To: All those with an interest in new connections to electricity distribution networks.

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Dear Stakeholder

Quicker and more efficient distribution connections

This letter explains the current arrangements for getting connected to the electricity distribution network. These arrangements aim to deliver an efficient process that protects the interests of all consumers. But we want to know if they work in practice and if/where they can be improved. We have listened to stakeholders who have proposed new arrangements which could speed up the process, and we'd like to hear your views on these and other potential changes.

Getting a new electricity connection to the local distribution networks promptly is important. It means businesses can begin trading, new homes lived in, and renewable energy can start being generated. That's why we've introduced measures[1] through the RIIO-ED1 price control, to improve the service provided by the companies which operate these networks – distribution network operators (DNOs), and taken steps[2] to improve competition in connections.

Along with service and choice of provider, one of the most important factors in getting connected is whether or not the network has enough spare capacity to accommodate a new connection. If significant work is needed then it can take months, sometimes years, for a connection to go ahead. It's not just about the time though. For some customers, having to pay upfront for network reinforcement can affect whether or not their project goes ahead.

There are ways to overcome these challenges. Delays can be avoided if new capacity is created in anticipation of future connection requirements. DNOs finding smart ways to reduce the need for additional capacity could also speed up the process. More flexible connection terms could lessen the initial cost burden which falls on some customers.

The current arrangements already allow, to a certain extent, the above to take place. In addition, stakeholders have identified ways in which these could be enhanced. There is a balance to be struck. Ultimately the cost of any work will be passed on to customers – either directly to the connection customer, or to customers more generally through their electricity bill. We are seeking to identify solutions which will benefit new connections but without making other customers worse off.

I look forward to hearing your views. Please send comments to olivia.powis@ofgem.gov.uk by 14 May 2015.

M.Frerk

Maxine Frerk
Interim Senior Partner - Smarter Grids and Governance

[1] https://www.ofgem.gov.uk/electricity/distribution-networks/network-price-controls/customer-service
[2] https://www.ofgem.gov.uk/publications-and-updates/findings-our-review-electricity-connections-market

Introduction

(i) Getting connected – who pays and why?

The infrastructure which delivers electricity to customers' premises is the distribution network. Electricity distribution network operators (DNOs) or independent distribution network operators (IDNOs) own and operate these networks. These companies are required by law to offer to connect anyone who asks. They can't discriminate and the system operates on a first come first served basis – with no differentiation between types of projects.

Customers should pay a fair price for the cost of the work required to connect them. When a customer asks for a connection, a DNO will assess its needs and the state of the existing network. If there's enough spare capacity to accommodate it, then the process should be fairly swift and reasonably inexpensive. We have facilitated competition in the connections market so that companies compete to connect new customers to the networks. This should mean that customers connecting have more choice, fairer prices and better service.

However, on some occasions connections cannot be completed until the network is enhanced (or reinforced) to ensure a secure supply is maintained for everyone. Where investment in the network is needed, the connecting customer pays for any assets which they alone will use and a share of any reinforcement they've triggered.[3] The remaining reinforcement costs are recovered from all other customers (referred to as Distribution Use of System (DUoS) customers) through the electricity bill.[4]

DUoS customers also pay the ongoing costs of running the network, including building new infrastructure to meet a general increase in demand for electricity. This type of investment could create capacity which may make it easier to connect in certain areas. However, we don't allow network operators to enhance the network and recover the cost of doing so from us all unless they can demonstrate how we will all benefit.

It's not easy to predict what type of new connections will emerge in the future. Economic conditions, government policy and planning restrictions can have a profound impact on the demand for new connections.

As a consequence, DNOs will generally wait until a customer has asked (and paid for) a connection before carrying out the necessary work. A number of important principles underpin this approach. The cost of the work gives the connecting customer a price signal that should encourage them to go where there's spare capacity on the network. It incentivises customers to engage with smart technology and energy efficiency solutions where the network is more constrained. It also protects other customers from having to pay for unnecessary infrastructure.[5]

Since 2010, there have been over one million new connections to the network. Around half a million distributed generation (DG)[6] installations are now exporting to the grid and 60

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[3] In certain instances, such as where particularly high cost work is involved, this may be up to 100% of reinforcement costs.

[4] A connecting customer will pay a share of any reinforcement needed up to one voltage above their point of connection. The cost of reinforcement at higher voltage levels is paid by DUoS customers. The share paid by the connecting customer should reflect the scheme with the lowest overall capital cost solely to provide the required capacity. In providing a connection sometimes a DNO may have to install assets with a greater capacity than required by the customer. When this is the case the cost of any additional capacity created is paid by DUoS customers.

[5] Further details on the connections process can be found in our 'Guide to the electricity distribution connections policy' at https://www.ofgem.gov.uk/publications-and-updates/guide-electricity-distribution-connections-policy

[6] Ofgem, Feed-in Tariffs Annual Report 2013/2014, available online at https://www.ofgem.gov.uk/ofgem-publications/91945/feed-intarifffitannualreport20132014.pdf

MW[7] of community energy schemes are up and running. The charging arrangements will have meant that any new connections will have paid their fair share.

Some new customers, however, may find that when reinforcement is required they can't get connected as quickly as they'd like, or as cheaply as they can afford.

(ii) Can the process be improved?

The existing framework allows for alternative arrangements which could make it easier to connect. DNOs can invest in anticipation of future connections, as indeed can other parties, and this would speed up the time it takes to connect. In this open letter we explain how and when we would expect this to take place.

But we want to know how these arrangements can be improved. We describe proposals that have been put to us by various stakeholders. These have arisen through engagement with stakeholders including those supporting new developments in major cities, along with representatives from the Community Energy and Distributed Generation sectors. Some of the scenarios presented may benefit specific customer groups, some may benefit all.

(iii) Making the case for change

We want customers to get connected as efficiently as possible and if necessary will make changes to the framework to achieve this. Our role is to protect the interests of all consumers and we must first understand how these changes might affect other customers.

We therefore want to hear your views on these proposals to understand the benefits they might bring and how they could affect other types of customers.

(iv) Structure of this document

The purpose of this open letter is to seek your views on existing arrangements, the changes which have been put forward by stakeholders and any other thoughts you have on how the process could be improved. We've used a number of scenarios to distinguish between the different ways in which investment could be made earlier or the connections process otherwise improved. These are not mutually exclusive. The scenarios are:

- **Scenario 1**: DNO funds (via DUoS) cost of anticipatory reinforcement (costs are socialised as no initial connection customer)
- **Scenario 2**: DNO funds (via DUoS) cost of anticipatory reinforcement when initial connection takes place (to be reimbursed by subsequent connection customers)
- **Scenario 3**: Connection customer funds cost of anticipatory reinforcement when initial connection takes place (to be reimbursed by subsequent connection customers)
- **Scenario 4**: Other ways of making it easier to connect.

For scenarios 1-3 we describe when earlier investment might take place, what barriers there may be and ask what could be done to address them. Where appropriate we use proposals made by stakeholders to illustrate potential changes and ask when these might be justified.

Scenario 4 looks at other opportunities to make it easier to connect. These include reducing the need for reinforcement and/or reducing the burden of paying for reinforcement upfront. We want to know your thoughts on what changes to current processes and arrangements are possible and in what circumstances would a different approach be justified.

When describing the process of getting connected to the network there is a risk of relying on technical terms. These may mean little to those outside of the industry and we will try to avoid them where possible. In some cases though these terms are the most effective way

[7] "The Community Renewables Economy: Starting up, scaling up and spinning out". Jelte Harnmeijer, Matthew Parsons, and Caroline Julian. ResPublica Green Paper, September 2013. Available online at http://www.respublica.org.uk/wp-content/uploads/2013/09/yqq_Community-Renewables-Economy.pdf

of describing a particular arrangement and so we have provided explanations in Appendix 5.

Scenario 1: DNO funds (via DUoS) cost of anticipatory reinforcement (costs are socialised as no initial connection customer)

Costs	Who pays initial cost?	Who pays back cost of reinforcement?	Justification
Connection	No costs as no connection		
Anticipatory Reinforcement	DUoS customers	No pay-back	Overall cost of reinforcement is anticipated to be lower for DUoS customers if invested upfront, rather than piecemeal approach.

When should this take place?

The 'socialisation' of reinforcement (spreading the cost of reinforcement across all customers) for new connections already takes place under existing arrangements. The cost of reinforcing the network to accommodate a new connection is shared between the connecting customer and all other customers and recovered through DUoS charges. This happens when additional reinforcement work may be necessary to provide a new connection, but which can't be charged to the connection customer.[8] In 2013-14, 70% of all reinforcement required for new connections was recovered through DUoS charges.

This approach is in response to new connection requests. In this section, we explore whether reinforcement costs can be socialised in anticipation of new connections, ie before any customer has requested a connection.

DNOs are responsible for managing their network efficiently. They have licence obligations to maintain efficient and economic networks and we can take action if they fail to deliver against these obligations. They should therefore anticipate where an increase in local demand and generation is going to arise and where more capacity is needed on the network. DNOs forecast the need for this type of investment and we allow them to recover revenue for these costs in the price control settlement.[9]

There is a strong incentive on DNOs to 'outperform' this settlement. If they spend less than they forecast and still deliver the same outputs, such as a reliable network, then they keep a share of any underspend, with the remainder passed to their customers. There are also mechanisms in the regulatory framework (RIIO-ED1) - High-Value Projects and load-related reopeners[10] which allow a DNO to fund additional expenditure not previously foreseen.

These arrangements should encourage DNOs to invest strategically in the network (ie before existing capacity has been reached) if in time this leads to a lower overall cost of reinforcement. This approach is more likely to be applied where the DNO anticipates general growth in electricity use through existing connections.

[8] This includes reinforcement at more than one voltage level above the point of connection and any cost of any capacity in excess of the minimum scheme.

[9] In its business plan, UKPN proposed £100m of strategic investment projects in London. We stated in our strategy decision that we were open to DNOs submitting a case for strategic investment projects in their business plans if they appropriately shared the risk of stranded assets between themselves, connecting customers and all other customers (DUoS customers). We stated that if a DNO could demonstrate benefits to DUoS customers of a strategic approach, then we would consider allowing DUoS customers to fund up to the level they would have done under an incremental approach. UKPN has demonstrated that the strategic investment projects it proposes are significantly lower cost and less disruptive for all its London customers than incremental approaches.

[10] For further information on these two mechanisms, please see Strategy decisions for the RIIO-ED1 electricity distribution price control - Tools for cost assessment, available online at https://www.ofgem.gov.uk/ofgem-publications/47072/riioed1deccostassessment.pdf

A DNO can also invest in reinforcement work in advance of new connections. In practice, this should apply when the cost of the reinforcement work - to DUoS customers - would be less if the work was carried out in advance, rather than in response to connections coming forward. The cost saving would need to be significant as under this arrangement the DNO would not receive any contribution from connecting customers for the reinforcement (as they would be investing prior to receiving a connection request).

What might prevent a DNO making this investment?

Forecasting future connections demand can be very difficult. A range of external factors can have a profound impact on what needs to connect, as well as where and when the connection is required. Uncertainty about future connections may discourage DNOs from investing in advance of a connection being requested. If the connection doesn't materialise then the DNO, and ultimately consumers will be left paying for assets that were not needed.

A DNO which takes this approach may also risk appearing to spend more and be less efficient than one who holds back expenditure until new connections emerge. Demonstrating the long-term efficiency of earlier investment can therefore be challenging.

What could be done to address this barrier?

DNOs may be more prepared to undertake this approach if third parties – such as developers or local authorities - could provide them with sufficient assurance that growth is highly likely to materialise. This could include evidence that the scheme is part of a regional government/local authority's development strategy and that investment in any associated infrastructure (transport, housing, other utilities) necessary to support growth is also being progressed.

This type of evidence could help the DNO demonstrate the cost savings to be made by investing upfront, rather than on an incremental basis.

Q1. Would a DNO be sufficiently confident about future connections demand and the benefits to DUoS customers to justify this approach? If so, in which circumstances?

Q2. What other barriers are there to DNOs taking this approach? How might these be overcome?

Scenario 2: DNO funds (via DUoS) cost of anticipatory reinforcement when initial connection takes place (to be reimbursed by subsequent connection customers)

Costs	Who pays initial cost?	Who pays back cost of reinforcement?	Justification
Connection	Connection customer		
Anticipatory Reinforcement	DUoS customers	Subsequent connection customers (via 2^{nd} comer rules)	DNO invests DUoS funding in anticipatory reinforcement as they are confident subsequent connectees will come forward and repay investment.

When should this take place?

DNOs can invest in additional reinforcement work to support an initial connection with the specific intent of accommodating further connections. For example, in an area where they have received a connection request and are aware of a number of additional connection requests which will come forward.

This additional reinforcement is initially funded by DUoS customers. The cost of this reinforcement work is then reimbursed by subsequent connection customers through the 'second-comer' rule. This is a mechanism which requires somone connecting using electricity infrastructure that was initially provided to make an earlier connection, to reimburse the party that funded the initial connection for a share of their cost. The current secondary legislation which supports the 'second-comer' arrangements may need to be amended to fully incorporate this approach; we note that DECC is currently reviewing this legislation.[11]

In taking this approach, a DNO has to be sufficiently confident that subsequent connection customers will appear as forecast and that the additional investment reduces overall reinforcement costs, making it easier for other customers to connect.

What might prevent a DNO making this investment?

Uncertainty about connections growth following the initial connectee can make it challenging to justify investing ahead of future connections. If further connection customers do not come forward to repay the investment then a DNO will have spent money unnecessarily and other customers will be left paying for infrastructure they don't need.

Although a DNO's revenue allowance will incorporate an element of DUoS funded reinforcement, this might not reflect fully the costs that could be incurred if a DNO were to be more proactive in using this approach to support future connections.

What could be done to address this barrier?

Stakeholders have suggested the following changes to current arrangements (more detail on the stakeholder proposal is provided in Appendix 1):

- Some DNOs have suggested an arrangement – 'the Regulatory Asset Value (RAV) Buyback Model' – in which they would apply to us for endorsement of certain schemes before they commit to expenditure. This model has drawn upon certain features of an

[11] https://www.gov.uk/government/publications/potential-changes-to-the-electricity-connection-charges-regulations-2002

existing arrangement in the regulatory framework which applies to specified projects on the electricity transmission network – Strategic Wider Works (SWW).[12]

- This proposal would require a DNO to provide us with robust evidence justifying forecasts of growth, scheme design, the benefits of early investment, financial commitment from customers and stakeholder support. Our approval of such schemes would assure them that their efficiently incurred costs would be recoverable, even if connections don't materialise. In order to grant approval we would need to consult on both financial and technical elements of the scheme.

- Once approved, new connection customers within a defined area would then be required to connect only to the enhanced part of the network and to pay a proportional contribution to the reinforcement costs based on the capacity required.

- The proposal could also allow for a 'premium' to be added to the charge paid by second-comers. This would enable DUoS customers to be paid back more quickly and might lessen the risk to them of funding stranded assets.

- In addition to the existing mechanisms which allow DNOs to amend their revenues to cover higher costs than were forecast, DNOs have suggested a new mechanism to finance additional expenditure associated with this type of scheme. This could be an adjustment within the existing period or at the beginning of the next price control (RIIO-ED2) for any expenditure that cannot be recovered from connection customers.

- As an alternative, DNOs could self-finance this investment if they believe it would help them to deliver their business plan more efficiently.

Q3. What are your views on this type of approach and the RAV Buyback Model? Are there any elements which are essential, not required or should be changed – and why?

Q4. Please give details of any projects or schemes this type of arrangement could have helped progress which would have not otherwise gone ahead?

Q5. What would justify requiring subsequent connection customers to only be able to connect to the new, enhanced part of the network?

Q6. What would justify a DNO charging a premium to subsequent connection customers to reimburse DUoS customers for the risk they bear in funding this work? What might be the impact of this? How should the premium be calculated?

Q7. Over what time period would it be reasonable to expect DUoS customers to be reimbursed for their initial funding?

Q8. When might it be appropriate for a DNO to have an upfront revenue adjustment to cover this type of scheme? Or should existing mechanisms be used?

Q9. Do you consider that this approach would have any implications on competition in connections?

[12] https://www.ofgem.gov.uk/publications-and-updates/guidance-strategic-wider-works-arrangements-electricity-transmission-price-control-riio-t1-0
https://www.ofgem.gov.uk/publications-and-updates/strategic-wider-works-sww-factsheet

Scenario 3: Connection customer funds cost of anticipatory reinforcement when initial connection takes place (to be reimbursed by subsequent connection customers)

Costs	Who pays initial cost?	Who pays back cost of reinforcement?	Justification
Connection	Connection customer		
Anticipatory Reinforcement	Connection customer	Subsequent connection customers (via 2nd comer rules)	Customer has commercial or social motivation to see new developments get connected more quickly and is confident subsequent customers will repay investment.

When should this take place?

This situation might arise where there is not enough certainty in the demand for future connections to justify a DNO investing in prospective reinforcement work.

If this is the case a customer (or third party) may instead choose to fund the work because they have a particular interest in enabling future connections in an area. This may be because a developer or landowner has a commercial motivation to see new developments get connected quicker. Or it could be a local authority that wants to accelerate certain schemes which align to a particular social policy, such as the promotion of community energy.

Under these arrangements the customer would apply for an initial connection but pay the DNO for an enhanced scheme that would provide the necessary capacity to accommodate future connections.[13] Again, the second-comer rules would be used to recover the costs of the enhanced scheme from subsequent connections and pay these back to the customer.

A variant on this might also involve a consortium of prospective connection customers being formed. This would enable the DNO to develop a combined scheme that meets all of their connection requirements. Each participant in the consortium would pay a share of the total cost, which would be less than they would pay if each made individual applications.

What might prevent this type of approach?

A third party may be motivated by the prospect of future connections, but would still need to finance the initial cost of work and face the risk that connections don’t come forward. Similarly members of a consortium may have concerns that other participants withdraw leaving those remaining having to pay a greater share of the combined scheme.

The DNO which operates the new network assets can’t discriminate between who it offers terms for a connection. This creates a risk that once a customer has invested, the spare capacity created could be used by a different type of scheme than originally anticipated. So for instance, a local authority may be seeking to support community energy projects. Once built though, the capacity could be immediately taken by a non-community scheme. The requirement on local authorities to comply with restrictions on state aid may also limit this approach.

[13] Although the third party may elect to operate an extension to the network as a private, unlicensed network, for the purpose of this consultation it is envisaged that any new assets would be operated under a network licence.

What could be done to address these barriers?

Stakeholders have come forward with a model for third party investment, which they have referred to as the 'Development Company (**DevCo**) Model. More details on the stakeholder proposal is provided in Appendix 2.

- Under this arrangement the DevCo would assume the role of the initial connection customer and would fund the enhanced scheme, using the second-comer rules to recover a proportion of their initial investment from subsequent connections. This arrangement is allowed for under the existing framework.

- However, the DevCo model proposes that, once built, new connection customers within a defined area would then be required to connect only to the enhanced part of the network (and to pay a proportional contribution to the reinforcement costs back to the DevCo).

- The DevCo model also proposes that a 'premium' is added to the charge paid by second-comers. This would be paid back to the initial customer and would allow them to earn a return from their investment, thereby making this type of arrangement easier to finance.

- It has also been suggested that enabling the initial customer to stipulate the type of schemes it wants to see benefit from its investment could encourage this approach. This would involve the DNO potentially offering or withholding terms for a connection, depending on the type of scheme that subsequently comes forward.

Stakeholders have also provided us with a report from a recent trial of a **consortium arrangement**. A summary of this report is included in Appendix 3. This explains how the consortium approach was organised and how well it worked. It includes recommendations for how to improve conditions for this type of arrangement.

Q10. What are your views on the DevCo model and process set out in Appendix 2? Are there any elements which are essential, not required or should be changed – and why?

Q11. Please give details of any projects or schemes this type of arrangement could have helped progress which would not have otherwise gone ahead?

Q12. What would justify requiring subsequent connection customers to only be able to connect to the new, enhanced part of the network?

Q13. What would justify a DNO charging a premium to second-comers to reimburse the customer? What might be the impact of this? How should the premium be calculated?

Q14. Over what time period would it be reasonable to expect the customer to be reimbursed for their initial funding?

Q15. What would justify the initial investor being permitted to restrict the type of schemes that would connect using the infrastructure it has paid for? For which type of schemes might this be appropriate?

Q16. Do you have any comments on the recommendations proposed in Appendix 3 to enhance consortium arrangements? What would justify these recommendations? Are there any other changes which would support consortium arrangements?

Scenario 4: Other ways of making it easier to connect

As well as understanding how earlier investment in the network could be better facilitated, we also want to know what other changes could make it quicker and easier to connect. In this section we are interested in your thoughts on whether there are opportunities to:

- Reduce the need for reinforcement
- Provide more flexible terms for the recovery of connection charges.

4.1 Reducing the need for reinforcement via network management

Any steps a DNO can take to reduce the need for reinforcement will speed up (and reduce the cost) of new connections. In recent years we've allowed DNOs to invest £120m[14] of customers' money to develop new approaches to maximise the use of capacity on existing assets, creating headroom which could be used for new connections. There may also be other ways to reduce reinforcement requirements.

When identifying the need for reinforcement for a new connection, a DNO must take into account the customer's needs and compare this against the amount of spare capacity there is on the network. Customers are able to negotiate to some extent on levels of security (and therefore reinforcement) they require, but a DNO must still maintain a secure supply for other users already connected. In general, the greater the level of security of supply needed, the greater the investment required and the higher the connection charge.

The DNO's assessment will take into account the various engineering recommendations and standards that determine the design of the connection including the amount of headroom needed to maintain the reliability of their network. The most important of these standards from a network capacity perspective is Engineering Recommendation P2/6.

The DNOs have recently initiated a review of Engineering Recommendation P2/6, led by the Energy Networks Association. This will be an open, consultative process giving all stakeholders the opportunity to contribute ideas about how DNOs can maintain the reliability of their networks efficiently while providing new connections promptly.[15]

Q17. What role, if any, could changes to engineering standards play in helping to accelerate the connections process without damaging reliability levels? In what circumstances would this be appropriate?

Q18. Which particular standards might most benefit the connections process if changed?

4.2 Reducing the need for reinforcement by managing connection offers

When a DNO assesses the need for reinforcement it takes account of the amount of capacity which is already being used by existing customers as well as taking into account any other capacity which has been allocated to other connection requests on the same part of the network.. However, in reality, many connection offers are never accepted. In 2012, UKPN reported that less than 6% of connection offers for Distributed Generation (DG) schemes were actually accepted.

A prospective connection customer may therefore be presented with an overly pessimistic view of the amount of actual capacity available on the network. Due to the low acceptance rates of connection offers, the amount of reinforcement ultimately required on the network may be less than indicated in a series of connection offers issued. Where possible DNOs try to address this by issuing 'interactive' offers. This is where the making of a new connection offer (if accepted) would affect the terms of other unaccepted connection offers.

[14] Through the Low Carbon Network Fund (LCNF).
[15] http://www.dcode.org.uk/dcrp-er-p2-working-group.html

To try to reduce the number of speculative connection applications, DNOs have recently submitted a business case to DECC to introduce 'assessment and design' fees, whereby a connection applicant pays in advance for the work required to provide a connection quote. This could reduce the number of connection requests they receive which prove to be speculative.

New connection customers could also benefit if a DNO were to be more proactive in withdrawing capacity which has been previously offered to (and may even have been accepted by) other schemes. This might be justified where a DNO believes that the capacity requested is not required as the project is giving no indication of being progressed.

Q19. What benefits might the introduction of assessment and design fees bring?

Q20. Could more flexibility in the way assumed available capacity is calculated help accelerate the connections process? Are there any other improvements to be made in how DNOs manage interactivity between schemes looking to connect to the same part of the network?

Q21. When might it be reasonable to withdraw capacity it has previously offered to customers?

Q22. Are there any other changes which could be made to reduce the need for reinforcement?

4.3 Flexible terms for the recovery of connection charges

In providing a connection, the DNO builds infrastructure which can have up to a 45 year asset life. In recovering its costs upfront, a DNO protects other customers from the risk of bad debt. If a DNO can't recover its cost from the connecting customer, then ultimately all customers (DUoS) will have to pay more.

For some customers, the burden of having to pay upfront for a connection can make the difference between whether or not their scheme goes ahead. Some schemes, including community energy projects have highlighted to us the difficulties which can arise from having to pay for a connection before they have any revenue coming in.

Some have suggested that DNOs could phase the recovery of their connection charges over a longer period of time. This might help some projects to connect that otherwise would not go ahead.

Q23. What would justify a DNO offering more flexible terms for connection charges? What might be the impact of this?

Q24. What type of schemes would most benefit from this arrangement?

Q25. What could be done to protect other customers from picking up any costs which cannot be recovered from the original connection customer?

Q26. Are there any other measures that would reduce the cost impact of connecting to the network?

Summary and next steps

In this consultation, we have described a number of existing and new scenarios to make it easier to connect new developments to the network. All, in some form or another, involve balancing the interests of different groups of customers – those connecting or already connected and those who may do so in the future. Because the future is uncertain, this inevitably introduces a risk that customers may end up paying for assets which are not required.

Some of the changes discussed in this consultation could increase this risk. Some of the changes could also result in one type of customer being treated differently from others and some connecting customers having to face higher charges than they might otherwise pay. That's why it's important to understand not just what could be changed but what would be the impact of these changes.

If we are to make these changes we need to be satisfied that the benefits delivered would justify any additional cost or risk. The benefit may be an electricity network which overall is more efficient and costs less to manage and maintain. But there may be other benefits. Non Traditional Business Models (NTBMs) are entering the energy marketplace. These offer new products or services, and ways of delivering them, which are different to those traditionally provided in the energy market. The emergence of NTBMs might bring with it new ways of looking at and assessing consumers' interests, such as social and environmental aspects, and are directly relevant to the issues explored in this letter[16] (see Appendix 4 for further details).

We would like your thoughts on the existing arrangements and which, if any, of the new ideas you believe would deliver the greatest benefit for new connections and why. We also want to hear any other suggestions you might have to deliver quicker and more efficient connections.

Q27. Which of the arrangements described above would deliver the greatest benefit to the connections process without placing additional risk or cost on the generality of customers, and why?

Q28. Should wider benefits beyond energy system benefits (such as those provided by NTBMs) be taken account of in DNOs' or third parties' considerations of any of the measures or mechanisms described in this paper?

Q29. Do you have any other suggestions for delivering quicker and more efficient connections?

We welcome any comment you have to the questions we have set out in our letter. Please send comments to olivia.powis@ofgem.gov.uk by 14 May 2015. Unless you clearly mark them as confidential, all responses will be published on our website.

We will continue to engage with interested parties and we will convene a workshop during mid-March 2015 to explore these issues in more depth. If you would like to participate, please respond to Olivia Powis by 27 February 2015.

Once the consultation has closed, we will outline a way forward and if appropriate, explore making changes to the regulatory framework.

[16] We will shortly be publishing a document seeking views about NTBMs and their potential impacts on consumer interests. We are keen to understand the potential costs and benefits of NTBMs and the implications for regulatory arrangements such as connections charging.

Appendix 1 – The Regulatory Asset Value (RAV) Buyback Model

Two similar mechanisms have been proposed by UK Power Networks (UKPN) and Scottish Power Energy Networks (SPEN), both based on the DNO funding initial reinforcement. This appendix provides a brief overview of how the model might work. This model is sometimes referred to as the RAV Buyback Model.

The concept

The RAV Buyback Model is based on a simplified version of the existing Strategic Wider Works (SWW) mechanism that was developed as part of the Transmission Networks price control (RIIO-T1). SWW responded to a number of uncertainties about the development of generation assets expected within the RIIO-T1 control period and allowed for the Transmission Operator to identify strategic reinforcement investments in the transmission network which, when approved by Ofgem as appropriate can be funded as discrete projects and provide certainty of funding. The agreed allowance required to fund the SWW is then added to the allowed revenue in each year and hence collected from customers through the normal revenue raising method (Tranmission Use of System (TUoS)).

At the distribution level, the model would enable DNOs to fund strategic reinforcement, while protecting consumers from the risk of funding stranded assets. The model would apply in a specific development area with limited network capacity and nascent development potential. The development area would be identified based on robust evidence including intelligence from the planning system, wide consultation with stakeholders and the collaborating DNO. The area would also need to consider whether it could be applied to Distributed Generation customers and the potential benefits to the wider local community i.e. the facilitation of other environmental benefits.

Once a suitable area has been identified, the DNO makes a case to Ofgem showing that strategic investment would provide a more efficient and economic network in time and that there is good evidence that new capacity would be fully utilised over a set period of time. Ofgem would then consult as necessary and agree to the investment as an addition to the regulated asset value, funded initially through DUoS customer revenues.

As connections are made to the reinforced area of the network, existing customers are effectively reimbursed the cost of the reinforcement carried out through the 2nd comer mechanism for an extended period of 10 years. If all new capacity is taken during the revenue control period, there is effectively no change to Distributed Use of System (DUoS) charges to customers.

This approach could help remove barriers to increased and timely investment in the electricity distribution network while limiting the risk of stranded assets for consumers.

Other potential features of the model

Other stakeholders have commented on the UKPN and SPEN mechanism and suggested potential changes.

In order to incentivise DNOs to design the reinforcement capacity wisely and to prevent the incentive to over-invest, a symmetrical benefit/penalty of 1% of returns on the investment has been proposed.

Normal connection regimes within the defined area could be suspended. An exclusive regime would be enabled, requiring new connection customers in the area to connect only to the reinforced part of the network and to pay a proportional contribution to the reinforcement costs based on the capacity required. Careful consideration would need to be given to potential restrictions to competition in this defined area on independent network operators if this was applied.

Connection customers within a defined development area could also be charged a small risk premium on the standard (section 16) minimum cost schemes. This would enable a small 'profit' to be returned to consumers through lower DUoS charges. Changes to the connection regulations would be required to ensure that the risk premium could be charged and connectors could not avoid this through other connection mechanisms.

Appendix 2 – Third party investment model

Stakeholders have developed various approaches to third party investment. In particular, HM Treasury and the Greater London Authority (GLA) have been working on the 'Development Company' model.

The concept
The Development Company (DevCo) model aims to provide a source of funding from outside the Regulated Asset Value and therefore insulates customers from the risk of investing in stranded assets. However, once a DevCo investment is made, capacity is 'bought back' by the DNO and is thereafter funded through DUoS charges. In this sense, the DevCo could be considered as a 'first-comer' connection customer and would benefit from 'second-comer' reimbursements as capacity is taken for new connections.

Once built, the DNO would become the licenced operator of that part of the network. This would require some regulatory changes, as the DNO would hold the new reinforcement assets as if it were an IDNO, which is currently prohibited. The DNO would also absorb the carrying costs of the new assets until such time as they are 'absorbed' into the DNO network, although the interest on capital would be carried by the DevCo pending the capital cost being recovered from connection charges passed through by the DNO to the DevCo as 'first comer'. As the new capacity is a source of future income to the DNO, this should be seen as a low cost, low risk investment in future revenue streams.

The DevCo would be structured as a partnership between developers, local authorities and other parties with an interest in securing connections and capacity in a defined area. Development agencies where created for the purposes or area redevelopment would be natural partners. For any particular region or locality (such as the Greater London area) the DevCo could be a permanent body which accumulates a portfolio of utility infrastructure investments made in respect of several developments in its area. Structuring a portfolio of investments in this way may reduce the time and costs of setting up the investment arrangements for each development and also present a wider range of investments to attract market interest. The partners provide the equity for the new investment which would be carried out by the DNO (this could happen now if the DevCo was contracted with an IDNO, but the resilience and efficiency benefits to the wider network could not be captured).

New connection customers to the new DevCo funded capacity would be charged a risk premium to recognise that investors had placed money at risk and to provide some level of coverage, should some capacity be left untaken in the short term. Any excess over-investment could be used by developer partners to subsidise their own connection costs and by local authorities on further infrastructure enhancement in the development area.
As with the RAV buy-back model, mechanisms need to be in place to ensure that new connections cannot be requested through other mechanisms, thus avoiding the risk premium.

The model in practice
The model would apply in an area with limited network capacity and nascent development potential. The area or areas would be identified based on robust evidence including intelligence from the planning system, wide consultation with stakeholders and the collaboration of the DNO.

In order for an area to be considered, a number of discrete, large commercial development opportunities will need to be identified. Investment would be made at the primary sub-station level in large single point assets.

Once a suitable area has been identified, a partnership is formed between developers, local authorities, local landowners and development corporations, and raises funds from partners to procure the agreed reinforcement. Membership of the partnership could be made a condition of outline planning consent. Through the DevCo, the partnership then contracts with the DNO as if a primary connection customer.

Normal connection regimes within the defined area are suspended and an exclusive regime enabled requiring new connection customers in the area to connect only to the enhanced part of the network and to pay a proportional contribution to the reinforcement costs based on the capacity required, plus a risk premium. This is handled as a modified version of the second-comer system.

The DNO builds out the agreed reinforcement and reimburses the partnership through a modified second-comer arrangement as capacity is taken. The DNO also becomes the licensed operator of the new capacity and becomes liable for the operations and maintenance of it.

DevCo partners either take the risk premium (if all capacity is taken) or reinvest surplus into other area infrastructure enhancements.

The DevCo model operates without a regulated asset base by relying on the market for funding. It is therefore a more flexible and responsive model which can combine utilities and operate alongside other regulated approaches. However, the DevCo may make take a long time to set up and is dependent on market interest for funding, but in some regions it may be feasible to set up a permanent DevCo which acquires a portfolio of investments.

Appendix 3 - Decentralised generation consortium trial model

Western Power Distribution (WPD) and Regen SW (a not for profit working on Distributed and Renewable Energy) set up a consortia in 2013 to test an approach by which a consortium of developers could share the costs incurred through having to upgrade the high constrained network, to help bring down the costs faced by individual developers. The following is a brief summary provided by the parties involved.

The concept
In March 2013 Ofgem published its "Strategy decision for the RIIO-ED1 electricity distribution price control". This proposed that to reduce the cost of grid reinforcement to individual developers and first movers, that developers apply for grid reinforcement as a consortium, teaming up with other developers operating in the same region. This could be done under section 22 of the Electricity Act.

This allows for a consortium of customers to approach their DNO, and steps outside of the individual connection offer mechanism. The approach gives the potential for developers to reduce costs by sharing upfront charges.

Consortia are a common feature of grid reinforcement for demand customers such as large housing and commercial developments. In these cases developers will form a single company responsible for the infrastructure to support the development. This company will form a contractual agreement with the DNO to reinforce the grid as necessary for the demands of the whole development and then split the costs amongst themselves. These developments will have planning permission and, therefore, a reasonable degree of confidence they will progress at some stage.

Bridgwater trial
Regen SW held an initial meeting of developers and WPD to gauge interest. Developers confirmed they were interested in exploring the consortium option.

WPD then looked at how it could create large capacity points on its network and presented three options for creating generation "hubs" to the group of developers. The group decided to progress an option around Bridgwater and Street due to the relatively short timescale and lower cost of reinforcement.

Between March and October 2014, Regen SW ran a process of engaging developers and identifying sites. The first round of sites from the existing group of DG developers were not enough to bring the cost down to a viable level, so another call for sites took place through Regen SW's wider network. Fifteen sites came forward: three sites were too far from the substations; four in the Street area; and eight in the Bridgwater area making Bridgwater the most viable option.

A potential legal structure for the consortium was developed by Stephens Scown solicitors and discussed with WPD's lawyers.

In November 2014, Regen held a meeting of six of the eight developers with sites in the Bridgwater area and WPD to discuss the potential for a consortium in more detail. In February 2015 three of those developers met, having signed a Non Disclosure Agreement, to discuss the details of their projects and grid costs and whether to progress with a consortium. They agreed to take the next step of asking WPD for a consortium quote under section 22.

Costs
There are a number of restrictions in the Bridgwater area, due to the connected and accepted generation:

- Most of the 33kV systems are at capacity, due to voltage or thermal restrictions

- The transformers are at the limit of their capacity. As such, no further generation can be added to this group without changing all four grid transformers.

The least cost connection option is to add a dedicated, stand-alone 132/33kV grid transformer for new generation. The standard grid transformer sizes are 30, 45, 60 and 90MVA. Cost of works at Bridgwater GSP to install new 30MVA grid transformer would be approximately £2 million (with an additional cost of approximately £350,000 for a 90MVA transformer). As the transformer would be a sole use asset, the new generator would be required to pay for the transformer in full, in addition to any cabling costs.

If a consortium were formed, the reinforcement cost would be shared in proportion to the MWs that each developer in the consortium required. And the more capacity required, the cheaper the cost per MW. For example, the cost per MW for a 30MVA transformer is over £66k, which drops to just over £26k for a 90MVA transformer.

There is also the potential to share cabling costs, depending on the location of each site. With the Bridgwater example, there is the potential to reduce the circuit length from 49,155 metres to 26,190 metres with a cost saving of approximately £4.2 million overall.

Insights and recommendations
Experience from this trial indicates that the potential for consortiums of distributed generation is limited to a set of circumstances where they could work:

- The connection work would have to be completed within a two year period to enable the solar industry to be confident about the subsidy regime. This means that consortiums would not work for 132kV reinforcements
- The cost of connection work needs to be viable –a ceiling of £100k per MW has been mentioned by developers, but this would vary between specific projects. It would help if the DNO is able to share some of the investment risk.
- A key issue with a consortium will be the attitude to a cluster of sites from the planning authority. Where local authorities are taking a more strategic approach, such as those with a low carbon Local Development Order, a consortium will be easier as planning timescales for projects are more aligned.
- Developers need a way of identifying nearby sites in order to start consortia discussions. This is difficult when the DNO cannot proactively share this information. Regen SW's collaboration service (http://www.regensw.co.uk/our-work/onshore-electricity/tackling-grid-constraints) is one approach to addressing this.

In summary, in a particular set of circumstances a consortium approach to network connections can help bring down high connection costs for distributed generation. In the majority of situations, however, this approach will not be commercially viable for developers.

Appendix 4 – Non Traditional Busienss Models (NTBM): potential benefits and costs

NTBMs offer new products or services (or ways of delivering them) that are different to those traditionally provided in the energy market. Those offering such services have diverse motivations (social and environmental as well as financial) and ownership arrangements, operate at various scales, may include existing market participants and over time have the potential to disrupt the existing energy system. We see potential in some NTBMs delivering desirable consumer outcomes. For example, some NTBMs may help manage the transition to a low carbon energy system by increasing efficiency or enabling greater demand-side flexibility. Some may help consumers better engage with the market by providing more transparent information, products and services that better suit their needs; others may make energy more affordable for local or vulnerable consumers. NTBMs may also lead to additional costs: for instance, rolling out demand-side response without being transparent could add to the costs of parties such as DNOs.

The following tables illustrate the types of costs and benefits that may be associated with NTBMs both in terms of their impact on the energy system and more widely. Because of the range of potential NTBMs covering generation, supply, distribution and service provision, the effects are captured at a high level and are not exhaustive.

Given that Ofgem's principal objective is to protect the interests of existing and future energy consumers[17], when we carry out our functions our focus is, therefore, on direct impacts on the energy system and consumers' interests. However, some existing NTBMs, especially the community energy sector, have highlighted wider benefits that their business models could deliver, such as new jobs, enhanced skills, greater social cohesion and wider economic development opportunities, and have argued that these should be taken account of in policy development and decision-making. We have summarised some of these wider benefits below.

Direct energy system impacts: examples of potential benefits and costs

Direct energy system <u>benefits</u>	Economic	• Consumer bill reductions through increased engagement and competitive pressure • Avoided/reduced network costs: losses, connection, reinforcement, transmission, distribution • System balancing cost reductions: eg, if NTBMs enable greater demand management • System diversity, flexibility and reliability/resilience • Innovation effects: new products, services and processes may drive down costs and enhance consumer choice • Increased energy 'literacy' and engagement may have knock-on effects: eg, success rates for energy efficiency projects, demand reduction, behavioural change, etc
	Environmental	• Carbon impacts • Additional environmental impacts: eg, air quality (and associated health effects), visual amenity
	Social	• Increased energy 'literacy' may lead to greater support for renewables deployment • May focus particularly on vulnerable, fuel poor or 'hard to reach' energy consumers
Direct energy system <u>costs</u>	Economic	• Additional grid connection costs (connection and potential reinforcement) • System integration costs: eg, enhanced distribution system management (such as local balancing) • Higher coordination costs due to increase in number of market participants • Equipment costs: eg, in consumer premises

[17] For further detail on Ofgem's duties see https://www.ofgem.gov.uk/publications-and-updates/powers-and-duties-gema

		• Decreased system reliability/resilience: eg, reliance on higher levels of intermittent and distributed generation • Potential risks to personal data, privacy, consumer protection, etc
	Environmental	• Carbon impacts • Additional environmental impacts eg air quality (and associated health effects), visual amenity
	Social	• Potential marginalisation of vulnerable consumers and others not able to access new digitally-based services and products

Wider indirect impacts: examples of potential benefits

Wider indirect <u>benefits</u>	Economic	• New jobs and enhanced skills for the local population • Economic development (potentially in areas with fewer opportunities)
	Environmental	• Greater understanding of low carbon energy may have knock-on effect on other behaviour: eg, transport choices • Community and municipal energy projects may lead to broader environmental awareness and schemes focused on, for example, the enhancement of green infrastructure and biodiversity
	Social	• May provide funds for non-energy-related projects through community funds/trusts • Wider social impacts on local communities: eg, social cohesion, community and civic engagement, development of community networks, etc

Appendix 5 – Glossary of terms

- **Price control** – The process that we, as the regulator, use to set the revenue that network companies are allowed to recover over a set period of time and the outputs that they are expected to deliver. We set output targets and allowed revenues by taking account of consumer needs and company performance over the last control period and predicted expenditure in the next. The next price control, RIIO-ED1 will run from 2015 to 2023.
- **Distribution Use of System (DUoS)** – The DUoS charge reflects the cost of receiving electricity from the national transmission system and feeding it directly into homes and businesses through the regional distribution networks. All customers of DNOs pay DUoS charges on an ongoing basis. They are recovered from a customer's electricity supplier and will be one of the elements of their bill.
- **Second-comer legislation** – The Electricity (Connection Charges) Regulations 2002 (ECCR) (also known as the 'second-comer' regulations) say that where someone connects using electricity infrastructure that was initially provided to make an earlier connection, the party that contributed to the initial connection can be reimbursed for a share of their cost by the subsequent connecting customer. This currently only applies if the subsequent connection is made within five years of the first.
- **High-value projects** – Schemes specified and agreed with individual DNOs to be undertaken during a price control period. There is also a process whereby revenue allowances can be re-set during the price control period to account for schemes which could not be agreed upon at the start of the price control.
- **Load-related reopener** – A process undertaken by Ofgem to re-set the revenue allowances (or the parameters that give rise to revenue allowances relating to load) under a price control before the scheduled next formal review date.
- **Section 16 applicant** – Under section 16(1) of the 1989 Electricity Act, DNOs are obliged to provide a Connection Offer to any person entitled to apply for a new, increased or reduced connection to the distribution network. Applications for a connection to a DNO's distribution network can either be made by the owner or occupier of the premises, or by an approved contractor, supplier or agent, acting with the consent of the owner or occupier.
- **Section 22 agreement** – Under section 22 of the 1989 Electricity Act, customers can enter into special agreements with the DNO, with respect to connection. These special agreements allow the parties to agree their own terms. As long as a special agreement is effective, the rights and liabilities provided for under sections 16-21 are not applicable.
- **Distributed Generation (DG)** – Any generation which is connected to the local distribution network, as well as combined heat and power schemes of any scale. The electricity generated by such schemes is typically used in the local system rather than being transported across the UK.
- **Community Energy (CE)** – Community energy covers activities focused on reducing energy use, managing energy better, generating energy or purchasing energy. This includes communities of place and interest with initiatives sharing an emphasis on community ownership, leadership or control where the community benefits. Schemes can have formal community ownership models such as community benefit or co-operative societies, social enterprises, community charities, development trusts and community interest companies, as well as projects without these formal structures. Specific legal definitions exist for the purpose of the Feed-in Tariff scheme.[18]
- **Regulatory Asset Value (RAV)** - The value ascribed by Ofgem to the capital employed in the licensee's regulated distribution business (the 'regulated asset base').

[18] In 2012 benefiting schemes were defined as Community Interest Companies, Community Benefit or Co-operative Societies, so long as these have no more than 50 employees. From April 2015 DECC plan to widen this to include registered charities and the wholly owned trading subsidiaries of registered charities, so long as these have no more than 50 employees.