ofgem

Making a positive difference
**for energy consumers**

# Unlocking the capacity of the electricity networks

associated document

# Context

Historically, new generation connected primarily to the transmission network, exporting power to demand concentrated at the lower voltage, or distribution level. Patterns of demand also tended to be relatively predictable, often with enough spare capacity on the network to accommodate gradual changes in network usage.

Recent growth in connections for new generation to the distribution network has outstripped many forecasts, with concentrations in certain technologies and regions. The capacity of the network to accommodate these new connections has become increasingly scarce with bottlenecks appearing in many areas. These physical constraints can at times mean new generation can't connect without reinforcement to add new network capacity, or can't export power once connected. New and changing forms of demand may experience similar issues.

As outlined in the overview document published alongside this, some degree of network constraint may be efficient, ensuring the costs we pay for the network are reasonable and the network is not oversized. But constraints can have negative impacts – adding cost and delays to a project for parties looking to connect and on the cost we all pay for the electricity system overall – which may be a concern if they are not efficiently managed.

New users may be unable to connect beyond the point where the network can transport more power, or where connected, may be limited in their ability to export electricity at certain times. Overcoming this can mean more investment is required – by DNOs and connecting customers – to accommodate them, or impact the value of the connection for the customer if they can't export when they want to.

Recent investments in innovation, such as through Ofgem's innovation mechanisms, have allowed alternative, more flexible connection arrangements to develop. These avoid the need for new capacity if generators agree to have their export capacity curtailed at times.  This can reduce connection time and costs. Network operators are also starting to consider how efficiently existing network capacity is used and monitoring parts of their network in real-time that they did not have to in the past.

These 'non-build' solutions provide DNOs and connecting customers with the ability to respond quickly and manage uncertainty about how network requirements may evolve. By deferring investment in new capacity, the risk of creating stranded assets (that have to be paid for but are not ultimately needed) may be avoided and connection times sped up. But it is important that flexible connections, and access arrangements more broadly, meet the needs of customers and function in a way which supports the efficient use and development of the system as a whole.

In this document, we consider the status of constraints across the networks, the progress made in addressing them, areas for further progress and next steps. We also outline the Connect and Manage arrangements which enable connections to the transmission system.

This document provides more detail for interested parties on:

**Chapter 1 - Current status of constraints on the network**

**Chapter 2 - How DNOs are responding to constraints**

**Chapter 3 - Progress update on 'Quicker, more efficient connections' investment trials**

**Chapter 4 - Overview of the Transmission Connect and Manage regime**

**Appendix 1 – SPEN criteria to evaluate strategic investment proposals**

**Appendix 2 – Additional proposed requirements from UKPN**

**Appendix 3 – Company names and abbreviations**

# 1. Distribution network congestion - status

**Chapter Summary**

In this chapter, we give an overview of the status of congestion across the distribution networks and some of the factors which contribute to constraints, including changing interactions with the wider transmission system. We also describe the impacts of constraints and areas where further progress is needed.

## Understanding the status of congestion

1.1. Before describing how DNOs are managing network constraints it is useful to provide an understanding of how constrained the distribution networks currently are. In presenting this picture in this chapter we have drawn on a number of sources of information, including:

- **DNOs' reported information:** Indicators of the nature and extent of constraints and approaches to assessing and managing congestion, including where they interact with the transmission network.

- **Stakeholders' views of the level and impact of constraints[1]:** A strong focus on constraints and congestion management in recent consultations helps build a picture of DNOs' approaches and the impacts on their stakeholders.

## Current status of the distribution network

**Interpretation of 'constrained'**

1.2. Establishing when the network is constrained is a recent and evolving subject and getting a common understanding of the issue across GB is challenging. For instance, there does not appear to be a single, clear definition of constraint used consistently by all DNOs – the area is complex with a range of factors which influence the physical presence of constraints and stakeholders' experience of them.

[1] Sources include DNOs' commitments under their 'Incentive on Connections Engagement' (ICE) plans: DNOs publish annual, forward-looking plans on actions for connections engagement, and stakeholders' views provided in response to a consultation earlier in 2016 and the consultation on DNOs' submitted ICE plans. The 2016 consultation and our decision can be accessed here

1.3. Notwithstanding these complexities, in order to provide a comparative analysis we asked DNOs[2] to assess which areas of their networks would be able to accommodate a 5 MW and a 25 MW generator:

- without requiring 'significant' reinforcement or a flexible solution (a firm connection could be provided)
- with a flexible solution (the DNO is actively addressing the constraint - described further below), where reinforcement would otherwise be required, or
- only with significant reinforcement (the connectee would need to contribute to new capacity to connect in that location).

**A note on the data – 'significant' reinforcement and constrained areas:**

We asked DNOs to report areas in terms of the number of bulk supply points (BSPs) which fell into each of the above categories, or a broadly equivalent category for their network, particularly if they did not use the term operationally. 'Significant' reinforcement for these purposes was defined as reinforcement of the 132kV network.

A grid supply point (GSP) is generally interpreted as the point of connection to the transmission network while a BSP is the point of transformation down to a voltage level below that. DNOs have included slightly different scopes of substations in their responses, notably:

- ENWL reported no constraints where 'significant' reinforcement would be needed, as per the interpretation above. For its network, we use BSPs transforming down to 66kV to contribute to total figures.
- NPg's figures include BSPs with transformation from a distribution voltage to a lower voltage of 33kV or 66kV.
- SPEN reports 132/33kV substations, though it notes this measure may underrepresent constraint levels on its highly interconnected SPMW network.
- SSEN reports supply points which step down to EHV or HV in their SSEH region, and for SSES, BSPs stepping down from 132kV to EHV or HV.
- UKPN notes its BSPs are typically but not exclusively 132/33kV substations. (In LPN for instance BSPs are more typically 132/11kV or 66/11kV).
- WPD's figures include BSPs that typically transform voltage from 132kV to either 66kV or 33kV or 11kV.

In Scotland, where the 132kV network forms part of the transmission rather than distribution system, GSPs may be technically equivalent to BSPs in that they transform between similar voltage ranges. All DNOs exclude single customer sites.

[2] Appendix 3 lists the DNO group names, licensees and the abbreviations used in this document.

1.4. There are many other possible ways of assessing constraint, and there are challenges involved in developing meaningful indicators on a consistent basis. We recognise that the information presented here only captures broad areas of the network where 'significant' reinforcement is required to connect generation. Stakeholders report that many areas of the network are also constrained at lower levels. However, we hope that this assessment provides a useful step towards an improved understanding of the subject.

1.5. In many regions, DNOs have responded to network constraints by offering flexible connection agreements, as outlined above. This is one of the main techniques that allow generators to connect where no traditional, firm capacity is available, by agreeing to curtail generation export on occasion. The most common approaches to enabling the flexible curtailment of export are through:

1) **Active Network Management (ANM)**[3]: ANM builds on flexible connection arrangements, where connectees' network access is managed (generation curtailed or import adjusted) without direct payment in return for a cheaper connection. This involves an automated system controlling network equipment and power flows, to monitor and respond to the state of the network in real time.

2) **Intertrips**: Typically used where there are transmission constraints, or to enable non-firm connections to be managed in a coordinated way, such as to manage fault-level constraints[4].

3) **Timed solution**: Parties have contractual agreements which vary by usage time. This can make better use of a network where demand and generation vary.

**Drivers of constraint**

1.6. The amount of generation connected and in the queue to be connected, gives a partial indication of the level of new demand across the networks, and the extent to which this can be met within existing network capacity. Figure 1 gives an overview of the size of connection queues across different DNO groups[5], together with the amount of generation already connected in each.

1.7. As can be seen below, at the time of reporting, WPD and UKPN had the largest amounts of Distributed Generation (DG) connected across their networks. Several DNOs, notably WPD and SSEN, had had a similar amount of accepted offers waiting to connect.

[3] The ENA produced a Good Practice Guide for ANM schemes which can be accessed here.
[4] UKPN notes that for the type of transmission constraint existing on the South Coast inter-trips have not been a viable solution.
[5] Figures were provided as of May 2016

1.8. While the chart below gives some indication of the extent to which requirements for capacity are being met across the networks, a range of factors may impact the queue length besides connection delays. For instance, it should be recognised that several offers are made for every connection offer accepted and therefore the amount that will actually connect is likely to be lower than the 'queue' size alone would suggest.

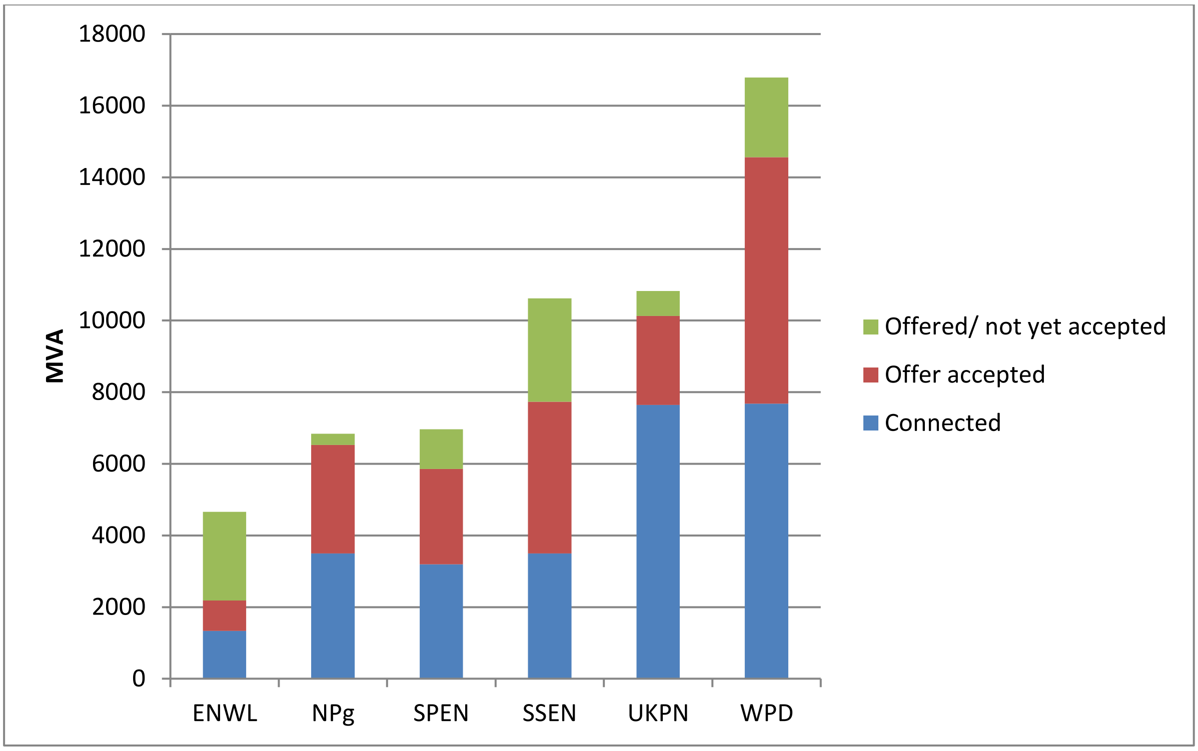


**Figure 1 - DG capacity connected and connections queue status (MVA[6]) – May 2016[7]**

1.9. Figure 2 below provides a view of the acceptance rates of DG connection offers, for each DNO group. These range between 4% and 28%, meaning that in some instances less than 1 in 20 connection offers will convert into an actual connection. SSEN notably has the highest acceptance rate with SSEH reporting a rate of 34%, despite reporting the largest proportion of constrained network areas which it manages through flexible connections. (Further detail on this is shown in Figure 3 below).

1.10. Only two DNOs were able to provide information about acceptance rates specifically for flexible connections – of these, WPD reports broadly similar rates for both flexible and firm offers, while UKPN's flexible connections were accepted

[6] VA is the unit of apparent power. Electrical engineers use this when designing and operating power systems because it takes into account active power (W) and reactive power (VAr). Even though reactive power does no real work it still heats conductors and produces losses so it has to be taken into account in sizing and running the electrical system.
[7] Some DNOs do not include lower voltage levels in their queue reporting

at a substantially higher rate than their traditional offers, which it attributes in part to the application process and the use of a feasibility study which identified curtailment levels up front.

1.11. In part, low acceptance rates may signal the lack of appeal of the connection offers being made, though they are also likely to reflect the extent to which a developer may submit multiple applications in the hope of identifying the one that is most commercially viable[8].

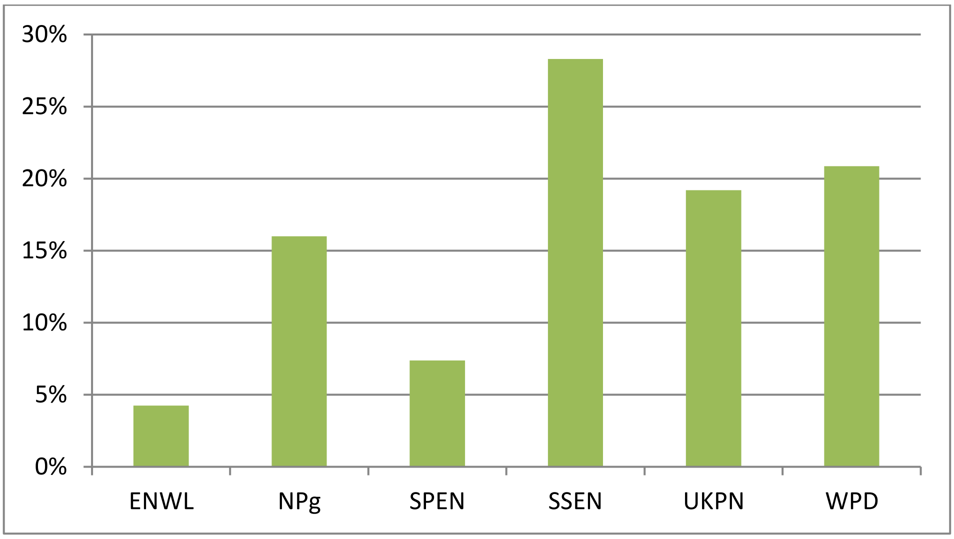


**Figure 2 - Acceptance rates reported for DG connection offers**

### Status of congestion

1.12. Five out of six DNO groups have parts of their networks where they identify ‘significant’ constraints (those requiring ‘significant’ reinforcement, as described above), and are managing these in a range of ways:

- In 13 out of 14 licensee areas, some BSP areas are so constrained that a firm connection could not be offered to a 5 MW or a 25 MW DG customer[9] without reinforcement, albeit in a small proportion of some network areas.

- In four out of these five DNO groups, there are some BSPs where a 25 MW DG customer would not be offered a flexible connection arrangement and could only connect if significant reinforcement was made.

[8] There is no fee to submit a connection request, so developers may submit multiple applications as part of the process of deciding where to connect.
[9] ENWL reported no significant constraints by this measure, and NPg and SPMW report a similarly low proportion of constrained areas. A level of constraint may exist on each network in practice, as can be seen, for example, by comparison with SPMW’s heat maps.

1.13. In total, across all DNOs' networks, around 50-60% of areas are unconstrained by this definition, depending on the size of generator looking to connect. In around 20% of BSP areas, DNOs would be able to offer a flexible connection for both 5 MW and 25 MW DG customers. In the remaining 22% of BSPs for a 5 MW generator and 30% for a 25 MW customer, the only option for connection would be significant reinforcement.

1.14. The picture reported across the networks is shown in more detail in Figure 3 below. While this reflects the status of the networks at the time of reporting, in May 2016, the situation may have changed for many DNOs since that date.[10]

1.15. While these metrics are useful indicators, they do not provide the complete picture of constraints across the network, and are not necessarily fully comparable, due to the differing natures and configuration of DNOs' networks, and the absence of a standardised methodology and language to characterise and describe constraints in a consistent way across the networks.

1.16. It is important – both for network operators and customers looking to connect - that they can readily understand where capacity is available on a firm or flexible basis across the whole system, and where processes to access new capacity may be beneficial. Further progress will be important in this area.

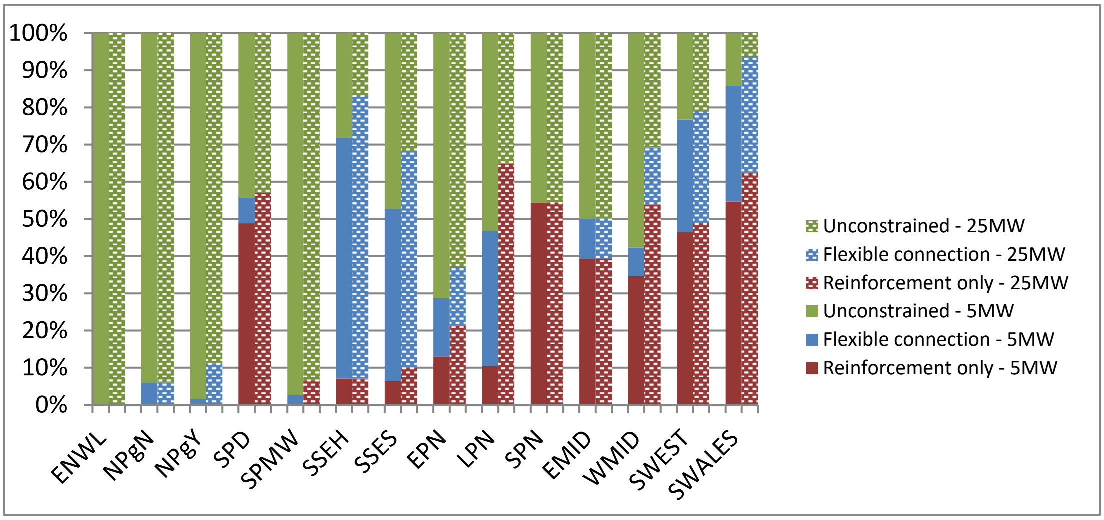


**Figure 3 – Level of 'significant' constraints (as per the interpretation above) reported in May 2016**

[10] For example, UKPN notes that some capacity has been recovered since May due to customer withdrawals, while in SPN it has been working with National Grid to address transmission constraints through a bilateral Regional Development Programme, which UKPN intends to supplement with work done under the TDI2.0 innovation project.

1.17. By this measure:

- ENWL reports no significantly constrained areas of their networks, closely followed by NPg, who reports low levels of significant constraint, and SP Manweb (SPMW), though SPEN note the metric used may underestimate the levels of constraint in their highly interconnected SPMW area.

- SPD, SPN and WPD's areas show the highest proportions of their networks where they are only able to offer connections across both sizes of generators with significant reinforcement, while LPN has high levels of constraint for larger generators only.

- SSEH reports a notably large proportion of its network where significant constraints are present and for which it could not offer a firm connection but a flexible connection would be available.

**Types and scale of constraint**

1.18. We also asked DNOs to also identify the primary cause of the constraint for areas of their network where they were enabling connection offers through flexible solutions. The key primary causes were categorised as follows:

- **Voltage**: a limit on the amount of additional load which can be accommodated without exceeding statutory voltage limits
- **Thermal**: a limit on the amount of additional load which can be accommodated within the thermal ratings of network assets
- **Fault level**: a limit on the network capacity to accept additional current which may occur following a fault on the network
- **Transmission**: a limitation which may be due to a range of physical causes but limits import from or export to the transmission system
- **Other**: this includes, for example, a constraint on Shetland due to network stability.[11]

1.19. A breakdown of these reported causes is shown in Figure 4 below.

1.20. In almost half (44%) of these schemes, the primary cause of constraint reported is a thermal constraint on the distribution network, while a quarter are reported

[11] SSEH has trialled an ANM scheme in Shetland, through the NINES innovation project, to address network stability. SSEN reports the Shetland network is now "full" (having reached its limits for technical capability and stability) and is constrained from allowing any further DG to connect at present.

as primarily due to constraints on the transmission network. Certain causes of constraints may be more concentrated in some regions.[12]

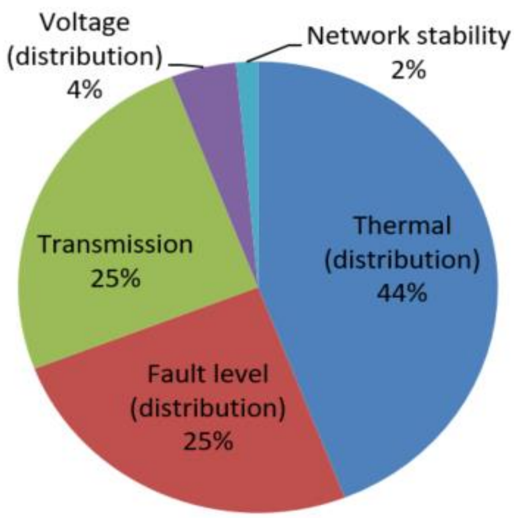


**Figure 4 – Primary cause of 'significant' (as defined above) constraint for flexible connections schemes reported[13]**

## Reported impacts of constraints and constraint management

### Connection costs and delays

1.21. The cost of reinforcement which would be required to obtain a firm connection in significantly constrained areas can reach into the tens of millions of pounds. While any reinforcement that is carried out would frequently be expected to enable multiple connections, the burden of cost would likely fall most heavily on the initial connectee, which may deter investment.

1.22. Some of these impacts are explained in more detail here:

- **Cost:** Stakeholder comments indicate that the scale of quotes can prevent projects from progressing due to delays or costs they find excessive.

[12] For instance, UKPN notes that in 23 of its 37 BSPs in SPN were constrained due to transmission constraints; 13 of the remaining 14 having a mixture of both DNO and transmission constraints.
[13] ENWL reported no specific areas with flexible connection schemes rolled out or planned and is excluded from this chart. It expects to be able to offer ANM in the next 18-24 months. SSEN figures include the network stability constraint on Shetland. SSEN counts ANM rolled out in one area as a single scheme, while for other flexible connection types each connection is counted separately.

- **Delay:** Some stakeholders suggested connection queues on parts of the network have meant customers not expecting to connect until the early 2020s.

- **Size and location limits:** Others reported limits on the size or type of generator able to connect in certain areas.

- **Requirement to move:** Customers noted they have had to move to avoid constrained areas or connect at higher voltages. This may have particular impacts for community energy groups, for instance, who cannot move generation to find free capacity. Some appropriate signals about locations where costs are high are useful, but they must be based on efficient congestion management approaches.

- **Limits on firmness:** Flexible connections can be a fraction of the cost[14] of reinforcement in a constrained area, so some connectees may choose to accept a managed or flexible offer. Their connection costs will be reduced, and they will be able to connect more quickly, as they avoid the need for some reinforcement. In exchange, they accept the possibility that they may not be able to export as much as they would like, or at the times they would like.

**Implications for wider system efficiency**

1.23. Constraints may affect customers' ability to efficiently connect, export to markets or provide wider services to the system, if not managed appropriately. As active management of the distribution network grows, including in the use of flexible connections, it becomes more important that actions are coordinated across the system to minimise inefficient impacts at transmission or on other parties.

1.24. Non-build solutions won't always be a substitute for reinforcement. If they are used more than is reasonable, or the customer doesn't have enough information or certainty to make an informed decision, this can make the investment case harder, pushing up costs to industry and ultimately consumers. Equally, while contracts are often fixed at the point of connection, the value parties place on network access can vary over time, so without a way of allocating this more dynamically, the potential benefits may be reduced.

1.25. DNOs now have many options, including flexible connections, which they can draw on to manage their networks efficiently. DNOs must engage with their customers, including on new or innovative proposals and understand the range of approaches taken by other DNOs and stakeholders, identifying and embedding best practice, including considering potential impacts on the wider system. The approaches DNOs are taking to assessing and managing congestion, including examples of good practice, and some potential impacts of inefficient use of flexible solutions are discussed further in the next chapter.

[14] There may additionally be costs paid by the customer to the transmission network owner or for required equipment, where applicable, eg for an intertrip.

# 2. Assessing and managing constraints on the distribution network

**Chapter Summary**

This chapter gives an overview of the progress DNOs have made in their approaches to managing congestion, building on the workplans we set out in our 'Quicker, more efficient connections' publication last year. We assess the benefits of these new solutions, outlining good practice. But we also consider some potential impacts if flexible arrangements are not used efficiently and set out the need for further progress in some areas.

2.1. There are various dimensions to constraints and the DNOs' management of congestion. One element in isolation may give only part of the picture. After the 'QMEC' consultation in February 2015, we set the DNOs a workplan, with specific actions to enable them to make better use of the existing network (without the need for reinforcement).

2.2. The DNOs have made improvements over the last year and in this chapter we describe the different approaches taken by DNOs, across a range of important aspects of connections and constraint management.

2.3. We want to raise DNOs' and stakeholders' awareness of how different companies are meeting this challenge of facilitating connections in a constrained network environment. This is an important step in highlighting good practice and making efficient congestion management business as usual.

## Where to connect?

**Forecasting and planning**

2.4. DNOs note uncertainty about future changes in constraints. While the scale of existing and planned flexible connections shown in Figure 5 below gives an indication of expected growth of generation constraints in the near term, more specific or longer term forecasting can be challenging.

2.5. NPg, WPD and UKPN report that they use scenario forecasts such as those developed through the business planning process, National Grid's Future Energy Scenarios or other network modelling in forecasting. They report considering a variety of factors such as seasonal changes, existing and proposed DG connections and demand levels which inform connection location and anticipated curtailment levels.

2.6. ENWL and SPEN use historic and actual connections activity to construct scenario projections for large DG, while at least one DNO, WPD, constructs short term forecasts as part of the connection process, which requires them to take a view on accepted connections which will proceed.

2.7. UKPN and WPD are working with Regen SW to understand requirements on their network, building on National Grid's Future Energy scenarios, together with regional information, and knowledge of enquiries to produce future demand/generation profiles for different growth scenarios[15]. UKPN notes it forecasts the growth of distributed resources by BSP/GSP to understand how constraints will evolve, having refined and updated its distributed resource forecasts for its EPN region and will be doing the same for SPN in 2017. SPEN engages with stakeholders to qualitatively assess future constraints.

2.8. SSEN reviews contracted positions and engages the level of interest when planning schemes and reinforcement. It monitors developments though its customer contracts team to get as early indication as possible for upcoming developments in the area.

2.9. It is important that DNOs undertake robust and coordinated planning to ensure they are prepared and responsive to changing demand for use of their networks. This is an area of focus for improvement in the ENA's TSO-DSO Transition Project[16]. We support enhanced forecasting and planning, taking account of other network and system operators' information. The industry should continue to develop and progress this area.

**Information provision**

2.10. As described above, connection costs and timescales can vary significantly between areas where networks are constrained. Information to help generators know where to connect is therefore crucial.

2.11. This is not just a question of whether the network is constrained or not. When the network is constrained, stakeholders want to know what level of curtailment they can expect - excessive curtailment or uncertainty about the ability to import or export can impact the viability of projects. For example, a generator's business case depends on its being able to sell its energy or other services to provide flexibility to the system. If a flexible connection contract places no limits on the level of curtailment they may experience, or circumstances where they

[15] Regen SW is currently working with WPD to produce scenarios for each of its licence areas. As of 1 February 2017 SWales and SWest studies are available and EMID is being studied in the first half of 2017. Regen SW is also working with its SWest and EMID licence area and for UKPN on its EPN licence area. More information can be found at https://www.regensw.co.uk/the-future-of-network-infrastructure-studies

[16] For further detail see the ENA's webpage http://www.energynetworks.org/

may be curtailed, this may make it harder for generators to demonstrate their business case to investors.

2.12. All DNOs with 'significant' constraints (by the definition outlined above) publish heatmaps, to show their customers where there is spare capacity on their network. Approaches vary by DNO, with some focussing on developing online tools such as interactive heatmaps or providing detailed asset information, while others place emphasis on early, individual engagement with connecting customers, both of which can be beneficial.

2.13. Stakeholder feedback tells us that the information provided is helpful, but that further improvements are needed. While heatmaps give useful information, they may not always be regularly updated or quantify the level of constraint. Stakeholders have called for a better indication of curtailment levels to inform future investment.

2.14. A majority of DNOs report improvements to heatmaps in their ICE plans for the coming year. Planned improvements include a range of information from load capacity, quotes issued and planned distribution reinforcements. Some of these measures are adopted by individual DNOs already. For example, some DNOs already indicate whether ANM is available in an area, the type of constraint and planned reinforcement with timescales in their heatmaps, in at least one case indicating where transmission constraints affect their networks.

2.15. Specific details of the DNOs' approaches are described below:

- ENWL is working to develop a generation index to support better quantification of constraints for DG. It notes concerns about the benefits of heatmaps unless they are very granular and updated. It engages early with individual developers to help them understand where best to connect, though it reported lower levels of 'significant' constraint, DG connected and with offers accepted than many other DNOs.

- NPg updates its heat maps monthly. It provides a register of available capacity at each substation and where ANM is available. Northern Powergrid notes its heat maps have been praised by stakeholders for the inclusion of demand head room in addition to DG, which it notes should be particularly useful for storage developers. NPg does not currently monitor actual curtailment levels, but notes all new ANM schemes will have the capability for provision of curtailment data to customers and for system planning.

- SPEN plans to improve information on transmission system impacts and to publish district investment plans. It also includes contracted capacity in its heat maps. As part of its 'ARC' project[17], SPEN developed monitoring of power flows at the GSP to give an indication of the likely ability to export from an area. It has developed the capability to monitor the number of instances of curtailment,

[17] SPEN's Accelerating Renewable Connections (ARC) Low Carbon Networks Fund project trials ANM

though has found it to be too onerous so does not plan to roll this out, though notes it will carry out detailed curtailment analysis for customers following their acceptance of a connection offer, for which a charge will be levied. It will publish a heat map shortly which will give a view of the impact of connecting generation at each voltage level.

- SSEN indicates transmission constraints on heatmaps and provides planned reinforcement work and timescales and plans to include operational network improvements, as well as quoted capacity.

- UKPN notes it monitors curtailment events for generators in existing ANM schemes. It also provides an interactive DG mapping tool together with a demand mapping tool and offers connection surgeries as well as providing detailed curtailment assessment reports to support flexible DG offers.

- WPD notes its ANM schemes are able to monitor curtailment levels. Though they are not currently actively monitoring this, they are able to report that actual curtailment levels are better than estimates. WPD makes asset information in DG heat maps and capacity registers available online.

## Making best use of the existing network - flexible connections

### Implementation in significantly constrained areas

2.16. Flexible connection schemes, including ANM, are being increasingly offered as business as usual and are enabling a significant amount of new connection offers on the constrained networks, in effect releasing network capacity for new connections. Flexible schemes have been adopted in 13 of 14 DNO regions, with more schemes planned at the time of reporting, as shown in Figure 5.

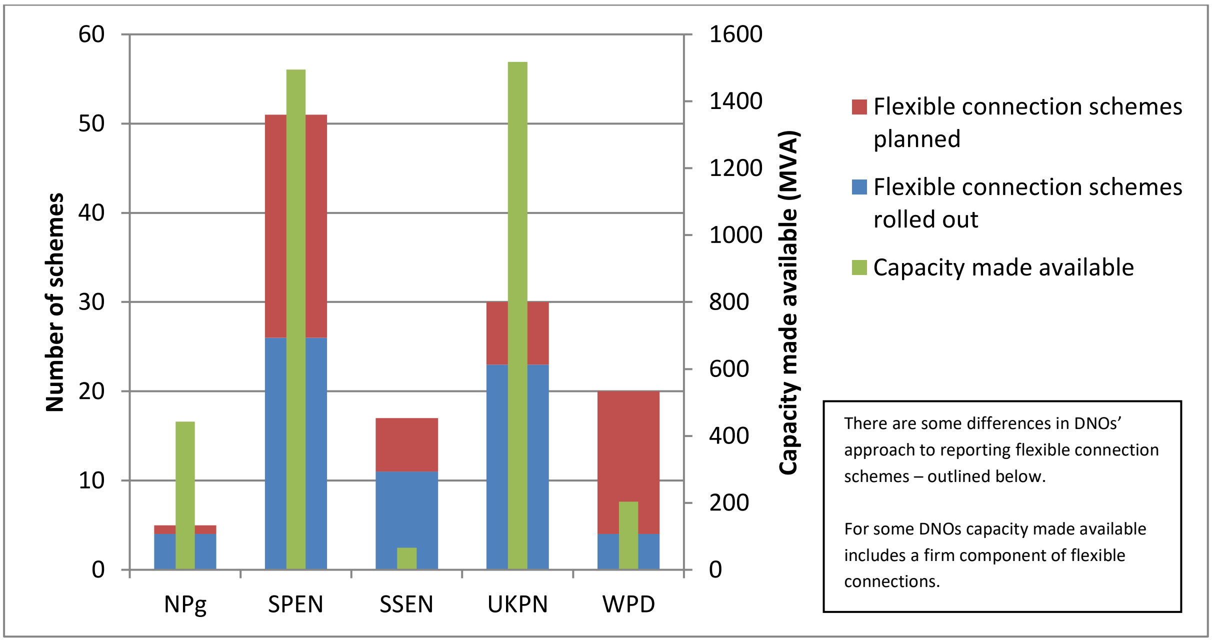

**Figure 5 – Flexible connection schemes implemented, with capacity released, and schemes planned as of May 2016[18]**

2.17. Though there are some differences in the approaches DNOs take to estimate capacity released, described below, they reported a total of around 3.7 GVA of capacity made available by flexible connections of a range of types of across constrained areas of the networks.

**A note on the data - flexible connections and released capacity:**

We asked DNOs to indicate the amount of capacity which had been released through the use of flexible connection arrangements.

Most DNOs reported the 'capacity made available' through these approaches as the extent to which the combined maximum (non-firm) export capacity of the generation connected or for which offers have been made to date exceeds the firm capacity of the network. There were some differences in the approach taken:

- For SPEN and SSEN "capacity made available" shows the capacity made available to the customer(s) (ie the capacity offered), which includes some firm capacity.

- WPD notes it has estimated the capacity released through its flexible connection schemes as the offers enabled up to a limit which customers are typically prepared to accept. WPD only reports ANM schemes here that include multiple connections under discrete BSP groups, though it notes it also offers timed connection, intertrips and export limiting to individual connection customers.

All DNOs report ANM deployed in a certain area as a single scheme (in most cases, within a GSP or, for UKPN, a BSP). Approaches differ for other types of flexible connections - while most DNOs continue to follow this approach, SSEN reports individual connections as distinct schemes here. SSEN only reported rolled out schemes and capacity made available where the customer is already connected. Some DNOs report values in MW and others in MVA – the total MVA presented here is therefore a minimum.

2.18. Some DNOs were also able to report the total capacity – both firm and non-firm - they were able to offer across their top constrained areas, where flexible connection schemes were offered. Though this is an illustrative indication, it can

[18] ENWL does not report any flexible connection schemes to manage congestion and report no 'significantly' constrained areas, by the definition outlined above. ENWL anticipates being able to offer customers ANM connections in around 18 – 24 months but does include the ability to curtail in abnormal system conditions in their standard connections.

be used to provide some broad insight into the extent to which individual schemes are able to increase the connection capacity of a constrained area, though noting the connection capacity is offered on a non-firm basis. Across the 20 constrained areas with flexible connection schemes where this data was available, total capacity available for connection was increased on average by around just under three times the firm limit of the network constraint.

2.19. DNOs offer a range of different types of flexible connection in constrained areas. Of those DNOs offering flexible connections, all offer some form of ANM, with several offering a range of intertrips, export limiting devices and timed solutions.

2.20. While two DNOs (ENWL and NPg) report less use of flexible connections to enable DG connections in the above chart, they also report lower levels of significant constraint on their networks. Of these:

- ENWL does not operate flexible connection schemes, though its connection offers allows for curtailment under abnormal system conditions , and is hence not included in these charts. It expects to be in a position to offer ANM to customers for congestion management in approximately 18-24 months following the installation of a new network management system that will have the appropriate functionality to support ANM.

- NPg notes it has offered flexible connections for many years, including for heavy industry demand customers. While it notes it has not historically reported the volumes of flexible connections provided, so precise figures cannot be included here, it has used intertripping schemes and earlier forms of network management, and first installed an early form of ANM in 2012. NPg is now implementing its first replicable ANM scheme due to a network constraint in a particular geographic area. It notes further ANM and some intertrips are planned, due to transmission constraints, which it identifies as the primary cause of constraint on its network, but it continues to provide unconstrained connection offers for the majority of DG and storage connections.

**Policy and Communication**

2.21. Most DNOs have a plan to roll out a programme of flexible connections with WPD having a clear roll-out plan for full 'ANM' outlined in their innovation strategy, with network wide availability by 2021. UKPN has a plan to rollout full ANM connections across the constrained areas of EPN by 2021 and across the constrained areas of SPN by the end of 2017.

2.22. It is essential that customers are made aware of the alternative connection offers when receiving a standard connection offer. WPD's conventional offer letter outlines highlights the potential opportunity for an alternative connection options and provides a link to the WPD 'Alternative Connections' web page where further information is available. It also maintains a mailing list, which customers can join through its website, and receive updates on alternative connections when necessary alerts as and when new ANM zones are to be opened up.

2.23. NPg, SPEN and SSEN also discuss flexible connection options as part of their application process and are among DNOs who run stakeholder workshops or surgeries to let customers know how to interact with the process. UKPN highlights the areas where flexible connections are being made available and invites customers to apply.

**When will curtailment occur?**

2.24. DNOs generally note the risk of curtailment lies with the customers, who are typically encouraged to carry out their own due diligence, but some also note the potential for commercial issues with ANM related to the lack of guarantee of curtailment levels. Customers must be provided with sufficient information and data in order to make an informed assessment of risks and decision about whether to enter into a connection involving curtailment. This should include some degree of understanding of the levels of curtailment they may be subject to.

2.25. DNOs report using different approaches to assigning curtailment among connectees – pro rata or LIFO[19] - with different reasons for their choices. While they primarily follow LIFO principles - for reasons including commercial simplicity and ease of curtailment modelling among other reasons (aligning with the ENA's Good Practice Guide) some note their thinking is evolving. One DNO notes it will use pro rata curtailment for a single constrained area, or during the early stages of an application window for a new ANM scheme.

2.26. Where new capacity becomes available within a scheme, either through changes in background demand or new investment, different approaches may be taken to allocating this. Several DNOs report they would allocate new capacity according to the existing operating principles of the scheme, though one noted specific allocation of any new network capacity may also be foreseen at the outset of the ANM or reinforcement scheme, depending on the driver for investment.

2.27. Stakeholder comments suggest the scope for curtailment can be broad, even in normal system conditions. Of a sample of 'alternative' connection offers provided by DNOs, several include the ability to curtail under a range of circumstances, including to manage relevant transmission constraints.

2.28. The ENA's ANM Working Group consulted on the presentation of curtailment assessment data by DNOs. As a result, the DNOs have an action to publish a statement on their websites explaining how they will enable applicants to determine what their curtailment will look like. These should be available in early 2017.

[19] These refer to the basis on which export is curtailed in an ANM arrangement. Curtailment may be allocated uniformly across participants in a scheme (pro rata), or in reverse order of connection ('last in first off' or LIFO).

2.29. Some of the different approaches taken by the DNOs are outlined here - stakeholders should engage with DNOs, making use of the ICE, to highlight the type of provisions they find most useful:

- ENWL offers curtailment data upon request based on historic fault and maintenance outages that would have affected the proposed connection. ENWL is also developing a systematic methodology for the calculation of curtailment factors that will be included within future connection offers.
- NPg provides up to three years of relevant network data for the ANM location in question so that the customer can perform its own curtailment assessment.
- SPEN will carry out detailed curtailment analysis for its customers following their acceptance of a connection offer. A charge will be levied for the provision of this service.
- SSEN provides customers with the data to conduct their own assessment and as part of standardising their flexible connections process SSEN will update its website with a statement informing customers of the data it offers in order to assess curtailment. It conducts internal reviews on an annual basis to monitor actual curtailment levels.
- UKPN provides an interactive DG mapping tool accompanied by a demand mapping tool. This indicates the type and voltage level of the constraint. When a flexible DG offer is made, a detailed curtailment assessment report outlining the main assumptions is used and is supplemented by a feasibility study. UKPN also offers customers support through their due diligence by providing additional information or holding a connection surgery. It also factors microgeneration forecasts into curtailment estimates.

**Efficiency limits of flexible connection offers**

2.30. DNOs take different approaches to determining whether or when no more flexible connections can be offered in an area. They mostly consider this to be an economic decision by the customer – when the terms of a connection become uneconomical, the customer will not accept the offer in that area.

2.31. One DNO notes it tends to limit the extent of flexible offers it makes, based on the demand diversity capacity. One DNO suggests that offers with estimated curtailment levels of 10% are routinely accepted, with some instances of up to 20%, while another reports acceptance rates typically dropping off from around 25%. One DNO noted it calculates a value for the capacity made available when it introduces a flexible connection and stops offering connections in that area when that amount of capacity is used up. In some cases, offers may be limited depending on the type of connection.[20]

2.32. DNOs outline different conditions under which they would identify and invest in further reinforcement in an ANM area. Generally, they note that changes in background demand (eg from microgeneration) which could lead to increases in levels of curtailment form part of the connectee's contractual risk, though SPEN offers ANM on an interim basis and plans to conduct cost benefit analysis (CBA) on the need for wider works. DNOs had the opportunity to justify revenue in their business plans specifically for strategic investment projects which one DNO successfully applied for.

2.33. DNOs adopt different approaches to customer engagement and investment decisions in actively managed areas. Examples of these approaches are:

- ENWL currently has no active ANM schemes, but intends to measure and compare actual and the assessed theoretical curtailment; if there is a significant difference between these then it would consider it efficient to carry out network investment in that area to bring the actual back to the indicative.
- NPg notes it may facilitate developer-led investment, which it would expect at the point where costs to the generator of curtailment exceeded this.
- SPEN offers ANM on both an interim and enduring basis, with some schemes pending wider works already planned. It intends to assess the need for wider works with a CBA. Triggers for ANM scheme review and curtailment rates will be identified as part of the scheme design.
- SSEN aims to minimise the potential for uneconomic flexible connections by only offering such arrangements where following customer engagement it is established that sufficient flexible capacity exists. This also builds on past experience of the point at which such arrangements became uneconomical.
- WPD outlines a range of background network conditions which could cause it to reinforce in an ANM area, including demand growth, age/condition of assets, new connections, or where an ANM could not keep the network within limits. WPD has published an update on its strategic investment work in its 'Shaping subtransmission'[21] work to reduce the delays customers face due to constraints in the south west.
- UKPN highlights that it looks to minimise constraints, in particular where an issue can be addressed through configuration of network/ANM systems. It notes it would consider options for relieving any excess constraints and engage with generation stakeholders on their economic efficiency and whether or not they would invest to remove the constraint, noting it would consider investment funded by general customers where this had been agreed as part of the ED1 price

[20] For example, one DNO reports that timed connections are limited in line with the amount of conventional PV capacity in that location. Another reported that soft-intertrip connections are limited to around three generators in a single constrained location, for operational reasons, while export limited connections can always be offered.
[21] https://www.westernpower.co.uk/docs/About-us/Our-business/Our-network/Strategic-network-investment/Shaping-Subtransmission-to-2030-South-West-2016-v1.aspx

control settlement, noting In this instance it may consider it to be acceptable to remove the constraints on connected generation and would require consideration with generators of the associated benefits.

2.34. We encourage stakeholders to engage with the DNOs to signal what sorts of offers and supporting information they want to see, including through the ICE.

## Other ways of managing network capacity

### Consortia

2.35. In constrained or remote areas, new generation connection applicants will be required to contribute to the cost of network reinforcement and/or connection assets to provide them with their connection and generation capacity. This can add significant costs to a scheme and affect viability. One option available to developers to overcome these costs is to establish a consortium of other generators wishing to connect to the same area of the network and share the connection charges between the parties involved.

2.36. All of the DNOs have information on consortia published on their website – with WPD, UKPN and SSEN also having a consortia register on their website for developers to register their interest.

2.37. Each DNO with more constrained networks has taken part in connection surgeries or workshops to discuss using consortia. Customer responses and take-up were mixed because of the challenges in aligning projects to commit and move forward together.

2.38. Half of DNOs have now conducted trials and the Scottish DNOs have recently had success in leading consortia. SPEN has reported four consortia developments led by them totalling almost 700 MW of contracted or connected projects– their mid-Wales development[22] making up almost 500 MW of this figure, plus two other developer-led consortia schemes totalling 90 MW. SSEN reported a number of smaller consortia now being progressed as well as Grudie Bridge (28 MW equating to 70% of the hydro capacity due to connect in Scotland in 2016) which is detailed in the next chapter.

2.39. A similar approach has been initiated by SSEN on Orkney with 64 developers having indicated an interest in sharing the reinforcement costs required to connect an additional 434 MW of generation on the islands.

22 http://www.spenergynetworks.co.uk/pages/connecting_mid_wales_windfarms_to_the_national_electricity_network.asp

**Queue management and milestones**

2.40. As described above, the queue of customers waiting to connect can add to the level of constraint in an area of the network. Much of this queue (and the capacity allocated to it) may never ultimately require a connection.

2.41. DNOs report that they are finding contracted projects are often not ready to progress, even when network capacity is available, for example due to delays in project planning, consenting, finance and other material issues. This can result in otherwise available capacity being tied up by 'stalled projects' that could productively be used by others. The requirement for additional, potentially unnecessary, reinforcement costs being in connection offers is also increased.

2.42. The ENA and DNOs took forward work to agree with stakeholders best practice in managing the queue. This led to a consultation on what changes a customer can make to a connection request, while maintaining a place in the connection queue. The consultation[23] sought views on the balance between allowing customers some flexibility while progressing a connection application, but remaining fair to other customers in the connection queue. Following this engagement, there will be a further round of consultation in 2017.

2.43. Although some DNOs already include milestones in their connection offers, the ENA has taken forward work to agree best practice across the industry. It issued a consultation on queue management principles in April 2016 on behalf of the DG-DNO steering group, and following feedback from this consultation, the ENA published *Fair and Effective Management of DNO Connection Queues: Progression Milestones Best Practice Guide* on 3 November 2016. How this guidance will be applied is a decision for each DNO to take.

2.44. We do not expect the application of this guidance to remove customers from the queue who are making reasonable progress in their projects and DNOs are expected to consider the individual challenges that developers are facing, particularly those outside of their control.

2.45. If the result of this work is that valid projects are being terminated then we would expect the ENA to revise the guidelines accordingly. We would also encourage stakeholders to feed back on the process and whether it is working for customers in practice through regulatory mechanisms such as the ICE to ensure that their views are being heard.

[23] http://www.energynetworks.org/assets/files/news/consultation-responses/Consultation%20responses%202016/Fair%20and%20Effective%20Management%20of%20DNO%20Connection%20Queues%20Treating%20Changes%20within%20Applications.pdf

2.46. SPEN has additionally built on the principles of the ENA Consultation on Progression Milestones to develop and consult on its own guidelines[24] to determine when it is appropriate for a DNO to:

(i) terminate a connection construction agreement;

(ii) be flexible and give more time for the development to, for example, clear planning hurdles; and

(iii) treat a project as having stalled and look at options for reassigning queue positions.

2.47. This work has been supported by Scottish Renewables and SPEN has engaged with stakeholders. SPEN published a policy position on 8 December 2016 and will implement this policy across its distribution licensed areas and is actively engaged with National Grid (SO) to encourage it to develop its own queue management principles on this basis. SPEN has also been communicating their proposals to the other DNOs with an aim to these principles becoming the GB-wide standard.

2.48. By September 2016, the DNOs estimate that in total, more than 350 MVA has been released as a result of moving customers back down the queue, terminating offers or recovering capacity that is held by customers not progressing their projects for example, because of problems with planning and changing subsidies. In particular:

- NPg contacted in excess of thirty customers and formally terminated eleven projects for various reasons, releasing 167 MW of capacity back onto the network.

- WPD estimated that since 1 April 2016, approximately 20 customers have been moved back down the queue (allowing others to move up) because they hadn't progressed their projects and met their milestones, and believes approximately 200 MVA has been released since 1 April 2016.

**Releasing unused capacity**

2.49. DNOs reported that a number of operational sites are underusing capacity for prolonged periods of time. This can contribute to a lack of available capacity for new connections. The modification proposal DCP 115[25] which we approved in July 2015 amended the National Terms of Connection to clarify the rights of DNOs to take appropriate action when customers underuse their capacity.

[24] http://www.spenergynetworks.co.uk/userfiles/file/Queue_Mgt_Consultation.pdf
[25] Distribution Connection and Use of System Agreement (DCUSA) DCP114 - National Terms of Connection Amendments - Capacity Management (over utilisation) and DCP115 - National Terms of Connection Amendments - Capacity Management (under-utilisation)

2.50. Since May 2016, four of the six DNO groups contacted their larger customers who were using less than 75% of their contracted capacity. By September 2016, the DNOs had identified a total of 29 MW of demand capacity and 13 MVA from DG customers that had been agreed to be handed back from customers. As this work is ongoing, there is still scope for significantly more capacity to be released. Although the DNOs have reported a low success rate, this capacity is created for comparatively very little cost and effort.

2.51. To facilitate this work in the future, the DNOs are also looking at alternative ways to identify unused capacity such as:

- a time limit for use of reserved capacity
- reducing the Authorised Supply Capacity (ASC) of those customers who use between 75% and 100% of their ASC
- challenging situations where installed and contracted capacity do not match; and,
- introducing terms and conditions in the offer that allows DNO to recover unused capacity.

**Identifying and managing transmission constraints**

2.52. DNOs highlight some regions of the networks are constrained due to congestion on the transmission system or limits on export. This was identified as the primary cause of constraint in around a quarter of flexible connection schemes reported. Some DNOs highlight substantial reinforcement requirements in their regions with the rapid growth of generation, meaning many BSPs are only able to offer a managed connection or require reinforcement, as shown in Chapter 1.

2.53. More broadly, other potential challenges with coordination were noted, including difficulty obtaining agreement to connect ahead of the conventional transmission reinforcement, limitations resulting from CUSC[26] restrictions on the use of ANM and the potential for conflicts between ANM and SO instructions.

2.54. SSEN reports National Grid has enabled earlier connections through Connect and Manage[27] in some constrained areas of its network, as well as intertrip or ANM arrangements ahead of reinforcement. Use of such techniques has been relatively limited to date and there may be potential to widen this approach. NPg notes it has some ANM schemes which monitor and manage for transmission and distribution assets simultaneously.

2.55. Where beneficial solutions can be identified through coordination, these should be made clearly available. UKPN notes it is working with National Grid in SPN to resolve the regional transmission constraints and release additional capacity for connections. UKPN expects that flexible connections will be made available in SPN in 2017.

[26] The CUSC is the Connection and Use of System Code which applies to the transmission system
[27] In Chapter 4 we outline the Connect and manage arrangements in more detail.

2.56. Collectively, the industry (through the Energy Networks Association (ENA)) has established a new TSO-DSO Transition Project, which replaces the previous Transmission-Distribution Interface group that looked at areas which need coordination between distribution and transmission. This work aims to address the increasing need for coordination across all aspects of system and network operation, including in managing congestion, facilitating connections and active management of the system.

2.57. Particular areas the group are considering under the project's four workstreams include principles for the co-ordination and management of TSO and DNO constraints, ANM principles of access, high level commercial agreements required between SO, DNO and the customer for sharing of flexibility services, whole-system charging, consistent customer experiences, statement of works process, storage and the potential models for the distribution utilities as they transition to DSOs. The project aims to address the increasing need for coordination across all aspects of system and network operation, including in managing congestion, facilitating connections and coordinated active management of the system. We support this endeavour and encourage further progress across the Project's workstreams.

# 3. Update on anticipatory investment trials

**Chapter Summary**

This chapter summarises progress on trials brought forward by DNOs and stakeholders to test different approaches to enabling anticipatory investment. Three of the six trials are demand-based and three generation.

3.1. In the QMEC update in September 2015 we asked DNOs and stakeholders to come forward with proposed schemes to trial models to enable investment ahead of need (without passing the cost onto the wider consumer base). We were intending that these trials would show us what is possible within the current regulatory and legislative framework and highlight any barriers that we may need to overcome if necessary.

3.2. Six trials were put forward: three demand-based (urban regeneration schemes) and three generation-based schemes. The details and progress of each are below.

## Overview of the trials' progress

**Trial 1: Consortium - Grudie Bridge (SSEN) – Update Aug 16**

3.3. Grudie Bridge is a GSP 30 miles North-West of Inverness in SSEN's SSEH network. The current electricity network in the area is now considered to be 'full' from an electricity generation perspective. In order to accommodate any further generation, the SSEH network required significant reinforcement. In addition to this, Scottish Hydro Electric (SHE) Transmission also required upgrades to its transmission network.

3.4. Because of the level of investment needed for the 33kV distribution reinforcement, SSEH decided to find out if interested parties wanted to progress with a consortium-type arrangement. This meant that all projects wishing to connect would share the initial high costs of the reinforcement works apportioned between the developers on a 'pound (£) per kilowatt (kW) to connect' basis, thereby lowering the hurdle to connecting parties.

3.5. In contrast, through the traditional approach taken by SSEH, under the Electricity Connection Charging Regulations (ECCR), costs would have been funded entirely by the first party to connect, with all future connections paying a 'second-comer' payment back to the 'first-comer' once the reinforcement and connection works were complete for their connection.

3.6. SSEH carried out a network study and determined that the 33kV reinforcement was economically viable if shared between the interested developers, after which the Grudie Bridge Consortium was then established. The consortium includes 25 different hydro connections, totalling around 28 MW in generation, equating to 70% of the hydro capacity due to connect in Scotland in 2016. Although not without its challenges, the consortium group has met regularly in its progress towards achieving successful connections.

3.7. By December 2016, 20 of the 25 generators in the consortium were connected as planned. The further 5 generators have requested to delay their connection dates and will be connected in 2017. The associated transmission network reinforcement works were also fully completed by SHE Transmission on 9 December 2016.

3.8. A similar approach has been initiated on Orkney with 64 developers having indicated an interest in sharing the reinforcement costs required to connect an additional 434 MWs of generation on the islands.

3.9. To help facilitate consortium arrangements, SSEH delivered a consortia register within its heatmap tool and published consortia guidance on its website. Commercial Contract Managers and Connections Designers also make customers aware of the opportunity to align application dates so that works can be considered together and costs shared. This has resulted in a number of smaller consortium arrangements now being progressed.

**Trial 2: Aggregating DG customers through a charging derogation (WPD)**

3.10. WPD is proposing a trial to provide a fairer apportionment of costs between a number of DG customers requiring capacity on the same part of WPD's network. The trial is designed to expand the options available to DG customers seeking a connection without increasing costs to other customers.

3.11. WPD is concerned that at present, a barrier to the connection of DG customers can be the 'High Cost Cap' (HCC). Where the cost of reinforcement is £200/kW or greater the total cost of that work must be paid by the generator (with no contribution from other customers) - this is the HCC.

3.12. WPD believes the HCC is appropriate where a single DG customer can only be connected through reinforcement investment on a part of the network where there is a low chance of the surplus new capacity being used by other DG customers in the short to medium term. However, where that new capacity will be used by immediate subsequent DG customers who have applied for and accepted a connection offer, WPD believes it is appropriate to share the reinforcement costs between the DG customers.

3.13. WPD is therefore seeking a derogation in order to run a trial to apply an alternative method to charging for reinforcement in which an aggregated capacity of DG customers are considered together so as not to trigger the HCC.

3.14. We have consulted on this proposal[28] and will be issuing an update shortly. If the trial is successful, it is proposed that the connection charging methodology will be amended accordingly.

3.15. The following section summarises the progress of the other trials:

**Trial 3: Ebbsfleet Development Corporation (UKPN)**

- Ebbsfleet Development Corporation (EDC) has been set up to provide a strategic framework for a new Garden City development at Ebbsfleet.
- The EDC has financial backing to invest upfront in infrastructure for the development.
- The EDC is seeking to agree an approach with UKPN to provide for the key infrastructure and recover these costs from developers who subsequently connect to the network created.

**Trial 4: Greater London Authority (GLA) DevCo Model – Charging a Premium**

- The Development Company (DevCo) model put forward by the GLA was one in which the DevCo provided investment in infrastructure to secure early and strategic development in the network, where the risks of advancing the infrastructure build are not reasonable for the regulated utility to take.
- In this model the DevCo wanted to recover a risk premium from subsequent customers connecting to the network and wished to do this via the ECCR (second-comer legislation).
- This may not be feasible because of compatibility issues with the types of expenses the electricity act permits to be recovered through the ECCR.
- Two options for pursing this model are: (i) a separate arrangement under a Section 22 agreement (not covered by ECCR arrangements); or (ii) Changes to primary legislation to accommodate this arrangement.

**Trial 5: Baltic Triangle, Liverpool (SPEN) SPEN Criteria**

- The Baltic Triangle is a regeneration area in Liverpool consisting of a number of small to medium sized businesses.

- There has been some level of connection (2.5 MVA) in this area, but the most efficient and quickest solution for these customers was to connect to a separate primary grouping outside of the existing substation grouping that serves the Baltic Triangle. SPEN has therefore not progressed with any reinforcement to this part of the network for future customers. This is because to date it has not identified an initial customer large enough to trigger the reinforcement required,

[28] https://www.ofgem.gov.uk/publications-and-updates/open-letter-consultation-derogation-standard-licence-conditions-slc-13-1-and-14-15-electricity-distribution-licence

nor does it feel certain enough to justify a DNO-led reinforcement scheme (off the back of an initial developer).

- SPEN has proposed a set of criteria that it would likely require from other parties – with perhaps a coordination role for the Local Authority/Local Enterprise Partnership (LEP) – to reassure it that it should consider and undertake strategic investment on the development. We invite stakeholders to engage with SPEN to develop this further.[29.]

**Trial 6: Various strategic projects SE England, UKPN criteria**

- There are a number of planned strategic sites across the South East of England currently being driven by the requirements of High Speed Two (HS2).[30] UKPN is considering the implications on wider infrastructure development in the area.

- As with SPEN (above), UKPN has proposed a set of criteria that it would likely require from other parties in circumstances where a developer is not able to fund the works (and the investment is not covered by existing price control funding). These criteria would help to provide reassurance that UKPN can consider and potentially undertake strategic investment on the development. We invite stakeholders to engage with UKPN on these proposed criteria and to understand how their development can be best progressed[31].

---

[29] See Appendix 1
[30] Further information on HS2 can be found here
[31] See Appendix 2

# 4. Transmission access regime: Connect and Manage

**Chapter Summary**

This chapter summarises the access arrangements for connection to the transmission network under the 'Connect and Manage' regime.

## Transmission connection regime: background

4.1. Generators[32] connect to the National Electricity Transmission System (NETS) under the Connect and Manage regime. The regime was introduced by the Department for Energy and Climate Change (DECC) in 2011 to improve access to the transmission network.

DECC, 2011: *"The objective of an effective grid access regime is to help deliver energy security and a clear path to delivering the UK's renewable energy targets. The intended effect is to provide sustained, commercially viable connection opportunities and firm connection dates reasonably consistent with project development timescales which will ensure the right environment for investment in new generation. The solution will need to be set in the context of protecting consumers, including minimising costs."*

4.2. Under Connect and Manage, generators are offered connection dates based on the time it takes the Transmission Owner (TO) to complete local *'enabling works'* – for example, local substation works. That is, generators can be connected before full network reinforcement *'wider works'* are completed. Network reinforcement is expensive and takes a long time.

4.3. However, connecting generators ahead of the completion of full reinforcement works may result in additional constraints on the NETS. Under the Connect and Manage regime the costs arising from the management of these constraints are socialised through Balancing Services Use of System charges, and ultimately passed on to the consumer.

4.4. As the National Electricity Transmission System Operator (SO), National Grid is responsible for identifying system needs and coordinating and developing options to meet those needs, to support efficient asset delivery and protect consumers against undue costs and risks[33]. In carrying out the Network Options Assessment (NOA) process, the SO should work to maintain an efficient and economic balance

[32] There is a separate connections regime for interconnectors and offshore transmission owners (OFTOs)
[33] National Grid Network Options Assessment report 2016, p.2

between investing in further infrastructure and constraining the use of the system when necessary – striking a balance between the stranding risk of assets from investing too early; and the potential high costs of managing constraints from investing too late.

**Connect and Manage: overview of performance**

*Timely connections*

4.5. Since the introduction of the regime, generation connection dates continue to advance. Under the RIIO-T1[34] arrangements we hold the transmission owner (TO) companies accountable for delivering a range of outputs, including timely connections. We have three years' worth of data on the connections outputs (2013-14, 2014-15 and 2015-16) which can be found on our website[35]. At this stage, the data shows the companies performing in line with their targets. On average, generators are able to connect six years earlier because they don't have to wait for the full reinforcement works to complete. The majority of applicants are able to get connection offers for their preferred timescales. For the period 1st April 2016 to 30th September 2016 75% of transmission connection offers met customers' requested dates.

4.6. The graph in Figure 6, below, illustrates, for each of the TOs' regions, the connection offers that met customers' requested completion dates, and the difference when the request was not met, for the period 1st April 2016 to 30th September 2016. In England and Wales, 14% of connection offers were made for a date later than requested by the customer. In Northern Scotland and Southern Scotland, around 43% and 38% respectively of offers were made for a date later than requested by the customer, reflecting the network constraints in that part of Great Britain.

4.7. These differences partly reflect local network conditions and associated design considerations. Some connections depend on other works being completed. These could include substation works, getting planning consents, collaborating with distribution network operators, and the timing of outages.

[34] RIIO-T1 is the first transmission price control to reflect the new RIIO (Revenues = Incentives + Innovation + Outputs) model.
[35] https://www.ofgem.gov.uk/network-regulation-%E2%80%93-riio-model/network-performance-under-riio/riio-t1-performance-data

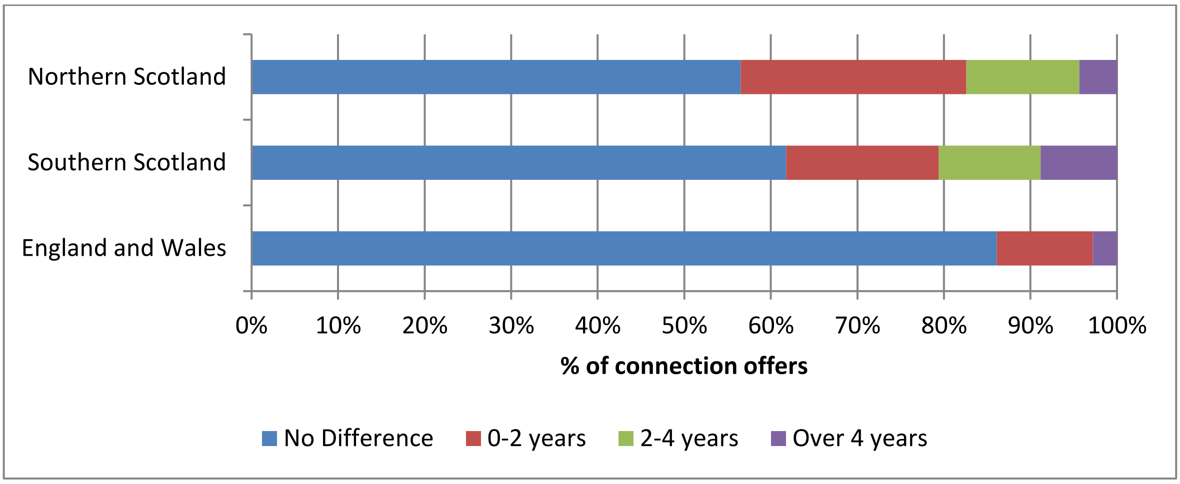


**Figure 6 - Difference between connection dates requested and offered, by region, for the period 1st April 2016 to 30th September 2016. (Source: National Grid)**

*Consumer bill impact*

4.8. The transmission access regime affects consumer bills through the socialised constraint costs[36].

4.9. Constraint costs arise as a result of the need to balance power flows across the transmission network. As more generation connects to the grid, there are instances when there is insufficient network capacity to transport energy from where it is economic to produce it to where it is in demand. National Grid, in its role as the SO, then has to ask generators to reduce their output (at a price) whilst at the same time ensuring the supplier receives the power from other generators (who must also be compensated) elsewhere on the network.

4.10. The SO can achieve this through the Balancing Mechanism (BM), which relies on decisions taken in the half hour before dispatch is required and is therefore more costly, or through contracts or trades negotiated further in advance. The latter can be a more attractive option when certain parts of the network are expected to be constrained, because of planned outages in the network (eg for maintenance during the summer) or because of a lack of transmission capacity relative to generation capacity in certain parts of the network. (The clearest example of this at the moment is Scotland).

[36] In support of its decision to socialise constraint costs DECC considered that the difficulty in allocating constraint costs would lead to greater complexity, and that the difficulty in predicting renewable generation dispatch would make forecasting constraint costs difficult for generators, both of which could deter investment.

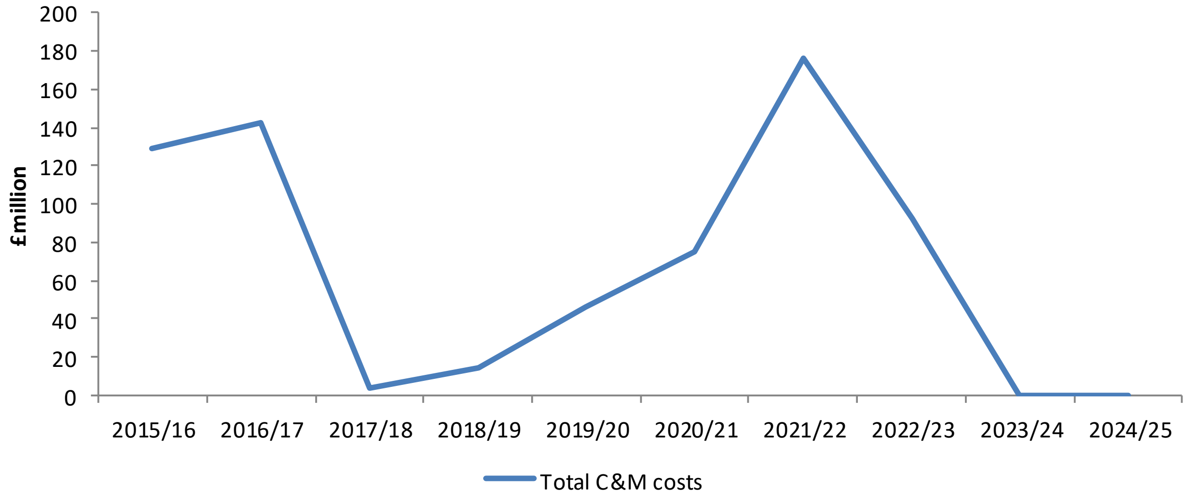


**Figure 7 - Connect and Manage Constraint Costs (Source: National Grid)**

4.11. Figure 7 shows the historical and forecast constraint costs attributable to the Connect and Manage network access regime. These costs are largely tied to the levels of network capacity utilisation and delivery of new network infrastructure. In this respect, the constraint costs are:

- **Lumpy**. As new generation connects to the network ahead of wider reinforcement, constraints occur more frequently. The cost of managing constraints increases. Once wider network reinforcement is completed, the constraints ease off and the associated costs decrease. This means that the cost to consumers will vary year on year. This can be due to a number of factors – the 'blocky' nature of reinforcements; the cost of delayed capital expenditure which can, in some cases, be better value for the consumer.

- **Likely to increase going forward**. Constraint costs are complex to forecast due to the high level of uncertainty associated with how the market will meet future demand (eg energy/technology mix – in particular, challenges in forecasting intermittent generation, government policy effects or other factors). However, it is reasonable to expect that as increasing levels of generation connect to a relatively static network, constraints are likely to increase until the network expands sufficiently and/or generation levels plateau.

4.12. This future uncertainty and future investment is addressed by the NOA process carried out by the SO. The assessment takes into account the range of future energy system scenarios and their impact on constraint costs. The SO reviews the transmission reinforcement options submitted by the individual TOs, and makes a recommendation as to which reinforcements are the most economic and efficient to deliver in the next 12 months, from a system-wide perspective. This is an economic assessment, optimising the choice between constraints costs and build solutions. The process aims to ensure that future constraint costs are managed within a range dependant on the value of the TO options submitted for assessment.

4.13. There are a number of incentives on the SO to control the costs of managing constraints on the system. Our balancing services incentives scheme sets a target for these costs. National Grid shares a proportion of any under or over-spends against this target, and has the incentive to keep constraint costs as low as possible. This scheme runs from 1 April 2015 until 31 March 2017 and we are currently reviewing what changes might be needed from April 2017 onwards. National Grid's licence conditions require it to act economically and efficiently. We monitor National Grid's actions and have the powers to take action if we consider it is in breach of its licence.

4.14. The Transmission Constraint Licence Condition (TCLC) came into force in July 2012. Its purpose is to prevent generators from benefitting at consumers' expense during periods of electricity transmission constraints. This could be by making dispatch decisions that create or exacerbate constraints, or by benefitting excessively from bids they make to reduce their output. The TCLC has so far had a positive impact. For example, the average amount paid per MWh to onshore wind farms to reduce generation is now significantly lower compared to before the TCLC came into force. We continue to monitor electricity generators' compliance with the TCLC.

# Appendix 1 – SPEN criteria to evaluate strategic investment proposals

SPEN has proposed a set of criteria to evaluate strategic investment proposals that are not included within current price control plans:

| CRITERIA | | EVIDENCE |
|---|---|---|
| **Development Details** | | |
| 1 | Location and type of development | Full details of area, identifying if part of regeneration plans<br>Scale / use of development |
| 2 | Details of load required | Breakdown of load required, based on local authority planning data |
| 3 | Planning Status<br>• Local plans<br>• Planning designation | Status and priority of local plans<br>Growth opportunities<br>Any planning permissions granted |
| 4 | Contribution of development to local /regional economy | Estimated gross value added by new economic activity in the developed area or to which the area will contribute elsewhere |
| 5 | Estimate of timescales, referencing time by which completion of required connection/ reinforcement work for first connection is needed. | Evidence of likely start dates and construction periods for buildings/infrastructure (to include plans/applications to install other utilities).<br><br>Evidence of the installation period for the reinforcement and connection work required, taking the development as a whole.<br><br>Identification of works to be done/land to be acquired and their location prior to first connection being requested. |
| **Technical** | | |
| 6 | Shortfall between existing available capacity and estimated demand post-completion of development | Existing electricity distribution capacity / utilisation / bottlenecks / existing connection commitments |
| 7 | Review the area within which the required reinforcement work would take place | Capacity estimated as required by forecast development completion date |
| 8 | Development of strategic solution to meet requirements | Evaluation and comparison of incremental solution, strategic solution and alternative options. |
| 9 | Review of non-traditional reinforcement options | Consider and evaluate options such as DSM, Flexible connections etc. |
| **Financial** | | |
| 10 | Total cost of strategic solution | Estimated cost of strategic solution<br>Comparison with incremental solution |

| | | |
|---|---|---|
| 11 | Cost recovery | Evaluation of the level of cost to be recovered from developers, connection customers and/or DUoS customers |
| 12 | Developer intention/willingness to invest in new developments | Formal commitment<br>Planning applications made, land interests acquired and viability constraints / risks |
| 13 | Risk of stranded assets | Evaluation and quantification of reduced take-up of capacity and impact on DUoS customers |
| 14 | Impact of phased development | Scenarios showing different levels / timing of capacity uptake |
| **Regulatory** | | |
| 15 | Assurance and regulatory mechanism for scheme/spend | Regulatory process to recognise scheme specific strategic spend, possibly detailing any conditions required (e.g. third party funding). |
| **Stakeholder** | | |
| 16 | Stakeholder support | Consultation Responses showing support or otherwise for specific DNO investment.<br>Evidence of continuing stakeholder support. |
| **Other** | | |
| 17 | Impact of doing nothing on:<br>• Economic impact on the development<br>• Social / regeneration impact on the area | Estimated financial impact on development costs |

# Appendix 2 – Additional proposed requirements from UKPN

The following are the criteria UKPN has proposed to evaluate strategic investment proposals that are not included within current price control plans and where reinforcement is not developer-led:

- **A formal commitment from a customer or customers, preferably with a statutory development body established to support the development area affected;**

The proposed second comer Regulations still require a first comer, as without a first comer the investment would not be recoverable from subsequent connectees. This must continue to be a key requirement to protect wider customers. A specifically funded development agency gives greater comfort that there will be impetus to drive the subsequent investment that will make use of the infrastructure provided.

- **Explicit support from wider stakeholders for the investment, achieved through consultation;**

If the investment was to be funded in part by DUoS customers, gaining explicit support would be a sensible approach in demonstrating need ahead of a high value project reopener application.

- **Outline planning consent;**

Outline planning consent would be necessary to ensure that cost risk is controlled. Wayleaves, easements and planning permission can be significant project risks.

- **The project not being included in existing revenues.**

If the proposed investment is part of existing plans and revenues assessed at the price control further Ofgem approval / intervention is not required. However for new large schemes the criteria would also require that the enhanced project was scrutinised by Ofgem before being undertaken and is therefore of sufficient value to trigger the HVP reopener (as this is the only reopener process available to DNOs). This would ensure that efficiencies that would be passed back to customers are not used to fund less certain IAoN investments and ensure that Ofgem do not have to rely on ex-post assessments.

- **Recognition that project timescales are governed by third parties and are by their nature uncertain for these projects**

With large projects the criteria and assessment will be very specific to the nature of the project being considered and the timescale for decision making inherently less certain. Ensuring investments are scrutinised and approved before they are undertaken reduces the risk to the DNO of uncertainty in ex-post assessments.

- **The proposed change to the connection charge apportionment rules (second comer rules) to be implemented to allow DNOs to make charges to subsequent customers for a period of 10 years to recognise the uncertainty over development period.**

# Appendix 3 – Company names and abbreviations

| DNO group | Licensee(s) | Abbreviation |
|---|---|---|
| Electricity North West Limited (ENWL) | Electricity North West Limited | ENWL |
| Northern Powergrid (NPg) | Northern Powergrid (Northeast) Limited<br>Northern Powergrid (Yorkshire) plc | NPgN<br>NPgY |
| SP Energy Networks (SPEN) | SP Distribution Ltd<br>SP Manweb plc | SPD<br>SPMW |
| Scottish and Southern Electricity Networks (SSEN) | Scottish Hydro Electric Power Distribution plc<br>Southern Electric Power Distribution plc | SSEH<br>SSES |
| UK Power Networks (UKPN) | London Power Networks plc<br>South Eastern Power Networks<br>Eastern Power Networks plc | LPN<br>SPN<br>EPN |
| Western Power Distribution (WPD) | Western Power Distribution (East Midlands) plc<br>Western Power Distribution (West Midlands) plc<br>Western Power Distribution (South West) plc<br>Western Power Distribution (South Wales) plc | EMID<br>WMID<br>SWest<br>SWales |