ED2 open letter response

NORTHERN POWERGRID'S KEY POINTS

- ED2 presents opportunities to meet the challenges of the low-carbon transition thanks to its better-established incentive framework when compared to all the other RIIO-1 controls…
- …which has brought extensive successes, ranging from lower costs to better service.
- To meet these net zero challenges Ofgem needs to set ED2 with a strong investment focus, including a realistic allowed equity return.
- Ofgem's current cost of equity proposals are undermining investor confidence because they:
  - fail to deliver the promised NPV neutrality;
  - contain two adjustments to reduce the allowance below the actual estimated cost; and
  - take no account of the political and regulatory risk facing the sector.
- In order to stay focused on funding the transition without encouraging unnecessary investment, or undermining incentives, Ofgem should use pay as you go volume drivers, based on electric car and heat pump uptake, to flex funding within the price control.
- Ofgem should build flexibility into its asset lives policy in order to create financial flexibility to fund the low carbon transition and be inter-generationally fair.
  - Set the asset life for business as usual levels of investment at the current average (*ca.* 25 years) to create much needed headroom to cope with any major increase in investment.
  - Retain flexibility to use the longer 45-year asset life, for any significant additional investment, to support any step change in the carbon reduction agenda.
  - A policy of 45-year depreciation would otherwise cause regulatory asset values to grow at a much faster rate, even with no major increase in expenditure, putting too much pressure on future customers who will also bear any increased costs from the low carbon transition.
- Ofgem needs to reap the benefits from totex cost arrangements and strong outcome incentives that already mitigate many potential conflicts of interest in distribution system operation (DSO):
  - DNOs are the right party to take decisions on operating their networks as DSOs.
  - Ofgem should avoid anything that undermines these arrangements, like setting parts of the price control for longer or treating flexibility costs differently to traditional costs.
- Ofgem should "mainstream" net zero into its existing suite of incentives (like reliability, connections, and customer service), rather than introducing an entirely new incentive.
- Ofgem should make good use of comparative competition (on costs and performance) at price control reviews, to set robust and evidence based targets, so it can step back from the micro-management which is endemic across the proposals and which would raise costs to consumers.
- A sharper business plan incentive is needed to meet the challenges of a dynamic sector:
  - meaningful rewards need to be available, to promote challenging cost forecasts; and
  - introducing a boundary between high and low confidence costs is a mistake – in practice it would distort company decisions on how they allocate costs and run their business.
- Ofgem should level the playing field in how connections are charged for across transmission, IDNO and DNO networks, where differences are causing distortions and raising system costs.

Contents

1. Executive Summary

1. As we enter the ED2 price control review, it is important to recognise the many successes of the system of network regulation that has been in place since privatisation, including lower costs, shorter power cuts, faster connections and better customer service.

2. Now more than ever, Ofgem must advocate for and continue these successes in regulation, to meet the challenges of the net zero transition. During the 2020s and beyond there will be greater reliance on electricity distribution networks to heat homes and power cars.

    a. There is now a target to achieve net zero carbon emissions by 2050; with an impetus behind calls to bring this date forward.

    b. The Government has already announced that fossil fuel boilers can't be installed in new homes from 2025, and electricity powered heat pumps will be the only viable alternative in many cases.

    c. The number of electric and hybrid vehicles on the roads is steadily increasing and, with the UK regularly breaching legal air quality limits, there is a growing impetus towards much faster uptake.

3. Alongside this, much more generation is now connected to electricity distribution networks, while the falling cost of batteries (including vehicle batteries), or smart household devices that "optimise" their energy use, also have the potential to significantly alter how electricity distribution networks are used. All of these create more opportunities, and need, for the smart and flexible operation of the distribution system.

4. Ofgem seems to have understood this context when it says that:

    > "*In many ways, the electricity distribution sector is likely (though it is not certain) to be the most dynamic of all the regulated energy sectors. We expect the electricity distribution networks to see the greatest impact arising from the forces of decarbonisation, decentralisation, and digitalisation.*" (The Consultation, page 5)

5. There are however other significant differences between electricity distribution and the other network sectors that Ofgem is currently setting price controls for. In electricity distribution:

    a. The incentive arrangements are better developed than any other energy network sector.

    b. Cost outperformance is generally lower (particularly if exceptions caused by Ofgem's flawed disaggregated benchmarking at the ED1 review are set aside).

    c. There is a longer history of data on output incentive performance that supports better calibration of targets.

    d. There are more independently owned groups so comparative competition at successive price control reviews can be more effective.

e. The RIIO totex approach has been implemented fully, across system operation and investment, so DNOs can act as DSOs with no conflict of interest.

f. Electricity distributors are transparently developing their approach to system operation so that wider stakeholders can input to their approach.

6. Ofgem should build on these strong foundations at ED2 and beyond, to set robust price controls. It should:

a. Incrementally improve the current framework where incentives are misaligned.

b. Make good use of the extensive evidence available in the sector to set cost and output targets.

c. Maintain competitive tension rather than micro-managing specific approaches.

7. Only strong incentives, including for investment, cost efficiency and consumer outcomes, can deliver the significant benefits to consumers from the lowest-cost pathway to meeting net zero targets.

8. But rather than building a framework that recognises this, Ofgem instead proposes to roll across the transmission and gas distribution price review methodology virtually unchanged.

9. We think it is a mistake to fail to recognise the significant differences between sectors that warrant a different approach, like the central importance of electricity distribution to the low carbon transition and the larger number of companies with independent ownership than any other sector.

10. Instead, Ofgem needs to:

a. Set ED2, and future ED price controls, with a focus on ensuring sufficient investment…

b. … and set a high enough cost of equity to support this, well above current proposals.

c. Increase cost allowances as the number of low-carbon devices in use rises, to fund the associated network rollout on a “pay as you go” basis.[1]

d. Make use of the time created by the ED1 asset life transition to review the arrangements and introduce more flexibility in the face of the net-zero requirements.

e. Take advantage of a RIIO ED framework that already has mitigated conflicts of interest and incentivises DNOs to work effectively as local electricity system optimisers...[2]

f. …rather than causing consumer detriment through an incentive on “net zero” outcomes that will depend far more on government policy rather than DNO or DSO actions.

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[1] If there is now sufficient certainty that new capacity is necessary to meet a “full electric” scenario by 2050, then Ofgem could alternatively require distributors to plan and invest on this basis under the existing framework.

[2] Northern Powergrid and other distributors are also taking steps, e.g. thought how they procure flexibility, to demonstrate to wider stakeholder that conflicts do not exist. Ofgem must also explain the merits of its regulatory system.

g. Step back from micro-management and use comparative competition instead.[3]

h. Recognise the value to consumers from electricity distribution companies establishing challenging business plans in electricity distribution in particular, through sizeable rewards, while removing distortions between different types of cost.

i. Level the playing field in how DNOs, IDNOs and transmission companies charge for connections, to remove the current distortions that are raising system costs.

11. We set out more on each of these steps necessary to set an effective ED2 price control in the next section, before we go on to answer Ofgem's specific consultation questions.

[3] While controlling in any benchmarking for the advantage given to Western Power Distribution from a generous ED1 settlement.

2. The steps necessary to set an effective ED2 control

12. We see nine key steps that Ofgem must take to set an effective ED2 control in the interests of energy consumers. These are described below.

2.1 Ofgem needs to set ED2, and future ED price controls, with an investment focus…

13. Whatever the detail of the scenario that ultimately plays out, there is a consensus that the electricity distribution sector will be instrumental in helping the UK to meet its target of net zero carbon dioxide emissions by 2050, and Ofgem is right to highlight this in its open letter.

14. Heat and local road traffic will be increasingly electrified during the ED2 price control period and beyond. The Climate Change Committee supports these expectations, stating that:

> *"Heat pumps are an established solution in many other countries, but not yet in the UK. Establishing them as a mass-market solution will take some time, with strong progress required during the 2020s. There are particular opportunities in new-build properties, homes off the gas grid, non-residential buildings and for hybrid heat pump systems retrofitted around existing gas boilers."* and that

> "*In our recent Net Zero report we recommended an end to sales of petrol and diesel cans and vans by 2035 at the latest and early deployment of hybrid heat pumps, increasing electrification in the 2020s. A heat decarbonisation strategy could imply further electrification beyond this*."[4]

15. Government has already said that it will "*introduce a future homes standard, mandating the end of fossil-fuel heating systems in all new houses from 2025."*[5] This means that, from 2025 at least, many new homes will have to be fitted with heat pumps. More policy steps like this are likely.

16. Looking beyond net zero, and potentially much nearer term than 2050, there is growing public and political awareness of the problems caused by highly polluted air in urban centres. Widespread damage to health and loss of life is being proven and the UK is routinely breaking legal limits for air quality. The only solution is a major acceleration in the uptake of ultra-low emission vehicles for local traffic, and the only available technologies at present are electric or hybrid cars. We think there is a high chance of significant uptake of these vehicles within the next decade, driven by government policy reform and falling technology costs.

17. For these reasons Ofgem needs to be acutely conscious of the investment needs that are likely to flow during the ED2 period and over the following two decades. Ofgem needs to give investors the confidence to back this, otherwise energy consumers could suffer from the costs associated with longer-term under-investment.

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[4] Climate Change Committee, July 2019, Reducing UK emissions: 2019 Progress report to Parliament

[5] Spring statement by the Chancellor of the Exchequer, March 2019, Hansard.

2.2 … and the cost of equity needs to be high enough to support this

18. If Ofgem wants to stimulate the investment necessary to bring about a low-carbon future, the cost of equity must be set high enough.

19. But in this respect Ofgem's methodology is seriously flawed.

    a. Ofgem has reduced the total market return, relative to the CMA's latest view, even though no new evidence has emerged since then.

    b. There is an unjustified reduction in the estimate of equity risk at 65% gearing, thanks to an adjustment based on RAV premia seen in the water sector (the "1.1x" adjustment).

    c. There is no recognition of the most significant risks facing the sector: political and regulatory risk (to the extent these aren't correlated with stock markets).

    d. Having calculated a point estimate that is already too low, Ofgem then arbitrarily reduces the allowed value below its own assessment of the required return.

20. If Ofgem continues with its proposals to set an allowed cost of equity below its actual value (having corrected the mistakes above), then there is agreement between academics[6] and respected regulatory authorities[7] that this carries risks of significant detriment to consumers.

2.3 Pay as you go volume drivers, based on electric car and heat pump uptake, are needed to allow funding to flex within the price control period

21. There is an age old problem in regulation: Ofgem needs to fund investment requirements but in order to minimise costs to consumers it also doesn't want unnecessary investments to go ahead.

22. If there is now sufficient certainty that new capacity is necessary, to meet a "full electric" scenario by 2050, then Ofgem could require companies to plan and invest on this basis. This would be the "lowest risk" approach to ensuring there is adequate network capacity. However, it is (almost) inevitable that this will result in some unnecessary costs to consumers – and they could be significant if a different pathway to net zero is taken, for instance a hydrogen economy.

23. Since we do not think there is enough certainty yet, we still advocate a system of pay as you go allowance drivers, with longer term commitment to this mechanism by Ofgem. Allowances would then flex based on externally monitored uptake levels of low-carbon technologies such as heat pumps, electric vehicles or domestic solar photovoltaic installations. For example, if twice as many

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[6] Dobbs, I.M, 2011, Journal of Regulatory Economics Volume 39, Issue 1, pp 1–28, Modelling Welfare loss Asymmetries Arising from Uncertainty in the Regulatory Cost of Finance. Working paper version available at the link below, see page 33. https://www.staff.ncl.ac.uk/i.m.dobbs/Files/Welfare%20loss%20JRegE.pdf

[7] See for example:

Competition Commission, A report on the economic regulation of the London airports companies (Heathrow Airport Ltd and Gatwick Airport Ltd), September 2007, page 49.

CMA, Bristol Water plc, October 2015, pages 333-334.

electric cars were registered then the associated funding would double; while if only half as many were registered it would halve.[8]

24. This would ensure that companies take commercial judgements on when there is sufficient certainty to make investments ahead of need; while also giving companies an "incentive" to ensure that those barriers to uptake that are within their control are mitigated, so that uptake (and DNO funding) is not slowed down by the DNOs own actions.

2.4 Make use of the time created by the ED1 asset life transition to review the arrangements and introduce more flexibility in the face of the net zero transition.

25. At the ED1 review, Ofgem took a cautious approach to extending asset lives, allowing all companies the transitional arrangements that they requested in their business plans.

26. This caution was warranted, as it has allowed a smaller and slower move to take place during the ED1 period. It has also allowed more information to become available on the range of potential future pathways for:

    a. electricity distribution expenditure required to meet the low-carbon transition, ranging from very limited change to significant investment; and

    b. the cost of capital, which has stayed lower for longer than expected, and where it is currently difficult to predict the timing of its recovery.

27. In light of this, ED2 presents an ideal opportunity to review the approach to asset lives in electricity distribution and put in place a system that is better suited to meeting these twin challenges. Both of the challenges have scope to place unprecedented strain on the finances of the electricity distribution sector. Yet the timing of both is highly uncertain.

28. In face of this, significant additional flexibility is needed. To create this, Ofgem should:

    a. Depreciate a baseline tranche of totex expenditure, e.g. a set £ per customer per annum figure, over something like the current average[9], helping to maintain DNO financeability and preserve low prices for future consumers.

    b. Depreciate all expenditure above this tranche at 45 years, so that any "peaks" in asset expenditure to meet the net zero transition can be spread over the lifetime of those assets without causing an undue spike in near-term charges.

29. This policy would have many advantages.

[8] There could still be a reopener like the present one, if expenditure strays too far from allowances, but the baseline allowance level would move up (and down) depending on actual levels of uptake, making it less likely that Ofgem would need to trigger the reopener if uptake levels are different to expectations.

[9] For Northern Powergrid, as a fairly representative DNO, the average at the end of the current regulatory year will be 24 years, while it will have risen to 29 years by the end of the ED1 period.

a. It would help maintain company cashflows so they can respond when investment is needed, whenever that might be.

b. It would ensure Ofgem is not trapped by the strained cashflows that uniform 45 year asset lives will create through the late 2020s and into the 2030s, if major additional investment is needed in that window.

c. It would avoid a "price escalator" that would raise network charges above current levels, even if expenditure does not need to increase, on account of higher long-term regulatory asset value (RAV).

d. It would reduce the inevitable upwards pressure on the cost of capital that would be caused by significantly larger RAV in the future.

e. It would create an inter-generationally fair distribution of outcomes.

2.5 Take advantage of a RIIO ED framework that already has mitigated conflicts of interest and incentivises DNOs to work effectively as electricity distribution system optimisers

30. Ofgem built the RIIO-ED framework to meet the challenges of the transition to a low-carbon future, including through the use of flexibility solutions and innovation to minimise constraint management costs. Ofgem now needs to let the system it already built work. DNOs are the right parties to continue holding the DSO role.

31. At its heart, the distribution system operator role is about ensuring cost and reliability are being effectively managed in face of requirements being placed the network, including to facilitate decarbonisation. These are all outcomes that the existing system incentivises, through a single price control that includes:

a. a single totex cost incentive rate, so DNOs earn higher profits if they can minimise costs (including by replacing traditional reinforcement with flexibility solutions);

b. a single regulatory capitalisation rate, applied to all types of costs, so DNOs have no incentive to favour particular costs which cause higher RAV; and

c. a suite of incentives so DNOs earn higher profits if they deliver good outcomes on reliability, customer service and connections, regardless of the approach they use to deliver those good outcomes (e.g. flexibility vs network investment).

32. These steps effectively regulated away the conflicts of interest in DSO activity and create the perfect conditions for a home-grown DSO that uses native competition to keep costs as low as possible to network users, while meeting necessary outcomes.

33. In contrast, in electricity transmission, Ofgem already treated system operator's "external" costs so differently to its internal costs and the costs of transmission investment, that the T1 settlement was

not a true RIIO settlement. Ultimately these regulatory headaches led Ofgem to ring fence the transmission system operator (the ESO) from the rest of the transmission business and give up on incentive regulation, replacing this with cost pass-through and discretionary awards. In doing so, clear accountability has been lost for transmission network performance, since ownership and operation are fragmented, while costs will gradually grow thanks to the loss of incentives.

34. Separating DSO functions would be a damaging and retrograde step for energy consumers that would lead to higher costs over the longer term and a loss of clear accountability for network stability. Likewise, a separate price control for DSO activity would lead to all the same regulatory headaches that Ofgem has faced in respect of the transmission system. Ofgem must avoid these pitfalls.

2.6 Avoid the detriment that could result from a badly designed "net zero" incentive

35. In terms of incentives, Ofgem's best option to ensure electricity distributors drive decarbonisation harder is:

    a. an explicit funding route for the low carbon roll out (like our longstanding proposal for "cost allowance volume drivers", set out above); and

    b. a strong emphasis on the positive outcomes in a low-carbon transition that the existing incentives will deliver.

36. We have also heard growing calls from stakeholders for some kind of incentive to support decarbonisation. If Ofgem designs such an incentive, it is critical that it is aligned to the role of the electricity distributors and avoids:

    a. unintended consequences from distorted incentives (e.g. incentivising DNOs to pursue approaches that raise overall system costs, or costs to the exchequer, with little or no environmental benefit);

    b. unwarranted gains (or penalties) for factors beyond DNO control, such as incentivising them based on an outcome that will be driven by government policy, not DNO action[10]; or

    c. discretionary awards, which are subjective in nature and drive significant additional administrative costs (for often unclear gains).

37. We cannot rule out that it will be possible to design an incentive that meets these criteria. But we also think this would be a significant challenge, thanks in part to the effective incentives Ofgem already has in place, such as the interruptions incentive.

[10] The Persimmon executive remuneration scheme offers a good case study. It was extensively criticised by politicians and the media because the incentive rewards were seen to result from government policy decisions rather than management actions. The fact that the rewards flowed while Persimmon was helping government to achieve certain policy targets did not aid public legitimacy. The same legitimacy problem may arise if DNOs were rewarded because more electric vehicles were on the road, or because more homes had heat pumps fitted.

38. It is therefore imperative for Ofgem and DNOs to ensure these wider stakeholders recognise the many ways the RIIO system was designed to support decarbonisation.

2.7 Ofgem must step back from micro management, instead relying on comparative competition in respect of costs and performance

39. Ofgem has repeatedly stressed the information asymmetry that it faces relative to company management. This asymmetry is not a legitimate excuse for any failures on Ofgem's part to set challenging targets in ED1. But it is the reason Ofgem should step back from trying to micro-manage the "how".

40. The management teams of the companies will always be better placed to take these decisions than Ofgem, since the companies bear both the commercial risks and benefits, and since they can set their resourcing in light of these. In contrast, Ofgem is staffed by civil servants that face none of these risks, and lacks the resource to try and directly manage the whole sector. These are good reasons for an economic regulator to focus on creating a framework that incentivises effective management, rather than trying to regulate the "how".

41. Yet time and again Ofgem's proposals show it to be intent on micro-management.

  a. Asset health indices are becoming a codified rule book that DNOs must use to justify their investment plans and by which they should take their day-to-day decisions.

  b. Audits of asset management data are being use to drive towards standard asset management practices, and Ofgem is perversely arguing for higher costs.

  c. Company cost allowances for DSO activities might be fine-tuned during the period, once the results of flexibility tenders are known, removing any incentive to save costs.

  d. Price control deliverables will be given greater emphasis than before, with checklists set by Ofgem to check companies did exactly what they said they would, stifling innovation.

  e. There will be an uncertain boundary between "high confidence" and "low confidence" costs with many disadvantages, including the distortions this will create in incentives to allocate or incur costs in one category rather than the other.

  f. There will be a new "regulator co-ordinated" mechanism to transfer accountability for issues, and allowances, between sectors, in stark contrast to the current "company co-ordinated" system of contracting to obtain services at cost reflective levels.

42. If Ofgem is taking all these decisions for the sector, it will need significant additional resources that are unlikely to be available.

43. Instead, Ofgem should focus its resources on setting a framework that uses incentives, and comparative competition amongst the six electricity distribution groups of companies[11], to reveal information over time that Ofgem can use to benefit consumers.

2.8 The business plan incentive must promote challenging cost forecasts through genuine rewards

44. Electricity distribution is, as Ofgem recognises, the most dynamic of the RIIO sectors. It is therefore this sector where there is most value to consumers from strong incentives for companies to challenge themselves on their whole cost base, including by looking to find synergies between business as usual costs and incremental low-carbon transition costs (e.g. displacing asset replacement with reinforcement).

45. It is also the sector with the most companies, so there is a realistic prospect of companies competing with each other to obtain rewards, as they did at ED1 when the combined effect of fast-track rewards and the IQI encouraged this.

46. These two factors do not apply in other RIIO sectors. In transmission, the price control process is effectively a series of bilateral negotiations. In gas distribution, the sector is much more concentrated than electricity distribution[12] and will be far less dynamic over 2021-26 than electricity distribution will be over 2023-28.

47. In the context of these differences, a simple roll-across of Ofgem's business plan incentive for the GD2 and T2 control is not appropriate. The incentive lacks genuine rewards for companies developing challenging cost forecasts. The "rewards" it claims to offer in respect of high confidence costs amount to nothing more than partial-protection for companies from lost allowances if their proposals are below Ofgem's benchmark[13], which was regulatory practice that pre-dates the information quality incentive and which suffered flaws that led to that incentive being developed. This aspect of the business plan incentive would be a retrograde step compared to the ED1 information quality incentive, if it were rolled across to electricity distribution.

48. Meanwhile, the idea that companies could include a "Customer Value Proposition" request for a reward in their business plans, in respect of low costs, doesn't cater well to cost performance, since it is a discretionary reward that suffers all the associated drawbacks, and since companies won't know if their costs are comparatively efficient at the time of submitting their business plan.

49. This must be addressed in the design of the business plan incentive for ED2. The incentive should feature substantial additional rewards for companies that challenge themselves on costs, whether or not the company asked for a reward in its business plan. This will be necessary if Ofgem hopes that

[11] While controlling in any benchmarking for the advantage given to Western Power Distribution from a generous ED1 settlement.

[12] One gas distribution company accounts for half the sector, while it has only three other comparators (or as few as two, recognising the partially shared ownership structure of two of the businesses).

[13] The protection is only partial because a low forecast may itself reduce Ofgem's benchmark and thus the allowances; the GD2 and T2 business plan incentive offers no protection from this effect.

the business plan competition on costs will reveal as much information at ED2 as it did at ED1, when the potential rewards (through the IQI and fast track award) were significant.

2.9 Align how connections are charged for across DNO, transmission and IDNO networks

50. At present IDNOs and transmission networks can spread the cost of a new connection over time, recovering the cost through ongoing charges.

   a. Transmission networks are allowed to spread the cost over time for specific customers, at the price control cost of capital, while (we understand) also adding the investment to regulatory asset value (RAV) so it is underwritten by the wider regulatory system.

   b. IDNOs are allowed to discount the cost of the upfront connection, cross-subsidising this from the ongoing distribution charges they can levy (where these exceed the ongoing maintenance costs, which is known as "tariff support").

51. DNOs, on the other hand, receive no regulatory RAV guarantee if they spread the cost of a connection over time (and offer finance at their own risk), while they are also explicitly prevented from offering tariff support by the connections charging methodology. This disparity is distorting end user decisions over which network to connect to. It favours transmission network or IDNO connections even if a connection to a DNO network would involve far fewer assets and lower costs. It is also stifling the role distribution networks can play in the low-carbon transition for existing users that need upgraded connections. This is imposing higher costs on energy consumers, over the long term, and it is difficult to see how this is consistent with Ofgem's duties to energy consumers. Ofgem needs to urgently resolve this distortion.

52. Assessed objectively, the DNO model offers the strongest locational pricing signal at the point in time connections are being considered and the greatest likelihood of economically efficient outcomes. Ofgem should therefore align all three sectors to this DNO approach.

53. If Ofgem is not willing to confront the vested interests which will support the current transmission and IDNO connection charging approaches then it should still align all three sectors on one of the other models.[14]

[14] Unlike changing the connection charging boundary for DNOs, which Ofgem has also been contemplating, this would not require changes to the Electricity Act 1989, since DNOs would still be able to recover the full cost of the connection as permitted by the legislation.

3. Questions on the strategic approach to ED2

54. In this section we respond to each of Ofgem's questions on its strategic approach to the review.

55. This section is laid out based on Ofgem's structure, from its *Open Letter Consultation on the RIIO-ED2 price control review* (the Consultation):

   a. Proposed objectives for the review;

   b. Supporting decarbonisation goals;

   c. Supporting strategic investment;

   d. Setting price controls for DSO functions;

   e. Driving innovation and competition;

   f. Encouraging a smart, flexible, energy system; and

   g. Catering to a big data environment.

Proposed objectives for the review

1. Do you have any views on the proposed objective for RIIO-ED2?

56. Ofgem's objective for the review should be supported by two sub-objectives, centred around ideas Ofgem has highlighted in the Consultation narrative in this area, as follows:

> *"Set a well-balanced price control that ensures that the DNOs deliver the value for money services that both existing and future consumers need, in particular by:*
>
> *i) enabling electricity distributors (DNOs) to go further in decarbonising the economy; and*
>
> *ii) keeping costs as low as possible for consumers while still paying for the required investment."*

Supporting decarbonisation goals

2. To what extent should we take into account outcomes linked to decarbonisation targets, and what outcomes might this involve?

57. Whatever the detail of the scenario that ultimately plays out, there is a consensus that the electricity distribution sector will be instrumental in helping the UK to meet its target of net zero carbon dioxide emissions by 2050, and Ofgem is right to highlight this in its open letter. We provide further context on this in our response to question 28 below.

58. For these reasons Ofgem needs to be acutely conscious of the investment needs that are likely to flow during the ED2 period and over the following two decades. Ofgem needs to give investors the

confidence to back this, otherwise energy consumers could suffer from the costs associated with longer-term under-investment.

59. To achieve this, the allowed cost of equity must be adequate (as we set out further in response to question 45).

60. In terms of incentives, Ofgem's best option to ensure electricity distributors drive decarbonisation harder is:

    a. an explicit funding route for the low carbon roll out (like our longstanding proposal for "cost allowance volume drivers", set out above); and

    b. a strong emphasis on the positive outcomes in a low-carbon transition that the existing incentives will deliver.

61. An explicit funding route would ensure that DNOs have every incentive to *facilitate* the uptake of low carbon devices, especially if the funding (either all of it, or part of it) was made contingent on end users actually being able to install and use these new technologies (as we propose, in our response to question 7, at paragraphs 82 to 84 below.

62. The wider suite of existing incentives for reliability, customer service, and connections can then be used to ensure DNOs take pro-active steps to support decarbonisation outcomes, by "mainstreaming" activities that will support decarbonisation into their measurement. For example:

    a. DNO incentives to quote and then complete new connections quickly can be extended to new or modified connections which involve disruptive loads, like heat pumps.

    b. Customer satisfaction survey incentives could be extended to all activities that can support decarbonisation (like third party data usage, installation of heat pumps, or witness testing of generation installations);

    c. Reliability incentives can continue to give DNOs an imperative to operate their system in a manner that mitigates risks of power cuts, including through new DSO activities.

63. Outcomes linked to decarbonisation targets, like those listed in the Consultation, will depend far more on government policy than on DNO actions. For instance the decarbonisation of transport will largely depend on government transport policy, the cost of competing technologies, and consumer attitudes. If Ofgem did build regulatory incentives directly on these outcomes, it would lead to the risk of windfall gains (or losses) on the part of DNOs, which would also raise the cost of capital.

3. Are there activities that DNOs are best placed to carry out in order to achieve these outcomes? What are the alternatives? Why would it be appropriate for energy consumers to fund these activities?

64. DNOs are best placed to carry out the combined role of ownership and operation of the electricity distribution system: the DSO role.

65. DNOs should not be used as delivery bodies to deploy wider energy system solutions, such as providing fleets of rental electric vehicles or installing energy efficiency measures. Instead they should be neutral network facilitators of a range of technologies, that send price signals to the market of the network costs associated with those technologies. This will allow market participants to internalise all the costs and benefits of their activities, and take economically efficient decisions. It is also consistent with Ofgem's longstanding policy of limiting the activities of DNOs to distribution activities, through the application of a ring-fence.

4. How should we assess DNO funding requirements and measure DNO performance in these areas?

66. We advocate that DNOs retain the full DSO role. This involves:

    a. minimising costs associated with the network meeting external requirements;

    b. sending price signals about the costs of network usage, as neutral market facilitators;

    c. providing the services market participants and end users need, and giving good service;

    d. offering connections quotations, and connections, that are timely; and

    e. maintaining a reliable distribution network so end users receive their power.

67. Ofgem must ensure DNOs internalise all of the costs and benefits associated with decisions relating to network management and system operation, and that all these costs are treated identically.

68. In terms of setting funding, cost allowances should be set through requirements to submit well justified business plans in this area, and through cross company benchmarking of totex costs to determine an efficient overall envelope of expenditure.

    a. These cost allowances should be treated in exactly the same way as any other totex cost: with the same efficiency incentive and RAV capitalisation rates, since this mitigates conflicts of interest that could otherwise result (for example if DSO allowances were treated differently to network investment).

    b. Over the longer term, cost incentives and comparative competition (through cost benchmarking at successive price control reviews) are critical to ensure efficient levels of cost are discovered, and passed through to consumers.

69. In terms of performance, Ofgem should ensure that DSO success is "mainstreamed" into all of the existing key outcome incentive areas, including reliability, customer service and connections. We say more on the specific actions this may involve at paragraph 62 above.

70. We do not advocate that DNOs be funded to deliver other policy objectives, such as transport decarbonisation, or energy efficiency measures. If a delivery body is required for those wider objectives, a separate regulatory framework appropriately focussed on the relevant activity should

be used.[15] This will ensure that DNOs can act as neutral market facilitators on a ring-fenced basis, rather than introducing a potential conflict of interest.

5. How should we incentivise DNO performance when the achievement of outcomes could be dependent on the actions of others?

71. The dependencies mentioned in the question are the fundamental problem for this type of incentive proposal, and the reason that Ofgem should not pursue this type of incentive.

72. We have also heard growing calls from stakeholders for some kind of incentive to support decarbonisation. If Ofgem designs such an incentive, it is critical that it is aligned to the role of the electricity distributors and avoids:

    a. unintended consequences from distorted incentives (e.g. incentivising DNOs to pursue approaches that raise overall system costs, or costs to the exchequer, with little or no environmental benefit);

    b. unwarranted gains (or penalties) for factors beyond DNO control, such as incentivising them based on an outcome that will be driven by government policy, not DNO action[16]; or

    c. discretionary awards, which are subjective in nature and drive significant additional administrative costs (for often unclear gains).

73. We cannot rule out that it will be possible to design an incentive that meets these criteria. But we also think this would be a significant challenge, thanks in part to the effective incentives Ofgem already has in place, such as the interruptions incentive.

74. Ofgem should also avoid a discretionary award based on Ofgem's assessment (or the views of other stakeholders) about "how much" DNOs have contributed to the outcome. Such judgements:

    a. are resource intensive, for Ofgem and the companies;

    b. heavily reward the quality of company submissions and stakeholder participation; and

    c. will be unable to genuinely separate company actions from wider factors in determining what "caused" the actions, thus defaulting to an essay writing competition.

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[15] Companies in the wider Northern Powergrid group are active in non-distribution activities, including oil and gas exploration and ownership and finance of smart meters on behalf of energy suppliers. These activities are undertaken on a competitive basis and outside the DNO regulatory ring-fence. Where new regulated activities are created, or where new competitive markets emerge, the group will consider these opportunities. Therefore Northern Powergrid may become involved in these activities in future, even though we believe they are not well-suited to delivery through a distribution business or within its ring-fence.

[16] The Persimmon executive remuneration scheme offers a good case study. It was extensively criticised by politicians and the media because the incentive rewards were seen to result from government policy decisions rather than management actions. The fact that the rewards flowed while Persimmon was helping government to achieve certain policy targets did not aid public legitimacy. The same legitimacy problem may arise if DNOs were rewarded because more electric vehicles were on the road, or because more homes had heat pumps fitted.

75. It is therefore imperative for Ofgem and DNOs to ensure these wider stakeholders recognise the many ways the RIIO system was designed to support decarbonisation.

Supporting strategic investment

6. How do we ensure that network companies are best placed to undertake strategic investment and manage the associated risk? How should the risks of these investments be managed?

76. As we set out in response to question 2 above, Ofgem needs to be acutely conscious of the investment needs that are likely to flow during the ED2 period and over the following two decades.

77. There is however an age old problem in regulation: Ofgem needs to fund investment requirements but in order to minimise costs to consumers it also doesn't want unnecessary investments to go ahead.

78. Ofgem therefore shouldn't try to "ensure" that strategic investments are undertaken, or write away the risks of building them, until it is entirely clear to Ofgem (and other parties) that the assets will be used and useful.

    a. Many of the associated risks come from government policy or other unpredictable factors (such as technology costs and consumer attitudes). The risks to the outcomes can therefore only be effectively managed through government policy action to force the outcome. Once those decisions, and action, are taken, then network companies will be best-placed to deliver and finance them under the existing system of regulation.

    b. The other risks come from a regulatory system that dis-incentivises investments that aren't needed. This is appropriate. It would be very expensive for consumers to fund large amounts of potentially unnecessary investment because of the direct cost of the investment and the higher cost of capital that would result (because "unsustainable" investments are more politically exposed).

79. To the extent Ofgem wishes to consult further on the issue, it would also be helpful if it could define examples of what the strategic investments might be, which would aid discussion of practical issues beyond the issues set out above.

7. What, if any, changes to the framework are required to support strategic investment?

80. Our response can be summed up in three points:

    a. Many strategic investments can be delivered through the existing framework.

    b. For uncertain requirements, funding should be provided through a "pay as you go" volume driver based on uptake of low carbon technologies, so DNOs have confidence they will receive funding if investments are needed but still bear the risk of decisions to invest early.

c. In any scenario, Ofgem needs to remove the major distortion between transmission, distribution and IDNO networks in whether connection charges can be spread over time.

The existing framework for funding network reinforcement

81. DNOs already undertake many strategic investments to anticipate future demands, and reduce their longer term costs of meeting these future demands. They are incentivised to do so by Ofgem's totex cost benchmarking approach at price control reviews and (during DPCR3 until ED1) through the IQI. Provided Ofgem sustains these incentives at ED2 and beyond, DNOs will undertake strategic investments that reduce their long term costs, where this can be supported by an investment appraisal. Where the costs of the strategic investment are too high, or the benefits too uncertain (e.g. because government policy remains uncertain), they will of course not undertake the investment. This has the advantage of limiting the risk that consumers fund unnecessary assets.

Potential adjustments to funding for DNO investments

82. If there is now sufficient certainty that new capacity is necessary, to meet a "full electric" scenario by 2050, then Ofgem could require companies to plan and invest on this basis. This would be the "lowest risk" approach to ensuring there is adequate network capacity. However, it is (almost) inevitable that this will result in some unnecessary costs to consumers – and they could be significant if a different pathway to net zero is taken, for instance a hydrogen economy.

83. Since we do not think there is enough certainty yet, we still advocate a system of pay as you go allowance drivers, with longer term commitment to this mechanism by Ofgem. Allowances would then flex based on externally monitored uptake levels of low-carbon technologies such as heat pumps, electric vehicles or domestic solar photovoltaic installations. For example, if twice as many electric cars were registered then the associated funding would double; while if only half as many were registered it would halve.[17]

84. This would ensure that companies take commercial judgements on when there is sufficient certainty to make investments ahead of need; while also giving companies an "incentive" to ensure that those barriers to uptake that are within their control are mitigated, so that uptake (and DNO funding) is not slowed down by the DNOs own actions.

Necessary changes to funding for connection investments

85. In any scenario, Ofgem must remove the major differences in how connections are charged for, including connections involving strategic long term investments, depending on the type of network that parties connect to.

86. At present IDNOs and transmission networks can spread the cost of a new connection over time, recovering the cost through ongoing charges.

[17] There could still be a reopener like the present one, if expenditure strays too far from allowances, but the baseline allowance level would move up (and down) depending on actual levels of uptake, making it less likely that Ofgem would need to trigger the reopener if uptake levels are different to expectations.

a. Transmission networks are allowed to spread the cost over time for specific customers, at the price control cost of capital, while (we understand) also adding the investment to regulatory asset value (RAV) so it is underwritten by the wider regulatory system.

b. IDNOs are allowed to discount the cost of the upfront connection, cross-subsidising this from the ongoing distribution charges they can levy (where these exceed the ongoing maintenance costs, which is known as "tariff support").

87. DNOs, on the other hand, receive no regulatory RAV guarantee if they spread the cost of a connection over time (and offer finance at their own risk), while they are also explicitly prevented from offering tariff support by the connections charging methodology. This disparity is distorting end user decisions over which network to connect to. It favours transmission network or IDNO connections even if a connection to a DNO network would involve far fewer assets and lower costs. It is also stifling the role distribution networks can play in the low-carbon transition for existing users that need upgraded connections. This is imposing higher costs on energy consumers, over the long term, and it is difficult to see how this is consistent with Ofgem's duties to energy consumers. Ofgem needs to urgently resolve this distortion.

88. Assessed objectively, the DNO model offers the strongest locational pricing signal at the point in time connections are being considered and the greatest likelihood of economically efficient outcomes. Ofgem should therefore align all three sectors to this DNO approach.

89. If Ofgem is not willing to confront the vested interests which will support the current transmission and IDNO connection charging approaches then it should still align all three sectors on one of the other models.[18]

8. How should we hold the companies to account for the delivery of strategic investment, and the outcomes that they are expected to deliver?

90. As we have set out in our response to question 2, Ofgem should hold companies to account for the low carbon objectives they contribute to by:

a. providing funding on a pay as you go basis, so that funding is only provided once uptake happens (i.e. once DNOs have addressed any barriers within their control); and

b. "mainstreaming" the transition to net zero into the various existing outcome incentives (such as customer satisfaction, reliability, time to quote and time to connect).

91. This would very directly hold companies to account; they would only receive funding if the uptake happened, while their revenues could be adjusted upwards or downwards depending on their performance.

[18] Unlike changing the connection charging boundary for DNOs, which Ofgem has also been contemplating, this would not require changes to the Electricity Act 1989, since DNOs would still be able to recover the full cost of the connection as permitted by the legislation.

92. If Ofgem also decides to fund major strategic investments on a “well ahead of need” basis, then it could also use specific pre-defined deliverables associated with those projects. This was the approach taken in DPCR5 to high value projects. There are, of course, costs from doing so, because it limits the optionality and ability for DNOs to innovate. However, Ofgem can mitigate some of these costs by specifying the deliverables in the highest-level terms possible, and by limiting their use to instances where projects meet set criteria (like a sufficiently large value).

93. Widespread use of price control deliverables should be avoided because of the damage this level of micro-management will do to incentive to control costs and to deploy innovation.

Setting price controls for DSO functions

9. Is there a need to separate out the revenues and outputs for ‘traditional’ DNO functions from DSO functions? How could this be achieved?

94. No, this would be damaging to consumers. DSO functions should target exactly the same outcomes as DNO functions, and their costs should be set and treated in exactly the same way.

95. At its heart, the distribution system operator role is about ensuring cost and reliability are being effectively managed in face of requirements being placed the network, including to facilitate decarbonisation. These are all outcomes that the existing system incentivises, through a single price control that includes:

a. a single totex cost incentive rate, so DNOs earn higher profits if they can minimise costs (including by replacing traditional reinforcement with flexibility solutions);

b. a single regulatory capitalisation rate, applied to all types of costs, so DNOs have no incentive to favour particular costs which cause higher RAV; and

c. a suite of incentives so DNOs earn higher profits if they deliver good outcomes on reliability, customer service and connections, regardless of the approach they use to deliver those good outcomes (e.g. flexibility vs network investment).

96. These steps effectively regulated away the conflicts of interest in DSO activity and create the perfect conditions for a home-grown DSO that uses native competition to keep costs as low as possible to network users, while meeting necessary outcomes.

97. In contrast, in electricity transmission, Ofgem already treated system operator’s “external” costs so differently to its internal costs and the costs of transmission investment, that the T1 settlement was not a true RIIO settlement. Ultimately these regulatory headaches led Ofgem to ring fence the transmission system operator (the ESO) from the rest of the transmission business and give up on incentive regulation, replacing this with cost pass-through and discretionary awards. In doing so, clear accountability has been lost for transmission network performance, since ownership and operation are fragmented, while costs will gradually grow thanks to the loss of incentives.

10. In the event of the DSO function being delivered by a separate party, how might we determine the revenues for DSO activities? What type of funding model would be appropriate to set DSO revenues? In this event, would changes also be required to DNO revenues and outputs?

98. Ofgem should avoid splitting the DSO role away from the DNO function.

99. Ofgem built the RIIO-ED framework to meet the challenges of the transition to a low-carbon future, including through the use of flexibility solutions and innovation to minimise constraint management costs. Ofgem now needs to let the system it already built work. DNOs are the right parties to continue holding the DSO role.

100. Separating DSO functions would be a damaging and retrograde step for energy consumers that would lead to higher costs over the longer term and a loss of clear accountability for network stability. Likewise, a separate price control for DSO activity would lead to all the same regulatory headaches that Ofgem has faced in respect of the transmission system. Ofgem must avoid these pitfalls.

11. Where a DNO is undertaking a DSO function, what type of outputs or outcomes are necessary to measure how efficiently they are performing this function? Over what time period could these be measured?

101. What matters to connected consumers is a reliable network delivered at the lowest possible costs, with fast restoration and good customer service when things go wrong.

102. Ofgem already has effective incentives in place to support these outcomes. Ofgem needs to build on these strong foundations and ensure it has “mainstreamed” into these incentives all of the “touch points” that DNOs have with energy users in relation to DSO and low carbon transition outcomes.

103. There may be new touch points that the evolving DSO role creates between DNOs and their connected users. Where this happens Ofgem needs to ensure its framework captures these interactions and gives DNOs the incentive to give good service. For example, this might involve new categories in the satisfaction survey incentive.

104. The last thing Ofgem needs is another discretionary award, targeted at DSO activity. Discretionary rewards have many drawbacks, for the reasons we explain in paragraph 74 above. Separate treatment and rewards for the outcomes of DSO activity could also introduce distortions, between different ways to solve a particular network issue, that should be avoided.

Driving innovation and competition

12. In what ways could the existing arrangements drive more innovation and competition?

105. The existing arrangements already drive extensive innovation and competition that is often not fully recognised. As we highlighted in our 2018 framework consultation response:

a. *"Competitive tendering is used extensively in procurement by distributors who have to comply with the Utilities Contract Regulations 2016. 80% of Northern Powergrid's direct operational work load consists of bought in goods, services and materials; the majority of which is tendered. This means that a large majority of the works that we deliver are already exposed to market forces.*

b. *There is extensive competition in network extensions to serve new connections, between distribution network operators and independent connection providers."*[19]

106. The existing RIIO arrangements, in particular the totex cost incentive and single capitalisation rate, were designed to encourage "native" competition between traditional investment solutions and innovative approaches such as demand response. DNOs are increasingly making use of these solutions as part of their business as usual model. For example, Northern Powergrid is evaluating the use of customer flexibility through market tenders on a level playing field with asset reinforcement or smart grid technical solutions.

107. Ofgem needs to give the incentives put in place under RIIO the time necessary for them to play out, and should resist the politically driven temptation to reinvent the regulatory "solution" every few years.

Encouraging a smart, flexible energy system

13. To what extent should we set (and incentivise performance against) baseline totex allowances for activities where flexible solutions could be provided?

108. The extent should be 100%.

109. Ofgem's totex benchmarking of actual and forecast costs will reflect the extent DNOs will be able to use flexibility solutions to reduce their costs. Ofgem has the tools necessary in RIIO to set robust cost allowances, provided it uses those tools (for instance by providing rewards for companies that submit challenging business plans that perform well on cost benchmarking).[20]

110. The totex approach to cost incentives within the price control period then acts to incentivise the use of flexibility solutions, because the cost of the flexibility solution (or any other innovative approach) will be treated in exactly the same way as a novel network technology solution or a traditional reinforcement approach.

111. Ofgem needs to maintain the strong incentives this creates for the discovery of lower cost approaches, so that it can set lower cost allowances in future based on this information, at successive price control reviews.

[19] Northern Powergrid, 2018, response to Ofgem's RIIO Framework consultation, page 11, paragraph 49

[20] The GD2 business plan incentive lacks these rewards. Ofgem must address this issue. We cover this issue in response to question 44 below.

14. Should we instead set allowances based on the costs revealed through the flexibility tendering process? How might this work?

112. Ofgem should set allowances for flexibility tendering in the same way as any other totex costs, and give companies the same incentive to reduce their costs regardless of how the reduction is achieved.

113. It must not try to reset allowances within the price control period based on the outcome of flexibility tendering.

114. As we highlighted in our response to Ofgem's 2018 RIIO framework consultation, the Competition and Markets Authority (CMA) has recognised the work that the Authority and other regulators have done in removing the distortions between different types of costs. It has also given clear guidance that Ofgem should give careful consideration to any changes to how costs are treated or assessed that might re-introduce such distortions, since this would be a backward step in regulation.

> *…GEMA and other economic regulators have – over many years – rightly recognised the potential for what can be relatively arbitrary classifications of costs to give rise to undesirable incentive effects (including the direction of material resources towards seeking to influence what should be included in different categories, where such decisions have significant financial consequences). In line with this, GEMA has developed approaches that have diminished the significance of such categories, and the development of a totex approach can be understood within this context.*
>
> *This suggests to us that careful consideration should be given to the risk that the use in the cost assessment process of specific cost categories, such as, smart/conventional, may lead to undesirable incentive effects representing a backward step in terms of incentive regulation. This is because of the potential for the use of such categories to distort incentives in undesirable ways.*[21]

115. If Ofgem were to set or revise allowances for flexibility within the period it would be explicitly going against the advice of the CMA. It would be damaging to consumers, because it would:

a. fundamentally undermine the incentive for companies to identify these solutions and minimise their costs by using flexibility solutions; and

b. mean new approaches may not be taken ahead, so lower future cost levels would never be revealed and couldn't be passed on to consumers through future price controls.

116. And since Ofgem would have "regulated away" any opportunity for outperformance on cost allowances through the use of flexibility tendering, this would be micro-management regulation at its worst. It would come at the expense of higher costs, and would be to the long term detriment of energy consumers.

[21] Competition and Markets Authority, 2015, Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc v the Gas and Electricity Markets Authority, Final determination, paragraph 4.128-4.129

117. Worse still, the proposal set out in Ofgem's question would also introduce the very conflicts of interest in respect of DSO functions that Ofgem is at .pains to stress that it wants to mitigate[22], because DSO costs would be treated differently to DNO costs.

118. Instead of causing all this damage through a separate flexibility price control, Ofgem should set baseline cost allowances at a level that can reasonably be expected for a company using a realistic mixture of traditional reinforcement and flexibility based on robust evidence. A totex cost benchmark (of recent and forecast costs) would achieve this. Once these allowances have been fixed, Ofgem should then let strong cost incentives work to reveal the actual minimum cost, and use this information to set baseline cost allowances in successive price control reviews.

Catering to a big data environment

15. To what degree should DNOs modernise their handling practices to adhere to data best practice, and therefore (among other things) provide available, transparent, and interoperable data about their networks? What measures will be needed to ensure data remains secure?

119. We respond to the two aspects of this question in turn below.

Data handling practice

120. DNOs should of course ensure that their data handling practice keeps up with changing uses of their data, including to the extent it is made necessary by the DSO role and through open data[23].

121. Ofgem's consultation fails to recognise, however, the many ways in which DNOs already share data, and it is important to understand this to take informed policy decisions. For example Northern Powergrid's public website includes:

a. an interactive map showing the available capacity for generation connection[24];

b. an interactive map showing capacity for demand connections[25];

c. a real time power cut map[26]; and

d. a portal for obtaining copies of local cable maps.[27]

[22] Ofgem, 2019, Position paper on distribution system operation, pages 4 and 5, including two of the four strategic objectives: "*clear boundaries and effective conflict mitigation between monopolies and markets*" and "*Neutral tendering of network management and reinforcement requirements, with a level playing field between traditional and alternative solutions".*

[23] In line with the recommendations of the Energy Data Task Force.

[24] https://cms.npproductionadmin.net/generation-availability-map

[25] https://cms.npproductionadmin.net/demand-availability-map

[26] https://cms.npproductionadmin.net/power-cuts

[27] https://myservices.northernpowergrid.com/safedig/login.cfm

122. Beyond this, we also share significant amounts of data with other organisations which have a need for it. This includes the ESO, in its role managing the electricity system, independent connections providers when they are working to build out new network, IDNOs where they need information about our system (when planning their own networks), and a range of other utilities who need data on our assets.

123. Undoubtedly the developing DSO role will require us to filter and publish even more data. In particular, we consider that part of the DSO role will be to provide data that benefits the competitive energy market to provide value for customers, even when its ultimate use may be unclear. In developing this role, the following questions will need to be answered.

a. Exactly what data should DNOs make available in this role, because it would be of benefit to market participants? In particular, how much data should be published where the costs of doing so are high and the benefits unclear?

b. Is inter-operability actually necessary (i.e. will it predominantly be used by national or local organisations) and, if so, what should the common formats and standards be?

c. What data do DSOs need to receive from other licenced market participants, such as generators on their network, or aggregators[28], and are common formats needed?

d. To what extent we should move away from company specific data sources to common data platforms that are shared by all DSOs or other industry participants?

124. These practical questions, and more, will be best addressed through a process of trials and customer feedback by individual DSOs, and industry working groups to define any common approaches.

Data security

125. Ofgem should place the onus on DNOs to ensure security and keep up with wider trends (such as greater control of individuals over the use and monetisation of any data that relates to them), without resorting to micro-management that will inevitably lead to poor outcomes.

126. In the context of the data provision aspect of the DSO role:

a. data may well be public, or at least a dataset that a wide range of organisations can access; therefore security means ensuring that the data itself is not capable of serious misuse;

b. integrity of the base data necessitates effective cyber security and also more traditional data system resilience; our views are set out in response to questions 24 and 25;

[28] Since aggregation is akin to generation, and since flexibility services are being increasingly relied upon to meet energy system needs, we think it will be important that aggregation be a licensed activity in future, to maintain system stability.

127. There is a separate regulator for personal data security and Ofgem should not attempt to duplicate this role, since that separate framework creates its own incentives (both financial and reputational).[29]

16. How should we structure RIIO-ED2 to encourage metadata to be made available, and for data to be presumed open? How should we measure DNO performance in this area, and on what basis should funding be set to deliver relevant outcomes?

128. Ofgem must ensure it does not micro-manage company data management, yet its proposals appear to run this risk.

129. If Ofgem were to define what data is made available, and how, set allowances based on a line-by-line assessment of the relevant costs, then measure company performance on “data outcomes” (which are not a measure of user satisfaction), it will be micro-managing, causing significant distortions in company decisions and damaging the long term interests of energy consumers.

130. Instead of micro-management, Ofgem should set a robust regulatory framework as follows.

a. Require DNOs to set out a data strategy in their business plans, giving visibility of how companies plan to manage their approach to data, and any specific commitments they are making, and report against this in their annual business plan commitment report.

b. Encourage outcome delivery by ensuring data provision services are “mainstreamed” into outcome incentives, for example including them as part of the main customer satisfaction incentive survey, potentially developing new survey categories if necessary.

c. Provide funding as part of the totex allowances, with efficient total costs benchmarked using top-down approaches, and then a totex incentive and capitalisation rate being applied, with a five-yearly reset that allows costs to be trued up based on revealed levels.

131. This approach is capable of delivering good outcomes.

132. Of course, where data standardisation is necessary for end user requirements, there will ultimately need to be an industry led process of determining these requirements, and if necessary licence or code obligations to ensure all DNOs then adopt these approaches.[30]

17. Do you agree with the themes we plan to include in our guidance on data best practice?

133. We agree with Ofgem that data should be visible and open (where the benefits of data publication outweigh the costs) and also that this data should be interoperable (where there are benefits to

[29] We recognise that Ofgem’s separate role as the competent authority for the NIS regulations implementation creates a specific additional role for Ofgem. In general we think Ofgem should not define and impose standards on companies, even “minimum standards” (as it describes its recent proposals in this area) since this would remove the onus from companies in respect of those standards, and potentially raise costs to energy consumers.

[30] If voluntary commitments are not sufficient.

users of data from multiple energy networks that outweigh to loss in innovation that a single standard will cause).

4. ED2 framework consultation questions

134. As with our response to the questions on strategic approach, we follow Ofgem's structure.

135. We note that Ofgem's RIIO-2 framework consultation, and decision taken in July 2018, explicitly applies to ED2. Our views on these aspects of Ofgem's ED2 framework consultation are unchanged.

136. The subsequent methodology consultation applied only to T2 and GD2. Our views on these same issues for ED2 would *typically* be those we previously expressed, although this will not always be the case, for example where there:

a. have been changes in Ofgem's decision relative to its proposals; or

b. are differences between the sectors that warrant a different approach.

Length of the price control

18. We welcome views on our proposed position of a five-year price control for RIIO-ED2.

137. Ofgem set the default length of price control for RIIO controls to five years in its RIIO-2 framework decision, which applies to ED2.

138. We have no further views to offer, beyond those we set out in our framework consultation response, and in our response to Ofgem's original RPI-X @20 consultation (that led to the RIIO-framework). In these, we highlighted that five year price controls are a robust approach, used in many regulated network controls in Great Britain, that provide regulators with a pressure release valve for unexpected events.

19. Are there any elements of RIIO-ED2 price control that we should consider setting over a longer or shorter period? Please give reasons.

139. No, there aren't elements of the ED2 price control that should be set over a different time period.

140. To do so would create boundaries in the treatment of different types of cost that would undermine the totex approach. As we highlighted in our response to Ofgem's 2018 RIIO-2 framework consultation, this would go against the best practice that Ofgem and other regulators have developed in removing the distortions between different types of costs, and against the advice of the CMA.[31]

141. For it to make sense to set allowances for a category of costs for a longer period, they would have to be costs where there are:

a. no other solutions to the same issue, so that totex incentives cannot be distorted by encouraging one approach over another;

[31] Northern Powergrid, 2018, Framework consultation response, page 31. The relevant CMA statements are also provided in this response, as part of our answer to question 14 above.

b. no inter-relationships with different parts of the cost base, for instance in how resourcing is scheduled (e.g. working hours vs. overtime); and

c. no opportunities or scope for discretion in cost allocation, because the activities and associated costs are very clearly ring fenced from other activities, to the extent the costs can be easily measured and monitored in isolation.

142. We do not expect any cost categories to meet this hurdle in electricity distribution, especially in light of the increasing substitutability between very distinct asset light and asset heavy solutions that it taking place as network management and operation becomes smarter.

Giving consumers a stronger voice

20. We welcome views on whether these enhanced engagement arrangements are appropriate for RIIO-ED2.

143. Our views are unchanged relative to the framework consultation, where we said that "*We support the desire to enhance consumer engagement but Ofgem must keep in place its own firm decision making process, so companies are disciplined to reject stakeholder proposals that are not in the interests of consumers. Otherwise Ofgem's decisions are vulnerable to appeal.*"[32]

144. We have recognised Ofgem's RIIO-2 framework decision and we are recruiting key personnel for our consumer engagement group (CEG). However, we can see some merit in the role of CEG being more flexible, for instance to allow for a degree of co-creation (where the expertise of the panel would help feed the business plan ideas). If this greater flexibility were permitted, we could still accommodate it within our plans.

145. Ofgem has more direct experience of the value it derives from the RIIO-2 challenge group and will be better placed than Northern Powergrid to reflect on whether this offers value for money to energy consumers, or whether the budget would be better spent by Ofgem on its own staff or consultancy.

Meeting the needs of consumers and network users

21. We welcome views on whether the proposed output categories and incentive arrangements are appropriate for RIIO-ED2.

146. Our views on the proposed output categories are the same as in our response to the T2 and GD2 methodology consultation. We support them as a logical framework under which all the RIIO-1 output categories can be consolidated.

147. Our views on incentives are also the same as in our previous RIIO-2 consultation responses. Ofgem should:

[32] Northern Powergrid, RIIO-2 framework consultation response, page 1

a. set consistent, challenging, evidence based targets for companies to incentivise performance within the price control period; and

b. use fixed targets as its default approach, recognising the damage that relative targets can do to within-sector collaboration and the costs this would impose on consumers.

148. At the ED2 price control, Ofgem will benefit from a well-established suite of incentives, with long term performance records. It should build on this.

22. We are interested to hear if there are new elements of the services DNOs will need to deliver that should be included in the current output categories. Alternatively, we welcome views on whether these should be captured by a new output category. For these new elements, we are interested to hear how delivery of these services should be valued and measured.

149. Northern Powergrid thinks that DNOs should continue to operate as the DSO, and that this will involve taking new approaches to existing services and potentially developing new services.

150. The outputs that would be delivered all fit within the existing output categories and incentive arrangements. Fundamentally, the DSO role is about ensuring:

a. distribution networks are reliable, with fast restoration when interruptions happen;

b. connections can be obtained with the lowest possible delivery times;

c. society's decarbonisation and air quality objectives are facilitated wherever networks have a role, including through meeting the demands this places on local networks; and

d. this is achieved at the lowest possible cost, giving value for money.

151. None of this is new. Ofgem already has incentives associated with each as part of ED1.

152. As we highlight in our response to question 2 above, Ofgem will however need to "mainstream" activities that support the low carbon transition into its suite of incentives, where they are not already reflected. For example Ofgem may wish to:

a. broaden the connection quotation, speed and satisfaction incentives to a wider range of connections, such as existing household's installing disruptive loads (which are likely to include low carbon technologies like heat pumps);

b. include ancillary services that DNOs provide for low carbon generation, such as witness testing, somewhere in the customer satisfaction survey; and

c. capture satisfaction of users that access information and data via DNO web portals (both in terms of information that is available today, and data that will become available in future as DNOs publish more).

23. We welcome thoughts on how to ensure that we continue to protect the interests of vulnerable consumers, particularly in light of the energy system transition.

153. Ofgem's primary duty is to all energy consumers and, while it must have regard to the interests of vulnerable consumers, that same duty also gives Ofgem the ability to have regard to the interests of any other group of customers (including consumers who are not vulnerable).

154. Ofgem therefore needs to ensure the steps it takes to protect the interests of vulnerable consumers do not cut against the interests of other consumers. Achieving this balance requires careful thought.

   a. Where network companies are able, through their day to day activities, to protect the interests of vulnerable consumers at limited additional cost, this appears sensible.

   b. Where the cost to energy consumers would be significant, and the outcome wouldn't be economically efficient, this does not appear to be justified.

155. Through the energy transition both of these may become more frequent (for instance if society in general becomes more energy dependent). But this does not obviously alter the role of Ofgem or energy networks.

156. There will also be many wider implications of the energy transition for how consumers, including vulnerable consumers, interact with the energy system more generally. For instance, time of use tariffs may become more prevalent. Consumers may need to smart-charge their cars to minimise their overall costs. Smart devices might provide services to the energy system. In all of these areas, Ofgem will need to have regard to the interest of vulnerable consumers. The extent to which DNOs are involved in the consumer interface will depend on the scope of the DSO role, and whether DNOs are directly involved in the consumer interface for these activities.

Maintaining a safe and resilient network

24. We welcome views on how DNOs should continue to ensure their networks are resilient, particularly in the context of the new or changing way assets are used.

157. Ofgem should not be trying to take decisions on how DNOs ensure their networks are resilient, whether or not assets are being used in different ways.

158. It should instead focus on understanding the necessary outcomes, and how its framework of economic incentives can contribute to these.

159. The key outcome is the reliability of power being provided to consumers. Provided that incentives are well calibrated, DNOs will take decisions that optimise the level of resilience. If Ofgem instead tries to replace these decisions with its own, through micro-management, worse outcomes (or higher costs) will result.

25. We are interested to hear stakeholder views on how DNOs should ensure their networks are resilient to physical and/or virtual threats, as well as being able to withstand the effects of adverse weather and the impacts of climate change.

160. Ofgem should place the onus on DNOs to meet these challenges, and make sure there are effective incentives on DNOs to do so. In doing so, Ofgem must step back from the micro-management it is increasingly resorting to.

161. Broadly speaking, strong incentives are in place.

   a. The interruptions incentive scheme provides strong incentives for DNOs to plan for all forms of resilience, including climate change, physical site security and the risk of cyber-attacks on system operation.

   b. Wider forms of data regulation give strong incentives to avoid the loss of personal data or sensitive personal data, since failures could lead to large fines being levied as well as significant reputational damage.

   c. Safety regulation puts in place additional incentives to ensure both public and employee safety is maintained, and failures can again lead to large fines and serious reputational damage.

   d. Likewise, the environmental regulator ensures that environmental protection is appropriately incentivised with duties and penalties for breaching them.

162. Ofgem has also put in place some leading indicators which can help indicate if DNOs are building up problems for the future.[33] At ED2 these will be called network asset resilience metrics (NARMs). Ofgem should however not:

   a. use these to micro-manage DNO asset replacement decisions, since this would be detrimental to consumer interests over the longer term (by causing higher costs);or

   b. mistake them for tools which can ensure resilience, since this will depend on many decisions outside the narrow definitions of asset replacement or network reinforcement.

163. The limitations of these measures emphasise the importance of a well-calibrated and complete set of economic incentives based on consumer outcomes like the interruptions incentive.

164. Ofgem should instead be using these measures as a backstop check that companies are delivering what they promised as part of the price control, and to ensure companies are taking the onus themselves to appropriately manage long term risks.

[33] Asset health and loading indices in the price control framework at DPCR5, ED1 and (prospectively) ED2.

26. We would also like to hear how stakeholders believe climate change mitigation and adaptation may affect network maintenance and development in the short, medium, and long term.

165. In the short to medium term, climate change could cause new issues that energy networks need to mitigate against. For example, additional sites may need to be protected from flooding risk, or more interconnection may be needed to reduce the impact of loss of a single site. This is well catered to by existing processes.

166. Over the longer term, climate change could have much bigger implications for design and build decisions, particularly if severe weather events become more extreme and prolonged, affecting larger areas of the network than they do at present. This could lead to altogether different approaches than those currently used.

    a. Many network users already have their own backup power sources in place. For instance hospitals will all have a backup power supply to cover their critical requirements. If climate change reduces the resilience of electricity networks, then more users may find this worthwhile, and this may be the least cost approach for the whole economy.

    b. There could be a role for DSOs in ensuring localised energy networks can remain operative even if wider-spread infrastructure has failed. Arguably, the IIS regime can once again incentivise this outcome.

27. We would like to hear views on how we ensure DNOs remain resilient to the challenges presented by an ageing and changing workforce.

167. These challenges are not new, and have been well managed both by DNOs and Ofgem's regulatory framework over the last decade as part of a gradual transition.

168. Ofgem should continue to place the onus on DNOs to ensure they have resilient workforce plans. Publication of these plans can be required as part of the business plan. The government has also put in place a funding mechanism for apprenticeships, funded by its apprenticeship levy, which gives DNOs a further commercial incentive to train new staff.

169. If Ofgem has concerns that workforce funding might be vulnerable to short-term cost-cutting, Ofgem could employ a use-it-or lose it approach, as was the case at DPCR5. However we note that:

    a. this has disadvantages in terms of introducing distortions into the totex approach to costs, and we do not think it is necessary as long as Ofgem incentivises companies to minimise their long-term costs; and

    b. the evidence from ED1, where workforce renewal was funded as part of totex, gives no indication that this expenditure has been systematically exposed to cost cutting.

170. The table below shows company expenditure during the ED1 period to date on operational training, which includes the cost of renewing the workforce. Overall, across the sector, expenditure is within

2% of the plans companies set out, with some companies having spent more and others less than their plans. In the context of cost allowances that were well below those company plans, on average, this does not indicate damaging cost cutting.

	Business plan	Actual	Proportionate difference
ENWL	25.6	20.2	-21%
NPg	34.7	35.2	+1%
WPD	93.7	112.2	+20%
UKPN	66.5	51.6	-22%
SP	47.9	38.6	-19%
SSE	32.0	36.3	+13%
Total	**300.3**	**294.1**	**-2%**

Delivering an environmentally sustainable network

28. We welcome views on how DNOs should work to minimise the impact of what they do on the environment and facilitate the transition to a low carbon energy system. We are particularly interested in the implications of the government's updated target of net-zero emissions by 2050.

171. The government's net zero by 2050 target will have significant implications for DNOs, as will the move towards cleaner air.

172. Heat and local road traffic will be increasingly electrified during the ED2 price control period and beyond. The Climate Change Committee supports these expectations, stating that:

> *"Heat pumps are an established solution in many other countries, but not yet in the UK. Establishing them as a mass-market solution will take some time, with strong progress required during the 2020s. There are particular opportunities in new-build properties, homes off the gas grid, non-residential buildings and for hybrid heat pump systems retrofitted around existing gas boilers."* and that
>
> *"In our recent Net Zero report we recommended an end to sales of petrol and diesel cans and vans by 2035 at the latest and early deployment of hybrid heat pumps, increasing electrification in the 2020s. A heat decarbonisation strategy could imply further electrification beyond this."*[34]

[34] Climate Change Committee, July 2019, Reducing UK emissions: 2019 Progress report to Parliament

173. Government has already said that it will "*introduce a future homes standard, mandating the end of fossil-fuel heating systems in all new houses from 2025.*"[35] This means that, from 2025 at least, many new homes will have to be fitted with heat pumps. More policy steps like this are likely.

174. Looking beyond net zero, and potentially much nearer term than 2050, there is growing public and political awareness of the problems caused by highly polluted air in urban centres. Widespread damage to health and loss of life is being proven and the UK is routinely breaking legal limits for air quality. The only solution is a major acceleration in the uptake of ultra-low emission vehicles for local traffic, and the only available technologies at present are electric or hybrid cars. We think there is a high chance of significant uptake of these vehicles within the next decade, driven by government policy reform and falling technology costs.

175. However, there is still significant uncertainty over the longer term pathway to net zero carbon emissions and clean local air. For example, hydrogen might ultimately play a significant role, meeting needs that may otherwise have required investments in electricity distribution networks. Ofgem therefore needs to ensure its framework is flexible and adaptive (through the low carbon volume driver to adjust allowances that we propose below).

176. We highlight how Ofgem should achieve the necessary investment, incentives and flexibility in funding in response to question 2 above, in response to questions 29- 30 below and throughout the rest of our question responses.

29. We also welcome views on what this may mean for the type of activities networks undertake, how these may be funded, as well as the outputs and/or incentives they should be exposed to.

177. The RIIO price control framework was built for this challenge. This means new activities (such as DSO functions, and flexibility tendering) can all be accommodated within that framework for funding and performance. DNOs should continue to be exposed to incentives to minimise their total costs, and deliver good performance in areas such as reliability, customer service and connections.

178. The main totex approach to funding costs has removed distortions that previously existed between different types of cost. The CMA recognised the steps that Ofgem had taken in this regard, and given clear guidance that Ofgem should give careful consideration to any changes to how costs are treated or assessed that might re-introduce such distortions, since this would be a backward step in regulation.[36]

179. However, there is still a major distortion between different types of energy network company in how connections can be charged for. As we explain in response to question 7 above, at paragraphs 85 to 89, Ofgem needs to resolve this distortion.

[35] Spring statement by the Chancellor of the Exchequer, March 2019, Hansard.

[36] See response to question 14 which also relates to this topic.

30. Finally, we are keen to understand how DNOs' performance should be measured, and how we should assess the value that consumers place on the provision of these services and activities.

180. DNOs should not be incentivised based on outcomes which are beyond their control, such as the level of uptake of new technologies by end users (like electric vehicles). These outcomes will be largely determined by the cost of these technologies, consumer attitudes and government policies.

181. Instead, we think DNOs should be incentivised to facilitate the low carbon transition through:

a. volume drivers that provide additional cost allowance as and when uptake occurs; and

b. "mainstreaming" of the low carbon transition into the existing outcome incentives, such as ensuring the relevant outcomes are built into the customer satisfaction incentive.

182. To assess and incentivise DNO performance, Ofgem needs to focus on metrics like those it already has in place on:

a. interruptions performance, which would penalise DNOs if they fail to maintain reliability as greater demands are placed on their network;

b. the speed of connection and the level of service given; and

c. the level of service provided in response to "general enquiries".

183. Within this framework Ofgem needs to revisit whether and where particular issues are recognised. For instance, if customers increasingly need DNOs to respond to requests to install heat pumps, Ofgem should consider bringing this within scope of the customer service incentive.[37]

184. To the extent new areas need to be incentivised under the existing incentives, Ofgem should consider whether it starts gathering data ahead of the ED2 period, so it can understand current DNO levels of performance on which to start calibrating its future incentive targets.

185. Turning to setting the incentive rates, consumer willingness to pay measures should be used wherever possible (as has been traditionally the case for reliability). In any areas where this data is not available, Ofgem will need to apply regulatory judgement and common sense. It should start by checking the potential value of incentive per customer interaction and whether this sounds reasonable.

[37] For example, if a user needs a modified connection for a disruptive load, the connection service they receive is currently outside the scope of the satisfaction survey; the other related issues that disruptive loads could cause (voltage problems or interruptions) are however within the scope of both the satisfaction survey and the interruptions incentive.

Enabling whole system solutions

31. We welcome views on how RIIO-ED2 can best capture the benefit of whole systems solutions. We are also interested in views on how these benefits should be measured.

186. Economically efficient whole-system outcomes will result if the participants in the system face the costs and benefits of their actions, and where clear accountability is allocated.

187. Energy network companies, or Ofgem, trying to take "whole system" decisions on behalf of other market participants will, by definition, lead to second best outcomes. Ofgem should therefore limit the extent it, or energy networks, micro-manage whole system outcomes.

188. Ofgem should also avoid placing too much weight on difficult-to-measure benefits; although tracking them may be important to demonstrate the societal and political value of steps taken by the sector.

189. Where measurement is challenging, Ofgem could make greater use of duties on distributors to consider the overall costs of their decision, as was the case with losses at ED1. For example electricity distributors may by able to reduce kWh energy consumption through voltage optimisation.

190. Most importantly, we continue to agree with Ofgem that it is not necessary to align the timing of the electricity transmission and distribution price controls (in line with Ofgem's RIIO-2 framework decision).

32. We further welcome stakeholders' opinions on whether the electricity distribution sector's approach to whole systems should be different from the other sectors and, if so, why.

191. We can't see why Ofgem's approach to regulating whole system solutions in the electricity distribution sector should be different from those of other sectors. In some cases electricity distribution is the flip side of the same coin.

192. However, we do not agree with the approach Ofgem has decided to take ahead for those other sectors. We set out this view in response to the GD2 and T2 methodology consultation:

> *[Proposals 3, 5 and 6 represent] Highly damaging and distortionary mechanisms to re-allocate accountability and funding on an on-going basis, subject to discretionary within-period decisions, which will create perverse incentives to focus more on lobbying than achieving low costs and leave it unclear as to who is to blame when things go wrong.*[38]

193. Ofgem's decision was to take ahead proposal 5: a co-ordinated cross-sector reopener that revises responsibilities and funding, and reallocates projects to different sectors (along with proposal 1, inclusion in the business plan incentive, which we supported).

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[38] Northern Powergrid response to Ofgem's T2 and GD2 methodology consultation, page 25, paragraph 123.

194. It is entirely unclear how this "*delivers the right balance of setting expectations, incentivising and supporting new and efficient whole system solutions, and managing the risks of introducing unnecessary complexity and perverse incentives"* as Ofgem claims[39]. It does **nothing at all** to manage the risks of introducing unnecessary complexity and perverse incentives because it will:

a. undermine clear accountability for failures to deliver, because it will be easier to argue that responsibility should be reallocated elsewhere than take the tough action necessary to address a whole system issue; and

b. split some types of cost down the middle, making it impossible to reliably separate "within reopener" from "outside reopener" costs, with all the distortions and perverse incentives that follow.

195. This type of mechanism will therefore fundamentally undermine the totex incentive mechanism, wherever it operates. The perverse incentives will also be lop-sided between sectors, with sectors where ownership (and information) is concentrated more easily able to lobby Ofgem for favourable outcomes, shifting onerous duties away towards other sectors even though the least cost approach might not lie there.

196. Instead Ofgem should focus on getting the uncertainty mechanisms right for each sector in its own right. This is something it already finds challenging, and which it will be distracted from if it embarks in building a new cross-sector mechanism.

Managing uncertainty

33. We welcome views on how we should manage the uncertainty associated with forecasting allowances, and whether there are any mechanisms we could or should consider in helping to manage this uncertainty.

197. Uncertainty mechanisms at ED2 should be limited to the relatively "big" risks where DNOs have little or no control over the outcome.

198. This is because uncertainty mechanisms have significant downsides. For example:

a. they can distort the incentives companies face and undermine the totex approach to regulation, where the costs are directly within DNO control, or substitutable with costs outside the reopener; and

b. they create additional administrative burdens during the price control period.

199. Up-front allowances will in contrast maintain strong incentives and avoid distortions, and so are preferable anywhere that:

a. the risks are not so large (relative to the envelope of overall expenditure);

[39] GD2 and T2 methodology decision, page 57, paragraph 8.20

b. the costs cannot be neatly ring-fenced; or

c. where there is available evidence on which to forecast future costs.[40]

200. In light of these facts, and since ED2 is a shorter price control period than ED1, we anticipate less use of uncertainty mechanisms at ED2 when compared to ED1, not more. Yet Ofgem's proposals seem to indicate it wishes to put in place a much wider range of adjustment and clawback mechanisms. This type of micro-management will be highly damaging to incentives and lead to higher long term costs for energy consumers.

201. We set out in the table below our views on each of the uncertainty mechanisms in the ED1 price control or that Ofgem has proposed for GD2/T2, along with views on how each potential mechanism could be designed to mitigate the damage to incentives it could cause.

[40] E.g. extrapolating from actual costs based on reasonable assumptions, or benchmarking of actual and forecast plan costs

Table 1: Northern Powergrid views on ED2 reopeners

Cost area	Status	Northern Powergrid view
Load related expenditure	ED1 reopener	**Retain but reform significantly.** An allowance volume driver is needed so that base allowances flex automatically based on the number of low carbon technologies (e.g. electric vehicles) operating in each distribution service area. The re-opener could still apply if expenditure strays significantly from the revised allowance. The current reopener, which relies entirely on expenditure levels, is detrimental to incentives.
Licence fees, exit charges*, DCC fixed costs, business rates	ED1 pass through	**Retain.** DNOs have little or no influence over the level of cost. Using the established mechanism avoids the need to spend excessive time during the price review forecasting costs. *Excludes new exit points, which are partially incentivised
High value projects	ED1 re-opener	**Retain.** The thresholds are sufficiently large to have a reopener, while still remaining below the £100m threshold at which bespoke competition may make sense.
Critical site security	ED1 reopener	**Retain.** The reopener is limited to security measures deemed necessary by the government. The site specific nature of the investments makes it easier to define cost boundaries than some other reopeners.
Street works costs	ED1 re-opener	**Replace or potentially remove.** The schemes and their costs are now relatively well understood. Instead either: a) use an automatic allowance driver based on timing of introduction of any (i) remaining permit schemes (ii) lane rental schemes; or b) set a probability adjusted ex ante allowance for the costs to maintain stronger incentives and remove cost boundary issues.
Rail Electrification	ED1 reopener	**Either extend or remove. A** reopener for rail electrification *and* new railway build may be appropriate if there is significant uncertainty. This uncertainty is however less likely in light of the shorter ED2 price control period (and backstop protection is also provided by the high value projects reopener).
Link boxes	ED1 reopener	**Remove:** this reopener was only introduced because UKPN requested significant additional costs late in the ED1 price control review. Insofar as there is an ongoing issue this should be funded through totex allowances.
Cyber costs	Proposed reopener at GD2 and T2	**Do not introduce.** Would create cost boundaries within IT and other business costs, distort incentives, and reduce the onus on companies to justify their costs via their business plans. Fund via totex allowance instead, reviewed every five years.
Cross sector co-ordination reopener	Proposed reopener at GD2 and T2	**Do not introduce.** Would create perverse incentives for companies to seek to hand back allowances on "out of the money" outputs. Instead ensure accountabilities are clear (e.g. for system voltage) and ensure networks are obligated to offer support to one another on cost reflective terms.

Note: we have not considered licensee-specific mechanisms

34. We seek views on the use of indexation, particularly on any adjustments for labour and construction cost inflation.

202. Ofgem should set an up-front ex ante allowance for expected real price effects, based on a balanced assessment of the evidence at each price control review.

203. If it does not, then it must make some allowance for the fact that labour costs[41] demonstrably rise at above the rate of inflation over the long term.[42] We can see two options:

a. indexation; or

b. assuming productivity growth and real pay growth cancel out, if this is backed by the evidence.

204. In order to reliably measure real-pay pressures in the electricity distribution sector under the first option, Ofgem would need to measure (and benchmark) the outcome of relevant pay settlements. Ofgem has previously expressed unwillingness to do this, therefore limiting it to indices that can only act as a distant proxy for the costs Ofgem is seeking to measure. Because these may well differ significantly from the actual pay pressures faced by DNOs, and their contractors, Ofgem would in fact be adding risk to the sector under this approach. This risk would need to be recognised in the cost of capital.

205. The second option would rely on the fact that real pay growth, over the long term, is the flip side of productivity growth. A simple assumption that the two will offset could therefore be justified. To take this approach, Ofgem would need to test whether a 1:1 relationship is backed by empirical evidence. If this were that case, Ofgem would set no indexation for real price effects but also assume no productivity into the base price control. A five yearly reset of price controls would then allow costs to be reset to the level that actual real price effects and productivity had led to.

35. We welcome views on our approach to highly anticipatory investment projects. We are interested to hear whether stakeholders would suggest additional processes or regimes for facilitating such investments that support the energy system transition whilst protecting consumers from potentially inefficient investments.

206. We expressed our views on this proposal in response to Ofgem's GD2 and T2 methodology consultation. Our views in relation to ED2 are the same, and we have seen no further details of the proposals that would allow us to offer different comment. In short, the current framework is suitable for anticipatory investments that are justified. Unjustified anticipatory investment should not go ahead:

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[41] Labour is also an input to the cost of construction and many DNO raw materials, so has a higher "weight" in DNO costs than direct and contractor labour alone. After this, commodity costs probably the most significant driver of a DNO's physical costs, through their impact on the cost of raw materials.

[42] This is self-evident based on the fact that living standards have risen in the UK over the long term, which would not have been possible without productivity growth and associated real pay increases.

From an electricity distribution perspective, we see no need at all for this direction of travel in relation to anticipatory investment.

a. In relation to reinforcement, covered by the price control arrangements, there is already a significant element of risk sharing, because companies face a totex efficiency assessment at the price control review and are then exposed to a cost sharing factors.

b. In relation to new connections, new connectees pay only for their share of the connection, and having covered this cost they take the commercial risk of whether the investment will pay off. New connections are also exposed to competition.

We can see more reasons for this type of framework in relation transmission investments, especially where they are major and lumpy, or if distortions in the existing framework mean new transmission connectees do not pay an appropriate share of the cost of that connection. But we would still caution against the direction of travel. Neither network companies, nor BEIS, nor Ofgem will be better placed than the market to decide whether highly anticipatory investments will be worthwhile. 'Picking winners' amongst speculative investment projects is likely to lead to white elephants and wasted money.[43]

36. We welcome views on the type of issues that should be considered through an inter-institutional group.

207. We urge caution in respect of an inter-institutional group like the one described. As we highlight above "*Neither network companies, nor BEIS, nor Ofgem will be better placed than the market to decide whether highly anticipatory investments will be worthwhile. 'Picking winners' amongst speculative investment projects is likely to lead to white elephants and wasted money."*

208. Of course, the government's function is to decide direction for the country on big issues. It may well want to seek advice from expert bodies and industry and so Ofgem and DNOs, as well as bodies such as the Climate Change Committee, do have a role to play. But once that direction is set by government, everything else (including funding for network costs) will follow under the current framework.

209. If Ofgem instead tries to fold the views of an inter-institutional group, and the views of certain groups of energy users, directly into the business planning process, **it will create an incentive for user-led arguments for asset investment** that is not present in the current system, since the costs will be spread widely but the benefits will be focussed on specific users.

210. Instead it is essential to maintain the current separation between government policy and network company business planning, since this separation acts to protect energy consumers.

[43] Northern Powergrid response to the GD2 and T2 methodology consultation, cross sector questions document, page 25, paragraphs 150-151

37. We invite stakeholders to advise what type of expenditure they believe should be subject to alternative arrangements for sharing risk, and what these arrangements may look like.

211. We do not believe any expenditure is likely to warrant alternative arrangements for sharing risk.

212. This is because:

a. low-regrets speculative expenditure will be able to go ahead immediately under the existing framework; and

b. all other speculative expenditure will be able to go ahead at an appropriate time, once it is sufficiently clear it will be necessary.

213. Ofgem should therefore not develop alternative arrangements for risk sharing.

Driving efficiency through innovation and competition

38. We welcome views on the proposed innovation stimulus. We are interested to hear views on the types of projects that should be funded through either the NIA funding or a new funding pot.

214. We do not think NIA funding should be limited to projects related to the energy transition and consumer vulnerability.

215. Ofgem's Framework decision was to limit the stimulus to "*innovation projects that might not otherwise be delivered under the core RIIO-2 framework*".[44]

216. Greater consumer benefits are likely to result if DNOs can direct the funding to a broad range of innovations. This is not limited to consumer vulnerability or energy transition projects, but also includes innovations directed at network costs, reliability or customer service. In many cases these may have a business case for the whole sector, but will not for an individual company, even if Ofgem's framework maintains strong incentives to maximise long term performance (and minimise costs). For "borderline" projects like this, freezing them out of innovation funding would lead to them not going ahead, and be damaging to energy consumers.

39. How can the benefits of the innovation stimulus be maximised by supporting schemes proposed by non-network parties?

217. Many schemes already taken ahead under the existing arrangements are proposed, or developed in collaboration with, non-network parties. The non-network parties that we regularly interact with, which include research institutions, vehicle manufacturers and equipment suppliers, can easily propose additional projects.

[44] Ofgem, July 2018, Framework Decision, page 57, paragraph 8.21

218. Through the ENA we have set up routine exercises to receive ideas and have them evaluated by network companies to adopt as projects.

219. If Ofgem is concerned some non-network parties may still find it difficult to pitch their ideas to the right people and secure funding, Ofgem could establish a central portal to make this pitch to the relevant parties. Not only could this give energy networks a richer source of ideas for innovation projects, it would also give Ofgem full visibility of those projects which are pitched but which do not go ahead. This would allow better understanding of why these projects do not go ahead and whether important opportunities are being missed.

40. We also welcome views on our proposals for the different competition models in RIIO-ED2, and what, if any, criteria should be set out for the use of early or late stage competition models.

220. Ofgem took the decision in July 2018 that it would apply the ET criteria (new, separable, high value) to any projects. We support this decision.

221. If a different set of criteria were justified in ED, logically they would also be justified in all other energy network sectors. Sector specific criteria are simply not supportable.

41. We also seek input from stakeholders on how native competition obligations and best practices can be used to ensure the best outcomes for consumers and to drive changes in the role of the networks in a transforming energy system.

222. Ofgem should avoid setting fixed obligations and instead ensure that the incentives for native competition are strong.

223. Ofgem has repeatedly stressed the information asymmetry that it faces relative to company management. This asymmetry is not a legitimate excuse for any failures on Ofgem's part to set challenging targets in ED1. But it is the reason Ofgem should step back from trying to micro-manage the "how".

224. The management teams of the companies will always be better placed to take these decisions than Ofgem, since the companies bear both the commercial risks and benefits, and since they can set their resourcing in light of these. In contrast, Ofgem is staffed by civil servants that face none of these risks, and lacks the resource to try and directly manage the whole sector. These are good reasons for an economic regulator to focus on creating a framework that incentivises effective management, rather than trying to regulate the "how".

225. Yet time and again Ofgem's proposals show it to be intent on micro-management.

   a. Asset health indices are becoming a codified rule book that DNOs must use to justify their investment plans and by which they should take their day-to-day decisions.

   b. Audits of asset management data are being use to drive towards standard asset management practices, and Ofgem is perversely arguing for higher costs.

c. Company cost allowances for DSO activities might be fine-tuned during the period, once the results of flexibility tenders are known, removing any incentive to save costs.

d. Price control deliverables will be given greater emphasis than before, with checklists set by Ofgem to check companies did exactly what they said they would, stifling innovation.

e. There will be an uncertain boundary between "high confidence" and "low confidence" costs with many disadvantages, including the distortions this will create in incentives to allocate or incur costs in one category rather than the other.

f. There will be a new "regulator co-ordinated" mechanism to transfer accountability for issues, and allowances, between sectors, in stark contrast to the current "company co-ordinated" system of contracting to obtain services at cost reflective levels.

226. If Ofgem is taking all these decisions for the sector, it will need significant additional resources that are unlikely to be available.

227. Instead, Ofgem should focus its resources on setting a framework that uses incentives, and comparative competition amongst the six electricity distribution groups of companies[45], to reveal information over time that Ofgem can use to benefit consumers.

228. Strong incentives for achieving the best outcomes in an energy transformation can be ensured through a combination of:

a. totex cost allowances;

b. top-down totex benchmarking at price reviews;

c. "main-streaming" low carbon into the measurement of incentives, like customer service and

d. a strong business plan incentive that rewards low-costs and penalises high costs.

229. Fixed obligations would amount to micro-management of how DNOs achieve native competition. If these obligations prevent other, better, approaches then the cost savings for energy consumers that result from native competition will be lower, harming their interests.

230. Ofgem should also recognise that reputation provides a strong incentive. This does not mean Ofgem should run a price control assessment, and to hang a reputational badge (e.g. a rank in the annual report) on the outcome. Instead, it means that Ofgem can recognise there is a reputational incentive on the basis that significant laggards can expect adverse publicity. DNOs have already developed public commitments around their use of native competition, demonstrating that a reputational incentive in this area is effective.

[45] While controlling in any benchmarking for the advantage given to Western Power Distribution from a generous ED1 settlement.

Forecasting and scenarios

42. We welcome views on our approach to planning, forecasting and scenarios for RIIO-ED2. In particular, do stakeholders have other suggestions as to how we can best manage forecasting risk for consumers?

231. To manage forecasting risk, Ofgem needs to put in place an effective regulatory mechanism that ensures allowances can flex in light of actual experience. We continue to propose an allowance driver based on the number and type of low carbon technologies deployed in each DNO's service area.

232. Effective scenario planning is essential for companies to develop business plans that they can sustain, and cost forecasts under different scenarios, which can be added across companies, will also help stakeholders (like government) understand potential implications of their decisions. However, common scenarios can't mitigate the risk to consumers of funding too much reinforcement within a five year price control period (if a common scenario was set too high). And it can't completely mitigate the risk to company financial health (if a common scenario is set too low).

233. Worse still, if Ofgem were to fix allowances at a level implied by a common scenario, this would remove a significant dimension of competition between companies under the business plan incentive: namely, the amount of "scenario risk" they were willing to factor into their baseline cost request. A company taking on more of this risk would offer consumers significant value. Yet planning for a common scenario might rule this out.

234. A regulatory mechanism is therefore vital to ensure that allowances flex between the level consistent with the "baseline" scenario and the level necessary once the real pathway of the country is known.

235. The current load related reopener achieves this to some degree, but it is a very blunt tool that can distort incentives. Instead Ofgem should set a cost allowance volume driver of the type Northern Powergrid advocated during the ED1 review, where the number and type of low carbon devices connected to each network are used to calculate updated allowances based on a pre-set formula.[46]

Business plan and totex incentives

43. We welcome views on our proposal to remove the early settlement process for RIIO-ED2, instead focusing on alternative mechanisms to receive high-quality and ambitious business plans.

236. We support the proposal to remove early settlement at ED2. The credibility of the incentive was damaged by how it operated at ED1 making it less likely for companies to believe it would be triggered again.

[46] The expenditure reopener could remain and operate in tandem with this approach, for extreme and unanticipated outcomes, with the trigger defined by expenditure moving outside of a threshold around this updated allowance.

237. We also support a strong incentive for companies to submit high quality and ambitious plans. This has been made more important through the loss of the early settlement incentives (and associated financial rewards) that were present at ED1. We set out our views on Ofgem's specific proposals in response to question 44 immediately below.

44. We also welcome views on our proposals to use the Business Plan Incentive and the confidence-dependent incentive rate arrangements for RIIO-ED2. In line with this, we are interested to hear stakeholder views on the range that should be used for both of these.

238. The business plan incentive, and incentive rate arrangements, need significant further development to be well-suited to a sector like electricity distribution.

239. Electricity distribution is, as Ofgem recognises, the most dynamic of the RIIO sectors. It is therefore this sector where there is most value to consumers from strong incentives for companies to challenge themselves on their whole cost base, including by looking to find synergies between business as usual costs and incremental low-carbon transition costs (e.g. displacing asset replacement with reinforcement).

240. It is also the sector with the most companies, so there is a realistic prospect of companies competing with each other to obtain rewards, as they did at ED1 when the combined effect of fast-track rewards and the IQI encouraged this.

241. These two factors do not apply in other RIIO sectors. In transmission, the price control process is effectively a series of bilateral negotiations. In gas distribution, the sector is much more concentrated than electricity distribution[47] and will be far less dynamic over 2021-26 than electricity distribution will be over 2023-28.

242. In the context of these differences, a simple roll-across of Ofgem's business plan incentive for the GD2 and T2 control is not appropriate. The incentive lacks genuine rewards for companies developing challenging cost forecasts. The "rewards" it claims to offer in respect of high confidence costs amount to nothing more than partial-protection for companies from lost allowances if their proposals are below Ofgem's benchmark[48], which was regulatory practice that pre-dates the information quality incentive and which suffered flaws that led to that incentive being developed. This aspect of the business plan incentive would be a retrograde step compared to the ED1 information quality incentive, if it were rolled across to electricity distribution.

243. Meanwhile, the idea that companies could include a "Customer Value Proposition" request for a reward in their business plans, in respect of low costs, doesn't cater well to cost performance, since it is a discretionary reward that suffers all the associated drawbacks, and since companies won't know if their costs are comparatively efficient at the time of submitting their business plan.

[47] One gas distribution company accounts for half the sector, while it has only three other comparators (or as few as two, recognising the partially shared ownership structure of two of the businesses).

[48] The protection is only partial because a low forecast may itself reduce Ofgem's benchmark and thus the allowances; the GD2 and T2 business plan incentive offers no protection from this effect.

244. This must be addressed in the design of the business plan incentive for ED2. The incentive should feature substantial additional rewards for companies that challenge themselves on costs, whether or not the company asked for a reward in its business plan. This will be necessary if Ofgem hopes that the business plan competition on costs will reveal as much information at ED2 as it did at ED1, when the potential rewards (through the IQI and fast track award) were significant.

245. Compared to the GD2 and T2 incentive, at ED2 Ofgem needs:

a. the clear prospect of material rewards for companies that submit plans based on challenging cost levels;

b. less focus on "discretionary" assessment by Ofgem of what constitutes a good plan, or the need to submit "value propositions" based on costs;

c. no distinction between high- or low-confidence costs, since this will distort incentives for companies to challenge themselves on costs across all of totex; and

d. sharing factors set based on the efficiency of company costs, rather than the proportions of the plan that fall in different pots and may be set on a discretionary basis (which will dampen incentives).

246. We would be happy to engage with Ofgem through the working group process to develop these proposals more fully ahead of the ED2 methodology consultation, if this would be beneficial.

Fair returns and financeability

45. We welcome stakeholder views on our proposals to introduce measures to enable network companies to finance their activities whilst ensuring they receive a fair return.

247. Ofgem's proposals for the cost of equity:

a. would not provide a fair return nor cover the cost of the necessary equity finance; and

b. will dis-incentivise investment in electricity distribution at a time it may need to increase.

248. Ofgem is however right to scrap its proposals for a damaging cashflow floor, while Ofgem should look again at asset lives for RIIO-2.

249. We set out below our views on these three topics in more detail.

<u>The cost of equity</u>

250. In the context of the transition to low carbon future, Ofgem's must ensure that the necessary investment in networks comes forward in a timely fashion, when it is needed.

251. If Ofgem wants to stimulate the investment necessary to bring about a low-carbon future, the cost of equity must be set high enough.

a. The 1 percentage point reduction in expected market returns, compared to the CMA's last decision, is not supported by any new evidence; instead it has been ex post rationalised based on evidence which was available to the CMA in 2015.

b. The 1.1x adjustment to Ofgem's re-gearing calculations is a departure from textbook re-gearing formulae, and regulatory good practice, for no sound reason, since it reduces the cost of equity below actual, observed, levels in order to try to regulate away RAV premia.

c. Ofgem's chosen framework for estimation, CAPM, will only capture the systematic risks facing the sector, and will omit the significant and currently heightened political risk which accompanies energy network investments, and raises required returns.

d. The further 0.5 percentage point deduction means Ofgem is setting a cost of equity below its own assessment, based on an unjustifiable assumption that it will set cost or incentive targets incorrectly in a price control where it is likely to take far more care in setting cost and output targets based on lessons learned from RIIO-1.

252. If Ofgem continues with its proposals to set an allowed cost of equity below its actual value (having corrected the mistakes above), then there is agreement between academics[49] and respected regulatory authorities[50] that this carries risks of significant detriment to consumers.

<u>Asset lives</u>

253. These damaging proposals for a reduction in the cost of equity come at a time when Ofgem's 2011 decision to extend asset lives to 45 years will be causing sustained upwards pressure on the actual cost of equity, because of the risks to investors associated with a much larger regulatory asset value (RAV) and the financial stress this transition will cause on debt credit metrics. Ofgem should consider reducing the asset life to reduce longer term growth to the RAV under credible business as usual scenarios for expenditure.[51]

254. At the ED1 review, Ofgem took a cautious approach to extending asset lives, allowing all companies the transitional arrangements that they requested in their business plans.

255. This caution was warranted, as it has allowed a smaller and slower move to take place during the ED1 period. It has also allowed more information to become available on the range of potential future pathways for:

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[49] Dobbs, I.M, 2011, Journal of Regulatory Economics Volume 39, Issue 1, pp 1–28, Modelling Welfare loss Asymmetries Arising from Uncertainty in the Regulatory Cost of Finance. Working paper version available at the link below, see page 33. https://www.staff.ncl.ac.uk/i.m.dobbs/Files/Welfare%20loss%20JRegE.pdf

[50] See for example:

Competition Commission, A report on the economic regulation of the London airports companies (Heathrow Airport Ltd and Gatwick Airport Ltd), September 2007, page 49.

CMA, Bristol Water plc, October 2015, pages 333-334.

[51] If incremental increases in expenditure are needed, Ofgem could still consider financing the incremental amount over 45 years, to ensure current consumers do not overpay. This would result in each generation paying for its fair share of any new incremental costs, while still benefitting from the discount accrued at and since privatisation.

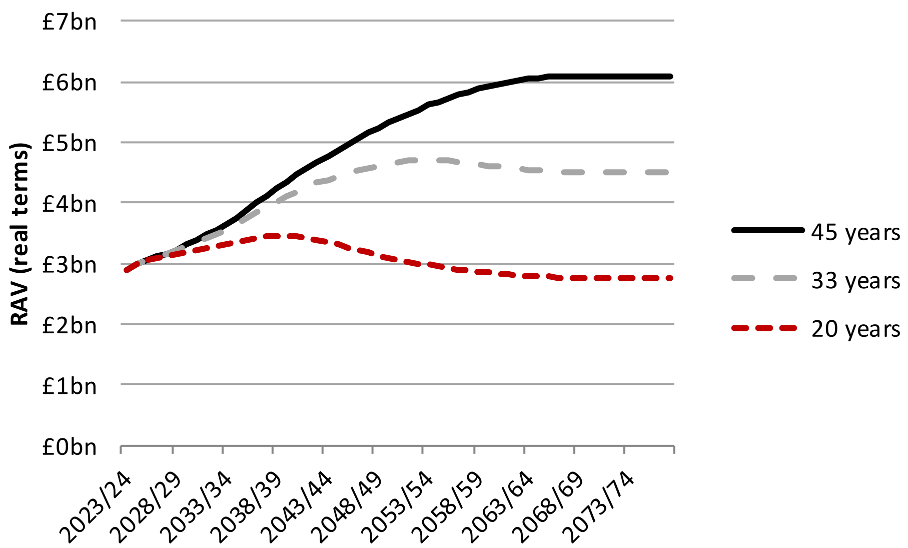
a. electricity distribution expenditure required to meet the low-carbon transition, ranging from very limited change to significant investment; and

b. the cost of capital, which has stayed lower for longer than expected, and where it is currently difficult to predict the timing of its recovery.

256. Ofgem's original 2011 decision to move to 45 year asset lives, and the financial modelling that supported it, could not have been expected to correctly anticipate the timing of any investment to support a low carbon roll-out, nor could it have anticipated the prolonged low interest rate we are currently in (and the additional strain this would place on company finances).

257. Unchecked, the current policy on asset lives will create major RAV growth, and a price escalator, even absent any real terms increases in DNO costs. The chart below shows how Northern Powergrid's RAV would evolve under three scenarios for asset lives, assuming that expenditure remains close to ED1 period levels.

Figure 1: Northern Powergrid's RAV under 20, 33 or 45 year asset lives



258. The transition was also not inter-generationally fair, except under very specific assumptions on the timing of expenditure to support a low-carbon roll-out. Under a wider range of scenarios, the change would benefit current consumers, who are already benefitting from past accelerated depreciation policies, to the detriment of future consumers.

a. Current customers are already paying prices at or below the "cost reflective" level, if asset lives had always been 45 years.[52]

b. The move to 45 year asset lives reduces this already-low price even further.

[52] This discount stems from a mixture of a "privatisation dividend" (1990 RAV being set below true asset values) and successive decisions by Ofgem to implement and then maintain accelerated depreciation policies.

c. RAV then starts to grow significantly, introducing a "price escalator" that will see charges increase rapidly for decades, to levels some way above those currently seen.

259. In light of this, ED2 presents an ideal opportunity to review the approach to asset lives in electricity distribution and put in place a system that is better suited to meeting these twin challenges. Both of the challenges have scope to place unprecedented strain on the finances of the electricity distribution sector. Yet the timing of both is highly uncertain.

260. In face of this, significant additional flexibility is needed. To create this, Ofgem should:

a. Depreciate a baseline tranche of totex expenditure, e.g. a set £ per customer per annum figure, over something like the current average[53], helping to maintain DNO financeability and preserve low prices for future consumers.

b. Depreciate all expenditure above this tranche at 45 years, so that any "peaks" in asset expenditure to meet the net zero transition can be spread over the lifetime of those assets without causing an undue spike in near-term charges.

261. This policy would have many advantages.

a. It would help maintain company cashflows so they can respond when investment is needed, whenever that might be.

b. It would ensure Ofgem is not trapped by the strained cashflows that uniform 45 year asset lives will create through the late 2020s and into the 2030s, if major additional investment is needed in that window.

c. It would avoid a "price escalator" that would raise network charges above current levels, even if expenditure does not need to increase, on account of higher long-term regulatory asset value (RAV).

d. It would reduce the inevitable upwards pressure on the cost of capital that would be caused by significantly larger RAV in the future.

e. It would create an inter-generationally fair distribution of outcomes.

<u>The cashflow floor</u>

262. Lastly, turning to the cashflow floor, Ofgem was right to scrap this mechanism in the GD2 and T2 methodology decision. It would have damaged incentives for management to improve performance, and insulated them from the market for corporate control, as well as being open to adverse selection problems (since rational investors could want management to access the facility, at times when the cost of debt or equity rose above allowed levels). For these reasons the proposals would have been detrimental to energy consumers and should not be revived.

[53] For Northern Powergrid, as a fairly representative DNO, the average at the end of the current regulatory year will be 24 years, while it will have risen to 29 years by the end of the ED1 period.

46. We are interested to hear from stakeholders on how they believe we should set allowances for the cost of debt, particularly around the method of recalibrating the index.

263. Ofgem has previously ruled out company specific pass through of the cost of debt, which we have previously advocated.

264. With this decision taken, Ofgem should now maintain its full indexation approach:

a. on a sector specific basis; and

b. recalibrated at successive reviews, where the evidence shows this is justified, to match the expected real debt cost of the sector.

265. At ED2 this would mean:

a. first testing if the existing indices will maintain a good match for sector debt costs (or company debt costs, in the case of company specific indices); and

b. where this test is failed, re-running the ED1 approach to index calibration.

266. Testing the suitability of existing indices, before recalibration, is necessary to meet the long term commitments to remuneration of the cost of debt that Ofgem made in its RIIO handbook, where it stated that *"At subsequent [to RIIO-1] price controls we envisage retaining the same index subject to a check that the index still provides a reasonable estimate of the cost of debt."*

267. Taking a sector specific approach is necessary to avoid an unreasonable assumption that the efficient cost of debt in electricity distribution is the same as in different sectors. National Grid's claim that this may be the case is entirely unreasonable because:

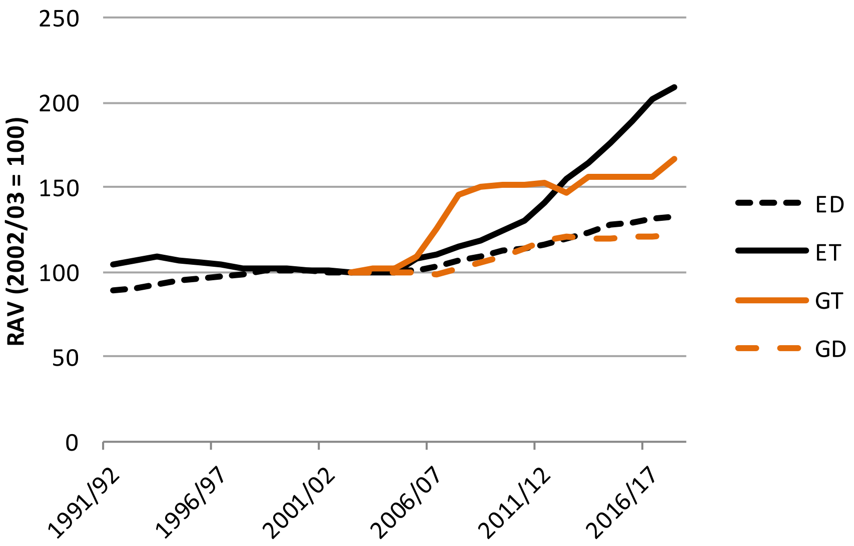
a. None of the gas distribution companies existed before the mid-2000s, or have any debt pre-dating their creation (we understand).

b. RAV growth in the transmission sector has been significantly higher than other sectors..

268. In the context of a generally declining debt cost, all else held constant the two factors above would reduce the actual debt cost of those sectors, when compared to electricity distribution, even if company treasurers took exactly the same approach to financing.

269. Moreover, the differences between sectors in terms of the RAV growth since debt interest rates declined are not small. The chart below shows the evolution of RAV since 1990/91 for the electricity network sectors and since 2002/03 for the gas network sectors.

Figure 2: Sector RAV growth, in constant prices



270. Amongst electricity networks, distributors had more RAV growth than transmission companies during the early to mid-1990s, and therefore had even more reason to issue debt at the prevailing rates of the day. However, since then, and especially since the much lower interest rates after the global financial crisis, transmission RAV growth has been far faster that distribution RAV growth.

271. Amongst gas networks, there are also significant differences in the timing and scale of RAV growth. Comparisons amongst these sectors are further complicated by the fact all of the relevant gas distribution licensees were newly formed, and newly financed, from the mid-2000s onwards. We understand that their observed cost of debt does not include any debt issued at the higher interest rates that prevailed before their formation, unlike other sectors.

272. To further illustrate the scale of the differences, the table below ranks the sectors based on RAV growth between 2002/03 and present.

Table 2: real terms RAV growth, 2002/03 to present

	RAV growth
Electricity transmission	109%
Gas transmission	67%
Electricity distribution	33%
Gas distribution*	22%

* Although sector RAV data is available back to 2002, the relevant licensees were all created and financed in the mid-2000s or more recently

273. Lastly, there is only one significant difference in methodology we can see between ED2 and ED1, which is Ofgem's decision to move to CPIH indexation rather than RPI indexation[54]. Ofgem will need to replace the RPI breakeven used in the deflation of the iBoxx index with a CPI(H) based measure. We propose that Ofgem use a high-quality third party forecast of CPI(H) inflation[55] for a time horizon broadly consistent with the price control period.[56]

47. We also welcome views on our proposed approach to setting allowances for the cost of equity, as well as our proposal to move away from RPI.

274. In our framework consultation response, we highlighted that Ofgem's previous conditions for moving away from a real-RPI allowed return had not been met, in particular the development of a liquid market in bonds that are linked to an alternative inflation measure.

275. Given Ofgem's framework decision in July 2018 to move away from RPI, we now support a full and immediate move at ED2. If there is merit in making a change it is difficult to justify a partial retention.

276. We still consider that CPI may offer a superior alternative to CPIH, since stronger institutional protections currently apply to the measurement of CPI which provides for greater investor certainty (although this could change in future). We therefore welcome the fact Ofgem's proposals for ED2 explicitly recognise that CPI inflation may be used for indexation at ED2.

Return adjustment mechanisms

48. Finally, we would like to hear stakeholders' views on our proposed introduction of a 'sculpted sharing factor' in instances of high out- or under-performance, or whether an alternative mechanism could be more effective.

277. As we said in our response to the GD2 and T2 methodology consultation:

> *"The proposed introduction of a return adjustment mechanism is a major departure from each, ex ante, incentive-based price control set since privatisation. The driver for the decision is well-rehearsed, and the price of a diminished incentive on companies to outperform is now seen by Ofgem to be one worth paying."*

278. Of the alternatives, the sculpted sharing factor is the least damaging option available, since it would.

  a. allow Ofgem to maintain the strong incentives while performance remains in a range around baseline allowed returns.

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[54] Subject to a final check on whether CPIH is the best available inflation index.

[55] Such as the OBR's inflation forecast.

[56] In calibrating its index, Ofgem also needs to deflate company actual debt costs, for the majority of debt which incurs a nominal interest rate. In doing so, it should use a forecast for expected CPI(H) inflation over the price control period, between 2023 and 2028. Inflation beyond 2028 will be taken into account in resetting the cost of debt allowance at ED3.

b. avoid the much worse damage that some of the alternatives would do, such as “return anchoring” or competed incentives, to collaboration across the sector.

279. With the risk of runaway returns constrained, and the incentive to innovate and outperform inevitably reduced, Ofgem should establish a high hurdle of evidence for any further dilution of the incentives that have served consumers so well historically.