Ofgem Consultation on Quicker and more efficient distribution connections

Response on behalf of the Solar Trade Association

About us

Since 1978, the Solar Trade Association (STA) has worked to promote the benefits of solar energy and to make its adoption easy and profitable for domestic and commercial users. A not-for-profit association, we are funded entirely by our membership, which includes installers, manufacturers, distributors, large scale developers, investors and law firms.

Our mission is to empower the UK solar transformation. We are paving the way for solar to deliver the maximum possible share of UK energy by 2030 by enabling a bigger and better solar industry. We represent both solar heat and power, and have a proven track record of winning breakthroughs for solar PV and solar thermal.

We are very concerned about the difficulties and costs faced by the solar industry in connecting solar installations (both rooftop and solar farms) to the distribution network, and therefore welcome the opportunity to respond to this consultation.

Respondent details

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Would you like this response to remain confidential?	No

Introduction

The ability for solar power installations to connect quickly and cost-effectively to the electricity distribution network is crucial to the future of our industry. We recognise that the network was not originally designed to accommodate significant amounts of distributed generation (DG) and the challenge that the rapid growth of DG poses to the Distribution Network Operators (DNOs) and Ofgem. Deployment of solar power has increased spectacularly in recent years as PV costs have plummeted – we estimate that current UK PV deployment is as high as 8GW, from only 30MW in early 2010. Virtually all of this capacity is connected to the distribution network, which in some parts of the country is facing saturation, thereby constraining further deployment.

Much of the deployed solar capacity is in the rooftop sector close to the location of electricity demand, however there has also been increasing deployment of much larger solar farms in more remote locations where connection to the network can pose greater challenges. The UK's theoretical solar resource is vast and deployment is limited mainly by the availability of suitable and cost-effective locations, whether building integrated or land-based. Importantly this includes the ability to connect to the network quickly, efficiently and at an acceptable price.

The challenge for government and the electricity industry is to move from a grid designed primarily for one-way traffic to one which accommodates the huge potential of distributed generation, now that technologies like solar and wind are set to become the most cost-effective forms of power generation (especially if carbon emissions are taken into consideration). We believe that DECC has been much too slow to recognise the importance and urgency of the need, in part because senior decision makers have so far failed to enunciate a clear vision for the future role that renewable energy should play in our low-carbon future. Such a clear strategic steer 'from the top' is sorely needed and we recognise that the lack of such a steer constrains the ability of Ofgem and the DNOs to act.

Nevertheless we strongly encourage Ofgem to plan on the basis that renewable energy will form a rapidly growing part of the energy mix and to join our industry in actively seeking the required long-term strategic clarity from government. We believe that distributed renewables will inevitably be a major contributor to the UK's energy future; it's just a question of when and where. It would be a tragedy if the main limiting factor for renewable growth became the ability to connect to the network, which is now becoming the case. Ofgem has a key responsibility to facilitate the integration of DG as part of its remit to promote sustainable development so we believe that it should be seeking proactively to remove barriers to DG.

We recognise that this Ofgem consultation seeks to do just that, by proposing a number of potential scenarios for speeding up the reinforcement of the distribution system. We welcome this initiative and want to emphasise the urgency with which any outcomes need to be implemented. It is clear that one of the key issues is the apportionment of the costs of network reinforcement. Ultimately the costs will be picked up by consumers either through DUoS charges or through LCF support programmes such as FiTs, the RO and CfDs. We understand the need to ensure that overall costs are minimised, but this must also be weighed against the urgency of tackling what is rapidly becoming the key constraint for DG.

It is for this reason that we strongly encourage Ofgem to give Scenario 1 the highest priority, allowing the DNOs to invest strategically in network reinforcement and recover their costs through DUoS charges. It is important to do this in consultation with generators and Local Planning Authorities (LPAs) to ensure that reinforcement meets the strategic needs of both. It is worth noting that as long ago as the 1990s the government sponsored DNOs and LPAs to undertake regional renewable resource assessments with just such an aim of identifying how to facilitate deployment. At the time the potential from solar power was hardly considered; now it must be seen as a key front-runner.

Whilst our preference is for priority to be given to Scenario 1, we agree that there could also be merit, in the right circumstances, in approaches based on the other three scenarios.

Background to our response

Britain reaps huge economic benefits from new infrastructure projects. They create immediate jobs, and deliver infrastructure which enable jobs and prosperity in the future. These projects include large scale redevelopment for housing and commercial property – particularly in London; low carbon distributed generation, transport, and community energy projects. These all require connections to the grid but increasingly often they trigger piecemeal grid reinforcement which causes delays and costs. This can stop projects in their tracks.

Many Distributed Generation developers are seeing their businesses come to a shuddering halt because of grid constraints. You only have to look at how the DNOs' heat maps change over the last couple of years to see how bad the story is. Grid offers in excess of £16m for a 200kW scheme are increasingly common, and can never be funded by a generator.

Historically DG developers have been encouraged by Ofgem to connect where there is grid capacity, in order to make best use of existing infrastructure and therefore minimise the costs to consumers.

This logic has worked historically to use up the spare capacity as the amounts of DG required nationally for the 2020 renewables targets have been well within the national constraints of the network which was over-engineered long ago. It is based on the premise that the level of DG in any one area should be no greater than the maximum demand.

However, this logic is now broken, for the following reasons.

- Local generation and demand on each cannot be simply balanced, and there are many circumstances where one area needs to import energy from another:
    - Planning permission for renewables is not possible in the green belts, conservation areas, national parks and other protected areas. Homes and businesses in these areas need to import their energy from other areas.
    - Physical deployment not practical on many roofs with e.g. flats, loft conversions, etc.
    - Weekday demand in commercial & industrial areas may exceed generation capacity of the DG which is feasible there, and generation capacity which is feasible may exceed weekend demand.
    - Weekday generation capacity in domestic areas may exceed weekday consumption, and evening and weekend demand may exceed generation.
- Furthermore the logic is broken for community projects which by their nature need a grid connection near the community in question.
- Whole regions can be constrained (e.g. the WPD's F Line).

The potential impact of future British energy scenarios on the grid is material, by some estimates up to £60bn of investment will be required[1]. This will be funded by consumers through electricity bills – either through DNOs and Distribution Use of System (DUoS) charges or through generators and FIT/ROC/CFD levies.

[1] https://www.ofgem.gov.uk/ofgem-publications/56763/sgfws3ph2results.pdf

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No regulations need to change to unlock new grid capacity. DNOs need confidence and evidence of grid strategy so OFGEM cannot (on retrospective analysis) claim they are stranded assets and prevent the DNO from recharging them to customers.

There is a workable mechanism for DNOs to fund *simple* investment ahead of need but here is no workable mechanism for funding *strategic* investment ahead of *immediate* need. This is largely because predicting the future needs is currently challenging for DNOs, since these needs are influenced by LPA plans, developer activity, government incentives & economic conditions, and there is no overarching plan or strategy for the grid.

So to resolve this grid lock (no pun intended), we need the new government to answer a few questions:

- What level of decarbonisation are we trying to achieve by 2030?
- How much DG is required?
- What type of grid is required to enable this DG?
- What is the most cost effective way to fund this?
- Do DNO business plans enable this, or is a reopener required?
- What do DECC and Ofgem want to become of the skills, jobs and capabilities that have built up in DG? BIS reported recently that in 2013 there were approximately 34,400 jobs in solar and 32,700 in wind. A long hiatus in the approach to accessing grid capacity will put these jobs at risk and will mean that when activity ramps up in the 2020s it will be from a standing start, which will make UK companies much more vulnerable to foreign competition.

Options

Ofgem have been asked by the government to consult on options to remove these blockages. The following options have been tabled:

- The connecting developer takes the risk of predicting future needs, funds the strategic reinforcement, and is reimbursed by subsequent connecting developers. This is business as usual, or the “do nothing” option.
- **Scenario 1:** The DNOs take the risk of predicting future needs, fund the strategic reinforcement and recharge the costs to DUoS customers.
- **Scenario 2**: The DNO takes the risk of predicting future needs, over and above initial connection contracted by a developer (which will be funded by electricity consumers through the FIT/ROC/CFD levy), funds the strategic reinforcement and recharges the costs to subsequent connecting developers (also funded through the FIT/ROC/CFD levy). This is sometimes called the Regulated Asset Value (RAV) buyback model.

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- **Scenario 3:** A customer or third party takes the risk of predicting future needs, funds the reinforcement, and is reimbursed by subsequent connecting developers. This is sometimes called the Development Company or DevCo model.

- **Scenario 4:** Alternative options

    a. Reducing the need for reinforcement with Network Management.

    b. Better connection offer queue management.

    c. Flexible terms for recovery of connection charges.

The business as usual option

The current second comer rules are unlikely to be widely used. Without an overarching grid strategy, it is hard to see how a developer's investment committee or bank would approve funding of grid investment on the basis that this might be recouped.

More importantly, the cost of capital for a developer is typically around 10%, in comparison to around 5% for a DNO, so consumers would pay around twice as much for this approach. For example, a £10m grid investment depreciated over 45 year life of the asset, could create £45m of finance charges if funded by a commercial developer, but only £22.5m if funded by the DNO.

Answers to Consultation questions

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

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?

Britain cannot decarbonise the electricity system without investment in the grid. Ofgem's business planning process for the DNOs suggested that up to £60bn of investment could be required. The decarbonisation is certain, but the technologies in the energy mix and their locations are not. Britain's future energy scenarios have been refreshed in 2014 for the Smart Grid Forum WS7 projects, and will need frequent refreshing in future. Ultimately these costs will be funded by electricity consumers, either through increased DUoS charges or through levies such as FITs/ ROCs or CFDs.

If the capital costs are funded by DNOs and recharged through DUoS, then the overall system costs are likely to be significantly lower than if they are funded by developers and recharged through FITs/ROCs or CFDs. As mentioned above, this is because the cost of capital for a DNO is typically 5%, but the costs of capital for a developer is typically over 10%.

The vital questions are how the DNOs take on the risk of predicting the future to ensure that they don't have stranded assets, and how to provide revised locational price signals to encourage

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developers to connect in a location that triggers the lowest cost investment. The Smart Grid Forum and IET's system architect are starting to flesh out some of the answers to these challenges.

We would suggest that both developers and the DNOs would gain confidence and certainty if a suitable and defined national capacity and locational strategy and charging methodology were to be set in place. Additionally, certainty with regard to the CFD process may assist and may also reduce any capacity being 'locked out' for prolonged periods.

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

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?

We are broadly supportive of the RAV buyback model although we would have concerns should the normal connection regime be suspended without due consultation.

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

We believe that similar arrangement may have existed in the past with the creation of 'Power Zones'.

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

We believe that developers should not be required to connect only to the newly reinforced network. They would need to be subject to market forces, choosing sites which trigger the lowest reinforcement costs – i.e. the current approach of "minimum cost scheme" should continue.

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?

Under the proposed arrangement DNOs would carry a risk of only the uncertainty of timing of recharge to subsequent developers. To compensate the DNO for this risk, it is reasonable for them to charge an additional premium to subsequent developers. However a premium to subsequent connections is also an administrative burden that would require a level of transparency.

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

The life of many DNO assets can be 45 years, and the life of the scheme which refunds the upfront investor needs to match this. The current second comer rules (which force subsequent developers to pay for reinforcement in the previous 5 years) include a perverse incentive for subsequent developers to delay their projects until after the 5 year recharge lapses. The administrative burden for DNOs to develop a computer system to manage this scheme is similar for 5, 10 or full life, and adopting a full life scheme is a fairer way of sharing the costs.

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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?

We are of the opinion that an up-front revenue adjustment may be appropriate if the requisite criteria can be established and justified but would favor adjustments within the existing period.

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

This approach may have implications for competitive connections, noting that reinforcement may become a contestable element. This would therefore require full consultation as part of the ECSG arrangements for competitive connections work.

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

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?

Whilst we can see clear advantages for the DevCo model for specific and demand type projects, we also have severe reservations as to its use in the context of DG projects. This observation is based on the inherent uncertainty of forming the DevCo consortia in anything resembling a timescale to suit grid connection requirements.

The DevCo would ultimately have to be underwritten by a developer or regional/local authority. It is likely that the public authority will need to take this responsibility otherwise a lead developer would have to underwrite all the other developers in the project.

Our concern is that DG is too dispersed for the DevCo model to work.

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

No response

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

No response

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?

We believe that a DNO should only seek to recover costs as defined under the current second comer rule. We therefore see no reason for DNOs to charge a premium to second-comers.

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

We would expect the customer to be refunded over the existing and established DUoS time frame unless this can be shown to be unacceptable and unreasonable. The question then arises as to how the existing time frame was originally formulated and derived? Should it subsequently be considered that a longer timeframe would allow a more acceptable period for reimbursement then we would support this stance.

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?

We do not see restriction being justified.

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?

See response to Question 10.

Scenario 4: Other ways of making it easier to connect

Network Management

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?

Undoubtedly, there are projects which on a case by case basis will be workable with reduced security of supply, or a managed connection which the DNO disconnects in certain circumstances. These projects should be explored, but they are not a silver bullet which will solve the fundamental issues set out above.

The Smart Grid Forum Work Stream 7 DS2030 project is modelling Active Network Management as one of several tools in the box, alongside other important tools. We are also aware that there may be ongoing trials to establish optimum working criteria for network circuits and switchgear. The results of these trials should be extended and adopted as business as usual and across all DNO areas.

Queue Management

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

The current interactive offer process works well.

Speculative grid applications could be reduced by conducting chargeable feasibility studies with chargeable assessment and design fees at the start of the application process. If this system were

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adopted, the lodging of the feasibility study needs to ensure a place in the grid application queue. Some DNOs now offer this application approach and it could be rolled out.

Most DNOs are already managing offers against milestones which were clearly set out and defined in the offer, withdrawing offers if suitable progress cannot be shown. There needs to be an appeal process to ensure DNOs are not withdrawing offers where developers have a valid reason for delay.

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?

No response

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

This matter is currently under discussion within the DG Steering Group. There appears to be a consensus that a regime of providing 'milestones' is the preferred way forward, allowing sufficient time for the developer to progress the necessary planning consents. Thereafter it is considered reasonable that the grid connection offer and associated capacity should be considered for withdrawal. However it should be noted that there are many factors outside the developer's control, for example the planning process and the new CfD application process.

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

We believe that reinforcement will be required once a network becomes saturated regardless of any limited support offered by 'smart connections'. We note that a number of DNOs are offering 'constrained' connection offers, however:

- Very often there is no other option available to the developers,
- The 'level' of the constraint is exceptionally difficult to quantify and
- We would suggest that no demand type connection would be in a position to accept any level of unconstrained (export) capacity and yet this is the only option available to some DG projects.

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

As discussed above, the cost of capital for a developer is typically around twice that for a DNO, so it would result in reduced costs to consumers if the DNO funded the assets, and recharged them connecting customers over the life of the asset.

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

No response

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

No response

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

We need a national strategy for reinforcement works together with an updated charging methodology.

Summary and next steps

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?

Provided there is clarity on what we are trying to achieve, and a grid strategy to support this, then Scenario 1 will – when the total system costs are taken into account – deliver the greatest benefit to connecting customers at the lowest cost to the consumer.

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