 1993.[22]

2.13 NIE created a new holding company in 1998, Viridian Group PLC (Viridian Group), which acquired the entire issued share capital of NIE. NIE remained a public company but was delisted from the London Stock Exchange. The purpose of the reorganization was to separate NIE's regulated and unregulated business activities. Unregulated business operations (including IT, telecommunications, property, transport, insurance and financial services) were transferred to a separate subsidiary. NIE's affiliate, NIE Powerteam Limited (NIE Powerteam), was established as a vehicle for operational functions.[23] NIE said that NIE Powerteam provided its services exclusively to NIE and consequently nearly all of NIE Powerteam's revenues are generated from NIE.[24,25] NIE Powerteam has approximately 1,000 employees

[19] These roles arise from NIE's licence condition 28. The purpose of the market registration service is to create a register of technical and other data as necessary to facilitate supply by a licensed supplier to premises connected to the total system and to provide information for settlement purposes. The market data service facilitates collection, processing and valuation of electricity flows at metered and unmetered premises. NIE also transfers such data as reasonably required and requested by licensed suppliers and SONI (as transmission system operator and Northern Ireland market operator). (NIE Statement of Case, Annex 1A.1, paragraph 5.17.)

[20] NIE Statement of Case, Annex 1A.1 paragraph 4.7.

[21] NIE Statement of Case, Annex 1A.1 paragraph 2.1-2.2.

[22] NIE Statement of Case, Annex 1A.1 paragraph 2.2.

[23] The UR said that in 2005, Powerteam was split into two separate legal entities: Powerteam Electrical Services Ltd (PES) and NIE Powerteam Ltd. PES is a third party contractor that provides services on a commercial basis. There are limitations on the level of work that PES can carry out for Northern Ireland Electricity Limited. It is not a regulated entity.

[24] ibid, Annex 1A.1, paragraphs 2.3–2.4. NIE said that NIE Powerteam provided de minimis training services to third parties and occasionally NIE Powerteam provided assistance to other DNOs in restoring supplies after storm damage to their networks. We understand that revenues for these services are a very small proportion of Powerteam's total revenues.

[25] The UR said that Powerteam effectively operated as a department of NIE. It said that NIE used Powerteam for the majority of its subcontracted labour work on the network. Powerteam provided network services including metering, meter reading, overhead lines, customer operations and plant/technical support to NIE, as well as providing other support functions under managed service contracts. The UR told us that a number of business functions were shared across NIE and Powerteam. Examples included: telecommunications, IT, corporate service allocations, finance, technical, facilities management, HR and business improvement. The UR said that Powerteam was becoming a subsidiary to NIE (enacted from 1 October 2013) to ensure ring fencing from ESB going forward.

compared with approximately 300 employees for NIE. NIE Powerteam was made a direct subsidiary of NIE with effect from 1 October 2013.[26]

2.14 In 2000, NIE separated its transmission system operation functions into a newly incorporated NIE subsidiary, SONI, to comply with EU legal requirements.[27] Also, in November 2007 (ahead of the launch of the SEM—see paragraph 2.24), NIE's regulated power procurement and supply businesses were transferred to a separately licensed Viridian Group subsidiary, NIE Energy Limited (now Power NI Energy Limited). NIE also agreed with the UR and the Department of Enterprise, Trade and Investment (DETI) to divest SONI in order to enhance further the independence of the transmission system operator in Northern Ireland[28,29] (see paragraph 2.28).

2.15 In December 2006, Viridian Group was acquired by Arcapita Bank B.S.C. NIE told us that this acquisition had little effect on it, as it remained as a subsidiary of Viridian Group, which then was reregistered as a private limited company.[30]

2.16 In July 2010, ESB[31] and Viridian Group reached conditional agreement for the sale of NIE to ESB. NIE was acquired by an ESB subsidiary, ESBNI, in December 2010. ESBNI also acquired NIE Powerteam, Powerteam Electrical Services (UK) Limited and Capital Pensions Management Limited[32] from Viridian Group.[33]

2.17 NIE said that it was subject to strict ring-fencing obligations pursuant to its Licences which separated it from the rest of the ESB group.[34] In Appendix 2.2, we discuss ESB and its relationship to NIE.

2.18 Some of NIE's recent financial results are set out in Table 2.1. An adjustment is made to the statutory operating profit to reflect the fact that charges in subsequent years are adjusted if there is over- or under-recovery of revenues relative to entitlements in particular years. In its annual reports, NIE said that it considers the adjusted, pro-forma operating profit figures to be more meaningful[35]. The profit figures in Table 2.2 include some discontinued operations (eg the sale of SONI). We note that NIE has not paid dividends to shareholders since 2010.

[26] 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.
[27] NIE Statement of Case, Annex 1A.1, paragraph 2.5.
[28] In August 2008, NIE and EirGrid plc (the independent transmission system operator in the Republic of Ireland) reached conditional agreement for the sale of SONI, and in March 2009 SONI was sold to EirGrid plc.
[29] NIE Statement of Case, Annex 1A.1 paragraph 2.7.
[30] ibid, Annex 1A.1, paragraph 2.6.
[31] ESB is owned by the Irish Government (95 per cent) and by employees (5 per cent). It is also one of the electricity suppliers in the island of Ireland.
[32] NIE said that Powerteam Electrical Services (UK) Limited designed, supplied and constructed high-voltage electrical infrastructure solutions for third party utility and private operators throughout GB and Ireland. Capital Pensions Management Limited is effectively an in-house team of three staff managing NIE's pension scheme.
[33] NIE Statement of Case, Annex 1A.1, paragraph 2.8.
[34] For example, licence condition 14 contains a ring-fencing obligation which prohibits the core regulated business activities of NIE being held or carried on by any of its affiliates. (NIE Statement of Case, Annex 1.A.1, paragraph 5.17.)
[35] http://www.nie.co.uk/documents/Annual-Reports/Annual-report-2013-FINAL-complete-13Mar14.aspx

TABLE 2.2 **NIE's selected financial results for 2008 to 2012**

£ million

Financial accounts	*Group statutory operating profit*	*Deduct/add back regulatory correction factor*	*Group pro-forma operating profit*	*Capital expenditure*	*Operational expenditure*	*Dividends declared and paid*
31/3/2008	130.8*	–17.3	113.5	120.0	81	Ordinary: 94.4, Preference: 2.1
31/3/2009	116.8†	–2.8	114	104.6	86.2	Ordinary: 110.6
31/3/2010	114.6	–5.8	108.8	95.1	90	Ordinary: 55
31/3/2011	68.8	29.6	98.4	109.1	112.8	Ordinary: none
31/3/2012	107	–14.4	92.6	130.6	87.6	Ordinary: none

Source: NIE Annual Report and Accounts 2009–2012. NIE Statement of Case, Annex 1A.1, paragraph 4.11.

*Operating profit from continuing operations £16.8 million.
†Operating profit from continuing operations £84 million.

NIE's Licences

2.19 The electricity market in Northern Ireland is a regulated market with participants licensed to engage in activities. NIE is subject to economic and customer service regulation by the UR (see paragraphs 2.41 to 2.58).

2.20 NIE's original licence dated 31 March 1992, granted under the Electricity Order, was to 'transmit electricity for the purpose of giving a supply to any premises or enabling a supply to be so given in the authorised transmission area'. The authorized area under the licence is Northern Ireland.[36] In accordance with and pursuant to Regulation 90(1) the Gas and Electricity (Internal Markets) Regulations (Northern Ireland) 2011 (the 2011 Regulations), as amended from 15 April 2011, NIE's original licence has had effect as if it were two separate licences, called the successor transmission licence (granted under Article 10(1)(b) of the Electricity Order) and the successor distribution licence (granted under Article 10(1)(bb) of the Electricity Order). The UR published the two successor licences (ie the two Licences with which we are concerned), in each case modified in accordance with Regulation 90(5) of the 2011 Regulations, on 11 March 2013. Many, but not all, conditions are common to both Licences. Part II of each Licence sets out the Licence conditions. Some conditions cover the preparation and exchange of information, such as Condition 2 which requires NIE to prepare regulatory accounts in respect of the transmission and distribution businesses each financial year and to have them audited (with the auditors' report being provided to the UR) and Condition 8 which requires NIE to provide to the UR such information as the UR may require to perform its statutory functions. Other conditions deal with financial matters, including the requirement in Condition 9A for NIE to take all appropriate steps to ensure that it obtains and maintains an investment grade credit rating.

2.21 Condition 42 and Annex 2 contain the charge restriction applicable to NIE's transmission and distribution business. These are identical in both Licences and are referred to as the Price Control Conditions in the reference.[37] Paragraph 7.1 of Annex 2 provides that the transmission and distribution charge restriction conditions apply so long as the Licences continue to be in force.[38] The Price Control Conditions cease to have effect (in whole or in part, as the case may be) if NIE serves a

[36] Paragraph 1 of Schedule 1 of the Licences.
[37] Regulation 90(3) of the 2011 Regulations provides that Annex 2 to each licence shall be taken as relating to the activities authorized by both licences taken together.
[38] Under paragraph 1 of Part I, each licence continues in force unless revoked in accordance with the terms specified in Schedule 2 (Terms as to Revocation) or determined by not less than 25 years' notice in writing given by DETI.

disapplication notice on the UR, which it may do in certain circumstances, and following a process, set out in the conditions.[39]

2.22 NIE is subject to a number of statutory duties as an electricity distributor and licensed participant in transmission. Its principal general duties are contained in Article 12 of the Electricity Order which provides that:

> 12.—(1) It shall be the duty of an electricity distributor to—
>
> (a) develop and maintain an efficient, coordinated and economical system of electricity distribution which has the long-term ability to meet reasonable demands for the distribution of electricity; and
>
> (b) facilitate competition in the supply and generation of electricity.
>
> (2) It shall be the duty of the holder of a licence under Article 10(1)(b), as appropriate having regard to the activities authorised by the licence, to—
>
> (a) take such steps as are reasonably practicable to—
>
> (i) ensure the development and maintenance of an efficient, co-ordinated and economical system of electricity transmission which has the long-term ability to meet reasonable demands for the transmission of electricity; and
>
> (ii) contribute to security of supply through adequate transmission capacity and system reliability; and
>
> (b) facilitate competition in the supply and generation of electricity.

Developments in the electricity market in Northern Ireland

2.23 Before privatization, Northern Ireland Electricity Service was the public utility responsible for electricity generation, transmission (including system operation), distribution and supply throughout Northern Ireland. The first stage in the privatization process was the sale in 1992 of NIE's generation capacity to three separate trade buyers who purchased power station assets (NIE was the sole customer through its then power procurement business). Competition for supply to all large electricity customers was introduced in 1999 and then in 2005 competition for supply to all non-residential customers was introduced.[40]

2.24 An important structural and regulatory change in the Northern Ireland electricity market occurred in November 2007 with the implementation of the SEM in the island of Ireland (see paragraph 2.23). The SEM was designed to promote the establishment and operation of a single competitive wholesale electricity market in Northern Ireland and the Republic of Ireland. It was implemented in Northern Ireland by means

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[39] Paragraphs 7.1–7.6 of Annex 2 contain details on the disapplication process. A disapplication request must specify the transmission and distribution charge restriction conditions (or any parts thereof) to which it relates. If the UR agrees to the request, such conditions will be disapplied, subject to certain timelines being followed. If the UR does not agree, it may either make a reference to the CC which will, as part of its investigation, decide whether or not the transmission and distribution charge restriction conditions specified in the disapplication request operate against the public interest. If the CC decides that such conditions do not operate against the public interest, NIE may terminate these conditions by giving notice to the UR. Alternatively, and in the absence of a reference to the CC, NIE may deliver written notice to the UR to terminate the application of the specified conditions.
[40] NIE Statement of Case, Annex 1A.1, paragraph 3.1.

of the SEM Order. The SEM consists of a gross mandatory pool market, into which all electricity supplied by generators of more than 10 MW capacity in (or importing into) the island of Ireland must be sold, and from which all wholesale electricity for consumption in or to be exported from the island of Ireland must be purchased.[41]

2.25 On 1 November 2007, the Electricity Regulations (Northern Ireland) 2007 (the 2007 Regulations) came into force. The 2007 Regulations implemented Directive 2003/54/EC and sought to achieve legal and functional separation of transmission and distribution system activities from those of supply and generation, and to ensure greater market freedom for consumers to purchase electricity from their supplier of choice.[42]

2.26 A further structural change in the Northern Ireland market has been driven by the EU Third Energy Package (IME3). IME3 has been implemented in Northern Ireland by the 2011 Regulations (see paragraph 2.20) among other legal instruments. The most relevant of the IME3 objectives to NIE's regulated activities are the unbundling of transmission and distribution networks and the certification of all transmission system operators.[43]

2.27 The 2011 Regulations introduced certain measures in Northern Ireland to ensure compliance with the unbundling requirements of IME3. Part III of the 2011 Regulations sets out the new ownership (or unbundling) regime for transmission networks, implementing full separation of electricity transmission from production and supply and sets down procedures for the certification of transmission operators. Part V of the 2011 Regulations introduced new (and transitional) powers for the UR unilaterally to amend electricity licences to ensure that licensed activities comply with the requirements of IME3.[44]

2.28 As a result of the unbundling requirement (see paragraph 2.27), SONI (rather than NIE) will be certified as the transmission system operator for Northern Ireland.[45] It was purchased by EirGrid—the equivalent system operator in the Republic of Ireland which is based in Dublin. SONI's income is derived from a 'system support service tariff' which is approved by the regulator.[46] SONI has two licensed activities: one for its system operator activities where the current price control concludes in 2015 and a separate Licence for its market operator activities which has a separate price control and commences on 1 October 2013. Its all-Ireland market operator activities are regulated jointly by the UR and CER.[47]

2.29 NIE is currently responsible, in conjunction with SONI, for planning, developing and maintaining the transmission network.[48] SONI said that it expected to take over all planning functions by April 2014, and it expected that it would then review NIE's investment plans. It acknowledged that some decisions on investment would have already been made by then in relation to the RP5 current price control period.[49]

2.30 The UR told us that while NIE was presently responsible for planning whether, where, when and how the transmission system should be developed (eg by way of upgrades to capacity, the construction of new lines to meet forecast demand growth,

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[41] ibid, Annex 1A.1, paragraphs 3.3–3.5 .
[42] ibid, Annex 1A.1, paragraphs 3.10–3.12.
[43] ibid, Annex 1A.1, paragraph 3.19.
[44] ibid, Annex 1A.1, paragraph 3.13.
[45] ibid, Annex 1A.1, paragraph 3.19.
[46] SONI hearing summary, paragraphs 1 & 2.
[47] ibid, paragraph 3.
[48] NIE Statement of Case, Annex 1A.1, paragraph 4.1.
[49] SONI hearing summary, paragraph 8.

etc), in future at least some or all of these planning decisions will be undertaken by SONI. It said that what this meant in practice was not yet fully developed. However, there were certain tasks, activities and decisions in relation to investment planning that were presently undertaken by NIE and would during the course of RP5 be undertaken by SONI. It said that this change in responsibilities would inevitably have an impact on matters relating to capital expenditure. While responsibility for physically developing the system would remain with NIE, so that it would therefore continue to incur capital expenditure, the primary decision-making role in relation to system development would pass to SONI. The UR said that this introduced an additional level of uncertainty in relation to the need for capital expenditure by NIE during RP5.

2.31 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. A summary of some of the relevant proposed principles is set out in Appendix 2.3. They said that these principles would be translated into a Transmission Interface Agreement (TIA) between SONI and NIE, and would be subject to regulatory approval.

2.32 Given the uncertainty regarding the arrangements to be concluded, our determination does not make any explicit allowance or adjustment for the transfer of responsibilities for transmission planning from NIE to SONI.

Government energy policy

2.33 In Northern Ireland, energy policy is the responsibility of the Department of Enterprise, Trade and Investment (DETI). Article 12 of the Energy (Northern Ireland) Order 2003 sets out the principal objective and duties of DETI and the Northern Ireland Authority for Utility Regulation in relation to the electricity sector. The principal objective is to protect the interests of consumers of electricity supplied by authorized suppliers.

2.34 The key document for energy policy is the Strategic Energy Framework (SEF), which was published by the Northern Ireland Executive in 2010. The SEF set out energy policy up to 2020. The document sets out key priorities to guide market participants, encourage investment in both renewable energy and the provision of new infrastructure (including electricity infrastructure). DETI told us that the aim was to improve security and diversity of energy supply and support economic activity while reducing carbon emissions.[50]

2.35 The SEF references the most significant policy intervention in recent times as being the creation of the SEM in Northern Ireland and the Republic of Ireland. As a result of developments at a European level, the SEM is now subject to further change to meet the requirements of the new target model to facilitate greater integration across the EU. DETI said that the Northern Ireland Executive believed that the key to growing the electricity market was a robust and stable electricity transmission system and that this was critical to a modern economy. It said that a robust, modern electricity grid was also an important requirement given the EU targets associated with decarbonization and regulatory and technical challenges of integrating renewables on to the grid.

2.36 Challenging renewables targets are set in the SEF for Northern Ireland. Under specific action (number 37) of the SEF DETI is tasked with ensuring cooperation between the UR, NIE and SONI to deliver the required electricity grid infrastructure.

[50] DETI submission.

2.37 The key target is that by 2020, 40 per cent of Northern Ireland's electricity consumption will come from renewable sources. A consequence of increased renewable generation is that the electricity transmission and distribution networks will be likely to need updating and reinforcing to cope with the incorporation of often small-scale generation (such as small wind farms) in dispersed areas. The quantities of generated electricity to be carried at points in the network, and the directions of flow, can change substantially. Further, the quantity, location and timing of these investments is uncertain.

2.38 Around 2009, NIE estimated that the scale of investment required to achieve both the renewables target set out in the SEF and the regular maintenance and development of the grid up to 2020 is in the region of £1 billion. The Northern Ireland Renewables Industry Group (NIRIG) told us that a lower level of around £360 million was required to fund the additional investment attributable to renewables.[51]

2.39 NIE told us that a more recent detailed NIE/SONI/Eirgrid study (Renewable Integration Development Project (RIDP)) had identified a joint Northern Ireland/Republic of Ireland transmission development proposal for the North and West of Northern Ireland that would imply a joint (Northern Ireland and Republic of Ireland) investment level of less than £500 million. However, NIE said that it would be wrong to assume that this scheme, in its entirety, would necessarily be required to meet government targets.

2.40 In addition to onshore wind generation in the North and West of the island, which was the particular focus of RIDP, NIE told us there was additional planned offshore wind farms on the east coast to contribute to meeting government targets. NIE said that while this might reduce the RIDP costs, there would also be costs associated with transmission reinforcement in the east of the province associated with this new offshore generation. NIE said that it had not as yet received an application from the offshore developers and could not therefore confirm the level of required transmission reinforcement.

The UR and its duties

2.41 The UR is an independent statutory body corporate. Its board is appointed by the Northern Ireland Executive. It is a non-ministerial government department responsible for regulating Northern Ireland's electricity, gas, water and sewerage industries. Previously known as Ofreg, its statutory duties are set out in the Energy Order and the Water and Sewerage Services (Northern Ireland) Order 2006.

2.42 The objectives of electricity regulation and the duties of the UR are set out in the Energy Order as amended, in particular by the 2011 Regulations[52] (which transposed certain requirements of the EU Third Energy package into law in Northern Ireland). The UR's statutory functions as set out in the Electricity Order[53] include:[54]

(a) granting licences for the generation, transmission, distribution and supply of electricity in Northern Ireland (Articles 10, 10A, 10AA and 11);

(b) certifying, monitoring and reviewing transmission licensees as independent operators pursuant to IME3 (Article 10B to 10K);

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[51] See summary of hearing with NIRIG.
[52] SI 2011, No. 155.
[53] SI 2003, No. 419 (NI.6).
[54] NIE Statement of Case, Annex 1A.1, paragraph 5.6.

(c) the power to modify electricity licence conditions (Articles 14 to 18 as discussed in more detail below); and

(d) a general obligation to keep under review and collect information in respect of activities connected with the generation, transmission, distribution and supply of electricity in Northern Ireland.

2.43 Generally, licences for the generation, transmission, distribution or supply of electricity in Northern Ireland are granted under Article 10 the Electricity Order.[55] The Electricity Order and the conditions of the licences granted under that Order are the principal means by which transmission and distribution of electricity in Northern Ireland is regulated.

2.44 The Electricity Order is supplemented, most notably in respect of the functions and duties of the UR and licensees respectively, by the Energy Order. Both the Electricity Order and the Energy Order have been amended by the SEM Order and the 2011 Regulations in order to achieve the objectives of market integration within the island of Ireland and to comply with wider market liberalization pursuant to IME3.[56]

2.45 The UR said that the details of and relationship between its various duties and objectives was somewhat complex, but at its core was a simple principal objective: to protect the interests of consumers. It said that in pursuing that objective, it was required to have regard, among other things, to the need to secure that all reasonable demands in Northern Ireland or the Republic of Ireland for electricity were met and the need to secure that licence holders were able to finance their activities.[57]

2.46 Specifically, the principal objective of the UR in carrying out its electricity-related functions as provided by the Energy Order is:

> to protect the interests of consumers of electricity supplied by authorised suppliers, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the generation, transmission, distribution or supply of electricity. [58]

2.47 Article 12(2) requires the UR to perform its functions:

> … in the manner which it considers is best calculated to further the principal objective, having regard to—
>
> (a) the need to secure that all reasonable demands in NI or RoI for electricity are met;
>
> (b) the need to secure that licence holders are able to finance the activities which are the subject of obligations imposed by or under Part II of the Electricity Order or this Order.

2.48 In addition, in performing the duties set out in Article 12(1), 12(1A) and 12(2), the UR must have regard to the need to protect the interests of:

(a) individuals who are disabled or chronically sick;

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[55] SI 2003, No. 419 (N.I.6).
[56] NIE Statement of Case, Annex 1A.1, paragraphs 5.2–5.3.
[57] UR Statement of Case, paragraph 6.
[58] UR website.

(b) individuals of pensionable age;

(c) individuals with low incomes; and

(d) individuals residing in rural areas.[59]

2.49 This list is not exhaustive. The UR may also, when carrying out its electricity functions, have regard to the interests of consumers in relation to gas, water or sewage services.[60]

2.50 The interests of consumers include their interests in the fulfilment by the UR of 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[61] (the Electricity Directive).[62] These include: promoting a competitive, secure and environmentally sustainable internal market in electricity; developing competitive and properly functioning regional markets; ensuring that customers benefit through the efficient functioning of their national market; eliminating restrictions on trade in electricity between member states; helping to achieve, in the most cost-effective way, the development of secure, reliable and efficient non-discriminatory systems that are consumer oriented; promoting 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; 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; ensuring that system operators and system users are granted appropriate incentives to increase efficiencies in system performance and foster market integration; helping to achieve high standards of universal and public service in electricity supply and contributing to the protection of vulnerable customers.[63] Article 36 of the Electricity Directive is set out in full in Appendix 2.4.

2.51 Subject to the duties set out in Article 12(2), the UR is required by Article 12(5) of the Electricity Order to carry out its electricity functions in a manner it considers best calculated to:

(a) promote the efficient use of electricity and efficiency and economy by licensees;

(b) protect the public from dangers arising from the generation, transmission, distribution or supply of electricity;

(c) secure a diverse, viable and environmentally sustainable long-term energy supply;

(d) promote research into, and the development and use of, new techniques by licensees; and

(e) secure the establishment and maintenance of machinery for promoting the health and safety of persons employed in the generation, transmission, distribution or supply of electricity.

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[59] Article 12(3) of the Energy Order.
[60] ibid.
[61] OJ L211/55, 14 August 2009.
[62] Article 12(1A) of the Energy Order.
[63] ibid.

2.52 Additionally, in carrying out those functions, the UR must have regard to the effect on the environment of activities connected with the generation, transmission, distribution or supply of electricity.[64]

2.53 The UR said that it sought to strike a balance in terms of these objectives, acknowledging that these could conflict. It said that it would seek to weigh up the balance of the objectives depending on the circumstances, and the balance was not always the same. It said that the principal objective was to protect consumers, but this was not just a question of obtaining the lowest price possible. It said that a fair amount of discretion and judgement was left to the regulator. It told us that some key indicators were relevant, for example the 40 per cent renewable target in the strategic energy framework. The SEF also referred to fuel poverty and industrial competitiveness. It also noted mandatory requirements, particularly on health and safety legislation. It said that where the legislation and policy was non-prescriptive, inevitably different decision-makers could strike different balances.

Price control reviews

2.54 There are no express provisions in either of the Electricity Order, the Energy Order or the Licences which provide for review of the charge restriction conditions in Condition 42 and Annex 2. However, in order to fulfil its statutory duties, the UR is required to keep under review whether NIE's obligations continue to be apt to attain the UR's statutory objectives. In practice, this requires the UR periodically to review NIE's price controls. In setting an individual price control, the UR generally indicates how long it is expected to apply, and, by implication, when it is scheduled to be subject to periodic review.

2.55 The UR has controlled charges for transmission and distribution by setting the revenues that NIE is allowed to raise during the following price control period. The UR said that the revenue it allowed enabled the company to recover its operating costs, depreciation and a reasonable return on investment. These revenues were collected from customers and generators through charges for use of the transmission and distribution systems.[65] The price control determination set these allowed revenues and proposed amendments to NIE's licences to implement this.[66]

2.56 Since privatization, price controls have been applied for four five-year regulatory periods:[67]

(a) 1 April 1992 to 31 March 1997 (RP1). The price control which applied during RP1 was notified to NIE by DETI.

(b) 1 April 1997 to 31 March 2002 (RP2). In RP2, the UR and NIE failed to reach agreement on the final proposal for the price control, resulting in a reference to the then Monopolies and Mergers Commission (MMC). Following NIE's application for judicial review of the UR's decision not to give effect to the MMC's conclusions, which was successful before the Northern Ireland Court of Appeal, RP2 was settled two years later, by the UR's acceptance that NIE should set its charges by reference to the revenue allowance provided for by the MMC.

(c) 1 April 2002 to 31 March 2007 (RP3). The UR proposed, and NIE agreed, licence modifications to implement the RP3 price control.

[64] ibid.
[65] UR RP5 final determination, paragraph 2.14.
[66] NIE Statement of Case, Annex 1A.1, paragraph 5.30.
[67] ibid, Annex 1A.1, paragraphs 5.31–5.35.

(d) 1 April 2007 to 31 March 2012 (RP4). The agreed licence modifications to implement the RP4 price control were made by the UR in December 2006.

2.57 The details of the RP4 price control conditions are set out in more detail in paragraphs 3.3 to 3.33.

2.58 In addition to price controls, the UR also sets guaranteed and overall standards for services provided to consumers (eg the timely restoration of consumers' supplies following an interruption and prescribed times for responding to voltage complaints) by NIE.

2.59 The RP5 price control review process formally commenced in July 2010 with the UR publishing its 'Strategy Paper for the RP5 price control' setting out its proposed approach to the price control for consultation.

2.60 On 6 October 2011, the UR announced a six-month delay in the implementation of the RP5 price control. Although the UR and NIE disagree as to the status of the RP4 price control after 31 March 2012, NIE said that the UR purported to extend the RP4 price control for an interim period from 1 April 2012 to 30 September 2012, and then for a further period to 31 December 2012.

2.61 The RP5 draft determination was published on 19 April 2012 for consultation. Further detail, including the RP5 Capex 'Fund 3' criteria and incentive mechanisms consultation, and the capitalization practice draft determination were published at the end of August 2012. NIE told us that it had concerns with the RP5 process, and that it had written to the UR in 2011 and 2012 urging improved transparency and engagement.[68]

2.62 The final determination was issued on 23 October 2012, with a licence modification notice and draft modified Licences. NIE wrote to the UR on 20 November 2012 stating that it was unable to accept the terms of the Final Determination. This rejection led to the reference to us.

2.63 In Appendix 2.5 we summarize at high level the UR's final determination for RP5, with its reasoning for its proposals as well as the reasons NIE gave for rejecting UR's final determination. Appendix 2.5 also sets out the arrangements after the expiry of RP4.

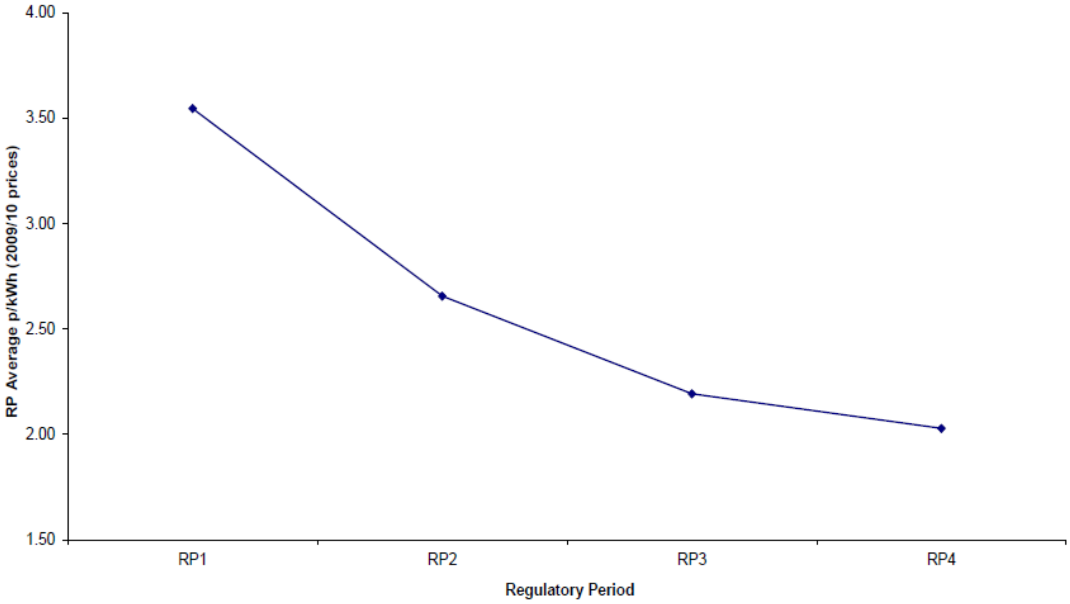
NIE's network charges and how they compare with other UK electricity distribution companies

2.64 NIE's average use of system charges over the first four price control periods are shown in Figure 2.1.

[68] NIE Statement of Case, Annex 1.A.1, paragraph 6.3.

FIGURE 2.1

NIE's network charges



Source: Figure 2.2 from NIE Statement of Case, p9.

2.65 NIE told us that there had been a 43 per cent reduction in real network charges since RP1, which it said reflected the efficiencies it had achieved over that time (for example, that staff numbers had fallen from 3,000 at privatization to 1,300 (including NIE and Powerteam).[69]

2.66 Table 2.3 gives an overview of NIE's distribution use of system charges and how they relate to the charges of some other UK electricity distribution companies. While we do not expect that charges will be the same for different distribution companies (for example, their costs will vary with the circumstances and proportionate size of their networks), relative charges do provide a point of reference which can be informative as a part of the assessment when considering whether charges are at a level consistent with the public interest.

2.67 The figures in Table 2.3 are annual distribution charges excluding VAT for each illustrative supply.[70]

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[69] ibid, paragraphs 1.8–1.9.

[70] In order to give a readable description of NIE's distribution use of system tariffs, we use a set of illustrative notional customers, defined as follows:

- A domestic customer with a consumption of 2,000 kWh a year and a prepayment meter. This is a lower than average level of consumption, but is compatible with running a modern home (with little waste and no use of electricity for heating).
- A domestic customer with a consumption of 2,000 kWh a year and a credit meter.
- A domestic customer with a consumption of 4,000 kWh a year and a credit meter. This is an average amount of consumption for a household without electric heading (both in Northern Ireland or elsewhere in the UK).
- A domestic customer with a consumption of 8,000 kWh a year and a credit meter. This might be a large house in which the occupants do not give much thought to energy conservation.
- A small business customer taking 8,000 kWh a year. This corresponds, for example, to 200 watts of background load (server, fridge, etc) plus 2,500 watts 50 hours a week (lighting and computers for something like ten desks or a shop).
- A business supply at 400 volts (not near the substation), with a capacity and maximum demand both equal 150 kVA, consuming an average of 100 kW uncorrelated with time of day, week or year, and no reactive power.
- A business supply]at 11,000 volts (not near the primary substation), with a capacity and maximum demand both equal 1,500 kVA, consuming an average of 1,000 kW uncorrelated with time of day, week or year, and no reactive power.
- A highway authority with 50 sets of traffic lights each taking 200 watts, and 2,000 street lights each taking 70 watts and operating at night (11 hours a day on average).

2.68 There are some differences in the scope of distribution use of system charges which are relevant to the interpretation of Table 2.3:

(a) In addition to its distribution use of system charges for the North of Scotland, SHEPD receives a special subsidy from all GB customers, collected through National Grid. This subsidy has existed in some form since before privatization and was intended to mitigate high distribution costs in the North of Scotland.

(b) NIE's distribution use of system charges include charges for metering and data management services (in support of market opening), including management of prepayment meters, the equivalent of which is managed and charged for separately in Scotland, England and Wales. This adds to NIE's charges reported in Table 2.3.

(c) On the other hand, Scottish distribution use of system charges include the costs of using 132 kV/33 kV transformers (which are part of the transmission network but recharged to the distribution company), whereas NIE told us that its 110 kV/33 kV costs were seen as transmission costs charged to SONI (and so not included in the charges quoted in Table 2.3). In addition to this, in England and Wales, distribution use of system charges also include the costs of using the 132 kV system and transmission/132 kV transformers.

TABLE 2.3 **Distribution use of system charges**

£/year

	NIE 2012/13	*North Scotland 2013/14*	*South Scotland 2013/14*	*South-west England 2013/14*	*London 2013/14*
Prepay 2,000 kWh	93	105	64	82	55
Domestic 2,000 kWh	83	105	64	82	55
Domestic 4,000 kWh	124	186	111	149	95
Domestic 8,000 kWh	207	347	206	283	176
Small business 8,000 kWh	237	297	185	227	120
Business 150 kVA	11,603	20,831	11,894	15,960	9,163
Business 1,500 kVA	57,135	164,955	89,776	117,018	70,349
Highway authority 150 kW	10,964	18,337	11,992	22,030	10,075

Source: CC calculations.

2.69 The electricity distribution company serving the North of Scotland, SHEPD (part of the SSE plc group), has a distribution network which is quite similar to NIE's. Both NIE and SHEPD have very long overhead networks compared with other UK regional distribution networks. For NIE, the average overhead distribution network (excluding 132 kV) per customer is 36 metres compared with 36.7 metres for SHEPD. In comparison, the numbers are 9.8 metres for the South of Scotland, 17.6 metres for the South-West of England, and very little in London.[71]

2.70 It can be seen that relative to north Scotland, except for one category, NIE charges are lower than for SHEPD. Relative to the other DNOs, results are more mixed. They are higher than for London, other than for large business customers. In fact, larger business customers tend to face lower distribution charges in Northern Ireland (these comparisons are only for use of the distribution system, not the total cost of power).

[71] The figures underlying these calculations are taken from public sources. We acknowledge that they refer to different periods (between 2008 and 2012). However, it seems unlikely that they will change very fast.

NIE's consumers of electricity and certain issues relating to the interests of consumers

2.71 The NIE transmission and distribution network serves around 840,000 electricity consumers (see paragraph 2.1*(g)*). Of these, nearly 780,000 are domestic consumers. Nearly 50,000 are small businesses which are billed quarterly. Around 10,000 are larger consumers metered half-hourly on MV <70 kVA or MV and about 400 are the largest consumers on half-hourly metered HV or EHV.

2.72 In this subsection we describe: *(a)* NIE's domestic consumers; *(b)* consumers' electricity bills; *(c)* the role of the Consumer Council of Northern Ireland (CCNI); *(d)* consumer concerns as revealed by CCNI research; *(e)* fuel poverty in Northern Ireland; *(f)* NIE's business consumers; and *(g)* consumers' willingness to pay for renewable energy.

Domestic consumers

2.73 In July 2013, the average domestic consumer in Northern Ireland had an annual domestic electricity bill (which includes transmission and distribution costs) of around £595, up from £505 in October 2012 (a rise of 17.8 per cent). In November 2007, electricity bills for domestic consumers averaged £385 a year. Between November 2007 and July 2013 electricity bills for domestic consumers in Northern Ireland rose by some 61 per cent. Average annual bills for an illustrative domestic consumer from 2007 to 2013 are shown in Table 2.4.[72]

TABLE 2.4 **Power NI average annual bill for consumer using 3,300 kWh of electricity on the standard tariff with postal bills paying by cash or cheque**

£

	Nov 2007	*July 2008*	*Oct 2008*	*Jan 2009*	*Oct 2009*	*Oct 2010*	*Oct 2011*	*Oct 2012*	*July 2013*
Cost (£)	385	439	585	522	496	496	588	505	595
% change	3.9	14	33.3	–10.8	–5	0	18.6	–14.1	17.8

Source: CCNI slides from hearing on 8 July.

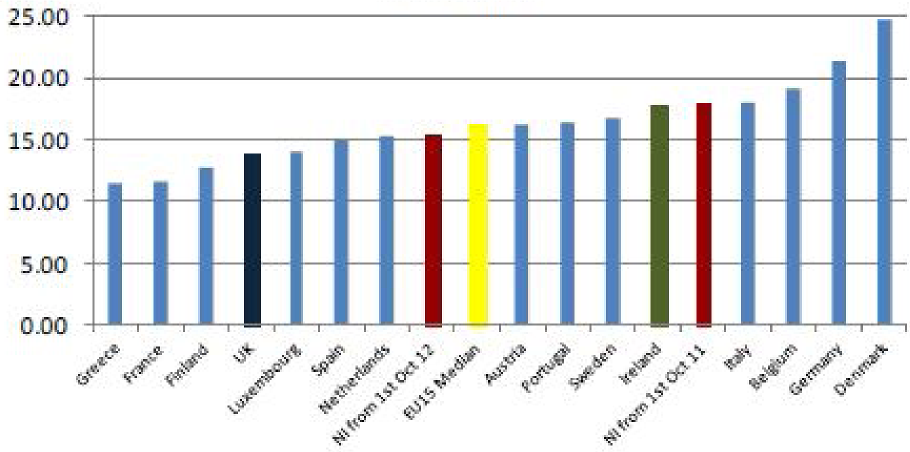
2.74 According to Power NI as at July 2013 following a 17.8 per cent rise in electricity charges, Northern Ireland domestic electricity prices were about 5 per cent higher than in comparable GB regions and about 8.7 per cent higher than the GB average. The long-run average difference in electricity prices between January 2009 and July 2013 is for Northern Ireland to be 10 per cent higher than GB.[73]

2.75 However, turning to international comparisons, between January and June 2012, the price that domestic consumers in Northern Ireland paid for their electricity was slightly below the median average for the 15 countries in the EU.

[72] This comparison uses an estimated consumption of 3,300 kWh of electricity. We understand that the average consumption of electricity by domestic consumers now exceeds this figure.
[73] www.uregni.gov.uk/uploads/publications/Retail_Tariff_Background_Briefing_May_2013.pdf.

FIGURE 2.2

Domestic electricity prices by country



Source: UR March 2013: NI Electricity Prices Data and Comparisons Information paper.

Consumers' electricity bills

2.76 In 2012/13, NIE's transmission and distribution charges made up around 25 per cent of domestic electricity bills. NIE told us that in the case of domestic consumers, network charges typically made up around 20 per cent of the final bill, generation costs 64 per cent, and other allocations around 16 per cent.[74] CCNI, however, told us that network charges made up 28 per cent of the average domestic bill (£167 a year) compared with 58 per cent for generation. The UR's final determination (paragraph 16.8) noted that network charges made up in the region of 20 per cent of domestic electricity bills. The UR's briefing paper on Power NI's 2013 Tariff Review background paper[75] showed that domestic customers' electricity bills were made up of the components shown in Figure 2.3.

[74] NIE Statement of Case, Annex 5A.1, p13.
[75] www.uregni.gov.uk/uploads/publications/Retail_Tariff_Background_Briefing_May_2013.pdf.

FIGURE 2.3

Components of domestic electricity bills in Northern Ireland, 2013

Retail tariff	=	Wholesale costs	+	SSS charges & cairt	+	PSO levy	+	Use of systems	+	Supplier charge	+	NIRO costs	+	Correction factors
What customers pay		Generation costs (cost of procuring electricity), capacity costs, imperfections (costs of electricity constraints), and MO charges		For system planning, operation and dispatch		Public Service Obligation costs which must be spread across all customers		NIE's costs of transmission and distribution of electricity		Costs to supply electricity to customers eg meter reading, billing		Net costs of NI Renewable Obligation – NIRO costs relate to government obligation to sell a proportion of their output as renewables		The difference between allowed revenue and NIE's actual revenue (mechanism whereby differences between forecasts for tariff-setting and actuals can be recouped or returned to customers) and first year effect
Split 13/14 100%		**58%**		**4%**		**2%**		**22%**		**9%**		**2%**		**3%**
Split 12/13 100%		**62%**		**3%**		**2%**		**25%**		**9%**		**1%**		**–2%**

Source: www.uregni.gov.uk/uploads/publications/Retail_Tariff_Background_Briefing_May_2013.pdf.

2.77 CCNI said that it would accept that for the current Power NI tariff, 25 per cent was the figure to use. However, it noted that this was just for Power NI's standard credit tariff. CCNI said that other tariffs of Power NI (eg direct debit payment and keypad) were cheaper and the tariffs of other suppliers considerably lower. Therefore, CCNI said that 25 per cent was the lowest figures that NIE network charges represented in Northern Ireland electricity bills.

2.78 Over the last five years NIE's charges have been reflected in domestic and industrial and commercial consumers' bills as shown in Table 2.5.

TABLE 2.5 **NIE network charges, annual cost for average use**

	Annual cost for average use (TUoS + DUoS) – nominal price base (£)				
Consumer type	*07/08 Nov 08–Sep 08 11 months costs*	*08/09 Oct 08–Sep 09*	*09/10 Oct 09–Sep 10*	*10/11 Oct 10–Sep 11*	*11/12 Oct 11–Sep 12*
Domestic	121	138	143	127	148
Small business (quarterly billing	454	517	538	478	554
Half-hourly metered MV <70 kVa	1,010	1,150	1,197	1,064	1,233
Half-hourly metered MV	6,983	7,951	8,279	7,357	8,523
Half-hourly metered HV	35,618	40,657	42,059	37,300	53,640
Half-hourly metered EHV	112,928	129,485	132,420	116,996	139,314

Source: NIE.

The role of the CCNI

2.79 The Consumer Council is an independent consumer organization. The CCNI has a statutory remit to promote and safeguard the interests of consumers in Northern Ireland and it has specific functions in relation to energy. Under the Energy (NI) Order 2003 the Consumer Council is empowered to:

(a) make proposals and provide advice and information and represent consumers on energy matters;

(b) obtain and keep under review information about consumer issues and the views of consumers on those matters;

(c) investigate and seek to resolve consumer complaints against companies about regulated matters;

(d) give information to Ministers, the UR, licence holders and any other body with a consumer interest; and

(e) publish information about complaints.

Consumer concerns

2.80 The CCNI undertook consumer research in June 2012 into what consumers wanted from the electricity network—see Table 2.6.

TABLE 2.6 **CCNI research into consumer priorities**

	First priority	*Second priority*
		per cent
The lowest possible price	69	20
A highly reliable supply with the lowest possible number of power cuts	19	52
That as much electricity as possible is generated by renewable means, ie from sustainable sources such as wind power	7	18
Don't know	5	10

Source: Consumer Council research, June 2012 (base 1,020 consumers).

2.81 While the lowest possible price for electricity was the top priority for consumers, and it was the first or second priority for 89 per cent of respondents, 71 per cent of respondents said that reliability of supply was the top or second priority.

2.82 The CCNI told us that its relationship with NIE over complaints handling was excellent. NIE was very cooperative and thorough in complaint investigations. The CCNI also said that NIE was willing to help in other instances, for example on switching issues between suppliers where the CCNI could not distinguish where fault lay.

2.83 Consumer complaints received by the CCNI concerning electricity generally were relatively low. In 2012/13, the CCNI received 194 inquiries regarding NIE. In addition, seven approaches were resolved at the stage 1 investigation stage, seven reached stage 1 referral and two others were treated as full complaints.

Fuel poverty

2.84 The UR and others drew our attention to the issue of fuel poverty in Northern Ireland, relating this in part to the economic crises that have affected the UK and have hit particularly hard in Northern Ireland.[76] Fuel poverty (which is defined as where more than 10 per cent of disposable household income needs to be spent on maintaining adequate heating provision) is much higher in Northern Ireland compared with other parts of the UK. The proportion of households in fuel poverty in 2011 in all parts of the UK is set out in Table 2.7.

TABLE 2.7 **Households in fuel poverty, 2011**

	%
England	15
Wales	25
Scotland	29
Northern Ireland	42

Source: www.gov.uk/government/uploads/system/uploads/attachment_data/file/199833/Fuel_Poverty_Report_2013_FINALv2.pdf.

2.85 The 42 per cent of households in fuel poverty in Northern Ireland represents some 294,000 households. 14.6 per cent of homes (103,000) need to spend 15 per cent of income to meet the required fuel expenditure and 5.9 per cent need to spend 20 per cent of household income.

[76] UR Statement of Case, UR2, paragraph 23.

2.86 The main reasons for the high level of fuel poverty in Northern Ireland are a combination of lower incomes, higher fuel prices, and high dependence on oil for heating. Natural gas networks have only recently been developed in Northern Ireland and serve only certain areas. In Northern Ireland 68 per cent of homes (rising to 82 per cent in rural areas) use home heating oil to heat their homes. In 2010, just over a million households in GB were estimated to have oil-fired central heating; just over 4 per cent of all households.[77] CCNI research suggests that in Northern Ireland on average it costs £657 each year more to heat a home using home heating oil compared with gas. However, the difference can vary significantly depending on whether condensing or non-condensing boilers are used, the quantity of oil purchased and other energy-saving measures that are in place. Energy prices do vary, particularly home heating oil which is subject to almost daily fluctuations in price. However, as an extreme example, where a household uses 20-litre emergency refills of home heating oil (rather than larger tanker deliveries) the cost of heating is estimated by the CCNI to be 127 per cent more expensive than using gas.

2.87 CCNI figures (see Table 2.8) show that overall energy bills (for all sources of energy: oil, gas and electricity) in Northern Ireland are significantly higher than in GB and have risen at a much faster rate between 2001 and 2011.

TABLE 2.8 **Average household energy bills, 2001 and 2011**

£

	Average bill 2001	*Average bill 2011*	*Percentage increase 2001–2011*
Northern Ireland	768.55	2,368.71	208
GB	541.33	1,258.09	132
Difference	227.22	1,110.62	389

Source: CCNI (from DECC, CCNI, Sutherland tables, Consumer Focus, Power NI, Phoenix Supply Limited, firmus energy).

2.88 46 per cent of households in Northern Ireland which use electricity for heating are in fuel poverty, compared with 59 per cent using solid fuel, 44 per cent using home heating oil and 34 per cent mains gas. However, only 3 per cent of households in Northern Ireland use electricity for central heating (compared with 68 per cent of households using home heating oil).[78]

2.89 While electricity is used to power a range of household appliances, and for lighting, cooking, etc, given the low volumes of households using electricity for heating in Northern Ireland (3 per cent) it seems that electricity prices are not a major factor in the high fuel poverty levels in Northern Ireland. However, for the small number of households which do use electricity for heating and who are on low incomes, obviously the price of electricity is very important.

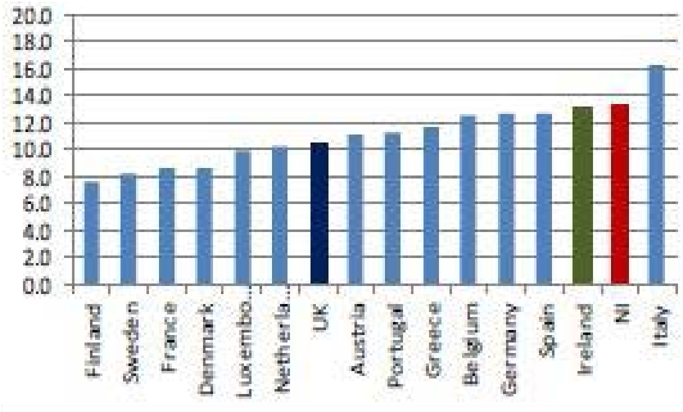
Business consumers

2.90 As shown in Figure 2.4, while domestic consumers in Northern Ireland are paying prices for their electricity which are slightly below the median for the EU, business customers[79] are paying prices which are among the highest in the EU. Only in Italy are business consumers paying a higher price per kWh of electricity than in Northern Ireland.

[77] *Energy consumption in the UK 2012*, DECC, Table 3.14.
[78] www.nihe.gov.uk/northern_ireland_house_condition_survey_main_report_2011.pdf.
[79] The prices shown relate to small industrial and commercial consumers with an annual consumption of less than 500 MWh.

FIGURE 2.4

Electricity charges for small business consumers by country, July to December 2011



Source: NIAUR March 2013: NI Electricity Prices Data and Comparisons Information paper.

2.91 For domestic consumers, Northern Ireland prices were around the EU average; for very small (up to 20 MWh per year) industrial and commercial (I&C) consumers, electricity prices were also around the EU average. Small (20 to 499 MWh per year) I&C consumers account for around 70 per cent of all non-domestic consumers in Northern Ireland; and for the remaining 30 per cent of I&C consumers electricity prices were among the highest in Europe.[80]

2.92 As shown in Table 2.1, about 14 per cent of NIE's income comes from distribution charges from small industrial or commercial consumers using low voltage and charges for street lighting. 30 per cent of its distribution income comes from larger industrial and commercial consumers using low voltage and high- and very-high-voltage users.

Renewable energy

2.93 CCNI consumer research (see Table 2.6) showed that 7 per cent of consumers considered increased use of renewable fuels as their first priority and 18 per cent placed it as their second priority in relation to energy.

2.94 However, other CCNI research also indicated that an increasing number of consumers were willing to pay more for their fuel so that renewable energy could be utilized. In answer to the question 'Are you willing to pay an additional cost on your energy bill so Northern Ireland can increase the amount of renewable energy it uses?', in the 2010 survey 54 per cent said yes, and 46 per cent no (in 2009, the figures were 41 and 59 per cent respectively).

[80] www.uregni.gov.uk/uploads/publications/Electricity_Pricing_Paper_website_-_March_2013.pdf.

3. The existing price control conditions and the public interest

3.1 In this section we consider whether the existing (ie RP4) price control conditions are against the public interest, and whether the continuation of each Licence operates against the public interest absent further conditions relating to recording, reporting and monitoring of information (see paragraph 1.1, which sets out the questions the UR referred to us).

3.2 In particular, we:

(a) describe RP4 in more detail (paragraphs 3.3 to 3.33);

(b) summarize the parties' submissions on RP4 and the public interest (paragraphs 3.34 to3.47);

(c) consider whether and in what ways RP4 operates, or may be expected to operate, against the public interest, and what detriments to the public interest arise as a result (paragraphs 3.48 to 3.81);

(d) make some observations on certain redundant terms within the RP4 price control arrangements (paragraph 3.82); and

(e) set out the structure of the remainder of our final determination (paragraph 3.83).

The RP4 Price Control Conditions

3.3 This subsection contains:

(a) an overview of the key features of the RP4 price control (paragraph 3.4);

(b) a summary of the different sections (or paragraphs) in the RP4 price control licence conditions (paragraphs 3.5 and 3.6);

(c) a more detailed description of section 2 of the Price Control Conditions, which provides formulae for the calculation of the maximum regulated revenue for NIE (paragraphs 3.7 to 3.23);

(d) a discussion of the RP4 capital expenditure 'budget' which featured in the UR's final proposals for RP4 but is not reflected in the price control licence conditions (paragraphs 3.24 to 3.30); and

(e) the reasons the UR originally offered for its choice of regulatory design for RP4 (paragraphs 3.31 to 3.33).

Overview of the key features of the RP4 price control

3.4 In summary, NIE told us that the key features of the RP4 price control were:

(a) The allowance for 'controllable' opex in each year of RP4 was set equal to the RPI-indexed level of actual costs incurred during the corresponding year in RP3 subject to one-off reductions for the first two years of RP4 of £2.6 million and £1.6 million, respectively. The UR considered that this approach would simplify the calculation of the opex allowance but would also give NIE incentives to reduce costs, creating customer savings.

(b) ‘Uncontrollable’ opex (defined as rates, wayleave costs and licence fees) did not form part of the rolling mechanism and was recoverable by NIE on a pass-through basis.

(c) The allowance for pensions costs in each year of RP4 was set equal to the RPI-indexed level of actual costs incurred during the corresponding year in RP3 subject to a disallowance of £225,000 a year in respect of ERDCs.

(d) RAB additions during RP4 were based on actual capex rather than allowed capex, with a separate mechanism for incentivizing capital efficiency. The five-year capex budget (net of customer contributions) was agreed at the start of RP4 (£374 million in 2010/11 prices, compared with £306 million in RP3 in 2010/11 prices). The RP4 price control allowed NIE to charge depreciation on such capex from then on (in accordance with the UR’s specified depreciation profile), and to earn an allowed rate of return on such capex from the year in which it was incurred. Non-core capex (eg expenditure on renewables projects) was provided for separately through the D_t term of the price control (see paragraph 3.16(c)) subject to the UR’s approval on a project by project basis.

(e) The capex efficiency incentive mechanism required annual reporting by NIE on the progress of its capex programme and significant changes in its investment priorities. Notified efficiency gains related to procurement of materials and services and labour productivity. For every £1 of demonstrated efficiency, NIE retained 38.9p and customers retained 61.1p.

(f) Cost of capital provided for the allowed rate of return to be set at the GB DNO level for the distribution portion of the regulated asset base. The UR provided for a 0.35 per cent post-tax reduction from the GB rate in relation to the assumed 18 per cent of transmission assets. This resulted in a post-tax real rate of return of 4.84 per cent for ‘distribution assets’ and of 4.49 per cent for ‘transmission assets’. The distribution rate of return tracked any downward movement in the GB rate at the next price control (affecting the last two years of NIE’s scheduled RP4 period).

Summary of the different sections (or paragraphs) in the RP4 price control licence conditions

3.5 The RP4 Price Control Conditions are set out in Annex 2, the ‘Transmission and Distribution Charge Restriction Condition’ of NIE’s transmission and distribution Licences. The two Licence documents have identical Price Control Conditions.

3.6 The Price Control Conditions are structured as follows:

(a) Section 1 provides definitions.

(b) Section 2 contains formulae and data tables to calculate the restriction on the maximum regulated transmission and distribution revenue. The calculations in section 2 rely, in part, on methods that are specified in a direction issued by the UR in December 2006 (referred to as the 2006 Direction). This section is discussed in more detail below (paragraphs 3.7 to 3.23).

(c) Section 3 defines some rules and adjustments that are triggered when regulated transmission and distribution revenue exceeds the maximum regulated transmission and distribution revenue.

(d) Section 4 obliges NIE to provide some data to the UR to demonstrate compliance with sections 2 and 3.

(e) Section 5 defines ‘excluded services’. Income from these services is excluded from the restriction on the maximum regulated transmission and distribution revenue. Excluded services include the provision of new connections.

(f) Section 6 allows the price control to be suspended by the UR in connection with a Security Period under the Northern Ireland Fuel Security Code.

(g) Section 7, ‘Duration of transmission and distribution charge restriction conditions’, defines a procedure for terminating the price control.

(h) Section 8 provides for the maximum regulated transmission and distribution revenue to be adjusted in some cases of change of law.

(i) Section 9 requires NIE to ‘make available’ funding to run a Vulnerable Customer Programme. This ceased to have any effect in 2010.

(j) Section 10 requires NIE to ‘make available’ funding to run a Sustainable Networks Programme. This ceased to have any effect in 2012.

(k) Section 11 requires NIE to report information about capital expenditure and capital expenditure plans.

(l) Section 12 requires NIE to report information about its calculation of tax and tax capital allowances.

More detailed description of section 2 of the Price Control Conditions

3.7 This subsection summarizes aspects of the revenue restriction in section 2 of the price control Licence conditions. It provides more detail on the implementation of the features of the price control summarized in paragraph 3.4.

3.8 Clause 2.1 is an obligation on NIE to use its best endeavours to ensure that in each year its regulated transmission and distribution revenue does not exceed the maximum regulated transmission and distribution revenue. The maximum regulated transmission and distribution revenue is defined as the sum of two components: *(a)* the maximum core revenue in relevant year t (MD_t), for which the remainder of section 2 sets out the formulae; and *(b)* a term which now has no effect and takes the value of zero.

3.9 Clause 2.2 specifies formulae to calculate the maximum core revenue in each of the financial years ended 31 March 2003 to 31 March 2007.

3.10 Clause 2.3 specifies formulae to calculate the maximum core revenue in the financial year ended 31 March 2008 and subsequent years. We highlight some particularly relevant aspects.

3.11 For ease of explanation, we can write the formula for the maximum core revenue as follows:

$$M_{Dt} = \mathrm{Min}(PC_t, CPA_t) + Z_t$$

3.12 Leaving aside the Z_t element for now, the restriction on maximum core revenue in year t is specified as the minimum of two elements:

(a) A price-capped regulated revenue entitlement term (PC_t) which is obtained by taking a specified value (0.0181), adjusting it for RPI inflation, then multiplying it by a forecast of the number of units of electricity transmitted and distributed for year t which is specified in the Licence, but only for the financial years ended March 2008 to March 2012. This term also includes an adjustment for any differences between the actual levels of certain 'uncontrollable' operating costs in year t and forecasts of those costs specified in the Licence.

(b) A term (CPA_t) which is described as the 'composite proposal allowance' for year t. We describe this term in more detail below.

3.13 The PC_t reflects one aspect of the UR's RP4 proposals, which was to cap NIE's revenue by reference to a transmission and distribution 'price' of 1.81p/kWh. In its draft proposals paper, the UR proposed to 'cap [transmission and distribution] prices during RP4 at the current level'.[81] The PC_t term in the Licence does not actually operate as a cap on prices. Instead, it is calculated as a notional or average price multiplied by a volume forecast that is hardcoded into the Licence. It operates as a revenue limit that is subject to RPI inflation. Further, part of the CPA_t term—discussed further below—represents an adjustment in respect of revenue forgone as a result of the PC_t term biting in the previous financial year. The UR told us that the PC_t did bite in the financial year ended 2008. In other years it had not had a bearing on the calculation of maximum revenues for NIE.

3.14 Subject to the limit from the PC_t term not biting, the maximum regulated revenue is calculated by reference to the CPA_t term. CPA_t incorporates all of the principal building blocks that make up the price control (ie opex, capex, weighted average cost of capital (WACC), depreciation and pensions). The formula for determining CPA_t is as follows:

$$CPA_t = CO_t + P_t + UO_t + Ret_t – TA_t + Dep_t + Tax_t + RRF_t$$

where these terms refer to, for each year t:

CO_t – an allowance for 'controllable' operating costs

P_t – an allowance for pension costs

UO_t – an allowance for certain 'uncontrollable' operating costs

Ret_t – return on capital

TA_t – an adjustment in respect of the allowed return on transmission assets

Dep_t – an allowance for depreciation

Tax_t – an allowance for tax

RRF_t – is an adjustment term which has the effect of compensating NIE for any under-recovery of revenue that it would have been due under the CPA_t term in the previous financial year but which it could not recover in that year because of the revenue cap imposed by the PC_t term in that previous financial year (this compensation would still seem to be constrained by the cap imposed by the PC_t term in the current financial year).

[81] UR Draft Proposals Paper, December 2005, p18.

3.15 In relation to elements of the CPA_t term, we note that the allowance for depreciation (Dep_t) and return on capital (Ret_t) are calculated according to the value of NIE's regulatory asset base (RAB) which is updated each year to reflect NIE's actual capital expenditure that year.

3.16 Regardless of whether the PC_t or the CPA_t term applies, the maximum regulated revenue also features a number of terms which fall under what we have labelled Z_t above, and which comprise:

(a) An allowance for change of law costs calculated in accordance with the change of law provisions in section 8, in relation to the years 2008 to 2012.

(b) An adjustment (PPS_t) to give effect to a profit-sharing term in respect of NIE Powerteam Limited.[82]

(c) An allowance (D_t) which is defined as the sum of eight different elements. These elements include any amount arising under the arrangements specified in the UR's 2006 Direction to provide NIE with financial incentives in relation to the efficiency of its capital investment. In the 2006 Direction these amounts are calculated by reference to defined measures of labour productivity and procurement efficiency and a rule that, for every £1 of demonstrated efficiency, NIE should retain 38.9p. The elements falling under the D_t term also include other costs that the UR determines should be included within the D_t allowance, following an application from NIE.

(d) A revenue entitlement (NSI_t) associated with interconnectors with the Republic of Ireland. For the financial years ended March 2008 to March 2012 this is defined as a specified value in the Licence, adjusted for RPI inflation.

(e) A corrector factor (KD_t), which can take a positive or negative value. It is calculated as the difference between the regulated revenue that NIE was entitled to collect in year t–1 and the regulated revenue that NIE actually collected, adjusted by application of a defined interest rate. The effect is that charges in year t are adjusted for any over- or under-recovery of revenues against the maximum permitted amount in year t–1.

3.17 Each of these terms of the CPA_t formula is required to be determined on the basis specified for that term in paragraph 2.3 of Annex 2. In some cases, Annex 2 cross-refers to a methodology contained in a direction made by the UR in the 2006 Direction. We now describe the rules applicable to determining some of the terms of the CPA_t formula for each year.

3.18 The allowance for controllable opex, CO_t, is determined by reference to the term ACO_{t-5}, being the level of actual controllable operating costs in relevant year t–5 (ie five years previously) and then adjusting it for inflation in the intervening period. This reflects the 'rolling opex' arrangement that formed the basis of the RP4 final determination. For the years ended 2008 to 2010, values for ACO_{t-5} were specified in Annex 2 of the Licence. The Licence says that for the financial years to March 2011 and March 2012, it should be calculated in accordance with the UR's 2006 Direction. The allowance for pension costs P_t in year t is calculated by taking a measure of NIE's cash contributions to the relevant pension scheme five years ago and adjusting for RPI inflation.

[82] During RP4 there was an arrangement pursuant to which 50 per cent of NIE Powerteam's profits were credited to customers in the form of lower allowed revenue.

3.19 The allowance for uncontrollable opex, UO_t, is set at the level of uncontrollable costs in relevant year t calculated as the aggregate of:

(a) amounts paid by NIE in respect of rates levied on NIE's transmission and distribution assets;

(b) amounts incurred by NIE in respect of wayleaves; and

(c) amounts allocated in respect of Licence fees payable to the UR.

3.20 The rate of return NIE is allowed to earn on its RAB is expressed as a vanilla WACC ($VWACC_t$). The allowed return, Ret_t, is calculated by multiplying the average value of the RAB in year t by the VWACC in year t.

3.21 The RAB term is calculated in accordance with the methodology set out in the 2006 Direction. That methodology proceeds on the basis that all 'operational capital expenditure' (ie actual capex) in a particular year will be added to the RAB for that year.

3.22 In 2008, 2009 and 2010, $VWACC_t$ was set equal to 0.05545 (ie 5.545 per cent). In 2011 and 2012, $VWACC_t$ was set equal to the lower of: *(a)* 0.05545; and *(b)* $VWACC_{2010}$, where $VWACC_{2010}$ means the weighted average cost of capital (stated as a decimal number) calculated on the basis of the values for the pre-tax return on debt and the post-tax return on equity used in determining the regulated revenue entitlement for the DNOs in GB for the distribution price control commencing on 1 April 2010. NIE noted that Annex 2 made no provision as to how to calculate $VWACC_t$ for any period after 31 March 2012.

3.23 The points above are not a complete or precise description of the calculation of NIE's maximum regulated revenue under the current Licence conditions, but are intended to capture the key elements relevant to understanding the operation of the current conditions.

The RP4 capital expenditure 'budget'

3.24 NIE and the UR told us that for the RP4 price control period there was a 'budget' relating to NIE's capital expenditure.

3.25 The Price Control Conditions of NIE's Licences (Annex 2) make no reference to any budget relating to NIE's capital expenditure. As explained above, the calculation of the maximum regulated revenue is updated each year in light of NIE's actual capital expenditure. There are no constraints in the Licence conditions or the 2006 Direction that have the effect of limiting the amount of NIE's capital expenditure that it can add to its RAB and feed through to the calculation of the maximum regulated revenue.

3.26 The UR's final determination (its paragraph 3.11) recognized that there is no capital expenditure budget within the Licence conditions and explained that the amount of capital expenditure 'to be spent in RP4' is stated in the RP4 final determination. When setting the price control for the RP4 period, the UR used the terminology of 'final proposals' rather than 'final determinations'. The UR's final proposals document for RP4, dated September 2006, is just seven pages long. This document refers to a capital expenditure 'budget' which seems to have been established by the UR in light of a review by its consultants, Mott MacDonald, of NIE's assessment of the overall network investment requirement for RP4. The UR proposed that the 'capex budget' for RP4 should be based on the assessment of investment requirements that is set out in a table on page 4 of its final determination document, which implies a total figure of £312 million over the five-year period from April 2007 to March 2012.

3.27 While this budget was not specified in the Licence conditions or the 2006 Direction, NIE seems to have treated it as an important part of the price control for RP4. NIE's owner at the time, Viridian Group Plc, issued a press release dated 6 September 2006 to say that its subsidiary NIE had accepted the final proposals published that day by the UR in connection with the five-year price control to apply to NIE's transmission and distribution business with effect from 1 April 2007 (RP4).[83] The press release says the following about the capital expenditure budget:

> As part of its acceptance, NIE has agreed to work to a capital expenditure budget for RP4 of £312m [footnote: Net of customer contributions, in 2004/05 prices and excluding investment associated with interconnection and the connection of renewable generation], in line with [the UR's] consultation paper of 9 June 2006.

3.28 NIE and its sister companies subsequently described the capital expenditure budget as a key feature of the RP4 price control. NIE Finance Plc issued an 'Offering Circular' on 31 May 2011 relating to the issuance of £400 million of 6.375 per cent Guaranteed Notes due in 2026, which were unconditionally and irrevocably guaranteed by Northern Ireland Electricity Limited,[84] which included information on 'key aspects of the RP4 price control' and says the following about capital expenditure (page 44):

> The five year capital expenditure budget (net of customer contributions) agreed at the start of RP4 was £374m (in 2010/11 prices) compared to £306m in RP3 (in 2010/11 prices). This investment is driven by the need to replace worn assets and to meet continued growth in customer demand. Capital expenditure is added to the RAB as it is incurred and earns the regulatory rate of return.

3.29 NIE has also referred to a five-year capital expenditure budget (net of customer contributions) in its annual report and accounts. NIE seems to have updated the reported budget in line with inflation. For instance, it refers to a budget of £345 million (in 2007/08 prices) in its report for the year ended March 2008 and a budget of £374 million (in 2010/11 prices) in its report for the year ended March 2011.

3.30 In the CC's experience, the absence of any reference in the Licence conditions to the budget referred to by the UR and NIE is not extraordinary. We have not found an explanation of the nature of the capital expenditure budget and, in particular, what was intended to happen if NIE spent more than the budget. It appears that any capital expenditure budget that NIE agreed to as part of its acceptance of the UR's RP4 price control proposals related to the period from April 2007 to March 2012. In its proposals for a new RP5 price control, the UR did not propose any similar 'budget' arrangements.

The reasons the UR originally offered for its choice of regulatory design for RP4

3.31 In 2005, when the UR was considering the possible design of price controls for RP4, it said that the design of the RP4 proposals reflected the following principles:

[83] www.viridiangroup.co.uk/default.aspx?CATID=216&CID=1346, retrieved 17 June 2013.
[84] www.nie.co.uk/documents/OfferingCircularGuaranteedNotes.aspx, retrieved 16 June 2013.

(a) a rule-based approach to the opex allowance that strengthened efficiency incentives and shared the savings with customers;

(b) a capex allowance based on actual rather than forecast expenditure, together with strengthened capex efficiency incentives; and

(c) an allowed rate of return on assets consistent with established precedent.[85]

3.32 In relation to opex, the UR noted that determining the efficient level of opex to allow (typically involving an examination of the company's operating cost base, benchmarking it against the cost bases of other electricity network companies both nationally and internationally, and undertaking a very detailed item by item analysis of individual expenditure category) was time consuming and resource intensive, and complicated by differences in the way that companies reported their costs. It also noted that under the 'traditional' approach the incentive to reduce costs diminished as the regulatory period progressed as the period before they were reflected in lower allowances in the next price determination was reduced. The UR therefore proposed a rolling mechanism where actual controllable opex in each year of the existing price control period was rolled forward with RPI indexation to become the controllable opex allowance for the corresponding year in the next period. Uncontrollable opex would be passed through. The UR told us that one explanation of this approach was that it implicitly assumed that NIE's opex needs were broadly stable from one period to the next, subject to further adjustment for specific items where NIE's business changed from one period to the next. On that basis, this system provided a five-year return on efficiency improvements or other outperformance.

3.33 The UR also noted in relation to capex, under the traditional approach, regulated revenue (to cover the costs of financing return and depreciation) of new capital expenditure depended on forecast capex. Once the capex allowance was agreed there was an incentive on the company to underspend and increase profits by avoiding the financing costs associated with the underspent capex. It noted that the UR faced difficulties in distinguishing an underspend due to valid efficiency gains and one due to investment being deferred into a later period. It therefore proposed for RP4 that the regulated entitlement would be dependent on pass-through of actual capex rather than allowed capex. It proposed separate mechanisms to incentivize capital efficiency. It said that this, combined with annual reporting of investments, would benefit customers through the savings in RAB financing costs, with improved transparency around the investment programme.

The parties' submissions on RP4 and the public interest

3.34 The UR and NIE both said that the existing RP4 price control conditions were now against the public interest,[86,87,88] principally on the basis that they were only intended to operate until 31 March 2012.

The UR's submissions on the RP4 price control conditions

3.35 The UR said that continuation of the adapted RP4 approach under its 'pragmatic approach' was an interim solution without adequate legal certainty and it was self-

[85] Northern Ireland Authority For Energy Regulation, Northern Ireland Electricity—Transmission And Distribution Price Control 2007–2012 Proposals Paper, 14 December 2005.
[86] UR Statement of Case, UR2, paragraph 16.
[87] NIE Statement of Case, Chapter 1, paragraph 1.7.
[88] ibid, Chapter 2, Part B, p22, paragraphs 7 & 8.

evidently not in the public interest for it to continue. In addition, the UR argued that some of the elements of the interim solution could not be said to be in the long-term public interest from a substantive perspective. It said that continuation would not promote efficiency and economy on the part of NIE and consequently would not adequately protect the interests of consumers in respect of services provided and prices charged.

3.36 The UR told us that the RP4 price control was not a good one. It said that history had shown that the decision to accept NIE's proposed combination of a rolling opex allowance with uncapped pass-through remuneration for capex provided NIE with an incentive to engage in regulatory gaming. It said that the structure of RP4 essentially had the effect of giving NIE a blank cheque to spend on capital works without clear definition of deliverables or sufficient incentive to be efficient. This was because capex was fully remunerated through the RAB irrespective of whether it was efficiently incurred, and it said that NIE was not incentivized to engage with customers to develop a plan for capex based on their needs and their willingness to pay.

3.37 Similarly in relation to operating expenditure, the UR said that the RP4 allowance reflected opex expenditure from five years earlier, whether or not that opex had been efficiently incurred and irrespective of any pressing need for new categories of opex. It also said that the five-year rolling mechanism for controllable opex would provide insufficient revenue for NIE to cover its efficient/unavoidable costs during RP5. It said that it was not in the public interest for this mismatch between revenue and costs to be left in place.

3.38 The UR noted that it was continuing to apply the WACC determined for the RP4 period, ie 4.7 per cent. It considered that figure to be substantially higher than NIE's current cost of capital (given the movements and developments in the financial markets) and therefore higher than the rate of return on capital that would be in the public interest.

3.39 It also believed that the Licence in its current form did not address its concerns around the issues of transparency and accountability, which the UR had proposed to address by way of including a new condition (a draft of which was included with the final determination) relating to the appointment of a reporter. It said that continuation of RP4 would not enable:

(a) appropriate mechanisms to be put in place to ensure that NIE was held accountable for the money that it received and that customers derived real benefit from the substantial sums that they were required to pay towards the electricity network in Northern Ireland; and

(b) appropriate mechanisms to be put in place to ensure that there was, going forward, much more transparency and accountability in NIE's activities, in its recording, reporting and monitoring of information in relation to price controls and in it accounting practices.

3.40 Last, it considered that continuation of RP4 would not enable appropriate treatment of pension costs, including financing the repair of NIE's deficit in a way that was fair for both customers and NIE.

NIE's submissions on the RP4 price control conditions and our task

3.41 With regard to the RP4 price control conditions, NIE submitted that the existing price control conditions as a whole operated against the public interest because they could no longer function effectively at all. It said that the existing conditions did not include certain regulatory mechanisms (eg in relation to performance and other incentive arrangements) which NIE considered were in the best interests of consumers. It argued that following the expiry of an existing price control, the interests of consumers required that a fresh assessment was made of the regulatory mechanisms and other tools that formed the basis of the price control going forward. It argued that we should, when considering whether the existing charge restriction condition operated against the public interest, make an assessment of whether the regulatory mechanisms and other tools embodied in that condition are best calculated to deliver optimum outcomes for consumers. NIE said that this was because the existing price control conditions would operate against the public interest to the extent that they fail to attain the UR's statutory duties, which are themselves directed at attaining optimal outcomes for consumers.

3.42 It said that:

(a) RP4 failed effectively to cap NIE's transmission and distribution charges;

(b) RP4 failed to provide NIE with effective incentives to provide an appropriate quality of services, in terms of the achievement of certain output standards (eg in relation to network performance);

(c) to the extent that RP4 caused the UR to believe that it might procure the continuation of the charge control by specifying new values for certain elements of the price control equation, created uncertainty which exposed NIE to risks and costs, and constrained its freedom to manage and run its T&D network as it judged best;

(d) RP4 failed to provide an effective mechanism for timely, fair and efficient resolution of claims by NIE for an adjustment to its allowed revenues; and

(e) some of RP4's provisions were unclear and created further uncertainty.

3.43 For example, NIE said that several of the terms comprising the CPA_t term were defined in the existing charge restriction condition in a manner that did not provide numerical values, or a means of calculating those values, for those terms for any period after 31 March 2012: the allowance for controllable opex; the allowance for pension costs; the allowed return; the adjustment in respect of the allowed return on transmission assets; and the allowance for tax costs. It also said that the RP4 arrangements made no provision for NIE's revenue requirements for RP5, such as new opex requirements (eg for Enduring Solution IT system[89] or provision for injurious affection), no restriction applied to RP5 capex spend referencing NIE's requirements, and the allowed rate of return took no account of the actual cost of capital. It also detailed some aspects of the regulatory mechanisms in RP4 which it said could not now be regarded as best calculated to deliver optimum outcomes for RP5.

3.44 It said that in consequence there was a risk that consumers would not be protected against excessive prices, and that NIE might not provide services of an appropriate standard. It said that uncertainty would be created which would deter capex and increase the cost of capital for NIE. It also argued that NIE faced uncertainty over requests for adjustments to allowed revenues and over interpretation of part of the tax term in the charge control formula.

[89] The UR told us that it did approve a large expenditure budget for the Enduring Solution IT system during the period RP4 was extended.

3.45 With regard to our task, NIE said that an assessment of whether the current Licence conditions operated against the public interest could be made by deciding what the best possible price control would be for NIE and then comparing the current Licence conditions against that desirable price control.

3.46 Further, NIE invited us to frame our public interest findings (ie which elements of the Annex 2 conditions operate against the public interest and with what adverse public interest effects) by reference to the way in which the existing Annex 2 conditions fall short of what is required to achieve the best available price control for the post-RP4 period (so that our assessment of what is the best available price control will inform its assessment of which elements of the existing Annex 2 conditions operate against the public interest, and what adverse effects ensue).[90]

3.47 It said that this approach would provide greater clarity and diminish opportunities for the UR not to follow our determination with regard to licence variations, as it said that the UR is bound by our findings with regards to the public interest, but not by the changes that we specify to the licences.[91]

Our assessment

Introduction

3.48 We did not consider it useful to identify a theoretically optimal price control regime given: the inherent uncertainties in regulation; that regulatory experience and notions of best practice continue to evolve; the practicable options available to us; and because, in order to maintain stability and clarity of the regulatory environment, we should not intervene in aspects of the price control absent evidence that current Licence conditions operate or may be expected to operate against the public interest (see paragraphs 3.45 to 3.47). While we had regard to theoretical regulatory concepts as appropriate, we proceeded on the basis of the available evidence to specify modifications to the Licence conditions that will best remedy or prevent the effects adverse to the public interest that we identified.

3.49 Accordingly, the approach we adopted was to consider for each aspect of the price control conditions whether it at present operates against the public interest and, if so, which was the best option available (given the available evidence and the constraints applying to us) that would address the adverse effect, and best serve the public interest.[92] This included the determination of appropriate allowances and any consequent adjustments arising from redesign of the price control. We then consider whether overall our proposals address the effects adverse to the public interest that we identified. We consider the public interest with regard to the approach outlined in paragraphs 1.11 to 1.14. In particular, in making our determination, we have had regard to the duties of the UR as set out in paragraphs 2.41 to 2.53, which applied to us for the purpose of this inquiry.

3.50 While we considered NIE's submission on the applicable legal regime carefully (see paragraphs 3.45 to 3.47), we did not consider it necessary or appropriate to particularise more fully our reasons for finding that particular features of the existing

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[90] NIE Response to the provisional determination, Chapter 21, paragraph 1.20, second bullet, see also paragraph 1.22.
[91] NIE Response to the provisional determination, Chapter 21, paragraphs 1.9 to 1.16.
[92] NIE broadly endorsed this approach in its response to the provisional determination, Chapter 21, paragraph 1.19, first bullet: 'All that the CC needs to do (or can do) is to decide what form and level of price control it judges, on the available evidence, and in light of existing regulatory experience and expertise, to provide the best available means of balancing and attaining the UR's statutory objectives. Indeed, this is what the CC appears to have done in its PD.'

Annex 2 conditions operate against the public interest.[93] We have no reason to expect that the UR will not seek to implement the modifications proposed in our final determination to give them their intended effect in good faith, to which it must 'have regard', nor do we see any need for us to seek to limit the UR's discretion in how it proposes to do this beyond the division of tasks between us and the UR, as set out in the statutory framework. Further, we note the effect of Article 17A of the Electricity (Northern Ireland) Order 1992, which effectively gives us power to veto modifications following this determination, if they do not appear to us to be requisite for the purpose of remedying or preventing all or any of the adverse effects specified in this determination as effects that could be remedied or prevented by modifications.

3.51 Therefore in this subsection we:

(a) set out how we find that the Price Control Conditions in each Licence operate or may be expected to operate against the public interest, and if so, what the effects adverse to the public interest would be (paragraphs 3.53 to 3.72). Our explanations as to why we consider alternative conditions and allowances we have identified provide outcomes which are more beneficial to the public interest are set out in more detail the relevant sections of the rest of this determination;

(b) consider 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 (paragraph 3.81).

3.52 In the subsequent sections of this determination, we specify how the adverse effects we identify could be remedied or prevented by modifications of the Conditions of each Licence (see paragraph 3.83).

The price control conditions and the public interest

3.53 Our evaluation assumes that tariffs to customers are set in line with changes in allowable revenue. We note that NIE has some ability to choose how tariff changes are implemented and to vary charges between transmission and distribution and between different classes of customer. In the absence of any specific methodology for implementing tariff adjustments, and absent indications of intended tariff changes for different groups, we assumed that any changes will not affect any particular class of customers disproportionately.[94] We also note that NIE's tariffs are subject to the UR's approval, which provides some protection against any particular group being disadvantaged.[95]

3.54 We determined that the Price Control Conditions in each Licence operate or may be expected to operate against the public interest because:

(a) the application of the current price control conditions is uncertain;

(b) aspects of the price control design are not sufficient to protect the interests of consumers; and

[93] As NIE suggested: response to provisional determination, Chapter 21, paragraph 1.22.
[94] Such concerns would be particularly important if, for example, particular classes of vulnerable customers might be impacted disproportionately.
[95] This approval means that tariffs are not necessarily directly reflective of allowed revenues, but we make no allowance for that in this discussion as we do not consider it likely that the UR would take actions which had the effect of preventing NIE from recovering allowed revenues.

(c) they contain formulae with parameters that are out of date.

3.55 We discuss these issues in turn.

The application of the current price control conditions is uncertain

3.56 The UR and NIE disagree over whether the Price Control Conditions continue to have legal effect. In practice, NIE acknowledged that it had acted as if it were bound by the Price Control Conditions (see Appendix 2.5, paragraph 52). However, some terms in the current Licence conditions are not defined for the period after March 2012. This means that suitable values or restrictions need to be inferred.

3.57 We think that the lack of formal definitions and specifications of important aspects of the price control algebra for the period from 1 April 2012 is not compatible with good administrative practice and may lead to further disputes between NIE and the UR in the future unless Licence modifications are made.

3.58 The consequence of these arrangements is that NIE, its investors, its customers, the UR and other stakeholders face considerable uncertainty over what price controls currently apply, how NIE should conduct itself, and what price controls will apply in the near future. We consider this situation to be against the public interest, for example because NIE cannot plan or invest appropriately, customers face uncertainty, and further disputes could increase costs.

Aspects of the price control design are not sufficient to protect the interests of consumers

3.59 We determined that aspects of the design of the RP4 Licence system for setting allowances and remunerating opex and capex operate against the public interest.

- *Capex*

3.60 The calculation of NIE's maximum regulated revenue according to the level of capital expenditure that NIE incurs may expose consumers to excessively high charges that reflect capital expenditure that was inefficiently or unnecessarily incurred by NIE—or missed opportunities for efficiency and innovation in relation to network investment. We determined that the public interest is better served by systems which, compared with cost pass-through, give NIE better incentives to enhance the efficiency of its capital expenditure.[96] In consequence, new capex allowances need to be set.

3.61 Another way in which cost pass-through for capex could also operate against the public interest, because it may expose customers to unnecessarily high charges, arises from the possibility for NIE's sister company, NIE Powerteam, to charge inappropriately high charges to NIE for the work it carries out on NIE's network.

- *Opex*

3.62 RP4 set a rolling mechanism, by which the opex allowance was set by the actual costs incurred by NIE five years previously, adjusted for inflation. This could give rise to an expectation on NIE's behalf that its actual costs would be passed through to consumers five years later. We found that this operated against the public interest as such a mechanism and expectation may give NIE insufficient incentives to be

[96] Our view is that the special capital efficiency incentive schemes for labour productivity and capital efficiency included as part of the licence conditions are not sufficient to address this risk.

efficient, so that its costs might be higher than necessary and that consumers may pay higher prices than necessary.

3.63 We consider that a benchmarking approach (ie setting opex allowances with reference to the costs of efficient comparators) provides a stronger incentive for NIE to operate efficiently than the incentives on opex efficiency under the RP4 controls.

- *Asymmetric treatment of capex and opex*

3.64 We consider that where the incentive rates for outperformance differ between opex and capex, this can create distortions in how NIE would organize its activities that could increase inefficiencies. In particular, under the RP4 price controls, the separate allowance schemes in relation to opex and capex provides NIE with unduly strong financial incentives to adopt working practices that favour capex-intensive practices over opex, but which may not be efficient. This is because NIE would expect its opex allowances to be unchanged within the price control period but for it to be able to pass through higher capex costs (on which it will continue to earn a return from the RAB). This could result in inefficient practices and so expose consumers to excessively high charges.

3.65 In addition, the interaction of the opex and capex arrangements may lead to excessively high charges on consumers if NIE changes its working practices or accounting practices over time so as to reclassify opex as capex, even where its activities remain essentially unchanged. Changes in capitalization practices could lead to activities for which the costs have fed into the calculation of NIE's opex allowance also being funded through its capex allowance.

3.66 The treatment of rates and wayleaves costs as 'uncontrollable' and recoverable by NIE on a full cost pass-through basis may expose consumers to excessively high charges that reflect unnecessary expenditure or missed opportunities for cost reductions. We considered that NIE may have some influence over these costs.

- *Additional cost allowance under Dt term*

3.67 We found that the UR's ability to approve, on a case-by-case basis, additional costs to be recovered through NIE's revenue control (under provision (viii) of the Dt term of the price formula) operated against the public interest. The scope for approval of such costs is limited to a cost pass-through basis, which would give NIE insufficient incentives to be efficient and so exposed consumers to the risk of excessive costs.

- *Revenue protection*

3.68 We found that NIE's price control licence conditions were deficient in respect of the treatment of income from revenue protection activities. First, although the UR and NIE had agreed a form of incentive scheme for some of NIE's revenue protection income, that scheme was not specified in NIE's licence conditions, which reduced the transparency of the regulatory regime. Second, we found that the scheme agreed between NIE and the UR was unduly focused on a subset of NIE's revenue protection income.

- *Pensions*

3.69 Like other items of opex, NIE's pension allowances during RP4 were set on the basis of a rolling mechanism, by which the allowance in any given year was the sum paid five years previously, adjusted for inflation.

3.70 We found the treatment of pensions costs in the current price control licence conditions to operate against the public interest because it may provide NIE with insufficient incentives to be efficient and expose consumers to unduly high pension costs, especially in relation to ongoing pension costs. For our determination for the period from 1 April 2012 to 30 September 2017, we decided to set an allowance for ongoing pension costs using cost benchmarks from GB DNOs, as part of our wider assessment of opex and indirect costs. Since ongoing pension costs are one element of employee remuneration, we considered it appropriate to treat ongoing pensions costs in a similar way to our approach to other ongoing labour costs.

3.71 In relation to the pension costs related to NIE's pension deficit repair contributions, we found that the current licence would not provide an appropriate basis for allowance for NIE's pension deficit repair costs over the period 1 April 2012 to 30 September 2017. This is because it does not allow for the distinction between a historic and an incremental deficit. It also does not take account of more up-to-date information on the level of NIE's historic pension deficit and the deficit repair payments which NIE will make into the scheme during RP5.

- *RAB for short-lived assets*

3.72 Under the current price control conditions, transmission and distribution investments are added to the RAB and depreciated over a 40-year period. We determined that this operates against the public interest for significant expenditure on assets which have a much shorter life, as it means that many future consumers must pay for assets from which they gain no benefit. We consider that this applies to tree cutting, because in our view it is inappropriate for future generations to be paying the costs of investments which have such a short life in relation to the period over which they are being depreciated for pricing purposes (40 years). We also consider that certain non-network capex investment (largely covering IT) should also be placed in a short-term RAB rather than expensed.

- *Separation of transmission and distribution revenue restrictions*

3.73 The current price control conditions specify a single maximum regulated revenue for NIE across its distribution and transmission services. We found that this operated against the public interest as it missed opportunities, now that there are separate Licences for NIE's transmission and distribution systems, to better align charges with costs and to reduce the risk that distribution charges reflect transmission costs (and vice versa).

- *Inconsistency between PSO charge control, and transmission and distribution charge control*

3.74 The current price control does not allow for NIE's historical capital costs for projects linked to the development of retail competition through distribution use of system charges (these costs are instead recovered through PSO charges). This may lead to an inconsistent treatment of costs between distribution charges and the PSO charges and potentially inappropriate PSO charges

- *Tariff volatility*

3.75 We found that the misalignment between the regulatory year and the tariff year created unnecessary tariff volatility, and that this operated against the public interest as it exposed consumers to unnecessary fluctuation in tariffs.

- *Information and transparency*

3.76 We found that the UR received insufficient reliable information in order for it to regulate NIE in a fully effective manner. Other stakeholders (such as consumer representatives) may also benefit from greater transparency and thus be better placed to influence conduct and regulation. Accordingly, we found this lack of information to operate against the public interest—and note that information and reporting was the subject of the second question referred to us by the UR. See paragraph 3.81 and Section 18.

The Price Control Conditions contain formulae with parameters that are out of date

3.77 The Price Control Conditions contain formulae with parameters that were specified in light of conditions prevailing or were expected to prevail during RP4.

3.78 For instance, as outlined in Section 13, we determined that the RP4 allowance for the cost of capital in the price control conditions is now too high, which would expose consumers to excessively high charges.

3.79 Further, we found that the allowances for NIE's corporation tax liability included in the calculation of NIE's maximum regulated revenue operate against the public interest (see Section 16). Most obviously, the rate of corporation tax and the nominal interest rate used in the calculations of these allowances are out of date (and higher than the current rates). There have also been disputes between the UR and NIE on the interpretation of the term in the current formulae relating to capital allowances.

3.80 More generally, given our findings regarding aspects of the price control (see above), it was necessary to define appropriate opex and capex allowances for the activities that we considered NIE would undertake during RP5. Accordingly, we found that the (inevitable, given the design of the Licences) failure of the Price Control Conditions in each Licence to do this was against the public interest.

Information reporting and transparency and the public interest

3.81 In response to the second question referred to us by the UR (see paragraph 1.2*(b)*), as explained in Section 18, we determined that the continuation of the existing Licences absent further conditions will operate against the public interest (see paragraph 3.76). Further, in order for the UR and other stakeholders to be able to make the most effective use of this information, it needs to be prepared in a format that is comparable to information available from the GB DNOs. This is so that the UR can, in particular, take views on the appropriateness of NIE's requests for allowances, and so that the UR can more effectively benchmark NIE's unit and overall costs. In the absence of such information, we consider that there is a risk that regulation will not be fully effective, which may result in customers being charged more than is needed, it may mean that NIE does not maintain suitable levels of service or certain categories of customers are disadvantaged, and it may mean that NIE might not be properly funded for certain activities or may face uncertainty over how it will be treated in the future by the UR.

Observations on redundant terms

3.82 We identified some terms under the RP4 price control arrangements that we think are redundant or will become redundant under the revisions to the price control that we have proposed. While we do not consider that their existence within RP4 operates against the public interest (which is the first question we needed to answer), in the context of determining how the price control conditions may be revised to address the adverse effects, we consider that in consequence their retention will operate against the public interest when these other changes are made. This is because redundant conditions are likely to create uncertainty over whether, or when, they might be used. We consider that regulation works most effectively, and firms are able to operate most efficiently, where there is regulatory clarity. The terms in question, as described in paragraphs 5.387 to 5.390 are:

(a) the Powerteam profit-sharing term (PPS_t); and

(b) the revenue cap implemented through the PC_t term (and the related RRF_t term).

Structure of the rest of the our final determination

3.83 Under Article 17(1) of the Electricity Order, where the CC reports in the terms described in its Article 17(1) (broadly, that licence conditions operate or may be expected to operate against the public interest and specifies the adverse effects this may cause, and also concludes that those effects could be remedied or prevented by modifications of the conditions of the licence, and specifies such modifications), the UR is required (subject to the provisions of Article 17) 'to make such modifications of the conditions of [NIE's licences] as appear to [it] requisite for the purpose of remedying or preventing the adverse effects specified in the report'. The UR is further required, before making such modifications, to 'have regard to the modifications specified in the report'.

3.84 Since we found that the Price Control Conditions in each Licence operate or may be expected to operate against the public interest and have specified resulting adverse effects, in the following sections we consider 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 (see paragraph 1.1). In particular:

(a) Section 4 considers issues regarding the timing of any modification to the Licence conditions;

(b) Section 5 considers high-level issues relating to the design of a future price control mechanism to ensure that NIE has incentives to be efficient;

(c) Section 6 considers the possible introduction of incentive mechanisms relating to NIE's performance;

(d) Section 7 provides an overview of our projections of NIE's efficient costs in RP5;

(e) Section 8 is concerned with indirect cost benchmarking (to ensure that NIE has incentives be efficient);

(f) Section 9 sets out our views of NIE's necessary core network investments;

(g) Section 10 details other elements of our cost assessment;

(h) Section 11 discusses relative price effects and likely productivity gains in RP5;

(i) Section 12 sets out our treatment of NIE's pension arrangements;

(j) Section 13 details our view of NIE's allowable rate of return on its RAB in RP5;

(k) Section 14 discusses certain issues between NIE and the UR that were unresolved regarding the operation of the current Licences in RP4;

(l) Section 15 is concerned with issues relating to NIE's capitalization practices;

(m) Section 16 is concerned with NIE's corporation tax allowances;

(n) Section 17 contains our assessment of whether our determination would allow NIE to finance its operations;

(o) Section 18 contains our view of the UR's proposal to introduce a reporter and further transparency requirements on NIE;

(p) Section 19 concerns the implementation of our decision regarding modifications to NIE's price control;

(q) Section 20 discusses NIE's external costs and the award of costs in relation to the inquiry; and

(r) Section 21 sets out our answers to the questions referred to us by the UR.

4. Timing and duration of a new price control

4.1 In light of our determination in Section 3 that NIE's current Licence conditions operate against the public interest and in line with our terms of reference, we considered whether we could specify Licence modifications to address the adverse effects on the public interest that we identified.

4.2 We decided that the new revenue control should govern the calculation of NIE's tariffs that apply from 1 October 2014 onwards. We also decided that our determination should revise the calculation of NIE's maximum regulated revenue for the period from 1 April 2012, to help compensate for deficiencies in the current price control licence conditions since that date. The revised calculations of NIE's maximum regulated revenue from 1 April 2012 will feed into the calculation of a potential refund to consumers against past charges and also the calculation of charges from 1 October 2014.

4.3 In this section we explain our decision:

(a) that the new price control should govern the calculation of NIE's tariffs from 1 October 2014 onwards;

(b) that the new price control should have a planned end date of 30 September 2017;

(c) in relation to Licence modifications, to address ambiguity in the current Licence conditions;

(d) to make adjustments to NIE's maximum regulated revenue for the period from 1 April 2012 to 30 September 2017; and

(e) regarding the price control licence conditions after the planned end date of 30 September 2017.

The only responses we received to Section 4 of our provisional determination concerned decisions about the financial year used for regulatory reporting and for calculation of NIE's revenue restriction. We address these issues in Section 19.

Tariffs from 1 April 2014

4.4 NIE currently sets new tariffs each year, which take effect on 1 October. NIE has set the tariffs applicable from 1 October 2013 to 30 September 2014. Unless changes are made to NIE's tariff-setting process, the earliest date at which our determination could affect NIE's tariffs is 1 October 2014.

4.5 Changes to NIE's tariff-setting process to allow an earlier effect on tariffs would be disruptive. There are also benefits to suppliers and consumers from advance notice of any significant tariff changes.

4.6 We therefore decided that the new price control should govern the calculation of NIE's tariffs that apply in the period from 1 October 2014 onwards.

Planned end date

4.7 The UR proposed a new price control with a planned end date of 30 September 2017. NIE told us that it was content that the new price control should run until 30 September 2017.

4.8 We decided that the planned end date for the new price control should be 30 September 2017. This date is consistent with the submissions of the parties. It also reflects two practical considerations, which we discuss in more detail below:

(a) preparations for the next price control review for NIE; and

(b) availability of information on expenditure forecasts.

Preparations for the next price control review for NIE

4.9 If we set a shorter price control period, there would be less time available for the UR and NIE to prepare for the next price control review.

4.10 NIE and the UR will need time to develop and apply effective annual cost reporting arrangements that are aligned with the cost reporting framework for the GB DNOs. Further, if they want the next price control to reflect Ofgem's output-based approach, NIE and the UR will need to establish reporting on measures of asset health and risk. There is a risk that such an approach cannot be introduced at the next price control review because reliable data are not yet available. A shorter price control period would exacerbate that risk. NIE told us that it did not expect to be able to report information on asset health until around 2016 or 2017.

Availability of information on expenditure forecasts

4.11 Another practical consideration in determining the planned end date for a new price control is the availability of forecasts of NIE's expenditure requirements—as well as review and assessment of those forecasts.

4.12 As part of price control processes, a regulator would typically be expected to determine the duration of the price control before asking the regulated company to prepare expenditure forecasts over that period. The price control review for NIE was originally planned on the basis that a new price control would run from 1 April 2012 to 31 March 2017. The expenditure forecasts that NIE originally submitted to the UR as part of its BPQ responses were prepared on that basis.

4.13 Following delays to the process, the UR subsequently proposed a new price control that would apply over the 4.75-year period from 1 January 2013 to 30 September 2017. The UR's calculation of price control proposals for the 4.75-year period reflected a different approach for operating expenditure and capital expenditure.

4.14 For operating expenditure (and pensions), the UR's price control proposals were calculated by first determining an allowance for a five-year period and then scaling this allowance down by a factor of 4.75/5 to determine an allowance for a 4.75-year period.

4.15 For capital expenditure, the UR's price control proposals were calculated on the basis of its determination of a capital expenditure allowance (subject to its proposed incentive and adjustment mechanisms) for the five-year period from 1 October 2012 to 30 September 2017. The UR took the aggregate expenditure allowance for the five-year period and allocated this between five 12-month periods between 1 October 2012 and 30 September 2017. The UR used these annual allocations of the capital expenditure allowance in the following way:

(a) For the period 1 October 2012 to 31 December 2012, the UR proposed that NIE's actual capital expenditure would be added to its RAB in line with the treatment of capital expenditure under NIE's existing price control licence conditions.

(b) For the period from 1 January 2013 to 30 September 2013, the UR proposed that NIE's allowance for capital expenditure would be equal to the capital expenditure allowance the UR allocated to the period from 1 October 2012 to 30 September 2013 minus NIE's actual capital expenditure (subject to this being efficiently incurred) in the period 1 October 2012 to 31 December 2012 (see *(a)* above).

(c) For each 12-month period from 1 October 2013 onwards, the UR proposed that NIE's allowance for capital expenditure would be equal to the capital expenditure allowance that the UR allocated to that 12-month period.

4.16 NIE's Statement of Case did not define clearly the period over which its expenditure forecasts applied. It referred at various points to forecasts during 'RP5' but did not define precisely what this meant. Due to delays to the UR's price control process, the term 'RP5' is ambiguous. The UR originally intended the RP5 price control period to run from 1 April 2012 to 31 March 2017, but the UR's final determinations for RP5 proposed a price control period from 1 January 2013 to 30 September 2017 with an allowance for capital expenditure based on the UR's assessment of NIE's expenditure requirements for the five-year period from 1 October 2012 to 30 September 2017. NIE did not revise its RP5 expenditure forecasts in light of changes to the time frame over which the UR's proposed RP5 period would apply (eg the UR's revised end date of 30 September 2017).[1]

4.17 On the basis of the forecasts and other information available, it was feasible for us to determine a price control with a planned end date of 30 September 2017. In contrast, an end date significantly later than 30 September 2017 would require further forecasts to be prepared and reviewed.

Licence modification to address ambiguity in current Licence conditions

4.18 In our provisional determination (paragraphs 4.20 to 4.27), we said that it was necessary to modify NIE's Licence conditions in relation to the formulae used for the calculation of NIE's maximum regulated revenue in the period from 1 April 2012 to 30 September 2014. This was for two reasons:

(a) Without modification, there would remain uncertainty in the period to 1 October 2014 as to whether NIE faces an enforceable revenue control and how any such revenue control should be calculated. This is because some elements of the formulae used to calculate NIE's maximum regulated revenue are not defined or specified for the period from 1 April 2012. We did not consider it appropriate to leave this uncertainty unresolved.

(b) The calculation of NIE's maximum regulated revenue in the existing price control conditions includes a revenue correction factor: the K_{Dt} term. The effect of this

[1] For instance, in Annex 5A.2 of its Statement of Case, NIE provided a reconciliation between its 'latest assessment of its capex requirement for RP5', its capital expenditure forecast from its BPQ (which was for the five-year period from April 2012) and the UR's final determinations. NIE did not identify any differences between its latest expenditure forecast and its original BPQ forecast on account of changes to the duration and start date of the price control.

term is to adjust NIE’s maximum regulated revenue in light of any under- or over-recovery in the previous financial year. We envisaged the retention of this revenue correction factor. If there was uncertainty about the calculation of NIE’s maximum regulated revenue in the period before 1 October 2014, reflecting point *(a)* above, there could be practical problems and disputes in the calculation of NIE’s maximum regulated revenue and the approval of tariffs for the period from 1 October 2014.

4.19 We proposed to limit any Licence modifications to the minimum changes necessary to ensure that all terms that are required to calculate the restrictions on NIE’s revenue are defined for the period from 1 April 2012 onwards. We said that we would define each term in a way that was as consistent as possible with other terms that were specified in the Licences.

4.20 Following our provisional determination, we carried out a more detailed review of how our proposals could be implemented through modifications to NIE’s price control licence conditions. We found the approach we proposed in our provisional determination to be unnecessarily complicated.

4.21 The approach specified in our provisional determination was intended to address the concern that, without licence modifications in relation to the period before 1 October 2014, there would be uncertainty as to whether NIE faces an enforceable revenue control in that period and how any such revenue control should be calculated. A simpler way to address that concern is to prohibit NIE from increasing its tariffs before 1 October 2014. NIE has already set tariffs for the period from 1 October 2013 to 30 September 2014 and neither NIE nor the UR has expressed any desire for these tariffs to be revised before 1 October 2014.

4.22 The other concern identified in our provisional determination was that, as a result of ambiguity about NIE’s maximum regulated revenue before 1 October 2014, there could be practical problems and disputes in the calculation of the correction factor feeding into NIE’s maximum regulated revenue in the period from 1 October 2014.

4.23 We identified a more straightforward way to address that concern, which would also reduce risks of ambiguity about NIE’s revenue control. This approach reflects the decision in Section 19 to retain a financial year of 1 April to 31 March as part of the specification of the restriction on NIE’s maximum regulated revenue in NIE’s price control licence conditions and the role of the correction factor for past under- or over-recovery in NIE’s current price control licence conditions.

4.24 We decided that the price control licence conditions should:

(a) contain revised calculations of NIE’s maximum regulated revenue for the period from 1 April 2012 onwards, which reflect the cost allowances and other aspects of our determination; and

(b) not place any retrospective obligations on NIE in relation to its tariffs before 1 October 2014.

4.25 The subsection below explains how the revised calculations of NIE’s maximum regulated revenue for the period from 1 April 2012 would feed through to charges.

Regulated revenues for the period from 1 April 2012 to 30 September 2017

4.26 In addition to the lack of explicit definitions for some elements of the current price control formulae for the period from 1 April 2012, we identified several other ways in which the current price control conditions operate against the public interest (see paragraphs 3.53 to 3.81). These features of the current price control are likely to have harmed either consumers or NIE in the past, since they have fed through to the calculation of the tariffs that NIE has imposed and the revenues it has collected.

4.27 We cannot change the tariffs that NIE has set in the past. Nor do we intend that NIE revises the tariffs that it has set for the period from 1 October 2013 to 30 September 2014. Nonetheless, we decided to seek to mitigate or compensate for the harm that consumers or NIE have experienced in the past as a result of the application of the RP4 price control beyond its intended end date.

4.28 Both parties expected us to determine licence modifications that sought to address the past defects of the RP4 price control as well as its potential future defects. NIE proposed that we should make licence modification so as to protect its position in relation to the period from 1 April 2012. The UR's submissions on the current price control and the public interest suggested that some aspects of the calculation of a new price control (eg the WACC term) could apply from 1 April 2012 with other elements applicable from 1 January 2013. Neither party suggested that a new price control should be introduced at a date subsequent to our final determination which is calculated in a way that ignores the amount of revenue that NIE has been permitted to collect in the period before that date.

4.29 Our determination relates to the amount of revenue that NIE 'ought' to receive in respect of the period from 1 April 2012, in light of our determination of:

(a) cost allowances for NIE's operating expenditure and capital expenditure requirements for the period from 1 April 2012;

(b) an allowance for NIE's pension deficit repair contributions for the period from 1 April 2012;

(c) an allowed return on NIE's RAB for the period from 1 April 2012; and

(d) an allowance for NIE's corporation tax liabilities in the period from 1 April 2012.

4.30 In each case, we used the same methods and approaches across the whole period from 1 April 2012 to 30 September 2017, supplemented where appropriate with available out-turn cost data. The practical effect is that our cost assessment in Sections 7 to 11, our determination of allowances for pensions in Section 12, our assessment of NIE's WACC in Section 13 and our determination of an approach to calculating allowances for corporation tax in Section 16 each concerns the period from 1 April 2012 to 30 September 2017, without any distinction between the period before and after 1 October 2014.

4.31 Thus, whilst our determination will affect tariffs from 1 October 2014 to 30 September 2017, much of the analysis underpinning our determination covers the period from 1 April 2012 to 30 September 2017.

4.32 The revisions to the calculation of NIE's maximum regulated revenue for the financial years from 1 April 2012 to 31 March 2013 and 1 April 2013 to 31 March 2014 would not lead to any retrospective obligation on NIE in relation to its tariffs. Instead, we decided that they should have two effects:

(a) We decided that NIE should provide a refund to suppliers that should be passed on to consumers, against its distribution charges in relation to any estimated over-recovery in the period since 1 April 2012. The value of the refund would be

based on differences between the revenue that NIE has collected in the period since 1 April 2012 and an estimate of NIE's maximum regulated revenue in that period. We explain the rationale and application of this refund in Section 19.

(b) We decided that any residual differences between NIE's actual revenues in the period since 1 April 2012 (after allowing for any refund) and the revised calculation of NIE's maximum regulated revenue for the period from 1 April 2012 should feed into the calculation of tariffs from 1 October 2014 through the calculation of the correction factor for any over- and under-recovery in past periods. We explain in more detail in Section 19 how the correction factors relating to past over- and under-recovery should be calculated.

4.33 We decided that it would not generally be appropriate to make adjustments in relation to NIE's past performance under any new incentive schemes or obligations established as part of this inquiry, since incentives cannot affect historical performance.

4.34 We did, however, decide that the calculated adjustments should reflect the application of the cost risk-sharing mechanism set out in Section 5. While this arrangement might be viewed as part of our new incentive framework, its purpose and effect is not limited to NIE's financial incentives. It is intended to share between consumers and NIE's investors the financial impact of any differences between our assessment of NIE's efficient expenditure requirements and NIE's actual expenditure. That sharing is desirable in the period from 1 April 2012 as well as in the period from 1 October 2014. Further, adopting a different approach to cost risk-sharing before and after 1 October 2014 could create perverse incentives and unduly distort NIE's expenditure decisions.

4.35 In the course of our inquiry, we also considered the possibility of:

(a) making adjustments to NIE's maximum regulated revenue in the period before 1 April 2012; and

(b) limiting changes to NIE's maximum regulated revenue to the period from 1 January 2013.

4.36 As we explain in the subsection below, we decided against both of these options.

NIE's maximum regulated revenue in the period before 1 April 2012

4.37 In September 2006, the UR and NIE agreed a price control that was intended to apply 31 March 2012. It is clear that both NIE and the UR expected a new (replacement) price control to take effect from 1 April 2012 but no sooner.

4.38 We did not identify a good reason to implement a new price control from 1 October 2014 that would undermine the financial basis of the 2006 price control agreement between NIE and the UR.

Changes limited to maximum regulated revenue from 1 January 2013

4.39 In its RP5 final determination, the UR proposed a form of extension of the RP4 price control to 31 December 2012, with the UR's new price control arrangements taking effect from 1 January 2013.

4.40 If there had been agreement between the UR and NIE to apply something along the lines of the RP4 price control—with agreement on the missing terms—to the period from 1 April 2012 and 31 December 2012, this might provide a reason against our determination making changes to NIE's maximum regulated revenue in the period from 1 April 2012 and 31 December 2012. We found no such agreement. NIE rejected the UR's RP5 final determination and denied that there was any agreement between NIE and the UR for a new price control or a price control extension to cover the period from 1 April 2012 to 31 December 2012.

4.41 We did not identify any sound basis for treating the period from 1 January 2013 to 30 September 2014 differently to the period from 1 April 2012 to 31 December 2012.

Price control licence conditions after planned end date

4.42 We have determined a new price control for NIE which is intended to apply until the planned end date of 30 September 2017. However, there is no guarantee that NIE and the UR will agree on licence modifications to implement a replacement price control by that planned end date.

4.43 To avoid a repeat of the situation currently experienced, in which NIE argued that there has effectively been no functioning price control applicable since 1 April 2012, we found it prudent to ensure that a price control applies to NIE in the period from 1 October 2017.

4.44 The price control that applies from 1 October 2017 should be seen as a form of interim price control before a new price control is established. This is necessary in the event of delays to the agreement of a new price control. When a new price control is determined—whether by agreement between the parties or determined by the CC—this could include adjustments in respect of the amount of revenue that NIE has collected in the period since 1 October 2017, to address any shortcomings of the interim price control applicable since 1 October 2017.

4.45 In the draft licence conditions published alongside its RP5 final determination, the UR proposed that the maximum regulated revenue for NIE from 1 October 2017 onwards should be calculated as the maximum regulated revenue in the previous financial year adjusted for RPI inflation.

4.46 An alternative option was that NIE's tariffs after the planned end date were restricted to no more than the maximum levels of each tariff set at the last formal tariff setting process before the planned end date (eg the tariffs introduced from 1 October 2016 if the planned end date is 30 September 2017). This option was particularly simple, which seemed advantageous for the type of interim price control envisaged above. Further, the imposition of a simple tariff control of this nature would more properly reflect the fact that we have not carried out the work necessary to determine an appropriate maximum revenue control for the period from 1 October 2017.

4.47 On this basis, we decided that the restriction on NIE's maximum regulated revenue for the period from 1 October 2017 is replaced with a prohibition on increases to the tariffs set from 1 October 2016.

4.48 NIE pointed out that Northern Ireland legislation may be amended, as envisaged in the EU energy directives, to empower the UR to introduce a new price control from 1 October 2017 without NIE's consent. Nonetheless, NIE said that it would be content with the type of arrangement proposed above. We agreed with NIE's view that potential changes to the UR's powers to make licence modifications without NIE's consent do not eliminate the need for some provision within NIE's Licence conditions in relation to maximum revenues or prices in the period from 1 October 2017.

5. Price control design

5.1 In Section 3, we established that the current price control for NIE is not in the public interest, and in Section 4 we considered certain timing and transitional issues concerning the introduction of a new price control. This section considers the design of the new price control. 'Price control design' refers to the work to establish a new price control for NIE excluding the work to determine the numbers to calibrate or populate that price control, which we consider in Sections 7, 8, 9, 10, 11, 12 and 13. This section is organized as follows. We:

(a) provide an overview of the features of the current price control Licence conditions that operate against the public interest and which are most relevant to our work on price control design (paragraphs 5.4 to 5.9);

(b) provide an overview of the type of price control framework we determined for NIE, which we describe as 'RAB-based incentive regulation'. This takes the form of revenue controls on NIE, with separate revenue controls for transmission and distribution (paragraphs 5.10 to 5.21);

(c) highlight some risks that arise under RAB-based incentive regulation that are relevant to decisions across several aspects of our price control design (paragraphs 5.22 to 5.30);

(d) summarize the UR's proposals for the design of a new price control for NIE and NIE's submissions on the design of a new price control (paragraphs 5.31 to 5.41); and

(e) consider in more detail a series of different aspects of price control design. We review the parties' submissions and discuss risks and concerns relevant to the public interest. In some cases we set out alternative options that we have identified (paragraphs 5.42 to 5.395).

5.2 The main focus of this section is on the overall structure of the price control, the way that it makes allowances for NIE's opex and capex and the financial incentives and financial exposure it provides to NIE in relation to its costs. This section does not contain our determination on all aspects price control design. Price controls may also include specific rules, obligations or financial incentives in relation to the regulated company's quality of service. These features of price control design are considered separately in Section 6. Section 6 also considers the treatment of NIE's revenues from revenue protection activities. In addition, as part of our cost assessment in Section 10, we made decisions which affect price control design, particularly in relation to NIE's recovery of costs in cases where there are interactions between NIE's connection charging regime and NIE's distribution and transmission charges. Section 16 contains our decision on changes to the calculation of an allowance for NIE's corporation tax payments in its price control licence conditions. Finally, Section 19 provides our decision on some more detailed implementation issues, including the implementation of aspects of price control design considered in Section 5.

5.3 In the course of our work on price control design, we took account of the RAB-based price control frameworks applied by other UK regulators, including Ofgem, Ofwat and the CAA. We faced constraints as to the practicable options available for the design of a new price control for NIE. We did not, in particular, consider it feasible to apply—or retrofit—Ofgem's RIIO price control framework in full to NIE as part of this inquiry. Ofgem's RIIO framework is complex, with many different elements. The implementation of Ofgem's approach would require a lengthy time frame.[1] Nonetheless, we have considered the potential application of particular aspects of Ofgem's approach as part of our work where practical and in light of submissions made to us as part of our inquiry.

The current Licence conditions and the public interest

5.4 In paragraphs 3.53 to 3.80 we set out aspects of the current RP4 price controls which we considered operated against the public interest. Our findings in relation to aspects of the price control design that are not sufficient to protect the interest of consumers are particularly relevant to this section. We note here certain aspects of how these operate against the public interest.

5.5 First, as noted in paragraph 3.65, the calculation of NIE's maximum regulated revenue according to the level of capex that NIE incurs may expose consumers to excessively high charges that reflect capex that was inefficiently or unnecessarily incurred by NIE—or missed opportunities for efficiency and innovation in relation to network investment. Therefore we consider it necessary to give NIE better incentives to enhance the efficiency of its capex—see, for example, paragraphs 5.70 to 5.96.

5.6 Another way in which cost pass-through for capex could expose customers to unnecessarily high charges arises from the possibility for NIE's sister company, NIE Powerteam, to charge inappropriately high charges to NIE for the work it carries out on NIE's network (see paragraph 3.66). This is noted in relation to the Powerteam profit-sharing term in paragraph 5.389.

5.7 We consider that where incentives regarding outperformance differ between opex and capex, this can create distortions in how NIE would organize its activities that could increase inefficiencies. In particular, under the RP4 price controls, the separate allowance schemes in relation to opex and capex provide NIE with unduly strong financial incentives to adopt working practices that favour capex-intensive practices over opex, even though such capex practices may not be efficient. In paragraphs 5.70 to 5.79 we discuss aspects of cost risk-sharing mechanisms, including proposals for alignment of cost risk-sharing across opex and capex. Where common incentives apply to both opex and capex, we expect the incentives that may unduly favour adoption of capex-intensive practices to be reduced or eliminated.

5.8 In addition, the interaction of the opex and capex arrangements may lead to excessively high charges on consumers if NIE changes its working practices or accounting practices over time so as to reclassify opex as capex, even where its activities remain essentially unchanged. Changes in capitalization practices could lead to activities notionally funded through an opex allowance also being funded through capex. This is discussed in Section 15.

5.9 Finally, the treatment of rates and wayleaves costs as 'uncontrollable' and recoverable by NIE on a full cost pass-through basis may expose consumers to excessively high charges that reflect unnecessary expenditure or missed opportunities for cost reductions. We considered that NIE may have some influence over these costs. This is discussed in paragraphs 5.316 to 5.365.

[1] In September 2012 Ofgem published an extensive consultation paper on its review of new price controls for the GB electricity distribution companies that will come into effect in April 2015.

Type of price control for NIE and associated issues

5.10 In this subsection, we: *(a)* specify the type of price control we found appropriate for NIE, *(b)* specify that there should be separate revenue controls for transmission and distribution, and *(c)* consider revenue controls and restrictions on specific prices.

Type of price control

5.11 We decided to specify a type of RAB-based incentive regulation. Under this type of regulation, we make forecasts of NIE's (efficient) expenditure requirements over a defined price control period, across both opex and capex, and use these as the basis to set a revenue control for NIE's relevant distribution and transmission services. The forecasts of NIE's capex feed into NIE's RAB. The revenue control is calculated to provide NIE with sufficient revenue (but no more) to enable it to cover its operating costs (including depreciation on the RAB) and to earn a fair rate of return on its RAB. The price control is designed in a way that is intended to provide NIE with financial incentives to operate efficiently and to avoid unnecessary expenditure, while also taking account of the difficulties of forecasting NIE's costs. The price control might include various mechanisms and arrangements to adjust NIE's revenue control and RAB in light of factors such as: its out-turn expenditure; measures of its service quality; measures of the volume of work it carries out; and additional costs approved by the regulator. The RP4 NIE price control may be seen as a form of this type of regulation, and the price controls proposed by the UR and NIE both amount to this type of price control.

5.12 We decided against either an approach based on cost pass-through subject to efficient spend or setting a price control based on an estimate of the price that a hypothetical competitive supplier would charge:

(a) An approach involving cost pass-through subject to efficient spend would not provide sufficient protection to consumers against the risks that the charges they face are too high because of inefficient expenditure or missed opportunities for efficiency improvements.

(b) A change to a price control based on the price of a hypothetical competitive supplier would represent a major change in the price control framework for NIE—and one that might be difficult to undo. A price control based on the price of a hypothetical competitive supplier would not be compatible with the existing regulatory treatment of NIE's RAB, which has implications for the level of prices faced by consumers and the risks faced by investors. We did not consider that such a change was proportionate or practical for the purposes of our inquiry.

Separate revenue controls for transmission and distribution

5.13 There were separate Licences for NIE's electricity transmission network (which operates at 110 kV and 275 kV) and NIE's lower-voltage distribution network. We decided on separate revenue controls for transmission and distribution, in line with the separate Licences.

5.14 NIE's business and accounting are not separated between transmission and distribution. Some allocation of costs between transmission and distribution will be required where these are not separately identified as either transmission or distribution costs.

5.15 Apart from consistency with the separation of Licences, separate revenue controls can help better align transmission charges with transmission costs and distribution charges with distribution costs. For example, major new transmission investment projects should not be funded through electricity distribution use of system charges, but there is a risk of this occurring if there is a single revenue control across transmission and distribution (especially if combined with a charging methodology that allocates a fixed percentage of revenues between transmission and distribution).

Revenue controls and restrictions on specific prices

5.16 The price control Licence conditions which are the subject of our reference take the form of a restriction on NIE's total revenues (excluding revenues from specified excluded services). This restriction does not determine maximum prices for specific services.

5.17 We identified a question as to whether such a control is sufficient to protect consumers from the risks of excessive charges for specific services. A control on aggregate revenues does not on its own ensure that charges for specific services or charges for specific types of consumers are reasonable. However, where controls on revenues (or weighted averages of prices) are applied, they can be combined with other forms of regulation that affect the charges or tariffs for specific services or groups of electricity consumers.

5.18 Ofgem's regulation of the use of system charges for electricity distribution network companies in GB combines controls on aggregate revenues (Ofgem calls this the 'price control') with licence requirements for companies to set charges using a very detailed charging methodology that is common across the companies. Ofgem approved the charging methodology and was involved in its development.

5.19 There is no similar arrangement in Northern Ireland. NIE does not have a charging methodology that is comparable with that of the electricity distribution network companies in GB in terms of level of detail or transparency.

5.20 NIE's charges are subject to approval by the UR. The process provides an opportunity for the UR to provide protection to consumers against the risks of excessive charges for specific services. We did not review the effectiveness of that process. If there are public interest concerns about the risks of excessive charges for specific services, we consider that these could be addressed as part of the UR's powers through that process rather than through changes to price control licence conditions. We did not consider it practical in the time frame of our inquiry to develop a detailed charging methodology for NIE that could be specified in the price control Licence conditions.

5.21 The UR's tariff approval powers and the current tariff approval process were not part of the price control Licence conditions that were the subject of our inquiry. We considered whether the existence of the UR's tariff approval powers may make the price control Licence conditions redundant. We did not find this to be the case. We did not consider that the existence of this tariff approval process fully mitigates the adverse public interest effects of NIE's current price control licence conditions. Nor did we consider that it would be in the public interest to seek to address those effects by removing the restriction on NIE's maximum regulated revenue altogether and relying entirely on the UR's tariff approval powers. That would be a major change to the regulatory regime in which NIE operates. It would create considerable uncertainty for NIE's investors and it would not obviously benefit consumers. It also would remove the opportunity for the CC to determine a series of important issues that matter to the regulation of NIE's charges which have been disputed between NIE and the UR.

Risks relevant to price control design

5.22 We now highlight some risks that arise under RAB-based price control regulation that were relevant to our decisions regarding several aspects of price control design.

5.23 Within the category of RAB-based incentive regulation, a hypothetical simple price control for NIE would involving setting a maximum revenue allowance for the years of the price control period based on regulatory forecasts of NIE's expenditure requirements (if it were run efficiently) over that period. The Licence conditions for NIE would restrict NIE's revenue (other than for excluded services) to no more than that amount. The subsequent price control could be set in a similar way, with fresh forecasts of NIE's expenditure requirements and no adjustments to NIE's RAB or maximum revenue calculation for any differences between previous regulatory expenditure forecasts and NIE's actual expenditure. This hypothetical simple revenue control is a useful reference point, but contains two risks in particular: *(a)* expenditure forecasting risks, and *(b)* risks of inefficiency or over-investment to the detriment of consumers. We consider each in turn.

Expenditure forecasting risks

5.24 Most of the aspects of price control design that we consider in this section concern potential modifications which might be made to that hypothetical simple price control. In most, if not all, cases, the potential justification for these modifications is that they may address or reduce one of the following problems:[2]

(a) *The difficulty of making accurate forecasts.* Any expenditure forecast over a five-year period is uncertain. Both consumers and NIE would be financially exposed to the regulatory forecast or cost assessment. If the regulator (or CC) over-estimates NIE's (efficient) expenditure requirements, this could result in charges that are more than necessary for NIE to provide its services and comply with its legal obligations. If the regulator underestimates NIE's (efficient) expenditure requirements, this could deny investors a fair return on capital and/or prevent NIE from financing its activities. There is also a practical issue: making expenditure forecasts that a regulator can reasonably use as part of the calculation of a price control can be a time-consuming process.

(b) *The opportunity to defer planned investment projects to the detriment of consumers.* Even if we make reasonable forecasts of an efficient level of expenditure for NIE over the price control period, it may be possible for NIE to spend substantially less than this amount by deferring (or cancelling) some investment projects that, while worthwhile, are not essential within the price control period for the company to provide services to consumers, meet network design and planning standards or to meet legal obligations. Such opportunities might operate against the interests of consumers (as in effect they pay for projects that are not undertaken as planned and may subsequently face further charges to cover the costs of projects when they are carried out).

5.25 The potential modifications described in this section may bring their own problems and risks which need to be considered alongside their ability to mitigate the problems above (paragraph 5.24). In some cases, there may be concerns that the cure is worse than the problem. Nonetheless, many of them are familiar features of RAB-based price controls set by UK regulators including the UR, Ofgem and Ofwat.

[2] The second problem might be seen as subset of the first.

Risks of inefficiency or overinvestment to the detriment of consumers

5.26 Depending on the design of a price control, there are risks that it harms the efficiency of the regulated company in a way that is ultimately to the detriment of consumers. In particular, some regulatory arrangements that are intended to limit the risks highlighted above in relation to expenditure forecasts and deferral of planned capex projects may lead to inefficient expenditure or unnecessary investment.

5.27 The aspects of price control design considered in this section may affect the financial incentives and opportunities that the regulated company has to identify and take opportunities to operate more efficiently. If the price control design is such that the revenues raised from consumers are adjusted (to some degree) in light of the company's actual expenditure, such adjustments will expose consumers to any inefficient decisions of the regulated company. Further, there are risks that any inefficiency feeds through to higher charges to consumers in the future if the price control determination at subsequent price control reviews is based, in part, on the level of costs it has incurred in the past.

5.28 Aspects of a price control may mean that there are limited profit opportunities available to the regulated company from cost savings, delivery of investment projects efficiently and avoiding unnecessary expenditure. There may also be a limited opportunity for a third party to profit from takeover of the regulated company and the implementation of new working practices. Limiting incentives for NIE to become more efficient may not be in the interests of consumers.

5.29 The price control may also provide the regulated company with opportunities to profit from doing things which are inefficient. For instance, the price control (and wider regulatory framework) may treat different categories of expenditure differently in a way that provides a financial incentive for the company to distort its expenditure away from what would otherwise be an efficient way of running the business.

5.30 Which risks apply, and their likely scale, depends on the details of the price control design and also the regulated company's perceptions about current and future regulation. We took account of these general considerations as part of our work on the more specific aspects of price control design considered below.

Overview of main parties' submissions

5.31 This subsection provides an overview of the main parties' proposals and submissions on price control design. We mainly focus in this section on the UR's proposals from its RP5 final determinations and those contained in NIE's Statement of Case. Over the course of the inquiry the parties have made further submissions and proposals on specific aspects, partly in response to our work. We discuss these in the more detailed sections that follow.

5.32 Our overview of the main parties' submissions provides context for our work on price control design and highlights some of the issues that these parties considered most important to our inquiry. Nonetheless, we have not restricted our work on price control to the issues raised by the parties. Some of our proposals represent alternative options that we consider more appropriate than those submitted by the parties.

The UR's proposals

5.33 Table 5.1 provides an overview of the UR's proposals for the design of a new price control for NIE. It focuses on some of the main differences between the UR's proposed treatment of different categories of NIE's expenditure. It does not capture some elements which are common across categories, such as the UR's proposals for an embedded reporter within NIE and for an efficient spend clause that would apply across NIE's capex.

TABLE 5.1 **Overview of the UR's RP5 proposals**

Category and features (not exhaustive)	*Expenditure coverage under UR's proposals*
Fund 1: output-measurable capital expenditure Upfront estimate of aggregate expenditure requirements based on forecast volumes and unit cost estimates NIE bears financial exposure for differences between its out-turn unit costs and UR's unit cost estimates (exposure through five-year delay to RAB adjustment for out-turn costs) Volume adjustment mechanism intended to deny NIE financial benefits from carrying out lower 'volume' of investment than forecast by UR at price control review; volume measure uses UR's unit cost estimates to assign weights to different types of activity or projects	• Transmission asset replacement • Distribution asset replacement
Fund 1: input-driven capital expenditure Upfront expenditure allowance, funded through RAB No adjustment to revenues or RAB for any differences between upfront allowance and out-turn expenditure	Capex relating to: • Fault and emergency work • Costs associated with replacing assets in storms • Reactive work • Capitalized overheads • Public realm work • Costs arising from new roads and street works legislation • Real price effects (RPEs) • ESQCR data collection and assessments
Fund 2 approach for specific load-related projects Some projects approved upfront by UR and estimate of their costs included in price control calculation Provision for UR to approve further projects during price control period, with estimated costs of such projects to be added to RAB at start of next price control review Provision for NIE to receive remuneration through RAB for investment that is not pre-approved by UR but which NIE can subsequently show was efficient NIE faces same financial exposure to its unit cost being different to UR's unit cost estimates as for output-measurable capex under Fund 1	• Expenditure on the distribution network to provide greater capacity to accommodate additional load
Fund 2 approach for metering capital expenditure Upfront forecast of costs used to calculate price control Adjustments for differences between forecast volumes and out-turn volumes based on upfront estimates of unit costs (volume driver mechanism)	• Costs of replacing and recertifying existing meters • Costs of installing new meters • Excludes smart meters
Fund 2 approach for connections capital expenditure Full cost pass-through	• Part of connection costs • Costs relating to certain network alterations
Capital expenditure fund 3 No upfront allowance used to calculate price control Provision for UR to approve further projects during price control period, with estimated costs of projects to be added to RAB at start of next price control review	• Projects to increase transmission and distribution system capacity and capability to accommodate renewable generation • Smart metering • Smart grid initiatives
Controllable operating expenditure Upfront allowance based on estimate of efficient expenditure requirement In the event of NIE underspend against upfront allowance, special incentive scheme applies—revenue adjustments made in future years intended to ensure NIE benefits from efficiency savings for five-year period (scheme based on Ofwat's historical operating expenditure incentive allowance) No financial adjustment or incentive scheme for overspend: NIE bears full exposure to its expenditure being above the upfront forecast during the price control period	• All opex with the exclusion of items specified under 'uncontrollable' operating expenditure below • Not defined by reference to specific activities or outputs
Uncontrollable operating expenditure Intended to pass through costs Price control calculated on basis of forecasts of NIE's costs for items within this category with adjustment for full difference between forecast and out-turn costs	• Rates • Wayleaves • Licence fees

Source: CC analysis.

5.34 Appendix 5.1 provides more detailed information on the UR's proposals for capex.

NIE's proposals

5.35 NIE made extensive criticisms of the UR's proposals for the design of a new price control.[3] Some relate to specific aspects of the proposals and are identified in the sections that follow. We highlight and comment on some of the more general points:

(a) NIE claims that the approach in the UR's final determinations would lead it to follow a prescribed plan for its asset replacement programme which reflects the volumes of work and projects forecast at the price control review, rather than running its business efficiently in response to changing priorities over the price control period.

(b) Some of NIE's criticisms of the UR's proposals for capex are that it would diminish NIE's financial incentives to innovate and manage its network efficiently, and that it would involve micro-management by the UR.

(c) NIE argued that it would be subject to excessive regulatory risk from the wide scope for the UR (and the proposed reporter) to make ex-post assessments of its expenditure decisions which affect its maximum regulated revenue and the value of its RAB.

(d) NIE criticized the UR's proposals as ambiguous and not sufficiently well developed to be feasible.

5.36 NIE also argued that the UR's proposed approach to the treatment of capital departed from the traditional or established forms of 'RPI–X regulation'. We agree: the UR's proposals differ substantively from the types of RAB-base price controls set for energy network companies and companies in other sectors in the 1990s and early 2000s.

5.37 The fact that the UR's proposals represent a different regulatory approach from that taken for price controls set in the 1990s and early 2000s is not, in itself, a valid criticism of the UR's proposals. In the past, the treatment of capex in RAB-based utility price controls has suffered from serious shortcomings which have been recognized by regulators other than the UR. Regulators such as Ofgem and Ofwat have sought to adapt their approaches over time to reduce the problems they have experienced. Ofgem's price control framework for energy network companies in 2013[4] differs extensively from its approach in 2003[5].

5.38 NIE clarified that its concerns with the UR's proposals were not so much that they involved changes in the regulatory regime, but with the nature of those changes and the overall philosophy towards price control regulation. NIE said that Ofgem's approach to regulation, which had evolved over time, had maintained a clear willingness on the part of the regulator to delegate management and operational decisions to the DNOs. With regard to the framework for energy network price controls (RIIO) that Ofgem established in 2010, NIE said:

[3] NIE Statement of Case, pp45–59.
[4] www.ofgem.gov.uk/ofgem-publications/64003/pricecontrolexplainedmarch13web.pdf.
[5] www.ofgem.gov.uk/ofgem-publications/46417/5090-dpcr4financialmodelguide6nov03.pdf.

RIIO explicitly re-endorsed the incentive-based model as the right form of regulation and still envisages that incentives work best when the DNO is given a single ex ante allowance for forecast capex, and is left free to determine how best to spend the resulting revenues. This both creates substantial financial incentives for the DNO to beat the capex allowance by achieving year on year operational efficiency gains, and also leaves the DNO free to manage its response to changing network priorities.

5.39 NIE said that there was a regulatory philosophy in GB which attached substantial value to creating incentives for DNOs to respond dynamically and efficiently to changing priorities in their distribution businesses and an alternative regulatory philosophy, favoured by the UR, which did not attach such value. NIE considered the former philosophy better than the latter.

5.40 NIE in effect requested us to adopt the following approach for capex in relation to the UR's proposals:[6]

(a) Fund 1 should be limited to 'rolling programme' capital investments for which NIE could predict, with reasonably accuracy, both the need to replace set volumes of certain types of assets and the efficient cost per unit.

(b) The UR's proposals for Fund 2 should not be adopted.

(c) The UR's proposals for Fund 3 should be adopted, but with some modifications concerning the process for project approval and the categorization of which projects were included within Fund 3.

(d) The remainder of NIE's capex should be subject to what NIE referred to as a traditional or conventional RPI–X approach. An upfront expenditure allowance would be set and NIE would bear a set proportion of any underspend or overspend relative to the upfront allowance. NIE proposed that it would face an incentive rate of 30 per cent, which would mean that around 70 per cent of variations between its actual expenditure and the regulatory forecasts should be passed through to consumers through adjustments to future charges and the RAB.

5.41 For opex, NIE proposed an upfront allowance for opex and a symmetrical efficiency incentive.[7]

Introduction and structure of our decisions on price control design

5.42 This subsection:

(a) discusses the organization and structure of our work on price control design (paragraphs 5.43 and 5.44);

(b) highlights the potential role of a reporter and links to price control design (paragraphs 5.45 to 5.47); and

(c) lists the issues that the remainder of this Section 5 considers (paragraph 5.48).

[6] NIE Statement of Case, pp54–59.
[7] ibid, p240.

The organization and structure of our work on price control design

5.43 The presentational structure we adopted departs in some ways from that adopted by the UR (eg the UR's proposals are organized by reference to a number of different expenditure 'funds'). The structure we have used has several benefits:

(a) Much of the dispute in relation to price control design in the inquiry focused on the 'three-fund' approach to capex that the UR's submissions highlight. However, there were other questions of price control design that we had to address and we aimed to draw these out clearly.

(b) The perception that the UR's proposed approach to capex involved three funds was an oversimplification. The UR's proposals involved different regulatory arrangements for each of six different categories of NIE's capex. The structure we have adopted in this section allows these differences to be presented clearly.

(c) Some questions of price control design, such as questions on an inefficient spend clause and what we have called 'cost risk-sharing mechanisms', apply at a general level and the structure we have adopted helps bring a more consistent approach across different categories of expenditure (where desirable).

5.44 While we present questions of price control design under separate headings, it is important that the decisions on each aspect are consistent and reflect a coherent strategy for price control and for the inquiry. In reaching our determination, we sought to achieve a coherent approach.

The potential role of a reporter and links to price control design

5.45 There are interactions between the UR's proposals for a reporter and our work on price control design. It is useful to draw the following distinction between two types of roles that a 'reporter' might play:

(a) ensuring the accuracy and reliability of data and other information provided by NIE in response to regulatory information requests; and

(b) making assessments of the asset management decisions and plans of NIE to support decisions that the UR will take on (i) whether to approve specific investment proposals identified by NIE and (ii) whether any of NIE's incurred expenditure was inefficient or wasteful and requires a financial adjustment to NIE's allowed revenues or RAB to protect consumers against inefficient costs.

5.46 In each case there is the potential for a reporter to have staff based at the premises of NIE with access to the information necessary to fulfil the reporter's functions: we call this an embedded reporter. The UR proposed an embedded reporter fulfilling roles falling under both categories *(a)* and *(b)* above.

5.47 We consider the potential role of a reporter in more detail in Section 18. In this section, we recognize that some potential options for price control design could involve a reporter fulfilling the type of role under category *(b)* and these are identified where relevant. In each case, the reporter would be an optional component which could help make the proposed regulatory arrangements more effective as it would allow the UR to draw on the knowledge of the reporter and its access to information. Such a reporter could also bring downsides, such as risks of regulatory micro-management and blurred responsibilities.

The issues that the remainder of this Section 5 considers

5.48 The remainder of Section 5 considers in more detail different aspects of price control design that we have determined. We use the annotation of D1, D2 etc to refer to different aspects of price control design that we cover. The aspects comprise:

(a) D1: Cost risk-sharing mechanism (paragraphs 5.49 to 5.96);

(b) D2: Inefficient spend clause (paragraphs 5.97 to 5.111);

(c) D3: Measures to tackle risks from deferral of planned network investment (paragraphs 5.112 to 5.214);

(d) D4: Investment projects for distribution network load-related expenditure (paragraphs 5.215 to 5.245);

(e) D5: Investment projects to increase transmission system capacity (paragraphs 5.246 to 5.279);

(f) D6: Smart grid initiatives (paragraphs 5.280 to 5.286);

(g) D7: Electricity meter investment and smart meter programme (paragraphs 5.287 to 5.303);

(h) D8: Pass-through of part of connections charges to NIE's RAB (paragraphs 5.304 to 5.315);

(i) D9: Pass-through of specified operating costs (paragraphs 5.316 to 5.384); and

(j) D10: Other terms to remove from current Licence conditions (paragraphs 5.385 to 5.395).

D1: Cost risk-sharing mechanism

Summary

5.49 We specified a mechanism to adjust NIE's maximum revenue and RAB according to differences between the expenditure forecasts we have used for our determination and the level of NIE's out-turn expenditure. We determined that 50 per cent of such differences should be passed through to consumers via adjustments to NIE's maximum regulated revenue and RAB.

5.50 The purpose of the mechanism is to provide some financial protection to both consumers and NIE against potential inaccuracies in our estimates of NIE's efficient expenditure requirements and against unforeseen future developments that affect NIE's costs—while also maintaining clear and strong financial incentives for NIE to operate and invest efficiently.

Introduction

5.51 We considered potential arrangements within the price control framework to make adjustments to NIE's revenues and RAB so as to pass through to charges, to some degree, differences between the regulatory forecasts of NIE's expenditure requirements and NIE's out-turn expenditure.

5.52 We use the terminology here of a 'cost risk-sharing mechanism'. Such a mechanism concerns the regulatory treatment of underspends and overspends against regulatory expenditure forecasts, the pass-through of actual expenditure (eg to the RAB) and NIE's efficiency incentives. Elements of the UR's proposals for the treatment of capex (eg proposed 'efficiency payments') and its proposals for opex incentives relate to what we treat as the cost risk-sharing mechanism.

5.53 A cost risk-sharing mechanism can help reduce consumers' financial exposure to the risks of:

(a) deferral or abandonment by NIE of investment projects that are included in the expenditure forecasts used to calculate the price control; and

(b) those regulatory expenditure forecasts being too high for any other reason.

5.54 Likewise such a mechanism can reduce the financial exposure of NIE to the risk that the expenditure forecasts used to calculate its maximum regulated revenue and RAB are too low.

5.55 Cost risk-sharing and pass-through arrangements also have drawbacks. They add complexity to the design of the price control framework. There may be a risk—if the degree of pass-through is too high—of undermining incentives for NIE to operate efficiently and to avoid inefficient expenditure. Indeed, there may be a risk of providing NIE with perverse financial incentives to incur expenditure unnecessarily (eg in order to increase its RAB). There may also be a risk of distorting NIE's working practices, cost reporting and capitalization policies if the nature and extent of cost pass-through is different for different categories of expenditure.

5.56 We decided to include a cost risk-sharing mechanism within the price control. This subsection:

(a) summarizes the UR's proposals in its RP5 final determination;

(b) summarizes NIE's proposals;

(c) considers the effect of the UR's proposals for different cost risk-sharing between expenditure categories;

(d) considers the effect of the UR's proposed opex outperformance rolling incentive;

(e) considers alignment of cost risk-sharing across opex and capex;

(f) considers concerns raised by the UR on our approach to cost risk-sharing; and

(g) provides our determination on the extent of cost risk-sharing under the mechanism.

Summary of the UR's proposals in its RP5 final determination

5.57 The UR's proposals for cost-risk sharing in relation to capex were embedded within its proposals for the different capex funds that it identified. These proposals are described in Appendix 5.1. The UR's proposals for cost risk-sharing included:

(a) Cost risk-sharing for capex would be implemented by adjusting NIE's RAB in light of its actual expenditure with a five-year delay. NIE's price control would initially be calculated to provide it with depreciation and allowed return on the value of its RAB which is based on regulatory forecasts of NIE's capex. NIE's RAB would be

subsequently recalculated in light of its actual capex so as to provide NIE with the depreciation and allowed return due on its actual capex (rather than the regulatory forecast)—but with that recalculation only taking effect on NIE's maximum regulated revenue after a five-year delay.

(b) For some parts of NIE's capex there would be no cost risk-sharing. NIE and consumers would be fully exposed to the expenditure forecasts made by the UR at the price control review with no adjustments for any differences between forecast expenditure and actual expenditure.

(c) For opex, the UR proposed a variant of the 'operating expenditure incentive allowance' that Ofwat introduced at the 1999 periodic review. Under this approach, financial adjustments would be made to try to ensure that NIE would benefit from any savings in its opex (against regulatory forecasts) for a period of five years.

Summary of NIE's proposals

5.58 For those categories of capex identified by NIE as suitable for an ex ante allowance, NIE's proposals were for NIE to bear a set proportion of underspend or overspend relative to that ex-ante allowance.[8] NIE proposed that we set a symmetrical efficiency incentive scheme for opex.[9]

5.59 NIE suggested that cost risk-sharing arrangements could either be applied as a 'fixed percentage to be determined' or as a scheme under which NIE would 'retain outperformance/underperformance (depreciation plus return) for five years'. NIE told us that it saw merit in an alignment of cost risk-sharing across opex and capex.

The UR's proposals for different cost risk-sharing between expenditure categories

5.60 The UR's proposals would involve substantially different policies on cost risk-sharing between different expenditure categories. Differences would apply between different categories of capex and between opex and capex.

5.61 The UR's proposals for output measurable capex in Fund 1 and for load-related expenditure in Fund 2 would involve a pass-through of differences between NIE's out-turn and forecast unit costs to the RAB after five years. This would mean that revenues would be adjusted to provide NIE with compensation for a substantial proportion of any overspend it incurs in relation to capex unit costs.

5.62 In contrast, there would be no similar mechanism in relation to overspend in relation to controllable opex. In effect, NIE would bear the full financial impact of its opex being above the regulatory forecasts but would be compensated if its asset replacement expenditure is above regulatory forecasts.

5.63 At the next price control review, there would be no guarantee that increases in NIE's opex would feed through to higher revenues in the subsequent price control period. The determination of a future allowance for NIE's opex may be partially or heavily influenced by the costs of other electricity companies as part of a benchmarking exercise, rather than simply being set using an extrapolation of NIE's own historical costs. An approach to cost assessment that gave weight to the results from benchmarking exercises, rather than NIE's historical costs, would limit NIE's ability to recover additional revenue at future price controls as a result of any cost increases it

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[8] ibid, p55.
[9] ibid, p240.

has experienced. The UR told us that it considered a benchmarking exercise necessary as part of price control reviews to meet the requirement of assessing whether NIE's costs are efficient.

5.64 There were also differences between different categories of capex. The UR's proposals for input-driven items within Fund 1 would involve no adjustment or pass-though for any differences between the costs NIE incurs for activities within this category. There would be no cost risk-sharing for this category of expenditure which implies a different regulatory treatment compared with output-measurable capex.

5.65 These differences may provide NIE with financial incentives to distort its working practices and accounting practices to favour specific categories of expenditure. There may be an opportunity for NIE to earn additional profits, at consumers' expense, simply from changes to working practices or accounting practices in a way that reallocates expenditure between categories. These risks seem particularly relevant to our inquiry given the concerns that the UR has raised about changes in NIE's capitalization practices in the past (see Section 15).

The UR's proposed opex outperformance rolling incentive

5.66 The UR's proposals were to introduce a new incentive scheme for opex which was a variant on the opex incentive allowance introduced by Ofwat at the 1999 periodic review.[10] The UR explained the aim of its proposals in relation to opex as follows:

> The rolling opex incentive proposed by the Utility Regulator for RP5 will allow NIE to keep controllable operating cost savings for (a fixed period of) five years, regardless of when in the control period the saving is made. We will however, where NIE over-spends on opex, confine any penalties to within the price control period. We believe this is a sufficient incentive to discourage the company from over-spending. This will be reinforced by ensuring that any such over-spends are not automatically reflected in the allowed revenue in the subsequent price control (RP6) – with the case for any such increases closely scrutinised.
>
> Our aim is to create an opex outperformance rolling incentive to ensure that NIE is not incentivised to maximise the period of time the savings are retained by making savings early in the regulatory period (with later savings perhaps deferred until the early years of the subsequent price control period to maximise potential outperformance revenue for the company).

5.67 The use of Ofwat's operating expenditure incentive allowance may provide a way to mitigate the UR's concern that NIE might make opex savings early in the regulatory period and might be discouraged from making savings later in the period. However, there are other ways to address that concern. Most importantly, the use of cost benchmarking analysis as part of cost assessment work can reduce the reliance placed on NIE's own historical costs in setting its price control, which limits this concern.

5.68 Further, Ofwat's operating expenditure incentive allowance should be seen in the context of the other elements of the regulatory framework in which it was applied. Ofwat's historical approach to the treatment of over- and underspends in relation to

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[10] Ofwat: Final determinations: future water and sewerage charges 2000–05, 1999, p91.

opex and capex is likely to have contributed to financial incentives for regulated water companies to favour capex over opex.

5.69 Ofwat has reviewed its own price control framework over the last few years and proposed extensive changes. It published a methodology paper in July 2013.[11] Ofwat said that it did not intend to retain the operating expenditure incentive allowance. Instead, Ofwat proposed a total expenditure or 'totex' approach. Under this approach, overspend and underspend in relation to operating would be treated the same way as for capex, with an 'efficiency sharing factor' determining the extent to which overspend and underspend against regulatory baseline levels of expenditure is passed through to consumers. Ofwat's proposals share similarities with the total expenditure approach developed by Ofgem. Ofwat was concerned that its previous approach to price control regulation introduced a bias in favour of capex.

Alignment of cost risk-sharing across opex and capex

5.70 We saw merit in better aligning the approach to cost risk-sharing—and hence efficiency incentives—across opex and capex. This regulatory approach has been applied by Ofgem to energy network price control reviews over the last few years and has also been proposed by Ofwat for its current review of water and sewerage price limits.

5.71 We decided on a form of cost risk-sharing in which we would specify a fixed percentage of the difference between the upfront allowances for NIE's expenditure requirements that we determined and NIE's actual expenditure which is to be passed through to charges to consumers via adjustments to NIE's maximum regulated revenue and RAB. The greater this percentage, the greater the extent to which NIE's actual expenditure is passed through to consumers. NIE's submissions identified this type of approach as a feasible option.

5.72 The approach of specifying a fixed percentage is more amenable to alignment of cost risk-sharing across capex and opex than an approach of making adjustments for out-turn expenditure after a delay of five years.

5.73 Ofgem's approach to the regulation of energy networks in GB uses a fixed percentage. It refers to the 'efficiency incentive rate', with a higher rate meaning less cost pass-through and greater financial exposure and efficiency incentives for the regulated companies. This efficiency incentive rate is effectively 1 minus the pass-through percentage outlined above.

5.74 One feature of the approach adopted by Ofgem (and supported by Ofwat) is that overspends and underspends in relation to opex would feed through and affect the level of the regulated company's RAB. Historically, the RAB for regulated companies such as NIE has been adjusted over time according to forecast capex and out-turn capex. The application of Ofgem's approach to NIE would represent a significant change in what the RAB represents.

5.75 In this light, we identified two options:

(a) implement cost risk-sharing in the same way for opex and capex, accepting that NIE's actual level of opex will affect the size of its RAB; and

[11] Ofwat 'Setting price controls for 2015–20: final methodology and expectations for companies' business plans', July 2013.

(b) maintain a policy that the RAB is only adjusted for forecast or actual capex. Under this approach the cost risk-sharing mechanism would be implemented through separate financial adjustments for capex and opex. Differences between forecast and out-turn capex would lead to an adjustment to NIE's RAB (and consequent adjustments to maximum regulated revenues). Differences between forecast and out-turn opex would lead an adjustment to NIE's maximum regulated revenue but no adjustment to NIE's RAB. The calculation of adjustments for opex and capex would be made with the aim of applying the same extent of cost pass-through in each case.

5.76 The first option would involve a lower risk that NIE faces financial incentives to distort its expenditure decisions (and cost reporting) in favour of capex. However, it would involve more substantial changes to the nature of NIE's RAB.

5.77 NIE told us that it was neutral regarding the choice between the two options in paragraph 5.75 above 'as long as the economic effect is the same'. However, we did not consider that the economic effect of these options on NIE is the same. While it is possible to make calculations to show that the net present value (NPV) of the effects of these two options could be the same, any calculations of this nature can only be approximate. We do not know NIE's precise valuation of the time value of money or its attitude towards any risks relating to the recovery of its RAB.

5.78 The UR raised concerns regarding intergeneration equity among consumers if the mechanism meant that variations in NIE's opex fed through to its RAB. The UR also told us that the first option in paragraph 5.75 might not be compatible with EU requirements for cost-reflective tariffs if the cost risk-sharing arrangement covered costs relating to the substantial investment required to accommodate renewable generation.[12]

5.79 We decided to adopt the approach under paragraph 5.75*(b)* above in which the cost risk-sharing arrangement operates through separate financial adjustments for opex and capex. We expect that, compared with current Licence conditions, our proposals would make a substantial reduction to the risk that NIE's incentives across opex and capex are not fully aligned—in particular, that NIE may have financial incentives to favour capex even where an opex solution would be more efficient. While some further reductions to that risk might be possible if we followed the approach under paragraph 5.75*(a)*, we were concerned that this would involve substantial changes in the nature of NIE's RAB which would not be easy to undo. The UR and NIE will have opportunities to give further consideration to a move to an approach to cost risk-sharing more in line with Ofgem's as part of the next price control review for NIE.

Concerns raised by the UR on proposed approach to cost risk-sharing

5.80 We shared some initial analysis on cost risk-sharing with NIE and the UR. The UR raised some concerns, particularly in relation to opex. We reviewed the UR's submissions and were satisfied that our approach remained appropriate. We provide more information on the concerns raised by the UR and our assessment of them in Appendix 5.2. In short, the UR was concerned that our proposals would: *(a)* weaken the incentives faced by NIE in relation to its opex; *(b)* introduce differences to the strength of financial incentives that NIE faces during the course of the price control period; and *(c)* fail to achieve consistent incentives across opex and capex.

[12] We did not investigate the UR's concern about compliance with EU requirements for cost-reflective tariffs as part of our inquiry. We decided that even leaving aside that concern, the approach favoured by the UR was preferable at this stage.

5.81 In its response to our provisional determination, the UR reiterated its view that, compared with the UR's final determination for RP5, our proposals would strengthen NIE's incentives in relation to capex and weaken them in relation to opex.[13] We did not consider that the UR's submissions on this matter raised new points that we had not considered in our provisional determination (including our assessment in Appendix 5.2). In particular:

(a) We disagreed with the UR's claim that our approach would halve NIE's financial incentives in relation to operating expenditure (compared with the UR's proposed approach). We did not accept the UR's argument that NIE would have insufficient financial incentives to improve its efficiency in relation to opex.[14]

(b) We considered that the UR's concerns were overstated. They overlooked the opportunities—which we have taken and which the UR could take when setting future price controls for NIE—to use the results of benchmarking analysis to set a price control for NIE that is not heavily dependent on NIE's historical expenditure.

5.82 We accepted that the cost risk-sharing mechanism and incentive structure that we have specified will not necessarily equalize NIE's incentives between opex and capex or ensure that NIE faces financial incentives to take decisions between opex and capex that are compatible with minimization of whole-life costs. We were not aware of any system of RAB-based price control regulation that does not entail some risk of distorting the regulated company's incentives between different categories of expenditure to some degree. Nonetheless, the approach we adopted—when taken in combination with our approach to cost assessment and benchmarking analysis—poses less risk of unduly distorting NIE's decisions between opex and capex than either *(a)* NIE's current price control Licence conditions or *(b)* the alternative approach proposed by the UR.

The extent of cost risk-sharing that is appropriate

5.83 We needed to decide on what percentage to use to calibrate the cost risk-sharing mechanism. We gave weight to regulatory precedent and two further factors. First, the greater the extent of pass-through, the more protection there is against cost forecasting and investment deferral risks (see paragraph 5.24). Second, if the extent of pass-through is too *high*, NIE may face insufficient financial incentives to *reduce* costs and operate efficiently. There is even a risk that NIE may have incentives to incur expenditure unnecessarily (eg in order to grow its RAB).

5.84 We: *(a)* consider regulatory precedent; *(b)* consider the parties' views; and *(c)* set out our determination.

Regulatory precedent

5.85 The most relevant regulatory precedent is from Ofgem's regulation of GB energy networks. Under Ofgem's approach, the efficiency incentive rate varies between companies: its exact value depends on Ofgem's decisions on whether to 'fast track' the price control review for the company (if it has a high-quality business plan) and on a regulatory incentive scheme relating to companies' business plans called the Information Quality Incentive scheme (or IQI). Accordingly, this means that Ofgem determines the approximate level of the efficiency incentive rate and hence—in the terminology we use here—the extent of cost risk-sharing.

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[13] UR response to provisional determination, paragraphs 28–31.
[14] UR response to provisional determination, paragraphs 29(b) & 31.

5.86 The most recent price controls that Ofgem set were for electricity transmission companies, the gas transmission company and the gas distribution companies from April 2013:

(a) For National Grid electricity transmission the efficiency incentive rate was set to 47 per cent and for National Grid gas transmission the rate was 44 per cent.[15]

(b) For the two Scottish electricity transmission companies, the efficiency incentive rate was 50 per cent.[16]

(c) For the gas distribution network companies, the efficiency incentive rates varied between 62 and 64 per cent.[17]

5.87 In its strategy decision for the next electricity distribution price control review, Ofgem proposed an approach in which the efficiency incentive rate would vary between companies within a range between 50 and 70 per cent.[18] This implies that the extent to which differences between forecast and actual expenditure is passed through to consumers would vary between companies in a range between 30 and 50 per cent. In the same document, Ofgem reports that the corresponding efficiency incentive rate in the current price control period, which started in 2010, was in a range of 53 to 59 per cent.

Parties' views

5.88 The UR submitted the following on the choice of incentive rate:

> We note that Ofgem and Ofwat have awarded high incentive rates to companies with good quality business plans and low incentive rates to companies where there has been less confidence in submitted plans. NIE T&D's RP5 plan is very clearly of the latter type and, as such, we would not expect the Commission to want to increase the financial rewards that NIE can earn in RP5 for beating its plan relative to the rewards that we proposed in our FD.

5.89 The UR told us that the implied efficiency incentive rate in its proposal was 30 per cent. This would represent an intention to pass through around 70 per cent of variations between forecast and actual costs to consumers.

5.90 In response to our provisional determination, the UR raised concerns with setting an implied efficiency incentive rate of 50 per cent,[19] as we had set out in our provisional determination. The UR said that it was concerned that this could prove to be an expensive experiment for consumers if NIE were to be able to abandon or defer substantial elements of its network investment plan.

5.91 Prior to our provisional determination, NIE submitted that an efficiency incentive rate of 30 per cent was appropriate for opex and capex, which it said was consistent with its previous proposals for capex.

[15] Ofgem 'RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas', December 2012, pp31 & 46.
[16] Ofgem 'RIIO-T1: Final Proposals for SP Transmission Ltd and Scottish Hydro Electric Transmission Ltd', April 2012, pp18 & 24.
[17] Ofgem 'RIIO-GD1: Final Proposals – Overview', December 2012, p29.
[18] Ofgem 'Strategy decision for the RIIO-ED1 electricity distribution price control: overview', March 2013, p34.
[19] UR response to provisional determination, paragraph 33.

5.92 NIE submitted that the efficiency incentive rates indicated by the regulatory precedent referred to above did not form a useful starting point for NIE for the purposes of our inquiry. NIE argued that because aspects of our approach to price control design differed from Ofgem's price control framework, we should not set a similar percentage to that implied by the efficiency incentive rate in Ofgem's recent decisions and proposals. NIE argued that our proposed arrangements to tackle concerns about the impact of investment deferral on consumers (section D3 below) were highly prescriptive and did not offer NIE the same degree of commercial freedom as for companies regulated by Ofgem.

Our determination

5.93 We considered these submissions carefully and determined a cost risk-sharing percentage of 50 per cent. This figure also represents what Ofgem would define as an efficiency incentive rate of 50 per cent. The choice of percentage is a matter of regulatory judgement. We gave particular weight to Ofgem precedent and an objective of ensuring that NIE's financial exposure to its costs was sufficiently high for it to avoid unnecessary expenditure and to have clear profit opportunities to improve the efficiency of its operations and investment.

5.94 Section 19 provides more information on how the cost risk-sharing mechanism should be implemented. This includes a specification of the costs that fall outside the scope of the cost risk-sharing mechanism. In addition, Section 16 discusses the interactions between the cost risk-sharing mechanism and the calculation of allowances for NIE's corporation tax liabilities.

5.95 Our decision will mean that there is substantially less pass-through of NIE's out-turn costs to consumers than proposed by the UR and NIE. We did not accept NIE's argument that the differences in our proposals and Ofgem's price control framework for electricity distribution companies implied that we should not take guidance from the efficiency incentive rate set by Ofgem and that we should instead choose a percentage that gives rise to a larger degree of protection to NIE against financial risk. We considered the Ofgem precedent relevant for our purposes because of a feature common to Ofgem's approach and our own: the objective of ensuring that regulated companies have sufficient financial incentives to reduce and restrain their costs. In line with Ofgem's approach, we did not consider the percentages proposed by NIE or the UR to be sufficient for these purposes.

5.96 The concerns that the UR raised in its response to our provisional determination are closely linked with the concerns raised by the UR about our treatment of investment deferral (see paragraphs 5.112 to 5.214). As discussed in paragraphs 5.81 and 5.82, we did not share those concerns to the same degree as the UR. Further, the concerns raised by the UR did not detract from the need to ensure that NIE faces sufficient financial incentives to operate and invest efficiently. We did not consider that the UR's alternative proposal of an efficiency incentive rate of 30 per cent was appropriate in that regard.

D2: Inefficient spend clause

Summary

5.97 We determined that NIE's Licence should include a provision that the UR can adjust NIE's maximum regulated revenue or RAB to protect consumers from exposure to costs incurred by NIE which the UR finds to be demonstrably inefficient or wasteful.

Introduction

5.98 The UR proposed an 'efficient spend clause' as part of its proposals for the different elements of NIE's capex. This would allow the UR to adjust NIE's regulated revenue and RAB to prevent consumers from being exposed to costs that the UR considered inefficient—perhaps in light of analysis from the UR's proposed reporter. NIE raised concerns about the ex-post nature of the UR's proposals and the regulatory risk it would face.

5.99 During the course of our inquiry, we established that the UR favoured a provision that would make clear that it could disallow from the calculation of NIE's price control any expenditure that was demonstrably wasteful. The UR was not seeking a clause that would penalize NIE for failing to achieve some hypothetical ideal or to make NIE's price control conditional on NIE's proof of its own efficiency.

Ofgem policy on demonstrably inefficient or wasteful expenditure

5.100 Ofgem includes provisions within its price control framework to make clear that it can make financial adjustments that have the effect of 'disallowing' the company from recovery of demonstrably inefficient or wasteful costs from charges to consumers.

5.101 For example, in its final proposals for a new price control for National Grid's electricity and gas transmission businesses, published in December 2012, Ofgem included the following in the Finance Supporting document:[20]

> Ofgem reserves the option to disallow costs from the RAV if they do not relate to the regulated business or are demonstrably inefficient or wasteful. We will specifically review all costs in relation to restructuring of a company's business or operations in relation to corporate transactions, including the associated redundancy costs to satisfy ourselves that these costs are efficient and will deliver future savings for the benefit of the consumer.

5.102 Similarly, in its strategy decision for a new price control for electricity distribution companies, Ofgem said that it 'reserves the option to disallow costs from totex and, hence RAV, if they do not relate to the regulated business or are demonstrably inefficient or wasteful'.[21]

Our determination

5.103 We considered that the Ofgem terminology of 'demonstrably inefficient or wasteful' expenditure seemed appropriate and consistent with the UR's intentions as clarified at the hearing in July 2013. Accordingly we determined that there should be a provision within NIE's Licence conditions which enables the UR to determine adjustments to NIE's maximum regulated revenues or RAB to protect consumers from exposure to any costs that the UR has found to be demonstrably inefficient or wasteful.

5.104 This clause will apply across all areas of NIE's expenditure. Although the UR's original proposals were in relation to capex, there seems no good reason to limit its application to capex: it should apply to all categories of NIE's expenditure. The

[20] Ofgem Final Proposals for NGET and NGG, p76.
[21] Ofgem 'Strategy decision for the RIIO-ED1 electricity distribution price control', March 2013, p63.

clause should apply regardless of whether NIE underspends or overspends in relation to regulatory forecasts.

5.105 Whilst NIE might face some 'ex post' financial risk under an inefficient spend clause of this nature, we do not consider NIE's exposure to such risk to be unreasonable in light of NIE's and the UR's duties.

5.106 By way of further clarification, we highlight two things that we would not expect to fall within the scope of such a clause:

(a) If something only turned out to be inefficient or wasteful with the benefit of hindsight, rather than with information reasonably available at the time, we would not expect it to be considered to be demonstrably inefficient or wasteful.

(b) The type of high-level econometric models used for benchmarking purposes in this inquiry, and by regulators such as Ofgem and Ofwat, can help produce estimates of a regulated company's expenditure requirements over a future period. The use of such models has desirable properties as part of a regime of incentive regulation because it can reduce the regulator's reliance on the regulated company's out-turn costs. However, such econometric models do not (by themselves) demonstrate inefficient or wasteful expenditure that is relevant to the clause above.

5.107 The UR told us that it supported the approach above. NIE also told us that it was content with this approach. NIE also asked for us to provide examples of the exceptional circumstances in which the inefficient spend clause might bite. We have not developed such examples. There is a danger in seeking to define the inefficient spend clause through hypothetical examples which inevitably abstract from many aspects that would be relevant to a factual investigation under this provision. We do not want to focus the scope of the inefficient spend clause on any particular examples that we might provide.

5.108 NIE also suggested that the principles above relating to the benefit of hindsight and the role of econometric models were very important and should be reflected in licence modifications. We agree.

5.109 In addition, NIE proposed that Licence modifications should include the following elements to reinforce our proposals above:

(a) a requirement that it should be for the UR to demonstrate that any particular item of expenditure was demonstrably inefficient or wasteful;

(b) a requirement that the UR raise with NIE any matters which it considered might lead to a determination that expenditure was inefficient or wasteful at the earliest opportunity that would enable NIE to take appropriate steps to prevent any further expenditure that might fall within the scope of the determination; and

(c) a requirement that, in any event, any determination that expenditure is inefficient or wasteful should be made no later than the conclusion of the UR's price control review for the period following that in which the expenditure was incurred or, in the case of expenditure that was not reported to the UR in the course of the price control review (eg because it post-dated the submission of NIE's business plan submission), within two years of the expenditure being incurred. (NIE said that it would expose NIE to unwarranted regulatory risk if the UR was able to reopen expenditure decisions many years after the expenditure had been incurred, and

when it was likely to be difficult for NIE to obtain evidence of the context and circumstances in which a particular expenditure decision had been taken.)

5.110 We agreed with the proposal in paragraph 5.109*(a)*: we thought this followed naturally from the way that we specified the clause above. We would expect the UR to publish a reasoned decision for any adjustment to NIE's maximum regulated revenue of RAB in light an assessment under the proposed inefficient spend clause.

5.111 While we accepted that the behaviour sought from the UR in paragraph 5.109*(b)* and *(c)* above would contribute to good administrative practice, we did not consider it necessary or appropriate to put such restrictions in place as part of modifications to NIE's price control Licence conditions. We expect that it would be in the UR's interests to address any concerns promptly because delays would tend to make it more difficult to collect the information necessary to justify any finding of demonstrably inefficient or wasteful expenditure. We did not consider it appropriate for us to give NIE an exemption from the clause if the UR has missed some interpretation of the 'earliest opportunity' or after a particular length of time.

D3: Measures to tackle risks from deferral of planned network investment

Summary of our determination

5.112 Under a system of RAB-based incentive regulation, NIE may have financial incentives to defer planned network investment projects with adverse financial consequences for consumers. We considered several options to mitigate this risk.

5.113 Our determination involves a policy that, at future price control reviews, there should be no double-funding of any deferred network investment. This will involve an assessment of the extent to which NIE's investment forecasts for the subsequent price control include expenditure that is needed because of deferral of projects and investment volumes identified in the forecasts used for our determination.

Introduction

5.114 We gave careful consideration to the risk that may arise under some forms of RAB-based price controls which concerns the potential opportunity for NIE to defer forecast investment projects to the detriment of consumers (see paragraph 5.24). In its RP5 final determinations and its submissions to us, the UR emphasized the importance of addressing this risk. At the same time, we also recognized that some investment deferral may be efficient.

5.115 In this subsection we:

(a) provide more information on the opportunity to defer planned projects to the detriment of consumers;

(b) list the different options we considered to tackle this risk and summarize our assessment of these options; and

(c) describe our approach in some detail and discuss the submissions that we received from the UR and NIE on this approach.

5.116 Appendix 5.3 provides further information and analysis of the options we considered.

Opportunity to defer planned projects to detriment of consumers

5.117 Unless a RAB-based price control involves full pass-through of any underspend against the regulator's upfront cost assessment, the regulated company may have a profit opportunity, or financial incentive, to spend less than envisaged at the price control review. Such profit opportunities can help encourage the company to operate and invest efficiently. However, there is a risk that the regulated company can profit from deferring or cancelling planned network investment projects, or reducing the volume of work it does on the network, to the detriment of consumers.

5.118 The following categorization is intended to illustrate in a simplified way one of the sources of this risk. We identify two (of several) possible purposes for expenditure that a regulated network company carries out during a five-year price control period:

(a) Some expenditure projects and volumes of work will be necessary within the five-year price control period to maintain services to electricity consumers, to deliver any specified 'outputs' or 'deliverables' required of the company under the price control, to comply with network design and planning standards, and/or to meet other legal obligations.

(b) There may be other expenditure projects and volumes of work which do not fall under *(a)* but which are nonetheless efficient or reasonable to carry out during the five-year price control period (eg in light of an appraisal of options on a whole-life cost basis). Such work may represent best practice asset management but its purpose is partly an economic one—achieving lower costs over the longer term—rather than one of simply maintaining services to current consumers and compliance with obligations. To take one example, a programme of planned asset refurbishment and replacement of overhead lines may be lower cost, over the long term, than case-by-case reactive replacement of specific assets which fail or are considered to be close to failure.

5.119 If the upfront cost assessment used in the calculation of the price control includes expenditure for the type of work under category 5.118*(b)* above, consumers may face charges that are intended to cover expenditure that the regulated company does not strictly need to carry out within that price control period. While it may be efficient for the company to carry out the work under 5.118*(b)*, if there is nothing to compel the company to do so, it may refrain from carrying out that work by delaying, scaling down or cancelling planned investment projects.

5.120 The scope for such investment deferral is linked to the fixed-term nature of the price control and the opportunity, at the next price control review, for the regulated company to make a fresh bid for the expenditure it needs over the following next price control period in light of the age and condition of its network assets. The potential harm to consumers arises not so much from the deferral itself but from the possibility that, as a result of the deferral, the company requires greater expenditure in the future, which may lead to higher charges to consumers in the future.

5.121 A further source of the risk relating to investment deferral arises from the possibility for different interpretations of the obligations that apply in relation to expenditure category 5.118*(a)* above. For instance, the regulated company might take one view of its safety obligations and determine that a particular substation on its network is unsafe and requires replacement before the end of the price control period. Another interpretation of its safety obligations may be possible in which the substation replacement can be deferred to the next price control period.

5.122 Finally, in considering the opportunity to defer planned projects to the detriment of consumers, we also recognize that there may be offsetting financial incentives and other factors that influence a company's behaviour. If the regulated company has included substantial work that would fall under category 5.118*(b)* above in its business plan submissions to the regulator at the price control review, and if the regulator's upfront cost assessment reflected those submissions, the company may be concerned that it will suffer reputational damage if it makes a large profit from deferring or cancelling those projects—which comes back to haunt it in some way at subsequent price control reviews. The regulated company may also build up a back-log of work needed on the network which there is no guarantee that it will be able to finance in the future. Further, depending on the details of the price control framework and the strategy of the company, the company may carry out some work that falls under category 5.118*(b)* because it faces financial incentives to invest as much as is reasonably possible in order to grow or maintain the value of its RAB.

Options identified to tackle investment deferral risk and our assessment

5.123 We considered a range of measures or options to help tackle this risk set out above (see Appendix 5.3 for more information):

(a) volume adjustment mechanism with volume cap;

(b) Ofgem outputs and secondary deliverables;

(c) NIE's proposed cap and collar mechanism;

(d) pass-through of network investment costs subject to a cap;

(e) capex allowance reflecting investment deferral risk;

(f) compliance with asset management documentation;

(g) no double-funding of deferred network investment; and

(h) 'do nothing'.

5.124 The breadth of options reflects the importance we gave to the concerns raised by the UR, NIE's strong criticisms of the UR's proposals, and the lack of an established and proven regulatory solution that was feasible for our inquiry.

5.125 We chose option *(g)*: no double-funding of deferred network investment. We summarize our assessment below and then describe option *(g)* in more detail. Appendix 5.3 provides more information on the other options, the main parties' submissions on these and our assessment of them.

5.126 We found that option *(b)* (Ofgem outputs and secondary deliverables) and option *(f)* (compliance with asset management documentation) were not feasible in the time-scale of our inquiry. The UR and NIE were both supportive of Ofgem's approach but it rests on detailed information about the condition of NIE's assets across its system. Neither NIE nor the UR considered it feasible to attain the information necessary to implement Ofgem's approach within the time frame of our inquiry. There currently exists no asset management documentation that would fulfil the role envisaged under option *(f)*. We did not consider it possible to develop such documentation during the time frame of our inquiry; NIE told us that this was not practical.

5.127 We did not consider that options *(c)* (NIE's proposed cap and collar mechanism) or *(d)* (pass-through of network investment costs subject to a cap) would provide sufficient financial incentives for NIE to avoid unnecessary expenditure and to improve the efficiency of its operations and investment. Both of these options would involve cost pass-through to consumers. Further, option *(c)* would provide particularly limited protection against the risks relating to investment deferral if the 'collar' in the scheme was not set close to the regulatory forecast of expenditure.

5.128 We saw some merit in option *(e)* (capex allowance reflecting investment deferral risk) but recognized that, while reducing risks of investment deferral to the detriment of consumers, it would be likely to lead to NIE missing opportunities to make investments that could help reduce costs to consumers over the long term.

5.129 The UR emphasized similarities between its favoured option *(a)* (volume-adjustment mechanism with volume cap) and our preferred option *(g)*. We found option *(g)* to be considerably better. It provides greater financial incentives for NIE to improve on the network investment plan used as the basis for our price control calculations: NIE would face financial incentives to defer investment where this is efficient and to abandon (or downsize) planned investment projects that are no longer needed. We consider these features of option *(g)* particularly desirable.

5.130 Further, we were concerned about the risk that option *(a)* would provide NIE with perverse incentives to skew its investment plan in favour of those categories of network investment that it is 'well paid' to do under the unit cost allowances underpinning the volume adjustment mechanism. We were also concerned about the potential need for an embedded reporter within NIE to help tackle that concern.

5.131 Finally, we considered whether our option *(g)* was better than a 'do-nothing option' and were satisfied that it is. As discussed further below, there is some risk that—compared with the do-nothing option—option *(g)* reduces the extent to which NIE would choose to reoptimize its network investment plan over the price control period. However, under option *(g)* NIE still has substantial freedom and incentive to adapt its investment plan over the price control period in light of changing conditions and new information. Any residual limitations on NIE's flexibility would be outweighed by the contribution it would make to the serious concerns that we have about investment deferral to the detriment of consumers.

5.132 We expect that option *(g)* would expose NIE to more financial risk than the do-nothing option. We did not consider this factor sufficient to lead us to prefer the do-nothing option. Under the do-nothing option we would expect NIE to have a much smaller exposure to financial downside in relation to the costs it incurs over the price control period than it has to financial upside in relation to these costs: NIE would have extensive opportunities to offset any unexpected cost increases (eg from unanticipated input price rises or abnormally high levels of faults) by scaling back investment in areas where it has scope for deferral. The financial risk to NIE seems more balanced under option *(g)*: whilst NIE would face some potential financial downside in relation to unexpected costs, it would also have significant opportunities for financial upside.

5.133 We describe our approach (option *(g)*) in detail in paragraphs 5.134 to 5.214 below. As part of the discussion we also consider a variation on it that was submitted by NIE during our inquiry.

Policy of no double-funding of deferred network investment

5.134 In this subsection we:

(a) provide more detail regarding our approach;

(b) discuss the need for clarity on planned investments as part of our determination;

(c) discuss efficiency and flexibility in network investment;

(d) consider interactions with the cost risk-sharing mechanism we have determined;

(e) consider possible financing adjustments in the calculation of pre-funded costs;

(f) specify annual reporting during the price control period;

(g) consider risks to effectiveness from potential 'rebranding' investment projects;

(h) note that questions about compliance with statutory obligations are separate;

(i) consider implications for regulatory framework at future price control reviews;

(j) compare our approach with that proposed by the UR;

(k) compare our approach with Ofgem's approach to network output measures;

(l) consider the UR's submissions on our approach;

(m) consider NIE's criticism of our approach; and

(n) consider NIE's proposed variation on our approach.

Our approach

5.135 The starting point for our approach is a recognition that the risk of NIE deferring network investment to the detriment of consumers stems in part from the opportunity for NIE to seek (and be allowed) additional revenue in subsequent price control periods to cover any costs it expects to incur to make up for the consequences of its investment deferral in the past.

5.136 The aim of our approach is not to prevent investment deferral—some of which may be efficient—but rather to protect consumers from adverse financial consequences in the event of investment deferral. Our approach is based on an expectation that, at future price control reviews, the regulatory determination of NIE's price control and RAB should be done by reference to a policy that there should be no double-funding of deferred network investment. The cost assessment carried out at the next price control review should seek to protect consumers from exposure to costs arising from deferral of investment planned for the period to 30 September 2017.

5.137 This will be achieved in practice through a clear specification of volumes of investment included in forecasts used to set the price control, regular reporting of volumes during the price control period and potential deductions for 'pre-funded costs' as part of the assessment of NIE's expenditure forecasts at the subsequent price control review. This, in turn, requires that, as far as possible, the price control we determine for the period 1 April 2012 to 30 September 2017 involves a transparent reconciliation between the overall capex forecast used to calculate the price control and NIE's investment plans for specific verifiable network investment projects

5.138 We envisage that, as part of the planned price control review for the price control period from October 2017, NIE would be asked to submit to the UR two numbers as part of its network investment or capex proposals:[22]

(a) *Forecast network investment.* This is NIE's estimate of its expected network investment requirements for the price control period from 1 October 2017 to 30 September 2022.

(b) *Pre-funded costs.* This is an estimate of the value of network investment under *(a)* that does not need to be included as part of the calculation of price controls from 1 October 2017 because it has already been included as part of the network investment requirements—and network investment strategy—that we have assumed for the purposes of setting the price control from 1 April 2012 to 30 September 2017.

5.139 The identification and deduction of the number in *(b)* is intended to provide protection to consumers against the risk that, in the future, they face charges which reflect forecasts of the costs of work that NIE needs to carry out in the period from 1 October 2017 as a consequence of deferral or abandonment of projects that NIE planned to carry out in the period from 1 April 2012 to 30 September 2017.

5.140 We do not consider the assessment of pre-funded costs under *(b)* to be a purely mechanistic exercise of comparing volumes of different types of network investments. It would be a partly qualitative exercise, drawing on information on how NIE has adapted its investment and asset management over time. Any shortfalls against planned volumes should be considered as potential pre-funded costs, but further review would be needed and NIE should have an opportunity to assess whether specific shortfalls qualify as pre-funded costs (eg such shortfalls would not lead to pre-funded costs if they have not increased future investment requirements, perhaps because circumstances changed or NIE addressed the need for the planned investment in a different way).

Clarity on planned investments as part of our determination

5.141 To implement our approach, we needed to clarify the assumptions on NIE's network investment requirements that underpin our price control determination. To meet this aim, our price control determination specifies the 'planned investments' that we use to calculate the price control and which reconcile to our overall allowance for capex. Appendices 9.2 and 9.3 set out the projects and highlight the planned investments that underpin the upfront allowance for NIE's network investment that we determined in Section 9. These planned investments can then provide a reference point for the estimation of pre-funded costs at the next price control review.

5.142 As part of the next price control review, the UR will need to review and, if necessary, revise NIE's estimates of pre-funded costs by reference to the asset management assumptions we used in the calculation of the price control from 1 April 2012 to 30 September 2017 and information on NIE's out-turn investment volumes in that period.

5.143 There is a practical issue concerning the timing of work on the next price control review. Work by NIE and the UR to set a new price control to apply from 1 October 2017 will need to be completed before full information is available on out-turn vol-

[22] We assume that this is a new five-year control but nothing turns on this assumption about the duration of a future price control period.

umes and projects in the price control period to 30 September 2017. We envisage that the new price control from 1 October 2017 will be calculated on the basis of the best available forecasts of the out-turn volumes for the remainder of the existing price control period and that any shortfalls in out-turn volumes against those forecasts are taken into account in the use of any ‘no double-recovery’ principle in setting the subsequent price control.

Efficiency and flexibility in network investment

5.144 Our approach is not intended to tie NIE to the delivery of a series of investment projects that it has planned or forecast as part of the price control review process. NIE will not face financial penalties for deviating from the investment plan used as part of the price control review.

5.145 If NIE carries out less network investment than envisaged in the plan used to calculate the price control, it could face financial consequences as part of the calculation of the subsequent price control. These consequences would be limited and forward-looking: NIE will only be financially exposed to planned network investment which was not done and which is still needed in the future.

5.146 NIE will have clear financial incentives to depart from its plan in a way that enhances the efficiency of its investment programme. For instance:

(a) *Efficient deferral of planned investment.* If NIE can defer planned asset replacement projects without increasing expected costs over the long term (and while still complying with statutory obligations, etc), it could benefit financially.[23] The opportunities for NIE to benefit financially from deferral would be conditional on the efficiency of the deferral. NIE would not have a financial incentive to defer planned investment projects simply to exploit features of the price control framework and increase its own profits.

(b) *Abandonment of unnecessary projects.* If NIE identifies a planned investment project that turns out to be unnecessary (eg replacement of transformer capacity that is no longer needed due to changes in the location of demand) it would benefit financially from abandoning that investment project, in line with our proposed sharing of cost savings determined by the cost risk-sharing mechanism (see paragraph 5.49) .

(c) *Downscaling over-specified projects.* If NIE identifies that a planned investment project could be scaled down in size, without any adverse long-term impact, the proposal could provide NIE with a financial incentive for NIE to do so.[24]

(d) *More efficient way to meet need for investment.* If NIE identifies an alternative way to meet the need for a planned project by carrying out a different network intervention at lower cost, it would have financial incentives to do so.[25]

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[23] Examples of efficient deferral include cases where NIE can defer an investment without any increase in long-term costs, and also cases where NIE can defer investment where the financial benefits from deferral (eg annual financing costs of investment) outweigh any additional costs arising from deferral (eg higher maintenance costs to keep older assets in service or a small possibility of having to replace an asset at relatively high cost in fault or emergency conditions).

[24] For example, NIE might forecast reductions in the demands on its system in a specific location and that find it possible to meet asset replacement needs through the installation of a transformer with lower capacity than planned. NIE could explain how the installation of the lower-capacity transformer addressed the planned need for a higher-capacity transformer and exclude the underdelivery of the higher-capacity transformer from the calculation of its pre-funded costs.

[25] For example, suppose that NIE had identified in its investment plan that a category of substations was unsafe because of features of its design, and had planned asset replacement on safety grounds before the anticipated end of the economic life of

5.147 A common feature of the opportunities above is that they relate to NIE adapting its plan in a way that it means it carries out less network investment than anticipated in a particular area.

5.148 We also considered the potential for NIE to adapt its plan in a way that it means it carries out more network investment than anticipated in a particular area. In some circumstances, NIE could carry out unanticipated investment without any adverse financial impact on NIE:

(a) While parts of NIE's plan are built up from the identification of specific network assets that require replacement, the planned investments that we would use to calculate the price control would relate to volumes of particular categories (eg 110 kV/33 kV transformers). NIE would have flexibility as to which specific assets within each category to replace, and could reprioritize within categories according to changing conditions and new information. We consider that NIE's opportunities to reprioritize in this way will be substantial.[26]

(b) Our allowances for capex include allowances for investment that falls under what NIE describes as fault and emergency work and reactive work. For these categories of investment, we do not specify planned investments that could fall under the calculation of pre-funded costs at future price control reviews. In effect, these allowances provide a contingency for unanticipated investment.

(c) For some other elements of NIE's investment plan it was not practical, based on the information available to us, to specify planned investments in terms of volumes of investment for specific types of network intervention or improvements at specified locations. This represented a small but significant proportion of the investments feeding into the allowance we determined for NIE's network investment direct costs. NIE would be able to scale down its planned investment in these areas without any effect on the calculation of pre-funded costs at the next price control review. While this reflects a limitation of our approach, it also provides some further financial contingency to NIE.

5.149 In other circumstances, it is possible that NIE may face an adverse financial impact from carrying out unanticipated investment. We can distinguish two scenarios:

(a) NIE might consider it necessary (eg due to safety obligations) to incur the unplanned investment and adapt its plan accordingly. Our proposal would not prevent NIE from adapting its plan in these circumstances. NIE's investors, would however, face some financial downside as a result of the unforeseen events that necessitate the change in plan.

(b) NIE might avoid a change in its plan that, whilst representing an efficiency improvement, would not be profitable for NIE. In this case, the economic effects our proposal could be to prevent NIE from adapting its plan.

5.150 In light of *(b)*, we accept that—compared with the 'do-nothing' option—our proposed approach is likely to reduce, to some degree, the extent to which NIE chooses to re-optimize its network investment plan over the price control period. However, for the reasons set out above, we consider that NIE would still have substantial freedom and

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these assets. Under our approach, NIE would have financial incentives to find ways to address the safety issues more efficiently (eg some form of innovative asset refurbishment may be possible).

[26] In our cost assessment, we have made limited reductions to the volumes forecast by NIE. BPI's report for us on NIE's investment plan supports the view that some of NIE's planned investment, whilst reasonable on a long-term economic and engineering basis, will not be strictly required in the period to September 2017 to maintain services to current consumers and comply with legal obligations.

incentive to adapt and improve its investment plan over the price control period in light of changing conditions and new information.

Interactions with cost risk-sharing mechanism

5.151 The implementation of a principle of no double-funding of deferred investment requires consideration of the cost risk-sharing mechanism discussed above in section D1 (paragraphs 5.49 to 5.96). With such a mechanism in place, the extent to which NIE is 'funded' for costs it has incurred depends not only on the regulatory expenditure forecasts used to calculate the price control but also on NIE's actual expenditure.

5.152 Our approach would work in the most straightforward way if there is stability from one price control period to the next in the extent of cost pass-through under the cost risk-sharing mechanism. We suggest that unnecessary changes to the extent of cost pass-through are avoided as far as possible.

5.153 If a change is made to the extent of cost pass-through in the next price control period, a financial adjustment would be required to offset that change in order to achieve the objective of no double-funding of deferred investment when viewed across multiple price control periods. That financial adjustment would be dependent on the level of pre-funded costs (paragraph 5.138) and the scale and direction of the change in the cost risk-sharing percentage.[27] The purpose of the financial adjustment would be to neutralize the effect of the change in the cost risk-sharing percentage from one price control period to the next on the treatment of costs arising from deferred investment.[28] To achieve its intended effect, any such financial adjustment should not be made to the regulatory expenditure allowances for the period from 1 October 2017 (which would themselves be subject to the cost risk-sharing mechanism), but rather as a separate adjustment to the calculation of NIE's maximum regulated revenues that is not subject to the cost risk-sharing mechanism.

5.154 We would expect it to be difficult to justify the introduction of a new revenue control that involves deductions against an NIE investment plan according to our policy on no double-funding of deferred network investment while failing to consider the impact of a change in the cost risk-sharing percentage.

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[27] We can illustrate the need for such an adjustment using a simplified example. Suppose that the capital expenditure allowances used in our determination include a planned investment project to tackle safety issues at a specific substation, with a cost of £1 million (2009/10 prices). Suppose that NIE defers that project to the period after 1 October 2017. Suppose that, as part of the next price control review, NIE includes that project in its investment plan for the period from 1 October 2017 at a cost of £1 million (2009/10 prices). If the cost risk-sharing percentage is maintained at 50 per cent for the period from 1 October 2017, then the £1 million costs of that project should be treated as pre-funded costs and excluded from any forward-looking capital expenditure allowances used to set a new price control from 1 October 2017. However, if the cost risk-sharing percentage is changed so that a greater proportion of NIE's out-turn costs is passed through to consumers, a deduction of £1 million of pre-funded costs would be insufficient to achieve the objective of the no double-funding policy. In those circumstances, NIE would have deferred a project worth £1 million but consumers would still fund £0.5 million of these forecast costs through the cost risk-sharing mechanism applicable in the period to 30 September 2017. If the £1 million project cost is excluded from the calculation of NIE's price control from 1 October 2017 but NIE benefits from pass-through of, for example, 70 per cent of its out-turn costs from 1 October 2017, consumers would face changes of an additional 0.7 million when NIE completes that project. The total consumer funding for the project would then be £1.2 million which includes an element of double-funding which arises from a failure to take account of interactions between pre-funded costs and changes in the cost risk-sharing percentage.

[28] For instance, in the example above we could calculate a financial adjustment as the value of pre-funded costs (£1 million) multiplied by the difference in the extent of cost pass-though from one price control period to the next (70 per cent minus 50 per cent = 20 per cent). This gives a financial adjustment of £0.2 million which should be deducted from NIE's revenue allowance for the period from 1 October 2017. Similarly, if the cost risk-sharing percentage was changed so that only 30 per cent of variations in out-turn costs were passed through to consumers, a £0.2 million increase in NIE's revenue allowances would be appropriate to ensure that the deduction for pre-funded costs is not excessive.

No financing adjustments in calculation of pre-funded costs

5.155 We considered whether the calculation of the value of pre-funded costs to be netted off NIE's investment requirements in setting the price control from October 2017 should include some allowance for the financing costs. We did not consider such an adjustment to be appropriate or consistent with the overall approach. The purpose of our approach is to protect consumers from adverse financial consequences from investment deferral. The aim is not to remove from NIE's RAB money that it did not actually spend, but rather to ensure that the subsequent price control does not expose consumers to additional costs for planned work that NIE avoided in the previous price control period.

5.156 This aspect of our approach does not address the risk that the capex allowance used to set NIE's price control is too high because it overlooks opportunities for efficient deferral of planned expenditure. Further, it provides no protection to consumers against the risk that the price control is calculated to include an investment project that never in fact needs to be done. We sought to tackle these risks, as far as possible, through our assessment of NIE's capex requirements (see Section 9). We have also taken these issues into account in our review of the criticisms of our approach raised by NIE in its response to our provisional determination.

Annual reporting during price control period

5.157 Our approach involves some administrative and regulatory burden. It relies on reliable records of the volumes of network investment carried out by NIE in each year of the price control period. However, much of this information is needed for other regulatory purposes. These include: *(a)* ensuring that there is better information available on NIE's unit costs and volumes at the next price control review; *(b)* supporting benchmarking analysis with GB electricity distribution companies; and *(c)* providing greater transparency on NIE's costs and investments to stakeholders.

5.158 The estimation of the value of pre-funded costs will be an important part of the new price control framework we established in the current inquiry. However, it would not be used directly for several years. There is a risk that it is neglected and also that, when it does come to be needed, practical difficulties are found in calculating or verifying it.

5.159 To tackle this concern, NIE must report to the UR during each year in the period to 30 September 2017 a provisional estimate of both forecast network investment for the subsequent price control period and the value of pre-funded costs. To support this, NIE must also report reliable information on out-turn volumes of network investment to date and volume forecasts for the remainder of the period to 30 September 2017.

5.160 Reporting volume information on an annual basis, rather than leaving it to the next price control review, would help to reveal and resolve any problems or concerns as to the reliability and consistency of data reported.

5.161 Further, it will be important that the estimates of pre-funded costs (and the data which underpin them) are maintained for subsequent price control periods: it should not be reset to zero after each price control review. For instance, it is necessary to ensure that investment deferred from the price control running to 30 September 2017 is not funded twice in either a new price control from 1 October 2017 or a new price control from 1 October 2022 (and so on).

5.162 The UR asked how our proposal would work with planned projects that were only partially completed by the end of the price control period. We envisage that if NIE has started a project but not completed it during the period to 30 September 2017, we would not normally expect NIE to include it in its investment plan for the period from 1 October 2017. However, if it does so, it should also be included in the calculation of pre-funded costs. A feature of our proposed approach is that the exact time at which investment is carried out by NIE is not critical as long as a consistent approach is taken, for each investment, in the investment plan covering a price control period and the estimation of pre-funded costs for that period.

Risks to effectiveness from potential 'rebranding' investment projects

5.163 We recognized that our approach may not fully address the risk that NIE defers planned investment projects to the detriment of consumers. There may remain some opportunities for NIE to defer planned investment and yet impose additional costs on consumers during the subsequent price control period for investment that is needed as a direct result of that deferral. In particular, different project descriptions or changes in asset management practices might mean that at the subsequent price control review NIE can 'repackage' or 'rebrand' work in a way that limits the effectiveness of the approach.

5.164 We did not consider that these issues invalidated our approach. We have not sought to identify a hypothetical ideal scheme, but rather the best practicable approach. Even accepting some risks from the potential for rebranding, we considered that our approach should make a major contribution to the price control framework for NIE and that it was preferable to the other options that we identified. Further, we expected that there will be opportunities for the UR to reduce any concerns about 'rebranding' by carrying out a critical review of NIE's assessment of pre-funded costs as part of the next price control review.

Separate treatment of questions about compliance with statutory obligations

5.165 The aim of the scheme set out above is to protect consumers from adverse financial consequences in the event of investment deferral, not to prevent investment deferral (some of which may be efficient).

5.166 In some circumstances, investment deferral might raise questions about NIE's compliance with its obligations to maintain and operate an efficient network and with its safety obligations. For instance, if NIE identified a particular 11 kV four-pole substation as high risk and requiring replacement, there may be a question as to its compliance with its safety obligations if, five years later, it has not replaced that substation.

5.167 The approach set out above is not intended to ensure NIE's compliance with its statutory and safety obligations. Although it is possible that the data reported as part of the approach might indicate areas of concern, any investigation of potential breach of safety and other obligations would be a separate matter.

Implications for regulatory framework at future price control reviews

5.168 Our approach has implications for the cost assessment at the next price control review for NIE. As set out above, it would be necessary to take any pre-funded costs into account for the purposes of setting that establishing a new price control applicable from 1 October 2017 that meets the policy of no double-funding of deferred investment.

5.169 Our approach does not constrain other aspects of the way that a new price control is established from 1 October 2017. NIE said that it was anxious that the adoption of such an approach did not jeopardize the effective operation of a price control model based on Ofgem's use of outputs and secondary deliverables for future price control periods. It is not our intention to jeopardize any potential use of such a model and we do not consider that the approach we have chosen would do so.

Comparison with the UR's approach

5.170 There are some similarities between the approach set out above and the UR's proposals for a volume adjustment mechanism under its output-measurable Fund 1 approach. Both approaches involve financial adjustments calculated as part of the subsequent price control review in light of a comparison between the forecast volumes of network investment used to calculate the original price control and the volumes of network investment that NIE actually carries out during the price control period.

5.171 There are, however, several important differences. The purpose of the adjustments at the subsequent price control review under the UR's proposals is to deny NIE financial benefits from any past deferral of planned investment. The purpose of the adjustments required under the approach set out in this section is to prevent consumers from exposure to additional costs that are attributed to any past deferral of planned investment.

5.172 The two approaches differ in terms of the financial consequences of NIE carrying out greater volumes than forecast for some categories of network investment.

5.173 The approach set out in this section would not allow NIE to offset the financial impact of greater than expected volumes in some categories of network investment (eg 33 kV overhead line refurbishment) with reductions to the volume of investment in other categories (eg 11 kV overhead line refurbishment). However, it would allow flexibility for NIE to reprioritize within categories without any adverse financial consequences (eg to select which particular 11 kV circuits to refurbish or which particular 110 kV/33 kV substations to replace).

5.174 The UR's proposed approach would provide a financial framework under which NIE could substitute between different categories of network investment in ratios relative to the regulatory assessment of the unit costs of work in those categories. This aspect of the UR's proposals poses risks of providing NIE with perverse financial incentives to carry out more network investment than necessary for those categories of network investment where the regulatory unit cost allowance is such as to provide an attractive profit opportunity for NIE. The UR's proposals for an embedded 'reporter' within NIE seem to be a necessary part of its approach, to help mitigate these risks.

Comparison with Ofgem approach to network output measures

5.175 Both NIE and the UR told us that, while not feasible for our inquiry, for future price control reviews they would like to adopt an approach to the regulation of NIE's network investment that used Ofgem's approach of network output measures and secondary deliverables (eg asset health indices). We considered how our decisions compare with Ofgem's approach.

5.176 Our approach shares some similarities with Ofgem's approach to network investment. For instance, Ofgem said the following in its initial proposals for a new price control for National Grid Electricity Transmission and National Grid Gas:[29]

> If a company achieves above target or below target against the NOMs [network output measures] target, it would need to justify this variance in its RIIO-T2 business plan. We would still take the RIIO-T1 NOMs target as an opening position when setting out the allowance for the company to deliver its RIIO-T2 NOMs target. This ensures that any under-delivery is not funded twice, and that any over-delivery receives funding.

5.177 Put differently, Ofgem proposed to calculate the subsequent price controls for National Grid (these controls are called RIIO-T2) in a way that did not provide it with any additional funding for shortfalls or under-delivery against what was envisaged in setting its initial price controls (RIIO-T1).

5.178 However, there are important differences with the approach above. In its submissions to us, NIE sought to stress that our approach was different in important ways.

5.179 Ofgem's approach seeks to measure underdelivery by reference to measures of the condition of specific network assets, whereas under the approach above the measure of underdelivery would be made by reference to the volumes of planned network investment projects. The Ofgem approach pays more attention to the benefits from planned investments (eg improvements to the condition of network assets) than to the planned investment projects themselves.

5.180 Using measures of asset condition may provide for greater flexibility for the regulated company to substitute and reprioritize network investment between different categories of work than the approach set out above. However, neither NIE nor the UR considered it feasible to provide the type of information that the Ofgem approach relies on within the time frame of our inquiry.

5.181 NIE argued that another difference between our approach and Ofgem's was that Ofgem would 'intervene' in more limited circumstances, where it found a material 'network outputs gap'.

5.182 Ofgem's approach is still evolving and its use of asset condition data has not yet been tested through one complete price control period. The UR suggested that it was possible that Ofgem made adjustments to GB DNOs' allowed revenues not only in light of data on asset condition but also in light of comparisons of the volumes of asset replacement projects delivered against the volume forecasts at the previous price control period. The UR highlighted that Ofgem's approach also involved detailed reporting of actual replacement volumes and unit costs.

5.183 Similarly, we recognize a possibility that the differences between the approach that Ofgem takes in the future and the approach discussed above (or the volume adjustment mechanism proposed by the UR) may turn out to be less substantial than they appear from the documents published by Ofgem to date.

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[29] Ofgem RIIO-GD1: Supporting document: Outputs, incentives and innovation, July 2012, p109.

The UR's submissions on the approach

5.184 Before publishing our provisional determination, we shared with the UR and NIE our analysis and options in relation to the risks to consumers from investment deferral.

5.185 The UR compared the approach set out above with the volume adjustment mechanism that it had proposed. It said that the two schemes were 'more similar than they are different' and that both were far superior to the other options we had identified. Nonetheless, the UR said that it preferred its original proposal because our approach:

(a) does not prevent NIE from earning considerable profits from proposing an unnecessary project and then cancelling it. The UR said that its proposed approach would prevent NIE from profiting from the cancellation of planned capital investment;

(b) would consciously give NIE a financial reward for deferring planned investments. The UR said that there could be a large scale of deferral and that NIE could profit between £1 and £10 for every £100 of capex that it deferred;

(c) would fail to protect consumers from 'instances of outright double-counting'. The UR said that 'insistence that NIE T&D should only be paid for completed and verified volumes is the only way to ensure that consumers don't pay twice'; and

(d) would be vulnerable to the 'rebranding' issue we raised above and may not be fully effective.

5.186 We do not agree that these points indicate the superiority of the UR's proposals. Points *(a)* and *(b)* in fact reflect desirable incentive properties of our approach. Since NIE could profit from the cancellation of planned capital investment projects, it would have a financial incentive to cancel projects that turn out to be unnecessary. Further, because NIE could profit from deferral of planned projects, it would have a financial incentive to defer planned investment projects where it is efficient to do so. The cost risk-sharing arrangement that we have proposed in section D1 means that consumers would benefit from cost savings achieved by NIE in this way.

5.187 Paragraph 5.185*(a)*, *(b)* and *(c)* also reflect the risk that the upfront expenditure forecast that we use to calculate the price control for NIE is too high. We accept that this risk exists but consider that the UR's proposed approach is a disproportionate response to it which would have adverse effects for NIE's efficiency of operations and investment. We sought to mitigate the risk that the upfront expenditure forecast is too high through our cost assessment work described in Sections 7 to 10.

5.188 We accept the existence of concerns in paragraph 5.185*(d)* but we do not consider them sufficient to prevent our approach from being the best of the feasible options. We do not expect that there would be systemic opportunities for NIE to escape the intention of the scheme through such rebranding, especially when the scheme does not apply mechanistically and instead involves an assessment of pre-funded costs by NIE which would then be reviewed by the UR.

5.189 Following publication of our provisional determination, the UR provided some further comments on our proposed approach. It told us that it believed that the approach we had proposed in our provisional determination would provide 'too great an incentive for NIE T&D not to do the work that it has said it will do'.[30] However, it was not our intention to develop a scheme that would ensure that NIE undertakes the investment that it had originally planned to do. We did not think that such a scheme would be in the interests of consumers. We do not want NIE to be required to deliver on its original investment plan. Such work may be unnecessary, overscoped or capable of deferral without adverse consequences. Our approach pursues a different objective which is to protect consumers from adverse financial consequences that might otherwise arise from any investment deferral.

5.190 The UR said that it thought that the effect of our proposed approach would be to encourage NIE to replace its current business plan with a 'do minimum' alternative, configured in such a way as to extract the maximum profit for shareholders out of the RP5 determination.[31] The UR did not elaborate on what the 'do minimum' alternative would entail. For capital expenditure that falls under our no double-funding policy, we would expect NIE to have financial incentives to defer investment where deferral is efficient, and to cancel or downsize projects that are not necessary. Our approach would encourage NIE to avoid unnecessary investment: we consider that to be a benefit. We have not identified any reason to think that our approach would provide NIE with a financial incentive to reduce its investment to a minimal level that would compromise the reliability of NIE's system or prevent NIE from investing in a way that is efficient from a long-term perspective.

5.191 The UR suggested in its response to our provisional determination that 'it is entirely realistic' to think that NIE could underspend its capex allowance by £100 million through a mix of investment deferral and abandonment and that NIE would profit by around £25 million from deferral of this scale.[32] The UR said that such an opportunity was not in the public interest.[33]

5.192 The UR's calculation of £100 million rested on an interpretation of BPI's assessment of NIE's investment plan that we did not accept (see paragraphs 9.28 and 9.29). We did not include any investment within our capex allowances that we knew could be deferred without increases in overall costs whilst still enabling NIE to meet its various obligations (eg safety).

5.193 We accepted that it was conceivable that NIE's out-turn capex over the period 1 April 2012 to 30 September 2017 could be substantially less than our capex allowances for that period. However, it was also conceivable that NIE's out-turn capex over the period 1 April 2012 to 30 September 2017 could be substantially greater than our capex allowances for that period. We took these issues into account in our response to NIE's criticisms of our approach (see paragraphs 5.196 to 5.211).

5.194 The UR's main suggestion in light of these issues was that we should change the cost risk-sharing mechanism to increase the extent to which NIE's actual costs would be passed through to consumers and improve reporting arrangements to enable the UR to identify deferrals where they took place.[34] We set out our decision on the cost risk-sharing mechanism in paragraphs 5.49 to 5.96. We did not accept the UR's suggestion of an efficiency incentive rate of 30 per cent (equivalent to pass-through of 70 per cent of differences between out-turn costs and our upfront allowances). We were concerned that this would provide insufficient financial incentives for NIE to operate and invest efficiently.

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[30] UR response to provisional determination, paragraph 36.
[31] ibid, paragraph 39.
[32] ibid, paragraph 40.
[33] ibid, paragraph 41.
[34] ibid, paragraph 10.

5.195 We made one change to our approach following the UR's response to our provisional determination on the issue of investment deferral. This was to remove the upfront expenditure allowance for some investment projects to increase transmission system capacity. Instead these projects will fall within the scope of the provision to allow the UR to adjust NIE's maximum regulated revenue and RAB to accommodate additional transmission capacity projects. This change is discussed further in subsection D5 (paragraphs 5.246 to 5.279).

NIE's criticism of our approach

5.196 Before our provisional determination, NIE provided a detailed response to our preliminary work on the approach proposed above. NIE raised the following concerns:

(a) Our approach would remove any incentive for NIE continuously to optimize the network in a way that both met outputs and drove down total cost for the long-term benefit of consumers.

(b) Our approach provided limited opportunity for NIE to reoptimize its network and adapt its investment in light of new information, external factors and new technology.

(c) Our approach would not provide a mechanism for NIE to be fully remunerated for investment that was not anticipated in the investment plan used to calculate the price control.

5.197 NIE's submission also explained why its investment plans might change over time and the need for unplanned network investment.

5.198 We considered NIE's claims on points *(a)* and *(b)* above to be overstated. As discussed above in paragraphs 5.144 to 5.150, NIE would have clear financial incentives to abandon or downscale planned projects that are not necessary and take opportunities to defer planned investment where this is efficient.

5.199 Nonetheless, we accepted that there is some risk that (compared with the do-nothing option) our approach could reduce, to some degree, the extent to which NIE would choose to reoptimize its network investment plan over the price control period. However, for the reasons set out in paragraphs 5.144 to 5.150, we considered that NIE would still have substantial freedom and incentives to adapt its investment plan over the price control period in light of changing conditions and new information. We considered that any residual limitations on NIE's flexibility would be outweighed by the contribution that our approach would make to the serious concerns that we have identified about investment deferral to the detriment of consumers.

5.200 NIE also criticized our approach in its response to our provisional determination.[35] It said that our approach would unduly limit its flexibility to manage its network investment in response to unforeseen developments that occur during the price control period. NIE said that its concern related to unforeseen developments which could not be met simply by reprioritizing work within existing programme categories. NIE said that whilst we acknowledged the need for flexibility, the approach proposed in our provisional determination did not allow flexibility to the extent that we claimed, and that our position was inconsistent and irrational. We had identified in our provisional determination a number of ways in which our proposed approach would provide flexibility to NIE and NIE disputed each of these.

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[35] NIE response to provisional determination, pp149–151.

5.201 Following NIE's response to our provisional determination, we gave further consideration to concerns raised by NIE about the costs of unforeseen developments that may occur during the price control period. We identified two questions:

(a) What is the potential scale of NIE's financial exposure to the costs of unforeseen developments affecting its asset replacement requirements?

(b) Do our capex allowances already provide sufficient contingency or opportunities that would enable NIE to offset such costs?

5.202 In January 2014, we asked NIE for further information on the costs of unforeseen developments that have arisen but which were not included in NIE's January 2011 investment plan, which formed the basis of our assessment of NIE's core network investment requirements in Section 9. This question covered costs that have arisen in a period of three years. NIE identified the following unforeseen developments in relation to asset replacement:[36]

(a) 110/330 kV transformer: Dungannon Main (approx cost £0.9 million);

(b) 275 kV current transformers (approx £0.1 million);

(c) disconnectors: Hannahstown Main (approx £0.6 million);

(d) Fuller Type F tap changers (approx £0.2 million);

(e) 110 kV surge arrestors (approx £0.1 million); and

(f) disconnectors: reactors (£0.1 million).

5.203 NIE told us that in total approximately £3.7 million of unforeseen asset replacement work had arisen to date (the specific examples that NIE cited amounted to £2 million[37]).

5.204 We also asked NIE to indicate the scale of expenditure which it must incur in the period from 1 April 2012 to 30 September 2017 which was not included in NIE's original investment plan that it had submitted to the UR in January 2011. NIE estimated that a provision of around £10 million should be made for such unforeseen developments.[38]

5.205 In considering the potential financial effect on NIE, we must also take account of the cost risk-sharing mechanism under which 50 per cent of variations in NIE's out-turn costs will be passed through to consumers. Of the specific unforeseen developments that NIE cited, as listed above, NIE would have a financial exposure of only 50 per cent of the costs it incurs, which is around £1 million. If the overall scale of unforeseen costs in the period to 30 September 2017 were £10 million, as NIE suggested, NIE would be exposed to £5 million.

5.206 We then considered whether our capex allowances may already provide sufficient contingency or opportunities that would enable NIE to offset such costs.

[36] This excludes an additional £0.5 million identified by NIE under the category of 'fault and emergency and other reactive works'. We have not included investment categorized as 'fault and emergency and other reactive works' within the scope of the D3 provision.
[37] See previous footnote.
[38] This excludes expenditure on distribution network load-related and reinforcement projects. These are not relevant here as our approach applies to asset replacement expenditure and not load-related or reinforcement expenditure.

5.207 The capex allowances we determined in Section 9 reflect our view of the asset replacement and refurbishment investment planned by NIE that it is reasonable for NIE to undertake (or have undertaken) in the period from 1 April 2012 to 30 September 2017. Nonetheless, despite the reviews of the UR and ourselves (supported by BPI), our assessment may have failed to identify some elements of NIE's original plan that NIE will find that it is able costlessly to defer or cancel.

5.208 We considered the potential scale of such opportunities. Our allowance for the direct costs of NIE's network investment programme is approximately £250 million.[39] We calculated that NIE would profit by approximately 10 per cent of the value of any asset replacement expenditure that it can defer (costlessly) for five years.[40] NIE would retain 50 per cent of the saving from cancelling or downscaling investment projects included in our assessment. We considered that there would be sufficient scope for a financial upside to offset the financial downside that NIE may face from unforeseen developments.[41]

5.209 The potential for NIE to benefit from investment deferral and cancellation was highlighted by the UR in its response to our provisional determination. The UR suggested that 'it is entirely realistic' to think that NIE could underspend its capex allowance by £100 million through a mix of investment deferral and abandonment and that NIE would profit by around £25 million from deferral of this scale.[42] We disagreed with some parts of the UR's interpretation and did not consider that these figures were a central forecast. Nonetheless, we agreed with the UR that our price control design provides NIE with the potential to experience significant financial upside.

5.210 Taking the above into consideration, we considered that the opportunities for NIE to enjoy a financial upside from departing from the investment plan we used to determine its capex allowance are at least sufficient to offset the potential financial downsides from the costs of unforeseen developments.

5.211 We did not consider that the concerns about unforeseen developments raised by NIE in its response to our provisional determination meant that our determination would provide NIE with either insufficient flexibility or insufficient revenue.

NIE's proposed variation on our approach

5.212 In the submissions from NIE that we considered before our provisional determination, NIE proposed a variant on our approach that it considered more appropriate. Under this variant, NIE would be able to defer 10 per cent of the volumes in each investment category without any adverse financial consequences at the next price control review (though NIE suggested that a different threshold could be used). NIE said that this would provide protection to NIE against unanticipated investment needs. It told us that it would allow it to incur unanticipated expenditure that enabled it to adopt more cost-effective solutions. It said that the variant would provide assurance that the majority of planned investments in all categories of investment would be delivered. Similarly, in its response to our provisional determination[43] NIE proposed a variation that would permit deferral up to a 10 per cent threshold to accommodate substitution

[39] This excludes load-related expenditure.

[40] For example, with a WACC of 4.1 per cent, annual RPI growth of 3.25 per cent and a 50 per cent cost pass-though under the cost risk-sharing mechanism, we calculated that the net present value of delaying £1 million of planned expenditure by five years (assuming that unit costs grow at a rate of RPI–1 per cent per year and no other cost impacts) would be around £0.1 million.

[41] As an example, if NIE were able to defer for five years £25 million of planned investment and also to cancel £5 million of planned investment out of a total of £250 million, it would benefit financially by around £5 million.

[42] UR response to provisional determination, paragraph 40.

[43] NIE response to provisional determination, p152.

with unforeseen outputs. NIE contended that this would permit it the flexibility for marginal variations in target volumes while not unduly limiting the effectiveness of the mechanism in safeguarding customers against the risk of inefficient deferral. NIE subsequently told us that it would be content for the overall quantum of substitution to be limited to £10 million as long as NIE had flexibility to defer up to 10 per cent in any one category of investment.

5.213 In our provisional determination, we said that we were not persuaded that NIE's proposed variation would represent a better approach. It would not protect consumers against the first 10 per cent of investment deferral in each category. We did not consider such deferral immaterial, especially if experienced across a number of different investment categories. Although NIE envisaged in its submission that this feature of its variant would allow it to reoptimize its network or investment plan by spending more in other areas, there is no link or mechanism to ensure that any money that NIE saves from deferral is used for that purpose; NIE might, instead, use the saving to provide higher profits to shareholders.

5.214 Following NIE's response to our provisional determination[44], we considered further the need for an alternative to our proposed approach. NIE's proposed variant would provide NIE with greater contingency for the costs arising from unforeseen developments. However, we did not identify a need to provide greater contingency for the costs arising from unforeseen developments (see paragraphs 5.200 to 5.211). We were satisfied that the original version of our proposed approach was appropriate. NIE's proposed variant seemed unnecessary. It would provide less protection to consumers against investment deferral and it would involve greater complexity.

D4: Investment projects for distribution network load-related expenditure

Summary

5.215 We considered whether to include a mechanism within the price control framework to adjust NIE's maximum revenue and RAB to vary the provision for investment to increase the capacity of NIE's distribution network. This would avoid the need to make an upfront allowance to cover all such investment in the period to 30 September 2017. We considered several options and decided that the disadvantages and limitations of these options were large compared with the benefits of such a mechanism. We decided instead to set an upfront allowance. We also decided that distribution load-related expenditure should not fall within the policy of no double-funding of deferred network investment set out in section D3 (paragraphs 5.112 to 5.214) .

Introduction

5.216 This subsection concerns the possibility of including mechanisms or provisions in the price control framework to allow some flexibility to NIE's revenue restriction and RAB in light of uncertainty about NIE's expenditure requirements for work to increase the capacity of its distribution network. It relates to the UR's proposals for load-related expenditure under Fund 2.

5.217 This subsection takes the following in turn:

(a) the UR's and NIE's proposals;

[44] NIE response to provisional determination, pp149–151.

(b) options we identified for load-related expenditure on distribution network;

(c) NIE's draft asset management documentation;

(d) our decision to set an upfront allowance; and

(e) exclusion from the D3 investment deferral provision.

The UR's and NIE's proposals

5.218 The UR's proposals are described in Appendix 5.1. In short, the UR proposed that it should be able to adjust NIE's price control during the price control period to make case-by-case approvals for additional expenditure to increase distribution network capacity and that NIE should also be able to carry out such expenditure without pre-approval and be remunerated for it if it could subsequently demonstrate that it was necessary and efficient. The UR's proposed reporter would support the UR on project approval and review of expenditure projects that were not approved in advance. The UR proposed that NIE update and provide information on its asset management strategy to help the UR's decisions on whether to approve funding.

5.219 In contrast, NIE proposed that there should not be any ex ante or ex post regulatory approval process during the price control period in relation to projects to increase distribution network capacity. NIE's proposals would involve a fixed upfront allowance that would be intended to cover its expenditure requirements to increase capacity on the distribution network to accommodate additional load. NIE's concerns with the UR's proposals include risks of regulatory micro-management, lack of flexibility and concerns about the ex-post nature of the reviews of investment projects that NIE carries out.

5.220 NIE did not consider it possible to use the unit cost forecasts relating to asset replacement to set additional allowances for distribution of load-related expenditure. NIE argued that unit costs for asset replacement could not be used for load-related expenditure under the UR's proposed Fund 2. This was because asset replacement involved replacement of selected assets and could not be equated to the cost of building a new overhead line.

5.221 In its rebuttal of NIE's submission to us on priorities for the inquiry, the UR argued that NIE's alternative proposals for load-related distribution projects would increase our workload in this inquiry:

> Accepting NIE T&D's proposal would increase the difficulty of the Commission's task in relation to capex by requiring the Commission to identify to an appropriate degree of accuracy an ex ante allowance for almost all capex, including for highly uncertain projects related to potential demand growth which we proposed for inclusion in Fund 2. This would mean gathering sufficient data to make an accurate once-and-for-all determination whether the various projects proposed by NIE T&D are really necessary and represent value for customers' money backed up by evidence of customer willingness to pay …
>
> We do not think it can be in the public interest in the circumstances of this inquiry to set an ex ante allowance for non-renewables investment where there is neither certainty of need nor accountability for deliverables.

5.222 NIE's proposed approach would place a greater requirement on upfront expenditure forecasts for load-related expenditure, whereas the UR's approach involves an element of 'wait and see'.

5.223 In terms of implementation, the UR's proposals were that there would be no adjustments to NIE's maximum regulated revenue during the RP5 price control period for any additional load-related expenditure beyond that set in the original allowance. Instead, if further projects are approved by the UR, NIE's revenues would be adjusted from the RP6 price control period. The UR's view seemed to be that in the interests of tariff stability, adjustments are made during RP6.

5.224 NIE said the following in response to the UR's comment that revenue adjustments for additional load-related projects under Fund 2 would be delayed until RP6 for the purposes of tariff stability:

> NIE questions whether it is appropriate to defer any revenue adjustment to RP6. While that might result in tariff stability during RP5 it holds the promise of a very substantial increase in tariffs in RP6. It is doubtful whether such an approach is in the best interests of customers. It also creates the risk that the RP6 price control review will be doubly onerous, as it will entail a major ex post review of NIE's capex works from RP5, as well as a forecast of its capex needs for RP6.

Options identified for load-related expenditure on distribution network

5.225 We identified four main options:

(a) Set an upfront allowance based on a forecast of the expenditure NIE will need to incur, over the price control period, to accommodate localised load growth on its distribution network. This would include an allowance for specific anticipated investment projects that are considered necessary and some forecast or contingency to cover other potential projects that might be needed.

(b) Set an upfront allowance based on forecasts of the costs of specific investment projects that we consider are (or will be) necessary and supplement this with a provision for NIE to come to the UR and seek adjustments to its maximum regulated revenue allowance and RAB to provide for further investment projects to increase capacity of the distribution network that become necessary during the price control period. As part of the approval process the UR would specify an upfront allowance for each allowed project before it is carried out.

(c) Set an upfront allowance based on forecasts of the costs of specific investment projects that we consider are (or will be) necessary and supplement this with a provision for NIE to be compensated through future revenue controls and RAB for any expenditure on distribution network capacity that it incurs and which it can subsequently justify to the UR as necessary and efficient expenditure. The amount of compensation would not necessarily provide full compensation for the costs it incurs. Instead a cost allowance for work that NIE has done under this provision would be calculated by reference to the unit costs used to set the price control (eg unit costs for asset replacement work or predicted load-related network investment) multiplied by the volume of work that NIE has undertaken. These unit costs would not reflect local conditions. NIE would be entitled to no remuneration in relation to increase in the capacity of the distribution system carried out by NIE that the UR does not consider to have been necessary.

(*d*) Set an upfront allowance based on forecasts of the costs of specific investment projects that we consider are (or will be) necessary and supplement this with a mechanism to increase automatically NIE's revenue control and RAB according to any additional investment carried out by NIE to increase distribution network capacity. The mechanistic adjustments to NIE's revenue control and RAB would be calculated by reference to unit cost allowances specified at the price control review and would be conditional on any increases to NIE's distribution network capacity being compliant with asset management documentation that explains in detail how NIE will make decisions on the need for additional investment in its distribution network capacity. This would refer to established network planning standards and NIE's statutory obligations and would also clarify how NIE intends to interpret aspects of these when making practical decisions. Subject to NIE's compliance with this documentation, the scope for regulatory intervention on an 'ex-post' basis would be limited to any inefficient spend clause that applies more generally (see section D2, paragraphs 5.97 to 5.111).

5.226 Option *(a)* represents NIE's proposals. Options *(b)* and *(c)* contain elements of the UR's RP5 proposals for distribution network load-related expenditure (the UR's RP5 proposals were for a combination of *(b)* and *(c)*). Under options *(b)* and *(c)* there is a potential optional role for the reporter envisaged by the UR to help the UR with up-front project approvals or backward-looking assessments of whether investment carried out by NIE was necessary.

5.227 We identified option *(d)* as a variant on options *(b)* and *(c)* which would provide some flexibility within the price control arrangement without requiring project-by-project review and approval by the UR and without exposing NIE to uncertainty about whether projects would be approved by the UR ex post.

5.228 We shared the options above with the main parties. The UR said that it would strongly prefer either option *(b)* or a combination of *(b)* and *(c)* with NIE having the ability to choose between seeking upfront approval from the UR for additional investment or relying on ex-post regulatory approval of investments it has already carried out. The UR did not expect it to be feasible to develop the necessary asset management documentation for option *(b)* and that even if this could be done the UR would be worried that NIE's spending could reflect documentation that presented an inefficient approach to asset management. The UR also submitted that option *(c)* on its own would expose NIE T&D and consumers to too much uncertainty.

5.229 NIE's Statement of Case had proposed option *(a)*. Of the other options, NIE told us that it had a strong preference for option *(d)* under which load-related expenditure would, if justified by reference to documented asset management criteria, lead to additional revenues calculated on the basis of unit cost allowances established as part of our determination.

NIE's draft asset management documentation

5.230 In relation to option *(d)*, NIE provided us with an initial draft of criteria for making additional investment decisions for distribution-load-related investment, and a worked example of the application of these criteria.

5.231 The UR told us that NIE's draft documents were too narrow in scope and insufficiently specific to form the basis of an arrangement under which NIE would self-certify expenditure for recovery from customers. In particular, NIE's draft documents did not make investment conditional on any cost-benefit analysis. The UR also thought that NIE's documents would allow it to err on the side of making expensive investments rather than potentially more efficient solutions, such as relying on the diversity of peaking times between different loads; dynamic line ratings; demand response; or distributed generation.

5.232 We thought that NIE's draft documentation provides helpful guidance on how NIE identifies capacity shortages on its network and how it designs investment proposals to address such shortages. Publishing such documentation could be helpful to energy consumers to use as a benchmark to design alternative solutions such as demand response and distributed generation.

5.233 However, our review of NIE's draft documentation identified barriers to its use as the basis for a price control adjustment mechanism:

(a) We agreed with the UR that NIE's documentation did not take sufficient account of ways of addressing capacity limitations that did not involve network investment, such as demand response and distributed generation.

(b) NIE's documentation only covered investment to meet additional demand. We were not clear on what basis, if any, it might be used in respect of the significant amounts that NIE said it might need to spend to accommodate additional renewable generation.

(c) We identified a risk that NIE's documentation could, in some cases, conflict with the security of supply standard, currently P2/5. This could mean that compliance with the documentation would place NIE in breach of its obligations (unless the UR granted it a derogation).

(d) We did not have a set of agreed unit costs covering the investment items that might be justified by the criteria, particularly for 33 kV and primary substation investments.

Our decision to set an upfront allowance

5.234 We decided that the options in paragraph 5.225*(b)* and *(c)* would involve too great a degree of regulatory micro-management in NIE's business and would carry an unduly high regulatory burden.

5.235 In its response to our provisional determination, the UR disagreed with our view that options *(b)* and *(c)* amounted to excessive micro-management and said that this reflected the degree of oversight that was necessitated by NIE's poor-quality business plan. However, these comments from the UR did not change the view we had expressed in our provisional determination.

5.236 We were initially attracted to the option in paragraph 5.225*(d)* as a means to tackle these specific disadvantages of options *(b)* and *(c)*. However, we did not think that NIE had submitted sufficiently precise criteria to form the basis of a mechanistic scheme to adjust investment allowances. This reflects the inherent complexity and diversity of distribution network investment projects and not necessarily shortcomings in NIE's draft documentation.

5.237 A further problem with the option in paragraph 5.225*(d)* is that we would need to specify upfront cost figures that can be used to calculate a mechanistic allowance. Whilst we could base these in part on the costs of projects that are already anticipated and included in NIE's forecasts, it would be more difficult to establish costs for other potential projects. There is also a risk that if the cost allowance for additional capacity under the mechanism is higher than NIE's actual costs, this could provide NIE with perverse financial incentives to carry out projects that are not necessary. We did not consider the envisaged asset management documentation and inefficient spend clause likely to be sufficient to prevent NIE from acting on those incentives.

5.238 We reconsidered the option in paragraph 5.225*(a)* in light of the drawbacks of the other options. NIE's updated forecast for distribution load-related expenditure was £24.6 million over the RP5 period.[45] Of this, our consultants BPI recommended that we allow £22.1 million based on the information currently available. BPI expected that further projects might be needed over the period to 30 September 2017, although these were difficult to forecast. The difference between the two is £2.5 million. In view of the scale of this difference, and the drawbacks of the other options above, we chose option *(a)* with an upfront allowance set for the period to 30 September 2017. As with other areas of expenditure, any difference between NIE's out-turn expenditure and this forecast will be subject to the cost risk-sharing mechanism described in section D1.

Exclusion of distribution load-related expenditure from scope of D3 mechanism

5.239 In our provisional determination, we did not propose to apply our policy on no double-funding of deferred investment to distribution load-related expenditure.

5.240 In its response to our provisional determination, the UR urged us to reconsider this aspect of price control design and proposed instead that we include distribution load-related investment within the scope of the approach to investment deferral set out in section D3.[46] The UR said that the need for protection against double-funding was at least as important for distribution load-related expenditure as for asset replacement work. The UR was concerned that if the growth in demand placed on the network by consumers slowed, NIE could postpone planned investment to subsequent price control periods and consumers would face additional costs for that investment. The UR also said that NIE would have very strong incentives to postpone any load-related work that would otherwise take place in the last 12 to 18 months of the period to 30 September 2017.

5.241 The effect of the UR's proposal would be that we would specify a series of planned investments corresponding to our capex allowances for distribution load-related expenditure and that these projects would be subject to the policy of no double–funding of deferred investment.

5.242 We decided not to adopt the UR's proposal. We were not in a position to specify a set of planned investments for load-related expenditure for the purposes of the D3 provision and were concerned that doing so could provide too little flexibility or contingency for NIE, especially for 33 kV reinforcement which represents the majority of distribution load-related expenditure. While the UR identified that slower than expected growth in the demands placed on the distribution network could reduce the need for load-related expenditure, it is also possible that such growth is faster than expected in some areas, which could give rise to additional costs to NIE.

5.243 We discussed the potential for investment deferral in paragraphs 5.117 to 5.122. The risks to consumers seemed more severe for asset replacement expenditure than for distribution load-related expenditure.

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[45] NIE Statement of Case, p413.
[46] UR response to provisional determination, paragraphs 46–49.

5.244 In its response to our provisional determination, the UR also said that it was concerned that we had not taken adequate account of the fact that NIE had a new obligation to consider alternatives to infrastructure investment for load-related projects.[47] NIE said that such alternatives could give rise to opex costs over a considerable period of time and that some of these costs could be incurred in the wholesale electricity market or by SONI rather than by NIE. The UR suggested that the new obligation on NIE provided a further reason to include distribution load-related expenditure within the scope of the D3 provision, though the UR also suggested that there might be other options.[48]

5.245 We did not find that including distribution load-related expenditure within the scope of the D3 provision would address the specific concerns raised by the UR. In particular, this aspect of the UR's response suggested that NIE's investment plan and our assessment of it may have overlooked requirements and opportunities for NIE to reduce its distribution load-related investment. This concern would not be addressed by our D3 provision and seemed more of an issue for the level of the capex allowances for distribution load-related expenditure (see paragraph 9.97).

D5: Investment projects to increase transmission system capacity

Summary

5.246 We specified provisions within the price control framework for the UR to adjust NIE's maximum revenue and RAB, during the price control period, to allow for additional investment projects to increase the capacity and capabilities of NIE's transmission system. The scale of transmission investment about which there is uncertainty is large and we consider such a mechanism proportionate in this case.

Introduction

5.247 This subsection concerns the possibility of including provisions in the price control framework to allow a within-period adjustment to NIE's revenue restriction and RAB calculation in light of substantial uncertainty about NIE's expenditure requirements for work to increase the capacity of its transmission system. It considers:

- *(a)* the UR's proposals for capex Fund 3, which would allow for project-by-project approval of transmission network investments by the UR during the price control period and NIE's submissions;
- *(b)* regulatory precedent;
- *(c)* risks under the UR's proposals;
- *(d)* our assessment of the options;
- *(e)* the scope of our chosen provision;
- *(f)* the UR's decisions under the provision;
- *(g)* the potential role of other infrastructure providers; and

[47] ibid, paragraph 46.
[48] ibid, Appendix/ Detailed comments on deferred Capex incentive, paragraphs 58–62.

(h) transmission load-related projects included in upfront allowances in provisional determination.

5.248 This section does not consider the treatment of cluster infrastructure. Where multiple generators seek new connections close to each other, it may be more efficient or better for visual amenity to construct new shared infrastructure as part of the connections rather than connecting each individually to the current network. NIE and the UR refer to such infrastructure as 'cluster infrastructure' and this will include transmission assets that extend NIE's 110 kV network. We provide our determination in relation to cluster infrastructure in paragraphs 10.320 to 10.337.

UR's proposals and NIE's submissions

5.249 The UR describes its Fund 3 proposals as follows:[49]

> Fund 3 is intended to cover large projects for which there is even greater uncertainty than in Fund 2, both as to timing and cost. This covers, in particular, smart metering and investments in the network required to accommodate the expansion of renewable energy that is anticipated to take place in order to satisfy EU renewable energy targets. The operation of this fund is straightforward: there are no allowances at this stage, but NIE T&D has complete freedom to present proposals for projects at any stage in RP5 and they will be approved to the extent that they are necessary and efficient. This approach insulates NIE T&D from essentially all of the (substantial) risk associated with these projects.

5.250 The UR told us that its intention was that its Fund 3 proposals should cover projects to address government policy related to reducing carbon emissions, and in particular the national action plans for renewable generation and energy efficiency. The UR said that the special treatment of these projects was required because of the extent of uncertainty at this stage, both as to whether projects were needed in the price control period and also to their costs. In August 2012, the UR issued a consultation paper on the approach it would take in dealing with requests for approval from NIE during the price control period.[50]

5.251 NIE supported the UR's proposed approach of setting no upfront allowance for certain large projects and instead adjusting NIE's price control and RAB as part of a project-by-project approval process. NIE raised some concerns about the process and risk of delays. NIE proposed that the UR's proposals for Fund 3 be applied but with some modifications:[51]

(a) a clearly specified process for UR approval of investment projects proposed by NIE;

(b) clearly specified rules for the regulatory treatment of approved projects (eg in relation to incentives);

(c) the inclusion within Fund 3 of the Ballylumford switchboard project; and

(d) the exclusion of work relating to smart grid development from Fund 3.

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[49] UR Statement of Case, p12.
[50] The UR 'Approval criteria and incentive mechanisms for RP5 Fund 3 - Investments for Renewable Electricity', August 2012.
[51] NIE Statement of Case.

5.252 We consider issues relating to smart grids separately in section D6, paragraphs 5.280 to 5.286. We focus here on transmission investment projects.

Regulatory precedent

5.253 The use of a project-by-project approval regulatory process for major transmission network projects is familiar from Ofgem's regulation of electricity transmission companies in GB. As part of new price controls for National Grid Electricity Transmission and the two transmission network companies in Scotland, Ofgem introduced its Strategic Wider Works mechanism, which allows the network companies to bring forward projects for regulatory approval during the eight-year price control period.

5.254 For National Grid, Ofgem's approach also allows National Grid to be remunerated for some investment without Ofgem pre-approval, if investment to increase capacity is consistent with a network development policy that National Grid has developed and had approved for Ofgem. We do not consider this approach feasible within the timescale of our inquiry. We suspect that it would also have practical problems in Northern Ireland that arise from the separation between *(a)* system operation and transmission planning and *(b)* transmission asset ownership.

Risks under the UR's proposals

5.255 We identified several risks of the UR's Fund 3 proposals which we might seek to address through the design of a project-by-project approval process:

(a) a risk that NIE is funded twice (or seen to be funded twice) if there is not a clear definition of what aspects of NIE's network investment is to be funded through an upfront allowance as part of the price control and what is funded through a project-by-project approval process;

(b) risk of delays to delivery of worthwhile projects to increase capacity of transmission system;

(c) missed opportunities for greater use of competitive processes for the planning, design and delivery of investment projects to increase the capacity of the transmission system, including transmission capacity within Northern Ireland and capacity between Northern Ireland and the Republic of Ireland or GB; and

(d) the potential for distortions to NIE's network investment, working practices and cost reporting if it faces different marginal financial incentives for underspend and overspend on these projects compared with other parts of its expenditure.

Our assessment of the options

5.256 There is substantial uncertainty about NIE's investment requirements to increase the capacity and capabilities of its transmission system. We determined that NIE's price control Licence conditions should include a provision to allow the UR to determine adjustments to NIE's maximum regulated revenue and RAB to allow for the costs of necessary investments of this nature. We took account of the regulatory precedent for such arrangements and the parties' support for this type of provision.

5.257 The practical operation of this arrangement would be conditional on NIE making applications to the UR for specific projects.

5.258 Any adjustments that the UR makes to NIE's maximum regulated revenue and RAB should be limited to that necessary to allow for the expected efficient costs of delivery of the investment project, in light of the UR's review of these costs. The cost risk-sharing mechanism set out in section D1 should apply in relation to out-turn costs for any projects approved. The same cost risk-sharing percentage would apply as for other elements of NIE's opex and capex to avoid unduly distorting NIE's working practices and cost reporting and to limit complexity of the regulatory framework.

5.259 In our provisional determination, we proposed that NIE should be placed under an obligation to develop and bring to the UR proposals for relevant investment projects that are in consumers' interests, drawing on input from SONI, and to provide the UR with the information necessary to assess NIE's application. Following submissions from NIE on this matter,[52] we decided not to include such an obligation. It did not seem appropriate to place NIE under an obligation to bring projects to the UR given the anticipated transfer of transmission planning responsibilities to SONI. If there are regulatory concerns about the relationship between NIE and SONI in terms of the transmission planning process, these seemed more of an issue for the transmission interface agreement (TIA) than for NIE's price control licence conditions.

Scope of provision

5.260 Our provision is intended to cover projects relating to NIE's electricity transmission network that increase its capacity or capability. This includes investment to expand NIE's transmission network to accommodate renewable generation. We do not consider it necessary or appropriate to limit it to projects attributable to renewable generation or government energy policy initiatives.

5.261 With the anticipated transfer of transmission planning responsibilities to SONI, a prerequisite for any project to be within scope of the provision is that the investment is requested by SONI. It would not make sense for NIE to propose increases to transmission network capacity to the UR for approval if SONI does not consider the project an appropriate development of the transmission network.

5.262 Our provision does not include asset replacement expenditure. Our upfront cost assessment from Section 9 is intended to cover NIE's asset replacement needs in the period to 30 September 2017.

5.263 In its response to our provisional determination, NIE argued that the scope of the D5 provision should explicitly include two transmission projects, which it referred to as the Ballylumford switchboard project and the Coolkeeragh–Magherafelt 275 kV overhead line project.[53] NIE said that this proposal reflected the particular risks of providing ex ante allowances for these projects and that including under the D5 provision provides a superior form of price control design and better serves the public interest. The UR agreed that these projects should be included in the scope of the provision.

5.264 We decided to adopt NIE's proposal that the Ballylumford switchboard project and the Coolkeeragh–Magherafelt 275 kV overhead line project should be in the scope of the provision. This means that our determination does not include any ex ante allowances for these projects. Instead, the UR will be able to adjust NIE's maximum regulated revenue and RAB during the price control period to allow for the costs of these projects, following submissions from NIE.

[52] NIE response to provisional determination, pp161–162.
[53] ibid, pp155–159.

5.265 We did not agree with NIE's view in its response to our provisional determination that the scale of uncertainty in cost should itself be a reason for including these projects in the scope of the provision. Without a clear boundary around the costs that are funded through ex ante allowances and what can be subject to within period determination by the UR, there is a risk of double-funding by consumers. Nonetheless, there seem sufficient grounds to include these projects in the provision without undermining the scope of that provision envisaged in our provisional determination. Whilst these projects involve elements of asset replacement, they will both require major decisions on the capacity of new transmission assets to be installed.

5.266 NIE said that its interpretation of the definition of the D5 mechanism could include distribution works directly required to facilitate transmission developments eligible under the D5 mechanism (such as project D22). We disagreed and decided that the D5 provision should not include distribution network expenditure. We did not consider that NIE's proposal would allow for a robust boundary between our upfront allowances and further allowances under the D5 provision. We determined a separate upfront allowance that is intended to cover all of NIE's distribution load-related expenditure requirements (other than those funded by connection charges).

The UR's decisions under the provision

5.267 It will be for the UR to take appropriate decisions under the provision. We expect that the UR will need to consider the following as part of its decision-making:

(a) whether NIE has already received some funding in relation to the project as part of the expenditure allowances used to calculate NIE's price control;

(b) an assessment of whether a proposed project is in the interests of consumers. That project assessment should include consideration of alternative options including (i) operational measures that can avoid or delay the need for network investment and (ii) the possibility of delaying a decision on the proposed project until more information is available on its need and appropriate design;

(c) a determination of an appropriate upfront cost allowance, against which NIE would face financial exposure under the cost risk-sharing mechanism (paragraphs 5.49 to 5.96); and

(d) the potential use of agreed delivery dates or milestones for the project, with financial consequences for NIE for late delivery.

5.268 In its response to our provisional determination, NIE said that it would be preferable if we made clear that any financial incentives in relation to costs and delivery dates should be symmetrical and should provide NIE with upside and downside risk.[54] In relation to the financial exposure in relation to costs, we said under *(c)* above that we would expect the cost risk-sharing mechanism that applies to other areas of NIE's expenditure also to apply to upfront cost allowances determined by the UR. That mechanism is symmetric and provides NIE with opportunities for financial upside as well as risks of financial downside.

5.269 We said under *(d)* above that we would expect the UR to consider the potential use of agreed delivery dates or milestones for the project, with financial consequences for NIE for late delivery. We are not in a position to adopt NIE's proposal that any financial incentives in relation to delivery dates should necessarily have a financial upside

[54] ibid, p162.

for NIE as well as downside. For some projects, early delivery may not provide any benefits to consumers. Further, there is a risk that the existence of schemes rewarding early delivery could encourage NIE to propose target delivery dates with unduly long lead times. We have not sought to develop an approach to financial incentives for delivery dates as part of our inquiry. We leave this to the UR to consider further.

5.270 During the course of our inquiry, NIE raised concerns about possible delays to necessary transmission investment projects arising from delays in any approval process involving the UR. While we recognize that delays could operate against the interests of consumers and that prompt decisions are part of good administration, we have not sought to address these concerns as part of our determination. Our inquiry is focused on NIE's price control Licence conditions and not the overall regulatory regime in Northern Ireland. While we could seek to make the UR's ability to veto projects proposed by NIE time limited, this would not necessarily ensure that the UR's decisions are as swift as possible: the UR might veto within the permitted time frame any proposals for which it does not consider that it has had sufficient time or information to consider properly.

The potential role of other infrastructure providers

5.271 Our inclusion of a provision within NIE's price control Licence conditions to allow NIE to be tasked with developing additional transmission investment in Northern Ireland does not mean that NIE is necessarily best placed to carry out that investment. The anticipated allocation of greater transmission investment planning responsibilities to SONI creates new opportunities for the involvement of parties other than NIE. The construction, ownership and maintenance of electricity transmission infrastructure in Northern Ireland is not a natural monopoly for which the only plausible provider is NIE.

5.272 We expect the UR to consider the potential for projects to be developed and subsequently owned and maintained by a party other than NIE (eg a party appointed by SONI or the UR through a competitive process). Whilst there would be administrative costs and practical difficulties to overcome in the establishment of more competitive arrangements in Northern Ireland, these are also potential benefits to be realized from competition.

Transmission load-related projects included in upfront allowances in provisional determination

5.273 In our provisional determination, we included in our assessment of NIE's capital expenditure requirements allowances for the costs of a series of projects to increase transmission system capacity. These were projects that we considered, on current information, to be necessary before 30 September 2017.

5.274 In its response to our provisional determination, the UR endorsed our proposals in relation to transmission system capacity improvement projects. However, the UR also proposed that the specific projects for which we had provided upfront allowances should also be remunerated under the D5 mechanism. The UR considered this more appropriate given the anticipated transfer or transmission planning to SONI. The UR raised a concern that under the approach proposed in our provisional determination, NIE would benefit financially from decisions to defer or abandon these projects, yet it would be SONI that had responsibility for decisions on transmission system capacity from April 2014.[55] NIE subsequently told us that it would have no objection were we to move all but one transmission load-related project out of the upfront capex allowances and into the D5 mechanism (the one exception was a project that had already started). NIE said that, in the context of SONI taking on the role of planning the transmission system from April 2014, this change 'could be helpful in ensuring allowances are formally considered against SONI's assessment of its licence requirements'.

5.275 The practical effect of moving these transmission capacity projects to the D5 provision would be as follows:

(a) there would be no upfront allowance for these projects: consumers would not face any costs for these projects if they do not happen;

(b) the UR would determine an upfront cost allowance for each project if and when it is needed and NIE's maximum regulated revenue and RAB would be adjusted to accommodate these costs; and

(c) the UR's determination could involve fresh review of expected project costs.

5.276 We identified some potential benefits from such a change. In particular, there are benefits from taking a consistent approach across all transmission capacity projects that NIE has not yet started, especially in light of the new role for SONI in transmission planning. Under the approach in our provisional determination, there was a risk of consumers facing unduly high costs if SONI cancelled one project that had been planned by NIE and included in upfront cost allowances and replaced it with a different project for which NIE was entitled to additional revenues through the D5 provision.

5.277 However, we also saw potential drawbacks with the UR's proposal. Compared with the approach in our provisional determination, there would be additional regulatory burden and risks of project delays from the need for the UR to review any projects before they proceed.

5.278 In light of these issues, we decided on an intermediate approach:

(a) There would be no upfront cost allowances for the transmission load-related projects other than project T36 which NIE has already started.

(b) If and when any of those projects is approved or recommended by SONI, it would become eligible for review by the UR as part of the D5 provision set out above.

(c) In carrying out that review, the UR would only make a fresh assessment of the costs of the project if there have been substantial changes to the nature or scope of the project since it was included in the NIE investment plan that we used for our determination. Otherwise, the costs would be based on the project cost estimates that we used for our provisional determination and which we specify in Appendix 9.4, with a profile of cost allowances based on the work programme and associated expenditure profile agreed between SONI and NIE.

5.279 We decided that this approach would represent an improvement on both the approach set out in our provisional determination and that suggested by the UR in its response to our provisional determination. It would bring benefits from a more consistent application of the D5 provision to transmission capacity investment whilst limiting the additional regulatory burden.

[55] UR response to provisional determination, paragraph 50.

D6: Smart grid initiatives

5.280 We made separate upfront allowances in our cost assessment for some smart grid initiatives proposed by NIE. We do not specify any provisions within the price control framework for the UR to adjust NIE's maximum revenue and RAB to allow for additional investment in smart grid initiatives.

5.281 The UR proposed that its proposed Fund 3 capex arrangement should also include the potential for the UR to make a within-period determination to approval additional revenues for NIE for smart grid initiatives (eg smart grid trials). These elements of the UR's Fund 3 proposals concern different issues to investment to expand capacity of the electricity transmission system.

5.282 The UR told us that the only way to ensure that these initiatives were taken forwards, given the lack of certainty on what was to be delivered or its costs, was to adopt an approach of project-specific approval during the price control period.

5.283 NIE did not support the inclusion of smart grid expenditure in the UR's Fund 3 proposals. Instead, NIE proposed that smart grid initiatives were considered as part of the determination of an upfront capex allowance.

5.284 We have not identified a need to include smart grid initiatives in a project-by-project approval process. We have included potential smart grid initiatives as part of our upfront cost assessment in Section 9.

5.285 In its response to our provisional determination, Simple Power proposed that the price control arrangement should include a mechanism through which NIE could submit to the UR projects relating to smart initiatives on its electricity distribution network during the price control period.[56] Simple Power said that the capability of the distribution network to handle the connection of increasing amounts of distributed generation (DG) could be greatly enhanced, not at excessive cost, by applying 'Smart technologies' and regimes of network operation outside the traditional conservative norms.[57] Simple Power also said that such technologies and modes of network operation were already being utilized by GB DNOs, albeit to varying degrees.

5.286 We recognized that, while we included NIE's proposed smart grid initiatives as part of our upfront cost assessment in Section 9, there may be further potential smart grid initiatives and opportunities that NIE had not identified in its submissions to us which could arise during the price control period. However, we were concerned that a project-by-project approval process for such initiatives could bring detailed regulatory micro-management and administrative burden during the price control period (we discussed similar concerns in relation to distribution load-related expenditure in paragraphs 5.234 to 5.238 above).

D7: Electricity meter investment and smart meter programme

Summary

5.287 We specified a form of 'volume driver' for NIE's capex on electricity meters. We set an upfront forecast for NIE's meter installation and replacement costs and combine this with an adjustment mechanism to vary NIE's allowed revenues and RAB accord-

[56] Simple Power response to provisional determination, p3.
[57] ibid, p1.

ing to differences between *(a)* the actual volume of meter replacement and installation that NIE carries out in each year of the price control period and *(b)* the forecast volumes that were used for the calculation of the upfront cost forecast. NIE will be remunerated on a cost-per-unit basis for each unit of meter replacement or installation.

Introduction

5.288 This subsection concerns the treatment of capex related to meters as part of the price control. The UR proposed a volume adjustment mechanism—what Ofgem might call a volume driver—for capex that NIE incurred to replace, recertify and install meters. The UR's proposals for metering capex fall under its Fund 2 proposals and are described in more detail in Appendix 5.1. We use the term 'conventional meters' to refer to electricity meters that are not smart meters: these include keypad meters.

5.289 This subsection:

(a) considers the options we identified for conventional meters;

(b) sets out our assessment for conventional meters;

(c) considers the implications of NIE's smart meter programme;

(d) considers the options we identified for smart meters; and

(e) sets out our assessment for smart meters.

Conventional meters: options identified

5.290 There was uncertainty about the amount of conventional meter installation, replacement and recertification that NIE will need to carry out in the period to 30 September 2017. We identified three potential options that we could take in relation to NIE's costs for meter installation, replacement and recertification:

(a) Make an upfront regulatory forecast of NIE's total costs of meter installation, replacement and recertification and use this as part of the calculation NIE's RAB and allowed revenues for the price control period. In line with treatment of other expenditure, the cost risk-sharing mechanism above (if any) would apply in relation to any differences between NIE's actual costs for meter installation, replacement and recertification and the upfront regulatory forecast.

(b) Make an upfront regulatory forecast of NIE's total costs of meter installation, replacement and recertification and combine this with an adjustment mechanism to vary NIE's allowed revenues and RAB according to differences between (i) the actual volumes of installation, replacement and recertification that NIE carries out in each year of the price control period and (ii) the forecast volumes that were used for the calculation of the upfront regulatory forecast. The intention would be for NIE to be remunerated on a cost per unit basis for each unit of meter installation, replacement and recertification it is required to carry out. The unit costs for different categories of meter work would be established as part of the price control determination.

(c) Determine meter costs as an excluded service for the purposes of the revenue control and provide no upfront funding for the estimated costs of meter replace-

ment and meter installation. Instead require NIE to set charges to suppliers for meter work that NIE can justify as reasonable in light of costs and the charges for comparable services by other companies. If NIE was found by the UR to have set charges at levels that were not compatible with this requirement, it could require NIE to reduce its charges to ensure compliance with the price control Licence conditions.

5.291 Option *(a)* reflects NIE's original proposals in its Statement of Case. The second option reflects the UR's proposals. NIE's proposals would be simpler but would expose consumers (and NIE) to greater cost forecasting risk. The UR's proposed approach would help reduce risks relating to uncertainty as to the volume of meter replacement. It might carry some risks of perverse financial incentives if NIE has flexibility over the timing and volume of work and if its costs vary significantly from the unit costs used to set the volume adjustment mechanism.

5.292 Option *(c)* would bring greater transparency to meter costs and provides an alternative to *(b)* as a means to avoid exposure to an uncertain upfront forecast of the volume of meter work. It would involve a substantial change to the price control arrangements for NIE and also to the commercial arrangements within the Northern Ireland electricity system because NIE does not currently charge suppliers directly for meter-related services. The UR told us that this might require modifications to electricity supply licences and that it would be willing to consider this option in the future as part of the deregulation of domestic supply prices. The UR did not consider this option feasible for the purposes of our determination of a new price control for NIE: 'While we consider that it would be something that we should investigate further in the context of the deregulation of domestic supply prices in the future, however, we are concerned that it would be impossible to implement within the time frame required for this price control period.'

5.293 Following sight of the options identified above, NIE told us that it acknowledged the potential benefits of option *(b)*. It said that it expected there to be significant timing issues associated with option *(c)* including issues relating to the need for adequate consultation on the change.

Conventional meters: our assessment

5.294 We chose the option in paragraph 5.290*(b)* above, in which an upfront forecast would be combined with adjustments in light of out-turn volumes according to unit cost allowances that we specify upfront. This helps address substantial uncertainty about volumes, especially in relation to meter certification. The approach under option *(c)* has attractions but did not seem practicable for our inquiry.

Potential implications of smart meter programme

5.295 A complication that arises in relation to the expenditure that NIE will need to incur in relation to metering activities is the potential introduction of smart metering. DETI announced its decision to proceed with a roll-out of smart metering in July 2012, with the detailed arrangements for the roll-out to be consulted on by the UR.[58]

5.296 The UR proposed the inclusion of costs relating to smart metering as part of its proposed Fund 3 mechanism (see Appendix 5.1). The UR said in its final determination that the purpose of including smart metering in its Fund 3 proposal was to ensure

[58] NIE Statement of Case, p58.

that NIE could undertake these activities without having to wait until the next price control review. NIE's Statement of Case did not raise concerns with the inclusion of smart metering within the UR's Fund 3 proposals but questioned the need for NIE to demonstrate the benefits of smart metering as part of any regulatory approval process.

Smart meters: options identified

5.297 The submissions of both NIE and the UR confirmed that there was not sufficient information available now on the timing and nature of the smart metering programme in Northern Ireland to provide an upfront regulatory forecast of NIE's smart metering costs in the period to 30 September 2017. In view of this, we identified two options:

(a) Make no special provision within the Licence for adjustments to NIE's revenues and RAB in relation to smart metering. Instead recognize the potential for such adjustments either through the change of law provision in the existing Licence conditions (COL_t) or through an agreement between the UR and NIE on a Licence modification.

(b) Include a mechanism within the Licence to allow the UR to make a determination that varies NIE's revenue, unit cost allowances and RAB in light of an upfront assessment of the estimated net cost impacts on NIE of an agreed smart meter programme.

Smart meters: our assessment

5.298 Before we published our provisional determination, NIE told us that its preference was for a Licence modification under option *(a)*. NIE said that it would be important for us to state that this was the process that we expected the UR to follow in order to permit NIE to recover the costs in relation to smart metering.

5.299 The UR suggested that a potential drawback of option *(a)* was that Licence modifications would require the agreement of NIE, which could introduce delays and a risk of another reference to the CC. The UR said that it would be concerned that a reference to the CC would be disproportionate for the single issue of the treatment of smart metering in NIE's price control. However, if NIE expects to incur additional costs as a result of new obligations that have been placed on it in relation to smart meters, it would be in NIE's interests to work constructively with the UR to agree Licence modifications to increase its maximum regulated revenue to cover those additional costs.

5.300 Option *(a)* would not allow the UR to place additional obligations on NIE in relation to smart metering without NIE's consent. We do not consider that the flexibility for the UR to place additional obligations on NIE without NIE's consent is part of the modifications that we need to make to NIE's price control Licence conditions as part of our inquiry. We expect that other elements of the legislative and regulatory framework would be available to ensure that NIE plays an appropriate role in the smart meter programme in Northern Ireland.

5.301 We chose option *(a)* and accordingly have not specified any Licence modifications specifically to accommodate potential changes in relation to smart metering. Instead, if changes are needed to NIE's maximum regulated revenue before 30 September 2017, we would expect the UR and NIE to make use of either the change of law provision in the existing Licence conditions (which we propose to retain) or a Licence modification.

5.302 In response to our provisional determination, NIE requested that we amend the change of law provision so that the imposition on NIE of any obligation in relation to a smart metering project is clearly stated to be a relevant change of law.[59] NIE said that this would reduce NIE's exposure to undue regulatory risk.

5.303 We did not consider it necessary or appropriate to amend the change of law provision as NIE had proposed. We did not identify any reason why the existing change of law provision would not apply to any new obligation placed on NIE in relation to smart metering that materially increases NIE's costs. NIE's response to our provisional determination did not explain why the existing obligation was deficient in that respect. We also considered that it would be inappropriate to dilute the general nature of the existing change of law provision by amending it so that it explicitly refers to one possible type of change of law.

D8: Pass-through of part of connections charges to NIE's RAB

Summary

5.304 NIE imposes charges for new connections to its network (also known as 'customer contributions'). These are subject to price regulation outside the NIE revenue control that was the main subject of our inquiry. At present, there is an arrangement by which an element of certain connection charges is 'subsidized' through NIE's RAB and revenue control, rather than falling entirely on the party seeking the new connection. We decided that costs relating to this subsidy from NIE's RAB should be recovered on a cost pass-through basis. This will be a temporary arrangement until 1 October 2014.

5.305 This subsection *(a)* considers the UR's RP5 proposals; *(b)* considers NIE's submissions; and *(c)* sets out our assessment.

UR's RP5 proposals

5.306 In its final determinations, the UR identified around £37 million of costs that would be subject to cost pass-through, subject to an efficient spend clause, which relate to 'connections and alterations'.[60] More information on this aspect of the UR's proposals is provided in Appendix 5.1.

NIE's submissions

5.307 Some of the criticisms that NIE made about the UR's proposed Fund 2 arrangements applied to the UR's proposals in relation to connections.[61] In particular, NIE was concerned about the potential for the UR to disallow expenditure that the UR considered inefficient, and about the role of the reporter. NIE proposed a 'traditional' approach under which the costs that the UR identified for Fund 2, including connections costs, would be part of an ex-ante allowance without the adjustments for identified inefficiency or differences between actual and forecast volumes.

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[59] NIE response to provisional determination, pp162–163.
[60] UR final determination, p46.
[61] ibid, pp54–55.

Our assessment

5.308 We first deal with the issue of the inefficient spend clause. We have considered an inefficient spend clause in section D2 (paragraphs 5.97 to 5.111). We recognize that such a clause, combined with the UR's proposals for an embedded reporter, might expose NIE to the risk of not recovering expenditure that it considers was efficient but which the reporter or the UR considers inefficient. The risk to NIE would depend on the nature and drafting of the clause. We consider that, if such a clause is to be included as part of price control design, NIE's financial exposure should be limited to instances where its expenditure is demonstrably inefficient or wasteful. We do not consider that such an approach would impose an unreasonable regulatory risk on NIE.

5.309 We looked at the costs that the UR proposed to treat on a cost pass-through basis. These comprise two elements:

(a) Some costs which are effectively a contribution from NIE's maximum regulated revenue and RAB towards the charges for new connections. The charges to consumers for new connections (also known as customer contributions) are subject to price regulation outside the NIE revenue control that is the main subject of our inquiry. The UR's proposals would limit NIE's recovery of these costs to costs incurred in the period to October 2014.

(b) More than half the costs proposed by the UR for full cost pass-through under the connections element of the UR's Fund 2 proposals did not relate to the costs of new connections. Instead these costs relate to necessary alterations that are not funded from upfront connection charges.

5.310 We found that cost pass-through of the costs under *(a)* was reasonable on the basis that the final connection charges are regulated through other means. There is a risk of pass-through of excessive costs, but that comes from the risk that the regulation of connection charges in general is not effective. If that is the case, the appropriate solution would be an improvement to the regulation of connection charges rather than a departure from the UR's cost pass-through proposals. The cost pass-through of the costs under *(a)* would be a temporary arrangement as the 'subsidy' from the RAB has been terminated.

5.311 We decided on a cut-off date for the cost pass-through arrangement of 1 October 2015. Any costs incurred after this date would not be recoverable through NIE's RAB. This cut-off date is in line with the UR's proposals and its policy decisions in relation to the connections subsidy (see Section 9 for further information).

5.312 For the implementation of this aspect of our price control design, we decided that the actual value of the costs qualifying for pass-through should be added to NIE's distribution RAB in the year in which they arise. We did not determine any upfront allowance for these costs.

5.313 We did not identify any good basis to include the alteration costs falling under *(b)* above as part of the cost pass-through arrangement. We decided instead that these are treated as for other elements of NIE's expenditure with an upfront regulatory forecast and subject to the general cost risk-sharing mechanism.

5.314 The UR told us that it agreed with our approach of excluding these alteration costs from the pass-through arrangement. NIE told us that it had no objection provided that we determined an adequate upfront allowance.

5.315 It will be important that cost reporting arrangements are in place to ensure that only the ‘subsidy’ that is provided through the revenue control and RAB for portions of the connection charges that NIE levies on parties requiring new connections is treated as a pass-through expenditure.

D9: Pass-through of some operating costs and treatment of injurious affection

Summary

5.316 We decided that NIE should be reimbursed on a cost pass-through basis for the regulatory Licence fees that it faces. We did not specify cost pass-through arrangements for NIE’s rates liabilities or wayleave costs. Instead we made upfront forecasts that cover these costs and NIE will be financially exposed to these costs through the cost risk-sharing mechanism.

5.317 We decided that there should be a provision in NIE’s price control licence conditions for the UR to determine an allowance for costs relating to injurious affection, informed by the outcome of the Lands Tribunal determinations.

Introduction

5.318 In the current price control, some of the operating costs that NIE incurs are passed through, in full, to consumers. These relate to: the regulatory Licence fees that NIE pays; wayleaves; and network and business rates (forms of taxation on NIE’s premises and assets). These costs were £87 million in the RP4 price control period in 2009/10 prices.[62]

5.319 In its draft determination, the UR proposed that NIE should have some financial exposure to rates and wayleave costs. In its final determination, following arguments from NIE that such costs were uncontrollable, the UR proposed that rates and wayleave costs should be treated as pass-through costs for the RP5 price control period.

5.320 In addition, NIE identified possible costs associated with legal claims for injurious affection which it considered were so unpredictable as to be unsuitable for ex-ante regulation. Claims of injurious affection concerned diminution in value to a property caused by the existence or use of public works carried out under or in the shadow of compulsory powers.[63] NIE is currently in receipt of claims for injurious affection and the Lands Tribunal of Northern Ireland is considering a number of these claims.[64] NIE said that it was content with the proposal from the UR’s draft and final determinations to wait until the outcome of the Lands Tribunal cases before considering how to treat the associated costs.

5.321 In its initial submissions, the UR asked that we reconsider whether NIE should have some financial exposure to the costs relating to rates, wayleaves and injurious affection. This subsection sets out:

(a) the parties’ original submissions on rates;

(b) the parties’ original submissions on wayleaves;

(c) the parties’ original submissions on injurious affection;

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[62] UR draft determination, paragraph 7.12.
[63] NIE Statement of Case, p176.
[64] ibid, p176.

(d) third party submissions on pass-through of operating costs;

(e) Ofgem's approach to wayleaves, rates and injurious affection;

(f) our assessment (including review of responses to our provisional determination); and

(g) a point on implementation of the pass-though mechanism.

The UR's and NIE's submissions on rates

5.322 There was some confusion on the nature of the rates that NIE pays and which were the subject of a cost pass-through arrangement. The UR had originally drawn a distinction between rates that NIE pays in respect of its network, under the Valuation (Electricity) Order (Northern Ireland) 2003, and other rates it pays in relation to its other buildings. We established that the latter are very small and our consideration of potential cost pass-through arrangements is limited to the former, which NIE has referred to as the cumulo assessment.

5.323 NIE said:

> NIE's uncontrollable cost forecast in respect of rates relates entirely to the cumulo assessment which is based on transmission circuit length and MVA transformer capacity. The specific properties occupied by NIE do not form part of the cumulo formula.
>
> Apart from the cumulo assessment, the only rates payable are in respect of a property which is rented by NIE Powerteam at Fortwilliam in Belfast. The annual rates payable in respect of this property (approx. £40k per annum) are accounted for as part of NIE Powerteam's indirect costs; the cost is not included in the uncontrollable rates forecast which relates solely to the cumulo assessment.
>
> Except as described above, NIE does not pay rates on its buildings and offices.

5.324 NIE said that its rates were fixed by a statutory formula over which it had no control and, for that reason, it was appropriate that these costs were funded on a pass-through basis.[65]

5.325 The UR provided a refined position in light of NIE's clarifications:

> NIE T&D are and will continue to be rated under the prescriptive Valuation (Electricity) Order (Northern Ireland) 2003 until 1st April 2015 (http://www.legislation.gov.uk/nisr/2003/77/made). From 1st April 2015 this prescriptive (hard coded formulae driven) statutory rule will be repealed and replaced with a new method based on a more conventional (current GB) valuation model. GB moved away from a formula driven prescriptive method in 2005. A rating review was planned for Northern Ireland in 2010, to bring us into line with the GB practice. Nonetheless it was postponed due to the view that the economic conditions at the time were too delicate.

[65] NIE supplementary submission, p86.

However, NIE T&D will be meeting with the NI Land and Property Services (LPS) over the next few months to kick off the process of a ratings review. This review will result in implementing a new revised conventional (GB) valuation model that is set to take effect from the 1st April 2015. It is the aim of the LPS (where possible) to try and harmonise the ratings valuation calculation methods in Northern Ireland with those in GB with regard to utility companies rates.

One important point is under the current prescriptive valuation order NIE T&D have no right of appeal, but under the revised conventional valuation model from 2015, they will have the right to challenge and appeal the valuation. First with the Land and Property Services Commission Valuator and then beyond that with the Northern Ireland Lands Tribunal.

While there are a number of buildings that are 'excepted' and thus valued separately, we agree with NIE T&Ds assessment that the 'cumulo assessment' set out in the current valuation order will continue to be in place up to 2015 which is calculated based on the Transmission Circuit Length and MVA Transformer capacity and these factors are driven by network demand. However, following April 2015 these costs cannot be deemed as uncontrollable as NIE T&D will have some influence and right of appeal under the newly revised conventional valuation model.

The UR's and NIE's submissions on wayleaves

5.326 In its initial submissions to the CC, the UR said the following in respect of wayleaves:

> These are payments that NIE T&D is required to make to landowners in respect of equipment that NIE T&D owns on their land. Unlike the position with respect to rates, there are no regulations that stipulate the amount to which landowners are entitled. Rather, those sums fall to be negotiated between the landowners (or their collective representatives) and NIE T&D. NIE T&D contends that they are uncontrollable because it treats the payments made by Scottish Power as a precedent for its negotiations. But that is just the choice that NIE T&D has made (no doubt reflecting the fact that it has no incentive to reduce costs in this area), rather than evidence that it does not have a choice. We note that Ofgem treats wayleaves as controllable, and consider that this is a matter that would benefit from the Commission's detailed appraisal.

5.327 NIE said:[66]

> NIE's current processes for paying wayleaves is efficient and UR's proposal that NIE might negotiate lower wayleave rates in NI would significantly increase the cost of administration and it is extremely unlikely that lower rates could be agreed.
>
> Wayleaves are therefore an uncontrollable cost and should be treated as a pass-through.

[66] NIE supplementary submission, p87.

5.328 NIE said that it did not negotiate wayleave payments on a case-by-case basis with individual landowners. Rather, its rates were based on ScottishPower's wayleave rates which were in line with the rates recommended by the Electricity Networks Association (ENA) which acted on behalf of the UK electricity network companies. NIE said that its approach had significant benefits in ensuring that landowners and their representatives were satisfied that the payment being made by NIE was fair and non-discriminatory and that any challenge to those rates was unlikely to be successful. NIE considered its current approach efficient in light of administrative costs.

The UR's and NIE's submissions on injurious affection

5.329 In its draft determination, the UR proposed the following in relation to costs associated with injurious affection:[67]

> NIE T&D included £11.4 million for injurious affection costs under uncontrollable opex. Injurious affection is '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'.
>
> NIE T&D believes that the number of claims and the trend towards significant settlements will have a similar impact as it has on the GB DNOs. However, to date this has not been NIE T&D's experience.
>
> We are therefore minded to treat this as an uncertain cost. However we cannot agree to an allowance proposed as there are no historical costs on which to determine a suitable baseline. We will therefore wait for the results of the Lands Tribunal before considering how to treat these costs.

5.330 In its initial submission, the UR proposed that we reconsider the treatment of costs associated with injurious affection:[68]

> Injurious affection: These are damages that NIE T&D anticipates needing to pay as a result of litigation (or potential litigation) from landowners in respect of any diminution in the value of their property caused by the existence or use of public works carried out under, or in the shadow of, compulsory powers. So far no such claims against NIE T&D have proceeded to judgment. There is therefore naturally a significant degree of uncertainty as to the costs associated with these claims, and they are, to some extent, out of NIE T&D's control. However, as with all litigation which is capable of settlement, NIE T&D must have some control over the outcome and we note that Ofgem treats such costs as controllable and consider that this is, again, a matter that would benefit from the Commission's detailed appraisal.

5.331 NIE said that it was content with the UR's (previous) proposed approach of awaiting the results from the Lands Tribunal before considering how to treat these costs and elaborated as follows:[69]

> NIE is currently in receipt of a number of claims for injurious affection and the Lands Tribunal of Northern Ireland is currently considering the

[67] UR draft determination, p107.
[68] UR Statement of Case, UR-2, p9.
[69] NIE Statement of Case, p176.

> legal and valuation issues associated with a number of these claims. The outcome of this process is uncertain. While precedent exists in GB, there is no precedent for the payment of such claims in Northern Ireland.
>
> It follows that the costs associated with injurious affection that NIE will incur in the next few years are so unpredictable as to be unsuitable for ex ante regulation. A different approach may be possible in later regulatory periods once the scale of these costs becomes known.

Third party submissions on pass-through of operating costs

5.332 Some third parties made submissions in relation to the cost items proposed in this section that provide further context.

5.333 The Ulster Farmers' Union (UFU) said that contrary to the UR's position, rates and wayleaves were not semi-controllable.[70] The UFU continued that it was concerned with the UR's proposals that the level of wayleave costs during the RP4 price control period was used as a baseline for an RP5 allowance. The UFU said that it feared this approach could mean a reduction in the wayleave payments to local landowners which it considered should be wholly unacceptable. The UFU felt that wayleave rates should be rising as new equipment was brought into its members' land during RP5.

5.334 Bombardier Aerospace urged careful consideration on the treatment of uncontrollable opex and how consumers were protected if there was cost pass-through.

5.335 Following our provisional determination, we received submissions on the treatment of pass-through costs from Phoenix Natural Gas Limited and the Consumer Council. We address the specific points raised by these parties in the relevant parts of our assessment below.

Ofgem approach to wayleaves, rates and injurious affection

5.336 In 2009, Ofgem set price controls for electricity distribution companies for a five-year period from April 2010. For this price control, Ofgem did not treat wayleave costs or injurious affection costs as cost pass-through items. Instead it included these costs in its ex ante allowance, and the GB DNOs are exposed financially to these costs.

5.337 Ofgem is currently carrying out a price control review for electricity distribution companies (RIIO ED1), intended to apply from April 2015. In March 2013 it published a decision on its strategy for the price control. Ofgem plans to include costs relating to wayleaves and injurious affection as part of the ex-ante allowance.[71]

5.338 Ofgem's approach for RIIO ED, Ofgem's March 2013 strategy decision, said the following in relation to business rates:[72]

> Our decision on business rates is to introduce the same incentivisation approach to business rates as applied to transmission and gas distribution licensees. This effectively retains business rates as a pass through from the next revaluation due in 2017, subject to DNOs demonstrating that they have taken appropriate actions to minimise the valuations. As a result of our decision of October 2012 to introduce measures to miti-

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[70] UFU submission, 31 May 2013.
[71] 'Strategy decision for the RIIO-ED1 electricity distribution price control: tools for cost assessment', p32.
[72] 'Strategy decision for the RIIO-ED1 electricity distribution price control: uncertainty mechanisms', p34.

gate charging volatility, this mechanism will operate with a lag. In practice this will mean that an allowance is provided based on the expected value of the pass through cost for the eight years of the price control. The mechanism will adjust this ex ante allowance to true up for actual costs incurred, but with a two year lag. The true-up will take account of financing costs from the delay in recovery of actual costs incurred.

Our assessment

5.339 The UR's approach to whether certain operating costs are to be subject to full cost pass-through turns on a view as to whether they are 'controllable' or 'uncontrollable'. The concept of 'uncontrollable' costs is reflected in the drafting of the current Licence conditions, which refer to 'uncontrollable operating costs'.

5.340 We do not consider that decisions on whether certain operating costs should be subject to full cost pass-through should rest on an assessment of whether the costs are 'controllable' or 'uncontrollable' or even 'semi-controllable'. Factors that affect the extent to which NIE can influence certain operating costs are relevant to decisions on whether to apply cost pass-through. As we highlight below, these not the only relevant considerations.

5.341 Further, the concept of 'uncontrollable' costs is not straightforward to apply. NIE has some influence over all the costs under consideration. For costs such as those relating to injurious affection, NIE will need to make decisions relating to the potential settlement of legal claims. It is also true for other items that have been described as uncontrollable.

5.342 An attempt to draw a firm distinction between controllable and uncontrollable is not what matters most for price control purposes. Our options included the following in relation to the operating costs considered in this section:

(a) Treat these costs in the same way as the remainder of NIE's opex, in which an upfront forecast of NIE's efficient expenditure requirements is made and NIE is subject to a cost risk-sharing mechanism in relation to overspends and underspends against the forecast. Under this approach, NIE would be financially exposed to these costs. A downside of this approach is the time and resource required by the regulator (or us) to determine a reasonable forecast of these costs. Another downside is the potential that the forecast is too high or too low.

(b) Treat these costs on a full pass-through basis. This approach does not suffer from the forecasting risk that arises under *(a)*. However, there is a risk of exposing consumers to unnecessarily high costs if NIE has some influence over its costs but faces no financial incentive to reduce or restrain them. There is also a risk of distorting NIE's working practices if it faces choices which affect the extent which the costs it incurs fall under the category of costs subject to full cost pass-through. For cost pass-through to be practical, it is necessary that the costs subject to pass-through can be separately identified and reported.

5.343 These are not the only plausible options. For each cost item, it may be possible to develop an alternative to the options above that provides some protection to consumers and NIE against the uncertainty in forecasting costs under approach *(a)* above but which does not completely remove NIE's financial exposure to the costs it incurs. Ofgem refers to such arrangements as 'uncertainty mechanisms'.

5.344 Factors which underpin views about the extent to which costs are 'controllable' by NIE will be relevant to the risks under the pass-through approach *(b)* above. But that is not the only consideration. For instance, the time and effort necessary to obtain a reasonable expenditure forecast, and the scale of the cost item, is relevant to decisions about whether to use approach *(a)* or something else.

5.345 In its response to our provisional determination, Phoenix Natural Gas Limited (PNGL) said:[73]

> The Commission has stated its view that whether or not a particular cost should be subject to full pass-through to customer should not depend on whether that cost is controllable, or even semi-controllable. This is a departure from the regulatory norm. PGNL considers that the established practice that uncontrollable costs should be treated as pass-through is in the public interest. Exposing companies to risk that they are unable to control or mitigate is likely to push up the cost of capital.

5.346 We disagreed with PGNL's description of our provisional determination. We did not say that whether or not a particular cost should be subject to full pass-through to a customer should not depend on whether that cost is controllable, or even semi-controllable. Instead, we said that factors that affect the extent to which NIE can influence costs are relevant to decisions on whether to apply cost pass-through, but that these are not the only relevant considerations.

Our assessment: Licence fees

5.347 Both parties proposed that Licence fees be treated as a cost pass-through item. This approach seems reasonable. Indeed, the UR has more influence on the level of Licence fees than NIE and it is no bad thing if the UR appreciates that the level of these will feed into consumer charges.

Our assessment: NIE's rates liabilities

5.348 NIE forecast rates of more than £12 million per year from April 2012 (2009/10 prices, source: NIE BPQ).[74] This is a large amount of money in the context of the price control review.

5.349 The Northern Ireland Finance Minister announced that a Northern Ireland ratings revaluation would take place in April 2015. The outcome of this revaluation is unknown. We would expect NIE to have some opportunity to make representations as part of the revaluation process and even to make use of appeal procedures if it was concerned that the revaluation was unfair.

5.350 In our provisional determination, we provided an upfront allowance for NIE's rates liability in the period from 1 April 2012 to 30 September 2017, with NIE's expenditure on rates subject to the cost pass-through mechanism applicable to other areas of expenditure. We explained that it was important to ensure that NIE is not financially indifferent to the outcome of the anticipated Northern Ireland ratings revaluation. Further, we said that we did not consider uncertainty about the outcome of the potential Northern Ireland ratings revaluation to be sufficient to mean that it would be inappropriate for NIE or consumers to face financial risk around a regulatory forecast of NIE's rates liability.

[73] PNGL response to provisional determination, p4.
[74] Section 10 provides forecasts of NIE's rates.

5.351 In its response to our provisional determination, NIE objected to our proposal to set an upfront allowance for rates and to include this within the scope of the cost risk-sharing mechanism. NIE accepted that it had some opportunity to make representations as part of the revaluation process, but said that there was still a very considerable margin of discretion on the part of those conducting the revaluation to impose a rates bill that was substantially different (and more likely greater) than the ex ante allowance that we had included in our provisional determination. NIE said that our provisional determination revealed a willingness to expose NIE to a level of financial risk that was disproportionate to NIE's ability to influence the outcome. It said that our proposed approach was at odds with Ofgem's position on business rates for RIIO ED1. NIE reported that Ofgem said that it would provide cost pass-through of business rates subject to the DNOs demonstrating that they had taken appropriate actions to minimize the valuations. NIE argued that Ofgem's approach was a more proportionate and fairer approach to incentivizing NIE to keep its rates bill to a minimum in the context of the forthcoming revaluation. NIE proposed that it should be adopted in preference to the approach proposed in our provisional determination.[75]

5.352 We reconsidered the approach to rates following NIE's response to our provisional determination. We decided not to change the approach to rates from that set out in our provisional determination, for the reasons below.

5.353 We were concerned that adopting Ofgem's approach, as proposed by NIE, would be less effective than the proposal in our provisional determination and that it would involve a higher regulatory burden and greater risk of future disputes.

5.354 Under the Ofgem approach, it would be necessary for the UR to decide whether NIE had demonstrated that it had taken appropriate actions to minimize its exposure to rates through the revaluation process. The unique nature of NIE's rates revaluation process meant that it would be difficult to assess whether NIE had 'taken appropriate actions to minimise the valuations'. We were unable to identify a way that such an assessment could be done well, which suggested that the approach may not be effective in ensuring that NIE takes appropriate action to limit its rates liability. In contrast, the approach proposed in our provisional determination would provide NIE with a clear financial incentive to limit its rates liability.

5.355 Further, under NIE's proposal there would be risks of disputes between NIE and the UR about any assessment made by the UR of whether NIE had taken appropriate actions to minimize its exposure to rates. This could distract the parties from other matters and involve resource costs.

5.356 The serious difficulties that we identified with the approach proposed by NIE in its response to our provisional determination might be acceptable if we found that the scale or nature of the financial risk that NIE would be exposed to under the approach set out in our provisional determination approach to rates was inappropriate. We requested further information from NIE on its historical rates liabilities. NIE's response provided the following information:

(a) NIE's annual rates liability was in the range of £10.6–£14.1 million (2009/10 prices) over the period from 2002/03 to 2012/13. The upper figure of £14.1 million was something of an anomaly because it included adjustments for previous years with respect to increases in circuit length and transformer capacity. Excluding that figure narrows the range to £10.6–£12.9 million.

[75] NIE response to provisional determination, pp169–170.

(b) The 2008/09 rates reassessment had no effect on NIE's rates liability as it was never implemented.

(c) The most recent revaluation came into effect on 1 April 2003 and increased NIE's rates liability from £10.6 million in 2002/03 to £11.2 million in 2003/04 (2009/10 prices).

(d) The valuation before that took effect on 1 April 1997. That revaluation increased NIE's rates liability from £6.8 million in 1996/97 to £9.3 million in 1997/98 (2009/10 prices).

5.357 We found nothing in this information or any other aspect of NIE's submissions that indicated that the approach we had proposed in our provisional determination would expose NIE to excessive or inappropriate financial risks. In reaching this view, we recognized that the rates revaluation is not scheduled until April 2015, which would mean that, at most, any revaluation would only affect NIE's rates liability for the last 2.5 years of the price control period. We also recognized that any variances between our upfront allowance and NIE's actual rates liability would be subject to the 50 per cent cost risk-sharing mechanism (paragraphs 5.49 to 5.96).

5.358 Towards the end of our inquiry, NIE submitted further information on the forthcoming rates revaluation which is expected to affect NIE from 1 April 2015. NIE said that it had held a meeting with a Senior Valuer from LPS and that the meeting highlighted fundamental changes to the way in which NIE's rates liability would be assessed. NIE said that our provisional decision to treat rates as a controllable cost was inappropriate. As it had said in its response to our provisional determination, NIE said that Ofgem's proposed treatment of rates for RIIO ED1 would be a proportionate and fair approach. We did not agree with NIE's further submission. We have not sought to characterize NIE's costs as either 'controllable' or 'uncontrollable' costs. Instead, we recognized that NIE has some ability to influence its rates liability. For the reasons set out above (paragraphs 5.348 to 5.357), we did not consider it appropriate for NIE's rates liability to be passed on to consumers in full or to use the Ofgem approach that NIE referred us to. Finally, we did not consider that the further information provided by NIE, at a late stage in our inquiry, was sufficient to warrant adjustments to our upfront allowance for NIE's rates liability in the period to 30 September 2017.

5.359 The Consumer Council welcomed our approach of removing NIE's rates (and also wayleaves) from treatment as a pass-though cost item, as it had argued at the outset of the price control process that these were items that NIE was able to exert some control over.[76]

5.360 PNGL responded to our provisional determination on rates.[77] It said that it did not consider that reasonable and accurate rates forecasts could be determined given the anticipated rates revaluation. We did not accept the potential implication of PNGL's submissions that elements of costs should be passed through to consumers unless we could determine 'accurate' forecasts of them. Nonetheless, in making our decision on the treatment of rates, we took account of the uncertainty about future rates liabilities related to the anticipated revaluation. PNGL also proposed that we adopt a version of Ofgem's approach to business rates, under which business rates were treated as a pass-though item subject to the DNOs demonstrating that they had taken appropriate actions to minimize rates. We considered and rejected such an approach for the reasons set out in paragraphs 5.353 to 5.357.

[76] Consumer Council response to provisional determination, p4.
[77] PNGL response to provisional determination, p4.

Our assessment: wayleaves

5.361 Ofgem does not treat wayleaves as a cost pass-through item. The indirect cost benchmarking analysis put to us by both NIE and the UR used measures of NIE's costs that included NIE's wayleave payments. Similarly, we included wayleaves costs in the group of costs subject to our benchmarking analysis of NIE's indirect and IMF&T costs (see Section 8). We did not identify a reason why NIE's wayleaves costs should be treated differently to other elements of NIE's indirect costs.

5.362 The submission to the inquiry from the UFU suggested that NIE can have a significant influence on the level of wayleave payments to landowners.

5.363 Whilst NIE asserted that its approach to wayleaves was efficient, its submission also revealed that it had potentially difficult trade-offs to make between the costs of way-leave payments to landowners, administrative costs of its wayleave payment process and the benefits of landowners' goodwill. In such a context, it did not seem appropriate for the price control to leave NIE financially indifferent to its wayleaves costs.

5.364 We decided not to treat costs associated with wayleaves as a pass-through item. Instead, we included wayleaves costs in the allowance for NIE's indirect costs and IMF&T costs that we determined using benchmarking analysis (Section 8).

5.365 NIE told us that it wanted to emphasize that departing from its current practice of basing wayleave rates on ScottishPower's wayleave rates was likely to lead to an increase in both the costs of wayleaves and the costs of administration. We express no view on whether NIE should make such a change of practice. This will be for NIE to decide.

Our assessment: injurious affection

5.366 In its draft determinations, the UR proposed an approach under which it would wait for the results of the Lands Tribunal before considering how to treat costs associated with injurious affection. NIE endorsed this approach. In its initial submissions, the UR suggested that we reconsider the appropriate approach.

5.367 The UR described its proposed approach in its draft determinations as one in which costs associated with injurious affection would be treated 'as an uncertain cost' and proposed that it would 'wait for the results of the Lands Tribunal before considering how to treat these costs'. The UR provided no further information in its draft and final determinations on what this would mean in practice or what its approach might be following the results of the Lands Tribunal. However, under the draft Licence modifi-cations that the UR published alongside its final determinations, the proposal was that 'amounts incurred by the Licensee in respect of injurious affection' would be subject to full cost pass-through.[78]

5.368 If the draft Licence conditions proposed by the UR were implemented, NIE would be entitled to full cost pass-through of costs incurred in respect of injurious affection. The UR might seek to amend the treatment of these costs, following the results of the Lands Tribunal, through subsequent Licence modification. However, Licence modifi-cation currently requires NIE's consent. NIE would be able to block any change in treatment which it does not consider preferable to full cost pass-through. While the UR could refer the matter to the CC, the UR might consider the treatment of injurious

[78] UR Draft Licence Modifications, Clause 4.4.

affection to be insufficiently important on its own to justify a reference. We consider that, under the draft Licence modifications proposed by the UR, the UR would be in a weak position to implement an alternative to cost pass-through following the Lands Tribunal decisions, unless it made the terms of such an arrangement sufficiently attractive to NIE for NIE to accept the higher financial risk that would come from a move away from full cost pass-through.

5.369 There are risks of distorting NIE's expenditure decisions if it faces no financial exposure to costs associated with injurious affection but is exposed financially to the costs of other decisions which affect the former (eg potential network diversions). In its RIIO ED1 strategy decision consultation paper on tools for cost assessment,[79] Ofgem said that, in relation to the options it was considering for the treatment of claims of injurious affection, it was important that the relative costs of settling a claim versus triggering a diversion were also considered. If NIE faced financial exposure in relation to network diversions but was fully insulated from the costs it incurs settling claims, it may favour the latter even if the former would bring the lowest overall cost.

5.370 There is a further risk that if injurious affection is a cost pass-through in the next price control period, but NIE expects it to face some financial exposure to these costs in the future (in line with the UR's suggestions and Ofgem policy), it may face financial incentives to settle as many claims as possible in the period whilst cost pass-through applies. This could expose consumers to unnecessarily high costs.

5.371 Against these concerns of inefficiency, the costs that NIE needs to incur in relation to injurious affection, and the timing of these costs, is difficult to predict. There is a risk for consumers, for example, from setting an upfront forecast that is too high.

5.372 We identified four approaches:

(a) full cost pass-though, as proposed in the UR's draft Licence conditions;

(b) no allowance for injurious affection within the price control, but a provision for the UR to amend the revenue control on NIE to include an upfront allowance once the results from the Lands Tribunal are known and NIE's costs can be forecast with more confidence;

(c) make a forecast based on any available data on the costs incurred in relation to injurious affection by GB DNOs; and

(d) make a forecast as under *(c)* but specify that this only comes into effect as an allowance for NIE once the results from the Lands Tribunal are known (this rests on this trigger point being defined).

5.373 The UR expressed a preference for option *(b)*. The UR considered options *(c)* and *(d)* too risky given the uncertainty as to the outcomes of the Lands Tribunal ruling. In relation to the approach under option *(c)*, the UR identified some issues that arose in seeking to use data from other DNOs. The UR told us that the relevant costs related to land value which varied between locations and it would be concerned about setting an allowance for NIE that was higher than necessary. The UR also expected that many of the more significant costs for NIE would relate to its 275 kV network whereas GB DNOs did not operate at 275 kV.

[79] Ofgem RIIO-ED1 Strategy consultation paper: tools for cost assessment, September 2012, p32.

5.374 NIE told us that it saw difficulties with each approach apart from full cost pass-though under option *(a)*. NIE said that option *(b)* would provide no effective legal recourse in the event that the UR failed to determine an appropriate upfront allowance once the results of the Lands Tribunal were known. NIE said that option *(b)* would expose it to an unacceptable degree of regulatory risk. In relation to option *(c)*, NIE said that it would not be possible for the CC to produce a meaningful forecast of NIE's costs in relation to injurious affection by reference to the costs incurred by GB DNOs. NIE said that option *(d)* rested on the feasibility of option *(c)* so the concerns in relation to option *(c)* applied; NIE also said that specification of a trigger point would be difficult.

5.375 We had strong reservations about an arrangement in which NIE could pass through any costs it incurs in relation to legal claims (whether valid or not) directly to consumers and in which NIE would face no financial exposure to the action it takes in this area. This is especially so if, as noted above, NIE expects cost pass-through to be a temporary arrangement after which it may be exposed financially: NIE might rush to settle claims that it would not otherwise pay so as to maximize the benefits it receives from the cost pass-through arrangement.

5.376 We chose paragraph 5.372*(b)* above: there will be no upfront allowance for costs relating to injurious affection but a provision for the UR to make an allowance in the future following the Lands Tribunal determination. In the absence of other data sources, we expect the UR to give weight to data from GB DNOs but also to take account of any differences between the Lands Tribunal determination and relevant precedent from GB.

5.377 We accept that NIE faces some regulatory risk under this option, but do not consider it unreasonable. Whilst the scale of costs is unknown, the order of magnitude is likely to be small in relation to NIE's regulated transmission and distribution businesses. NIE has forecast, albeit tentatively, injurious affection costs of £2.5 million per year.[80]

5.378 In its response to our provisional determination, NIE did not object to paragraph 5.372*(b)* but said that it was concerned that it provided NIE with no effective legal recourse in the event that the UR failed to determine an adequate upfront allowance for injurious affection once the results from the Lands Tribunal were known. To limit the UR's discretion in relation to the determination of the future allowance, NIE requested that we specify the parameters and considerations which the UR was to have regard to when determining the allowance. NIE said that this would serve to discipline the UR (and increase the prospect of a well-founded decision in due course) and provide NIE with a more robust basis for any judicial review challenge by making clear to the court what criteria the UR should have applied in making its determination. NIE also specified some constraints or obligations that it thought the UR should face in determining an allowance for injurious affection costs.[81]

5.379 In light of the points raised by NIE, we considered it appropriate to clarify that, in setting an allowance for injurious affection, the UR should consider not only the costs that NIE will incur in the future in relation to injurious affection but also any costs which NIE has efficiently incurred in the period since 1 April 2012 which are not allowed for in our determination of a new price control for the period from 1 April 2012 to 30 September 2017.

5.380 We did not consider it necessary to impose further constraints or obligations on the UR in relation to its determination of an allowance for the costs of injurious affection. We would expect the UR to set a reasonable allowance in light of submissions from

[80] NIE response to provisional determination, p171.
[81] ibid, pp171–172.

NIE and consultation with stakeholders. We considered it a disproportionate regulation and premature to seek to establish what method or criteria the UR should use to determine an appropriate allowance once the Lands Tribunals decisions are known. If we were to specify the method or requirements that the UR must follow more precisely, there are risks that we could inadvertently prevent the UR from taking an approach that would otherwise be sensible.

5.381 We also received a response to our provisional determination on the treatment of injurious affection costs from Powerline Compensation Ltd (Powerline). Powerline was concerned that our approach could provide an opportunity for NIE to seek further delay on claims for injurious affection. Powerline said that its preference, as the representative of some 1,000 homeowners in Northern Ireland, would be for the CC to state clearly that it would encourage NIE to settle all cases in an acceptable and timely fashion based on mainland settlement evidence if and when the Tribunal found that compensation was indeed payable in these cases in Northern Ireland.[82] We did not agree with this submission. We decided that it was for NIE to determine how and when to settle claims, in light of its legal obligations and the Lands Tribunal's decisions. We considered that our task was confined to making an appropriate allowance for the costs that NIE may face in relation to such claims as part of our determination of a modified restriction on NIE's maximum regulated revenue.

Implementation of pass-through mechanism

5.382 NIE raised a concern with the draft Licence modifications proposed by the UR to implement a cost pass-through mechanism for specified operating costs. The UR's proposed mechanism would make use of an upfront forecast of the level of the relevant costs, with adjustments made if out-turn costs are higher or lower than this. NIE raised two points:[83]

(a) The upfront forecast of the level of the relevant costs proposed by the UR was lower than NIE's forecast (the difference related to rates and wayleaves).

(b) The proposed Licence modifications contained no mechanism for the recovery of any shortfall in costs against the forecast in the last year.

5.383 NIE said that both problems could be overcome by defining the relevant costs as pass-through costs without specifying ex-ante value, which NIE said was the approach under the current Licence conditions. The effect of NIE's approach was that NIE would need to make its own forecast of these costs for the purposes of calculating its maximum regulated revenue in a particular financial year and would subsequently need to deal with any difference between its forecast and out-turn costs through an adjustment through the corrector factor (KD_t), in the current Licence.

5.384 We accepted NIE's proposed approach to implementation. Nonetheless for the purposes of forecasting the impact on our proposals on prices, we make forecasts of costs subject to pass-through.

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[82] Powerline response to provisional determination.
[83] NIE Statement of Case, p112.

D10: Other terms to remove from current Licence conditions

Summary

5.385 We decided to remove several elements of NIE's current price control Licence conditions that are no longer necessary or consistent with other elements of our determination.

Assessment

5.386 To implement the price control design set out above will require a series of changes to NIE's Licence conditions. There are elements of the existing Licence conditions that should not be maintained.

5.387 We identified the following elements as redundant:

(a) the Powerteam profit-sharing term (PPS_t);

(b) the revenue cap implemented through the PC_t term (and the related RRF_t term); and

(c) provision (viii) under the D_t term.

5.388 The UR told us that it agreed that the elements above were redundant.

5.389 The redundancy of the Powerteam profit-sharing term arises from our view that the costs reported for NIE which may affect the calculation of NIE's maximum regulated revenue or RAB should not include the Powerteam profit margin. Rather than seeking to share Powerteam's profit between consumers and NIE's investors, we propose that the price control is set in a way that does not expose consumers to any NIE Powerteam charges to NIE that are in excess of NIE Powerteam's costs.

5.390 The revenue cap implemented through the PC_t term is an element of the current price control Licence conditions which the parties did not draw attention to in their submissions to us. For example, its existence was not highlighted in NIE's description of the RP4 price control.[84] This term seemed to be treated by the parties as redundant. Neither of the parties has made a case for maintaining it. We did not identify a good reason to do so.

5.391 Provision (viii) under the D_t term provides for the maximum regulated revenue to be adjusted to allow for additional costs approved by the UR. This term has been used by the UR on a number of occasions to increase NIE's maximum regulated revenue during the RP4 price control period. We consider it to be no longer necessary or appropriate. The following points seem relevant in this regard:

(a) The current Licence conditions already include a change of law provision which allow maximum regulated revenue to be adjusted by the UR in cases of change of law. We do not propose the removal of the change of law provision (COL_t) and propose Licence modifications to ensure that it continues to apply.

(b) We considered above the potential to allow flexibility within the price control for the UR to approve adjustments to maximum regulated revenue and RAB in light

[84] ibid, pp402–403.

of the expenditure requirements that arise in relation to specified activities (eg investment in transmission system capacity).

(c) The cost risk-sharing mechanism described earlier in this section provides some financial protection against unexpected cost increases.

(d) If both NIE and the UR believe that the price control should be adjusted to provide NIE with more money, they could agree Licence modifications to this effect. This process might involve higher administrative costs than approval for additional funding under the D_t term, but also has potential benefits in terms of transparency and accountability.

5.392 NIE told us that it had no objection to the change in relation to the Powerteam profit-sharing term and the revenue cap implemented through the PC_t term, but that the position with regard to the D_t term was more complicated. NIE said that if the 'catch all' D_t term was removed, a series of specific further elements were needed:

(a) The recovery of costs effectively promised to NIE under previous regulatory decisions.

(b) Additional costs that NIE might incur in relation to Enduring Solution.

(c) A mechanism to allow recovery of costs associated with exceptional weather events that cost NIE more than £1 million. NIE proposed that it received additional revenue, in such cases, to cover its costs.

(d) A mechanism to allow NIE to recover bad debt from other customers.

5.393 In light of the above, we decided that the Licence modifications to remove provision (viii) of the D_t term are accompanied by:

(a) a provision to allow NIE recovery of specific costs approved under previous regulatory decisions by the UR, as specified in paragraph 5.392*(a)*;

(b) a provision for the UR to make an adjustment to NIE's price control for significant changes in the specification of the service that NIE is required to provide in relation to market systems and the Enduring Solution (such adjustments should be subject to consultation and published documentation); and

(c) a mechanism to ensure that NIE can recover bad debt from other customers. This seems compatible with the notion of an aggregate revenue control with adjustments for over- and under-recovery.

5.394 We provide in paragraphs 10.356 to 10.368 our assessment of which specific costs approved under previous regulatory decisions by the UR should be included in the calculation of NIE's maximum regulated revenue from 1 April 2012 to 30 September 2017. This includes some costs that we had identified in our provisional determination and our assessment in relation to some further costs that NIE identified in its response to our provisional determination and subsequent submissions.

5.395 We were not persuaded by NIE's proposals that the price control is reopened in cases of storms that cost more than £1 million. NIE did not establish the need for such a mechanism and we were concerned that it could expose consumers to inefficient costs. We included an expenditure allowance for atypical weather events as part of our cost assessment in Section 10.

6. Regulation of quality of service and revenue protection income

Introduction and summary

6.1 In Section 5 we considered the design of a new price control for NIE, in light of our finding of the ways in which the current price control licence conditions operate against the public interest. This section considers several further aspects of price control design which concern the regulation of NIE's quality of service and the price control treatment of NIE's revenue protection activities. We take the following issues in turn:

(a) guaranteed standards;

(b) customer interruptions incentive scheme;

(c) electrical losses incentive scheme; and

(d) revenue protection and illegal abstraction of electricity.

6.2 Appendix 6.1 provides further information on the parties' submissions on these issues, some related matters and our assessment of them.

Guaranteed standards

6.3 NIE is currently required to meet a series of standards concerning aspects of its service to consumers. 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.

6.4 Some of the standards give customers experiencing shortfalls against standards a right to specified amounts of 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 consumer following a fault, it must pay the consumer £50, and an additional £25 for every 12 hours that the electricity stays off after the first 24 hours.

6.5 The specification or implementation of guaranteed standards are not the subject of our inquiry since they are not part of the price control licence conditions referred to us. While NIE has concerns about the UR's interpretation of the current standards and about potential future changes to the standards, we did not consider that these are matters that we should seek to resolve.

Customer interruptions incentive scheme

6.6 The price controls for GB electricity distribution companies include a financial incentive scheme concerning the number and duration of interruptions to customers' electricity supplies. Both NIE and the UR proposed the introduction of such a scheme in Northern Ireland.

6.7 The introduction of a well-designed interruptions incentive scheme for NIE would be reasonable. However, the specification of an interruptions incentive scheme is a complex matter. A poorly designed scheme could be worse than no scheme and impose unnecessary costs on consumers. NIE and the UR disputed several important aspects of the design and calibration of such a scheme.

6.8 We did not find that the absence of such a financial incentive scheme operated against the public interest and we have not included the introduction of such a scheme in our final determination.

6.9 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.

6.10 In its response to our provisional determination, the UR said that it had a concern that the potential benefits to NIE from deferring capex (under the arrangements in relation to investment deferral set out in Section 5 (paragraphs 5.134 to 5.214) would not be offset by an incentive on NIE to maintain customer interruptions and customer minutes lost at current levels. The UR said that this would distort NIE's decision further towards avoiding capital investment. The UR said that some form of obligation to maintain current standards would be welcome.[1]

6.11 NIE already has statutory obligations in relation to maintaining its network.[2] Further, we have decided that NIE should report its performance in terms of customer interruptions and customer minutes lost and explain any shortfalls against its forecast performance. We considered that the existing obligations combined with additional reporting would provide some discipline to prevent NIE from reducing service quality through deferral of planned investment.

6.12 Nonetheless, we considered whether some form of obligation to maintain current standards, as the UR suggested, could provide additional safeguards for consumers. The UR did not specify how its proposed obligation would work in practice. We did not think that a general obligation to 'maintain current standards' would be effective as an enforceable constraint that goes beyond NIE's existing obligations. We considered a more specific obligation for NIE to ensure that its performance against measures of customer interruptions and customer minutes lost does not fall below some specified threshold based on recent levels of performance. However, there is year-to-year volatility in NIE's performance against these measures and NIE's performance is influenced by external factors such as the weather. It did not seem appropriate to require NIE to do everything in its power to avoid measured performance being worse than the specified threshold. While this is an issue that the UR and NIE may consider further in future price control reviews, we did not include any additional obligation on NIE in our final determination.

Electrical losses incentive scheme

6.13 In its RP5 proposals, the UR set out its ambition to introduce a financial incentive scheme for NIE concerning the volume of electrical losses on its network. The UR did not include a losses incentive scheme in its RP5 proposals but envisaged introducing such a scheme during the RP5 period following work to resolve data issues.

6.14 Ofgem has withdrawn the electricity distribution losses incentive scheme that previously applied to distribution companies in GB. That scheme had not worked as intended.

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[1] UR response to provisional determination, UR-147, paragraph 63.
[2] The Electricity (Northern Ireland) Order 1992, Article 12.

6.15 Neither NIE nor the UR proposed that we should introduce an incentive scheme for electrical losses as part of our inquiry, though both were keen that we did not suggest that it would be inappropriate for such a scheme to be introduced in the future.

6.16 NIE has a statutory duty to 'develop and maintain an efficient, co-ordinated and economical system of electricity distribution'.[3] We did not find that the absence of a specific financial incentive scheme for electrical losses from NIE's price control licence conditions operated against the public interest.

6.17 We have not included the introduction of a losses incentive scheme in our final determination.

Revenue protection and illegal abstraction of electricity

6.18 The illegal abstraction of electricity from NIE's electricity system indirectly imposes costs on other electricity consumers who are consuming lawfully. The act of consuming electricity illegally does not directly impose a cost on NIE because NIE is not exposed financially to any losses of electricity on its network.

6.19 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.

6.20 NIE has certain powers to recover money directly from electricity consumers in cases of illegal abstraction of electricity. In 2009/10, NIE received around £425,000 in revenue arising from its revenue protection activities. This figure was around £660,000 in 2010/11 and £434,000 in 2011/12 (all 2009/10 prices). NIE also incurs costs investigating and dealing with instances of illegal abstraction.[4]

6.21 We considered how the income and costs relating to NIE's revenue protection activities should be treated as part of the new price control. The subsections below set out:

(a) the proposal on revenue protection from our provisional determination;

(b) the parties' responses to our provisional determination;

(c) our assessment of NIE's proposals for an alternative incentive scheme; and

(d) our decision in relation to the treatment of NIE's income and costs from revenue protection activities in the period 1 April 2012 to 30 September 2017.

Our provisional determination

6.22 In our provisional determination we proposed an approach that was similar to, but extended, the current incentive scheme that applies in the case of revenue protection income in relation to cases of vacant non-domestic premises.[5]

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[3] ibid, Article 12.
[4] NIE told us that these amounts are the gross income received and that 50 per cent of the income received in respect of the incentive scheme (net of costs) and 100% of other revenue not covered by the incentive scheme is passed back to customers via a reduction in UoS entitlement. NIE said that the net revenue retained by NIE only arises in respect of the incentive arrangements and that the incentive was £142,000 in 2009/10, £281,000 in 2010/11 and £187,000 in 2011/12 (all figures in 2009/10 prices).
[5] Appendix 6.1 provides further information on the current scheme.

6.23 We proposed that 50 per cent of the income that NIE receives each year in relation to revenue protection activities (including money recovered by NIE from parties who have engaged in illegal abstraction of electricity) should be used to offset NIE's maximum regulated revenue from other services in that year.

6.24 We said that we had sought to ensure that NIE could benefit financially from its efforts to recover money in cases of illegal abstraction of electricity whilst also ensuring that consumers benefit from the money recovered, which can help offset the costs to consumers from illegal abstraction.

6.25 The value of 50 per cent reflected the design of the current incentive scheme reported by NIE and the UR for vacant non-domestic premises, which the UR had proposed to retain. However, our proposed scheme would apply not only to revenue from cases of vacant non-domestic premises but also to any other revenue that NIE has collected in other circumstances of illegal abstraction. We did not identify a good basis for differing treatment of NIE's income from revenue protection activities between vacant non-domestic premises and other premises and we saw merit in limiting the complexity of the arrangements for revenue protection.

6.26 Our provisional determination also proposed that the revenues from revenue protection activities would feed into NIE's revenue restriction after a two-year lag to allow time for the preparation of accounting information. As set out in paragraphs 6.42 and 6.43, we decided on an alternative way to implement the intended arrangements which is equally feasible and more consistent with other elements of our determination.

Parties' responses to our provisional determination

6.27 In its response to our provisional determination, the UR said that it was content with our proposal to extend the revenue protection scheme beyond its current scope of vacant non-domestic premises.[6]

6.28 In its response, NIE referred to our proposals to widen the scope of the existing arrangement for revenue protection income to apply not only to revenue from cases of vacant non-domestic premises but also to revenue that NIE has collected in other circumstances of illegal abstraction. NIE said the following.[7] Such an extension would represent only a very minor change in scope to the existing arrangements because it is framed in terms of the revenue recovered by NIE. The intent of our proposal would better be achieved if the scheme was based on 50 per cent of the value of the electricity units identified by NIE as illegally abstracted in relation to its revenue protection activities. This would have substantial public interest benefits. It would provide NIE with a strong incentive to detect illegal abstraction of electricity from domestic premises and occupied non-domestic premises and the benefits of detection would be shared with consumers as well as NIE. As well as sharing the benefit (value) of previously unbilled units recovered by NIE, consumers would also benefit in full from the prevention of any further illegal abstraction that would have occurred but for the intervention of NIE's revenue protection service.

6.29 The alternative scheme proposed by NIE in its response to our provisional determination was similar to that proposed in its Statement of Case (see Appendix 6.1).

[6] UR response to provisional determination, UR 147 paragraph 62.
[7] NIE response to provisional determination, pp177–178.

6.30 NIE's alternative scheme would supplement the arrangements we had proposed in our provisional determination with an additional and separable financial incentive scheme which would provide additional revenue to NIE in relation to cases of illegal abstraction of electricity detected by NIE for which NIE does not recover any money from electricity consumers (eg cases at domestic premises or occupied non-domestic premises).

6.31 NIE told us that under Northern Ireland retail market procedures (as approved by the UR), NIE could not recover revenue directly from consumers for the majority of revenue-protection activities.[8] Rather, NIE instigated recovery on behalf of the relevant electricity supplier, through adjustments to meter readings. This meant that, once the need for adjustments was identified by NIE, any revenue due for units of electricity illegally abstracted was administered routinely through wholesale and retail market settlement arrangements (ie through adjustments to IT system records to reflect units illegally abstracted). It then fell to electricity suppliers to pursue their customers for previously unbilled units.

6.32 Under NIE's proposal, it would remain for electricity suppliers to recover money from their customers in cases of illegal abstraction of electricity, but NIE would receive a separate financial reward based on 50 per cent of the value of electricity that NIE estimates (as part of adjustments to meter readings) to have been consumed illegally. That reward would be funded through the restriction on NIE's maximum regulated revenue and recovered from distribution use of system charges levied on all suppliers.

6.33 In addition to its alternative incentive scheme, NIE asked for further clarification regarding how our arrangements for revenue protection would be implemented, in particular in relation to the treatment of costs associated with revenue protection activities.

Our assessment of NIE's alternative incentive scheme

6.34 We did not consider that it would be appropriate to introduce the type of financial incentive scheme proposed by NIE as part of our inquiry. This was for a number of reasons.

6.35 NIE did not demonstrate that its proposed scheme would provide net benefits to consumers and did not provide any other analysis or evidence to support its contention that the scheme would be in the public interest. The payments to NIE under its proposed scheme would come from charges to all consumers and not from money (if any) recovered from consumers at premises where illegal abstraction of electricity has been detected. We were not satisfied that NIE's proposed scheme would be cost-effective from the perspective of consumers as a whole or that it is preferable to other feasible options.

6.36 We did not consider our inquiry well-suited to consideration of the type of incentive scheme proposed by NIE. To develop an appropriate regulatory approach towards the illegal abstraction of electricity, it would be better to start with the problem rather than with one possible solution (ie a financial incentive scheme on NIE implemented through NIE's price control licence conditions). As we explain in Appendix 6.1, and as emphasized to us by the UR, there are other ways to tackle illegal abstraction besides a financial incentive scheme on NIE. These could involve other parts of the

8 ibid, p177.

supply chain such as electricity suppliers. However, our inquiry is concerned with NIE's price control licence conditions.

6.37 We noted NIE's comments that under Northern Ireland retail market procedures, it could not recover revenue directly from electricity consumers for the majority of revenue protection activities. We were reluctant to introduce a financial incentive scheme to encourage NIE to take action in relation to protection activities that may cut across the roles and responsibilities of other participants in the Northern Ireland electricity industry, such as suppliers. Electricity suppliers in Northern Ireland have not engaged actively on revenue protection issues during our inquiry. The UR expressed no support for NIE's proposed scheme and had rejected a similar proposal in its final determinations for RP5.

6.38 We also had some concerns about the practicalities of the scheme proposed by NIE. The scheme would be heavily dependent on data on adjustments to meter readings made by NIE. Those adjustments would be based on estimates that involve assumptions and judgement. The scheme could provide financial incentives that distort NIE's adjustments to meter readings. This would have adverse consequences for any electricity consumer whose meter is adjusted by NIE as part of its revenue-protection activities. These consumers may include not only consumers who have intentionally consumed electricity illegally but also consumers whose meter was not working properly through no fault of their own. Further, the payments to NIE under the incentive scheme would come from charges for all consumers. We would expect that considerable work would be required to ensure that the data and reporting arrangements were fit for purpose under NIE's proposed scheme.

Our decision in relation to NIE's revenue protection activities

6.39 We decided to retain the policy from our provisional determination that 50 per cent of the revenues or income that NIE collects in relation to its revenue protection activities should be retained by NIE and 50 per cent should be shared with consumers through reductions to charges falling within NIE's maximum regulated revenue. This income falling under these arrangements should include:

(a) any money recovered by NIE directly from an electricity consumer in relation to NIE's powers in relation to illegal abstraction of electricity;

(b) any money recovered directly from third parties to cover the cost of network repairs or other repairs associated with illegal abstraction; and

(c) any income that NIE generates from the provision of revenue-protection services to third parties.

6.40 Since our provisional determination, and in light of comments from NIE, we gave further consideration to the implementation of this policy and the treatment of costs of NIE's revenue protection activities.

6.41 The income that NIE receives in relation to revenue-protection activities is not (currently) treated as an excluded service and therefore forms part of the revenue that falls under the restriction on NIE's maximum regulated revenue. In the absence of any specific provision within NIE's price control licence conditions for the treatment of such income, the effect would be that each £1 of income from revenue protection would offset by £1 the revenue that NIE can collect from other charges within the revenue restriction (eg distribution use of system charges).

6.42 To give effect to our intention that (only) 50 per cent of the income that NIE receives from revenue protection activities should offset NIE's maximum regulated revenue from other services, there should be a term in the licence formulae for NIE's maximum regulated revenue that increases NIE's maximum regulated revenue in each financial year by 50 per cent of the value of the (gross) income from revenue-protection activities that NIE receives in that year.

6.43 Since NIE will not know what revenues it will collect in any financial year, it will need to make a forecast at the time it sets tariffs. Any differences between NIE's actual revenues from revenue protection and NIE's forecast of these revenues will feed through the correction factor for over- and under-recovery and lead to an adjustment to NIE's maximum regulated revenue in the subsequent financial year. This requirement for a forecast of elements of the calculation of NIE's maximum regulated revenue when setting tariffs is a feature of NIE's current licence conditions which we have decided to retain (see paragraphs 19.14 to 19.17).

6.44 We decided that any costs that NIE incurs in relation to revenue-protection activities should qualify for the cost risk-sharing mechanism set out in Section 5 (paragraphs 5.49 to 5.96). The effect of this is that NIE will bear 50 per cent of its costs from revenue protection activities as well as retaining 50 per cent of its income from revenue-protection activities.

6.45 In a submission subsequent to its response to our provisional determination, NIE told us that the costs associated with its revenue protection unit were £530,000 in 2009/10, £507,000 in 2010/11 and £499,000 in 2011/12 (2009/10 prices) and that these costs relate to employment costs and overhead costs such as fleet, IT/Telecoms and property costs associated with the revenue protection department. NIE said that our final determination should make allowance for these costs which were excluded from our provisional determination.

6.46 We did not consider it appropriate to provide any additional cost allowance for NIE's revenue protection costs beyond our decision to include NIE's revenue protection costs in the cost risk-sharing mechanism. Such an allowance might be necessary if we found that NIE was likely to incur costs to meet its legal obligations in respect of revenue protection which it would be unable to recover from either its 50 per cent share of revenue protection income or other cost allowances included in our determination. This did not seem to be the case. The average of NIE's revenue protection costs across the period 2009/10 to 2011/12 (see paragraph 6.45) was similar to NIE's average revenues from revenue protection in these years (see paragraph 6.20). Further, these costs may reflect discretionary expenditure that NIE has incurred in response to the financial rewards under the current incentive scheme rather just than the costs of meeting its legal obligations.

6.47 We considered that it would amount to excessive funding of NIE's costs of revenue protection activities if our determination provided an upfront allowance for these costs and also allowed NIE to retain 50 per cent of the income from its revenue protection activities.

6.48 Our policy on the treatment of revenues and costs from NIE's revenue-protection activities differs to some degree from that under NIE's existing price control arrangements. We considered whether it would be appropriate to apply these changes only from a date following our determination, rather than from 1 April 2012. However, that would add complexity to the price control design and cost assessment needed for our determination and risks of unintended consequences. We did not consider such complexity proportionate in the light of the scale of costs and revenues above, which are reasonably similar. We decided that these arrangements should apply from 1 April 2012 to 30 September 2017.

7. Overview of cost assessment and determination

7.1 We had to determine appropriate figures for NIE's opex and capex that could be used as part of the calculation of a new price control for NIE. Our aim was to estimate the expenditure that NIE would incur if it operated and invested efficiently, given the services (and outputs) it will provide and the obligations that it will face. Our detailed cost assessment analysis is provided in Sections 8 to 11.

7.2 This section provides an overview of several elements of our approach to cost assessment. It gives particular attention to the steps we took to ensure that we made best use of the information available on the costs of electricity network companies in GB, which allows benchmarking analysis to be carried out for parts of our cost assessment work. It is structured as follows:

(a) we recap the period over which we made our cost assessment;

(b) we explain the role of benchmarking in our cost assessment;

(c) we consider the alignment of our cost assessment with the cost categories used by Ofgem;

(d) we explain how our work on cost assessment was structured;

(e) we explain how we adjusted our cost assessment for real price effects (RPEs) and productivity;

(f) we present an overview of the results of our detailed cost assessment; and

(g) we consider the potential additional transmission expenditure which could result from our price control design.

Period over which we make a cost assessment

7.3 Section 4 discussed issues relating to the timing of a new price control for NIE. In light of the approach set out in that section, our cost assessment must cover the following two periods:

(a) The period over which our new price control is intended to determine the calculation of NIE's tariffs, which is 1 October 2014 to 30 September 2017. We explain in Section 4 that the earliest practical date for our price control to affect tariffs is 1 October 2014. An end date of 30 September 2017 is consistent with the UR's final determination and was not disputed by either of the parties.

(b) The period from 1 April 2012 to 30 September 2014. As we explain in Section 4, we made financial adjustments as part of the calculation of the revenue control in the period under *(a)* above in light of differences between NIE's actual revenue in the period 1 April 2012 to 30 September 2014 and our assessment of the revenue it 'ought' to recover in respect of that period. These financial adjustments compensate consumers if we think that NIE has collected too much revenue in the period since the anticipated end of the RP4 price control and 1 October 2014; or compensate NIE if we think that it has collected too little revenue in that period.

7.4 The combined effect is that we made our cost assessment over the 5.5-year period from 1 April 2012 to 30 September 2017. In our work on cost assessment, we tend to use the term price control period to refer to the 5.5-year period which our assessment covers.

Role of benchmarking in cost assessment

7.5 There is considerable merit in using benchmarking analysis as part of our price control determination, as this can provide information on the costs that NIE might efficiently incur (see paragraph 7.1). In particular, benchmarking analysis can help reduce reliance on the use of data on NIE's historical costs in setting a new price control for NIE. This has several benefits in the context of RAB-based incentive regulation:

(a) If an allowance for NIE's costs were based purely on an extrapolation of its historical costs, this would expose consumers to any inefficiency reflected in NIE's past costs.

(b) If NIE expects that its price control allowances for certain categories of expenditure (eg opex) will be based on its past spend in those areas, this may reduce its financial incentives to achieve efficiency improvements and restrain its costs. Reductions to NIE's costs would be expected to lead mechanistically to lower revenue allowances in the future. In contrast, setting price controls by reference to the costs of other electricity network companies reduces the extent to which NIE's revenues and profits would depend on its own costs—whilst still using historical information on electricity network costs. This can help provide NIE with financial incentives to achieve efficiency improvements and avoid unnecessary expenditure.

(c) Using cost information from a range of other companies can help reduce the exposure of price control calculations to any data anomalies that may be reflected in the reported costs for NIE.

7.6 Appendix 7.1 provides further discussion of the points above.

7.7 We used comparisons of costs between NIE and the GB DNOs as part of our cost assessment, drawing on and further developing analysis presented by NIE and the UR. As discussed below, we found that the desire to make best use of benchmarking analysis had important implications for the way that we approached the cost assessment for NIE.

Alignment of cost assessment with Ofgem cost categories

7.8 NIE organized its forecasts and submissions on its expenditure requirements between the categories of opex and capex. Similarly, the UR's final determination involved separate cost assessment for opex and capex.

7.9 We did not organize our cost assessment using a firm boundary between opex and capex. This is for several related reasons:

(a) The information available to us, particularly that resulting from benchmarking analysis comparing the costs of NIE to the GB DNOs, was not conducive to drawing a firm boundary between opex and capex.

(b) Relying on accounting boundaries between capitalized and non-capitalized expenditure for regulatory cost assessment purposes poses risks of double-counting in areas of expenditure that may straddle those boundaries (eg repairs, maintenance and tree-cutting costs). This is particularly so given the potential for NIE's capitalization practices to change over time (see Section 15) and for differences in capitalization practices between NIE and other companies whose costs might be used for benchmarking purposes.

(c) Adopting a different approach to cost assessment between opex and capex risks creating distortions in the financial incentives that NIE faces. While it was not practicable for us to adopt a single comprehensive method cost assessment for all aspects of NIE's costs, a firm distinction between opex and capex in cost assessment analysis may bring unnecessary differences of approach.

7.10 The information available to us reflected the way that Ofgem requires GB electricity distribution companies to report costs and the way that Ofgem itself carries out cost assessment. Ofgem's approach to cost reporting and cost assessment effectively ignores accounting boundaries between capitalized and non-capitalized costs and instead relies on bespoke cost categories or classifications that Ofgem has developed over time for its regulatory purposes. Ofgem's approach reflects, in part, the concerns highlighted under paragraph 7.9*(b)* and *(c)* above. Ofgem's approach involves some high-level classifications between different types of costs and a large number of granular cost categories.

7.11 Ofgem's approach to cost categorization—and particularly the distinction it draws between 'direct' and 'indirect' costs—is of critical importance to our cost assessment work in this inquiry. In their submissions to us, both NIE and the UR relied on benchmarking analysis of NIE's indirect costs against GB DNOs. NIE also sought to support its expenditure forecasts with reference to comparisons of some of its direct costs against those of GB DNOs.

7.12 Ofgem distinguishes between direct and indirect costs as follows:[1] 'Indirect activities are those activities which do not involve physical contact with system assets.'

7.13 Ofgem then explains that it distinguishes between two main categories of indirect costs: 'closely associated indirects' which can be considered closely associated with network investment and operational activities involving physical contact with system assets; and the remainder, which it calls 'Business Support' activities.

7.14 Drawing on its distinction between direct and indirect costs, Ofgem defines five main categories of expenditure: *(a)* network investment: non-load-related expenditure; *(b)* network investment: load-related expenditure; *(c)* network operating costs; *(d)* closely associated indirect costs; and *(e)* business support costs (another category of indirect costs). Table 7.1 provides examples of the subcategories within each of these five categories which help to illustrate what they cover.

[1] Ofgem (2011) Electricity Distribution Price Control Cost and Revenue Reporting—Regulatory Instructions and Guidance: Version 2.

TABLE 7.1 **Cost categories for Ofgem's current electricity distribution price control review**

Ofgem cost category	*Examples of cost subcategories*
Network investment: non-load-related expenditure	• Asset replacement • Operational IT and telecoms • Legal and safety (investment driven by safety requirements) • Quality of supply • Environmental areas (eg losses, oil pollution, SF6 leakage) • Enhanced site security
Network investment: load-related expenditure	• Connections • General reinforcement • Fault level reinforcement
Network operating costs	• Trouble call (resolution of faults) • Inspections and maintenance • Tree cutting
Closely associated indirect costs	• Call centre • Control centre • Engineering management and clerical support (includes wayleaves) • Network design and engineering • Network policy • Operational training (including workforce renewal) • Project management • Small tools, equipment, plant and machinery • Stores • System mapping • Vehicles and transport
Other indirect costs: business support costs	• Human resources and non-operational training • Finance and regulation • CEO and corporate • IT&T including non-operational capex • Property management

Source: Ofgem.

7.15 Ofgem's cost definitions cut across accounting classifications of costs between capitalized expenditure and non-capitalized expenditure (ie opex). While the category of network investment may align with capitalization, the categories of indirect costs and network operating costs will include costs that companies capitalize and costs that companies do not capitalize. By way of illustration, Figure 7.1 shows our estimate of NIE's indirect costs for 2011/12 and an approximate decomposition of this between the elements of indirect costs that NIE capitalized and the elements of indirect costs that are treated as opex.

FIGURE 7.1

Illustration of breakdown of NIE indirect costs between opex and capex

NIE indirect costs 2011/12 (£48.2 million)	
Indirect costs reported under NIE opex including wayleaves (£25.5 million)	Indirect costs capitalized by NIE or NIE Powerteam (£22.7 million)

Source: CC analysis.

7.16 Similarly, the costs falling under Ofgem's category of network operating costs (eg faults and tree cutting) include costs that NIE capitalized and costs that NIE does not capitalize.

7.17 NIE's submissions made extensive use of benchmarking analysis which compared NIE's costs against GB DNOs, based on the Ofgem cost definitions:

(a) NIE submitted a series of reports providing econometric benchmarking analysis to compare NIE's historical indirect costs against the indirect costs of GB DNOs. This analysis covered both categories of indirect costs from the table above: closely associated indirect costs and business support costs.

(b) The econometric benchmarking analysis also included comparisons of the main elements of NIE's 'network operating costs' against the corresponding costs of the GB DNOs. This was presented as an analysis of NIE's 'R&M' costs.

(c) NIE also submitted a report which provided a comparison of the unit costs of a series of standardized types of network investment project between NIE and the average among the DNOs in GB. These comparisons were made for unit costs on a direct cost basis to allow comparison between NIE (ie the unit costs excluded costs that Ofgem would categorize as indirect costs).

7.18 NIE does not currently report its costs according to Ofgem's cost reporting definitions. The benchmarking reports presented by NIE involved analysis to convert NIE's costs to a format that was compatible with the Ofgem cost definitions to allow, as far as possible, like-for-like comparisons with the costs of GB DNOs.

7.19 NIE said that the benchmarking analysis demonstrated that its costs were efficient.

7.20 However, NIE's expenditure forecasts and submissions in relation to cost assessment suffered from two major limitations (leaving aside the details of the methods used for benchmarking):

(a) The benchmarking analysis that NIE provided was based on Ofgem's cost categories (eg indirect costs, network investment direct unit cost). However, NIE's expenditure forecasts were not presented in this way: NIE's expenditure forecasts were organized according to a distinction between opex and capex. NIE did not reconcile its expenditure forecasts for the price control period with the Ofgem cost categories that were used for its benchmarking analysis.

(b) The benchmarking analysis that NIE provided in relation to indirect costs and network operating costs involved a comparison of NIE's historical costs (eg in 2009/10) with the corresponding historical costs of GB DNOs. However, NIE's expenditure forecasts for the price control period were not reconciled with its historical costs.

7.21 An effect of *(a)* is that a finding that NIE's costs are efficient in the particular categories of costs subject to benchmarking analysis does not provide assurance on the efficiency or reasonableness of NIE's expenditure forecasts. An effect of *(b)* is that a finding that NIE's costs were efficient in the past does not provide any assurance on the efficiency or reasonableness of NIE's expenditure forecasts.

7.22 Nonetheless, we recognize that NIE and its consultants put considerable effort into work to allow for like-for-like comparisons between the costs of NIE and the GB DNOs, despite differences in the regulatory reporting framework between Northern Ireland and GB. These efforts made substantial contributions to our own cost assessment work.

7.23 We developed an approach to cost assessment that differed from that taken by NIE and by the UR in order to address the concerns above and to make the best use of the available information on the costs of the GB DNOs. In summary:

(a) In relation to NIE's network investment (including asset replacement and load-related expenditure), we allocated NIE's expenditure forecasts between the categories of direct and indirect costs. For direct costs, we determined an allowance for NIE based on a project-level review of NIE's capital investment plan. We did not use the implied element of indirect costs in NIE's plan.

(b) We carried out a separate cost assessment for NIE's indirect costs and a category of costs that we refer to as inspections, maintenance, faults and tree cutting (IMF&T). The latter includes the main elements of what Ofgem refers to as network operating costs, which are a type of direct cost in Ofgem's terminology. We produced an allowance for NIE's total indirect and IMF&T costs using estimates of an efficient level of costs based on our benchmarking of GB DNOs.

7.24 The two elements above cover the majority of NIE's costs, but not all of them. There were a number of other elements to our cost assessment work. For instance, NIE's substantial rates liability is not captured in the direct or indirect cost analysis above. Further, NIE carries out functions such as meter reading and meter replacement which are not done by the DNOs in GB. We carried out separate assessments of these other elements, drawing on information provided by NIE and the UR.

7.25 Our analysis of NIE's indirect costs and IMF&T costs covered what NIE reports as opex and costs that NIE reports as capex. We had to produce separate allowances for opex and capex so that we could determine what costs should be funded through NIE's RAB and what costs should be covered by annual allowances during the price control period. To do so, we allocated our allowance for indirect and IMF&T costs according to 2011/12 data on the relative proportions of NIE's opex and capex in these categories.

Structure of our work on cost assessment

7.26 In light of the approach set out above, we structured our work on cost assessment into three main categories:

(a) *Indirect costs and IMF&T costs.* We made an allowance for NIE's indirect costs and its costs for inspections, maintenance, faults and tree cutting based on econometric benchmarking analysis using cost data from NIE and the 14 DNOs in GB.

(b) *Direct costs of core network investment.* This covers the direct costs of NIE's asset replacement investment as well as the load-related investment on NIE's distribution and transmission networks. It excludes indirect costs and the costs relating to IMF&T which are covered above. Our approach to cost assessment for this category of costs was based on a review of a network investment plan prepared by NIE, drawing on input from engineering consultants BPI.

(c) *Other elements of cost assessment.* This covers a number of other elements of NIE's costs which are not captured in *(a)* or *(b)* above.

7.27 We provide our cost assessment for these three categories in Sections 8, 9 and 10 respectively.

Adjustments for real price effects and future productivity improvement

7.28 We determined that, as for the current licence conditions, the restrictions on NIE's maximum regulated revenue are adjusted each year according to changes in the RPI.

7.29 All the figures that we have used for our cost assessment are in 2009/10 prices. This price basis was used for UR's RP5 price control review and is used for NIE's expenditure forecasts.

7.30 As part of our cost assessment we made adjustments to the cost allowances based on 2009/10 prices:

(a) We applied annual adjustment factors which were intended to take account of the extent to which we expect the input prices that NIE faces (eg for wages and materials) to grow by more or less than the annual change in the RPI. The factors relate to what we call 'real price effects' or RPEs in line with Ofgem's terminology.

(b) We assumed that NIE will be able to make ongoing productivity improvements over time at a rate of 1 per cent per year for both opex and capex.

7.31 Table 7.2 explains how we have applied these adjustments to individual cost categories.

TABLE 7.2 **Application of RPEs and productivity by cost category**

Cost category	*Base year for application of RPEs and productivity*	*Rationale*
Opex		
IMF&T (applicable to both opex and capex)	2011/12	Year we used in benchmarking analysis
Enduring Solution	2012/13	New costs prepared in 2012/13
All other opex	2010/11	These allowances are generally based on outturn data between 2009/10 and 2011/12
Capex		
Direct capex	2009/10	Base year of the price control
Non-network capex	2009/10	Base year of the price control
Capital costs of NIE Powerteam assets	2010/11	These allowances were based on NIE out-turn costs the years between 2009/10 and 2011/12
NIE Powerteam tools and equipment	2010/11	
Network investment embedded in managed service charge	2010/11	
Metering capex: allocation of overheads to Metering RAB	2010/11	
Metering capex: Metering RAB	2011/12	We have set unit costs for two metering programmes based on out-turn unit costs in 2011/12 and 2012/13. For other programmes the base year is more appropriate. We considered different base years for different metering programmes would add unnecessary complexity. We therefore used 2011/12 as the base year for RPEs and productivity for all metering programmes.
Other		
Rates	No RPEs and productivity	Not appropriate to apply RPEs and productivity to these costs
RIGS implementation costs		
Costs of the investigation		
Deductions for excluded revenues		

Source: CC analysis.

7.32 We provide more information on these adjustments in Section 11.

Overview and synthesis of cost assessment

7.33 This section sets out the determination from our cost assessment which provide inputs to the financial model used to assess the likely impact on NIE's maximum regulated revenue and RAB.

7.34 For our determination, we used the UR's financial model for NIE which it used for its final determination and which was subsequently updated following our provisional determination. The financial model covers the period from 1 April 2012 to 30 September 2017. It uses financial years running April to March for the period 1 April 2012 to 31 March 2017. This is then followed by a six-month period from 1 April 2017 to 30 September 2017. The tables below follow this format.

7.35 We provide separate tables for:

(a) those capex and opex allowances which will be subject to the application of adjustments for productivity and RPEs, before the application of those adjustments (Tables 7.3 and 7.4);

(b) the capex and opex allowances in a) after the application of adjustments for productivity and RPEs (Tables 7.5 and 7.6);

(c) costs and deductions which are not subject to the application of productivity and RPEs (Table 7.7);

(d) capex allowances after the application of adjustments for productivity and RPEs, allocated according to RAB (Table 7.8); and

(e) opex after the application of adjustments for productivity and RPEs, allocated to Transmission and Distribution (Table 7.9).

TABLE 7.3 **Summary table: capex before the application of RPEs and productivity (Sections 8, 9 and 10)**

£ million, 2009/10 prices

	2012/13	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*2017/18*
Section 8						
Indirect & IMF&T costs (excluding trees) allocated to capex	21.48	21.48	21.48	21.48	21.48	10.74
Distribution capitalized tree cutting	5.42	5.42	5.42	5.42	5.42	2.71
Transmission capitalized tree cutting	0.14	0.14	0.14	0.14	0.14	0.07
Section 9						
Distribution direct costs	22.60	27.01	44.65	44.65	44.65	22.32
Transmission direct costs	3.07	5.81	17.84	17.84	17.84	8.92
Section 10						
Non-network capex: ICT	1.48	3.75	2.20	2.20	2.20	1.10
NIE Powerteam assets used for capex	0.80	0.80	0.80	0.80	0.80	0.40
NIE Powerteam tools and equipment used for capex, plus non-network capex: premises	0.22	0.25	0.24	0.23	0.23	0.13
Network investment embedded in managed service charge	1.27	1.27	1.27	1.27	1.27	0.64
Metering capex: Metering RAB*	3.29	3.29	7.49	7.14	7.14	3.57
Metering capex: allocation of overheads to Metering RAB	0.65	0.65	0.65	0.65	0.65	0.33
Total capital expenditure before RPEs and productivity	60.41	69.86	102.18	101.81	101.81	50.92

Source: CC analysis (rounded).

*Subject to volume adjustment mechanism.

TABLE 7.4 **Summary table: opex which is subject to RPEs and productivity, before application of these adjustments (Sections 8 and 10)**

£ million, 2009/10 prices

	2012/13	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*2017/18*
Section 8						
Benchmarked indirect & IMF&T costs (exc connections) allocated to opex	26.57	26.57	26.57	26.57	26.57	13.28
Indirect costs of connection work not funded through connection charges	0.41	0.41	0.41	0.41	0.41	0.21
Section 10						
Capital costs of NIE Powerteam assets used for NIE's opex	0.20	0.20	0.20	0.20	0.20	0.10
NIE Powerteam tools and equipment used for NIE's opex	0.05	0.05	0.05	0.05	0.05	0.03
Meter reading	3.40	3.40	3.40	3.40	3.40	1.70
Metering maintenance	0.07	0.07	0.07	0.07	0.07	0.04
Other operating costs relating to keypad meters	0.21	0.21	0.21	0.21	0.21	0.11
Allocation of NIE administrative costs to meter reading	0.30	0.30	0.30	0.30	0.30	0.15
Allocation of NIE administrative costs to market opening	0.29	0.29	0.29	0.29	0.29	0.15
Additional allowance for atypical weather storm costs	0.36	0.36	0.36	0.36	0.36	0.18
AGU	0.02	0.02	0.02	0.02	0.02	0.01
Enduring Solution	5.60	5.50	5.10	4.70	4.50	2.25
Operating expenditure to be subject to RPEs and productivity	37.47	37.38	36.98	36.58	36.38	18.19

Source: CC analysis (rounded).

TABLE 7.5 **Summary table: capex after the application of RPEs and productivity (Sections 8, 9 and 10)**

£ million, 2009/10 prices

	2012/13	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*2017/18 (6 months)*
Section 8						
Indirect & IMF&T costs (excluding trees)	21.01	20.80	20.61	20.42	20.30	10.06
Distribution capitalized tree cutting	5.30	5.24	5.20	5.15	5.12	2.54
Transmission capitalized tree cutting	0.14	0.14	0.13	0.13	0.13	0.07
Section 9						
Distribution direct costs	21.61	25.58	41.90	41.52	41.27	20.45
Transmission direct costs	2.93	5.50	16.74	16.59	16.49	8.17
Section 10						
Non-network capex: ICT	1.42	3.55	2.06	2.05	2.03	1.01
NIE Powerteam assets used for capex	0.77	0.76	0.75	0.75	0.74	0.37
NIE Powerteam tools and equipment used for capex, plus non-network capex: premises	0.21	0.23	0.23	0.21	0.21	0.12
Network investment embedded in managed service charge	1.22	1.21	1.19	1.18	1.18	0.58
Metering capex: Metering RAB	3.22	3.18	7.19	6.79	6.75	3.35
Metering capex: allocation of overheads to Metering RAB	0.62	0.62	0.61	0.61	0.60	0.30
Total capital expenditure after RPEs and productivity	58.44	66.80	96.62	95.40	94.83	47.00

Source: CC analysis (rounded), based on Table 7.3 with RPEs and productivity applied

TABLE 7.6 **Summary table: opex which is subject to RPEs and productivity, after the application of these adjustments (Sections 8 and 10)**

£ million, 2009/10 prices

	2012/13	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*2017/18 (6 months)*
Section 8						
Benchmarked indirect & IMF&T costs (excl connections) allocated to opex	26.27	25.93	25.67	25.47	25.36	12.59
Section 10						
Adjustment for connection costs funded through price control	0.40	0.39	0.39	0.38	0.38	0.19
Capital costs of NIE Powerteam assets used for NIE's opex	0.19	0.19	0.19	0.19	0.19	0.09
NIE Powerteam tools and equipment used for NIE's opex	0.05	0.05	0.05	0.05	0.05	0.02
Meter reading	3.28	3.24	3.20	3.18	3.17	1.57
Metering maintenance	0.07	0.07	0.07	0.07	0.07	0.03
Other operating costs relating to keypad meters	0.20	0.20	0.20	0.20	0.20	0.10
Allocation of NIE administrative costs to meter reading (£m)	0.29	0.29	0.28	0.28	0.28	0.14
Allocation of NIE administrative costs to market opening (£m)	0.28	0.28	0.27	0.27	0.27	0.13
Additional allowance for atypical weather storm costs	0.35	0.35	0.34	0.34	0.34	0.17
AGU	0.02	0.02	0.02	0.02	0.02	0.01
Enduring Solution	5.60	5.43	4.98	4.56	4.34	2.16
Operating expenditure after productivity and RPEs	36.99	36.41	35.66	34.99	34.65	17.21

Source: CC analysis (rounded), based on Table 7.4 with RPEs and productivity applied.

TABLE7.7 **Opex costs and deductions not subject to RPEs and productivity**

£ million, 2009/10 prices

	2012/13	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*2017/18 (6 months)*
A. Opex costs						
Section 10						
Rates	12.60	12.70	12.70	12.80	12.90	6.45
Section 18						
RIGS implementation costs		1.00				
Section 20						
Costs of the investigation		1.20				
B. Opex deductions for excluded revenues						
Section 10						
Connection charge contribution to O&M	–0.36	–0.36	–0.36	–0.36	–0.36	–0.18
Tort insurance claims and scrap income	–1.31	–1.31	–1.31	–1.31	–1.31	–0.66

Source: CC analysis.

TABLE 7.8 **Overall assessment: capex after RPEs and productivity allocated by RAB**

£ million, 2009/10 prices

	2012/13	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*2017/18 (6 months)*
Total RAB additions: distribution RAB	41.62	44.10	58.01	57.48	57.13	28.32
Total RAB additions: transmission RAB	5.65	9.48	23.17	22.96	22.82	11.31
Total RAB additions: metering RAB	3.84	3.80	7.80	7.40	7.35	3.64
Total RAB additions: new 5-year RAB—distribution	7.03	8.70	6.94	6.87	6.83	3.39
Total RAB additions: new 5-year RAB—transmission	0.30	0.72	0.70	0.70	0.69	0.34
Total RAB additions	58.44	66.80	96.62	95.40	94.83	47.00

Source: CC analysis (rounded), allocates Table 7.5 according to RAB.

TABLE 7.9 **Overall assessment: opex after RPEs and productivity allocated to transmission and distribution**

£ million, 2009/10 prices

	2012/13	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*2017/18 (6 months)*
Opex allocated to transmission	5.73	6.02	5.65	5.64	5.63	2.80
Opex allocated to distribution	42.19	43.62	41.04	40.48	40.25	20.02
Total opex after productivity and RPEs	47.92	49.65	46.69	46.12	45.88	22.82

Source: CC analysis (rounded), based on Tables 7.6 and 7.7.

7.36 In Tables 7.8 and 7.9 above we have presented our cost allowances separately in respect of Transmission and Distribution, reflecting our decision that each should be subject to separate revenue control. We used the following method to allocate capex and opex between transmission and distribution. For capex, some of the cost categories are already attributed to either transmission or distribution (eg network investment direct costs are split between transmission and distribution and all metering costs are attributable to distribution). For residual elements of capex (eg indirect costs and non-network capex) we allocated the costs in each year between transmission and distribution according to the relative share of capex in that year which was already attributed to transmission. For opex, we used an approximate figure of 15 per cent to allocate the total allowance for opex to transmission. We have applied 15 per cent after first excluding opex costs relating to metering, market opening and the Enduring Solution project (these opex costs are allocated directly to distribution). Our figure of 15 per cent reflects the assumption used in Section 8 that 7.5 per cent of NIE's indirect costs (excluding costs allocated to metering, meter reading and market opening) are for the 275 kV network, which we have doubled on the basis that NIE's transmission activities cover 275 kV and 110 kV infrastructure.

7.37 We also note that the profile of the RAB additions in Table 7.7 above reflects an attempt to align the profile of our expenditure allowance for NIE's network investment with NIE's actual expenditure in 2012/13 and its forecast expenditure in 2013/14.

Forecast expenditure outside core allowances

7.38 In addition to our core allowances NIE will incur expenditure and make RAB additions in other areas during RP5. We have forecast these expenditures for the purpose of our review of financeability and estimating tariff impacts. These are shown below in Tables 7.10 and 7.11.

TABLE 7.10 **Summary table: forecast capex expenditure outside core allowances**

£m, 2009/10 prices

	2012/13	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*2017/18 (6 months)*
Section 10						
Legacy Dt items	8.1	9.6	12.3	7.4	-	-
Connection charges: Distribution RAB	5.0	2.5	1.5	1.0	0.5	0.3
Wind farm clusters	-	0.1	1.3	3.2	2.0	0.0
Housing sites > 12 premises adjustment: Distribution RAB	0.8	0.2	0.5	0.3		
Total additional RAB additions	13.9	12.4	15.6	11.9	2.5	0.3

Source: CC analysis.

TABLE 7.11 **Summary table: forecast opex expenditure outside core allowances**

	2012/13	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*2017/18 (6 months)*
Section 10						
Legacy Dt items	6.4	5.0	1.8	0.0	0.0	0.0
Licence fees	1.9	1.9	1.9	1.9	1.9	1.0
Total additional opex	8.3	6.9	3.7	1.9	1.9	1.0

Source: CC analysis.

Potential additional transmission investment (D5)

7.39 We included a mechanism within our price control design (D5) which allows the UR to adjust NIE's revenue control, during the price control period, to allow for the costs of additional investment to increase the capacity of the transmission system (see Section 5). The amount of this investment which will take place before September 2017 is uncertain.

7.40 We asked NIE to forecast potential investment in this area for the purposes of our financial modelling in respect of tariff impacts and financeability. Table 7.12 shows that it forecast the potential for around £97 million of such investment.

TABLE 7.12 **Potential additional transmission load-related expenditure (2009/10 prices, direct cost basis)**

	Prior to March 2014	*April 2014–March 2015*	*April 2015–March 2016*	*April 2016–March 2017*	*April 2017–Sept 2017*	*Total RP5*
Potential additional D5 expenditure in RP5 (direct cost basis)	0.1	1.0	23.9	49.8	22.3	96.9

Source: NIE, CC analysis.

Notes: Projects included are:
1. CPS—MAG 275kV Overhead Line Conductor Replacement (T18).
2. Castlereagh and Tandragee Voltage Support (T24).
3. North West Reactive Compensation (T25).
4. Ballyumford Switchboard project (T26).
5. Airport Road 110/33kVsubstation (T27).
6. Ballyumford—Eden—110kV Circuit upgrade (T28).
7. Eden—Carnmoney 110kV Line upgrade (T29).
8. 4th Transformer at Castlereagh 275/110kV substation (T30).
9. Armagh Main 110/33kV Substation (T31).
10. Dungannon Main 2nd 110/33kV substation (T32).
11. Castlereagh—Knock 100kV Partial cable replacement (T33).
12. Tandragee 275kV Substation 2nd Bus coupler (T34).
13. Cregagh 110kV substation isolators and earth switches (T38).
14. Hannahstown & Kells 275kV substation (T39).
15. RIDP Omagh—Turleenan 275kV circuit (pre-construction).
16. RIDP Kells—Coleraine 110kV reinforcement.
17. North South Interconnector—Construction of Turleenan and 400 kV circuit to border.

We have excluded the net contribution to Wind Farm clusters, for which we have made provision elsewhere (see Section 10).

7.41 Table 7.12 has been adjusted to reflect only the direct costs of this potential additional investment, using the same approach which we use in Section 9. It does not include any distribution-load-related projects, as we have made a separate RP5 allowance for these.

7.42 We noted that a significant amount (£41.7 million) of this potential additional investment related to the North–South Interconnector, which we understood was highly uncertain. We also noted that NIE's forecasts were purely indicative and any additional adjustments to the price control would be dependent on the UR's assessment and SONI's plans.

8. Benchmarking analysis for indirect costs and IMF&T costs

Introduction

8.1 We determined annual allowances for NIE's indirect costs and its costs for IMF&T based on the results from benchmarking analysis covering NIE and 14 electricity distribution network companies in GB.

8.2 Both NIE and the UR carried out econometric benchmarking analysis for NIE's indirect costs and IMF&T costs. We sought to build on the analysis carried out by the parties. In line with the analysis of NIE and the UR, our analysis relies on cost categorizations established by Ofgem which the GB DNOs are required to use for reporting their costs. The costs we label 'IMF&T' costs represent the majority but not all of a wider category of costs that Ofgem labels 'network operating costs'.

8.3 We provided information on these cost categories in Section 7 (Table 7.1). Indirect costs include costs in areas such as network design and engineering, project management, network control centre, human resources, finance and regulation. For both NIE and the GB DNOs, the category of indirect costs includes costs that are capitalized and costs that are not capitalized. The same is true for the costs falling under the category of IMF&T costs.

8.4 Our benchmarking analysis therefore cuts across NIE's capex and its opex. Since we maintain the approach of including forecast capex but not opex in the calculation of NIE's RAB, we need to separate our allowance for indirect and IMF&T costs between opex and capex. We do this by applying an allocation factor based on our calculation of the proportion of NIE's indirect costs and IMF&T costs that were capitalized by NIE.

8.5 In our provisional determination, the base year for our analysis was 2009/10. This year was the focus of the work carried out by NIE and the UR as part of the RP5 price control review. Since our provisional determination, NIE provided information on its costs for the financial years 2010/11 and 2011/2012 to complement the data we had used on the costs of the GB DNOs. We subsequently updated our analysis and produced estimates of an efficient level of costs for NIE for the financial year 2011/12. For the determinations from our cost assessment that are presented in Section 7 we extrapolate from 2011/12 over the period from 1 April 2012 to 30 September 2017 by applying a series of annual adjustments for RPEs and ongoing productivity improvement.

8.6 This section describes our benchmarking analysis and how we interpreted the results. It is organized into three main steps:

(a) We produce estimates of NIE's historical indirect costs and network operating costs that are intended to be consistent, as far as possible, with the cost reporting categories and definitions applicable to the cost data we have obtained from Ofgem for GB DNOs. We refer to these as 'benchmarked costs'. See paragraphs 8.8 to 8.56.

(b) We carry out benchmarking analysis using relatively simple econometric models to compare the costs of NIE against GB DNOs. As part of the benchmarking analysis we make some adjustments to render NIE's indirect costs more comparable with those of GB DNOs. See paragraphs 8.57 to 8.154.

(c) We draw on results from the benchmarking analysis, and NIE's historical costs, to produce an assessment of level of NIE's 'benchmarked costs' over the price

control period if it operated efficiently and provided the same services and outputs as the distribution companies in our sample did in 2011/12. See paragraphs 8.155 to 8.234. This assessment excludes any potential impacts from input price inflation (or real price effects) and future productivity improvements, which are considered in Section 11.

8.7 This section is supported by five appendices:

(a) Appendix 8.1 provides a summary of the UR's approach to the calculation of a proposed allowance for NIE's controllable opex in its RP5 final determination, with particular attention to the econometric benchmarking analysis used by the UR.

(b) Appendix 8.2 highlights some of the criticisms of the UR's approach and analysis that raised by NIE. It sets out NIE's alternative proposals for an allowance for controllable opex.

(c) Appendix 8.3 provides further information on the method and data we used to calculate an estimate of NIE's indirect costs that is comparable with the indirect cost data reported by GB DNOs.

(d) Appendix 8.4 provides further information on the method we used to make adjustments to the costs of NIE and DNOs in GB to take account of data on differences in wages between different parts of the UK.

(e) Appendix 8.5 provides further information on the econometric model specifications used for our benchmarking analysis, the data sources and results.

Step (a): GB DNO data set and calculation of benchmarked costs for NIE

8.8 This subsection describes the data set we used for the GB DNOs and how we made estimates of NIE's costs that were comparable with the cost data for the GB DNOs. It is organized as follows:

(a) We first identify the data we use for the costs of GB DNOs (see paragraphs 8.9 to 8.17). Our calculation of NIE's costs for the benchmarking analysis is intended to be aligned with the basis on which this data is provided.

(b) We describe our approach to the calculation of NIE's indirect costs (see paragraphs 8.18 to 8.21).

(c) We describe our approach to the calculation of NIE's costs for IMF&T (see paragraphs 8.22 to 8.28).

(d) We provide our estimates of NIE's indirect and IMF&T costs, which we use for our benchmarking analysis (see paragraph 8.37).

(e) We describe the outcome of a further review of the GB DNO cost data following submissions from NIE and the UR on our provisional determination and we explain our choice of the financial year for the estimation of cost benchmarks for NIE (paragraphs 8.38 to 8.56).

Data source for GB DNO cost data

8.9 Ofgem does not regularly publish cost data for GB DNOs. While these companies fill in detailed reporting templates on costs and other matters each year, the data is not routinely published.

8.10 In December 2009, as part of its final proposals from its DPCR5 price control review, Ofgem published the financial model that it used to calculate price controls for the GB DNOs for the five-year period from 1 April 2010.[1] This model took the form of an Excel workbook. The Excel workbook contains historical data on the costs of GB DNOs, including data reported for indirect costs (split between 'Indirects closely associated with directs' and 'Business support' costs) and data for network operating costs (split between 'I&M' (inspections and maintenance), 'faults', 'trees' and 'other').

8.11 Absent other publicly available data, the consultants working for NIE and the UR used this cost data from Ofgem's DPCR5 financial model for the purposes of benchmarking NIE with GB DNOs.

8.12 This cost data available from the DPCR5 financial model had some limitations:

(a) Historical cost data are only available for years to 2008/09. For 2009/10 the data is forecasts of spend (albeit forecasts made part-way through the year to which they apply). The base year used by the UR and NIE for the price control review was 2009/10.

(b) There is a lack of transparency or clarity as to the nature of the historical cost data in the published DPCR5 financial model. Ofgem's reporting requirements and definitions have changed over time. Further, as part of the DPCR5 price control review process, Ofgem requested additional cost data from companies. It is not clear from the publicly available information exactly what the cost data reported in the DPCR5 financial model relates to.

8.13 The lack of transparency has been particularly problematic in this inquiry in relation to the treatment of costs attributed to connections activities. Both Frontier Economics (Frontier) (in analysis for NIE) and CEPA (in analysis for the UR) took the view that the historical indirect cost data published as part of the DPCR5 financial model excluded indirect costs attributed to connections, but this did not seem to us to be consistent with the cost reporting requirements applicable at the time. Neither Frontier nor CEPA provided references or other evidence to substantiate that view. We put some follow-up questions to Frontier and CEPA and it seems that their view on the costs data that they have used reflects their knowledge or recollections gained from work for Ofgem or GB DNOs.

8.14 We asked Ofgem a series of questions to clarify the basis for the historical indirect cost data in the published DPCR5 financial model. Ofgem told us that:

(a) the indirect cost data in the DPCR5 financial model for years 2008/09 and 2007/08 should include any indirect costs estimated as relating to the elements of connection costs that companies did not recover through connection charges or customer contributions;

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[1] www.ofgem.gov.uk/ofgem-publications/46746/fp1core-document-ss-final.pdf.

(b) the indirect cost data in the DPCR5 financial model for these years should exclude any indirect costs estimated as being attributable to sole use connections; and

(c) the indirect cost data in the DPCR5 financial model for these years should include any indirect costs estimated as being attributable to connection reinforcement that was charged to the connecting customer.

8.15 On that basis, the benchmarking comparisons submitted by NIE and the UR did not involve a like-for-like treatment of connection costs: some costs that GB DNOs attribute to connections are included within the DPCR5 financial model data whereas the indirect cost estimates for NIE used by Frontier and CEPA are intended to exclude all NIE indirect costs attributed to connections. The effect is to understate NIE's costs relative to the GB DNOs, which may have a significant effect on the results from the benchmarking analysis.

8.16 In light of these and other issues, we have not used the data from the DPCR5 financial model for the econometric benchmarking analysis we use for our determinations. Instead, we obtained cost data directly from Ofgem. The data is for the following financial years: 2009/10; 2010/11 and 2011/12. The data is reported on the basis of the new regulatory reporting rules introduced following Ofgem's DPCR5 price control review. This data provided a greater degree of transparency because we can trace the data provided by Ofgem back to published reporting rules and to the data templates that companies are required to complete.

8.17 Data was not available in the newer RIGs format for years before 2009/10. Further, Ofgem told us that because of new reporting requirements that were introduced, some of the data reported in 2009/10 (the year before the new reporting templates formed part of the DPCR5 reporting arrangements) was on a best endeavours or trial basis.

Data on NIE's indirect costs

8.18 We sought to calculate estimates of NIE's indirect costs and IMF&T costs that were consistent, as far as possible, with the reporting basis used for the Ofgem data on GB DNOs. We built on the estimates and methods developed by Frontier and CEPA and a series of further submissions from NIE and the UR on the matter.

8.19 We summarize our calculation of NIE's indirect costs as follows:

(a) We started with data reported for NIE's 'controllable' opex and capitalized overheads. We included in our calculation of NIE's indirect costs the individual elements of its controllable opex and capitalized overheads that we identified as falling under the definition of indirect costs, excluding the charges to NIE from NIE Powerteam.[2]

(b) We included the estimates developed by Frontier of the portion of NIE Powerteam's costs that should be categorized as indirect costs. Frontier's estimates were calculated using a detailed cost mapping exercise. CEPA's benchmarking analysis for the UR also relied on Frontier's estimates.

[2] In contrast to the approach adopted by CEPA and Frontier, we do not start with NIE's total controllable opex and make deductions, though we have carried out a separate reconciliation between our estimate of NIE's indirect costs and NIE's total controllable opex.

(c) We included costs attributed to wayleaves. These were not categorized as part of NIE's controllable opex in NIE's BPQ response but they fell under Ofgem's definition of indirect costs. Consistent with the approach taken by Frontier and CEPA, we deducted the element of these costs attributable to wayleave administration by NIE Powerteam to avoid double-counting in relation to NIE Powerteam costs included in *(b)* above.

(d) We included some other costs incurred by NIE which were not reported under controllable opex but which nonetheless seemed part of its indirect costs and relevant to comparisons with GB DNOs.

(e) We made further adjustments in light of submissions from the parties. These included adjustments proposed by NIE to convert the reported cost data into a cash basis (eg removing effects of provisions and accruals and prepayments that are not incurred as part of the ordinary level of business) to be consistent with Ofgem's cash reporting rules. They also include adjustments to remove estimates of costs incurred by NIE which are attributed to other businesses or external parties and adjustments to remove an allocation of administrative costs or overheads to functions carried out by NIE but not GB DNOs (eg meter reading).

8.20 The costs included under *(a)* and *(b)* include current service pension costs of NIE and NIE Powerteam. In contrast, pension costs were not included in the benchmarking analysis carried out by Frontier and CEPA because the DPCR5 financial model data that they used explicitly excluded pension costs. However, the indirect costs data that Ofgem provided us with did include pension costs. As pension costs are one element of labour costs, we considered it better to carry out benchmarking with ongoing pension costs included (but excluding historical deficit pension costs).

8.21 Appendix 8.3 provides a more detailed explanation of our approach to the calculation of an estimate of NIE's indirect costs.

Inspections, maintenance, faults and tree cutting costs

8.22 Frontier's benchmarking analysis for NIE included comparisons of indirect costs and separate comparisons of what Frontier called 'R&M' costs. CEPA's analysis for the UR included benchmarking analysis that compared measures of costs that comprised the sum of indirect costs and the costs labelled 'R&M' costs by Frontier.

8.23 Frontier's analysis of 'R&M' costs were based on data from Ofgem's DPCR5 financial model for categories of costs that Ofgem defines as network operating costs. In Ofgem's DPCR5 financial model, the historical data on network operating costs was broken into four categories: *(a)* I&M; *(b)* faults; *(c)* tree cutting; and *(d)* other. Frontier's analysis focused on the first three categories of network operating costs. Frontier referred to these as 'Repairs and Maintenance (R&M) costs'.

8.24 We too have included these costs within the scope of our benchmarking analysis, but we used different terminology. Frontier's use of the term 'R&M' is potentially confusing. The costs covered by this term in Frontier's analysis included costs which are capitalized by NIE and do not correspond to what NIE reported under the heading of 'repairs and maintenance' in its response to the RP5 BPQ on opex. They also included costs which NIE does not itself treat as repairs and maintenance (eg tree-cutting costs). We used the term IMF&T to distinguish these costs from repairs and maintenance and to represent the costs from the three categories above that we cover: inspections, maintenance, faults and tree cutting. Where the context does not require as much precision, we sometimes refer to these costs as network operating costs as they represent a large proportion of Ofgem's definition of network operating costs.

8.25 In line with our approach to indirect costs, we used data provided by Ofgem for the financial years 2009/10, 2010/11 and 2011/12 rather the data from the DPCR5 financial model. The network operating costs available for these years are presented under the following headings: *(a)* inspections and maintenance; *(b)* trouble call; *(c)* tree cutting; *(d)* severe weather—atypical; and *(e)* NOCs Other. We used data for *(a)*, *(b)* and *(c)* which corresponds to the costs reported for inspections, maintenance, faults and tree cutting under the previous reporting definitions and the DPCR5 financial model. Neither NIE nor the UR raised concerns about any changes in the definitions of Ofgem's network operating costs adversely affecting the benchmarking analysis.

8.26 The Frontier benchmarking analysis included estimates of NIE's costs for the category we refer to as IMF&T costs. These estimated were based on data on the costs recorded by NIE against various activities falling within IMF&T. However, the costs recorded by NIE include indirect costs whereas the IMF&T cost category should include direct costs only. Frontier therefore made an adjustment to NIE's recorded costs to exclude indirect costs. This involved a decomposition of NIE's recorded costs into two categories:

(a) materials and bought-in services (MBIS), which Frontier assumed to be entirely direct costs; and

(b) NIE Powerteam costs, which include direct costs and indirect costs.

8.27 Frontier's calculation of IMF&T costs included an adjustment to *(b)* which was intended to strip out the element which was indirect costs so that estimated IMF&T costs included direct costs only. This adjustment was calculated using an estimate of the proportion of NIE Powerteam costs that are direct costs.

8.28 We used the calculation of NIE's IMF&T costs originally produced by Frontier, but with a significant adjustment relating to ongoing pensions costs. Frontier's original benchmarking analysis had used cost data for GB DNOs from Ofgem's DPCR5 financial model which was reported as excluding pension costs and Frontier's estimates of NIE's IMF&T costs excluded pension costs. We made adjustments to include ongoing pension costs in our benchmarking analysis. We found that Frontier's estimate of NIE Powerteam's direct costs in 2009/10 was around 13 per cent higher if ongoing pensions costs were included in the analysis than if ongoing pensions costs were excluded. We revised Frontier's calculation of the NIE Powerteam costs that contributed to IMF&T costs to include NIE's Powerteam's ongoing pension costs; this increased the NIE Powerteam element of IMF&T costs by around 13 per cent. We then recalculated NIE's total IMF&T costs on this basis.

8.29 As part of its response to our provisional determination, NIE said that it had made an error in the figures it had provided on IMF&T costs. The error related to the estimated costs of tree cutting associated with overhead line refurbishment and re-engineering programmes. NIE said that its original estimates of the cost of tree cutting associated with overhead line refurbishment or re-engineering work were derived on the basis of budgeted rates, as out-turn costs were unavailable. NIE provided revised estimates for IMF&T costs that were consistent with those from our provisional determination but adjusted for out-turn rather than budgeted tree cutting costs. The effect of this correction was to increase the estimated level of NIE's IMF&T costs by £0.3 million in

2009/10.[3] We accepted NIE's submission on this aspect of the calculation of IMF&T costs and revised the figures we used accordingly.

Updated data for NIE's costs in 2010/11 and 2011/12

8.30 In our provisional determination, we used our benchmarking analysis to produce estimated cost benchmarks for NIE for the financial year 2009/10. The year 2009/10 had been the 'base year' for the UR's price control review and was the most recent year for which detailed cost data were available from NIE's response to the UR's BPQ.

8.31 The benchmarking analysis we used drew on data for the GB DNOs for three financial years: 2009/10, 2010/11 and 2011/12. We did not have sufficient data to calculate indirect and IMF&T costs for NIE for 2010/11 and 2011/12. NIE had told us that it would take substantial additional resource and time to provide the data to enable us to reproduce our calculations of indirect and IMF&T costs for 2010/11 and 2011/12 and this posed risks of delaying our inquiry. We said in our provisional determination that we did not consider that requiring NIE to provide data for these two additional years would represent proportionate regulation. Therefore, the data set we used contained data for the GB DNOs for 2009/10, 2010/11 and 2011/12 and data for NIE for 2009/10 only.

8.32 For our provisional determination, we focused primarily on cost benchmarks estimated for the year 2009/10. Nonetheless, these estimates were influenced by the data across all three years of the sample period. Specifically, the results from each econometric model involved an estimate of the impact of the explanatory factor in the model on costs and that estimate drew on the data across all three years of the sample. This feature of these models is desirable because it reduces the risk that the estimated impact of the explanatory factor on cost is unduly influenced by data for any one year. Our econometric models allowed for there to be differences in the level of industry-level costs from one year to the next, which meant that the choice of year for the cost benchmark could have a significant impact on the results.

8.33 In its response to our provisional determination, NIE criticized our benchmarking analysis for focusing on cost benchmarks for 2009/10. NIE said that the fact that we did not have the relevant cost data for NIE for 2010/11 and 2011/12 was not a reason not to use the cost benchmarks for 2011/12 based on the available GB DNO data.[4] In addition, NIE provided new data for its indirect and IMF&T costs for 2010/11 and 2011/12. NIE argued that we should update our benchmarking analysis so that we set allowances for NIE based on cost benchmarks for 2011/12 using the new data provided by NIE.[5]

8.34 We requested a substantial amount of supporting data and calculations relating to the updated cost estimates that NIE provided for 2010/11 and 2011/12. We carried out a review of this information which included the following:

(a) we checked that a number of supporting calculations used to produce estimates of its indirect costs and IMF&T costs in 2010/11 and 2011/12 were consistent with those used for 2009/10;

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[3] NIE response to the provisional determination, p19.
[4] NIE response to the provisional determination, p2.
[5] NIE response to the provisional determination, p3.

(b) we raised queries with NIE in relation to some cost items that had varied substantially from one year to the next; and

(c) we reconciled new data provided by NIE with its published regulatory accounts for 2010/11 and 2011/12.

8.35 As part of this process, we identified that the calculations used by NIE for its costs in 2010/11 and 2011/12 used an allocation of staff to connections activities based on a figure for 2009/10 that we had used for our provisional determination. NIE told us that it had not had time to carry out the work required to update this allocation. As part of our request for a full set of updated information for 2010/11 and 2011/12, NIE provided updated allocations of staff to connections activities. When we revised the estimates of NIE's costs for the updated information, it reduced the measure of NIE's indirect costs (excluding connections) in 2011/12 by around £1.5 million. NIE also provided a revised figure for this allocation for 2009/10 as its original allocation overlooked the role of apprentices and generation connections.

8.36 In the light of the new input data from NIE, we calculated estimates of NIE's indirect costs for 2010/11 and 2011/12. We also ensured that the estimates provided by NIE of its IMF&T costs were calculated using a consistent methodology to that used for 2009/10. We were satisfied that including our updated estimates of NIE's costs in our benchmarking analysis would improve the quality of the analysis.

NIE's indirect and IMF&T costs

8.37 Table 8.1 summarizes the cost figures we calculated for NIE and used for our benchmarking analysis.[6] These are cost data before any adjustments to exclude costs attributed to connections or to NIE's 275 kV network which are discussed under step *(b)* below.

TABLE 8.1 **Costs for NIE used for benchmarking analysis (before adjustments for 275kV network and connections)**

			£ million
	2009/10	*2010/11*	*2011/12*
Indirect costs	47.1	47.6	48.2
IMF&T costs	14.5	17.0	19.3
Indirect and IMF&T costs	61.6	64.6	67.5

Source: CC analysis.

Further review of GB DNO cost data and choice of year for cost benchmarks

8.38 The UR disagreed with NIE's view that we should automatically *(a)* update the benchmarking analysis from our provisional determination to include the new data from NIE for 2010/11 and 2011/12 and *(b)* use cost benchmarks for 2011/12 to set allowances for NIE's indirect and IMF&T costs. The UR queried whether we had time

[6] In early March 2014, as we were finalizing our determination, NIE made a submission that certain costs should be excluded from our calculation of NIE's IMF&T costs for the purposes of our indirect and IMF&T cost benchmarking analysis because NIE considered these exceptional (NIE also submitted that certain exceptional revenues should be deducted from our assessment of NIE's tort income). The costs that NIE considered should be excluded were £0.57 million in 2010/11 and £0.94 million in 2011/12. Given the relative scale of the costs NIE identified as exceptional, and the late stage at which NIE made this submission to us, we did not investigate NIE's point in detail and did not make an adjustment to our estimates of NIE's IMF&T cost.

to carry out a sufficient investigation of the new data from NIE and of the apparent increases in costs among the GB DNOs between 2009/10 and 2011/12.

8.39 As explained in paragraphs 8.34 to 8.36, following extensive work on cost data submitted by NIE for 2010/11 and 2011/12, we decided that it was appropriate to include cost estimates for NIE for these years in our analysis. Our estimates for NIE's costs for 2010/11 and 2011/12 involved some adjustments to the estimates provided by NIE in its response to our provisional determination.

8.40 The UR identified that the GB DNO cost data as originally provided to the parties alongside our provisional determination showed substantial increases in costs (relative to the RPI) between 2009/10 and 2011/12.[7] The UR expressed a concern that it would not be appropriate for us to unthinkingly reflect these cost increases in the allowances for NIE without understanding their nature. The UR thought, in particular, that the GB DNOs' costs could have increased for specific or peculiar reasons and that there was a real need for us to understand these increases before we could take the GB cost increases as evidence that the efficient level of costs for NIE had materially increased between 2009/10 and 2011/12.

8.41 The UR also raised a specific concern that the cost increases amongst the DNOs between 2009/10 and 2011/12 may relate to improvements in service quality (in terms of the levels of customer interruptions) that were driven by a regulatory incentive scheme in GB and may be unrepresentative of the costs faced by NIE.

Investigation of changes in GB DNO costs

8.42 Following our provisional determination we carried out a review of the changes in GB DNO costs between 2009/10 and 2011/12. We found that the increase in average costs over this period was not reflective of similar cost trends across all of the 14 DNOs. Instead, it reflected some quite large increases (eg above 20 per cent) for some of the DNOs in specific subcategories of the costs that we used in our analysis.

8.43 We contacted the relevant DNOs and asked for further information on these costs increases. We found that changes in cost allocations over time, rather than changes in overall costs, lay behind much of the identified increases in indirect and IMF&T costs. For instance:

(a) Following the acquisition of two DNOs by WPD, there was a change in the allocation of costs, in the acquired DNOs, between direct costs and closely associated indirect costs which reflected WPD's interpretation of Ofgem's reporting guidance.

(b) One DNO explained that there had been a change in the working arrangements with its contractors. This change involved a move to more 'open book' arrangements which allowed for greater visibility of indirect costs incurred by the contractors. This led to a relocation of costs from direct costs to indirect costs.

(c) One DNO explained that a substantial increase in its reported costs under the 'trouble call' category (part of our measure of IMF&T costs) was due to a change in the allocation of costs between asset replacement expenditure (a direct cost outside the scope of our econometric benchmarking analysis) and trouble call costs, following additional guidance from Ofgem. The costs concerned the replacement of cable due to fault initiated condition assessment.

[7] Following the provisional determination, we made revisions to the GB DNO data (paragraphs 8.49–8.56). These revisions reduced the size of the cost increases between 2009/10 and 2011/12 on which the UR had previously commented.

8.44 The DNOs we contacted also identified other factors besides cost allocation:

(a) One DNO had experienced an increase in its IMF&T costs between 2010/11 and 2011/12 due to an unusual number of severe weather events. These weather events did not qualify under the Ofgem definition of 'atypical severe weather events' (which are excluded from our measure of IMF&T costs).

(b) One DNO reported increases in costs due to inflation in labour and materials costs and increases in the volume or work carried out (eg increases in network design and project management indirect activities associated with increased activity in the capital investment work programme).

8.45 We did not consider it possible to understand fully all the factors behind movements in GB DNO costs from one year to the next. However, we considered that our review provided a sufficient basis for decisions on the approach to cost benchmarking for the purposes of our inquiry.

8.46 We decided that we should use 2011/12 cost benchmarks rather than 2009/10 cost benchmarks as the basis of a projection of NIE's costs over the period from 1 April 2012 to 30 September 2017. The 2011/12 cost benchmarks would give greater weight to more recent data. We did not identify grounds to consider that the changes in the GB DNO reported costs between 2009/10 and 2011/12 were due to factors that meant it was inappropriate to use 2011/12 cost benchmarks. Further, we considered the 2011/12 data likely to be more accurate and reflective of Ofgem's cost definitions than data for 2009/2010. 2009/10 was the first year of a new cost reporting framework and the DNO's responses to our queries indicated that some changes in costs between 2009/10 and 2011/12 reflected clarification from Ofgem of how costs should be reported and allocated.

8.47 Our review did help to highlight the risks of inconsistencies between DNOs and over time, in the way that costs are allocated and reported which could have an adverse effect on the accuracy of the results from our benchmarking analysis. For instance, reported indirect costs can be affected by the precise working arrangements between a DNO and its contractors even if the underlying costs are the same. We took account of these risks as part of our assessment, in particular in our decision to use the results for the fifth-ranked company as the cost benchmark (paragraphs 8.127 to 8.141).

8.48 Finally, we considered the implications that we could draw from the GB DNO cost data for our estimates of the effects of RPEs and productivity growth on NIE's costs (see Section 11). In its response to our provisional determination, NIE said that we 'may wish to reflect on whether evidence of recent cost increases in the available GB DNO data for [indirect costs and IMF&T costs] indicates that there is a need to assume similar real cost increases in other costs'. We considered this matter but decided that it was not appropriate to assume that cost increases in other cost categories would follow those experienced in reported indirect costs and IMF&T costs for the GB DNOs between 2009/10 and 2011/12. The substantial increases in GB DNO indirect costs and IMF&T costs between 2009/10 and 2011/12 were not predominantly attributable to RPEs and the effects of productivity growth. They reflected other factors such as changes in cost allocations, increased costs from storms and increased volumes of work.

Revisions to GB DNO data

8.49 As part of the review of the GB DNO cost data following our provisional determination we contacted each GB DNO directly to verify the data we had received from Ofgem.

For the vast majority of data entries, the GB DNOs confirmed that the data we had used fitted with their own records. However, we also made several revisions to the data as part of this process. We shared the revisions we made with Ofgem and Ofgem did not raise any concerns with these. We also shared the revisions we made with NIE and the UR and neither party disagreed with them.

The UR's submissions on service quality improvements in GB

8.50 The UR raised a specific concern that the cost increases among the DNOs between 2009/10 and 2011/12 may reflect improvements in service quality (in terms of the levels of customer interruptions) that were driven by a regulatory incentive scheme in GB. The UR thought that NIE's service quality was below that of the GB companies and the cost increases in GB would not be representative of NIE's costs.

8.51 NIE submitted that there was no basis on which to suppose we needed to adjust our benchmarking analysis to account for a difference in quality of service between NIE and the GB DNOs. NIE provided comparisons of its performance in 2011/12 in terms of customer interruptions and customer minutes lost against the GB DNOs. This showed that NIE's performance against these measures was worse than average. NIE ranked 10^{th} out of 15 DNOs on the customer interruptions measure and 11^{th} on the customer minutes lost measure. However, NIE said that its performance was within the 'ballpark' of GB DNOs, despite the greater exposure of the NIE network to weather-related faults as a consequence of NIE's high voltage network being more extensively comprised of overhead line than the GB networks.

8.52 The UR sent us some further analysis which purported to show that NIE's performance in terms of unplanned customer minutes lost in 2010/11 was worse than that of all the GB DNOs. NIE argued that the UR's analysis was flawed because the data used for unplanned customer minutes lost for the GB DNOs related to only a subset of the distribution network (the high voltage network) but the UR compared this with data on unplanned customer minutes lost across NIE's entire distribution network.

8.53 NIE also disputed the link drawn by the UR between customer interruptions and benchmarked costs. It argued that it was widely accepted that DNOs were targeting improvements in quality of service through capital investment, not the costs covered by our benchmarking of indirect and IMF&T costs.

8.54 We reviewed the analysis and arguments submitted by NIE and the UR on service quality. We did not identify a basis on which to use 2009/10 cost benchmarks rather than 2011/12 cost benchmarks or to make an adjustment to our analysis for differences in service quality between NIE and the GB DNOs.

8.55 Although the analysis submitted by NIE indicated that its customer interruptions performance was below the GB DNO average in 2009/10, NIE performed better than a number of the GB DNOs. We thought that NIE's operating environment and relative extent of overhead line provided reasons why it might experience more interruptions than the average GB DNO. We also agreed with NIE that the performance comparisons submitted by the UR in relation to 2010/11 were flawed.

8.56 We did not agree entirely with NIE's objection to the link drawn by the UR between service quality and the costs covered by our benchmarking analysis. It may be the case that DNOs improve service quality through capital investment. However, it is also the case that DNOs will take decisions that affect their operating costs (and feed into IMF&T costs) that will affect service quality, especially in terms of response times to address customer minutes lost. NIE's submissions did not demonstrate that the only source of improvement in service quality was from capital investment. However, we recognised that differences in service quality between companies may reflect differences in capital investment rather than IMF&T costs.

Step (b): benchmarking analysis

8.57 The second step of our approach was to carry out benchmarking analysis. We used several models and methods and compared companies in different ways (eg indirect costs only or indirect costs plus IMF&T costs).

8.58 This subsection provides more information on the methods we used for benchmarking analysis and presents results. It is organized as follows:

(a) We describe our approach to cost adjustments for differences in wage rates between Northern Ireland and other parts of the UK (paragraphs 8.61 to 8.74).

(b) We describe our approach to making an adjustment for the fact that owns and maintains 275 kV network infrastructure whereas GB DNOs do not operate network infrastructure at this voltage level (paragraphs 8.75 to 8.84).

(c) We describe our approach in relation to indirect costs that are attributed to connections and excluded services (paragraphs 8.85 to 8.95).

(d) We explain and describe the adjustment we made to the GB DNO cost data to remove what Ofgem refers to as 'disallowed related party margins' (see paragraphs 8.96 to 8.104).

(e) We describe our approach in relation to the treatment of costs relating to wayleaves (paragraphs 8.105 to 8.107).

(f) NIE's submissions on distortions to benchmarking analysis relating to vehicle leasing (paragraphs 8.108 to 8.115);

(g) We describe the econometric models we have used (paragraphs 8.116 to 8.126).

(h) We discuss the choice of the cost benchmark for our analysis (paragraphs 8.127 to 8.141).

(i) We provide results from the analysis (paragraphs 8.142 to 8.154).

8.59 We provide further information on our adjustments for regional wage differences in Appendix 8.4. We provide further information on our econometric model specifications, results and data sources in Appendix 8.5.

8.60 We built on the extensive work undertaken by the consultants for NIE and the UR. We did not seek to carry out more granular benchmarking analysis (eg potential benchmarking analysis for more granular cost categories within indirect costs, which Ofgem includes within its suite of analytical approaches for benchmarking of GB distribution companies). Nor have we sought to develop more sophisticated econometric models. The disputes between the parties in their initial submissions to us concerned detailed aspects of the methods and calculations used for benchmarking. Neither party sought to reject the principle of benchmarking NIE against GB DNOs or to reject the type of high-level econometric models that the consultants working for the parties have used. Further, we were constrained by the information available on NIE's costs which is not reported to the same degree of granularity as GB DNOs.

Wage adjustments

8.61 In its benchmarking analysis for the UR, CEPA made adjustments to the cost data for NIE and each of the GB DNOs to try to take account of differences in wage rates between different parts of the UK. Frontier made no such adjustment in its original benchmarking analysis and this difference of approach explains a large part of the difference in results between CEPA and Frontier.

8.62 NIE objected to the principle of making wage adjustments on the basis that whilst wage adjustments would tend to worsen NIE's apparent performance relative to GB DNOs, there might be other differences between NIE and those DNOs that were not taken into account but which would improve its performance. NIE also submitted that if wage adjustments were to be made, they should be calculated using an alternative method set out in analysis by Frontier. This alternative method gives rise to a very small wage adjustment for NIE.

8.63 We considered wage adjustments as part of our comparisons across different electricity distribution companies in the UK. Wage differences between different parts of the UK could lead to substantial differences in costs. There are publicly available data sources that allow wage comparisons between regions within the UK. We did not accept NIE's argument that we should not make regional wage adjustments unless we make adjustments for other factors that may improve NIE's relative performance in the benchmarking exercise. There will be many factors that affect companies' relative costs that we cannot take appropriate account of in the benchmarking exercise. But that should not prevent us taking account of specific factors where we consider that an adjustment is likely to make a positive contribution to the cost comparisons between companies.

8.64 We reviewed the submissions of the parties on the calculation of wage adjustments. We also thought more widely about what adjustment methods are possible with the available data.

8.65 The data source we used is weekly wage data from the Annual Survey of Hours and Earnings (ASHE). For the UK and the regions of GB this data was obtained from the Office for National Statistics, while for Northern Ireland it was obtained from the Northern Ireland Statistics and Research Agency. We also considered the ASHE hourly wage data.

8.66 There is no single 'correct' method for making a wage adjustment to the costs of NIE and GB DNOs as part of benchmarking analysis. Some methods would use relatively detailed or granular wage data on the type of occupations that are relevant to NIE's business. But the sample size for this data is quite small and we have some concerns about its accuracy. However, if more aggregated data is used, there is a greater risk that estimation results are influenced by wage data for occupations that are not relevant to NIE's activities.

8.67 We produced results from benchmarking analysis using three different wage adjustment methods to adjust each company's cost data before estimation of the econometric model. These methods are summarized as follows (more detailed information is in Appendix 8.4):

(a) *Method WA1.* We use an allocation carried out by Frontier for NIE of the NIE and NIE Powerteam workforce to the most granular occupational categories available in the ASHE regional wage statistics (four-digit SOC code). For each region in the UK, we calculate a weighted average of regional wages (relative to the UK as a whole) based on the ASHE wage data for those occupational categories (relative to the UK as a whole), with weights determined by the weight given to each occupational category in the Frontier allocation for NIE (we use the same occupational categories and weights for the GB DNOs). We adjust the cost for each company according to the weighted average of regional wages relative to the UK as a whole for the region that the DNO operates in.

(b) *Method WA2.* This wage adjustment method uses the same approach as for WA1 except that, for each occupational category, we replace the ASHE wage data used in method WA1 (four-digit SOC code) with wage data for the more aggregated occupation category that it falls under (ie the three-digit SOC code that the relevant four-digit SOC code falls under). This approach uses wage data for which there is a larger sample size than for method WA1.

(c) *Method WA3.* This method for wage adjustment uses ASHE data on average regional wages relative to UK averages to adjust the costs of each company. It does not take any specific account of the occupational categories of staff working for NIE or other electricity distribution companies.

8.68 In addition, we produced results from benchmarking analysis that do not involve any wage adjustments. We label this approach method WA0.

8.69 As far as possible, we calculated the wage adjustments using annual data on regional wages that are averaged over a five-year period. This helps to reduce concerns about small sample sizes in the ASHE regional wage data.

8.70 In all cases we used data on average wages rather than median wages. Average wages are more relevant when forecasting the total costs across a group of staff within the occupational categories used. In contrast, median wages would be more relevant to a forecast of the wages of a particular employee picked at random from those categories.

8.71 Frontier identified that mean wages may be more prone to sampling error than median wages and that this might be a reason to prefer median wages. We did not consider this point sufficient to favour median wages. However, it did add to the case for wage adjustment methods that make use of a larger sample size.

8.72 There is also a choice between whether to use data on weekly wages or hourly wages. CEPA's analysis for the UR used weekly wages. Frontier's analysis for NIE used hourly wages. We calculated potential adjustments for both weekly and hourly wages (see Appendix 8.4). We considered weekly wages the better choice and we focused our main analysis on methods involving wage adjustments based on weekly wage data. We considered that weekly wages were more relevant to the type of salaried occupations that are relevant to the workforce of NIE and NIE Powerteam.

8.73 NIE argued that it was wrong for us to use wage adjustments based on weekly rather than hourly wage data and said that it was irrelevant that the relevant professions are typically paid weekly. NIE reported that working hours are higher in GB than NI for the most relevant occupations, by 2.5 per cent. NIE considered hourly wage data the only reasonable approach.

8.74 Despite NIE's submissions, we did not consider the use of weekly wage data unreasonable. CEPA's analysis for the UR used weekly wage data. We also found that the ONS reports information on regional differences in earnings and differences in earnings by occupation using weekly data wage data.[8] Further, NIE referred us to research by IDS in support of its contention that there is little variation in pay levels outside London and the South East; the IDS research that NIE referred us to used regional weekly wage data from the ASHE. In any event, as shown in Appendix 8.4, the differences between our calculated wage adjustments on an hourly and weekly basis were generally small. The main exception was the wage adjustments for some DNOs under method WA1; that method used the most granular data and, in turn, relied on data for which the sample size was smaller. The differences in hourly and weekly wage data under the method WA1 may be due to inaccuracies from a smaller sample size rather than any defects from using the weekly wage data.

Treatment of costs attributed to 275 kV network

8.75 NIE's electricity network infrastructure is divided into a transmission system and a distribution system. The transmission system includes lines operated at 275 kV and 110 kV and the distribution system includes lines operated at voltages of 33 kV and below.

8.76 The data from Ofgem that we used concerns the costs of the 14 regional licence DNOs in GB. These companies differ from NIE in the following ways:

(a) The 12 DNOs in England and Wales operate networks with voltages up to 132 kV. In England and Wales, National Grid operates a separate transmission network at voltages of 275 kV and 400 kV.

(b) The two regional DNOs in companies in Scotland operate networks with voltages up to 33 kV. In Scotland, voltages of 132 kV and above are categorized as transmission and the transmission networks are operated by separate licensed entities that are subject to separate price controls from the DNOs.

8.77 The indirect costs and network operating costs of NIE will include costs relating to 275 kV network infrastructure. None of the GB DNOs operate 275 kV networks.

8.78 In its cost benchmarking analysis for NIE, Frontier made an allocation of NIE's costs with the aim of removing the element of costs attributed to 275 kV infrastructure before making comparisons with the costs of GB DNOs. Frontier's approach can be summarized as follows:

(a) 7.5 per cent of NIE's indirect costs are attributed to 275 kV network infrastructure, with the remaining 92.5 per cent of indirect costs attributed to the rest of NIE's transmission and distribution systems. The figure of 7.5 per cent is derived from Frontier's estimate of the proportion of NIE's RAB additions for transmission and distribution that is attributed to the 275 kV network, using information on the proportion of transmission capex relating to the 275 kV network over the period 2003 to 2010. The 7.5 per cent figure applies to 2009/10.

(b) For network operating costs (which Frontier refers to as 'R&M' costs), the majority of costs are allocated between 275 kV and sub-275 kV infrastructure through a detailed bottom-up analysis. Only a small percentage of these costs are allocated using the 7.5 per cent assumption.

[8] ONS(2013) 'Annual Survey of Hours and Earnings, 2013 Provisional Results', pp 26–30.

8.79 CEPA's October 2011 report for the UR presented benchmarking analysis that used the same 7.5 per cent adjustment for NIE's 275 kV network as Frontier, with CEPA reporting as follows:[9]

> NIE's submission estimated that approximately 7.5% of opex relates to the 275kV transmission network. We have considered this against estimates for capex carried out at 275kV and believe that this estimate is relatively robust, and as such have used the 7.5% adjustment to remove 275kV work from the opex estimate.

8.80 In making comparisons of NIE's indirect costs against GB DNOs, we have also scaled down NIE's indirect costs by 7.5 per cent, in line with the approach developed by Frontier and CEPA.

8.81 For IMF&T costs, we made use of the more granular allocation of costs between 275 kV and the rest of NIE's network available from Frontier's analysis. This results in around 2 per cent of NIE's IMF&T costs being allocated to 275 kV and removed from NIE's costs before comparisons with GB DNOs.

8.82 A limitation of the approach used by Frontier and CEPA is that it overlooks the differences between Scotland and the rest of GB in the composition of the distribution network. The comparisons carried out by Frontier and CEPA do not seem to take account of the fact that the DNOs in Scotland do not operate 132 kV networks. The impact this has on results from benchmarking analysis for NIE is dependent on the details of econometric model used for benchmarking purposes. Frontier suggested that the effect would tend to overstate the relative efficiency of the two Scottish DNOs.

8.83 We did not find a practical alternative to the approach taken by Frontier and CEPA in relation to the Scottish DNOs. One option might be to exclude cost data from the two Scottish DNOs from the analysis because they do not include the costs associated with 110 or 132 kV infrastructure. However, in other ways these companies are more similar to NIE than the DNOs in England and Wales (eg number of customers, sparsity of network) and it could be detrimental to the comparability of the sample with NIE to exclude them.

8.84 Another option might be to include in the benchmarking analysis some cost data reported by the transmission companies operating in Scotland, to bring costs related to 132 kV assets (and potentially 275 kV assets) into the cost comparisons with NIE. Whilst this was not practical for our inquiry, the UR and NIE might consider this for the future.

Treatment of costs attributed to connections and non-distribution activities

8.85 We also sought to exclude, as far as possible, indirect costs incurred by NIE that do not relate to its transmission or distribution activities (eg by deducting the value of recharges from NIE to other businesses for the recovery of costs incurred by NIE). Similarly we made adjustments to the GB DNO data to exclude costs attributed to non-distribution activities (ie activities that are not part of their distribution businesses).

8.86 We also considered adjustments for costs relating to new connections. Both Frontier and CEPA scaled down their estimate of NIE's indirect costs by around 20 per cent

[9] CEPA 2011, p8.

before making comparisons with the DNOs in GB in order to remove an estimate of the element of NIE's indirect costs that is attributable to connections activities. Frontier and CEPA stated that this adjustment was appropriate because the GB DNO data that they used on indirect costs excluded indirect costs attributable to connections. However, as discussed under step *(a)* above, we found that the estimate of NIE's indirect costs used by Frontier and CEPA did not involve the same treatment of connection costs as the GB DNO data from Ofgem's DPCR5 financial model (see paragraphs 8.10 to 8.16). We did not use the data from the DPCR5 financial model for the benchmarking analysis we present in this section.

8.87 We used cost data obtained directly from Ofgem which is reported under the RIGs reporting requirements established as part of the DPCR5 price control review. The data provided by Ofgem allowed us to make comparisons of indirect costs between NIE and GB DNOs on a basis that excludes indirect costs attributed to connections and also on a basis that includes any indirect costs attributable to connections.

8.88 Conducting the benchmarking analysis on costs excluding connections costs has some advantages. In particular, different companies may carry out different volumes of connection activity, which contribute to cost differences between companies, but these differences may not be adequately captured in the econometric models we used. However, there are also drawbacks from the exclusion of connection costs, because the analysis will be vulnerable to any inconsistencies between DNOs in the sample in cost allocation methods for connections. Given the size of the adjustment to exclude connection costs (around 20 per cent for NIE), such inconsistencies could have a significant impact on the results.

8.89 We produced results for indirect costs with and without adjustments to exclude costs attributed to connections. We discuss under step *(c)* how we used these results in making a determination of an indirect cost allowance for NIE (see paragraphs 8.155 to 8.234).

8.90 On this basis, we used two different measures of indirect costs for GB DNOs in our comparisons with NIE:

(a) the total gross costs reported by GB DNOs for indirect costs minus costs attributable to non-distribution activities; and

(b) the indirect costs under *(a)* above minus all costs identified as attributable to connections activities (covering connections activities funded through connection charges as well as connection activities funded through the main price control).

8.91 For the benchmarking comparisons in our provisional determination, we made deductions to NIE's costs using an allocation factor for costs attributable to connections that had been proposed by NIE and its consultant Frontier in August 2013. This used an allocation factor of 20.3 per cent to allocate NIE's indirect costs in 2009/10 to connections activities. This figure was based on an allocation of NIE and NIE Powerteam staff between connections work and other activities.

8.92 Following our provisional determination, NIE provided a revised allocation to connections of 20.9 per cent for 2009/10, explaining that its previous figure of 20.3 per cent did not include allocation of generation connections or apprentices to connections activity. NIE also provided updated allocations for 2010/11 and 2011/12. We used NIE's revised and updated allocations as part of our updated benchmarking analysis.

8.93 NIE had previously developed a bottom-up measure of the appropriate connections adjustment for 2009/10 based on analysis of accounting and management information. NIE said that this revealed that the indirect cost allocation to connections should be 21.7 per cent. This is slightly higher than the revised allocation of 20.9 per cent for 2009/10 based on staff time that NIE provided after our provisional determination. We were concerned that NIE's bottom-up allocation method may give undue prominence to NIE Powerteam within NIE's business: the various activities carried out by NIE (eg network asset replacement, repairs and maintenance, metering activities and new connections) involve not only the costs of NIE Powerteam but also other costs (eg using staff from NIE or subcontractors). In line with the approach in our provisional determination, we used a connections allocation based on NIE's estimates of the proportion of staff working on connection, rather than the figure or approach from NIE's bottom-up analysis.

8.94 In its response to our provisional determination, NIE also identified an error in the way that we had calculated an adjustment to its costs to remove costs attributable to connections. NIE said that we have failed to apply the connections allocation factor to the entirety of the relevant pension costs and that, once corrected, this would exclude a further £0.54 million of indirect costs in 2009/10.[10] We agreed with NIE's submission on this point and decided to revise our calculation as proposed by NIE. Our review of this issue revealed that we should also apply the connections allocation factor to some adjustments we had made to remove from the calculation costs we attributed to NIE's metering and market opening activities. This had an offsetting effect and reduced the costs attributable to connections by £0.53 million in 2009/10 and £0.56 million in 2011/12.

8.95 Overall, we attributed £8.5 million of NIE's indirect costs in 2009/10 to connections activity (excluding costs attributed to NIE's 275kV network). The corresponding figure for 2011/12 was £9.7 million.

Adjustment to GB DNO data to remove disallowed related party margins

8.96 For our provisional determination, we used estimates of NIE's costs which drew on data on the costs incurred by NIE Powerteam rather than the charges from NIE Powerteam to NIE. We did not consider it appropriate that the estimates of NIE's direct and indirect costs that fed into the benchmarking analysis should include any of the historical profit generated by NIE Powerteam in its transactions with NIE.

8.97 In contrast, the data from Ofgem on the costs for the GB DNOs that was available to us at the time of our provisional determination was based on measures of 'gross costs' and would reflect any charges to the DNO by a 'related party' which could be an affiliate company that shares the same owner as the DNO. These charges could include a profit element or margin. Further, the GB DNO cost data that we used included margins that are excluded from the costs that Ofgem allows to be added to each DNO's RAB. These margins could reflect profit elements that bear no relation to the economic costs of carrying out the relevant distribution network activities.

8.98 Under Ofgem's rules for the DPCR5 price controls that apply from 1 Aril 2010 to 31 March 2015, the costs to be added to each DNO's RAB[11] are 'intended to refer to costs of the distribution business incurred by the licensee or a related party of the licensee undertaking distribution business activities where those costs are recharged to the licensee, but do not include any internal profit margins of the licensee or

[10] NIE response to provisional determination, p19.
[11] Ofgem refers to the RAV (regulatory asset value) rather than RAB (regulatory asset base) but the meaning is the same here.

related party margins, except where permitted'.[12] Ofgem said that 'related party profit margins will be excluded from costs added to [RAB] unless the related party concerned earns at least 75 per cent of its turnover from sources other than related parties and charges to the licensed entity are consistent with charges to external customers'.[13] Ofgem refers to margins that are excluded from the RAB under this turnover rule as 'disallowed related party margins'.

8.99 We recognized that, in principle, disallowed related party margins may include real economic costs and that excluding these in full might understate the costs of carrying out the relevant activities. In particular, if the services of a related party used assets owned by that related party, disallowing margins would mean that the cost data would ignore any financing costs for those assets. However, we did not consider that the likely effect of this issue was sufficient to mean that we should not exclude the disallowed margins. We took account of the following.

8.100 First, we would expect the GB DNOs to take steps to avoid a situation in which significant economic costs faced by a related party would not be recoverable as a result of Ofgem's policy on disallowed third party margins. These steps include decisions on which activities the related party is involved in and on the structure of the related party (eg whether the related party owns significant assets or whether assets necessary for the work of the related party for the DNO are owned by the DNO or leased). To the extent that the data on 'disallowed third party margins' for the GB DNOs reflect the economic costs of carrying out distribution activities, these are costs that the GB DNOs have knowingly foregone.

8.101 Second, we looked at the example of NIE Powerteam. We would expect that the margins charged by NIE Powerteam to NIE would be treated as disallowed related party margins under Ofgem's turnover rule. NIE Powerteam's balance sheet showed assets of £2.5 million for property, plant and equipment on 31 March 2010.[14] If we assume for illustration a nominal cost of capital of 10 per cent, the implied financing costs would be less than £0.25m per year. This level of financing costs is small compared to the total costs incurred by NIE Powerteam in 2009/10 in relation to work for NIE, which were around £48 million. Analysis provided to us by NIE, which we used in the calculation of NIE's indirect costs, shows that the margin between NIE Powerteam's charges to NIE and its costs (including depreciation) was £1.8 million in 2009/10. We do not claim that NIE Powerteam is representative of related party transactions for the GB DNOs but we draw the following from this example:

(a) it shows that it is feasible for a DNO to arrange its affairs in such a way that it uses a related party with very limited fixed assets for a large amount of its work; and

(b) it shows that the margin charged by a related party to a DNO may be far in excess of the financing costs of the assets owned by the related party.

8.102 In light of the above, and Ofgem's policy on disallowed related party margins, we found that it was appropriate to make adjustments to deduct disallowed related party margins from the GB DNO cost data. We considered that such an adjustment would provide for a better estimate of the underlying costs of the GB DNOs. It is also more consistent with the approach we used to calculate NIE's indirect and IMF&T costs.

[12] Ofgem (2009) 'Electricity Distribution Price Control Review Final Proposals—Financial methodologies', p6.
[13] Ofgem (2009) 'Electricity Distribution Price Control Review Final Proposals—Financial methodologies', p9.
[14] NIE Powerteam statutory accounts 2009/10.

8.103 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. We made deductions from each GB DNO's indirect costs and IMF&T costs to remove disallowed related party margins. The method we used to make these adjustments is set out in Appendix 8.5. As part of this method, we made attributions of the disallowed related party margins to connections and non-distribution activities.

8.104 We found that, on average across the 14 GB DNOs and three years of our data sample, the adjustment we made to remove disallowed related party margins was around [✂] per cent of the GB DNO's indirect and IMF&T costs (excluding connections).

Treatment of wayleaves costs

8.105 In its original benchmarking reports for NIE in February 2011, Frontier included NIE's wayleaves costs as part of the calculation of NIE's indirect costs. Ofgem's category of indirect costs includes wayleaves costs and the publicly available cost data for the GB DNOs from the DPCR5 financial model included wayleaves costs. CEPA took the same approach in its analysis for the UR.

8.106 Frontier maintained its approach to wayleaves in an updated benchmarking analysis submitted by NIE in August 2013. However, in a report submitted by NIE in October 2013, Frontier proposed a different approach: either that wayleaves should be excluded from the benchmarking analysis or that adjustments should be made to NIE's wayleave costs to normalize them. Frontier said that NIE incurred a high absolute level of wayleave costs and that this was attributable to NIE's extensive EHV/HV overhead line network. Frontier's report indicated that some of the econometric models we use are unlikely to account for the impact on costs of differences between companies in terms of the length of their EHV and HV overhead line networks.

8.107 We did not seek to exclude wayleave costs or to make an adjustment for NIE's relatively high wayleave costs as part of our benchmarking analysis. This is due to several factors:

(a) We did not consider it appropriate to exclude automatically a category of costs from our benchmarking analysis on the basis that NIE has relatively high costs in that category due to factors that are not fully taken into account in the econometric models. Our approach to benchmarking analysis is based on relatively aggregated econometric models and it is inevitable that they will not take full account of all such effects.

(b) While Frontier argued that our benchmarking analysis might be unfavourable to NIE in relation to wayleaves, other aspects of the analysis might be favourable. For instance, the UR argued that the econometric models that we used were favourable to NIE because they did not take enough account of NIE's relatively limited requirements for tree-cutting expenditure.

(c) We accept that it might be possible to develop a method for normalization adjustments for wayleaves, but this would require considerable further analysis. Our experience from our work on wage adjustments was that seeking to make normalization adjustments can be resource-intensive. Given the small scale of the differences in wayleave costs between NIE and other companies, relative to

NIE's total indirect costs, we did not consider it proportionate to develop work on potential normalization adjustments in the course of this investigation.

(d) Finally, we could not exclude the possibility that NIE's relatively high historical wayleave costs reflect, to some degree, the fact that these costs have been subject to full cost pass-through and NIE has not been financially exposed to the level of its wayleave costs.

NIE's submissions on distortions to benchmarking analysis relating to vehicle leasing

8.108 In a submission in January 2014, NIE identified that its indirect costs included a significant amount of costs for the lease of vehicles by NIE Powerteam. NIE reported that the NIE Powerteam costs for 'vehicle rental (contract hire)' were £2.3 million in 2011/12. These costs are treated as indirect costs as part of our benchmarking analysis. NIE argued that a company that hires a greater proportion of its vehicles than average will suffer two detriments in our benchmarking analysis for NIE's indirect and IMF&T costs:

(a) it will have higher cost included in an indirect benchmark and may be found to be less efficient than is actually the case (or equivalently, allowed costs will be set at too low a level by companies that choose to buy rather than hire); and

(b) it would receive a low non-operational capex allowance.

8.109 NIE said that it hired the majority of its vehicle needs and that it was clear that, in consequence, it would suffer the two detriments outlined above.

8.110 NIE said that it believed that Ofgem was aware of this potential distortion to benchmarking analysis and has in the past applied company-specific normalization adjustment to adjust both the costs included in benchmarking and the allowance for non-operational capex to reflect an average approach to vehicle sourcing. NIE said that we should expand our work with Ofgem to take account of this distortion and should apply an appropriate adjustment to its benchmarking and allowance for non-operational capex.

8.111 We did not make any specific adjustments to our benchmarking analysis or cost assessment in light of these issues raised by NIE on vehicle leasing. This was for a number of reasons, which we set out below.

8.112 We disagreed with NIE's view that it was clear that NIE had suffered the detriments above. NIE's contention that it had been disadvantaged by our approach to benchmarking is dependent on a theory that, over the data period of our benchmarking analysis, it leased (rather than owned) a significantly greater proportion of its vehicles than the average DNO. NIE provided no evidence to support such a theory. The information reported by NIE on its vehicles policy was focused on NIE without comparisons to GB DNOs.

8.113 Second, the most recent Ofgem publication available to us on GB DNO cost benchmarking did not set out a clear method that would allow us to deal with the issues raised by NIE in relation to vehicles. In December 2013, Ofgem published a consultation as part of its RIIO ED1 price control review, which included an annex on its assessment of GB DNO's business plan expenditure.[15] That document indicated that Ofgem had excluded vehicles costs from its benchmarking of closely associated

[15] Ofgem (2013) RIIO-ED1 business plan expenditure assessment - methodology and results

indirect costs and had made a separate analysis of vehicles costs but it did not discuss the issues raised by NIE in detail or specify an alternative method that we could use with the data available to us.[16]

8.114 Third, the benchmarking analysis we carried out for the purposes of our inquiry has been less detailed and perhaps less sophisticated than that carried out by Ofgem for the GB DNOs. Differences in the cost reporting frameworks between NIE and the GB DNOs have meant that substantial work was necessary to allow for a comparison between NIE's costs and the costs of the GB DNOs. We considered that it was not practicable in the timescale of our inquiry to seek to replicate the type of benchmarking analysis and cost assessment carried out by Ofgem for the GB DNOs.

8.115 We took account of the less detailed nature of our benchmarking in our decision to use the fifth rather than the fourth ranked company for our cost benchmark (paragraphs 8.127 to 8.141)). We also recognised that although NIE had identified that potential limitations in our benchmarking analysis may be detrimental to NIE, the UR had also identified that potential limitations in our benchmarking analysis may be beneficial to NIE. Overall, we did not consider that our benchmarking analysis was unfair to NIE. However, we recognized that there may be scope for improvements to such analysis in the future.

Econometric model specification and estimation method for indirect costs

8.116 We used econometric models to compare cost data from NIE and the 14 GB DNOs. We drew on the approach taken by Frontier and CEPA and also considered a slightly wider set of models.

8.117 Our data for GB DNOs covered the years 2009/10, 2010/11 and 2011/12. We had data for NIE on a consistent basis only for 2009/10. We included time dummy variables in our model specification to make some allowances for industry-level changes in costs from one year to the next (relative to the RPI, which we used to deflate cost data before comparing costs).

8.118 We used relatively simple models with a single explanatory factor intended to take some account of differences in the scale of each company's distribution activities. In particular, we considered models that include the following explanatory factors:

(a) a composite scale variable used by Ofgem for its DPCR4 price control review: for each company, this is a weighted average of the company's number of connected customers, length of network and units of electricity distributed. We call this CSV(1); and

(b) a different composite scale variable that Ofgem used for some if its analysis during its DPCR5 price control review, which is based on a weighted average of an estimate the modern equivalent asset value (MEAV) of the company's distribution system and an aggregated measure of the direct costs of the company's capex programme. We call this CSV(2).

8.119 These variables are defined in more detail in Appendix 8.5.

[16] NIE subsequently proposed an alternative method that we could use in relation to vehicles costs, which it considered consistent with the spirit of the approach taken by Ofgem. This would have required us to request additional data from Ofgem, to revise our benchmarking analysis to exclude vehicles costs and then carry out a separate assessment of vehicles costs. This suggestion from NIE was at a late stage in our inquiry and we did not consider it practicable.

8.120 The benchmarking analysis carried out by Frontier focused on models with the DPCR4 composite scale variable we label CSV(1) above. Frontier had considered whether it was possible to use the more complex and detailed types of models used by Ofgem for its DPCR5 price control review but found that this was not practical.

8.121 CEPA carried out benchmarking analysis for models with both explanatory factors CSV(1) and CSV(2) above.

8.122 We sought to replicate the model specification of Frontier and CEPA. In each case, the dependent variable in the regression analysis is indirect costs. In line with the sensitivity analysis presented by Frontier and CEPA, we estimated versions of these models in which cost and explanatory factor data are converted to logs before model estimation and versions in which they are not.

8.123 In addition, we used a different type of model which compares measures of indirect costs *per connected customer*, rather than comparing indirect costs. We specified two such models:

(a) One model includes a constant and time dummy variables but no explanatory factor. This model effectively provides a simple comparison of average costs per customer. This model provides a useful reference point and comparison against more complicated models. For example, a comparison with the results from this model can help illustrate the extent to which more complicated models make allowances for differences between companies besides differences in the number of connected customers on the network.

(b) The other model includes an explanatory factor specified as natural logarithm of the average length of the company's network per customer. For this model, we use the natural logarithm of the cost per customer as the dependent variable.

8.124 The six models we have considered are summarized in Table 8.2.

TABLE 8.2 **Model descriptions**

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

Source: CC.

8.125 The simple econometric models we used cannot take full account of all differences between electricity distribution companies in the UK that affect their costs. However, they could provide an approximation of the level of costs of a company with a given scale of activity (as proxied by the explanatory factor in model) if it were reasonably efficient.

8.126 In its Statement of Case (p188), NIE said that it was not reasonable to apply a downward wage adjustment to NIE's costs for the purposes of comparison with GB DNOs without taking account of other significant differences between regions. It said that taking account of the sparse nature of NIE's network was likely to offset the regional wage adjustment. However, NIE did not substantiate this point. In any event, the models we considered included models which take some account of differences in sparsity of network. For instance, the explanatory factor in model M6 estimates the impact on indirect costs per customer of differences between companies in the length of network per customer. All the other models apart from model M3 take some account of differences between companies relating to sparsity.

Choice of benchmark company used to estimate 'efficient' costs for NIE

8.127 In its final determination, the UR proposed cost reductions for NIE that would bring NIE's costs in line with the estimates from CEPA's econometric model for a company of NIE's scale if it were at the 'upper quartile' of performance in the model.

8.128 We did not consider that it was appropriate to use the upper quartile concept for our benchmarking analysis. This was first and foremost for practical reasons. There is no settled definition of the upper quartile in a series of integers (whole numbers). We found that Microsoft Excel and the statistics package Stata used different methods to calculate the upper quartile of a discrete distribution. In fact there are a number of different methods for calculating quartiles which give different results.[17] Related in part to the ambiguity about the concept of an upper quartile, we found it hard to convey what is meant by using the upper quartile for our benchmarking analysis. We decided instead to choose a benchmark that was defined by reference to the benchmarking results for one of the companies in our sample.

8.129 For our provisional determination, we used our benchmarking analysis to produce an estimate of the costs that would have been incurred in 2009/10 by a company of NIE's scale which faces Northern Ireland wage conditions. We calibrated our estimates to the level of costs for a company that would rank fifth out of the 15 companies in our benchmarking analysis.

8.130 We said that we did not consider it reliable to view the company ranked first in the sample as an achievable benchmark for efficient costs: the results for such a company may be particularly influenced by data error and circumstances that are not representative across DNOs in the UK.

8.131 We shared our preliminary view on the choice of the benchmark company with NIE and the UR ahead of our provisional determination. NIE submitted a report on our benchmarking analysis which said that a benchmark based on the fifth company was prudent and reasonable. In contrast, the UR said it was concerned that a benchmark based on the fifth-ranked company was insufficiently ambitious. The UR considered the fourth-ranked company a more appropriate benchmark than the fifth-ranked company. In our provisional determination, we said that we did not share the UR's view, particularly in light of the risk that the econometric models we have used do not fully account for all the differences between companies that affect their costs.

8.132 In its response to our provisional determination, the UR reiterated its view that we should use a more demanding benchmark than the fifth company. The UR said that 'there are good reasons to demand more, on behalf of NIE T&D's customers, than for NIE T&D to match the efficiency of the fifth most efficient DNO' and provided two specific arguments for this:[18]

> First, there is no reason to believe that the weaknesses in the econometric models tend to understate rather than overstate the costs of an efficient DNO. As noted above, there are swings and roundabouts in any benchmarking exercise, and it is just as likely that the missing explanatory factors would point to inefficiency on NIE T&D's part rather

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[17] Langford, Eric. 'Quartiles in Elementary Statistics' *Journal of Statistics Education*. 14.3 (2006):
[18] The UR response to the provisional decision, paragraphs 76–78.

than efficiency. There is accordingly no reason to react to the uncertainty inherent in the modelling exercise by allowing NIE T&D to "aim low". Moreover, for the Commission to suggest that "aiming low" is an acceptable consequence of NIE T&D producing poor quality data is to create perverse incentives on NIE T&D to resist our calls for progress on transparency between now and RP6.

Second, we would also ask the Commission to take into account that under the D1 cost risk sharing proposal discussed above, NIE T&D is much less exposed to the risk of underperformance than it would usually be. If (as we hope) the Commission accepts our submission that the capex incentives need to be softened in the public interest, and (as we anticipate) the Commission continues to set a single incentive rate across opex and capex, the result will be that NIE T&D's opex incentives are very soft indeed. In our view, that should mitigate the Commission's concern about the risk of setting an excessively ambitious target.

8.133 The UR's second argument above was not relevant to our determination. It might have applied if we had made a change to the cost risk-sharing mechanism that weakened the financial incentives that NIE would face in relation to its opex, compared to the proposals from our provisional determination. As set out in Section 5 (paragraphs 5.49 to 5.96), we have not changed the cost risk-sharing arrangements in response to the submissions from the UR on our provisional determination. We expect NIE to be subject to clear and strong financial incentives in relation to the opex that falls within the scope of our benchmarking analysis.

8.134 We disagreed with the first point made by the UR, which concerns the effect of modelling limitations and data issues on the results from the benchmarking analysis.

8.135 Weaknesses or limitations in the econometric models and any errors or inconsistencies in the data set we used will contribute to the variance in costs across the 15 companies in the sample. We would expect this to have an effect on the statistical properties of the cost benchmarks. We would expect this variance to introduce a bias that overstates the relative performance of companies ranked better than the median performance and understates the relative performance of companies ranked worse than the median. Where we see a company that has performed relatively well in the benchmarking analysis we would expect that, on the balance of probability, its performance or rank has been improved (to some degree) by modelling limitations and data issues.

8.136 In the presence of modelling limitations and data error, we expect that our choice of the fifth company for the benchmark means that, on the balance of probability, NIE would need to be more efficient than the fifth company if its costs are to match our estimated cost benchmark. An effect of modelling limitations and data issues is that the cost benchmark is more demanding than it might appear.

8.137 We noted that Ofgem has set less demanding benchmarks than the upper quartile, such as benchmarks based on the upper third or median company, where it has had more concerns about the accuracy of its benchmarking analysis (eg because of data inconsistencies).[19]

[19] Ofgem (2009) *Electricity Distribution Price Control Review Final Proposals: Allowed revenue—Cost assessment*, p4.

8.138 Finally, we did not accept the UR's statement that 'for the Commission to suggest that "aiming low" is an acceptable consequence of NIE T&D producing poor quality data is to create perverse incentives on NIE T&D to resist our calls for progress on transparency between now and RP6'. We did not 'aim low'. The limitations in our benchmarking analysis are not primarily driven by NIE providing 'poor quality data'. To the extent that NIE's data was not reported on a consistent basis with the GB DNOs, or did not allow more granular cost comparisons, this was a consequence of the regulatory reporting framework that NIE had been subject to rather than a consequence of poor quality data submissions from NIE.

8.139 In a subsequent submission, the UR said that the difference between using the fourth and fifth ranked companies as the benchmark could be worth around £1.3 million to £1.4 million per year. The UR said that this was a substantial sum. In making our decision on the choice of cost benchmark, we recognized that this could have a significant impact on the cost allowances we determined for NIE (the precise figures depended on which models and wage adjustments were used).

8.140 Stepping back from the specific arguments made by the UR and NIE, we were satisfied that it was appropriate to base our assessment for indirect and IMF&T costs on estimated costs that were calibrated using the costs for a company that would rank fifth out of the 15 companies in our benchmarking analysis.

8.141 Our choice of the cost benchmark reflects the specific circumstances of our inquiry and, in particular, the nature and limitations of the benchmarking analysis we have carried out. It also reflects the submissions made to us by parties in the course of our inquiry. It should not act as a constraint on the choice of cost benchmarks for any future price control reviews.

Results from cost benchmarking comparisons

8.142 We can use the results from our econometric models to make an estimate of the relative costs of each company that takes account of some of the differences between them—specifically, the differences reflected in the explanatory factors used in the model. For instance, model M6 provides an estimate of the impact on cost per connected customer of differences in length of network per connected customer. Similarly, our wage adjustments allow us to take account of estimates of the impact of regional differences in wages across the UK.

8.143 If we attribute all cost differences between companies that are not explained by the explanatory factors in our econometric models (or our wage adjustments) to efficiency differences, we can produce a ranking of each company in terms of its relative efficiency in the sample. A rank of 1 would represent the company with the lowest level of costs relative to the level of costs predicted for it by the econometric model (after the application of any wage adjustments).

8.144 We can also produce an efficiency 'score' for each company. As stated above, we use the company ranked fifth as our cost benchmark. We calculated an efficiency score for NIE by dividing our measure of NIE's costs in 2011/12 by the level of costs that we estimated from the model for NIE if it were as 'efficient' as the company ranked fifth in our sample of 15 companies.

8.145 In the results below, we report the rank and score for NIE on this basis. Appendix 8.5 provides more information on how we calculate the rank and score.

8.146 The concepts of efficiency rank and score used here need to be interpreted with caution and not taken out of context. They relate to efficiency under a hypothetical assumption that our modelling approach allows us to isolate accurately the impact of all differences between companies, aside from efficiency, that affect their costs. That is not the case. The estimated impacts of each explanatory factor can only provide an approximation of the way that that factor affects companies' costs. Further, the econometric models we have used do not take account of all possible differences between companies that affect their costs.

8.147 These considerations are some of the reasons why we propose to set a cost allowance for NIE on the basis of the company ranked fifth in the sample. We consider it unlikely that the company ranked first is as efficient—and its level of costs as achievable—as a naive interpretation of the model might suggest.

8.148 We consider that the cost benchmarks we have derived from the econometric models provide a reasonable basis on which to set a cost allowance for NIE within the context of a system of RAB-based incentive regulation. We do not consider them sufficient to prove whether or not NIE was efficient in 2011/12.

8.149 With these caveats in mind, we provide results from our benchmarking analysis in terms of the efficiency score and rank of NIE. Tables 8.3 to 8.6 show results for each of our six econometric model specifications and for four different approaches to the wage adjustment applied to cost data before model estimation (including no adjustment). We report results for indirect costs only and for comparisons of indirect costs and IMF&T costs. We also produce results with and without adjustments to exclude indirect costs attributed to connections activities.

TABLE 8.3 **Comparisons of indirect costs excluding connections, 2011/12**

Wage adjustment	*M1*		*M2*		*M3*		*M4*		*M5*		*M6*	
	Score %	*Rank*	*Score %*	*Rank*	*Score %*	*Rank*	*Score %*	*Rank*	*Score %*	*Rank*	*Score %*	*Rank*
None	99	4	97	4	171	13	100	5	100	5	100	5
WA1	103	7	101	6	187	14	109	7	101	7	100	5
WA2	105	7	106	6	190	14	110	7	105	7	105	6
WA3	103	7	103	6	189	13	109	7	103	6	104	7

Source: CC analysis.

TABLE 8.4 **Comparisons of indirect costs and IMF&T costs, excluding connections, 2011/12**

Wage adjustment	*M1*		*M2*		*M3*		*M4*		*M5*		*M6*	
	Score %	*Rank*	*Score %*	*Rank*	*Score %*	*Rank*	*Score %*	*Rank*	*Score %*	*Rank*	*Score %*	*Rank*
None	98	4	95	4	147	13	100	6	97	4	105	7
WA1	100	4	100	5	154	14	103	8	100	5	108	7
WA2	102	7	103	6	157	13	106	8	102	6	109	8
WA3	100	5	100	6	162	13	101	6	100	6	105	8

Source: CC analysis.

TABLE 8.5 **Comparisons of indirect costs including connections (2011/2012)**

Wage adjustment	*M1*		*M2*		*M3*		*M4*		*M5*		*M6*	
	Score %	*Rank*	*Score %*	*Rank*	*Score %*	*Rank*	*Score %*	*Rank*	*Score %*	*Rank*	*Score %*	*Rank*
None	100	6	101	6	176	14	100	6	101	7	103	8
WA1	105	7	105	8	193	14	106	7	106	8	104	9
WA2	109	8	110	8	196	14	112	9	111	8	108	9
WA3	108	7	108	8	191	14	113	8	108	8	107	8

Source: CC analysis.

TABLE 8.6 **Comparisons of indirect costs and IMF&T costs including connections (2011/2012)**

Wage adjustment	*M1*		*M2*		*M3*		*M4*		*M5*		*M6*	
	Score %	*Rank*	*Score %*	*Rank*	*Score %*	*Rank*	*Score %*	*Rank*	*Score %*	*Rank*	*Score %*	*Rank*
None	101	6	96	4	151	14	103	6	97	4	110	8
WA1	101	8	101	6	162	14	104	9	101	6	113	9
WA2	106	8	106	6	164	14	109	9	106	7	115	11
WA3	103	7	103	6	170	14	105	8	103	6	110	9

Source: CC analysis.

8.150 We explain under step *(c)* below how we have set a cost allowance for NIE, in light of our analysis, in the next section. Here we make a few brief observations on the results.

8.151 Including the costs for IMF&T in the benchmarking analysis tended to improve NIE's score compared to the results for comparisons of indirect costs only. The most consistent exception to this was model M6, where the opposite occurred.

8.152 Excluding indirect costs attributed to connections from the benchmarking analysis tended to improve NIE's score.

8.153 The two disaggregated wage adjustments (WA1 and WA2) both tended to worsen NIE's score relative to the case where there was no wage adjustment (WA0). Of these two, WA2 had the larger effect, making NIE' score further above the benchmark. The simple regional wage adjustment (WA3) also tended to worsen NIE's efficiency score compared to the results for no wage adjustment (WA0).

8.154 The method and data used for these results differed in several ways to that used for the results from our provisional determination. These differences are described in the preceding subsections under both steps *(a)* and *(b)*. For instance, the results above are for 2011/12, whereas we presented results for 2009/10 in our provisional determination. Also, the results above involve adjustments to the GB DNO costs to remove disallowed related party margins; these adjustments have the effect of reducing the GB DNO costs feeding into the benchmarking analysis.

Step (c): assessment of benchmarked costs for price control period

8.155 This subsection provides our assessment of an allowance for NIE's costs using the results from the benchmarking analysis. It is structured as follows. We:

(a) explain why we placed more weight on the results from the benchmarking analysis for indirect costs and IMF&T costs taken together, rather than the results for indirect costs only (paragraphs 8.156 to 8.170).

(b) explain why we gave more weight to the results from the benchmarking analysis that excludes indirect costs attributed to connections (paragraphs 8.171 to 8.174).

(c) explain on which of the alternative econometric models we have placed most weight (paragraphs 8.175 to 8.194).

(d) explain on which of the alternative wage adjustment methods we placed most weight (paragraphs 8.195 to 8.221).

(e) draw on the results from the benchmarking analysis to propose an allowance for NIE's indirect and IMF&T costs, excluding indirect costs attributable to connections (paragraphs 8.222 to 8.227).

(f) describe an adjustment to that allowance which reflects an estimate of the indirect costs related to connections that NIE will need to recover through its revenue control, rather than connection charges (paragraphs 8.228 to 8.235).

Inclusion of IMF&T costs in benchmarking analysis

8.156 We reported results from benchmarking analysis for indirect costs only and for the aggregation of indirect costs and IMF&T costs. The results differ significantly.

8.157 Both NIE and the UR made submissions on which type of benchmarking analysis is most appropriate for our inquiry. NIE's submissions argued that the analysis including IMF&T costs was most appropriate. The UR argued that the analysis excluding IMF&T costs were more appropriate.

8.158 We decided that the analysis including both indirect and IMF&T costs most relevant and useful and place most weight on these in determining an allowance for NIE. The main reasons for this are as follows:

(a) This approach allows us to bring systematic benchmarking analysis using GB DNO data to bear not only on indirect costs but also IMF&T costs. This is an important consideration given our view of the benefits of benchmarking analysis as part of cost assessment within a system of RAB-based incentive regulation.

(b) Taking indirect cost and IMF&T costs together in a single analysis helps to reduce the vulnerabilities of the benchmarking analysis to differences in cost allocation between these categories.

(c) While we accept that the explanatory factors in the econometric models may not fully and properly take account of all differences between companies that affect their costs, we consider that these deficiencies are shared by the models of indirect costs only. We do not agree with the view that the models of indirect costs only are robust and the models of indirect and IMF&T costs are not.

8.159 NIE's consultants made similar points.

8.160 We summarize below the alternative view presented by the UR and our response to it. Before our provisional determination, the UR raised two different types of concern with including IMF&T costs in the benchmarking analysis:

(a) The UR was concerned that the estimates of NIE's IMF&T costs that are used in our analysis were under-reported.

(b) The UR did not consider it appropriate to include IMF&T costs in the types of econometric models that we use.

8.161 On the first point, the UR did not provide alternative figures but rather raised general concerns about the data provided by NIE. We accept that there is some risk that the cost estimates provided by NIE and its consultants may understate NIE's costs. The methods used by Frontier, to the extent that we rely on them, seem reasonable but there is room for discretion and subjectivity in the cost allocations.

8.162 The UR told us that it believed that the costs included by Frontier for inspections, faults, maintenance and tree cutting were for a smaller scope of work than that reported to Ofgem under these categorizations. The UR said that Frontier had only considered the costs that were expensed under some of these headings.

8.163 The UR also raised concerns about inconsistencies in the data that NIE provided in relation to repairs and maintenance costs. The UR referred to differences in NIE's 'opex repairs and maintenance' for 2009/10 between its BPQ response, the R&M costs in the Frontier analysis and a submission in response to questions that we had asked on potential changes in NIE's capitalization practices. In contrast to the UR, we did not take the view that the costs in these separate submissions should match. For example, the costs covered in Frontier's benchmarking analysis include capitalized costs falling under the relevant Ofgem categories for network operating costs; these costs would not be reported under repairs and maintenance in NIE's BPQ response on opex. Further, we did not identify large discrepancies between NIE's BPQ response and the more recent submission on repairs and maintenance. NIE submitted data on its repairs and maintenance costs in response to questions that we had asked on potential changes in NIE's capitalization practices. These provide a figure of £9.7 million for 2009/10 for repairs and maintenance expenditure that is reported under operating expenditure rather than capitalized. The figure reported under repairs and maintenance in NIE's BPQ response on opex is £10 million.

8.164 We consider two further factors relevant in terms of concerns about the IMF&T costs for NIE:

(a) Our use of benchmarking results from NIE and 14 GB DNOs meant that we placed considerable weight on the costs of other companies, which helped to mitigate (though not completely eliminate) concerns about NIE's data.

(b) The effect on our cost assessment of NIE underreporting costs is ambiguous and quite possibly detrimental to NIE and beneficial to consumers. The effect of NIE's costs on the estimated coefficients from the econometric models is hard to predict in advance. However, if we take account of NIE's historical costs alongside the costs from the benchmarking, a lower figure for NIE's reported costs could reduce the allowance that we choose to set.

8.165 We now consider the UR's points on the econometric model specifications. The UR argued that the econometric models we specified (M1 to M6) did not give a sufficiently robust explanation of differences in IMF&T cost between DNOs. The UR said that IMF&T costs were partly a function of the size of a network (which was captured to some degree by our econometric models) but also heavily influenced by factors like technical configuration, standards, levels of historical investment, age and current service quality. The UR argued that these things meant that two networks of the same scale might require dramatically different volumes of inspection, maintenance, fault repair and tree cutting in any given period.

8.166 We do not consider the econometric models we have used for indirect costs to be unsuitable for IMF&T costs. These models include factors that we expect to be an important driver of IMF&T costs, particularly the inspections, maintenance and faults elements (eg length of network and number of connected customers).

8.167 These may not take account of all possible factors that affect companies' costs, but that criticism also applies to the indirect costs models. For instance, as discussed under step *(b)* above, NIE argued that its wayleave costs were relatively high because of the relative extent of its EHV and HV overhead line networks but this is not fully captured in the econometric models that we have used.

8.168 The UR sought to illustrate its concerns with including IMF&T costs in the econometric benchmarking analysis by comparing results from that analysis with BPI's separate assessment of NIE's tree-cutting expenditure which formed part of BPI's assessment of NIE's capex proposals (see Section 9). The UR argued that the results from the econometric analysis costs indicated that NIE was relatively efficient in IMF&T costs in 2009/10 compared with GB DNOs but that this contradicted the separate analysis of NIE's tree-cutting costs carried out by BPI, which found NIE's forecast tree-cutting costs to be too high.

8.169 However, we were not persuaded by the argument made by the UR. The econometric analysis we carried out compares NIE's historical costs with the historical costs of GB DNOs. In contrast, BPI's assessment concerned NIE's forecast capex for the RP5 price control period. NIE's forecast capex on tree cutting is substantially higher than NIE's 2009/10 expenditure on tree cutting. NIE's capex forecast included £33.25 million over the RP5 period in respect of capitalized tree-cutting costs (including indirect costs). BPI recommended the exclusion of around £3.4 million of tree-cutting costs from NIE's forecast expenditure,[20] which produces an implied capex allowance for tree cutting of £29.8 million. If BPI's allowance for tree-cutting costs were spread evenly over a five-year period, this would equate to around £6 million per year. The capitalized elements of NIE's distribution network tree-cutting costs in 2009/10 were around £5.2 million (including indirect costs attributed to tree cutting). The effect of BPI's assessment is to reduce the extent to which the forecast capitalized tree-cutting costs for NIE are above NIE's 2009/10 tree-cutting costs.

8.170 In its response to our provisional determination, the UR said that it 'continued to believe that we placed excessive weight on econometric analysis of IMF&T costs that are highly suspect because the explanatory variables employed are too general to have any real explanatory power in respect of direct network costs'.[21] We did not consider that the UR had provided new evidence or arguments on this matter. The UR also suggested that if we were to use GB DNO cost benchmarks for tree-cutting costs, we should require NIE to carry out equivalent the volumes of tree cutting work.[22] We did not consider it necessary or appropriate to require NIE to run its tree-cutting activities in the same way as the GB DNOs and would expect there to be practical difficulties with such a requirement (eg due to differences in the extent of overhead line and extent and type of vegetation across the UK).

Exclusion of costs attributed to connections

8.171 We produced results for models that include indirect costs attributed to connections activities and models that exclude direct costs attributed to connections activities.

8.172 We considered on which to place most weight for our cost assessment. We gave attention to three main issues:

(a) A large element of NIE's connection costs are funded by customer contributions and should not be funded as part of the expenditure allowance set as part of our determination. Excluding connection costs allows a better alignment between the

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[20] From projects D7; D8; D9.
[21] UR response to the provisional determination, paragraph 71.
[22] ibid, paragraph 72.

costs used for benchmarking analysis and the costs for which we want to make an allowance as part of our cost assessment.

(b) Excluding connection costs helps to address a possible vulnerability of the econometric benchmarking analysis. The econometric models we used are not well suited to taking account of variations between different companies in the amount of connection work that each company is required to carry out in any financial year. The explanatory variables in these models capture differences in the scale of companies' networks but not differences in the amount of new network connection activity. This point is particularly important because there is greater scope for competitive third parties to carry out connections in GB than Northern Ireland, which will tend to reduce the role of GB DNOs in connection work. It is also important in view of the scale of connection activity—NIE estimated that it was about 20 per cent of indirect costs. The differences in NIE's performance in the benchmarking models including and excluding connections could be explained by the differences in the amount of connection work.

(c) If connection costs are excluded, the benchmarking results may be adversely influenced by differences between companies, or over time, in the methods used to allocate indirect costs between connection activities and other activities. Carrying out benchmarking analysis without an adjustment to exclude connection costs tackles this concern.

8.173 In view of a combination of *(a)* and *(b)*, we decided to focus on the benchmarking analysis that compared indirect costs and IMF&T costs excluding costs attributable to connections.

8.174 On its own, we would not necessarily consider point *(b)* decisive. As we have discussed elsewhere in relation to wayleave costs (see paragraphs 8.105 to 8.107) and IMF&T costs (see paragraphs 8.156 to 8.170), we are reluctant to shrink the scope of benchmarking analysis to address claims about the limitations in the econometric models.

Discussion of alternative econometric models

8.175 We produced cost benchmarks for six different econometric models (M1 to M6). We describe below the outcome of our decisions on which econometric models to place most weight on in determining an allowance for NIE's indirect and IMF&T costs.

8.176 Both CEPA and Frontier used Models M4 and M1 in their analysis for the UR and NIE respectively. Model M4 is a version of M1 except that the dependent variable and explanatory factors are converted to natural logarithms before model estimation. These models reflect a model used by Ofgem in its DPCR4 price control review.

8.177 Of these models, we considered the logarithmic version (M4) to be a significantly better model of how the composite scale variable is likely to affect costs (as an approximation). Model M4 implies a proportionate relationship between the dependent variable and the composite scale variable (eg a 1 per cent increase in the composite scale variable is estimated to increase indirect costs by 0.5 per cent). In contrast, model M1 implies a relationship in which the impact of the composite scale variable on costs is the same for all values of the composite scale variable (eg a 1 unit increase in the composite scale variable is estimated to increase indirect costs by £0.5 million regardless of whether the scale of the company, as measured by the composite scale variable, is high or low). We found the relationship implied by model M1 (and similarly model M2) difficult to justify.

8.178 Models M1 and M4 take account of the number of connected customers, network length and the amount of electricity transmitted. However, these models impose hard-coded weights on each of these elements rather than using the available data to estimate the impact of each of these factors on costs. Due to the small sample size and nature of the data, we considered it unlikely to be possible to specify an alternative version of Model M4 that enabled us to make accurate estimates of the effects of each of these three factors on costs. Nonetheless, the results of Models M1 and M4 (and also M2 and M5) will depend on the weight attached to each of the elements in the composite scale variable and we did not have grounds to believe that these were the most appropriate weights.

8.179 We indentified model M6 as an alternative model which does not use a composite scale variable. It compares costs per connected customer between companies, and produces an estimate of the impact of variations in network length per connected customer on costs per connected customer. Model M6 tackles some of the shortcomings of Models M1 and M4:

(a) It does not rely on a composite scale variable that requires the external specification of weights for different explanatory factors.

(b) It does not treat the volume of electricity distributed as an important determinant of variations in costs between companies and over time.

8.180 The specification of Model M6 corresponds to a model used in the past by Ofwat as part of its relative efficiency analysis of water companies' opex.[23] That model specifically concerned expenditure on companies' water distribution networks. In Ofwat's model, the dependent variable was the natural logarithm of distribution network expenditure per connected property, and the explanatory factor was the natural logarithm of the length of water mains per connected property.

8.181 We recognized that a possible disadvantage of Model M6 is that while it allows for differences between companies in terms of the length of network (per customer), it does not allow for economies of scale with respect to the number of connected customers.

8.182 In its response to our provisional determination, NIE criticized our decision to place the most weight on cost benchmarks from models M4 and M6 in setting allowances for NIE's indirect and IMF&T costs. NIE argued that model M6 was flawed and that we should focus on model M4 only. NIE said that model M6 assumes constant returns to scale and that there is no empirical basis for such an assumption for GB DNOs. NIE said that this deficiency of M6 is particularly important in the case of NIE, which is the smallest company in the UK sample. NIE also criticized the specific arguments we had made in favour of using model M6.

8.183 We did not agree with NIE's position on models M4 and M6. We found that NIE's criticism of model M6 rested on an invalid inference from the results we reported in our provisional determination. Further, while NIE identifies potential limitations of model M6, it did not take sufficient account of the limitations of model M4 (and the other models).

8.184 We accepted that model M6 suffers from the limitation that it does not allow for economies of scale in relation to the impact of the number of customers on costs. However, for companies of the scale of NIE and the GB DNOs we were not

[23] For example, see Ofwat 'Relative efficiency assessment 2008-09—supporting information', December 2009.

persuaded that, as an approximation for the purposes of our benchmarking analysis, it was inappropriate to use a model which does not allow for variation in cost per customer between companies.

8.185 Beyond an assertion about the implications of our results from models M4 and M6 (which we discuss below), NIE's response did not provide any references to evidence or research that supported the view that it was inappropriate to use model M6. Nor did NIE explain why companies of the scale of NIE suffered from a lack of economies of scale in relation to customer numbers in terms of their indirect and IMF&T costs.

8.186 We did not accept NIE's argument that it was 'clear from the CC's own results (and indeed from numerous previous studies on the GB DNO data over many years) that there is no empirical support for an assumption of constant returns to scale within the GB DNO dataset'. NIE argued that the estimated coefficients for the explanatory factor in model M4 (and M5) being below 1 demonstrated economies of scale and showed that model M6 was inappropriate. We disagreed. The fact that the estimated coefficient in model M4 is below one does not demonstrate that an assumption of constant returns to scale in relation to number of customers is inappropriate or that model M6 is inappropriate. Instead, it shows that the estimated effect of the specific single explanatory factor in model M4 (a composite scale variable) on costs was less than proportionate, such that a one per cent increase in the composite scale variable was estimated to lead to an increase in NIE's indirect and IMF&T costs of less than one per cent. Such a finding may say something about the effect of the composite scale variable on indirect and IMF&T costs. However, it says little about economies of scale in indirect and IMF&T costs in relation to the number of customers. By way of example, if the composite scale variable gave weight, in addition to customer numbers, to a factor that had little effect on DNO's costs, the estimated coefficient on the composite scale variable could be below 1 even if there was, in fact, constant return to scale in relation to customer numbers.

8.187 All the models we used impose restrictions on how potential factors such as network length and number of customers affect costs. Model M6 imposes certain restrictions, but so does other models including NIE's preferred model M4. While NIE said there is no empirical basis for the restriction in model M6, NIE did not provide or refer to any empirical basis for the restriction in model M4 in the specification of the composite scale variable.

8.188 NIE's response to our provisional determination criticized a number of the other points we had made in our provisional determination in relation to models M4 and M6. We deal with those that remain relevant to our final determination below.

8.189 NIE said that the fact that model M6 corresponds to a model used in the past by another regulator (Ofwat) does not obviate the need to confirm that its underlying assumptions in respect of scale economies are supported by the data. We did not agree with NIE's submissions on economies of scale (see paragraphs 8.182 to 8.187). We were satisfied that model M6 was reasonable when applied to UK electricity distribution companies.

8.190 In our provisional determination, we said that the inclusion of the units of electricity distribution in Models M1 and M4 may worsen rather than improve the accuracy of these models. A variation in the amount of electricity distributed by a DNO seems unlikely to have a large impact on its indirect costs and IMF&T costs. Differences between companies in the volume of electricity distribution may provide a proxy for other differences (eg the scale and capacity of network infrastructure) that do affect these costs and which are not fully captured in differences in network length of number of customers. However, there is year-to-year volatility in the volume of electricity distributed. This volatility may have little impact on indirect and IMF&T costs but could adversely affect the model's results. We considered that a benefit of model M6, when considered alongside M4, was that it did not use a composite scale variable that gave significant weight to throughput.

8.191 In its response to our provisional determination, NIE said that the fact that model M6 does not treat the volume of electricity distributed (throughput) is not in itself a strength of model M6 but a weakness. NIE said that it is appropriate to attach some weight to a measure of throughput, as this will be closely correlated with peak demand on the network, which is itself an important driver of network capacity and hence cost. We agree that peak demand is an important driver of costs but we were not confident that differences between DNOs and over time in annual measures of throughput gave accurate indications of the effects of peak demand on costs. Further, we were concerned that model M4 could give excessive weight to differences in throughput. In model M4 the relationship between throughout and costs is not estimated using the data; instead model M4 estimates the relationship between the composite scale variable and costs, and the composite scale variable may give too much weight to throughput and too little weight to network length as a driver of costs.

8.192 Taking the considerations above into account, we considered it appropriate to use cost benchmarks from models M4 and M6. While model M6 has some imperfections and limitations, so does model M4 and we considered it more appropriate to look across both than to rely exclusively on either of them. We found NIE's criticisms of model M6 overstated. We decided that we should give equal weight to cost benchmarks from models M4 and M6 in our assessment. We recognized that both models involve approximations and limitations.

8.193 We did not give weight to the cost benchmarks from models M2 and M5. These models use a composite scale variable that is calculated as the weighted average of an estimate of the MEAV of each company's network and a measure of its network investment expenditure. We included this model in our presentation of results because it was used by CEPA in its analysis for the UR. We had concerns about using outturn cost data as an explanatory factor. For example, in models M2 and M5 any inefficiency or unnecessary expenditure within a particular company's network investment expenditure would not show up as relative inefficiency but would instead indicate that the company has higher requirements for indirect costs and IMF&T costs if it operates efficiently. In addition, we had greater concerns about the accuracy of the MEAV estimates for the companies in the sample than about the accuracy of the explanatory factor data used for models M4 and M6. In addition, the data we used in our analysis of these models was not fully updated for the years 2010/11 and 2011/12.[24]

8.194 Model M3 is based on a simple comparison of costs per connected customer. It makes no allowances for other differences between companies. We did not consider this model suitable for setting an allowance for NIE. Nonetheless, we considered model M3 a useful reference point. Model M3 provides a measure of average indirect and IMF&T costs per connected customer. Comparing the cost benchmarks from models M4 and M6 against those for model M3 provides an indication of the extent to which M4 and M6 take account of differences between NIE and other GB DNOs beyond differences in the number of connected customers.

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[24] We estimated results for these models using cost data for the period 2009/10 to 2011/12 but with the same explanatory factor data for 2010/11 and 2011/12 as for 2009/10 (we used the data provided in CEPA's analysis which did not run beyond 2009/10). This was an approximation to avoid the need to request and process a large amount of additional data from Ofgem; this would have been disproportionate given the other limitations of these models.

Discussion of wage adjustments

8.195 In our provisional determination, we said that:

(a) we placed more weight on cost benchmarks that involved a regional wage adjustment. We noted, however, that in some cases this had relatively limited effects.

(b) our preferred wage adjustment method was method WA2, which strikes a balance between including occupational categories that are relevant to the activities of NIE and the GB DNOs and avoiding the risks of data error from a small sample size.

8.196 Neither NIE nor the UR commented on the regional wage adjustments used in our indirect and IMF&T cost benchmarking analysis in their responses to our provisional determination.

8.197 Towards the end of our inquiry, we shared updated results from our benchmarking analysis with NIE and the UR. The updated results reflected significant changes to our analysis compared to our provisional determination, including the use of 2011/12 cost benchmarks rather than 2009/10 cost benchmarks. NIE made further submissions on regional wage adjustments after seeing the updated results.

8.198 NIE said that it was extremely concerned about the very large effect that a regional wage adjustment may have on the outcome of our analysis if we preferred wage adjustment method WA2. NIE identified that the effect of method WA2 on the cost benchmarks (compared to no wage adjustment) was greater for our updated analysis than for the analysis used for our provisional determination. NIE argued that there was a convergence in regional pay and increasing evidence of national markets for labour. NIE provided various arguments that method WA2 was inappropriate.

8.199 The UR did not support NIE's contentions that no regional wage adjustment was appropriate and criticised some of the inferences drawn by NIE by reaffirming the continued presence of regional relativities between Northern Ireland and the GB marketplace, especially within labour markets, which the UR said contrasted with the limited evidence of convergence within the GB marketplace outside London and the South-East.

8.200 We organize our discussion of NIE's further submissions into the following three subsections before summarizing our decision on the regional wage adjustments:

(a) the effects of the regional wage adjustments on our updated benchmarking analysis;

(b) NIE's further submissions on convergence in regional wages; and

(c) NIE's further submissions on the calculation of the wage adjustments.

The effects of the regional wage adjustments on our updated benchmarking analysis

8.201 In light of NIE's submissions, we identified the following differences between the cost benchmarks from our provisional determination and those from the updated analysis for our final determination:

(a) For our provisional determination, the impact on the cost benchmark of using method WA2 rather than method WA0 was £0.9 per year in the case of model M4

and £0.2 million per year in the case of model M6. The impact of WA2 on the cost benchmarks from our updated benchmarking analysis was greater. Using WA2 would reduce the cost benchmark by £2.4 million and £2.6 million per year for models M4 and M6 respectively (compared to WA0).

(b) In our provisional determination, for models M4 and M6, wage adjustment method WA2 produced cost benchmarks that lay between the results under WA0 and WA1. For the updated analysis that we produced for our final determination, method WA2 led to lower cost benchmarks than WA0, WA1 and WA3.

8.202 Given these differences, we did not feel that the emphasis that we had placed on method WA2 in our provisional determination should automatically be maintained for our final determinations.

8.203 We retained the view from our provisional determination that WA2 strikes a balance between including occupational categories that are relevant to the activities of NIE and GB DNOs and avoiding the risks of data error from a small sample size. However, we did not consider it appropriate to focus solely on the results from wage adjustment method WA2. A focus on WA2 would mean a focus on the wage adjustment method with the largest impact on the cost benchmarks, but method WA2 was not necessarily superior in all ways to method WA1. In particular, method WA1 is more closely aligned than WA2 with the occupations relevant to NIE's activities, even if it does suffer from a smaller sample size.

8.204 We considered it more appropriate to give similar weight to wage adjustment methods WA1 and WA2.

8.205 We did not consider method WA3 to offer any significant advantages over methods WA1 and WA2 and did not give weight to this in our final determination.

NIE's further submissions on convergence in regional wages

8.206 NIE submitted a range of information and arguments to support its view that there is increasing evidence of national markets for the types of labour used by NIE and strong convergence in pay for skilled staff across the UK regions. We reviewed NIE's submissions but did not consider that these meant that it would be appropriate to focus on cost benchmarks that do not involve any regional wage adjustments (ie methods WA0). Nor did NIE's submissions lead us to identify or use any alternative wage adjustment methods to WA1 and WA2.

8.207 NIE reported its own experience that more than half of those leaving NIE recently left to take up positions with GB DNOs. We did not consider that this was sufficient to mean that NIE faces the same labour costs as the average DNO in GB.

8.208 NIE said that GB DNOs were specifically targeting NIE's skilled staff by offering them flexible working arrangements including the ability to work remotely allowing them to remain in Northern Ireland while working for a GB DNO or contractor. We did not consider that this was sufficient to mean that NIE faces the same labour costs as the average DNO in GB.

8.209 NIE said that its recent pay increases to its staff have been higher than those offered by GB based network operators and have been necessary to retain and motivate its skilled staff in the face of efforts from competitors in GB to recruit staff from NIE. NIE also submitted that these recent pay awards, which were based on RPI, contained an element of catch-up following several years of tight wage control. NIE submitted that its current pay levels remained efficient and within relevant benchmarks after the application of these recent pay increases. Even if the recent pay increases that NIE gave its staff were necessary in the face of competition for labour from companies operating in GB, we did not consider that this was sufficient to mean that NIE faces the same labour costs as the average DNO in GB.

8.210 NIE said that convergence in regional pay has been flagged repeatedly in a wide range of research published by IDS (an organisation providing information and analysis on employment matters) and NIE sent us extracts from research by IDS. The research by IDS that NIE included with its submissions did not seem sufficient to mean that NIE faces the same labour costs as the average DNO in GB. Most of the extracts provided by NIE did not relate to labour in the electricity distribution and transmission sectors. They did not comment specifically on labour costs in Northern Ireland. Further, we were concerned that reliance on this type of information could be vulnerable to selection bias (other extracts from published research may make the opposite points).

8.211 NIE also said that the research by IDS highlighted that there is little variation in pay levels outside London and the South East and further supported NIE's argument that a regional wage adjustment is not justified. We did not accept that evidence that there is little variation in pay levels outside London and the South East supported an argument that a regional wage adjustment is not justified for our benchmarking of 15 DNO across the UK. The IDS research that NIE submitted to us used regional ASHE weekly earnings data to highlight the differences in pay between *(a)* London and the South-East and *(b)* other parts of the UK. We considered that this supported a regional wage adjustment based on ASHE regional weekly earnings data, as under our methods WA1 and WA2.

8.212 NIE said that Ofgem, in all of its recent cost assessment work for its RIIO-ED1 review, had made use of a regional wage adjustment that recognises only a London/South East effect, but no other regional variation. We reviewed Ofgem's most recent cost assessment documents for its RIIO-ED1 price control review. Ofgem's published documents confirmed that it made adjustments for differences in labour costs between regions in GB, but did not provide enough information on its method to reveal how it made those adjustments. Ofgem reported that it took into account the additional labour costs associated with working in London and the South-East, that it had calculated labour cost indices using Annual Survey of Hourly Earnings (ASHE) data and that it had made regional labour cost adjustments for all the GB DNOs.[25]

8.213 Ofgem's RIIO-ED1 publications certainly did not support an approach to the cost analysis for NIE that would involve no adjustments for regional wage differences. Even if Ofgem's RIIO-ED1 analysis to date has focused on adjustments for differences between London and the South-East compared to the rest of the UK, Ofgem's RIIO-ED1 publications did not provide an alternative approach to the regional wage adjustments that we could consider using instead of methods WA1 and WA2.

NIE's further submissions on the calculation of the wage adjustments

8.214 NIE said that the wage adjustment method WA2 (and also WA3) is based on an analysis of types of labour that are completely irrelevant to NIE and the GB DNOs as these use 3-digit SOC codes rather than 4-digit SOC codes as proposed by NIE. We

[25] Ofgem (2013) 'RIIO-ED1 business plan expenditure assessment—methodology and results', p 20.

disagreed. Method WA2 is based on data for more aggregated occupational categories than WA1 but this does not mean that the data used are irrelevant.

8.215 We also disagreed with NIE's argument that our concerns about the small sample sizes for the data on four-digit SOC codes (which is used for WA1) was rendered completely irrelevant by our use of averaging of data across five years and numerous SOCs to provide an overall adjustment. We adopted an approach of taking averages over five years to help reduce the risks of inaccuracy from a small sample size, but we did not believe that this approach necessarily eliminated those risks. As a result, we considered that results based on wage adjustment method WA2 were a useful complement to results based on wage adjustment method WA1.

8.216 Further, a concern with using the most granular (four-digit) SOC codes under method WA1 is that the wage adjustments could be significantly influenced by the wages paid by NIE, which poses a risk of the wage adjustment becoming circular. If NIE offered inefficiently high wages for a particular occupation, this could feed through to the calculated regional wage adjustment. Method WA2 reduces the extent to which the regional wage adjustment could be influenced by the wages paid by NIE while still taking account of relevant occupations.

8.217 NIE reiterated its criticism of our use of wage adjustments based on data on weekly earnings rather than hourly earnings. We did not agree that we should use hourly wage data. We discussed this issue further at paragraphs 8.72 to 8.74.

8.218 Finally, NIE said that the use of regional wage adjustments reduced the R-squared model estimation results and that this called into question whether there is evidence to justify our proposed regional wage adjustment, in particular now that that the effect of the adjustment is so material. We did not consider it necessary, from a statistical perspective, that any contemplated wage adjustment method should only be applied if it increased measures of R-squared. Since there may be genuine differences in cost efficiency between the DNOs in our sample, finding that one model has a lower R-squared than another does not necessarily mean that the former model is the more accurate model. In any event, for models M4 and M6 the differences in R-squared in the comparisons of indirect and IMF&T costs (excluding connections) between wage adjustment methods WA0, WA1 and WA2 were small. In the case of model M6 the wage adjustments increased R-squared. Appendix 8.5 provides further information on the estimation results from our models.

Summary of decision on regional wage adjustments

8.219 Following our provisional determination we reviewed our approach to the use of regional wage adjustments in light of the further detailed submissions made by NIE.

8.220 We decided to set an allowance for NIE's indirect and IMF&T costs using the cost benchmarks estimated using wage adjustment methods WA1 and WA2, with equal weight to each of these.

8.221 We recognized that wage adjustment methods WA1 and WA2 can only provide an approximate estimate of the effect of any regional wage differences on the (relative) costs of DNOs operating in different parts of the UK. Nonetheless, we considered that the likely accuracy of our benchmarking analysis would be improved by making such adjustments rather than either *(a)* making no adjustments at all for regional wage differences or *(b)* using any of the other methods that we identified during the course of our inquiry.

Cost benchmarks and determination of allowance

8.222 For the reasons set out above, we decided to set a cost allowance for NIE covering both indirect costs and IMF&T costs and excluding costs attributed to connections. Table 8.7 shows, for each econometric model and wage adjustment method, cost benchmarks for NIE for 2011/12. We calibrated these benchmarks to reflect the level of costs for a company that would rank fifth out of the 15 companies in our benchmarking analysis.

TABLE 8.7 2011/12 **cost benchmarks for indirect and IMF&T costs (excluding costs attributed to connections)**

£ million

	WA0	*WA1*	*WA2*	*WA3*
Cost benchmark M1	58.0	57.1	55.6	57.0
Cost benchmark M2	60.2	57.0	55.6	56.9
Cost benchmark M3	38.8	36.9	36.3	35.1
Cost benchmark M4	57.0	55.3	53.6	56.2
Cost benchmark M5	59.0	57.0	55.6	57.0
Cost benchmark M6	54.2	53.0	52.4	54.5

Source: CC analysis.

8.223 For comparison, our estimate of NIE's indirect and IMF&T costs, including costs attributed to its 275kV network and excluding costs attributed to connections were: £52.3 million in 2009/10; £55.0 million in 2010/11 and £57.0 million in 2011/12 (all in 2009/10 prices).

8.224 In light of the considerations and decisions set out above, we determined an allowance of £53.6 million for NIE's indirect costs and IMF&T costs, excluding indirect costs attributed to connections. This reflects the average of the cost benchmarks for our preferred models M4 and M6 and our preferred wage adjustment methods WA1 and WA2.

8.225 We examined the impact of the regional wage adjustments we had made. We compared the allowance of £53.6 million with the average cost benchmark that we would obtain for models M4 and M6 if we made no wage adjustment (WA0). We calculated that our approach to the regional wage adjustment led to an allowance that was 2.2 per cent lower than if we made no such adjustment. The implication of our approach is that we estimated that NIE's costs (if it operated efficiently) would be around 2.2 per cent lower than the average GB DNO as a result of regional wage differences. We considered such an adjustment reasonable.

8.226 We also considered the overall balance of our assessment. NIE told us that the overall balance of our benchmarking analysis appeared heavily skewed against it. NIE said that while it accepted that no benchmarking exercise is perfect and that there will inevitably be 'swings and roundabouts'. NIE was concerned that our decision would not be reasonable in the round, with a number of very significant items weighted against it. NIE highlighted the following: our use of model M6; our regional wage adjustment; no adjustment for differences between DNOs in terms of the extent to which they lease or own vehicles; and the inclusion of wayleaves in our cost assessment. We responded specifically to NIE's submissions on each of these in the preceding subsections. In addition, we were satisfied that, taken collectively, these issues did not mean that our determination was unfair or based on analysis that was skewed against NIE. This was for three main reasons:

(a) we disagreed with NIE's view that it was inappropriate to use model M6 or to make a significant regional wage adjustment. However, we recognized that the

vehicle leasing and wayleave issues identified by NIE are cases where the limitations of our benchmarking analysis may (if considered in isolation) work against NIE.

(b) we explicitly took account of the limitations in our benchmarking exercise in our choice of the benchmark company (8.127 to 8.141) . In particular we decided to use the fifth-ranked company, despite this being significantly less demanding than the benchmark advocated by the UR.

(c) there were a number of aspects of our benchmarking analysis that act in NIE's favour and counteract the claims made by NIE. For instance, the UR pointed out several factors that could lead to NIE's efficient costs being below our cost benchmarks, which include the relatively low level of tree cover in Northern Ireland and the extensive consumer engagement that GB DNOs conduct.[26] Further, our estimated cost benchmarks were influenced by a number of estimates and assumptions provided by NIE which we did not have opportunities to examine critically in detail.

8.227 Finally, NIE argued that in setting allowances for its indirect and IMF&T costs, its historic costs should be allowed in full and with a 'glide path' of at least two years applied going forward to move from NIE's historic costs to an allowance based on our cost benchmarks. NIE said that it would be extremely unreasonable (and in NIE's view unprecedented) to impose a retrospective efficiency discount. We did not accept this argument. We used our cost benchmarks to determine allowances for NIE's indirect and IMF&T costs that should apply from 1 April 2012 to 30 September 2017. We did not consider it appropriate to pass-through NIE's historic indirect and IMF&T costs in full to consumers as this could expose consumers to inefficient costs and could undermine the incentive properties of the price control framework. Further, we did not consider that a glide path was compatible with the cost risk-sharing mechanism we determined as the glide path would increase the extent of pass-through of NIE's actual costs beyond that envisaged for the cost risk-sharing mechanism. Nonetheless, to the extent that NIE's actual costs are lower than the upfront allowances that we have determined, NIE will be compensated for part of the difference through the cost risk-sharing mechanism.

Indirect costs of connection work not funded through connection charges

8.228 The allowance above (paragraphs 8.219 to 8.226) is for NIE's indirect costs and IMF&T costs excluding indirect costs attributed to connections.

8.229 NIE makes separate connection charges to customers and revenues from these connection charges are outside the scope of the restriction on NIE's maximum regulated revenue. We would expect the majority of NIE's indirect costs attributed to connections to be funded through connection charges. However, there may be a relatively small element of costs that are not. The main areas of such costs that we identified were elements of network reinforcement costs (system costs) that are not 100 per cent recoverable via connection charges under NIE's connection charging policy, and, perhaps, indirect costs incurred in the preparation of quotes which are not charged for or accepted.

8.230 Ahead of our provisional determination, we asked NIE to provide further information about its allocation of indirect costs to connection activities and the extent to which these costs are recovered from connection charges. More specifically, we asked NIE

[26] UR response to the provisional decision, pp 21 & 22.

for an estimate of the value (£ million) of the NIE indirect costs in 2009/10 that is attributable to the indirect costs of connection activities which were recovered from connection charges or customer contributions paid to NIE. NIE was not able to provide such an estimate. It said that the main reason for this was that it did not collect its cost data on the same basis as used for regulatory reporting by the GB DNOs and that a split of connection costs recovered from customers between direct and indirect costs was not readily available.

8.231 Absent the information we sought from NIE, we used other information available to make an approximate adjustment to our allowance for NIE's indirect and IMF&T costs to provide for indirect costs related to connections that are not covered by connection charges. In particular, we considered information on the costs arising from system reinforcement work that are attributed to connections but not covered by connection charges.

8.232 NIE provided submissions to us that reported that relatively little connection activity by NIE was associated with system reinforcement work. NIE estimated that around 4.3 per cent of total connections by value in 2009/10 was recorded as system improvement or reinforcement work and that none of the costs associated with system improvement or reinforcement work was presently recovered from connecting parties.

8.233 For our provisional determination, we used the information for 2009/10 to calculate an additional allowance of £0.4 million for indirect costs for connection activities that were not covered by connection charges. We proposed this amount as an addition to the allowance for indirect and IMF&T costs that we had estimated using our preferred GB DNO cost benchmarks (which excluded connections costs). We calculated the figure of £0.4 million by multiplying the element of NIE's indirect costs that we treated as attributable to connections for the purposes of our benchmarking analysis (around £9 million) by the proportion of NIE's connections activity by value, that NIE recorded as system jobs (4.3 per cent).

8.234 For our final determination, we updated the calculation above for the three-year period 2010/11 and 2011/12, using new data provided by NIE on the proportion of connection costs it attributed to system reinforcement work and our estimates of NIE's indirect costs attributed to connections (which drew on updated information provided by NIE).

TABLE 8 **Estimates of NIE's indirect costs for system reinforcement not funded through connection charges**

	2009/10	*2010/11*	*2011/12*
NIE system reinforcement work as percentage of connections work by value (%)	4.3	3.0	5.1
Estimate of NIE's indirect costs allocated to connections (including costs related to 275 kV network) (£m)	9.22	9.64	10.53
Approximate estimate of NIE's indirect costs for system reinforcement not funded through connection charges (£m)	0.40	0.29	0.54

Source: CC analysis.

8.235 We decided to make an additional allowance of £0.41 million per year, based on the average over the period 2009/10 and 2011/12 of our estimate of NIE's indirect costs for system reinforcement that are not funded through connection charges.

9. Core network investment

9.1 This section considers NIE's core network investment allowance for RP5,[1] ie the core network investment expenditure that we find NIE should incur if it operated and invested efficiently, given the services (and outputs) it will provide and the obligations that it will face (see paragraph 7.1).

9.2 The great majority of investment covered in this section concerned capex on asset replacement and refurbishment work required to maintain the safety and operation of NIE's distribution and transmission systems (eg replacement in light of the age and condition of assets).

9.3 In addition, some expenditure also related to: the capitalized costs associated with actions by NIE to resolve faults and emergency situations on its network; investment to increase capacity of NIE's distribution system to accommodate additional demands on it (load-related expenditure); a small amount of IT; and projects to improve the quality of service of particular groups of customers (for example, rural customers).

9.4 Core network investment excluded expenditure on New Connections, Metering, Non-network capex and investments previously agreed by the UR and NIE as being Fund 3 projects. We consider such expenditure in Section 10.

9.5 We did not consider RPEs as a lump sum to be added to the capex allowance (as the UR did in its final determination). Instead, we set a percentage adjustment which should be made to our cost allowances in respect of RPEs and Productivity. Our decision in this area is in Section 11.

9.6 This section is structured as follows. We:

(a) explain the background to core network investment and our approach to setting an allowance in this area (paragraphs 9.7 to 9.15);

(b) summarize the conclusions of our engineering consultants' (BPI) review of NIE's core network investment plan (paragraphs 9.16 to 9.32);

(c) provide an additional review of three of NIE's projects (paragraphs 9.34 to 9.78);

(d) make a forecast for non-recoverable alterations (paragraphs 9.79 to 9.84);

(e) make four additional adjustments to BPI's recommended core network investment allowance (paragraphs 9.85 to 9.107);

(f) summarize the effect of the adjustments in *(c), (d)* and *(e)* to produce an adjusted allowance for core network investment (paragraph 9.108);

(g) make a forecast of the direct-only costs contained in this allowance (paragraphs 9.109 to 9.132);

(h) consider what adjustments to our allowance are required for different time periods (paragraphs 9.133 to 9.143); and

(i) set out our determination (paragraph 9.145).

[1] We would note that all capex values quoted in this section are in 2009/10 prices.

Background and our approach to core network investment

9.7 NIE submitted a core network investment request of £526.4 million. This was for a five-year period, April 2012 to March 2017. Table 9.1 shows how this reconciles to the request included in NIE's Statement of Case.

TABLE 9.1 **NIE's core network investment request**

	£m
Core request per NIE SoC	607.3
Less: RPEs	–37.5
Less: projects now agreed with the UR as Fund 3	–43.4
Core network investment defined by CC	526.4

Source: NIE Statement of Case, pp413 & 414; CC analysis.

Note: An additional £0.9 million was added to project T36. This represents the difference between the total in the Statement of Case (£606.4 million) and the above table (£607.3 million).

9.8 In its final determination, the UR awarded NIE a core network investment allowance of £335.4 million, a difference of £191 million to NIE's request of £526.4 million.

9.9 NIE's core network investment submission comprised 79 individual projects which together amounted to its request of £526.4 million. We recognized that in order to assess NIE's submission it would be necessary for us to employ engineers with specialist knowledge of electricity transmission and distribution networks. We therefore used the Ofgem framework agreement to tender for engineering consultants. BPI was selected as a result of this tender process.

9.10 In our terms of reference for BPI, we asked it to:

(a) identify the projects, and planned volumes of work, which need to be undertaken before 1 October 2017 in order to maintain services to customers, comply with applicable network design and planning standards and/or meet any other obligations;

(b) identify the projects and planned volumes of work which, whilst not necessary to maintain services to customers, comply with applicable network design and planning standards and/or meet any other obligations, and have been included in NIE's business plan for the period to 1 October 2017 with sufficient justification; and

(c) identify any projects or volumes of work within *(b)* that any reasonable electricity transmission/distribution company would undertake before 1 October 2017 because deferring or cancelling them would undoubtedly increase whole-life costs.

9.11 In addition, we asked BPI to review the unit cost forecasts that underpinned NIE's submission.

9.12 Our intention in setting the terms of reference was to be able to identify the amount of core network investment which might be appropriate for RP5 in several scenarios. These included:

(a) *Setting core network investment at the minimum required level*. This would represent category *(a)* in BPI's terms of reference. We believed that this category represented an estimate of the minimum amount of core network investment which NIE would need to complete in RP5 in order to meet its obligations. It

excluded investment which might be sensible to complete in order to pre-empt network problems, improve service quality or reduce network costs in the long term.

(b) *Setting core network investment to include all well justified projects.* This would represent category *(a)* plus category *(b)* in BPI's terms of reference. This estimate included all projects which had been included by NIE with sufficient justification. It should therefore include all projects which, in BPI's judgement, it would be sensible for NIE to complete in RP5.

(c) *Setting core network investment at the minimum level but also including projects which, if not completed, would clearly increase all life costs.* This would represent category *(a)* plus category *(c)* in BPI's terms of reference. Category *(c)* is a subset of category *(b)*. Projects in this category were distinct in that, in BPI's judgement, any engineer would recommend completing these projects to avoid increasing all life costs. Setting the allowance at this level would involve excluding a number of projects (those in category *(b)*) which in BPI's judgement should be completed in RP5.

9.13 Given the constraints applying to the review and the large number of individual projects in NIE's plan, we asked BPI to focus its detailed review on those projects where the greatest differences existed between the UR's final determination and NIE's request. In addition we asked BPI to review a small sample of higher value projects where the UR had agreed to NIE's request in full.

9.14 BPI had full access to the capex submissions made to us by the parties, as well as NIE's original project submissions and the UR's responses to those submissions. This included the work which had been conducted by engineering consultants on behalf of the UR (SKM) and NIE (PB Power). In addition, BPI attended a site visit to Northern Ireland.

9.15 Following the publication of its draft report, BPI received written responses from both parties and held face to face meetings with both parties. These meetings enabled both the UR and NIE to identify specific areas where they considered BPI needed to re-evaluate its draft conclusions. Following the submission of additional material clarifying points made at these meetings BPI prepared the final version of its report (BPI's final report), which was published on our website on 12 November 2013.[2] In January 2014, BPI produced a further report to respond to NIE's comments on the provisional determination (BPI's response report) (see paragraphs 9.24 and 9.25). It is attached at Appendix 9.1.

Summary of BPI's final report and response report on core network investment

9.16 In this subsection we summarize *(a)* the key recommendations of BPI's final report, *(b)* parties' comments on our provisional determination and BPI's response to NIE's comments, and then *(c)* explain how we used BPI's recommendations.

BPI's key recommendations in its final report

9.17 Table 9.2 shows BPI's estimate of the categories of core network investment contained in our terms of reference (see paragraphs 9.10 to 9.12 above).

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[2] www.competition-commission.org.uk/assets/competitioncommission/docs/2013/northern-ireland-electricity-price-determination/131112_bpi_final_report.pdf.

TABLE 9.2 **BPI's estimate of categories *(a)*, *(b)* and *(c)* for RP5**

	£m
Category *(a)*	197.5
Category *(b)*	195.1
Category *(c)*	55.6

Source: BPI report.

9.18 In the remainder of this subsection, we focus on BPI's recommended core network investment allowance. This was those projects in categories *(a)* and *(b)* (that is, those projects which in its judgement had been included in NIE's plan with sufficient justification to be completed in RP5).

9.19 BPI recommended a core network investment allowance for RP5 of £392.6 million. This was £133.8 million lower than NIE's submission and £57.2 million higher than the UR's final determination for RP5. Table 9.3 below shows some of the largest differences between BPI's core network investment recommendation and NIE's submission.

TABLE 9.3 **Largest project differences between BPI's recommendation and NIE's request**

£ million

	NIE submission	*BPI recommendation*	*Difference*
Project D56—Network Resilience ('Ice Accretion')	35.0	0	35.0
Projects D43/T40—ESQCR legislation	25.0	2.4	22.6
Project D12—Distribution Overhead Lines Fixed Costs	18.1	0	18.1
Project D48—11kV Network Performance (remote control facilities in the rural network)	9.0	0	9.0
Projects D45/T41—Capitalized Overheads	27.2	20.5	7.2
Project D49—Smart Grid	9.4	3.0	6.4
Project T14—110/33kV Transformers replacement	10.7	6.9	3.8
Projects D17/18; T21/22 Reactive/Fault & Emergency	28.5	25.1	3.4

Source: BPI final report.

9.20 The differences between BPI's recommendation and NIE's request can be broadly categorized as follows:

(a) *Volumes of work.* This is where BPI recommended that a different volume of work should be completed during RP5 than that proposed by NIE:

(i) For some projects, BPI recommended a reduction in NIE's volumes of work. For example, it recommended the replacement of six 110/33 kV transformers (including one spare) rather than the eight which NIE had requested (Project T14).

(ii) For other projects, BPI recommended zero volumes. That is, in its view, these projects were not necessary (for example, Project D56—Network Resilience/Ice Accretion).

(b) *Unit costs.* This is where BPI recommended that the unit costs submitted by NIE for a project should be adjusted. BPI's report only contains one adjustment of this type: to tree-cutting costs on overhead line programmes. For these projects (D7, D8, D9) BPI accepted NIE's proposed volumes of work but proposed a 10.8 per cent reduction to the unit costs associated with the tree-cutting element of the projects.

(c) *Legislation.* NIE requested £25 million in relation to Electricity Safety, Quality & Continuity Regulations (ESQCR) legislation and £4.4 million in respect of Road and Street Works (RASW) legislation. BPI did not think that £22.6 million of NIE's ESQCR request was necessary.

(d) *Indirect costs.* Five of NIE's projects wholly comprised indirect overhead costs. These are Capitalized Overheads (D45 and T41), Distribution Overhead Fixed Lines (D12) and Design & Consultancy (D20 and T23). BPI made an allowance of £30.1 million in this category compared with NIE's request of £57.3 million.

Parties comments on our provisional determination and BPI's response to NIE's comments

9.21 In response to our provisional determination, the UR said that it was clear that in BPI's opinion, work that fell only into category *(b)* and was not included in category *(c)* was 'not necessary' during RP5 (see description of categories in paragraph 9.10). This was because, in its view, this work was neither mandatory nor likely to reduce the whole life cost of the assets. It considered that our provisional decision to grant allowances for all projects that BPI endorsed in category *(b)* (in the UR's words: 'projects that are justified but unnecessary for RP5'), combined with our incentives for deferral and abandonment created by the combined effect of D1 and D3, operated against the public interest.[3] (See paragraphs 9.27 and 9.28 for our discussion on the categorization of capex categories.)

9.22 In response to the provisional determination, the UR also reiterated its view that BPI's approach had an in-built upward bias[4] and that this should be taken into account when considering marginal judgement calls on capex. It also said that, given that the provisional determination included capex allowances which stretched all the way to the bottom of category *(b)*,[5] we should not contemplate increasing it any further in response to NIE's submissions.[6]

9.23 In response to our provisional determination, NIE raised concerns with regard to BPI's rationale for disallowing certain asset replacement volumes of work. These were projects T14 (110/33kV transformers), T15 (22kV reactors) and D15 (secondary substations). The disallowed volumes amounted to £6.9 million of direct costs.[7]

9.24 We asked BPI to review NIE's comments and, as necessary, adjust its recommendation in light of this evidence. BPI's response was set out in its response report. BPI also commented further on 11kV network performance (project D48), network resilience (ice accretion) (project D56), ESQCR compliance (projects D43 and T40) and the implications of extending the control period by six months.

9.25 BPI's response report is attached as Appendix 9.1. We refer to BPI's response report where relevant in the subsections on projects D48, D56, D43 and T40 and on the six-month extension period. In relation to the other three projects on which NIE raised

[3] UR response to the provisional determination, paragraph 81, and annex document, paragraphs 26–33.
[4] Because BPI focused on those projects where the biggest differences existed between UR's FD and NIE's submission, therefore ignoring projects where UR's FD may have overestimated project costs.
[5] Projects that were sufficiently well justified in NIE's submissions.
[6] UR response to provisional determination, paragraphs 80 & 81.
[7] NIE response to provisional determination, Chapter 3, paragraphs 6.1–6.20.

concerns (T14, T15 and D15), BPI considered that no further allowances should be given to NIE. Specifically, BPI said that:

(a) for project T14 (110/33kV transformers), its view remained that the condition monitoring used by NIE did not provide evidence to show that the assets that NIE said should be replaced during the regulatory period were in fact at risk of failure during that time. The risk and impact model used by NIE to take decisions on asset replacement had no clearly stated threshold above which assets should be replaced, it only showed that the ranking of risk of failure. BPI recognized that this was an area where engineering judgement was required but that it considered an allowance for replacement of six transformers was reasonable (including one as a spare);

(b) for project T15 (22kV reactors), similar reasoning applied to that for project T14—namely that there was insufficient justification for changing four reactors in the control period; and

(c) for project D15 (secondary substations), NIE had requested an allowance for re-cabling without quantifying the costs or providing a cost benefit analysis which demonstrated that it was economic to complete this work.[8]

How we used BPI's final report and response report

9.26 Following a detailed review of BPI's final report and response report, we decided to adopt its recommendations in respect of adjustments to the planned volumes of engineering work over the period. We decided to do this because in our view, planned volumes of engineering work is an area involving a substantial element of engineering judgement and we considered that BPI was in a strong position to advise on this judgement.

9.27 We decided to include in our core capex allowance the planned volumes of work from categories *(a)* and *(b)* from our terms of reference (see paragraph 9.10). That is, all projects which, in BPI's view, NIE had included in its plan with sufficient justification.

9.28 We considered the UR's comments on the categorization of projects (see paragraph 9.21). Our approach to the categories of capex, and the approach that BPI took, was that category *(c)* was a subset of category *(b)*. In BPI's recommendations, it was able to establish first, a number of projects which in its view could be costlessly deferred, which it did not include in categories *(a)*, *(b)* or *(c)*; second, a number of projects which it considered would clearly increase whole-life costs if deferred or cancelled, which it included in category *(c)*; and third, a number of projects for which it was unable to identify that deferral or cancellation would be costless but which in its judgement should be carried out in RP5. This last category of projects was included in category *(b)* but not in category *(c)*.

9.29 The implication of BPI's judgement was that the deferral or cancellation of these category *(b)* investment projects could lead to adverse consequences and increased costs in the future and that it was reasonable to include them in the investment plan to 30 September 2017. The primary difference between those projects in category *(c)* and those only in category *(b)* was therefore that those in category *(b)* had greater elements of engineering judgement and uncertainty in terms of their timing but that in BPI's view, deferral or cancellation could incur costs; whereas those in category *(c)*

[8] BPI response report, section 5, pp6–8, Appendix 9.1.

would undoubtedly increase whole life costs if deferred or cancelled. We were therefore satisfied that we were right to include both category *(b)* and *(c)* capex in our allowance because, on the information available to us, they could not be costlessly deferred or cancelled.

9.30 We noted the UR's concerns regarding a potential upward bias in BPI's approach (see paragraph 9.22). Our approach to capex necessarily focused on a subset of projects proposed by NIE for RP5. This was because it was not practicable to review thoroughly all projects. As such, the focus of our and BPI's work was not on projects where the parties were in agreement but on those projects where there was the greatest difference in opinion between the parties. We applied additional scrutiny to the following projects:

(a) Project D56—Network Resilience (Ice Accretion);

(b) Projects D43 and T40—ESQCR compliance; and

(c) Project D48—11 kV Network Performance.

9.31 It was also necessary for us to make a number of adjustments to BPI's recommendations. We added a forecast for non-recoverable alterations, because we decided that non-recoverable alterations should have an ex-ante allowance rather than be treated on a pass-through basis (see Section 5). We also made adjustments in respect of RASW legislation, the Ballylumford switchboard project (T26) and the allowances for transmission as well as distribution load-related expenditure.

9.32 As explained in Section 7, we decided that it was important to make a core network investment allowance for NIE which was on a direct cost basis. We therefore considered direct and indirect costs in more detail and made a direct-only allowance.[9]

9.33 The issues described in paragraphs 9.30 to 9.32 are set out and explained in the remainder of this section.

Additional project review

Project D56—Network Resilience

9.34 We gave this project further scrutiny because it had the single largest difference between NIE's core network investment submission and BPI's recommendation. It was also the single largest project difference between NIE and the UR in the UR's final determination.

9.35 This project was prompted by increasing concern (arising out of three events between 2001 and 2010) regarding a potentially high impact ice accretion[10] event affecting NIE's 25mm^2 conductors. The project would involve a pilot programme of replacing small section 25mm^2 conductors with 50mm^2 conductors.

9.36 NIE requested £35 million for this pilot project. It had originally submitted a claim of £127 million for RP5.

[9] We define direct and indirect costs according to Ofgem's cost reporting rules and as relied on by Frontier and PB in their analyses for NIE.
[10] Ice accretion on power transmission lines is caused by freezing raindrops, super-cooled cloud droplets or snowflakes on the cable surface. This phenomenon can cause significant damage to electric power transmission networks.

9.37 The purpose of the replacement of the smaller sized conductors is to reduce the risk and impact of an 'ice accretion' event. NIE said that the impact of such an event would be geographically isolated but could result in tens of thousands of customers being off supply for an extended time. While the larger replacement conductors might still suffer damage in such an event, the degree of damage would be greatly reduced.

9.38 The UR told us that NIE had not provided any information on the planned outage impact; that it had not done anything to look at whether customers felt this was valuable or not; and that it had not done any cost-benefit analysis (CBA) for a pilot project which was forecast to cost £35 million.

9.39 BPI said that ice accretion was regarded as a low probability event in the UK electricity supply industry, and that it also tends to be geographically localized. It noted that NIE did not consider the quantity of $25mm^2$ conductor as having a fundamental impact on network performance in terms of average weather. BPI concluded that, because of the low probability of severe cold weather events and in particular ice accretion, it did not accept the wholesale replacement of $25mm^2$ conductors would significantly improve the overall performance of the network for the majority of NIE's customers. It also concluded that the benefits of the proposed pilot programme were dubious at best and in all likelihood would provide no more information than was already available.[11]

9.40 In response to the provisional determination, NIE submitted that a decision by the CC not to fund 11kV network resilience would be inconsistent with the CC's obligations with respect to protecting the interests of vulnerable customer groups and customers living in rural areas.[12]

9.41 We considered the evidence submitted by NIE and the UR as well BPI's final report and response report. We noted that $25mm^2$ conductors were being replaced anyway through NIE's conventional refurbishment and re-engineering programmes. As such this project represented a proposal to accelerate this replacement cycle due to the specific network risks identified by NIE.

9.42 NIE's project proposal was for replacement over a 15-year period. This compares with a replacement period of approximately 30 years if the project was not approved (using age-based replacement, assuming a conductor life of 70 years).

9.43 We were concerned about the size and potential benefits of the proposed pilot project, which BPI had suggested may not provide significant amounts of additional new information. In addition, we were concerned that this was a project which, if completed over 15 years, would involve a total capital cost well in excess of £500 million. We believed that we should require strong evidence to approve a project of this size given the cost implications for consumers (including those in vulnerable groups and those living in rural areas). At a minimum, we would expect a robust cost benefit analysis, customer consultation on costs and consideration of alternative approaches before a project of this scale could be approved. We judged that NIE's proposals on this project were not supported by strong evidence and as such it was not in consumers' interests to fund the project. NIE's response to the provisional determination offered no further evidence to persuade us that this project would be in consumers' interests. We decided that it was appropriate to accept BPI's recommendation and to reject this project for RP5.

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[11] BPI final report, p121.
[12] NIE response to the provisional determination, Chapter 3, paragraph 2.5.

Projects D43 and T40—ESQCR compliance

9.44 We gave this project further scrutiny because of the proposed phasing between RP5 and RP6 which had been recommended by BPI.

9.45 The ESQCR regulations specify safety standards and are aimed at enhancing the level of protection to the public from the dangers posed by electrical equipment. The ESQCR regulations became law in Northern Ireland in December 2012. They replaced the Electricity Supply Regulations (Northern Ireland) 1991 and brought Northern Ireland in line with Great Britain's current measure which is the ESQCR 2002 (amended in 2006 and 2009). For certain requirements the ESQCR regulations allow for a phased introduction over a period of either five or ten years. The Explanatory Memorandum to the ESQCR Regulations notes that NIE:[13] 'has applied to the Utility Regulator for extra funding to be spent over a number of years. The Regulator will keep the arrangements under review to monitor the effectiveness of the new measures and associated costs'.

9.46 The ESQCR Regulations identify the main duty holders responsible for maintaining safety and power quality standards and continuity of supply. They impose requirements on the installation and use of electrical networks and equipment owned or operated by generators, distributors (which includes transmitters) and meter operators and the participation of suppliers in providing electricity to consumers (all 'duty holders'). NIE is one such duty holder.

9.47 In December 2012, DETI published guidance on the ESQCR Regulations (DETI Guidance).[14] The purpose of this document is to provide guidance to duty holders on their responsibilities in the Regulations and to clarify necessary actions for duty holders to demonstrate compliance with them.

9.48 Projects D43 and T40 related to compliance with the ESQCR regulations. NIE estimated that the total cost of compliance with this legislation (which would be phased over RP5 and RP6) was £95.2 million. NIE's estimate was based on a network sampling exercise which it had conducted. It requested £25 million for RP5. It said that its forecast related only to new elements, above its existing programmes, relating to compliance with new ESQCR legislation.

9.49 A split of NIE's total estimated costs of £95.2 million for RP5 and RP6 is shown in Table 9.4.

[13] www.legislation.gov.uk/nisr/2012/381/pdfs/nisrem_20120381_en.pdf.
[14] www.detini.gov.uk/guidance_document_12_12_12_final_version.pdf.

TABLE 9.4 **NIE's forecast ESQCR costs for RP5 and RP6**

	£m
Asset register	0.75
Patrolling costs	3.5
Fitting safety signs, stay insulators, and anti-climbing devices on 11 kV poles over 65% of the network	9.8
2,500 km of urban LV network 50% of which will require alterations	50.0
11 kV & 33 kV alterations	17.3
Fitting safety signs on LV poles and stay insulators where appropriate	5.7
Fitting safety signs and anti-climbing devices on 33 kV & 110 kV poles	1.7
Vegetation management	4.7
Public awareness	1.8
Total (RP5 and RP6)	**95.2**

Source: NIE.

9.50 NIE proposed a split of work between RP5 and RP6 as shown below in Table 9.5.

TABLE 9.5 **NIE's forecast ESQCR costs for RP5 and RP6**

	£ million	
	RP5	*RP6*
Asset register	0.75	-
Patrolling costs	3.5	-
Compliance remedial work	18.4	66.1
Vegetation management	1.5	3.2
Public awareness	0.9	0.9
Total	**25.0**	**70.2**

Source: NIE.

9.51 NIE said that DETI's guidance required it to spread compliance work more evenly (than implied by the UR's and BPI's allowances) across the RP5 and RP6 periods: 'It is DETI's expectation that duty holders will spread workloads associated with these new requirements equally across the permitted timescales.'

9.52 The UR allowed £1.25 million in respect of additional ESQCR costs in RP5. It told us that there was significant overlap with NIE's other investment programmes. It also told us that NIE's ESQCR submission was not supported by significant detail in relation to the surveys which had been used to make NIE's forecast. The money allowed by the UR was for additional survey work and for NIE to gather additional information on the LV network in particular. The UR told us that it suspected that there would be more investment required in the LV network in particular.

9.53 BPI recommended an allowance of £2.38 million in respect of ESQCR. It believed that the £95.2 million estimate of RP5 and RP6 compliance, which was based on sampling, appeared high compared with GB networks. In addition, it said that it could not conclude if the sampling was representative of the network as a whole.[15]

9.54 BPI viewed the priority as the establishment of an asset register based on detailed survey findings to build up a clearer view of actual proposed volumes of work. Any remedial work should then be based on data collected in RP5.[16] BPI reiterated these concerns in its response report.

[15] BPI final report pp110 and 111
[16] ibid, pp110 & 111.

9.55 BPI was also concerned that economies of scope were available and might not have been fully identified by NIE. It therefore introduced a reduction to its final allowance for an asset register and patrolling costs; this was based on overhead line assets which would be visited every five years as part of NIE's routine patrolling programme.[17]

9.56 We noted that the ESQCR Regulations specify the date from which NIE (and other duty holders) must start complying with the requirements and that they allow for a phased introduction over a period of either five or ten years for certain requirements.[18] The ESQCR Regulations do not prescribe how the work done to meet the requirements by the specified start date must be allocated across the period before the start date. As noted in paragraph 9.45 above, DETI's Guidance states that it expects that duty holders will spread workloads associated with these new requirements equally across permitted timescales.[19]

9.57 We considered whether, despite the absence of a binding legislative requirement to complete more of this work in RP5, it might be more efficient and appropriate to allow NIE to complete additional compliance remedial work in RP5 and also comply with the expectation in DETI's Guidance that the cost be spread out over a ten-year period.

9.58 We thought that, as a complete asset register had not yet been completed, there must be considerable uncertainty regarding the eventual cost of ESQCR compliance. For this reason we found that we could not place significant weight on NIE's £95.2 million estimate of ESQCR costs for RP5 and RP6. We therefore agreed with BPI that establishing a full ESQCR asset register was the highest priority for RP5.

9.59 We also thought that considerable economies of scope must exist between ESQCR compliance and NIE's other capex programmes. We were not convinced that these economies of scope had been fully identified. In our view, once a full asset register has been completed and additional economies of scope identified the cost of this programme might be significantly different.

9.60 Nevertheless, we also recognized that, even if the final cost estimate was subject to very significant revision, it was still likely to be a large number and that BPI's recommendation would require a very significant increase of operations in this area in RP6. We believed that this was unlikely to be the most efficient way to conduct this work.

9.61 In our provisional decision we weighed up the factors set out in paragraphs 9.56 to 9.60 and on balance we judged that it would be appropriate to allocate an additional £8 million to this programme of work for RP5, which increased the ESQCR allowance for RP5 from £2.38 million to £10.38 million.

9.62 In response to our provisional determination:

(a) NIE said that, after patrolling costs of approximately £3.5 million, the remainder of our provisional £10.38 million allowance would finance only approximately 12 per cent of the estimated non-compliance issues. It said that a further allowance of £5 million of direct costs would permit approximately one-quarter of the estimated non-compliance issues to be addressed during RP5 and would go some way towards complying with DETI Guidelines.[20]

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[17] ibid, pp110 & 111.
[18] Regulation 2 of the ESQCR Regulations.
[19] www.detini.gov.uk/guidance_document_12_12_12_final_version.pdf.
[20] NIE response to the provisional determination, Chapter 3, paragraphs 5.1–5.3.

(b) the UR said that our proposed additional funding of £8 million gave rise to substantial risk of double funding because the GB DNOs report ESQCR tree cutting costs under ‘tree cutting’ and not ‘ESQCR’. Our benchmarked IMF&T allowance (see Section 8) should therefore already allow for the ‘vegetation management’ aspect of ESQCR compliance.

(c) the UR was concerned that this additional allowance came with no required outputs for NIE.[21] In response, NIE said that there were some areas of work for RP5 where it could specify the quantity of work that was required today because it was not concerned with patrolling the network to identify the requirement (for example, fitting safety signs to overhead line poles). However, for RP5, part of the requirement is for NIE to patrol the network to identify the work that will be subsequently required and will also end up as part of the work required for RP6. Therefore until it had patrolled and reviewed the network to see what needed to be done, it could not specify outputs completely. NIE proposed that at the end of the period, NIE would be able to report what it had done with the ESQCR allowance and what it had identified as being required to be done to its network to meet the new safety requirements if patrolling revealed a need for safety signs or the moving of cables that were too close to buildings, for example. NIE’s view was that the section of the RIGs relating to ESQCR would be relevant for reporting purposes with additional reporting in relation to patrolling activity and splitting LV work into LV undereaves and LV overhead lines.

9.63 We considered NIE’s arguments regarding the spreading of costs over RP5 and RP6. We found that our concerns with regard to cost uncertainty and economies of scope (see paragraphs 9.58 and 9.59) remained and we did not consider that NIE had provided evidence to persuade us otherwise. We therefore considered it remained a priority for NIE to establish a full ESQCR asset register and further funding beyond that indicated in our provisional determination was not in the public interest.

9.64 We noted that, as shown in Table 9.4 above, vegetation management was a relatively small proportion of the estimated cost of ESQCR compliance—it represented around 4.9 per cent of the estimated total cost for RP5 and RP6. Any risk of double funding, to the extent it exists, was therefore no more than £0.5 million of our £10.38 million allowance. Excluding vegetation management costs from the total estimates (leaving £90.5 million) would still require a significant increase in compliance work required for RP6. Taking these points together, in our view the risk of double funding did not justify reducing the allowance further.

9.65 We note that NIE and the UR both agreed that it would be helpful for NIE to specify outputs for ESQCR. The main aim of this reporting is to facilitate the UR’s setting of an appropriate allowance for ESQCR for RP6. Taking into account differences between the NI network and the GB network (for example, the quantity of LV undereaves wiring in Northern Ireland), we decided that NIE should report on its ESQCR compliance in line with Ofgem’s RIGs, with additional details on NIE’s patrolling activity and splitting LV work into LV undereaves and LV overhead lines (as it proposed to us, see paragraph 9.62*(c)*). These reporting requirements should be agreed with the UR in the same manner for all other RIGs, as set out in section 18.

9.66 Overall, and taking into account the further representations following our provisional determination, we judged that it was appropriate to maintain the allowance we proposed in our provisional determination, which was to increase the ESQCR

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[21] UR response to the provisional determination, paragraphs 83 & 84.

allowance to £10.38 million from BPI's recommendation of £2.38 million, with reporting of outputs to be agreed with the UR but based on the relevant parts of Ofgem's RIGs with additional details on NIE's patrolling and LV activity.

Project D48—11 kV Network Performance

9.67 We gave this project further scrutiny because it concerned an investment which was targeted at improving service quality to a relatively small group of rural consumers.

9.68 NIE requested £9 million for this project, but both the UR and BPI made no allowance for it. The aim of this project was to improve the quality of service for certain rural customers by reducing the time to restore supplies after faults. This is achieved through the installation of remote control facilities. These can isolate the faulty section of a circuit and restore supply to the healthy parts of the circuit therefore eliminating the delays caused by operational staff travelling to and switching sections of circuit.[22]

9.69 NIE commenced a small programme of installation in RP4. The 80,000 customers supplied from the circuits targeted in its RP4 work experienced outages of on average two hours a year. After improvement, outages were reduced by 30 minutes a year.[23]

9.70 The RP5 programme would apply this technology to approximately 150,000 customers who experience similar levels of poor network performance. NIE expected to be able to reduce outages by 20 minutes a year for these customers.[24]

9.71 NIE said that its analysis showed that the investment of £9 million in RP5 would result in an improvement of 4.4 CML by 2016/17, which NIE rounded up to 5.0 as a stretch target for this project. One unit of CML means 842,000 minutes lost a year.

9.72 NIE said that research by the UR showed that time taken to restore supply was the most important network issue. In addition research highlighted the difference in experiences between rural and urban consumers.[25]

9.73 NIE said that the UR should not rely on the conclusion that customers in general were satisfied with service standards when disallowing investment specifically designed to benefit rural customers. This was because rural customers' experience of service levels can be very different to that of the average customer.[26]

9.74 In response to the provisional determination, NIE submitted that a decision by us not to fund 11kV network performance would be inconsistent with our obligations with respect to protecting the interests of vulnerable customer groups and customers living in rural areas.[27]

9.75 In its final report and response report, BPI said that, although this project would lower CML, it was unlikely that the difference would be substantial enough to be recognized by customers generally.[28] It said that NIE's performance indices compared favourably

[22] NIE Statement of Case, p95.
[23] ibid, p95.
[24] ibid, pp95 & 96.
[25] ibid, p96.
[26] ibid, p97.
[27] NIE response to the provisional determination, Chapter 3, paragraph 2.5.
[28] BPI final report, p115.

with the GB DNOs and that this performance could be further improved through operational processes without further expenditure.

9.76 The target benefit is between 4.4 to 5.0 units of CML a year, once the investment is fully completed. We therefore considered whether the target benefit, of the order of 3.7 to 4.2 million minutes a year, or 62,000 to 70,000 hours a year, was good value at a total capital cost of £9 million.

9.77 We noted that £9 million amounted to an annual cost to customers of around £0.7 million in today's prices.[29] That is, the investment would increase distribution charges by around 0.4 per cent, costing every domestic customer in Northern Ireland an additional 52p a year including VAT if all tariffs were scaled proportionately (or an additional 87p a year including VAT if the money was recovered only from domestic customers) in order to ensure that every year, for 50,000 customers, an interruption that would have lasted an hour and a half without remote control would be reduced to a quarter of an hour. The annual cost was equivalent to £14 for each instance where a customer was restored more quickly using remote control (or around £11 per hour). We noted that NIE did not present significant evidence of customers' willingness to pay for this investment.

9.78 We decided that, on balance, there was not sufficient evidence of customers' willingness to pay for this investment and that the customer benefit was not sufficiently compelling that we should allow it as in the public interest.

Non-recoverable alterations

9.79 These costs are incurred when NIE makes an alteration to its network due to a proposed customer development where the cost is not recoverable from the customer. This happens when a development is on land where a Wayleave Agreement is in place.

9.80 We did not identify any good reason why these costs should be treated on a cost pass-through basis (see Section 5). We therefore decided that these costs should be treated in the same way as NIE's core network investment expenditure with an upfront regulatory forecast and subject to the general cost risk-sharing mechanism. We therefore made an allowance for non-recoverable alterations within our core network investment allowance.

9.81 NIE forecast £19.7 million in non-recoverable alterations during RP5 (£19.8 million including RASW). This was based on the 2010/11 out-turn with an annual 1 per cent uplift in volumes throughout RP5.

9.82 The out-turn expenditure and number of non-recoverable alterations projects completed in each year of RP4 is shown below in Table 9.6.

TABLE 9.6 **Non-recoverable alterations during RP4, 2009/10 prices**

	2007/08	*2008/09*	*2009/10*	*2010/11*	*2011/12*
Non-recoverable alterations	3.4	4.0	3.6	3.9	3.6
Number of completed projects	964	1,012	873	919	1,040

Source: NIE.

[29] Assuming 2.5 per cent depreciation and 4.1 per cent cost of capital, rolled forward to 2013/14 prices using RPI.

9.83 Table 9.6 shows that the average annual expenditure on non-recoverable alterations during RP4 was £3.7 million. NIE told us that the out-turn in 2012/13 was £3 million and that 766 projects had been completed. NIE said that in setting an allowance we should use the average annual expenditure of the six-year period (five years of RP4 and 2012/13). It said that this would equate to £3.6 million per year or £19.8 million over 5.5 years.[30]

Our RP5 forecast

9.84 We considered that the latest data points were more relevant in our consideration than the earlier years of RP4. Nevertheless, we recognized NIE's comments on our provisional determination that our provisional allowance of £3.3 million placed too much weight on 2012/13 out-turn figures. We noted that the out-turn for 2012/13 was somewhat below the level which had existed in the five years before that. We therefore adjusted our allowance to the average of the last three years (2010/11, 2011/12 and 2012/13), which was £3.5 million per year. Over five years this results in a forecast of £17.5 million, which compared with NIE's original forecast of £19.7 million.

Additional CC adjustments to BPI recommendation

9.85 We made adjustments in respect of:

(a) Project D44—Road and Street Works (RASW) legislation;

(b) Project T26—Ballyumford 110 kV switchboard replacement;

(c) additional allowance for distribution-load-related expenditure; and

(d) transmission-load-related projects.

Project D44—'RASW legislation'

9.86 This project related to the additional cost of RASW legislation in Northern Ireland in RP5. We noted that RASW legislation had not yet been implemented in Northern Ireland, although NIE said that it was expected to be implemented within RP5.

9.87 The UR told us that it had recently spoken to the Street Works Manager in the Roads Service who had informed it that the outstanding elements of the RASW legislation, particularly with respect to fixed penalties and to the fees for the permit scheme, had been reviewed by DETI this year. It said that the manager had confirmed to the UR that there were no plans to enforce these requirements from the legislation in the foreseeable future.

9.88 DETI told us that the Department for Regional Development (DRD) was no longer actively progressing the RASW proposals in Northern Ireland, although the primary legislation remained in place and DRD reserved the right to review the position in the future. DRD said that there was no longer a robust business case for introducing such a scheme and that there were no plans to review that decision at present.

9.89 Following this response from DETI, NIE said that given the uncertainties regarding implementation of the legislation, it would be content with no upfront allowances on

[30] NIE response to the provisional determination, Chapter 10, paragraph 3.4.

the basis that it would be able to apply the change in law provision if the scheme was implemented.

9.90 We therefore decided that no allowance for RASW legislation should be made in our core network investment forecast. This results in a reduction of £4.4 million to BPI's recommendation.

Project T26—Ballyumford 110 kV switchboard replacement

9.91 In our provisional determination we included a core network investment allowance of £15.3 million for this project. BPI had allowed £14.7 million.[31]

9.92 In response to our provisional determination, NIE reiterated its view that this project should not be included in the core network investment allowance but should instead be included in the D5 mechanism. This was because the project involved significant forecasting risk due to the scale of the costs and the engineering uncertainties involved. The project costing was based on a desk top assessment, NIE had not previously carried out a project of this type before and there was scope for significant variations in cost due to site unknowns and the switchboard specification.[32]

9.93 The UR said it believed that SONI should be responsible for determining the scope of the project and that it was of the opinion that this project was best placed within the D5 mechanism.

9.94 As set out in paragraphs 9.92 and 9.93, both NIE and the UR agreed that this project should be placed in the D5 mechanism. We agreed that this project involves major decisions on the capacity of new transmission assets to be installed and as such would be appropriate for the D5 mechanism. We therefore excluded it from our core network investment allowance.[33]

Allowance for distribution-load-related expenditure

9.95 As discussed in Section 5, we considered the use of some form of provision or mechanism in the price control to adjust NIE's expenditure allowance according to further specific distribution load related projects that become necessary. We did not consider that this would be proportionate. Instead, we decided to make an additional allowance, further to the figure recommended by BPI, for other distribution-load-related investment which may be required in the period.

9.96 The UR submitted that we had not taken adequate account of the fact that NIE has an obligation to consider alternatives to infrastructure investment for load related projects. It said that these alternative options would result in opex costs over a considerable period of time in place of the capex costs for load related projects; in addition some of these costs may be incurred in the wholesale market or by the TSO rather than by NIE.[34]

9.97 We did not consider that it was practicable for our consultants to conduct a detailed review of how the new obligations on NIE may affect every distribution load related

[31] BPI had allowed £14.7 million for this project, which did not included £0.6 million of Project Management costs which we allowed in our provisional determination.
[32] NIE response to the provisional findings, Chapter 8, paragraphs 1.9 & 1.10.
[33] NIE also said in its response to the provisional determination that we should be clear about the inclusion of the Coolkeeragh-Magherafelt 275kV overhead line project (project T18) in the D5 mechanism. We had already excluded this project from our ex ante allowance so we have not made any changes to the core network investment allowance in this section.
[34] UR response to provisional determination, paragraphs 46 – 48 and appendix paragraphs 58 – 62

project. It was therefore not possible for us to assess whether each of these projects might, over a considerable period of time, be replaced with either opex costs or costs incurred elsewhere in the supply system. We therefore based our allowance on the best evidence available to us, which was those distribution load related projects which BPI reviewed and NIE's submission in this area.

9.98 NIE submitted a forecast for distribution-load-related expenditure of £24.6 million and BPI recommended an allowance of £22.1 million.[35] BPI recommended a reduction of £1.4 million in respect of 33/11 kV transformers (D36), where it recommended load-related works at nine sites compared with the 15 sites which had been requested by NIE. It also recommended not allowing the Dungannon Main 33 kV switchboard (D27), for which NIE had requested £1.1 million.[36]

9.99 In total, BPI therefore recommended a reduction of £2.5 million compared with NIE's forecast for distribution-load-related expenditure. The reduction was entirely in respect of 33 kV distribution-load-related expenditure. The reduction represented costs forecast by NIE for which there was uncertainty as to the need and timing for investment to increase 33 kV distribution network capacity (eg it would depend on localized load growth).

9.100 Our additional allowance was 50 per cent of £2.5 million (ie £1.25 million), which reflected our view that not all of the potential projects identified by NIE would be needed before 30 September 2017.

9.101 In addition we added back £0.68 million of distribution load related projects[37] which had been excluded from BPI's original distribution load related allowance. BPI had not reviewed these projects and we therefore decided that they should have been included its original distribution load related allowance. In total we therefore adjusted NIE's distribution load related expenditure allowance by £1.9 million, representing the sum of our additional allowance of £1.2 million and the £0.7 million of projects which we added back to BPI's original recommendation.

Transmission-load-related projects

9.102 In our provisional determination, we included an allowance for nine transmission-load-related projects (including the T26 Ballyumford switchboard replacement discussed above in paragraphs 9.91 to 9.94). Under the D5 mechanism (see Section 5), NIE can also apply to the UR for approval of additional transmission-load-related projects. We noted that SONI would soon take over the role of planning for the transmission system and it would therefore have responsibility for deciding which projects should be carried out. Given this, we considered whether all transmission-load-related projects should be moved to the D5 mechanism.

9.103 In response, NIE said that moving all transmission load-related projects to the D5 mechanism could be helpful in ensuring allowances are formally considered against SONI's assessment of its licence requirements. It had no objection to moving all these projects to the D5 mechanism, with the exception of project T36 (Belfast North Main) which had already commenced construction. It also noted that the transmission and distribution elements of the project to establish the new Airport Road 110/33kV

[35] BPI final report, p33.
[36] BPI final report, p33.
[37] Projects D31/D33/D35

substation (projects T27 and D22) were linked. NIE said that the regulatory treatment of these two projects should be aligned.

9.104 The UR proposed that all transmission-load-related projects should fall under the D5 mechanism—it was concerned that under our provisional determination proposals NIE may benefit financially from decisions to defer or abandon these projects.

9.105 We decided to exclude all future transmission-load-related projects from our allowance (see Section 5). We considered that this was in the public interest given that the responsibility for transmission planning will soon pass to SONI. Consumers would face unduly high costs if SONI cancelled one project that had been planned by NIE and included in upfront cost allowances and replaced it with a different project for which NIE is entitled to additional revenues through the D5 provision

9.106 We therefore excluded all transmission load related projects from our allowance, with the exception of one project (T36) which had already begun. We did not exclude project D22, which NIE said was linked to project T27 and should therefore have the same regulatory treatment. This was because our distribution-load-related expenditure allowance is a general ex-ante allowance designed to cover all distribution load related projects which will occur in the RP5 period. As such it is not an allowance which is tied to specific distribution projects. With regard to transmission-load-related projects proposed by NIE under our D5 mechanism, the UR would only make a fresh assessment of the costs of the project if there had been substantial changes to the nature or scope of the project since it was included in the NIE investment plan that we used for our determination (see paragraph 5.278). Otherwise, the costs would be based on the provisional allowances that we specify in Appendix 9.4.

9.107 The effect of excluding these projects[38] was to reduce our core network investment allowance by £11.7 million.

Our adjustments to BPI recommendation

9.108 We revised BPI's core network investment recommendation to reflect our project adjustments described above and also our non-recoverable alterations allowance for RP5. Table 9.7 shows the effect of these adjustments on BPI's recommended capex allowance.

TABLE 9.7 **CC adjustments to BPI's recommended RP5 allowance**

	£m
BPI recommendation	392.6
CC additional ESQCR allowance	+8.0
Add non-recoverable alterations allowance	+17.5
Remove RASW legislation (D44)	–4.4
Exclude Ballyumford switchboard (T26)	–14.7
Exclude transmission-load-related projects (except T36)	–11.7
Additional distribution-load-related allowance	+1.9
Adjusted total	**389.2**

Source: CC analysis (may not sum due to rounding).

[38] Excluded projects: T27, T30, T31, T33, T34, T38, T39 (T26 has been dealt with separately).

CC direct costs forecast

9.109 As explained in paragraph 9.32, we decided that it was important to estimate the direct cost element of our adjusted core network investment allowance (of £389.2 million, as revised in Table 9.7 above).

9.110 Based on NIE's original submission, it was not possible for us fully to separate out all indirect costs to derive a direct-only allowance. This was because of the way in which NIE reports data.

9.111 The indirect costs on which we benchmarked NIE are contained in the following areas of NIE's core network investment forecast:

(a) five separately identified overhead projects in NIE's capex submission. These were Capitalized Overheads (D45 and T41), Distribution Overhead Fixed Lines (D12) and Design & Consultancy (D20 and T23). These projects were wholly indirect costs.

(b) the Fault & Emergency (D17; T21) and Reactive (D18; T22) projects. Our benchmarking covered these costs in their entirety.

(c) tree cutting, which was one element of the cost of the OHL asset replacement programmes within Transmission (T17; T19) and Distribution (D7; D8; D9). Our benchmarking included tree cutting.

(d) within the charge-out rate for Powerteam. This charge-out rate was used to build up the individual project costs and as a result individual capex projects contained an element of indirect costs which could not be easily separated.

9.112 In order to identify the direct cost element of BPI's recommendation we needed to subtract the indirect costs from *(a)* to *(d)* above. In the following section we explain our approach to doing this.

Our approach to estimating direct costs

9.113 BPI's recommendation in respect of the five separately identified wholly indirect projects is shown below in Table 9.8.

TABLE 9.8 **BPI's recommendation for indirect overheads projects**

	£m
Capitalized overheads—Distribution (D45)	18.2
Capitalized overheads—Transmission (T41)	2.3
Design & Consultancy—Distribution (D20)	3.4
Design & Consultancy—Transmission (T23)	6.2
Overhead Lines Fixed Costs—Distribution (D12)	0.0
Total	**30.1**

Source: BPI final report.

9.114 It can be seen from Table 9.8 above, that BPI included an allowance of £30.1 million in respect of indirect-only projects (£27.2 million less than NIE's submission). To reach a direct-only allowance we therefore excluded BPI's allowances for each of these projects (a total of £30.1 million).

9.115 We also excluded amounts relating to Inspections, Maintenance, Faults and Tree cutting (IMF&T), which were included in our benchmarked allowance.

9.116 NIE said that the cost of inspections work on overhead lines projects were included in the overhead lines fixed costs project D12 (which we excluded in reaching our direct-only core capex allowance). It said that plant inspection and maintenance painting activities were included in NIE's opex submissions and we therefore did not need to make an adjustment for these activities.

9.117 BPI allocated the amounts shown below in Table 9.9 to Fault & Emergency and Reactive projects.

TABLE 9.9 **BPI's recommendation for Fault & Emergency and Reactive projects**

	£m
Fault & Emergency (D17)	12.9
Fault & Emergency (T21)	2.9
Reactive (D18)	8.7
Reactive (T22)	0.5
Total	**25.1**

Source: BPI final report (may not sum due to rounding).

9.118 These activities were fully included within our benchmarking and we therefore excluded these projects in our estimate of direct-only costs.

9.119 NIE's submission included £33.25 million in respect of tree-cutting costs. BPI excluded £3.4 million of tree-cutting costs,[39] leaving £29.8 million of tree-cutting costs still in BPI's recommendation. Tree cutting was included within our benchmarking and we therefore excluded these costs from our estimate of direct-only costs.

9.120 In our provisional determination, we used a direct unit cost benchmarking report prepared for NIE by PB Power (PB) in order to estimate the level of indirect costs included in NIE's individual projects. In this report, PB benchmarked a sample of the direct unit costs contained in NIE's capex forecast against the GB DNOs.

9.121 Since the GB DNO unit cost data was prepared on a direct cost basis, it was necessary for PB to adjust NIE's unit costs (which contain an element of indirect costs) to make them comparable. PB therefore adjusted NIE's unit costs to estimate its direct cost only; it concluded from its analysis that NIE's direct unit costs were efficient.

9.122 We mapped the direct unit costs used in PB's benchmarking exercise to NIE's capex submission. This gave us a sample from which it was possible to make a number of observations regarding the level of indirect costs included in NIE's projects.[40]

9.123 Following our provisional determination, NIE made submissions that our cost assessment had failed to provide for the costs of non-operational capex and that these costs were not included in either the direct cost allowances for NIE's network investment considered in this section or in our allowances for NIE's indirect and IMF&T costs (Section 8). We consider non-operational capex in Section 10. In the course of our review of NIE's submissions on non-operational capex, we obtained more detailed information from NIE on the data and calculations used for the estimates of NIE's direct unit costs in PB's benchmarking report, which fed into our analysis above. This revealed two issues with the direct cost estimates which we had used in our provisional determination.

[39] From projects D7; D8; D9.
[40] Direct unit cost sample and method provided to the parties on 23/9/2013.

9.124 First, the direct unit costs reported in the PB report were calculated using a notional hourly rate for NIE Powerteam's direct costs that had subsequently been revised in further benchmarking analysis for NIE. The notional hourly rate used for the direct unit cost estimates in the PB report was £23.95. However, in subsequent benchmarking analysis carried out for NIE by Frontier Economics, Frontier produced a revised estimate of the notional hourly rate on a direct cost basis of £22.74. Frontier Economics explained in its June 2011 report that, following a review in May 2011, it had identified that a slightly greater proportion of the overall NIE Powerteam hourly rate was associated with costs that Ofgem would classify as indirect costs.

9.125 Second, we identified that the direct unit costs reported in the PB report did not include any allowance for ongoing pension costs. Our provisional determination included allowances, as part of our benchmarking exercise in Section 8, for the ongoing pensions costs attributed to NIE's indirect and IMF&T costs. However, the direct unit costs that we had taken from the PB report did not allow for ongoing pension costs. The NIE Powerteam cost allocation spreadsheets reported that around £1.7 million of NIE Powerteam's 2009/10 pension costs were attributed to direct cost categories. We used this figure, and the information that NIE provided to us on the calculations used to produce its (revised) notional hourly rate on a direct cost basis, to produce an estimate of NIE's notional hourly rate on a direct cost basis including ongoing pension costs, of £24.87 per hour.[41]

9.126 We also reviewed our calculation of the proportion of direct costs within OHL projects. In our provisional determination we had excluded tower painting, which was classified as a 100 per cent direct cost by PB, from our sample calculation. On further review we considered this was a relevant item which should be included in our sample calculation.

9.127 These changes together resulted in a slightly higher estimate of the proportion of direct costs in NIE's plan compared to our provisional determination:

(a) for OHL projects we estimated that direct costs were 72.2 per cent of total project costs, as compared to 69.2 per cent in our provisional determination; and

(b) for other asset replacement and reinforcement costs we estimated that direct costs were 95.2 per cent of total project costs, unchanged from our provisional determination.[42]

9.128 Our sample of projects totalled £281.8 million. Within these projects we were able to identify unit costs with a total value of £201.3 million which PB Power had used in its analysis, 53 per cent of which related to overhead line work and 47 per cent of which related to other asset replacement and reinforcement work.

9.129 In our provisional determination, we made an estimate of the direct cost element of the costs of (capitalised) non-recoverable alterations, using an assumption that 72 per cent of capitalised non-recoverable alterations costs were direct costs. The figure of 72 per cent was based on the proportion of direct costs in capitalised IMF&T costs, using the data on IMF&T costs in 2009/10 that we used for our benchmarking analysis of NIE's IMF&T costs. For our final determination, we revised our calculation of the proportion of direct costs in NIE's capitalised IMF&T costs using the data from our updated benchmarking analysis that spanned the period 2009/10 to 2011/12. The

[41] We obtained the revised estimate by taking the £1.7 million of pension costs that are attributed to direct costs and dividing by the total chargeable hours including overtime used in the notional hourly rate calculation, to calculate an uplift to the hourly rate to allow for these pension costs.
[42] Unchanged once rounded to one decimal place

average proportion of direct costs in capitalised IMF&T costs between 2009/10 and 2011/12 was 76 per cent and we have applied this percentage to our cost allowance for non-recoverable alterations to obtain an estimate of the direct cost element of these costs.

9.130 We used the results of our sample analysis to estimate the amount of direct costs and indirect costs which were contained within projects which BPI had approved. We did this in the following way:

(a) We split BPI's approved projects into two main categories: OHL projects; and other asset replacement and load-related projects:

(i) for OHL projects we estimated that direct costs were 72.2 per cent of total project costs; and

(ii) for other asset replacement and reinforcement costs we estimated that direct costs were 95.2 per cent of total project costs.

(b) We assumed that ESQCR costs were an entirely separate allowance and we have therefore allocated these costs in full (that is an allocation of 100 per cent).

(c) For non-recoverable alterations we assumed direct costs are 76.0 per cent of total costs (see paragraph 9.129).

(d) For the IT costs and our additional distribution-load-related expenditure allowance we assumed a similar rate to our other asset replacement and reinforcement costs. That is, direct costs are 95.2 per cent of total costs.

9.131 Applying the relevant adjustment factors above to each of the projects approved by BPI resulted in a direct-only core network investment estimate of £263.1 million. Table 9.10 shows the results of this analysis.

TABLE 9.10 **CC estimate of direct-only core network investment**

	BPI recommended project value (CC adjusted) £m	*Adjustment factor applied %*	*Estimate for direct-only costs £m*
Transmission			
OHL	18.4	72.2	13.3
Other asset management and replacement	59.5	95.2	56.6
Distribution			
OHL	83.9	72.2	60.5
Other asset management and replacement	104.3	95.2	99.3
Other			
Smart Grid	3.0	95.2	2.9
Customer priorities	2.3	95.2	2.2
ESQCR	10.4	100.0	10.4
Non-recoverable alterations	17.5	76.0	13.3
CC additional distribution load related allowance	1.2	95.2	1.1
IT	3.7	95.2	3.5
Total	**304.2**		**263.1**

Source: CC analysis (figures may not sum due to rounding).
Note: In this table the £0.7 million of distribution load related projects described in paragraph 9.101 have been added into the Distribution OHL project total

9.132 Our estimate of the direct-only elements of BPI's adjusted recommendation is therefore £263.1 million, which compares with a recommendation of £389.2 million including indirect costs (see paragraph 9.108 and Table 9.7). A reconciliation between the original BPI allowance and our CC estimate of direct-only costs is shown in Table 9.11.

TABLE 9.11 **CC reconciliation of BPI core network investment recommendation to CC direct cost only estimate**

	£m
BPI recommendation per report	392.6
Additional ESQCR allowance	+8.0
Add non-recoverable alterations allowance	+17.5
Remove RASW legislation (D44)	–4.4
T26 Ballyumford switchboard project to D5	–14.7
Exclude transmission-load-related projects (except T36)	–11.7
CC additional distribution-load-related allowance (including projects added back)	+1.9
Adjusted total	**389.2**
Indirect costs deducted:	
Indirect cost projects	–30.1
Tree cutting	–29.8
Fault & Emergency and Reactive	–25.1
Estimate of indirect costs embedded in projects	–41.1
Direct-cost-only estimate	**263.1**

Source: CC analysis (figures may not sum due to rounding).

Adjustments required for time periods

9.133 NIE prepared its RP5 submission on the basis of a five-year period. Our cost assessment period runs from April 2012 until September 2017, a 5.5-year period. We therefore considered what adjustments to our core network investment allowance might be necessary given that our cost assessment period was six months longer than the period which NIE had originally assumed in its submission.

9.134 We asked NIE what core network investment it had completed in 2012/13 and what it forecast for 2013/14 based on current run rates. NIE's response is shown below in Table 9.12.

TABLE 9.12 **NIE's actual/forecast core network investment in 2012/13 and 2013/14**

		£ million
	2012/13 actual	*2013/14 forecast*
Core network investment	52.7	59.8

Source: NIE.

Note: Does not include non-recoverable alterations.

9.135 We noted that NIE's forecast for 2013/14 already contained a significant increase in core network investment in the first quarter of 2014. For January to March 2014 NIE forecast £20.7 million of core network investment, as compared with £12.4 million in the comparable quarter in 2013 (an increase of 67 per cent).

9.136 We also noted that BPI had concluded that the proposed investment programme involved a considerable amount of network development.[43]

[43] BPI final report, p30.

9.137 We considered what the implied increase in the annual investment rate would be, assuming a five-year cost assessment period. That is, assuming that NIE completed the remaining core network investment over a three-year period.[44] The result is shown in Table 9.13.

TABLE 9.13 **Implied increase in annual investment rate for core network investment assuming a five-year cost assessment period**

	£m
CC direct-only allowance for RP5 (excluding non-recoverable alterations)*	249.8
CC benchmarked capitalized indirect costs (assume 5-year allowance)	135.1
CC total capex allowance (excluding non-recoverable alterations)*	384.9
Less: core network investment undertaken in 2012/13 and forecast for 2013/14	–112.5
To complete	272.4
Per year (assuming 3 years remaining, work completed evenly in this period)	90.8
Uplift on 2012/13 actual (%)	72.3

Source: CC analysis.

*Excluding non-recoverable alterations to make comparison on a like-for-like basis.

9.138 Table 9.13 above shows that, assuming a five-year cost assessment period, a 72.3 per cent increase in annual run rate for core network investment would be required. If we instead assume a 5.5-year cost assessment period, the increase in annual run rate falls to 47.6 per cent.[45] In our view, this still represents a challenging increase in run rate for the remainder of RP5.

9.139 We considered whether the implied increase in core network investment for the remainder of the cost assessment period was so great that our allowance should be reduced. We decided against this approach because, while the run rate is challenging, all the projects included in our allowance had been assessed as being well-justified in RP5.

9.140 We then considered which of the projects recommended by BPI, we should adjust (ie increase by 10 per cent)[46] in order to make the allowance appropriate for our longer cost-assessment period. In our provisional determination, we decided that it was not appropriate to scale up the vast majority of core network investment projects. This was because we considered that the investment ramp-up was already very challenging and that the vast majority of projects could simply be delivered to a slightly later date. Of the direct capex projects, we only scaled up non-recoverable alterations, which increased our direct-only core network allowance by £1.2 million.[47]

9.141 In response to our provisional determination NIE said that, in addition to the £1.2 million we had allowed for non-recoverable alterations, it was also necessary to make two additional adjustments to our allowance. These amounted to £13.4 million and were in respect of:

(a) *Load-related network reinforcement.* This related to projects D22 to D38. NIE said that the extra six months to September 2017 would coincide with the preparation of the network for the following winter peak in demand. The work for these projects was normally done in spring to autumn during periods of lower demand when load can be transferred off the stressed parts of the network. NIE

[44] Here we assume two completed years (April 2012–March 2014) leaving three years remaining of a five-year cost assessment period.
[45] Total capex £438.8 million (5.5 years of indirect costs) minus £114.8 million completed leaves £324 million over 3.5 years (£92.6 million).
[46] To adjust for a 5.5-year revenue control rather than a 5.0-year revenue control, ie 5.5/5.0 = 1.1.
[47] All Indirect cost allowances were, including those relating to capex, were time dependent and therefore scaled up.

said that a full year's direct-cost load-related expenditure of £4.1 million was therefore required.[48]

(b) *Rolling programmes.* This related to projects D7, D8, D9, D10, D11 and D15. NIE said that a significant portion of the work was in rolling programmes which NIE had been carrying out for a number of years, for example overhead line work which was carried out to a 15-year cycle. NIE said that the CC's proposal would mean changing the length of these cycles. It said that finance for such programmes for the six-month extension period should be provided in full at the pace originally proposed because the work had been fully justified and NIE had no concerns with respect to resourcing and delivering at that pace. This would require an additional direct capex allowance of £9.3 million.[49]

9.142 In BPI's response report, it said that:

(a) while it was generally true that the majority of load-related reinforcement would need to be carried out between April and September, some reinforcement work can usually safely take place outside of this period. It said that this was 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. BPI's view was therefore that it would be reasonable to allow for 75 per cent of the overall annual load-related network expenditure for the six-month extension period from April to September.

(b) for rolling programmes, it would be inefficient and impractical for NIE to interrupt its work as NIE would need then face considerable difficulty remobilizing the necessary skilled resources in order to restart the programmes. BPI also recognized that interrupting the rolling programmes could compromise safety at, for example, the customers' premises.

9.143 Based on BPI's view in its response report, we made additional allowances in respect of load related network reinforcement and rolling programmes to reflect the extended control period. These amounted to £3.2 million for load-related network reinforcement (75 per cent of the annual allowance) and £9.5 million for rolling programmes. We also retained the allowance for an additional six months of non-recoverable alterations from our provisional determination (see paragraph 9.140) which amounted to £1.3 million.[50] Together these allowances for the additional six months in our price control period increase our direct cost core network investment allowance for the period by £14.0 million to £277.2 million.

9.144 The planned investment outputs attached to this allowance are outlined in appendixes 9.2 and 9.3.

Determination

9.145 We approached NIE's core network investment allowance in the following way:

(a) We used BPI's report as a starting point. BPI's recommendation was based on those projects which it judged had been sufficiently well justified in NIE's core network investment plan.

[48] £4.5 million being 20 per cent of our distribution-load-related expenditure allowance of £22.6 million.
[49] NIE response to the provisional determination, Chapter 3, Section 3 including Table 3.1.
[50] These additional allowances are slightly higher than those underlying NIE's response because we have increased the direct cost adjustment factor in respect of overhead lines and non-recoverable alterations.

(b) We used BPI's recommendations with regard to the volumes of work that should be completed in RP5.

(c) We applied additional scrutiny to three of NIE's projects, which struck us as requiring an additional review (see paragraphs 9.34 to 9.78). On this basis we added an additional £8 million to NIE's allowance for complying with ESQCR legislation (Projects D43 and T40).

(d) We made additional adjustments in respect of non-recoverable alterations (see paragraphs 9.79 to 9.84), RASW legislation (see paragraphs 9.86 to 9.90), the T26 Ballyumford switchboard project (see paragraphs 9.91 to 9.94), an additional allowance for distribution-load-related expenditure (see paragraphs 9.95 to 9.100) and excluding all but one Transmission load related projects (see paragraphs 9.102 to 9.107).

(e) After making the adjustments in *(c)* and *(d)* our adjusted core network investment allowance was £389.2 million (see paragraph 9.108).

(f) We then adjusted this allowance to reflect only direct costs. Our direct-only core network investment allowance was £263.1 million (see paragraphs 9.109 to 9.132).

(g) Finally, adjusting our direct-only allowance for a longer cost-assessment period increased our allowance to £277.2 million for RP5 (see paragraphs 9.133 to 9.143).

(h) The planned investment outputs attached to this allowance are outlined in appendixes 9.2 and 9.3.

10. Other elements of cost assessment

Introduction

10.1 This section addresses other elements of our cost assessment that are not covered in either our assessment in Section 8 (NIE's indirect costs and its costs of IMF&T) or Section 9 (NIE's direct costs or its network investment).

10.2 Our approach to cost assessment differed from that taken by the UR, in particular in relation to our assessment of IMF&T costs. We placed greater weight than the UR on estimated cost benchmarks from comparisons of the costs of the GB DNOs and less weight than the UR on NIE's historical costs or NIE's forecasts. As a result, some of the specific criticisms that NIE made in its Statement of Case about the UR's cost assessment were not directly relevant to our approach. Nonetheless, we took account of NIE's submissions, and the analysis underpinning the UR's RP5 final determination, as part of the application of our approach.

10.3 In addition to the cost allowances for NIE that we determined in Sections 8 and 9, we identified three grounds for additional cost allowances or adjustments:

(a) Some categories of costs (eg rates and licences fees) are not included in the cost benchmarks used in Section 8. Nor are they covered in our assessment of NIE's network investment direct costs. We made separate allowances for them.

(b) We make adjustments for differences in the services or outputs provided by NIE compared with the GB DNOs that we used for our benchmarking analysis. For example, NIE installs and replaces electricity meters and carries out meter reading and we make separate assessments of the costs of these services.

(c) We consider potential adjustments for the impact on costs of anticipated changes in the services, outputs or obligations that NIE faces—to the extent that these are not already captured in the cost allowances set using GB DNO cost benchmarks.

10.4 Table 10.1 sets out the different elements of costs covered in this section and provides the rationale for their inclusion by reference to these points.

TABLE 10.1 **Cost allowances and adjustments**

Cost item and cross-reference	*Rationale for separate cost assessment or adjustment*
Rates under the Valuation (Electricity) Order (Northern Ireland) 2003 (paragraphs 10.9–10.24)	Not covered in our benchmarking analysis of indirect and IMF&T costs or in our assessment of NIE's network investment direct costs Business rates incurred by GN DNOs are reported as part of 'non-activity-based costs' and are not included in either direct or indirect costs
Licence fees (paragraphs 10.25–10.30)	Not covered in our benchmarking analysis of indirect and IMF&T costs or in our assessment of NIE's network investment direct costs Licence fees incurred by GB DNOs are reported as part of 'non-activity-based costs' and are not included in either direct or indirect costs
Direct costs of network investment embedded in managed service charge (paragraphs 10.31–10.42)	Some of the costs of the activities covered by the 'managed service charge' charged by NIE Powerteam to NIE qualify as the direct costs of NIE's network investment, but are not included in our assessment of NIE's network investment direct costs in Section 9
Non-network capex: ICT (paragraphs 10.43–10.75) Non-network capex: other items (paragraphs 10.76–10.105)	Non-network capex not covered in our benchmarking analysis of indirect and IMF&T costs or in our assessment of NIE's network investment direct costs.
Metering capex (paragraphs 10.106–10.150)	Services provided by NIE that are not provided by GB DNOs
Metering reading (paragraphs 10.151–10.161)	Services provided by NIE that are not provided by GB DNOs
Other operating costs related to Keypad meters (paragraphs 10.162–10.164)	Services provided by NIE that are not provided by GB DNOs
Overheads for metering and market opening (paragraphs10.165–10.183)	Administrative costs and overheads for services provided by NIE that are not provided by GB DNOs
Enduring Solution opex (paragraphs 10.184–10.268)	Services provided by NIE that are not provided by GB DNOs
Connection charges funded through RAB, including housing sites with 12 or more dwellings (paragraphs 10.269–)	Time-limited 'subsidy' to certain connection charges from use of system charges Costs of subsidy not covered in cost base for GB DNO benchmarking analysis
33 kV network reinforcement for small-scale generation (paragraphs 10.303–10.319)	Costs of reinforcement work following connections of small-scale generators that are not covered in our capex assessment
Cluster infrastructure (paragraphs 10.320–10.337)	Costs of constructing new shared infrastructure for multiple generators connecting to the network rather than connecting each individually.
Storm costs in atypical severe weather (paragraphs 10.338–10.352	Not covered in our benchmarking analysis of indirect and IMF&T costs The Ofgem data report we have used reports costs relating to atypical severe weather events separately and we have not included these in our benchmarking
Costs associated with aggregated generator units (paragraphs 10.353 and 10.354)	Services provided by NIE that are not provided by GB DNOs
Legacy Dt costs (paragraphs 10.355–10.368	Costs relating to prior approvals by the UR that are not covered in our benchmarking analysis or our capex assessment

Source: CC.

10.5 This section considers each element in turn.

10.6 In addition, we considered whether our cost allowance for NIE should be offset by an estimate of revenues that NIE expects to receive from other sources which we have not already taken account. We made adjustments for the element of connection charges associated with operation and maintenance (O&M) (paragraphs 10.369 to 10.372) and NIE's tort and scrap income (see paragraphs 10.378 to 10.390).

10.7 We also discuss several issues raised by the parties that we took into account as part of our determination of a cost allowance for NIE, namely research and development, road and street works legislation, enhanced regulatory reporting requirements, information leaflets and advertising in relation to ESQCR, workforce renewal, distribution service centre: additional operating costs, and PAS 55 certification (paragraphs 10.448 to 10.450).

10.8 Finally, our cost assessment did not seek to make adjustments for the anticipated transfer of transmission planning activities to SONI. We discuss the implications of the SONI transfer for our determination at the end of this section (paragraphs 10.451 to 10.456).

Rates under the Valuation (Electricity) Order (Northern Ireland) 2003

10.9 NIE pays rates in respect of its network, under the Valuation (Electricity) Order (Northern Ireland) 2003. These are determined by reference to formulae based on transmission circuit length and MVA transformer capacity.

10.10 In its Statement of Case, NIE forecast rates liabilities of £69 million over the RP5 period (2009/10 prices). Tables 10.2 and 10.3 below provide a decomposition of the rates forecast provided in NIE's original Statement of Case. NIE provided forecasts in 2009/10 prices and nominal prices. The figures are for financial years running from 1 April to 31 March.

TABLE 10.2 **NIE forecast of rates**

£ million, 2009/10 prices

	2012/13	*2013/14*	*2014/15*	*2015/16*	*2016/17*
Core	12.6	12.7	12.7	12.8	12.9
Renewables and North–South Interconnector	0.5	0.7	1.0	1.4	1.6
Total	13.1	13.4	13.8	14.2	14.5

Source: NIE.

TABLE 10.3 **NIE forecast of rates**

£ million, nominal prices

	2012/13	*2013/14*	*2014/15*	*2015/16*	*2016/17*
Core	14.2	14.8	15.3	15.8	16.4
Renewables and North–South Interconnector	0.6	0.8	1.2	1.8	2.1
Total	14.8	15.6	16.5	17.6	18.5

Source: NIE.

10.11 NIE's forecasts above distinguish between the rates liability for its 'core' network and the liability associated with network expansion including investment in the planned North–South interconnector and investment to accommodate renewable generation.

10.12 During the inquiry we asked NIE for updated forecasts. NIE said that its forecast in respect of the core network (ie excluding renewables and North–South interconnector) remained as used in its Statement of Case and reproduced above under 'core'.

10.13 NIE said that its forecast rates liability associated with renewables and the North–South interconnector would depend on the roll-out of these programmes, which had been delayed. NIE subsequently provided an updated forecast of its additional rates liability associated with renewables and the North–South interconnector. NIE said that its updated forecasts 'have reduced significantly due to delays in the roll-out of renewables projects plus the delay in the North/South Interconnector project'. NIE's updated forecasts were for no additional rates liability under the heading 'Renewables and N/S Interconnector' in the years 2012/13, 2013/14 and 2015/16 and a liability of around £0.1 million in 2015/16 and 2016/17.

10.14 NIE cautioned that its forecasts beyond 2015 were speculative at this stage since a rating revaluation was expected to take place in 2015 and this would change the key variables on which the rates were based.

10.15 NIE also provided information on actual and provisional rates liabilities in 2012/13 and 2013/14:

(a) NIE's actual rates liability for 2012/13 was £14.2 million (nominal prices). This is in line with NIE's (nominal) forecast for 2012/13 for 'core' rates above.

(b) NIE received a rates bill of £14.6 million for 2013/14 (nominal prices). NIE said that this bill was an estimate and potentially subject to revision. This figure is about £0.2 million less than NIE's nominal forecast for 'core' rates above.

10.16 This information shows that for 2012/13 and 2013/2014, an allowance for rates based on NIE's forecast liability for what it calls 'core' network would have been sufficient to cover its total liability (£0.2 million more than sufficient if the rates bill for 2013/14 is not revised).

10.17 We made a cost allowance for NIE's rates liability based on its forecast for core rates above in Table 10.2.

10.18 We also needed a forecast that runs to 30 September 2017, whereas NIE's forecasts run to 31 March 2017. For the six-month period from 1 April 2017 to 30 September 2017, we calculated an allowance by extrapolating NIE's core forecast to produce a figure of £13.0 million for the financial year from 1 April 2017 and dividing this by two.

10.19 Our allowances for rates will be subject to RPI indexation. We did not make any RPE or ongoing productivity adjustments as part of the calculation of these allowances for rates.

10.20 We did not consider it necessary to make any additional allowance in relation to NIE's updated forecasts for rates associated with 'renewables' and the North–South interconnector. There appears to be considerable uncertainty about the investment projects that NIE expects to lead to an increase in its rates. Further, under our determinations (see paragraphs 5.250 to 5.269), the development of transmission and interconnection projects would be dependent on a project-level approval by the UR. We decided that, if the UR approves any additional NIE investment projects to increase the capacity of the transmission system, the UR should consider whether delivery of these projects gives rise to any significant incremental rates liability in the period to 30 September 2017 and, if so, include an allowance in the cost assessment for that project approval. Neither the UR nor NIE should seek to use that opportunity to make any adjustments to NIE's price control for changes to NIE's rates liability.

10.21 We recognize that the anticipated rating revaluation could affect NIE's rates. We do not know whether this revaluation will increase or decrease rates. We did not seek to take account of the effect of the anticipated revaluation on our forecasts.

10.22 We did not use the forecasts of NIE's rates contained in the UR's final determination. The UR said that it considered its forecast annual amount of £13.1 million (2009/10 prices) for the RP5 period to be generous to NIE. The UR's figure from its final determination is higher than NIE's recent forecasts. The UR did not seek to revise its rates forecasts ahead of our determination.

10.23 In its response to our provisional determination, the UR urged us to reflect upon the exclusion of rates from the adjustments for RPEs and productivity growth.[1] We reviewed the UR's submissions on this point and decided that there was no basis for a change to the approach we used in our provisional determination. The UR's submissions on this issue overlooked a difference between the way that we set an allowance for rates and the methods used for other elements of the cost assessment.

10.24 For much of our cost assessment work, including the benchmarking analysis of indirect and IMF&T costs and our assessment of network investment direct costs, our calculations used historical data on costs (or unit costs) that applied to a past financial year (eg 2009/10 or 2011/12) and made explicit extrapolations of these costs (relative to the RPI) over the period to 30 September 2017. These extrapolations involved adjustments for our estimates of RPEs and the effects of productivity growth. In contrast, the allowances we set for NIE's rates liabilities are not based on our extrapolations of past costs, but rather on a forecast of future costs provided by NIE. We had no reason to believe that NIE's forecasts were provided on a basis that required a subsequent adjustment for RPEs and productivity growth. We would consider it inappropriate to take those forecasts and apply our adjustments for RPEs and productivity growth.

Licence fees

10.25 We decided that the licence fees set by the UR that NIE is required to pay should be subject to a pass-through mechanism intended to remove NIE's financial exposure to these costs and to pass them on to consumers.

10.26 We decided on a mechanism in which we include in the calculation of the price control a forecast of NIE's licence fees for each year of the price control and combine this with an adjustment mechanism for any differences between forecast and out-turn licence fees.

10.27 In its calculations for its final determination, the UR had used a figure of £0.8 million for licence fees for the first year of its RP5 final determination, and figures for subsequent years that declined by 5 per cent per year.

10.28 NIE told us that its actual licence fees incurred in 2012/13 and 2013/14 were £1.0 million and £2.2 million respectively in nominal prices or £0.9 million and £1.9 million in 2009/10 prices.

10.29 We did not consider the potential trajectory of licence fees in any detail, especially given the impact of the pass-through mechanism which limits the importance of these forecasts.

10.30 We used in our calculations a forecast of £1.9 million per year, which reflects the most recent information available to us.

[1] UR response to provisional determination, paragraphs 55–60.

Direct costs of network investment embedded in managed service charge

10.31 In its response to our provisional determination, NIE said that we had failed to provide an allowance for the direct costs incurred by NIE Powerteam and recovered from NIE under the 'Managed Service Charge'. NIE said that the relevant costs would be reported as direct network investment costs under Ofgem's cost reporting framework but that these costs were not included in either the capex plan that we had used for our assessment of NIE's direct network investment costs (Section 9) or our allowance for indirect costs based on GB DNO cost benchmarks (Section 8). NIE said that the direct cost element of the managed service charge was £1.6 million in 2011/12 and requested that we include in our determination an annual allowance of £1.6 million for these costs.[2]

10.32 NIE explained that the costs covered by the NIE Powerteam managed service charge included the costs that NIE Powerteam reported as 'technical engineers' and as 'ops and outage'.[3]

10.33 The 'technical engineers' were involved in the commissioning of new HV switchgear and transformers and HV cable fault location. NIE estimated that 69 per cent of the direct costs attributed to 'technical engineers' would be categorized as a network investment direct cost under Ofgem's RIGs. The remainder would fall under network operating costs. NIE estimated the figure of 69 per cent using timesheet data.

10.34 The costs reported under the 'ops and outage' category concerned switching duties on the system that were necessary to isolate and restore supply and carry out voltage checks. NIE estimated that 50 per cent of direct costs of 'ops and outage' were attributable to network investment (excluding connections), with the remainder attributable to work on new connections and network operating costs.

10.35 NIE's request for an additional allowance of £1.6 million was based on the costs attributed to these two cost categories in 2011/12:

(a) the costs reported for NIE Powerteam 'technical engineers' (£1.48 million), multiplied by 69 per cent; and

(b) the costs reported for NIE Powerteam 'ops and outage' (£1.13 million) multiplied by 50 per cent).

10.36 NIE explained that the costs falling under the managed service charge had formed part of its original forecasts of capitalized overheads. We had not made any explicit allowance for NIE's forecasts of capitalized overheads as we expected the costs falling under capitalized overheads to be entirely indirect costs. However, on review of NIE's submissions on the managed service charge, we found that this was not the case. We accepted NIE's argument that these costs would be categorized as network investment direct costs under the Ofgem cost categories and that we had not provided an allowance for them through either our allowance for indirect and IMF&T costs from Section 8 or our assessment of network investment direct costs in Section 9. We decided that we should include in our determination a separate allowance for the direct costs of network investment embedded in managed service charge.

10.37 We reviewed NIE's submissions on the appropriate level of allowance. Partly prompted by concerns that the UR had raised on the allowance sought by NIE, we asked a series of further questions to NIE about the costs falling under the managed

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[2] NIE response to provisional determination, pp28–29.
[3] ibid, p29.

service charge. We established that the calculations underpinning the allowance sought by NIE overlooked the fact that some of the costs attributed to 'technical engineers' would be related to connections work outside the restriction on NIE's maximum regulated revenue. We asked NIE to provide estimates of the 'technical engineers' costs attributable to connections. We did not accept NIE's initial response to this request (an allocation of 5 per cent) as it seemed small in the context of NIE's description of the role of 'technical engineers' and the scale of NIE's connections activity.

10.38 NIE subsequently provided revised estimates, which were that for 2011/12 the share of 'technical engineers' time on connections (demand and generation) was 27.3 per cent. NIE told us that the extent to which that share of 27.3 per cent was representative of the expected balance of 'technical engineers' work over the price control period would depend on the volatile flow of demand and generation connections work, in particular large-scale generation. NIE said that its early estimates suggested that the share in 2012/13 was in the range 12 to 13 per cent. NIE also provided estimates of the share of 'technical engineers' time on connections of 6.9 per cent in 2009/10 and 7.1 per cent in 2010/11.

10.39 Our allowance for the direct costs of network investment embedded in the managed service charge is based on an average of relevant costs over the three-year period from 2009/10 to 2011/12. We decided that it was more appropriate to take an average rather than a single year's data, to avoid the allowance being unduly influenced by any year-to-year fluctuations in costs or cost allocations. We did not use NIE's 'early estimates' for 2012/13 because these were preliminary estimates made before the end of the year and because we did not have relevant cost data for 2012/13.

10.40 For the 'ops and outage' component, we used NIE's estimates that 50 per cent of the costs reported for NIE Powerteam in this category were direct costs of network investment (excluding connections costs). This provided costs of £0.56 million in 2009/10, £0.53 million in 2010/11 and £0.57 million in 2011/12.

10.41 For the 'technical engineers' component, we revised NIE's initial estimate that 69 per cent of the costs reported for NIE Powerteam in this category were direct costs of network investment to remove the costs that NIE subsequently attributed to connections work. Specifically, we deducted from NIE's original estimate of 69 per cent the proportion of costs that NIE attributed to connections work (6.9 per cent in 2009/10, 7.1 per cent in 2010/11 and 27.3 per cent in 2011/12). This revision provided costs for 'technical engineers' of £0.80 million in 2009/10, £0.75 million in 2010/11 and £0.62 million in 2011/12.

10.42 Summing across the 'ops and outage' and 'technical engineers' components and taking an average across the three-year period, we determined an annual allowance for the direct costs of network investment embedded in the managed service charge of £1.27 million.

Non-network capex: ICT

Background

10.43 NIE incurs ICT costs in running its network. Historically these costs were treated as an opex allowance for tariff purposes because the replacement cycles for these items are substantially shorter than for most network-related capex.[4]

10.44 NIE forecast a requirement for £15.1 million for non-network capex in RP5. This represented an increase of 49 per cent on the RP4 out-turn of £10.2 million. A summary breakdown of this forecast is shown below in Table 10.4.

TABLE 10.4 **NIE's non-network capex forecast**

	£ million	
	RP4	*RP5*
IT Infrastructure	4.5	5.9
Corporate telecoms	1.6	1.4
Business IT	4.0	7.7
Total	10.2	15.1

Source: NIE.

Note: The total includes an additional £0.1 million for Renewables Development Group which has not been included as a separate category.

10.45 The UR allowed NIE £7.6 million for non-network capex in its RP5 final determination.

Views of the parties

10.46 NIE said that non-network ICT capex consisted of three main components. It said that its cost forecast was built from the bottom up:

(a) *IT infrastructure (£5.9 million)*. This investment is required to upgrade and develop the data centre and desktop hardware used to operate and access NIE's business applications. The need for refresh is driven by five-year replacement cycles for all equipment with the exception of laptops, where the cycle is three years.

(b) *Telecoms infrastructure (£1.4 million)*. This investment is required to upgrade and develop NIE's business voice and data telecoms network. The need for refresh is driven by five-year replacement cycles for business voice and data telecoms equipment.

(c) *Business applications (£7.7 million)*. This investment is required to introduce the IT applications needed to meet new business requirements and upgrade existing applications to maintain supportability.[5]

10.47 NIE said that the 49 per cent (£5.0 million) increase in forecast expenditure for RP5 compared with RP4 was driven by two main factors. These were:

[4] NIE Statement of Case, pp177&178.
[5] ibid, p179.

(a) Several large hardware components will reach end of life during RP5; minimal expenditure had been required in these areas during RP4. This has resulted in an increase of £1.4 million in IT Infrastructure investment for RP5.

(b) There is anticipated spend of £2.8 million on SAP during RP5. This is driven by the need to consolidate NIE financial and materials management functionality (currently provided from the Viridian Group SAP platform) on to the NIE SAP platform being implemented for Enduring Solution, followed by the requirement to upgrade the entire platform at the end of the period.

10.48 NIE said that if we established a mechanism whereby additional items of expenditure could be separately approved by the UR, then NIE was content for £1.4 million of the SAP spend (for a SAP IS-U upgrade) to be removed from the non-network capex submission. A separate approval request for this upgrade project could then be submitted by NIE during the course of RP5.

10.49 NIE submitted that the non-network capex proposed in the UR's final determination was inadequate and did not allow it to ensure that important ICT applications and infrastructure remained fit for purpose through RP5.[6]

10.50 It said that the UR had ignored the recommendations made by Gemserv (the UR's consultants) when making its allowance for RP5. With regard to the Gemserv report NIE said that: it was it was unclear on what basis Gemserv had developed its allowance; and it was unclear why Gemserv's more superficial approach was more appropriate than NIE's detailed bottom-up review.

10.51 NIE said that Powerteam did not incur any ICT capex costs and that therefore no such costs were included in its charges. All non-network ICT capex was incurred by NIE. It said that the reasoning behind the UR's 50 per cent disallowance was therefore wrong.[7] NIE said that its non-network capex submission included costs for the implementation, replacement and upgrade of NIE's IT and Telecoms assets. All of these assets were owned by NIE and none of the depreciation associated with these assets was charged to NIE Powerteam.

10.52 It submitted that there was no double counting of costs;[8] nor was there reason to be concerned with the NIE/Powerteam arrangement as regards cross-subsidy. This is because Powerteam provides services exclusively to NIE and recovers its costs from NIE.

10.53 The UR commissioned Gemserv to review NIE's non-network capex proposal. Gemserv conducted a top-down analysis of NIE's requirements for RP5 because it could not reconcile the NIE bottom-up cost table with the supporting evidence. It concluded that:

(a) there was insufficient information to provide an independent view of the NIE request, especially because NIE had varying degrees of confidence in its own cost projections;

(b) it agreed with the principle of IT System rationalization, but the benefits of migrating legacy systems to SAP had not yet been proved; and

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[6] ibid, p182.
[7] ibid, p178.
[8] The UR said that this statement contradicted the information provided to the UR in the BPQ on 11 February 2011 and subsequently submitted to the CC with NIE's Statement of Case.

(c) there was no proven business case to support some of the non-critical business items included in the planned investment portfolio.

10.54 Gemserv said that it had therefore concluded that using RP4 as the basis for the allowance during RP5 was the most appropriate way forward. It said that using this approach it believed that an allowance of £12.3 million for RP5 should be adequate for NIE's requirements and allow it to comply with its licence obligations during RP5. Table 10.5 below summarizes Gemserv's conclusions.

TABLE 10.5 **Gemserv's conclusion on non-network capex for RP5**

£'000

	Predicted RP4 out-turn	*Gemserv recommended changes for RP5*	*Proposed allowance for RP5*
IT infrastructure	4,540	250	4,790
Corporate telecoms	1,634	–235	1,399
Business IT	4,042	725	4,767
Renewables development group	6	74	80
SAP finance		750	750
Business innovation		500	500
Total	10,222	2,064	12,286

Source: Gemserv.

10.55 It can be seen from Table 10.5 that Gemserv made a number of adjustments to the RP4 out-turn to reach its allowance of £12.3 million. These were:

(a) *IT infrastructure.* An additional allowance of £250,000 was included to cover items such as additional security and other Internet infrastructure requirements.

(b) *Corporate telecoms.* Gemserv found no reason to disagree with NIE's proposed budget for RP5, which was for a reduction of £235,000 compared with RP4.

(c) *Business IT applications.* An additional £250,000 was allowed for the UR's requirement for a new reporting system. Gemserv allowed an additional £475,000 for the cost of a street works system,[9] which was 50 per cent of NIE's request. This disallowance was because Gemserv considered that NIE's submission represented the total, rather than incremental, cost of the project. It considered that this allowance might be generous.

(d) *Renewable Development Group.* Gemserv considered that this required new expenditure for RP5.

(e) *SAP Finance.* NIE currently uses the Veridian Group (VG) finance system. This project represents the cost of migrating all finance and materials functionality to a new NIE SAP system (Enduring Solution) from the VG system. Gemserv recommended a 50 per cent reduction in NIE's request in this area. This was because: an element of the cost was necessitated by the sale of NIE to ESB; competitive tendering may reduce the costs further; and the Enduring Solution project is investing heavily in the provision of financial data.

[9] Mainly related to record management.

(f) *Business innovation.* This is an allowance to encourage NIE to look for IT systems to support business innovations that provide customer benefits and drive down costs.

10.56 The UR said that the £12.3 million allowance proposed by Gemserv was not comparable with the £15.2 million NIE forecast. This was because the Gemserv recommendation excluded £1.4 million relating to a partial refresh of Enduring Solution which was deemed not sensible as a stand-alone implementation and which could be delayed until the start of RP6 or incorporated in a future smart metering project. On a like-for-like comparison Gemserv's £12.3 million proposal was therefore only £1.3 million different from NIE's forecast.

10.57 The UR said that it believed that the costs associated with Powerteam should form part of the unit rates or indirect costs which had been benchmarked in other parts of RP5. It said that approximately 50 per cent of the request for non-network capex covered Powerteam staff and this is why it disallowed 50 per cent of the request. It said that NIE had sufficient IT resources to discharge its duties.[10] The costs associated with IT (both capex and opex) should be included within the Business Support costs which we have benchmarked against the GB DNOs.

10.58 The UR said that Powerteam was supposed to be comparable to an independent contractor and therefore any cross-subsidies to a sister company under the price control and double counting of costs should be avoided. It said that NIE did not provide a breakdown between the equipment required for its own staff and those of its sister company.

10.59 The UR said that it did not have confidence that NIE's requested costs were in addition to costs which it had already approved. It said that it did accept that some costs were required and in the absence of tangible evidence it made the assumption that 50 per cent of the request related to Powerteam and 50 per cent to NIE. It said that if it had apportioned costs on the basis of staff numbers this split would have resulted in an allowance of approximately only 25 per cent.

Pelicam advice

10.60 We commissioned Pelicam, a specialist IT Project Assurance consultant, to provide high level advice on NIE's non-network capex submission. Pelicam had access to all relevant non-network capex documentation. In addition, it attended a formal meeting between us, NIE, the UR and Gemserv.

10.61 Pelicam said that NIE was planning to spend £5.9 million on new IT infrastructure during RP5 with no apparent benefit to the customer other than 'keeping the lights on'. It said that it was hard to imagine an unregulated company allowing such a large-scale IT investment with zero return on investment.

10.62 Pelicam took the view that NIE could not demonstrate that it was approaching least cost for its IT opex. It concluded that NIE could reduce its IT opex through a combination of competitive bidding, some degree of offshoring and further IT infrastructure optimization.

10.63 Pelicam recommended that NIE be awarded £30,000 for an IT specialist to manage a comprehensive legacy software evaluation and testing programme rather than

[10] UR final determination, Appendix D, p81.

£400,000 for modifying legacy software. It thought that £400,000 was a risk-averse provision.

Our decision on non-network capex and RP5 forecast

10.64 We considered NIE's BPQ submissions as well as the UR's responses and the Gemserv report which it commissioned. We also asked the parties for clarification and we held a hearing with the parties, our adviser (Pelicam) and the UR's adviser (Gemserv).

10.65 We first considered whether we should apply a discount to NIE's forecast, for the reasons outlined by the UR in paragraphs 10.57 to 10.59. That is because the costs submitted by NIE had already been (or should have been) accounted for elsewhere.

10.66 The evidence submitted by NIE (see paragraphs 10.51 and 10.52 above) stated clearly that there was no double counting of costs between Powerteam and NIE. NIE also said that none of the depreciation associated with the non-network capex assets was charged to Powerteam. We therefore found that it would not be appropriate to disallow any of NIE's submission because of double counting of costs between NIE and Powerteam.

10.67 We then considered whether to use Gemserv's report as a basis for setting the RP5 allowance. This report used a top-down approach based on NIE's RP4 allowance; it concluded that an allowance of £12.3 million was appropriate. Gemserv made allowances for a number of additional projects in the RP5 period (see paragraph 10.55) and also scaled down a number of NIE's projections for RP5.[11]

10.68 While we welcomed the insights which this report provided, we decided against using the same approach because we were concerned that replacement cycles could mean that an appropriate RP5 allowance might be significantly different from the allowance from RP4. For example, significantly fewer (or many more) items may be due for replacement in RP5 compared with RP4.

10.69 We decided to use NIE's BPQ submission as a basis for our RP5 allowance. We then made the following adjustments:

(a) We excluded £1.4 million for an upgrade to the Enduring Solution SAP IS-U platform. This is because the business case for this part of the upgrade had not been finalized. NIE said that it was happy for this to be removed from its submission. In our view, if the business case for this upgrade had not been finalized then it should not be included in the RP5 allowance.

(b) We excluded £400,000 relating to modifying legacy software. This is because both Gemserv and Pelicam believed that this was a very risk-averse provision (see paragraph 10.63). Instead, we included a £30,000 allowance for an IT specialist to manage a comprehensive legacy software evaluation and testing programme, as recommended by Pelicam.

[11] The UR said that Gemserv's analyses did not differentiate between costs incurred by Powerteam and those incurred by NIE. Gemserv did not have visibility of the other work that the UR was undertaking in relation to indirect cost benchmarking and the overall costs of services provided by Powerteam. The UR based its decision on the totality of the information available to it, not only this one report.

(c) We excluded £350,000 relating to RASW legislation. NIE said that removing the additional RASW requirements would reduce required investment to £0.75 million (from £1.1 million) during RP5.

10.70 Items *(a)* to *(c)* in paragraph 10.69 above amount to total reduction in NIE's allowance for RP5 of £2.12 million. NIE's RP5 submission was for £15.05 million. Our allowance for non-network capex in RP5 was therefore £12.93 million, which represents a 26 per cent increase in expenditure compared with RP4.

10.71 We considered whether we should increase this allowance to reflect a longer RP5 period than was envisaged by NIE when it prepared its submission (our RP5 period ends in September 2017 rather than March 2017). NIE's actual expenditure on non-network capex in 2012/13 was £1.48 million and it forecast expenditure of £3.75 million in 2013/14.

10.72 We noted that this allowance related to capex items, rather than expenditure on overheads. We did not consider that there was any reason why these capital investments could not be made over a slightly longer period (an additional six months) and we therefore made no adjustment this. Our allowances use NIE's actual and forecast expenditure in 2012/13 and 2013/14; we then spread the remainder of the RP5 allowance evenly over the remaining 3.5 years of RP5 (which amounts to an annual allowance of £2.2 million for 2014/15 – September 2017)

Treatment of non-network capex as opex

10.73 Non-network capex is currently treated as an opex item rather than being capitalized into the RAB and expensed over a number of years. This means that this expenditure is paid for immediately by current customers rather than being spread over a number of years. We considered whether it was in the public interest for this treatment to continue.

10.74 The RAB is a means of allowing NIE to recover capital investments over a suitable period determined by the regulator. In our view the most appropriate treatment for capital items such as non-network capex is for them to be capitalized and depreciated over a time period which broadly reflects their asset life. Treating capital items in this way should ensure that the balance between current and future tariffs is appropriate (so that, broadly, consumers at any moment are paying a fair share of the costs of capital investments). Expensing non-network capex immediately is at odds with this and risks penalizing current consumers for the benefit of future consumers. For this reason, we found that treating non-network capex as opex was not in the public interest.

10.75 NIE's main RAB is expensed over 40 years. Capitalizing non-network capex into this RAB would result in it being expensed over a period much greater than its asset life. We therefore concluded that NIE should create a separate RAB for expenditure on non-network capex and other short-life assets (such as tree cutting—see Section 15). This new RAB should have an asset life of five years.[12]

[12] We note that the replacement cycle for non-network capex is generally five years or less (NIE Statement of Case, pp177 & 178).

Non-network capex: other items (non-ICT)

Background and views of the parties

10.76 Following our provisional determination, NIE said that we had not included an allowance in respect of anticipated purchase of the following GB RIG non-operational capex items: vehicles, non-operational premises, plant and machinery, small tools and equipment, and office equipment. During RP4, expenditure on these five items averaged £1.5 million a year and varied between £1.0 million and £2.0 million. In 2012/13, expenditure on these items amounted to £1.1 million and NIE forecast total expenditure of £9.3 million for RP5.

10.77 NIE said that, in addition, the provisional determination contained no mechanism through which NIE could recover the undepreciated historic costs of these non-operational assets and that without an additional allowance, these costs would be 'stranded'. It said that in order to recover fully the net book value as at 31 March 2012, an adjustment of £2.4 million in RP5 was necessary.

10.78 NIE also said that there was a potential distortion in our benchmarking analysis of NIE's indirect and IMF&T costs that may arise as a result of differences between companies in how vehicles are sourced (ie whether vehicles are leased or owned). If vehicles were leased, the costs would be recorded under indirect costs, whereas if vehicles were purchased, the costs would be recorded under non-operational capex. NIE raised concerns that such a distortion to our benchmarking analysis could have a significant detriment to NIE under the approach to cost assessment we have taken.

10.79 The UR said that, whilst it appeared that no allowance had been made for the items of non-operational capex referred to by NIE (see paragraph 10.76), in its view the approach taken in the provisional determination meant that efficient levels of capital expenditure had been accounted for. It said that the approach taken by BPI inherently included a judgement of efficient levels of capital expenditure based on Powerteam charge-out rates and that these charge-out rates included non-operational capex. It said that this also applied to NIE's claims for stranded non-operational capex costs. The UR did not consider any adjustment warranted in relation to the potential benchmarking distortion identified by NIE.

Structure of our assessment

10.80 We take the following elements of NIE's assessment in turn:

(a) NIE Powerteam assets used for NIE's activities ;

(b) NIE Powerteam tools and equipment costs; and

(c) capex related to non-operational premises.

10.81 We consider NIE's submissions on distortions to the benchmarking analysis relating to vehicle leasing in paragraphs 8.108 – 8.115..

NIE Powerteam assets used for NIE's activities

10.82 The vast majority of the additional costs identified by NIE in its submissions on non-operational capex relate to capital assets owned by NIE Powerteam.

10.83 NIE Powerteam has some assets which are used in the provision of services to NIE. These NIE Powerteam assets include vehicles, mobile plant, fixtures and fittings and computer software.

10.84 NIE Powerteam's statutory accounts provide the following information (converted to 2009/10 prices):

(a) NIE Powerteam's net book value of property, plant and equipment and intangible assets (eg software) was £2.55 million in 2009/10, £2.74 million in 2010/11 and £2.64 in 2011/12.

(b) NIE's Powerteam's depreciation charge for property, plant and equipment and amortization of intangible assets was in total £0.81 million in 2009/10, £0.88 million in 2011/12 and £0.93 million in 2011/12.

10.85 The Powerteam capital assets are not part of NIE's RAB and do not contribute to the allowed return or regulatory depreciation charges under NIE's current price control licence conditions.

10.86 We examined whether the allowances we set in our provisional determination included any of these costs. We asked NIE for further information on the calculations that its consultants had used to produce estimates of NIE's costs on a direct cost basis. We confirmed that neither NIE Powerteam's depreciation charge nor an allowance for the financing costs of its capital assets was included in:

(a) the adjusted hourly rate that had been used by NIE's consultants to produce estimates of the direct costs unit costs for NIE's network investment programme (we used these direct cost unit costs in Section 9); and

(b) the adjusted hourly rate that fed into the estimates of NIE's IMF&T costs (a type of direct cost) that fed into our cost benchmarking exercise in Section 8.

10.87 We also confirmed that NIE Powerteam's depreciation charges and profit margin were not included in our estimate of NIE's indirect costs, which we used for our benchmarking of indirect and IMF&T costs.

10.88 We decided that it was appropriate to make an adjustment to the cost allowances we set in Sections 8 and 9 to provide for the economic costs of NIE Powerteam's capital assets used to operate, maintain and develop NIE's transmission and distribution systems (excluding costs attributed to connections costs which are funded by customer contributions).

10.89 We did not consider it practicable to carry out a detailed review of NIE's forecasts of NIE Powerteam investments in non-network capex and the needs case for the specific investments expected by NIE. Instead, we decided to rely on information on NIE's past costs, using information on the depreciation and net book value of NIE Powerteam's assets as a guide to the economic costs of NIE Powerteam's asset, which had been omitted from our provisional determination.

10.90 For the years 2009/10, 2010/11 and 2011/12, we took information from NIE's detailed cost allocation for NIE Powerteam and NIE Powerteam's statutory accounts and produced an estimate of the costs associated with NIE Powerteam's assets. We used the following approach:

(a) We took NIE Powerteam's depreciation charge and deducted the depreciation charge allocated to meter reading (the depreciation reported for meter reading has fed into our separate cost assessment for meter reading).

(b) We calculated an approximate allowed return (or financing costs) for the NIE Powerteam capital assets by taking the net book value of its assets in each year and multiplying by a 10 per cent rate of profit. That rate of return figure was intended as an approximation in nominal terms on a pre-tax basis.

(c) We took the sum of *(a)* and *(b)* and deducted 20 per cent. NIE had provided information to us in relation to the indirect and IMF&T costs benchmarking analysis, which indicated that around 20 per cent of NIE Powerteam staff (including apprentices) were attributed to connections activities.

10.91 Table 10.6 shows the outcome of these calculations.

TABLE 10.6 **Calculation of approximate NIE Powerteam capital asset costs**

£ million, 2009/10

Cost item	*2009/10*	*2010/11*	*2011/12*
NIE Powerteam depreciation, excluding depreciation allocated to meter reading	0.76	0.82	0.85
Allowance for 10% return on net book value of NIE Powerteam capital assets	0.26	0.27	0.26
Total	1.02	1.10	1.11
Total less costs attributed to connections	0.81	0.88	0.89

Source: NIE / CC analysis.

10.92 In light of these calculations, we decided that our cost assessment should include an additional allowance of £1 million a year in relation to the costs of NIE Powerteam's assets used for NIE's transmission and distribution activities (excluding connections activities which are funded from customer contributions). This allowance is slightly higher than the costs in Table 10.6, which provides for some growth in costs resulting from any increase in NIE Powerteam's workload.

10.93 Some of the NIE Powerteam capital costs relate to activities carried out by NIE for which costs are capitalized (eg network investment) and some relate to activities carried out by NIE for which costs are not capitalized (eg the element of IMF&T costs that is not capitalized). We decided that these costs should be allocated 80 per cent to NIE's capex allowances (ie forming part of NIE's RAB additions) and 20 per cent to opex. The figure of 80 per cent reflects our estimates of the approximate proportion of NIE Powerteam direct costs that are capitalized over the period 2009/10 to 2011/12.[13] We decided that the costs allocated to capex allowances should be allocated between the transmission, distribution and the distribution and transmission five-year RABs in approximate proportion to the capex allowances for these RABs.

10.94 We did not consider it necessary to adopt the approach to non-operational capex that NIE proposed in its submissions following our provisional determination. NIE essentially sought that our determination for the period from 1 April 2012 to 30 September 2017 should include: (*a)* NIE's forecasts of the purchase costs of new NIE Powerteam assets and *(b)* payments of over the 5.5-year price control period of the

[13] We calculated this using information on the NIE Powerteam cost allocation used for our benchmarking analysis in Section 8, combined with information from NIE on the element of IMF&T NIE Powerteam costs that is treated as opex.

residual net book value of NIE Powerteam's existing capital assets. Unless such costs were added to NIE's RAB, it would mean that charges to consumers between 1 April 2012 and 30 September 2017 would include the full purchase costs of any non-operational assets that NIE Powerteam purchased during that period and the depreciated cost of previously purchased capex, even if they provide economic benefits beyond 30 September 2017. We considered that this approach would unduly ignore accounting information on depreciation and could provide an unfair burden of costs on consumers in the short term.

10.95 The approach we adopted is more consistent with the way that the economic costs of NIE Powerteam's capital assets have been recovered and also with what NIE told us about its expectations for the RP5 price control period. NIE told us about how it had originally expected the NIE Powerteam capital costs to be recovered:

> Capital expenditure in respect of vehicles, mobile plant and fixtures and equipment have historically been added to fixed assets and recovered through an annual depreciation charge which was encompassed in the Powerteam hourly rate. In its submission NIE had anticipated that this approach would continue during RP5, providing a mechanism through which these historic costs would be recovered.

In effect, we have set an additional allowance to provide for the recovery of depreciation on NIE Powerteam's assets (eg vehicles, mobile plant, fixtures and equipment and computer software). The allowance we set also includes a return on capital component to recognize the financing costs associated with NIE Powerteam's assets.

10.96 As part of our assessment, we reviewed the UR's submissions in response to NIE's submissions on non-operational capex. The UR said that it considered that the costs we had allowed for NIE's network investment costs in our provisional determination inherently included a judgement on the efficient levels of capex based on NIE Powerteam's charge-out rates, which included non-operational capex. We did not agree with the UR's submissions. As we have set out above, we found that the adjusted NIE Powerteam unit costs used to calculate the NIE network investment unit costs did not include non-operational capex. The submissions from the UR did not address the concern we identified, in light of NIE's submissions, that our provisional determination did not allow for the depreciation and financing costs related to NIE Powerteam's assets.

NIE Powerteam tools and equipment costs

10.97 Following review of NIE's submissions, we found that the cost assessment in our provisional determination did not cover the NIE Powerteam costs reported under the category of 'Tools & equipment'. The Ofgem cost category of 'Small tools and equipment' forms part of non-operational new assets and is outside the categories of network investment direct costs and indirect costs. These costs were not included in the estimates of NIE's unit costs on a direct cost basis (which fed into the assessment in Section 9). Nor were they included in the indirect and IMF&T cost benchmarking analysis presented in Section 8.

10.98 We decided that our cost assessment should include a separate allowance for the NIE Powerteam tools and equipment costs.

10.99 We did not consider it practicable to carry out a detailed review of NIE's forecasts of NIE Powerteam tools and equipment costs. We adopted a similar approach to that for the NIE Powerteam capital costs above, using data on costs in 2009/10, 2010/11 and 2011/12. We took information from the detailed cost allocation for NIE

Powerteam on the NIE Powerteam tools and equipment costs allocated excluding costs reported for meter reading. We then deducted 20 per cent, which represented an allocation of these costs to connections activities outside the scope of the revenue control we determined.

TABLE 10.7 **Allocations of NIE Powerteam tools and equipment costs**

£ million, 2009/10

	2009/10	*2010/11*	*2011/12*
NIE Powerteam tools and equipment costs, excluding costs allocated to meter reading	0.24	0.26	0.29
NIE Powerteam tools and equipment costs, excluding costs allocated to meter reading and costs attributed to connections	0.20	0.21	0.23

Source: NIE.

10.100 In light of Table 10.7, we decided that our cost assessment should include an additional allowance of £0.25 million a year in relation to the costs of NIE Powerteam's tools and equipment costs used for NIE's transmission and distribution activities (excluding connections activities which are funded from customer contributions). This allowance is slightly higher than the costs in the table above, which provides for some growth in costs resulting from any increase in NIE Powerteam's workload.

10.101 Some of the NIE Powerteam tools and equipment costs will relate to activities carried out by NIE for which costs are capitalized (eg network investment) and some relate to activities carried out by NIE for which costs are not capitalized (eg the element of IMF&T costs that is not capitalized). We decided that these costs should be allocated 80 per cent to NIE's capex allowances (ie forming part of NIE's RAB additions) and 20 per cent to opex. The figure of 80 per cent reflects our estimates of the approximate proportion of NIE Powerteam direct costs that are capitalized over the period 2009/10 to 2011/12.[14] We decided that the costs allocated to capex allowances should be allocated between the transmission, distribution and the distribution and transmission five-year RABs in approximate proportion to the capex allowances for these RABs.

Capex related to non-operational premises

10.102 NIE said that our provisional determination did not include an allowance for capex relating to non-operational premises. NIE provided a forecast of £0.18 million in total for such expenditure between 1 April 2012 and 20 September 2017.

10.103 We agreed that the cost allowances from our provisional determination did not include any allowance for capex on non-operational premises. These capital costs are incurred by NIE rather than NIE Powerteam and are not part of the NIE Powerteam capital costs discussed above.

10.104 NIE provided data on its historical spend on non-operational premises between 2007/08 and 2011/12 as well as annual forecasts for the price control period. NIE's capital expenditure on non-operational premises differed across the period, with £0.7 million of expenditure in 2007/08, £0.2 million in 2008/2009 and less than

[14] We calculated this using information on the NIE Powerteam cost allocation used for our benchmarking analysis in Section 8, combined with information from NIE on the element of IMF&T NIE Powerteam costs that is treated as opex.

£0.1 million in the remaining years. NIE's forecasts for non-operational premises expenditure were as shown in Table 10.8.

TABLE 10.8 **NIE forecast of non-operational capex relating to premises**

Period	*NIE forecast*
	£m
2012/13	0.024
2013/14	0.046
2014/15	0.044
2015/16	0.027
2016/17	0.028
2017/18 (first 6 months)	0.014

Source: NIE

10.105 Given the small scale of costs, we did not carry out a detailed review of NIE's non-operational capex (premises) forecast. We decided to accept the forecasts provided by NIE, which did not seem unreasonable in light of the information on past spend since 2007/08. We decided that these should be included in the RAB additions for the new five-year RAB, consistent with the approach we decided for non-operational ICT.

Metering capex

Background

10.106 NIE provides metering services to its suppliers. This covers over 800,000 premises in Northern Ireland. Approximately one-third of NIE's domestic customers have Keypad meters, which are prepayment meters and which have grown rapidly in the last decade. The total population of Keypad meters is approximately 270,000.[15]

10.107 The UR proposed a ring-fenced allowance of £20.5 million for metering in RP5.[16] Its proposal was that NIE would only be paid for the volumes of metering work it actually carried out in RP5; it agreed with NIE the unit cost for each type of metering.

10.108 NIE requested that we increase the allowance for metering by £17 million. It said that it was content that the full amount of £37.5 million would be ring-fenced and subject to logging up or down by reference to the actual amounts expended in RP5.[17] Table 10.9 shows the split of NIE's request, including volumes and costs.

[15] NIE Statement of Case, paragraph 5.3, p99.
[16] UR final determination, paragraph 5.79, p38.
[17] NIE Statement of Case, paragraphs 5.17–5.21, p102.

TABLE 10.9 **NIE's metering capex request for RP5**

	Annual meter volumes	*Unit cost £*	*Annual meter costs £'000*	*RP5 total cost (5 years) £'000*
1. Certification	25,000	23.72	593	2,965
2. Recertification	11,000	23.72	261	1,305
3. Commercial recertification	1,000	242.00	242	1,210
4. Keypad recertification	35,000	76.51	2,678	13,387
5. Keypad 'other'	24,500	81.63	2,000	10,000
6. SOSA—other	19,500	27.80	542	2,710
7. Commercial	3,575	259.86	929	4,645
8. Service and support	N/A	N/A	250	1,250
Total			7,495	37,472

Source: NIE; CC analysis.

*Scheduling of ServicePower Appointments—system used by NIE for scheduling customer appointments for metering work (volumes and costs exclude keypad activities included in category 5 above).
Note: N/A = Not applicable.

10.109 NIE's metering capex request in Table 10.9 can be split as follows:

(a) *Legislation driven (Categories 1–4; £18.8 million in RP5)*. The Certification, Recertification, Commercial Recertification and Keypad Recertification categories are all driven by legislative requirements. Certification involves the replacement of old-style meters which have never been certified. Recertification is driven by a legal requirement to certify meters after a period of time. The certification periods are prescribed in the relevant legislation and it effectively involves replacement of the meter.[18] The largest request in this area for RP5 relates to Keypad meters, which are required to be certified every ten years.[19]

(b) *Growth in Keypad meters (Category 5; £10.0 million in RP5)*. The Keypad 'other' category mainly reflects the continued expected growth in Keypad meters in RP5. It is reflective of NIE's current activity levels.

(c) *Commercial meters (Category 7; £4.6 million in RP5)*. This category reflects meter installations caused by customers changing tariffs, meter replacements and generator meter asset replacement.

(d) *Routine SOSA metering work (Category 6; £2.7 million in RP5).* This category reflects other[20] routine metering work driven by customer demand and managed through the SOSA scheduling system.

(e) *Overheads (Category 8; £1.25 million in RP5).* Service and support are separately identified metering overheads.

Views of the parties

10.110 In this section we summarize the views presented by the parties. This covers: *(a)* metering legislation; *(b)* forecast volumes; and *(c)* forecast unit costs.

[18] The Meters (Certification) Regulations (Northern Ireland) 1998 (the 1998 Regulations).
[19] The relevant legislation actually predates Keypad meters. According to the legislation they have a default certification of ten years.
[20] Other than Keypad appointments; mainly domestic credit meters.

Legislation

- *The UR's submissions*

10.111 The UR said that the 1998 Regulations came into effect on 1 February 1999 and were closely aligned to the equivalent GB regulations. The legislation requires meters to be certified after a specified time period. In a few cases there is a difference in the certification period for the same type of meter between the GB and Northern Ireland regulations.

10.112 It said that there were no relevant differences in the manufacture or use of these meters between the two jurisdictions and that it was aware of no reason why some types of meters should have shorter certification periods in Northern Ireland than in GB. For this reason it considered that the certification period for some types of meter (particularly Keypad meters which were more prevalent in Northern Ireland) were not appropriate and should be changed.

10.113 The UR said that in 2005 it agreed with NIE to scale back meter certification for those meters which had been installed before 1 February 1999 and would need to be certified by [✂]. It had intended to promote legislative change to extend the period within which such meters needed to be certified. However, it was unable to obtain agreement to a legislative change being brought forward.

10.114 The UR said that historically the focus of NIE's work had been on replacing meters which had never previously been certified. However, due to the scaling back of the programme it was conscious that over time there would be an increase in meters with expired certification periods. This would particularly be the case from 2011/12.

10.115 In response to the provisional determination, the UR said that it had appointed an Electricity Meter Examiner (from the National Measurement Office) under the Electricity (NI) Order 1992 and that it was presently liaising with the National Measurement Office and DETI on changes to the 1998 Regulations. It said that it had instructed the Meter Examiner to review and update the 1998 Regulations to align certification periods with those in GB. It said that the outcome of this process meant that an estimated 180,000 meters would move out of the uncertified category back into their updated certification periods. It said that it was also working on its smart metering strategy for Northern Ireland, including a road map for implementation. It considered that as a result there would need to be liaison between itself and NIE during RP5 with regard to developing a three-year implementation plan for metering capex.[21]

- *NIE's submissions*

10.116 NIE said that the 1998 Regulations came into force in 1999, and as a result it established a certification programme targeting the replacement of uncertified 'dumb' meters with certified meters having equivalent (limited) functionality. This work was driven by a statutory obligation to remove all uncertified meters by [✂].[22]

10.117 NIE said that in 2005 this programme was subsequently scaled back with the agreement of the UR. One of the reasons for this was that evidence suggested that the meters being replaced were accurate and they were being replaced with meters

[21] UR response to provisional determination, paragraphs 90–92, and UR response to NIE submissions, UR164.
[22] NIE Statement of Case, p100, paragraph 5.6.

which themselves had limited functionality. NIE said that at this time the UR undertook to make the necessary legislative amendments to ct this change of policy.[23]

10.118 NIE said that its RP5 submissions to the UR assumed that greater progress would have been made in making the regulatory decisions necessary to roll out smart meters (which could replace uncertified meters). In addition it thought that the outstanding legislative amendments would have been completed before the start of RP5.[24]

10.119 NIE said that it was unclear at this stage when any roll-out of smart meters might begin[25] and that [✂] uncertified meters remained in service.[26] It said that as a result it would be necessary to replace the uncertified meter population as soon as possible and that it could not rely on the roll-out of smart metering as the means of replacing uncertified meters in a timely manner.[27] In addition it may face an obligation to recertify Keypad meters, which by default the meter regulations stipulated should be recertified every ten years. NIE said that this was because the 1998 Regulations predated the introduction of Keypad meters and therefore did not specifically prescribe a certification life for Keypad meters, and that any meter type not specifically referred to in the Regulations had a default certification life of ten years.

10.120 NIE said that the impact of certification and recertification was that an additional £17 million would be required to recommence the full meter certification programme that was set aside in 2005: it therefore requested £18.9 million in respect of meter certification and recertification compared with its original BPQ request of £1.9 million.[28] The largest component of this was £13.4 million in respect of Keypad recertification.

10.121 NIE said that it was sceptical as to whether the necessary changes to the 1998 Regulations (to lengthen certification periods) would be achieved by the UR without undue delay. It therefore submitted that any allowance in RP5 should make provision for it to undertake the certification/recertification works required by the current regulations.

10.122 We asked NIE how the UR's proposed legislative change would impact its metering volume forecast. It said that the impact would be limited to Keypad meters; assuming GB certification lives (15 years) the number of Keypad meters requiring certification in RP5 would be [✂] (compared with [✂] if the certification life remained at ten years).

- *DETI*

10.123 We asked DETI how realistic it was to expect the legislative change proposed by the UR to be enacted by early 2014. It said that assuming a standard consultation period for legislation of three months and required Ministerial approval, this timeline, while not necessarily unworkable, would be very challenging.

[23] ibid, paragraphs 5.7 & 5.8, p100.
[24] ibid, paragraphs 5.8 & 5.9, p100.
[25] ibid, paragraphs 5.4 & 5.5, pp99 & 100.
[26] ibid, paragraph 5.8, p100.
[27] ibid, paragraph 5.11, p100.
[28] ibid, paragraph 5.13, p101.

Forecast volumes

10.124 We asked NIE to provide the actual volumes of work which it had completed in each category of metering in 2012/13. NIE provided meter volumes for the period 1 June 2012 to 31 May 2013.[29] These are shown below in Table 10.10.

TABLE 10.10 **NIE meter volumes, 1 June 2012 to 31 May 2013**

'000

	Actual volumes	*RP5 annual volume forecast*
Certification	0	25
Recertification	0	11
Commercial recertification	0	1
Keypad recertification	0	35
Keypad 'other'	22	24.5
SOSA—other	32	19.5
Commercial	5	3.6

Source: NIE.

10.125 It can be seen from Table 10.10 that NIE is not currently undertaking any planned certification/recertification volumes. NIE said that these programmes had not yet commenced pending confirmation of the price control arrangements. Actual volumes in respect of the other two categories ('Keypad other' and 'Commercial') broadly reflect NIE's RP5 volume forecast.

Forecast unit costs

- *The UR*

10.126 The UR said that as part of the RP5 process, its consultants reviewed NIE's unit costs and believed that they were appropriate based on metering approvals it had assessed during RP4. In addition, it said that additional cost analysis was not necessary due to the risk-sharing mechanism which it had proposed.

10.127 In response to our provisional determination, the UR said that the Powerteam average labour cost used to formulate our unit cost allowances in metering was far too high because an efficient operator would use cheap contracting labour to carry out this most basic of tasks.[30] It said that employment costs with external contractors should be based on costs associated with staff currently fulfilling a similar job role within NIE, not an average Powerteam labour rate. It said that, alternatively, NIE could test the market with an external contractor so the UR could be assured Powerteam rates were competitive.

- *NIE*

10.128 We asked NIE if the unit costs submitted in its forecast differed from its recent actual unit costs. We also asked NIE to justify the unit costs contained in its new certification/recertification programme.

[29] Data was provided for this period since this was when SOSA (post Enduring Solution) went live.
[30] UR response to provisional determination, paragraph 94.

10.129 NIE said that its best assessment of recent unit costs for commercial and Keypad metering in 2011/12 and 2012/13 were as follows (see Table 10.11).

TABLE 10.11 **NIE's recent actual unit costs in Commercial and Keypad—Other**

£

	2011/12	*2012/13*	*Submitted in RP5 plan*
Commercial	202	207	260
Keypad—Other	70	74	81.63

Source: NIE.

10.130 NIE said that its submitted commercial unit cost of £260 included an estimated profit element of £[✂].

10.131 In response to our provisional determination, NIE said that the unit costs used by us, which were the simple average of out-turn costs in the last two years, may not be adequately representative of future costs because the mix of commercial work activities in the last two years reflects the economic downturn, with a lower volume of higher-cost metering activities than may emerge during RP5 in line with continuing economic recovery. It said that an appropriately balanced unit cost for commercial metering would be £230, based on a simple average of a credible range of annual costs in the range £200 to £260.[31]

10.132 Table 10.12 shows the unit cost split between materials and labour for the new programmes of certification/recertification work driven by the 1998 Regulations.

TABLE 10.12 **NIE's metering capex request for RP5**

	Unit cost £	*Labour £*	*Materials £*	*RP5 total cost £m*
1. Certification	23.72	[✂]	[✂]	3.0
2. Recertification	23.72	[✂]	[✂]	1.3
3. Commercial recertification	242.00	[✂]	[✂]	1.2
4. Keypad recertification	76.51	[✂]	[✂]	13.4

Source: NIE.

10.133 NIE said that the following assumptions were built into the unit costs outlined above:

(a) *Certification and recertification (1 and 2 above)*. [✂]

(b) *Commercial recertification (3 above)*. [✂]

(c) *Keypad recertification (4 above)*. [✂]

10.134 In response to our provisional determination, NIE said that its current view was that its time estimate for certification and recertification should be increased. It said that this would in turn increase the unit cost allowances by 18 per cent (to £[✂]) for each of the Certification and Recertification work programmes. It said that this was based on a more detailed assessment of how this work would be delivered than was available at the time of its BPQ submission.[32] Specifically, it was based on the labour requirement for Certification and Recertification taking [✂] minutes rather than

[31] NIE response to provisional determination, Chapter 16, paragraphs 1.11–1.17.
[32] ibid, Chapter 16, paragraphs 1.6–1.8.

[✄] minutes. It said that this extra time allowance was required because it was likely that once a metering electrician arrives at a customer's premises where the meter is 30 to 40 years old, they would also face a significant volume of additional work because other routine metering work would only then become apparent. The UR was concerned about this response from NIE. It said that only a limited number of the proportion of meters would be 30 to 40 years old and it said that the additional costs for cut-out replacement were already covered under the asset replacement allowances.

10.135 In addition, NIE said that the Certification and Recertification work programmes would require significant deployment of contractor resources which were not included in its original BPQ submission. These additional costs comprised £0.35 million in 2014/15 for initial mobilization of contractors (including six weeks of training for installers) and ongoing contract management costs of £0.55 million (comprising one new contract manager and six new administrative staff to handle work scheduling and service orders) over 3.5 years from April 2014 to September 2017.[33] In response, the UR was concerned that the 34 additional, untrained contractor meter electricians required to do this work was at an excessive rate and with excessive training allowances.

Our decision on metering and RP5 forecast

10.136 We decided on a similar approach to metering to that proposed by the UR for RP5 (see Section 5). That is, we made an upfront forecast, based on volumes and unit costs. However, an adjustment will be made so that NIE is only paid for the actual volumes of work it completes at a specified unit price.

10.137 This approach recognizes that, given the legislative changes to certification periods currently being pursued by the UR and possible developments in smart metering, actual volumes could be quite different from forecast volumes.

10.138 To make our forecast we therefore examined NIE's volume and unit cost forecasts for RP5.

10.139 NIE's volume forecast for RP5 is shown in Table 10.9 above. We noted that NIE made this forecast with the expectation of fulfilling[34] its current statutory duties in respect of the 1998 Meter Certification regulations. We also noted that NIE was currently undertaking no volumes of work in respect of these regulations (see paragraph 10.125). We considered that there were four options available to us in constructing our metering volume forecast:

(a) Accept NIE's volume forecast; NIE's volume forecast for RP5 would amount to a forecast of £37.5 million based on its unit costs.

(b) Adjust the volumes for 'Keypad meters' to reflect the revised volumes that would apply if metering legislation was changed in line with the UR's proposed timetable outlined in paragraph 10.115 This would result in [✄] Keypad meters requiring certification in RP5 (compared with [✄] if the certification life remained at ten years). This would amount to a £[✄] reduction in the metering forecast submitted by NIE (to £[✄]).[35]

[33] NIE response to provisional determination, Chapter 16, paragraphs 1.9–1.10.
[34] NIE advised that the volumes of meter certification/recertification planned for RP5 fell short of making provision for all meters for which current certification lives will have expired by the end of RP5.
[35] 93,000 fewer Keypad recertifications at a unit cost of £76.51.

(c) Apply NIE’s volumes of recertification/certification from April 2014 only. In this scenario, the volumes of recertification/certification in 2012/13 and 2013/14 would be zero, reflecting the actual outcome in those years. This is because NIE was not undertaking any of this work. The impact of this change in volumes would be to reduce NIE’s forecast by £7.6 million in the period (£3.8 million in each of 2012/13 and 2013/14).

(d) A combination of (b) and (c) above.

10.140 We were concerned that the legislative timeline proposed by the UR would be very challenging (see paragraph 10.123). Equally, given that NIE was currently undertaking no certification/recertification work we decided it would not be appropriate to make provision for volumes of metering which it had not completed. We therefore decided that option *(c)* above was most appropriate. That is, we used NIE’s volume forecast, adjusted to reflect its actual (zero) volumes of recertification/certification in 2012/13 and 2013/14.

10.141 Based on Table 10.11 (see paragraph 10.129), we decided that it was necessary to revise the unit costs assumptions in our metering forecast for each of ‘Commercial’ and ‘Keypad—Other’. We did this so that the unit cost assumptions in these categories of metering better reflected NIE’s recent actual out-turn costs. In each case our revised unit cost represented the average of the 2011/12 and 2012/13 out-turn unit costs: £205 for Commercial and £72 for Keypad—Other. We placed weight on these figures as they provided us with evidence of actual costs. We considered that NIE’s view that the mix of Commercial work would change during RP5 (see paragraph 10.131) was plausible but lacked supporting evidence to suggest that a higher unit cost would be appropriate.

10.142 We considered the unit cost assumptions presented by NIE in respect of its new programmes of certification/recertification (see paragraphs 10.132 and 10.133 above). We did not find any reason to adjust the original forecast unit costs for these categories of work. We found that NIE’s suggested increase in unit costs for certification/recertification, which it proposed following our provisional determination, lacked robust supporting evidence. We therefore decided not to increase the unit costs as NIE suggested. In particular, the additional 6 minutes of time required for each visit was based on the possibility of more work being required when an electrician visits premises.

10.143 We also did not change our unit cost assumptions in light of the UR’s submission that the Powerteam average labour cost used to formulate the CC’s provisional unit cost allowances may be too high. We found it hard to reconcile this with the statement that the unit costs were appropriate based on metering approvals it had assessed during RP4 (see paragraphs 10.126 and 10.127).

10.144 Our volume and unit cost assumptions result in the annual forecast in Table 10.13.

TABLE 10.13 **CC annual metering forecast for RP5**

	Annual meter volumes	*Unit cost £*	*Annual meter costs £'000*
1. Certification*	25,000	23.72	593
2. Recertification*	11,000	23.72	261
3. Commercial recertification*	1,000	242.00	242
4. Keypad recertification*	35,000	76.51	2,678
Annual cost for volumes applying 2014/15—September 2017: £3,774,000			
5. Keypad 'other'	24,500	72.00	1,764
6. SOSA	19,500	27.80	542
7. Commercial	3,575	205.00	733
8. Service and support	N/A	N/A	250
Annual cost for volumes applying 2012/13—September 2017: £3,289,000			

Source: CC analysis.

*The forecast annual volumes in respect of certification/recertification do not apply for the first two years of the forecast. That is, they apply from 2014/15—September 2017.
Note: N/A = Not applicable.

10.145 We considered NIE's request for a further allowance for additional overheads (see paragraph 10.135). We recognized the need to train new contract staff and provide them with the necessary equipment in order to mobilize them effectively. It was not clear to us why there should not be some economies of scope from existing staff in handling contract management and administration. We therefore decided that an allowance of £0.35 million for mobilization in 2014/15 and an annual allowance of £0.08 million (half of NIE's request) for 3.5 years would be appropriate. This amounted to a total of £0.63 million over RP5.

10.146 Combining the costs for those programmes which will apply for the entire RP5 period (items 5 to 8 above in Table 10.13) with those programmes which will apply only from 2014/15 to September 2017 results in the RP5 forecast shown in Table 10.14.

TABLE 10.14 **CC metering forecast for RP5**

£'000, 2009/10 prices

	2012/13	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*6 months to September 2017*
A. Programmes applying 2012/13—September 2017	3,289	3,289	3,289	3,289	3,289	1,645
B. Programmes applying 2014/15—September 2017			3,774	3,774	3,774	1,887
C. Additional overheads	0	0	430	80	80	40
Total (A + B + C)	3,289	3,289	7,493	7,143	7,143	3,572
Total for RP5 period: £31,929,000						

Source: CC analysis.

10.147 We note that, based on our decisions on Price Control Design, this forecast will be subject to an adjustment to reflect actual volumes at the unit costs specified in Table 10.13 above.

10.148 In its response to our provisional determination, the UR proposed reform of the RAB in respect of metering capex. It proposed a new metering RAB with a depreciation period more closely aligned to actual metering life cycles (10 to 15 years rather than the general RAB depreciation period of 40 years).[36] It added that this change was even more important with the advent of smart metering that may have shorter life cycles than dumb (non-smart) meters.

10.149 In its hearing, NIE said that it did not object to creating a single metering RAB.

10.150 We noted that keypad meters are currently depreciated over 15 years, whereas other types of meters are depreciated over 40 years. We noted that the meter certification period for keypad meters is ten years and that meters, depending on their type, can be certified for 10, 15, 20 or 25 years. The great majority (74 per cent) of non-keypad meters have a certification life of 10 to 20 years under the NI Regulations (this proportion is less under the GB Regulations but still covers the majority—56 per cent). We considered that consistency of approach to metering capex would be in the public interest. Given that keypad meters are depreciated over 15 years and the certification periods for other meters tend to be 10 to 20 years, we decided that all capex on meters from the start of RP5 should be added to a single 15-year metering RAB.

Meter reading

10.151 In its final determination,[37] the UR proposed an allowance of £13.6 million for meter reading (£2.72 million per year), following a review of salaries and a review of historical data supplied by NIE.

10.152 In its Statement of Case,[38] NIE set out a meter reading forecast for the RP5 period of £17.9 million or £3.58 million per year. NIE followed this with the statement that 'In the final year of RP4, the Utility Regulator provided an allowance of £3.45m'.

10.153 NIE's Statement of Case focused on criticisms of analysis of meter reading costs carried out by the UR. For instance, NIE disputed the UR's figures on the salary and other employment costs of meter readers, on the number of meter readers required and on central support costs relating to meter reading.

10.154 NIE said that the UR provided 'no justification for the disallowance of the costs allocated to meter reading, which are consistent with the current levels of costs incurred'.[39]

10.155 NIE did not explain in its Statement of Case how its forecast costs were consistent with its expenditure on meter reading.

10.156 We looked at historical information on the costs of meter reading activities.

10.157 Costs to NIE of meter reading are reported in the opex BPQ response in the worksheet on 'Dt costs'. These show costs for meter reading of £3.1 million in 2007/08, 2008/09 and 2009/10. However, these figures represent charges from NIE Powerteam to NIE for meter reading. They include a significant profit margin for NIE Powerteam that we do not intend to allow for in our cost assessment.

10.158 Further data on historical meter reading costs is provided in the Excel workbooks accompanying the updated Frontier Economics benchmarking analysis submitted by

[36] NIE response to provisional determination, paragraphs 93–94.
[37] UR final determination, p52.
[38] NIE Statement of Case, p115.
[39] ibid, p120.

NIE on 2 August 2013 and 12 August 2013. The reported costs for meter reading for NIE Powerteam were as follows (2009/10 prices):

(a) £2.6 million in 2007/08.

(b) £2.6 million in 2008/09.

(c) £2.8 million in 2009/10.

(d) £3.1 million in 2010/11.

10.159 NIE subsequently provided further information on its historical costs and an explanation of the increases in costs that it has experienced. NIE reports the provided more recent cost information than available in its BPQ response:

(a) £3.3 million in 2011/12.

(b) £3.4 million in 2012/13.

10.160 NIE explained that the cost increases over time were due to the combination of *(a)* a requirement from the UR which meant that it had to increase meter reading visits in the case of Keypad meters, and *(b)* the effect of the introduction in Northern Ireland of the Agency Workers Directive in December 2011.

10.161 We made an annual allowance of £3.4 million in light of NIE's most recent historical costs and its explanation that the cost increases reflect the impact of greater obligations and legislative change.

Other operating costs relating to Keypad meters

10.162 In its Statement of Case,[40] NIE provided forecasts of £1 million over the RP5 period for various costs relating to Keypad meters. These costs include plastic cards for Keypad meters (£422,000), staff costs (£356,000) and business continuity services (£133,000). NIE said that the UR's final determination included an allowance of only £0.7 million which represented a £0.3 million shortfall.

10.163 NIE subsequently provided further information on its Keypad opex which linked its forecast to historical expenditure. The main points we take from this are as follows:

(a) NIE said that the number of Keypad meters had increased over time, from about 190,000 in 2007/08 to about 297,000 in March 2013; and

(b) NIE reported that its forecast in its Statement of Case was for £210,600 per year compared with expenditure in 2012/13 of £196,800.

10.164 We made an annual allowance of £0.21 million in line with the forecast in NIE's Statement of Case.

[40] NIE Statement of Case, pp121–123.

Overheads for metering and market opening

Provisional determination

10.165 As part of our calculation of NIE's 2009/10 indirect costs for the purposes of the GB DNO benchmarking analysis, we excluded an allocation of NIE's administrative costs and overheads attributed to metering capex, meter reading and market-opening services which GB DNOs would not provide. The value of this allocation was £1.15 million.

10.166 Our provisional determination included a separate allowance for overheads for metering and market opening, calculated using information on the historical costs excluded from our benchmarking analysis. To avoid double counting, we made some deductions from the allocation of £1.15 million. We said that the allowance for metering capex already included £0.25 million for service and support costs and we deducted this from the £1.15 million allocation. We made a corresponding adjustment for meter reading of £0.06 million based on information provided by NIE about the historical costs we had used on meter-reading expenditure. NIE had told us that there was a charge from NIE to NIE Powerteam's meter-reading costs of around £60,000 per year. We did not identify an allocation of NIE's overheads within the cost figures we used for the Enduring Solution. On this basis, we deducted £0.25 million and £0.06 million from £1.15 million to produce an allowance for metering and meter reading overheads of £0.84 million.

NIE's response to our provisional determination

10.167 Following our provisional determination, NIE said that we had excluded the following metering costs from our assessment:

(a) the revenue protection unit (about £0.5 million a year);

(b) metering maintenance (about £0.07 million a year); and

(c) administration costs (about £0.69 million a year).

10.168 We discuss the treatment of revenue protection costs in Section 6.18 – 6.48. We address the second and third issues in the subsections below.

Metering maintenance costs

10.169 NIE said that our provisional determination excluded costs associated with 'metering maintenance'. These costs were as follows (2009/10):

(a) £68,000 in 2009/10;

(b) £62,000 in 2010/11; and

(c) £74,000 in 2011/12.

10.170 NIE said that these costs 'relate to the maintenance of domestic and small commercial meters (eg inspections and special meter reads)'.

10.171 NIE provided information which indicated that we had not provided an allowance for these costs as part of our allowance for meter reading or metering overheads.

10.172 We decided to allow an additional allowance of £0.07 million a year for these costs, based on the average of the costs reported for the three financial years above. This should form part of NIE's opex allowance.

Allocation of NIE overheads and administrative costs

10.173 We separate NIE's claim for administration costs of £0.69 million per year into two elements, which reflect the detailed points in NIE's submission. We first consider the allocation of NIE overheads and administrative costs to metering, meter reading and market opening (excluding NIE Powerteam's overheads). We subsequently consider NIE's submission in respect of NIE Powerteam's overheads.

10.174 NIE said that it was wrong for us to have deducted £0.25 million from the allowance we made in our provisional determination for metering overheads. It said that the allowance we provided for metering overheads related to an allocation of NIE's administration costs but the figure of £0.25 million that we deducted related to NIE Powerteam costs.

10.175 If, as NIE contended, the annual costs £0.25 million included in NIE's submission on metering capex which formed part of our metering capex allowances relate to NIE Powerteam costs, then it would not be consistent to make the deduction of £0.25 million from the overheads and administrative costs of NIE. We accepted NIE's submission on this point and have not made such a deduction.

10.176 We did not agree with NIE's terminology, which implied that the allocation of overheads provided for in our provisional determination was for 'NIE's administration costs' (excluding NIE Powerteam overheads). The NIE costs feeding into our allocation to metering, meter reading and market opening were around £14 million over the period 2009/10 to 2011/12. This is a large amount of costs and we consider that these costs are better presented as NIE's 'overheads and administrative costs' (excluding NIE Powerteam overheads) rather than simply NIE's administrative costs.

10.177 Following our provisional determination, we revised and updated our benchmarking analysis for indirect and IMF&T costs. In particular, we used additional data provided by NIE to include estimates of NIE's indirect and IMF&T costs for 2010/11 and 2011/12 in the data set used for benchmarking (our provisional determination used data only on NIE's indirect and IMF&T costs in 2009/10).

10.178 Table 10.15 shows the allocations of NIE's overheads and administrative costs' (excluding NIE Powerteam overheads) to metering, meter reading and market opening from our revised and updated benchmarking analysis. It also includes a deduction of £60,000 per year for NIE overheads that we understood to be already embedded in the costs we used to set an allowance for meter reading (see paragraph 10.166). (NIE did not object to this deduction in its response to our provisional determination.)

TABLE 10.15 **Approximate allocations of NIE and NIE Powerteam costs to metering, meter reading and market opening used for CC indirect and IMF&T cost benchmarking analysis**

	2009/10	*2010/11*	*2011/12*
Allocation of NIE overheads and administrative costs to metering (£m)	0.49	0.48	0.46
Allocation of NIE administrative costs to meter reading (£m)	0.34	0.37	0.37
Deduction for NIE overheads and administrative costs already included in our separate allowances for meter reading	–0.06	–0.06	–0.06
Allocation of NIE overheads and administrative costs to market opening (£m)	0.32	0.29	0.25

Source: NIE / CC analysis.

10.179 We decided to set an allowance for NIE's overheads and administrative costs (excluding NIE Powerteam overheads) allocated to metering, meter reading and market opening that reflected the average of the figures above. Specifically, we determined the following:

(a) an allowance of £0.47 million a year for metering capex, to be included as part of the RAB additions for metering;

(b) an allowance of £0.30 million a year for meter reading, to be included as part of NIE's opex allowance; and

(c) an allowance of £0.29 million a year for market opening, to be included as part of NIE's opex allowance.

NIE Powerteam overheads

10.180 NIE identified that for the benchmarking analysis used in our provisional determination, we excluded from our estimate of NIE's indirect costs in 2009/10 an amount of £0.44 million, which represented NIE Powerteam overheads (or administration costs) that were attributed by NIE to its metering activities.

10.181 For the updated benchmarking analysis that we have used in our final determination, the corresponding NIE Powerteam overheads attributed to metering averaged £0.43 million a year in the period 2009/10 to 2011/12.

10.182 The allowances we determined for NIE's metering capex (see paragraphs 10.106–10.150) include annual allowances of £0.25 million for 'service and support' costs. NIE confirmed that these related to NIE Powerteam costs (see paragraph 10.174). We considered that there would be double counting if we included these costs in addition to the NIE Powerteam overheads attributed to metering as part of our indirect and IMF&T cost benchmarking exercise. Around £0.26 million (on average) of the NIE Powerteam overheads attributed to metering costs were reported under the NIE Powerteam cost category 'internal support'; the remainder fell under the categories of procurement, safety and stores.

10.183 We decided that it was appropriate to include an additional allowance for NIE Powerteam overheads that NIE had attributed to metering, but to deduct the £0.25 million a year allowance for 'service and support' costs that formed part of our separate allowances for NIE's metering capex. We decided that an additional £0.18 million a year should be added to the allowances for NIE's metering capex for NIE Powerteam overheads attributed to metering.

Enduring Solution

Introduction

10.184 In this section we consider the determination of the opex allowance for the Enduring Solution project. A summary of relevant submissions from the UR and NIE is at Appendix 10.1.

10.185 In summary, Enduring Solution is the IT system introduced to support competition in the retail market. It was intended to aid complete separation of the customer billing processes and legacy IT systems previously shared by NIE and Power NI, and to provide a level playing field for all suppliers, unrestricted switching capability for customers and support of global aggregation for settlement of the all-island wholesale market. The project became operational in May 2012. The opex costs relate to IT support and market-opening costs such as staff costs to perform functions relating to meter reading, billing, switching suppliers, and other market-opening processes. Enduring Solution is an example of new controllable opex, which is not directly comparable with the activities of GB DNOs.

10.186 In its final determination, the UR decided on an allowance of £21.5 million for the RP5 period, whereas in its July 2012 submission, NIE had requested £29.4 million. NIE adjusted this to £28.9 million in its Statement of Case to the CC (due to removal of pension costs previously included in the NIE manpower figures).

10.187 Both the UR and NIE expressed concerns about the processes followed in reaching the determination (see Appendix 10.1, paragraphs 2 to 5).

10.188 In reaching our final determination, we were not directly concerned with the processes that were followed by the UR and NIE; rather we are concerned with determining an appropriate opex allowance given the information that is now available.

10.189 In this subsection we set out:

(a) the background to Enduring Solution (paragraphs 10.190 to 10.192);

(b) its treatment in the UR's determination (paragraphs 10.193 and 10.194);

(c) a breakdown of Enduring Solution costs (paragraphs 10.195 to 10.217);

(d) our discussion of cost assessment (paragraphs 10.218 to 10.267); and

(e) our determination on Enduring Solution (paragraph 10.268).

Background to Enduring Solution

10.190 As noted in paragraphs 2.23 – 2.24, the Northern Ireland Electricity market was opened to supplier competition between 2005 and 2007. In order to facilitate this, and to meet legislative and regulatory requirements for a fully competitive retail electricity market, a new IT system, Enduring Solution, was developed. NIE told us that this was the largest and most complex IT project it had ever undertaken.[41] It was implemented in May 2012.

[41] NIE Statement of Case, paragraph 5.13, p126.

10.191 NIE said that the Enduring Solution project introduced significant changes to market and business processes. Examples of outcomes were that: it allowed approximately 838,000 retail customers to move between electricity suppliers; it introduced improved functionality for customers; it ensured data integrity for the wholesale and retail markets; and enabled harmonization between the markets in Northern Ireland and the Republic of Ireland.[42] It said that NIE's role was different from GB DNOs' in that NIE was responsible for managing all market processes and the provision and maintenance of all accurate, up-to-date data necessary to support the successful operation of the competitive retail and wholesale electricity markets, whereas in Great Britain responsibilities for these functions were spread across many different industry participants including meter data collectors, data aggregators, suppliers and meter installers. It said that consequently, Enduring Solution was a necessarily complex suite of applications, providing a much wider range of functionality than that required of any GB DNO. NIE said that additional resources were required to support these functionally rich, higher cost applications, and as a result, Enduring Solution had created a step change in NIE's operating costs.[43]

10.192 NIE said that examples of these costs included staff costs to deal with 'exceptions' (the term used to describe data errors such as invalid meter readings) and to produce Distribution Use of System (DUoS) bills on an individual site basis for an additional 700,000 sites. Some of these processes were previously handled by Power NI. A variety of new code, reports and systems interfaces were required for the IT systems, all requiring support and maintenance. There was also a large increase in data transactions of various types, potentially producing exceptions, and a very large increase in messages between market participants.[44] NIE said that all of these changes drove increased IT support costs, including infrastructure costs, software licence costs and IT support resource costs.[45]

The UR's final determination

10.193 The UR did not set out a detailed explanation in its provisional determination or final determination documents on how it reached its allowance (of £21.4 million) for Enduring Solution. It noted that NIE had revised its estimates, and was also concerned about NIE's failure to tender separately the Enduring Solution managed service contract. The UR submitted to us several reports undertaken by Gemserv, evaluating NIE's submissions and on which the UR said its determinations were based. The successive Gemserv reports largely assessed cost allowances incrementally as NIE supplied further information and revised its estimates. Gemserv said its remit had been to assess costs as though they were efficiently and competitively procured. Gemserv told us that it was unable to adopt a bottom-up review approach because of issues around ambiguity and supporting information.

10.194 The UR told us that it was concerned that reaching a determination through assessment of iterations of estimates could carry a risk of bias, because it was in NIE's interests to highlight areas where it identified a need to add further costs, but less so to correct overestimates. However, we note that NIE did propose some downwards adjustments.

[42] ibid, paragraph 5.18.
[43] ibid, paragraph 5.17.
[44] ibid, paragraphs 5.23 & 5.24, p128.
[45] ibid, paragraph 5.25, p129.

Breakdown of Enduring Solution costs

Overall costs

10.195 In July 2012, NIE provided the UR with an updated analysis of forecast costs associated with operation of the new market processes and systems over the RP5 period. It said that cost estimates were refined up to this date, for example because of user acceptance testing indicating the presence of significantly more functionality requiring support than was previously anticipated.[46] Table 10.16 sets out a comparison of NIE's assessment of its opex requirements compared with the UR's final determination, broken down by principal cost categories.[47] This incorporates savings on legacy IT systems costs.

TABLE 10.16 **Enduring Solution—NIE's July 2012 forecast versus final determination**

£ million

Cost category	*NIE forecast*	*Final determination*	*Shortfall*
1. Applications Support Resources—SAP	12.5	7.2	5.3
2. Applications Support Resources—non SAP	0.8	1.4	(0.6)
3. Infrastructure Support Resources	2.4	2.7	(0.3)
4. Hardware, Software and Market Entry Costs	7.3	7.3	0.0
5. Outsourced Business Process (BPO) staff	2.9	2.4	0.5
6. Internal costs to support market processes	4.4	3.4	1.0
Total Enduring Solution operating costs	**30.3**	**24.4**	**5.9**
7. Legacy Reductions	(1.4)	(2.0)	0.6
8. Support costs paid by ESB networks	0.0	(1.0)	1.0
Total	**28.9**	**21.4**	**7.5**

Source: NIE Statement of Case, Table 6.17.

10.196 We note that Gemserv allowed higher costs than requested in some categories because it had taken a hard line against funding Wipro support costs (see Appendix 10.1, paragraph 25). In consequence, the final determination can be construed as an allowance as an overall package in the round.

10.197 We now consider each of the eight cost categories set out in Table 10.16 in turn:

(a) Applications Support Resources—SAP;

(b) Applications Support Resources—non SAP;

(c) Infrastructure Support Resources;

(d) Hardware, Software and Market Entry Costs;

(e) Outsourced Business Process (BPO) staff;

(f) Internal costs to support market processes;

(g) Legacy Reductions; and

[46] ibid, paragraph 5.34, p130.

[47] At a late stage in our process prior to the publication of our provisional determination, we discovered that the UR had wrongly informed NIE that a £385,000 additional application support allowance had been allowed in its determination against non-SAP applications, whereas it was actually allowed against the SAP application. Consequently NIE's submissions have been based on this incorrect data. We have corrected the values in the text and tables sourced from NIE to reflect the allocations the UR intended. The total value of allowances is not affected.

(h) Support costs paid by ESB networks.

Applications Support Resources—SAP

10.198 This cost relates to the outsourced technical resources required to support the main Enduring Solution application (SAP IS-U), to undertake routine maintenance, resolve defects, fix data issues, respond to business and supplier queries and deliver software enhancements.[48]

10.199 NIE said that it outsourced its IT service delivery to Capita Managed IT Solutions (Capita; the contract had originally been placed with Northgate Managed Services (NMS), which was acquired by Capita. We use Capita to refer to both Capita and NMS in this section). The contract had been competitively tendered for a five-year minimum term in 2009. NIE told us that when the managed services contract was awarded, it was understood the new Enduring Solution services would be incorporated into the managed services via a change control. NIE considered that incorporating the Enduring Solution services into that contract was the most cost-effective and low-risk approach, with one organization rather than two providing complete services.[49] It said that the introduction of a second major outsourced IT provider would give rise to additional costs and greater risk as ownership of specific system issues could become blurred and restoration processes extended.[50] It said that there would be costs in transferring activities to a new provider (eg new service desk resources, costs of terminating existing services, transferring staff to a new provider etc).[51]

10.200 NIE said that it had conducted detailed activity analysis since Enduring Solution had become operational to confirm the final forecast of outsourced technical support costs.[52] NIE said that the provider's average daily rate for SAP applications support was extremely competitive when compared with various benchmark rates.[53] It told us that the allowances included work for minor enhancements going forward but not for major system upgrades or to respond to unforeseen market developments, which would need a separate funding process. NIE also noted that there was uncertainty over how future efficiently incurred costs arising from market harmonization would be treated.[54]

10.201 NIE said that the UR's disallowance of a large part of its predicted costs meant that there would be an entirely inadequate level of funding to allow the retail market processes to operate effectively. It said that at the proposed levels of resourcing, the new SAP IS-U application could not be properly maintained, leading to increasing data and system defects and so impacting suppliers and customers significantly.[55]

Applications Support Resources—non-SAP

10.202 This cost category relates to the Capita technical resources required to support the other (non-SAP) Enduring Solution applications, to undertake routine maintenance,

[48] NIE Statement of Case, paragraph 5.39, p132.
[49] ibid, paragraphs 5.40 & 5.41, p132.
[50] ibid, paragraph 5.44, p132.
[51] ibid, paragraphs 5.45 & 5.46, p133.
[52] ibid, paragraph 5.52, p133.
[53] ibid, paragraph 5.55, p134.
[54] ibid, paragraph 5.62, p135.
[55] ibid, paragraph 5.68, p136.

resolve defects, fix data issues, respond to business and supplier queries and deliver software enhancements.[56]

10.203 NIE said that this was delivered via a change control to the existing NIE Managed Services Agreement with Capita. NIE said that it had been analysing in detail the level of resources that had been required to maintain and service these Enduring Solution systems since it went live, and had challenged these costs to ensure that the required service was delivered at lowest cost.[57] It said that the Capita day rate for support for these types of applications was in the competitive range of benchmarked costs.[58]

10.204 NIE noted that the UR had allowed £0.6 million more for costs than it had requested, reflecting an earlier submission which had been reduced (in part because of cost sharing with ESB).[59] The reason for this higher allowance being maintained (due to reasons outside the scope of this category) is set out in Appendix 10.1, paragraph 25.

Infrastructure Support Resources

10.205 This cost category relates to the Capita technical resources required to support all the infrastructure and network components associated with Enduring Solution, including routine monitoring, maintenance and resolution of defects.[60] NIE said the increased resourcing level was being driven by the large number of new infrastructure components (servers, databases, operating systems and network equipment) introduced to the NIE estate due to Enduring Solution.[61] It said that the daily rate for infrastructure support from Capita was extremely competitive.[62]

10.206 As with the previous category, NIE noted that the UR had allowed more costs than it had requested, reflecting an earlier submission, due to reasons explained in Appendix 10.1, paragraph 25. NIE also noted that the UR had recognized savings in Applications Support and Infrastructure Support due to sharing of costs with ESB Networks by applying a separate reduction of £1.0 million to the overall Enduring Solution allowance, but NIE was not aware how this reduction related to this Infrastructure Support allowance.[63]

Hardware, Software and Market Entry Costs

10.207 This cost category relates to the third party costs associated with hardware maintenance, software licences and other market services such as carrying out an accreditation process for new suppliers as they enter the market.[64]

10.208 NIE said that hardware maintenance and software licence costs were calculated as a standard percentage of the initial implementation costs. Other market services costs were based on historical information and assumptions on the future number of new suppliers entering the market. The UR allowed all the costs that NIE had submitted in its determination.

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56 ibid, paragraph 5.72, p137.
57 ibid, paragraphs 5.73 & 5.74, p137.
58 ibid, paragraph 5.75, p137.
59 ibid, paragraphs 5.76–5.79, p137.
60 ibid, paragraph 5.82, p138.
61 ibid, paragraph 5.85, p138.
62 ibid, paragraph 5.86, p139.
63 ibid, paragraphs 5.87 & 5.90, p139.
64 ibid, paragraph 5.93, p140.

Outsourced Business Process (BPO) staff

10.209 This cost relates to the Capita Business Process staff who process exceptions (eg invalid meter readings), correct erroneous transfers (eg invalid registrations that have to be backed out), engage with suppliers and manage meter point data.[65]

10.210 NIE said that these costs related to 19 BPO staff who carried out these activities. It said that pre-Enduring Solution, 22 staff had been required to perform this function, the number having increased with the introduction of full competition generating additional data exceptions and interactions with suppliers. However, NIE estimated that the team size could be reduced because the new IT systems provided greater automation and validation.[66] The UR disallowed £0.5 million of these costs. NIE said that this ignored the 12-fold increase in the volume of transactions and assumed that the new systems would deliver a reduction in resources required. It said that in consequence there would be a significant risk that data errors would not be addressed in a timely manner leading to problems for suppliers and customers. It said it was likely that market service levels would not be met and that overall data quality within the system would degrade.[67]

Internal costs to support market processes

10.211 NIE told us that this cost related to the new NIE staff who were required to operate the competitive market processes. This included the following activities:

(a) production of distribution use of system bills for suppliers (adding around 700,000 meter points to be billed at individual site level, rather than the previous single distribution use of system bill created from the legacy billing system shared with Power NI);

(b) production of aggregated supplier data to the all-island wholesale electricity market;

(c) responding to customer queries, eg concerning supplier switching processes and meter works appointments;

(d) management of governance arrangements to ensure market process adherence and developments in market design (noting the regulatory requirement to harmonize the Northern Ireland and Republic of Ireland retail electricity markets);

(e) management of services provided by third party service providers to support the Enduring Solution systems and Keypad prepayment meter infrastructure;

(f) administration of supplier data queries, connection agreements, and market documentation; and

(g) resolution of data issues relating to metering fieldwork.[68]

10.212 NIE noted that its role as market operator was unique and so could not be directly benchmarked, for example to confirm optimal resourcing levels. It said that it undertook careful analysis of resourcing requirements and its model was shared with the UR. It reviewed requirements after the project went live and resourcing was re-

[65] ibid, paragraph 5.99, p141.
[66] ibid, paragraphs 5.100–5.103, p141.
[67] ibid, paragraph 5.105, p142.
[68] ibid, paragraphs 5.108 & 5.109, p142.

adjusted. It said that the resources required were settled at 25 FTE staff (compared with 13 pre Enduring Solution). It said that the need for extra staff was driven by the very large increase in DUoS billing, data aggregation (for the wholesale settlement market), to take over data and process issues previously managed by Power NI on the shared legacy billing system, to facilitate an appointment booking system for suppliers, to manage third parties providing IT services, and to deal with market governance arrangements for the harmonized island of Ireland market.[69]

10.213 NIE said that the UR had disallowed some £1 million of costs over RP5, corresponding to seven FTE staff. NIE said that the inadequate levels of staff resources implied by the final determination would have a significant negative impact on the provision by NIE of data provision services used for settlement of the wholesale market, as well as on the accuracy of DUoS and retail billing. Further there would be delays in resolving business process exceptions (for example, in metering fieldwork) which would lead to a deterioration of services provided to end customers.[70]

Legacy Reductions

10.214 This category relates to savings in NIE's existing IT support costs due to certain application and infrastructure decommissioning following the introduction of Enduring Solution.[71]

10.215 NIE said that it had provided the UR with an estimate of savings in November 2011, ahead of detailed decommissioning analysis. It said that it updated the calculations after Enduring Solution went live and submitted its lower estimate in July 2012. However, NIE noted that the UR had adopted the earlier, higher reduction figure in its determination, representing a shortfall of £0.6 million.[72]

Support costs paid by ESB networks

10.216 NIE told us that as part of Enduring Solution, a new market messaging application and infrastructure was implemented for the Northern Ireland market; this was used to process messages between market participants and the market operator. As part of the market harmonization initiative, this subsequently became an all-island solution which was also used by ESB Networks to manage Republic of Ireland market messages. It said that the support costs for the application and associated infrastructure were now shared between NIE and ESB networks.[73]

10.217 NIE said that the UR had disallowed an additional £1 million of costs to recognize the sharing of costs with ESB. It said that cost reductions due to sharing were already built into NIE's submission (in cost categories 2 and 3 above). As the UR's determination in these categories had exceeded NIE's submissions by £1.3 million, NIE considered that this £1 million reduction represented an acceptable recognition of cost sharing with ESB networks.[74]

[69] ibid, paragraphs 5.110–114, p143.
[70] ibid, paragraph 5.116, p144.
[71] ibid, paragraph 5.119, p145.
[72] ibid, paragraphs 5.120 & 5.122, p145.
[73] ibid, paragraphs 5.126 & 5.127, p146.
[74] ibid, paragraph 5.129, p146.

Discussion of cost assessment

10.218 In Appendix 10.1 we set out evidence from the UR (and Gemserv) on its assessments of allowances for Enduring Solution and reasons for disallowing some of the costs, and NIE's responses.

10.219 We concentrated on issues relevant to the areas where the UR's determination was most at odds with NIE's requests, ie (using the numbering in Table 10.16) categories 1 (Applications Support Resources—SAP), 5 (outsourced business process staff), and 6 (internal costs to support market processes). Our assessment and determination of cost allowances is set out below. After some general observations, we set out our conclusions on each of the eight cost categories in turn:

(a) Applications Support Resources—SAP;

(b) Applications Support Resources—non SAP;

(c) Infrastructure Support Resources;

(d) Hardware, Software and Market Entry Costs;

(e) Outsourced Business Process (BPO) staff;

(f) Internal costs to support market processes;

(g) Legacy Reductions; and

(h) Support costs paid by ESB networks.

10.220 We then consider some other aspects that were raised by the parties.

General observations

10.221 We start by noting observations drawn by NIE and by Gemserv about the Enduring Solution project which help explain the differing perspectives on whether or not the project was only incurring efficient costs. We also look at the actual out-turn costs in the first 12 months since Enduring Solution went live.

10.222 NIE said that it regarded Enduring Solution as a well-managed project (a view the UR agreed with), delivered by a Systems Integrator following a competitive procurement exercise. The Enduring Solution system had been supporting the Northern Ireland retail market effectively for the past 12 months. It said that the system had created a step change in NIE's operating costs. NIE argued that support costs were based upon a detailed review of activities and they had been validated in the period since go-live. It said that support was being provided at an annual cost of 13 per cent of the original implementation cost which compares favourably with external benchmarks (see Appendix 10.1, paragraph 31).[75]

10.223 In the Gemserv assessments, apart from revisions of cost estimates, attention was particularly drawn to two related concerns. First, NIE had originally developed Enduring Solution as an Oracle product, but then changed to a SAP IS-U platform. Second, the Enduring Solution support and maintenance services were not separately tendered, but rather were incorporated into the existing managed service

[75] NIE Supplementary Submission, Annex 3, paragraphs 2.1–2.3 & 2.5.

contract, even though the provider was not necessarily best placed to support the SAP platform. Gemserv told us that it believed some aspects were not efficiently procured.

10.224 NIE provided details of the support costs that had been incurred in the first 12 months since the project went live—see Table 10.17.

TABLE 10.17 **Enduring Solution out-turn opex costs**

£'000, 2009/10 prices

Cost category	*RP 4 Extension Go-live—30 Sep 12*			*RP5 Year 1 1 Oct 12—30 Sep 13*		
	Sub	*Actual*	*Var*	*Sub*	*Actual*	*Var*
ICT						
Applications Support—SAP	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Applications Support—Other	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Infrastructure Support	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Hardware, Software and Market Entry	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
BPO resources	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Subtotal	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Legacy Reductions	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Transitional costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Total ICT	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Manpower	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Total operating costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: NIE.

10.225 NIE said that there had been variations in expenditure from forecasts on some elements for the following reasons:

(a) Infrastructure support effort had been lower than anticipated during the first year of operation, due to a reduced level of hardware patching, firmware upgrade and other maintenance activity required for a newly implemented hardware platform. It said that these activities would be expected to ramp up over the course of the RP5 period.

(b) Later than planned purchase of additional SAP licences.

(c) On BPO resources, the need to retain six temporary resources until December 2012.

(d) Lower than submitted manpower costs due to later than planned recruitment of resources who were not in post until early 2013 and some staff turnover. NIE said it did not think it would be able to continue to run with lower manpower than was set out in its submissions.

10.226 NIE told us that the two areas which were proving particularly demanding were in metering resources, because of the loss of synergy with the separation of the legacy systems shared previously with Power NI, and in keeping markets and operations harmonized across the whole of the island of Ireland.

10.227 Given the explanations offered by NIE, we were not able to conclude that the out-turn costs provided persuasive evidence on whether the cost allowances determined by the UR were or were not appropriate.

10.228 The UR also noted that it had allowed substantial transition costs on top of these allowances to support the systems in the first few months of operation (these are not part of our assessment of ongoing support costs).

Applications Support Resources—SAP

10.229 Material from the parties explaining the derivation of the UR's allowance for this category, and the parties' submissions on the reasons why these costs should or should not be allowed, are set out in Appendix 10.1.

10.230 In assessing an appropriate allowance for SAP applications support, we noted that Gemserv was asked to evaluate costs against an efficient company procuring services efficiently. This was a principle working in the interests of consumers and deterring inefficiencies and forms a suitable default assumption in most cases. We also agreed that the change in systems from Oracle to SAP and the consequence that NIE found it had to allow Capita to seek further resources to support SAP, were not examples of the most efficient practice. This was likely to have resulted in NIE facing total costs higher than would be those had it originally tendered for a SAP product with a support package. In retrospect, it would have facilitated the delivery of Enduring Solution had contracts allowed for change and adjustments in the context of developments that had arisen. Nonetheless we also noted that the project had been successfully delivered and now appeared to be working well.

10.231 However, while we accepted this, we also found it informative to consider whether decisions taken at the time were ones that a reasonably efficient company could be expected to have taken, without the benefit of hindsight.

10.232 In that light, we were not persuaded that NIE's original decisions to adopt an Oracle solution, nor to tender for a single IT services delivery package, represented poor decisions at the time they were taken. Similarly, we were not persuaded that NIE made a poor decision when it decided to change from Oracle to SAP following the acquisition by ESB. In that circumstance, we did not consider that it was an inappropriate decision not to separately tender for SAP support given the termination costs that would have been incurred, nor the practical difficulties of then having two different IT service delivery providers. We noted that Capita tested the market to some extent by comparing Wipro with two other potential providers. This mitigated to some extent against Gemserv's concern that Wipro appeared to have been in a very strong position when negotiating terms with Capita and NIE.

10.233 We were concerned that elements of NIE's cost projections going forward did not seem fully to reflect efficient practice. In particular, we were surprised by the slow rate of efficiency gain envisaged. For example, while we accepted that when a new project is rolled out, one would want support to be available locally, it appeared that NIE had been slow to endorse the cost savings which might have arisen from progressive offshoring of most support once the system has been established. [✂] Indeed, in our view reductions might even be achieved more rapidly than allowed for in the UR's determination.

10.234 We had some concerns about the approach the UR had adopted in assessing costs. The nature of this project meant that benchmarking costs was challenging, although we acknowledged that there were no other practicable ways to test NIE's cost and resource projections. While it was sensible procedurally for Gemserv to assess NIE's revised submissions on an incremental basis and only accept these where well evidenced, it seemed implicitly to give greater weight to NIE's initial estimates and had resulted in some questionable decisions, such as rejection of some of NIE's projected reductions in costs.

10.235 Given these competing considerations and the very limited availability of reliable benchmarking information, we considered that determining the appropriate allowance rested to a considerable extent on judgement. Our concerns were that NIE did not appear to fully exploit opportunities for cost reductions over the life of RP5.

10.236 We therefore concluded that while a higher allowance should be set for the first year, somewhat higher than the UR's determination, but not fully meeting NIE's requests because of the limitations in the processes it had followed. This allowance should then reduce because of the potential for efficiency gains.

10.237 We decided that an additional allowance of £2.5 million over RP5 be provided: £900,000 in 2012/13, declining by £200,000 each year so that there is an additional allowance of £100,000 in 2016/17.

10.238 This adjustment meant that while the total value of the SAP support allowance was increased by £2.5 million to £9.68 million, it declined at a faster rate than in the UR's determination. From a 2012/13 allowance of £2.76 million it declined each year by –15.7 per cent, –19.2 per cent, –21.9 per cent and finally (2015/16 to 2016/17) –14.2 per cent.

10.239 In response to our provisional determination, NIE said that our SAP Applications Support allowance was based upon a much more significant degree of offshoring than was assumed in the NIE submission, which would give rise to a very high level of risk to the operation of the retail market and was not therefore in the public interest. It considered that the reductions in support costs were unachievable, particularly in light of the criticality of the Enduring Solution system in supporting the Northern Ireland retail market. The allowance implied that the SAP support team would have to be located offshore. It added that the replacement of locally-based, highly-skilled jobs with offshore service provision was complicated by the TUPE legislation protecting existing staff. It said that it had received bids from providers which included a significant amount of offshoring when the contract was tendered in 2009, but that these were more expensive than alternative bids which were based onshore.[76]

10.240 We considered NIE's arguments on offshoring. In our view, NIE was not prevented from offshoring. We considered that offshoring support contracts had been successfully used in critical national infrastructure utilities. Given such offshoring opportunities, we did not consider the implied average daily rates to be unachievable. Although TUPE regulations can complicate outsourcing approaches, they do not prevent such arrangements and the outsourcing industry has been successfully dealing with this legislation for many years. We noted that the onshore-based bid to which NIE compared the costs of the offshore-based bid was not capable of providing the SAP support that NIE required and was not on a like-for-like basis to the offshore-based bid.

10.241 Having considered NIE's arguments, we therefore found that none of them warranted adjustments to the SAP support allowance contained in our provisional determination, as described in paragraphs 10.237 and 10.238 .

Non-SAP applications support resources and infrastructure support resources

10.242 As set out in paragraphs 10.204 and 10.206, in the case of non-SAP applications support resources and infrastructure support resources (categories 2 and 3), the UR's allowances exceeded NIE's request by £0.6 million and £0.3 million respectively. This was because Gemserv had adopted a general policy of not revising its original cost allowances unless the reasons for this had been well supported by NIE

[76] NIE response to provisional determination, Chapter 17, paragraphs 1.24–1.35.

(even where this was for a reduction), and because it was taking a view of allowances in the round where it had taken a hard line against funding Wipro support costs.

10.243 Our assessment of the SAP Applications Support Resources was intended to cover reasonable costs, and so other costs do not need to be viewed in the round to compensate for this. We also considered that the threshold of proof to accept a revision of costs from NIE would be different where it was reducing a cost estimate. In the absence of reason to believe that NIE's cost forecasts were inappropriate, we made a £0.9 million reduction in cost allowances for these two categories, such that the allowances were £0.8 million for non-SAP applications support and £2.4 million for infrastructure support.

Hardware, software and market entry costs

10.244 We reviewed this area of the UR's final determination (Table 10.16, category 4) but did not identify reasons to consider that the allowance was inappropriate. Neither NIE nor the UR made any comments on this in response to our provisional determination and we have therefore continued to set an allowance of £7.3 million.

Outsourced business process staff

10.245 The UR's and NIE's submissions in relation to the assessment of allowances for this category of costs are set out in Appendix 10.1.

10.246 This category represented a forecast where there was uncertainty over how future levels of activity would develop given the benefits of new systems but potentially increasing demands. We noted that Table 10.17 shows a small overspend in this category but due to the temporary retention of transitional staff.

10.247 Little evidence was offered by either party in relation to the appropriate staffing allowance, particularly in how it would develop over time. The lack of clarity over Gemserv's assessment and lack of robust evidence to support NIE's projections hampered our assessment. We found it surprising that costs were not projected to fall over time given that we would expect queries and data inconsistencies to decline as the systems bed in.

10.248 Taking note of probable long-term impacts on costs, we concluded that some disallowance against NIE's projections was appropriate. We concluded that an allowance of £2.65 million was appropriate.

Internal costs to support market processes

10.249 The UR's and NIE's submissions in relation to the assessment of allowances for this category of costs are set out in Appendix 10.1.

10.250 The precise staff numbers that were disallowed by Gemserv as set out in its July 2012 report did not appear to correspond directly to the costs identified in NIE's final submission. However, in relation to the staff roles that were identified, we first noted the disagreement between the UR and NIE on whether NIE requires staff to deal with customer queries. In our view, the UR's position that suppliers rather than NIE should be the point of customer contact is a reasonable and practical policy. While NIE may wish to maintain helpful relations with the public, they are unlikely to be direct customers of NIE, and this policy would seem to help perpetuate customer confusion. Therefore we accepted the UR's view that such support should not be funded.

10.251 In relation to the other identified functions, NIE's assertion that Gemserv had failed to undertake robust analysis to support its opinion was unpersuasive. Its role was to review the legitimacy of NIE's applications, not to produce an alternative submission. It provided reasons for its rejection of certain resourcing, particularly that there was unlikely to be a need for specialist metering electricians for SEM faults. In the absence of other evidence, we concluded that the UR's allowance in this category was appropriate.

10.252 In response to our provisional determination, NIE submitted that, irrespective of who made the meter-reading appointment call, NIE needed an allowance for call centre resources. It said that direct engagement with the customer by NIE to resolve meter-related queries was likely to result in quicker resolution of queries and be the most cost-efficient approach. NIE said that, if the supplier were to call NIE on the customer's behalf, this was more likely to result in multiple calls to resolve a single query and might result in a need for additional call centre resources beyond the 1.5 FTEs requested. NIE also said that we needed to allow for 1.5 FTEs in meter works administration in order to help resolve inconsistencies in meter point data and 1.5 FTEs in market-facing functions so as to support various market forums.[77]

10.253 In its response hearing, the UR said that it wanted suppliers rather than NIE to engage with customers. It said that otherwise there was confusion between NIE and the suppliers—NIE should be providing the service to the suppliers for them to engage with the customers in this area.

10.254 We considered NIE's request for further resource for these functions. We noted that NIE continued to hold a differing view from the UR of the way in which the market should operate. We remained of the view (see paragraph 10.250) that the UR's policy in this area was reasonable and practical and NIE provided no further evidence to persuade us otherwise. For these reasons, we did not consider it to be in the public interest to allow the 1.5 FTE call centre agents and the 1.5 FTEs in market-facing functions. With regard to the 1.5 FTEs for meter works administration, NIE did not provide us with any evidence to change our view in paragraph 10.251. We therefore did not change our provisional assessment.

Savings related to legacy reductions

10.255 In our provisional determination, we reviewed this area of the UR's final determination (Table 10.16, category 7) but did not identify reasons to consider that the allowance was inappropriate.

10.256 In its response to the provisional determination, NIE submitted that our provisional determination adopted an earlier estimate of legacy IT support cost savings (of £2.0 million) rather than the actual savings which emerged following detailed analysis and decommissioning of the legacy applications (of £1.4 million). NIE said that the actual savings presented in Table 10.17 were consistent with £1.4 million and should therefore be used.[78]

10.257 Having reviewed the detailed analysis that NIE provided in relation to savings from the decommissioning of legacy applications, we decided that it would be more appropriate to use the £1.4 million forecast from the updated analysis than the £2.0 million forecast from the 2011 analysis.

[77] ibid, Chapter 17, paragraphs 1.12–1.14.
[78] NIE response to provisional determination, Chapter 17, paragraphs 1.20–1.23.

Savings related to sharing with ESB networks

10.258 In our provisional determination, we included cost savings of £1 million which were being delivered through sharing of the TIBCO market messaging system with ESB Networks. As described in paragraph 10.243, we used NIE's proposed allowances in respect of non-SAP applications support resources and infrastructure support resources. These were lower than the allowances the UR included in its determination by £0.6 million and £0.3 million respectively.

10.259 In response to our provisional determination, NIE submitted that there had been a double count of £1 million of reductions. It said that this was because:

(a) NIE's submission on Enduring Solution prepared in July 2012 identified costs of £0.8 million for non-SAP applications support and £2.4 million for infrastructure support. This submission included all the projected reductions in NIE operating costs which resulted from the sharing of the TIBCO platform with ESB Networks.

(b) In its final determination, the UR adopted the approach of maintaining the allowances in these areas at a higher level than the NIE submission but recognized the cost savings via a separate £1 million reduction.

(c) The CC had set the allowances in these areas to NIE's submission figures, which included the TIBCO savings, but also retained the £1 million reduction introduced by the UR.[79]

10.260 We considered these arguments and found that our approach in the provisional determination double counted the cost savings related to sharing of the TIBCO platform with ESB Networks. To correct this, we excluded the additional savings of £1 million related to sharing of the TIBCO platform with ESB Networks (as these savings were already included in the allowances of £0.8 million for non-SAP applications support and £2.4 million for infrastructure support—see paragraph 10.243).

Other aspects

- *Pension costs*

10.261 In response to our provisional determination, NIE said that we had omitted £0.5 million of relevant pension costs which needed to be recovered through the Enduring Solution allowance. This was because the provisional determination made no separate allowance for current service pension costs, which were deemed to be included in the indirect cost allowance. However, the indirect cost allowance related to the core business only and excluded Enduring Solution.[80]

10.262 On the basis of paragraph 10.261, we believed that an additional allowance of £0.5 million for Enduring Solution pension costs was appropriate.

- *RPEs and productivity*

10.263 We made an explicit adjustment in the allowances for expected gains in productivity on SAP applications support. The numbers already took account of the adjustment made by Gemserv to neutralize the effect of the RPI–X term. We allowed this so as

[79] ibid, Chapter 17, paragraphs 1.6–1.8.
[80] ibid, Chapter 17, paragraphs 1.16–1.19.

to have the effect of offsetting the 1 per cent productivity adjustment we applied generally to costs.

10.264 In response to our provisional determination, NIE said that RPEs and productivity should not be applied for the period 2009/10 to 2012/13. This was because the Enduring Solution operating costs were new costs which began to be incurred only in 2012/13. NIE's submission was prepared using actual costs incurred in 2012/13 prices, converted to the 2009/10 price base. NIE said that it was not appropriate to adjust the allowance to recognize notional differences between NIE's costs and RPI in the period from 2009/10 to 2012/13, nor was it appropriate to apply productivity adjustments during a period prior to the service commencing.

10.265 We decided that, as the Enduring Solution estimates provided by NIE were submitted in July 2012 but at 2009/10 prices,[81] it would be appropriate only to apply any RPE and productivity adjustment from 2012/13 onwards.

- *Transitional costs over the initial operational period*

10.266 Gemserv said it understood that NIE had incurred high transitional costs over the initial operational period. With this in mind, and the proposed disallowance of the new Wipro cost line, it recommended that an additional short-term allowance should be made under a separate Dt term adjustment. We did not consider the suitability of these allowances in this section as we consider that they relate to the original implementation of the project rather than ongoing operational expenditure support.

- *Allowances for 2012*

10.267 Our determination covers relevant costs from 2012. These allowances cover the period where NIE raised concerns on unresolved RP4 issues (see paragraphs 14.5 to 14.10). These allowances are set as upfront allowances, and so are not adjusted for the actual incurred costs shown in Table 10.17.

Our determination on Enduring Solution

10.268 The allowances for Enduring Solution are shown in Table 10.18, with the UR's final determination (from Table 10.16) for comparison. These allowances cover the five-year period April 2012 to March 2017, as shown in Table 10.19. The final year allowances can be adjusted pro rata for our proposed RP5 period of 5.5 years.

[81] NIE Statement of Case, paragraph 5.32.

TABLE 10.18 **Enduring Solution—the CC's determination (5 year period)**

£ million

Cost category	*CC determination*	*UR final determination*
1. Applications Support Resources—SAP	9.7	7.2
2. Applications Support Resources—Non SAP	0.8	1.4
3. Infrastructure Support Resources	2.4	2.7
4. Hardware, Software and Market Entry Costs	7.3	7.3
5. BPO staff	2.7	2.4
6. Internal costs to support market processes	3.4	3.4
Total Enduring Solution operating costs	**26.3**	**24.4**
7. Legacy Reductions	–1.4	(2.0)
8. Support costs paid by ESB Networks	0.0	(1.0)
9. Pensions allowance	0.5	N/A
Total	**25.4**	**21.4**

Source: CC.

Note: N/A = not applicable (as UR included Enduring Solution pension costs within the current pension service costs).

TABLE 10.19 **Enduring Solution—the CC's determination, allowances by year**

Year	*CC provisional determination £m*
2012/13	5.6
2013/14	5.5
2014/15	5.1
2015/16	4.7
2016/17	4.5
2017/18	2.3 (six months)

Source: CC.

Connection charges funded through RAB

10.269 In this subsection, we consider the capital cost of connecting: *(a)* new domestic and smaller businesses; and *(b)* housing sites with 12 or more dwellings, to the electricity network.

New domestic and smaller businesses

Background

10.270 This expenditure is the capital cost of connecting new domestic and smaller businesses to the electricity network. Until 1 October 2012, new domestic and smaller businesses connecting to the network received a subsidy which meant that they were only required to pay 60 per cent of the cost of their new connection. The remaining 40 per cent, a subsidy, was capitalized into the RAB and effectively paid for by all NIE's customers.

10.271 This subsidy was removed so that for all applications for connection made from 1 October 2012, the full cost of a connection was paid by the applicant. However, where prior to 5 April 2012 (the date of publication of the UR's decision to remove the subsidy) NIE made a connection offer to an applicant under the previous charging regime (ie with a 40 per cent subsidy) and that offer was accepted, NIE must honour the terms of that connection offer. It is not uncommon for connection works associated with developments to be completed some four or five years after the date on which the offer was accepted. Moreover, under transitional provisions agreed by the

UR, where NIE received applications for connection after 5 April 2012 but prior to 1 October 2012, and offers were made prior to 1 January 2013, the applicant would receive the subsidy as long as the connection is completed by 1 October 2014.

10.272 NIE requested an allowance of £15.8 million for new connections costs for RP5 (£17.4 million including RASW costs). RASW costs are the costs associated with the introduction of RASW legislation; the costs cover permitting, fixed penalty notices, overrun charges and additional labour costs.

10.273 The UR accepted NIE's New Connections request, with the amount ring-fenced so that only NIE's actual spend was passed through to consumers. It envisaged that any over- or underspend against the connections expenditure capex forecast would therefore be adjusted on an ex post basis to reflect out-turn expenditure. NIE agreed with the UR that its connections allowance should be logged up or down by reference to the amounts actually expended by NIE during RP5.[82]

Views of the parties

10.274 NIE said that there needed to be an allowance for the connections costs which would not be recovered directly by way of connection charges levied on the connecting party. NIE said that its forecast for RP5 reflected the phasing out of the new connections subsidy, with costs falling from £7.5 million in year 1 to £0.8 million in year 5.[83]

10.275 NIE said that net connection costs out-turned at £5.0 million in 2012/13. When compared with its forecast of £7.5 million for 2012/13 this represented a shortfall of 33 per cent.

10.276 In response our provisional determination, NIE said that it accepted that the UR's policy decision, published in April 2012, stated that customers making applications prior to 1 October 2012 would receive the subsidy only 'as long as the connection was completed by 1 October 2014'. However, neither the UR's policy decision, nor the CC's provisional determination, took account of cases where the connection application was made before the change in policy took effect, but there had been a delay in carrying out the connection works for reasons beyond the control of either NIE or the applicant, with the result that connection may not occur until after 1 October 2014.[84]

Our decision on new connections costs and RP5 forecast

10.277 We decided that the cost pass-through of these items was not against the public interest (see paragraphs 5.304 – 5.315). This was because the risk of excessive costs should be mitigated by effective regulation of connections charges and also because the arrangement was a temporary one (as the subsidy cost would be phased out). We therefore made an estimate for the period for the purpose of our financeability modelling and estimating tariff impacts, but we noted that this would be adjusted to reflect actual net expenditure on new connections.

10.278 Given the difference between NIE's forecast for net connections and the out-turn, we considered that it was appropriate to make a downward adjustment to NIE's net connections forecast of 33 per cent in year one and in each subsequent year. This was

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[82] ibid, Chapter 5, paragraph 5.22 (p102).
[83] ibid, p424. In addition RASW costs fall from £0.8 million to £0.1 million.
[84] NIE response to provisional determination, Chapter 10, paragraph 1.4.

because the out-turn in 2012/13 suggested that the path of new connections would be shallower than originally forecast by NIE.

10.279 We included a forecast for the whole RP5 period to reflect cases where a connection application was made before the change in connections policy took effect and there had been a delay in carrying out these works (see paragraph 10.276).

10.280 We noted that RASW legislation had not yet been implemented in Northern Ireland, although NIE said that it was expected to be implemented within RP5. The UR told us that it had recently spoken to the Street Works Manager in the Roads Service who had informed it that the outstanding elements of the RASW legislation, particularly with respect to fixed penalties and to the fees for the permit scheme, had been reviewed by DRD this year. It said that the Manager had confirmed to the UR that there were no plans to enforce these requirements from the legislation in the foreseeable future.

10.281 We asked DETI whether RASW legislation was likely to be implemented during RP5. DETI told us that the Department for Regional Development (DRD) was no longer actively progressing the RASW proposals in Northern Ireland, although the primary legislation remained in place and DRD reserved the right to review the position in the future. DRD said that there was no longer a robust business case for introducing such a scheme and that there were no plans to review that decision at present. We therefore made no allowance for RASW legislation in our forecast.

10.282 This resulted in the following forecast (Table 10.20) for NIE's net connections costs.

TABLE 10.20 **Net connections forecast for RP5**

£ million

2009/10 prices	*2012/13*	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*6 months to September 2017*
Net connections costs	5.0	2.5	1.5	1.0	0.5	0.3
RASW costs (net connections)	0.0	0.0	0.0	0.0	0.0	0.0
Total net connections capex	5.0	2.5	1.5	1.0	0.5	0.3

Source: CC analysis.

10.283 Our total forecast for net connections costs (including RASW costs) in RP5 was £10.8 million. This compared with NIE's forecast of £17.4 million. The difference in the forecast was explained by: an additional six months in our forecast due to a longer RP5 period; a cut to NIE's forecast which we made to reflect a shallower path of actual new connections; and the exclusion of RASW costs. Our final determination was £2.5 million higher than our provisional determination of £8.3 million, which did not take account of delayed connections—see paragraph 10.279.

Housing sites with 12 or more dwellings

10.284 Housing site developers with 12 or more dwellings connecting to the network face a standard charge based upon the average cost of connections for all completed developments.[85] In 2013, the Standard Connection Charge was £876 per connection.

[85] NIE Statement of Case, Annex 5A.5, paragraph 12 (p425).

Parties' views

- *NIE*

10.285 NIE said that a housing site developer would only be required to pay the connection charge as and when each dwelling became occupied. It said that this created a timing difference between NIE incurring costs and recovering them. It said that there was also a risk that the income from standard connection charges could be higher or lower than NIE's costs because, for example, a dwelling might never be occupied.

10.286 NIE said that we should make provision for a housing site RAB. It said that the Standard Connection Charge did not include any financing costs nor any adjustment in respect of over- or under-recovery of costs in the previous year. It said that costs and revenues had up to now been added to the general RAB, such that the cash-flow difference had been passed through to customers.

10.287 NIE said that, without a housing site RAB, it would not be in a position to provide forward investment to enable current standard connection charging in this area to continue. It added that the UR would need to withdraw its decision to retain standard connection charging and any existing liabilities would need to be recoverable to reflect the legacy policy.[86]

10.288 NIE said that the volume and mix of projects completed could vary significantly year on year. Actual expenditure incurred by NIE net of connections contributions received in the period 2008/09 to 2011/12 ranged from £1.2 million to £1.6 million and in 2012/13 were £0.8 million. For the nine months from 1 April 2013 to 31 December 2013, net costs were £0.1 million.[87] This gave an average for the past five years of £1 million per year. NIE said that it was not possible to forecast future connection net contributions as this depended upon the housing market, but that recent years were not a good guide to the future as past uncompleted houses were now being released on to the market, leading to increased connection activity.

10.289 NIE said that we had two options:

(a) to maintain the existing approach with actual costs and revenues being added to a new housing site RAB with an opening RP5 value of nil. NIE requested that provision be made for the allowance to be calculated on an annual ex post basis to reflect the actual level of net expenditure incurred;[88] or

(b) to abolish the standard connection charge and require developers to pay the connection charges upfront. It said that the second option would require a RAB adjustment for a transitional period from 1 April 2012 to the date of the change to the Statement of Charges to reflect costs incurred less contributions received from developers. It also said that addition of financing costs to the standard connection charge would result in significant volatility in the charge and cross-subsidy issues between developers. The UR

10.290 The UR said that the existing mechanism inherently allowed NIE to add to or subtract from the general distribution RAB, the net costs of connections in any particular year,

[86] ibid, paragraphs 2.1–2.6.
[87] All figures are current prices rather than 2009/10 prices
[88] ibid, paragraphs 2.1–2.6.

therefore any connections costs net of contributions were financed by the wider customer base. It said that it was content with this mechanism, which allowed financing costs by only deducting the contribution on connection of each dwelling.

10.291 The UR said that the removal of the connections subsidy for domestic customers and small businesses from October 2012 was to ensure that the full costs were paid for by those parties benefiting from the connection. The UR said that it was never its intention to develop a housing site RAB. It further added that any change in the charging methodology would be subject to its approval and would require public consultation.

Our consultation

10.292 As we did not make a provisional determination on housing sites with 12 or more dwelllings, we gave the parties an opportunity to respond to our proposed decision in this area.

10.293 We said that we considered that there was a lack of clarity between the UR and NIE around the treatment of these costs. We said that, in our view, this issue would be best dealt with through connection charges rather than through the creation of a new housing site RAB. We also recognized that in 2012/13 and 2013/14 NIE had incurred costs in this area, and we considered that it was appropriate to make an adjustment for these. We therefore decided that a one-off RAB addition (of £1 million) should be made to NIE's main RAB to reflect these costs. We decided not to make any further allowance for the period after 2013/14 as we said that we would expect the parties to resolve this issue via the connections charge.

- *The UR's views*

10.294 In response, the UR said that our proposed £1 million RAB addition was arbitrary and not reflective of costs. It proposed instead that these costs should be treated under the D8 mechanism until the point when the connection charge statement may change (1 October 2014). It added that changes to the connection charging statement without proper consideration and a public consultation would not be in the public interest.

10.295 It said that NIE's issue appeared to be how to finance net connection costs (including finance costs) in RP5. It proposed that, prior to any changes in connection charges, net connection costs should be added to the RAB using the D8 mechanism for new connection charges.

10.296 The UR also said that, whilst building a financing charge into the standard connection charge would be difficult, it was willing to discuss future solutions.

- *NIE's views*

10.297 In response, NIE said that it was not practicable to build a financing cost into the standard connection charge because of the uncertainty regarding both the timing and number of future connections.

10.298 NIE also said that it was content with UR's proposal that any net connection costs for housing sites with 12 or more dwellings were included within the D8 mechanism until such time as the existing connection charge methodology was modified (following consultation).

Our decision on housing sites with 12 or more dwellings

10.299 We considered NIE's request for a housing site RAB and the responses of both parties to our consultation. We believed that this issue would be best dealt with through connection charges rather than through the creation of a new housing site RAB. We noted that it was not for us to determine the Standard Connection Charges and NIE and the UR could agree to change the Standard Connection Charge in future to address any issues arising from the UR's change in policy.

10.300 We disagreed with NIE's view that it was not practicable to build financing costs into the standard connection charge. Most businesses are required to set prices despite some level of uncertainty and we did not consider that the uncertainty in this instance was so great that it would prevent a new connection charge being established.

10.301 We recognized that, until the new charge is established, NIE will incur costs in this area and we considered that it was appropriate to account for these. We also recognized that 1 October 2014 may be a very tight timetable in which to agree a new connection charge (given the need for public consultation). We therefore decided that, until 1 October 2015 (from when we would expect new connection charges to apply), net connection charges should be added to the distribution RAB on a cost pass-through basis.

10.302 We have included an estimate of net connection costs until 1 October 2015 to our model. Based on NIE's actual net costs in 2012/13 and the first nine months of 2013/14, we estimated net costs of £0.8 million in 2012/13 and £0.2 million in 2013/14. For 2014/15 we assumed the simple average of these two estimates—£0.5 million. We make a further estimate of £0.3 million for 2015/16, representing the first six months of the year (until 30 September 2015), after which the new connection charging statement will apply. These are estimates for the purposes of our modelling and in reality actual connection charges incurred (until 1 October 2015) will be added to the distribution RAB.

33 kV network reinforcement for small-scale renewable generation

Background

10.303 This expenditure covers network reinforcement which is caused by the increase in small-scale renewable generation. The connection charges which small-scale generators pay to connect to the electricity network do not currently cover this network reinforcement work. Therefore, it was necessary for us to decide if we should make an allowance for this reinforcement work, and if so, how it should be dealt with within our price control design structure.

10.304 As we were made aware of this issue just prior to our provisional determination, we did not make a provisional decision in this area. Instead our provisional determination invited submissions from the parties as to how this issue should be dealt with within the price control design structure which we had provisionally proposed.

10.305 NIE said that there was ongoing discussion between the UR and NIE in relation to:

(a) whether NIE's connection charging methodology should be modified to provide that applicants seeking LV connection may in certain circumstances be required to contribute to the cost of 33kV reinforcement; and

(b) the assessment of whether it would be manifestly inappropriate for NIE to apply its current connection charging methodology to an application for LV connection.[89]

Views of the parties, DETI and other respondents

10.306 NIE said that, whatever the outcome of these discussions, it was clear that for the period between October 2014 and September 2017, it would be subject to significant costs in this area. It estimated that this reinforcement work could require an ex ante allowance of around £30 million, although this amount was at present uncertain. NIE said that the UR had already made an approval under the Dt term on 21 October 2013 for £2.0 million[90] of low-cost reinforcement work.[91]

10.307 NIE said that, whilst the CC could provide an ex ante allowance as part of the allowance for distribution-load-related expenditure, this would be inappropriate given the uncertainty of the cost.

10.308 NIE suggested that instead the CC should allow for case-by-case approval with different approaches for low-cost and higher-cost reinforcements. Low-cost reinforcement allowances would be based on unit cost allowances and actual volumes of work completed, with NIE exposed under the cost-risk sharing mechanism. Higher-cost reinforcements would be based on the D5 mechanism but form part of NIE's distribution licence.[92]

10.309 In its response to the provisional determination, the UR said that NIE's request for funding in this area was at best unprofessional, unjustified and out of time. It suggested that the proposal should be rejected.[93] The UR said that the only way to assess this expenditure was to look at the detail of what is proposed and the impact, neither of which it had done to date as the information had not been provided by NIE. The UR said that, in the event such expenditure were justified, if it was to occur through a process where it was recovered through the distribution system tariff, it would be allocated through to everyone who used the 33kV network, such that all customers would pay a percentage based on their usage of the 33kV network. It added that to move the cost to the small-scale renewable generators would require a change in the UR's connection policy. It said that it would take a year to 18 months to review that connection policy and it did not see it as a priority at this stage.

10.310 Given the potential effect of this work on DETI's renewable generation targets, we sought DETI's views. DETI told us that it had no role in agreeing NIE's Connection Charging Policy and that this was a matter for the UR. It added that it had not discussed or expressed views as to how costs for 33kV reinforcement work should be recovered. DETI said that, given the constraints on the system, it was examining whether there were opportunities under the 2014–2020 European Regional Development Fund to part-fund investment in parts of the 33kV network. It said that approval for any such funding could take 18 months to two years. The UR noted that NIE's request for funding through the revenue control may affect the European Commission's consideration to bring forward funding for which the consumer may benefit.

[89] NIE response to provisional determination, Chapter 15, paragraph 1.1.
[90] 2009/10 prices.
[91] NIE response to provisional determination, Chapter 13, paragraph 1.9; UR response hearing, transcript page 47.
[92] NIE response to provisional determination, Chapter 15, paragraphs 1.6-1.11.
[93] UR response to provisional determination, paragraph 85

10.311 The Ulster Farmers Union said that 'conditional offers' to applicants wishing to connect to the network were creating uncertainty and that it supported NIE's request for a £30 million ex ante allowance for 33kV reinforcement work.[94]

10.312 Simple Power's view was that the same capacity could be made available on the 33kV network to connect renewable generation at a cost much less than £30 million. It said that there appeared to be simple, cost-effective solutions being applied on other networks in GB that would greatly benefit the small-scale renewable industry in Northern Ireland if they were applied. It said that our price control should include a mechanism whereby such solutions could be submitted to the UR during RP5.

10.313 Following the parties' response to our request for further submissions on this issue (see paragraph 10.305*(b)*), we outlined our proposed decision to them. We said that it was not in consumers' interest to make an allowance for further work in this area.

10.314 In response, NIE said that any EU funding was at least 18 months to two years away and NIE's understanding was that any potential EU funding would, at most, contribute only 50 per cent of the costs. It said that as a result of this decision:

(a) It would need to change its connection charging policy so that a generator connecting would pay the full cost of 33kV reinforcement works.

(b) It would need to withdraw around 130 conditional connection offers to small-scale generators—which would render the vast majority unviable.

(c) It might become impractical for NIE to draw down any significant EU funding that was made available because the scheme would rely on receipt of matching contributions from small-scale generator connections (which it said would be unviable).

(d) Stakeholders in small-scale generation would be very concerned.

10.315 In response, the UR said that it was generally content with the arguments put forward by us with regard to 33kV network reinforcement for small-scale renewable generation. It said that the £2.3 million investment it approved was considered to be consistent with NIE's duties to develop and maintain an efficient, coordinated and economical system of electricity distribution which had the long-term ability to meet reasonable demands for the distribution of electricity and to facilitate competition in the supply and generation of electricity. It said that it was continuing to work with NIE, SONI and DETI over the next year to progress the opportunities under the 2014–2020 European Regional Development Fund to part-fund investment in parts of the 33 kV network from which the consumer may benefit.

Our determination

10.316 We found that there was a disagreement between the UR and NIE as to how these costs should be treated and that NIE's connection policy did not currently allow for recovery of these costs. We considered that an upfront allowance was not a feasible option as NIE had itself accepted that an ex ante allowance was not an appropriate mechanism, and there was a lack of robust estimates of the costs that would be incurred. We noted that the UR had given approval for £2.0 million under the Dt term in October 2013, nearly all of which was due to be spent in 2014/15. We considered that there were two options—either to adopt NIE's proposal (see paragraph 10.308)

[94] UFU response to provisional determination.

or to make no further allowance over and above the legacy Dt costs already provided for.

10.317 We were not persuaded that this investment represented good value for money for consumers and we therefore decided that it was not in the public interest. We considered that NIE's proposal carried the risk that unnecessary or inappropriate investment might be made, with customers consequently being exposed to these costs. We also noted that, even if the costs were efficiently incurred, customers might be exposed to costs with little direct benefit.

10.318 We considered the risks of not giving an allowance. We were concerned that it might potentially deter or delay connections from small-scale generators and/or reduce the renewable generation provided to the network. It also ran the risk that NIE might have to make 33kV reinforcement work that would not be funded by either its connections charges or the revenue control. However, we considered that these risks could be mitigated by:

(a) The funding of £2.0 million already provided for under the Dt item, most of which remained unspent as at 31 December 2013.

(b) The UR and NIE reviewing the existing connections charging policy and considering further whether connecting parties should pay the full cost or whether all customers should continue to bear the cost on the basis that the connection of additional generation is of general benefit. However, it was clear that this work was not a priority for the UR at this stage.

(c) Funding for this work by other means. We noted that DETI and the UR were considering other mechanisms for gaining funding for this work so as to assist with meeting the renewables targets. The UR was concerned that providing an allowance would jeopardize this funding.

(d) NIE making connection offers which allow the generation on to the network without planning to reinforce the network. In this event the generator may at times be unable to export on to the network.

10.319 On balance, we decided that it was not in the public interest to make an allowance for further work in this area. This is because we believed that the risks of NIE's proposal outweighed any potential benefits. In addition, we considered that there were a number of ways in which any risks could be mitigated.

Cluster infrastructure

10.320 Where multiple generators seek new connections close to each other, it may be more efficient or better for visual amenity to construct new shared infrastructure as part of the connections rather than connecting each individually to the current network. NIE and the UR refer to such infrastructure as 'cluster infrastructure'. Our provisional determination did not include any specific proposals on cluster infrastructure. We set out below our determination in relation to cluster infrastructure in the light of NIE's and the UR's submissions on this issue.

NIE's submissions

10.321 NIE said that in May 2013, NIE and the UR concluded a process of establishing a methodology for cluster substations. NIE said that under this methodology it was agreed that where multiple wind generators sought new connections close to each other, it was more economic and efficient to construct shared infrastructure rather than connect each generator individually with separate infrastructure. NIE said that a key principle of the methodology was that all customers would fund the difference between the cost of connecting a cluster substation and the contributions received from developers until such time as the total available capacity at the site had been fully utilized and paid for by wind-farm developers connecting to the cluster. NIE requested that we make provision within our determination for the funding of costs associated with the development of cluster substations.[95]

10.322 NIE provided estimates of cluster infrastructure costs and forecast a funding requirement for the period to 30 September 2017 (net of generator contributions) of around £7 million. NIE said that its cost estimates would be refined during the pre-construction phase of each project in advance of NIE seeking construction approval from the UR.

Treatment of cluster infrastructure in NIE's statement of charges for connections

10.323 The charging principles for cluster infrastructure that NIE referred to fed into NIE's statement of charges for connections, applicable from 1 October 2013. This statement was approved by the UR. The statement specifies how NIE's cluster infrastructure costs and charges should affect the RAB and opex allowances that feed into NIE's maximum regulated revenue for transmission and distribution charges. The restrictions on NIE's maximum regulated revenue for transmission and distribution charges are the subject of our inquiry.

10.324 NIE's submissions setting out its proposed approach to cluster infrastructure suggested that all consumers (through distribution or transmission charges) would be providing working capital for the interim period between NIE incurring costs and charging generators. However, that would be an incomplete picture of the implications for consumers of the approach to cluster infrastructure in NIE's current statement of charges for connections.

10.325 The approach to cluster substations indicated in NIE's current statement of charges makes explicit reference to NIE's RAB : [96]

(a) Each year any costs that NIE incurs in relation to cluster infrastructure would be added to its RAB.

(b) There will be deductions from the RAB for any contributions from generators connecting to the cluster.

10.326 The approach to cluster infrastructure in NIE's statement of charges involves a case-by-case UR approval process for clusters and their costs:[97] 'The UR's approval is required for the capital expenditure associated with each cluster. This is because electricity customers may contribute initially to the cost of the cluster.'

10.327 NIE's statement of charges for connections states that in relation to generation cluster infrastructure (paragraph 7.10), there may be a shortfall in the recovery of costs (capital and O&M) by NIE and that any shortfall shall be recovered by NIE

[95] NIE response to provisional determination, pp159–161.
[96] NIE Statement of Charges, page 23
[97] NIE Statement of Charges, page 68

through network charges, by the addition of such costs to the RAB in respect of capital costs and by an addition to NIE's opex allowance in respect of O&M costs.

10.328 We identified that consumers may end up paying for cluster infrastructure costs, beyond the provision of 'working capital', for the following reasons:

(a) Some anticipated generation projects may be cancelled or downsized, meaning that there is unused capacity in the cluster that is never paid for by generators connecting to the cluster.

(b) NIE's costs (upfront capital or ongoing maintenance) may be greater than those it forecast and used to calculate connection charges paid by generators.

10.329 NIE also said in its statement of charges for connections that there could also be over-recovery of costs and, if so, these would lead to a reduction to NIE's RAB.

Submissions from the UR

10.330 The UR did not explicitly support or disagree with NIE's proposed treatment of cluster infrastructure within its distribution and transmission revenue control.

10.331 The UR told us that we had the authority to decide on this proposal as part of our determination, but cautioned as follows:

(a) The UR considered it beneficial if any deviation had agreement from both NIE and the UR. The UR said that if a dispute arose in relation to NIE's connection charges, the UR would have to make a legal determination on it based on its interpretation of its duties.

(b) NIE's statement of charges for connections (October 2013) is a document required under the licence. The UR said that any deviation away from this document would need to go through open consultation and approval by the UR.

Our assessment

10.332 We identified some concerns with the approach to cluster infrastructure in NIE's current statement of charges and proposed in NIE's response to our provisional determination:

(a) It enables full cost pass-through of NIE's cluster infrastructure costs to consumers in the event that NIE does not recover those costs from generators connecting to the infrastructure. There may be a lack of financial incentives for NIE to be efficient in the delivery of cluster infrastructure, with risks that consumers face charges reflecting inefficient expenditure.

(b) Consumers may face costs if the capacity subsequently used by generators connecting to cluster infrastructure is insufficient to recover the costs of the cluster infrastructure from connection charges. We did not identify any offsetting financial benefit to consumers from these arrangements. It did not seem obvious why consumers should be exposed financially in this way (eg rather than connecting generators paying a premium on costs to recognize the risks of under-utilized assets).

(c) There may be risks of delays and a disproportionate regulatory burden from the involvement requirement from the UR in the approval of cluster infrastructure

costs under the regulatory approval process in NIE's statement of charges for connections.

10.333 However, we also identified support from both the UR and NIE for that approach to cluster infrastructure. In particular:

(a) The UR and NIE seem to have spent considerable time developing the approach to cluster infrastructure.

(b) The approach proposed by NIE and included in its statement of charges for connections seems consistent with a UR-published decision on the approach to cluster infrastructure from April 2011.[98].

(c) NIE provided evidence (in the form of an unpublished four-page meeting note) of agreement between the UR and NIE in April 2013 on charging principles for cluster infrastructure that were consistent with the approach in NIE's statement of charges.

(d) The UR approved NIE's statement of connection charges, which includes NIE's approach to cluster infrastructure.

10.334 We considered that it would be unduly disruptive to the charging arrangements that NIE and the UR have established for cluster infrastructure if our determination did not allow them to be implemented. We recognized, in particular, that the development of alternative arrangements may take time (including consultation) and that there could be delays to generation projects and risks of missed opportunities for development of efficient cluster infrastructure.

10.335 Overall, we decided to that NIE's price control licence conditions should allow the costs that NIE actually incurs in relation to cluster infrastructure to be added to NIE's RAB (with deductions for relevant generator contributions) provided these are in line with the UR approval process and method for calculating RAB additions set out in NIE's statement of charges from 1 October 2013 (or any subsequent statement approved by the UR).

10.336 We suggest that the UR and NIE consider whether revisions can be made to the connection charging arrangements for cluster infrastructure to address the specific concerns identified above.

10.337 For the purposes of our financial modelling in Section 17, we have used estimates provided by NIE of RAB additions for cluster infrastructure to 30 September 2017 (net of generator contributions). These total around £6.6 million over the period. These NIE forecasts involve slight revisions to the forecasts in NIE's statement of case.

Storm costs relating to atypical severe weather

Background

10.338 This category of costs covers major storm events. These were classified by NIE and the UR as severe weather events costing more than £1 million, although both parties agreed that this definition should be redefined.

[98] UR decision paper, April 2011

10.339 In our benchmarking analysis (see Section 8), we used data for GB DNOs on costs relating to IMF&T. These are reported under the wider cost category used by Ofgem of 'network operating costs'. We did not include the costs reported by GB DNOs under another element of network operating costs which is 'Severe Weather—Atypical'. Ofgem defines an exceptional severe weather event in its regulatory reporting rules, with reference to a threshold number of incidents caused by the event which is specified separately for each company.

10.340 An allowance for NIE set on the basis of either the GB DNO benchmarking analysis or the historical level of IMF&T costs that we have used for NIE would not include provision for costs of atypical severe weather events (as defined by Ofgem) or the type of extreme event such as the March 2010 ice storm in Northern Ireland. We assumed that Frontier's exclusion of the costs attributed to the March 2010 ice storm was made on the basis that this would qualify under 'Severe Weather—Atypical' in Ofgem's reporting framework. We therefore considered how this category of costs should be treated in our determination.

Views of the parties

10.341 NIE did not make a request for an ex ante allowance for major storm events. It proposed instead that storms that gave rise to costs above £1 million should be subject to a force majeure arrangement under which the UR could make adjustments to NIE's maximum regulated revenue during the price control period to allow it additional money to cover the costs it incurs in these circumstances.

10.342 The UR also proposed regulatory arrangements involving the potential for ex post adjustment, determined by the UR, to provide NIE with additional revenue to cover the costs of atypical storm events.

Decision on storm costs relating to atypical severe weather

10.343 Under both the UR's and NIE's proposals major storm events would be passed straight through to consumers. We did not favour such an arrangement. First, we believed that wherever possible we should avoid cost pass-through which could expose consumers to unnecessarily high costs: we wanted to give NIE incentives to mitigate costs.

10.344 Second, we found that the proposed definition of a major storm that would trigger cost pass-through (an event costing more than £1 million) could give rise to perverse incentives when considered alongside our treatment of normal or typical storms (and other expenditure more generally).

10.345 This is because our benchmarked indirect cost allowance included an allowance for typical storms. If storms costing more than £1 million were passed through but storms costing less than £1 million were subject to an ex ante allowance, NIE would face a powerful incentive to increase the cost of storm events to the £1 million pass-through threshold. We found that such an arrangement would not be in the public interest and we therefore decided that it was appropriate to set an ex ante allowance in this area despite the inevitable difficulties in setting the level of the allowance.

10.346 We recognized that setting an ex ante allowance for severe weather involved a substantial degree of judgement. Such events are rare and costly. We first considered GB DNO data on gross costs for severe atypical weather. This data is shown below in Table 10.21.

TABLE 10.21 **GB DNO gross costs for severe atypical weather events, 2009/10 to 2011/12**

	2009/10	*2010/11*	*2011/12*
GB DNOs reporting cost in this category	0	0	1
Gross costs reported (£m)	0	0	5.3

Source: GB DNO data provided to CC by Ofgem.

10.347 It can be seen from Table 10.21 that over the three years of our data no GB DNOs reported costs in this category in 2009/10 or 2010/11 and one GB DNO reported costs in this category in 2011/12 (of £5.3 million). Over the three-year period of our sample the simple average cost per GB DNO was £126,000; for 2011/12 the simple average cost per GB DNO was £378,000.

10.348 In our provisional determination, we provisionally decided on an RP5 allowance of £200,000 a year, or £1.1 million for the whole period.

10.349 In response to our provisional determination, NIE said that severe weather events had occurred with much greater frequency in Northern Ireland than 1 in 20 years: there had been three such events in the period 2003/04 to 2012/13 which had in total cost £6.3 million.[99] NIE said that this implied an annual cost of £0.63 million and an RP5 allowance of £3.5 million. It said that the experience of three 'Severe Weather 1 in 20 events' in the period 2003/04 to 2012/13 meant that the CC should not base its allowance on the assumption that NIE would experience only one such event in 20 years.[100]

10.350 We asked NIE about the nature of storms in 2013/14. NIE said that there had been six storms since March 2013, all of which occurred between 5 December 2013 and 6 January 2014. It said that none of these would have passed the 1 in 20 threshold but that the aggregated impact was equivalent to a 1 in 20 event and cost £1.3 million (£1.1 million in 2009/10 prices). It said that this cost was greater than the CC's allowance for the whole of RP5.

10.351 In light of recent storm events, DECC has instigated a review into the effects of disruption, but these findings were not published ahead of our final determination.

10.352 We considered that the frequency of NIE's experience of severe weather events since 2003/04 was relevant evidence and was longer than the period of data that we had available for GB (see Table 10.21). We did not consider that the aggregated cost of storms in 2013/14 was relevant to our assessment because costs arising from non-severe weather events are already covered in our benchmarking analysis. On balance, we decided that NIE's experience in the last ten years meant that we should give a higher allowance than in our provisional determination. However, we did not want to base an allowance solely on NIE's experience and decided to take into account the GB data that we had obtained as this was the only benchmark data we had available. We decided on an RP5 allowance of £2.0 million for the whole period (ie an annual amount of £0.36 million).

[99] One low-cost event in 2003/04, one in 2007/08 (£3.7 million) and one in 2012/13 (£2.4 million).
[100] NIE response to provisional determination, Chapter 3, paragraphs 4.1–4.5 & Table 3.2.

Costs associated with aggregated generator units

10.353 In our provisional determination we included an additional allowance of £33,000 per year for operating costs associated with the arrangements for aggregated generator units (AGU). In a report submitted by NIE, Frontier Economics explains as follows:

> The AGU arrangements were established to facilitate a collection of small customer-side stand-by generators (geographically dispersed across NI) trading energy in the Single Electricity Market. NIE provides support for these market arrangements through its meter data collection and registration functions. These functions are not the responsibility of network operators in GB ...

10.354 The figure of £33,000 was based on NIE's costs for 2009/10 reported in its opex BPQ response.

10.355 Following our provisional determination, NIE provided us with updated data on its operating expenditure in 2010/11 and 2011/12 which we used for an update to the benchmarking analysis. In light of the updated data and to improve consistency across different elements of our cost assessment, we decided that it would be appropriate to set an allowance for NIE's operating costs associated with the arrangements for aggregated generator units based on an average of the costs over the three-year period from 2009/10 to 2011/12 (2009/10 prices). On this basis, we have determined an annual allowance of £17,000.

Legacy Dt costs

10.356 The RP4 licence contained a term (the Dt term) under which NIE could seek approval from the UR to fund specific items for which allowances had not been made. These allowances were maximum amounts and were only paid to the extent that actual costs which were properly and efficiently incurred were recovered by NIE.

10.357 We decided not to include a Dt term in our price control design. However, a number of the items which had been approved by the UR included expenditure which was potentially relevant to RP5. We therefore considered how these items should be treated within our price control.

Views of the parties

10.358 NIE said[101] that the figure for RP4 Dt items included in its Statement of Case (of £8.5 million) was based on a start date for the price control of 1 January 2013, not 1 April 2012. This figure therefore required updating. It said that an allowance should be made for the following items:

(a) opex for which NIE had received an allowance from the UR, which it had not fully spent by 1 April 2012 (and which therefore required carrying over to the RP5 control);

(b) additional renewables baseline opex, which had not yet been approved by the UR; and

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[101] NIE response to provisional determination.

(c) capex which had already been approved by the UR and which had not been fully spent by 1 April 2012.

10.359 Table 10.22 summarizes NIE's updated request with regard to RP4 Dt items.

TABLE 10.22 **Summary of NIE's request for legacy Dt items**

£ million, 2009/10 prices

Dt legacy item	*Amount unspent at 1.1.12*	*2012/13*	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*Total RP5 spend*
Opex approved by the UR							
(a) SONI pension deficit repair	4.3	1.7	1.7	0.9	0.0	0.0	4.3
(b) Network Management System	3.3	1.6	1.7	0.0	0.0	0.0	3.3
(c) North–South Interconnector	4.1	1.7	1.6	0.8	0.0	0.0	4.1
(d) Renewables baseline opex	0.3	0.3	0.0	0.0	0.0	0.0	0.3
(e) Smart Grid trial	0.1	0.0	0.1	0.1	0.0	0.0	0.1
(f) Market opening legacy systems cost	0.5	0.5	0.0	0.0	0.0	0.0	0.5
(g) Enduring Solution—transitional costs	0.7	0.7	0.0	0.0	0.0	0.0	0.7
(m) Enduring Solution project	0.2	0.2					
Total	13.5	6.7	5.0	1.8	0.0	0.0	13.5
Opex not yet approved by the UR							
(h) Additional renewables baseline opex	N/A	0.1	0.3	0.0	0.0	0.0	0.4
Capex approved by the UR							
(i) 33kV reinforcement	2.0	0.0	0.3	1.7	0.0	0.0	2.0
(j) Wind farm clusters	1.8	0.3	0.2	0.0	0.0	0.0	0.4
(k) Medium term plan I	5.1	1.8	0.2	0.0	1.8	0.0	3.8
(l) Medium term plan II	25.2	0.1	8.9	10.6	5.6	0.0	25.2
(m) Enduring Solution project	5.9	5.9	0.0	0.0	0.0	0.0	5.9
Total	40.0	8.1	9.5	12.3	7.4	0.0	37.3

Source: NIE response to provisional determination, Chapter 13, paragraphs 1.4–1.11 and Tables 13.1–13.2, and subsequent responses to CC questions.

Note: The Enduring Solution project covers both opex and capex.

10.360 These costs related to the following:

(a) 'SONI pension deficit repair' related to the transfer of the SONI pension deficit to NIE upon the disposal of SONI. The UR had approved £13.6 million expenditure on 30 June 2008 (nominal prices). NIE sought an allowance for £4.3 million in RP5. The UR said that these costs related to employees who no longer formed part of NIE and hence these costs were not incurred in relation to the services provided by the benchmarked DNOs and so an allowance should be made for them.

(b) 'Network Management System' related to the replacement of the network management system (NMS). The UR had approved £3.5 million (nominal prices) of opex in May 2012 and a further £0.3 million (nominal prices) in January 2013. As at 1 April 2012, none of the allowance had been spent. The UR said that an allowance should not be made for these costs because we had already made an allowance of £2.35 million a year for non-network capex and NIE had only spent £1.48 million in 2012/13 on non-network capex.

(c) 'North–South Interconnector' related to expenditure on the North–South Interconnector project. The UR approved £5.7 million (nominal prices) expenditure in several approvals running to September 2012, of which £4.1 million was unspent as at 1 April 2012. The UR said that costs relating to this project may not have been captured in the benchmarking exercise we had completed and so an allowance should be made.

(d) ‘Renewables baseline opex’ related to staff to support connections of large-scale wind farms onshore. The UR approved £0.3 million of expenditure on 23 April 2013. As at 1 April 2012, none of the allowance had been spent. The UR said that these costs formed part of our benchmarked costs and therefore should not be allowed.

(e) ‘SMART Grid Trial’ related to a project to test consumer habits in relation to use of smart meters. The UR approved £0.3 million (nominal prices) in June 2011. The UR said that allowance should be made for these costs.

(f) ‘Market opening legacy system costs’ related to the cost of the operation of the previous market system (before Enduring Solution). The UR approved £0.5 million of expenditure in June 2012. As at 1 April 2012, none of the allowance had been spent. The UR said that these costs should be allowed.

(g) ‘Enduring Solution – Transitional Costs’ related to the transitional costs for the Enduring Solution system. The UR approved £0.7 million in January 2013. As at 1 April 2012, none of the allowance had been spent. The UR said that NIE’s request for transitional costs for Enduring Solution for these costs appeared consistent with our provisional determination, although it noted that the claim was for the period after Enduring Solution went live and it was not clear if this would be a double count with our allowances given for Enduring Solution.

(h) ‘Additional renewable baseline opex’ related to costs NIE had incurred in the period up to 31 December 2012 for renewables baseline opex (see *(d)*). NIE said that it had continued, and would continue, to incur staff costs associated with renewables development activities at a run rate of approximately £30,800 per month (£26,500 in 2009/10 prices) from 1 January 2013 up to the date of the transfer of the transmission investment planning function to SONI. NIE said that the exact amount would depend on the date of transfer to SONI (currently anticipated to be in April 2014, which would give an allowance of £0.36 million in 2009/10 prices).[102] The UR said that, as with *(d)* above, these costs formed part of our benchmarked costs and therefore should not be allowed.

(i) ‘33kV reinforcement’ related to reinforcement of the 33kV network following connections of small-scale generators (see paragraphs 10.303 – 10.319). The UR approved £2.0 million for this work on 21 October 2013. NIE forecast that the great majority of this would be spent in 2014/15. The UR said that this capex should be included as an allowance and added to the RAB (but not within the D5 mechanism).

(j) ‘Wind farm clusters’ related to pre-construction work on four wind-farm-cluster substations (Killmallaght, mid Antrim, Pomeroy and Altahullion). The UR approved these projects on 21 December 2010, of which £1.8 million was unspent at 1 April 2012. Of these four projects: one had subsequently been abandoned; one had now been constructed with actual costs less than forecast; and two had been given planning permission with forecast spend lower than the UR’s approval. NIE forecast expenditure of £0.4 million in RP5. The UR said that an allowance should be made as an ‘up to’ pass-through amount, following the same mechanics as the D8 mechanism. It said that it did not consider that NIE’s forecast expenditure of £0.4 million (an underspend) was due to efficiency savings.

[102] NIE response to provisional determination, Chapter 13, paragraphs 1.10–1.11.

(k) ‘Medium term plan I’ related to three projects (reconductoring of sections of the line between (i) Kells–Coleraine and (ii) Omagh–Dungannon; and replacement of two transformers at Omagh main substation). These projects were part of NIE’s medium term plan (MTP) relating to network development to accommodate increased renewable generation. The UR approved £9.2 million for these projects on 15 June 2011, of which £5.1 million was unspent at 1 April 2012. NIE forecast expenditure of £3.8 million in RP5. The UR said that an allowance should be made as an ‘up to’ pass-through amount, following the same mechanics as the D8 mechanism. It said that any underspend on these projects was unlikely to be due to efficiency savings.

(l) ‘Medium term plan II’ related to three projects ((i) Kells–Coleraine uprating; (ii) Tamnamore substation phase 2; and (iii) Omagh–Tamnamore third circuit). The UR approved expenditure of £25.5 million on these projects on 22 February 2013 on a cost pass-through basis, of which £25.2 million was unspent as at 1 April 2012.[103] In its approval, the UR said that these costs would be added to the transmission renewables RAB and would be amortized at 3 per cent a year for the first 20 years and 2 per cent a year for the next 20 years. NIE said that these projects should be treated in a manner consistent with the original approval and that inclusion in the D5 mechanism would alter the risk balance and retrospectively change the basis of the approval. The UR disagreed with NIE and said that these three capex projects should be included within the D5 mechanism.

(m) ‘Enduring Solution project’ related to £27.7 million for the establishment costs of the Enduring Solution project. NIE said that this money was spent on computer hardware and software, IT implementation services and programme management services. The UR approved this capex on 18 June 2013 (£21.6 million of which had been spent prior to 1 April 2012), £6.1 million was unspent as at 1 April 2012, with £0.2 million to be allocated to opex and £5.9 million to be allocated to capex. The UR said that this expenditure should be added to the RAB but that its approval related to both opex and capex.

Our decision on legacy Dt costs

10.361 We considered each of the items in NIE’s updated request. In each case, we considered first whether we had already made an allowance for such expenditure elsewhere in our revenue control (for example, in our benchmarking analysis or capex allowances) and second, for any unspent amounts, whether an allowance should be made. We considered the opex and capex items in turn.

Opex

10.362 We decided that it was not appropriate to make an additional allowance for renewables baseline opex or additional renewables baseline opex. This was because in our view this type of expenditure was already covered within our benchmarked indirect cost allowances.

10.363 We decided that it was appropriate to make an allowance for the following items: SONI pension deficit repair; Network Management System; the North–South interconnector; Smart Grid trial; the cost of the market-opening legacy system; and Enduring Solution transitional costs. In each case these items covered expenditure which was not captured in our benchmarking exercise and for which allowances had

[103] www.uregni.gov.uk/uploads/publications/Medium_Term_Plan_Final_Decision.pdf.

not been made elsewhere in the revenue control. We noted that much of this expenditure had already occurred (in 2012/13 and 2013/14) and a total of only £1.8 million would apply for the remainder of RP5 (in 2014/15).

10.364 We noted that the UR agreed with this approach for all items except Enduring Solution transitional costs and the Network Management System. With regard to Enduring Solution transitional costs, our ex-ante allowance for this project (see paragraph 10.228) did not cover transitional costs and it was therefore appropriate to include an allowance for these costs here. Our allowance for the Network Management System was distinct from our non-network capex allowance and the two allowances related to separate expenditures (which both related to IT).

10.365 Our forecast for legacy Dt opex items is therefore £13.3 million for RP5, as set out in Table 10.23 below.

Capex

10.366 For the five capex projects, we found that these all related to projects for which we had not made an allowance elsewhere and which NIE had either already begun, completed or was committed to starting. We did not consider it in the public interest to change the approval process adopted by NIE under the Dt term on RP4 for these projects. However, we did need to consider the most appropriate treatment of these capex allowances under our new price control design.

10.367 We did not find that there was a reason to change to the terms of the original approvals made by the UR. We therefore decided that in each case the most appropriate treatment was the terms of the original approval as set out by the UR in its approval document.

10.368 Our forecast for legacy Dt capex items in RP5 therefore amounts to £37.3 million. Our allowances are summarized in Table 10.23.

TABLE 10.23 **CC allowance for legacy Dt items—opex and capex**

Dt legacy item	*2012/13*	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*Total RP5 spend*
Opex approved by the UR						
(a) SONI pension deficit repair	1.7	1.7	0.9	0.0	0.0	4.3
(b) Network Management System	1.6	1.7	0.0	0.0	0.0	3.3
(c) North–South Interconnector	1.7	1.6	0.8	0.0	0.0	4.1
(e) Smart Grid trial	0.0	0.1	0.1	0.0	0.0	0.1
(f) Market opening legacy systems cost	0.5	0.0	0.0	0.0	0.0	0.5
(g) Enduring Solution – transitional costs	0.7	0.0	0.0	0.0	0.0	0.7
(m) Enduring Solution project	0.2	0.0	0.0	0.0	0.0	0.2
Total	6.4	5.0	1.8	0.0	0.0	13.3
Capex approved by the UR						
(i) 33kV reinforcement	0.0	0.3	1.7	0.0	0.0	1.9
(j) Wind farm clusters	0.3	0.2	0.0	0.0	0.0	0.5
(k) Medium term plan I	1.8	0.2	0.0	1.8	0.0	3.8
(l) Medium term plan II	0.1	8.9	10.6	5.6	0.0	25.2
(m) Enduring Solution project	5.9	0.0	0.0	0.0	0.0	5.9
Total	8.1	9.6	12.3	7.4	0.0	37.3

Source: NIE and CC analysis.

Revenue deducted for customer contribution to operation and maintenance (O&M) charges

10.369 NIE's statement of charges provides that where authorized generators seek a connection that will be used wholly or mainly for export to the distribution system, the connection charge shall include an element to provide for the operation and maintenance (O&M) costs over the lifetime of the connection.[104]

10.370 Without some form of adjustment in respect of this feature of NIE's connection charges, NIE would be funded twice for an element of its O&M expenditure: first through the connection charge and then through the allowances we determined for NIE's indirect costs and its costs for IMF&T in Section 8.

10.371 For our provisional determination, we made an approximate estimate of the annual revenue from customer contribution to O&M charges. This estimate was based on NIE's current statement of charges for connections. NIE's statement of charges specifies that the O&M element of the connection charge shall be set at 1.2 per cent of the connection charge, discounted back to a present value using the regulated rate of return over the lifetime of the connection agreement. Where a connection agreement does not have a defined duration, an assumed duration of 20 years is used for the calculation of O&M charges.[105]

10.372 To estimate the total incoming revenue attributable to this element of connection charges, we took the relevant total amount of capital contributions from connection charges to be £7.8 million a year. This was the amount that was released to the profit and loss statement in 2009/10, and we considered that it reflected an average level of past capital contributions from customers. We assumed that half of the assets constructed attracted a capitalized operation and maintenance charge of 16 per cent.[106] Our estimate of the annual income attributable to the release of capitalized operation and maintenance charges was an allocation of the amount of capital contributions (£7.8 million) to O&M charges according to an estimate of the overall proportion of those capital contributions that are for O&M charges. This gave an estimate of £0.6 million.[107]

10.373 In its response to our provisional determination, NIE requested that our calculation of O&M revenue was adjusted to use more appropriate input data. NIE said that its analysis of connections capital additions in 2009/10 showed that 26 per cent of the cost of additions in that year was in relation to generation connections and requested that this figure replaced our assumption of 50 per cent. NIE also identified an oversight in the figure we had used for capital contributions from connection charges for 2009/10 and provided a revised figure of £7.3 million. NIE said that the revised estimate for annual revenue from customer contributions to O&M charges should be £0.3 million, rather than £0.6 million.[108]

10.374 We accepted NIE's submission that we should recalculate the estimate for 2009/10 using the revised figures it had provided.

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[104] NIE 'Statement of charges for connection to the Northern Ireland Electricity distribution system: effective from 1 October 2013', paragraph 6.6.
[105] ibid, paragraphs 6.6.3–6.6.5.
[106] Using a discount rate of 4.1 per cent and a notional series of charges of 1.2 per cent of asset value for 20 years, the resulting capitalized O&M charge is about 16 per cent of the asset value.
[107] This proportion is calculated as (0.16*0.5) / (0.5+0.5*1.16) which reflects the assumption from our provisional determination that 50 per cent of connections attract a 16 per cent capitalized charge on top of the asset value and 50 per cent just reflect the asset value.
[108] NIE response to provisional determination, pp29–30.

10.375 Following our provisional determination, NIE also provided us with updated data on its revenues and costs in 2010/11 and 2011/12 which we used to update the benchmarking analysis. In light of NIE's updated data and to improve consistency across different elements of our cost assessment, we decided that it would be appropriate to determine an estimate of the revenue attributable to the O&M element of connection charges by taking an average of estimates based on data for 2009/10, 2010/11 and 2011/12 rather than only using 2009/10 data.

10.376 We used the same estimation method as in our provisional determination, but revised our estimate for 2009/10 using input data provided by NIE (see paragraph 10.373). This gave an estimate of £0.29 million for 2009/10,[109] which is consistent with the figure provided by NIE in its response to our provisional determination. We used the same estimation method to produce estimated for 2010/11 and 2011/12, using updated data requested from NIE.[110] This produced estimates of the revenue from customer contributions to O&M of £0.26 million for 2010/11,[111] and £0.51 million for 2011/12.[112]

10.377 Taking an average across these estimates for 2009/10, 2010/11 and 2011/12, we decided to make a deduction of £0.36 million a year from our operating expenditure allowance for the contribution to NIE's O&M costs from capitalized O&M contributions.

Revenue deducted for tort insurance claims and scrap income

10.378 In a written submission to us following the hearing with the UR in December 2013, the UR asked that we consider how to account for 'unregulated income' which NIE receives for various directly chargeable activities. The UR highlighted that, under the current price control licence conditions, net unregulated income is deducted five years after it was received as part of the calculation of an allowance for NIE's operating costs.

10.379 Following further review of information on NIE's excluded services and data from NIE's regulatory accounts, we identified a need for a deduction from our cost allowances in respect of the income that NIE receives under the heading of 'tort insurance claims and scrap income'.

10.380 NIE's revenue from tort insurance claims and scrap income is treated as an excluded service for the purposes of NIE's price control licence conditions and does not form part of the restriction on NIE's maximum regulated revenue. This income can help to offset NIE's expenditure requirements for activities covered by the restriction on its NIE's maximum regulated revenue from transmission and distribution services.

10.381 In line with some other aspects of our cost assessment, and reflecting our use of a data set for our indirect and IMF&T cost benchmarking covering 2009/10 to 2011/12, we considered a deduction for NIE's revenue from tort insurance and scrap income based on its average income of the period 2009/10 to 2011/12, which was £1.45 million (2009/10).

[109] Calculated as 7.3*(0.16*0.26)/((1-0.26)+0.26*1.16).
[110] For 2010/11, NIE reported customer contributions of £7.4 million and that 23 per cent of the relevant costs related to generation connections. For 2011/12, NIE reported customer contributions of £7.5 million and that 46 per cent of the relevant costs related to generation connections.
[111] Calculated as 7.4*(0.16*0.23)/((1-0.23)+0.23*1.16).
[112] Calculated as 7.5*(0.16*0.46)/((1-0.46)+0.46*1.16).

10.382 NIE submitted that a revenue deduction based on its average tort insurance and scrap income over the three years from 2009/10 to 2011/12 would not be appropriate, owing to the abnormally high tort and scrap income over these years and the availability of some data on its actual tort and scrap income since 1 April 2012.

10.383 NIE reported that it incurred costs associated with damage to its cables as a result of construction work at a new hospital site of £574,000 in 2010/11 and £944,000 in 2011/12 and that its tort income in relation to these costs was £574,000 in 2010/11 and £906,000 2011/12. NIE said that the costs and the tort income associated with the damage at this hospital site was totally exceptional in nature and should be excluded from our analysis of NIE's tort income (and also from our analysis of NIE's costs).

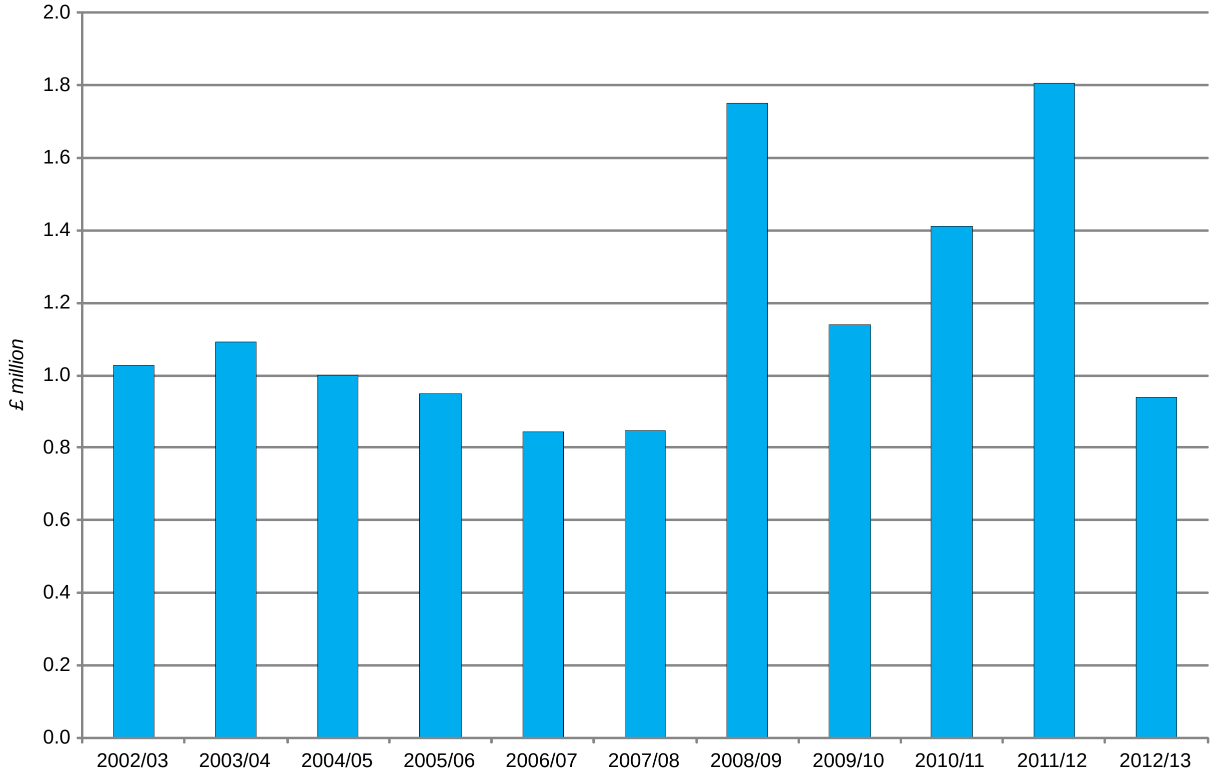
10.384 NIE provided information on its revenue from tort and scrap income since 2002/03. NIE said that this revealed that these revenues in 2011/12 were very much greater than was typical, with recoveries in 2010/11 also materially above longer run averages. NIE submitted that for future years we should determine an adjustment by reference to a longer run of data, and may in particular wish to give weight to the full series of data that NIE had provided which suggested to NIE a long-run average recovery of £1.129 million a year (2009/10 prices). NIE also provided recent data (for 2012/13 and 2013/14) that it said suggested a return to historic average levels of recovery of £1 million a year or less.

10.385 NIE also said that, if a deduction was applied for the period from 1 April 2012 based on its average tort and scrap income from 2009/10 to 2011/12, it would impose an immediate and unjustified loss on NIE in the years 2012/13 and 2013/14. NIE said that we would, in effect, be imposing retrospectively a deduction to allowances that would result in NIE bearing a wholly unjustified loss (of £514,000 in 2012/13 and £703,000 in 2013/14), simply because it has made 'normal' levels of recovery. NIE said that there could be no justification for the retrospective application of a discount in respect of tort, insurance claims and scrap income, and NIE submitted that for these two years which were now (completely or very largely) in the past, we should make use of actual out-turn data when modifying allowances.

10.386 Figure 10.1 shows NIE's tort and scrap income over the period 2002/03 to 2012/13, based on the data provided by NIE.

FIGURE 10.1

NIE's tort and scrap income (£ million, 2009/10)



Source: NIE.

10.387 The UR said that, while tort and scrap income may have been abnormally high between 2009/10 and 2011/12, we should be consistent with the methodology we have applied in different parts of our cost assessment. This is because, for example, other cost assessments may have also been based on an exceptional year, which could be to NIE's benefit. The UR proposed that, to be symmetrical, we should use the same base period methodology across the other elements of cost assessment.

10.388 In our view Figure 10.1 does not support NIE's contention that we should ignore its income in 2010/11 and 2011/12 and give weight to the full series of historical data from 2002/03. For instance, although NIE described the damage at the hospital site in 2010/11 and 2011/12 as 'totally exceptional', the average of NIE's tort income in these two years (£1.61 million) was lower than its tort and scrap income in 2007/08 (£1.75 million). Although there are fluctuations in the level of income over the period of the chart, the data suggested that NIE's tort and scrap income has increased over time. NIE's submissions did not persuade us that it was appropriate to take an average of NIE's income from 2002/03 or to ignore the tort income that NIE received in 2010/11 and 2011/12 in relation to the damage at the hospital site.

10.389 We did not agree with NIE's view that the deduction for NIE's tort and scrap income in 2012/13 and 2013/14 should be based on actual out-turn data. First, the out-turn data from NIE for 2013/14 did not cover a full year and covered a period of time for which NIE had not yet prepared its statutory or regulatory accounts. Second, we did not take NIE's out-turn expenditure data for other elements of our cost assessment that covered periods in the past. The deduction we made for tort income over the period 1 April 2012 to 30 September 2017 is not a deduction against NIE's out-turn expenditure in that period but rather a deduction against regulatory cost allowances that we have determined, including cost allowances based on GB DNO cost benchmarks. Third, an estimate of a reasonable deduction over 5.5 years allows for more smoothing of year-to-year fluctuations in tort and scrap income than an estimate that applies over 3.5 years. We were satisfied that the annual deduction we made represented a reasonable estimate of annual average tort and scrap income for the entire period from 1 April 2012 to 30 September 2017, even recognizing that this annual average was higher than NIE's actual tort and scrap income in 2012/13 (and higher than NIE's forecast income for 2013/14).

10.390 In light of NIE's submissions and the fluctuations in tort and scrap income from year to year, we decided to make a deduction from NIE's regulatory cost allowances based on NIE's average tort and scrap income from the start of the RP4 price control (2007/08) to the most recent full year of data from NIE (2012/13). In our view this dataset, spanning the six most recent full years, provides an appropriate basis on which to forecast a relatively volatile item. .On this basis, we determined that £1.31 million per year should be deducted from NIE's opex allowance over the period 1 April 2012 to 30 September 2017. We did not agree with UR's view that it was necessary to use the same historical period for all elements of our cost assessment. We were concerned that a focus on data for the three-year period from 2009/10 to 2011/12 would give too much weight to relatively high levels of tort and scrap income in 2010/11 and 2011/12 and did not expect this to be offset by other elements of our cost assessment.

10.391 We considered other sources of unregulated income to NIE. We did not identify any excluded services which warranted a further deduction. Most of NIE's revenue from excluded services comes from connection charges and we sought to exclude the costs of connections work from our cost allowance for NIE. Our allowance for NIE's indirect and IMF&T costs in Section 8 is based on benchmarking analysis that excludes indirect costs attributed to connections and our allowances for NIE's network investment direct costs does not include work which we expect to be covered by connection charges.

10.392 In its written submission following the hearing with the UR in December 2013, the UR suggested that there may be an issue with the unregulated income during the RP4 price control period being 'stranded', which may call for an adjustment as part of our determination. We did not accept that any adjustment was necessary for unregulated income earned by NIE that the UR had suggested was 'stranded'. We set cost allowances for NIE's opex over the period 1 April 2012 to 30 September 2017 and in doing so we deducted a forecast of NIE's revenue from 'tort insurance claims and scrap income' (based on historical data). We did not consider that any further adjustment was needed. The deduction of excluded services income from five years previously was a feature of the method used to set an allowance for NIE's opex under the RP4 price control framework. As part of our determination, we made substantial changes to that framework including changes to the method used to set allowances for NIE's opex. We did not consider it appropriate to seek to compensate consumers or NIE for the financial effects of any changes from one price control framework to the next.

Research and development

Our provisional determination

10.393 In its statement of case, NIE sought £2.5 million over the RP5 period for R&D. No such allowance was provided in the UR's final determination for RP5.[113]

10.394 In GB, Ofgem has developed a complex set of regulatory arrangements to provide DNOs with funding for R&D and other innovative activities. This includes the Low Carbon Networks Fund (LCNF) through which DNOs can bid for funding which is paid for through charges to consumers.

10.395 NIE told us that the costs incurred by GB DNOs in relation to the LCNF and other innovation-funding schemes were not included in the DNO's core regulated costs and that, absence a specific allowance, our benchmarking analysis of indirect costs and IMF&T costs would not provide funding for NIE to carry out R&D.

10.396 NIE provided some information on the R&D it expected to undertake in its Statement of Case,[114] which we considered as part of our assessment. However, NIE did not provide detailed information on how it proposed to spend an R&D allowance and why this expenditure was likely to be in consumers' interests.

10.397 We did not accept that NIE would do no R&D or innovative activities if we made no allowance for it. For example, the use of benchmarking analysis in price control reviews provides some incentives for improvements that can help reduce costs. Further, NIE would have the opportunity to propose innovative investment projects, on which it could earn a return on capital, as part of its investment plans at future price control reviews.

10.398 However, we accepted that NIE might not face the same pressures to innovate as a firm in a competitive market. An allowance for R&D could help increase NIE's innovative activity. Even so, compared with firms in a more competitive market or commercial environment, NIE would not face the same degree of market discipline and feedback processes that help direct R&D and innovative efforts to productive uses.

10.399 We considered two options:

(a) No specific additional allowance for R&D.

(b) A special allowance for R&D of £0.5 million per year on a 'use it or lose it' basis (ie an allowance of £0.5 million per year, but with a provision for a future revenue adjustment to claw back any amount of this allowance that is not spent on R&D). Under this approach NIE would report to stakeholders annually, through a publication on what it has done with the R&D allowance.

10.400 In our provisional determination, we proposed that, on balance, the public interest was best served by option *(a)*, under which we provided no additional allowance for R&D.

[113] NIE Statement of Case, p159.
[114] ibid, pp159–162 & 250–252.

NIE's response to our provisional determination

10.401 NIE raised two main concerns with the proposed approach to its request for an R&D allowance in our provisional determination:[115]

(a) NIE argued that the emphasis we placed on using cost benchmarking analysis across the GB DNOs meant that it was incoherent not to provide an extra revenue allowance for R&D and that our benchmarking analysis would place NIE at a disadvantage compared with the GB DNOs; and

(b) NIE said that it would be in the public interest for the revenue control to provide it with an allowance of R&D of £0.5 million per year on a 'use it or lose it' basis and provided further information on what it envisaged.

10.402 We discuss more detailed elements of NIE's submissions, and some further comments made by NIE at the hearing with NIE in December 2013, in the assessment that follows.

Third parties' responses to provisional determination

10.403 In its response to our provisional determination, NIRIG raised concerns at the low level of allowance provided for innovation. It said that in an era of significant changes to both the generation mix and potential demand-side management, NIE should have the resources and flexibility to respond with innovative solutions.

10.404 The UFU said that it was disappointed that our provisional determination had not appropriately addressed R&D. It said that the current connection problems experienced in the lower-voltage line had forced landowning generators to look at alternative ideas. The UFU highlighted potential innovation for the distribution system in Northern Ireland but said that this would only work if supported by buy-in from NIE (and other decision-makers) in the form of a commitment to enhanced R&D. The UFU warned of an opportunity missed in terms of both job and knowledge creation.

Our assessment of NIE's submissions on implications of benchmarking analysis

10.405 NIE said that the approach we took in our provisional determination placed NIE at a considerable disadvantage relative to the GB DNOs against which NIE was benchmarked which received additional revenue for R&D funding. NIE said that our approach of using cost benchmarks from GB DNOs but not also providing an extra revenue allowance for R&D equivalent to that provided to GB DNOs (and not adjusting the GB DNO cost data to take account of the difference between NIE and GB DNOs in opportunity to conduct R&D and other innovative activities) was incoherent.[116]

10.406 NIE noted that the PD contemplated (but provisionally rejected) an option which would provide NIE with a special allowance for R&D of £0.5 million per year on a 'use it or lose it' basis. While noting that this would represent only some 50 per cent of the funding available to an equivalent GB DNO, NIE confirmed that this option would be acceptable to NIE for RP5.

10.407 At the hearing in December 2013, NIE said that one of the GB DNOs had picked out particular Low Carbon Network Fund projects and its own innovation as something that it thought would contribute to it being able to deliver the 1 per cent ongoing

[115] NIE response to provisional determination, pp195–199.
[116] ibid.

productivity improvements. NIE said that although it could copy best practice from elsewhere, there was still the need to apply it to NIE's own slightly unique circumstances and, as things stood, NIE was not funded for that adaptation.

10.408 We did not accept the implications of NIE's arguments that the emphasis we have placed on benchmarking analysis requires, for coherence, NIE to be given an explicit funding allowance for innovation from its revenue control. This was for three reasons:

(a) The type of R&D activity that NIE had identified in its provisional determination response as a priority for additional funding if an additional R&D allowance was provided (see paragraph 10.411) did not seem well suited to reducing NIE's indirect and IMF&T costs and its network investment unit costs.

(b) Despite NIE's reference at the hearing to the link drawn by one of the GB DNOs between its innovation funding and ongoing productivity, NIE recognized in its response to our provisional determination[117] that the specific innovation funding that Ofgem provided to GB DNOs was not primarily directed at helping DNOs to reduce the costs which were the focus of the benchmarking analysis we have used for our determination (eg indirect and IMF&T cost benchmarking and network investment unit cost benchmarks); instead that funding for GB DNOs was intended to contribute to innovation relating to (other) aspects of government energy policy. While there may be some spill-over effects from the GB DNOs' innovative activity, the purpose of the additional R&D funding provided through Ofgem's price controls is not to reduce the types of costs and unit costs that have fed into our benchmarking analysis for NIE.

(c) There are a number of ways in which NIE differs from the GB DNOs. Any benchmarking analysis must tolerate some differences between the companies in the sample that are not fully adjusted for. On balance, we did not consider our benchmarking analysis unfair to NIE.

10.409 We decided that NIE's argument on the use of benchmarking analysis for NIE's price control does not, in itself, provide grounds to include an additional allowance for R&D in our cost assessment.

Our assessment of the public interest case for additional R&D allowance

10.410 NIE requested that we provided a special allowance for R&D of £0.5 million per year on a use-it-or-lose-it basis (an option we considered but rejected in our provisional determination). NIE said that this would be in the public interest. It said that we had missed the point about what the innovation allowances provided by Ofgem were designed to achieve, including achievement of government energy targets.

10.411 NIE sought to respond to the concern raised in our provisional determination that it had not provided detailed information on how it proposed to spend any R&D allowance by providing a short outline of its R&D priorities for the RP5 price control period and highlighting the public interest benefits of such work. The R&D priorities identified by NIE were as follows:[118]

(a) Identify and investigate developing active network control technologies. NIE said that this was intended to facilitate maximum penetration of small-scale generation on the 11 kV network which requires the development of advanced active

[117] ibid, p197.
[118] ibid, p196 - 199.

network control and voltage control systems that could reconfigure the state of the network, and the connected generation, in response to varying network demands and generator output conditions.

(b) Investigate technical challenges and the potential benefits of Energy Storage. NIE said that this was intended to investigate the feasibility of connecting energy storage devices on the distribution network to manage the output of variable generation (such as wind turbines) and improve the contribution of embedded generation to security of supply on the distribution network.

(c) To consider potential commercial models to allow NIE to contract with specific embedded generators, energy service providers and demand customers in areas with limited network capacity to enable NIE to better manage energy flows (eg demand-side management) in response to network issues. NIE said that such commercial arrangements were essential to ensuring that the benefits of technical innovations could be utilized in practice by NIE as alternatives to conventional expansion of the distribution network.

(d) To consider relevant learning emerging from the LCNF-funded R&D being undertaken by GB DNOs and consider opportunities for this to be applied by NIE. NIE would also continue to work in collaborative research with industry, academia and other DNOs on other areas of common interest.

10.412 NIE submitted that it is in the public interest for the RP5 price control to provide a better balance between the short term benefits of reducing costs to customers during RP5 (by providing no funding for R&D) and medium to long term considerations that are necessary enablers of government energy policy, such as actively facilitating the connection of renewable generation and wider environmental and economic public interest benefits. NIE stated that the achievement of government targets for sustainability depends on radical changes in the design and operation of existing distribution networks which can only be delivered in practice through regulatory arrangements that are fully focused and aligned with government energy policy. [119]

10.413 NIE argued that unless NIE conducts R&D during RP5, electricity customers in NI will bear the risk that the design, operation and commercial arrangements governing the distribution network will present a barrier to the pace of change in emerging technologies that are actively encouraged by government initiatives and incentives. These include facilitating consumer-led demands such as electric vehicles, micro and small scale generation, as well as the potential benefits offered by smart metering to the distribution network. NIE said that, more generally, electricity customers in NI run the risk of reduced quality of supply, higher connection charges (e.g. customers with renewable generators) and higher capital investment in the medium to longer term than might have been the case if sufficient R&D to assess emerging technologies had been invested upfront.

10.414 NIE said that the public interest benefits that arise from it undertaking this work in RP5 include:

(a) Lower DUoS charges for all electricity customers (because of lower network investment costs);

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[119] NIE response to provisional determination, pages 196 to 199.

(b) Environmental benefits (because of the reduced need for network expansion as well as increased contribution of renewable generation to meeting government targets to reduce emissions);

(c) Lower connection costs for customers with small scale generators and other new technologies;

(d) Connection of new technologies to the network managed without compromising quality or security of supply experienced by electricity customers; and

(e) Other societal benefits for job creation and the wider NI economy.

10.415 NIE said that with specific funding, some of these benefits are likely to begin to materialise during RP5 with consequential benefits to customers.

10.416 At the hearing, we asked NIE to elaborate on its submissions for the R&D allowance and to explain its contention that 'there is no detriment to customers overall in providing an R&D allowance as there can be no doubt that R&D is a benefit to customers in the shorter and longer term'.[120] NIE referred to the nature of the R&D that it would do. It said that it was not in the business of leading-edge research, but that it made sense for NIE to be a 'fast follower'. It said that, with modest funding for the RP5 price control period, it could do quite a lot by learning from the GB DNOs but that work would still be needed by NIE to apply lessons to NIE's own system and circumstances. NIE highlighted the work that the GB DNOs had done over the last several years on smart grid initiatives to connect more distributed generation. NIE said that the key focus of its innovation would be to alleviate problems on the distribution network relating to the connection of distributed generation and that the detriment from these problems was not of particular detriment to NIE, but rather to generator developers and Northern Ireland consumers more generally..

10.417 In the light of NIE's response to our provisional determination and the discussion of R&D at the hearing with NIE in December 2013, we reconsidered whether an additional allowance for R&D of £0.5 million per year on a use-it-or-lose-it basis would be in the public interest.

10.418 We thought that NIE's response to our provisional determination and further submissions gave too little weight to the costs to consumers from its proposed R&D allowance. We did not accept NIE's view that 'there can be no doubt that R&D is a benefit to customers in the shorter and longer term'[121]or that R&D would necessarily lead to 'lower DUOS charges for all electricity customers'[122]NIE's response ignored the possibility that the outcomes for consumers from the allowance are not worth the costs to them. Further, the costs would fall on the generality of consumers through use of system charges even though some of the main beneficiaries of NIE's R&D priorities (paragraph 10.411) would be generation developers.

10.419 We were not persuaded by NIE's further submissions following our provisional determination. The additional information that NIE provided was relatively brief: a short outline of NIE's R&D priorities (less than a page of text) and a high-level list of the public interest benefits that NIE envisaged (less than half a page of text). Further, we thought that NIE might do some of the activities it had identified as R&D, such as review of its commercial arrangements, as part of its normal business.

[120] ibid, p195.
[121] ibid, p195.
[122] See paragraph 10.414(a)

10.420 Overall, we decided not to provide the additional allowance for R&D that NIE had proposed, as we were not confident that such allowance would be cost-effective for consumers.

Road and street works legislation

10.421 In its Statement of Case, NIE said[123] that it would incur additional operating costs associated with new RASW legislation once the Street Works (Amendment) (Northern Ireland) Order 2007 had been brought into force. NIE said that these costs would relate to opex and capex and could relate to:

(a) overrun changes where work exceeded the required limit;

(b) permit schemes in relation to which NIE is required to pay to carry out work within specified areas; and

(c) the additional costs of directions to NIE as to when work could be carried out (eg at weekends or after working hours).

10.422 NIE submitted opex forecasts of £2.1 million in relation to RASW legislation.

10.423 As discussed in paragraphs 9.75 to 9.79, over the course of our inquiry we received further information on the proposed changes to RASW legislation.

10.424 DETI told us that the Department for Regional Development (DRD) was no longer actively progressing the RASW proposals in Northern Ireland, although the primary legislation remained in place and DRD reserved the right to review the position in the future. DRD said that there was no longer a robust business case for introducing such a scheme and that there were no plans to review that decision at present.

10.425 We made no upfront allowance in relation to additional costs that NIE may incur as a result of new RASW legislation. If such costs do arise, NIE would be able to seek a change to the revenue restriction in its licence conditions through the change of law provision.

10.426 NIE told us that given the uncertainties regarding implementation of the RASW legislation, NIE would be content with this approach.

Enhanced regulatory reporting requirements

10.427 We did not include any additional allowance for changes in NIE's regulatory reporting requirements.

10.428 In its Statement of Case, NIE said that it would incur additional costs relating to the UR's proposed reporter function which were not recognized by the UR.[124] Since we are not supporting the specific proposals made by the UR for a new reporter function NIE will not incur these costs and we made no allowance for them.

10.429 We decided that NIE should report costs in line with the Ofgem regulatory reporting arrangements for GB DNOs. We recognized that these changes in the regulatory reporting obligations for NIE could give rise to material increases in indirect costs.

[123] ibid, pp156 & 157.
[124] NIE Statement of Case, p158.

10.430 We did not include any additional allowance for regulatory reporting costs as part of our cost assessment in our provisional determination. This was not because we did not accept the principle of making an additional allowance but rather because we were unable to quantify what an appropriate allowance might be. We proposed to review any submissions from NIE and other stakeholders on a cost adjustment for regulatory reporting set-up costs in reaching our final determinations.

10.431 In Section 18 we set out our treatment of costs relating to regulatory reporting under Ofgem's RIGS framework.

Information leaflets and advertising in relation to ESQCR

10.432 NIE forecast £0.2 million over the RP5 period 'for the production of information leaflets and advertising in order to meet NIE's obligations under the ESQCR legislation'.[125] We did not make an adjustment to our cost assessment. The GB DNOs faced obligations in relation to ESQCR legislation in the years covered by our benchmarking analysis. We would expect any costs relating to information leaflets and advertising to be included within a GB DNO's indirect costs.

Workforce renewal

10.433 In its Statement of Case, NIE requested £4.9 million for workforce renewal over the RP5 period.

10.434 NIE said that at its last price control review Ofgem provided a separate allowance for workforce renewal of £173 million.[126] We confirmed this amount in Ofgem's final proposals: it is the total across 14 GB DNOs for the five-year period in 2007/08 prices.

10.435 Ofgem's glossary for its current price control review defines workforce renewal as follows:

> Workforce renewal involves the recruitment of training of new staff and upskilling of existing staff to replace leavers from the operational workforce (roles meeting definitions of 'craftsperson', 'engineers' and 'non-engineering roles'). It includes learner costs associated with both classroom and new recruits and upskilling. It includes trainer and course material costs associated with classroom training. It also includes training centre and training admin costs associated with new recruits and upskilling. It includes the recruitment costs associated with operational trainers.

10.436 NIE explained in its Statement of Case why it expected cost increases relating to training and recruitment which fell under the category of workforce renewal.

10.437 In its RP5 proposals, the UR did not include an allowance for workforce renewal. The UR said the following in its submissions to us:[127]

> Given the state of the economy in Northern Ireland (and in the wider UK and in the Republic of Ireland), it is difficult to understand why labour costs ought to increase substantially over the RP5 period. NIE T&D

[125] ibid, p159.
[126] ibid, p147.
[127] UR Statement of Case, p5.

suggested that the consequence of not allowing it to increase spending on wages was that skilled staff would leave to take up employment elsewhere, but NIE T&D was unable to provide convincing evidence to support that proposition. Moreover, to the extent that the additional workforce opex costs anticipated by NIE T&D were associated with the extraordinary capex programme that it had proposed, they would not in fact be likely to be incurred in light of the findings that we reached in relation to capex (as to which see our paper on capex). That is something that can be revisited during the course of this inquiry if the Commission takes a different view of the amount of capex that is required.

10.438 Our assessment of these issues started from the perspective that the costs that GB DNOs experienced relating to workforce renewal in 2009/10 are reflected in our benchmarking analysis.

10.439 NIE suggested that this would provide an insufficient allowance because 'the GB DNOs were ramping up their expenditure on workforce renewal during 2009/2010 (the last year of DPCR4) but that expenditure had not reached the level embodied in the DPCR5 allowances'.

10.440 Our view was that workforce renewal costs are included in our benchmarking analysis and that it would amount to double counting to add in NIE's forecast from its Statement of Case of £4.9 million over the RP5 period.

10.441 However, we accept that if there have been significant increases in workforce renewal costs across the UK then our allowance may underestimate NIE's costs in relation to workforce renewal.

10.442 NIE suggested that we could seek data from Ofgem to examine how costs specifically related to workforce renewal have changed over time.[128] We have not done so. We would be reluctant to make an adjustment to our cost allowance for NIE on the basis that one specific category of costs has increased over time. Other categories may have decreased. Such an approach would be asymmetric.

10.443 We did not make an adjustment for workforce renewal. We have not identified a sound basis on which to make such an adjustment in light of the issues above.

10.444 We should highlight that there are other areas of our cost assessment where the lack of information to determine a reasonable adjustment has worked in NIE's favour. For instance, we included a separate allowance for Enduring Solution. However, the indirect cost benchmarking analyses submitted by NIE and the UR recognized that some element of the costs of Enduring Solution were likely to cover activities that are carried out by GB DNOs. In this respect, adding a separate allowance for Enduring Solution to cost benchmarks from analysis of GB DNOs may include an element of double counting. NIE suggested that the extent of overlap might be in the region of £0.13–£0.19 million,[129] while the UR suggested that a figure of £500,000 was conservative. Neither party provided an explanation of its figures and we found it an area that it was difficult to come to a reasonable decision on and have made no explicit adjustment.

[128] ibid, p6.
[129] ibid, p188.

Distribution service centre: additional operating costs

10.445 NIE sought an allowance of £0.8 million over the RP5 period for additional opex relating to its distribution service centre which it said arose from the proliferation of renewable generation connecting to the system.[130] These costs were based on NIE's view that it needed to recruit four additional staff, three within the SCADA section and one control engineer. NIE reported that the UR included no such allowance as part of its RP5 proposals.

10.446 This aspect of NIE's submissions raises similar issues to workforce renewal, albeit with a smaller level of costs forecasts by NIE:

(a) Costs related to NIE's distribution service centre fall under the Ofgem category of indirect costs and the allowance we make based on our benchmarking analysis should already reflect such costs.

(b) NIE submitted that increases over time in the level of distributed generation connections meant that its costs would be higher than those implied by benchmarked costs from 2009/10.

10.447 Given the relatively small scale of the costs forecast by NIE (around £160,000 per year) and the difficulties we face in estimating the incremental impact of *(b)*, we did not make an adjustment to our cost assessment.

PAS 55

10.448 In its Statement of Case, NIE sought an additional £0.1 million to cover the costs of PAS 55 certification (which NIE has now gained). We did not include a separate allowance for PAS 55. This did not meet the criteria set out at the start of this section and we did not identify any other reason to include it.

10.449 NIE submitted a further argument why a specific allowance for PAS 55 certification was appropriate:

> Throughout the price review UR placed considerable emphasis on PAS 55 and included an allowance of £0.1 million in its FD in line with NIE's submission for costs associated with gaining accreditation in RP5. NIE took this as a de facto obligation, and proceeded in good faith with the certification process, even though the price control was not settled at that point. As CC will be aware, PAS 55 certification has now been achieved – in advance of the RP5 price control taking effect. Consultancy costs incurred to date and to be incurred over the next 12 months (associated with post certification surveillance audits) are expected to amount to c £0.1 million. Their recovery should be provided for in the RP4 price control modifications for the period 1 April 2012 to 30 September 2014.

10.450 We did not accept this argument. We did not consider that NIE is entitled to revenue to cover the costs it incurred obtaining PAS 55 certification by virtue of the fact that the UR placed emphasis on such certification and included an allowance for it in the price control proposals that NIE rejected.

[130] NIE Statement of Case, p169.

Transfer of activities to SONI

10.451 The EU decision on TSO certification which requires the transfer of transmission planning activities to SONI was made on 12 April 2013.

10.452 NIE submitted its Statement of Case to us in May 2013. The expenditure forecasts in its Statement of Case did not take account of the transfer of transmission planning to SONI.

10.453 In October 2013, NIE sent us a short submission which set out the changes required to NIE's expenditure forecasts as a result of the proposed transfer of activities to SONI, which is anticipated to take effect on 1 April 2014. NIE forecast that the transfer would result in reductions in operating costs of around £2 million a year against its original plan (that plan included substantial increases in opex related to work to accommodate renewable generation; NIE referred to this as the renewable baseline). NIE also identified reductions to its pension costs.

10.454 This submission from NIE was just over a page in length. It did not provide a basis on which we could make an assessment of the impact of the anticipated transfer on our cost assessment. Further, there remained uncertainty about the details of that transfer and it seemed difficult to estimate the impact on NIE's costs.

10.455 The UR told us that it was not necessary for us to consider the impact of the anticipated transfer of some transmission network planning responsibilities to SONI as part of our inquiry and that the details of final roles and responsibilities would not be approved until after February 2014.

10.456 Given the time frame of our inquiry and the uncertainty about the details of the transfer from NIE to SONI, we made our cost assessment on a basis that excludes the planned transfer to SONI. We decided that the UR should make an adjustment to NIE's price control licence conditions as part of the modifications to NIE's transmission licence to implement the transfer of transmission planning to SONI. We would expect the UR to take account of the way that we have made our cost assessment in deciding on an appropriate adjustment (eg our use of GB DNO benchmarking for indirect costs and an adjustment to scale up benchmarked costs to include an allowance NIE's 275 kV network).

11. Real Price Effects and productivity

Introduction

11.1 Over a revenue control period, an efficient firm will be subject to two different pressures on its cost base:

(a) *productivity* (for example, increased output with constant inputs), for which we estimate potential incremental efficiency improvements over the period; and

(b) *input prices* (for example, labour and materials), for which we estimate RPEs[1] over the period.

11.2 In this section, we set out how we expect an efficient firm's costs to move compared with RPI. This is so that we can apply any difference (either positive or negative) to NIE's cost allowances so that they better reflect the likely path of costs which an efficient firm would face. The section is structured as follows. We:

(a) explain the period relevant to our determination (paragraphs 11.3 to 11.10);

(b) estimate productivity and RPEs using a bottom-up approach (paragraphs 11.11 to 11.81);

(c) compare our bottom-up estimate with relevant indices and recent regulatory determinations (paragraphs 11.82 to 11.87); and finally

(d) apply the combined effect of productivity changes and RPEs to NIE's cost allowances (which are set out in Sections 7 to 10) (paragraph 11.88).

The relevant period for our determination

11.3 Our determination of this price control had the unusual feature that we were setting allowances and considering productivity gains and changes in input prices part way through the price control period. We therefore had to consider how best to apply productivity changes and RPEs to historic data.

11.4 In our provisional determination, we estimated productivity changes and RPEs for the period running from 2009/10 (the base year) to September 2017.

11.5 In response to our provisional determination, NIE said that out-turn data for 2010/11 and 2011/12 showed that the combined effect of RPEs and productivity justified a larger revenue allowance. It said that, based on the outturn expenditure data for the GB DNOs provided to it by the CC as part of this inquiry, GB DNOs' indirect and IMF&T costs had increased by 0.4 per cent over the period whereas we had assumed that they had reduced by 4.0 per cent. We had also assumed a 2.2 per cent reduction for capex. It said that for indirect and IMF&T costs, we should use 2011/12 as the base year, and for capex in the period 2009/10 to 2012/13, we should assume at the very least that RPEs and productivity cancel out.[2] It said that this would be the case in an economy in steady state. It said that this was because, as labour becomes more effective over time and creates savings, these would be captured by labour rather than being shared between customers and shareholders.

[1] Real price effects (RPEs) make a forecast of how a firm's costs will differ from inflation (in this case RPI) over a period.
[2] NIE response to the provisional determination, Chapter 2, paragraphs 1.4–1.19 & 3.12–3.38 and putback response.

11.6 The UR said that it disagreed with these comments and that there was not enough evidence to invalidate the CC's analysis of RPEs and productivity in these years or to suggest that capital unit costs would not have moved according to underlying price inflation and productivity in the industry. Its view was that the change in GB DNOs' indirect and IMF&T costs was likely to be attributable to factors that were not directly relevant to capital unit costs.

11.7 We considered these arguments for each of indirect and IMF&T costs and capex:

(a) For indirect and IMF&T costs, with the availability of additional benchmark data, we were able to make 2011/12 the base year—see paragraph 11.8*(a)*.

(b) For capex, we did not find that the additional data provided by NIE cast material doubts on our RPEs and productivity estimate. During the historic estimate period, capex costs at the GB DNOs declined substantially. We did not believe it was credible to ascribe either the increase in indirect costs or the decrease in capex costs over this period principally to RPEs and productivity. Indeed for the most significant element of our forecast over this period, labour, we placed significant weight on the actual wage settlements of the GB electricity network companies. We noted that the economy had not been in a steady state over this period and so there was good reason to focus on actual wage settlements of benchmark companies in these circumstances.

11.8 Having considered these options, we took the following approach for our final determination:

(a) For indirect and IMF&T costs, our RPE and productivity estimate was from 2011/12 until the end of our revenue control. This was because we set an efficient allowance for NIE's indirect costs based on benchmarked GB DNO cost data from 2011/12 (see paragraphs 8.30 to 8.36) . This benchmarked allowance represented an estimate of the indirect costs of an efficient firm in 2011/12 and we therefore only needed to consider how RPEs and productivity would affect costs after this date. This approach was different to that in our provisional determination, where we did not have available 2011/12 benchmark data.

(b) For capex, our RPE and productivity estimate is for the period following the base year of the revenue control (2009/10) until the end of our revenue control (September 2017). This is because the cost estimates in NIE's original BPQ, were in 2009/10 prices.

(c) For certain other costs we have set allowances based on cost data from different dates (for example, Enduring Solution costs). For these cost categories, we decided to apply our RPEs and productivity estimate from the year which we considered was appropriate given the source of the data which we had used. We outline how we have applied RPE and productivity adjustments to each cost category in Table 7.2 in Section 7.

11.9 Given these historic and forward-looking aspects of our estimates, throughout this section we have referred to:

(a) a historic estimate—covering the three-year period from 2009/10 (the base year) to 2012/13; and

(b) a forward-looking estimate—covering the four-and-a-half year period from 2012/13 to September 2017.

11.10 For completeness, each of the years in our estimate runs from April to March: the first year of the historic estimate is from April 2010 to March 2011 and the last full year of the forward-looking estimate is April 2016 to March 2017. As our revenue control ends in September 2017, in addition we made an estimate for the six-month period April 2017 to September 2017.

Bottom-up estimation of productivity and RPEs

11.11 In this subsection, we consider:

(a) the level of annual productivity growth;

(b) RPEs; and

(c) NIE's additional request relating to the EU Transformer Directive; before

(d) setting out our overall estimate of RPEs and productivity.

The level of annual productivity growth

11.12 To make an estimate of productivity we considered:

(a) other recent regulatory decisions on productivity;

(b) the EU KLEMS growth and productivity accounts;

(c) the recently submitted RIIO-ED1 business plans of the GB DNOs; and

(d) the views of the parties and then

(e) set out our conclusions.

11.13 We did not consider extrapolating from NIE's past productivity gains as we preferred an assessment of productivity which was independent of the company (see Section 8, paragraphs 8.1 to 8.6 on the benefits of benchmarking).

Other recent regulatory decisions on productivity

11.14 We considered some recent productivity estimates made by other regulators. These are shown in Table 11.1.

TABLE 11.1 **Opex and capex productivity assumptions in other price control reviews**

	%
Opex productivity	
UR—Water and sewerage	0.9
PPP Arbiter—underground infracos, central costs	0.7
PPP Arbiter—underground infracos, opex	0.9
Ofgem—GB DNOs	1.0
Ofgem—Transmission & Gas Distribution	1.0
ORR—Network Rail, opex	0.2
ORR—Network Rail, maint	0.7
Capex productivity	
PPP Arbiter—underground infracos	1.2
Ofgem—GB DNOs	1.0
Ofgem—Transmission & Gas Distribution	0.7
ORR—Network Rail	0.7

Source: UR, CC analysis.

Notes:
1. UR's PC13 Water and Sewerage determination relates to 2012.
2. PPP Arbiter's decision for underground infrastructure companies (infracos) relates to 2010 Ofgem's decision for DNOs relates to 2009.
3. Ofgem's decision for Transmission and Gas Distribution relates to 2012.
4. ORR's decision for Network Rail relates to 2008.

11.15 These decisions indicated a range of productivity assumptions of between 0.7 and 1.2 per cent for capex and between 0.5[3] and 1.0 per cent for opex. We decided that Ofgem's decisions in respect of the GB DNOs and also in respect of Transmission & Gas Distribution were most relevant because they related to businesses which most closely resembled NIE:

(a) In 2009, Ofgem set a 1.0 per cent productivity assumption for both capex and opex for the GB DNOs. Ofgem said that this was consistent with its own productivity analysis and the assumptions made by First Economics in a report for the GB DNOs. It said that it had received limited challenge from the GB DNOs on its productivity assumption.[4]

(b) In 2012, Ofgem used a 1.0 per cent assumption in respect of opex and a 0.7 per cent assumption in respect of capex for Transmission and Gas Distribution. Its assumptions drew on the EU KLEMS data set (which we discuss below in paragraphs 11.16 to 11.20). Its opex assumption was based on UK average industry partial factor productivity measures for 1970 to 2007 (ie labour, and labour and intermediate inputs); its capex assumption was at the top end of construction total factor productivity[5] (TFP), which was its preferred industry, but below TFP for other industries. Ofgem noted that its opex efficiency assumption of 1.0 per cent was in line with network company assumptions.[6]

EU KLEMS data

11.16 Other regulators and consultants have completed a significant amount of relevant work using the EU KLEMS[7] data set. These data provides growth and productivity accounts for 36 sectors, subsectors and sub-subsectors of the UK economy for the period between 1970 and 2007.

[3] Representing the simple average of the ORR opex and maintenance decisions from 2008.
[4] Ofgem DPCR5 Allowed Revenue—Cost Assessment, 7 December 2009, p81.
[5] TFP is a measure of productivity which encompasses all elements of production.
[6] Ofgem RIIO-T1/GD1. Real Price Effects and ongoing efficiency appendix, 17 December 2012, Chapter 3.
[7] EU KLEMS: www.euklems.net/.

11.17 We considered that EU KLEMS was a useful source of information covering a long period, albeit that it had the disadvantage of ending in 2007 and being backward-looking.

11.18 Table 11.2 shows the aggregate average annual productivity growth rates (ie for the UK economy as a whole) based on different measures of productivity.

TABLE 11.2 **Average annual TFP growth rates for different sectors using EU KLEMS, 1970 to 2007**

per cent

Sector/group	*TFP (VA)*	*Labour & intermediate input productivity (VA) at constant capital*	*TFP (GO)*	*Labour & intermediate input productivity (GO) at constant capital*	*Labour & intermediate input productivity (GO)*
Unweighted average all industries	1.3	1.5	0.5	0.5	0.8

Source: EU KLEMS/Ofgem RIIO—T1/GD1: Real Price Effects and ongoing efficiency appendix, p15, 17 December 2012.

Notes:
1. The averages used by Ofgem exclude the following industries: real estate, public administration, education, health and social services.
2. VA = value added measure.
3. GO = gross output measure.

11.19 For opex, we considered that measures of labour productivity would be a more appropriate benchmark than TFP. This is because NIE's opex costs are close to 80 per cent labour and labour productivity should therefore be the most significant driver of opex productivity. This compares to a labour content of around 50 per cent for NIE's capex. This would support a marginally higher productivity assumption for opex than capex when using the EU KLEMS data.

11.20 Overall, we considered that the aggregate EU KLEMS data could support a range of estimates of productivity of between 0.5 and 1.5 per cent. A summary of the EU KLEMS data and reports which we considered is contained in Appendix 11.1.

Evidence from the business plans submitted by the GB DNOs

11.21 The GB DNOs had all recently submitted business plans to Ofgem as part of its RIIO-ED1 (2015–23) price control. We considered that the incremental efficiency improvement forecast in these plans was a relevant data set. This was because, rather than relating to the past, it reflected a forward-looking view of potential incremental improvements in efficiency from a set of comparable companies.

11.22 In addition, we noted that in its guidance Ofgem said that efficiency assumptions should represent the level which even the most efficient business would be able to achieve.[8] There should therefore be no 'catch-up' embedded in these estimates of efficiency.

11.23 Most of the GB DNO business plans contained an assumption that overall cost efficiency could be improved at 1 per cent a year.[9] These included WPD, Electricity North West, SSE and Scottish Power. UK Power Networks expected to absorb the impact of any RPEs fully through efficiencies. Northern Powergrid's plan contained an assumption of 1.0 per cent efficiency in opex and 0.7 per cent in capex.

[8] www.ofgem.gov.uk/publications-and-updates/strategy-decision-riio-ed1-overview , paragraph 4.40.
[9] In these examples, unless otherwise stated, costs are totex (ie opex plus capex).

Views of the parties

11.24 NIE told us that it did not take issue so much with the 1 per cent annual efficiency assumption that was introduced by the UR for RP5, but that it had a fundamental issue with the 7 per cent benchmarking reduction that applied was applied to its opex costs. NIE also told us that a study for Ofgem, which looked at six years' worth of cost data for the 14 GB DNO licensees, showed annual efficiency improvements not significantly different from zero.

11.25 In response to our provisional determination, the UR said that NIE should be capable of producing the same level of efficiency as the GB DNOs have made in their business plans.[10]

Conclusion on productivity

11.26 To reach our decision on productivity, we considered the evidence provided by other regulatory decisions, the EU KLEMS data and the recent business plans of the GB DNOs. We considered that the recent business plans of the GB DNOs and Ofgem's recent decisions in respect of the GB DNOs and Transmission & Gas Distribution were particularly relevant. This was because these businesses overlapped significantly with NIE's business activities.

11.27 Based on this evidence, we considered that we should expect NIE to make an incremental efficiency improvement of 1 per cent a year for each of opex and capex.

11.28 We therefore determined that we should apply a productivity assumption of 1 per cent a year to NIE's costs (ie to each of opex and capex). As noted in paragraph 11.5, our productivity estimate applies from 2009/10 in respect of capex and from 2011/12 in respect of opex.

RPEs

11.29 In this subsection, we make an estimate for RPEs, ie an estimate for how we expect NIE's cost inflation to differ from RPI. We begin by explaining some key aspects of our approach. We then derive our estimate by examining the component parts of RPEs.

Our approach to RPEs

11.30 NIE's overall costs were split according to the categories which Ofgem had used in DPCR5.[11] These categories of cost were:

(a) *labour,* which was split between 'specialist' and 'general' elements;

(b) *general materials,* which comprised construction materials excluding metals;

(c) *specialised materials,* which included cables, cable containment, transformers and switchgear;

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[10] UR response to PD, paragraph 108

[11] Ofgem commissioned CEPA to produce price inflation forecasts for that charge control and we have therefore assumed that the definitions contained in CEPA's report, *Update of Input Price Inflation Forecasts for DPCR5* (2009), accurately reflect the category definitions.

(d) *plant and equipment,* which was equipment that was not an integral part of the network but was used on site—for example: welding and lifting equipment, mobile generators, testing equipment, transport equipment, and plant costs such as mobile offices; and

(e) *other,* which was items that could not be classified as one of *(a)* to *(d)* above.

11.31 We found that these broad cost categories were a reasonable starting point for our analysis. We therefore decided that we would estimate RPEs for each of these broad categories of cost and then use these estimates to model an overall RPE for each of capex and opex. To do this we took the following approach:

(a) we estimated nominal price inflation for each input category;

(b) we calculated an RPE for each input category by comparing our nominal price inflation estimate to RPI,[12] and then

(c) we assigned a weighting to each input category for each of capex and opex in order to calculate an overall capex RPE and opex RPE for each year of the revenue control.

11.32 We now explain in further detail some of the key aspects of our approach, including those areas where our estimation method differed from that proposed by the parties, namely: *(a)* use of the OBR forecast; *(b)* distinction between specialist and generalist labour; *(c)* estimating price inflation for input categories for which there was no OBR forecast; and *(d)* input weightings.

- *Use of the OBR forecast*

11.33 We considered that the OBR's economic and fiscal outlook represented a coherent and independent forecast which covered the entire period of our estimate. The OBR forecasts both RPI and wages. It also forecasts the level of producer output price inflation. We did not identify a better alternative to the OBR's data. We therefore decided that, wherever possible, we would use the OBR data as the basis for our RPE estimate.

11.34 The OBR's forecasts are updated in March and December of each year. We used the March 2013 forecasts for our provisional determination and the December 2013 forecasts for our final determination.[13]

- *Distinction between specialist and generalist labour*

11.35 When constructing its proposed RPEs, the UR and its consultants First Economics (FE) split labour into 'specialist' and 'general' categories. It used a premium of 1.25 per cent above general wage inflation to forecast specialist labour inflation. Separately, NIE defined its specialist labour as composing all managerial, professional and engineering staff as well as the majority of its industrial and administrative staff.

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[12] We calculated RPI using the change in RPI index in October on the previous year. We used ONS actual RPI data until October 2013 and the OBR forecast for the remainder of the period. This is the method as used in the revised financial model. For the final six month period ending September 2017 we used a six month RPI period from October 2016 to April 2017 (rather than the nine-month RPI period used in the financial model).
[13] On 19 March 2014 the OBR released an updated forecast that varied only slightly from the December 2013 forecast, and it was not practicable for us to use this revised forecast.

11.36 NIE made several submissions with regard to its specialist labour.[14] However, we did not find that the distinction between specialist and generalist labour was helpful. This was because these are very broad categories involving employees with different types of skills who could be subject to quite different labour supply and demand conditions.

11.37 We did not believe that by using these categories we would be able to make a more precise estimate of NIE's labour inflation and we considered that in many instances the distinction between the two categories would be arbitrary. We therefore did not split NIE's labour between 'specialist' and 'general' categories.

11.38 In response to our provisional determination, NIE said that we should either base our forecast on evidence that pertains to specialist labour or that we should continue to make use of a general index, but apply a specialist labour uplift to account for the evidence of real wage increases for specialist labour. NIE said that we had not taken account of the evidence that there was a shortage of skilled engineers, the future effect of this shortage on real wages for skilled engineers, or the challenges faced by NIE that arise as a result of it being the only operator in Northern Ireland, which makes it necessary for NIE to train the entirety of its staff itself.[15]

11.39 We considered whether, on the basis of the evidence submitted to us, we should introduce a specialist labour uplift as suggested by NIE. We noted that, although NIE is the only operator in Northern Ireland, it can determine which employees it takes on and consequently who it trains and how it trains them. We also continued to hold the view that any split between specialist and general labour categories was relatively arbitrary and was unlikely to introduce greater reliability into our estimate. We therefore decided that there was insufficient evidence to justify the use of a specialist labour premium above the level of general labour inflation contained in the OBR forecasts.

- *Estimating price inflation for input categories for which there was no OBR forecast*

11.40 The OBR does not make a forecast for each of the input categories listed in paragraph 11.30. It does, however, forecast overall producer output prices. To estimate price inflation for these input categories we therefore identified a number of price inflation indices which we considered were relevant to each particular input category. In each case, we used an unweighted average of our selected category price inflation indices. Table 11.3 shows the indices which we used for each input cost category.

[14] For example, NIE noted that in their assessments for RP5 both NIE and UR had made a distinction between specialist and general labour, using a premium of 1.25% above general wage inflation to forecast specialist labour wage inflation. However the CC's estimate of future labour RPEs was based on the OBR's forecast of average weekly earnings, a measure covering the entire labour market. NIE submitted that this measure would fail to take account of the specialist nature of staff employed in the electrical network sector. It would also take no account of the present and ongoing pressures to retain and attract staff. NIE submitted that it was not clear that the CC has taken any account of the substantial body of evidence that exists to suggest that there is a shortage of skilled engineers or the future effect of this shortage on real wages for skilled engineers.

[15] NIE response to the provisional determination, Chapter 2, paragraphs 3.25–3.28.

TABLE 11.3 **CC choice of relevant indices for each input category**

Category	*Indices chosen*	*CC comment*
General materials	BIS: Resource Cost Index of Infrastructure Materials (FOCOS) BIS: Resource Cost Index of Building (non-housing) Materials (NOCOS)	Captures inflation in a wide range of purchased building materials
Specialist materials	ONS PPI: Electric motors, generators and transformers; electricity distribution and control equipment (JV6R) ONS PPI: Electricity distribution and control apparatus (JV72) ONS PPI: Other electronic and electric wires and cables (K32F) ONS PPI: Cold Drawn Wire (JV2C) BEAMA: Materials in Electrical Engineering	These indices capture a number of specialist inputs purchased by electricity network operators
Plant & equipment	ONS PPI: Machinery and equipment output BCIS: Plant and Road Vehicles (90/2)	Covers a broad range of general and special purpose machinery which should be a relevant to electricity network operators
Other	RPI	We have assumed that inputs in this category inflate with RPI

Source: CC analysis/ONS.

Note: We made use of Ofgem's work on RPEs in DPCR5 and Scottish Power Energy Network's 2015–23 business plan submission (Annex 3.3, Tables 2.1–2.3) in selecting these indices: www.spenergynetworks.co.uk/pages/distribution_business_plan.asp.

11.41 We adopted different approaches for the historic estimate and forward-looking estimate:

(a) For the historic estimate, we used the actual rate of inflation from these indices.

(b) For the forward-looking estimate (2012/13 to September 2017) we applied the long-term average level of inflation indicated by these indices over the period 1996 to 2012. We chose this period because:

(i) in our view it was a sufficiently long period which covered both expansion and contraction in the UK and global economies; and

(ii) producer output prices as a whole increased by on average 1.9 per cent a year over the period 1996 to 2012. This was very close to the average level of producer output price inflation forecast by the OBR over the period for which we are making a forward-looking estimate of price inflation (1.8 per cent). The OBR was therefore forecasting a level of producer output price inflation during our estimation period which was broadly representative of the level of producer price inflation seen in our sample period.

11.42 We chose not to 'fade up' or 'fade down' the level of input price inflation from the level seen in 2012/13 towards the calculated average for the 1996 to 2012 period. To do so would be to place undue significance on the rate of input inflation which occurred in 2012/13.

11.43 In response to our provisional determination, NIE said that with regard to specialist materials, we should also make use of BEAMA[16] forecasts, an index specifically prepared for use in the electrical industry and itself built from ONS PPI data.[17] The

[16] British Electrotechnical and Allied Manufacturers' Association.
[17] NIE response to the provisional determination, Chapter 2, paragraphs 3.30–3.34.

UR said that we should use one or more of the BEAMA series alongside the ONS data. We noted the position of both parties and the relevance of the BEAMA forecasts. For our final determination we therefore added the BEAMA series 'Materials in Electrical Engineering' alongside the indices we previously used in the Specialist Materials category (see Table 11.3).

11.44 Although we added the BEAMA series to our relevant indices, we chose not to include BEAMA's own forecast for input inflation in electrical engineering (which was available until the end of 2016). This was because we considered that to include one forecast from one external party (other than the OBR) would be inconsistent with our overall approach. Our approach (as set out in paragraph 11.33) was to use the OBR forecasts wherever possible and where these were not available we used the longer-term average level of input price inflation indicated by relevant indices from the period 1996 to 2012.

- *Input weightings*

11.45 The UR proposed applying Ofgem's weightings from DPCR5 for each input category. These use a notional company structure, which was derived as the average of the weights contained in the DNOs' business plans for DPCR5.[18] Ofgem will continue to use this approach in RIIO-ED1. The DPCR5 weightings are shown in Table 11.4.

TABLE 11.4 **Input weights assumed by Ofgem in DPCR5**

per cent

	Capex			*Opex*		
	Load-related	*Non-load-related*	*Non-operational capex*	*Network operating costs*	*Closely associated indirect costs*	*Business support costs*
General labour	30	32	31	59	51	45
Specialized labour	30	32	16	30	25	22
General materials	9	10	53	8	11	4
Specialized materials	14	15	0	0	0	0
Plant & equipment	9	10	0	0	0	0
Other	8	1	0	3	13	29
Total	100	100	100	100	100	100

Source: Ofgem, Electricity Distribution Price Control Review Final Proposals, Allowed revenue and cost assessment, 7 December 2009, Table 5.2.

11.46 This approach has the advantage of being simple and not encouraging any particular type of company structure. NIE was also keen to report along the same lines and be benchmarked against the GB DNOs for efficiency.

11.47 We considered whether it would be in the public interest to use these weightings or NIE's own input weightings (as shown in Table 11.5). Table 11.5 combines general and specialist labour to reflect our view that this distinction was not helpful (see paragraphs 11.35 to 11.37 above).

[18] Ofgem, Electricity Distribution Price Control Review Final Proposals, Allowed revenue and cost assessment, 7 December 2009, paragraph 5.8.

TABLE 11.5 **NIE's proposed RPE weightings**

	Capex weight	*Opex weight*
Labour	52.8	77.3
Materials—general	11.6	7.7
Materials—specialist	18.6	0
Plant & equipment	5.9	0
Other	11.0	15.0
Total	100.0	100.0

Source: NIE Statement of Case, 10 May 2013, p218.

Note: Numbers may not sum due to rounding.

11.48 In our provisional determination, we decided that it would be most appropriate to use NIE's own input weightings. This was because these weightings reflected the specific characteristics of NIE's own business. We considered that the risk that NIE (or any company) would change its input weightings in order to try to improve future RPE allocations was very low.

11.49 In response to our provisional determination, the UR said that it was very concerned that NIE (and other companies that it regulates) would try to tilt the weights in its favour at future reviews and that the UR would be unable to challenge these estimates credibly.[19] It said that it thought the purpose of RPEs was to track how the benchmark of costs moves over time. In response, NIE said that, although NIE's concern was theoretically possible, we had only made material departures from Ofgem's weights in relation to materials, an input category that should be straight forward to measure. It also said that it thought concerns over the extent to which NIE may seek to "game" input weights at future regulatory determinations were overstated and that UR should be able to satisfy itself in this respect through detailed scrutiny of its capex plans More generally, NIE rejected completely any suggestion that it might seek to distort data it may submit in response to requests made by the UR.

11.50 As described above in paragraphs 11.46 and 11.48, we considered that there were merits in both a notional company structure and in using NIE's own input weightings. In this instance, we continued to prefer an approach which better reflected the specific characteristics of NIE's own business. We noted that whatever method the UR chooses to use to construct RPEs in RP6 would not be known by NIE in advance and there would therefore be little chance that NIE could tilt its input weightings in order to improve its RPE allocations in the next review.

Our RPE forecast

11.51 In this section, we explain our historic and forward-looking RPE estimates for each category of input, ie:

(a) labour;

(b) general materials, specialist materials and plant & equipment; and

(c) other items.

[19] UR response to the provisional determination, paragraph 105.

- *Labour RPEs*

11.52 NIE submitted that for the historic estimate its actual wage settlements should be used.[20] These were significantly in excess of the levels of labour inflation seen in the UK economy as a whole. We considered that NIE's proposed approach had the advantage of accurately reflecting the actual agreements which it had reached with its workforce during the period in question. However, we found two disadvantages to its proposed approach:

(a) NIE's settlements represented only a partial measure of its labour costs as they did not properly capture the price of bought-in labour, for example subcontractors;[21] and

(b) using NIE's settlements would amount to a straight pass-through of actual wage settlements to consumers. Taking a pass-through approach would introduce the risk that a company could be rewarded for inefficient wage settlements.

11.53 We decided that these two disadvantages were significant enough that it would not be in the public interest to use NIE's own wage settlement data as a basis for setting the historic estimate for labour inflation.

11.54 We considered the alternative measures of wage inflation available to us. Since the historic estimate for labour inflation was for a period where out-turn data were available, we found that there were several potentially relevant data points.

11.55 First, we considered average weekly earnings. Average weekly earnings data are a good measure of general wage inflation in the UK economy. This measure of labour inflation was 2.8 per cent in 2010/11, 0.9 per cent in 2011/12 and 2.1 per cent in 2012/13.[22]

11.56 Second, we considered the UR's submission that we could use JIB[23] hourly rates of pay. These might be particularly pertinent for some of the bought-in labour elements of NIE's costs (ie that element which is subcontracted). The relevant JIB hourly rates were held constant between January 2010 and January 2013 in response to the recession and the drop-off in the volume of work in the contractor market. That is, there was a rate of nominal labour inflation of zero.

11.57 Third, we considered whether the wage settlements of the GB electricity network companies over this period might be a useful alternative benchmark. These data suggested a level of labour inflation slightly in excess of the UK labour market as a whole. The public data on trade union settlements are shown in Table 11.6.

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[20] NIE Statement of Case, 10 May 2013, Ch8, paragraph 3.4.
[21] NIE's wage settlements represent around 80 per cent of its entire workforce including bought-in labour. See NIE response to the provisional determination, Chapter 2, paragraph 3.23.
[22] We have adjusted the AWE data to reflect a constant working week (ie no change in hours worked over the period).
[23] Joint Industry Board for Electrical Contracting Industry.

TABLE 11.6 **Union nominal pay settlements at GB electricity network companies, 2010 to 2012**

			per cent
	2010	*2011*	*2012*
Range	2.0–4.9	2.5–5.2	2.5–4.5
Average	3.0	3.6	3.7

Source: NIE Statement of Case, Annex 8A.1, p442.

Note: The data comprises only the settlements of Unite and Prospect unions at the following companies: [✂]

11.58 We found that these data offered two advantages: they were from a larger sample which was independent of NIE, and the businesses concerned overlapped significantly in the type of labour they employed (albeit on a different island). At the same time, we recognized that the data still provided a narrow measure of NIE's labour costs.

11.59 Fourth, we considered the ONS ASHE survey.[24] These data provided information on various categories of labour, showing the rate of labour inflation in certain categories of labour which might be more relevant to NIE. Table 11.7 shows this data.

TABLE 11.7 **ONS ASHE data on various categories of labour in the UK and Northern Ireland**

	2010		*2012*	
Category (code)	*UK*	*Northern Ireland*	*UK*	*Northern Ireland*
Professional occupations (2)	1.5	2.2	0.2	2.0
Engineering professionals (212)	1.5		2.1	
Electrical engineers (2123)	3.2		3.3	
Electronics engineers (2124)	3.0		2.1	
Electrical/electronics technicians (3112)	3.0		0.8	
Engineering technicians (3113)	2.9		1.2	
Building and civil engineering technicians (3114)	–0.3		–4.8	
Skilled metal and electrical trades (52)	3.1	–0.6	0.6	–1.9
Electrical and electronic trades (5249)	3.4		0.5	1.5
Electricians, electrical fitters (5241)	3.3		–1.6	
Skilled construction and building (53)	2.8	1.4	–0.2	2.9

Source: ONS ASHE data/CC analysis.

Notes:
1. Where cells are blank data is not available.
2. In 2011 the categories were changed and therefore % change for 2011 is not available.
3. OBR AWE was 1.6 per cent for 2010 and 2.0 per cent for 2012.

11.60 NIE said that the categories 'Electrical engineers (2123)' and 'Electrical/electronics technicians (3112)' were most relevant to an assessment of its workforce. We found that these data suggested that certain relevant electrical engineering professional and trades saw labour inflation over this period that was slightly above that seen in the UK economy as a whole.

11.61 Of the four data sources that we considered, we placed most weight on the wage settlements of the GB electricity network companies. This was because of the significant overlap with NIE in the type of labour these companies employed. We also

[24] Annual Survey of Hours and Earnings.

relied, although to a lesser extent, on the ONS ASHE survey. This was because these data allowed us to consider categories of labour particularly relevant to NIE.

11.62 In our provisional determination, we said that the wage settlements of the GB electricity network companies indicated a rate of nominal wage inflation in the range of 3.0 to 3.7 per cent over the period 2010 to 2012; and that the ONS ASHE data indicated a rate of nominal wage inflation slightly below this level. We provisionally judged that a rate of nominal wage inflation of around 3.25 per cent was appropriate for the historic estimate (2009/10 to 2012/13).

11.63 In response to our provisional determination, the UR said that a rate of labour inflation of 3.25 per cent for the period 2009/10 to 2012/13 overstated the rate of wage inflation that an efficient company would have faced because it did not take into account the lower wage inflation we had identified in the contractor market.[25]

11.64 NIE reiterated its view that its pay increases over the period 2009/10 to 2011/12 were a necessary and efficient response to prevailing labour market conditions. It said that by failing to recognize its pay settlements as part of the overall dataset, we were effectively applying an efficiency discount to it, in circumstances where our benchmarking revealed that no such discount was justified.[26]

11.65 We continued to believe that a straight pass through of NIE's labour costs (as described in paragraphs 11.52 and 11.53) was not in the public interest. The rate of labour inflation we used (3.25 per cent) placed significant weight on the wage settlements of the GB electricity network companies, although it was a little below the simple average over the 2010 to 2012 period (3.4 per cent), reflecting the lower rates of labour inflation indicated by our other data sources. We did not therefore consider further downward adjustments were required, as the UR suggested.

11.66 For the forward-looking wage inflation estimate (2012/13 to September 2017) we used the OBR forecast for average weekly earnings. This was consistent with our decision to use OBR forecast data wherever possible. In our provisional determination, we said that it was appropriate to make an adjustment to this data to reflect constant working hours so that our forecast reflected increases in hourly wages rather than a measure of hourly wages plus changes in hours worked. For the forward-looking estimate this resulted in a slight increase in the level of pay inflation as the OBR forecasted a slight reduction in hours worked over the period.

11.67 In response to our provisional determination, the UR said that a reduction in hours worked may well reflect greater productivity, in which case hourly earnings need not increase faster than weekly earnings. It said that we should stick with the OBR forecast and avoid the additional complexity and risk from making an adjustment.[27]

11.68 In our view, a reduction in working hours may well represent an increase in labour productivity and, as such, it should be captured in our assessment of productivity rather than in our labour inflation estimate. We therefore kept our adjustment to this data so that our estimate reflected increases in hourly wages.

11.69 Table 11.8 summarizes our labour RPEs for the period.

[25] UR response to the provisional determination, paragraph 98.
[26] NIE response to the provisional determination, Chapter 2, paragraph 3.29.
[27] UR response to the provisional determination, paragraph 100.

TABLE 11.8 **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 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. Figures from 2013/14 onwards differ from those in the provisional determination due to a computational error.

11.70 Further details of the underlying nominal wage inflation estimate which was used to derive the RPEs in Table 11.8 above are in Appendix 11.1.

- *General materials, specialist materials and plant & equipment RPEs*

11.71 Table 11.9 shows our general materials, specialist materials and plant & equipment RPEs for the RP5 period. We derived these using the method described above in paragraphs 11.40 to 11.42.

TABLE 11.9 **General materials, specialist materials and plant & equipment RPEs, 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 RPE	3.9	1.3	–2.1	1.6	1.2	0.7	0.7	–0.4
Specialist materials RPE	6.4	0.5	–4.6	0.7	0.2	–0.2	–0.2	–0.9
Plant & equipment RPE	–2.9	–2.7	–2.0	–0.2	–0.6	–1.1	–1.1	–1.3

Source: CC analysis.

11.72 Further details of the underlying nominal estimates which were used to derive the RPEs in Table 11.9 are in Appendix 11.1.

- *Other*

11.73 For other items we have assumed a level of input inflation equal to inflation as measured by RPI.

11.74 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.[28] NIE said that it was important to look at IT costs in the round, particularly taking into account our separate and detailed treatment of Enduring Solution which accounted for the majority of NIE's IT expenditure. It said that it did not believe that the change proposed by the UR would be properly justified without material changes to other parts of our RPEs estimate.

11.75 In our view there are likely to be elements of this category which exhibit a rate of inflation both above and below RPI. We decided that, on balance, it was a reasonable assumption that this category of input inflation would on average equal RPI over the period.

[28] UR response to the provisional determination, paragraphs 101–103.

Summary of our RPE estimate

11.76 Combining the RPEs for each of the input categories with our capex and opex input weightings (see paragraphs 11.45 to 11.47) results in the RPEs shown in Table 11.10. Table 11.10 also shows the RPE estimate submitted by NIE for RP5 and the UR's final determination in this area. As noted in paragraph 11.5, our RPE estimate applies to the years following 2009/10 in respect of capex and to the years following 2011/12 in respect of opex.

TABLE 11.10 **CC capex and opex RPEs compared with NIE and the UR's final determination**

	2010/11	*2011/12*	*2012/13*	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*6m to Sept 2017*
CC capex RPE	0.8	–1.0	–1.2	0.0	0.1	0.1	0.4	–0.4
CC opex RPE	N/A	-1.5	–0.1	–0.3	0.0	0.2	0.6	–0.2
NIE's proposed RPEs								
Capex RPE	1.5	1.9	0.6	0.4	1.2	1.3	1.1	
Opex RPE	0.5	1.1	1.3	0.3	1.0	1.3	1.1	
UR's final determination								
Capex RPE	+£0.6 million as a fixed allowance for RP5							
Opex RPE	–£3.3 million as a fixed allowance for RP5							

Source: CC analysis; NIE Statement of Case, Chapter 8, Table 8.3, p218; and UR final determination.

Note: N/A = not applicable.

11.77 It can be seen from Table 11.10 that our estimate of capex and opex RPEs was lower than that submitted by NIE. It was closer to that made by the UR. The two most significant reasons for the difference between our estimate and NIE's submission were:

(a) We did not use NIE's actual wage settlements for the historic estimate of labour RPEs (see paragraphs 11.52 to 11.62).

(b) We did not use a distinction between 'specialist' and 'generalist' labour (see paragraphs 11.35 to 11.37).

NIE additional request arising from the EU Transformer Directive

11.78 We considered NIE's request for an additional £5.0 million during RP5 due to the EU Transformer Directive, which requires that transformers up to 36 kV should be designed and constructed to meet new standards.[29]

11.79 We decided that this was not an item which we would expect to be considered specifically in an RPE estimate. Our RPE estimate makes a broad allowance for the estimated level of input price inflation which an efficient firm will experience in RP5 and it would not be in customers' interests to make additional uplifts to this allowance for very specific input items. This was because the overall level of input price inflation which an efficient firm experiences will be the result of the level of inflation experienced in many different input items: some of these inputs will experience positive levels of inflation relative to RPI, others negative; if we were to include

[29] NIE Statement of Case, Chapter 8, paragraph 6.5.

additional allowances for individual items where above-average levels of inflation might be expected, we would introduce an unfair upward bias into our RPE estimate.

11.80 In our view, our RPE estimate adequately captures the effect of cost changes relative to RPI at an overall input category level: this overall category RPE includes items where cost increases are greater than RPI (such as transformers up to 36kV), items where cost increases are broadly in line with RPI, as well as items where cost increases are less than RPI.

Conclusions from our bottom-up analysis

11.81 Table 11.11 summarizes the combined effect of our RPE and productivity estimates for the period from 2009/10 until September 2017 based on our bottom-up analysis. As noted in paragraph 11.5, our estimate applies from 2009/10 in respect of capex and from 2011/12 in respect of opex.

TABLE 11.11 **Combined effect of CC productivity and RPEs for RP5**

	2010/11	*2011/12*	*2012/13*	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*6m to Sept 2017*
CC capex RPE plus productivity	–0.2	–2.0	–2.2	–1.0	–0.9	–0.9	–0.6	–0.9
CC opex RPE plus productivity	n/a	-2.5	–1.1	–1.3	–1.0	–0.8	–0.4	–0.7

Source: CC analysis.

Comparisons with relevant indices and recent regulatory determinations

11.82 While our estimates were built on a bottom-up basis, we also considered whether they represented a reasonable estimate of the movement in an efficient firm's costs over the period. We did this by comparing our estimates with relevant indices and recent regulatory determinations.

11.83 For opex, between April 2012 and September 2017 (5.5 years), we estimated that the combined effect of productivity and RPEs[30] was a nominal increase in costs of approximately 13.5 per cent. This represented a cumulative reduction in costs relative to RPI of approximately 5.2 per cent over the period, a little less than 1 per cent per annum. We compared this to the OBR's forecast for the CPI and producer output price inflation over the same period. We found that the cumulative nominal increase in opex costs which we had estimated was very similar to the OBR's forecast for the cumulative nominal increase in CPI inflation over the same period (13.2 per cent) and 3.3 percentage points more than the OBR's forecast for producer output price inflation over this period (10.2 per cent). In our view, a cumulative change in opex below the forecast level of RPI, but above forecast producer price inflation and broadly in line with forecast CPI represented a reasonable estimate of the combined effects of productivity and RPEs.

11.84 For capex, between April 2010 and September 2017 (7.5 years), we estimated that the combined effect of productivity and RPEs was a nominal increase in costs of approximately 20.8 per cent. This represented a cumulative reduction in costs relative to RPI of approximately 8.4 per cent over the period, a little over 1 per cent per annum. We found that the cumulative nominal increase in capex costs which we had estimated was around 1.4 percentage points less than the OBR's forecast for the

[30] Compound inflation.

cumulative nominal increase in CPI inflation over the same period (22.2 per cent) and 2.5 percentage points more than the OBR's forecast for producer output price inflation over this period (18.3 per cent). In our view a cumulative change in capex below the forecast level of RPI and CPI, but above forecast producer price inflation represented a challenging but achievable estimate of the combined effects of productivity and RPEs over this period.

11.85 In response to our provisional determination, NIE said that we had deemed it reasonable to adopt and apply one assumption from the GB DNOs Fast Track plans (their assumption in respect of ongoing productivity across the entire cost base) but had essentially ignored the GB DNOs' RPEs.[31] It said that WPD's RIIO-ED1 business plan, which had been fast-tracked by Ofgem, represented the latest and most relevant precedent from GB. It had forecast a net effect of RPEs and productivity of RPI+0.4 per cent a year on average, whereas we had provisionally estimated RPI-0.9 per cent a year on average. This forecast, other GB DNOs' forecasts (ranging from RPI-0.1 per cent to RPI+0.4 per cent a year on average) and other recent regulatory settlements[32] suggested that we had misinterpreted the data and, in the face of comparators, our RPE estimate was manifestly unreasonable. It said that our estimate should be revised to bring assumptions into line with the wider consensus.[33] NIE suggested between RPI+0 and RPI+0.4 per cent a year on average.

11.86 We did not believe that it was necessary to bring our RPE and productivity estimates into line with the GB DNOs Fast Track plans. We noted that acceptance of a GB DNO's Fast Track plan by Ofgem does not necessarily endorse the RPE and productivity assumptions. We found that, upon review of Ofgem's commentary on WPD's RPE and ongoing efficiency assumptions, Ofgem had raised specific issues with regard to the validity of the choice of cost indices and the time periods used to form the RPE assumptions.[34]

11.87 Based on the comparisons above, we were satisfied that our bottom-up analysis of RPEs created opex and capex RPE and productivity estimates which were reasonable.

Our determination

11.88 Table 11.12 sets out our estimate for the annual change in costs due to the combined effects of RPEs and productivity between 2009/10 until September 2017.

TABLE 11.12 **Combined effect of CC productivity and RPEs for RP5**

	2010/11	*2011/12*	*2012/13*	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*6m to Sept 2017*
CC capex RPE plus productivity	–0.2	–2.0	–2.2	–1.0	–0.9	–0.9	–0.6	–0.9
CC opex RPE plus productivity	N/A	-2.5	–1.1	–1.3	–1.0	–0.8	–0.4	–0.7

Source: CC analysis.

[31] NIE response to the provisional determination, Chapter 2, paragraph 3.13.
[32] For example, for National Grid's Electricity Transmission business (RIIO-T1), Ofgem used a combined adjustment for RPEs and productivity of RPI+0.1% over the period 2011/12 to 2020/21.
[33] NIE response to the provisional determination, Chapter 2, paragraphs 1.4–1.19 & 3.12–3.38.
[34] Ofgem, Assessment of the RIIO-ED1 business plans, Supplementary annex, Appendix 5, paragraph 1.28.

12. Pensions

Introduction

12.1 In this section we set out our decisions on pensions. We are mainly concerned with the defined benefit (DB) pension scheme of NIE's regulated business (known as 'Focus') which is currently in deficit. The section is structured as follows. We:

(a) explain some of the background to the NIE Pension Scheme;

(b) describe the approach to pensions adopted in RP4;

(c) decide the questions necessary to our determination on pensions. Broadly these are: which entities have pension costs relevant to our determination; whether and how to allow for any pension deficit repair payments which NIE is making; what provision should be made for historic early retirement deficit contributions; and how to provide for pension costs which are not linked to deficit repair; and

(d) summarize our conclusions and state our pension allowances for RP5.

12.2 The extensive background, arguments made by the parties, and discussion of relevant pensions precedents can be found in Appendix 12.1.

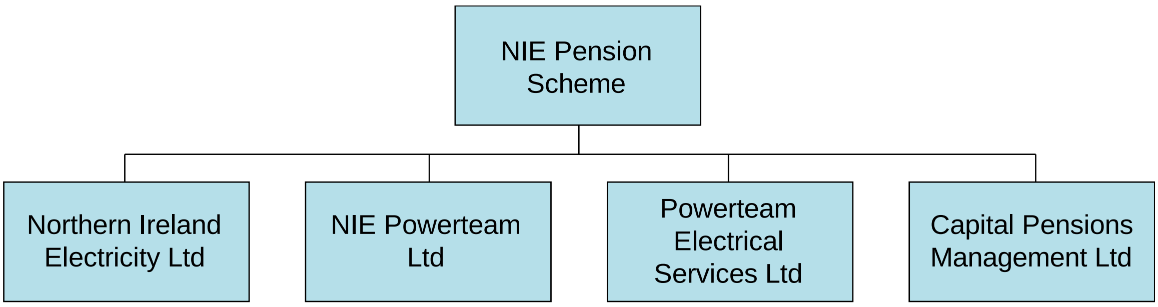
Background to the NIE Pension Scheme

12.3 NIE was privatized in 1993 and inherited sponsorship of the NIE Pension Scheme (the scheme), a DB pension scheme. Protected persons[1] represent 97 per cent of the scheme's members.[2] The DB is separate and distinct from NIE's defined contribution (DC) scheme, which is known as 'Options'.

12.4 The participating employers in the scheme are shown in Figure 12.1.

FIGURE 12.1

Membership of the NIE Pension Scheme



Source: NIE RP5 final determination, p66.

12.5 Figure 12.1 shows that the scheme covers three other legal entities in addition to NIE Ltd. These are:

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[1] Protected persons are protected by statute and their pension benefits cannot be reduced without their consent. This applies to both past and future service.
[2] NIE Statement of Case, Chapter 10, paragraph 2.2.

(a) *NIE Powerteam Ltd*, which employs a large number of staff and carries out work on the NIE network which is within the scope of NIE T&D's regulated activities;[3]

(b) *Powerteam Electrical Services Ltd,* which provides services that fall outside the scope of NIE's regulated activities; and

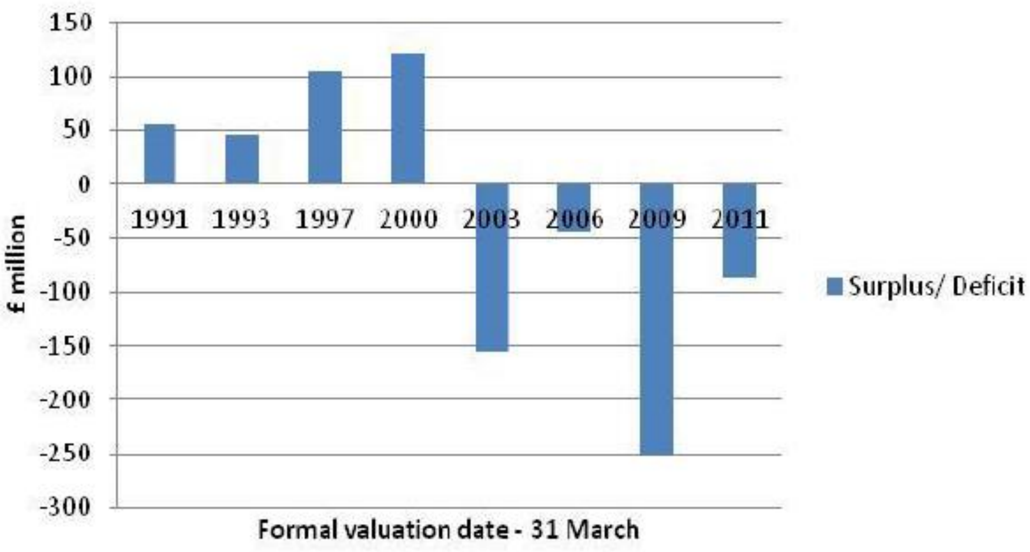
(c) *Capital Pensions Management Ltd,* which employs a small number of staff responsible for managing the pension scheme.[4]

12.6 Prior to March 1998, all new employees working for NIE were given membership of the DB scheme. At this time NIE decided to close the scheme to new joiners and opened the DC 'Options' scheme for employees who joined after March 1998.[5,6] Protected Persons cannot be transferred from the DB 'Focus' scheme to the DC 'Options' scheme.[7]

12.7 Figure 12.2 shows the development of the scheme's surplus/deficit (that is, scheme assets less scheme liabilities) at its formal valuation dates since 1991.

FIGURE 12.2

NIE Pension Scheme surplus/deficit at formal valuation dates



Source: UR Statement of Case, Chart 2, p2.

12.8 It can be seen that there has been considerable variation in the funding position of the scheme and a notable deterioration since the early 2000s. This has been a common feature of DB pension schemes in the UK. As a result of the scheme's deficit NIE currently makes two types of payment to the scheme.

(a) ongoing pension payments, which represent the cost of additional benefits being accrued by existing employees who are still members of the scheme; and

[3] The relevant costs for NIE Powerteam appear to have been consolidated into the costs of transmission and distribution activities in NIE's regulatory accounts although this is not explicitly stated.
[4] UR Statement of Case, paragraph 4.
[5] ibid, paragraph 3.
[6] NIE Statement of Case, Chapter 10, paragraph 2.5.
[7] ibid, Chapter 10, paragraph 2.5.

(b) annual deficit repair payments, which aim, over a relatively long period (in this instance March 2022) to bring the scheme into surplus. During RP5 these deficit repair payments will be £13.8 million a year.[8]

12.9 Deficit repair payments represent the recovery of historically understated labour costs. They are an intergenerational transfer since the set of consumers who pay additional charges in order to repair the deficit are not the same as those who benefited from understated costs in the past. The UR's and NIE's views are set out in Appendix 12.1.[9]

12.10 NIE said that the performance of the scheme since the last formal triennial valuation (in March 2011) had been adverse and that the deficit at 30 September 2011 was approximately £150 million. The annual actuarial report as at 31 March 2012 showed a deficit of £156.4 million.[10] NIE agreed an increase in its deficit repair payments following the 2009 valuation and these payments continued following the 2011 annual valuation.[11] The latest scheme valuation showed a deficit of £135.5 million as at 16 May 2013.[12]

12.11 The scheme deficit that has developed since 2003 is in contrast with the much healthier position in the 1990s when the scheme was in surplus. This surplus was drawn on between 1997 and 2003 to fund benefit improvements for members and contribution cost reductions for NIE. The latter included the cost of funding both benefits as well as early retirement schemes run by NIE.[13] NIE suggested that the scheme surplus was broadly distributed 2:1 between the company and employees.[14]

12.12 NIE's shareholders, as part of an agreement with the trustees struck during the 2006 acquisition by Arcapita, agreed to clear the deficit as at 31 March 2006 by the payment of special contributions.[15]

RP4 approach to pensions

12.13 In RP4, pension total pension costs (that is, the 'Focus' deficit repair costs as well as the ongoing costs of both 'Focus' and 'Options') were treated as a separate category of opex and an annual allowance was set through a rolling mechanism similar to that used for controllable operating costs. Thus in a given year NIE was allowed a fixed sum equal to the total cash pension contribution made five years previously, adjusted upwards for cumulative RPI inflation since that date. A further adjustment was made to exclude 30 per cent of the portion of the cash contribution which related to early retirement deficit contributions (see paragraph 12.17(g)). The UR therefore took pension costs from RP3 and inflated them by RPI in order to set a pension allowance for the corresponding year of RP4. The allowance was based on cash payments to the scheme and not on the costs accrued in any one year.

12.14 NIE's deficit repair contributions to the pension scheme increased during RP4. As a result its payments to the scheme exceeded its RP4 allowances by a total of £19.6 million in RP4.

[8] 2009/10 prices.
[9] See paragraphs 13 & 58, for example.
[10] NIE Statement of Case, Chapter 10, paragraph 2.7.
[11] ibid, Chapter 10, paragraphs 2.7 & 2.14.
[12] NIE Supplementary Submission, Annex 8, paragraph 2.5.
[13] ibid, Chapter 10, paragraph 2.9.
[14] ibid, Chapter 10, paragraph 2.10.
[15] ibid, Chapter 10, paragraph 2.12.

12.15 Both the UR and NIE said that the RP4 approach to pensions was no longer in the public interest. For example, the UR said that continuation of RP4 would not enable appropriate treatment of pension costs, including financing the repair of NIE's deficit in a way that was fair for both customers and NIE.

Our approach to pensions and the questions we must decide

12.16 We noted the parties' views on the appropriateness of the RP4 rolling mechanism. We found that moving away from the RP4 rolling mechanism allowed us to use benchmarking for ongoing pension costs (see paragraph 3.70 regarding our finding on the RP4 pensions mechanism). We also wanted to give NIE greater incentives to manage its pension liabilities efficiently on a forward-looking basis and to make our approach more consistent with Ofgem's approach to pensions. We therefore considered what alternative approach would be in the public interest.

12.17 In order to reach a determination on pensions, we considered that it was necessary to decide:

(a) which of the legal entities shown above in Figure 12.1 should we include in our determination (see paragraphs 12.19 to 12.21); and

(b) how we should treat the deficits of any schemes which we include in our determination (before consideration of any special items) (see paragraphs 12.22 to 12.29).

We then needed to consider how to deal with certain aspects of the historic deficit:

(c) how any deficit repair payments which we decided should be borne by consumers are recovered by NIE through allowances in RP5 (see paragraphs 12.30 to 12.38);

(d) whether there is a need for any in-period adjustments (see paragraphs 12.39 to 12.46); and

(e) whether any allowance in RP5 was needed for deficit repair costs paid in RP4 that exceeded the RP4 allowances (see paragraphs 12.47 to 12.60).

Finally we considered two other matters:

(f) The NIE pension scheme incurred liabilities relating to unfunded early retirement schemes run by NIE between 1997 and 2003. This is known as the ERDC (early retirement deficit contribution) liability. In RP4, NIE funded 30 per cent of this liability and consumers funded 70 per cent. NIE said that previous special contributions to the pension scheme made by its shareholders should be offset against any ERDC liability. The UR said that NIE should fund 45 per cent of this liability. We needed to determine how these items should be treated in RP5 (see paragraphs 12.61 to 12.77).

(g) NIE also incurs ongoing pension costs which are not linked to deficit repair. These are the costs of NIE's employer contributions to its DB and DC schemes. We needed to decide how these ongoing pension costs be treated in RP5 (see paragraphs 12.78 and 12.79).

12.18 In the following subsections, we set out and explain our decisions in respect of each question listed above. We also outline the financial implications of our decisions for NIE's pension allowances in RP5.

Legal entities to be included in our determination

12.19 We considered which of the legal entities shown in Figure 12.1 above should be included in our determination. Funding relevant costs is in the public interest. Otherwise there would be a risk that services would not be provided. Relevant costs should only include items relevant to providing the services consumers receive.

12.20 We decided that only the pension schemes which provide services exclusively to the regulated business of NIE were relevant costs. These are NIE Ltd and NIE Powerteam Ltd (which provides services exclusively to NIE). Capital Pensions Ltd and Powerteam Electrical Services Ltd, which do not provide services exclusively to NIE, should therefore be excluded.

12.21 We note that this is in line with the UR's final determination for RP5, which resulted in a regulatory fraction of 99.26 per cent. We expect that the regulatory fraction will be reviewed when pension allowances are next set.

Treatment of pension deficits included in our determination

12.22 Our starting point was the scheme deficits at the start of RP5. We considered how these deficits should be treated.[16] We first considered what ability NIE has during RP5 to influence the level of deficits which have accumulated in the relevant schemes. We found that, because the pension scheme had been closed to new members since 1998 and 97 per cent of the members were 'Protected persons',[17] NIE was likely to have a limited ability to mitigate the level of the pension scheme deficit during RP5.

12.23 We considered that it was in the public interest to give NIE a strong incentive to try to manage its pension liabilities. This was because the current deficit is large and has been volatile in recent years: any actions which NIE can take to minimize its liabilities will ultimately be passed through to consumers through lower prices.

12.24 In this regard, we noted that only about 39 per cent of current NIE employees are protected persons.[18] During RP5 NIE therefore has a much greater ability to manage any incremental pension costs. We expect that over time the percentage of current employees who are protected persons will continue to fall as new employees join the defined contribution scheme and older employees (who are in the DB scheme) retire. On this basis, we found that there was merit in taking a different approach during RP5 to costs relating to the historic deficit and those relating to any new incremental deficit which may arise from additional pensionable benefits awarded to employees in the period.

12.25 This is the approach which has been taken by Ofgem in GB. For the GB DNOs, Ofgem distinguishes between the historic deficit and an incremental deficit. The historic deficit represents the difference between assets and liabilities attributable to pensionable service up until a defined cut-off date. The incremental deficit represents the difference between assets and liabilities for any pensionable service after this date. We noted that Ofgem had spent considerable time refining and agreeing its

[16] The UR's and NIE's views are set out in Appendix 12.1—see paragraphs 9 & 29.
[17] Protected persons legislation affects some former nationalized industries. Protected persons are protected by statute and their pension benefits cannot be reduced without their consent. Benefits must continue to be at least as good as they were in the public sector at the time the business was privatized. This applies to both past and future service.
[18] Data provided by NIE.

methodology to calculate each deficit and that these are now included within its Pensions RIGS.[19]

12.26 We decided that NIE should also follow this approach, using the Ofgem Pension RIGS, with a cut-off date for the historic deficit of 31 March 2012. We then considered what proportion of the costs incurred since this date relating to each of the historic and incremental deficits should be attributable to each of NIE and consumers during RP5.

12.27 Based on our view that NIE is likely to have a limited ability to mitigate the historic scheme deficit, we decided that in principle (and before considering any special items) 100 per cent of historic deficit repair costs should be passed through to consumers during RP5.

12.28 We decided that costs relating to any incremental deficit should be funded 100 per cent by shareholders. This is because we believe that NIE has a much greater ability to influence its forward-looking pension costs during RP5, as only 39 per cent of current employees are protected persons. Shareholders funding 100 per cent of costs relating to any incremental deficit should provide NIE with a strong incentive to manage these liabilities, which we believe is in the public interest. We expected that, in conjunction with ongoing service costs, these costs would be subject to benchmarking with the GB DNOs in future price controls.

12.29 Our decision is a significant change in approach from that adopted by the UR during RP4 and harmonizes the treatment of pensions between NIE and the GB DNOs, which are its closest comparators. We consider that this will provide an additional benefit in future revenue controls by increasing the comparability and benchmarking of pension costs between NIE and the GB DNOs.

Deficit repair allowances

12.30 Since we decided that, during RP5, 100 per cent of the incremental deficit should be attributable to NIE (paragraph 12.28), we made no allowance for deficit repair payments for the incremental deficit.

12.31 We then considered what allowances we should make for payments to repair the historic deficit. We noted that NIE had agreed with its trustees a 13-year recovery plan which concluded in March 2022.[20] We also noted that there was some regulatory precedent (for example, Ofgem, CC Bristol Water[21]) for a 15-year recovery period.

12.32 In our provisional determination we proposed to base our allowance for RP5 on a 15-year deficit recovery period to recover the historic deficit as at 31 March 2012. This amounted to a historic deficit repair allowance of £10.8 million a year in RP5.[22] This was a longer recovery period than NIE had agreed with its trustees (it agreed a recovery period ending in March 2022). We also said that we saw some benefit in matching the deficit recovery period with the actual repayment schedule which NIE had agreed with its trustees.

[19] www.ofgem.gov.uk/ofgem-publications/42762/pdam-decision-letter-final-12apr2013.pdf.
[20] NIE Statement of Case, Chapter 10, paragraph 6.4.
[21] See Appendix 12.1, paragraphs 78 & 92.
[22] Fifteen-year annuity to recover a deficit of £139.3 million (2009/10 prices), using a 2.08 per cent real discount rate (the scheme valuation discount rate). We did not specify allowances in our provisional determination and we asked the parties how we should approach setting allowances in light of our provisional determination.

12.33 We reviewed our provisional determination proposal and decided that, whilst it was reasonable in isolation, when we considered it together with other aspects of our final determination, the recovery period was too long. In particular we thought that the difference between NIE's forecast cash deficit repair payments to the scheme and our annual deficit repair allowance was too great. We therefore considered two alternative approaches to setting the deficit repair allowance. These were to base the allowance on:

(a) a ten-year annuity profile (ending in March 2022) for the deficit as at 31 March 2012; or

(b) the forecast deficit repair cash payments which NIE will make into the scheme during RP5 (which it had agreed with the trustees).

12.34 We decided to base our deficit repair allowance on the historic deficit repair contributions which NIE is forecast to make into the scheme during RP5. NIE's historic deficit repair payments are intended to repair the deficit by March 2022 (a deficit recovery period of ten years from the start of RP5). When considered together with all other aspects of our price control we believed that this still represented a reasonable recovery period for the historic deficit and that it was a simpler and more consistent basis on which to set an allowance for RP5.

12.35 NIE is forecast to contribute £13.8 million[23] in deficit repair payments in each year of RP5. We therefore decided to set an allowance of £13.7 million a year (after taking into account the regulatory fraction of 99.26 per cent, see paragraphs 12.19 to 12.21).

12.36 In response to our provisional determination, NIE said that the notional 15-year deficit repair period ending in 2027 should not be a 'stop dead' date.[24] In our view, this would be a matter for the UR to decide at subsequent regulatory determinations. Our decision to match NIE's deficit repair allowance during RP5 to the profile of the deficit repair contributions which are currently agreed with its trustee is for RP5 and is based on the evidence currently available to us.

Financing timing differences

12.37 In our provisional determination we made an allowance for NIE to recover the financing costs arising out of a difference between NIE's cash flow payments to the trustees (which conclude in March 2022) and our deficit repair period (which would have concluded in March 2027).

12.38 We have now decided that NIE's allowance for historic deficit repair costs in RP5 should be based on its estimated cash payments to the scheme in RP5. As such these timing differences no longer occur and there is not a requirement for us to provide an allowance for these financing costs.

In-period adjustment mechanism

12.39 In our provisional determination we proposed that historic deficit repair costs should be revisited at each formal triennial actuarial valuation and additionally if any changes were made to the repayment schedule currently agreed with the trustees. In

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[23] 2009/10 prices, rising with RPI.
[24] For example, if during the 15-year period the historic deficit were to increase materially in the latter part of the 15-year period, the deficit repair period might be extended by the UR in order to protect different generations of consumers.

their responses to our provisional determination both parties raised questions as to the scope of this mechanism and how it would work in practice.[25]

- *Parties' views*

12.40 NIE said that the three-year review cycle for pension allowances to repair the historical deficit should run in parallel to, and no longer form part of, the five-year price control reviews. It also said that adjustments to pension deficit allowances following each three-yearly valuation should operate with effect from 1 April two years after the effective valuation date, thereby allowing for the time taken to complete the actuarial valuation and for the UR to carry out its reasonableness review.[26]

12.41 The UR said that it disagreed with our proposal to revisit historic deficit repair costs at each triennial valuation. It said that the 15-year notional recovery period has a purpose—it protects today's customers from bearing too high a burden in respect of pension deficits which they did not cause and which relate to services enjoyed by a previous generation of customers. It also questioned how changes to NIE's repayment schedule for the historic deficit would be reflected in NIE's allowances.[27]

- *Our determination*

12.42 We considered two issues:

(a) whether any in-period adjustments should affect the historic deficit repair allowance of £13.7 million; and

(b) when any in-period adjustments would take place.

12.43 In our view, the aim of an in-period adjustment mechanism would be to ensure that, for the historic deficit only, NIE (and consumers) are kept neutral with regard to any changes in the deficit repair payment profile during RP5. That is, NIE (and consumers) should not gain or lose from any changes in the repayment profile agreed with the trustees during RP5.

12.44 We noted that the deficit contributions agreed by the trustees and NIE following the 2009 and 2011 valuations of the scheme made an allowance for investment performance and other developments in the period immediately following the valuation dates.[28] This meant that the repayment profiles agreed by the trustees did not align with the most recent formal actuarial valuation.

12.45 There appeared to us to be two ways to provide adjustments for changes in repayment profiles—either at the end of RP5 or at each point at which a revised repayment plan is subsequently agreed with the trustees.

12.46 We determined that an adjustment at the end of RP5 was preferable because it would minimise the scope for in-period adjustments during RP5. Provided NIE (and

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[25] UR response to the provisional determination, paragraphs 127–129 and NIE response to the provisional determination, Chapter 4, paragraph 1.34.
[26] NIE response to the provisional determination, Chapter 4, paragraph 1.34.
[27] UR response to the final determination, paragraphs 128 & 129.
[28] For the 2009 valuation, post valuation date experience was favourable and the agreed deficit repair plan aimed to address a funding deficit of £175 million as at 31 March 2010, rather than the deficit of £251 million stated in the 2009 valuation. For the 2011 valuation, post valuation date experience was adverse and the existing deficit repair plan was retained in order to address a deficit of approximately £150 million as at 30 September 2011.

consumers) are properly compensated at the end of RP5 for any financing costs (using NIE’s WACC for RP5) resulting from changes in the repayment profile during RP5, neither NIE (or consumers) should be worse off in NPV terms than if there were recalculations during RP5. Whilst the UR will wish to review the pension policy for RP6 and set its own allowance, we considered that it was essential that, whether or not the UR retained this approach to the historic repair deficit, an adjustment is made at the end of RP5 to ensure NIE (and consumers) were kept NPV-neutral for any changes in the deficit repair plan during RP5.

Deficit repair payments from RP4 in excess of RP4 allowances

12.47 During RP4 NIE made pension deficit repair payments in excess of its RP4 allowance (as described at 12.13 above). NIE claimed that it should now be ‘refunded’ £23.5 million of costs which, it said, would otherwise be ‘stranded’ from RP4. These costs were the £19.6 million excess payments over allowances it made in RP4 and £3.9 million of consequential financing costs.[29]

12.48 In our provisional determination, we said that unless some provision for these costs was made, NIE would have funded a greater proportion of deficit reduction costs than would have resulted from our proposed pension policy. We said that these costs should be funded by consumers because they related to the historic deficit.

12.49 Following the provisional determination, we took account of representations made to us and reconsidered our proposal. We decided that there should not be any allowance for deficit repair payments in excess of RP4 allowances. We consulted the parties on this change of position.

Views of the parties

- *The UR*

12.50 In response to our provisional determination, the UR said that making an allowance for these costs amounted to backdating our new pension policy from the start of RP5 to the start of RP4. It said that this was inconsistent with our approach of not reopening past price controls, other than in exceptional circumstances. It added that the choice of the start of RP4 as the period for backdating was arbitrary and that in principle there was no reason why our decision should not be backdated further to, say, the start of RP2 when NIE took a pension holiday and was contributing less than its opex allowance funded by customers.[30]

12.51 The UR also said that NIE would never have recovered all of its excess contributions made during RP4 even if the RP4 rolling mechanism had continued indefinitely. It said that in net present value terms, the very most that NIE could claim to suffer as a result of the discontinuation of the RP4 rolling mechanism was £11 million.[31] In response to our further consultation (see paragraph 12.49), the UR said that the proposed amendments to our approach created a more evenly balanced package overall. It said that under our amended approach customers would pick up the majority share of NIE’s deficit repair payments and also take on most of the risk that these increase in the future; whilst shareholders would take on around £40 million of the £155 million deficit as quid pro quo for the sizeable benefits they had enjoyed in the surplus years. In its view this was a fair deal overall and in the public interest.

[29] Using NIE’s pre tax WACC.
[30] UR response to the provisional determination, paragraphs 114–122.
[31] UR response to the provisional determination, paragraphs 17 & 18.

12.52 The UR said that it completely rejected NIE's argument that the UR had recognized that pension costs were uncontrollable since as far back as 2005. It said that its RP4 price control proposals paper from December 2005 and decision paper from October 2006 clearly identified pension costs as 'controllable' opex.

- *NIE*

12.53 In response to the UR's comments (see paragraphs 12.50 and 12.51), NIE submitted that internal coherence required that the shortfall be made good. NIE said that its request for these 'stranded costs' was not predicated on any argument that RP4 was deficient in its treatment of pension costs. It said that the costs were at risk of becoming stranded because we had decided to move from the rolling mechanism cost of recovery applied in RP4 to a different system of cost recovery in RP5, whereby NIE would recover pension deficit repair costs incurred from 1 April 2012 according to a different profile. It said that, unless we allowed these costs, they would be lost in the transition from one profile of cost recovery to another. NIE added that there was no internal inconsistency with our approach to capitalization in RP4 and our approach to provisionally allowing these costs because the capitalization issue was a request for retrospective adjustment.

12.54 In response to our further consultation NIE made the following points:

(a) Our conclusion that the RP4 rolling mechanism was simply a means of setting an allowance for RP4 with no mechanism for cost recovery had no basis in fact and could not be reasonably drawn. In support of its position, NIE said that discussions between the UR and NIE took place at a time when Ofgem had already developed a clear and well-documented policy in respect of pension deficit funding. NIE produced evidence which in its view demonstrated that both the UR and NIE had paid close regard to that policy when negotiating the RP4 price control mechanism. It added that none of the current team at the UR were involved in the RP4 price control.[32] NIE said that we had made an enormous and unjustified logical leap by concluding that, because the RP4 mechanism did not allow NIE to recover its full financing costs, the RP4 mechanism was not a mechanism for cost recovery.

(b) NIE did not rely on the narrow public law grounds of 'legitimate expectation'. Rather, since the CC accepted that NIE's pension costs were uncontrollable, and, by implication, that they were uncontrollable in RP4 and since that was also recognized by the UR in the setting of the RP4 price control, it was clearly necessary for the CC to ensure that no pensions costs became stranded by virtue of its decision to move away from the RP4 rolling mechanism. A failure to compensate NIE for the consequences of the move from one cost recovery mechanism to another would be inconsistent with the conclusion (understood from the start of RP4) that pension deficit repair costs were uncontrollable and fall to customers.

(c) We had failed to recognize the essential distinction between pension costs, which were uncontrollable, and opex costs, which were controllable. NIE said that both the UR and NIE recognized, in agreeing the RP4 price control, that an ex-ante allowance was not an appropriate treatment for such uncontrollable costs.

[32] NIE also said that it had been common ground between the UR and NIE that pensions costs were uncontrollable and that the decision to separate pensions from controllable opex reflected an intention to treat them differently. It noted that pensions costs were allocated a separate term in the licence modifications to implement the RP4 price control precisely because they were to be distinguished from controllable opex.

(d) The fact that the CC was setting a price control for the period beginning 1 April 2012 did not absolve it from the need to adjust its RP5 mechanism to ensure that the bargain adopted in RP4 in respect of the recovery of pensions costs is honoured. But, even if the CC concluded that the RP4 pensions costs mechanism was not necessarily intended to secure total cost recovery, the CC should ‘true-up’ as a logical consequence of the recognition that pension deficit repair costs are uncontrollable and this would be consistent with Ofgem’s approach. In addition, the baseline for assessing pension costs should be 1 April 2007 since that is the point at which NIE's price control first recognized the need to allow NIE to recover its pension costs separately from its controllable opex—at that point the scheme was in surplus and since that date a new deficit has arisen due to factors entirely beyond NIE’s control.

(e) NIE did not accept that if the CC made an adjustment for RP4 it would open up previous price control periods too. Price controls prior to RP4 contained no explicit allowance for pension costs and there is no way of ascertaining whether those controls under or over provided for NIE’s pension costs.[33]

12.55 NIE reiterated that it was common ground in RP4 that pensions costs were uncontrollable and that the decision to separate pensions from controllable opex reflected an intention to treat them differently. It disputed UR’s submissions with regard to the RP4 pensions allowance and the ERDC liability.[34]

Assessment

12.56 We considered carefully the responses to our provisional determination and our further consultation on this issue. In particular, we considered whether or not it would be in the public interest to maintain our provisional determination and make a provision for the difference between actual payments and allowances in RP4.

12.57 We decided that it would not be in the public interest to make an allowance for these payments. There are two main issues. The first is whether moving away from the rolling system of allowances means that NIE will lose out and, if it will, whether we should compensate it. The second is whether our decision that in RP5 we will allow NIE to recover historic deficit repair payments means we should also allow it to recover the difference between past deficit repair costs and past allowances for those deficit repair costs. Before we address those questions we should repeat that both parties have acknowledged that the RP4 pensions rolling mechanism is no longer in the public interest and we that believe that there are clear benefits to moving away from the rolling system operated in RP4. We have described these benefits, which include a distinction between the historic and incremental deficits and an overall approach which facilitates a greater degree of benchmarking, in Section 3. Further, the approach now adopted on pensions is, like many other aspects of this determination, very different to that adopted in RP4. Our determination is a package that we have balanced as a whole.

12.58 The period for which we are assessing pension allowances is RP5: that is 1 April 2012 to 30 September 2017. While our determination is of course part of a longer period of regulation that begins before and will carry on after RP5, and while pensions and the pensions policy of NIE and the UR are necessarily long-term issues, nothing that we have seen concerning the arrangements made in RP4 seems to us to dictate that NIE should be able to recover the deficit repair payments it made

[33] NIE response to consultation pp1–10.
[34] NIE comments on UR-180.

in excess of its RP4 allowances in the face of a significant change in regulation. The evidence presented to us by NIE does not in our view establish that NIE had real grounds for believing that the rolling mechanism would continue indefinitely. Nor are we persuaded that the RP4 allowances were intended as a method to allow for the recovery of all of NIE's pension deficit repair costs.

12.59 We considered the points made by NIE. Taking each point in paragraph 12.54 in turn:

(a) We were not persuaded that the evidence submitted by NIE showed that the RP4 rolling mechanism was intended as a mechanism to pass through NIE's pension costs. In our view, the RP4 rolling mechanism was a means of setting allowances for RP4. The UR used a method of taking pension costs from RP3 and inflating them by RPI in order to set a pension allowance. In forming this view we were most informed by the RP4 licence conditions and the UR's final determination, rather than emails between the parties at the time. We found that the fact that the RP4 rolling mechanism did not allow NIE to recover its financing costs was a further indication that it was not a mechanism for cost recovery.

(b) Even had the rolling mechanism continued (and RP5 allowances had been based on RP4 pension cost, adjusted for inflation) NIE would not have recovered its full pension costs in RP5 and it would also have incurred significant financing costs. In our view the framework of the RP4 pensions allowance is not one of full cost pass-through.

(c) We decided that, for the RP5 period, NIE is likely to have a limited ability to mitigate the historic deficit (see paragraph 12.22). It does not follow that our approach to pensions in the period 1 April 2012 to 30 September 2017 should be applied retrospectively to payments and allowances to repair the historic deficit in previous price controls. On the basis of the evidence we did not find that applying our RP5 approach to pensions to prior periods would be in the public interest (see further Section 15 discussion of revisiting RP4 decisions). In addition, we did not accept (as NIE claimed) that pension costs had been recognized by the UR as uncontrollable during RP4 (see *(a)* above).

There were many other aspects of our revenue control where we had changed the way in which allowances should be set. For instance, we rejected the RP4 rolling mechanism for opex in favour of benchmarking. We did not make any compensating adjustments for opex expenditure in RP4 being different to the allowances; nor had NIE suggested there was any basis for such adjustments to be made.

(d) On the basis of the evidence presented to us, we did not agree that the RP4 mechanism recognized pension costs as uncontrollable and subject to pass through. Our decision that NIE has a limited ability to control the historic deficit (we do not accept the historic deficit is wholly uncontrollable but only that NIE has a limited ability to mitigate the deficit) is a decision regarding RP5 and is reflected in the allowances that we are setting for this period. Logic does not require our decision on setting a pension allowance for RP5 to be applied to RP4. We were not persuaded that there was a bargain agreed in RP4 between NIE and the UR which required an RP5 allowance for RP4 pension costs which were in excess of allowances (see *(a)* above). We did accept NIE's view that the baseline for assessing NIE's pension costs and liabilities should be 1 April 2007 rather than 1 April 2012: we are setting pensions allowances for RP5 and our approach to pensions applies to the recovery of payments to repair the deficit from 1 April 2012. We found that whether NIE has or has not recovered its past pension

payments to repair the historic deficit is an outcome of past events and past price control decisions. We are seeking to set allowances in relation to pension payments to be made in the period 1 April 2012 to 30 September 2017 to repair the historic deficit. We did not consider that Ofgem's pension policy during RP4 determined what is in the public interest now.

(e) We considered that, if we were to make an adjustment for the change in approach to pensions (as NIE requested), there would be no good reason for us to be concerned with just the RP4 period; we would need to consider the profile of payments in price controls prior to RP4 in order to ascertain whether NIE had experienced a shortfall. There were periods in the past where NIE was paying less than its allowance (for example, at the start of RP2, NIE took a pension contribution holiday while continuing to receive funding for pension costs through its opex allowance), and periods where the payments exceeded the allowance (such as during RP4). NIE has in the past taken decisions that have influenced the level of the deficit (for example, in RP2) and we do not think it would be appropriate for us to revisit decisions only from RP4 when considering how payments should be funded.

Our determination

12.60 After careful consideration and in light of the parties' submissions on both consultations, we decided to revise our provisional determination on this matter. We found that it is not in the public interest to provide NIE with any allowance for costs incurred in RP4 in excess of those allowances provided for in RP4.

Early retirement deficit contribution liability and past shareholder contributions

12.61 ERDCs represent the liability from unfunded early retirement schemes run by NIE between April 1997 and March 2003. Employees taking up the early retirement schemes during this period were entitled to unreduced pension benefits with pension payments beginning immediately rather than at their specified retirement age. At the time, NIE did not make additional contributions to the pension scheme relating to these early retirement schemes. The ERDC liability represents the amount which would have been paid into the scheme at the time had these additional benefits been fully funded (adjusted for the investment returns that these contributions would have made in the period since).

12.62 In RP4, these ERDC liabilities had been split 30:70 between shareholders and consumers. This effectively adopted Ofgem's decision on ERDCs, which was made in 2004. This split apportioned the ERDC liability between shareholders and consumers on the basis of the benefit which each received (in the form of lower costs) from early retirement schemes.

Parties' views

12.63 The parties' views on ERDCs and past shareholder contributions are set out in Appendix 12.1.

12.64 NIE accepted that its shareholders should bear 30 per cent of the ERDCs incurred from unfunded early retirement schemes run by NIE between April 1997 and March 2003. NIE submitted that its previous shareholder contributions (of the value of £68 million) should, however, be offset against its share of the ERDC liability. These shareholder contributions were made during and at the end of RP3. NIE said that these payments reduced the scheme deficit and that it would be entirely one-sided for the CC to take account of liabilities arising from earlier periods but to ignore shareholder contributions made in more recent years.[35]

12.65 In its response to our consultation NIE said that if the CC rejects its primary case, the most that could be reasonably disallowed owing to ERDCs is approximately £0.5 million. This was because:

(a) The ERDC liabilities have been discharged. This is because the majority of individuals retiring early in the period 1997 to 2003 would have passed their normal pension age by 31 March 2012. Based on the profile of NIE's early retirees, no more than 13 per cent of the original ERDC quantum is relevant.

(b) The scheme was in surplus in 2007 due to the payment of shareholder contributions. Therefore, the ERDC adjustment should be calculated on the basis of the value of outstanding ERDC liabilities as a proportion of total scheme liabilities (not as a proportion of the deficit). ERDC liabilities can be no greater than the estimated incremental change in the value of the ERDC liabilities since 31 March 2007.

(c) ERDC liabilities do not vary materially with mortality assumptions. When determining the proportion of the deficit that has opened up between the 2007 and 2012 that may be explained by ERDCs, it is necessary to remove the effect of changes in mortality assumptions. The adjusted deficit, after adjusting for this mortality strain, is £74 million.

12.66 The UR said that this was an attempt to rewrite history and that no link existed between these contributions and ERDCs. 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.[36] The UR also said that, on the basis of facts 45 per cent of the ERDC liability, rather than 30 per cent, was a more appropriate attribution for NIE's shareholders.[37]

12.67 The UR said that NIE had reached the view that the ERDC liability should be close to zero because:

(a) it wanted to hypothecate its extra contributions exclusively to cover ERDCs, completely ignoring other past actions that had contributed to the current deficit; and

(b) it focused on the early retirement-related liabilities that NIE still had at 1 April 2012, which were inevitably quite small given the passage of time, rather than the assets that the scheme lost as a result of past decisions not to fund early retirement benefits and to use the scheme surplus instead.

It said that neither of these positions was fair to customers. In response, NIE said that the UR misrepresents its case. It would not be unfair to consumers for the CC to recognize that NIE has paid shareholder contributions that more than offset its ERDC liabilities. Neither would it be unfair for the CC to recognize that at the beginning of RP4, the NIE pension scheme was not in deficit as a direct result of the payment of those special contributions. It would, however, be entirely unfair and arbitrary for the CC to take account of ERDC liabilities that arose in the period prior to 2003 but to

[35] NIE response to the provisional determination, Chapter 4, paragraphs 1.28 & 1.29.
[36] UR Supplementary Submission, paragraphs 19, 55 & 58–60.
[37] Ibid, paragraphs 123–126.

take no account of shareholder contributions that were made more recently (in 2005 and 2007), in particular when those payments had the effect of funding in full all of the schemes liabilities whatever their origin, based on then prevailing actuarial assumptions. NIE said that no reasonable regulator could regard that as an equitable outcome.

Our determination

12.68 We considered the current attribution of ERDCs between shareholders and consumers. Based on the additional submissions made by NIE and the UR with regard to the specific profile of those taking early retirement between 1997 and 2003, we judged that the specific circumstances of this case could support an attribution of ERDC costs to shareholders of between 23 and 45 per cent.[38]

12.69 With regard to past shareholder contributions, we were not presented with any evidence which showed that these contributions were linked to ERDCs and we did not believe that there was a conceptual reason why they should be attributed in this way.

12.70 With regard to both past shareholder contributions and the current attribution of ERDCs we considered that these were only two of a number of historic items which affected the current funding position of the scheme. These items included ERDCs, past payment holidays, benefit improvements for members and past shareholder contributions. Of these items, only 30 per cent of ERDCs had been attributed to NIE in RP4.

12.71 We did not consider that it would be appropriate to reconsider one or two of these historic items in isolation without considering all such items. Overall, NIE shareholders are currently allocated 30 per cent of the ERDC liability and no other items are taken into account. We were not presented with compelling evidence that the overall effect of this was either too harsh or too generous and in our view, the available evidence does not support a change to the existing position.

12.72 We considered NIE's submission that the most that could be reasonably disallowed owing to ERDCs is approximately £0.5 million. We did not think that there was merit in applying a NIE's revised methodology (see paragraph 12.65) to the calculation of this liability. In particular we believed that this method ignored the assets that the scheme had lost as a result of past decisions not to fund early retirement benefits and to use the scheme surplus instead (as UR argued, see paragraph 12.67).

12.73 In addition, we believed that the pension scheme position as at the start of RP4 (when the scheme was in surplus) was not a relevant data point for us when considering the allowances which we are making for RP5. We were concerned with the scheme valuation and the ERDC liability valuation as at the start if RP5 (the period for which we are making allowances) as well as NIE's agreed deficit repair payments to the scheme during the price control.

12.74 We decided that NIE shareholders should continue to be attributed 30 per cent of ERDCs, and that previous shareholder contributions should not be offset against this liability. This attribution of ERDCs to NIE amounted to £39.7 million[39] as at 31 March 2012.

[38] CC provisional determination, paragraphs 12.45 & 12.46.
[39] 2009/10 prices.

12.75 In our provisional determination we used a deficit recovery period of 15 years, which we also applied to ERDCs. This amounted to an annual ERDC disallowance of £3.1 million.[40]

12.76 The deficit repair allowance is based on the cash payments which NIE will be making to the scheme in RP5 (see paragraphs 12.30 to 12.36) and our ERDC disallowance needs to be consistent with this approach. The attribution of 30 per cent of ERDCs to NIE represents 28.3 per cent of the historic deficit as at 31 March 2012.[41] We therefore decided that the ERDC disallowance for RP5 should be 28.3 per cent of NIE's historic deficit repair allowance of £13.7 million during RP5. This amounts to an annual ERDC disallowance of £3.9 million during RP5.

12.77 As deficit repair payments and the ERDC disallowance are both linked it is essential that, in the event of an end of RP5 adjustment being required (see paragraphs 12.42 to 12.46), both items are taken into account.

Ongoing pension service costs

12.78 The ongoing service costs for NIE represent the cost of servicing its DB and DC pension schemes through employer contributions (ie not deficit repair). NIE said that its projection for RP5 was £11.1 million, equivalent to around £2.2 million a year.[42]

12.79 Our indirect cost benchmarking of NIE (see Section 8) included pension service costs. Our indirect cost allowance therefore includes an allowance for ongoing pension service costs. We therefore decided that no additional allowance for ongoing pension service costs was necessary because otherwise we would be double counting these costs (once within our benchmarked allowance and additionally within a separate pension service allowance). This is also consistent with our view that, wherever possible, pension service costs should be benchmarked. In future revenue controls, we would expect that any ongoing pension service cost benchmarking would also include any incremental deficit or surplus.

Conclusion and pension allowances for RP5

12.80 We decided that:

(a) Only the pension schemes which provide services exclusively to the regulated business of NIE should be included in our revenue control. These schemes are NIE Ltd and NIE Powerteam Ltd (see paragraphs 12.19 to 12.21).

(b) The deficits in the included schemes should be split into historic and incremental deficits using the Ofgem Pension RIGS methodology; the cut-off date for the historic deficit will be 31 March 2012. The historic deficit will be funded 100 per cent by consumers; any incremental deficit arising will be funded 100 per cent by NIE (see paragraphs 12.22 to 12.29).

(c) Our historic deficit repair allowance for RP5 should match the deficit repayment payment profile that NIE has agreed with the trustees of the pension scheme. This is £13.7 million per annum during RP5 (see paragraphs 12.30 to 12.38).

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[40] Fifteen-year annuity using a 2.08 per cent real discount rate (the scheme valuation discount rate). We did not specify allowances in our provisional determination and we asked the parties how we should approach setting allowances in light of our provisional determination.
[41] £39.7 million divided by £140.3 million (both 2009/10 prices). £140.3 million is before the application of the regulatory fraction.
[42] NIE Statement of Case, Chapter 10, paragraph 1.2. The projection is based on a five-year price control period.

(d) If the current repayments in respect of the historic deficit change during RP5, then an adjustment to compensate NIE (or consumers) for any associated financing costs should be made at the end of RP5 (see paragraphs 12.39 to 12.46).

(e) NIE should not be given an allowance for pension payments made in RP4 that exceeded its RP4 allowance (see paragraphs 12.49 to 12.60).

(f) The current split of ERDC liabilities (30 per cent to shareholders; 70 per cent to consumers) should be retained and no adjustment to NIE's ERDC liability should be made for previous shareholder contributions. The annual ERDC disallowance is £3.9 million a year during RP5 (see paragraphs 12.61 to 12.77).

(g) NIE's ongoing pension service costs will be included in our indirect benchmarking and therefore no additional allowance is included. In future, we would expect that benchmarking will include any incremental pension deficit (see paragraphs 12.78 and 12.79).

Comparison of our allowances to provisional determination

12.81 NIE's pension allowances for the RP5 period are almost unchanged at £53.9 million, as compared with £54.1 million implied by our provisional determination. However, this small change masks a number of important changes to our allowances between provisional and final determination:

(a) We have increased the historic deficit repair allowance from £10.8 million to £13.7 million a year as we are now using NIE's actual payments to the scheme (as opposed to a 15-year recovery period) as the basis for our allowance. There is a corresponding (but smaller) increase in the ERDC disallowance from £3.1 million to £3.9 million. The overall effect of using a shorter recovery period is that NIE's allowance (including the ERDC disallowance) for historic deficit repair increases from £7.7 million to £9.8 million a year. This increase amounts to £11.5 million over the RP5 period.

(b) We no longer make an allowance for RP4 pension payments in excess of allowances, which reduces NIE's allowance by £1.8 million a year, or £9.9 million over the RP5 period.

(c) We no longer make an allowance for timing differences (as they will no longer exist), which reduces NIE's allowance by £1.8 million over the RP5 period.

12.82 We noted that although our pension allowances for RP5 are largely unchanged when compared with our provisional determination, the underlying impact of our decision is negative for NIE because we have decided not to make an allowance for RP4 payments in excess of its allowances.[43]

12.83 Table 12.1 below summarizes our pension allowances for RP5 and compares these to the allowances implied by our provisional determination. These allowances reflect the decisions described in paragraph 12.80 above.

[43] In our provisional determination we proposed allowing NIE to recover these costs over a 15-year period.

TABLE 12.1 **Pension allowances for RP5 and comparison with those implied in our provisional determination***

	2012/13	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*6m to Sept 2017*	*Total RP5*
Final determination	9.8	9.8	9.8	9.8	9.8	4.9	53.9
Provisional determination	9.6	9.7	9.8	9.9	10.0	5.1	54.1
Final determination—individual allowances							
Historic deficit repair	13.7	13.7	13.7	13.7	13.7	6.8	75.4
ERDC disallowance	–3.9	–3.9	–3.9	–3.9	–3.9	–1.9	–21.5
Total	9.8	9.8	9.8	9.8	9.8	4.9	53.9
Provisional determination—individual allowances							
Historic deficit repair	10.8	10.8	10.8	10.8	10.8	5.4	59.4
ERDC disallowance	–3.1	–3.1	–3.1	–3.1	–3.1	–1.5	–17.0
RP4	1.8	1.8	1.8	1.8	1.8	0.9	9.9
Financing differences	0.1	0.2	0.3	0.4	0.5	0.3	1.8
Total	9.6	9.7	9.8	9.9	10.0	5.1	54.1

Source: CC analysis.

*In our provisional determination we outlined our provisional decisions in respect of pensions but we did not include explicit allowances.

Notes: Assumptions used in implied allowances from our provisional determination:

1. Historic deficit repair allowance based on the recovery of the historic deficit of £139.3 million (2009/10 prices) using a 15-year annuity, payments assumed half way through each year, using a real discount rate of 2.08 per cent (the scheme valuation discount rate used to calculate the deficit).
2. ERDC disallowance based on a residual ERDC liability of £39.7 million (2009/10 prices) calculated using the same annuity profile as in 1) above.
3. RP4 under-recovery allowance based on an amount of £23.5 million calculated using the same annuity profile as in 1) above
4. Timing differences are caused by 15-year deficit repair period (as opposed to actual payments forecast to be made by NIE during RP5). Cost of finance assumed to be NIE's WACC for RP5.

13. Allowed rate of return

Introduction

13.1 This section sets out the detail of our approach to assessing NIE's cost of capital for the period 1 April 2012 to 30 September 2017. It considers:

(a) the general approach to cost of capital estimation and the position of the parties to this inquiry (paragraphs 13.2 to 13.30);

(b) gearing (paragraphs 13.31 to 13.38);

(c) the cost of debt and the evidence for a Northern-Ireland-specific premium (paragraphs 13.39 to 13.80);

(d) the cost of equity:

(i) arguments for a Northern-Ireland-specific premium (paragraphs 13.84 to 13.114);

(ii) the risk-free rate (RFR) (paragraphs 13.115 to 13.129);

(iii) the market return and the ERP (paragraphs 13.131 to 13.161); and

(iv) beta (paragraphs 13.162 to 13.183); and

(e) sets out our conclusions on the weighted average cost of capital (WACC) (paragraphs 13.184 to 13.194).

General approach

13.2 Our approach is to base NIE's price cap on the revenue required by an efficient licence holder to cover its efficiently-incurred costs, including a return on its RAB. We considered that it is in the public interest to ensure that an efficient firm can do that, rather than necessarily the actual firm currently holding the licence. If we did not take this perspective, we would dampen the incentives on the actual firm to act in the public interest. See paragraph 17.2. We consider that an efficient licence holder's return on RAB should be equal to its expected cost of capital. Allowing a return at this level is consistent with our duty to secure that NIE is able to finance its licensed activities. In calculating return, the relevant costs are those projected for an efficiently managed licence holder and may be above or below out-turn costs depending on whether NIE is more or less efficient than the benchmark.

13.3 This subsection considers:

(a) which company's cost of capital is relevant—that of the regulated (licensed) company or its ultimate holding company?;

(b) which time period is relevant—the period for which we are determining the price cap (2012 to 2017) or the longer term?;

(c) how to estimate the WACC;

(d) inflation;

(e) the allowed rate of return under the current price control, RP4; and

(f) the UR's and NIE's estimated WACC.

Relevant company

13.4 NIE is a subsidiary of ESB, and is majority owned by the Irish Government.[1] However, under the existing regulatory regime for electricity, NIE is treated as a 'ring-fenced' company. In particular, NIE is required at all times to conduct its regulated business as if it were substantially a free-standing business and a separate public limited company. It is also required to take all appropriate steps to obtain and thereafter maintain at all times an investment grade credit rating.

13.5 As noted in paragraph 13.2, we are therefore concerned with the cost of capital of an efficient licence holder as a stand-alone 'ring-fenced' company.

Relevant period

13.6 We are calculating the required return over the period 1 April 2012 to 30 September 2017 and we think it is the expected cost of capital in that period that is relevant. Long-run averages are relevant only to the extent that they affect the cost of capital in that period. They may do so for two main reasons:

(a) Regulated companies finance long-life assets in part through the issue of fixed-rate debt with long maturity and the cost of existing fixed-rate (embedded) debt is affected by interest rates at the time the debt was issued.

(b) Asset prices and/or yields may have a tendency to revert to a longer-run mean value and, if so, past levels are relevant to estimating the expected level over the relevant period.

13.7 We noted that we were setting the cost of capital in early 2014 for a five-year period that began in April 2012. We therefore had the benefit of over 18 months of actual data.

Estimating the weighted average cost of capital

13.8 The cost of capital is a weighted average of two components:

(a) the cost of debt (c_d); and

(b) the cost of equity (c_e), which is the return required to induce the marginal investor to purchase shares in the business.

13.9 The weightings (gearing or g) reflect the relative importance of each type of financing in the licence holder's capital structure:

Equation 1: $WACC = c_d.g + c_e.(1–g)$

13.10 Both the UR and NIE calculate a 'vanilla' WACC (combining a post-tax return on equity and a pre-tax return on debt)[2] and propose a separate allowance for projected

[1] 95 per cent of the shares are state owned. The remaining 5 per cent of the shares are owned by an Employee Share Ownership Trust (source: ESB Annual Report and Accounts 2012).
[2] As stated here, the WACC does not reflect the impact of the deductibility for corporation tax purposes of interest payable on the allowed return. This is sometimes known as the 'vanilla WACC'. As we do not use any alternative definitions in this section,

Corporation Tax payments (where the projected tax payment is calculated within a financial model). We use the same approach. The total return on the RAB is shown in equation 2:

Equation 2: *(Required return/RAB) = WACC + (Tax/RAB)*

13.11 At the most general level, there are three potential approaches to estimating the WACC, which we discuss in turn:

(a) direct estimation of the licence holder's cost of capital;

(b) direct estimation of the cost of capital of comparator companies; and

(c) model-based estimation of the licence holder's cost of capital, either based on data for the licence holder itself or comparators or both.

Direct estimation

13.12 Payments on existing fixed-rate (embedded) debt are a known quantity, and the cost of floating-rate and new fixed-rate debt can be estimated from existing yields together with expected trends in interest rates.

13.13 NIE's equity is not quoted, so there is no current market information on its cost of equity. In any event, the cost of equity is much more difficult to estimate directly than the cost of debt, even for a quoted company where the marginal shareholders' current valuation (the market price of its shares) is known. This is because the marginal shareholders' expected future return (in the form of dividends and other payments) from holding the shares is not observable[3] and, under the type of incentive regulation applied in the UK and Northern Ireland to energy, water and other utilities, very difficult to estimate directly. In the USA, many utilities are still subject to cost of service regulation, and the cost of equity is more often estimated directly (by calculating the rate of return that equates the current value of a stock to the present value of its future stream of dividends).

Direct estimation for comparator companies

13.14 Data for comparator companies may be useful for two reasons. First, it may be available where there is no data for the company concerned. Second, even where there is individual company data, comparator company data may be relevant to assessing the costs that an efficient licence holder would incur (in regard to the cost of capital as well as other areas of the price control, such as opex).

13.15 Current equity valuations are available for a small number of quoted GB utility companies: National Grid, SSE, United Utilities, Severn Trent and Pennon. National Grid is involved in gas and electricity transmission. SSE is involved in power generation, electricity distribution, and gas and electricity supply. The transmission and distribution activities of National Grid and SSE are regulated by Ofgem. United Utilities, Severn Trent and Pennon are water and sewerage companies and are regulated by Ofwat. In considering the relevance of such evidence to NIE, it is important to recognize that there are differences in the business activities, the customer base and the regulatory framework.

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we simply refer to it as the 'WACC' (rather than the 'vanilla WACC'). The deductibility of interest payable is taken into account when setting NIE's RP5 corporation tax allowance—see Section 17.

[3] The expected future return also depends on future regulatory decisions.

Model-based estimation

13.16 The advantage of model-based estimation is that it can provide additional relevant data (although necessarily based on assumptions about the working of capital markets). Given the availability of direct data on the cost of debt, model-based estimation is only relevant to the cost of equity. The main model discussed in this section is the capital asset pricing model (CAPM). NIE proposed an adjustment to the usual CAPM approach to allow a Northern-Ireland-specific premium on the cost of equity (see paragraph 13.85).

13.17 The CAPM relates the cost of equity to the RFR (r_f), the expected return on the market portfolio (r_m), and a firm-specific measure of investors' exposure to systematic risk (beta or β):

Equation 3: Cost of equity: $c_e = r_f + \beta \,.\, (r_m - r_f)$

Estimates of r_f, r_m and beta are required to estimate the cost of capital via the CAPM.

13.18 In our 2007 report on Heathrow and Gatwick,[4] we looked at alternatives to the CAPM and found that:

(a) CAPM remains the tool with the strongest theoretical underpinnings;

(b) it is not at all clear from the academic literature that other models have better predictive power, particularly when applied to UK companies; and

(c) none of the alternative models helps to overcome the problems that CAPM has in dealing with limited market data.

13.19 We think that these points remain valid. Hence, we also still think that although the CAPM has its limitations, it is the most robust way for a regulator to measure the returns required by shareholders. Moreover, we have placed considerable weight on the CAPM in previous regulatory inquiries. Consistency and predictability of regulatory approaches is in the public interest.

13.20 Our projected cost of equity will therefore be based primarily on our estimates of four parameters: g, r_f, r_m and beta. These parameters can change as a result of movements in financial markets, whilst at the same time there is continuing work by financial and academic analysts on new data and on the reinterpretation of existing data. In addition, there can be considerable uncertainty over the appropriate level for some inputs. All these factors suggest to us that we should not approach the cost of capital calculation mechanistically, but will need to exercise a degree of judgement when selecting our parameters, and similarly in evaluating the outcomes and reaching our conclusions.

Inflation

13.21 We estimate the WACC in real terms, net of inflation. In doing so, it is sometimes necessary to derive real rates from nominal prices, for example yields on government and corporate debt. Since we are forecasting the WACC for the period 2012 to 2017, we use an estimate of inflation over this period to derive the corresponding real return.

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[4] *BAA Ltd: a report on the economic regulation of the London airport companies (Heathrow Airport Ltd and Gatwick Airport Ltd)*, CC, presented to the CAA on 28 September 2007.

13.22 Since NIE's price control is RPI–X based, we estimate a measure of RPI over the relevant period to ensure consistency across all aspects of the modelling. Using inconsistent inflation estimates could result in prices that are below those required to allow an efficient licence holder to earn its cost of capital.

13.23 Our estimate of expected inflation over the RP5 period is 3.25 per cent, based on actual and forecast inflation over the period (Section 11 paragraphs 11.33 to 11.39). Our estimate is based on OBR forecasts.

13.24 NIE said that a lower inflation forecast should be used to calculate the real cost of capital, and submitted that the relevant market implied break-even inflation rate was 2.75 per cent, based on Bank of England calculations. We considered that there was merit in the adoption of a consistent inflation forecast throughout our determination and viewed the OBR as a reliable source on this matter. We acknowledge however that there are differences in view on forecast inflation and that the OBR estimate may be towards the upper end of the range. While we have retained the OBR forecast in our calculation of the WACC range, we have considered the scope for forecasting error in the choice of point estimate. See paragraph 13.188.

The allowed rate of return under the current price control, RP4

13.25 During the RP4 price control covering the period from 1 April 2007, the rate of return has been set at two different points. The allowed WACC was 5.635 per cent until 31 March 2010, and about 0.2 per cent lower from 1 April 2010. These figures were based on Ofgem's electricity distribution and transmission price controls.

The UR's and NIE's estimated cost of capital

13.26 Before discussing the components of the WACC, we set out the UR's and NIE's projected cost of capital for NIE (see Table 13.1).

TABLE 13.1 **Projected real cost of capital for RP5, 2012 to 2017**

		per cent
	UR	*NIE*
Gearing	50.0	60.0
Cost of debt	3.4	3.6
WACC (vanilla WACC)	4.6	5.2
Cost of equity		
RFR	2.0	2.0
ERP* ($r_m – r_f$)	5.0	5.25
Equity beta†	0.74	0.9
Northern Ireland premium	0.0	1.0
Cost of equity	5.7	7.7

Source: UR final determination; UR Statement of Case, paragraph 27; NIE Statement of Case, Table 15.4.

*Equity risk premium.
†In this table the difference in gearing tends to exaggerate the difference in beta—see discussion in cost of equity section in paragraphs 13.81 to 13.183 below.

13.27 The UR told us that it considered that its analysis that underpinned its original RP5 proposals was out of date and that several factors could lead us to allow lower returns than were included in its RP5 proposals. We consider the UR's points in further detail under the discussion of the relevant parameter of the WACC.

13.28 A comparison of elements in the WACC is not entirely straightforward because of the difference in gearing. This may affect the WACC in two ways:

(a) Higher gearing increases the riskiness of both debt and equity and therefore increases the required rate of return on both debt and equity. The effect on the WACC is at least partially offset because a higher weighting is attached to cheaper debt and a lower weighting is attached to more expensive equity.

(b) In principle, higher gearing reduces tax payments as higher gearing implies more debt and hence higher interest payments, and interest is tax deductible (this is known as the debt tax shield). However, both the UR and NIE calculate tax allowances from a financial model that projects forward from NIE's current actual gearing level, which (at about 45 per cent) is about the same as the level of gearing assumed in calculating the WACC (see Table 13.1). Thus, our understanding is that, under the UR's and NIE's modelling, a higher gearing in the WACC would not be associated with lower projected tax allowances in the price control model, because these allowances are projected on the basis of the actual level of gearing that is not affected by the gearing in the WACC.

13.29 Table 13.1 shows that NIE's estimated WACC is 60 basis points higher than the UR's. NIE's assumed cost of equity is 200 basis points higher than the UR's. NIE's assumed cost of debt is 20 basis points higher than the UR's. When adjusted for gearing, the UR's and NIE's beta assumptions are similar. The gearing assumption itself has a negligible effect (see Appendix 13.1).[5] The differences in the estimation of the cost of equity relate to the ERP (which affects the WACC by nine basis points) and the Northern Ireland premium (which affects the WACC by 40 basis points).

13.30 As we were determining an efficient licence holder's revenue allowance, we were not limited to considering only the submissions made by the UR and NIE when considering the appropriate WACC.

Gearing

13.31 In this subsection, we consider the gearing in the WACC (ie the 'g' in equation 1), by considering: *(a)* the UR's submissions; *(b)* NIE's submissions; and *(c)* setting out our view.

The UR

13.32 The UR used a gearing ratio of 50 per cent in its final proposals, based on NIE's actual gearing (measured as the ratio of the book value of debt to the RAB. The UR thought that this was the right starting point when NIE was about to enter a growth phase.[6]

13.33 The UR told us:[7]

> The Commission may want to investigate whether NIE T&D's starting level of gearing (i.e. approximately 50%) is appropriate; in much the same way as the Commission investigated the historical causes of Bristol Water's gearing level during the recent Bristol Water price control inquiry. If any such investigation were to reveal that avoidable shareholder distributions had added to NIE T&D's debts, thus limiting

[5] Here, and elsewhere in this section, in assessing changes in gearing we have had to make assumptions about NIE's debt beta. We have assumed a level of 0.1, but results do not tend to be sensitive to the level of debt beta. In light of this, we did not carry out work to assess the level of NIE's debt beta.
[6] UR final determination, paragraph 12.26.
[7] UR Statement of Case, paragraph 43.

the business' capacity to fund new capex through borrowings in the current period, that may call into question the justification for allowing revenues to be brought forward now.

NIE

13.34 NIE proposed a range of 55 to 65 per cent for the gearing ratio with a point estimate of 60 per cent. Its estimates were informed by assumptions made by Ofgem in its 2009 and 2012 price control reviews for electricity and gas distribution and transmission networks.

13.35 NIE told us that it had consistently maintained its gearing below a threshold of 57.5 per cent set at the RP4 price control review.

CC discussion

13.36 Different levels of gearing may be associated with different levels of WACC and, in principle; an optimal level of gearing might be estimated by attempting to balance the different effects (including the risks and costs of any financial distress that might be associated with higher gearing). Generally, after taking into account the tax shield from more debt, the WACC is not very sensitive to the level of gearing—the vanilla WACC increases but the tax-adjusted WACC remains broadly constant.[8] In the case of NIE, the relationship between the WACC and gearing is also affected by the difference between the cost of its existing embedded debt and the cost of its new debt which is likely to be lower, see paragraph 13.80 below. An increase in NIE's gearing increases the proportion of NIE's lower cost new debt and tends to reduce its average cost of debt, with the result that its vanilla WACC remains broadly constant (and its tax-adjusted WACC decreases).

13.37 In our financial modelling (see Section 17), we started with NIE's current approximate level of gearing (around 45 per cent), and based on our assumptions for projected net revenues and dividends over RP5, we forecast average gearing to be 45 per cent. This is thus the level that we have assumed for the purposes of calculating the WACC.

13.38 As regards the impact of gearing on tax payments, the CC has expressed a view in the past that tax payments should be projected on a basis that is consistent with the forecast WACC, including the gearing assumption in the WACC. As discussed in paragraph 13.10, the projection of tax payments is an integral part of the computation of required revenue and of the price cap. We need to make sure that the licence holder, if efficiently managed, can earn its cost of capital under our assumed gearing, and this requires there to be consistency between gearing in the WACC and in the tax modelling.[9]

Cost of debt

13.39 Our analysis of the cost of debt is structured as follows:

[8] We discussed this point in *Bristol Water* (2010) (see Appendix N, paragraphs 30–35 and Annex 2 of that report).
[9] See *Bristol Water*. If the company reduces gearing to the notional level, it will incur higher tax payments than assumed in financial modelling, and its required return will be greater than assumed in financial modelling. Moreover, even if the company were able to continue with its higher gearing, its (vanilla) WACC will tend to be higher than assumed in financial modelling (see Appendix N) and its required return will consequently also be higher than assumed in financial modelling.

(a) We examine the costs of NIE's existing debt, including NIE's argument that there is a Northern Ireland debt premium.

(b) We examine the cost at which new debt might be raised during the price control period.

(c) We calculate the cost of debt as a weighted average of the estimated costs of existing and new debt.

The cost of existing debt

13.40 NIE's debt comprises primarily two bonds, on which a total value of £572 million was outstanding as at 31 June 2013.[10] There is no bank debt or intra-group liabilities.

13.41 Table 13.2 summarizes the parties' assumptions on the cost of debt.

TABLE 13.2 **Parties' assumptions on the real cost of debt**

	All debt %
UR's assumed cost of debt	
Cost of debt	3.4
NIE's assumed cost of debt	
Cost of debt	3.6

Source: UR Statement of Case, paragraph 27; NIE Statement of Case, Chapter 15, paragraph 3.32.

13.42 In this subsection we consider *(a)* the UR's submissions; *(b)* NIE's submissions; *(c)* the views of the SEM Committee; and *(d)* previous CC inquiries. We *(e)* discuss; *(f)* assess the case for a Northern-Ireland-specific risk premium; and *(g)* set out our determination on Northern Ireland premium and the cost of existing debt.

The UR

13.43 The UR said that its RP5 proposals had assumed that any new borrowing would have the same cost as NIE's existing debt. It noted that the cost of debt had fallen since it made its RP5 proposals and that, with hindsight, this approach might overstate the cost of new borrowings.[11]

13.44 The UR said that the premium yield on NIE's debt had reduced and almost disappeared in late 2012 and early 2013, and that this had coincided with a financial restructuring by ESB, NIE's parent company, in 2012. According to the UR, this showed that the premium was caused by investor concern about ESB's weaker credit quality prior to the financial restructuring, and customers should not be required to pay for any adverse consequences of NIE's particular ownership structure.[12]

13.45 The UR said that the cost of debt in NIE's proposals was higher than the yield on NIE's actual debt and that NIE was asking customers to pay £114 towards each £100 of interest that NIE actually incurred, and there was no good reason for that margin.

[10] NIE report and accounts for the six months ended 30 June 2013, www.nie.co.uk/documents/Annual-Reports/NIE-Interim-Accounts-Jun13-FINAL-clean.aspx, note 8.
[11] UR Statement of Case, paragraph 9.
[12] UR Supplementary Submission, paragraph 71.

13.46 The UR said that if we allowed NIE's embedded debt costs, there might be a case for disallowing a portion of NIE's actual interest costs so as to avoid a situation in which customers in Northern Ireland had to pay more for their electricity as a consequence of NIE's current ownership arrangements.

NIE

13.47 NIE's estimate of the cost of debt is based on Ofgem's DPCR5 benchmark for GB electricity networks of 3.6 per cent. NIE proposed to add a Northern Ireland premium in the range of 65 to 104 basis points (with a point estimate at the lower end of the range) calculated by reference to historical differences in yields between NIE's bond and comparators.

13.48 NIE said that there was empirical evidence that its bond due in 2026 (issued in 2011) had been trading at a substantial discount to comparable bonds issued by regulated electricity distributors elsewhere in the UK. The discount corresponding to a premium on the yield to redemption of the order of 65 to 104 basis points (based on 6- and 12-month averages[13] respectively). There was a reduction in the yield difference in late 2012.

13.49 NIE also argued that evidence of a Northern Ireland premium was apparent from an examination of yields on bonds issued by PNGL.

13.50 NIE sent us a paper by Frontier which estimated the premium to be 76 basis points. This was based on the average difference in yield between NIE's 2026 bond and that of a basket of comparable GB utility bonds, over a one-year period ended 1 June 2013.

13.51 NIE disputed the UR's view that there was a connection between the premium and ESB's ownership of NIE. It said that because the bond was secured on NIE's licensed business, its market price reflected risks associated only with NIE itself. NIE said that the fall in NIE's bond yield occurred several months after the completion of ESB's refinancing and this meant that it was unlikely that the two events would be linked.

13.52 NIE raised the following questions, which, it said, undermined the UR's position that the premium was a consequence of ESB's ownership:[14]

(a) Why was there a premium on NIE's short-dated bond before NIE was purchased by ESB?

(b) Why was there a premium on NIE's short-dated bond even before the Irish debt crisis led to spikes in the yields on Irish government debt?

(c) Why is there a similar premium observed on the bond issued by Phoenix Natural Gas Ltd (PNGL), which has no links to ESB?

(d) Why has the SEM Committee, which includes three representatives from the UR, decided to take account of a 'risk premium' that reflects 'spread differentials between NIE and UK utility bonds' in its decision paper on new entrant costs if it believes that this spread only arises as a consequence of ESB's ownership of NIE and therefore does not apply more generally?

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[13] Ended on 5 March 2013.
[14] NIE supplementary submission, p144, paragraph 3.5.

13.53 In response to our provisional determination, NIE put forward econometric evidence to investigate the relationship between the yields on NIE and ESB bonds which it said showed that the relationship was very weak. NIE said that this evidence supported its view that the observed premium on NIE's bond, relative to GB peers, was driven by NI-specific factors and was not linked to ESB's ownership.[15]

The SEM Committee

13.54 The SEM Committee, a joint committee of the UR and its Republic of Ireland counterpart which determines some parameters affecting electricity wholesale markets across the island of Ireland, allowed a Northern Ireland premium of 50 basis points in estimating the financing costs that a hypothetical new peaking power station would incur.[16]

Previous CC inquiries

13.55 In recent regulatory inquiries,[17] the CC indicated that it would normally factor a measure of existing 'embedded' fixed-rate debt costs into its calculation of the cost of debt.

CC discussion

13.56 We consider that there are three elements to the cost of debt:

(a) the cost of existing fixed-rate (embedded) debt;[18]

(b) the cost of existing and new floating-rate debt (which depends on short-term interest rates during the price control period, as well as the relevant spread over government debt); and

(c) the cost of new fixed-rate debt (which depends on interest rates for this duration and type of debt at the time of issue, as well as the relevant spread over government debt).

Each of these three elements should be weighted according to its projected importance in the licence holder's overall debt during the projection period. Among the points we considered was whether the relative importance of floating and new fixed-rate debt should depend on longer-run costs as well as which was expected to be cheapest during the price-cap period. For instance, during a period of low interest rates, floating-rate debt might be expected to be cheaper than longer-dated new fixed-rate debt, but it may nevertheless be reasonable to issue longer-dated fixed-rate debt if short- and longer-run interest rates are expected to increase (and hence there is a cost to delaying issue of fixed-rate debt).

13.57 There are two approaches to the cost of existing fixed-rate debt:

(a) Set the rate based on an average rate derived from an appropriate index over a period prior to the price control period. This has the advantage of giving companies incentives to reduce the cost of their debt to outperform the index. Ofgem

[15] NIE response to provisional determination. Frontier Economics, November 2013, p28.
[16] Fixed Cost of a Best New Entrant Peaking Plant, Capacity Requirement & Annual Capacity Payment Sum for the Calendar Year 2013, Decision Paper, 31 August 2012.
[17] *Bristol Water plc* (2010); *BAA Ltd* (2007 report on Heathrow and Gatwick, op cit) and *Stansted Airport Limited, Q5 price control review*, CC, presented to the CAA on 23 October 2008.
[18] This is relevant except to the extent that it matures prior to the end of the price-cap period.

has recently moved to such an approach using a ten-year trailing average index for A and BBB rated bonds with maturities over ten years.

(b) Set the rate based on the actual cost of NIE's embedded debt. If used as a general approach, this would give NIE weaker incentives to reduce its cost of debt, particularly towards the end of price-cap periods.

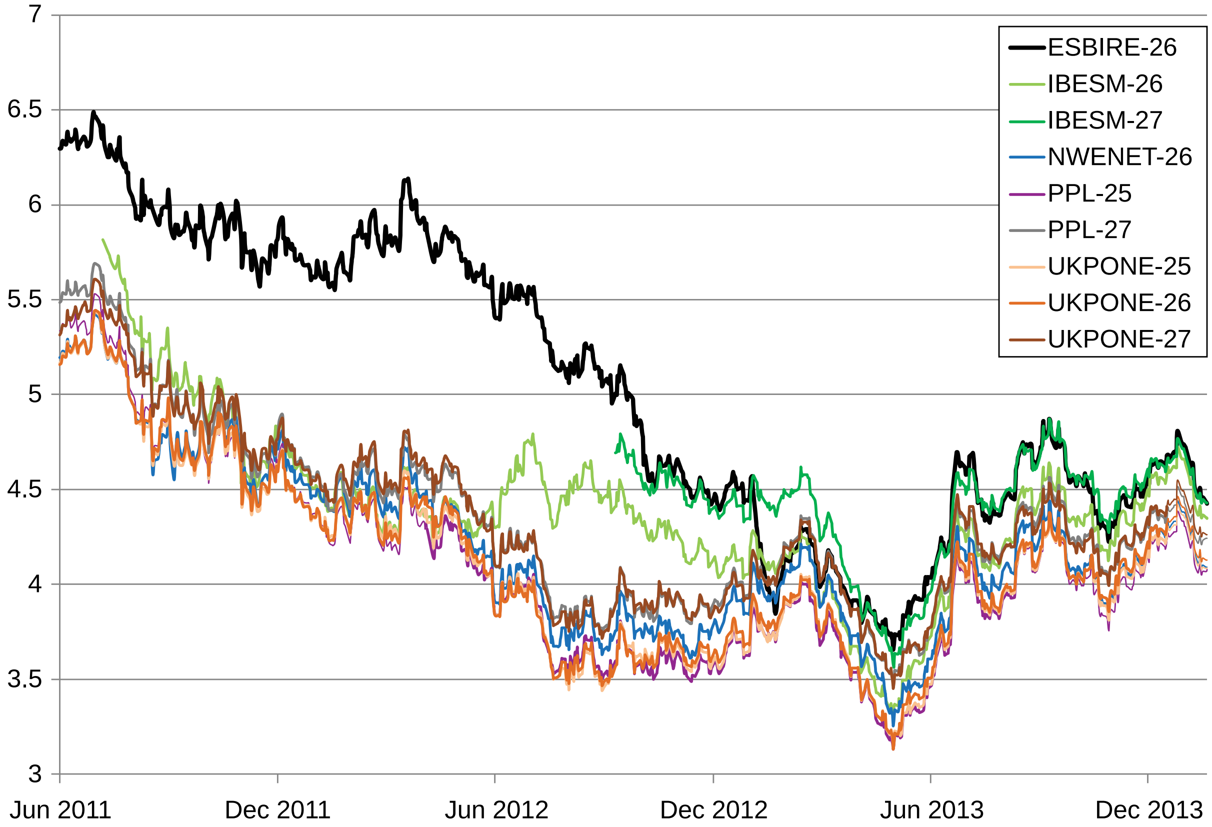
13.58 As regards *(a)* we considered that the appropriate benchmark index was not obvious, noting that NIE's bond has traded at a premium to GB utility bonds. In addition, such approaches may be less appropriate in the context of regulating a single firm. Accordingly, we followed the established regulatory approach of estimating the cost of embedded debt based on NIE's actual debt, with appropriate consideration of whether it had been incurred prudently and efficiently through examination of the yield on NIE's bond and comparable bonds issued by GB electricity distribution companies.

The case for a Northern-Ireland-specific risk premium

13.59 Figure 13.1 shows the yield to maturity on NIE's 2026 bond and comparable bonds issued by GB electricity distribution companies. The chart starts on the date at which NIE's 2026 bond was issued.

FIGURE 13.1

Yield to maturity on NIE's 2026 bond and comparable bonds issued by GB electricity distribution companies



Key:

ESBIRE-25	NIE Finance 6.375% due 2 June 2026 (BBB+)
NWENET-26	Electricity North West 8.875% due 25 March 2026 (BBB+)
UKPONE-25	Eastern Power Networks 6.5% due 31 March 2025 (BBB+)
UKPONE-27	London Power Networks 6.125% due 7 June 2027 (BBB+)
UKPONE-26	South Eastern Power Networks 5.5% due 5 June 2026 (BBB+)
PPL-27	Western Power Distribution South West 5.875% due 25 March 2027 (BBB+)
PPL-25	Western Power Distribution West Midlands 6% due 9 May 2025 (BBB+)
IBESM-26	SPD Finance UK 5.875% due 17 July 2026 (BBB)
IBESM-27	SP Manweb 4.875% due 20 September 2027 (BBB)

Source: Bloomberg.

13.60 We noted that there was a difference in yields of more than 100 basis points for most of 2011 and 2012. Since January 2013 the difference in yields has reduced to between 0 and 50 basis points.

13.61 We considered the possibility that the difference in yields might be in some way associated with ESB's ownership of NIE. ESB conducted a financial restructuring in late 2012. The events highlighted on ESB's website are:

(a) 4 September 2012: ESB prices bond in market (€600 million with five-year maturity).

(b) 12 November 2012: ESB issues €500 million bond (seven-year maturity).

(c) 31 January 2013: ESB welcomes revised outlook from Fitch Ratings.

(d) 13 February 2012: ESB signs new €1.35 billion bank credit facility.

(e) 13 February 2013: Standard and Poor's improves outlook for ESB and NIE.

13.62 We examined price data for ESB's bonds in pounds, euros and US dollars, and for comparator UK, German and US government bonds. While we found no other large price movements on the specific days in January 2013 where NIE's bond yield fell relative to comparable bonds, we observed that, at a broader level, the premium on ESB bonds was particularly high at the time where the NIE premium was high, and that the falls in the ESB premium and the NIE premium took place within months of each other.

13.63 There were few reported trades in NIE's bond. The daily price data that we used reflects bids and offers published by market makers rather than actual transactions. We cannot rule out the possibility that the timing differences were simply due to a lack of market efficiency in these quoted prices.

Determination on Northern Ireland premium and the cost of existing debt

13.64 We accept that there appears to be a premium in the yield on NIE's debt compared with comparable instruments issued by other electricity distribution companies in the UK.

13.65 NIE produced econometric evidence to suggest that ESB ownership had not affected the premium on NIE bonds. However, we noted that the credit rating of NIE was dependent on ESB ownership.[19]

13.66 We did not rule out the possibility that the premium, which was at its greatest in 2011 and 2012, was in part caused by market concern about ESB, which was alleviated following ESB's successful refinancing in the latter part of the calendar year 2012. To the extent that this was the cause, then we would agree with the UR that it should not be reflected in price limits. But we were not certain to what extent the premium could be attributed to ESB ownership.

13.67 Accordingly, it is our view that the cost of the licence holder's existing debt should be assessed based on the actual interest cost of NIE's outstanding bonds.

13.68 There are two bonds secured on NIE's licensed transmission and distribution business: a £175 million bond maturing 2018 with a coupon rate of 6.875 per cent; and a £400 million bond maturing 2026 with a coupon rate of 6.375 per cent. The weighted average cost of this existing debt is 6.5 per cent nominal. The 2026 bond is listed on the London Stock Exchange.

13.69 We therefore assumed a real cost of existing debt of 3.2 per cent based on a weighted average cost of embedded debt of 6.5 per cent and inflation of 3.25 per cent[20].

The cost of new debt

13.70 Our approach to estimating the cost of new debt was to:

[19] Fitch, in its statement of 16 October 2013 said 'The affirmation of [NIE's] long term IDR (issuer default rating) and the Stable Outlook reflect NIE's ties to its ultimate parent ESB [ ] including full ownership, the fact that NIE's liquidity funding is provided by ESB, and a back-to-back interest rate swap arrangement entered in to by the two companies in April 2011.'
[20] Using Fishers' equation: (1+coupon)/(1+inflation)–1.

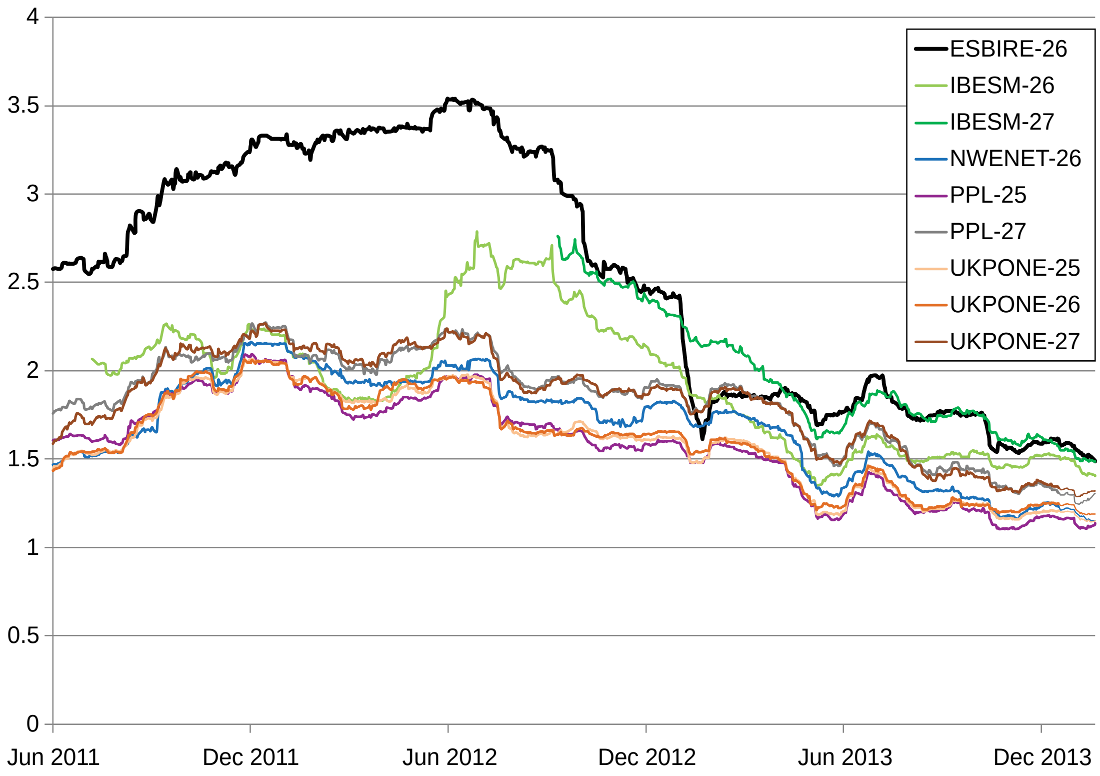
(a) Consider the yield to maturity on NIE's £400 million bond: this is equivalent to the return that an investor would earn by purchasing an NIE bond now and holding it until the capital is repaid in 2026. This provided a proxy for the rate at which NIE could borrow now if it was offering a fixed rate to 2026. During the period in which we undertook our analysis between August 2013 and January 2014, NIE's 2026 bond traded at a spread over the benchmark gilt of between around 150 to 165 basis points.

(b) We examined market data for publicly traded bonds and recent new issues and compare this benchmark data to the indications of pricing that NIE supplied in its Statement of Case.

13.71 In Figure 13.2 we plot the yield spread of NIE and comparator bonds over a benchmark UK government gilt.

FIGURE 13.2

Premium of yield to maturity over 2026 gilt



Source: Bloomberg.

13.72 Figure 13.2 indicates that there have been significant fluctuations in the spread of NIE's bond over the past few years, which reached 3.5 per cent in the middle of 2012. Since around January 2013, the spread on NIE's bond has reduced considerably and is now similar to that on comparator bonds, although at the upper end of the range. The spread on comparator bonds issued by other UK electricity distribution companies has generally remained between 1 and 2.5 per cent throughout the period, and the spread on all the bonds (including NIE's) is now below 2 per cent.

13.73 We considered recent bond issues by GB utilities in the ratings category BBB+ and BBB—see Table 13.3. We found that recent issues of nominal debt by utility companies rated BBB+ or BBB were priced at coupons of between 3.6 and 5.9 per cent and were trading at yields in the range of 3.3 to 4.6 per cent. We concentrated on nominal debt as we considered it unlikely that an efficient licence holder would be able to raise index-linked debt.

TABLE 13.3 **Selected nominal bond issues by UK utility companies since June 2011**

Issuing company	*Composite rating*	*Coupon*	*Maturity*	*Currency*	*Amount £m*	*Issue date*	*Yield 24/02/13*
Western Power Distribution West Mids PLC	BBB	3.875	17/10/2024	GBP	65	17/10/2013	4.049
Yorkshire Water Services Bradford Finance Ltd	BBB	4.965	13/06/2033	GBP	90	12/06/2013	N/A
Anglian Water Services Financing PLC	BBB	4.500	22/02/2026	GBP	200	22/02/2013	4.870
Severn Trent Utilities Finance PLC	BBB+	3.625	16/01/2026	GBP	500	16/01/2013	4.062
SP Manweb PLC	BBB	4.875	20/09/2027	GBP	350	20/09/2012	4.439
Severn Trent Utilities Finance PLC	BBB+	4.875	24/01/2042	GBP	250	24/01/2012	4.635
Wessex Water Services Finance PLC	BBB+	4.000	24/09/2021	GBP	300	24/01/2012	3.486
Southern Gas Networks PLC	BBB	4.875	05/10/2023	GBP	300	05/10/2011	3.954
Eastern Power Networks PLC	BBB+	4.750	30/09/2021	GBP	400	04/10/2011	3.491
SPD Finance UK PLC	BBB	5.875	17/07/2026	GBP	350	18/07/2011	4.350
South Eastern Power Networks PLC	BBB+	5.625	30/09/2030	GBP	200	17/06/2011	4.348
London Power Networks PLC	BBB+	5.125	31/03/2023	GBP	250	17/06/2011	3.709

Source: Bloomberg.

13.74 We consider that the cost of new debt for an efficient licence holder might be higher than that of the BBB+ and BBB-rated utility companies due to its small size relative to some of these utilities. We therefore based our assessment of the cost of new debt on the spread of NIE's 2026 bond over gilts as at August 2013, noting that the spread had declined slightly since then (see paragraph 13.72).

13.75 In response to our provisional determination, NIE said that we should assume a term premium of 10 basis points above the observed spread on the NIE 2026 bond because any new debt would be likely to be slightly longer duration (15 years vs 13 years).[21] However, we consider that the duration of any future debt issuance is a matter for NIE taking into account debt market conditions at the time.

13.76 For maturities of 15 years and over, nominal yields are around 3.6 per cent (see Figure 13.4 below). In response to our provisional determination, NIE said that we should apply an uplift to current nominal gilt yields of 50 basis points to take account of forecast increases in gilt yields, giving a range of 3.4 to 3.9 per cent.[22] We consider that the timing of any future debt issuance is a matter for NIE taking into account its view of debt market conditions over the price control period. It could adopt hedging strategies to lock in current rates if it considered this to be appropriate. Hence, we did not consider that it was necessary to provide NIE with any additional allowances, over and above that which it would face if it went to the debt markets now, in anticipation of higher rates in the future. We have included an additional 20 basis points to cover issuance costs and fees (including for interest rate hedges). These spreads need to be combined with our estimates for gilt yields to calculate the total cost of debt.

[21] NIE response to provisional determination, Frontier Economics, November 2013, p10.
[22] NIE response to provisional determination, Frontier Economics, November 2013, p9.

13.77 Based on gilt yields, spreads, and fees together with an assumed range for RPI inflation of 3.25 per cent[23] over the relevant period, we estimate cost of new debt of 2.14 per cent (see Table 13.4).

TABLE 13.4 **Summary of CC assumptions on the cost of new debt**

Benchmark gilt yield	3.60
Spread	1.65
Implied coupon	5.25
RPI inflation rate	3.25
Real interest rate*	1.94
Fees	0.20
Total	2.14

Source: CC calculations.

*Calculated using Fisher Equation: (1+coupon)/(1+inflation)–1.

The cost of debt as a weighted average of the estimated costs of existing and new debt

13.78 We consider that in order to maintain a gearing ratio of around 45 per cent over the course of the remainder of RP5, NIE would need to raise some new debt before the end of the period. NIE said that it had not yet entered into any discussions with providers of debt finance and the timing and quantum of any future debt finance was uncertain.

13.79 We therefore assumed a ratio of 90 per cent embedded debt to 10 per cent new debt, consistent with a modest amount of new debt being raised in the second half of RP5.

13.80 Taking the real cost of existing debt of 3.2 per cent and a projected real cost of new debt of 2.1 per cent our weighted average real cost of debt is 3.1 per cent for the period, assuming 90 per cent embedded and 10 per cent new debt.

Cost of equity

13.81 Under the CAPM model, the cost of equity depends on the RFR, the ERP (that is the difference between the market return and the RFR, $(r_m - r_f)$ in equation 3) and the value of beta.

13.82 Our preferred approach is to deduct our estimate of the RFR from our estimate of the equity market return to derive the ERP. There are two principal reasons for preferring to calculate the ERP in this manner: first ERP estimates can vary depending on the class of risk-free instrument used in the calculation; second the market return has tended to be less volatile than the ERP (as measured, for example, by the ratio of standard deviation to mean), and there is some evidence of the ERP being negatively correlated with Treasury bill rates over the short term. This subsection is therefore structured as follows.

13.83 We first address *(a)* NIE's submission that its cost of equity should be subject to a Northern Ireland premium and analyse *(b)* the RFR used to calculate the cost of equity, *(c)* the equity market return *(d)* the ERP and *(e)* beta in turn.

[23] See paragraph 13.23.

A Northern Ireland equity premium?

The UR

13.84 The UR told us that NIE was wrong to seek a return on equity above the CAPM estimate.[24] As regards the argument based on a comparison with the additional income opportunities available to electricity distribution network operators elsewhere in the UK, the UR pointed out that NIE had not been subject to the requirements of the incentive schemes under which these income opportunities arose; and that in any event the NIE price control should reflect the costs of financing NIE's business, not the profits made by other companies.

13.85 As regards the argument based on an inference from a Northern Ireland premium on the cost of debt, the UR disputed that such a premium existed. It also said that any Northern-Ireland-specific risk factors that might underpin a higher cost of debt would be diversifiable and so do not need to be compensated by higher expected rates of return. The UR said that its position was consistent with the position taken by the Monopolies and Mergers Commission in its 1997 inquiry on NIE price controls.[25]

NIE

13.86 In NIE's Statement of Case, the estimated cost of equity is obtained by adding a premium of about 1.0 per cent to the results of a calculation based on Ofgem's CAPM approach.[26]

13.87 NIE told us that this premium was required to mirror the effect of certain incentive schemes introduced by Ofgem in the 2009 electricity distribution price control review, which increased expected returns to other UK electricity distribution companies above the headline allowed rate of return if these companies could meet, not beat, their targets.

13.88 NIE also told us that a Northern Ireland premium on the cost of debt justified a premium on the cost of equity. We understood its reasoning to be based on the following steps:

(a) Debt and equity are 'contingent claims on the same productive underlying assets'. This means that the systematic risk drivers that give rise to a premium on the cost of debt must also give rise to a premium on the cost of equity.

(b) The spread between the yield on NIE's bonds and the yield on comparable bonds issued by GB utilities shows that there must be higher risks attributable to operating networks in Northern Ireland.

(c) NIE's equity investors should be remunerated for bearing the part of these underlying risks that falls on equity, where those risks are systematic rather than diversifiable.

13.89 NIE sent us a paper by Frontier which sought to explain that the premium on the cost of equity that it had proposed was conservative.

13.90 The paper analyses the link between a cost of debt premium and a cost of equity premium on the basis of a decomposition of the cost of debt premium of NIE com-

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[24] UR Statement of Case, paragraph 28.
[25] ibid, paragraph 21.
[26] NIE Statement of Case, Chapter 15, paragraphs 3.22–3.29.

pared with similar companies elsewhere in the UK. Frontier estimated the premium to be 76 basis points, using a one-year average to 1 June 2013.

13.91 Frontier assumed that there was no default risk premium element, because the NIE bond and the comparator bonds used in its analysis had equivalent credit ratings.

13.92 Frontier analysed the premium on the cost of debt as follows:

(a) a liquidity risk premium of 29 basis points or less; and

(b) a systematic risk premium, which is therefore at least approximately 47 basis points.

13.93 Frontier described the systematic risk premium as representing compensation to bondholders for bearing the non-diversifiable risk associated with corporate bonds.

13.94 Frontier estimated a cost of equity premium by multiplying the estimated systematic risk premium on debt, 47 basis points, by estimates that it drew from the academic literature of the elasticity of equity with respect to debt. The elasticity estimates ranged from 6 to 14, but Frontier only used figures between 6 and 12.4. This gives estimates of the cost of equity premium between 280 and 580 basis points, which is higher than those NIE had used in its calculations.

PNGL submission

13.95 PNGL sent us a paper by Professor Ian Cooper which provided theories as to how a Northern Ireland premium on the cost of debt might be reflected in a Northern Ireland premium on the cost of equity.

13.96 The report by Professor Cooper included in the PNGL submission provides a detailed analysis of the possible basis for such a Northern Ireland premium on the cost of equity.

13.97 The analysis uses a decomposition of the debt premium in three parts:

(a) Premium to compensate for default risk, if any. This is the part of the premium that would be related to investors' perception of a higher expected default loss on Northern Ireland bonds than on comparator.

(b) Premium return for systematic risk, if any. This would be a premium return required by investors if there was a higher systematic risk in holding Northern Ireland bonds than comparator non-Northern-Ireland bonds.

(c) Premium due to other factors, if any. This could include, for example, illiquidity, which would impose costs on debt investors by making the secondary market less useful.

13.98 Professor Cooper argued that it was legitimate to uplift the allowed cost of equity if there was a premium on the cost of debt due to default risk. While in principle it might be better to make an explicit cost allowance for the (asymmetric) risk of default, in practice it was reasonable to incorporate that allowance in the allowed cost of equity. To quantify the effect, Professor Cooper relied on a statistic that the average loss percentage on a debt default was 59 per cent, and an assumption that a debt default would be associated with a 100 per cent loss for equity investors. Looking only at this risk, the compensation to equity investors for default risk should therefore be 1.69 (=1/0.59) times the corresponding element of the premium on the cost of debt. This calculation is on the basis that Northern-Ireland-specific uncertainty is a downside risk (ie that it is not compensated by an upside potential for equity). Professor Cooper argued that this was an appropriate description of the additional risk in Northern Ireland because he attributed the premium to higher regulatory uncertainty and the immaturity of the regulatory process in Northern Ireland.

13.99 With respect to any part of the premium on the cost of debt attributable to systematic risk, Professor Cooper calculated that each 1 basis point element on the cost of debt was associated with 6.79 basis points on the cost of equity. This calculation relied on the assumption that the relevant element of systematic risk associated with holding debt and equity derived from a single underlying element of systematic risk in the business (rather than, for example, from a systematic element in the way in which a non-systematic risk was shared between equity and debt investors). Professor Cooper cited an estimate that 51.5 per cent of the spread of corporate bond yields over government securities was attributable to systematic risk rather than default risk. If this allocation could be applied to the Northern Ireland premium element of the spread, then each 1 basis point premium on the cost of debt would therefore translate to a 3.49 basis point premium on the cost of equity. Professor Cooper said that this multiplier might be reduced if only part of the non-default element debt premium was associated with systematic risk.

13.100 Professor Cooper did not infer any cost of equity premium from a premium on other (non-default non-systematic) risks.

Further points raised by parties

13.101 In response to Frontier's paper, the UR drew our attention to the fact that Frontier was silent on the question of how the higher exposure to non-diversifiable systematic risk to which it attributed part of the cost of debt premium had come about.

13.102 In response, Frontier emphasized what it saw as empirical evidence for a difference in systematic risk, suggested that NIE bore higher regulatory risk than other UK electricity distribution networks in part because of a shorter regulatory period, and that this regulatory risk was pro-cyclical in part because of a tendency for regulatory decisions to be tougher during recessions so that regulated companies would 'share the pain' of the wider economy.

13.103 The UR also thought that Frontier had not established the absence of a default risk element, and that there was a risk of a pick-and-mix error in adopting NIE's approach in a context where the allowed cost of debt included any Northern-Ireland-specific premium.

13.104 In response, Frontier told us that its approach to controlling for differences in default risk using credit ratings was appropriate and was very similar to an approach adopted by the CC in its 2008 Stansted price control inquiry, and that it was implausible that the Northern Ireland premium could be attributed entirely to default risk and illiquidity because that would imply that NIE's credit rating differed by several notches from what would reflect default risk.

13.105 The UR told us that PNGL was in the process of changing ownership at a reported premium to its regulatory asset value, and suggested that the real-life behaviour of investors was more significant than theoretical arguments about alleged Northern-Ireland-specific risks.

CC discussion

13.106 The theories put forward by NIE, PNGL and Frontier to infer a cost of equity premium from a cost of debt premium all rely on the assumption that part of any premium on the cost of debt is appropriately modelled as debt investors' share of an underlying risk associated with NIE's business which is higher than for comparators; and that equity investors would bear, and expect to be remunerated for, their share of the same underlying risk.

13.107 The estimates of the cost of equity premium derived in this way are proportionately greater than the part of the cost of debt premium which is attributed to remuneration for financial risk (default risk or systematic risk, depending on the theory). This makes sense within these theories: equity investors are exposed to a greater share of an underlying business asset value risk than debt investors.

13.108 We do not think that we can rely on any of these theories in order to adjust our estimates of an efficient licence holder's cost of equity.

13.109 This is because there is a possibility that any higher risk that bondholders bear (or perceive that they bear) might be offset by lower risk borne by equity holders. In other words, it is possible that, instead of being a consequence of a higher underlying business risk, any higher risk borne by debt holders might be merely the result of a different allocation in the case of NIE of an equivalent business risk between equity and debt.

13.110 If it were the case that the additional risk reflected in NIE's higher cost of debt was connected with a lower risk borne by equity investors, then a cost of debt premium would imply a reduction in NIE's cost of equity—the opposite of the theories put forward by NIE, PNGL and Frontier. Such a rebalancing of perceived risk between debt and equity could have occurred if NIE's bondholders perceived a risk that ESB, at the time where it might have been perceived as under financial stress, might have attempted to rely on NIE's cash flows to finance itself; that might have led to a perception that risks were being imposed on NIE bondholders in order to finance the wider ESB group. But we do not think that it would be appropriate to rely on such a theory given the regulatory ring-fencing obligations to which NIE is subject.

13.111 Importantly, the observed premium on NIE bonds has decreased significantly since January 2013 (see Figure 13.2) and does not now appear significantly higher than Frontier's highest estimate of a liquidity premium. It appears to us that the yield on NIE's bonds is no longer indicative of any additional risk perceived by bondholders compared with similar companies elsewhere in the UK, and therefore that none of the theories outlined above applies.

13.112 NIE tried to demonstrate that there were factors which could, under some hypotheses, suggest that it should be allowed a higher return on equity than that suggested by standard CAPM comparisons.

13.113 We consider that the hypotheses on which the theories put forward by NIE and PNGL implicitly rest are plausible in theory but that equally plausible theories exist that would have different implications for the cost of equity. NIE's theory is not sufficiently supported by evidence for us to place weight on it.

13.114 It is our view that the cost of equity should be calculated on the basis of the standard CAPM with no adjustment for a Northern Ireland premium. By applying a standard CAPM approach to the WACC we consider that we are allowing a fair return for the risks assumed by NIE and its investors. We do not consider that it is necessary to mirror the effects of Ofgem's incentive mechanisms when setting the rate of return for NIE.

Risk-free rate used to calculate the cost of equity

The UR

13.115 The UR said that the RFR used in the CAPM might now appropriately be set to a level lower than 2 per cent. Reasons included negative yields on index-linked gilts, and the fact that forecasts of RPI-measured inflation but not CPI-measured inflation had shifted up.[27]

NIE

13.116 NIE said that it considered an RFR of 2 per cent above RPI, as had been proposed by the UR in its RP5 proposals, was appropriate. NIE thought that setting the real RFR at this level would ensure consistency with Ofgem's DPCR5 determination and was consistent with taking a long-term view of market parameters during periods of anomalous economic activity, and that this would be sound regulatory practice.[28]

Previous CC inquiries

13.117 Since 2000, the CC has taken the view that long-dated index-linked gilt yields are in principle the most suitable basis for estimating the RFR applicable to the cost of equity. The CC has, however, considered that long-dated index-linked gilt yields have been affected by distortions (associated, for example, with pension fund dynamics) and that these need to be corrected in estimating the RFR applicable to the cost of equity. The CC has reached a judgement about the RFR on the basis of medium- and shorter-dated index-linked gilt yields.

13.118 At the time of the Stansted report, index-linked gilt yields were mostly yielding below 2 per cent. The CC concluded that there was no mechanistic way of interpreting the data and that it was required to exercise a certain amount of judgement before selecting a precise value for the RFR. Its judgement was that the RFR in recent years had been approximately 2.0 per cent, and that this was an appropriate assumption to use for 2009/10 to 2013/14.[29]

13.119 In its Bristol Water price determination, the CC used a range of 1 to 2 per cent, noting that market data on long index-linked gilts supported the lower end of this range.[30]

Discussion

13.120 We continue to regard index-linked gilt yields as in principle the most suitable source for estimating the RFR, since index-linked gilts have negligible default and inflation risk. Long maturities appear most relevant to the RFR in the cost of equity since equities also have long (indefinite) maturity. Figure 13.2 shows the index-linked yield curve for recent periods. For maturities of 15 years and more, the current index-linked yield curve is roughly flat at 0 per cent—the same yield curve derived by averaging yields over the last five years is about 0.5 per cent. Shorter-dated yields

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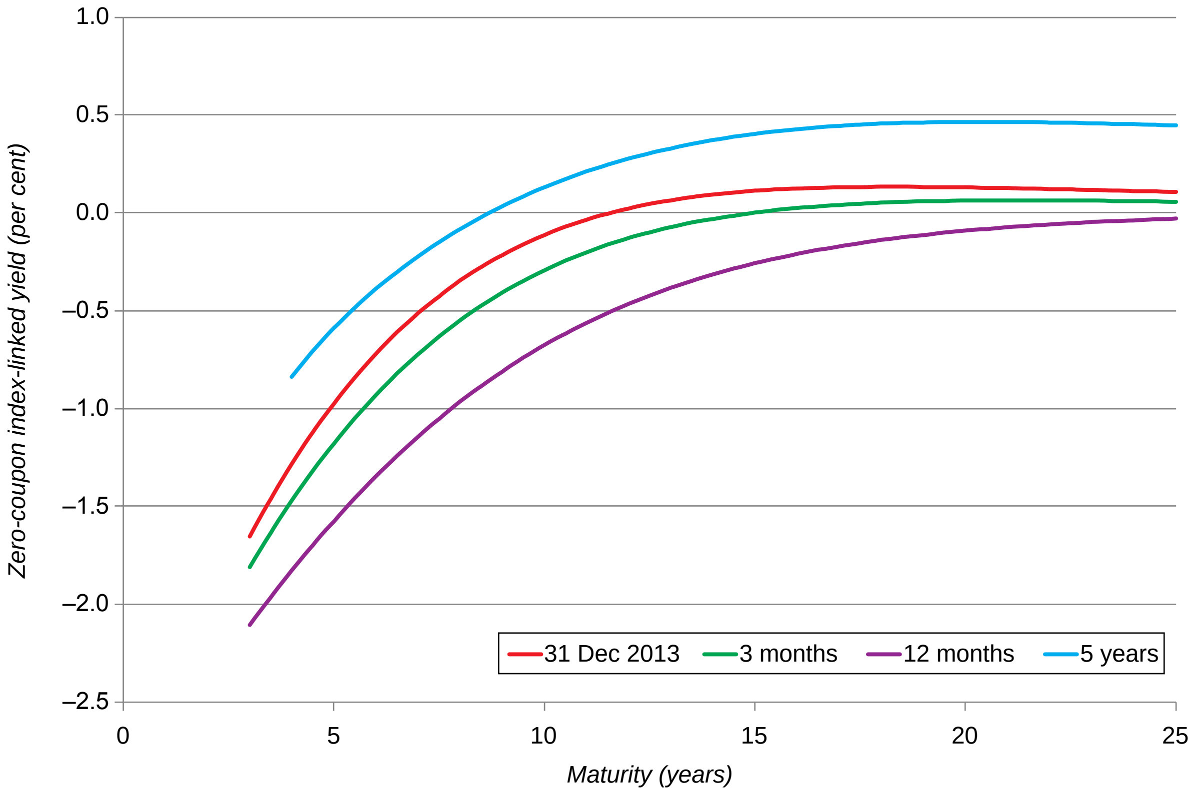
[27] UR Statement of Case, paragraph 16.
[28] NIE Statement of Case, Chapter 15, paragraph 3.18.
[29] CC, 2008, Stansted Airport, paragraph 11.29.
[30] Bristol Water, 2010, Appendix N, paragraphs 66–74.

have fallen significantly over the last five years, reflecting action by the authorities to address the credit crunch and recession, and are currently very low.

FIGURE 13.3

Index-linked yield curve

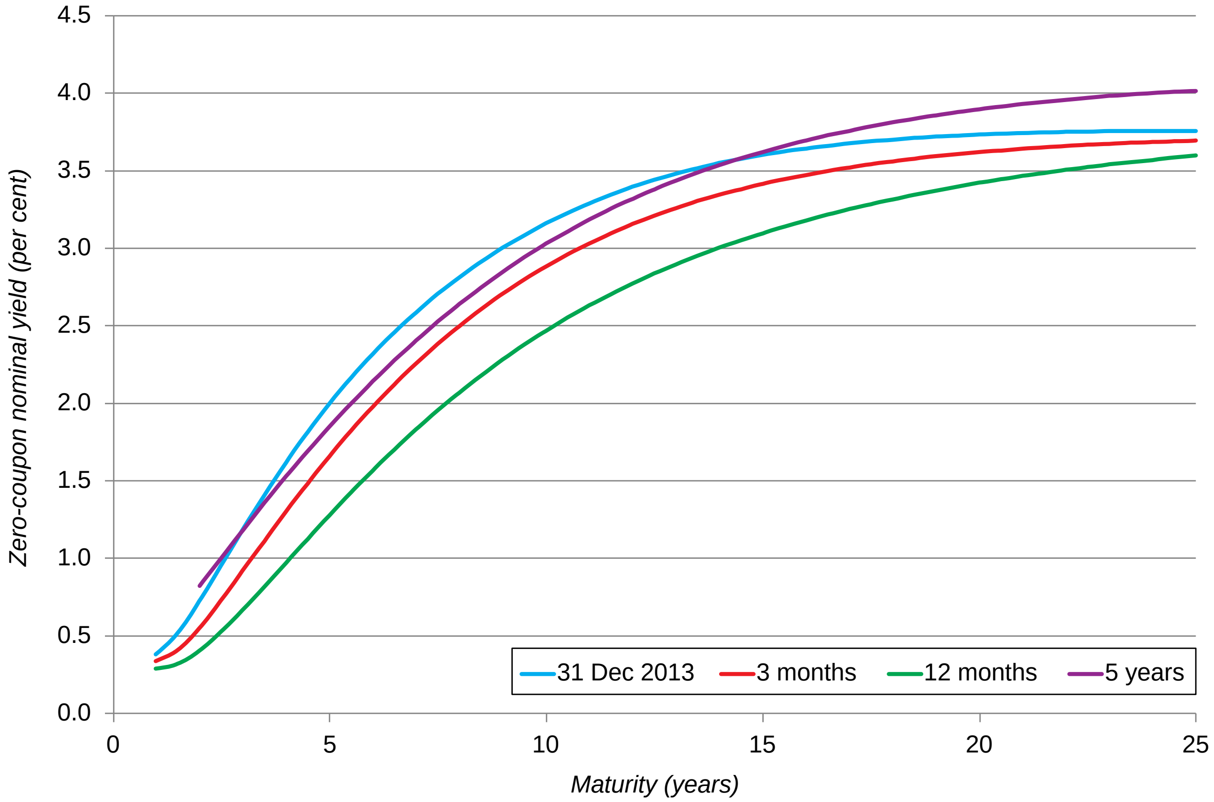


Source: Bank of England, real spot yield curve data.
Note: The four lines show yields on 31December 2013 and average yields over the three-month period from October to December 2013, the calendar year 2013, and the five-year period covering calendar years 2009 to 2013.

13.121 Nominal gilts also have negligible default risk, but are subject to inflation risk. Nominal gilt yields can be used to estimate a real RFR if assumptions are made about expected inflation and any inflation risk premium. Figure 13.3 shows nominal gilt yields on a similar basis to Figure 13.2. The nominal yield curve is upward sloping with yields of around 0.5 to 1 per cent on short-dated instruments and around 3 to 4 per cent on longer-dated gilts of maturities above ten years.

FIGURE 13.4

Nominal yield curve (spot)



Source: Bank of England, UK nominal spot curve data.
Note: The four lines show yields on 31December 2013 and average yields over the three-month period from October to December 2013, the calendar year 2013, and the five-year period covering calendar years 2009 to 2013.

13.122 We also considered long-run measures of returns on different asset classes as set out in Table 13.5. Gilt rates are those on longer-term government instruments and returns are likely to include an element of inflation risk. Bill rates are those on short-term government paper and may thus be regarded as a better measure of the riskless interest rate. However, it is doubtful that Treasury Bills have been free of inflation risk (for example, rates were negative from 1970 to 1979 when inflation was high).

TABLE 13.5 **Long-run realized real returns for different UK asset classes**

	Barclays 1899–2012	*Credit Suisse Geometric mean 1900–2012*	*Credit Suisse Arithmetic mean 1900–2012*
Gilts	1.3	1.5	2.4
Bills or cash	0.9	0.9	1.1

Source: Barclays Capital Equity Gilt Study 2013, Credit Suisse Global Investment Yearbook 2013.

CC discussion

13.123 In previous reports in the last ten years, the CC paid attention to distortions in the index-linked markets that may affect the shape of the yield curve. In Bristol Water (2010), the CC noted that shorter-dated index-linked yields were affected by action by the authorities to address the credit crunch and recession and were therefore less relevant to estimating the RFR. In inquiries prior to 2010 the CC put less weight on longer-dated maturities, noting possible distortion from pension fund asset allocation policies.

13.124 We note that the effects of monetary policies and pension fund dynamics are increasingly well understood by the markets. Consequently we expect the market prices of ILGs to incorporate effectively expectations of the effects of these factors and therefore to provide a reasonable guide to future returns.

13.125 We note the view of Elroy Dimson, Paul Marsh and Mike Staunton in the 2013 edition of the Credit Suisse Global Investment Returns Yearbook:

> Today's low yields partly reflect the quest for safe havens, are heavily influenced by central bank policies, and may be affected by regulatory pressure on pension-fund and insurance-company asset allocations. They may also be impacted by demographic factors, such as dissaving by retiring baby boomers, but the evidence here is, at best, weak (see Poterba, 2001) Should we be concerned that today's long bond yields may be artificially low?
>
> This question is hard to resolve conclusively, but two points are relevant. First, many alleged 'distortions' are likely to be permanent. Regulatory pressures on insurers and pension funds are unlikely to diminish; pension funds are maturing and should lean towards higher bond weightings; baby-boomer retirement is ongoing; and, with a stock market that could easily see an increase in volatility …, the safe-haven demand for bonds could even increase.
>
> Second, these factors are all common knowledge. While the impact of quantitative easing (QE) and other unconventional monetary policies may be hard to measure, the policies themselves are disclosed and transparent. It would be curious, therefore, if the market prices of bonds of different maturities failed to incorporate expectations of the impact of these factors. We should therefore expect bond market prices and yields to provide a reasonable guide to prospective returns.

13.126 It is plausible that index-linked gilt yields are low due to the imperfections associated with RPI as a measure of underlying inflation. We note the historical gap between RPI and CPI measures of inflation of around 0.8 per cent, and the forecast increase in the gap. To the extent that CPI better reflects underlying inflation, measures of return relative to RPI (of which index-linked gilts are one such measure) may be reduced as a result of that gap. This may be a factor behind negative short-term real yields. However, given that the RAB is also indexed by RPI we do not need to adjust our estimate of the RFR for this effect.

13.127 Long-dated index-linked yields have remained below 1 per cent for at least the last five years (see Figure 13.3). The prolonged period of low yields may suggest that long-run rather than temporary factors are at work. We therefore now see some grounds for assuming a lower RFR, more in line with actual long-dated index-linked yields. We think that there is some justification for an uplift to take account of the uncertain effects of quantitative easing.

13.128 In response to our provisional determination, NIE said that given the deep uncertainty over when ILG yields will recover, the CC should err on the side of caution and go to the top of its estimated range of 1.5 per cent. It said that the DMS view that the alleged 'distortions' in ILG yields were likely to be permanent was unfounded, noting that QE cannot be maintained indefinitely.[31] However, we considered that in adopting a range for the RFR of 1 to 1.5 per cent, which is considerably above rates on long-duration index-linked debt (of approximately 0 per cent), we were adequately allowing for the possibility that rates might rise during the remainder of RP5.

13.129 We adopted a range of 1 to 1.5 per cent for the real RFR. We note that the lower end of this range is well above current short-term real interest rates (which are negative). In addition, the upper end of the range is well above the long-term rate of interest on Treasury Bills of 1.1 per cent (see Table 13.5).

13.130 In the next subsection we consider the equity market return and ERP. As discussed in paragraph 13.82 our preferred approach to estimating the ERP is to estimate the expected return on the market and then deduct the RFR.

Equity market return and risk premium

13.131 The expected market return is the return that investors require for investing in equities. The ERP $(r_m - r_f)$ is the part of this return that compensates them for the additional risk associated with investing in equities, rather than in risk-free assets.

The UR

13.132 The UR said that a fall in the RFR would have led to a fall in returns on equity.[32]

NIE

13.133 NIE supported an ERP of 5.25 per cent, based on Ofgem precedent. It accepted that a figure of 5.0 per cent as used by the UR in its proposals could also be supported.

Previous CC inquiries

13.134 In the Stansted regulatory report, the CC derived an ERP of 3 to 5 per cent by subtracting its RFR of 2 per cent from a market return of 5 to 7 per cent. The CC effectively took a figure from near the top of this range because it considered that the consequences of setting too low a figure for the cost of capital (lack of investment) were worse than the consequences of setting too high a figure (higher charges). The implied figure for the market return would be 6.6 per cent and for the ERP 4.6 per cent.[33]

13.135 In the earlier Heathrow and Gatwick regulatory report, the CC similarly assumed a market return of 5 to 7 per cent (with an RFR of 2.5 per cent and ERP of 2.5 to 4.5 per cent). The CC also effectively took a figure from near the top of the range.[34]

13.136 In its Bristol Water report, the CC said that the market return was 5 to 7 per cent and the implied range for the ERP was 4 to 5 per cent. It said that historical average realized returns on equities for short holding periods supported the upper end of the range[35] but noted that current expected returns may be lower than the average expected historical returns. The lower end of the range was consistent with some

[31] NIE response to provisional determination, Frontier Economics for NIE, November 2013, Section 3.3.
[32] UR Statement of Case, paragraph 16.
[33] Because the chosen WACC (7.1 per cent) was 81 per cent of the way up the range for the WACC.
[34] CC, 2007, *BAA Ltd*, paragraphs 4.75–4.79 & 4.108.
[35] Bristol Water, Appendix N, paragraph 93.

forward-looking estimates based on combining observed dividend rates with forecast rates of dividend growth.

Sources of evidence

13.137 There is no universally accepted method for deriving the expected market return or the ERP. Both concepts are concerned with investors' ex ante expectations of returns, which are largely unobservable. The academic literature on the subject is large and can be categorized into three types: studies that assume that historical realized returns are equal to investors' expectations (so-called 'historical ex post' approaches); studies that fit models of stock returns to historical data to separate out ex-ante expectations from ex-post good or bad fortune (so-called 'historical ex ante approaches'); studies that use current market prices and surveys of market participants to derive current forward-looking expectations (so-called 'forward-looking approaches'). We use historical approaches (both ex ante and ex post) as our primary sources for estimating the equity market return, with forward-looking approaches being used only as a cross-check on our resulting ERP estimates. We consider evidence on the equity market return based on historical ex post and historical ex ante approaches in paragraphs 13.138 to 13.150. We consider forward-looking approaches in the context of the ERP in paragraphs 13.151 to 13.161.

- *Historical ex post approach*

13.138 The key assumptions behind the historical ex post approach are that expected returns remain constant over time and that average realized returns reflect the expected return.

13.139 The simplest approach is to calculate the arithmetic average of historical returns. It is appropriate to take an average of annual returns if there is a constant underlying return and the return in each year is independent of that in other years (see Appendix 13.2). Since annual returns have been highly variable, this approach requires looking at a long run of historical data. The DMS data set now contains 113 years of data from 1900 to 2012. Table 13.6 below shows arithmetic estimates for mean annual real returns on equities, bonds and bills for the period 1900 to 2012, together with statistics for the standard error and standard deviation of the estimates.

TABLE 13.6 **Returns on UK asset classes, 1900 to 2012**

	Mean returns % PA		
	AM	*SE*	*SD*
Real returns			
Equities	7.1	1.9	19.8
Bonds	2.4	1.3	13.7
Bills	1.1	0.6	6.3

Source: Credit Suisse Global Investment Returns Sourcebook 2013.

13.140 Table 13.7 shows average returns over the period from 1900 to 2012 for different holding periods. It is usual to quote figures for the average of one-year returns but investors in the equity market usually expect to invest in the market for longer than a year. We therefore show average returns for some longer holding periods as well, using a number of different estimators.

TABLE 13.7 **Real returns, 1900 to 2012**

per cent

	Return on equity				*ERP‡*			
	*Simple**	*Overlapping†*	*Blume§*	*JKM§*	*Simple**	*Overlapping†*	*Blume§*	*JKM§*
UK market, DMS data								
1-year holding period	7.1	7.1	7.1	7.0	6.0	6.0	6.0	5.9
2-year holding period	7.5	7.0	7.1	7.0	6.2	5.8	6.0	5.9
5-year holding period	6.7	6.8	7.0	6.8	5.2	5.3	5.9	5.7
10-year holding period¶	6.4	6.8	6.9	6.6	5.1	5.3	5.8	5.5
20-year holding period	6.7	6.9	6.8	6.1	5.7	5.6	5.7	5.1
UK market, Barclays data								
1-year holding period	6.9	6.9	6.9	6.8	5.8	5.8	5.8	5.8
2-year holding period	7.2	6.7	6.8	6.8	6.0	5.5	5.8	5.7
5-year holding period	6.2	6.4	6.8	6.6	4.8	5.0	5.7	5.6
10-year holding period¶	6.0	6.4	6.7	6.3	4.7	4.9	5.7	5.3
20-year holding period	5.9	6.4	6.5	5.8	5.1	5.1	5.5	4.9

Source: CC calculations based on *Credit Suisse Global Investment Sourcebook 2013*, written by Dimson, Marsh and Staunton (DMS) and Barclays Equity Gilt Study.

*The mean is calculated from the formula $(\sum(R_{t+h}/R_t)/(110\text{-}h))^{1/h}$ 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. Years are dropped at the beginning of the data period if the holding period is not a multiple of the total data period.
†The mean is calculated from the formula $(\sum(R_{t+h}/R_t)/(110\text{-}h))^{1/h}$ 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.
‡ ERP is calculated relative to UK Treasury bills.
§The Blume unbiased estimator is a weighted average of arithmetic and geometric mean and the JKM (Jacquier, Kane and Marcus) small sample efficient estimator is calculated from the estimated mean and variance of lognormal returns..
¶Average of 10- and 11-year holding periods.
Note: Returns for holding periods greater than one year are expressed as annual equivalent returns.

13.141 The data in Tables 13.6 and 13.7 suggests an average market return of around 6 to 7 per cent (for both world and UK markets). In order to calculate the historical ERP, it is necessary to subtract the historical RFR from the historical market return. Index-linked gilts have not been available for the full period and it is usual to use the return on Treasury Bills as a proxy for the RFR. However, it is doubtful that Treasury Bills have been free of inflation risk (for example, rates were negative from 1970 to 1979 when inflation was high). The data in Table 13.6 suggests an average ERP over Treasury Bills of about 5 to 6 per cent.[36] The standard error around these historical estimates is substantial, implying a 95 per cent confidence interval of around 3 to 11 per cent for the market return and around 3 to 9 per cent for the ERP.

- *Historical ex ante approaches*

13.142 The ex post method has drawn significant criticism in finance literature and many studies have concluded that it does not provide a reliable indication of the ERP. Mehra and Prescott (1985) observed that the high historical returns provided by equities relative to government bonds are inexplicable in the context of standard economics models that describe risk. Similarly Blanchard, Shiller and Siegel (1993) concluded that the ex post ERP appears far in excess of what is justified by standard asset-pricing models with reasonable levels of risk aversion.

13.143 Fama and French (2002) estimate the underlying return from the sum of average dividend yield and the average rate of dividend growth.[37] Using the full run of historical data for the UK, this suggests an underlying expected market return of 5.5 per cent[38] and an ERP over Treasury Bills of 4.4 per cent (using Barclays data

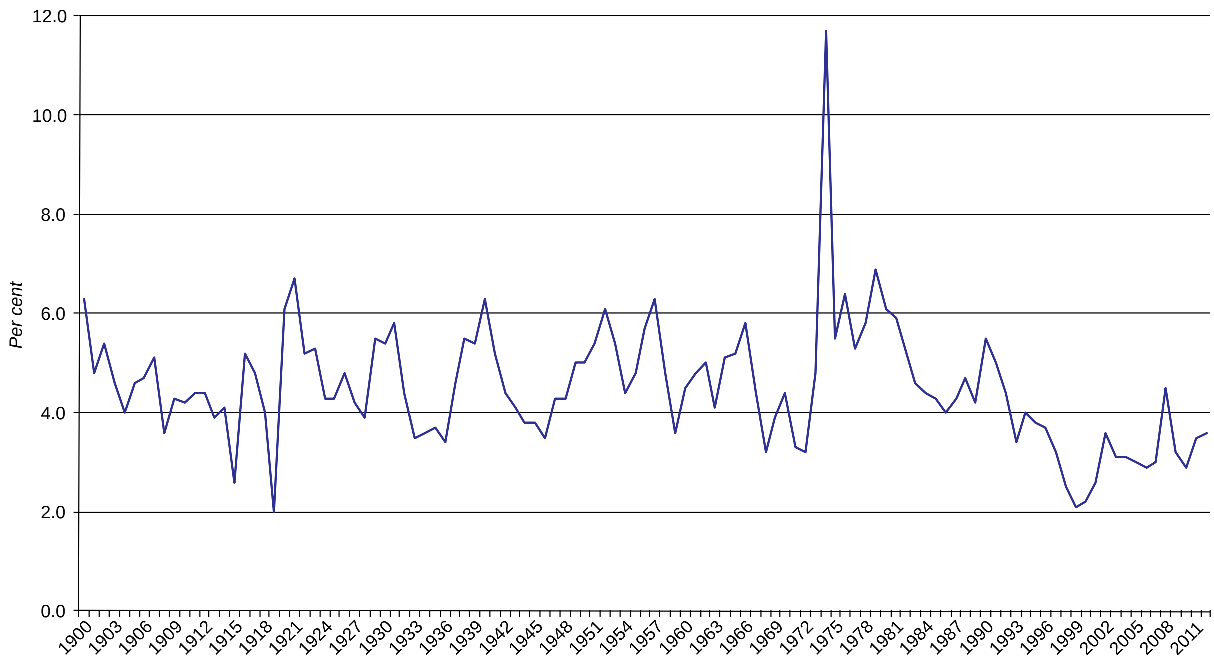
[36] ERPs are sometimes calculated relative to long-dated gilt yields, rather than Treasury Bills. As gilts are subject to additional risks compared with Treasury Bills (greater inflation risk and also price volatility risk), we have not shown ERPs relative to gilts.
[37] Fama, E F and French, K R, 'The Equity Premium', *Journal of Finance*, April 2002.
[38] This results from average dividend yield of 4.5 per cent and dividend growth of 1 per cent a year (Barclays data).

which prior to 1962 comprises fewer companies than DMS but shows broadly similar (albeit slightly lower) results for average returns).

13.144 Fama and French's work for the USA provided evidence of a fall in expected returns over time, with expected returns being lower since 1950 than before 1950. Many other papers have reported similar findings, though the issue remains controversial.[39] The statistical evidence for the UK is less extensive[40] but, as illustrated in Figure 13.5, the current dividend yield (about 3.6 per cent) is below the historical average (4.5 per cent). Unless future dividend growth is higher than in the past, this would suggest that expected returns are about 1 per cent lower than the past average, implying a market return of about 4.5 per cent and an ERP over Treasury Bills of 3.4 per cent (using Barclays data).[41]

FIGURE 13.5

Dividend yield for UK market (Barclays data)



Source: Barclays Equity Gilt Study 2013.

13.145 DMS (2008) sought to infer what investors may have been expecting, on average, in the past, by separating the historical equity premium into elements that correspond to investor expectations and elements of non-repeatable good or bad luck. These elements include the mean dividend yield, the growth rate of real dividends, the expansion of the price/dividend ratio, and change in real exchange rates. DMS

[39] Welch and Goyal, 'A comprehensive look at the empirical performance of equity premium prediction', *Review of Financial Studies*, 2008, which did not find robust evidence that forecasts of the ERP based on dividend yields were better at predicting future returns than the assumption of a constant ERP. The issue of the *Review of Financial Studies* in which this paper appeared included other papers suggesting that the evidence suggested the ERP was predictable , for example: Campbell, J and Thompson, S: 'Predicting Excess Stock Returns Out of Sample: Can Anything Beat the Historical Average?' and Cochrane, J: 'The Dog That Did Not Bark: A Defense of Return Predictability'.
[40] Two papers that did find evidence of a reduction in the expected market return or ERP for the UK (albeit at different times) are Buranavityawut, N, M C Freeman and N Freeman (2006), 'Has the equity premium been low for 40 years?', *North American Journal of Economics and Finance*, 17, pp191–205; and Vivian, A, 'The UK equity premium, 1901-2004', *Journal of Business and Financial Accounting*, 2007. The first paper suggests that the expected equity premium may have fallen in the 1960s in the UK and other countries, while the second paper suggests that there was a permanent decline in the UK market dividend-price ratio during the early 1990s.
[41] These figures do not take into account payments to shareholders other than dividends, for example share repurchases.

concluded that the worldwide historical premium was larger than investors were likely to have anticipated because of factors such as unforeseen exchange rate gains and unanticipated expansion in valuation multiples. Noting that dividend yields are lower than in the past, DMS inferred that, for the world index, a forward-looking risk premium (over Treasury Bills) would be 4.5 to 5 per cent.[42] Given a difference of 1 per cent between average return on bills and ERP (see Table 13.3), this implies an expected return of 5.5 to 6 per cent.[43]

CC discussion

13.146 The interpretation of the evidence on market returns remains subject to considerable uncertainty. The CC said in recent regulatory inquiries that 7 per cent is an upper limit for the expected market return, based on the approximate historical average realized return for short holding periods. We think that it is now appropriate to move away from this upper limit based on historical ex post realized returns and place greater reliance on ex ante estimates derived from historical data which tend to support an upper limit of 6.5 per cent. We note the following points in support of setting an upper limit for the market return of 6.5 per cent:

(a) We consider that the expected return on the market is a more stable parameter than the expected ERP. However, it remains the case that it exhibits volatility over time and cannot therefore be regarded as fixed.

(b) We note that past returns necessarily incorporate, inter alia, revisions in expectations for future cash flows and discount rates. DMS (2007) attempted to address this issue directly by decomposing past realized returns. We share its view that some elements of the return, in particular the historical expansion in valuation ratios, is unlikely to be repeated in the future.

(c) In applying the CAPM, we seek to derive the *expected* return on the market. This is not necessarily the same as the realized return, even over long time horizons, if unexpected events occur. In this regard we note that attempts to estimate the historical expected ex ante return suggest that this is considerably lower than the realized return.

(d) A forward-looking expectation of a return on the market of 7 per cent does not appear credible to us, given economic conditions observed since the credit crunch in 2008 and lowered expectations of returns.

13.147 We consider that the appropriate upper limit for the market return is 6.5 per cent. In the context of setting a cost of capital for an efficient licence holder, we are less concerned with a lower limit to the expected market return (since we would wish to avoid the licence holder's cost of capital being too low), but in this context we consider 5 per cent an appropriate lower bound figure.[44]

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[42] *Credit Suisse Global Investment Sourcebook 2013.*
[43] *Credit Suisse Global Investment Sourcebook 2010 and 2013*, section 2.6.
[44] Figures lower than 5 per cent may well be appropriate in other contexts, for example providing advice to equity investors on the lower end of the range of expected returns before costs. In this context, we note that the Financial Services Authority (FSA) requires UK financial advisers to project nominal returns on a notional product two-thirds invested in equities and one-third in fixed income (before costs and personal tax) using rates of 5, 7 and 9 per cent. From 2014 onwards the FSA has reduced the assumed returns to 2, 5 and 7 per cent. Assuming RPI of 2.9 per cent, this implies real returns of –0.9, 2.1 and 4.1 per cent.

The equity risk premium

13.148 Having formed a view on the range for the equity market return, we now consider the ERP. We noted above that returns for index-linked gilts were not available for the full historical period and the Treasury Bill rate may not be a true RFR. This means that it is not valid to add ERPs based on Treasury Bills to our RFR based on underlying longer-dated index-linked gilt yields. As discussed in paragraph 13.82, we therefore prefer to derive the ERP by subtracting the RFR from the expected market return. A further reason for using this approach with historical data is that, historically, the market return has tended to be less volatile than the ERP (as measured, for example, by the ratio of standard deviation to mean) and there is some evidence of the ERP being negatively correlated with Treasury Bill rates over the short term.

13.149 We associate the lower market return (5 per cent) with the lower RFR (1 per cent) and the higher market return (6.5 per cent) with the higher RFR (1.5 per cent). This produces a range of 4 to 5 per cent for the ERP.

13.150 We consider the reasonableness of our range for the ERP derived from historical data against forward-looking approaches to estimating the ERP and other relevant cross-checks in the following paragraphs 13.151 to 13.156.

- *Forward–looking approaches*

13.151 A commonly used approach is to project dividends using analysts' forecasts (which extend out by four or five years) and a longer-term dividend growth rate. The expected return is then the discount rate at which the present value of future dividends is equal to the current market price. A limitation of this approach is that it is necessary to make an assumption about future long-term growth of dividends (which has a major effect on the calculation since dividends beyond year 4 or 5 account for a large part of present value at plausible discount rates). We think such approaches, since they are based on current market data and short-run forecasts, are likely to be more suitable for estimating the short-run ERP and less so for estimating the long-run equilibrium ERP. Since we are concerned with the latter, we place less weight on results derived from this approach.

13.152 Figure 13.6 shows estimates of ERP using this methodology published in the *Bank of England Financial Stability Report*[45] (following the methodology discussed in the Bank of England Quarterly Bulletin).[46]

13.153 These estimates are based on the assumption that the future long-term growth in dividends per share is equal to an estimate of the potential growth of the economy—however, the authors of the article note that this choice of future long-term growth rate is essentially arbitrary. The estimates in Figure 13.6 suggest that since 2007 the expected ERP has fluctuated around 5 per cent, towards the upper end of the historical inter-quartile[47] range of between 4.25 and 5.34 per cent. We attempted to calculate the expected market return implied by these estimates of the ERP by adding the yield on zero-coupon ten-year gilts[48]: Calculated on this basis, since the 2008 financial crisis the market return has fluctuated around 6 per cent. It has declined markedly following the financial market turmoil of 2009 to 5 per cent or less. Indeed, the Bank of England's November 2013 Financial Stability Report notes rising

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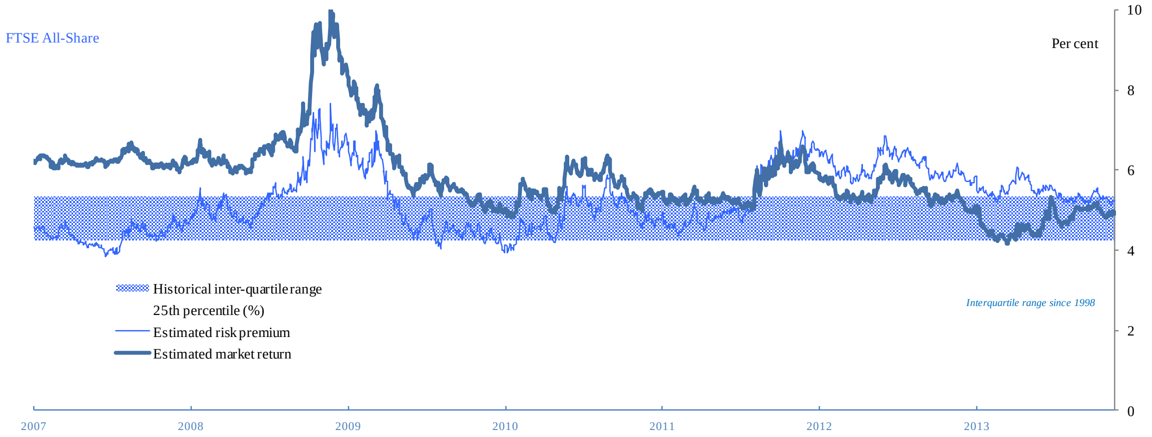
[45] See Chart 1.6 of the November report: www.bankofengland.co.uk/publications/Documents/fsr/2013/fsrfull1311.pdf.
[46] Mika Inkinen, Marco Stringa and Kyriaki Voutsinou: 'Interpreting equity price movements since the start of the financial crisis', *Bank of England Quarterly Bulletin*, 2010 Q1.
[47] Calculated by the Bank of England based on a longer time series of data between 1998 and 2013.
[48] Sourced from the Bank of England's website.

equity prices, improved earnings expectations, and a fall in equity risk premia towards long-term average levels.[49]

FIGURE 13.6

Estimated ERP and approximate implied real market return



Source: Bank of England and CC calculations.

13.154 We agree with the authors of the *Bank of England Quarterly Bulletin* article (see the footnote to paragraph 13.152) that it is essentially arbitrary to assume future long-run growth in dividends per share equal to potential economic growth. Indeed, we see empirical support for expecting long-run growth in dividends per share to be less than potential economic growth. The historical growth rate in real dividends for the UK from the Credit Suisse/DMS data is only 0.5 per cent[50] and around zero using the Barclays data[51]—this is significantly less than real UK economic growth over the same period (1900 to 2010) of 1.89 per cent.[52] It is also the case that growth in dividends per share has been significantly less than economic growth in more recent periods. Since 1950, growth in dividends per share has been 1.1 per cent, compared with 2.4 per cent for GDP growth, while since 1980, growth in dividends per share has been 1.6 per cent, compared with 2.3 per cent for GDP growth.[53]

13.155 Bearing in mind these points and also that analysts' forecasts may be subject to upward bias,[54] we consider that the approximate 5 per cent ERP and 5 to 6 per cent market return suggested by Figure 13.6 are likely to be at the upper end of expected returns. Taken in the round, we consider that they tend to support a range for the ERP of 4 to 5 per cent and a market return of 5 to 6.5 per cent.

- *Consensus or survey-based approaches*

13.156 Another possible source for forward-looking estimates of the ERP is surveys of investors, market participants and academics. However, the results of such surveys

[49] Bank of England, Financial Stability Report November 2013, p8 and Chart 1.6.
[50] *Credit Suisse Global Investment Returns Sourcebook 2013*, Table 11.
[51] For the Barclays data, we calculated a trend growth rate in real dividends over 1900 to 2009 of 0.2 per cent from a regression of real dividends on time (the Barclays data showed a very sharp decline in real dividends up to 1915 and the geometric mean growth in dividends for 1900 to 2009 was –0.2 per cent).
[52] Lawrence H Officer and Samuel H Williamson, 'Annualized Growth Rate and Graphs of Various Historical Economic Series', MeasuringWorth.Com. See: www.measuringworth.com/growth/.
[53] These figures are calculated using the Barclays dividends data and ONS data for GDP.
[54] A large body of literature suggests that there may be a tendency for analysts' forecasts to overreact to changes and on average to be too optimistic, for example W F M DeBondt and R H Thaler (1990), 'Do Security Analysts Overreact?', *American Economic Review* 80, pp52–57.

tend to depend on the identity and outlook of the respondents and how they interpret the questions being asked. Some surveys do not clarify the time frame over which the parameters are to be estimated (the long-term equilibrium ERP or a shorter-term estimate); whether an arithmetic or geometric averaging approach should be used; or whether the ERP is over bonds or bills or some other instrument. In this report we have preferred to consider the underlying data on which survey respondents presumably base their views.

- *Other relevant cross-checks*

13.157 We note that the implied range for the ERP of 4 to 5 per cent[55] appears consistent with the following evidence:

(a) the lower end of the 5 to 6 per cent range suggested by the pure historical analysis conducted by DMS (see paragraph 13.141);

(b) DMS's decomposition approach (see paragraph 13.145) suggesting an ERP of 4.5 to 5 per cent; and

(c) Fama & French's ex ante approach based on the DGM suggesting an ERP of 4.4 per cent (see paragraph13.143).

13.158 In response to our provisional determination, NIE said that we had relied on a very narrow evidence base, drawing almost exclusively on the forecasts of DMS, and ignored a wider set of evidence. NIE cited a survey by Fernandez et al that gave the average forward-looking ERP as 5.5 per cent.[56] Notwithstanding our reservations about survey estimates (see paragraph 13.156) we consider that the median result from this survey of 5 per cent is the more appropriate statistic as it reduces the influence of outliers. This is consistent with the upper end of our range for the ERP.

13.159 NIE also said that we ignored the evidence of an inverse relationship between the ERP and RFR and that given ongoing economic uncertainty, risk premiums had increased rather than decreased since the financial crisis. NIE provided us with evidence that there had been an upward step change in risk since 2008, citing a 44 per cent increase in average market volatility in the five-year period since the financial crisis compared with the five-year period leading up to it.[57] Figure 13.7 plots implied market volatility on the FTSE 100 over a ten-year period.

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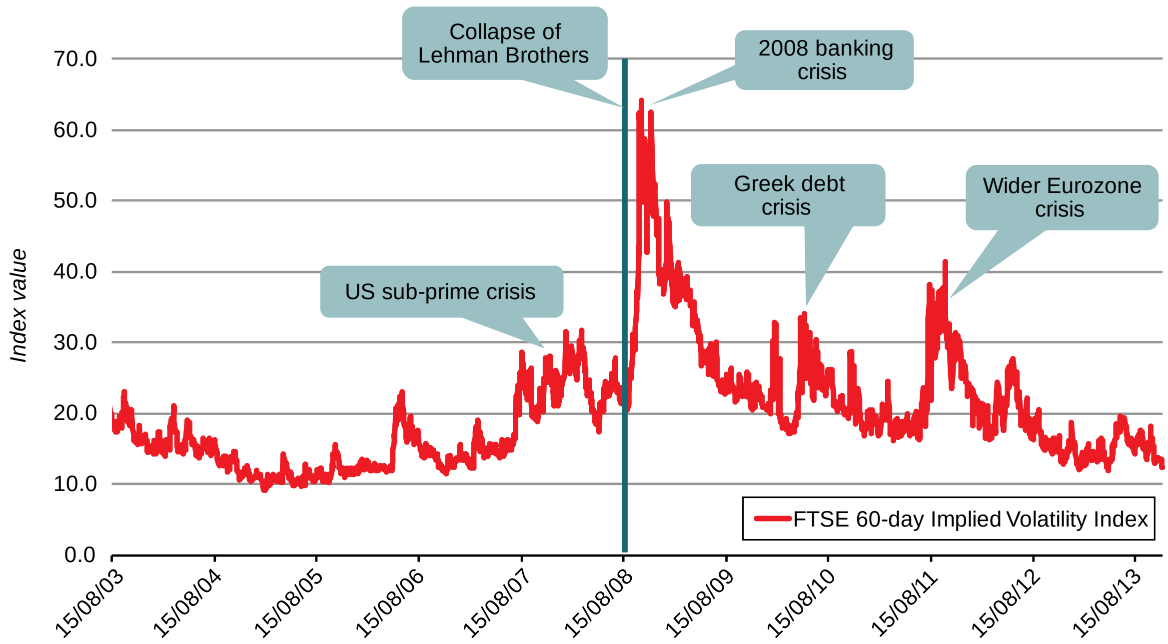
[55] We associate the lower market return (5 per cent) with the lower RFR (1 per cent) and the higher market return (6.5 per cent) with the higher RFR (1.5 per cent).
[56] NIE response to provisional determination, Frontier Economics for NIE, November 2013, Section 3.1.2.
[57] NIE response to provisional determination, Frontier Economics for NIE, November 3013, Annex 2.

FIGURE 13.7

FTSE 100 Implied Volatility Index



Source: Bloomberg, Frontier Economics analysis.

13.160 We considered the points raised by NIE but interpreted the data differently. We observed that volatility had now declined to pre-crisis levels. Whilst it is clear that volatility was raised following the financial crisis, we do not see this event as having increased the long-term equilibrium expected return on the market or the long-term equilibrium ERP. Commentators noted a 'flight to quality' whereby risky equities were shunned in favour of risk-free instruments, share prices fell sharply, and as a result yields on equities rose. However, we see this as a short-term phenomenon. On a prospective basis, we see no reason why equity investors should expect to earn higher returns in the future than they have done in the past.

13.161 We therefore estimate a range of 5 to 6.5 per cent for the market return, and an implied range of 4 to 5 per cent for the ERP.

Beta

13.162 Beta is a factor in the CAPM reflecting the risk of a particular asset or portfolio of assets relative to the market as a whole.

13.163 Within a CAPM framework, changes in gearing affect equity betas. Hence, it is necessary to adjust for gearing differences in order to make comparisons between equity betas (for example, by calculating the asset beta, ie the beta at zero gearing). Our analysis takes this into account.

The UR's submissions

13.164 First Economics (for the UR) produced Table 13.8 showing asset betas for comparator utilities.

TABLE 13.8 **Ranges for utility asset beta based on recent data (figures at the end February 2011)**

	Low	*Average*	*High*
Spot estimate	0.22	0.27	0.32
Average over last year	0.26	0.32	0.43
Annual averages over last 5 years	0.26	0.39	0.63
Annual averages over last decade	0.08	0.31	0.63

Source: First Economics based on data from Thomson DataStream data, and assuming a debt beta of 0.1.

Note: Sample includes: National Grid, Anglian, Pennon, Kelda, Northumbrian, Severn Trent, United Utilities, Viridian, ScottishPower and Scottish and Southern Energy. Of these, six remain listed and are in the sample over the last year.

13.165 First Economics performed a comparative analysis of the systematic risk of NIE with GB electricity distribution and transmission companies, based on the following factors:[58]

(a) exposure to demand risk: revenue cap vs price cap;

(b) exposure to cost risk; and

(c) operational gearing: average industry RAB to revenue ratio.

13.166 Based on the comparative analysis, First Economics concluded that it was difficult to distinguish NIE from the conventional network businesses in GB and particularly from GB electricity distribution companies, pre-RIIO. First Economics noted that Northern Ireland and GB electricity networks' operational gearing was comparable and that they faced similar demand risks through the operation of a revenue cap. First Economics concluded that NIE exhibited the same sort of risk profile as a conventional GB-regulated network operating under a five-year RPI–X price control, and that, all things being equal, they should therefore have the same beta.[59]

13.167 First Economics recommended a range of 0.34 to 0.44 but noted that it had a preference for the upper end of this range on the grounds that the implied cost of equity when using the lower end of the range felt implausible. It recommended that the UR should choose a point estimate for the asset beta of between 0.4 and 0.425.[60]

13.168 The UR noted that statistical measures of beta reported by Ofgem for National Grid, SSE plc, and for the three listed WaSCs, appeared to have fallen in recent years and were now lower than the previous equity beta estimates on which the UR's RP5 asset beta assumption of 0.42[61] was based. The UR said that this implied that investors had come to appreciate better the low-risk nature of regulated utilities.

13.169 The UR told us that its proposals for the structure of the price control would reduce systematic risk for NIE T&D in such a way as to warrant a further reduction in assumed beta.

NIE's submissions

13.170 NIE told us that there had recently been abnormally high volatility in equity markets, so that measured betas for utility companies were temporarily depressed and did not

[58] First Economics, 'An estimate of NIE T&D's cost of capital', December 2011, p5.
[59] ibid, p9.
[60] ibid, p10.
[61] Based on a debt beta of 0.1.

reflect accurately the underlying business risk faced by the companies. On that basis, a long-term perspective was more appropriate.[62]

13.171 NIE suggested that the approach taken to determine the beta, RFR and ERP should use a long-term time horizon, and told us that the CC had recognized this principle in past determinations.[63]

13.172 NIE's proposed figure for equity beta was based on a notional debt beta of 0.1 and a notional asset beta of 0.42. Asset beta is defined as the weighted average of equity beta and debt beta, using notional gearing as the weight for the debt beta. These figures were proposed by the UR in its draft proposals for RP5 and adopted by NIE.[64]

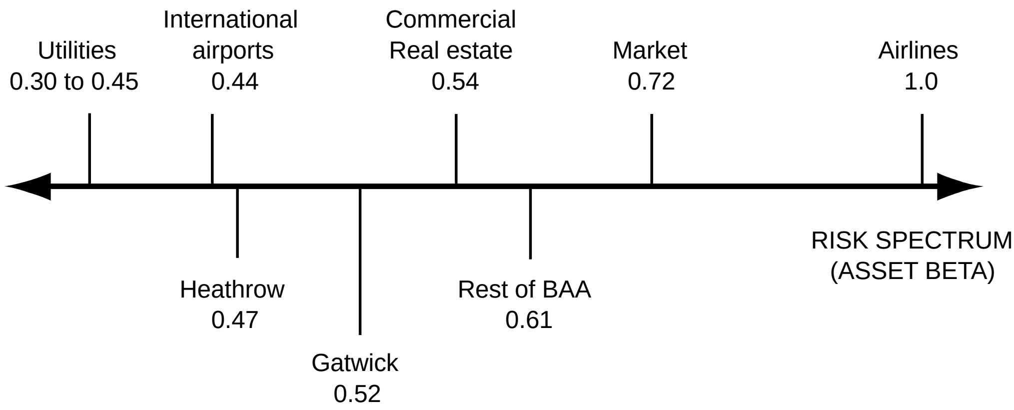
Previous CC inquiries

13.173 The most recent price-cap-setting inquiry was Bristol Water. In that inquiry, the CC derived asset betas from an analysis of daily total return data for listed WaSCs. It then added 18 per cent on to these figures to allow for Bristol Water's higher operational gearing.[65] The implied asset beta range was 0.32 to 0.43.[66]

13.174 Airports are likely to have different risk characteristics from water companies. However, the Heathrow and Gatwick airports inquiry included a comparison of asset betas, shown in Figure 13.8 below. Utilities are positioned at the lower end of the spectrum at between 0.3 and 0.45.

FIGURE 13.8

Risk spectrum (asset beta)



Source: CC analysis in Heathrow and Gatwick regulatory report (2007).

CC estimates of beta

13.175 As already noted, equity beta depends on gearing, but even after adjusting to a similar gearing basis, a company's estimated beta can vary for a number of reasons, including:

[62] NIE supplementary submission, p146, paragraph 4.6.
[63] ibid, paragraph 4.8.
[64] NIE Statement of Case, Chapter 15, paragraph 3.20.
[65] Bristol Water (2010), Appendix N, paragraph 137.
[66] Assuming a debt beta of 0.1. Ibid, Table 11.

(a) Differences in the estimation period and in the frequency of returns data used for estimation. Daily, weekly or monthly data may be used. Daily data is usually preferred as it is likely to have the smallest standard errors and may be regarded as more statistically robust (providing the share's trading frequency is sufficient) but monthly betas may be more reliable, particularly for thinly traded stocks. We have concentrated on betas calculated from daily data in this inquiry.

(b) Whether the data is adjusted for any tendency of true betas to converge to be closer to the market value of one than are estimated betas. Blume adjustments[67] or Bayesian adjustments are two such adjustment mechanisms. We did not see the merits of such adjustments in the context of regulated utilities whose underlying risk profile may be expected to be stable and whose beta may be expected to be below 1.

(c) The assumption made about debt beta in adjusting for gearing. In this case we have assumed a debt beta of 0.05. This is lower than in recent CC cases such as Bristol Water (2010), reflecting the relatively low level of gearing. (The debt beta is assumed to increase with gearing. However, debt beta assumption makes little difference to estimated cost of capital as long as the gearing assumption in the WACC is not too different from the gearing of the companies for which the equity beta was estimated).

13.176 Appendix 13.4 sets out our estimates of equity and asset beta for comparator UK utilities using daily data. Using a series of two-year windows beginning between April 2000 and September 2011, we estimate a rolling asset beta for a utility portfolio of 0.33 assuming a debt beta of 0.05. We estimate a 95 per cent confidence interval around this estimate of 0.24 to 0.45. The summary statistics are show in Table 13.9.

TABLE 13.9 **Asset betas**

	Two years, daily data		
	Mean	*95% interval**	
SSE	0.43	0.26	0.62
National Grid	0.32	0.23	0.42
United Utilities	0.30	0.20	0.46
Severn Trent	0.28	0.10	0.43
Pennon	0.25	0.02	0.46
Portfolio	0.33	0.24	0.45

Source: CC calculations based on Bloomberg data.

*Over the period, 95 per cent of the observations fell within this range.

13.177 The data that we looked at over a ten-year period (see Appendix 13.4, Figure 1) indicates that utility company betas do not tend to converge to 1. Hence, we see no justification for applying the Blume adjustment to utility company betas. As regards a Bayesian or Vasicek adjustment, we accept that such an adjustment could be appropriate if we were estimating the beta for a quoted company (as such an adjustment would combine information on that specific company's beta with information on other companies' betas). However, this is not what we are doing. We are estimating a beta for a portfolio of utility companies to apply to an unquoted utility company (NIE) and therefore we see no role for a Bayesian or Vasicek adjustment.

13.178 With regard to the calculation of gearing for estimating the asset beta, we have used net debt in our calculations; that is long-term debt net of cash balances. We note that this may give lower measures of gearing (and hence higher asset betas) than if long-

[67] The Blume-adjusted beta is a weighted average of raw beta and 1, where the weight on the raw beta is 0.67.

term debt is used with no adjustment for cash balances. We regard either method as justifiable, although for certain companies one approach or the other may be more appropriate depending on the requirement for working capital.

CC discussion

13.179 Measured asset betas for GB utility companies are low, reflecting the relatively low risk of the underlying regulated business—this also means that utility companies tend to be regarded as ‘defensive’ investments.

13.180 Historical observations of beta measure companies’ historic systematic risk profiles. We considered whether there could be a case for suggesting that an efficient licence holder’s beta will be lower or higher than NIE’s was in the past. We concluded that there was no strong case for thinking beta would be different than in the past and consequently that we could estimate beta from historical data.

13.181 The comparators that we use to estimate beta include GB regulated energy and water utilities. These are regulated by Ofwat and Ofgem under regulatory frameworks that are well established and well understood by investors. We think the regulatory framework applying to NIE is similar to that of Ofgem in many respects, particularly to that applying pre-RIIO, and we note the findings of First Economics in this respect (see paragraph 13.166). However, we also note that Moody’s scores the regulatory regime one notch lower than that of GB reflecting that regulation is less well established.[68] Our comparator set is smaller than that of First Economics because it only includes those companies that were listed in August 2013. We consider the results from both First Economics’ and our own calculations.

13.182 We note that there is significant volatility in our own, and First Economics’, beta estimates, and quite different estimates can be produced by using different time periods, different sampling techniques, different debt betas, and different comparator sets. For example, First Economics’ estimate (see Table 13.8) of beta using annual windows over a ten-year period is 0.31, whereas over five years it is 0.39. Our own ten-year average using a series of overlapping two-year windows is 0.33. Estimates using more recent data are lower. We note that the 95 per cent confidence interval around the two-year daily data asset beta for our GB portfolio over the last two years is 0.24 to 0.45 (see Table 8 above and Appendix 13.4).

13.183 Given that beta can vary over time we think that it is right to base our estimate on a relatively long run of data. Our own and First Economics’ estimates suggest longer-run estimates of between 0.31 and 0.4. Taking into account that our comparator set is not an exact match for NIE and its regulatory framework we have selected a range for beta towards the upper end of the range suggested by these estimates. Accordingly, we estimate a range of 0.35 to 0.4.

Estimated cost of capital

13.184 The main factors underlying our determination of the cost of capital were:

(a) We consider that the gearing assumed in the WACC should be consistent with the gearing used to assess financial ratios and calculate tax.

[68] See for example, Moody’s Investor Service: ‘New Competition Commission Referral Suggests Regulatory Uncertainty Remains in Northern Ireland’, 9,May 2013.

(b) We kept in mind the financial ratios that the assumed level of gearing would generate. Our financial modelling (see Section 17) aimed to generate ratios consistent with the efficient licence holder maintaining investment grade status. On a cautious basis, we chose to apply NIE's existing 45 per cent gearing in order that our projections are consistent with an efficient licence holder maintaining investment grade status.

(c) Our estimate of the licence holder's existing cost of debt is 3.2 per cent and that of its new debt is 2.1 per cent, giving a weighted average cost of debt of 3.1 per cent, assuming 90 per cent embedded and 10 per cent new debt.

(d) As regards the cost of equity:

(i) Current index-linked yields are about 0 per cent—as they may still be affected by market distortions we consider that a range of 1 to 1.5 per cent for the RFR is appropriate.

(ii) A reasonable range for the market return is 5 to 6.5 per cent, implying an ERP of 4 to 5 per cent.

(iii) We estimate the licence holder's asset beta at between 0.35 to 0.40, and hence its equity beta (at 45 per cent gearing and assuming a debt beta of 0.05) to be 0.6 to 0.7.

13.185 Based on these assumptions, we calculate a range for the licence holder's WACC of 3.3 to 4.1 per cent—see Table 13.10.[69]

TABLE 13.10 **Calculated WACC range for an efficient licence holder**

	CC low	*CC high*
Gearing (%)	45	45
Cost of debt (pre-tax) (%)	3.1	3.1
Cost of equity (post-tax) (%)	3.4	5.0
WACC (%)	3.3	4.1
Cost of equity calculation		
RFR (%)	1	1.5
ERP (%)	4	5
Equity beta	0.6	0.7
Cost of equity (post-tax) (%)	3.4	5.0
Asset beta calculations		
Debt beta assumption	0.05	0.05
Asset beta	0.35	0.40
Gearing (%)	45	45

Source: CC calculations.

13.186 Our calculated range for the (post-tax) cost of equity at 45 per cent gearing of 3.4 to 5.0 per cent for an efficient licence holder compared with our estimated (pre-tax) cost of new debt of 2.1 per cent in total (and 1.9 per cent before fees).

13.187 We consider that the lower bound of 5 per cent for the expected return on the market was less well supported than the upper end of the range of 6.5 per cent. We consider that the weight of evidence tended to support numbers between 5.5 and 6.5 per cent for the expected market return. While we decided to retain 5 per cent as a possibility,

[69] With a debt beta of zero, some of the individual numbers are changed but the range remains the same.

we were less confident with this estimate and, as a corollary, with numbers at the low end of the WACC range.

13.188 Additionally we noted that the inflation assumption that we adopted in computing the cost of debt, based on OBR forecast inflation, was higher than indicated by some market-based forecasts. (See paragraph 13.24) While we considered that our use of the OBR forecast was reasonable and consistent with its use in other aspects of the price control, we acknowledge that the OBR estimate may be towards the upper end of the range. Given that a lower inflation forecast would tend to increase the real cost of debt and thus the WACC, we consider that this supports the choice of a number towards the upper end of the WACC range.

13.189 Bearing in mind the available evidence and other aspects of our final determination (see Section 17), we adopted the upper end of this range, 4.1 per cent, as the WACC for RP5.

13.190 Our cost of capital range was lower than that of the UR and that of NIE—see Table 13.11:

(a) Our cost of capital was different from the UR's mainly because we estimated a lower cost of equity of 3.4 to 5.0 per cent (the UR estimated 5.7 per cent). Our cost of debt was also lower than its estimate. The combined effect was that our WACC range of 3.3 to 4.1 per cent and our point estimate of 4.1 per cent were lower than the UR's point estimate of 4.6 per cent.

(b) Our cost of capital was below NIE's estimate because we estimated a lower cost of equity. We did not allow a Northern-Ireland-specific premium on the cost of equity and we have lower estimates for the RFR and ERP.

TABLE 13.11 **Cost of capital for an efficient licence holder**

	CC range	*CC point estimate*	*UR original*	*NIE regeared**
Gearing (%)	45		50	50.0
Cost of debt (pre-tax) (%)	3.1		3.4	3.6
Cost of equity (post-tax) (%)	3.4–5.0		5.7	6.9
WACC (vanilla WACC) (%)	3.3–4.1	4.1	4.55	5.2
Cost of equity calculation				
RFR (%)	1.0–1.5		2	2
ERP (%)	4.0–5.0		5	5.25
Equity beta	0.6–0.7		0.74	0.74
Asset beta	0.35–0.40		0.42	0.42
NIE premium	0		0	1
Cost of equity (post-tax) (%)	3.4–5.0		5.7	6.89

Source: CC calculations.

*Adjusted to 50 per cent gearing using 0.1 debt beta.

Comparison with previous regulatory decisions

13.191 We consider that consistency with previous decisions is relevant and any significant changes should be satisfactorily explained and well justified.

13.192 Table 13.12 shows a comparison with the WACCs recommended in the CC's most recent regulatory reports on Heathrow and Gatwick (2007) and Stansted airports (2008) and Bristol Water (2010). Our cost of debt for the licence holder is lower than the CC's recommended cost of debt for the airports, reflecting more recent credit market conditions. Our cost of equity for the licence holder is lower than the range of the CC's recommended cost of equity for the airports, reflecting the lower risk that utility companies face compared with airports. Our cost of equity sits within the range proposed for Bristol Water. As discussed earlier in this section, the range for the assumed market return of 5 to 6.5 per cent is narrower than the range the CC assumed in the airports and Bristol Water inquiries of 5 to 7 per cent. We also assume a lower range for the RFR of 1 to 1.5 per cent.

TABLE 13.12 **Comparison of WACC with recent CC reports**

	NIE	*Heathrow Oct 07*	*Gatwick Oct 07*	*Stansted Oct 08*	*Bristol Water June 10*
Gearing (%)	45	60	60	50	60
Cost of debt (pre-tax) (%)	3.1	3.6	3.6	3.4–3.7	3.9
Cost of equity (post-tax) (%)	3.4–5.0	4.8–7.7	5.0–8.4	5.0–8.2	3.6–6.6
WACC range* (%)	3.3–4.1	4.0–5.2	4.1–5.5	4.2–6.0†	3.8–5.0
WACC estimate* (%)	4.1	5.1	5.3	5.6†	5.0
Cost of equity calculation					
RFR (%)	1.0–1.5	2.5	2.5	2.0	1.0–2.0
ERP (%)	4.0–5.0	2.5–4.5	2.5–4.5	3.0–5.0	4.0–5.0
Market return (%)	5.0–6.5	5.0–7.0	5.0–7.0	5.0–7.0	5.0–7.0
Asset beta	0.35–0.40	0.42–0.52	0.46–0.58	0.55–0.67	0.32–0.43
Equity beta	0.6–0.7	0.90–1.15	1.00–1.30	1.00–1.24	0.64–0.92

Source: CC calculations.

*We have calculated vanilla WACC consistent with pre-tax WACCs shown in the CC airports reports.

13.193 We compared our estimated WACC for the licence holder with recent findings of sectoral regulators (see Table 13.13). In order to facilitate the comparison, we have adjusted the CC cost of capital to a comparative level of gearing. Our WACC range, converted to a gearing of 65 per cent, comparable with recent Ofgem decisions, is 3.5 to 4.2 per cent, the upper end of which is equal to that used by Ofgem in its most recent gas distribution decision.

13.194 The basis of our estimates of WACC is set out fully in this section, and consequently provides a full explanation of any differences from estimates of the cost of capital used by sectoral regulators.

TABLE 13.13 **Comparison of CC estimates of NIE's WACC with recent Ofgem decisions**

	*CC NIE range (regeared)**	*RIIO–GD1 2013–2021*	*National Grid gas transmission 2013–2021*	*National Grid electricity transmission 2013–2021*	*Ofgem DPCR5 Dec 09*
Gearing (%)	65	65	62.5	60	65
Cost of debt (pre-tax) (%)	3.1	2.92†	2.92†	2.92†	3.6
Cost of equity (post-tax) (%)	4.3–6.3	6.7	6.8	7	6.7
WACC (%)	3.5–4.2	4.2	4.4	4.55	4.7
Cost of equity calculation					
RFR (%)	1.0–1.5	2	2	2	NA§
ERP (%)	4.0–5.0	5.25	5.25	5.25	NA§
Equity beta	0.81-0.96	0.9	0.91	0.95	NA§
Asset beta	0.35–0.40	NA§	NA§	NA§	NA§
Cost of equity (post-tax) (%)	4.3–6.3	6.7	6.8	7	6.7

Source: CC calculations.

*Different gearing level assumed for purpose of comparison. It is assumed that the change in gearing does not affect the cost of debt but does affect equity beta via the Miller formula. A debt beta of 0.1 is used in this calculation.
†iBoxx ten-year simple trailing average index for 2013/14—the value of the index may change during the price control period, and any changes will be reflected in the WACC.
§Unclear from decision.

14. Unresolved RP4 issues

Introduction

14.1 In its Statement of Case,[1] NIE drew our attention to three outstanding issues with respect to the RP4 period:

(a) the UR's failure to approve RP4 capex efficiency incentive payments, with a total value of £4.2 million;

(b) costs incurred by NIE in RP4 which have not been approved in relation to the Enduring Solution IT project, with a value of £1.3 million; and

(c) an outstanding question regarding the interpretation of the capital allowances term in the RP4 price control with a value of £0.9 million.

14.2 NIE said that because these issues remained unresolved, it had consequently under-recovered relative to its full RP4 revenue entitlement. NIE therefore argued that these issues should be fairly and definitively resolved as part of the RP5 price control process. It said that the amounts in question should therefore be taken into account when setting the correction factor (K_t) to be applied.[2]

14.3 The UR, in its response to NIE's submission, stated that all three of the issues raised were matters relating to RP4. It argued that issues were either outstanding points relating to the implementation of RP4 (including the interpretation of some aspects of the licence), or related to decisions that the UR had already taken. It therefore said that the matters were not appropriate for us to review or that we would have no jurisdiction to do so.[3]

14.4 In the following subsections, we review the points raised by the UR and consider whether these are issues that fall within our terms of reference. While our role is to consider whether the price control conditions of RP4 operate against the public interest and, as necessary, determine price control conditions for RP5, previous determinations may arguably be relevant if they materially affect recoverable revenues going forward. For example, this could arise if a material error in relation to a previous control affected the RAB applicable to the RP5 period.

The three unresolved issues

RP4 capex efficiency incentive payments

14.5 NIE said that the D_t term in the RP4 price control conditions (see paragraph 3.16(c)) provided a mechanism for NIE to recover additional regulated revenues in respect of: 'amounts arising under arrangements approved by the Authority which are designed to incentivise efficiency in network capital investments, and which shall be calculated in accordance with the 2006 Direction' (D_t term, subparagraph (iv)).[4]

14.6 In practice, NIE submits its claims for capital efficiency incentive allowances to the UR annually, basing its assessment of labour productivity on capex outputs relating to certain selected activities repeated from year to year (and which have been used consistently throughout RP4). NIE said that the UR approved NIE's assessments for

[1] NIE Statement of Case, Chapter 12.
[2] NIE Supplementary Submission, Annex 10, paragraph 2.4.
[3] UR Supplementary Submission, section 21.
[4] NIE Statement of Case, Chapter 12, paragraph 2.1.

2007/08 and 2008/09, but had not yet approved its claims for subsequent years. It had also applied for approval of further capex efficiency incentive payments attributable to relevant capex efficiency gains for the RP4 extension period (nine months to 31 December 2012). It said that the UR was now questioning whether it was appropriate to use the methods applied in previous years to measure NIE's efficiency in respect of procurement and manpower costs. While the UR had now appointed consultants (BDO) to audit both the productivity element and the procurement element of the claims, it noted that there was substantial delay in resolving the claims. It also said that it was not appropriate for the UR to change the basis of operation of the incentive mechanism during RP4, without formally amending the 2006 Direction in accordance with its terms.[5] We identified no further NIE submission on this point in response to our provisional determination.

14.7 The UR agreed that the issue remained outstanding. It said that it was questioning the accuracy and completeness of the method used in previous years and the data that underlay it.

14.8 It said, in summary, that the mechanism provided for NIE to retain 38.9 per cent of the efficiency savings that it achieved in two categories: *(a)* procurement efficiencies, and *(b)* labour productivity efficiencies. In respect of procurement, the efficiencies were to be measured by the difference between actual procurement costs and the costs that would have been incurred under the corresponding procurement contract in 2006/07 (the last year of RP3), after adjusting for inflation. In respect of labour productivity, the efficiency was to be measured by reference to the variation in manpower used for a particular capex project in a year in RP4, and the amount of manpower that would have been used for the same work in 2006/07. The 2006 Direction did not, however, specify the output measures that were to be used for the purposes of calculating labour productivity.

14.9 The UR said that it had undertaken a detailed examination for the claims after 2008/09 because the value of the claimed efficiencies was much more substantial than the previous years (£590,000, £1.1 million and £1.78 million respectively). It stated that it had commissioned an audit of these claims.[6] It said that the BDO audit provided grounds for several concerns about the efficiency submissions that NIE had made in relation to these three years. It noted that some of these concerns related to what appeared to be calculation errors or inappropriate calculation methodologies used by NIE, and also it was concerned that NIE might have been selective in the activities that it had measured to calculate its efficiencies.

14.10 The UR said that in any event this was an RP4 issue that should be dealt with by the regulator in the usual way.[7] It stated that no special circumstances applied in this case (it drew a contrast to the capitalization issues (see Section 15), where it argued that there was a special circumstance in regard to what it characterized as customers paying twice for the same activities). It said that it was waiting for us to confirm whether it agreed that this was not an issue for our redetermination before it reached a conclusion on this issue. It agreed with our provisional view that, absent a public interest justification, the RP4 settlement should not be reopened in this inquiry.[8]

[5] ibid, Chapter 12, section 2.
[6] UR Supplementary Submission, paragraph 21.
[7] UR Supplementary Submission, section 12.
[8] UR response to the provisional determination, paragraph 156.

Unapproved costs in relation to the Enduring Solution IT project

14.11 NIE said that the D_t term of the RP4 price control provided that NIE should be entitled to recover additional regulated revenues in respect of: 'any other costs which the Authority shall determine, upon an application to it by the Licensee shall be included as excluded transmission and distribution costs'.[9]

14.12 NIE said that it had incurred operating costs in relation to the Enduring Solution IT project for the period up to 31 December 2012 of £5.4 million. However, the UR only approved £4.1 million of these costs. NIE said that it considered that the relevant operating costs associated with the Enduring Solution system had been efficiently incurred and NIE should have been entitled to recover them. It said that the UR had not provided any reasonable rationale for disallowing costs, but had merely referred to having applied the same considerations as are applied in the final determination for RP5, in disallowing part of NIE's forecast Enduring Solution costs.[10] We identified no further NIE submission on this point in response to our provisional determination.

14.13 The UR argued that NIE was requesting that we should review a decision that the UR had already taken in RP4. It had considered NIE's request under the D_t mechanism and granted it in part. It said that the statutory framework did not provide for any appeal process from such decisions, but NIE could have sought judicial review of it. The UR argued that we need not investigate this issue.[11] It agreed with our provisional view that, absent a public interest justification, the RP4 settlement should not be reopened in this inquiry.[12]

Interpretation of the capital allowances term in the RP4 price control

14.14 NIE said that the provisions of the RP4 price control which regulated the return which NIE may earn on capital employed allow for a basic return to be adjusted by an amount in respect of NIE's tax liability on such return, so as to provide for NIE to earn an appropriate post-tax return. The calculation provided for adjustments to be made for non-network capex, depreciation, interest and capital allowances. The adjustment for capital allowances (CA_t) provides that there should be deducted from the base return: 'an amount in pounds sterling equal to the level of capital allowances agreed with HM Revenue & Customs in respect of relevant year t calculated in accordance with the Capital Allowances Act 2001 (or successor legislation) and relevant industry agreements or rules'.[13]

14.15 NIE said it considered that the CA_t term should be construed as referring not to the total amount of capital allowances theoretically available to NIE in year t, but to the allowances claimed and offset against NIE's taxable profits. It said that the UR took the converse view, namely that the CA_t term should be construed as referring to the maximum amount of capital allowances available to be claimed in year t, on the basis that NIE should not be permitted to increase customers' bills by choosing not to optimize the tax position of the regulated T&D Business.[14]

14.16 The UR required NIE to set its tariffs from 1 October 2010 on the assumption that the CA_t term requires NIE to take account of the maximum available capital allowances, rather than the capital allowances claimed in 2008/09 and in successive years. NIE

[9] NIE Statement of Case, Chapter 12, section 3.
[10] ibid, Chapter 12, section 3.
[11] UR Supplementary Submission, section 12.
[12] UR response to the provisional determination, paragraph 156.
[13] NIE Statement of Case, Chapter 12, section 4.
[14] ibid, Chapter 12, section 4.

said that this approach entailed it forgoing RP4 revenues of £0.9 million, in respect of the 2008/09 disclaim, relative to the revenues to which NIE would be entitled by reference to its proposed reading of the CA_t term.[15]

14.17 It submitted that the UR's interpretation of the CA_t term was wrong, and it was inconsistent for the UR to seek to reverse the 2008/09 capital allowances disclaim but not to similarly reverse the 2006/07 disclaim. NIE said the 2006/07 disclaim had no adverse effect on customers (as the price control provided for a pre-tax return), but benefited customers in future years by ensuring that a larger pool of capital allowances would be available to be offset against taxable profits in future years. NIE argued that the UR should take account of the overall effect of NIE's approach, and should recognize the combined impact of the disclaims on customers. NIE also said that, to the extent that there would need to be a CA_t term in the RP5 price control, it would be helpful if we would clarify how it should be applied, and so that it was clear what was, for regulatory purposes, the value of the residual pool of capital allowances available to NIE at the opening of RP5.[16]

14.18 In response, the UR characterized NIE's request as effectively asking us to review the UR's legal interpretation of a particular provision of NIE's RP4 price control. It said that this was a matter that NIE could have but chose not to raise by way of judicial review. It said that the CC had no jurisdiction to rule on the legal interpretation of the RP4 price control.[17] It agreed with our provisional view that, absent a public interest justification, the RP4 settlement should not be reopened in this inquiry.[18]

Assessment

14.19 In considering these points, we note that our terms of reference refer us to the price control conditions in each licence at present, with a view of considering whether or not these operate against the public interest. The issues raised above are points of relative detail and/or divergence of interpretation between the parties relating to the implementation of the RP4 controls. Such issues would be a matter for the UR and NIE to resolve. NIE pointed out that resources consumed by judicial review could be prohibitive if matters were not decided quickly and fairly. Nonetheless, given our terms of reference, it is not obvious why these should engage us for the purpose of our redetermination.

14.20 In addition, where the implementation of a price control that has been agreed for a five-year period requires decisions by the regulator during that period, it could harm the public interest for us to go back and replace the decisions of the regulator with its own decision. This could lead to regulatory uncertainty, for example if all decisions were up for redetermination at the next review even if they were taken several years previously.

14.21 However, we do consider that previous determinations may arguably be relevant to our redetermination, for example if they affect recoverable revenues in RP5 through the RAB. In particular, we accept that there may be particular circumstances when it may be appropriate to revisit elements of past determinations that continue to have an effect on the current price control. From the perspective of considering these points under the public interest test, much would depend on how significant or material these are in terms of substance. If we believed that the points raised under these headings were important enough and/or that something has gone substantially

[15] ibid, Chapter 12, section 4.
[16] ibid, Chapter 12, section 4.
[17] UR Supplementary Submission, section 12.
[18] UR response to the provisional determination, paragraph 156.

wrong to the extent that not addressing it now would lead to adverse outcomes significant enough to contravene the public interest, then we think that we could consider it in more detail.[19] We take the three issues in turn.

Our view of RP4 capex efficiencies

14.22 We note that the UR has commissioned an audit of these efficiencies and is making a decision on this basis. While the delay in reaching its determination may be unfortunate, no evidence has been provided to us to indicate either that this is a relevant point for our redetermination, nor that the UR has made any kind of technical error, resulting in materially adverse effects on consumers, in its assessment. NIE has not pointed to any particular circumstances that indicate that a substantial impact adverse to the public interest is carried into RP5. We conclude that this is an issue regarding the implementation of the RP4 licences that does not fall into the scope of our redetermination.

Our view of unapproved costs in relation to the Enduring Solution IT project

14.23 We agree with the UR that it has undertaken its assessment and reached a decision. Again, NIE has not pointed to any particular circumstances that indicate that a substantial adverse effect on the public interest is carried into RP5.

14.24 However, we address allowances for Enduring Solution, as a new controllable opex activity, in paragraphs 10.184 to 10.268. We have to consider an appropriate opex allowance for ongoing activities in RP5. The sum at issue here relates to expenditure on Enduring Solution in the period from April to December 2012, and so falls within the period that we have assessed in that section. Under these circumstances, we consider that the disputed expenditure can be classed as an RP5 issue and appropriate allowances for it are to be set under our determination of opex allowances—see paragraph 10.268.

Our view of interpretation of the capital allowances term in the RP4 price control

14.25 The essence of NIE's argument is that the UR's interpretation of the CA_t term is wrong, and that it has acted inconsistently in the treatment of disclaims in different years, which give different benefits and costs to consumers and NIE in the long term.

14.26 We do not believe that it is appropriate for us to address arguments that relate mainly to a difference in interpretation or other disagreement between NIE and the UR on their understanding of what the licence says in relation to past control periods. It does not seem likely that these differences in interpretation of the rules give rise to what may be a material error. We did, however, consider whether there may be issues around inconsistent application of the interpretation of the licence and whether these would be sufficiently material to potentially operate against the public interest. We note that the correction proposed by NIE amounts to £0.9 million. In this context, whether or not there has been some kind of technical error, it is not obvious that a one-off adjustment of up to £0.9 million (in past, non-capitalized, revenue allowances) constitutes a sufficiently material error, such that aspects of a past determination

[19] NIE suggested a variety of other reasons as to why it may be appropriate to correct past errors or resolve issues from the previous price control. Some of these points are clearly relevant to a redetermination of the current type, such as where issues refer to events within the period covered by the new price control period, or the error undermines confidence in the fairness and effectiveness of the regulatory system to a material extent such that the public interest going forward is adversely affected. We do not agree that past decisions should be corrected just because evidence or reasoning used in setting the new control conditions has evolved, or because a variety of separate issues can be added together to make a more material impact.

should be revisited. In our judgement, we do not consider that NIE has demonstrated sufficient grounds for us to believe that the UR's interpretation might be incorrect or inconsistent with a sufficiently substantive impact, so as to justify reconsideration of this point.

14.27 However, we note that that it is important to reduce the risk of ambiguity and dispute in the future where it is possible to provide clarity on interpretation of rules upfront ahead of the implementation of a new price control. Further, modelling the new price control requires assumptions to be made on what capital allowances will be available to NIE. Section 17 sets out our analysis and determination.

Conclusion

14.28 For the reasons set out above, we decided not to make adjustments for the unresolved RP4 issues identified by NIE in relation to RP4 capex efficiency incentive payments or interpretation of the capital allowances term in the RP4 price control. Our evaluation of costs for the Enduring Solution project for April to December 2012 is set out in Section 10, and Section 16 contains our determination regarding corporation tax allowances.

15. NIE's capitalization practices

Introduction

15.1 The UR asked us to investigate whether changes in NIE's capitalization practices meant that, in effect, consumers would have paid twice for certain activities in RP4.[1] It suggested that this might have arisen because the activities had been funded through both an opex allowance and capex allowance, when NIE had changed its accounting treatment of certain activities from opex to capex. It considered that changes in capitalization practices might have contributed to the apparently high levels of opex outperformance achieved by NIE in RP4.

15.2 We received three substantive responses to our provisional determination on this issue from stakeholders: namely from the UR,[2] CCNI[3] and MNI.[4] We also held further hearings with both the UR and NIE and requested and received further information from NIE. We have considered these responses and the other additional information we have received in reaching our decisions on this issue.

15.3 The section is structured as follows. We:

(a) describe the distinction between capex and opex, by way of background (paragraphs 15.4 to 15.8);

(b) set out the UR's concerns over NIE's capitalization practices (paragraphs 15.10 to 15.20);

(c) set out NIE's response to those concerns (paragraphs 15.21 to 15.27);

(d) summarize responses to our provisional decision (paragraphs 15.28 to 15.45); and

(e) determine the three issues arising from our consideration of NIE's capitalization practices in the light of our provisional decision and subsequent submissions, namely whether:

(i) the design of RP4 is in the public interest (paragraphs 15.47 to 15.53);

(ii) there should be a regulatory adjustment to the RAB because of the effect of changed capitalization practices (paragraphs 15.54 to 15.96); and

(iii) the regulatory treatment of tree-cutting expenditure is in the public interest (paragraphs 15.96 to 15.101).

The distinction between capex and opex

15.4 Capex relates to expenditure on fixed assets. Fixed assets[5] are items where it is expected that longer-term future economic benefits will accrue to their owner, in this case from their use in the business of transmitting and distributing electricity to the

[1] Capitalization practices means the categorizing of expenditure for accounting purposes between that relating to an asset, in this case fixed assets, or not. See paragraphs 15.4 & 15.5 for a discussion of fixed assets.
[2] UR response to provisional determination.
[3] CCNI response to provisional determination.
[4] MNI response to provisional determination.
[5] Fixed assets represent the productive capacity of a business and are intended for use in the business on a longer-term basis. In this context 'longer-term' means expected to provide economic benefits in accounting periods beyond the balance sheet date.

end consumers. Fixed assets relate not only to physical assets but also intangible assets created by investment, for example, in software or by cutting trees in the vicinity of physical assets. The latter example creates an asset (the empty space) because without this expenditure NIE would not be able to operate its overhead network safely, or with the required resilience, and such expenditure benefits future accounting periods.

15.5 Only expenditure on fixed assets should be capitalized, not least so that their cost can be matched to revenues earned in future accounting periods. All other expenditure should be expensed as opex to the profit and loss account in the period in which they are incurred.

15.6 Much of NIE's expenditure, whether of a capital or operational nature, relates to subsequent expenditure on existing fixed assets, ie expenditure on already-existing fixed assets that maintains these assets in proper working order and/or replaces part(s) of the asset when those part(s) fail or are due to fail. NIE's fixed assets mainly comprise its network of overhead and underground transmission and distribution lines and its network of substations. NIE described its overhead lines as 'perpetual assets',[6] and this description can be applied more broadly to all its network assets.

15.7 Perpetual assets are where components of the broader asset are replaced continuously in cycles, rather than the complete asset being replaced at end of life.[7] In other words, although the individual components of the composite asset do not last forever, NIE's intention is that the composite asset shall remain in working order in perpetuity.

15.8 Subsequent expenditure on existing assets can, in accordance with the relevant accounting standards, be categorized between opex and capex and, in line with NIE's working practices, between planned and reactive work (see Appendix 15.1, Table 2).

15.9 'Reclassification' of expenditure between opex and capex occurs when expenditure on activities which previously had been categorized as opex (or would have been categorized as opex had they been undertaken at the time), in accordance with one set of accounting policies, is subsequently categorized as capex.

The UR's concerns over capitalization practices

15.10 The UR told us that it had been concerned by the development of NIE's opex outperformance over time. It said that the reduction in controllable opex achieved by NIE between 2004/05 (£43.5 million[8]) and 2006/07 (£29.1 million) was extraordinary in that a business that had been in the private sector since 1992 was able to reduce its controllable opex by more than one-third in real terms in the space of two years.[9]

15.11 Opex outperformance arises where a regulated company spends less on opex than the ex ante allowances it has been given. It is allowed to retain all or a proportion of that saving. However, typically opex allowances are reset at the next price control taking account of this reduced opex expenditure. Outperformance is therefore intended to act as a short-term incentive mechanism to encourage efficiencies which are later passed through to consumers.

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[6] Section 5.3.4.1, Refurbishment: www.nie.co.uk/documents/Policy-Statements/Asset_mgmt_strategy.aspx.
[7] ibid, Section 5.3.4.1, Refurbishment.
[8] The outperformance figures quoted by the UR are as per its submissions, whereas the figures in Table 15.1 reflected a figure provided by NIE.
[9] UR Statement of Case, paragraph 4.

15.12 The UR said that the reduction in opex needed to be understood in the context of the incentives that were in place in respect of opex and capex at the time. In RP4, controllable opex was remunerated on a rolling 'allowance' basis based on opex expenditure five years previously. In contrast, capex was remunerated on a pass-through basis (see paragraph 3.9).[10] The UR said that it followed that, if NIE could reclassify as capex in RP4 expenditure that had previously been treated as controllable opex, it would retain the allowance for opex (ie as outperformance) and, in addition, benefit from an increase in its RAB. That process of reclassification would therefore increase NIE T&D's profit by £1 for every £1 of expenditure shifted. That extra £1 would come from consumers, who could pay twice for the same expenditure: once through NIE T&D's opex allowance in RP4 and again over the following 40 years as a result of the increase in RAB.[11]

15.13 The UR told us that its investigations showed that NIE had changed its approach to capitalization in December 2005 (and noted that a new version of NIE's *Network Capital Expenditure Procedures Manual* had been issued at that time which revised its guidance on cost classification). It said that there was evidence of £35.6 million of opex being reclassified as capex over the course of the final two years of RP3 and the five years of RP4, in particular:

(a) The proportion of tree-cutting expenditure classified as capex increased from an average of 33 per cent in 2003 to 2005 to 88 per cent through RP4.

(b) The proportion of repairs and maintenance channelled through NIE's sister company, NIE Powerteam, classified as capex increased from 58 to 71 per cent from 2004/05 to 2010/11.

(c) NIE had increased its capitalization rates for indirect costs[12] (in other words, support activities attributable to capex items ('overheads')).

15.14 The UR said that while it had identified these three areas of activity as showing cost reclassification, it was possible that other areas might also be affected, although it offered no evidence of this.[13]

15.15 The UR therefore invited us to consider whether NIE's opex saving (in RP4 and the last two years of RP3[14]) was the consequence of changes in accounting approaches, whether consumers in effect were being required to fund work that had been capitalized into the RAB but which had already been covered by NIE's RP3/RP4 opex allowance, and if so whether any actions, such as an adjustment to the RAB, should be taken. (See Appendix 15.1 for our analysis of the UR's claims, and at a high level, paragraph 15.91.)

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[10] The UR told us that the design of the charge control did not reflect normal regulatory practice but in fact was unusual and partly derived from an NIE 'composite' proposal to the UR from March 2005 for the basis of the RP4 price control settlement. NIE presented this proposal to the UR as *(a)* a way of saving costs, 'the cost of efficiency studies is avoided', and *(b)* 'the use of actual expenditure to determine future entitlement removes ambiguity around the allocation of costs between opex and capex. For regulatory purposes actual expenditure is recovered either via the RAB over 40 years or via the opex allowance but not both'.

[11] UR Statement of Case, paragraph 5.

[12] ibid, paragraph 6.

[13] The UR suggested that tower painting; line patrols and line survey work; unproductive time, including design costs for projects that were not commissioned; and the treatment of NIE Powerteam costs in general, could all be suitable for further investigation (UR Statement of Case, UR6, paragraph 13a).

[14] The UR sought to make an adjustment in respect of the last two years relating to the RP3 period (ie in relation to both 2005/06 and 2006/07) as it was from 2005/06 that it had concluded that a marked increase in capitalization of expenditure had occurred. To the extent that the structure of RP3 replicated the risk that some expenditure could be funded twice, then consumers would also risk paying higher prices than they otherwise would have.

15.16 In its final determination, the UR proposed to reduce NIE's RAB by an amount it calculated to correspond to this overpayment: £31.7 million.[15] It said that it believed that was the minimum that must be done, as any other approach involved knowingly requiring consumers to pay again over the next 40 years (through the depreciation of, and return on, the RAB) for the work that they had already paid as opex during RP3 and RP4.[16]

15.17 It referred to the CC's *Phoenix Gas* report, which states:

> 5.89 The intention of rewarding outperformance is to encourage the achievement of efficiencies. Therefore outperformance should be an accurate reflection of cost savings that were efficiently incurred, rather than where, for example, the regulated company provides deliberately misleading information to the regulator or where the regulator made a technical error (eg a calculation error).
>
> 5.103 … We think that funding PNGL twice for the same expense is a technical error and that this would operate against the public interest.

15.18 The UR indicated that its concerns did not depend on changes in the precise accounting policies and practices adopted by NIE. Rather it said that there had been at least changes in accounting estimates (ie the detailed application of accounting principles), and its analysis had shown that there were changes in accounting estimates that had a material impact on the allocation of costs between opex and capex.[17] It also said that it did not assert that any accounting rules had been broken.[18] It said that changes in capitalization had not been shown to reflect changes in NIE's underlying activities within the relevant cost categories.[19]

15.19 The extent of, and the trend in, NIE's outperformance of the controllable opex element of the price controls it was subject to over RP3 and RP4 is set out in Table 15.1.

TABLE 15.1 **NIE's outperformance of its controllable opex allowance across RP3 and RP4, 2009/10 prices**

£ million

	RP3					*RP4*					*Totals*		
	02/03	*03/04*	*04/05*	*05/06*	*06/07*	*07/08*	*08/09*	*09/10*	*10/11*	*11/12*	*∑RP3*	*∑RP4*	*% ∆ RP3 to RP4*
Allowance	71.4	61.5	57.9	54.0	44.8	50.4	44.8	43.9	33.9	29.1	289.7	202.2	(30)
Out-turn	53.4	46.6	43.9	33.9	29.1	28.5	27.2	29.1	27.5	27.7	206.9	140.0	(32)
Outperformance	18.0	14.9	14.0	20.1	15.7	21.9	17.6	14.8	6.4	1.4	82.8	62.2	(25)
% outperformance	25	24	24	37	35	43	39	34	19	5	29	31	

Source: NIE.*

*The allowances for 2007/08 and 2008/09 are different from out-turn costs in 2002/03 and 2003/04 because of adjustments that the UR made to these out-turn costs to set allowances for the first two years of RP4. These adjustments were £3.0 million and £1.8 million respectively in 2009/10 prices. Source for the value of these adjustments is Table 1, p7, of the December 2005 RP4 initial proposals document. See paragraph 15.12 for an explanation of the relevance of this point.

[15] This £31.7 million UR estimate relates to the impact on the RAB as at the end of RP4, whereas the estimate of £35.6 million in paragraph 15.13 reflects the UR's estimate of the reclassification effect in total.
[16] UR Statement of Case, UR6, paragraph 14.
[17] UR final determination, paragraphs 4.55–4.57.
[18] ibid, paragraph 4.58.
[19] For example, UR Statement of Case, paragraph 9, third sentence.

15.20 The total contribution of each of the elements as set out in paragraph 15.13 (ie tree cutting, repairs and maintenance, and overheads) to total controllable opex over a 12-year period between 2001/02 to 2011/12 is set out in Table 15.2.[20]

TABLE 15.2 **Contribution of activities to NIE's controllable opex between 2000/01 and 2011/12, 2009/10 prices**

£ million

	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*
Repairs & maintenance excl tree cutting	18.2	16.1	13.8	13.7	13.4	11.0	10.0	9.8	10.0	9.1	9.6	10.5
Tree cutting	0.1	0.8	0.9	0.7	1.5	0.9	0.7	0.4	0.4	0.6	0.5	0.3
Repairs & maintenance incl tree cutting	18.3	16.9	14.7	14.4	14.9	11.9	10.8	10.2	10.5	9.7	10.1	10.8
All other costs including capitalized overheads	61.2	53.7	47.8	42.8	38.1	31.2	28.3	27.6	25.9	28.2	26.4	25.8
Total costs before capitalization of overheads	79.5	70.6	62.5	57.2	53.0	43.1	39.0	37.8	36.3	37.8	36.5	36.6
Less capitalized overheads	–6.3	–8.1	–9.1	–10.6	–9.1	–9.2	–9.9	–9.3	–9.1	–8.7	–9.0	–8.9
Total controllable operating costs	73.2	62.5	53.4	46.6	43.9	33.9	29.1	28.5	27.2	29.1	27.5	27.7

Source: NIE.

Note: There are some discrepancies in the out-turn controllable opex numbers in 2009/10 prices in the analyses provided by the UR and NIE, and therefore the precise extent to which NIE outperformed this allowance in RP3 and RP4. This situation arose because the UR had not been able fully to take into account NIE's out-turn costs restated in 2009/10 prices, particularly in relation to 2011/12, when making its submissions to us. On the advice of the UR, we used numbers supplied by NIE in our review of the cost evidence, both here in Section 15 and in Appendix 15.1, as NIE would be able to supply us with final out-turn numbers across the whole period of analysis up to and including 2011/12. While there are some differences between the numbers provided by the UR in its submissions and NIE, we do not consider that the extent of these differences is material to the reasoning and conclusions set out in this section.

NIE's response to the UR's concerns

15.21 NIE rejected the UR's case for the proposed adjustments to the RAB. NIE said that the final determination represented an attempt to reopen the RP3 and RP4 price controls, without any compelling reason and without regard to the UR's wider statutory duties and objectives.[21] NIE submitted that much of the determination was misconceived as it was based on assumptions which were incorrect, and it addressed questions which were, in principle, irrelevant to the setting of the RP5 price control.[22] It also said that it had not, in any relevant sense, changed its capitalization practices.[23]

15.22 NIE acknowledged that it had outperformed its RP4 controllable opex allowance by £62 million[24] (amounting to some 3 per cent of regulated revenues for RP4). It said that it considered that this outperformance was a legitimate return to NIE under the system of RPI–X incentive regulation, having regard to the efficiency of its operations, and it said that the UR had failed to recognize that the RP4 price control had worked to the benefit of consumers.[25]

15.23 NIE's analysis of its outperformance of its controllable operating cost allowance for RP4 is shown in Table 15.3.

[20] In relation to the last element, overheads, NIE had estimated the amount of total overhead costs incurred that were attributable to capital items and deducted that, to arrive at controllable opex.
[21] NIE Statement of Case, Chapter 11, paragraph 1.10.
[22] ibid, Chapter 11, paragraph 1.8.
[23] ibid, Chapter 11, paragraph 1.8.
[24] The £62 million is shown in the final column of Table 15.1.
[25] NIE Statement of Case, Chapter 11, paragraphs 1.7–1.8.

TABLE 15.3 **RP4 opex outperformance, 2009/10 prices**

	£m
Repairs & maintenance costs	15.6
IT and telecoms costs	11.3
Salary costs	9.6
Corporate costs	8.5
Managed service costs	8.4
Other reductions	4.6
Insurance costs	4.2
Total	62.2

Source: NIE Statement of Case, Table 15.10.1 (rows have been reordered).

15.24 NIE said that the outperformance results showed that RP4 worked well, in that it had driven reductions in NIE's opex and had enabled NIE to adopt new and more effective ways of managing its assets, and these reductions in costs were factored into the assessment of allowable costs for RP5.[26]

15.25 NIE said that any argument that there would be double-charging during RP5 or beyond, if NIE were allowed to retain its existing RAB, was misconceived, and rested on an assumption that the RP3 and RP4 opex allowances were 'earmarked' to cover particular costs which NIE had instead capitalized. It said that this was simply incorrect.[27]

15.26 It said that the UR had failed to justify the amount of the proposed RAB reduction. It said that the UR's report (from CEPA[28]) was fundamentally unsound. For example, it stated that the analysis did not distinguish between changes in capitalization practices and changes in NIE's underlying activities.[29] It said that the UR had not addressed whether NIE had experienced additional opex costs in relation to any other items which were not covered by the carry-over of opex from RP3. It said that the UR failed to recognize the gains to efficiency arising from increased capex (such as overhead line refurbishment) with the resulting reduction in opex maintenance costs, more accurate cost analysis, and enhanced accuracy and transparency, which would bring lower opex costs, better data and a more modern network in the future.[30]

15.27 NIE said that within the context of regulatory systems, there was a very strong presumption against a retrospective reduction in the RAB. Any discretionary ex-post RAB reduction should not proceed without also taking account of other potentially countervailing factors such as the effect on confidence in the regulatory regime. Ex-post adjustments were bound to diminish confidence in the predictability and fairness of the regulatory regime, and to prevent NIE from raising finance as efficiently as it otherwise could, to the ultimate detriment of consumers.[31]

Submissions following our provisional decision

15.28 In this subsection, we summarize submissions responsive to our provisional decision on the following topics:

(a) the attribution of any double-funding to flaws in the overall design of the RP4 price control;

[26] ibid, Chapter 11, paragraph 2.10.
[27] ibid, Chapter 11, paragraph 6.1.
[28] Cambridge Economic and Policy Associates.
[29] NIE Statement of Case, Chapter 11, paragraph 6.1.
[30] NIE Supplementary Submission, Annex 9, paragraph 6.1.
[31] NIE Statement of Case, Chapter 11, paragraph 6.1.

(b) regulatory certainty;

(c) the exploitation of future gaming opportunities;

(d) algebra of price control versus interpretation in context;

(e) NIE's intent;

(f) tree cutting did not create an asset;

(g) five-yearly tree cutting had historically been treated as opex;

(h) quantification difficulties should not act as a bar to making an adjustment;

(i) reassurance that it would not happen again; and

(j) future regulatory treatment of tree-cutting expenditure.

15.29 We cross-refer to where we address these points in the reasoning supporting our final decision at the end of each relevant paragraph.

The attribution of any double-funding to flaws in the overall design of the RP4 price control

15.30 The UR stated that the design of RP4 price control had not been materially different from all other types of price control historically in operation in this and other regulated sectors such as water.[32] While it was true that the design of RP4 gave an additional incentive for capex bias, it was nevertheless the case that virtually all price controls at the time created fairly substantial incentives for reclassification from opex to capex. The CC had in previous regulatory inquiries endorsed charge controls with these structures. The CC could not therefore say that flaws in the design of the price control created a unique problem.[33] (See paragraphs 15.52 and 15.53 for our view.)

Regulatory certainty

15.31 The UR stated that through our provisional decision we were sending a message that unless that there was a specific hook, then any loopholes that were left open in price controls were there to be exploited, or for just unforeseen consequences, perverse outcomes could arise, but nothing could then be done by the regulator or the CC to correct for that. (See paragraph 15.61 for our view.)

15.32 The UR provided five examples[34] which it said illustrated where GB or UK regulators had stepped in and corrected matters arising from previous price control settlements where the interests of consumers had been materially prejudiced.[35] (See paragraph 15.62 for our view.)

[32] UR response to provisional determination, paragraphs 159 & 162.
[33] UR response to provisional determination, paragraph 174.
[34] UR response to provisional determination, Appendix *Correcting for unforeseen outcomes – Regulatory Precedent*. The examples given were: *(a)* MMC, the CC's predecessor (NIE inquiry, 1997: double-funding of capex); *(b)* MMC (British Gas Transco inquiry, 1997: a change to depreciation rules); *(c)* CC (BAA inquiry, 2002: double-funding of pensions costs); *(d)* CAA (BAA inquiry, 2002: double-funding of pensions costs); and *(e)* ORR (Network Rail price control review, 2008: double-funding of tax payments).
[35] UR response to povisional determination, paragraph 168.

The exploitation of future gaming opportunities

15.33 The UR stated that our framework for capex regulation would be vulnerable to gaming in the same way that RP4 was. It would be of considerable concern if NIE were as a result to think that it had permission to exploit the boundaries that existed between different types of capex and different time periods. The UR noted that our provisional determination created a stronger incentive on NIE to defer capex that it had seen before.[36] (See paragraph 15.61 for our view.)

Algebra of price control versus interpretation in context

15.34 The UR said that we should interpret the regulatory settlement purposively, in other words in terms of what it was intended to achieve. The UR said that we should apply the 'interested bystander' test: how would such an interested bystander respond if asked at the time the RP4 determination was being made what should happen were there to be quite a lot of reclassification from opex to capex during RP4. It said that such a bystander would note that NIE T&D had been clear in its Composite Proposal that "actual expenditure is recovered either via the RAB over 40 years of via the opex allowance but not through both" and state that any reclassification that would result in consumers paying twice should be unwound. (See paragraphs 15.78 to 15.84 for our view.)

NIE's intent

15.35 The UR told us that NIE must have known the impact that its reclassification exercise would have on consumers' bills. The UR argued that a company that put the interests of its consumers first (and especially in light of the high-level nature of the RP4 price control) would have expressly brought this issue to our attention and would not now be pushing so hard to be allowed to charge consumers twice for the same expenditure. Given that NIE sought and had been granted a 'light touch' regulatory framework for RP4, involving minimal monitoring and reporting, NIE could not complain that the UR had not identified these issues earlier. The UR further argued that the flip side of a light-touch regulatory framework must always be scrupulous good faith and transparency. Unless we were satisfied that NIE met that standard, we should not treat the passage of time as a reason to make consumers pay twice as a result of changes in NIE's capitalization practices.[37] (See paragraph 15.92(e) for our view.)

Tree cutting did not create an asset

15.36 MNI told us that it failed to understand how cutting trees under general maintenance could be considered to create an asset. It saw that NIE's move of such costs from opex to capex during the course of RP4 meant that consumers had paid twice for that service, as the cost had already been included in the opex allowance agreed at the start of RP4. MNI failed to understand how charging twice for a service could in any way be considered compliant with accountancy standards. Quite simply, if a retailer were deliberately to charge a customer credit card twice for the same goods, they would not only be in breach of trading standards legislation but would also be liable for criminal fraud. Consumers would see little difference with this scenario.[38] (See paragraph 15.4 for our view on whether tree cutting can be considered an

[36] ibid, paragraph 161.
[37] UR response to provisional determination, paragraph 183.
[38] MNI response to provisional determination, (unnumbered) p1–2.

asset. See paragraph 15.91 for our assessment of whether consumers had funded the same tree cutting through both an opex allowance and a capex allowance.)

Five-yearly tree cutting had historically been treated as opex

15.37 The UR said 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.[39] (See paragraph 15.91 for our view.)

Quantification difficulties should not act as a bar to making an adjustment

15.38 The UR told us that it understood our concern about penalizing NIE for what might be genuine efficiency gains and therefore our desire not to make adjustments that were not fully justified. The UR told us that it was important that we sent the right message for all the reasons of principle it had already expressed (summarized in paragraphs 15.31 to 15.34), and that we could, if necessary, be conservative and make an adjustment only where we had found clear evidence of reclassification. The UR referred to examples of reclassification to be found in our provisional determination regarding repairs and maintenance, namely within non-recoverable alterations and routine maintenance.[40] (See paragraph 15.91 for our view.)

15.39 The UR also pointed to the movement in capitalized repairs and maintenance from £5.8 million to £10.2 million from 2004/05 to 2010/11 as illustrated by the summarized accounting information in Appendix 15.1, Table 3, of the provisional determination. This example clearly showed a substantial increase in money moved to capital expenditure, without any change in performance, in an area where NIE T&D does not measure any outputs, and therefore we could make an adjustment without any risk to penalizing any efficiency gains made by NIE.[41] (See paragraph 15.90 for our view.)

15.40 The UR said that as we had stated that the extent of the classification was not trivial, we should then at least make a non-trivial adjustment.[42]

15.41 CCNI told us that, whilst it accepted our assertion that we 'could not obtain a robust estimate of the adverse effect', the fact remained that a benefit had been accrued by NIE and a loss taken by consumers. It was unreasonable to ask consumers to accept that the possibility remained that they had paid, and still could pay, twice for their electricity services. CCNI did not believe that this state of affairs was in the public interest and asked us to reconsider this matter.[43] (See paragraphs 15.78 to 15.84.)

15.42 MNI said that our concern was that a lack of clarity made it difficult for us to quantify the double payment. MNI believed that as a result, further work was required in this area. Furthermore it asked us to make clear that any double payment would be repaid through the new price control.[44] (See paragraphs 15.78 to 15.84.)

[39] UR response to provisional determination, paragraphs 164 & 192.
[40] The UR referred to the provisional determination, Appendix 15.1, paragraphs 35 & 36 (non-recoverable alterations) and paragraphs 31–34 (routine maintenance).
[41] UR response to provisional determination, paragraph 194.
[42] ibid, paragraph 187.
[43] CCNI response to provisional determination, (unnumbered) pp2–3.
[44] MNI response to provisional determination, (unnumbered) pp1–2.

Reassurance that it would not happen again

15.43 CCNI told us that consumers in Northern Ireland required assurances that this unacceptable practice would not recur in future price controls. CCNI asked us to recommend improvements to the current regulatory model so that such 'double-funding' could not take place in the future.[45]

15.44 MNI asked us to examine this matter further with the benefit of expert advice and provide clear proposals to prevent this happening in the future.[46] (See paragraph 15.95.)

Future regulatory treatment of tree-cutting expenditure

15.45 In response to our proposal that future capitalized tree cutting should be captured in a short-life RAB, and therefore this cost recovered from current consumers, rather than also from consumers well into the future, the UR said that the public interest would be better served if tree cutting were not to be capitalized at all, save as part of a programme of greenfield overhead line building (as opposed to maintenance of existing lines). The UR argued that this would be a less complex way of dealing with issue.[47] (See paragraphs 15.96 to 15.101.)

Assessment and determination of the three issues arising from our consideration of NIE's capitalization practices

15.46 We assess three issues arising from our consideration of capitalization issues:

(a) whether the design of RP4 is in the public interest (paragraphs 15.47 to 15.53);

(b) whether there should be a regulatory adjustment to the RAB because of the effect of changed capitalization practices (paragraphs 15.54 to 15.96); and

(c) our determination of the regulatory treatment of tree-cutting expenditure (paragraphs 15.96 to 15.101).

The design of RP4 and the public interest

15.47 As described in paragraph 15.12, the current (RP4) regime has an asymmetric approach to opex and capex. For opex, the UR set an allowance based on costs relating to the five previous years,[48] whereas for capex, the allowance reflects actual expenditure[49] in the RP4 period. The approach to opex allowances can be characterized as a 'rolling opex' mechanism and the approach to capex recovery as 'cost pass-through'.

15.48 A feature of the RP4 price control's design was its lack of clarity over what the rolling opex allowances were supposed to cover. This lack of clarity led to a difference in understanding between the UR and NIE as to the coverage of the allowances (and has not helped us in deciding whether a particular activity should consistently have

[45] CCNI response to provisional determination, (unnumbered) p3.
[46] MNI response to provisional determination, (unnumbered) p2.
[47] UR response to provisional determination, paragraphs 199–201.
[48] That is, opex actuals in the years 2002/03–2006/07 are the basis for the corresponding opex allowance for the year falling five years later in RP4 (2007/08–2011/12).
[49] NIE, however, regarded itself as being subject to an overall budget for capital expenditure. For a fuller discussion of the extent to which NIE was subject to a cost-pass-through constraint—see paragraphs 3.29–3.38.

been treated as opex during RP4). Accordingly, we found that the design of the price control carried the risk that NIE could reclassify activities previously classified as opex, prospectively as capex.

15.49 The design of the price control also gave NIE an incentive to undertake such re-classification. If it reclassified activities from opex to capex, it could keep as out-performance any underspend of its opex allowance. It would also benefit from using that opex allowance to incur capital expenditure and so increase the RAB. Once capital expenditure is accepted into the RAB, then consumers must pay for it over its (40-year) lifetime via a combination of enhanced depreciation allowances and an enhanced allowance for the return on the RAB.[50]

15.50 Accordingly, if reclassification occurred, there was a risk that consumers would pay higher prices than they otherwise would have paid, had NIE's capitalization policies remained consistent throughout.

15.51 While such risk might be mitigated by ongoing monitoring of the operation of the price control, or an ex-post adjustment made by the regulator, the ability of the UR to estimate the full extent of any reclassification on an ex-post basis is constrained by practical considerations (see paragraphs 15.78 to 15.84).

15.52 We note the UR's argument (see paragraph 15.30) that the design of most, if not all, price controls at the time, including those resulting from MMC/CC determinations, created an incentive for capex bias, both in terms of giving an incentive to invest in capital-based rather than opex-funded solutions and to reclassify opex activities as capex activities. Even so, the design of the NIE RP4 price control gave the regulated firm particularly strong incentives to do this.

15.53 We therefore concluded that this asymmetric approach to opex and capex of the RP4 licence operated against the public interest. See also Section 5: our decision on cost risk-sharing[51] takes into account the experience of the operation of the RP4 price control as set out in this section.

Whether we should adjust the RAB because of the effect of changed capitalization practices

15.54 Our finding in paragraph 15.53 above is based on the risk that the structure of the RP4 control could, if uncorrected, lead to double-funding. In this subsection, we assess whether this effect arose in practice. If it had, we considered whether we should make a regulatory adjustment in order to protect consumers from possible adverse effects arising from the operation of the capitalization issues in RP4 and part of RP3, for example through a reduction in NIE's RAB to strip out past capex, or possibly some other adjustment to compensate for any activities funded by both an opex and a capex allowance.

15.55 We assessed whether there are other explanations for the levels of outperformance achieved and whether any changes from opex to capex were justified or efficient, and did not operate against the public interest. Our assessment of the costs of the elements of NIE's controllable opex that the UR brought to our attention in its Statement of Case, namely tree cutting, repairs and maintenance and capitalized overheads, is set out in Appendix 15.1.

[50] The allowance for the return on the RAB is the principal mechanism by which the regulated firm earns profits. It is computed as the WACC multiplied by the (average) RAB balance during the period.
[51] See paragraphs 5.70–5.117.

15.56 This subsection sets out:

(a) the factors we considered in deciding whether we should adjust the RAB;

(b) our observations on developments over the period following our review of the cost evidence;

(c) developments in accounting standards and NIE's documentation of its approach regarding the distinction between opex and capex;

(d) the ability to identify reclassification of opex as capex; and

(e) our evaluation and conclusion.

The factors we considered in deciding whether to adjust the RAB

15.57 NIE acknowledged that there had been some reclassification of opex as capex as a result of NIE's focus on identifying all of its expenditure on replacement assets. We considered the circumstances in which it might be in the public interest to adjust NIE's RAB. We set out the factors we considered relevant to this case:

(a) whether expenditure on some activities was funded by consumers more than once;

(b) regulatory certainty and the undesirability of revisiting past settlements;

(c) the ability to identify and estimate robustly any 'adverse' effect;

(d) the materiality of any adverse effect; and

(e) NIE's intent in making changes and any failure to communicate these changes.

- *Expenditure on some activities being funded by consumers more than once*

15.58 We consider that it is not in the public interest that Northern Ireland consumers should fund activities more than once, for example through both an opex allowance and a capex allowance. This is the principal 'harm' that might arise from reclassification.

- *Regulatory certainty and the undesirability of revisiting past settlements absent good cause*

15.59 We consider that it is in the long-term interest of consumers that there is regulatory certainty for firms such as NIE so that they have incentives to become more efficient. The regulatory 'contract' is that, on the one hand, firms should have the confidence to invest and plan for the future on the understanding that the regulator will not revisit the rules of a regulatory agreement after the event, and that, on the other, consumers should in the longer term reap the benefits of efficiency savings realized through outperformance of price control settlements.

15.60 Therefore we find that revisiting the terms of previously set price control should be considered very carefully because it might otherwise undermine the regulatory 'contract' under which firms in regulated industries operate, and therefore their confidence to act in a way which would reap longer-term benefits for consumers.

15.61 However, this is not an absolute rule. We consider that an outcome clearly detrimental to consumers would not be in the public interest, and therefore circumstances could arise where it might be appropriate to revisit the terms of previous price controls. Examples of where we might disturb a previously agreed regulatory settlement include: *(a)* where an error of a technical nature had been made, for example in setting one of the parameters needed to implement a price control, and as a result consumers pay more for services than they should; *(b)* where the firm had intentionally gamed the intended operation of the price control; or *(c)* where reclassification had occurred which directly affected the calculation of the extent to which a regulated firm had outperformed a particular target, which in turn had directly increased the regulated firm's profits.

15.62 The UR provided us with five examples of where it sought to illustrate where GB or UK regulators had stepped in to correct matters arising from previous price control settlements. However, we note that each of these examples provided appeared to relate to clearly delineated issues of principle. There were no examples where the matter in dispute turned on the consistency or otherwise of accounting practices over time.

15.63 Accordingly, we consider that a strong public interest case for an adjustment arising from the other factors outlined would be required to justify an adjustment affecting a past settlement. This factor (ie regulatory certainty and the undesirability of revisiting past settlements absent good cause) has applied to our thinking throughout this inquiry: see also our consideration of pension payments, in particular paragraphs 12.49 to 12.62.

- *The ability to identify and estimate robustly the 'adverse' effect*

15.64 A consideration of whether it would be in the public interest to make an adjustment is whether we could identify and quantify the extent to which consumers had overpaid with a reasonable degree of confidence. For example, we would want to avoid inadvertently penalizing NIE for outperformance of its controllable operating cost allowance through genuine efficiency gains.

15.65 We note that obtaining sufficient understanding of the factual circumstances for each activity to establish that reclassification has occurred is a resource-intensive activity requiring specialist accounting and engineering input to review material provided by NIE and the UR. Even when the facts have been established, exercise of professional judgement may be required to determine whether reclassification adverse to the public interest had occurred in each case. (See Appendix 15.1, paragraph 38, for a list of activities where we went through this process.)

- *The materiality of the adverse effect*

15.66 The amount of any overpayment by consumers is also a factor in weighing up the public interest.

- *NIE's intent in making changes and any failure to communicate these changes*

15.67 While evidence of NIE's intent would not itself mean that reclassification had occurred that was adverse to the public interest and would justify an adjustment to the RAB, such evidence could provide an indication that NIE had misused the system and that activities were being relabelled deliberately in order to undermine the proper operation of the RP4 charge control. Evidence of intent might help resolve otherwise ambiguous evidence (for instance, as to whether activities had been reclassified or were in fact different).

Our observations on developments over the period of review following our review of the cost evidence

15.68 We reviewed and analysed the available evidence: see Appendix 15.1. Over the period we reviewed, there appeared to have been five significant developments affecting subsequent expenditure on existing assets, and the category of expenditure to which tree cutting, repairs and maintenance and capitalized overheads primarily relate:

(a) NIE greatly increased the extent to which it undertook tree cutting as part of its overhead line rolling programmes (ie a change in scale of an existing capitalized activity).

(b) NIE undertook several initiatives including, for example, investing in assets, such as at substations, that had lower ongoing maintenance requirements (ie change in activities).

(c) NIE adopted a more systematic/programmatic approach to managing existing network assets (ie change in approach from reactive work to planned programmes).

(d) NIE set out to identify fully that element of its total subsequent expenditure on existing assets (whether planned or reactive) that constituted the replacement of existing assets, and therefore should be treated as capex rather than opex (ie reclassification of spend).

(e) NIE subsumed some activities previously classed as opex into capital programmes.

15.69 In addition, our analysis of the development of controllable opex over RP3 and RP4 suggested that the scale of NIE's outperformance was unlikely to be attributable in large part to the reclassification of opex as capex (see paragraphs 15.90 to 15.95).

Developments in accounting standards and NIE's documentation of its approach regarding the distinction between opex and capex

15.70 The UR characterized what had occurred, particularly since 2005/06, as NIE changing its capitalization policies/practices/procedures so that there had been a reclassification of some expenditure from opex to capex. As part of our review, we reviewed the accounting standards in force over the period of review to see if they affected NIE's approach to capitalization. We also looked at the NIE documentation of the approach it had taken towards capitalization that the UR had referred us to. This assessment is set out in Appendix 15.2.

15.71 As discussed in Appendix 15.2, it appeared to us that NIE changed its approach towards capitalizing some subsequent expenditure on existing assets. This change in approach was in line with its switch in accounting standards from UK[52] to inter-

[52] Under which, if the asset has been given a single asset life, then any further expenditure 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. See Appendix 15.2, paragraph 8, for a fuller explanation.

national accounting standards[53] on 1 April 2005. The result of this switch was that some ‘repairs and maintenance’ expenditure (ie that relating to the replacement of a component of a wider asset before the end of that wider asset’s expected life) which would have previously been categorized as opex under UK standards was subsequently treated as capex under international standards. However, this shift in approach did not appear on its own to have produced any sharp increase in capitalization from one particular accounting period to the next.

15.72 Rather, it appeared that NIE had invested in its management and information systems to identify all expenditure that in accordance with the international standards it had newly adopted should be capitalized, ie all expenditure on the replacement of assets.

15.73 At the same time, NIE also increased the level of existing activities which it capitalized (eg programmed tree cutting) as well as changing the activities it undertook as a result of a shift of emphasis towards planned (generally capitalized) programmes rather than reactive work. All these factors, among others, may have contributed to the observed trends in the relative amounts of capex to opex. The increase in the proportion of capex over time reflects the switch in approach towards capitalizing expenditure embodied in accounting standards but began before NIE adopted international accounting standards in 2005/06.

15.74 NIE’s investment in its management and information systems can be characterized as NIE improving its ability over time to implement its policy towards capitalizing all expenditure on replacement assets. Under accounting standards (both UK and international), changes to reported costs as a result of a firm’s increased ability to implement fully a chosen accounting policy do not count as a change in accounting policy. Had NIE in fact changed its accounting policy, rather than merely more fully implemented its previously adopted accounting policy, then NIE would have been required under Condition 2 (regulatory accounts) of its licence to have restated its prior period figures on to the same basis as the current period’s figures. Had there been a restatement of prior period figures, then the UR would not only have been alerted to a change in NIE’s treatment of certain of its costs but would also have been able to quantify the effect of the change of treatment.[54] See paragraph 15.92*(e)*.

15.75 As set out in Appendix 15.1, NIE also bundled some activities previously classified as opex repairs and maintenance into its capital programmes. To the extent that such expenditure qualified as expenditure on replacement assets, then this development can be seen as part of the same overall trend whereby NIE sought to identify all its asset replacement expenditure in order to capitalize it.

15.76 In summary, it appeared that NIE had become significantly better at identifying its expenditure on replacement assets and had classified it as capex, which was in line with the international accounting standards that NIE adopted.

15.77 From our analysis of expenditure, it was apparent that the trend to capitalize an ever greater proportion of NIE’s total expenditure on replacement assets (relating to both tree cutting and more generally repairs and maintenance) began well before the end of RP4 in March 2007. The UR did not request copies of NIE’s capitalization policies until June 2010, approximately four years after the regulatory financial statements for

[53] Under which expenditure relating to the replacement of parts of a wider asset should be capitalized. See Appendix 15.2, paragraph 9, for a fuller explanation.
[54] The difference between the prior period figures as originally reported with the restated comparative figures as reported for the current period would give an estimate of the impact of change in accounting policy for the prior period.

2005/06, published in September 2006, had shown a £10 million drop in controllable opex compared with the total for the previous year.

The ability to identify reclassification of expenditures in practice

15.78 We considered the circumstances under which the UR's concern regarding reclassification and double payment could be realized. This effect might arise were the same activities relabelled. However, no such effect would arise if NIE had increased capex (measured on a consistent basis across time) without reducing opex (also measured on a consistent basis across time) in absolute terms, as no reclassification between them would occur, despite the changes in proportions of opex and capex.

15.79 However, we saw that NIE had made changes to the way in which it organized its activities, for example approaching repairs and maintenance or tree cutting in a planned rather than reactive way, which for certain activities such as tree cutting was the basis on which NIE classified an activity as capex or opex. NIE also changed some of its activities, such as investing in new assets that require less opex-type maintenance.

15.80 The explanations NIE offered for the evolution of the relative mix of opex and capex expenditure indicated that at least some of these developments were likely to be more efficient in the longer term and so reduce total costs. We did not think that actions taken in order to achieve efficiencies would be against the public interest. Indeed NIE was deliberately given incentives to pursue such efficiencies by setting allowances, such as that for controllable opex, which it could outperform. In this context, distinguishing between outperformance arising from the adoption of efficiency-enhancing measures and those stemming from the reclassification of the costs of continuing activities was likely to be difficult. Identifying which cause, or combination of causes, applied in each particular case could only be ascertained after careful investigation into the factual circumstances relating to each activity across the relevant time period, ie over the ten-year period 2002/03 to 2011/12 in the case of RP4, and even further back for RP3.

15.81 We note that no distinction was drawn in advance in terms of directing NIE as to how it was to achieve outperformance. We also noted that the RP4 determination did not include any direction as to whether there was an expectation that the opex allowance was intended to cover exactly the same opex activities as RP3, even though the allowance was derived from RP3 expenditure. This was consistent with NIE having discretion to pursue what it saw as the optimal pattern of opex.

15.82 Further, there was no specified list of activities which were to be treated as opex. Adherence to accounting standards on their own would not ensure consistent classification of activities between opex and capex.[55] As a result, each continuing activity would need to be reviewed individually to ascertain whether there had been consistency of accounting treatment over time, as there could be other, legitimate, explanations for the observed changes in levels of spend shown within summary accounting information.

15.83 There was also the possibility that some activities, while not necessarily replicating the predecessor activities in all respects, would have been treated as opex activities had the previously prevailing accounting treatment continued in force. For such 'new' activities there would be another practical difficulty in that NIE only documented its accounting policies regarding the opex/capex distinction to a limited extent. To the

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[55] See Appendix 15.2, paragraphs 14–17.

limited extent that these policies were in fact documented, NIE did not fully adhere to those policies. In these circumstances, what constituted the prevailing accounting policy might depend on the recollection of individual NIE accountants and/or ex-post rationalization by other parties.

15.84 Accordingly the comprehensive identification of all instances of reclassification of expenditure over the period would require close examination of a wide range of individual activities.

Estimating the extent of the reclassification of opex as capex

15.85 In its final determination, the UR estimated the extent to which, in its view, NIE had reclassified opex as capex and had substituted opex activities for equivalent (again, in its view) capex activities at £31.7 million.[56] As a result, the UR proposed that NIE's RAB should be reduced by this amount at the outset of RP5.

15.86 To ascertain whether reclassification adverse to the public interest had in fact taken place, we considered the approach the UR's consultants CEPA had taken. For both tree cutting and overheads, the amount of reclassification was estimated using historically determined capitalization rates. The analysis undertaken in relation to repairs and maintenance considered both the amounts transferred out of repairs and maintenance (eg relating to the cost of replacing assets following a fault being identified) and the activities, which in the consultants' view had been captured within planned capital programmes, but still relied in part on estimates using historically determined capitalization rates.

15.87 We did not accept this approach. The proportion of total costs capitalized is the result of applying a particular approach to capitalization. The fact that this proportion had changed over time is likely to be due to a number of reasons (see paragraph 15.72). Changes in capitalization policy and/or changes in the implementation of a capitalization policy are only two possible explanations.

15.88 We considered alternative approaches.[57] We also investigated each of the examples that the UR drew to our attention following our provisional determination. (See Appendix 15.1, paragraphs 17, 38, 39 and 42.)

15.89 We concluded that, given that over the period: *(a)* NIE had changed the mix of its activities to some extent, *(b)* NIE had adopted an approach to asset management that favoured pre-planned capital programmes over reactive repairs and maintenance, and *(c)* there were examples of developments outside NIE's control which influenced the balance of its spend between capex and opex, there was no summary-level approach which we could adopt which would robustly isolate the reclassification effect from changes resulting from any of these other factors.

Our evaluation and conclusion

15.90 We considered that we should make an adjustment only if we were satisfied that reclassification from opex to capex had occurred that operated against the public interest, bearing in mind the factors listed in paragraph 15.57. We found that we

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[56] This £31.7 million UR estimate relates to the impact on the RAB as at the end of RP4, whereas the estimate of £35.6 million in paragraph 15.13 reflects the UR's estimate of the reclassification effect in total.

[57] For example, for repairs and maintenance we calculated the amounts capitalized and expensed each year on average over RP3 and over RP4 and compared the two figures. We then repeated this exercise comparing the annual averages for the period up to and including 2004/05 with the period after 2005/06. We chose this latter split because the period from 2005/06 reflected the period in respect of which the UR wanted to make a RAB adjustment.

could not be satisfied that this was the case by looking at summary accounting information. We therefore investigated in detail a number of activities that the UR drew to our attention, both in its response to the provisional determination and in its hearing (see paragraph 15.38). Based on the available evidence, we were not satisfied that NIE had reclassified opex activities as capex during RP4 and RP3 in a way adverse to the public interest.

15.91 In relation to tree cutting, we found that there had been no reclassification because NIE had adopted a consistent approach to capitalization throughout the relevant period. See Appendix 15.1 (paragraph 17 for tree cutting, paragraph 40 for non-recoverable alterations and paragraphs 38 and 39 for routine maintenance activities) for further detail.

15.92 In arriving at our conclusion, we took all the factors listed in paragraph 15.57 into account:

(a) We found that changes in the balance of NIE's opex and capex activities reflected a mix of causes, including additional capex activities, the replacement of reactive opex with planned programmes of capitalizable activities, and improvements in information allowing replacement of assets to be better planned and better recorded. In addition, NIE will have achieved genuine opex efficiency improvements.

(b) With regard to regulatory certainty, we considered that intervention to correct for any such reclassification effects long after they occurred could be harmful to investors' perceptions of regulatory stability.

(c) In terms of our ability to identify and estimate robustly any adverse effect, with regard to NIE's opex allowance, we note that the UR had not specified that the rolling opex allowance had been set with the intention of covering exactly the same items of expenditure as had been incurred in the previous period. Rather, it was in effect a general allowance, and NIE had incentives to outperform in various ways including by changing the mix and levels of opex. This approach left the classification of 'new' activities open to NIE's interpretation of the newly adopted international accounting standards, whereas the UR might have expected adherence to the previous accounting standards to maintain consistency of approach across time.

(d) With regard to materiality, while we found some indications, we did not find sufficiently good evidence to show that NIE had engaged in reclassification of activities from opex to capex to a significant extent. Even the indications we found did not suggest reclassification at anything like the level suggested by the UR.

(e) Finally, with regard to intent, over time, NIE made a number of changes to the way it operated, maintained and renewed its electricity supply network, most notably through a shift from reactive activities to planned activities. NIE had also been able to identify better its fixed asset capex. We did not consider that any reclassification of expenditure that might have arisen from NIE's improved ability to identify all its capex as being against the public interest. We considered whether NIE intended to undermine the proper operation of the RP4 charge control or otherwise to take advantage of the possibility of double-funding. With the lapse of time it was not possible to establish NIE's intent *(a)* at the time it made its Composite Proposal for RP4 to NIE, *(b)* when it developed its capex proposals for RP5 which included capital programmes which incorporated to some extent activities previously undertaken as opex and *(c)* through the period

when it was enhancing its ability to identify all its expenditure on replacement assets. These developments took place within a broader context of NIE seeking to be more planned and programmatic in maintaining its network. The transition from UK to international accounting standards in which NIE was required to capitalize all its expenditure on replacement assets was a factor encouraging it to identify all such expenditure. We therefore saw no evidence of intent on the part of NIE to bypass the intended mechanism of the RP4 price control.

15.93 Accordingly, we decided not to adjust NIE's RAB on account of any 'reclassification'.

15.94 However, we note that from the UR's perspective there was a lack of transparency on NIE's part in its dealings with the UR. For example, the UR had not appreciated from the explanations given to it as part of the run-up to RP4 that most, if not all, of the targeted asset replacement programmes comprised wholly or mainly tree cutting. As mentioned in paragraph 15.77, there appeared to have been a lack of ongoing monitoring of subsequent developments once price controls had been set. We also note that NIE did not communicate developments in its accounting practices to the UR as they occurred. For example, NIE did not inform the UR that it was changing its accounting approach to periodic tree cutting (ie instead of cutting trees reactively every five years or so, it now organized a capital programme to achieve the same outcome).

15.95 In order to address the risk that reclassification of expenditure from opex to capex could lead to consumers paying twice for the costs of the same activity, we have made changes to the design or structure of NIE's price control. As explained in Section 5 under D1: Cost risk-sharing mechanism (paragraphs 5.49 to 5.96), we determined that the design of the new price control (applicable from 1 April 2012) should feature a consistent approach across opex and capex towards the treatment of differences arising between out-turn expenditure and the upfront allowances we have determined in Section 7. For example, under the new 50:50 cost risk-sharing mechanism, a reclassification of £100 of expenditure on an activity from opex to capex would lead to a reduction to £50 to NIE's allowance for opex in that year and a £50 increase to the additions made to NIE's RAB in that year.

Evaluation of the regulatory asset life for tree cutting in the public interest

15.96 As noted in Appendix 15.2, paragraph 22, there was an issue of whether it is in the public interest that tree cutting should have the same regulatory asset life as all other capitalized network expenditure, namely 40 years. This situation is relevant to the prices consumers ultimately pay in any one period, as it is regulatory depreciation charges based on an expected 40-year life which are reflected in the prices for that period.

15.97 In our view, it was not in the public interest for future generations to pay the costs of investments which have such a short life in relation to the period over which they are being depreciated for pricing purposes (40 years) and which will result in non-trivial differences between the prices charged to consumers across the generations. We acknowledge that the RAB is a means of allowing NIE to recover capital investments over a suitable period determined by the regulator, in this case 40 years. However, in the RAB, all capital investments are given the same asset life for regulatory depreciation purposes. This is the case even though some assets are very long lived (eg 50+ years), some short lived (eg less than five years).

15.98 In the case of tree cutting, the cost in any one year can be significant and the activity of tree cutting needs to be repeated regularly. In the recent past, NIE has modified its approach to managing vegetation in the vicinity of overhead lines, ie the precise balance of programmed tree cutting (capitalized) and reactive tree cutting (expensed as incurred), with a resultant substantial increase in capitalized tree cutting.

15.99 It was therefore possible that future consumers would be paying for up to eight past cycles of tree cutting when only the most recent is relevant to them, whereas current consumers would only be paying for a disproportionately small fraction of the capitalized cost currently being incurred. We judge that this situation does not reflect a proper balance between the interests of current and future consumers, and is therefore against the public interest.

15.100 As explained in paragraph 15.45, the UR argued that the public interest would be better served if no tree cutting was capitalized apart from that associated with a greenfield overhead line-building. We disagreed with this suggestion because there is a clear and important distinction in principle between tree cutting that creates an asset (ie tree cutting that is worth doing in a planned way because it delivers both cost savings and economic benefits to future periods) and expenditure on tree cutting which does not create an asset. In those cases where the cost-minimizing approach would be to cut trees only in response to problems actually occurring, no asset would be created (as no future economic benefits would be expected). We also note that such an approach (ie following the classification that NIE adopts in its financial statements) is consistent with the approach we have taken more generally to the classification of NIE's costs as set out in Section 5.

15.101 We therefore concluded that NIE should create a separate RAB for expenditure on its future[58] capitalized tree cutting with a regulatory asset life of no longer than five years.[59] In the same vein, we also consider that expenditure on other assets with a similarly short economic useful life, which taken together represent a significant block of expenditure, should likewise be included within a short-life RAB.

[58] By 'future', we mean the period from which our price control redetermination would be effective, namely 1 April 2012.
[59] We understand that it is necessary to cut down trees in the vicinity of overhead lines every three to five years to maintain safety clearance and storm resilience of these lines. We therefore consider that five years should be the upper limit for the period over which the short-life RAB should be depreciated.

16. Allowance for corporation tax

Introduction

16.1 This section sets out our determination regarding our allowances for corporation tax in the calculation of NIE's maximum regulated revenue. NIE's current price control licence conditions include an allowance for corporation tax payable on NIE's taxable profits.

16.2 Our approach to the determination of NIE's WACC is made on the basis that the allowed return calculated using the WACC will be supplemented by a separate allowance for corporation tax. Our provisional determination did not set out in detail how an allowance for NIE's corporation tax should be determined for the period from 1 April 2012 to 30 September 2017.

16.3 In its response to our provisional determination, NIE proposed a change to the current price control licence conditions to resolve a matter of dispute between the UR and NIE on the interpretation of the capital allowance term in the formulae used to calculate an allowance for corporation tax.[1]

16.4 Following our provisional determination, we considered in more detail the calculation of the allowance for corporation tax in the current price control licence conditions and consulted with NIE and the UR.

16.5 This section is structured as follows:

(a) Overview of corporation tax (paragraphs 16.6 to 16.9).

(b) The corporation tax allowance in NIE's current licence conditions (paragraphs 16.10 to 16.12).

(c) Our public interest findings on the tax calculation in NIE's current licence conditions (paragraphs 16.13 to 16.19).

(d) Revisions to the definition of capital allowance term, in light of NIE's response to our provisional determination, and submissions on the treatment of amortization of deferred revenue expenditure in the tax calculation (paragraphs 16.20 to 16.33).

(e) Interactions between the tax calculation and the cost risk-sharing mechanism (paragraphs 16.34 to 16.41).

(f) The interest and gearing elements of the tax calculation (paragraphs 16.42 to 16.46).

(g) Our decision in relation to the potential alternative approach based on upfront allowances for corporation tax (paragraphs 16.47 to 16.56).

(h) Our determination (paragraphs 16.57 to 16.63).

[1] NIE response to provisional determination, pp201&202.

Overview of corporation tax

16.6 Corporation tax is a tax on profit. In the UK, corporation tax is not levied on a company's accounting profit as reported in the profit and loss statement in its audited accounts. Instead it is levied on the company's 'taxable profits'.

16.7 HM Revenue & Customs (HMRC) reported that the main rate of corporation tax applied to taxable profits is set to 24 per cent for the financial year ending 31 March 2013, 23 per cent for the financial year ending 31 March 2014, 21 per cent for the financial year ending 31 March 2015 and 20 per cent for subsequent financial years.[2]

16.8 The level of taxable profits may differ to accounting profit for a number of reasons. For instance, the calculation of taxable profits does not involve the same depreciation and amortization of investments as used for a company's audited accounts. Instead, the calculation of taxable profits for the purposes of corporation tax involves deductions for 'capital allowances' in respect of investments carried out by the company. The treatment of capital allowances in NIE's current licence conditions has been disputed between the UR and NIE.

16.9 The calculation of these capital allowances are governed by rules set by HMRC. HMRC introduces capital allowances as follows:

> Capital allowances are a tax relief designed to allow the cost of certain of your company or organisation's assets to be written off against its taxable profits. They take the place of the depreciation shown in the financial (commercial) accounts, which isn't allowable for Corporation Tax purposes.
>
> There are different types of capital allowances. For each allowance, there are special rules to calculate how much, if any, relief you can claim. You have to follow these rules, rather than the method used in your accounts for calculating depreciation.

The corporation tax allowance in NIE's current licence conditions

16.10 The allowance for corporation tax specified in NIE's price control licence conditions can be seen to provide an estimate of corporation tax in light of *(a)* the rate of corporation tax and *(b)* an estimate of taxable profit from NIE's transmission and distribution activities.

16.11 The estimate of NIE's taxable profit for each year is calculated in light of: *(a)* the price control allowance for an allowed return on the RAB for that year; *(b)* an estimate of the value of NIE's interest payments on its debt, at an assumed level of gearing; and *(c)* the difference between the price control allowances for depreciation and the value of NIE's capital allowances. The capital allowance term is defined in the licence conditions as follows:[3] 'an amount in pounds sterling equal to the level of capital allowances agreed with HM Revenue & Customs in respect of relevant year t calculated in accordance with the Capital Allowances Act 2001 (or successor legislation) and relevant industry agreements or rules.'

[2] www.hmrc.gov.uk/rates/corp.htm retrieved 14 January 2014.
[3] Clause 2.3 of Annex 2 of NIE's licence.

16.12 Under NIE's licence conditions,[4] it is required to submit a tax report each year which contains the information used for the calculation of its corporation tax allowance.

Public interest findings on the tax calculation in the current licence conditions

16.13 We identified four features of the tax allowance calculation in the current licence conditions that may operate against the public interest:

(a) The corporation tax rate used in the calculation is out of date. The current calculation specifies a 30 per cent tax rate which is higher than the rates reported by HMRC (see paragraph 16.7).

(b) The interest term in the tax calculation uses a rate of interest and assumption for NIE's gearing which are out of date.

(c) The interpretation of the capital allowance term in the tax calculation (paragraph 16.11) is disputed between NIE and UR. If the current licence conditions remain, this could perpetuate ambiguity and produce further disputes in the future about the calculation of a new price control for NIE. There is also a lack of clarity on the treatment of amortization of deferred revenue expenditure in the tax calculation.

(d) One possible interpretation of the capital allowance term in the current licence conditions would lead to a revenue control that could expose customers to higher charges than necessary in circumstances in which NIE, as part of the tax strategy across its corporate group, does not claim its full capital allowances in tax return in a particular financial year.

16.14 The first problem identified above is that the corporation tax rate used in the calculation in NIE's current price control conditions is out of date. This can be addressed by revising the formula for the calculation of NIE's tax allowance to refer to the prevailing rate of corporation tax in each financial year.

16.15 NIE told us that although the corporation tax rate included in the current licence condition is out of date, in practice, the prevailing statutory tax rate has been used when calculating NIE's revenue restriction under the current price control licence conditions. Nonetheless, NIE agreed that it was preferable for the licence to be updated to reflect changes in the rate of corporation tax.

16.16 The second problem identified above can be addressed through revisions to the interest element of the tax calculation (see paragraphs 16.42 to 16.46).

16.17 The third and fourth points are related. NIE's interpretation of the capital allowance term[5] could give rise to the potential adverse effect on consumers under (d). The UR's alternative interpretation could help to protect consumers from the outcome under (d).

16.18 As a result of these features, we found that the calculation of corporation tax allowances in the current price control licence conditions operates against the public interest.

[4] Clause 12 of Annex 2.
[5] NIE Statement of Case, pp312–315.

16.19 In addition to the problems highlighted above, we identified the need for consequential changes to elements of the tax calculation as a result of our decisions on other changes to NIE's price control (see paragraphs 16.34 to 16.40).

Revision to the definition of the capital allowances term

Our provisional determination

16.20 In our provisional determination, we recognized the dispute between the UR and NIE in relation to the interpretation of the capital allowance term (see the provisional determination, paragraphs 14.14 to 14.28). We said that that it was not appropriate to seek to revisit the UR's interpretation of the capital allowance term for the period 1 April 2007 to 31 March 2012 (the period originally envisaged for RP4). We indicated that we intended to resolve the ambiguity about the capital allowances term as part of the implementation of a new price control for NIE, and said that we would review the approach in the light of responses to our provisional determination.

NIE's proposed revisions to the capital allowance term

16.21 In its response to our provisional determination, NIE requested that we resolve the current uncertainty about the capital allowances term and made the following proposals (pages 201 and 202):

> The UR has, to date, argued that the CAt term should be applied so as to assume that NIE has utilised all available capital allowances in the year in which they first become available. This assumption is generally favourable to consumers, since it leads to the maximum possible reduction in NIE's taxable profits in the year in which capital allowances first become available.
>
> NIE proposes that, in future, the CAt term should be applied on the assumption proposed by the UR, so as to maximise immediate benefits to consumers in the manner outlined above.
>
> But if, in practice, NIE does not utilise all its capital allowances in the year in which they first become available (e.g. because deferral is more favourable to the corporate group of which NIE forms part), then, in applying the CAt term in future years, any capital allowances which were assumed, for the purpose of applying the CAt term in previous years, already to have been used in a previous year, should be assumed no longer to be available to NIE, so as to avoid any 'double counting' of such capital allowances.

16.22 NIE argued that this approach would:[6]

> maximise benefits to consumers (by allowing them to take advantage of all available capital allowances as soon as they are available to NIE) whilst leaving NIE free to plan its tax affairs to the overall benefit of the corporate group of which it is a member, and protecting NIE from any risk of double counting of its capital allowances.

[6] NIE response to provisional determination, p201.

16.23 NIE said that it would be content to provide an appropriate reconciliation as between available tax allowances, and the allowances utilized in its tax assessment, as part of its annual tax reporting obligations to the UR.

16.24 NIE's response to our provisional determination (page 202) also pointed out that the licence modifications would need to make provision for an appropriate allocation of capital allowances between NIE's transmission and distribution activities.

Our concerns with NIE's proposal and further submissions from NIE and the UR

16.25 NIE's proposed amendment to the capital allowances term in the current licence conditions would bring it in line with the UR's preferred interpretation of that term.

16.26 NIE's proposal would help address the concern that charges to consumers could be too high in circumstances where NIE does not claim its full allowances as part of its tax strategy across the corporate group.

16.27 However, we also identified some concerns with NIE's proposed change. These relate more to concerns about the methods and available data for the capital allowances term, rather than the intended aim of the proposal. Compared with NIE's interpretation of the current licence conditions, NIE's proposals would diminish the link between the value of capital allowances used in the calculation of the allowance for corporation tax and the information on capital allowances from NIE's tax submissions to HMRC. An assessment of a company's capital allowances can involve complex calculations and interpretation of tax law. A calculation of what capital allowances NIE would theoretically be able to claim if it had hypothetically claimed its full allowances in all previous years (from a specified start date) seemed open to alternative interpretations.

16.28 Related to these concerns, the UR told us that the tax reports submitted by NIE under the current price control licence conditions did not include reconciliations between the regulatory tax allowance and the actual tax computation submitted to HMRC and that it did not account for all elements of the regulated transmission and distribution business.

16.29 NIE responded to the concerns that we had identified with its proposal:

(a) NIE pointed out to us that these concerns already arose under the UR's interpretation of the capital allowances term in the current licence conditions.

(b) NIE said that, in the event that it decided to defer capital allowance claims, it would still need to allocate expenditure to the appropriate pools in the normal manner: it would simply opt not to claim some or all of the allowances. In this scenario NIE proposed that it would maintain two sets of records: one supporting its statutory tax return submissions and one supporting the calculation of its regulatory tax allowance. NIE said that it would be very straightforward to reconcile the two.

(c) NIE said that it did not consider the allocation of its capex to tax pools to be particularly complex or open to interpretation.

(d) NIE told us that it was essential that the opening capital allowance/deferred revenue pool balances as at 1 April 2012 were correct. NIE said that, on the basis that the (correct) 1 April 2012 opening pool balances formed the basis for the tax allowance calculations from that date, it did not consider that there would

be difficulty in establishing the total amount of capital allowances available to NIE in any given period.

16.30 The UR did not make detailed comments on NIE’s proposals, but did raise a general concern about the potential for an approach to the corporation tax allowances that would be difficult to complete and validate.

Our decision on NIE’s proposed changes to the capital allowanced term

16.31 We decided that, on balance, NIE’s proposed amendment of capital allowances was preferable to the treatment of capital allowances in the current licence conditions. We took account of NIE’s view that it would not be difficult to establish the total amount of capital allowances available to NIE in any given period and NIE’s proposal to maintain two sets of tax records and to reconcile between tax for regulatory purposes and its statutory tax return.

Amortization of deferred revenue expenditure

16.32 We identified a further issue concerning the interpretation of the capital allowances term in the current licence conditions. NIE told us that amortization of deferred revenue expenditure was included as part of capital allowances. However, the definition of capital allowances in the current licence conditions is not clear on the treatment of deferred revenue expenditure.

16.33 NIE proposed that the capital allowance term is amended to explicitly include amortization of deferred revenue expenditure. We decided to accept this proposal as it seemed appropriate to include the deferred revenue expenditure in the tax calculation and because NIE’s amendment would improve transparency and reduce the risks of future disputes.

Interactions between tax allowances and cost risk-sharing mechanism

16.34 As set out in paragraphs 5.49 to 5.96 we sought to align better the approach to cost risk-sharing—and hence efficiency incentives—across NIE’s opex and capex. We decided that 50 per cent of differences between the cost allowances we set and NIE’s out-turn costs should be passed through to consumers, for both opex and capex.

16.35 The current price control licence conditions take account of NIE’s out-turn capex but not its out-turn opex in the calculation of the allowance of NIE’s corporation tax liability. This could lead to significant distortions to NIE’s financial incentives between opex and capex. These differences could undermine the efforts we have made elsewhere in our determination to better align NIE’s financial incentives across opex and capex.

16.36 We estimated that, for a corporation tax rate of 21 per cent (the rate for the tax year from 1 April 2014), the return to NIE’s investors from a £100 underspend on capex would be approximately £50 after corporation tax, and the return to investors from a £100 underspend on opex would be approximately £40 after corporation tax. Such a difference is not compatible with the intentions of our cost risk-sharing mechanism.

16.37 We considered how to address this issue. One potential approach was to revise the tax allowance calculation to take account of NIE’s out-turn opex to the same degree as out-turn capex. NIE said that such an approach would not achieve the intended effect of our cost risk-sharing mechanism. On review, we found that such an approach would, on its own, pass through to consumers too little of the differences between our upfront allowances and NIE's actual costs. We examined whether that defect could be addressed by increasing the extent of cost pass-through used in the calculation of allowances for opex and capex so that, after allowing for the tax allowance calculation, the pass-through to consumers was around 50 per cent.[7] However, we considered that such an approach was unlikely to be effective in relation to capex as the pass-through of actual expenditure to the RAB would be too high and it would not be possible to ensure that the effect of this was offset in future tax allowance calculations.

16.38 To achieve the intention of our cost risk-sharing mechanism, we decided that it was necessary that the information on capital allowances used in the tax calculation should relate not to NIE's actual capital allowances but to the capital allowances that NIE would be able to claim if its opex and capex in each year was in line with the annual allowances for opex and capex used in the calculation of NIE's maximum regulated revenue. The allowances here refer to the annual allowances that reflect the cost risk-sharing mechanism, not the upfront allowances we set in our determination. As explained in Section 19 paragraphs 19.48 to 19.53, the annual allowances for opex and capex will reflect our upfront allowances for NIE's opex and capex and also NIE's out-turn opex and capex.

16.39 By itself this would be a significant change to the tax calculation in the current licence conditions because it would mean that the data for capital allowances used for the calculation of NIE's maximum regulated revenue would differ from the data on NIE's capital allowances from NIE's tax returns. The capital allowances would relate more to a notional company for regulatory purposes than to NIE. However, a change of this nature is already a consequence of the separate decision we took on the definition of the capital allowances term to deal with situations in which NIE chooses to defer capital allowance claims in its tax submissions (see paragraphs 16.21 to 16.31).

16.40 The approach we determined is consistent with NIE's submission that the tax allowance for capex should be based on the amount of capex added to the RAB and not actual expenditure incurred.

16.41 We recognized that this approach may bring additional complexity in the tax calculation but we considered this in the public interest to align better the financial incentives for NIE on opex and capex.

The interest and gearing elements of the tax calculation

16.42 The tax calculation in NIE's current licence conditions includes an element which deducts an estimate of (nominal) interest payments as part of the estimate of taxable profit. The interest term in the tax calculation uses a rate of interest and assumed level of gearing (proportion of debt to NIE's RAB) which are out of date: they reflect regulatory assumptions made for the RP4 price control and are not consistent with the assumptions on gearing and the analysis of NIE's cost of debt that we have used for our determination.

16.43 NIE told us that the gearing assumption used for tax purposes should mirror the regulatory assumption on gearing used in the WACC determination (see Section 13)

[7] Specifically by increasing the pass-through of actual expenditure to opex and capex allowances from 50 per cent to 50 per cent multiplied by (1 + the prevailing corporation tax rate). For current and planned corporation tax rates, the adjusted proportion of pass-through would be around 60 per cent.

and that it should be consistent with the gearing used in our financial modelling (see Section 17).

16.44 The UR said that the tax allowance calculation should use the levels of gearing assumed and calculated by the financial model which we used for our financeability analysis (Section 17).

16.45 We decided that our assumptions on gearing should be consistent across the tax calculation in the price control algebra, our determination of NIE's WACC and the tax calculation in the financial modelling used for our financeability analysis. On this basis, we decided that the gearing assumption in the tax calculation should be 45 per cent.

16.46 We decided that the interest element of the tax calculation should be consistent with the analysis of NIE's WACC (Section 13). Our analysis used a 'real' cost of debt of 3.1 and an average RPI forecast for the price control period of 3.25 per cent. We therefore determined a nominal cost of debt for the purposes of the interest rate in the tax calculation of 6.45 per cent.

Potential alternative approach based on upfront allowances for corporation tax

16.47 The approach to corporation tax in NIE's current licence conditions differs from that taken by other regulators such as Ofgem and Ofwat. Ofgem and Ofwat set price controls using estimates of companies' corporation tax derived from financial models, with provisions to make financial adjustments if factors affecting corporation tax payments change (eg tax rates or measures of the regulated company's gearing).

16.48 The draft licence modifications proposed by the UR as part of its RP5 final determinations included allowances for corporation tax based on a limited revision to the formulae in NIE's current price control licence conditions. Nonetheless, in submissions towards the end of our inquiry the UR proposed that NIE's corporation tax allowances should be based on upfront allowances in line with the approach used by Ofgem.

16.49 We were concerned that implementing an approach similar to that taken by Ofgem and Ofwat would be a complex and time-consuming task. This would involve work to:

(a) establish the method and input data for the calculation of upfront allowances for corporation tax;

(b) determine how these upfront corporation tax allowances should be revised or recalculated to take account of decisions by the UR during the price control period to approve increases to NIE's maximum regulated revenues and RAB to allow for the costs of additional transmission network investment; and

(c) determine whether and how these upfront corporation tax allowances should be revised or recalculated in light of other changes that affect NIE's tax liability (eg changes to tax rates and rules on capital allowances and variations in NIE's actual debt interest payments and gearing).

16.50 NIE told us that it agreed that it would not be proportionate for us to undertake the further work to adopt an approach involving upfront allowances for corporation tax with specified adjustments.

16.51 The UR responded to our concerns that setting upfront allowances would be complicated and time-consuming. The UR identified that the calculation of tax allowances would require only small adjustments to the financial models that had been used during our inquiry. The UR also said that setting upfront tax allowances would be more consistent with other aspects of our determination where we set upfront allowances rather than using an ‘ex post’ approach.

16.52 We were not persuaded by the UR’s submissions. We accepted that we could use the financial models that we used for our financial modelling in Section 17 to estimate NIE’s tax liability. Nonetheless, the second and third concerns above would remain.

16.53 In its submissions the UR proposed a method which would combine upfront allowances for corporation tax with pre-specified and limited adjustment mechanisms. The UR did not provide further information on what those adjustment mechanisms should be, except that these should be similar to those used by Ofgem. The UR’s submissions did not resolve the concerns we had with the work required to develop such an approach for NIE. Ofgem’s approach to adjustments to tax allowances is complex and differences between Ofgem’s price controls and our determination mean that it would not be straightforward to transpose Ofgem’s approach to the case of NIE.

16.54 We did not agree with the UR’s arguments in relation to consistency with other elements of our determination. For instance, although we have set upfront allowances for NIE’s opex and capex, we have also specified a cost risk-sharing mechanism that takes account of NIE’s out-turn expenditure. The overall allowances for NIE’s opex and capex that feed into its maximum regulated revenues will be determined by formulae that depend on out-turn data that becomes available during the price control period. We did not identify any inconsistency between our approach to corporation tax allowances and our approach to opex and capex allowances.

16.55 One general concern we had with the type of tax allowance calculation in NIE’s current licence is that it is based on a simplified estimate of corporation tax payments and may overestimate NIE’s corporation tax by overlooking legitimate opportunities for NIE to reduce the corporation tax that it pays. However, the type of approaches used by Ofgem and Ofwat are also based on simplified estimates of corporation tax payments and did not offer any greater assurance that the tax allowances would accurately reflect the level of tax that an efficient company would incur.

16.56 Overall, we did not consider that the development of upfront allowances for corporation tax, combined with specified adjustments, was practicable during our inquiry. It will be for the UR to consider whether to develop such an approach as part of its next price control review for NIE.

Summary of determination

16.57 We decided that NIE’s allowances for its corporation tax liability over the period 1 April 2012 to 30 September 2017 should be calculated using a revised version of the corporation tax allowance calculation from the current price control licence conditions. We explain below the revisions that should be made.

16.58 We found that the corporation tax rate used in the tax calculation was out of date. We decided that the formulae in the tax calculation should be revised to use the prevailing corporation tax rate applicable to NIE in each financial year.

16.59 We found that the interest term in the tax calculation used a rate of interest and assumption for NIE’s gearing which were out of date and inconsistent with our determination of NIE’s WACC. We decided that the tax calculation should use a notional gearing assumption of 45 per cent in each year and a nominal cost of debt of 6.45 per cent.

16.60 We found that the capital allowances term in the tax calculation needed revision to address potential sources of uncertainty and dispute and to help achieve the intended effects of the cost risk-sharing mechanism that we determined in Section 5. We decided that the capital allowances term in the corporation tax calculation should be relabelled ‘regulatory capital allowances’ and defined in a way that makes the following clear:

(a) The regulatory capital allowances should include amortization of deferred revenue expenditure.

(b) The regulatory capital allowances should relate to NIE’s transmission and distribution activities.

(c) The regulatory capital allowances from 1 April 2012 should be calculated on a notional basis under the hypothetical assumption that NIE’s opex and capex in each year from 1 April 2012 was equal to the opex and capex allowances used in the calculation of NIE’s maximum regulated revenue (these allowances reflect the combination of the upfront allowances we have determined and NIE’s out-turn expenditure, through the application of the cost risk-sharing mechanism).

(d) The regulatory capital allowances should be the maximum amount of capital allowances that would be available to NIE, irrespective of whether or not NIE chooses to utilize such allowances in full. However, if NIE opts to defer capital allowance claims in respect of any capital allowances in any given year, the amount of capital allowances calculated to be available in any subsequent year should exclude any amounts for which claims were so deferred, to avoid any double counting of capital allowances.

16.61 The Licence conditions should require that the calculation of regulatory capital allowances should be as consistent as possible with the information on capital allowances and deferred revenue expenditure from tax submissions, notwithstanding the potential divergences between NIE’s actual tax affairs and the regulatory capital allowances arising from points (b), (c) and (d) above. For instance, the attribution of the regulatory capex allowances to different tax pools should be consistent with NIE’s attribution of its actual transmission and distribution capex.

16.62 Since we decided to set separate revenue controls for transmission and distribution, separate calculations for the allowances for corporation tax will be needed for transmission and distribution. This will require an allocation by NIE of the regulatory capital allowances between transmission and distribution.

16.63 We also decided that NIE should prepare and submit to the UR audited tax reports for each financial year from 1 April 2012 that enable a full reconciliation between information submitted to HMRC on NIE Ltd’s tax affairs (which should be made available to the UR) and the information used for the calculation of the corporation tax element of NIE’s maximum regulated revenue. In line with NIE’s proposal to us, NIE should maintain two sets of records: one supporting its statutory tax return submissions and one supporting the calculation of its regulatory tax allowance. The tax reports to the UR should reconcile the two. These reports should be published subject to the minimum redactions necessary to protect confidential information.

17. Financial modelling and the possible effect of our determination on consumers

Introduction

The aim of our modelling

17.1 NIE is subject to Licence conditions obliging it to take all appropriate steps to obtain and maintain at all times an 'investment grade' credit rating (for example, condition 9A, paragraph 4 of NIE's distribution Licence).[1] This obligation reflects the public interest that a firm holding the Licences should not only have sufficient funds to pay interest on its (reasonably incurred) historical debts but it should also be able to incur further debts at reasonable (ie investment grade) cost in future.

17.2 In fulfilling our obligation to have regard to the need to ensure that a licence holder can finance its activities (see paragraph 17.21), we considered that it is in the public interest to ensure that an efficient firm can do that, rather than necessarily the actual firm currently holding the licence. If we did not take this perspective, we would dampen the incentives on the actual firm to act in the public interest. Accordingly, we have adopted the term 'efficient licence holder' in conducting our analysis.

17.3 In this section, we describe the financial modelling we carried out to forecast the total revenues an efficient licence holder may raise over RP5 from providing transmission and distribution services, ie the price-controlled revenues which are the subject of this reference. We also describe the financial modelling we undertook of this profile of revenue and its associated expenditure.

17.4 We then describe the approach to, and the results of, the modelling we undertook to forecast the financial ratios of the efficient licence holder over RP5 based on our assumptions for gearing and dividends. Our modelling reflected our judgments as set out in preceding sections of the efficient level of costs and the cost of capital required by investors.

17.5 We undertook this financial modelling because, even though the price control we set would allow an efficient licence holder to earn its cost of capital on all its price-controlled investments, this does not necessarily mean that such a licence holder would be able to generate sufficient cash to finance its activities internally and to service its financing costs. In such a situation the licence holder would need to be able to: *(a)* access the funds necessary to deliver the envisaged price control and *(b)* service that funding. In the case of debt finance, this means being able to service the interest payments as they fall due and, in the case of equity finance, being able to pay dividends, make one-off payments or generate a capital gain to equity owners, which over the long term meet the reasonable expectations of equity investors in utility businesses like NIE's transmission and distribution business.

17.6 We also used the financial modelling described in paragraphs 17.3 and 17.4 to assess the possible effect of our decisions on the level of prices that Northern Ireland consumers will pay over RP5 for the transmission and distribution element of their electricity bills.

[1] See paragraphs 17.52–17.73 for a discussion of 'investment grade' credit ratings.

Assessing the position of an efficient licence holder

17.7 Any assessment which seeks to assess the position of an efficient licence holder requires us to form a view as to how potential lenders would assess its credit-worthiness, and so the rates at which they would be willing to lend to it. This is influenced by its ability to service its debt finance, which is measured by certain financial ratios, in particular interest-cover ratios. These are considered relevant to maintaining 'investment grade' credit status. Our view of the appropriate level of interest cover, and the other relevant ratios, was informed by discussion with credit rating agencies (see paragraphs 17.52 to 17.73).[2] We note that two credit agencies issue a rating for NIE Limited, the incorporated entity which provides the price-controlled transmission and distribution services.

17.8 There were three broad themes to our consideration of financial structure, performance and ratios. We considered that: *(a)* the licence holder would be a stand-alone business which does not undertake any other activities apart from those that it was obligated to supply (see paragraphs 17.21 to 17.26); *(b)* it would efficiently undertake the Licence activities (see paragraphs 17.27 to 17.30); and *(c)* it would exhibit the same set of properties that underpinned our setting of each of the individual RP5 allowances (see paragraphs 17.31 to 17.45).

17.9 We set the level of allowances for RP5, including that for the allowed return on the RAB, at a level at which we considered that an efficient licence holder would be able to provide the transmission and distribution services envisaged under RP5. We set these costs independently of the particular identity of the firm which will in fact provide these services (see paragraph 17.30). We likewise assessed the ability of a licence holder to finance the RP5 price control independently of the particular identity of the firm. We therefore considered whether the model reflected an efficient licence holder, rather than necessarily the particular circumstances of NIE.

17.10 In this section we:

- *(a)* describe our financial modelling (paragraphs 17.11 to 17.46);
- *(b)* set out the targets for the financial ratios generated by the model (paragraphs 17.47 to 17.73);
- *(c)* set out the financial ratios initially modelled for the efficient licence holder (paragraphs 17.74 to 17.90);
- *(d)* give our view on the drivers of the financial ratios (paragraphs 17.91 to 17.97);
- *(e)* assess the ability of the efficient licence holder to finance RP5 (paragraphs 17.98 to 17.112); and
- *(f)* assess the possible effect of the RP5 price control on consumer prices (paragraphs 17.113 to 17.115, and Appendix 17.1).

Description of our financial modelling

17.11 In our financial modelling, we generated estimates of:

[2] These agencies provide information to the debt markets that is relevant to the credit quality of industry sectors, countries and specific companies. They publish credit ratings which provide a guide to investors as to the credit quality of the issuer and the likelihood of default. The ratings may be categorized broadly into two classes: investment grade and sub-investment grade.

(a) maximum regulated revenues[3] during RP5 based on a combination of the upfront cost allowances (both opex[4] and capex[5]), and the vanilla[6] WACC we set as part of this determination plus the depreciation in RP5 of the RAB value rolled forward from the end of RP4;

(b) the corporation tax (revenue) allowance associated with (a) and the estimate of the corporation tax that the licence holder would have to pay;

(c) the forecast cash and net debt position and interest payable, resulting from the above, for this licence holder; and

(d) the forecast profits and financial ratios generated from (a) to (c) above.

17.12 We used the model developed by the UR to assess the combined effect of all the individual elements of this determination. The UR provided us with a model which, as its first stage, generated maximum regulated revenues over the period 1 April 2012 to 30 September 2017 based on the individual values for each allowance and the allowed return as set out in our provisional determination, for example for NIE's capex and opex allowances, WACC over this period and actual and forecast movements in the RPI index. The model also used these values to calculate the allowances for corporation tax payable on taxable profits.

17.13 To generate the level of the allowed return in each period, the model multiplied the average of the opening and closing RAB balances (ie a mid-year balance) by the value of the WACC adjusted to take account of the fact that this rate of return was being applied to a mid-year, rather than a year-end balance.[7] Our modelling assumes that the efficient licence holder earns a return on the RAB equal to our assumed WACC of 4.1 per cent.[8] As set out in paragraph 17.90, one party suggested that we should not adjust the WACC in this way. We disagreed because this formula only corrects for the fact that cash flows during any one period are incurred on average midway during the year, rather than all being incurred at the end of the year. We considered that using an unadjusted WACC in the model would not reflect the way in which cash flows are incurred during a year.

17.14 To generate the level of the corporation tax allowance in each period, the model used a measure of taxable profits which deducted a notional interest charge, rather than the level of interest payable generated by the model. This notional interest charge was computed in respect of a notional value of net debt, where this notional value of net debt was given by multiplying the level of gearing assumed for the purpose of computing this corporation tax allowance by the value of the RAB. We took this approach to be consistent with our determination of the corporation tax allowance—see paragraphs 16.42 to 16.46. The estimate of the forecast corporation tax payable, however, differed from the revenue allowance for corporation tax, in that the former was calculated on the levels of interest forecast by the model.

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[3] We introduce the concept of maximum regulated revenues in paragraphs 3.7–3.23.
[4] These opex allowances are as set out in Table 7.9. Forecast opex expenditure outside core allowances is in Table 7.11.
[5] These capex allowances are as set out in Table 7.8. Forecast opex expenditure outside core allowances is in Table 7.10. Potential additional transmission investment (D5) is as set out in paragraphs 7.39–7.42.
[6] The vanilla WACC weights a cost of equity post corporation tax with a cost of debt that does not take account of the fact that interest is deducted to arrive at profits for corporation tax purposes. The impact of interest being tax-deductible is, however, taken into account when computing the efficient licence holder's corporation tax allowance, and therefore when computing its maximum regulated revenues.
[7] The formula for this technical adjustment in the model is WACC divided by the square root of 1+WACC. We decided to replicate this technical adjustment to the WACC (as determined within Section 13) within the calculation of the maximum regulated revenues in NIE's licence.
[8] See paragraph 13.189.

17.15 Once the UR's model had generated maximum regulated revenues for each period of RP5, it worked out the cash implications of the RP5 programme and the resulting (forecast) financial ratios (see paragraphs 17.74 to 17.77 below). Our modelling assumed that the efficient licence holder pays interest consistent with the real cost of debt in the WACC of 3.1 per cent per year.[9] It also assumed that all investment is financed from retained profits and, if required, new debt.

17.16 Our initial modelling of the financing of an efficient licence holder took NIE Limited's balance sheet on 1 April 2012 as the starting point. We discuss further in paragraphs 17.20 to 17.46 the adjustments we considered might be necessary to model the efficient licence holder.

The modifications we made to the UR's model

17.17 We modified the UR's model to calculate the maximum regulated revenues over the period 1 April 2012 to 30 September 2017 to the extent that our final determination for individual allowances differed from those in our provisional determination. We also modified the model to take account of our revised values for the cost of equity (now 5.0 per cent per year in real terms post-corporation tax), the cost of debt (now 3.1 per cent per year in real terms), the level of gearing (now 45 per cent) and the RPI inflation forecast (now 3.25 per cent per year) supporting our allowed rate of return as set out in Section 13.

17.18 We further modified the UR's model to reflect a change in position on one issue, namely that the level of pension deficit repair payments of the efficient licence holder should reflect the level of the allowances we determined, and not the actual payments NIE would make over the period (see paragraphs 17.32 to 17.35). We also activated the feature in the UR's model to require the interest payable for the purposes of calculating the corporation tax allowance to be based on a gearing assumption of 45 per cent.

17.19 We then used the model so modified, in particular the values generated by it for maximum regulated revenues, costs, regulatory depreciation,[10] interest payable and corporation tax paid, to assess the financial ratios we consider relevant (as described in paragraphs 17.71 to 17.73).

Modelling the efficient licence holder

17.20 In the following subsections we set out our view of how the efficient licence holder might differ from NIE Limited, and the consequential adjustments (if any) we made in our modelling to assess the efficient licence holder's, rather than NIE Limited's, ability to finance the RP5 price control.[11] We consider:

(a) the scope of its activities (paragraphs 17.21 to 17.26);

(b) its opening financial position (cash, debt and gearing) (paragraphs 17.27 to 17.29);

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[9] See paragraph 13.80.
[10] The UR's model calculates profits on the basis of regulatory depreciation, rather than using accounting depreciation from either NIE's regulatory or statutory financial statements, to support the calculation of certain interest coverage ratios. This approach to depreciation has been adopted in response to feedback that both UR and we have received from rating agencies that they consider this measure of profitability to be most relevant to evaluating the credit risk of transmission and distribution businesses such as NIE's.
[11] In many respects there are no difference between the features of the notional firm and that of NIE, for example its opening RAB balance and the opex and capex allowances that it will be granted.

(c) its efficiency (paragraph 17.30);

(d) its investment in D5 capital expenditure (paragraph 17.31);

(e) its pension deficit (paragraphs 17.32 to 17.35);

(f) the rate of interest payable on its (embedded) debt (paragraphs 17.36 and 17.37);

(g) its dividend pay-out policy (paragraphs 17.38 to 17.41); and

(h) the under-recovery or over-recovery of its revenues as at 1 April 2012 and forecast for 1 October 2014 (paragraphs 17.42 to 17.45).

Scope of the activities

17.21 We first considered how the scope of the efficient licence holder's activities for this exercise might differ from NIE's Limited. Article 12 (2)(b) of the Energy Order (Northern Ireland) 2003 states:

> The Department and the Authority shall carry out those functions in the manner which it considers is best calculated to further the principal objective, having regard to – the need to secure that licence holders are able to finance the activities which are the subject of obligations imposed by or under Part II of the Electricity Order or this Order.

17.22 The activities that are the subject of these obligations encompass other activities beyond electricity transmission and distribution services to be provided within the framework of our price control determination—see, for example, paragraphs 19.18 and 19.19. The distribution and transmission services, however, comprise the dominant element of NIE's revenues.

17.23 In addition to its distribution and transmission services, NIE collects revenue from its PSO charges. The PSO charges include charges for: the net costs recovered by NIE on behalf of Power NI (PPB) in relation to legacy power purchase agreements; certain costs incurred by suppliers in procuring electricity from renewable sources; certain costs associated with the maintenance of a land bank of sites effectively reserved for the generation of electricity in Northern Ireland. In addition, the PSO charges historically included the recovery of costs incurred by NIE which are excluded from NIE's regulated transmission and distribution charges relating to several projects carried out as part of the development of non-domestic and domestic electricity retail competition in Northern Ireland.

17.24 We considered whether our financial modelling should take into account the revenues recovered by NIE from PSO charges and the costs of NIE's responsibilities under the PSO agreements referred to in NIE's Licences. NIE's PSO charges are specified in Annex 1 of NIE's Licences, and Annex 1 was not included in our terms of reference: our inquiry concerns the revenue restriction in Annex 2 to NIE's Licences. We recognized that the nature of the PSO charge control may give rise to significant over- or under-recovery from one year to the next (due to differences between forecast and out-turn costs) which would lead to adjustments to PSO charges in subsequent years. Although this may have a short-term cash-flow impact on NIE, we did not consider that the potential for over- or under-recovery would mean that an efficient licence holder would as a result be unable to finance its activities or that it had implications for our determination of the restriction on NIE's revenue from transmission and distribution charges.

17.25 Accordingly, we decided that the relevant activities should be restricted to the RP5 price-controlled activities, and in particular, for the reasons set out in paragraph 17.24, not also cover PSO activities. We therefore excluded from our review the PSO agreements and the costs and revenues attributable to any associated PSO charges over the RP5 period. We also excluded any over- or under-recovery on PSO revenues by NIE at either 1 April 2012 or forecast at 1 October 2014 from our analysis.

17.26 As mentioned in paragraph 19.21, the UR included within its financial model all of the un-depreciated capital costs incurred by NIE in projects linked to the development of retail competition (market opening) from 1 April 2012 for the purposes of working out the level of the cost allowances in relation to the distribution business. These costs had been previously recovered through PSO charges whereas the related opex elements had been recovered, and would continue to be recovered, through distribution charges. The inclusion of these un-depreciated capital costs therefore reflected the UR's new policy that all expenditure in this area, be it opex or capex in nature, should in future (ie from 1 April 2012) be recovered through distribution charges.

Opening financial position (cash, debt and gearing)

17.27 As explained in paragraph 17.16, we used NIE's actual financial position as our starting point. The key metric here is NIE's gearing which is measured as its net debt (gross debt minus any cash balances) at any one point in time as a percentage of its RAB at the same point in time. We did not find it necessary to consider alternative starting levels of net debt. A lower level of starting net debt would tend to imply higher prices due to a higher corporation tax allowance, while a higher level of starting net debt would tend to worsen the efficient licence holder's financial ratios, making it more difficult to retain an investment-grade credit rating. The initial results of our subsequent modelling are described in paragraphs 17.74 to 17.76 below.

17.28 The model as provided by the UR reflected the values on the balance sheet of NIE as at 31 March 2012 (as audited for its Annual Report). These values reflected gross debt of £599.3 million and a cash balance of £51.4 million, giving a figure for net debt of £547.9 million.[12] However, the UR had made an adjustment to net debt in order to generate an opening gearing of 50 per cent. We unwound this adjustment.

17.29 As explained in paragraphs 17.42 to 17.43, we increased the cash balance by £2.5 million to take account of the firm's under-recovery of RP4 transmission and distribution revenues as at 1 April 2012 to reflect the cash balance the efficient licence holder would have had, had it been able to forecast the level of maximum regulated revenues for RP4 accurately in advance. This translated into a value of 46 per cent for gearing as at 1 April 2012 measured on the basis set out in paragraph 17.50.

Efficiency

17.30 We considered that the licence holder, with the allowances and WACC that we determined and subject to addressing any issues arising from the timing of cash flows, should be able to finance the RP5 price-controlled activities if it is efficient. In the preceding sections of this determination, we set out our findings regarding the levels of the capex and opex allowances and WACC that we find necessary for a

[12] See NIE Limited's Annual Report and Accounts 31 March 2012, p43, note 20.

licence holder to carry out the price-controlled functions during RP5. We set most of these allowances, using benchmarked data, at the level of costs which in our view an efficient firm would incur, and have therefore used these values in our modelling. We therefore made no further adjustments to model efficient costs.

Investment in D5 capital expenditure

17.31 The capex allowances in the model in the first instance reflect a £55 million funding allowance in 2009/10 prices for expenditure to increase the capacity/capability of the transmission system, including, for example, investment that might be required to accommodate new renewable generation. This £55 million reflects NIE's forecast of £97 million largely covering the period April 2015 to September 2017 on a direct cost basis minus the £42 million for the North–South interconnector project. As a sensitivity analysis we also tested for the full £97 million of NIE's forecast as well as for a lower figure of £30 million (in the event that not all of the projects are undertaken), all in 2009/10 prices (see paragraph 17.107).

Pension deficit

17.32 When setting NIE's allowances for its historic pension deficit repair costs,[13] we used as our starting point the level of payments that NIE is expected to make to the scheme during RP5 to help extinguish its actual pension deficit. These payments are forecast to continue until March 2022 (see paragraph 12.36), which is shorter (by five years) than the notional 15-year period (ending March 2027) which we used to profile deficit repair allowances in our provisional determination. Using this shorter deficit repair period results in a higher historic pension deficit repair allowance for each period in RP5 (see paragraph 12.84*(a)*).

17.33 For the reasons set out in paragraphs 12.71 to 12.80, we disallowed 30 per cent of the liabilities associated with ERDCs when determining the level of pension deficit repair allowances. As stated in paragraphs 12.71 to 12.77, we considered that it is for NIE's shareholders, rather than consumers, to shoulder the burden of this 30 per cent disallowance, and this decision was reflected in the level of the allowances we set for historic deficit repair costs over RP5.

17.34 To maintain internal consistency with the basis of setting these allowances,[14] we used the value of these allowances as the measure of the efficient licence holder's pension deficit cash outflows in our modelling. To do otherwise would be inconsistent with our view that the adverse consequences associated with the 30 per cent dis-allowance is specifically for NIE's shareholders to address, rather than something to be taken into account when assessing the ability of the efficient licence holder to finance the RP5 price control.

17.35 However, we recognize that ERDCs will adversely affect NIE's cash flows as NIE's expected payments on this account will be £3.9 million per year (in 2009/10 prices) higher than our allowances. We have considered this effect as a sensitivity later (see paragraph 17.107).

[13] Pension deficit repair cost allowances have been made on the basis of expected payments to the pension scheme rather than on the basis of costs determined on an accruals accounting basis.
[14] See paragraph 17.8 for where we first articulate this principle.

The rate of interest payable on (embedded) debt

17.36 As set out in paragraphs 13.8 and 13.9, when determining the allowed rate of return for NIE we assumed that part of its funding would be provided by debt finance. We had a choice of estimating the cost of debt at the firm's historically efficiently incurred (nominal) rates of interest or use the cost that we would expect the firm to incur efficiently should it seek fresh debt funding now. Our determination of the efficient level of the cost of debt[15] was informed by the levels of interest payable on NIE's historically incurred debt because there was no evidence to suggest that this debt had either been inefficiently incurred at the time it had been taken out or that restructuring this debt now would be financially sensible.[16]

17.37 In order to maintain consistency with our determination for the cost of debt, the model assumes that rate of interest payable on net debt is at a single nominal rate of 6.45 per cent per year. This 6.45 per cent per year has been derived from the real cost of debt of 3.1 per cent per year (see paragraph 13.80) and the expected inflation rate of 3.25 per cent per year (see paragraph 13.23), which in turn is based on an OBR RPI inflation forecast of December 2013.[17]

Dividend payout policy

17.38 Equity holders earn a return on their equity investment equal to the cost of equity in the WACC. Equity holders earn this return from receiving dividends and from the gain in the value of equity (RAB-debt); the value of equity increases through the retention of profits within the business and through the indexation of the RAB by the RPI.

17.39 For the purpose of modelling financial ratios, it was necessary to make an assumption about dividends to be paid out during RP5. We considered that the efficient licence holder would in the first instance seek to implement a dividend payout policy which paid a regular return to its equity holders consistent with the range for the post-tax cost of equity reflected in our WACC determination, namely 3.4 to 5.0 per cent per year.[18] For this purpose, we assumed, consistent with our choice of the upper bound of the plausible range for WACC,[19] that the cost of equity would be 5.0 per cent per year. We reflected this level of dividend payout as our initial assumption in the model. This equated to the efficient licence holder paying its equity holders annual dividends worth 2.75 per cent per year of its RAB.[20]

17.40 The return to equity of 5.0 per cent per year is expressed in real terms. An implicit assumption of the financial model is that shareholders are compensated for the erosion in the real value of their investment by inflation by the growth in the capital value of their shares. This growth would reflect the increase in the value of the RAB following its indexation by RPI at the end of each period.

17.41 A wide range of assumptions could be consistent with efficient operation of the licence. As noted in paragraph 17.39 we assumed dividends equal to 2.75 per cent of the RAB in our initial modelling. In subsequent modelling, this was revised (see para-

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[15] See paragraphs 13.39–13.80.
[16] See paragraphs 13.64–13.69.
[17] 6.45% = 1.031 x 1.0325 – 1 expressed as a percentage.
[18] See Table 13.10.
[19] See paragraphs 13.185–13.189.
[20] This percentage reflects the assumptions built into our estimate of NIE's WACC, which in itself reflects an assumption that 45 per cent of NIE's funding is provided by debt holders and 55 per cent by equity holders. Thus NIE's equity holders could be seen to have funded 55 per cent of the RAB and therefore in the long run would expect to earn a return on that investment in the form of dividends (or otherwise) at their cost of equity. A combination of the 55 per cent equity funding ratio and the post-tax real cost of equity (5.0 per cent) implies a dividend rate of 2.75 per cent of the RAB.

graph 17.105). We note that in the last three financial years NIE Limited has not paid out any dividends to its equity holders.

Under-recovery of RP4 revenues as at 1 April 2012

17.42 As tariffs are set in advance and maximum regulated revenues are to some extent determined only after the event (for example, to take account of out-turn volumes), there is inevitably a degree of over- or under-recovery of maximum regulated revenues relating to prior periods at the beginning of the following price control period. We call these forecasting errors.

17.43 We saw no reason why there should be any bias in the long run towards over- or under-recovery. Accordingly, we modelled cash flows as if the efficient licence holder made no forecasting errors. This approach therefore involved making good the negative impact on NIE Limited's actual cash balance as at 1 April 2012 of the £2.5 million revenue under-recovery position as at 1 April 2012.

Over-recovery of RP5 revenues since 1 April 2012

17.44 In this determination we set the level of maximum regulated revenues NIE will be able to raise from its customers over the period 1 April 2012 to 30 September 2014. However, NIE will only be able to set tariffs on the basis of this determination from 1 October 2014, the start of the tariff year following the publication of this final determination. Using the calculation of maximum regulated revenues based on this final determination, we estimate that since 1 April 2012 NIE may have billed/will bill more revenue than the maximum regulated revenue that we have determined for that period (see paragraph 19.31).

17.45 We considered that this difference, albeit a temporary timing difference, might be relevant to our analysis as it could directly influence the level of billed revenues in the final three years of RP5, ie from 1 October 2014. In contrast to underlying revenues, billed revenues correspond to the revenues which would be recognized in the efficient licence holder's accounts for the same period. However, as set out in paragraph 19.41, we found that any overpayment should be refunded to NIE's customers. As a result we assume that the efficient licence holder would not have overcharged its customers over this period.

Summary of differences between NIE Limited and the efficient licence holder

17.46 In summary, the efficient licence holder that we modelled differed from NIE in that it:

(a) is a stand-alone business undertaking no other activities—it excludes NIE's PSO activities (paragraphs 17.21 to 17.26);

(b) efficiently provides the price-controlled services (paragraph 17.30);

(c) makes historic pension deficit repair contributions which are equal to its pension deficit repair allowance—it does not fund that element of the ERDC liability which we determined is for NIE's shareholders to finance (paragraphs 17.32 to 17.35); and

(d) has not historically overcharged or undercharged its customers in respect of transmission and distribution charges (paragraphs 17.42 to 17.45).

The targets for the financial ratios generated by the model

17.47 The following subsection discusses in turn:

(a) the financial ratios calculated by the UR's model (paragraphs 17.48 to 17.51); and

(b) target financial ratios (paragraphs 17.52 to 17.73).

The financial ratios calculated by the UR's model

17.48 In its final determination, the UR's financeability analysis relied primarily on the post-maintenance interest cover ratio (PMICR). The 'post maintenance' refers to 'profits after the maintenance of the capital stock', which in this case is measured by regulatory depreciation. Put simply, this ratio indicates the extent to which profits measured on this particular basis are available to service the interest payable to debt holders.

17.49 In the model, PMICR during RP5 is defined as:[21]

> (maximum regulated revenues – opex allowances – forecast regulatory depreciation – pension deficit repair allowances - forecast corporation tax paid)/(forecast net interest payable), that is (adjusted forecast return)/ (forecast net interest payable)

Where:

- 'maximum regulated revenues' are the maximum revenues NIE is allowed to charge in relation to a period plus any 'k' correction factor. Maximum revenues reflect the sum of a number of individually specified or calculated allowances.

- 'opex allowances' are the values for those allowances which are designed to cover operating costs.

- 'forecast regulatory depreciation'[22] is the amount of regulatory depreciation estimated by the model based on the value of the RAB as at 1 April 2012, the RP5 capex allowances, the depreciation rate and RPI inflation assumptions in the model;

- 'pension deficit repair allowances' are as explained in paragraphs 17.32 to 17.35;[23] and

- 'forecast net interest payable' relates to the net of projected interest payable on debt[24] and interest receivable on cash balances.

17.50 The UR's financial model calculates the following financial ratios besides PMICR:[25]

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[21] We used term 'forecast' to denote those values generated by the model. These forecast values are to be contrasted with the values for the allowances, which are inputs into the model. We use the term 'maximum regulated revenues', rather than 'forecast maximum regulated revenues', to maintain consistency with the terminology used for the same concept as set out in NIE's licence.
[22] As forecast regulatory depreciation is calculated net of capital contributions, there is no need to take separate account of forecast receipts from this source.
[23] The opex and capex allowances include amounts to recover 'normal' pension costs.
[24] Interest payable is measured before the capitalization of interest.

- funds from operations (FFO)/forecast net interest payable;
- FFO/forecast net debt; and
- gearing.

Where:

- FFO is maximum regulated revenues – opex allowances covering operating costs – pension deficit repair allowances – forecast corporation tax paid;
- 'forecast net interest payable' is defined as in the previous paragraph;
- 'forecast net debt' equals the forecast net balance on financial assets, primarily cash minus debt; and
- 'gearing' is defined as forecast net debt / forecast value of the RAB.

17.51 The inputs into the ratio calculations for each period, and therefore the ratios themselves, are computed on a nominal basis, ie the inputs for each period are expressed in the current prices of that period.

Target financial ratios

17.52 In this subsection, we consider the approximate levels of financial ratios consistent with retaining investment-grade status. We first explain what factors are generally taken into account in setting investment credit ratings before discussing the values for financial ratios that rating agencies associated with particular credit ratings. We then set our view of the relevance of financial ratio targets to our determination.

Investment credit ratings

17.53 We note that NIE's Licence condition is to maintain an investment-grade credit rating, and that no specific target rating within investment grade is set. This provides flexibility for the licence holder to decide on the appropriate credit rating to target in order to finance its activities efficiently. We saw no reason to be more prescriptive in this regard. However, we note that the typical distribution of ratings in the utilities sector may provide an indication of the appropriate credit rating to adopt.

17.54 In the Bristol Water inquiry, the CC targeted a Baa1/BBB+ rating.[26] In the Airports inquiries, the CC targeted a BBB+ rating for Heathrow and Gatwick and an A– rating for Stansted.[27]

17.55 Table 17.1 sets out comparative investment-grade credit ratings for Moody's and Fitch and S&P.

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[25] Precise definitions may vary between rating agencies, in particular whether the numerator or denominators in the ratios are computed before or after tax or before or after interest. We set out the definition of the ratios as reflected in the UR's model.
[26] *Bristol Water plc* (2010).
[27] *BAA Ltd* (2007 report on Heathrow and Gatwick, op cit) and *Stansted Airport Limited*, *Q5 price control review*, CC, presented to the CAA on 23 October 2008.

TABLE 17.1 **Comparative investment-grade credit ratings**

Moody's	*Fitch/S&P*	*Description*
Aaa	AAA	
Aa1	AA+	
Aa2	AA	High grade
Aa3	AA–	
A1	A+	
A2	A	Upper medium grade
A3	A–	
Baa1	BBB+	
Baa2	BBB	Lower medium grade
Baa3	BBB–	

Source: Moody's Rating Symbols & Definitions; S&P Credit Ratings Definitions & FAQs; Fitch Definitions of Ratings and Other Forms of Opinion.

Rating agency methodology

17.56 This section provides relevant background on rating methodologies.

- *Moody's*

17.57 Moody's publishes a number of credit rating methodologies for the utility sector, including for regulated electric and gas networks.[28] This sets out the relative weight it attaches to key factors, which are:

- Regulatory Environment & Asset Ownership Model (40 per cent weight);
- Efficiency and Execution Risk (10 per cent weight);
- Stability of Business Model & Financial Structure (10 per cent weight); and
- key credit metrics (40 per cent weight).

17.58 Moody's objective, according to the regulated networks methodology, is for users of the methodology to be able to estimate a company's rating within two alphanumeric notches. The rating indicated by the methodology is based on the combination of the four factors, ie companies that score very highly on regulatory environment and asset ownership model (underpinning a low business risk profile) can sustain weaker financial metrics and still maintain a solid investment-grade rating. The credit ratios that Moody's publishes in relation to scoring under the methodology are generally expressed in terms of a three-year historical average. In setting credit ratings, Moody's examined forward estimates for credit ratios based on management plans and a range of sensitivities. The rating agency does not publish detailed forecasts or estimates.

17.59 Moody's has a published rating for NIE's parent, ESB, but has not published a rating for NIE on a stand-alone basis. ESB is rated using Moody's EMEA regulated network methodology. ESB's rating had fallen from Baa1, when the rating was first published in January 2011, to Baa3 in July 2011. The rating was downgraded by two notches to Baa3 on 14 July 2011 following a review announced on 18 April 2011 and a down-grade of the Republic of Ireland's credit rating to Ba1 from Baa3 on 12 July 2011. According to the press release announcing the rating action, ESB's ratings 'are constrained by that of Ireland due to the company's inability to disconnect itself from

[28] *Moody's Global Infrastructure Finance: Regulated Electric and Gas Networks*, August 2009.

local economic and market circumstances'. Moody's noted that ESB had very strong ratios for the Baa3 category and that the indicated rating under the agency's methodology grid was A3. The outlook for the Irish sovereign debt had stabilized recently.

17.60 Moody's ratio guidance for UK Regulated Water and Energy Network Utilities is set out in Table 17.2. Moody's notes that the ratio guidance applies to stand-alone regulated businesses funded on a corporate basis, and that actual ratings may be based on the financial profile of the group or reflect the benefits of structural enhancements. Smaller companies would be expected to exhibit stronger adjusted interest cover ratios for an equivalent gearing ratio.

TABLE 17.2 **Target ratios and indicative credit ratings—UK Regulated Water and Energy***

Moody's credit rating	*Adjusted interest cover†*	*Gearing (net debt / RCV) %*	*FFO / net debt* %*	*RCF / capex‡ %*
A1	2.5–3.5	40–50		
A2	1.8–2.5	50–60	12–20	1.5–2.5x
A3	1.6–1.8	60–68		
Baa1	1.4–1.6	68–75	8–12	1.0–1.5x
Baa2	1.2–1.4	75–85		

Source: CC based on Exhibit 4 of 'UK Water Sector: Speed of Money cannot address Potential Financeability Concerns', 16 May 2013.

*FFO / net debt and RCF / capex ratios are taken from Moody's Global Infrastructure Finance methodology and do not specifically relate to UK utility companies. They are average ratios for A and Baa rating bands.
†Adjusted interest cover = (FFO + (net interest – non-cash interest) – capital charges) / (net interest – non-cash interest) where FFO = funds from operations (cash flows from operations less working capital movements plus net interest expense).
(FFO – dividends paid/capex.
Notes:
1. RCV = regulatory capital value.
2. RCF = Retained Cash Flow. It represents a measure of recurring cash flow from operations after dividends but before working capital changes, capital expenditures or other investing and financing activities.

- *Fitch*

17.61 Fitch published a long-term Issuer Default Rating (IDR) and a senior unsecured rating for NIE. The current ratings are:

- IDR: BBB+/Stable Outlook (on a stand-alone basis the IDR would be BBB+/Rating Watch Negative, but the public rating assumes support from NIE's parent ESB, rated at IDR of BBB+/Stable Outlook).

- Senior unsecured: A-/Rating Watch Negative.

17.62 Fitch said that it applied its rating guidelines for UK DNOs to NIE, shown in Table 17.3. In doing so, it recognized that the transmission activity of NIE was benign in terms of the business risk profile of NIE in relation to UK DNOs but scored regulatory risk slightly higher.

TABLE 17.3 **Indicative ratings guidelines for UK DNOs**

IDR	*Senior unsecured*	*Adjusted PMICR*	*Debt/RCV %*
A–	A	<1.9	<60
BBB+	A–	1.6–1.9	60–75
BBB	BBB+	1.4–1.6	75–80
BBB–	BBB	1.3–1.4	85–90

Source: Fitch.

17.63 Fitch said that it focused on average metrics for the regulatory period. It said that ratings were not restricted to the application of these two ratios. Other important factors considered when deciding on the IDR were cash flow generation, operational and regulatory performance, under- and overperformance of opex and capex, liquidity and capital structure, dividend policy, and parent support if appropriate. Fitch generally focused on the five-year outlook but for regulated utilities there was limited earnings visibility beyond the end of the price control. For NIE this meant looking at ratios until September 2017.

17.64 In terms of NIE's ratios, Fitch noted that there was an unusually large divergence in the rating indications from gearing (A–) and PMICR (BBB–). Fitch said that it considered that this was largely a result of the UR setting a WACC similar to that of Ofgem whereas the incentives offered to NIE under the UR regulatory framework were little in comparison with those under the RIIO framework, and NIE's cash cost of embedded debt was relatively high compared with Ofgem-regulated comparators. As a result, modelled cash flows and interest cover were lower for NIE.

17.65 The NIE rating of BBB+/stable was linked to parent support from ESB. Fitch told us that the outlook/rating review depended on the results of our redetermination and NIE's subsequent budget review, and that it was looking for assurance that engineering assumptions were realistic to resolve the rating watch.

17.66 The UR's model also generated an FFO / interest cover ratio. We sourced our target for this credit metric from a paper by Fitch published in August 2012.[29] For this ratio the paper quoted a midpoint target of 3.5 for a rating of BBB.

- *Standard & Poor's Ratings Services*

17.67 On February 13, 2013, Standard & Poor's Ratings Services (S&P) revised to stable from negative the outlook on its 'BBB+/A-2' long- and short-term corporate credit and 'BBB+' senior unsecured debt ratings on NIE. S&P said that the ratings on NIE reflected those of its 100 per cent parent, ESB. S&P also said:

> The ratings on NIE are also underpinned by its solid position as the sole electricity transmission asset owner and the electricity distribution network owner and operator in Northern Ireland. On 23rd October 2012 the UR published its final determination for the five year price control period Jan 1 2013 – Sept 30, 2017. We view the price control as challenging for NIE and this introduces a level of uncertainty around the regulatory framework in Northern Ireland that we do not generally anticipate when assessing the business risk profile of a regulated utility.

Views of the parties on target financial ratios

17.68 The UR focused on the PMICR. It referred to a threshold value of 1.4 for that ratio quoted by Fitch (with reference to a BBB+ rating for an electricity distribution company). The UR said: 'We regard 1.4 as an acceptable level but regard 1.5 to be a more desirable benchmark'.[30]

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[29] Rating EMEA (= Europe, Middle East and Asia) Regulated Network Utilities, Sector Credit Factors.
[30] UR RP5 final determination, paragraph 14.21.

17.69 The UR agreed with our provisional determination that the target credit rating should be Baa1/BBB+.[31]

17.70 NIE stated that the target PMICR should 1.5[32] or 1.6.

Our view of target financial ratios

17.71 We noted that NIE's relatively low gearing ratio indicates that it can support a Baa1/BBB+ rating ('solid' investment grade) with a lower interest cover ratio than would otherwise be the case. We recognized that this suggested a focus on PMICR.

17.72 We also had regard to target values for the broader set of credit ratios set out in Tables 17.2 and 17.3 as these largely form the outputs from the financial model that we have used. We note from our discussions with credit ratings agencies that the value of particular ratios forms an important part of a broader assessment to assign credit ratings. A broad range of other factors would form part of the overall ratings assessment.

17.73 In Table 17.4 below we set out our view of the target levels for the individual credit risk financial ratios that should, taken together, form part of our assessment of whether the efficient licence holder would be able to finance the RP5 price control. Our assessment of financeability considers the average of these credit ratios over the remaining period of the price control and does not focus on one specific credit ratio more than another. We also note that the credit ratings agencies assessments look at factors beyond these credit ratios, including for example the ownership of NIE Limited by ESB and the whole of the regulatory determination (see paragraphs 17.63 to 17.65).

TABLE 17.4 **Our view of appropriate targets for the efficient licence holder for forecast credit risk financial ratios**

Forecast financial ratio	*Defined in paragraph*	*Target based on*	*Our target ratio averaged across the period*
PMICR	17.49	Tables 17.2 & 17.3	1.4 or more
FFO / net interest payable	17.50	Paragraph 17.66	3.5 or more
FFO / net debt	17.50	Table 17.2	10% or more
Gearing	17.50	Tables 17.2 & 17.3	70% or less

Source: CC analysis.

The financial ratios initially modelled for the efficient licence holder

17.74 The initial modelling generated net borrowing requirements in order to deliver the RP5 price control which were in excess of the funds available to the efficient licence holder at 1 April 2012, as set out in Table 17.5 below.

[31] UR Response to Provisional Determination, paragraph 204.
[32] NIE's response to the provisional decision. The graph at Table 6.2 is labelled with 'NIE and UR consensus target 1.5x'.

TABLE 17.5 **Levels of additional debt financing required for the efficient licence holder to finance RP5 price control plus its opening and closing levels of net debt (£million, nominal prices)**

Initial net debt	545
2012/13	23
2013/14	29
2014/15	78
2015/16	92
2016/17	98
2017 (6 months to Sep 2014)	47
Closing net debt	913

Source: CC analysis based on modified UR financial model.

17.75 The forecast financial ratios generated by the model taking into account the extra interest that would need to be paid on the increased borrowing (as set out in Table 17.5) for each period of RP5 are as set out below. In this table we also calculate average coverage ratios covering the remaining period of the RP5 price control).

TABLE 17.6 **Forecast financial ratios for the efficient licence holder over RP5 price control and coverage ratios averaged over the period 1 April 2014 to 30 September 2017**

	Dividends expressed as		*Gearing*	*Coverage ratios*		
					Interest coverage ratios	
	% of equity holders' share of RAB	*£m*	*Net debt / RAB*	*FFO / net debt*	*FFO / interest payable*	*PMICR*
As at 1 April 2012			0.46			
2012/13	5.1	33	0.47	0.22	3.2	1.2
2013/14	5.2	34	0.48	0.22	3.5	1.3
2014/15	5.4	36	0.50	0.19	3.2	1.2
2015/16	5.6	38	0.53	0.18	3.0	1.2
2016/17	5.9	42	0.55	0.18	2.9	1.2
6 months to 30 Sep 2017	6.1	22	0.56	0.18	2.8	1.2
5½ year total		204				
3½ year average				0.18	3.0	1.2
Target ratios			*0.7 or less*	*0.10 or more*	*3.5 or more*	*1.4 or more*

Source: CC analysis based on modified UR financial model.

Note: The dividends % shown in the first column of this table is derived using actual gearing as per column 3 whereas the £m shown in column 2 is the result of applying the cost of equity (5.0 per cent) to the proportion of the RAB that equity holders are assumed to own based on the gearing assumption of 45 per cent used in our WACC calculations.

17.76 The results above show that for the three and a half years from 2014/15 onwards (ie those future periods that are influenced by our determination), two credit ratios are clearly better than our target levels: gearing is below the 70 per cent target and FFO / net debt is above the 10 per cent target throughout. FFO / interest payable is below our target of 3.5. PMICR remains at a level of around 1.2 throughout, 0.2 below our target of 1.4.

17.77 These results indicated that, without taking actions beyond that reflected in our initial modelling, the efficient licence holder might not be able to maintain the investment-grade credit rating on its debt.

Views of the parties

17.78 In the following subsection we set out parties' and our own views on the results of the initial financial modelling. Parties' comments relate to either the ratios generated by the model used to support the UR's final determination or the ratios we quoted in our provisional determination, which broadly raised similar issues regarding the values for key ratios, in particular that for PCIMR, that we identified from our initial modelling.

The UR's views

17.79 On the basis that the forecast ratios generated using the values contained within its final determination were below target, the UR proposed to allow additional revenues to NIE during the then proposed RP5 period. The UR described its proposed increase in allowed revenues during its proposed RP5 period as an 'NPV neutral fix'. It did not describe any mechanism by which a deduction of an amount of revenue equivalent (in NPV terms) as the increase during RP5 would be implemented.[33]

17.80 The UR told us:

> We would like to emphasise once again that it is very important for the CC to treat cost of capital and financeability as two separate work-streams. As we have said previously, we would be very concerned if the CC were to feel a need to revisit and adjust its allowed return when it runs its financial model, irrespective of the financial ratios that it observes in its initial model runs.
>
> For completeness, the available fixes for weak interest cover include (a) dividend retention and equity issuance[34], (b) issuance of index-linked debt, and (c) NPV-neutral revenue advancement. A backfitted, higher cost of capital is not a suitable fix because it hands shareholders additional value at the expense of customers, when the root cause of weak interest cover is not an inadequate total return but rather the scale of NIE T&D's capital programme and the regulatory convention of allowing only part of the nominal cost of capital (ie the RPI-stripped real cost of capital) into the annual price control calculation.

17.81 The UR referred to a report published by Fitch on 28 February 2007.[35] The UR said that Fitch had specifically mentioned that the RAB should not be affected in order to address a financeability problem, and that Fitch would see through any regulatory adjustments. For this reason, it appeared to us that the UR had not, as explained in paragraph 17.79, made a deduction to the RAB for its NPV neutral fix in the financial model accompanying its final determination.

17.82 In addition to the limitations identified by Fitch, the UR said that the PMICR was particularly sensitive to gearing and interest costs; credit metric thresholds were calibrated at a time when inflation rates were much lower than were forecast in the relevant quinquennium, therefore the desired thresholds may be somewhat out of date; and that the credit ratings were assessed on a wide range of criteria, and typically a weighting of only about one-third was given to credit metrics.[36]

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[33] UR RP5 final determination, paragraph 14.28.
[34] See paragraphs 17.100–17.105 for our view.
[35] 'Post-Maintenance Interest Coverage Ratios for UK Regulated Utilities'.
[36] ibid.

17.83 The UR also pointed out that in our provisional determination we had modelled values for the payment of pension deficit repair contributions that did not reflect our proposed decision to disallow from maximum regulated revenues a certain proportion of the overall payment that related to early retirees.[37] (See paragraphs 17.32 to 17.35 for our view.)

17.84 The UR also argued NIE had extracted excessive dividends totalling nearly £300 million over the period 2006/07 to 2009/10, which far exceeded the dividend yield one would normally expect from a regulated company. It pointed to the 2010 Bristol Water inquiry where the CC had simulated the winding back of the payment of dividends beyond the 5 per cent yield that the CC had considered at the time to be a normal rate. The UR argued that once this had been done, interest coverage ratios would look much healthier. The UR therefore urged us to look to solutions that involved NIE's shareholders either not receiving dividends and/or injecting fresh equity.[38] (See paragraphs 17.100 to 17.104 for our view.)

NIE's views

17.85 NIE told us that its business would not have been financeable under the UR's proposals.[39] NIE said that the expenditure allowed for by the UR was insufficient to operate the business, and therefore NIE could not in fact achieve the financial performance indicated by the UR's model.

17.86 In its response to the provisional determination, NIE explained that part of the reason for weak financial ratios was the inadequate allowances and the cost of capital that we had provisionally determined. (We addressed the adequacy of individual allowances in previous sections of this report.) NIE pointed out that the payment of all of its deficit repair contributions would need to be taken into account when assessing financeability.[40] (See paragraphs 17.32 to 17.35 for our view.)

17.87 NIE pointed to the weak PMICR ratios consistent with our provisional determination but stated that the solutions we had discussed in our provisional determination, namely reducing dividends, raising new equity finance, obtaining finance from other group companies or issuing index-linked debt, were either not workable or otherwise inappropriate. In particular, it argued that any company looking to the public capital markets for equity share capital needed to be able to offer the prospect of a fair return on its equity in order to attract new equity, and that prospect would be severely impaired by a price control settlement which (on the CC's own admission) would be likely to entail a curtailment of dividend payments.[41] (See paragraphs 17.102 to 17.103 for our view.)

17.88 Subsequently, NIE said that, if weak credit metrics were observed, this provided evidence that important elements of the price control were in need of revision. In NIE's view, a well calibrated price control should not give rise to the need to advance revenue or re-profile depreciation, except in highly unusual circumstances. Even then, NIE said that accelerating revenue should only be contemplated in cases where financeability concerns were likely to be temporary, rather than sustained. In its case, NIE considered that accelerating revenue would be wholly inappropriate. This was because, first, NIE presently had a modest debt burden and a well-calibrated price control would not be expected to give rise to financeability concerns for a utility with

[37] UR response to final determination, paragraph 204 c).
[38] ibid, paragraphs 207–210.
[39] NIE Statement of Case, Chapter 17.
[40] NIE response to final determination, Chapter 6, paragraph 1.2.
[41] ibid, Chapter 6, paragraphs 1.13–1.15.

relatively low gearing. Second, NIE anticipated that RP5 levels of capex would be sustained into RP6 and beyond, implying that a temporary fix would simply store up (and probably exacerbate) financeability concerns to be addressed at RP6.

Other parties' views

17.89 Phoenix argued that it was not appropriate to assume dividends should be reduced, were a financeability problem to be identified. It stated that we should determine whether a company was financeable given the returns required for debt and equity.[42] (See paragraph 17.102 for our view.)

17.90 Hastings also queried the adoption of the application of a formula to the value of WACC within the model, describing the net result as giving an accounting rate of return.[43] Hastings argued that it was wrong to assume that a firm would be able to continuously earn its WACC because capital was not immediately and always reinvested in the business. (See paragraph 17.13 for our view.)

Our view on the drivers of the financial ratios

17.91 The efficient licence holder will generate profits during the RP5 price control on its capital investments in two ways. First, the efficient licence holder will realize profits in cash based on a 'real' return on its RAB during the RP5 price control (determined to be 4.1 per cent per year—see paragraph 13.189). By 'real' we mean that the return has been measured in such a way that it excludes that element of the return which compensates the investor for the impact of changes in the purchasing power of money over the period on the value of their investment at the beginning of the period.

17.92 Second, the efficient licence holder will earn profits through the indexation of its RAB by RPI at the end of each year (forecast to be 3.25 per cent per year for the purposes of our investigation[44]). Indexation of the RAB leads to higher regulatory depreciation charges and return on the firm's assets over the period until these assets are fully depreciated. Higher regulatory depreciation charges and return increase the level of maximum regulated revenues in subsequent price control periods on a 1:1 basis. If most of a firm's assets are depreciated over 40 years, this means the growth in the value of the RAB following indexation (which serves to compensate investors for the impact over time of the change in the purchasing power of money on the value of their investment) is returned to investors in the form of cash (through the mechanism of enhanced allowances for depreciation and return on the RAB) over the 40-year period following an asset's addition to the RAB. Therefore the indexation of the RAB initially awards the efficient licence holder 'unrealized' profits. These 'unrealized' profits are then subsequently converted into 'realized' profits (ie turned into cash) in large part after the end of the period with which we are concerned. Adding the realized and the unrealized element of profits together, the efficient licence holder earns a full nominal[45] return of its capital investments during RP5.

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[42] Phoenix response to the final determination, (unnumbered) pp3–4.
[43] The model applies a formula of WACC/(1+WACC)^0.5 to calculate a value for the allowance for return on RAB balances, rather than simply applying the WACC to RAB balances.
[44] On 19 March 2014 the OBR released an updated forecast that varied only slightly from the December 2013 forecast, and it was not practicable for us to use this revised forecast.
[45] A full nominal return is one that compensates investors for the (expected) erosion in the general purchasing power of the value of their investments by providing that compensation in the period during which that erosion takes place, in this case by indexing the value of the RAB. The erosion in the general purchasing power of purchased items and services is often described by the term 'general inflation' or simply 'inflation'.

17.93 As these capital investments are substantial and full compensation for the effects of inflation are deferred over a period of up to 40 years, this can lead to a mismatch between the levels of cash that are generated from the firm's realized profits on its investments (ie the 4.1 per cent per year WACC return specified in 'real' terms) and the levels of cash outflows necessary to service interest payable during the RP5 price control period (ie the 6.45 per cent per year rate of interest payable specified in nominal terms).

17.94 The efficient licence holder therefore has to pay interest on debt at a nominal rate (real rate plus inflation) but earns only a real return on its RAB in cash in the first instance. This means that maintaining financial ratios consistent with an investment-grade credit rating will tend to require lower gearing than would otherwise be the case (ie if debt was index-linked or inflation was lower).

17.95 This phenomenon is sometimes described as a 'real/nominal mismatch'. This mis-match is exacerbated by the fact that forecast inflation at 3.25 per cent per year is relatively high in relation to the real WACC. This means that over 40 per cent[46] of the nominal return on investment is not realized in cash terms until after the end of the current price control period.

17.96 By way of illustration, if conventional (non index-linked) debt accounts for 50 per cent of the efficient licence holder's funding, the interest payable each year on, say, £1,000 of investment will be £32.5 per year (ie £1,000 x 50 per cent x 6.5 per cent[47]). Based on a WACC of 4.1 per cent, the efficient licence holder earns profits in cash of just under £41 per year on the £1,000 investment. Based on this simple scenario the firm's PMICR ratio will be 41/32.5, ie 1.26, below our target 1.4 PMICR coverage ratio. This illustrates that, with a WACC of 4.1 per cent and interest rate of 6.5 per cent, an efficient licence holder would need to have gearing of less than 50 per cent to achieve a PMICR of 1.4.

17.97 The indexation of the RAB for inflation has been associated with RPI-X style price controls in the energy sector (and also the water and airports sectors) for at least two decades. The 'real/nominal mismatch' is therefore something that an efficient licence holder could have taken into account when deciding on the level of their borrowings.

The ability of the efficient licence holder to finance RP5

17.98 We considered carefully the points made by NIE (see paragraphs 17.85 to 17.88), in particular the argument that part of the reason for weak financial ratios was the inadequate allowances and the cost of capital that we had provisionally determined. With regard to the building blocks of our determination, we considered these fully in the previous sections of this report and in respect of the WACC, we set this at the top of our range—see paragraphs 13.187 to 13.189.

17.99 In this subsection, we consider ways to address the ability of the efficient licence holder to finance RP5. We consider:

(a) reduction of dividends or issuance of equity; and

(b) other options

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[46] Calculated as 3.5 per cent inflation over the nominal WACC of 7.48 per cent. 7.48 per cent = (1.041 x 1.325)–1) expressed as a percentage.
[47] 6.5 per cent is the rate of interest in this illustration.

Reduction of dividends or issuance of equity

17.100 The CC has encountered weak financial ratios in projections starting with companies' actual gearing, in previous CC inquiries.[48] Financial structure, including gearing, is a matter for companies to determine and in those cases we found that weak financial ratios did not persist when financial modelling was carried out at lower, but still reasonable, levels of gearing. We recognized that modelling on the basis of lower gearing involved the assumption that shareholders supply the finance in some form (ie inject equity). However, we recognized too that shareholders could expect to obtain the real cost of equity included in the WACC on these funds. Moreover we noted that, if shareholders were able to withdraw large sums in periods with strong cash flow, it was reasonable they should also be willing to supply finance in periods of weaker cash flow. We considered that shareholders had an incentive to supply finance as long as the overall rate of return is in line with the WACC, and that the regulatory regime has appropriate provision for situations where shareholders are unable to, or refuse to, supply finance.[49]

17.101 These considerations remain relevant in the present case. The present case differs from Bristol Water (2010) and BAA (2007) in that the starting level of gearing is lower, at 46 per cent.

17.102 We noted that a high level of dividend had been paid by NIE over the period 2006/07 to 2009/10[50] (although no dividends had been paid since then). We did not consider that the owners of the efficient licence holder would have any right to a specific level of dividends at any particular point in time. The level of dividends in fact paid is a matter for NIE, and it is not sensible in financial modelling to include payment of dividends if it leads to weak financial ratios. It is important to bear in mind that equity holders are remunerated either through dividends or through capital gains on the value of their equity (for example, via retained earnings, the indexation of the RAB by the RPI index and/or the real reduction in the value of non-index-linked debt) or by a combination of these mechanisms.

17.103 We therefore disagreed with NIE's argument, as set out in paragraph 17.87, that any company looking to the public capital markets for equity share capital needed to offer the prospect of a return on its equity that does not curtail dividend payments.

17.104 In order to address weak financial ratios, an alternative approach to curtailing the level of dividends paid to equity holders would be to issue fresh equity. While raising equity is a distinct option from curtailing dividends, in terms of who is making the decision (management of the firm or shareholders) and its mechanics, the options in financial modelling terms are in principle equivalent. The forsaking of expected dividends is conceptually the same as injecting fresh capital into a business. As a result we did not consider raising fresh equity as a separate option from curtailing dividends.

17.105 In our financial modelling, we therefore considered what levels of dividend payments over RP5 would be consistent with the efficient licence holder achieving a PMICR of 1.4 averaged over the remaining period of the price control. In relation to financial structure, our view is that it is reasonable to base modelling on the level of gearing

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[48] Relevant cases are: *Bristol Water PLC—a reference under section 12(3)(a) of the Water Industry Act 1991*, CC, October 2010; *BAA Ltd—A report on the economic regulation of the London airports companies (Heathrow Airport Ltd and Gatwick Airport Ltd*), presented by the Competition Commission to the Civil Aviation Authority 28 September 2007; *Mid Kent Water Plc—a report on the references under sections 12 and 14 of the Water Industry Act 1991*, CC, August 2000.
[49] Where shareholders refuse to supply finance for a regulated company to carry out its duties, the company would be in breach of its licence obligations.
[50] See paragraph 17.84.

assumed for the efficient licence holder at the start of the period of about 46 per cent and not assume any significant increase in equity either from existing shareholders or new shareholders. The results are shown in the following tables.

TABLE 17.7 **Levels of additional debt financing required for the efficient licence holder to finance RP5 price control plus its opening and closing levels of net debt targeting PMICR ratio of 1.4 (nominal prices)**

	£m
Initial net debt	545
2012/13	–2
2013/14	2
2014/15	48
2015/16	58
2016/17	60
2017 (6 months to Sep 2014)	26
Closing net debt	736

Source: CC analysis based on modified UR financial model.

TABLE 17.8 **Level of dividends consistent with a PMICR ratio of 1.4, forecast financial ratios and coverage ratios averaged over the period 1 April 2014 to 30 September 2017 for the efficient licence holder over RP5**

	Dividends expressed as		*Gearing*	*Coverage ratios*		
					Interest coverage ratios	
	% of equity holders' share of RAB	*£m*	*Net debt/ RAB*	*FFO/ net debt*	*FFO / interest payable*	*PMICR*
As at 1 April 2012			0.46			
2012/13	1.3	8	0.45	0.23	3.3	1.2
2013/14	1.3	9	0.43	0.24	3.7	1.4
2014/15	1.2	9	0.44	0.22	3.5	1.3
2015/16	1.3	10	0.44	0.22	3.5	1.4
2016/17	1.3	11	0.45	0.21	3.4	1.4
6 months to 30 Sep 2017	1.3	6	0.45	0.21	3.4	1.4
5½ year total		52				
3½ year average				0.21	3.4	1.4
Target ratios			*0.7 or less*	*0.10 or more*	*3.5 or more*	*1.4 or more*

Source: CC analysis based on modified UR financial model.

17.106 This analysis demonstrates that the efficient licence holder would be able to pay a modest level of dividends compared with the level of dividend payments initially modelled of 5.0 per cent per year and achieve the target PMICR of 1.4. This level of dividends totals roughly £50 million across this period calculated as the sum of the dividends expressed in current price for each period. At the same time the efficient licence holder would exceed the targets for gearing and FFO/net debt and fall fractionally short of the midpoint target for FFO/interest payable.

17.107 We also conducted sensitivity analysis on the effect on the PMICR of *(a)* the value of D5 expenditure and *(b)* the level of the pension deficit repair allowances during RP5. Using the scenario set out in Table 17.8 as our benchmark, we found that:

(a) modelling D5 expenditure at either £97 million or £30 million in 2009/10 prices instead of the £55 million modelled results in marginal changes to the average PMICR when rounded to the nearest decimal place. With £97 million D5 expenditure, the PCIMR reduces to 1.3. With £30 million, the PCIMR remains at 1.4; and

(b) taking into account the amounts of NIE's total expected payments to its pension scheme during RP5 to help address its actual deficit instead of the allowances granted, the average PMICR ratio would reduce to 1.2.

17.108 We also considered the effect on the forecast credit ratios of implementing a tiered interest rate structure in the modelling. This tiered interest rate structure would reflect one (higher[51]) rate of interest payable on the embedded debt of the efficient licence holder and another (lower[52]) interest payable on any new debt the licence holder required, rather than the single cost of debt (6.45 per cent per year) reflected in the modelling underpinning the outputs shown in Table 17.8. However, we found that we forecast marginally reduced financial ratios compared with before, ie PMICR ratio of 1.3 rather than 1.4: much spare cash was generated in the early years as a result of the efficient licence holder not paying dividends. However, the benefit of the lower interest payable had been offset by the fact that the rate of interest receivable on the resulting cash balances would be of the order of 0.5 per cent per year in nominal terms.[53] This approach reflected our view that the efficient licence holder would not in practice be able to repay its embedded debt without incurring a substantial penalty.

Other options

17.109 We also considered a number of other options potentially available to the efficient licence holder to help address weak financial ratios. These included: issuing index-linked debt; specifying an alternative index to the RPI be used in the annual uprating of the value of the RAB; and advancing into RP5 revenue that would otherwise be earned during subsequent price control periods. As set out in paragraphs 17.78 to 17.89 we received submissions from parties on some of these alternatives. However, based on our analysis as set out in paragraphs 17.100 to 17.105, we found we did not need to pursue any of these options.

Conclusion

17.110 Credit metrics form one, albeit important, element of the assessment of an efficient licence holder's creditworthiness and its ability to maintain investment-grade status on any debt it has issued or might issue in future. We made our assessment by examining a range of factors that credit ratings agencies examine rather than considering creditworthiness as solely a function of attaining or exceeding a particular threshold on an individual financial ratios such as PMICR.

17.111 In the light of our revised modelling, we considered that the efficient licence holder had options open to it that would allow that licence holder to maintain a target PMICR ratio of 1.4 while at the same time meeting or exceeding the targets for the other relevant metrics of creditworthiness. In particular we considered that the efficient licence holder could limit dividends to its equity holders. Adopting this policy would enable the efficient licence holder to fund its capex programme using investment-grade debt and maintain that status on its existing debt. We also noted that the reason why the efficient licence holder had a PMICR ratio of below 1.4 in our initial modelling was, as explained in paragraphs 17.91 and 17.97, due in part to there

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[51] The cost of debt on the embedded net debt was assumed to be 6.5 per cent per year in nominal terms—see paragraph 13.69.
[52] The cost of debt on any new debt was 5.4 per cent per year, also in nominal terms. The 5.4 per cent per year was based on a real cost of debt of 2.1 per cent per year (see paragraph 13.77 where the figure quoted is 2.14 per cent per year) and expected inflation of 3.25 per cent per year. 5.4 per cent per year = 1.021 x 1.0325–1 expressed as a percentage.
[53] The nominal rate of interest receivable on cash balances is based on Bank of England base rate.

being a time lag between the efficient licence holder earning its return on its investment and when that return would be fully realized in cash.

17.112 Based on our assessment of the options open to the efficient licence holder, we concluded that it had the flexibility to manage the financing of the RP5 control.

Assessment of the possible effect of the RP5 price control on consumer prices

17.113 This subsection 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.[54] For the purposes of this analysis we 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.[55]

TABLE 17.9 **Change in prices excluding impact of any one-off refund: year-on-year change across transmission and distribution**

				per cent per year
	Announced		*Forecast*	
Increase at 1 October each year	*2013*	2014	2015	2016
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.

17.114 We forecast that the transmission and distribution component of the representative domestic customer's annual bill will reduce by approximately £10 relative to RPI by the end of the four years to September 2017 from £152 per year to around £142 per year in 2012/13 prices.

17.115 Further detail regarding our analysis, and the uncertainties surrounding our forecasts, are contained in Appendix 17.1.

[54] 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.
[55] 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.

18. The reporter and information transparency

Introduction

18.1 In its reference, the UR required us to determine (see paragraph 1.2) 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.

18.2 In this section, we therefore consider whether additional requirements regarding the reporting, recording and monitoring of information should be added to NIE's licence (we note that with regard to the verification of data there is no suggestion that data recorded by NIE is inaccurate). In particular, we consider in turn two specific issues. These are whether, for RP5:

(a) a reporter function (as proposed by the UR) should be introduced; and/or

(b) NIE should be required to produce and publish additional information about its business.

18.3 We *(c)* set out our conclusions.

The reporter

18.4 In this subsection, we:

(a) summarize the UR's proposal;

(b) summarize NIE's arguments against introducing a reporter; and

(c) set out our determination.

The UR's proposal to introduce a reporter

18.5 The UR said that the public interest required a significant improvement in the current levels of transparency and accountability in NIE's activities, not least due to new substantial stakeholder interest arising from increased renewable generation and market opening. It said that:[1]

(a) the quality and quantity of reporting from NIE on its regulated activities had not been adequate (for example, with regard to capitalization practices). It said that high-quality reporting and independent verification of data were essential even for a substantive capex programme of the current magnitude of RP4;

(b) NIE's business plan had been of poor quality and information submitted by NIE in the past had not been transparent;

(c) the proposed substantial increase in capex over RP5 meant that the need for high-quality reporting was even greater than it had been in the past; and

(d) under its capex structure proposals those projects for which the necessity, timing or scale was not yet clear would be reconsidered and approved on an annual

[1] UR Statement of Case, paragraphs 3–9.

basis throughout RP5 (via Funds 2 and 3, as described in Section 5, Table 5.1). This would require constant communication and transparency between the UR and NIE throughout the price control period.

18.6 It described the role of the reporter as having three limbs:[2]

(a) a technical role, auditing the outputs and unit costs of NIE's capex for the purposes of implementing the RP5 capex proposal, and advising the UR in relation to NIE's annual submissions for approval of further projects under capex Funds 2 and 3 in the following years;

(b) a financial role, reviewing NIE's accounting practices and advising the UR in relation to the same, so as to identify potential problems such as the capitalization practices issue referred to in paragraph 18.5(a) before they arose; and

(c) a general ad-hoc role, investigating and reporting on any particular issues that the UR would consider gave rise to concern from time to time.

18.7 The UR envisaged that the reporter would play a particularly important role with regard to its assessment during RP5 of projects where the necessity, timing or scale was not yet clear. The UR proposed that these projects should be reconsidered and approved on an annual basis throughout RP5. It submitted that this would require constant communication and transparency between it and NIE throughout the price control period. The reporter was a way of achieving this communication and transparency.[3]

18.8 The UR submitted that the introduction of a reporter did not add to its information-gathering powers; but an independent, embedded (part-time) reporter would enhance the UR's understanding of NIE's business. It said that its proposals were less onerous than those required by Ofgem (under RIGs).

18.9 The UR said that the larger capital programme was not the trigger for introducing a reporter, only the reason to have a larger quantity of reporting. In its view, the factual background of this case required a step change in the quality of accountability and transparency: a reporter was a good way of achieving that.

18.10 It said that the reporter might not be deemed to be the perfect solution. Instead it was an essential step in the move towards more effective regulation. During its development of this policy, it identified both pros and cons with this approach. However, in its judgement (and based on its experience of the transition that it facilitated in Northern Ireland Water), this solution would be most effective method of ensuring the transparency and accountability that all stakeholders required going forward.

NIE's arguments against a reporter

18.11 NIE said that the UR's proposed reporter would be considerably more 'hands-on' than the reporters in the previous Ofwat regime.[4] In NIE's view, a reporter was un-

[2] In the UR Terms of Reference for the Reporter, September 2012, paragraph 2.2, the areas of work are described as: Financial accounts; Capital expenditure reports; Capital expenditure database; RAB additions and disposals; Compliance Plan; Annual reporting requirements; Other regulatory submissions; special investigations.
[3] UR Statement of Case, paragraph 9.
[4] NIE Statement of Case, Chapter 14, paragraphs 2.5 & 2.6.

necessary and much of the role would not be required if we adopted the traditional approach to regulating capex.[5]

18.12 NIE said that a reporter would be a further step towards a regulatory model that tended towards micro-management and it would create uncertainty as to whether NIE or the reporter was responsible for decision making.[6] That is, there were un-answered questions around the reporter's accountability, its legal status (eg if the UR were effectively to delegate some of its functions to the reporter), and NIE's right of redress etc (eg if the UR were to base its regulatory decision on findings made by the reporter which NIE considered to be erroneous).[7]

18.13 With regard to the remainder of the role (for example, validating information, capex reporting, regulatory submission), NIE said that a reporter was no substitute for clear rules and reporting arrangements and NIE would work with the UR to meet its increased reporting requirements.[8] It said that it would strongly support establishing a Northern Ireland equivalent to Ofgem's RIGs (eg to facilitate benchmarking against the GB DNOs) and confirmed its commitment to working with the UR to develop further output measures (in the form of load and health indices).[9]

18.14 Finally, NIE considered that the total cost of embedding a reporter would be significantly higher than the UR's cost estimate of £1.5 million over RP5 due to the cost of servicing the needs of the reporter.

Our conclusion on the reporter

18.15 We considered the submissions of both parties, in addition to the third party submissions which were made on this issue (these are summarized in Appendix 18.1).

18.16 With regard to the current data reporting arrangements, we found that NIE's current reporting structure made comparisons and benchmarking against its closest comparators, the GB DNOs, a lengthy and difficult exercise (see Section 8). The current reporting structure also made it difficult to estimate the direct-cost element of Core Network Investment. As a result, it was difficult to compare NIE's unit costs for network investment to the GB DNOs. We also found that the classification of costs between NIE and Powerteam made NIE's cost structure more complex and difficult to understand (see Section 8). In our view, enabling a clearer understanding of NIE's costs and better comparability of its performance against the GB DNOs is important and is in the public interest.

18.17 We therefore found that NIE's current data reporting needed to be improved and we decided that a step change in data transparency was required. In our view, an increase in the quality of standardized data reporting which also enables NIE to be compared with its peers is in the public interest. This is because it will provide all stakeholders with more transparency and greater confidence about how NIE is performing.

18.18 We did not find that the introduction of a reporter was the best way to achieve greater data transparency. In particular, we were concerned that the introduction of a reporter, as envisaged by the UR, would potentially involve significant amounts of investigatory work rather than auditing/verification of data. For example, the UR

[5] ibid, Chapter 14, p327.
[6] ibid, Chapter 14, paragraphs 2.1–2.2 & 2.7.
[7] Cover letter to NIE's Statement of Case, 10 May 2013, paragraph 15.
[8] NIE Statement of Case, Chapter 14, p327, and NIE Supplementary Submission, Annex 12, paragraph 2.2.
[9] NIE Supplementary Submission, Annex 12, paragraphs 3.18 & 3.21.

proposed that the embedded reporter should review and advise on accounting practices.

18.19 We decided that greater data transparency would be best achieved through the publication of more useful data which would be prepared according to clearly-defined rules. The UR, through its existing powers, would be able to audit and verify this data as it considered appropriate.

18.20 The UR also proposed that the reporter would advise it on assessing projects (see paragraph 18.7). Our price control design will require some project assessment by the UR during RP5 (see Section 5). We therefore considered whether a reporter would be a valuable additional resource in this process. We found that this was unlikely to be the case because the UR could employ its own consultants to review projects just as a reporter could (as it did with SKM for RP5). We found that the additional benefits which an embedded reporter might bring over a consultant employed by the UR were small and would be significantly outweighed by the risk that the reporter would be seen as a decision maker.

18.21 For the reasons outlined in paragraphs 18.16 to 18.20 above, our preferred approach to transparency was to focus on significantly increasing the amount of useful and comparable data which NIE produces. We consider that this should address the issues of data transparency which we found to be against the public interest (see paragraphs 3.75, 3.80, 18.16 and 18.17). We consider that this approach will achieve much of what the UR aimed to achieve with the introduction of a reporter, but without the aspects of this arrangement which concerned us (see paragraphs 18.18 and 18.20).

18.22 We consider that as far as is possible any additionally reported data should be made publicly available. We discuss our decision on how to increase the quality of data reporting in the next subsection.

Increased reporting

18.23 In this subsection, we explain our decision regarding how to increase the quality of data reporting in RP5. We (a) summarize the views of the parties, (b) our provisional determination and the parties' responses to it and (c) set out our determination in this area.

The parties' views of regulatory reporting

18.24 The parties seemed to be broadly in agreement that additional regulatory reporting would be beneficial.

NIE

18.25 NIE told us that there was a perception that transparency could be improved and that this could be helped by increased reporting: it said that it wanted to engage on this issue. It told us that any requirements should be specified as clearly as possible, as early as possible, so that it could start to work to put the necessary processes and systems in place.

18.26 NIE also told us that increased reporting should facilitate benchmarking of NIE against the GB DNOs, because they were the most relevant comparators. It said that trying to get NIE's cost reporting on a basis which was similar to GB was a sensible approach and it thought that this would also appeal to the UR.

18.27 NIE told us that the UR had already asked for its views on a pro forma of reporting metrics that could be used.

The UR

18.28 The UR expressed concern about the level of transparency and accountability in NIE's operations. It said that effective reporting was an essential prerequisite for effective regulation and so it had proposed measures to improve the quantity and quality of information that it collected from NIE.[10]

18.29 The UR told us that it wanted additional reporting beyond that provided in RP4. It said that for benchmarking purposes NIE should report on the same basis as the GB DNOs. It told us that the regular annual reports currently available did not provide anywhere near the equivalent level of detail to the GB DNOs and that there was nothing which could be used to benchmark NIE against the GB DNOs.

18.30 The UR said that its benchmarking was based on the price control submission and not the annual reports. It said that the amount of cost mapping required and the errors that had been uncovered through our process meant that it would not be sustainable to review and repeat this exercise every year.

18.31 The UR told us that if we decided that the Ofgem reporting standards (the RIGs) should be adopted, then this would make it easier to analyse and benchmark NIE. It said that the reason it had decided against this was because of concerns about the burden it would put on the company: the Ofgem RIGs were very extensive. It therefore thought that a reporter was more appropriate.

Our provisional determination and the parties' responses

18.32 In our provisional determination we proposed the creation of a new licence condition which required NIE to complete the full DNO RIGs, with the UR granting exemptions for those elements which it considered were either not relevant or not useful. In addition we proposed that NIE would be able to apply to the UR, with reasons, for an exemption if it considered that other elements would not be useful (the UR would then be required to evaluate whether an exemption should be granted).[11]

18.33 We provisionally determined that synchronizing the reporting year end with Ofgem would be efficient and that the first year of full reporting would be the year ending 31 March 2015. This would allow for one year of reporting (April 2014 to March 2015) before the 2015/16 reporting year, which was likely to be the base year for next price control. We believed that the availability of a suitable set of RIGs reporting data for this base year was very important and would provide a significant benefit for RP6.

18.34 We also consulted with the parties on a number of issues, including: making specific RIG exclusions within the licence; publication of the data; and how best to capture NIE's Transmission business.

The UR

18.35 The UR said that while it would have preferred the additional benefits that a reporter would have offered, the key point was the data that it would receive. If NIE were to

[10] UR Statement of Case, paragraph 3.
[11] Provisional determination, Chapter 17, paragraphs 17.39 & 17.40.

deliver on the requirement to provide data which is comparable with the RIGs submissions made by the DNOs, then that key point would have largely been satisfied.[12]

18.36 With regard to implementing RIGS as a Licence condition, the UR said that:

(a) NIE's Licences should be modified as part of our inquiry so as to include an obligation for NIE to report to the RIGs;

(b) it was important, both for benchmarking and for implementation of the our cost-sharing mechanism that the RIGs should be implemented as fully as possible, and in respect of as much of RP5 as is possible; and

(c) the process of finalizing the reporting framework would require separate consultation in Northern Ireland. The UR therefore proposed that the final determination in this area should be implemented by way of a general licence condition empowering it to stipulate detailed RIGs for NIE to comply with in due course via a 'direction'. It said it would consult with NIE prior to issuing any directions within formal regulatory letters.[13]

18.37 The UR also proposed an amended, slightly more detailed Licence condition which would:

(a) allow a company-regulator consultation period, time-limited to cover off specific data lines which did not seem appropriate for the functioning of RP5; and

(b) give the UR the ability to make the necessary directions as to which elements of the RIGs are exempt on the basis of being disproportionate to the functioning of RP5 and as to any other changes in local circumstances or changes in Ofgem's RIGs.[14]

18.38 The UR said that our proposed first year of reporting (March 2015) was too late. It said that Ofgem's advice was that the sooner NIE started submitting data, the better. This was because, even if early submissions were affected by errors, the process of working through those errors would bring forward the day on which a robust data set would be available.[15] It said that it would amend the reporting requirements by adopting a 'confidence grading' system, similar to that which applies to Ofwat. Under this process NIE would set out its confidence levels in the information recorded. It said that this would allow the UR to outline and agree the steps that NIE would take over time to improve its data submissions.[16]

18.39 The UR also considered that it was important that NIE changed its reporting years from March year ends to September year ends. This would align regulatory reporting with the all-island tariff year. It said that while this would result in a different reporting year to the GB DNOs, Ofgem had made it clear that what was required was a defined 12-month period and when this 12-month period starts and finishes did not impact on the ability to benchmark effectively.[17] The UR added that this was because Ofgem was looking to expand its benchmarking outside the UK, where there would inevitably be different tariff years and reporting years.

[12] UR response to the provisional determination, paragraph 211.
[13] UR response to the provisional determination, paragraphs 216.
[14] UR response to the provisional determination, paragraph 217.
[15] UR response to the provisional determination, paragraphs 214 & 215.
[16] UR response to the provisional determination, paragraph 212.
[17] UR response to the provisional determination, paragraphs 23 & 24.

18.40 The UR said that it was concerned with the high-level of implementation costs identified by NIE. It said that the costs needed to be scrutinized and benchmarked against GB DNOs. It said that NIE needed to present a detailed timeline, project plan and risks and gap analysis to enable justification for these costs.

NIE

18.41 With regard to the UR's proposal that RIGs should be implemented by way of a general Licence condition empowering the UR to stipulate RIGs for NIE to comply with in due course via a 'direction', NIE told us that this approach was 'fine'. It also told us that it was totally committed to RIGs but that it would prefer that implementation was done in a positive working relationship with the UR to get the best result rather than trying to define exact RIGs at this stage. It said that the objective should be made clear: to facilitate benchmarking against the GB DNOs and to give the information required.

18.42 NIE said that first reporting in 2014/15 was a completely impractical target. It said that it would not be possible to put in place the necessary changes to its processes and IT systems in time for April 2014. In its view the shortest practical delivery time was two years: it therefore proposed reporting on a best endeavours basis in 2015/16 (as this would be the base year for RP6) with the first reporting year based on full RIGs being 2016/17.[18] NIE said that it was in the process of doing a manual mapping of 2012/13 costs to the Ofgem RIGS to identify where the existing gaps were.

18.43 NIE initially had some concerns about the proposed April to March reporting period, which it said aligned with neither its statutory accounting year (which is December—ESB's year-end) nor the tariff year (which is September).[19] NIE said that it made sense to have the regulatory entitlement aligned with the tariff year. It said that it did not see any problems with benchmarking a year-end of March (for GB DNOs) against a year-end of September (for NIE).

18.44 After further detailed discussions about the reporting year-end NIE said that it had no objections to a March reporting year end to facilitate benchmarking, provided the K factor used to calculate the regulatory entitlement for the October to September tariff year is based on the K factor at 30 September in order to minimise volatility in DUoS tariffs and to ensure NIE recovers its regulated entitlement.

18.45 NIE said that it was difficult to determine the cost of work required to adopt the RIGs without knowing the full scope of reporting. It submitted that a high level estimate of the costs of adopting the full Ofgem RIGS was £10–15 million. In its view the least risk option for NIE and customers was:

(a) NIE to be provided with funding to initially procure the services of a client side advisor to assist with scoping and procurement.

(b) Delivery/out-turn costs to be approved on the basis of robust competitive procurement.

(c) Annual operating costs to support reporting requirements to be approved based on efficiently incurred costs.

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[18] NIE response to the provisional determination, Chapter 20, paragraphs 1.3–1.11.
[19] NIE response to the provisional determination, Chapter 20, paragraph 1.19.

(d) NIE to update the UR regularly on progress and cost throughout the programme.[20]

18.46 NIE also said that an annual allowance of £100,000 should be given for the cost of a data assurance audit as well as any reporting requirements not included in Ofgem's RIGS.[21]

Conclusion on regulatory reporting

18.47 We found that increasing the quantity and quality of data reporting is in the public interest. We identified two significant benefits from better data reporting:

(a) it would improve the level of transparency of NIE's business for both the UR and other stakeholders. The need for more transparency was repeatedly mentioned by the UR and by third parties. NIE also recognized that there would be benefits from increased transparency.

(b) it would make comparison of NIE's performance with the GB DNOs much easier. Being able to assess the performance of a regulated business against comparable companies' should improve regulatory outcomes. For example, comparing NIE's volumes, direct unit costs and indirect costs with the GB DNOs would provide the UR with important information in setting its next price control. We have found that NIE's current reporting made these comparisons a lengthy and difficult exercise.

18.48 We considered that the Ofgem RIGs for the GB DNOs were the logical starting point for any new reporting requirements. These are the standardized annual data reporting requirements which the GB DNOs produce. The RIGs cover a very significant proportion of NIE's network (although not the 275 kV network) and both parties agreed that the GB DNOs represented the most appropriate comparators for performance. In addition, Ofgem had worked for a number of years to develop and refine its rules on data collection; adopting the RIGs would allow all stakeholders to benefit from a system which was robust and which had been in place for several years.

18.49 We recognized that in order for increased reporting to work well and deliver significant benefits to stakeholders, the UR would have to have the capacity to process any additional data. We noted that Ofgem had available to it significantly greater resources than the UR. However, the UR said that it would be content to adopt the RIGs system and we had no reason to believe that it would not be able to process the additional data effectively. It had also begun engaging with Ofgem with regard to RIGs implementation.

18.50 We used benchmarking extensively in setting our cost allowances (see Sections 7 and 8). One of the main benefits we identified from increased data reporting was the ability to make benchmarking exercises easier in future. It would allow NIE to assess cost performance and to set cost allowances independent of NIE's historic costs. However, for this to be effective it was important that the UR can access the relevant GB DNO data sets from Ofgem (in some form). Our experience in this inquiry indicated that the UR would be able to access relevant GB DNO data in future charge controls.

[20] NIE response to the provisional determination, Chapter 20, paragraphs 1.12–1.14.
[21] NIE response to the provisional determination, Chapter 20, paragraphs 1.17 & 1.18.

18.51 We therefore determined that a requirement to deliver increased regulatory reporting based on the RIGs should be specified as a Licence condition.

18.52 We also considered whether we should include a Licence condition requiring the independent verification of this data by a suitable third party (for example, an auditor). We decided that requiring director sign-off of the regulatory reporting data would add sufficient assurance of its accuracy.

18.53 Following the parties' responses to our provisional determination, we considered that both NIE and the UR were in principle agreed that RIGs reporting should be adopted by NIE. We considered the three additional points with regard to implementation, namely:

(a) how a Licence condition should be implemented;

(b) what the reporting period should be and when the first reporting year should be; and

(c) how the costs of implementation should be dealt with.

How a Licence condition should be implemented

18.54 In our provisional determination we proposed the creation of a new licence condition which required NIE to complete the full DNO RIGs in 2014/15 with the UR granting exceptions where required (see paragraph 18.32).

18.55 In their responses, the parties seemed to agree that a general Licence condition was the most appropriate way for us to stipulate RIGs reporting:

(a) the UR said that RIGs reporting should be implemented by way of a general licence condition empowering it to stipulate detailed RIGs for NIE to comply with in due course via a 'direction' (see paragraph 18.36).

(b) NIE told us that it agreed with this approach and would prefer licence implementation this way rather (through working with the UR) than trying to define the exact RIGs at this stage (see paragraph 18.41).

18.56 We recognized that a general Licence condition facilitating better reporting was the most appropriate solution given the need for NIE and the UR to work further on specifying the scope of the RIGS. We believed that the UR would be best placed to specify those elements of the RIGs which would be most beneficial to it for RP6 and subsequent regulatory reporting periods. In addition, some aspects of NIE's business are unique to Northern Ireland (for example, metering) and would require bespoke reporting, which the UR was in the process of developing in conjunction with NIE. The UR would therefore be able to be flexible to NIE's reporting capabilities.

18.57 This general Licence condition would therefore:

(a) oblige NIE to report to the RIGs in 2014/15 and 2015/16 (see discussion below) for the purpose of facilitating benchmarking against the GB DNOs and to give the information required for the UR to assess NIE's performance;

(b) give the UR the ability to make directions to NIE setting out which elements of the RIGs are exempt on the grounds of being unnecessary due to differences in the Northern Ireland network compared with GB; and

(c) require NIE to report using a confidence grading system ,which would set out its confidence in the data it would be reporting. This would allow NIE and the UR to identify those aspects of the RIGs which would need greatest focus and development.

The regulatory reporting period and the first reporting year

18.58 Although both parties initially agreed that the regulatory reporting period should be October to September rather than April to March (as in our provisional determination), we have set out in Section 19 our decision and reasons to require NIE to fulfil its obligations in respect of regulated revenue for the year ending 31 March.

18.59 We then considered what implications this had for the first reporting year in which NIE would use the RIGs. There remained some difference of opinion between the parties (see paragraphs 18.38 and 18.42) but in practice both parties seemed to accept that NIE should move to RIGs reporting as soon as possible and that the first year of reporting might be less robust than subsequent years.

18.60 We considered that we needed to allow the process of reporting to scale up over time. We noted that NIE was already in the process of doing a manual mapping of 2012/13 costs to the Ofgem RIGs and that this would highlight the gaps that needed to be addressed. We believed that there were likely to be a number of issues to resolve following this exercise but that the number of issues arising would be likely to decline with each reporting year.

18.61 The Licence conditions we specify provide NIE and the UR with flexibility in the implementation of the RIGs and allow scope for addressing unexpected difficulties. We have not therefore specified a standard that NIE must apply in complying RIGs, as this is already captured in the Licence conditions above. However, we considered it important to set out our expectations with regard to the next two reporting years (2014/15 and 2015/16). We continued to believe that the availability of RIGs reporting in 2015/16, the likely base year for the next price control, was very important and in the public interest. We also considered it was important that both NIE and the UR had one year of exposure to RIGs reporting before the base year, even if that first year of reporting (2014/15) had a number of areas with low confidence grading or had some gaps, which would be agreed with the UR.

Implementation costs

18.62 In response to our provisional determination NIE submitted a high-level cost estimate for RIGs implementation of £10 million or more (2013/14 prices) and proposed that its efficiently incurred costs should be approved by the UR during RP5.[22]

18.63 In response to our request for additional details on this estimate NIE set out the main elements of its RIGS implementation cost estimate. These are shown below in table 18.1.

[22] NIE response to the provisional determination, p205.

TABLE 18.1 **NIE estimate of RIGs implementation costs**

	Estimate £'000 (2013/14 prices)
RIGS Mapping & Accounting Structure design	350–500
Development of non-RIGS reporting	150–250
RIGS Manual reporting (to March 2016)	600–900
OJEU Procurement costs	350–500
Time Capture/recording	1,150–1,750
Account Structure Implementation	2,700–4,400
RIGs Reporting Delivery	1,050–1,700
Health Indices development	900–1,500
Project Management	1,400–1,850
HR & Communications Support	250–350
Business change management	550–700
RIGS test cycle	150–200
Total	9,600–14,600

Source: NIE.

Note: Total in 2009/10 price base is £8.3–12.6 million.

18.64 The UR said that it was concerned with the high level of implementation costs identified by NIE (see paragraph 18.40).

18.65 Our benchmarked allowance for indirect costs (see Section 8) is based on DNOs which are already reporting under Ofgem RIGs and therefore the cost of the preparation of this data (including data assurance costs, as mentioned by NIE) is already included in our benchmarked allowance. To give NIE an additional allowance for the cost of preparing and reporting this data would therefore be double counting of those costs.

18.66 However, we considered that there were also likely to be significant one-off set up costs, particularly with regard to cost capture within NIE's reporting systems, for which it would be appropriate to give an additional allowance during RP5. We found that at this stage these costs were highly uncertain and would only become clearer once the scope of the RIGS had been more fully specified.

18.67 We asked the GB DNOs about their RIGS set-up-related costs:

(a) SSE said that it had not incurred any specific back office systems costs for capturing and providing information for regulatory reporting. This was due to funding that it had already received under DPCR5 for a back office replacement project. It was therefore able to incorporate the new regulatory reporting requirements as part of this rather than requiring any specific additional funding. It said that going forward there would be some changes to its front office asset data systems. Replacement of these systems will be required due to age and limited functionality. Funding for these systems forms part of its RIIO-ED1 business plan which will be resubmitted to Ofgem in March 2014.

(b) Western Power Distribution (WPD) said that during DPCR4, the extent of the data requirements for regulatory reporting was such that no changes or additions to its information systems were required. It said that there was one staff member dedicated to working on the regulatory reporting pack at a cost of around £70,000 a year including pensions, NI, holidays etc.

It said that regulatory reporting for the DPCR5 period is more extensive and complex. Also, one year into the DPCR5 period the WPD Group enlarged from two DNOs to four DNOs. The cost associated with the preparation of regulatory reporting during DPCR5 are (1) staff £0.375 million and (2) IT systems £0.5 million.

WPD also said that in order to simplify business processes and enable data to be provided on a more frequent basis, it has introduced an additional IT system. This system applies the regulatory reporting rules to costs extracted from its general ledger system, therefore reducing the need for manual application of the reporting rules. The cost of this IT system development was in the order of £0.5 million.

(c) Scottish Power estimated that the annual costs of undertaking regulatory reporting across its two distribution businesses was around £1.4 million. It said that it estimated that it incurred one-off costs of around £0.7–1.0 million in respect of its two distribution businesses to adapt its IT systems to ensure data was captured according to RIGS.

Northern Powergrid said that it did not specifically track the costs of completing the annual regulatory reporting pack for costs and outputs (the RIGs). However, it did produce an estimate for ongoing costs at 3.3 person years or £250,000 on an annual basis for the group's two distribution licensees. It said that it had not carried out significant one-off set-up costs to implement new reporting systems because its approach has been to incorporate changes for reporting of costs and outputs when the systems were due for replacement. This process has taken place over many years. It suggested that if multiple updates to systems were required then this could cost many millions of pounds. It said that there were some important contextual points which we might wish to consider when assessing any future costs for NIE. The main point was that the regulatory obligations for reporting of costs and outputs had grown significantly since their introduction in 2004/05 but, importantly, this has been over a protracted period. This had allowed the GB DNOs to steadily build their capability in an evolutionary manner.

Our determination on implementation costs

18.68 We considered that there were three options available to us with regard to RIGS implementation costs during RP5. These were:

(a) to provide an ex-ante allowance;

(b) to provide a mechanism which allowed the UR to approve costs; and

(c) to reduce the scope of the RIGS requirement.

18.69 In principle, providing an ex-ante allowance was our preferred option. Elsewhere in our price control design we have, wherever possible, tried to set ex-ante allowances and reduce the amount of cost pass through. However, we found that in this instance we were unable to set such an allowance. This was because we had very little reliable data on which to make a decision. We considered that the data points provided by the GB DNOs suggested a much lower allowance than NIE's estimate. However, the system changes required at the DNOs were clearly more incremental and in any one period smaller in scope than was required in this case. As such, while these estimates were informative, we did not consider that they represented a like for like benchmark.

18.70 Equally, we considered that we could place little reliance on NIE's estimate of £9.6 million to £14.6 million, which surprised us. We were concerned that NIE's estimate was based on an approach which would mean wholesale replacement of multiple systems at the same time rather than a more incremental approach which involved more manual data production to begin with but which would ultimately be cheaper and more efficient (for example, delaying the replacement of certain IT systems until they reached the end of their useful life and would be replaced anyway in the normal course of business). We were also concerned that it would be difficult to isolate these costs from other costs in NIE's business for which we had already made allowances.

18.71 We considered that there were two ways in which we could provide a mechanism under which the UR would approve NIE's costs during RP5. First, as suggested by NIE, the UR could approve NIE's efficiently incurred costs during RP5. Alternatively, we could provide an upfront allowance and, if NIE could demonstrate to the UR that this allowance was insufficient, the UR could approve additional funding. We considered that the second approach was more likely to be effective because we were concerned that the first approach more closely resembled cost pass through. We therefore set an initial allowance for implementation costs of £1 million[23] for the price control period, although NIE may apply to the UR for additional funds.

18.72 We would expect that, if NIE seeks additional approval for additional RIGS implementation costs during RP5, the UR would be able to satisfy itself whether any additional costs are efficient and in the public interest. In particular, we would expect the UR to consider reviewing the detail of RIGS reporting if NIE is unable to materially reduce the size of its current implementation estimate.

Conclusion on the reporter and overall transparency

18.73 We found that it would be in the public interest for there to be a step change in NIE's data reporting. We considered that this would bring significant benefits to stake-holders. For the reasons outlined in paragraphs 18.18 to 18.21, we decided that the introduction of a reporter function was not the best way to achieve this.

18.74 We decided that a general Licence condition should be added which required NIE to report against the Ofgem GB DNO RIGs:

(a) an obligation for NIE to report to the RIGs in 2014/15 and 2015/16 for the purpose of facilitating benchmarking against the GB DNOs and to give the information required for the UR to assess NIE's performance;

(b) giving the UR the ability to make directions to NIE setting out which elements of the RIGs are exempt on the grounds of being unnecessary due to differences in the Northern Ireland network compared with GB; and

(c) requiring NIE to report using a confidence grading system, which would set out its confidence in the data it would be reporting.

18.75 We found that the availability of RIGs reporting in 2015/16, the base year for the next price control, was very important and in the public interest. We considered it was important that both NIE and the UR had one year of exposure to RIGs reporting before the base year, even if that first year of reporting (2014/15) had a number of areas with low confidence grading or had some gaps, which would be agreed with the UR.

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[23] 2009/10 prices, applied as a single RIGS implementation allowance in 2013/14

18.76 We set an initial allowance for RIGS implementation costs of £1 million over the price control period and have provided a mechanism whereby NIE can seek additional funding provided that these costs are efficient and in the public interest (see paragraph 18.72).

19. Implementation issues

Introduction

19.1 This section addresses several issues concerning the implementation of our decision regarding modifications to NIE's price control:

- *(a)* specification of the revenue restriction in NIE's price control licence conditions (paragraphs 19.3 to 19.13);
- *(b)* maximum regulated revenue for financial year not being known in advance (paragraphs 19.14 to 19.17);
- *(c)* distribution costs currently falling under the PSO charges (19.18 to 19.30);
- *(d)* refunds for transmission and distribution over-recovery since 1 April 2012 (paragraphs 19.31 to 19.40);
- *(e)* further information on implementation of elements of price control (paragraphs 19.41 to 19.86);
- *(f)* transparency of revenue restriction in price control licence conditions (paragraphs 19.87 to 19.94); and
- *(g)* the financial year used for NIE's maximum regulated revenue and for regulatory reporting requirements (paragraphs 19.95 to 19.124).

19.2 Several of these issues were raised by the parties following our provisional determination, and we consider them in turn.

Specification of revenue restriction in price control licence conditions

19.3 NIE's current licence conditions impose a requirement on NIE to: 'use its best endeavours to ensure that in any relevant year the regulated transmission and distribution revenue shall not exceed the maximum regulated transmission and distribution revenue' (clause 2).

19.4 The current licence conditions do not specify NIE's maximum regulated transmission and distribution revenue as £ million values for each financial year. Instead the licence conditions contain a series of formulae which are used to calculate NIE's maximum regulated revenue. These include formulae for different price control 'building blocks' (eg allowances for opex, depreciation and return on NIE's RAB).

19.5 The way that the revenue control is expressed in NIE's current licence conditions is not the only way to implement the type of revenue control that we have developed for NIE. We identified three options:

- *(a)* The current approach in which the licence conditions specify NIE's maximum regulated revenue through a series of formulae for price control building blocks.
- *(b)* The licence conditions could specify NIE's maximum regulated revenue in a given financial year as a level of 'baseline revenue' (eg £200 million) adjusted for inflation, which could then be subject to a number of further financial adjustments. These financial adjustments would give effect to the decisions we have taken on price control design (eg to vary NIE's maximum regulated revenue in light of NIE's out-turn expenditure to give effect to the cost risk-sharing mechanism, or to

increase NIE's maximum regulated revenue to make allowances for the costs of additional transmission network investment projects approved by the UR). In some cases, the financial adjustments intended to implement elements of the price control design could be specified as formulae in the price control licence conditions and form part of the restriction on NIE's maximum regulated revenue. In other cases, the relevant financial adjustments could be calculated by the UR and implemented as part of the calculation of NIE's baseline revenues for the subsequent price control period or implemented at some later date.

(c) A financial model could be developed which would calculate the maximum regulated revenue for NIE for each year of the price control period, using input data specified in our final determinations (eg upfront allowances for opex and capex and WACC) and other input data that becomes available during the price control period and which feeds into the calculation of NIE's revenue control (eg NIE's out-turn expenditure which affects maximum regulated revenue through the cost risk-sharing mechanism). NIE's price control licence conditions would specify that its maximum regulated revenue is determined by the results from updating this financial model each year for the relevant input data. There would be no formulae in the price control licence conditions; the licence conditions would instead refer to the financial models.

19.6 Option *(a)* was adopted by the UR in the draft licence modifications that it published alongside its RP5 final determinations. The current revenue controls for the GB DNOs (which run to 31 March 2015) are expressed in a way that is most similar to option *(b)*. The more recent energy network revenue controls that Ofgem has established for electricity transmission, gas transmission and gas distribution involve a financial model along the lines of option *(c)*.

19.7 NIE supported option *(a)* above. The UR proposed a version of option *(c)* though it also told us that it considered option *(a)* feasible.

19.8 We decided to adopt option *(a)*. In favouring option *(a)* we sought to limit the scope for ambiguity in the way that NIE's price control operates and also to limit the risks of errors and unintended consequences from the implementation of our determination.

19.9 Despite changes to the design of the price control for NIE, option *(a)* would allow the licence modification to build on and adapt the formulae and methods already in place in NIE's price control licence conditions.

19.10 Option *(c)* would require the development of a new type of model for NIE. This model would be more complicated than the type of financial model that had been used by the UR and us for the purposes of financeability analysis and estimation of the effects on tariffs from changes to NIE's maximum regulated revenue. We were concerned about the scale of the model development required under option *(c)* and the risk of modelling errors and unintended consequences which would then be hard-coded into NIE's licence conditions. We did not consider that this was an appropriate approach for the purposes of our inquiry.

19.11 The financial model needed for option *(b)* would not be as complicated as that needed for option *(c)* and there would be overlap with the financial modelling used for our analysis of financeability and our estimation of the effects on NIE's revenues from changes to NIE's maximum regulated revenue. However, we identified the following concerns with option *(b)*:

(a) If we sought to specify the various adjustments needed to baseline revenue to implement our price control design (eg cost risk-sharing mechanism or volume

driver for metering capex) through formulae specified in licence conditions, these formulae would be as complicated as (and probably more complicated than) the formulae required under option *(a)*. This approach seemed worse than option *(a)* in terms of the overall modelling and formulae complexity and risks of unintended consequences and did not offer offsetting benefits.

(b) Alternatively, rather than specifying the various adjustments needed to baseline revenue to implement our price control design through formulae in licence conditions, we could leave these adjustments to be determined by the UR according to high-level methods that we specify. The UR would retain some discretion in determining the value of those adjustments. This approach would help limit the complexity and risk of unintended consequences from the price control formulae. However, it would leave substantial ambiguity as to how the revenue control operates and risks of future dispute between NIE and the UR regarding the financial adjustments needed to implement our determination. We did not consider such an approach to appropriate.

19.12 The UR told us that irrespective of which option we adopted, there would be a need for modelling work to give effect to our determination. We considered whether this point should affect the choice between the options above.

19.13 In order to implement a price control for NIE that is expressed through formulae in price control licence conditions (option *(a)* above) it will be necessary to calculate the revenue restriction resulting from these formulae. The required calculations are complex and we would expect a model (or set of calculations) implemented on a computer software package to be used. In that sense, some form of model is needed as part of the regulatory framework for NIE under option *(a)* as well as options *(b)* and *(c)*, and so there would be risks of modelling error under option *(a)* too. However, we did not find that this undermined our basis for favouring option *(a)*. Under option *(a)* it would be for NIE and the UR to ensure that the model used to calculate and approve NIE's tariffs is a valid implementation of the formulae in the price control licence conditions. Option *(a)* provides two potential benefits in this respect. First, there may be opportunities in the period between our determination and NIE's setting of tariffs for the period from 1 October 2014 for testing and refinement of any model to be used to set tariffs. Second, if there were to be any inconsistencies in a model used to implement the formulae in the price control licence conditions these could be corrected by revising that model, without a need to change the price control licence conditions.

Maximum regulated revenue for financial year not known in advance

19.14 A feature of NIE's current licence conditions is that, at the start of each financial year, it is not possible to know exactly what NIE's maximum regulated revenue for that financial year will be. For instance, the maximum regulated revenue for a given financial year depends on NIE's actual level of capex in that financial year, which will not be known until sometime after the end of that financial year. The practical effect is that, in setting tariffs, NIE must make a forecast of what its maximum regulated revenue will be over the period in which those tariffs apply.

19.15 NIE's licence conditions include a correction factor through which the maximum regulated revenue for each financial year is adjusted for differences between NIE's maximum regulated revenue in the previous financial year and the amount of qualifying revenue that NIE actually collected in that previous financial year. This has the effect of compensating consumers or NIE for any errors in the forecasting of NIE's maximum regulated revenue in the previous year.

19.16 It would be possible to adopt an approach in which we seek to limit the extent to which the calculation of NIE's maximum regulated revenue for a given financial year depends on data not available before the start of that year. This could increase the predictability of the level of NIE's maximum regulated revenue. However, this would not guarantee that NIE's actual revenue in any year matches or does not exceed its maximum regulated revenue for that year. When NIE sets its tariffs there is uncertainty about the volumes of units that it will supply to customers over the financial year which can contribute to actual revenues being more or less than maximum regulated revenue. Further, this alternative approach would require more complicated formulae to implement aspects of our price control design, such as the cost risk-sharing mechanism.

19.17 We therefore decided to retain the current approach in which the specification of NIE's maximum regulated revenue for a given financial year is dependent, in part, on out-turn data for that financial year (such as NIE's costs for that year).

Distribution costs currently falling under the PSO charges

19.18 Our inquiry concerns Annex 2 to NIE's Licences, which place a restriction on NIE's revenues from transmission and distribution charges. Annex 2 defines transmission and distribution charges to mean all charges for the provision of transmission and distribution services,[1] but excluding charges levied under the PSO Agreements.

19.19 NIE also collects revenue from its PSO charges which are levied in respect of the PSO agreements. The PSO charges include charges for: the net costs recovered by NIE on behalf of Power NI (PPB) in relation to legacy power purchase agreements; certain costs incurred by suppliers in procuring electricity from renewable sources; certain costs associated with the maintenance of a land bank of sites effectively reserved for the generation of electricity in Northern Ireland. In addition, the PSO charges include recovery of certain costs incurred by NIE which do not form part of NIE's regulated transmission and distribution charges. These are the costs of several projects carried out as part of the development of non-domestic and domestic electricity retail competition in Northern Ireland. For instance, these include the capital costs of establishing the Enduring Solution system. Annex 1 to NIE's Licences specify the restriction on its PSO charges.

19.20 In its RP5 final determinations (paragraph 16.3), the UR proposed to reallocate the costs associated with obsolete retail market IT systems from the PSO into the distribution use of system tariffs and also to accelerate depreciation.

19.21 In its submissions to us, including the financial modelling work it carried out for our inquiry, the UR proposed that all of the un-depreciated capital costs incurred by NIE in projects linked to the development retail competition (market opening) should be included in NIE's RAB from 1 April 2012 for the purposes of our determination of the revenue control for NIE's electricity distribution activities. The costs would be removed from the PSO charges. The UR also proposed an accelerated depreciation profile for the FEMO and NI2007 elements of the RAB, which it described as a move to five-year depreciation. The effect of the UR's accelerated depreciation profile is that these elements of the RAB would be fully depreciated by 31 March 2016. The

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[1] And also including charges for 'wheeling', where wheeling is defined as the transportation of wheeled units on any part of the total system where a wheeled unit is defined as a unit (whether generated inside or outside Northern Ireland) which enters the total system at any point and is delivered to a place outside Northern Ireland.

depreciation profile for the Enduring Solution RAB would remain the same (ten-year depreciation).

19.22 The UR's proposal would address a potential inconsistency in the way that costs incurred by NIE are split between the PSO charges and distribution charges. Throughout our inquiry, the UR and NIE proposed that the operating costs associated with the Enduring Solution IT system are included in our cost assessment and form part of NIE's maximum regulated revenue for distribution. However, the historical capital costs of establishing the Enduring Solution system are currently included in the PSO charge control.

19.23 NIE agreed with the principle that the market-opening costs should be transferred to distribution charges and removed from the PSO charges. However, NIE said that this transfer should be from 1 October 2014. NIE said that the UR's proposal would result in a very significant over-recovery on PSO charges, which it estimated to be around £24 million. NIE warned that the UR's proposal would lead to a negative PSO tariff for the period commencing 1 October 2014.

19.24 NIE has already set PSO charges for the period to 30 September 2014 and these charges were calculated on the basis that the historical market-opening capital costs were included in the PSO charges. Deducting those costs retrospectively would reduce the maximum revenue that NIE 'ought' to have collected from PSO charges resulting in an over-recovery in PSO charges at 30 September 2014. The PSO charge control includes a correction factor through which the PSO over-recovery at 30 September 2014 would lead to an offsetting reduction to PSO charges in the tariff year from 1 October 2014, which could lead to negative PSO charges.

19.25 We decided that in principle the historical market-opening capital costs ought to be transferred from the PSO charges to distribution charges. Both parties agreed with this principle, although they differed on the implementation date.

19.26 We were concerned with the prospect identified by NIE of significant negative PSO charges. Negative PSO charges would effectively represent a payment from NIE to suppliers for electricity consumption by their customers. While the PSO charge control is not the subject of our inquiry we did not want our determination on regulated distribution charges to contribute to negative PSO charges.

19.27 We were also concerned that the benefits from a reduction in PSO charge, or even negative PSO charges, may not be fully passed through to consumers especially if the reduction is of a transitory nature with limited notice period. Whether it was fully passed through to consumers would depend on both regulation and competition at the retail level. We were not in a position to review retail regulation and competition to a sufficient degree during our inquiry to be certain that consumers would receive the benefits from such a reduction.

19.28 We identified an alternative way to implement the UR's proposal that would avoid potential negative PSO charges. This has the following features:

(a) The historical capital costs of projects linked to the development retail competition which have been recovered through PSO charges would be included in the calculation of maximum regulated revenue from distribution charges from 1 April 2012. The costs should be included by incorporating the depreciated values of the RABs for these projects at 1 April 2012 in the RABs that are used for the calculation of maximum distribution regulated revenue. As the UR had proposed, there would be an accelerated depreciation profile for the FEMO and NI2007 elements of the RAB, which the UR described as a move to five-year depreci-

ation. The effect of the UR's accelerated depreciation profile is that these elements of the RAB are fully depreciated by 31 March 2016.

(b) Annex 1 of NIE's licence would be amended as necessary to ensure that the PSO charges applicable from 1 April 2012 do not include charges for the historical capital costs of projects linked to the development retail competition (market opening) which were included under *(a)*.

(c) NIE would be required to provide a refund to electricity suppliers against the PSO charges it has imposed prior to 1 October 2014 which covers the charges attributable to the costs under *(a)* in the period from 1 April 2012. The refund to each supplier should reflect that supplier's payments to NIE for PSO charges since 1 April 2012 as far as reasonably practical.

(d) The UR would arrange for the refund payment to each supplier to be conditional on the supplier committing to passing on the refund to its customers in full in a reasonable and practical manner.

19.29 Although there may be some administrative costs in the processing of the refund, we considered that a refund was a more transparent and appropriate way to deal with the specific historical issue relating to the inconsistent treatment of NIE's costs in PSO charge control. The transparency of the refund should help ensure that it is passed through to consumers.

19.30 In terms of NIE's current licence conditions, we found that Annex 2 operated against the public interest because it did not allow for the recovery of the historical capital costs of projects linked to the development of retail competition through distribution use of system charges (these costs were instead recovered through PSO charges). This leads to an inconsistent treatment of costs between distribution charges and the PSO charges and potentially inappropriate PSO charges. In addition to changes to Annex 2 to include the relevant costs in the calculation of the revenue restriction on distribution charges, it may be necessary to make consequential changes to Annex 1 to ensure that the PSO charges from 1 April 2012 do not double count these costs. Although Annex 1 is not a part of NIE's Licences referred to us, there is potentially a need for modification of Annex 1 to address a defect of Annex 2.

Refunds for transmission and distribution over-recovery since 1 April 2012

19.31 We decided in Section 4 that our determination should apply to NIE's revenues and costs over the period from 1 April 2012 to 30 September 2017 but that our determination will not affect NIE's tariffs before 1 October 2014. We estimated that the revenues that NIE has collected (and will collect) in the period from 1 April 2012 to 30 September 2014 may be greater than the maximum regulated revenue that we have determined for that period (see paragraph 17.44).

19.32 One way to deal with any over-recovery would be to allow it to feed into the correction factor in NIE's current price control licence conditions.

19.33 Following our review of the specific issue arising from the historical inclusion of some capital costs from NIE investment projects in the PSO charges (paragraphs 19.18 to 19.30), we identified that it would be possible to use a similar refund mechanism to give effect to another element of our determination, at least in respect of distribution charges. This would work as follows, in the case of distribution revenues:

(a) NIE would make an estimate of the maximum regulated revenues under the distribution revenue control for the period to 30 September 2014 (the maximum

regulated revenue will depend on out-turn cost data so this can only be an estimate); compare this with its estimates of revenues from distribution services in the period to 30 September 2014, and calculate the extent (if any) to which its actual revenue is likely to exceed the maximum regulated revenue.

(b) NIE would provide refunds to electricity suppliers to the total value of any estimated over-recovery in respect of suppliers past payments to NIE for distribution charges (subject to *(c)*). The refund from NIE to each supplier would reflect that supplier's distribution charge payments to NIE in the period of over-recovery as far as reasonably practical (taking account of the administrative costs).

(c) The refund payments from NIE to each supplier would be conditional on the supplier agreeing a refund policy with the UR that allows for refunding half-hourly metered customers on the basis of actual usage over the period of over-recovery and providing an equivalent (on aggregate but not necessarily at the individual level) credit to non-half-hourly metered customers.

(d) Any refunds provided by NIE should be reflected in the calculation of NIE's transmission and distribution revenues used for the purposes of NIE's price control licence conditions. As such, the effect of the refunds will be to reduce the scale of the correction factor that feeds into NIE's tariffs from 1 October 2014.

19.34 We considered a refund approach preferable to allowing any substantial historical over-recovery to feed through the correction factor in the calculation of NIE's maximum regulated revenue from 1 October 2014. This was for a number of reasons:

(a) Making the full adjustment for over-recovery through the correction factor would contribute to tariff volatility. An over-recovery at 30 September 2014 would lead to a transitory reduction to tariffs from 1 October 2014, after which tariffs would be expected to increase. The changes in distribution and transmission charges could send the wrong signals about the direction or level of future charges. A refund would be more transparent, as the temporary and backward-looking nature of it would be clear. Suppliers could highlight the temporary nature of the refund in their bills to consumers.

(b) We were not certain that consumers would get the full benefits from a temporary reduction in distribution and transmission charges made at relatively short notice (see discussion in paragraph 19.27).

(c) Making a full adjustment for any over-recovery through the correction factor could lead to NIE earning revenues in tariff years from 1 October 2014 to 30 September 2017 which are substantially lower than the revenues that we found, after detailed assessment, that NIE should recover in that period. That could weaken NIE's financial position in the period from 1 October 2014 and the financial ratios for NIE that are used by credit ratings agencies could suffer unduly (see Section 17 for further discussion of the relevance of these financial ratios). In contrast, a refund against past charges would more properly reflect the extent to which NIE's revenues in the past were too high relative to the revenues that we found that NIE ought to have recovered in relation to its past activities.

19.35 The main drawbacks we identified with the refund approach were the potential resource costs to NIE and suppliers from administration of the refund and the need for some regulatory activity by the UR to arrange for suppliers to pass through the refund to consumers. We did not consider the resource costs likely to be disproportionate to the benefits of the refund so long as the value of the refund was not an immaterial amount. Further, we did not expect that electricity suppliers in Northern

Ireland would impede the proper provision of a refund to their customers against past electricity charges, especially when such a refund policy can help reduce tariff volatility.

19.36 We shared our proposals on the refund with NIE and the UR. The UR agreed that there were more appropriate or transparent means than the correction factor in relation to the past over-recovery. The UR identified some issues that it said could mean that the refund policy would not be practical without further consideration. These included consideration of how the refund would apply in the case of consumers switching supplier or changing address, the management of any outstanding balance of the refund activity, the administrative costs and the 'vires' to impose any obligations on suppliers to pass on refunds. We recognized the points raised by the UR but did not consider them an impediment to the approach or that they meant that the refund would not be worthwhile. Rather, we considered these issues that we would expect NIE, the UR and suppliers to work through as part of the detailed implementation of any refund.

19.37 NIE's response focused on how it would administer a refund in order to apportion it between suppliers on a reasonable and practicable basis. NIE's response related to any potential refund for over-recovery as well as a potential refund related to the past PSO charges (see paragraphs 19.18 to 19.30). NIE suggested a fixed amount per customer for non-half-hourly customers and a more tailored refund for half-hourly metered customers based on their usage from 1 April 2012 to 30 September 2014. NIE said that it would expect that the UR would wish to discuss with suppliers how they would pass on the refund to their customers. We welcomed NIE's proposals on how it could administer any refunds in a reasonable and practicable way. However, we did not consider it appropriate to seek to specify these details of the administration of any refunds as part of our determination. There is a financial difference between a refund and adjustment through correction factor. In the absence of a refund, the over-recovery at 30 September would feed into charges through the correction factor. The revenue adjustment from 1 October 2014 would include an element of interest that NIE would effectively pay on the balance of over-recovery. That interest element would contribute to a further reduction to NIE's charges from 1 October 2014. Given the prevailing low interest rates, this interest effect would be relatively small. For instance, at a 0.5 per cent interest rate, the annual interest on a £10 million over-recovery would be £50,000. We did not consider the absence of an adjustment for interest under the refund scheme to be material and it could help offset any administrative costs.

19.38 The UR had suggested to us that rather than NIE refunding suppliers, NIE could refund consumers directly. NIE responded by saying that this was not a practical option because NIE did not have all the appropriate payee names and addresses. NIE also said that it would be very costly for NIE to pay the refund. We did not adopt the approach suggested by the UR. We considered it more appropriate for suppliers, which have direct commercial relationships with consumers, to provide refunds to consumers.

19.39 Accordingly, we determined that a refund was preferable to allowing an over-recovery to feed through the correction factor impacting tariffs from 1 October 2014. We decided that it would be for NIE to determine its best estimate of the size of the refund (if any) that would clear the estimated historical over-recovery in relation to its maximum regulated revenue from distribution services. NIE should do this before the 1 October 2014 tariff-setting process concludes. We expect NIE, the UR and suppliers to work through the detailed implementation of the refund, bearing in mind the reasonable costs of its administration and so the extent to which the refund is in the public interest.

19.40 In the case of transmission, NIE charges SONI and SONI charges suppliers, so any refund would need to be implemented through SONI. Our inquiry concerns the price control on NIE and NIE's Licences. We did not identify a basis on which we could require SONI to make a refund to its suppliers, so we decided not to require any refund from NIE in relation to transmission charges. However, we considered that if there was substantial historical over-recovery in NIE's transmission service charges, a refund would be desirable. It would, in our view, be open to NIE and the UR to seek to agree such a refund with SONI. If a transmission refund was agreed between the UR, SONI and NIE, then the refund could reduce the extent of any historical transmission over-recovery and bring the benefits set out in paragraph 19.34 above.

Further information on implementation of elements of price control design

19.41 Sections 4 to 16 set out our determination on the design and specification of a new price control for NIE and how this should operate. In this subsection we provide further information on how the new price control should be implemented.

19.42 Our decision to build on and adapt the formulae in NIE's current licence conditions reflected a desire to limit the scope for ambiguity in the way that NIE's price control operates.[2] We decided that the more mechanistic elements of price control design, such as cost risk-sharing arrangements, should be implemented through formulae in the price control licence conditions. Other elements that affect or adjust the revenue that NIE should collect in respect of its activities in the period 1 April 2012 to 30 September 2017 should be implemented through specific terms in the price control, for which the value should be formally determined by the UR through a published decision (in the interests of transparency).

19.43 We shared some of our preliminary views on this matter with the main parties during the course of our inquiry. NIE raised a specific concern that our desire for NIE's Licence conditions to specify the rules that affect the calculation of NIE's maximum regulation revenue or RAB might drive us to favour unduly mechanistic approaches to price control design. We did not consider that our determination suffered in this respect. We took into account the risks of ambiguity and future disputes when comparing options, but we did not give undue weight to options that could be relatively well specified in licence conditions.

19.44 In its submissions to us, the UR suggested that it might be better to make adjustments to implement aspects of our price control design as one-off adjustments as part of the next price control review rather than annual adjustments during the price control period. The UR said that this could reduce the administrative burden on the UR and NIE, although the UR also recognized a drawback that such an approach might lead to substantial adjustments to NIE's revenues from one price control period to the next, resulting in step changes in tariffs. We considered the potential regulatory burden but did not agree with the UR's suggested approach. The UR's approach would offer less clarity regarding the way that the price control operates which could lead to disputes between the UR and NIE (and perhaps third parties) about any financial adjustments made at the next price control review, which could increase regulatory costs. If there are to be disputes on interpretation it is better that they are revealed, investigated and resolved as soon as possible. Further, the UR's suggested approach overlooks a practical problem: some of the data needed to make the adjustments envisaged by the UR will not be available at the time that the UR

[2] Option *(a)* from the subsection 'Specification of revenue restriction in price control licence conditions' in paragraphs 19.3–19.13.

proposes to make those adjustments. For instance, at the time of the next price control review the out-turn cost data needed to implement our cost risk-sharing mechanism will not be available for the last year or two years of the price control period. It is not possible to make a one-off adjustment at the next price control review to fully implement the mechanism. The UR's approach could lead to adjustments to implement our price control design not being made to the price control review subsequent to the next price control review (perhaps in the year 2022).

19.45 We found that the format of NIE's current price control licence conditions, with formulae for different price control building blocks, to be well suited to an approach in which the cost risk-sharing mechanism and other elements of our price control design are implemented on an annual basis and specified in the price control formulae.

19.46 We have not sought to specify a comprehensive set of formulae to be included in the licence modifications. Following our determination, it will be for the UR to develop and consult on modifications to NIE's Licences. We set out below the aspects of price control design that we consider should be specified directly in NIE's licence conditions and provide further information on the implementation required to give effect to our determination.

Cost risk-sharing mechanism

19.47 The cost risk-sharing mechanism (paragraphs 5.49 to 5.96) should be specified directly in formulae used to calculate the opex allowances and RAB additions for each year.

19.48 The scope of costs covered by the cost risk-sharing mechanism ('qualifying opex' and 'qualifying capex') should cover all out-turn operating costs and capitalized costs incurred by NIE which are not specifically excluded. Excluded items comprise:

(a) the costs of items that we have determined should be subject to full cost pass-through;

(b) pension deficit repair contributions;

(c) costs incurred for activities subject to connection charges and other services that are treated as excluded services for the purposes of the revenue restriction;

(d) any costs recharged by NIE to associated businesses or related parties;

(e) any profit margin charged to NIE by a related party such as NIE Powerteam[3] (except for a transparently calculated element that provides for a reasonable allowance for depreciation and return on capital in relation to assets to the extent that these are employed by the related party in the provision of services to NIE and not otherwise reflected in NIE's qualifying opex or capex or recoverable through NIE's connection charges);

(f) any costs incurred by NIE as part of the PSO agreement or otherwise recoverable under the restriction on NIE's PSO charges (Annex 1 to its Licences);

[3] NIE Powerteam was renamed NIE Networks Services in December 2013.

(g) The costs of external advisers incurred by NIE in relation to our inquiry (including but not limited to the costs of external advisors that NIE sought to recover in its submissions on its inquiry costs, which were around £2.8 million (see paragraph 20.4); and

(h) any other costs which the UR determines are manifestly unreasonable to include in the cost risk-sharing mechanism.

19.49 The scheme should be implemented for opex as part of the formulae specifying the allowance for NIE's opex in its price control licence conditions. NIE's allowance for opex for each financial year should be calculated as the upfront opex allowance that we have determined for that year (see Section 7) plus 50 per cent of the difference between NIE's qualifying opex in that year and the upfront allowance for that year. This is equivalent to the opex allowance for each year being calculated as the average of our upfront opex allowance for that year and NIE's qualifying opex for that year.

19.50 The scheme should be implemented for capex as part of the formulae specifying the RAB additions in NIE's price control licence conditions. The RAB additions for each RAB in each year should be calculated as the upfront capex allowance that we have determined for that year and that RAB (see Section 7) plus 50 per cent of the difference between NIE's qualifying capex that is attributable to the relevant RAB in that year and the upfront allowance for that year. This is equivalent to the RAB additions being set as the simple average of our upfront capex allowances for that year and NIE's qualifying capex that is attributable to the relevant RAB.

19.51 In setting tariffs, NIE will need to make a forecast of out-turn expenditure. Any differences between those forecasts and out-turn expenditure will feed through to the correction factor term in NIE's restriction on maximum regulated revenue.

19.52 The mechanism will rely on annual reporting of cost data and calculation of the price control according to specified formulae and the latest data. We expect the reporting arrangements to draw on the new reporting arrangements we require from NIE, which are based on Ofgem's RIGs (see Section 18). However, Ofgem's own reporting arrangements are not based on accounting splits between opex and capex so we expect a separate stage of cost reporting and reconciliation to be needed to provide information on qualifying opex and capex for the purposes of the cost risk-sharing mechanism. NIE should provide information to reconcile total opex and capex with qualifying opex and capex.

Inefficient spend clause

19.53 The formulae for the revenue restriction should include a term to implement any financial adjustment determined by the UR under the inefficient spend clause (see paragraphs 5.97 to 5.111). To give effect to such a determination may also require revisions to NIE's RAB, as part of the calculations at the next price control review.

Policy of deferred network investment

19.54 Our decision on the regulatory treatment of deferred network investment (see paragraphs 5.112 to 5.214) does not require modifications to price control formulae to calculate NIE's maximum regulated revenue in the period to 30 September 2017. Instead, our decision, including the policy of no double funding of deferred network investment, should be implemented as part of the regulatory cost assessment that is used to set new price controls for NIE to apply from 1 October 2017.

Investment to increase transmission system capacity

19.55 To implement our decisions on investment to increase transmission system capacity (see paragraphs 5.246 to 5.279), the formulae for NIE's transmission RAB additions should include a provision for the UR to determine positive adjustments for the costs that it decides to allow for in respect of investment to enhance the capacity or capability of the transmission system.

19.56 Any costs incurred by NIE for such investment would qualify for the cost risk-sharing mechanism.

Metering volume driver

19.57 The price control formulae for the calculation of RAB additions for metering RAB should include adjustments to give effect to the volume driver for metering capital expenditure (see paragraphs 5.287 to 5.303). The adjustment should take the difference between NIE's actual volumes of meter work in each category and the forecast volumes we used for our determination, multiplied by the unit cost allowances we determined for each category (see Table 10.13), updated as appropriate for the RPE and productivity assumptions we determined for metering capex in Sections 7 and 11. The adjustments should apply in each year from 1 April 2012, based on out-turn volumes in that year.

Connection charges funded through the RAB

19.58 The price control formulae should include a term to add qualifying connections costs (from our decision in paragraphs 5.304 to 5.315) to the distribution RAB additions in the year in which they were incurred. There should be no upfront allowance for these costs.

Pass-through of licence fees

19.59 To implement our decision on regulatory licence fees (see paragraph 5.347) the price control formulae should include a term to add licence fee costs to the opex allowance in the year in which they were incurred by NIE. There should be no upfront allowance for these costs.

Costs associated with injurious affection claims

19.60 To implement our decision in relation to injurious affectation (see paragraphs 5.366 to 5.381) there should be a provision in price control formulae for opex allowance and RAB additions for the UR to determine additional allowances for the costs associated with injurious affection claims.

Additional services required from NIE for market systems

19.61 There should be a term in the price control formulae for the UR to determine an addition to NIE's opex allowance or RAB additions if there are significant changes in the specification of the service that NIE is required to provide in relation to market systems and the Enduring Solution (such adjustments should be subject to consultation and published documentation).

Legacy Dt costs

19.62 The price control licence conditions should allow for NIE's recovery of costs relating to the specific Dt items that we decided to allow for in the period from 1 April 2012 (see paragraphs 10.356 to 10.368). The costs that NIE can recover should be limited by the original terms of the UR's approval (eg on maximum costs or restrictions).

Treatment of revenue protection income

19.63 There should be a term in the price control formulae for the restriction on NIE's revenue from distribution services that increases the maximum regulated revenue by 50 per cent of the qualifying revenue protection income in that year (see paragraphs 6.39 to 6.48).

Temporary RAB contribution to connection charges for certain housing sites

19.64 As set out in paragraphs 10.299 to 10.302, the price control licence conditions should allow NIE to recover its net connection costs (ie costs less customer contributions) in respect of housing sites with 12 or more dwellings until 1 October 2015 (after which we would expect new connection charges to apply). The net costs should be added to (or subtracted from) the distribution RAB.

Cluster infrastructure

19.65 NIE's price control licence conditions should allow the costs that NIE actually incurs in relation to cluster infrastructure to be added to NIE's distribution or transmission RAB (with deductions for relevant generator contributions) subject to the conditions and policy specified in our decision on cluster infrastructure in paragraphs 10.332 to 10.337.

Potential further allowance for regulatory reporting

19.66 Provision should be made for a mechanism whereby NIE can seek additional funding in respect of regulatory reporting costs subject to the conditions and policy specified in our decision on regulatory reporting costs in paragraphs 18.68 to 18.72.

Allowance for corporation tax

19.67 The formulae for the calculation of corporation tax in the price control licence conditions, and NIE's regulatory reporting requirements in relation to corporation tax, should be revised as specified in paragraphs 16.57 to 16.63.

Asset disposals

19.68 Under NIE's current price control licence conditions, and the accompanying methodology document, the calculation of NIE's RAB each year involves the deductions for the proceeds from asset disposals five years earlier. The proceeds from asset disposals may include, for example, revenue from the sale of land which had previously been the site of an electricity substation.

19.69 NIE told us that, under the current arrangements, when an asset was disposed of, the RAB was reduced five years after the disposal by the amount of the disposal price less any reasonably incurred costs. NIE said that it was content for this mechanism to continue for the new price control from 1 April 2012.

19.70 NIE provided information that showed that the average value of asset disposals during the period 1 April 2007 to 31 March 2012 was around £13,000 per year in 2009/10 prices.

19.71 The UR submitted the following in relation to the treatment of asset disposals:

(a) It considered that for asset disposals there was currently a 'rolling mechanism' and that a change of policy should consider the previous regulatory policy;

(b) It said that asset disposal should be managed as cost-efficiently as possible ensuring compliance with all local and/or national legislation and environmental regulations.

(c) It said that compliance with these requirements and the incentive within the opex allowance were sufficient and that it would not recommend continuing the asset disposal incentive.

(d) It said that 'further future improvements in asset disposal should be driven from NIE's path to delivery of asset management excellence as identified in its asset management strategy'.

19.72 We did not accept the UR's argument that there was no longer a need for any financial incentives on NIE in relation to asset disposal. That argument seemed to rest on the view that the incentives relating to opex are sufficient, but we did not understand from the UR's submissions how any financial incentives on NIE's opex would feed through to its financial incentives in relation to proceeds from asset disposals. Further, the UR did not propose and justify an alternative approach to asset disposals that we could review.

19.73 If anything, we thought that the current arrangements for asset disposal may provide NIE with insufficient financial incentives. A cost pass-through to the RAB after five years may not provide NIE with particularly strong financial incentives to maximize proceeds from asset disposals. However, given the small scale of asset disposals in the past, we did not find that the current treatment of asset disposals operated materially against the public interest and warranted revision.

19.74 We decided that the treatment of asset disposals from 1 April 2012 to 31 March 2017 should be the same as under the existing licence conditions and RAB calculation method.

Allowed return calculation

19.75 We decided that the calculation of NIE's allowed return should make use of an adjusted formula where the WACC we have determined is first scaled down by dividing it by the square root of 1+WACC, before multiplication by the RAB to calculate the allowed return (see paragraph 17.13 and its first footnote).

RAB calculation

19.76 Under NIE's current price control licence conditions, elements of the method for calculating the opening and closing value of NIE's RAB are contained in a separate document, referred to as the '2006 Direction', which was for some time unpublished.

19.77 We decided that all aspects of the methods needed to calculate NIE's RAB and depreciation should be specified in NIE's Licences (or in appendices to these).

Closing correction factor at 31 March 2012 and RP4 capex efficiency payments

19.78 We decided that the calculation of NIE's maximum regulated revenue for 2012/13 should not specify formulae for the K_{Dt} correction factor that rely on formulae for NIE's maximum regulated revenue in previous financial years. That approach would mean that the Licences would need to retain many pages of formulae to be used to calculate NIE's maximum regulated revenue in previous price control periods in order to calculate the correction factor that should apply from 1 April 2012. This seemed overly complex and unnecessary. Instead, we decided that the relevant adjustment for the correction factor from 1 April 2012 should be hard-coded into the formulae for NIE's maximum regulated revenue in the price control licence conditions.

19.79 We asked NIE and the UR to confirm the values of the correction factor that would feed into NIE's maximum regulated revenue from 1 April 2012 under the current price control licence conditions (2009/10 prices):

(a) £9.630 million over-recovery at 31 March 2012 that NIE attributed to distribution use of system charges; and

(b) £11.877 million under-recovery at 31 March 2012 that NIE attributed to transmission.

19.80 These figures represent the correction factor term (K_{Dt}) that would apply (absent licence modifications) to the calculation of NIE's maximum regulated revenue for the period from 1 April 2012 to 31 March 2013. This correction factor reflects the cumulative position at 31 March 2012 in relation to past over- and under-recoveries and includes interest in relation to the over- and under-recovery between 1 April 2011 and 31 March 2012.

19.81 The UR said that it was content for us to accept these figures from NIE. NIE did not comment further on them.

19.82 We therefore decided that the price control licence conditions should specify:

(a) a deduction of £9.630 million against NIE's maximum regulated distribution revenues in 2012/13; and

(b) an addition of £11.877 million to NIE's maximum regulated transmission revenues in 2012/13.

19.83 For financial years from 1 April 2013 onwards, the maximum regulated revenue (in each year running 1 April to 31 March) would include a correction factor for any over- or under-recovery in the previous year based on a formula for the correction factor corresponding to that in the current Licence conditions.

19.84 NIE and the UR confirmed that the figures quoted above for the correction factor reflect the UR's interpretation of the disputed capital allowances term in the current price control Licence conditions. We decided in Section 14 that for our determination we would not seek to revise the UR's decision on this matter for the period to 31 March 2012 (see paragraphs 14.26 and 14.28).

19.85 NIE and the UR confirmed that the figures quoted above for the correction factor did not include any adjustments to give effect to the payments due to NIE under the RP4 capex efficiency incentive for 2009/10, 2010/11 and 2011/12. The UR had not completed its assessment of the level of payments due to NIE under the RP4 capex efficiency incentive in time for our final determination.

19.86 We decided in Section 14 that it should be for the UR to determine what payments are due to NIE under the capex efficiency incentive that applied under the RP4 price control (see paragraphs 14.22 and 14.28) in the period to 31 March 2012. We decided that, to give effect to this decision, NIE's price control Licence conditions should include a term that provides for an adjustment to the calculation of NIE's maximum regulated revenue in the year 1 April 2012 to 31 March 2013 to provide for the payments due to NIE (if any) under the RP4 capex efficiency incentive for 2009/10, 2010/11 and 2011/12. The value should be determined by the UR in a way that is consistent with the calculations that applied under the price control licence conditions established to implement the RP4 price control, and allowing for an interest rate in the calculations that is consistent with that used for the correction factor adjustments for over- and under-recovery.

Transparency of revenue restriction in price control licence conditions

19.87 NIE's current licence conditions contain formulae that are used to calculate NIE's maximum regulated revenue in each financial year. It is not possible for any third party to calculate NIE's maximum regulated revenue for a given financial year from NIE's price control licence conditions and other publicly available information such as NIE's regulatory accounts.

19.88 The formulae in NIE's current price control licence conditions rely on:

(a) historical data that was available when the price control was implemented through licence modifications; and

(b) data that was not available when the licence modifications were made (eg data on NIE's out-turn capex over the period from 1 April 2007).

19.89 The calculations relating to NIE's RAB make extensive use of historical data, some of which stretches back to the early 1990s. However, the licence conditions neither specify all the values of the historical RAB data nor give a full set of references to sources where the data can be verified.

19.90 The financial model used by the UR as part of its price control review contains historical data relating to NIE's RAB which can be used for the calculation of its maximum regulated revenue.

19.91 This feature of NIE's current licence conditions reduces its transparency to third parties. Third parties cannot check whether the revenue control for NIE has been calculated correctly in accordance with the licence conditions.

19.92 To address these concerns about transparency, we decided that all historical data needed for the calculation of NIE's maximum regulated revenue is specified in NIE's price control licence conditions (eg as tables appended to the formulae). The relevant historical data should be extracted from the version of the UR's financial model that we used for our final determination.[4]

19.93 For data used in these calculations that is not available when licence modifications are made (eg expenditure and revenue data for the period from 1 April 2013), we decided that the data should be published in NIE's publicly available regulatory accounts.

19.94 The UR supported the approach of 'hard coding' relevant historical data in NIE's Licences where this represents a roll-forward of inputs or outcomes of previously-determined price control decisions. The UR said that this would help provide a firm foundation for setting future revenues that were explicitly recognized by both the UR and NIE.

The financial year for NIE's maximum regulated revenue

19.95 There are potential inconsistencies between the following elements of NIE's regulatory and commercial framework.

(a) **Regulated revenue year**. We use this term to refer to the period over which NIE's revenue is counted for the purposes of the restriction on the maximum regulated revenue specified in NIE's the price control licence conditions. This currently runs from 1 April to 31 March. NIE's current licence conditions require it to 'use its best endeavours to ensure that in any relevant year [from 1 April to 31 March] the regulated transmission and distribution revenue shall not exceed the maximum regulated transmission and distribution revenue' (clause 2).

(b) **Regulatory reporting year**. This is the period used for regulatory reporting of NIE's costs, revenues and other financial information. NIE's regulatory accounts currently cover the period from 1 April to 31 March.

(c) **Tariff year**. NIE currently sets its tariffs on an annual basis for the period from 1 October to 30 September. This period is aligned with other elements of the commercial arrangements across the single electricity market covering Northern Ireland and the Republic of Ireland.

19.96 In addition, NIE's statutory accounting period operates over a different period, running from 1 January to 31 December. We did not consider this accounting period relevant to our inquiry. NIE's statutory accounting period is a decision influenced by its parent company and could change if NIE is acquired by another party.

Our provisional determination

19.97 In Section 4 of our provisional determination, we identified the possibility of changing NIE's regulatory reporting period to run from 1 October to 30 September. We had envisaged that the regulated revenue year could run from 1 October to 30 September. We identified the following benefits from such a change (paragraph 4.54):

[4] The relevant historical data was provided by UR and is in sheet 'Input1' and in rows 80–85 of sheet 'Input' of the UR's financial model v58.

There are potential practical benefits in alignment between the financial year for price control purposes (ie the financial year to which algebra to calculate maximum regulated revenue apply) and the financial year for regulatory accounts and other annual regulatory reporting. This is because the price control calculations will draw on regulatory accounting and reporting information.

19.98 We also identified drawbacks from such a change in our provisional determination (also paragraph 4.54):

(a) The implementation costs and possible risks of inconsistencies from a change in reporting years.

(b) The introduction of an inconsistency between the regulatory reporting period for NIE and that for GB DNOs, which provide cost and other data to Ofgem for financial years that run from 1 April to 31 March.

19.99 In their responses to our provisional determinations, both NIE and the UR raised concerns about the need for reconciliation across different financial periods if NIE's regulatory reporting year remained 1 April to 31 March but the regulated revenue year changed to 1 October to 30 September. NIE suggested that this was discussed further as part of the engagement with the UR on the scope of the RIGS. The UR explicitly proposed a change so that regulatory reporting was for the period from 1 October to 30 September.

Further analysis and consultation with NIE and the UR

19.100 Following our provisional determination, we gave further consideration to the choice of regulated revenue year and regulatory reporting year and shared some further analysis and options with NIE and the UR. The following issues seemed particularly important:

(a) The adverse effect on future benchmarking analysis and cost comparisons if NIE's reporting year is no longer aligned with the reporting year for the GB DNOs.

(b) The current situation in which the regulated revenue year is not aligned with NIE's tariff year may contribute to tariff volatility.

(c) The potential need for additional regulatory reporting and reconciliation of NIE's costs across two different accounting periods if the regulated revenue year is not aligned with the regulatory reporting year.

19.101 In its submissions to us, the UR said that it did not agree with our concern about inconsistencies in regulatory reporting periods between NIE and the GB DNOs. The UR said that it had discussed the issue of benchmarking with Ofgem and reported that Ofgem benchmarked internationally, using data from countries with different financial rules and time frames.[5] We agreed with the UR that benchmarking analysis was feasible across companies with different regulatory reporting periods. However, our concern was that a change of regulatory reporting year for NIE would incrementally lessen the accuracy of benchmarking comparisons. It would also increase the complexity of future benchmarking analysis and raise additional questions on methods and the interpretation of results. If the reported costs for NIE change sub-

[5] UR response to the provisional determination, p9.

stantially from one year to the next—something we saw in the data we used in this inquiry—the choice of which year's data for NIE is compared against which year's data for the GB DNOs could have a significant effect on results. Further, a change of reporting year for NIE would not only introduce inconsistency in reporting years between NIE and the GB DNOs, it would also disrupt the time series of historical data for NIE. The UR's submissions did not satisfy us that a change in the regulatory reporting year would not have significant adverse effects in the future.

19.102 The potential tariff volatility under point (b) arises in part because the action that NIE takes to comply with the revenue restriction that runs from 1 April to 31 March is to change the tariffs that apply over a period that runs from 1 October to 30 September. For example, if the forecasts and estimates used by NIE to set tariffs need to be revised (as is inevitable), the tariff changes that it must make to comply with its regulated revenue restriction: *(a)* can only affect revenues in the second six-month period of that regulated revenue year and not the first six months; and *(b)* also affect revenues in the first six-month period of the subsequent price control year. The effect of *(a)* is that any unanticipated tariff change to address potential over- or under-recovery will need to be of greater magnitude than if the regulated revenue year were 1 October to 30 September because there is a shorter period of time over which the tariffs can help to bring revenues back in line with maximum regulated revenue. The effect of *(b)* is that any unanticipated changes in tariffs made by NIE to bring anticipated revenues back in line with maximum regulated will affect NIE's revenues in the first six months of the subsequent regulated revenue year—which may, in turn, need to be taken into account in the following year's tariff changes to enable NIE to comply with the revenue restriction for the subsequent regulated revenue year. In addition, NIE said that the seasonality in revenues led to tariff volatility under the current arrangements.[6]

19.103 In its submissions to us, NIE emphasized its concerns about tariff volatility if the regulated revenue year was not aligned with the tariff year.

19.104 NIE identified that it might be possible to tackle the concerns we had identified through a change to NIE's tariff year to align with its regulatory reporting year. NIE suggested that we sought the views of the UR on whether a change in tariff year was a practical option having regard to the retail market arrangements. In its submissions to us, the UR did not show any support for a change in NIE's tariff year. The UR referred us to its joint decision with CER in April 2007 to align the retail tariff period, and by implication, all underlying cost component periods, in both regulatory jurisdictions. The regulatory arrangements governing NIE's tariff year lie outside of the price control licence conditions that are the subject to our inquiry. Without explicit support from the UR for a change in the tariff year, we did not consider it practical to take decisions in our inquiry that rested on a change in NIE's tariff year.

19.105 NIE also proposed an alternative option which would allow for the regulated revenue year to differ from the regulatory reporting year, without giving rise to problems of additional cost reconciliation identified at point (c) above. The key features of NIE's approach are as follows:[7]

[6] NIE submitted that the tariff volatility under point (b) was 'systemic' rather than due to getting forecasts wrong and arose because of the licence obligation to set tariffs so as to avoid an over-recovery at the end of regulatory period, and given the seasonality of units between winter and summer, there would always be a K under- or over-recovery at the end of each tariff period. NIE provided a worked example which it said illustrated that point.
[7] We have presented NIE's approach in a different way and used different terminology to NIE.

(a) The restriction on the maximum regulated revenue which NIE must use its best endeavours not to exceed would be specified for a financial year that runs from 1 October to 30 September.

(b) The various price control building blocks specified in the price control licence conditions (eg formulae that specify allowances for opex, RAB additions, allowed return, etc) would be defined for a regulatory reporting year that runs from 1 April to 31 March. The cost and revenue data from the regulatory reporting would feed into these calculations for each of the price control building blocks.

(c) The price control building blocks from *(b)* would be used to calculate the maximum revenue for each regulatory reporting year. This would be an intermediate step to the calculation of the maximum regulated revenue on an October to September basis for the purposes of *(a)*. The price control licence conditions would define the maximum regulated revenue for each 1 October to 30 September period as the average of the maximum regulated revenue over the two 1 April to 31 March periods that it spans.[8]

19.106 The UR did not support this proposal from NIE. The UR was concerned about the complexity of the approach and its potential effects on transparency for stakeholders. The UR said that within the time frame available it was not in a position to carry out any detailed analysis or modelling on NIE's proposal and that no public consultation had been carried out in relation to NIE's proposal. The UR also highlighted that there were a number of different sources of tariff volatility. The UR stated that tariffs had gone up and down in the past few years and that the tariff changes were largely driven by wholesale and generation cost changes. The UR suggested that volatility in NIE's tariffs was something it could seek to tackle as part of the next price control review for NIE.

19.107 NIE responded to the UR's submissions on its proposal. NIE reiterated its concerns about the systemic tariff volatility introduced by having different regulatory and tariff periods. NIE acknowledged that the major component of retail tariff volatility was due to wholesale price movements, but argued that it could not be in the public interest to have systemic volatility in the network charge component which would only exacerbate the problem. NIE said that its proposal was a practical solution to the network charge volatility issue, that the tariff-setting principles were exactly the same and the complexity was minor.

Our assessment

19.108 We accepted NIE's argument that the misalignment under the current price control conditions between the regulated revenue year and the tariff year could contribute to unnecessary volatility in tariffs. We decided that this feature of the current licence conditions operated against the public interest (see Section 3).

19.109 We considered the proposal submitted by NIE to be a valuable contribution to the inquiry. Under this approach, the revenue restriction that NIE would face when it sets its tariffs would be defined for a period from 1 October to 30 September which is the

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[8] As an example, information from our determination and NIE's regulatory accounts for the period 1 April 2015 to 31 March 2016 would be used to calculate maximum regulated revenue for 1 April 2015 to 31 March 2016. Suppose this was £200 million. Similarly, information from our determination and NIE's regulatory accounts for the period 1 April 2016 to 31 March 2017 would be used to calculate maximum regulated revenue for 1 April 2016 to 31 March 2017. Suppose this was £210 million. The maximum regulated revenue for the period 1 October 2015 to 30 September 2016 would be calculated as the average of these, £205 million.

same period over which NIE's tariffs apply. This would help to reduce tariff volatility. In addition, the current regulatory reporting year would be retained, which would avoid a change to NIE's regulatory accounting period and avoid inconsistency between NIE and the GB DNOs in the regulatory reporting period.

19.110 We considered the UR's arguments against NIE's proposal but were not persuaded by them. Even if the major factor driving tariff volatility is wholesale price movements that is no reason not to take practical and proportionate measures that are available as part of our determination to reduce tariff volatility.

19.111 We recognized that the approach could add to the complexity of the algebra in the price control licence conditions and of the work to calculate and approve tariffs each year. But we did not consider that any such drawbacks would be sufficient to outweigh the likely benefits from limiting tariff volatility whilst supporting consistency of cost reporting between NIE and the GB DNOs.

19.112 We did not consider it necessary or proportionate regulation to carry out further public consultation, as the UR had suggested, if we were to adopt NIE proposal. NIE's proposal would affect a detailed aspect of the formulae in its price control licence conditions. We did not consider the incremental complexity or regulatory burden to be sufficiently material to warrant wider consultation. NIE said that the complexity from its proposal was minor. No parties other than NIE and the UR had responded to the section of our provisional determination on the choice of financial year for regulatory reporting and regulated revenue.

19.113 We decided to adopt the approach with the features set out in paragraph 19.105 above. However, we decided to make a change to one element of NIE's original proposal, which concerns the correction factor. We also recognized a need to specify clearly how the revenue restriction should be calculated for the last six months of the price control period. We address these two issue below.

Correction factors for over- and under-recovery

19.114 In its proposal, NIE suggested that the correction factor applying to the restriction on NIE's regulated revenue in each period from 1 October to 30 September would include a correction factor which was calculated by reference to over- or under-recovery against the maximum regulated revenue in the period from 1 October to 30 September. However, we identified problems in relation to the transition from the present arrangements in which the correction factor applied for a reporting year running from 1 April to 31 March to arrangements in which the correction factor applies for a tariff year running from 1 October to 30 September. There would be an intermediate six-month (or 18-month) period as a result of the transition and we did not identify an accurate approach to calculating the over- or under-recovery in relation to this intermediate period. This problem related to the seasonal nature of NIE's revenue (greater revenues in the winter), which meant that we could not simply assume that NIE's revenues for a six-month intermediate period were equal to half its annual revenues.

19.115 NIE provided us with a worked example of its approach. However, that worked example was simplified and rested on an assumption that there was zero historical over- or under-recovering feeding into tariffs from 1 October 2014. That simplification had the effect of assuming away the transitional problem we had identified. We did not consider that the various submissions from NIE provided a feasible solution in relation to the correction factor.

19.116 In the course of our work, we considered an option in which the correction factor that feeds into maximum regulated revenue for the tariff year from 1 October would be based on the value of under- or over-recovery up to the previous 31 March (only). This would avoid the transitional problem by retaining a regulatory reporting year basis for the correction factor. The UR told us that it considered it more accurate and consistent always to base the correction factor on past under/over-recovery. However, NIE argued that such an approach could contribute to tariff volatility. We agreed that such an approach could lead to unnecessary fluctuations in tariffs. This was linked to a drawback of this approach which is that tariffs set from 1 October each year would not take account of any actual or forecast over- or under-recovery in the preceding six-month period from 1 April to 30 September. We decided not to adopt this approach.

19.117 We decided instead that:

(a) NIE's maximum regulated revenue in each reporting year should include a correction factor for differences between its maximum regulated revenue in the previous reporting year and its revenue from transmission and distribution services in that previous reporting year; and

(b) any over- or under-recovery would feed into NIE's maximum regulated revenue in a tariff year because the maximum regulated revenue in a tariff year would be the average of the maximum regulated revenue for the two reporting years that it spans (which would include correction factors for those years).

19.118 The price control licence conditions would specify formulae to calculate NIE's maximum regulated revenue for the reporting year 1 April 2012 to 31 March 2013 and for the reporting years 1 April 2013 to 31 March 2014, but these would not feed directly into restrictions on NIE's maximum regulated revenue in tariff years before 1 October 2014. Instead, they would be used to calculate the correction factors for any over- or under-recovery in the period 1 April 2012 to 31 March 2014, which would feed into NIE's maximum revenue for the reporting year from 1 April 2014 to 31 March 2015 and, in turn, the restriction on NIE's revenue in the tariff year 1 October 2014 to 30 September 2017.

19.119 In setting tariffs, NIE would need to make a forecast of its maximum regulated revenue in the upcoming tariff year using estimates of past over- and under-recovery and forecasts of potential future over- or under-recovery (eg over- and under-recovery resulting from tariffs it has already set).

19.120 The price control licence conditions should require NIE to set tariffs so as to eliminate the existing and forecast cumulative over- or under-recovery. We decided that NIE should also publish a report that sets out its forecast maximum regulated revenues and its forecast over- or under-recovery in all future years.

Period from 1 April 2017 to 30 September 2017

19.121 Under NIE's original proposal to us for revisions to the regulated revenue year, the maximum regulated revenue for the period from 1 October 2016 to 30 September 2017 would be based on 50 per cent of the maximum revenue calculated from price control building blocks for the reporting year from 1 April 2016 to 31 March 2017 and 50 per cent of the maximum revenue calculated from price control building blocks for the reporting year from 1 April 2017 to 31 March 2018.[9] As part of our inquiry we have not sought to determine cost allowances for the period to 31 March 2018; our determination of cost allowances is limited to the period to 30 September 2017.

19.122 Nonetheless, such an approach would not prevent a new price control taking effect from 1 October 2017 and has practical benefits for the price control formulae. It avoids the need to define price control formulae for a special six-month period from 1 April 2017 to 30 September 2017. We were concerned that if the licence conditions specified a restriction on NIE's revenues for a special six-month period this could increase complexity in price control formulae (the formulae for each price control building block would need to include additional formulae to be used for a one-off six-month period) and also bring risks of unintended consequences arising from the seasonality in revenues and costs. Further, the implementation of the cost risk-sharing mechanism seemed problematic for a six-month period when the accounting information on costs that will feed into the mechanism is prepared on an annual basis running from 1 April to 31 March.

19.123 We decided to adopt the following approach:

(a) Consistent with the approach to the preceding tariff years, the maximum regulated revenue for the period from 1 October 2016 to 30 September 2017 would be based on 50 per cent of the maximum revenue calculated from price control building blocks for the reporting year from 1 April 2016 to 31 March 2017 and 50 per cent of the maximum revenue from price control building blocks for the reporting year from 1 April 2017 to 31 March 2018.

(b) For the reporting year 1 April 2017 to 31 March 2018 the upfront cost allowances to be included in the price control licence conditions should be calculated as the allowance that we have determined for the six-month period from 1 April 2017 to 30 September 2017 multiplied by two. This should mean that the allowances we intend for the six-month period 1 April 2017 to 30 September 2017 feed into tariffs in the period to 30 September 2017 (the end of our price control period) by first being multiplied by two and then being divided by two.

(c) When the UR sets a new price control to apply from 1 October 2017 it should determine cost allowances for the period 1 October 2017 to 31 March 2018 and revise the cost allowances specified in the price control formulae for the reporting year 1 April 2017 to 31 March 2018, based on the difference between its allowances for the period 1 October 2017 to 31 March 2018 and the allowances we determined for 1 April 2017 to 30 September 2017 (which are multiplied by two under *(b)* above to provide full-year allowances). In determining cost allowances for the period 1 October 2017 to 31 March 2018, the UR should take account of the way that we have set cost allowances for the six-month period 1 April 2017 to 30 September 2017, particularly in respect of areas where we have taken some account of seasonality in costs (aspects of the network investment allowances) and where we have not (the allowances for indirect and IMF&T costs).

(d) When the UR sets a new price control to apply from 1 October 2017, the UR could also revise other aspects of the building blocks for the revenue calculation for the period 1 April 2017 to 31 March 2018 (eg the WACC parameter in the

[9] NIE subsequently told us that it had made an error in its proposals and that, in respect of the tariff year to 30 September 2017, it should have said that 'maximum allowed revenue' should be based on 50 per cent of the Regulatory allowance for 2016/17 plus the Regulatory allowance for the six months to 30 September 2017 plus the K factor at 30 September 2016.

formulae for the allowed return). However, the UR should avoid changes having any retrospective effect for the period from 1 April 2017 to 30 September 2017 (eg if the UR decided to use a revised figure for WACC from 1 October 2017 it might set the WACC for the period 1 April 2017 to 30 September 2018 using an average of the WACC from our determination and its new WACC but should not seek to impose any new WACC on the revenue to 30 September 2017).

19.124 Table 19.1 summarizes the implications of our decision on the regulated revenue year. It also confirms that, for consistency with our determination, any new price control that takes effect from 1 October 2017 should include a correction factor for under- or over-recovery calculated for the period up to 30 September 2017.

TABLE 19.1 **Summary of our decision on regulated revenue calculations**

Tariff year	*Calculation of revenue restriction*
Period before 1 October 2014	No revenue restriction
	Instead, a prohibition in the licence conditions on tariff increases before 1 October 2014
	Maximum regulated revenue in reporting years 1 April 2012 to 31 March 2013 and 1 April 2013 to 31 March 2014 are calculated for the purposes of calculating the correction factor that feeds into maximum regulated revenue in reporting year 1 April 2014 to 31 March 2015
1 October 2014 to 30 September 2015	50% of maximum revenue for reporting year from 1 April 2014 to 31 March 2015
	+
	50% of maximum revenue for reporting year from 1 April 2015 to 31 March 2016
1 October 2015 to 30 September 2016	50% of maximum revenue for reporting year from 1 April 2015 to 31 March 2016
	+
	50% of maximum revenue for reporting year from 1 April 2016 to 31 March 2017
1 October 2016 to 30 September 2017	50% of maximum revenue for reporting year from 1 April 2016 to 31 March 2017
	+
	50% of maximum revenue calculated for reporting year from 1 April 2017 to 31 March 2018
New price control applicable from 1 October 2017	To be determined as part of next price control review
	Should provide for correction factors in respect of any over- or under-recovery in regulated revenue years 1 April 2016 to 31 March 2017 and 1 April 2017 to 31 March 2018

Source: CC

20. NIE: costs of inquiry

20.1 In this section we consider whether NIE should be able to recover external costs arising from our inquiry, and, if it should, in what amount. Any costs so recovered will be passed on to consumers in Northern Ireland as part of NIE's opex. The UR's costs too will be borne by consumers in Northern Ireland and UR will decide to what extent the CC's costs, which will only be direct costs, will also be passed on and borne by the consumers of Northern Ireland.

20.2 We:

(a) set out NIE's claim;

(b) the UR's response; and

(c) our assessment and determination.

NIE's claim for external costs

20.3 NIE asked to recover its 'costs arising directly from the CC investigation' incurred on external advisers. From 30 April 2013, the date of the reference, these amount to £1.96 million, comprising approximately £670,000 for legal advice, £1,130,000 for economic advice, £110,000 for advice on Capex and £50,000 for advice on pensions. NIE did not ask for any of its internal costs although these were likely to be material.

20.4 In addition, NIE subsequently sought to recover a further £840,000 which it said represented the costs it incurred between the date the company rejected the UR's final RP5 determination (20 November 2012) and the date of the reference (30 April 2013) to us. This was on the basis that during that—by comparison with other regulatory references long—period of five months NIE were engaged with its lawyers, economic advisers and others in preparing and drafting its extensive Statement of Case which was submitted to us on 10 May 2013. The £840,000 comprised approximately £435,000 for external legal advisers, £320,000 for external economic advisers, £67,000 for advice on Capex and £16,000 for advice on pensions. In total, therefore, NIE sought some £2.8 million as costs arising directly from our inquiry, comprising £840,000 before the determination was referred in preparation of NIE's Statement of Case and £1.96 million after the date the determination was referred to us.

20.5 In support of its claim, NIE said that a reference was an important part of the protection afforded a regulated company which has wider public benefits. NIE had behaved reasonably in instigating the reference and most of its costs were incurred responding to our requests. If NIE could not claim its costs, these would fall on its shareholder. NIE said that it would be wrong only to look at the extent to which NIE's proposals were adopted by the CC, the more relevant question would be the extent to which work undertaken by the company had assisted the CC in coming to a better decision for the price control.

The UR's response

20.6 The UR said that it did not believe it would serve the public interest if customers were to bear NIE's inquiry costs. While it was in the regulated company's power to reject a proposed price control, it would depend on the circumstances whether or not, and if so the extent to which, such rejection would serve the interests of consumers. For example, if the relevant price control which was subject to the reference already provided an appropriate balance of customers' and the company's interests, customers should not bear the company's costs. The UR stated that while the present inquiry did add some value, only a small proportion of NIE's claimed costs should be allowed to reflect such limited value, as many of NIE's claims would not be substantially reflected in the CC's determination. At the very least, the UR said, the costs NIE may recover should not exceed the level of the URs external costs or the CC's external costs.

Our assessment and determination

20.7 Unlike some other regulatory jurisdictions there is no express statutory basis in either the Electricity (Northern Ireland) Order 1992 or the Energy (Northern Ireland) Order 2003 to enable NIE to recover its inquiry costs. However, in previous regulatory inquiries, the CC has made allowances for parties to recover some of their external costs, even absent a statutory basis.[1,2] We agree with the parties (paragraphs 20.5, 20.6) that the fundamental question is whether it is in the public interest for NIE's external costs to be paid by consumers rather than NIE, whether in whole or part.

20.8 We considered first whether or not NIE acted reasonably in rejecting UR's suggested price control. In our view, with which the parties agree, there are now significant areas where the RP4 price control is not in the public interest, not least because some of its terms have expired (see Section 3). Our final determination differs significantly from both RP4 and from the UR's final determination for RP5. These differences reflect our view of the way in which the public interest is best served, our conclusions building on submissions made to us by NIE and the UR, as well as our other investigations.

20.9 Second, we note that the sums involved in our determination are significant, with the value of our price control for the period from 1 October 2014 to 30 September 2017 amounting to more than £200 million a year and being in the region of £1.1–£1.2 billion over the period of the whole determination. Very little of the overall price control determination has not been revised by our determination. We also note that there are specific aspects of our determination that are not about price in a narrow sense. For example, we considered how some of the UR's proposals, such as the possible introduction of a reporter, served the public interest and considered among other things the burden that the introduction of a reporter would impose on NIE. We rejected the introduction of a reporter, developing instead an approach based on an improved reporting system resulting in greater transparency. The burden put on NIE was one of the considerations we took into account.

20.10 We therefore consider that this was a suitable case for a reference. Since we have conducted a thorough and wide-ranging investigation it is inevitable that NIE, the UR

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[1] Phoenix Natural Gas Limited price determination, presented to Northern Ireland Authority for Utility Regulation 28 November 2012. The CC allowed the company part of its inquiry costs, included as an additional opex allowance, on the basis of 'the principles applied by statue in equivalent price-control references in other utility sectors' (for example, by section 12(3A) of the Water Industry Act 1991) and the general principle of proportionality and materiality. See Phoenix report, at paragraph 10.12. Phoenix had submitted that its costs amounted to £2.02 million and the CC accepted that this sum was reasonably incurred. It also, among other things, considered whether the costs were incurred efficiently and the degree to which Phoenix had succeeded in the inquiry. On that basis, the company was permitted two-thirds of its costs, ie £1.347 million.

[2] Bristol Water plc, Final Determination, 4 August 2010. Section 12(3A) of the Water Industry Act 1991 required the CC to decide to what extent it was reasonable to allow Bristol Water its costs incurred in connection with the determination. In doing so, the CC 'had to have regard' to the extent to which its determination would support Bristol Water's claims in the determination. Bristol Water's costs amounted to approximately £2.5 million. While the CC considered some aspects of these costs to be high, it had no reason to believe that they had been incurred unnecessarily and accordingly, were taken into account in full. The CC then added its own costs (resulting in a total cost of £3 million) and decided that it was reasonable to allow the company around one-fifth (£600,000) of the combined amount of its own and the company's costs. (In the current case, a proportion of the CC's costs will be recovered through NIE's licence fee and as such we have not considered their recovery through the current determination.)

and the CC will incur considerable costs. For these reasons we decided in principle that consumers should bear some of NIE's inquiry costs. However, NIE's recovery of costs should be limited to the external costs arising directly from the CC inquiry. Having decided that question of principle, we next considered the amount of costs to allow. This involves a number of factors. One consideration is that if parties to our inquiries are to recover their costs it is important that they should incur those costs efficiently. This general proposition about cost recovery applies with particular force where, as here, the ultimate liability for costs will be borne by consumers. We have therefore reduced the amount of costs claimed to encourage efficiency. In making this reduction we are not finding that NIE has behaved with particular lack of efficiency. A second consideration is that it is not unreasonable for there to be an element of cost sharing between consumers and the regulated company, a proposition that is present in all our thinking about NIE's cost recovery. This proposition too applies with particular force where the question of the efficiency with which costs are incurred and then passed on to consumers is in point.

20.11 We also took a range of more specific factors into account laying some stress on the degree to which NIE assisted us to reach a decision that properly balances the competing considerations of the public interest. We were influenced in part by the extent to which arguments have been successful or unsuccessful in the process by which the final determination was reached, and part by the difficulty of relying on this principle in something as complex as a price determination. Among other factors, we also considered the extent to which NIE's costs were determined by work that we had requested, the overall level of cooperation from NIE during the inquiry and the quality of evidence provided in response to our information requests. We also looked at the extent to which we adopted or rejected NIE's proposals and the benefits resulting from its participation in the inquiry overall. We accept that, in an investigation such as this, NIE must be able to pursue its interests and provided it does so reasonably we do not think that the fact that we have not accepted the approach it prefers is a reason to deny it cost recovery. Instead, as noted above, we laid stress on the degree to which, overall, we think NIE has assisted us to take a decision that best reflects the public interest.

20.12 More specifically again, we decided whether costs were, overall, reasonably incurred having regard to the reasons why they were incurred, the amount and nature of work that NIE carried out and by whom it was carried out. We also considered the absolute level of the costs and whether they were proportionate having regard to the revenues receivable under the determination overall and the major differences in proposed revenues between the company and the regulator. In doing so, we made an adjustment to reflect the extent to which we have been persuaded by NIE's views and, more broadly, the extent to which consumers will have benefitted from a better price control as a result of representation made that may not be fully adopted in our final determination.

20.13 We found NIE's contribution to this inquiry generally positive and helpful (as we did the UR's). It responded promptly to a very large number of requests for information and its submissions have been broadly helpful even where we have not been persuaded. The amounts at stake in the determination are very large and our re-determination has been very wide in its scope (far wider than, for example, than in Bristol Water or Phoenix).

20.14 We also had regard to the UR's external costs for the duration of the inquiry of approximately £630,000 and our total costs of approximately £800,000, both of which indicate that this has been a complex inquiry. At the same time while we did not adopt many of the positions preferred by NIE our final determination differed significantly from both RP4 and the UR's final determination which NIE rejected. We also bear in mind that allowing NIE to recover costs, consumers in Northern Ireland have to pay for decisions made by NIE in its conduct during the inquiry over which they have no influence. While we do not criticize NIE's conduct this is nonetheless an important factor.

20.15 Having taken account of all the above considerations we concluded that it is in the public interest to share NIE's £2.8 million external inquiry costs between NIE shareholders and its consumers. We therefore allowed NIE to recover £1.4 million.

20.16 Notwithstanding the level of cost we found justified, we also considered how the practicalities of including such an allowance as additional opex would affect the prices consumers pay and whether it, more generally, serves the public interest. Accordingly, we decided that NIE's costs of £1.4 million should be treated as opex and included as an additional allowance in 2013/14. This allowance amounts to £1.2 million in 2009/10 prices and is included in our financial modelling.

21. Determination

21.1 The UR referred three questions to us:

(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.

21.2 For the reasons given in Section 3, we found that the Price Control Conditions in each Licence operate or may be expected to operate against the public interest.

21.3 For the reasons also given in Section 3, we found that 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.

21.4 For the reasons given in Sections 4 to 19, we found that 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 Price Control Conditions of each Licence.