Regional Development Plan

South West Peninsula Technical Report

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This technical report is to summarise the findings from the SW Peninsula Regional Development plan.

Contents

1 Introduction

1.1 What is a Regional Development Program?

The Regional Development Programs (RDPs) were set up to provide detailed analysis of areas of the network which have large amounts of Distributed Energy Resource (DER) and known transmission / distribution network issues in accommodating that DER. The idea is to use this analysis to innovate and push the boundaries of current thinking with a "design by doing" approach to resolving the issues pushing towards Distribution System Operator (DSO) type solutions and informing thinking for the DSO debate.

By solving a specific case study that has a pressing need to improve outcomes for customers in innovative ways, it is possible to make progress faster than the more conventional method of agreeing changes in approach at industry forums before making changes to the way the industry works. While there are risks that working in this way leads to a lack of standardisation across the Great Britain (GB) network, this has been successfully managed by close cooperation and using the regional development programs as case studies for the Energy Networks Association (ENA) Open Networks Project. Techniques and processes used within the RDPs will be replicated across other network areas as appropriate, resulting in innovative approaches being deployed much more rapidly.

Initially the RDPs have been set up on a project basis, but as the techniques and findings of the RDPs move into regular practice, it is envisaged that the RDP approach will continue to develop into a series of Business as Usual (BAU) developments.

1.2 Why choose the SW-Peninsula Network?

The South West (SW) Peninsula network has been chosen, because Western Power Distribution (WPD) and National Grid (NG) identified that conventional transmission and distribution capacity issues could potentially limit the perceived volume of potential DER in the SW particularly, as renewable solar and wind resources are favourable in the region and so the region is expected to play a major part in meeting the future governmental green energy targets. Analysis was required to fully understand the requirements and capability of the network in the region, to manage the future capacity requirements and meet developers' needs in the most efficient way for both developers and consumers. In doing so it is expected to push the boundaries on conventional thinking in the area of connection of generation and system operation, moving towards a network with significantly more management of DER in operational timescales. The interaction between the transmission system and the higher voltages in the distribution system have been shown to significantly increase as the volume of DER grows into the future and therefore highlights the need to manage the network more collectively into the future. Western Power Distribution (WPD) and National Grid have been and continue to be willing partners to innovate and overcome whole system challenges.

1.3 Executive Summary

The following lists summarises the achievements of the SW Peninsula RDP to date and the aims of the implementation plan in the coming months:

Findings of Study Analysis

Headline

Conducting a detailed joint transmission and distribution network analysis showed benefits in understanding network security issues under conditions not previously experienced and enabled the investigation of a range of build and operational solutions to show under what conditions "Whole System" solutions benefit the consumer and DER project developers.

In more detail:

1. Detailed Analysis of the Transmission (T) and Distribution (D) networks in a coordinated way identified the importance of the work as a number of problems were identified, where considering of each network's issues alone would give different and possibly conflicting solutions. One example: in addition to the historic issues of potential overloading, fault levels and steady state voltage control, once generation growth goes beyond 1.7GW despatch (2.6GW connected) across the WPD-SW licensed area, the SW Peninsula area becomes at increased risk to fast voltage collapse for the worst transmission circuit fault / outage combinations. The configuration of the 132kV distribution network will play a big part in defining where the fast voltage collapse limit sits.
2. Once diversity of generation is taken into account the existing network and planned measures to manage the network are largely adequate for the maximum amount of generation that would be credible to connect out to at least 2020.
3. The SW peninsula network is and will remain characterised by high demands in winter and large volumes of solar generation on sunny days in spring and summer. For winter: falling MVAr demands and increasing volumes of thermal generation mean high winter demands do not present any new transmission network challenges, however greater levels of winter demand due to electrification of heat and transport will increase the level of distribution network reinforcement required.
4. Sunny days in spring and summer do present a significant challenge to both transmission and distribution, particularly when windy and / or coincident with low consumer demand. Analysis shows that the loadings in the peak solar condition are for a relatively short time period in the year and therefore there is an economic balance to be obtained in managing the generation to the network capability rather than building new network to meet the peak requirement. In the short term investment in systems to better control generation on the distribution network, sometimes to resolve transmission issues and developing the functionality of the existing networks to actively work together will therefore be important.

Whole System Regional Network Options Assessments and Investment Recommendations

Headline

A Network Options Assessment (NOA) Cost Benefit Analysis (CBA) process has been used to demonstrate the most efficient way to manage the Whole System interactions on the network and find the correct balance between operational solutions and investment in network infrastructure on both the D and T side of the boundary.

In more detail

5. The original brief for the Whole System NOA study was to cut the geographical area down to a more manageable area, namely North Cornwall and Devon which is rich in renewable potential but is known to be near capacity by conventional means. The results of the studies showed T / D interactions which made it necessary to extend the area considered for Whole System interactions to cover South Cornwall and Devon in order to get the correct economic solution for the original area. This has been combined with the wider RDP results to obtain the optimum transmission solution for the complete SW Peninsula area. Note that the analysis of the distribution system has been more limited outside the original Whole System area.
6. The most constrained area relates to the capacity around Alverdiscott Grid Supply Point (GSP) and particularly the Supergrid Transformers (SGT's). The study shows the industry wide most economical solution based on the WPD 2015 Future Energy Scenarios (FES) is to add further SGT capacity at this site. This would be difficult to progress under the present industry funding / securities arrangement, hence a need to review incentives and charging arrangements as the industry moves into the next regulatory period.
7. Once the Alverdiscott capacity is optimised there is a wider constraining boundary which sits across 4 transmission circuits and 2 interconnecting distributions circuits in Devon (Figure 3.5 in main text). The distribution overloads seen for transmission faults in this group are beyond the standard (N-1) that the Distribution Network Operator (DNO) would normally operate the network to and so the recommended Whole System solution would be to install overload protection to trip the interconnection in the event of overload, but ensure that protection does not operate until 1 second after the fault to allow transient voltage instability to settle down on the transmission system before segregation of the distribution network. 1 second is a typical operating time for such a scheme. The scheme would not trip customer sites, and just break the parallel between GSPs. Any further or resultant overload on the remaining transmission circuit needs to be removed by N-3 intertripping.
8. For the time being on the rest of the wider SW Peninsula network the combination of facilities to enable pre-fault constraints on DER on a commercial basis and N-3 intertripping will be the most economical solution to ensure continued operability of the network.
9. Fault levels will be potentially overstressed at Indian Queens and Exeter 132kV substations from as early as 2020. An operational solution has already been adopted at Exeter, this solution together with an operational solution for Indian Queens can be enhanced by low value light current schemes Automatic Voltage Control (AVC) modifications at Exeter and installing an auto-close scheme at Indian Queens, which are adequate to cover all scenarios up to 2025 and all 2030 scenarios, except the most onerous Gone Green. To meet the 2030 Gone Green scenario potentially significant upgrades to substation infrastructure may be required.
10. The whole system study has shown that by changing the way the networks are managed, with close cooperation between the DNO's developing Distribution System Operator (DSO) function and National Grid Electricity System Operator (NGESO) it is possible to connect fairly ambitious levels of DER with significantly lower need for expensive reconductoring / uprating works on the 400kV and 132kV systems that may have been traditionally considered.

Changes to the way the SW Peninsula Network will be managed

Headline

The technical implementation of WPD's Active Network Management (ANM) system including ability to dispatch DER for transmission constraints, together with development of ways of procuring flexibility from DER participants and the harmonisation of connection agreement terms between transmission customers and distribution customers will enable a simplified connection process to be achieved with more efficient outcomes for consumers and more consistency for developers.

In more detail

11. Although the analysis indicates capacity is likely to be adequate to at least 2020 and possibly beyond, a large quality of the transmission capacity available is already allocated to contracted parties, an increase in interest could potentially lead to viable developers getting delayed connection offers as a result of the allocation process. Early adoption of revisions to the DER connection package towards a "deep Connect and Manage" approach should alleviate this issue, particularly when combined with the measures below which together enable increased operational solutions.
12. A new single stage connection offer process for applicants in this zone would remove the requirement to make offers subject to statement of works and enables generators to have all the distribution and transmission contractual terms in their initial offer. This results in quicker, more efficient connections for all customers.
13. The use of deep Connect and Manage with visibility and control of DER as Enabling Works, socialised transmission securities and the use of NOA processes to decide transmission reinforcements on a wider basis, provides more consistent outcomes to customers and a more manageable position for network companies. The DER are no longer tied into specific transmission works which means their risk profile is no longer effected by their place in the queue and will not affect their connection date. The reinforcements can be planned on a consistent industry best view thereby removing risks around speculative applications.
14. Commercial arrangements for DER flexibility will be developed to allow the appropriate level of participation, through multiple routes, without undue burden on infrequent participants.
15. The RDP has recommended the development of a Control System and processes for Transmission/Distribution operational interactions that will allow more efficient outcomes for customers and consumers.
16. A very low volume of DER means that service conflicts between transmission and distribution network needs are not currently a problem, but analysis shows that an increased number of actively managed distribution networks will mean it will be in the future. A process for assessing and managing service conflicts is to be trialled in the implementation phase of the RDP. At the procurement stage there may be a need for coordination of services required to secure the network against peak demands, but less so for services required to secure the network around generation export where distribution services are uncompensated connection conditions. In the dispatch phase the DSO will provide system limits and the transmission services will be dispatched by the TSO within those limits. It will also potentially provide compliance for the input of distribution constraints into Project TERRE (Trans-European Replacement Reserves Exchanges). Project TERRE is a cross-border balancing project which is designed to fulfil one of the requirements of the European Union Electricity Balancing Guidelines.

Further Development

17. The region would benefit from significant further work that has not been possible in this RDP particularly: to develop better use of DER MVAr capability in managing limiting voltage conditions and in how the industry can incentivise the use of commercial energy storage devices to economically assist the management of the network, particularly the solar lead peak network flows in the South West.

1.4 Key Recommendations for Industry Follow Up

The following list summarises where learning from the RDP needs further industry consideration and / or should be considered for adoption more widely and therefore requires action by the relevant industry body to do so:

1. The RDP has demonstrated the value in NGESO modelling the effect of the distribution system on the transmission system and how well managed interaction also adds value. To enable this consistent modelling of the combined transmission system and distribution system is essential, as is the ability to model this interaction under changing conditions, E.g. changing solar output. Therefore the Week 24 data should be reviewed to align with RDP modelling techniques, which will also align with the data for the trial reassessment process under RDP Appendix G. **Action for Open Networks, Work Stream 1, Product 12 to consider**.
2. The RDP demonstrates the benefits of a deep application of connect and manage to avoid tying the connection of small DER to significant transmission reinforcement works. Where volumes of DER are involved the consistent application of the Wider System Cancellation Fee across DER and transmission connections is required. The rules for the inclusion of DER in the wider application fee calculation and for application of that fee to DER should be reviewed to obtain a more consistent approach. **Action for NGESO Market Change Electricity**.
3. Incentive setting for RIIO T2 and ED2 should take note of whole system findings to ensure future incentives encourage the most efficient “Whole System” investments to be built. In this example the study demonstrates that further SGT capacity at Alverdiscott is the most efficient solution, but to build that capacity under current regulation the costs would be split between all the new users involved with each user having to take the risk of increased costs if their competitors pull out, which they are generally not able to take; it is therefore unlikely that the SGT capacity would be built. **Action for Charges Futures Forum - Network Access Taskforce**
4. Consistency of demand and generation data has caused rework, delays and uncertainty throughout the RDP process. Adjustments were required to the 2015 WPD Future Energy Scenarios (FES) scenarios to account for shortfalls in the original data and there was significant misalignment between the 2015 WPD FES and the 2017 NG FES in the area. Further work is required to better align the DNO FES, regional FES and NG national FES which will ensure improved outcomes for both distribution and transmission systems and particularly for “Whole System” interactions. **Action for Open Networks, Work Stream 1, Product 5 to consider.**
5. The whole system analysis in this RDP has been a learning activity and taken much time and resources. A process is now required to be able to update the recommendations of the whole system study as backgrounds change. This will need to be faster and less resource intensive and will need a suitable trigger to indicate the need to re-start the analysis. **Action for Open Networks, Work Stream 1, Product 1 to consider.**

2 Assumptions on the evolution of the network

2.1 The chosen region

The RDP studies concentrate on the WPD-South West Licenced area. The transmission system has differing limitations in differing regions. The WPD South West licensed area sits inside 2 different transmission system constraints, the majority of the substations sit on the part of the network known as the SW Peninsula, this part of the transmission network historically has been limited by a peak winter demand, but as DER has connected in this area, the winter demand has reduced and now is generally limited in the spring and summer seasons with large volumes of solar generation exporting from the distribution system onto the transmission system. With the distribution network having seen a greater variability in seasonal loadings due to intermittent generation, Low Carbon Technology (LCT) demand and storage, both peak winter demand and peak spring/summer export conditions are causing capacity limits to be reached. On a short term basis, capacity issues here have the potential to be eased by better operational management of the network. The length of time this would remain the most economical decision would vary depending upon the trajectory and mix of LCT and DER uptake and the counterfactual conventional reinforcement costs. The CBA for using operational management solutions will persist longer for transmission issues than distribution issues, due to the larger individual scheme costs and greater amount of diversity.

2 GSP substations; Iron Acton and Seabank, sit in a different limiting area of the network. This part of the network is characterised by large volumes of controllable generation exporting from a mixture of transmission and distribution connected power stations in South Wales. The limitation here known as SWALEX, is at winter peak and is concerned with days where prevailing weather conditions cause only very low volumes of less controllable renewable generation to run and so there is a reliance on thermal generation or storage. The transmission capacity on the circuits through Seabank and Iron Acton are at thermal limits for credible faults in this area. Any generation constraints under these conditions undermines the ability to meet the total system demand and therefore system security. It is not appropriate to operationally constrain off generation at the very time it is relied on and so a different solution to the transmission capacity issues in these 2 GSPs is required to that of the rest of the WPD-SW licenced area. (Note – this does not affect renewable generation at the GSPs, because the criteria to connect renewable generation is based on economics rather than the need to ensure security of supply at time of limited renewable resources.)

Bath is WPD's only Bulk Supply Point (BSP) off Melksham GSP, with little to no DER activity and therefore does not have a need to progress any more advanced solutions for the connection of DER in this location in the foreseeable future.

The solutions in this RDP therefore apply to the substations in the SW Peninsula group, namely Abham, Alverdiscott, Axminster, Bridgwater, Exeter, Indian Queens, Landulph and Taunton GSP's and not Iron Acton and Seabank. It should be noted that for convenience, the total WPD connected DER figures in this document are quoted for the complete licensed area.

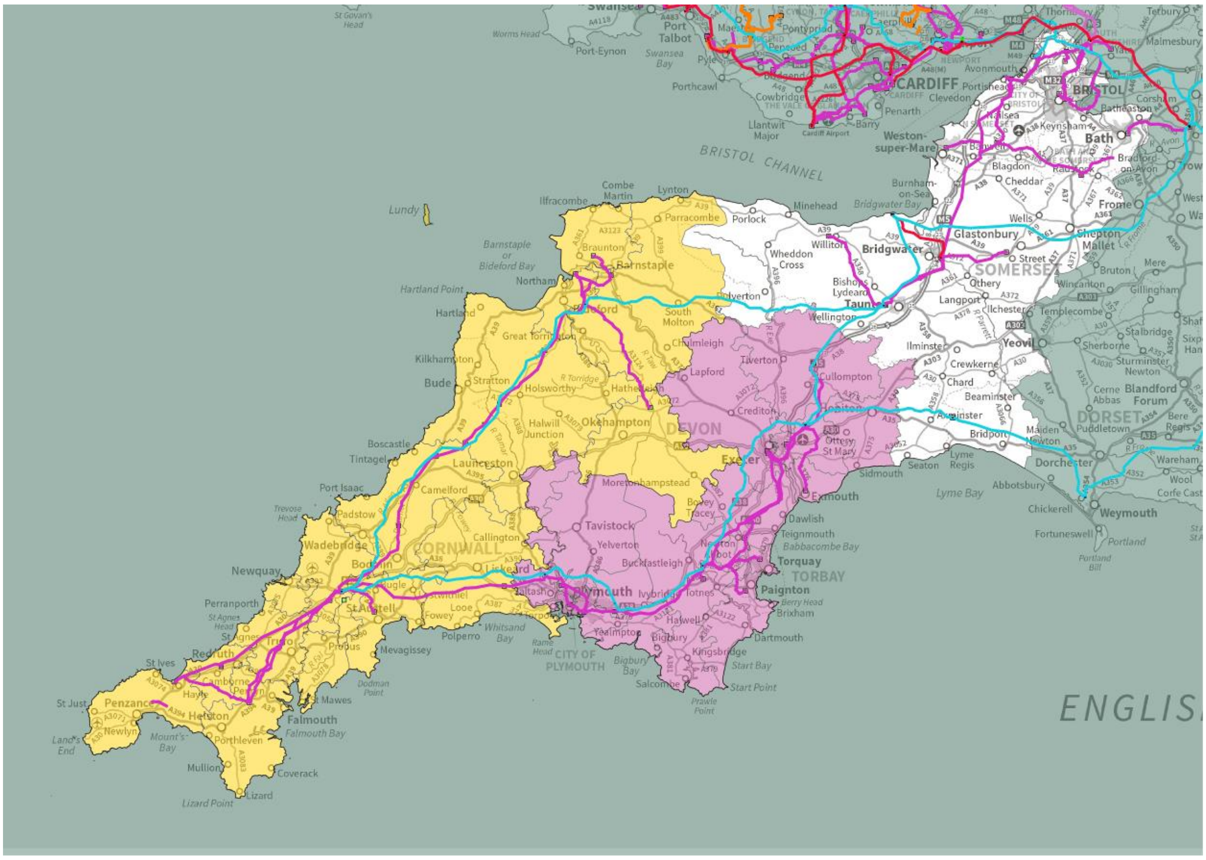


Figure 2.1 showing 400/275kV transmission system, 132kV distribution system and the WPD-SW Licensed area.

Key: 400kV lines blue, 275kV lines red, 132kV lines pink, Indian Queens / Alverdiscott GSP's yellow, Exeter, Abham Landuplh GSP's pink and the rest of the WPD-SW licensed area white.

2.2 History of DER connections on the South West Peninsula network to date

Traditionally requests for additional DER would be assessed on the distribution network by two "edge case studies": one considers the maximum demand with minimum credible generation and the other the minimum demand at the point of maximum generation. This ensures the network remains compliant at all times between, but the second criteria will often limit the capacity available for generation unless network reinforcements are delivered. Note at distribution level there is not a standard to detail what the network requirements for generation connections are. At transmission level Security and Quality of Supply Standard (SQSS) does both generation and demand, at distribution level Engineering Recommendation P2 just covers demand.

For transmission network capacity, the DNO would make an application on behalf of the DER via the Statement of Works process usually once a DER has signed the DNO connection offer. For convenience in data handling these were often bulked together in batches. These would be assessed against the criteria in the SQSS, which allowed some flexibility with transmission generation to be set to that which might reasonably be expected to operate at the period of the study, but with no visibility and control of DER available to the NGESO, the DER would be set as per the distribution study in the worst case scenario. If the DER connection did not cause the transmission system to go outside limits, a response in 28-days would allow the generation to connect. Where the transmission network does go outside limits a response in 90-days would indicate the reinforcements required and a formal offer made to the DNO, who in turn pass it onto the developer including their contribution to the costs. DER developers were rarely able to secure these costs causing difficultly for the progression of the project.

In this region, DNO restrictions on the F-route (132kV route paralleling Bridgwater to Seabank) and the K route (132kV route paralleling Indian Queens and Alverdiscott) and transmission restrictions on the Alverdiscott SGTs are of particular concern, with the potential to effect DER connections to the network.

Pre RDP developments have improved this situation with WPD reconfiguration of the F-route, increasing the operating temperature of the K-route and the introduction of intertripping for outages on the Alverdiscott SGTs.

A bulk statement of works assessment over winter 2015/16 using the above approach indicated a number of 400kV transmission circuit overloads and steady state voltage issues across the SW Peninsula region. To address these issues and provide an improvement in customer outcomes for the connection of DER a number of new initiatives were considered and this region was the first to trial them in spring 2016. This involved a number of improvements:

- Requirements for emergency operation of the network have been clarified and improved upon. This allowed a move away from considering all DER operating at full load at once. Instead an estimate was made of the maximum output at which each technology will operate under the worst case planned transmission system condition. The difference between 100% dispatch and maximum planned condition dispatch freed up capacity for use by future users. In the very unlikely event that system conditions and / or generation levels went beyond those the industry reasonably required to plan against, a process to emergency disconnect DER could be enacted to take care of this scenario.
- Where the GSP assets are connection assets, for all except Axminster on the SW Peninsula group (+ Iron Acton and Melksham in the licensed area), the DNO has been provided with details on the technical capabilities of the assets. Where the distribution connected customers decide not to invest in additional connection assets and prefer to curtail their generation instead, the DNO can manage the generation against the demand and capacity from planning of capacity through to real time operation without further need to consult the NGESO (Transmission infrastructure assets and the risks, management of power flows and investment decisions for these assets remain a transmission responsibility). This is an extension of the DNO’s traditional role and is part of the transition towards becoming a DSO.
- There is an ongoing requirement that DER must have a 0.95 lead / lag MVAr capability, dispatched by fixed Power Factor(PF) control, to compensate for the steady state voltage issues they cause. This part, as have most parts, of the network now have steady state voltage issues and this measure allows for early connection against those issues on an uncompensated basis.
- The Appendix G process was introduced allowing the DNO to add limited volume of new connections without going through the formal statement of works process, as well as the ability to swap new technically equivalent projects for cancelled projects, even between GSPs.
- DER N-3 intertripping via distribution visibility and control platforms for transmission outage / fault combinations to be added, as soon as possible at a later date to ensure economic operation under outage conditions. In effect this is a partial move towards the

implementation of connect and manage without the need for commercial control of the generation.

The above measures allowed the majority of connection requests in the area to go ahead and these improvements have managed the connection of new generation in the SW Peninsula area since April 2015. RDP analysis shows these measures will be adequate in the near future up to the maximum expected volumes of generation expected to connect by 2020* and possibly beyond. It is recognised there will be a need to go further for higher levels of DER beyond this and hence the need for this RDP.

*As identified in the WPD 2015 FES document (See below).

2.3 Defining Future Network Needs

Each year National Grid produces Future Energy Scenarios (FES) documents which detail 4 different projections of the UK energy requirements and how these are to be met well into the future. While these include national estimates on volumes of future DER, the allocation to different nodes on the network is approximate. In 2015, WPD employed Regen to add local intelligence to the national position and produce a regional FES for the SW licenced area, with generation allocated at BSP level. This follows the format of the national FES and indicates the generation and demand requirements on a local level for 4 different scenarios. This data has been used to analyse the potential future network needs of the area.

The WPD-South West FES provided detailed figures for 4 scenarios in 2015, 2020, 2025 and 2030 i.e. 16 sets of data. This volume of detailed network studies was not practical so it was decided to study the worst case of 2020, 2025 and 2030. In each case the Gone Green scenarios are the worst case. The increase in generation is approximately 1GW in each case, giving a fairly even range for detailed study. The transmission generation in the area does not significantly change between now and the 2025 study, but for 2030 the potential commissioning of Hinkley C (replacing Hinkley B) and the FAB interconnector to France via Alderney requires some sensitivity work as the potential change in transmission generation and network configuration will have a significant effect.

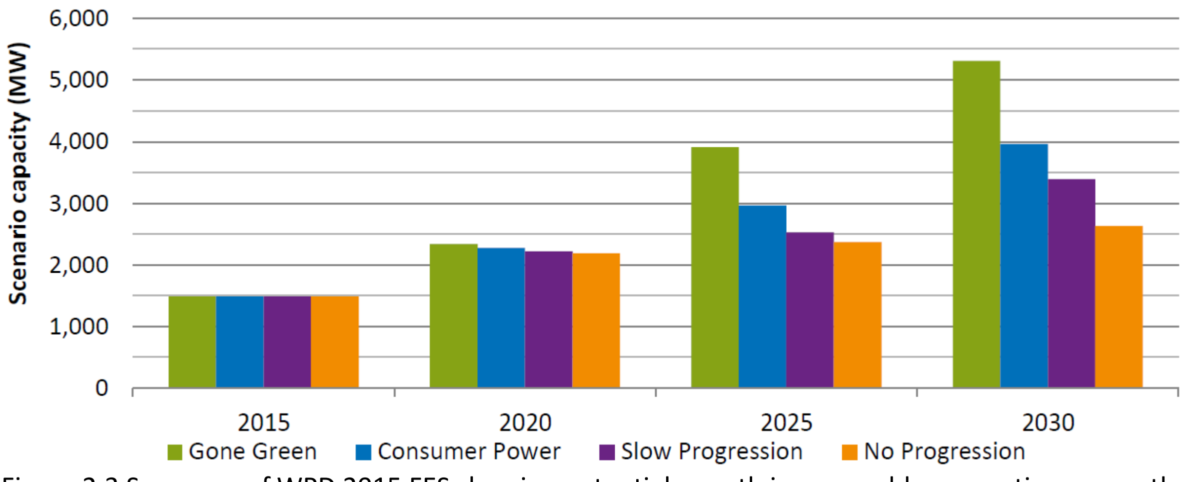


Figure 2.3 Summary of WPD 2015 FES showing potential growth in renewable generation across the south west area.

It should be noted where as these are often referred to as the 2020, 2025 and 2030 studies, these represent the worst credible case for those years and there is every possibility that a less onerous scenario will occur in reality and so these studies alone do not represent what the industry should plan for. Economic analysis has been added to the transmission system study results on the basis of “least worst regrets” to determine the most appropriate way forward with the network and insure connections can go ahead but the risk of stranded investment is managed.

WPD have recently asked Regen to review and update their FES analysis and extend further into the future, first indications from this process are of a slower take up in the early years with the peak take up on the worse scenarios in 2025 and 2030 having increased in this area. On this basis the results of the system studies remain broadly valid, but will require a regular review over time.

2.4 Overview of the Principle Transmission Issues

Technical:

- N-1 pre-fault thermal capacity i.e. potential circuit overloads caused by the switch out of Hinkley - Melksham circuits and possibly Hinkley – Taunton circuits for maintenance / repair in the higher generation scenarios.
- N-3 thermal capacities, i.e. circuit overloads during the planned maintenance activity of one circuit and the unplanned failure of 2 circuits on a common transmission tower. The GBESO is required to ensure power supplies to customers across the wider region are maintained in that situation although it is not a requirement to ensure all generation stays connected or that supplies are maintained in a particular locality under this very onerous condition.
- The use of generation inter-trips as a solution for N-3 capacity issues and the potential restriction on that inter-trip use owing to known performance issues of Loss of Mains (LoM) protection being incompatible with frequency containment policy.
- Interactions with wider south coast boundary capacity issues (SC1), including SEPD and UKPN DER DG for loadings on Bramley – Fleet – Lovedean route. See Figure 2.4.
- Pre-fault High voltages
- Fast voltage collapse particularly under N-3 conditions where the I^2 X losses from the long heavily loaded remaining transmission circuit cause a drop in voltage. This leads to either or both of total voltage collapse in a few 100mS or G59 under voltage tripping of DER, because of the slow recovery time on the voltage. The G59 under voltage tripping can also effect generation slightly outside the boundary of the group.

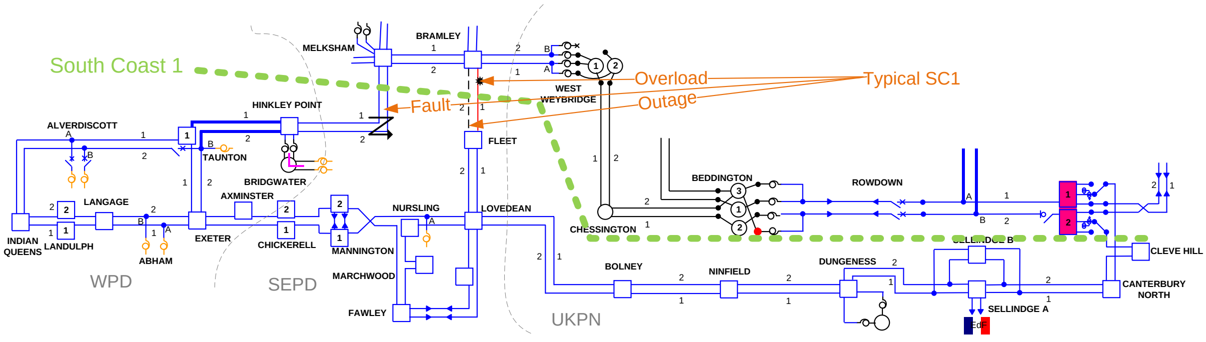


Figure 2.4 Diagram to show typical wider South Coast (SC1) Constraint.

Commercial:

- Resolve T/D connection process issues – ensure capacity allocated on same basis on both networks in a timely manner.
- Resolve capacity blocking issues, ensuring capacity is effectively used and new generators are not unnecessarily held in queues. Ensure T / D generation secure capacity on an equal basis.
- Ensure the market opportunity for both T+D generation.

System Operability Issues:

Not directly connected to SW Peninsula and a blocker of connections, but RDP solutions potentially help to resolve by introducing the ability to pay DER to change their output at times of system stress.

- Insufficient controllable generation to balance and regulate the wider network.
- Inadequate generation with inertia (rotating generation) to manage system frequency.

2.5 Overview of the Distribution System Issues

Technical:

- SGT and some 132kV circuit overloads at Alverdiscott due to generation, following credible distribution and or transmission Summer outages in the 2020 Gone Green scenario
- Alverdiscott SGT, 5 x 132kV circuits and 3 GT overloads due to generation, following credible Summer outages in the 2025 Gone Green scenario
- 132kV circuits between Hayle-Rame and Indian Queens-Cambourne due to peak demand, following credible Winter outages in the 2025 Gone Green scenario
- Multiple Winter demand and Summer generation circuit capacity exceedances in the 2030 Gone Green scenario
- Significant multiple 132kV circuit overloads upon N-3 transmission outages

Commercial (similar to transmission issues):

- Resolve T/D queuing issues – ensure capacity allocated on same basis on both networks.
- Resolve capacity blocking / ensure T / D generation secure on an equal basis.
- Ensure the market opportunity for both T+D generation.

Operability:

- Limitations on the ability for distribution assets to provide sufficiently increased post fault short term ratings, which would reduce the volume of required pre-fault curtailment.
- Limitations on the balance of actions carried out pre-fault as opposed to post-fault due to the speed of actions carried out by ANM systems.
- An increased volume of distribution connection generation being permitted to access the network through ANM systems increases the reliance on ANM systems and their operational availability.

2.6 Key areas of RDP Focus

The table below indicates the RDP goals and the current status of the work.

Initiative	Main Objective	Status
1. Network Modelling	To review, enhance and jointly agree the assumptions on generation and load in both the distribution and transmission and identification of the key limiting factors including the voltage stability limits and particularly the interaction across the T+D boundary.	Revised modelling at transmission level to model complete 132kV network to first busbar below 132kV, with 1MW and above generation connected below 132 being represented by equivalent PV, Wind, thermal and battery generators at that bar. Fault levels modelled by equivalent in feeds at the first bar below 132 (with sync gen equivalent at that bar removed). Key limiting factors identified, which required some dynamic voltage modelling for worst conditions to understand the post fault voltage instability risks. Key interactions across the T / D boundary identified, which if correctly managed can improve the outcome for customers and consumers.
2. Move towards DSO	To look at the provision of visibility and control of DER to manage the distribution network and in particular its ability as an economic alternative to asset investment on the transmission network. This will include a further review of the T/D connections process and the purchase of flexibility from DER to manage the network.	The low frequency of high solar output events at the same time as the limiting system outages, means the ability to control DER output at these times is an economic solution to manage the transmission network. A process is in train to modify the connections process in this area to make the provision of visibility and control of output a key requirement of connection and to facilitate the required backstop pricing and flexibility markets to ensure operability and cost effective outcome.
3. T/D Services Coordination and DER dispatch.	To inform the procurement process for future ANM equipment and operational control protocols such that there is a system in place to control the dispatch of DER resources and subsequently manage transmission issues and potential conflicting actions between the transmission and the distribution networks.	Principles for assessing service conflict in planning timescales are available, as are the signal requirements to manage service conflict in real time. A program to determine how those signals feed into NGESO IT systems have been devised and an implementation program for trialling signals agreed.
4. Whole system network planning	Seeks to prove the principles of whole system network planning by performing a cost-benefit analysis to determine the most cost effective measures including transmission build, distribution build and operational measures to achieve the minimum cost and risk to the consumer in enabling the volume of renewable connections in the North Cornwall / Devon areas required by developers in response to the Government's green energy	T and D options identified and power system studies performed to identify limits. After some teething problems aligning boundary limits describing different T and D network capabilities and also generation data compatibility issues resolved a CBA using "Least Worst Regrets" has identified the optimum solution for the transmission system using whole system operational and build options. Two reports have been

	policy. To form recommendations regarding processes to enable whole system network planning to be used going forward.	produced, one detailing the options and solutions for the SW Peninsula group and the other the processes used in the work.
5. Protection system stability	To determine the impact of current loss of mains (LoM) protection settings on system stability after a fault. Determine how these undermine capacity and seek to address capacity restrictions.	Interim ban on new vector shift across SW Peninsula in place. Final solution relies on DC0079 retrospectively removing Vector Shift and adjusting all rate of change of frequency (RoCoF) setting to new policy. Analyses of VS incidents ongoing to inform priorities for DC0079 roll out. Interim risk reduction devised to target immediate settings changes on 700MW of vector shift protected DER across southern England to RoCoF. G59 under voltage protection identified as an additional limiting factor under onerous circumstances.

3 Regional Planning

3.1 Our approach to joint T/D modelling & planning

There are a number of modelling, operational and planning initiatives which have been considered to improve outcomes in this zone. Many of these are consistent with other industry initiatives under consideration outside of the RDP zone. The RDP explores how the consistent application of these initiatives can be used to improve the ability to connect the required volume of renewables within the zone in an economic way:

1. Improvements in the offline transmission system load flow and stability model:
    a. DER above 1MW to be modelled separately from demand at first 33kV busbar. Generation split into type / fuel, e.g. solar, wind, storage etc. and further split into generation actually at the 33kV and generation below 33kV. The type / fuel allows for easy scaling of the model to look at different scenarios. The generation at 33kV can be accurately modeled to give the correct voltage performance, and that below will always be an approximation on voltage performance.
    b. Operability review to ensure the options on the WPD 132kV network and the transmission network are properly coordinated to achieve the best benefits.
2. Improvements in the distribution planning load flow model:
    a. Moving from a two edge-case based analysis to a time series based analysis using representative days covering the range of operation credible for the worst-case conditions on the network
    b. Significant uplift in the level of automated analysis for confirming security of supply compliance
    c. Improved accuracy of the transmission equivalent model used during distribution system analysis
    d. Automated analysis techniques developed for optimising the actions to be taken when operating ANM systems using technical best principles of access.
    e. Methodology developed to estimate the energy curtailment required to abate network exceedances under ANM

3. Studies undertaken to identify the network limitations against the most onerous DER connection scenarios considered credible for 2020, 2025 and 2030.
4. A Whole System study to look at the most efficient across industry solution to connect the required level of DER in the North Cornwall / Devon area (Indian Queens and Alverdiscott GSPs), where the potential for renewables is greatest, but the network is most limited. Note: the nature of the technical problems on the network necessitated spreading the area to include south Cornwall / Devon (Landulph, Abham and Exeter GSPs). The whole system study looked at a mix of operational (control and curtailment), conventional build, transmission and distribution solutions to find the most economical solution for the end consumer of connecting generation as per the FES scenarios on a least regret basis.
5. Expansion of the CBA techniques being used by the Whole system study to cover the complete region to determine the correct balance between operational and asset build solutions at transmission level.
6. Developing the control systems and commercial terms and conditions required to implement new connections based on managing DER output rather than building a network to accommodate the worst case condition.
7. Adopting a "Deep Connect and Manage" approach to new connections, with the aim of providing similar conditions for transmission and distribution customers, ensuring all network capacity can be used and is not tied up in the connection queue process and that the most economic connection arrangements from the whole system study and economic analysis can be implemented.

3.2 Outputs of Study Process – Identification of Capacity Limitations

Based on the above approach a detailed power system analysis was carried out as part of this RDP. Initial steady state load flow studies indicated the following Transmission and Distribution network issues:

- There are significant interaction between transmission fault /outage combinations and the configuration of 132kV network, particularly in the Alverdiscott area with overloads on the Alverdiscott SGTs and the 132kV K-route between Alverdiscott and Indian Queens GSP. Furthermore the 132kV circuits that parallel the Landulph – Abham – Exeter GSPs tend to overload for faults that trip the parallel 400kV route. The load flow studies demonstrated that the voltage and thermal limitations on this part of the network is significantly dependent on 132kV network configuration.
- On a wider system boundary known as B13[1], the main 2 issues were numerous overloads in the N-3 condition and pre-fault overloads in during planned outages on Hinkley Point – Melksham and Hinkley Point – Taunton 400kV circuits.
- The worst fault / outage combination is Indian Queens – Alverdiscott – Taunton 400kV planned outage and Exeter – Abham – Langage 400kV double circuit fault outage. For this combination, once the DER output level reaches 1.7GW (as measured across the WPD-SW licensed area), there is a risk of fast voltage collapse and uncontrolled generation trip triggered by G59 protection setting on small embedded generators. This issue is more probable to persist under a credible but less likely scenario of Langage machine running when DER output is high.
- Fault level studies identified potential switchgear overstress at Indian Queens and Exeter 132kV substations as the DER level increases. Studies indicate that changes to the running arrangement of these substations and DNO network configuration can help to manage fault level.

[1] B13 Boundary is defined by 400kV circuits between Hinkley point –Melksham and Chickerell – Mannington substations. Depending on the level of generation within the boundary there is thermal limitation of export or import of power on this boundary

3.3 Identification of transmission connections capacity and agreed approach to capacity allocation to distribution customers.

3.3.1 Compatibility with SQSS and Connect and Manage (C+M)

The SQSS security standard should be applied to the network ahead of the SQSS economic standard. The purpose of the security standard is to ensure that under peak demand conditions if the availability of "uncontrollable" renewables is limited, there is sufficient network capacity to meet the demand from controllable generation sources. The SQSS could be considered slightly out of date in this area; because it specifies which generation sources can be used. The Capacity Mechanism, which is the means by which the industry now procures generation to secure the winter peak demand under these conditions, takes a broader approach to generation type. In practice with a high demand in the SW Peninsula group and zero contribution from the large quantity of wind and solar in the group, the security standard does not restrict the next tranche of generation and so the security standard does not currently limit this part of the network. This is not the case for Seabank and Iron Acton GSP's which sit in the SWALEX group as this group has a large account of low merit thermal generation and the security standard is likely to be an issue.

Having satisfied the SQSS security standard, the SQSS economic standard would be applied to generation connections and generation connections allowed under the rules of Connect and Manage (C+M). C+M requires 7- deterministic rules as detailed in CUSC to be applied. Any SQSS works beyond those rules would then be considered wider works, which are not required to be completed before connection provided the network also passes an economic test. The economic test will be in the form of a local NOA CBA – see section 3.6.

Detailed analyses for the application of connect and manage and assessment of compliance with the 7 deterministic C+M rules can be found in appendix A. The key requirement from this analysis is that the ability to operate the network under all conditions is achieved by having visibility and a means of operational control on the new connecting DER.

C+M also requires actions to make the network compliant with SQSS as soon as possible. Generally if there are any such actions they are managed by the transmission companies and do not affect the generators terms and conditions. In this case there is one action that requires action from the developer and DNO and that is the provision of N-3 intertripping to manage post fault overloads in the industry most economical way.

It is necessary to include the terms and conditions for the N-3 intertrip in the NGESO-DNO Bilateral Connection Agreement (BCA) and the DNO – DER connection agreement. Also a suitable operability scheme is required to trip the generation. It is proposed to interface the South West Operational Tripping Scheme (SWOTS) to the ANM scheme controlling the DER to provide this functionality.

3.3.2 Capacity Available

Each application would be considered under the principles of Connect and Manage, which requires the generation background to be set to that which ought reasonably to be foreseen to arise in the course of a year of operation. A summary of the application of FES scenarios to this zone is shown in appendix A and indicates the range of outcomes in this area. Lead times on the build options recommended via economic analysis are relatively low as is the volume of constraints in the chosen options. On that basis there is no reason to put an immediate cap on the volume of DER that can be offered a connection under this regime, although good management of new connections to the network is required to ensure accurate knowledge and provision of the data to allow effective management of the network under the connect and manage principles and a regular review of the Whole System CBA to allow the correct build solutions to trigger at the optimum time.

3.3.3 Fair Capacity Allocation / Securities

To ensure the allocation of capacity can be consistently and fairly handled between T and D on an equal basis and that there is due process in place to apply connect and manage principles fully, the transmission wider network cancellation fee will be consistently applied to all applicants. Under the connect and manage regime the trigger is each DER providing visibility and control and therefore is the individual DER applicants connection date. The wider cancellation fee is a socialised cost per MW that represents the cost of cancelling wider transmission (which are themselves socialised in the connect and manage model) in the event that applicants reserve capacity and do not proceed. Note: If there were no reinforcement to connect generation in the area there would be no works and wider cancellation fees would be zero. The wider cancellation fee ensures there is cost recovery for potential abortive works and an incentive on developers to ensure their connection applications are realistic and up to date.

To apply the C+M principles a process is required to decide, if generators are meeting their original intended contractual obligations or not. This is because a principle of C+M is that once a connection offer under the regime is given it cannot be withdrawn even if system conditions adversely change. However conversely, if the generators intent changes it is fair that the new intent is assessed on the latest background and any terms and conditions amended accordingly. In its simplest form this could be building a power station to the specification and time in the connection contract. However, even the best planned projects get delayed often for reasons outside the developers reasonable control, under these circumstances it is not reasonable to change the C+M terms in the contract (if they have changed) or apply a cancellation fee. Neither is it fair that a project that has no intention of proceeding to plan should hold capacity and not be responsible for the costs of proving capacity at their requested date. This is resolved by the application of QMEC,[2] which is the new agreed industry standard on fairly administering queuing processes for DER.

3.3.4 Revised T /D Appendix G process – Meeting Connections Goal

The way that transmission capacity allocation works with DER has been an area of industry debate and concern for some time. The introduction of the trial Appendix G process improved this area.

[2] For more information on the Fair and Effective Management of DNO Connection Queus please go to: http://www.energynetworks.org/assets/files/news/publications/Reports/ENA%20Milestones%20best%20Practice%20Guide.pdf

Further work was required, to achieve the ultimate goal, i.e. that a DER customer could always get an offer in 90-days inclusive of all the transmission and distribution contractual requirements and not be subjected to any statement of works clauses for further assessment. Furthermore, uncertainties on how to apply Appendix G to individual applications could result in DER capacity often considered to be interactive between applicants when that was not necessarily the case. The very deep application of Connect and Manage adopted in this RDP together with learning from the earlier Appendix G trial allowed further development of the Appendix G concepts and processes, such that it is now possible under this RDP for WPD-South West to make clear offers in 90-days including all T +D conditions, to whoever applies. Interactivity will be very rare under the very deep application of Connect and Manage. If it did occur it would be on the basis of a single transmission / distribution queue and would be around real capacity issues rather than a need to go through a project progression assessment process. To achieve this, a revised assessment process between transmission and distribution has been derived - the new process is detailed in appendix A and illustrated in the diagram below.

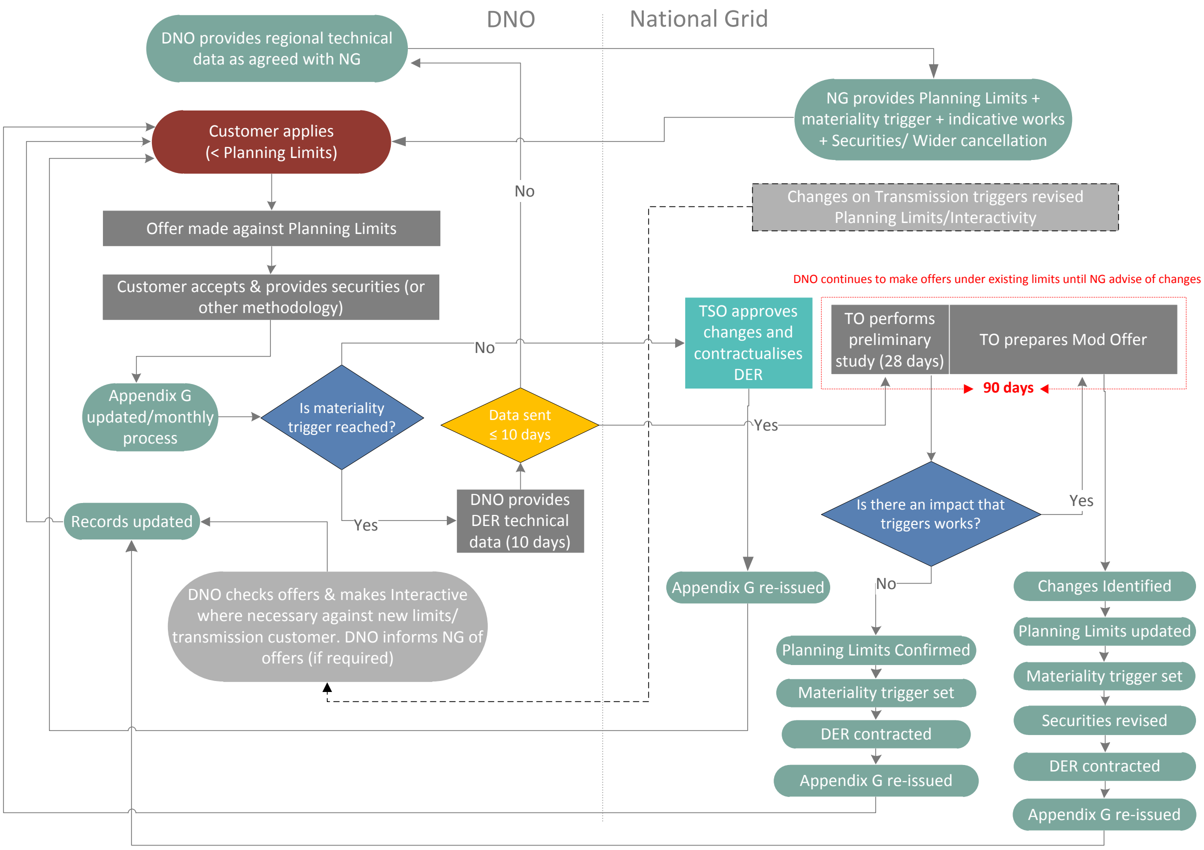


Figure 3.3.4 Revised appendix G process.

3.3.5 Changes to DER / DNO Connections Process and Contracts

Prior to these changes customers were required to go through what could potentially have been a 6-12-month period of uncertainty around whether to invest in their development (this is illustrated on the left of figure 3.3.5 below). The process developed through the RDP allows for the customer to take a decision on whether to progress, as soon as they receive their WPD connection offer (right hand side of diagram below). This offer is with the customer within 90 days from application.

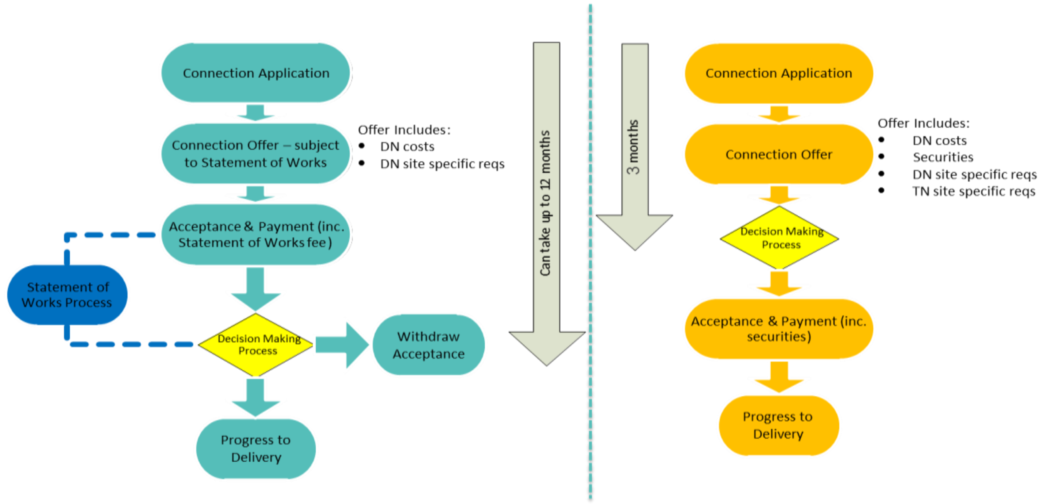


Figure 3.3.5 DER connection offer process

Customers in this area will now receive a WPD connection offer which advises them of both the distribution and transmission requirements for connection. This includes but is not limited to:

- Control & Visibility (subject to commercial agreement between parties);
- requirements for disconnection under abnormal conditions
- the need for LoM protection to be provided in the form of RoCoF (for small generators);
- their security and liabilities in relation to the wider transmission works associated with this area.

3.4 LoM Protection

3.4.1 Summary of Loss of Mains issue

Historical settings on DER Loss of Mains (LoM) protection are a potential risk to security of supply. Vector Shift relays have proven to be inherently unstable and can detect out of zone transmission fault current as a loss of mains event sending a trip signal to the associated DER before the transmission fault has even cleared. The nature of this issue is such it cannot be relied on to occur every time nor guaranteed that it will not occur. RoCof relays set at 0.125Hz/sec (as current policy for DER under 5MW) are unstable at periods of low system inertia. Such periods are now a regular occurrence, because of the large proportion of the total system demand being met by non-synchronous generation. The relay settings are too sensitive and below the rate of acceleration the system will typically see for a large generation loss when levels of synchronous generation, which provide Inertia to slow the acceleration of the system down, are reduced by large amounts of DER such as solar or wind meeting national demand instead. If RoCof protection operates under these circumstances it will further cause the system to decelerate.

The Vector shift and RoCof issues can combine such that a transmission fault combined with a Vector shift loss disconnects enough generation such that RoCoF is above 0.125Hz/sec, causing an increased loss of generation and further deceleration, this is only likely to be arrested by LFDD (Low Frequency Demand Disconnection). LFDD relays tend to be fitted upstream of much of the DER and so in many cases further generation will be disconnected until eventually an equilibrium is reached with a large proportion of the national demand being disconnected.

Under normal operation transmission circuit faults just outside the SW Peninsula can already cause enough Vector Shift relays to trip to cause a loss larger than it is possible to secure RoCoF to. The only way to reduce the embedded non synchronous generation currently available, is to use of emergency instructions to lower the volume of embedded non-sync gen on the system, as there are no commercial control actions currently available. An electrical fault that trips Hinkley B generation combined with Vector shift operation will cause a potential loss above the RoCoF level.

These problems associated with LoM protections currently limit the use of intertrip. As generation increases Intertrip will be required on the SW Peninsula network to trip generation in the event of an N-3 condition. Alternate reinforcements are not economic or practical and so resolution of the LoM protection issues is required before a significant expansion of generation in the area.

In summary careful management of LoM protection and volumes of generation on intertrip / at risk to a transmission fault, is required to avoid the risk of a significant and national loss of supply event.

Grid Code / Distribution Code working group GC/DC0079 have recommended a new LoM policy of RoCoF set at 1Hz/s with a 0.5s time delay and a ban on Vector Shift. This is approved for new connections after Feb 2018 but retrospective relay changes are yet to be approved and implemented.

3.4.2 Action Taken

WPD South West banned the use of Vector shift ahead of DC0079 for all new connections in this zone. DC0079 came into effect for all new connections from Feb 2018 and enforces new RoCoF settings nationwide. There is ongoing work to accelerate the retrospective change of 700MW of existing Vector Shift fitted DER to RoCoF on the new settings. These will be targeted across the south coast, in the SEPD and UKPN areas as well as WPD, and will reduce the immediate risk of an incident leading to demand disconnection. Note this is a risk reduction exercise; the risk will not be eliminated completely until all retrospective relay changes are complete.

3.4.3 Control of Residual Risk

In the short term NGESO will continue to reduce large transmission generation losses to below the 0.125Hz/sec trigger level. This is only just credible with the worse trigger level being near the capacity of many nuclear generating units.

GBSO is looking to manage the worse cases of Vector shift risk, recent analysis shows the most effective and economic way of doing so is an accelerated relay change program. National Grid – Commercial Operations is developing a program to do this separately to the RDP.

3.4.4 Further Work

Joint work between the SO and WPD continues, to further investigate incidents that have had volumes of DER tripping to increase understanding and develop interim risk management in the area. This work will also identify frequent tripping DER and help target the biggest risks during implementation of Distribution Code change DC0079 retrospective measures.

3.5 Whole System Study

Key to the future success of a more active distribution system and its interaction with the transmission system is a better understanding of how the systems can be made to work together in the best interests of customers and consumers. Furthermore this requires an improved understanding of when it is appropriate to invest in new transmission or distribution equipment to get the best overall benefit on a “Whole System Basis” and when it may be more appropriate to curtail generation instead. A process is also required to make these decisions on a routine basis in the future. A main deliverable of this RDP was to trial and develop such a process. It was initially thought it would be more straightforward to trial and develop on a smaller geographic area and so the North Cornwall / North Devon area was chosen, this area is known to have significant renewable potential and is at the limits of the network by conventional means. The area is basically Alverdiscott and Indian Queens GSP’s coloured yellow on figure 2.1 above. During the detailed power system analysis significant interaction between the capacity available in these GSP’s and the power system interaction between the transmission and distribution network in the Landulph, Abham and Exeter GSP’s was found and so the area was expanded to cover the transmission system and transmission / distribution interaction in that area, South Cornwall and Devon, coloured pink on figure 2.1 above.

The transmission system and 132kV / parts of the 33kV distribution system was analysed and constraints were identified on 2 key boundaries. Boundary 1 dealing with capacity restrictions on the Alverdiscott SGT’s and the 132kV K route circuits which parallel Alverdiscott and Indian Queens GSPs. Boundary 2 details capacity restriction on the 400kV circuits heading out of the group towards Exeter and Taunton, together with the paralleled 132kV circuits between Landulph, Abham and Exeter as illustrated in figure 3.5 below. Capacity on boundary 2 can also be limited by fast voltage collapse under certain circumstances.

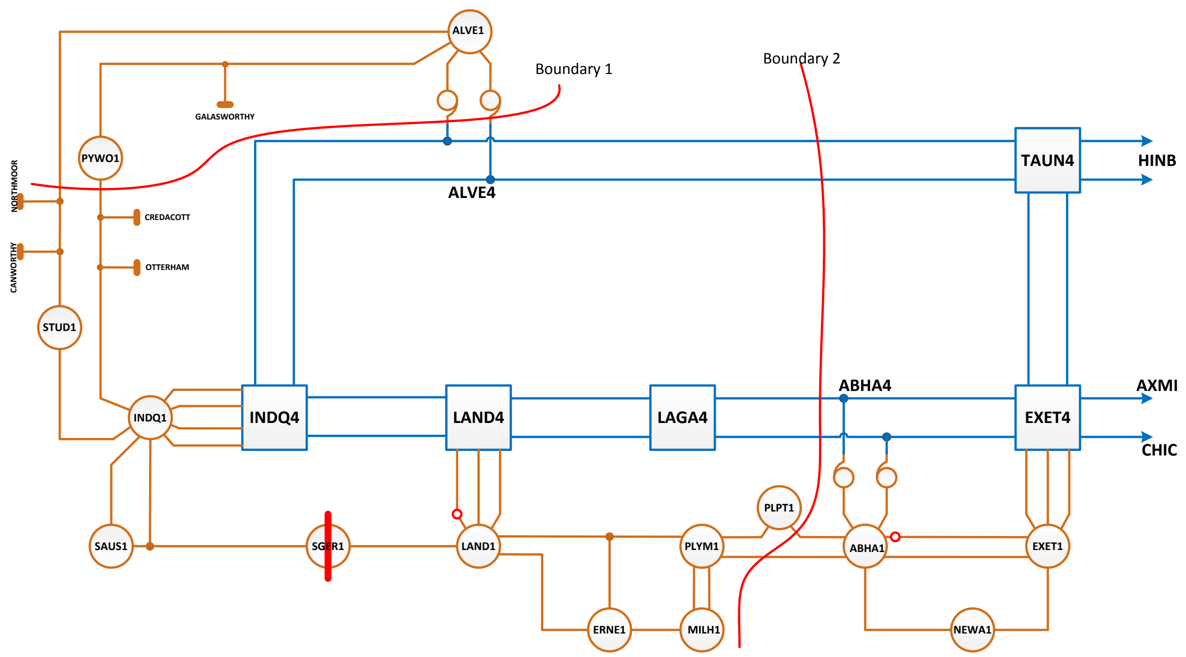


Figure 3.5 showing capacity limitation boundaries.

Capacity limits for each boundary have been calculated and varied across the year to represent typical outage patterns. The cost of constraining DER to meet the boundary limits was calculated for each of the FES scenarios on the basis of the short run marginal cost of that generation including the effect of any subsidies that a generator would be expected to receive. It is noted that under the current regulatory regime all these constraint costs will not necessarily be paid to the generator, they are however costs to the industry and any costs that affect the efficiency of the industry are ultimately borne by the consumer. The purpose of this exercise is to find the most efficient solution and the simplest way to do so is to ignore who pays a cost and to concentrate on comparing the cost of different capacity solutions with the savings they make on the counter factual case of doing nothing and putting measures in place to manage the network.

A number of reinforcement options were identified. For each reinforcement any improvement in generation constraint costs for each FES scenario are identified and set against the capital cost of the scheme to find the net present value, taking into account the financing costs and the change in value of money over the lifetime of the asset. Some of the options are complementary, i.e. combining options together can be more beneficial than just selecting the highest value option, particularly where there is more than one network problem to solve. Hence once the options of most value are identified the analysis is rerun by combining the most efficient options to see if greater value can be achieved. The final stage, to take care of the uncertainty in generation background, involve least regret analyses which determine, which option or combination of options should be taken forward given the best information on the range of scenarios that is currently available.

In practice it was not necessary to put all the potential options through the formal costing process, because several could be eliminated from logical interpretation of the study results.

More information and greater detail on the processes used in the whole system analysis can be found in the processes report available on the WPD and National Grid RDP web pages:

www.westernpower.co.uk/RDP

https://www.nationalgrid.com/uk/publications/regional-development-programmes

The following table summarises the options considered and the outcomes.

Option	Description	Outcome
Boundary 1 Capacity Options		
Split the Alverdiscott - Indian Queens 132kV K-route interconnection.	Additional Switchgear to enable both GSP's to be operated separately. The big advantage of this option is that it improves the effectiveness of generation curtailment from an average of 50% to 100%. It also helps resolve fault level issues at Indian Queens.	This option is a good medium term option
Additional Cooling to uprate Alverdiscott SGT's	A small increase in SGT rating at lower capital cost.	This option is shown to be economic if the DER growth is towards the lower end of the scenarios

Uprate Alverdiscott - Indian Queens 132kV K-route interconnection.	Rebuild the circuits with larger conductors and towers.	Uprating the circuits will reduce the curtailment required, but will only be economic under the highest DER growth scenarios.
A third SGT at Alverdiscott	Requires addition bay at 132kV substation and the introduction of 2 bus section switches in the 400kV substation to get significant increase in capacity.	This option is shown to be economic if the DER growth as at the higher end of the scenarios.
A new GSP at Pyworthy	A very costly and significant investment involving a new 400kV substation with 2 SGT's connecting to the existing 400kV overhead line. The existing 132kV sub would require reconfiguration.	The CBA shows option is not economic . The capital cost of the option is more than a third SGT at Alverdiscott and the reconductoring of Pyworthy – Alverdiscott, there is little generation connected between the 2 sites so that is logical.
Boundary 2 Capacity Options		
Prefault Split on Abham – Landulph 132kV interconnecting circuits	Split the network between GSPs to stop overloads on the interconnecting circuits for the parallel transmission faults. This will require significant investment to ensure the network remains N-1 secure for distribution faults. It also reduces the transient voltage stability limit.	More expensive than post fault split and causes voltage issues.
Post fault Split on Abham – Landulph 132kV interconnecting circuits	Split the network as an automatic post fault action, by means of overload protection. This avoids significant capital investment as normally the network configuration is unchanged. The overload protection would split the network only when needed and leave all customers supplied. If the operating time is greater than 1 second then the transient voltage issues will have settled down. Overloads for 1 second should be within the 3 second fault rating of the equipment.	This is the most economical solution to resolve overloads on this part of the distribution system and also helps resolve voltage issues. Once the network is split, this will increase the transmission overload.

Uprating Abham – Landulph 132kV interconnecting circuits	Reconductoring of circuits and replacement of cables. There are some significant cable lengths in the circuits.	Resolves issues but more expensive than post fault split.
N-3 intertripping for transmission faults	The South West Operational Tripping Scheme (SWOTS) is already being installed to control overloads. The cost of this scheme is relatively expensive, but is required anyhow for transmission generation connections and to ensure operability of higher volumes of DER in the area. The SWOTS will interface with the WPD ANM scheme and trip volumes of DER in the very rare event of an N-3 event.	This is the preferred option to remove any transmission overloads in the area, which are almost only as a result of an N-3 event.
Reconductoring the Alverdiscott – Taunton 400kV OHL	This would be the conventional solution to overloads caused by generation that traditionally could not be controlled and is very expensive because of the length of the circuits.	Except in the N-3 condition only very small overloads exist, which can be cured by manual post fault actions on generation. N-3 intertripping will resolve remaining overloads at a fraction of the cost.
Boundary 2 Capacity Voltage Stability Options		
Prefault Split on Abham – Landulph 132kV interconnecting circuits (as above)	This option is **not a solution**, it has been included here to indicate it makes the transient voltage performance of the network **worse that the base case.**	Negative option – not selected
Post fault Split on Abham – Landulph 132kV interconnecting circuits (as above)	By delaying the splitting of the network by 1 second, allowing the first transient swing to recover voltage stability of the wider network is improved	Very cheap option also best to control thermal overloads above and is preferred option.
Protective Reactive Switching of existing 400kV MCS or Reactors	Use the SWOTS to get very fast post fault tripping of the 200MVAr reactor or insertion on the 225MVAr capacitor at Indian Queens	A reasonable cost effective way to improve the transient voltage performance of the network and may be next in line should the MVar performance of the network change, but not currently necessary on transfers studied with the 132kV

		network paralleled over the first swing.
Indian Queens Sync Comp contract	There is current a contract in place for wider voltage support for sync comp on the Indian Queen generator. This will provide fast voltage support for this local DER related issue. The contract is of limited duration.	Not the most cost effective solution to the local problem.
Addition of a SVC / Statcom	An expensive piece of static equipment to provide dynamic voltage support in the area. This would generally be considered the conventional solution to a transient voltage issue.	Not the most cost effective solution to the local problem.

<u>Recommendations from whole system study.</u>

In the short term up to 2020 and there is little cost benefit in further network investment further than continue to develop facilities for improved control and visibility of DER to both the transmission and distribution operators and to develop the real time transmission / distribution interface which will improve the efficiency of the whole system network operation. This includes both local Active Network Management (ANM), particularly at Alverdiscott and wider commercial control of DER.

Following from this the optimum solution recommended for this zone at this time is to split the Indian Queens – Alverdiscott K route, which allows the Alverdiscott ANM to be more targeted and effective. Then for the longer term a 3rd SGT at Alverdiscott should be considered along with the partial uprating of the K-route (with the route split it is only necessary to do part of it). These two longer term reinforcements need to be regularly monitored against updated scenario planning as a lowering of green ambition would make them uneconomic. In the case of the SGT capacity a lowering of green ambition means up-rating the existing SGT's becomes more economic. Moving away from the local issues at Alverdiscott overload protection should be installed to break the Landulph – Abham interconnection in no sooner than 1 second. (Note - Some coordination with back-up protection systems may be required which are often set to utilise the 3 second equipment rating.) N-3 intertripping will ensure continued operability for these rare but high impact events.

More information on the options and analysis undertaken to optimise can be found in the Whole System report …….here (add link)

3.6 Extension of Whole System Study to a Transmission Regional Solution

The whole system study demonstrates that operational solutions play a big part in providing the most economical solution for further volumes of connections in the whole system study area. In effect the whole system study area expanded from North Cornwall and Devon (Alverdiscott and Indian Queens), to include south Cornwall and Devon (Landulph, Abham, Exeter) as well owing to the interactivity of whole system solutions between these areas. Analysis of the RDP study results indicates that outside this area there are 2 main issues to be resolved:

(a) Pre fault overloads on the Melksham – Hinkley Point and Hinkley Point – Taunton ccts during planed outages of one of these circuits.
(b) A large variety of overloads during the N-3 condition, i.e. planned outage followed by DC fault.

Hot wiring to cheaply increase the capacity of the circuits in (a) is programmed and taken into account in the study results. Any further reinforcements would involve reconductoring with advanced type conductor (approximately £95M for these routes) or the consenting and building of new routes (£100'sM). The CBA technique used in the Whole System study has been extended to cover a wider boundary on these routes and indicates such a high cost is not justified and the economic solution is N-3 intertripping and increased visibility and control to be able to curtail DER on the few occasions capacity is inadequate.

3.7 Fault levels

In additions to the thermal and voltage capacity limits detailed above, detailed fault level assessments show potential overstress and therefore limits on capacity at Indian Queens and Exeter 132kV substations. While most WPD and NG circuit breakers have been replaced at these sites, the substation infrastructure e.g. Isolators, bars and earthing along with Exeter CB250 limit the capability at these substations.

A fit and forget approach to the operation of these substations will require complex and expensive work to replace the infrastructure at these sites. The problem is reasonably immediate with issues indicated in the worst 2020 WPD scenarios and so potentially will impact on customers contracts soon if not resolved. RDP studies have shown that by adopting a more pro-active management of the fault levels on these sites, which the move towards DSO should bring, it should be possible to operate the sites for the foreseeable without the need for significant investment in substation infrastructure.

At Exeter, two running arrangements have been identified which potentially resolve the switchgear overstressing. Running the site with a SGT on standby, improves some critical network loadings under high DER conditions, allows access to the bars for maintenance and can be implemented immediately. However under high demand/ low DG conditions this configuration can increase critical network loading conditions between Landulph and Plymouth. Operating the site in an asymmetric split with all 3 SGT's on load will resolve the high demand loading issues. This option potentially needs AVC upgrades on 1 BSP. By understanding the demand and DER profiles it should be possible to remotely switch between the 2 running arrangements on a seasonal basis managing any outages into the most appropriate running arrangement.

At Indian Queens operating the site on a symmetrical bus coupler split will resolve the fault level problems. The symmetry in this running arrangement means that it is possible to remain split for the planned or fault outage of 1 SGT. If it is necessary to run the site solid on 3 SGTs this is also possible in the lower scenarios, but as generation connections move towards the higher scenarios it will require the network splitting between Indian Queens and Alverdiscott to achieve acceptable fault levels in that condition. To ensure the maximum SGT capacity is available, particularly for the N-2 case in generation export, it is desirable to install an auto-close scheme. This possibly could be achieved by adapting the Indian Queens load transfer scheme, which has not been used since the installation of the 4th SGT, but contains some of the functionality required for auto-close.

4 Operability Scheme Design

4.1 Identification of local areas for schemes and timeline for implementation

The area to be covered by the ANM scheme needs to cover all GSPs on the SW Peninsula network: Axminster, Exeter, Abham, Landulph, Indian Queens, Alverdiscott, Taunton and Bridgwater GSPs.

The RDP implementation plan is summarised in section 5 below. While the current rate of new connections are slower than anticipated at the start of the RDP process, the need to manage the queue effectively and ensure the industry is ahead and not a blocker if and when incentives are in place to build significant DER in the area makes it desirable to implement the arrangements in this RDP as soon as possible. With the first offers on that basis planned for release in July 2018, implementation of the operability control arrangements need to follow in Q4 2018.

This is also consistent the ENA Open Networks requirement to learn from DSO trials during 2018.

4.2 Definition of local operability schemes

4.2.1 Overview of proposed WPD DER control system

WPD will provide visibility and control of DER connected to its distribution system through its centralised Network Management System. A WPD-owned Generator Constraint Panel (GCP) will form part of the remote equipment at the DER's connection point that will monitor the boundary interface and provide direct control of the DER's G59 circuit breaker or equivalent. The GCP will be controllable via WPD's SCADA communications system back to the centralised Network Management System.

Depending on the capability of the GCP and the DER, the power will be controlled either on or off, or granularly in a series of pre-defined steps; across the whole service delivery range of the DER. Confirmation of service delivery will be received from both the DER itself and the GCP monitoring the boundary interface.

The centralised Network Management System will aggregate the real-time dispatch levels of the technology specific DER contributing to the net power flows at each GSP and pass this information across an ICCP link to the SO. A link will also provide a discrete breakdown of the controllable DER contributing to the net power flows at each GSP, enabling the SO to identify and dispatch individual DER.

4.2.2 Principles of dispatch

Further detail is required to establish the most appropriate way of coordinating the dispatch of DER for transmission and distribution services in real time. The key principles are:

- Under normal operation security of the distribution network will always be maintained by ANM ahead of accommodation of transmission services

- Further work is required to determine T / D process and the action of ANM under emergency conditions where it may be desirable for wider network security to take precedence over local security.

- The centralised Network Management System will latch instructions until those are withdrawn – i.e. it will not release intertripped generation until instructed.

- The technical design of the ANM should be developed towards holding headroom or foot room to accommodate transmission services in the future where it is appropriate to do so. Recognising at present that this will not be possible until significant and difficult commercial interactions are resolved by the wider industry, the scheme will, for the time being, be limited to ensure a DNO local ANM does not back fill a transmission N-3 intertrip.

The ANM will dispatch DER services that are contracted with WPD involvement (RDP and local distribution) and resolve D constraints. The ANM also calculates a headroom and if applicable foot room signal for each DNO active constraint zone and also passes this information to the SO via the data link. (See section 4.4 for service conflict signal details.) The SO selects DER dispatch options from the ANM or from direct providers. Where services from direct providers are dispatched the SO must first check the service conflict headroom / foot room signals to ensure there is no conflict and the net service at the GSP will be provided.

The SO will provide real-time visibility of the actions it is undertaking within the DNO active constraint zone so that the DNO can manage any resulting service conflict or begin to reduce assumptions on capacity requirements.

In control timescales a process called scheduling is used to start planning the use of services including those from DER several hours ahead of real time. This is necessary to ensure long notice thermal generation is warmed when required to ensure enough generation will be available to meet the demand and margin requirements in real time. To enable this process to occur accurately a forecast of DER output and where output and services are curtailed owing to DSO constraints will be required in scheduling timescales. This function is unlikely to be available at the beginning of this roll out of DSO TSO operability schemes but the initial volumes affected are low enough to have limited effect on national / regional margins. It is the intention to continue to innovate and look to develop a DSO input to scheduling activities in due course.

4.2.3 D-principles of Access following NGESO instructed DER services

Under Deep Connect and Manage, the DSO will provide static DER sensitivity factors and backstop pricing, as well as real-time visibility of DER output and network headroom and footroom signals. The NGESO will be responsible for undertaking the relevant forecasting and analysis before instructing the DER services through the DSO. Any alterations in sensitivity factors from the static position due to network topology changes or variations in underlying demand and generation will result in a difference in net response at the GSP and managed through further NGESO actions.

Due to the diversity factors of demand and generation used in distribution network planning and the contractual obligations upheld through network access rights, the DSO is not able to alter the operation of adjacent generation or demand to ensure the net response at the GSP is preserved.

4.2.4 Dispatch of Intertripping

The SQSS requires the 400kV system in this area to be secured to double circuit standards even if the network is already depleted by an outage. The normal most economical method to reduce constraint costs are to trip generation quickly in the event of a fault; an intertrip. This allows generation to operate freely pre-fault more or less all the time, because the probability of the fault is extremely low.

Intertrip opportunities will be limited by frequency containment policy, which currently is regularly restricted by RoCoF relay settings effectively being too fast for the low inertia system that will occur at times when the system is supported via DER and interconnectors, precisely the conditions the intertrip is required for. Vector shift protection is also an issue with the strong possibility of significant numbers of Vector Shift relays seeing the fault current present during normal protection system operating time as an islanding condition. It is assumed that GC0079 will deliver retrospective relay changes to remove Vector Shift and adjust all RoCoF to 1Hz/sec with 0.5sec time delay. This should remove the relationship between LoM protection and intertripping. However, owing to the setting on G59 under voltage protection it will be important to manage the system transient voltage performance to ensure total generation tripping, from intertrip, G59 protection and disconnection as a result of the fault (e.g. busbar fault with large generator attached) remain within the system infeed loss. This may particularly be the case as some of the generation with worse G59 relay voltages may be outside the post fault constrained zone that intertripping is required for.

Normal protocol is the intertripping on a linear network such as the SW Peninsula is on a Last in /First out (LiFo) basis, unless there is a technical reason to do otherwise.

Care should be taken to ensure DER that is intertripped for a wider transmission N-3 event, is not back filled by a more local ANM zone seeing capacity had become available on the previously constraining local zone as a result of the intertrip action.

4.3 Commercial frameworks, curtailment funding and settlement approach

4.3.1 Effect on DER Project Developer

The approach to the arrangements detailed in this section on the DER developer has been considered throughout their development in order to make any new requirements as simple and least burdensome as possible. A fact sheet is to be written and published to explain flexibility requirements to developers. In principle a small renewable player who has a simple business case based on subsidised tariffs and has no desire to participate in other markets need only submit curtailment prices once on connection. Clearly if a DER developer's business case is around providing flexibility to the industry e.g. storage, their involvement will be naturally much higher as they will need to operate in flexibility markets anyhow, although provision of a backstop bid on connection will ensure the network remains operable even if their business model changes.

4.3.2 Commercial Interactions between transmission & distribution (setting out DER route to market for transmission constraints)

Initially, NGESO will seek curtailment prices from DER to allow them to be compensated for flexibility they provide to manage transmission constraints. These prices will be submitted as part of the connection process and will represent 'back-stop' prices that will apply/endure should the DER not wish to participate in future procurement events for transmission constraint management services. Once submitted to WPD, DERs will then be able to review and re-submit these prices if their circumstances change.

Where possible, transmission constraint management services are procured competitively; usually via tender. Given it has been determined that the most cost-effective way to unlock capacity on the SW Peninsula is via a service-based, rather than asset-based approach, National Grid will require sufficient new DER to be available to provide constraint management services on an ad-hoc basis, or participate in procurement events for transmission constraint management services where appropriate. These services will be structured so that treatment of DER curtailment will be on an equivalent basis to that for transmission connected service providers. By doing this, it can be ensured that DER will not be financially disadvantaged when having their output curtailed to manage transmission constraints.

Further work will be required to ensure services procured for transmission constraint management take account of all necessary distribution network interactions.

Appendix B shows the proposed RDP Procurement Principles and their interaction with ANM.

As is the case for transmission connected service providers, a DER's effectiveness at managing overloads depends on the type of fault and the proximity of the DER to the overloaded transmission circuit. National Grid will consider how effective at managing constraints each service offer will be when it is assessing which sources of curtailment would represent an economic and efficient solution to the constraint.

Summary

WPD and National Grid will work together to develop a technical and commercial framework for coordinated management of services in the region. Both new and existing DERs will be brought into constraint management procurement for the SW Peninsula GSPs. Where these are structured, organised tenders WPD and National Grid will closely coordinate so as to facilitate DER operating in multiple markets and 'stacking' participation in services, as required. It is most desirable to remove as much service conflict as is economically viable at the procurement phase as possible.

4.3.3 Approach to Distribution constraints

DERs will each have a connection agreement with WPD defining their operational requirements, including any technical capabilities that DERs will need to have, such as Control & Visibility, Loss of Mains protection and a 0.95 lead/0.95 lag power factor capability.

Given the existing and emerging constraints on the South West distribution network, it is proposed that all new DER connections should include an Active Network Management (ANM) capability. As per existing Alternative Connection regimes, a DER will be obliged to accept some curtailment when the predetermined constraints are binding, with the level of curtailment dependent on the magnitude of the constraint (the 'Principles of Access').

If the distribution network is unconstrained, the DER will not be obliged to curtail if distribution constraints emerge at a later date.

In due course, it is expected that this ANM system will be the means by which the local flexibility market is enabled allowing DERs to participate and enable WPD to manage distribution constraints.

4.3.4 Participant charging, access rights and obligations under schemes

Access rights are generally unchanged:

Where flexible connections are offered at distribution level or the design of the connection has inherent unavailability during outages, these will remain as uncompensated constraints.

Transmission connection asset costs are charged to WPD. Where additional or modified connection assets are required for a DER connection, WPD would seek to recover these costs from the DERs involved. Generally the DERs do not want to pay these costs so an alternative connection is offered instead on an uncompensated basis. This is compliant with SQSS under the user choice or design variation clause.

Costs to improve infrastructure asset / wider system capability are recovered from Transmission Network use of system (TNuoS). Constraint costs when DER are used to resolve transmission constraints up to the standard they are entitled to be connected to in the SQSS will be recovered from Balancing Services use of System (BSuoS) charges, in the same way as any other transmission balancing service would. In practice that will cover all occasions where transmission curtailment will have an effect on the DER's business case.

Note on N-3 intertripping

Where generation inter-tripping is the correct economic solution to a constraint arising from an N-3 event on the transmission system, the service is considered a network service provided by automatic actions via a TO-owned inter-trip interfacing to DNO-owned ANM equipment. This will be an uncompensated service which will manage the difference between the N-1 connection standard required for a small generator and the N-3 standard required for demand groups over 1500MW (and wider transmission network security). Curtailment assessment analysis shows the considered N-3 event in the region to be a low-risk; less than 1 in 100 year event. Unlike transmission or large distribution connected plants, small and medium DERs do not pay transmission charges in exchange for transmission access rights and therefore have no formal transmission access rights and no compensation when access is disconnected for events beyond the security standard for that class of plant.

4.4 Conflicts of Service Study

4.4.1 Service dispatch conflicts in the area

Currently, there are services, such as Enhanced Frequency Response, being procured by the SO directly to DER connected in the distribution network. These directly contracted services are not coordinated by the DNO, which can lead to possible conflicting actions. This section describes the concept of service conflicts, consequences and steps to mitigate them.

4.4.2 Service conflicts - Overview

As many DNOs are accommodating increasing number of DER connected in their networks, they have been looking into ways to manage their system optimally. This has led to a widespread deployment of Active Network Management (ANM) schemes across their networks to manage distribution constraints. By limiting the output of DER at certain times, ANM allows increased connection capacity beyond that which could connect using traditional planning assumptions.

Dispatch of DER will build from the principle of using ANM to solve distribution constraints first and then offer additional flexibility upstream to National Grid within the bandwidth of capacity available on the distribution system. National Grid ESO may have directly procured additional services from DERs, which also need to operate in the bandwidth of capacity available on the DNO networks, many of these services will not be under direct control of the WPD ANM. For example a frequency response provider will provide a service in the windows in their contract or via direct instruction. The actual output of the frequency response provider will be automatically adjusted by the DERs local controller and will increase / decrease output proportional to the difference between target frequency and actual frequency. (The target frequency is 49.95, 50.00 or 50.05 Hz.)

The industry stakeholders, particularly through the Energy Networks Association (ENA) TSO-DSO working groups, have identified the potential for ANMs to, at times, conflict with embedded SO services by negating service output. SO services embedded in the DNO network may be impacted by ANMs either:

- For services which increment: If the ANM is active at the time (or doesn't have sufficient headroom), then the service effect will be negated seconds later following ANM action to curtail alternative generation.
- For services which decrement: If the ANM is active at the time, the controlled DER will "fill in" the space made by the service with the extent of the fill in being determined by the volume of other DG/DER being curtailed prior to the decrement service.

An illustrative example of an incremental service conflict is given in Figure 4.4.2a where an ANM is actively curtailing distributed generation to 70MW in order to control the flow on a DNO circuit within its rating limit of 50MW. In this example there is an embedded SO service, Short Term Operating Reserve (STOR), within the ANM Zone not itself under ANM control. Should the STOR service be called upon by the SO to generate 20MW, seconds later the service's output could potentially be nullified by the ANM pulling back an equal amount of DER output to return the circuit to within its rating.

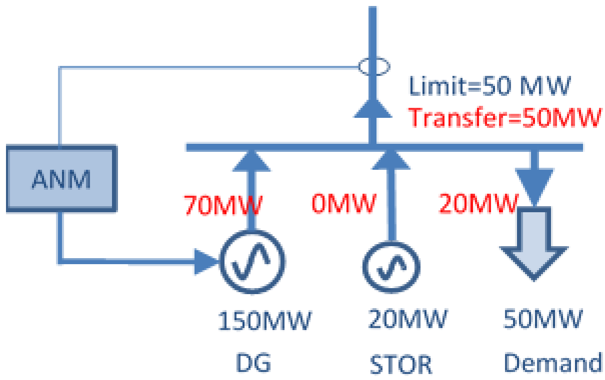


Figure 4.4.2a Example embedded incremental service conflict

An illustrative example of a decremental service conflict is given in Figure 4.4.2b below where an ANM is actively curtailing distributed generation to 70MW to control the flow on a DNO circuit with a rating limit of 50MW. In this example, there is an embedded SO service, Enhanced Frequency Response (EFR), within the ANM Zone not itself under ANM control. Should the EFR service automatically absorb power in response to a rise in system frequency as per its service requirement, the ANM would detect the spare capacity and seconds later the service's output could be nullified by the ANM releasing an equal amount of previously curtailed DER output.

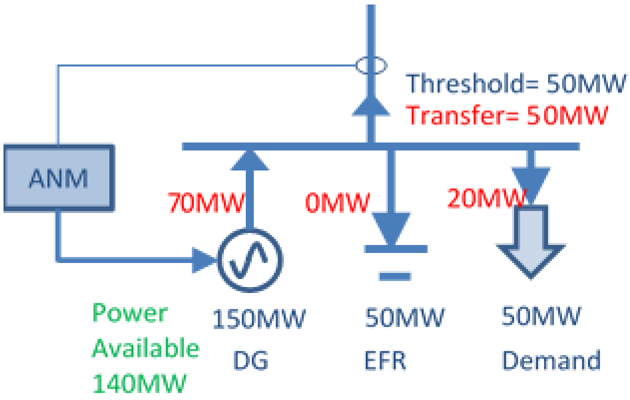


Figure 4.4.2b Example embedded decremental service conflict

What are the Consequences of the Problem?

The SO will to continue to procure balancing services from providers embedded in the distribution network. Furthermore, ANM types of control systems are expected to be deployed in other areas of the system. Thus, the risk of conflicting actions can be expected to grow. The consequences to the system's operation without mitigation would be, at times when ANMs are active, services do not deliver the expected net output either requiring additional services to be run at extra cost, or presenting a risk to system security.

In the particular case for the SWPen, the risk of service conflicts is likely to materialise at solar PV peak when the DNO network is constrained. NGESO may still choose to procure new Short Term Operating Reserve (STOR) services in the region on an economic basis because large volumes of solar generation will increase system generation margins making it unlikely that the full volume of national STOR provision will be required in these conditions. For security reasons the NGESO control room does need to know when the STOR is limited (or likely to be limited) by ANM controlled constraints to ensure the appropriate reserve is available from other sources and uneconomic called off is avoided.

4.4.3 Service Conflict – Planning timescales.

By running the DNO curtailment study process twice, one without a new service and once with a new service and comparing the results, it is possible to determine the times when an effective service would not be available and what the value of that service to the system operator would be. It is envisaged that this process would be used in procurement timescales to determine if there is value in contracting a service. The input assumptions to the curtailment study would need to be set appropriately by the body looking to purchase the service to ensure these are consistent with the service requirements. E.g. if assessing a new STOR service in an ANM zone with an existing STOR service, use of historic data for STOR dispatch will give a misleading answer as most likely the need for both would appear at one time. The existing STOR service would need studying at full load in order to see the probability of curtailment of the new service in the ANM zone.

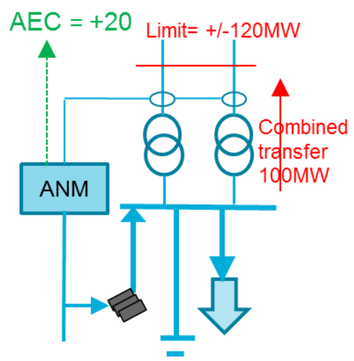
A WPD trial has to date looked into the process for doing such an assessment, as part of the implementation phase of this RDP it is proposed to share data on services and trial this approach by means of a case study around ANM action in the Alverdiscott GSP.

4.4.4 Real Time Service Conflict Identification (In a TSO Led Procurement and Dispatch Model).

The ENA Open Networks 2017 WS1 Product 5 work has identified possible real time signalling for operation in a DSO environment. If or when required two of these signals are of use in managing service conflict. The first signal would be sent from the ANM to NGESO for each significant distribution export constraint in the ANM area:

Additional Export Capacity (AEC) MW (+/-)

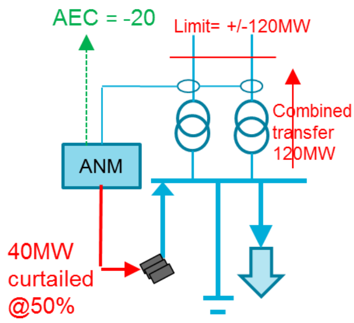
The additional power that can be exported across constraining circuit(s) **before DER will be constrained off**.



- +ve signal indicates additional transfer capacity available (MW) across the circuit(s).

e.g. Signal=+20 means 20 additional MW could flow across boundary
e.g. a 50% sensitivity service could **export** additional 40MW.

- -ve signal indicates volume of DER currently **constrained off** to meet limit (converted using each DER sensitivity to circuit transfer flow).



e.g. Signal=-20MW means additional 20MW would **export** on boundary if DER were not **constrained off**. e.g. 40MW of DER at 50% sensitivity

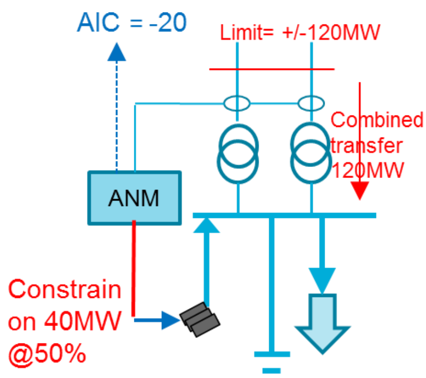
- Services' sensitivity will be stored centrally and would come from proposed standing data exchanged also required for planning services. The SO would calculate their contribution to the transfer enabling efficient call off of services.

The second signal is similar, but is for importing constraints (where generation is constrained on for security). It may be that there are no import constraints in the zone and so this would be omitted:

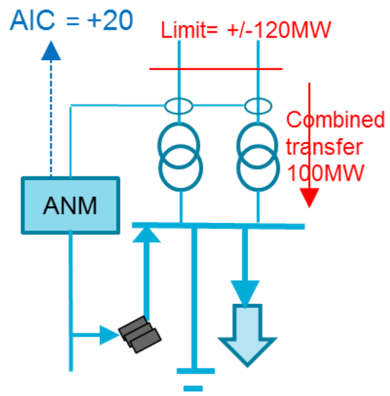
Additional Import Capacity (AIC) MW (+/-)

The additional power that can be imported across constraining circuit(s) **before DER will be constrained on**.

- +ve MW indicates additional import capacity available in MW across the circuit(s).



e.g. Signal=+20 means 20 additional MW could **import** across boundary e.g. a 50% sensitivity service could import additional 40MW.



- -ve MW indicates volume of DER currently **constrained on** to meet limit (converted using sensitivity to circuit transfer).

E.g. Signal=-20MW means additional 20MW would **import** on the boundary if DER was not **constrained on**. e.g. 40MW of DER at 50% sensitivity

4.5 Integration of Schemes into the Control Environment and provision of Visibility & Control across the TSO / DSO boundary

The following signals will be exchanged between the TSO and DSO boundary and will enable the TSO-led and joint procurement models to be demonstrated. It is anticipated that this information is shared at each GSP initially, but may be required lower down on a per constraint basis, should the number of distribution constraints increase.

From the DSO:

- headroom and footroom information at points of constraint
- visibility of ANM operations
- visibility of passive DG/DER operation
- visibility of flexibility instructed
- visibility of flexibility contracted
- background data for network modelling (flows, topology, switch states, impedance, ratings etc.)

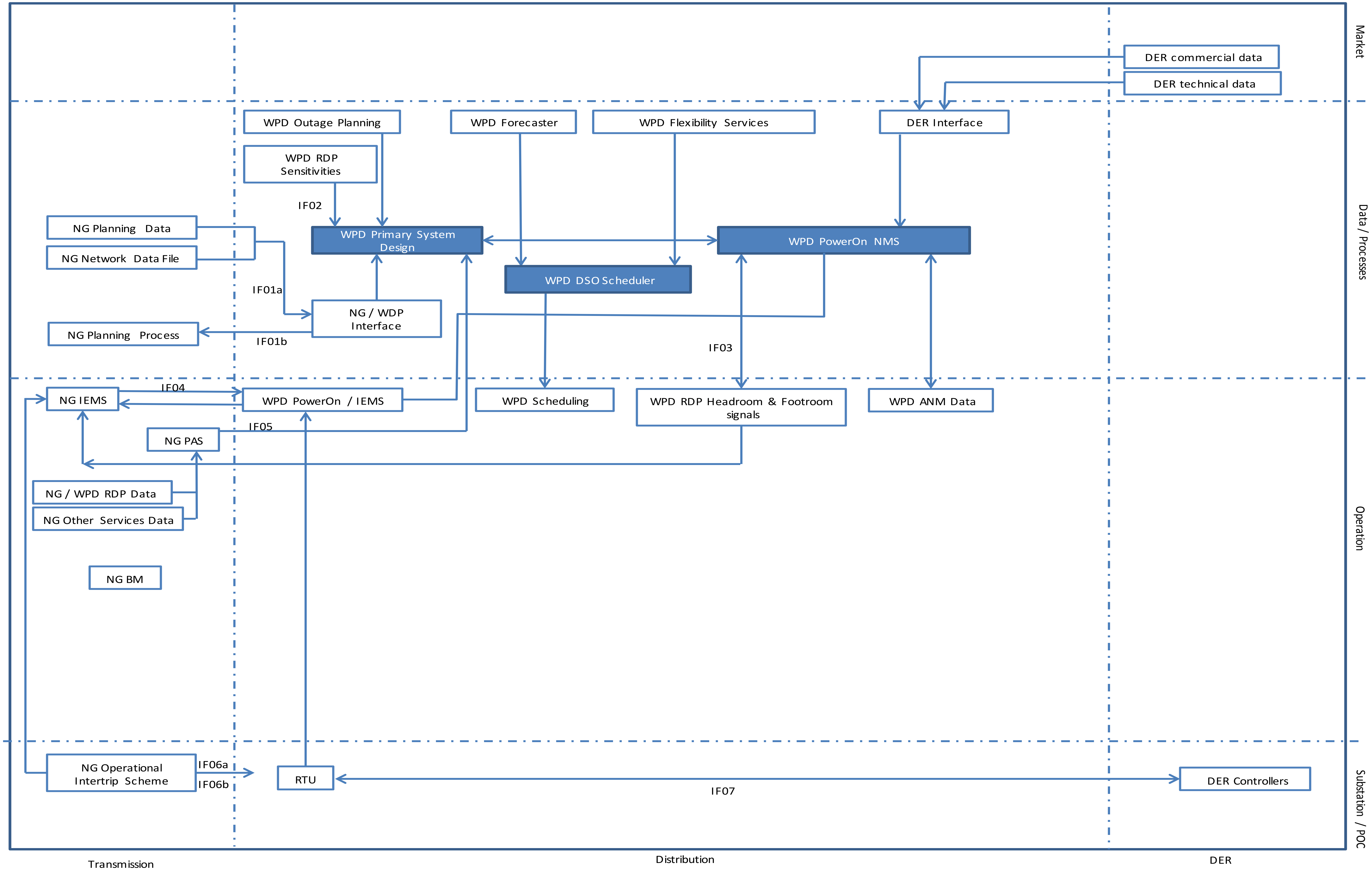
From the TSO:

- TSO boundary constraint information
- visibility of flexibility instructed within distribution network
- visibility of flexibility contracted within distribution network
- background data for network modelling (flows, topology, switch states, impedance, rating etc)

The schematic diagram below shows the data and control linkages that are required for more integrated control and visibility across the transmission / distribution boundary. The table that follows details the actual exchanges to be implemented during the RDP Implementation.

ID	Interface Name	Source System (From)	Target System (To)	Data
IF01a	NG Planning Data	NG various	WPD / NG Interface	Network model files, Nodal dada R,X,B data, In feeds from wider system OC2 outage data, changes to 400kV running arrangements in operational timescales etc.
IF01 b	WPD Planning Data	WPD Various	NG offline studies, Real time state estimator / security assessor, demand forecasting tools	Network model files, Nodal data R,X,B data, In feeds from local system OC2 outage data, changes to 132kV running arrangements in operational timescales etc.
IF02	WPD calculation of DER Sensitivities to constraints	WPD System	NG - Integrated Energy Management System (IEMS) then Platform for Ancillary Services (PAS)	Non real time and potentially real time calculation. Real time calculation from Substation Control and Data Acquisition (SCADA) measurement data.
IF03a	WPD RDP headroom & Footroom data	WPD	NG	Real time calculation / measurement data. Requirement for future calculation of signals for scheduling to be confirmed.
IF03 b	NG constraint headroom & footroom data	NG	WPD	T constraint limit & boundary.
IF04	RDP Background data / DNO datalink	NG WPD	WPD NG	Real time network state, SCADA measurement and indications. Network model & data point map.
IF05	NG Dispatch instructions	NG PAS system	WPD	Instructions for delivery at DER Point of Connection (POC). Potential requirement for NG to facilitate MW dispatch on WPD's behalf.
IF06a	Operational Intertrip Scheme tripping signals	NG	WPD	Protection trip relays, via SWOTS. MW volume of DERs armed in blocks. Aggregate DER signals / volumes per fuel type per GSP to indicate the current output of the DERs armed to SWOTS. Aggregate DER signals / volumes per fuel type per GSP to indicate the total DER output per fuel type which could be armed to SWOTS.
IF06 b	Operational Intertrip Scheme arming / de-arming / RTS of generation following trip	NGESO	WPD	Formal control room to control room (manual) procedure. Real time feedback on volume selected via Inter Control Centre Protocol (ICCP) link.
IF07	DER Controller Interface	DER	WPD	Instructions from NG / WDP to DER for active power set points. Initially available for DER connected since Q3 2016 as either ON or OFF. Instruction to change DER operating mode and movement to more refined DER MW control to be devolved in the future.

Table 4.5 Data and control linkages



Schematic Diagram 4.5 Data and Control Linkages

5 Future Developments

While the SW Peninsula RDP has demonstrated the next steps to develop the power system and operational capabilities in the region in the best interest of likely customers connections and consumers, the following lists potential further developments along a similar theme that could deliver benefits and therefore warrant further investigation:

- Real time control of DER MVARs to improve voltage profiles aid more capacity.
- Analysis the cost effectiveness and, if effective, actively encourage storage in place of network build solutions.
- Develop the DSO control interface forward from real time into scheduling timescales, particularly the ability to manage service conflict.
- Explore what further savings are available by better coordination of generation flexibility actions across voltage levels further down the network.

6 Proposed RDP SW Implementation Program

The following chart shows the high level plan to implement the arrangements discussed in this RDP.

Activity	April					May				June				July					August				September				October					November				December					January			
	2	9	16	23	30	7	14	21	28	4	11	18	25	2	9	16	23	30	6	13	20	27	3	10	17	24	1	8	15	22	29	5	12	19	26	3	10	17	24	31	7	14	21	28
Complete design phase	■	■	■	■	■																																							
Disseminate design phase						■																																						
New RDP Connection Contract launched					■	■																																						
Engagement launched inviting existing connected / accepted DER to migrate to the RDP Connection contract terms					■	■	■	■	■																																			
RDP Flexibility Procurement procurement engagement																			■																									
RDP Flexibility procurement goes live																										■																		
Agree technical architecture				■	■	■	■	■	■	■	■	■	■	■	■																													
Design PAS RDP functionality				■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■																								
Build and test PAS RDP functionality																■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■								
NG builds ancillary services management functionality into PAS																■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■								
Agree Conflict of services												■																																
ICCP Link installed between NG EMS And WPD DMS				■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■																								
NG / WPD ICCP Go Live																								■																				
TSO led trial Go Live																																								■				
Operational Intertrip scheme requirements				■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■				
Real time data requirements				■	■	■	■	■	■	■	■	■	■	■	■																													
Control system available in principle																																								■				

Appendix A: Paper on Application of "Deep" Connect and Manage

WPD - Regional Development Program - Application of Connect and Manage and Change to Connection Terms and Conditions

Issue: Final
Date: 18/04/18
By: A Minton

Issue

There is a need to find ways to offer and manage additional capacity to new DER on the SW Peninsula to ensure future requirements can be met. This area is already part of the "Appendix G" trial, but there is a need to go further.

Detailed dynamic network analysis has enabled a full understanding of the network behavior and risks in facilitating this.

CBA work has demonstrated the economic need for some reinforcements in the area, but has also shown that many network constraints are more economically resolved by better management of the network. This includes both better control and visibility for management in operational timescales and better management on new connection contracts, which is the subject of this paper.

Summary

This paper details the approach that is required to allow future connections to DER developers in the SW Peninsula group, linking with the CBA output. This can be achieved by a very deep application of the Connect and Manage regime to DER in the area. It will require some changes to the terms and conditions in the BCA to allow WPD to offer connections to DER developers. This will change the way in which WPD manages access with its customers. It is proposed to take this forward in this zone via a new trial under the Regional Development Program. The proposed approach also addresses the issue of allocating a limited volume of transmission capacity and how that is handled across the transmission / distribution boundary in a fair way, without undue delay to developers in both the application process and connection date, providing a single stage application process for DER applicants. This is **a key customer improvement** the regulatory authority has required the industry to make.

RDP Scope

The WPD South West RDP applies to the SWPen network, which includes Bridgwater, Taunton, Alverdiscott, Indian Queens, Landulph, Abham, Exeter and Axminster GSP's and is designed to "trial by doing" new ways to manage the "Whole System" in real and planning timescales.

Connect and Manage

Connect and Manage can apply to both embedded generator connections as well as direct generator connections. The System Operator can offer a connection under this regime, provided a number of technical requirements are met and there are diverse constraint management options available to operate the system until the wider works are completed on the proviso that this doesn't incur excessive costs. Furthermore any actions to make the network fully compliant with SQSS shall occur as soon as possible after the connection date if not possible to do beforehand.

Economics and Capacity

In this South West example, a CBA has demonstrated that as network limitations are reached, constrained operation of the network is initially economic for the 4 WPD FES scenarios studied. That will also often be the case well into the future. As time passes and scenarios firm up it will be possible to reinstate any build works for any proposed transmission build solutions within the specified lead time if deemed as economic. The longest lead time for the possible works associated with DER will be no longer than 5 years. Hence in this piece of work it is only necessary to consider the next 5-years. The RDP studies have considered 12-years to enable a view of longer term economic outturns to be understood. The contracted position and additional DER connections on the 4 FES scenarios over the next 12-years are:

	2018	2018	2030	2030	2030	2030	2030
	Appendix G*	Appendix G**	No Progression	Slow Progression	Consumer Power	Gone Green	Average
Total Embedded	2027	687	3403	4278	5145	6190	4754
Wave / Hydro	34	0	15	25	30	230	75
Embedded Solar	1033	94	2000	2520	3100	3514	2784
Embedded Wind	394	37	450	604	604	833	623
Embedded Battery	15	141	51	205	574	416	337
Thermal	551	404	889	920	836	1197	961

*Appendix G contracted and connected position.

** Appendix G contracted, but not yet connected, the majority are currently contracted to connect by end of 2020.

Each application would be considered under the principles of Connect and Manage, which requires the generation background to be set to those that which ought reasonably to be foreseen to arise in the course of a year of operation. A summary of the application of FES scenarios to this zone is shown in above and indicates the range of outcomes in this area. Lead times on the build options recommended via economic analysis are relatively low as is the volume of constraints in the chosen options. On that basis there is no reason to put an immediate cap on the volume of DER that can be offered a connection under this regime. However good management of new connections to the network is required to ensure accurate knowledge and provision of the data to allow effective management of the network under the connect and manage principles. A regular review of the Whole System CBA to allow the correct build solutions to trigger at the optimum time is also required.

A requirement of Connect and Manage is that once a generator has a contracted connection date, under Connect and Manage that date and terms and conditions remain unchanged even if the background data the connection is based on changes. Note this works both ways, hence if the generator requires a substantial change to the contract, e.g. change in technology, substantive change in date* it should be assessed on the latest background. (* A change in date owing to build / commissioning delays would not typically cause the Connect and Manage terms and conditions to change. A significant or repeated date change on an uncommitted project should.)

WPD are adopting the QMEC requirements, "Fair and Effective Management of DNO Connection Queues", which is the new industry agreed standard to ensure embedded generators cannot reserve capacity without adequately progressing projects. WPD also intend to implement the proposed QMEC material changes process which will reset a project's application date in the event of a material change such as a change in technology. Application of these principles with the Appendix G process adequately ensures generator led changes are reassessed on the latest Connect and Manage backgrounds if required.

Technical requirements

The technical requirements of Connect and Manage are:

1) Achieve compliance with the "Pre-fault Criteria" set out in Chapter 2 (Generation Connection Criteria Applicable to the Onshore Transmission System) of the NETS SQSS
2) Achieve compliance with the "Limits to Loss of Power Infeed Risks" set out in Chapter 2 (Generation Connection Criteria Applicable to the Onshore Transmission System) of the NETS SQSS
3) Enable The Company to operate the National Electricity Transmission System in a safe manner
4) Resolve any fault level issues associated with the connection and/or use of system by the C&M Power Station
5) Comply with the minimum technical, design and operational criteria and performance requirements under the Grid Code
6) Meet other statutory obligations including but not limited to obligations under any Nuclear Site License Provisions Agreement
7) Avoid any adverse impact on other Users

These technical requirements will be interpreted and managed in this trial as follows:

1) Achieve compliance with the "Pre-fault Criteria" set out in Chapter 2 (Generation Connection Criteria Applicable to the Onshore Transmission System) of the NETS SQSS

This criterion requires the individual power station in question to be modelled at full output and those power stations around to be modelled as reasonably expected to operate over a year of operation. In this case, given each individual DER station is very small compared to the constraint on the transmission network, in effect this means modelling the net embedded generation as expected to operate over the year against the requirement there shall be no pre-fault overloaded circuits. The criteria also require outages to be modelled where appropriate. Output from the RDP modelling shows: no pre-fault stability or voltage issues and margin on the pre-fault loads with the network intact and for the majority of the outages. There are outages e.g. Hinkley – Melksham 1+2, where this was not the case. For these outages the transfer limit out of the SWPen network has been calculated with the network optimised for the best performance. The calculated boundary limit (seasonal) has been compared with the output from the BID3 European economical dispatch program for this group using the 4 FES scenarios to obtain the annualised percentage of time on each scenario a pre-fault overload would be present. The SQSS deterministic criteria are designed to keep the network secure and provide the correct balance between asset build and constraint solutions. In determining the deterministic standard, the economic cut off for build solutions was used such that assets are required to cover 2 standard deviations from the mean i.e. 95% of the time. Therefore applying the same principle on the statistical data available in this case, if the annualised percentage of a potential pre-fault overload is less than 5%, it is possible to declare the network compliant against this criterion. That is the case.

2) Achieve compliance with the "Limits to Loss of Power Infeed Risks" set out in Chapter 2 (Generation Connection Criteria Applicable to the Onshore Transmission System) of the NETS SQSS

This is generally not an issue as the sizes of the DER power stations are small. (There may be some temporary issues around the performance of LoM protection until the GC/DC079 modifications resolve Vector Shift and RoCoF issues are delivered. A short term solution to manage new connections in the area without increasing the existing risk has been devised.)

3) Enable the Company to operate the National Electricity Transmission System in a safe manner

To operate in a safe manner the SO has to ensure the network can be constrained to the position that is safe. This is usually deemed to be the operational standard detailed in chapter 5 of SQSS. To achieve this, the SO has two requirements - visibility on what the DER is doing and the ability to constrain generation, when required, to an acceptable level. While these are normal requirements for large and transmission connected generation they are new requirements for small generation.

4) Resolve any fault level issues associated with the connection and/or use of system by the C&M Power Station

There is a requirement to do regular fault level studies on actual and contracted technical data to ensure the network remains safe. Routine fault level management is built into revised RDP connections assessment and Appendix G process. The RDP studies have indidacated suitable solutions (mainly operational) for the problem sites at Exeter and Indian Queens 132kV are available until at least 2025. Care needs to be taken should works be identfied on transmission assets at either GSP, as these will attract attributable securities to be applied to any triggering parties during the offer process.

5) <u>Comply with the minimum technical, design and operational criteria and performance requirements under the Grid Code</u>

For small generators the Grid code does not apply. Requirements may be listed as Site Specific Requirements instead. Where medium size power stations are connected on the distribution system these will be caught by the Grid Code under the Licensed Exempt Medium Power Station criteria, and specified under a separate Appendix E.

6) <u>Meet other statutory obligations including but not limited to obligations under any Nuclear Site License Provisions Agreement (NSLPA)</u>

Provided the network can be operated in accordance with chapter 5 of the SQSS and any changes to NSLPA listed circuits (in this case transmission circuits) are properly considered, the NSLPA should not restrict the connection of DER. The ability to emergency disconnect (already a Site Specific Requirement) gives the NGESO the ability to ensure the DER does not result in any breach of duty of care to the public under health and safety legislation under extreme operating conditions.

7) <u>Avoid any adverse impact on other Users</u>

Adverse impact on other users can be technical i.e. a lower standard of security, or it can be commercial i.e. The commercial terms of a connect and manage connection should not give preferential terms and conditions that are not available to other users.

Any network security issues will be managed by constraining generation, the generation that is constrained will be fully compensated for their loss of opportunity and so no adverse impact.

Under this proposal the DER will sit in a single connection queue with directly connected and BEGA generation. To avoid adverse impact all generators in that queue need to secure capacity on the same basis. Currently that is not the case, directly connected and BEGA generation are required to secure their connection via the wider security process, generation connecting via the SoW process have often avoided doing so. To avoid adverse impacts on certain users, all generation in the single queue need to be treated equally and wider securities applied in a common way (see below for detail).

Long term full SQSS Compliance

It is a transmission responsibility to meet the requirement to make the network compliant with SQSS as soon as possible; generally under C+M this does not affect the generator. The exceptions to this are below.

N-3 Intertrip ANM

Where the correct economic solution is to curtail generation in the event of an N-3 event, it is possible to connect a small generator under C+M without that action in place, but the contractual commitment must be in place to make the intertrip available when the associated control system becomes available.

In this case the service is considered a network service provided by automatic actions via a TO-owned intertrip interfacing to DNO owned ANM equipment, and manages the difference between the N-1 connection standard required for a small generator and the N-3 standard required for demand groups over 1500MW and wider transmission network security.

Delayed Enabling Works

Where the DER applications electrically contribute to the need for works required to meet the C+M criteria of a pre-contracted large party, it is proposed that in the future these are known as delayed enabling works. This will not stop the new party from connecting, but will mean that the generator will be required to secure a proportion of these works via the wider cancellation fee process (See below).

Changes required to Appendix G Process

To both apply the new capacity arrangements and to facilitate the single stage connection application process to DER customers the industry requires, it is proposed to further adapt the existing trial Appendix G process to facilitate the above as follows:

The materiality limit concept will be changed to a materiality trigger and will not prevent the DNO offering capacity which would result in the total volume exceeding that trigger, provided the DNO enters into a time bound process and provides the technical data to have that trigger reassessed. (Note removing the concept of headroom belonging to developer capacity in the GSP, also allows the CUSC rules to be met and make the application of wider securities consistent and fair across all applicants.)

The DNO, as before, will make offers in accordance with the terms and conditions in appendix G and the associated BCA, ensuring all the technical restrictions are applied. As an example, it is the DNO's responsibility to ensure the fault level limit at the associated interface busbar is not exceeded whatever combinations of offers are accepted. When an offer is accepted by the user, the DNO will up-date the Appendix G, as per current process. Once the materiality trigger is breached, the DNO will provide the required technical data and request a stage 1 SoW for the network to be reassessed. Provided that competent SoW application is received within 2-weeks the DNO can continue to make offers on the original basis. If the DNO does not comply they must stop making further offers on the original basis and any offers they do make will need to be "subject to statement of works". If the SoW reassessment does not change the terms and conditions the materiality trigger will be raised and the App G will be updated within the 28-days. To ensure the need for a time bound process is met, the adoption of retrospective invoicing for statement of work / project progressions will be adopted.

If a change in works are required then as part of the SoW response, the TO will provide a technical report clearly setting out the compliance issues and NGESO will agree with the TO and provide the

DNO a timetable to indicate to the DNO when new terms and conditions will be available in draft form and the date a new BCA shall be issued. The SoW will automatically transfer into a project progression and the revised BCA will be given to the DNO no longer than 90-days from the start of the original SoW request. Draft terms and conditions will be discussed with the DNO as soon as they become available and a minimum of 2-weeks before the formal offer BCA. A number of standard templates have been created. Once the DNO has received the new BCA no more offers on the original terms and conditions are to be made. The DNO will have been fully informed of new T+C's and should make offers from that date on that basis. Any existing offers have the remainder of their 90-day offer period to accept, at the end of this period any unsigned offers will lapse and if the customer wants to take the project forward will require re-offer in the new terms and conditions.

See Apendix 1 below for process flow chart.

In the event of a change in circumstances on the transmission system, e.g. a change in directly connected generation or a revised strategy from the NOA process, the SO will advise the DNO and up-date the BCA with revised term and conditions. Any DNO offers after the receipt of a new BCA should be on the revised terms and conditions. Offers made beforehand will normally remain valid for up to 90-days from the date the offer(s) were made. It is fairly unlikely with this approach, but if the transmission connection is large and soon enough that the principles of Connect and Manage no longer apply there could be a requirement to run the interactivity process on the combined transmission / distribution queue.

Adopting this revised approach enables a single stage connection approach for embedded connections **and** manages the risk those connections pose to the transmission system. It should be noted that a DNO may still be making offers up to 100-days after a transmission reassessment trigger is met and those offers may not be contracted until 90-days after that and therefore efforts are required not to increase transmission risk by extending these timescales. To mitigate these risks the DNO must still apply all the original technical restrictions, e.g. fault level headroom, connection asset reverse power limits, etc. as per the original assessment.

Changes to the Appendix G template have been devised to facilitate the more flexible approach.

Changes Required in Security Process

CUSC section15.2.C requires a wider cancellation fee process to be applied to all directly connected generators and all embedded generators applying via the BEGA route, but only applies to embedded generation applying via the SoW route if there is a construction agreement. In the methodology proposed in this paper the provision of visibility and control will be considered enabling works and require a construction agreement. If that was not the case this would lead to an advantage over other users because it would allow the DER to reserve capacity on more favorable terms than Large or BEGA plant. In fact the DER doing so on a purely speculative basis and continually delaying without making any commitment, would create difficulties in the deep application of C+M. Assuming positive trial outcomes it is proposed to recommend a modification to the CUSC to apply wider cancellation equally to all. Note: Scottish App G trials have already tested a similar approach and have been found to be advantageous.

To have the desired effect of having a credible managed list of DER applications the way in which the wider security fee is applied under Appendix G requires change, such that the DNO may recycle cancelled capacity to other users, but not the cancellation fees as has been practice. CMP223 provides for the cancelation fees to be applied to the individual generators but a working process need to be in place to ensure these are consistently collected from the generators in order to drive the correct behavior in reserving capacity.

Visibility and Controllability

In order to ensure the transmission network can be safely operated, visibility and control of DER is required by the SO. This will be via commercial terms for DER who chose to submit to a suitable mechanism. The detail of how to efficiently provide commercial control will not be a condition of connection merely that it shall be provided. That leaves the path open to competitive aggregation if the user choses that route. WPD and National Grid will develop an ANM control scheme and a basic commercial route to market for this service, as a very low cost option available to participants.

Embedded Large Generators

Embedded large generators require both a connection agreement with the DNO to which they connect and a Bilateral Embedded Generation Agreement (BEGA) with the NGESO for the use of the transmission system. Currently these must be applied for separately. This potentially causes an issue with the concept of a single queue for both transmission and distribution connected generation, with the DNO requiring it to be added to the queue on its application date and similarly for the NGESO. Clearly one generator cannot have 2 places in a single queue. To resolve this issues developers should be informed that additional competency checks will be added to both the DNO connection application and the SO BEGA application, such that neither will be declared a competent application until the corresponding application is received. This will ensure a single place in the queue.

Large generators will also have any wider security fees applied via the BEGA agreement. Clearly, it would not be fair to apply these twice and so in this case they will not be applied via the DNO agreement. Any Attributable Works will be applied via the DNO agreement as in this case these all relate to assets charged directly to the DNO.

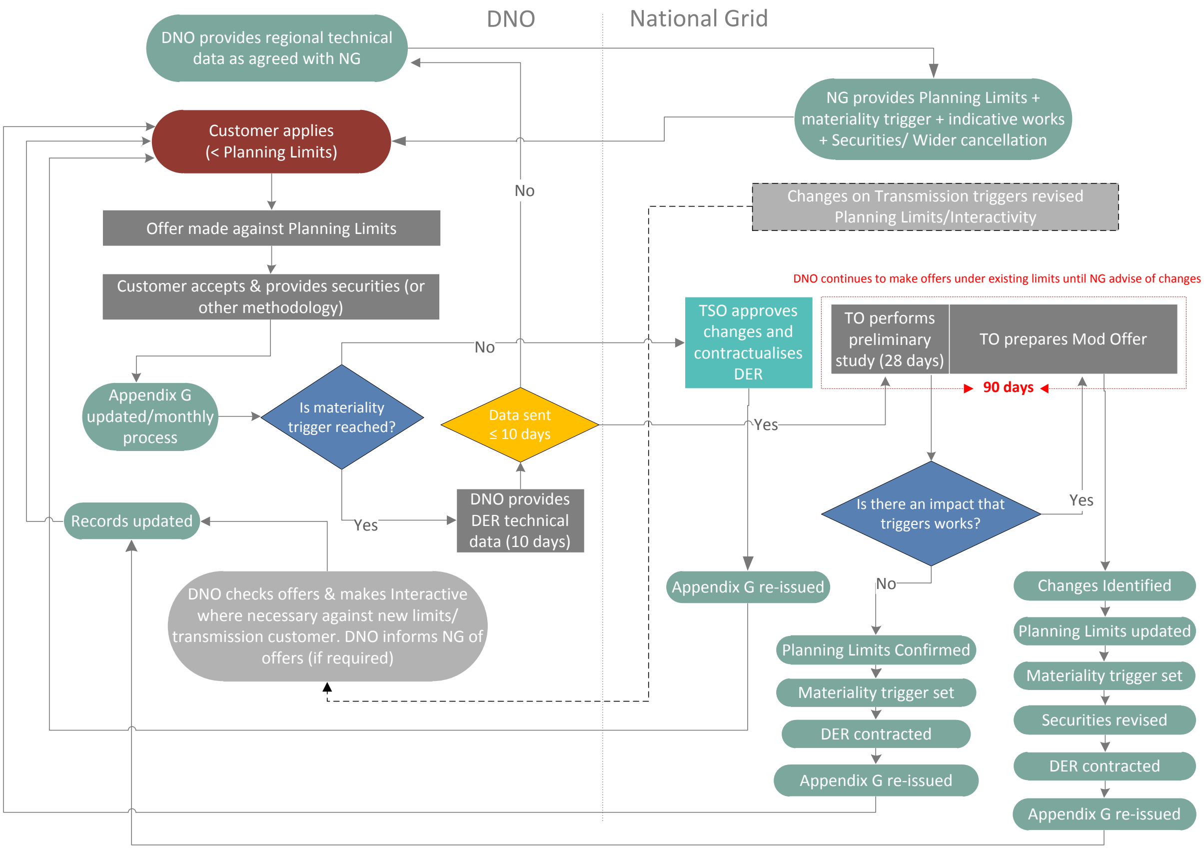
Transition of Generation with Non-firm Terms and Conditions and legacy Queue.

Ideally new terms and conditions would apply to all generation, but it is generally not possible to alter existing signed contracts and therefore the revised terms and conditions will only be enforced on new generation applications going forward. Any existing or contracted, but not yet connected generation will be able to transfer if they wish to.

The recent termination of a significant volume of offers in the area, means there are, at the time of writing, no accepted offers with interim restrictions on generator availability under outage conditions applicable, these would have been the main group to target for transition to avoid a limited numbers of customers under a different arrangement and to ensure longevity going forward. There would also be an advantage to this group of customers, giving them the opportunity to easily get paid for something that was previously uncompensated.

WPD will continue to apply queue management, where applicable, which will ensure that capacity is released when projects are not progressing and enable that capacity to be offered in the new arrangements.

Appendix 1 Revised Appendix G Process



Appendix B: Draft Proposals for the RDP Coordinated Procurement Principles

This section represents the initial thinking on the methodology behind the inclusion of DER services in processes for procurement of transmission constraint management services in the SW Peninsula.

Public engagement

National Grid and WPD will jointly engage with DER at suitable public forums to communicate the intent behind the need to procure transmission constraint management services from DER, whether on an ad-hoc basis, or via a more organised, tender-based approach. Any RDP tender for transmission constraint management services will be presented as a coordinated procurement exercise by both companies.

Requirements setting

For a tender-based approach, National Grid will define the requirement for the service to be economically procured, including from RDP participants, and will share this with WPD, ahead of tendering.

Bid information required from market participants

RDP bids will need to include price, availability, planned activities during the availability window (i.e. whether the DERs will be providing other balancing services, wholesale energy etc) and any other information that is jointly agreed by WPD, National Grid, and any other DNOs to be necessary for the efficient management of the distribution network.

Sharing of bid information

National Grid and WPD will have the same rights to access confidential information from bidders. WPD will need to provide reassurance to DERs that no conflict of interest exists between access to this information and its other activities in the flexibility space.

Selection of successful bids

Selection will be based on economic merit, based on price submitted, bidder availability, network availability, and effectiveness at meeting National Grid's fundamental requirement. To this end, the selection process will be a joint activity, with a joint recommendation.

Contracting party

The counterparty to contracts signed with successful bidders will be National Grid.

Interactions between RDP and Other WPD Flexibility Services

Every effort would be made to ensure compatibility and operability between services procured from DER to manage D network issues, and those procured by National Grid to manage T issues.

Appendix C: Glossary of Abbreviations

ANM	Active Network Management
App G	Appendix G – a list of DER that forms part of the GSP transmission to distribution bilateral connection agreement that details the terms and conditions how an induvial DER's are able to influence flows between the transmission system and distribution at the GSP.
AEC	Additional Export Capacity
AIC	Additional Import Capacity
AVC	Automatic Voltage Control
BCA	Bilateral Connection Agreement
BSP	Bulk Supply Point
BSouS	Balancing Services use of System
CBA	Cost Benefit Analysis
C+M	Connect and Manage
D	Distribution
DER	Distributed Energy Resource
DNO	Distribution Network Operator
DSO	Distribution System Operator, which is in license and regulatory terms the same body as the DNO, in this report the term DSO is used rather than DNO to indicate where there are changing and evolving responsibilities in the area of actively managing the distribution system.
ENA	Energy Networks Association
FES	Future Energy Scenarios
G59	The engineering recommendation document setting out the technical requirements for connecting power stations above 3.7KW to the distribution system.
GB	Great Britain
GCP	Generator Constraint Panel
GSP	Grid Supply Point
ICCP	Inter Control Centre Protocol
IEMS	Integrated Energy Management System
Least Worst Regrets	A method of analysing a range of uncertain scenarios and devising the current most economical way forward. See the RDP whole system planning – processes document for more details.
LCT	Low Carbon Technology
LCT demand	Low Carbon Technology Demand, for example heat pumps and electric vehicles.
LiFo	Last in First out
LoM	Loss of Mains – a protection system to prevent small generators from Islanding in the distribution system.
N-3	A term used to describe the condition on a network with "N" circuits when 1 circuit is out of service for planned work and another 2 circuits, that share common transmission towers, trip out of service owing to a fault giving N-3 circuits.
NMS	Network Management System
NOA	Network Options Assessment
NG	National Grid
NGESO	National Grid Electricity System Operator
PF	Power Factor
PAS	Platform for Ancillary Services

POC	Point of Connection
QMEC	Fair and Effective Management of DNO Connection Queues
RDP	Regional Development Program
SCADA	Substation Control and Data Acquisition
SGT	Supergrid Transformer
STOR	Short Term Operating Reserve
SOF	System Operability Framework
SoW	Statement of Works
SWOTS	South West Operational Tripping Scheme
SQSS	Security and Quality of Supply Standard (Applicable to transmission networks in Great Britain.)
SW	South West
SWPen	South West Peninsula – the name given to the transmission group that covers South West England.
SWALEX	South Wales Export – the name given to the transmission group that includes all south Wales and some nearby English GSP's that has a restriction on generation export capability to the wider network.
T	Transmission
TERRE	Trans-European Replacement Reserves exchanges – A European Union Energy Market requirement for the facilitation of sharing reserve services between member states.
TNouS	Transmission Network use of System
TO	Transmission Owner
TSO	Transmission System Operator
UKPN	United Kingdom Power Networks
WPD	Western Power Distribution