Regional Development Programme

South East Coast
Regional Strategy Document
Technical Report

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This is the final report of the "Design Phase" of the South East coast Regional Development Plan. The report summarises the work done and lays out high-level requirements for the "Implementation phase".

Contents

1 Introduction

1.1 What is a Regional Development Program?

The Regional Development Programmes (RDPs) were set up to provide detailed analysis of areas of the network which have large amounts of Distributed Energy Resources (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 moving towards Distributed System Operator (DSO) type solutions and informing thinking for the DSO debate.

By using innovative approaches to solving a specific case study that has a pressing need to improve outcomes for customers, it is possible to make progress faster than the more conventional method of agreeing changes in approach at industry forums; ahead of 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 GB network, this has been successfully managed by close collaboration and using the RDPs as case studies for the ENA Open Networks Project. Techniques and processes used within the RDPs can be used as the basis for a number of work packages within the ENA Open Networks Project and 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) practices. It has been considered logical to split each RDP into a high-level design phase, “Design Phase”, followed by a detailed “Implementation Phase” of the IS, commercial frameworks and control room processes.

1.2 Why choose the SE-Coast Network?

The SE-coast network has been chosen, because UK Power Networks (UKPN) and National Grid ESO (NGESO) identified that transmission capacity issues were beginning to impact on customer connection dates. DER developers rely on the ability to be able to connect to the network quickly, so this was perceived as a potential barrier to the growth of renewables in the area. UKPN engaged with their customers both at local and regional events, and established the need to move quickly in this area to resolve the network constraints affecting the connection of further DER. Through the RDP, UKPN and NGESO developed a set of objectives which were consulted upon, agreed through UKPN DER customer forums and ultimately delivered (or are in the process of being delivered). UKPN and National Grid have been and continue to be willing partners to innovate and overcome whole system challenges.

1.3 Executive Summary

This report documents the work completed and findings from the design phase of the Regional Development Programme, which will be taken forward into an implementation phase. Key outputs from the RDP were: a revised connections process to facilitate new DER in the area; the development of a mechanisms by which DER could be utilised to manage transmission constraints; enhanced off line Modelling of the T/D network; and enhanced real-time data sharing between control centres.

The following list summarises in more detail the achievements and findings of this RDP and remaining work to be implemented in the next phase.

Key Achievements:

1. Revisions to the DER connection package are now in place to allow DER customers in this area of the network to connect to in the timescales they require. This is an enduring process with no immediate cap on the volumes that can connect.
2. A new single stage connection offer process for applicants in this zone is now in place meaning that UKPN no longer makes offers subject to statement of works and generators now get all the distribution and transmission contractual terms in their offer within 90-days. This realises a significant an improvement of up to 12 months in some cases.
3. Harmonisation between transmission customers and distribution customers – a simplified connection process has been achieved and flexibility contracts are being developed.
4. The improved quality and flexibility of power system studies better inform the operability issues and technical risks in the area, and as a result have increased the capacity available in the area and enabled a process for managing DER to be devolved on an enduring basis.
5. The regional development work has built on the National Grid Electricity System Operator (NGESO) Network Options Assessment (NOA) process, which has greatly improved consistency between how transmission capacity is financed and allocated.
6. A process map for how services could be procured on a whole system and coordinated basis has been developed and was a key input into 2018 Open Networks Work Stream 1 Product 2.
7. The benefits of joint investigations of events affecting Transmission and Distribution were realised through analysis of inadvertent tripping of DER due to Vector Shift Loss of Mains Protection (LoM), with the findings feeding into industry programmes to change from Vector shift protection to high setting RoCoF.
8. A comparison of the cost and effectiveness of asset solutions (shunt reactors) installed on the distribution network versus equivalents on the transmission network to mitigate high voltage challenges was made. The initial findings were fed into 2018 Open Networks Work Stream 1 Product 1.
9. A system for assessing and managing service conflicts has been defined and a plan is in place ace to implement trials. These trials will provide the learnings for 2019 Open Networks Work Stream 1B Product 3.

As the RDP Continues into its implementation phase, stages for further development have been identified which will define the processes for transmission and distribution operational interactions. These are as follows:

10. Commercial arrangements and associated contracts for DER flexibility are in development to allow the appropriate level of participation without undue burden on infrequent participants.
11. First in class control system (Distributed Energy Resource Management System (DERMS) - Active Network Management (ANM)) schemes are under development to dispatch the flexibility required to allow DER to contribute to constraint markets and ensure the system remains operable.
12. A high level IS and communications architecture has been developed to provide: Control room to Control room Visibility and Control, Operational Intertripping and Service Conflict Management.

13. Further work is required to implement the control systems and interfaces within NGESO's Electricity Network Control Centre (ENCC) and to inform the suitability of service conflict protocols.

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, therefore requiring action by the relevant industry body:

1. The RDP has demonstrated both the value in NGESO modelling the effect of the distribution system on the transmission system, and UKPN having visibility of local transmission network data and embedded services. The RDP findings demonstrate, 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 and transparency on embedded TSO services. Therefore it is recommended:
   a) 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;
   b) Data exchange mechanisms of local transmission data and TSO services are put in place;
   c) Database, metering and calculation requirements are determined to ensure the residual 33kV or 66kV demands are accurately known; and
   d) The above are considered for application in both Investment and Operational planning processes.

   Action for 2019 Open Networks, Work Stream 1b, Product 4 to consider.
2. The RDP demonstrates the benefits of 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 to ensure any wider works are adequately secured on a fair basis. The rules for the inclusion of DER in the wider system cancellation 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. The best approach to managing the impact of distribution constraints on embedded NGESO services is still to reach consensus in the industry. It should be noted that the approach agreed for trial in the UKPN (South East coast) is different to that in the WPD South West RDP. The findings from the trials in this and the WPD RDP should be used to inform the debate on the best approach to take account of related activities and requirements such as Trans European Replacement Reserves Exchange (TERRE). **Action for 2019 Open Networks, Work Stream 1b, Product 3 to assess the outcomes of real time conflict of service trials.**
4. Comparison of cost effectiveness of reactors installed at transmission and a number of distribution voltages narrowed down the range of credible options but greater confidence in costs comparison is required to confirm the conclusions. **Action for 2018 Open Networks, Work Stream 1, Product 1 to assess the findings and undertake further development work as required.**

2 The Evolution of the Network

2.1 History of DER Connections within the South East Coast Area to Date

Traditionally requests for additional DER would come to NGESO via the Statement of Work (SoW) process and as part of this process the National Grid Transmission Owner's System Design department study the network with a limited representation of the DNO network. If there is no significant impact, the DER is allowed to connect. Where the DER has a significant impact, a full "Project Progression" process is required. This will result in either changes to the terms and conditions in the DNO connection agreement, or works required on the transmission system, secured via the DNO Bilateral Connection Agreement (BCA).

In the case of the SE-Coast, the agreements to connect new interconnector projects; NEMO and Eleclink had, in effect already used all the "traditional" capacity on this part of the network, already with a significant number of reinforcements planned and some non-firm capacity already agreed.

The Project Progression for the SE-coast DER used the best modelling available at the time and with some non-firm conditions allowed connection of all the immediate connections, but allowed little headroom for further connections.

The past offer that was made from National Grid to UKPN and which UKPN have used to connect c.1GW DER in this area was based on the original Appendix G trial format; this has already achieved a degree of redefinition of the relationship at the Transmission - Distribution boundary:

- The DNO has the ability to swap new technically equivalent projects for cancelled projects, even between GSPs;
- Where the GSP assets are connection assets, all of them in this case, the DNO have been given the technical capabilities of the assets. Then where the DNO or their customers decide not to invest in additional connection assets and prefer to curtail generation instead, the DNO can operate in effect on a DSO basis against these assets. This is achieved through managing the generation against the demand and capacity, from planning of capacity through to real time operation without further need to consult National Grid TO or NGESO. (Either or both National Grid companies remain responsible for transmission infrastructure assets and the risks, management of power flows and investment decisions for these assets);
- Requirement that DER have a 0.95 lead / lag MVAr capability to compensate for the steady state voltage issues they cause. Dispatched by fixed PF control. Most parts of the network now have steady state voltage issues, this allows for early connection against those issues on an uncompensated basis; and
- Requirements for emergency operation of the network have been clarified.

It is recognised that this was a trial and there were/are areas that require improvement:

- The concept of a limited Materiality Headroom has benefits in areas with a low volume of connections whereas in areas of high demand for connections this has made managing volume of potential new connections difficult and ultimately derives no benefit against the original SoW process;
- Security has not been effectively applied to DER, hence there is little incentive to stop unrealistic projects holding capacity at the expense of further projects;
- Transmission and distribution queue issues have not been addressed; and
- Does not address DER potential against the more complex voltage issues that often limit this part of the network. (Power Potential to help address.)

The transmission works planned or delivered to improve capacity on the SE-coast network include: Re-conductoring and thermal uprating of overhead line (OHL) circuits; the by-passing of limiting cables with high rated conductor systems; the addition of additional static and dynamic voltage compensation equipment; and the upgrading of control systems. All these works maximise the available capacity on the existing routes. That capacity has then been allocated to customers on the basis of the Security & Quality of Supply Standard (SQSS) and in the case of DER as modified by the requirements of Connect and Manage (C&M).

To go beyond the above with traditional transmission build solutions a new transmission route is required. This would be a substantial new route from the South East London area to Sellindge or the area west of Sellindge. The estimated cost of such a route would be £0.5 – 1 Bn with considerable environmental considerations, and hence a build estimate of in excess of 5 years.

In 2016, firm connections for additional generation in the area including DER were therefore made contingent on this new route, and the consents to build the route, potentially delaying new projects until 2026 or beyond.

2.2 Customer Needs

The DER community in this part of the network have expressed some frustration at being prevented from the connection of their prospective projects in the timescales they desire. The delays detailed above potentially remove the business case for many small players, which is often based around quick connection to take advantage of any incentives that may be available.

To address this, as detailed in section 1.2, UKPN engaged with their customers and gauged support to move towards more actively managed connections in this area, as a way of gaining access to the network in a timelier and cost effective way.

2.3 Overview of the Principle Transmission Issue[1]

The diagram in Figure 2.3 shows the SE Coast transmission network and associated generation in-feeds. Also highlighted is the overload and voltage collapse that results from one of a number of constraining network conditions most significantly the loss of the double-circuit between Kemsley and Cleve Hill. Under this scenario, there will be a requirement to constrain generation to manage the system.

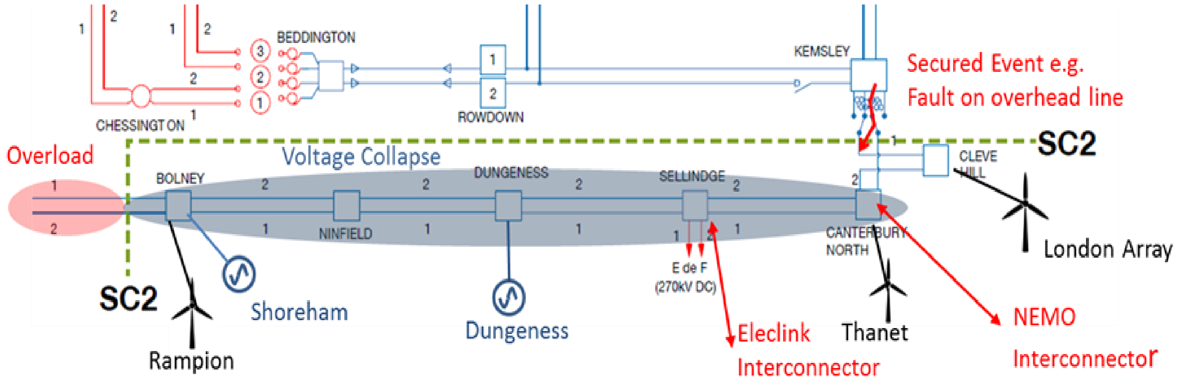

Figure 2.3 Overview of the South-East Coast transmission network issue

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[1] RDP analysis was conducted on the network ahead of the creation of Richborough GSP (attributed to the NEMO enabling works)

The transmission issue manifests itself upon the connection and commissioning of the NEMO interconnector to Belgium, which achieved full commercial operation in January 2019.

2.4 Identification of additional transmission network constraints

There are a number of additional network constraints both technical and commercial that need to be managed.

Technical:

- N-1 pre-fault thermal capacity for Canterbury – Kemsley, Canterbury – Clevehill and Clevehill- Kemsley circuit outages
- N-2 and N-3 thermal capacities
- The use of intertrips for N-3 capacity and the restriction on that intertrip owing to known performance issues of LoM protection being incompatible with frequency containment policy;
- Interactions with wider south coast boundary capacity issues (SC1), including SEPD and WPD DER for loadings on the Bramley – Fleet – Lovedean route. See Figure 2.4; and
- Transient over-voltages. Very short term (>100mS) and so difficult to control, but voltages high enough to damage plant and equipment. These tend to occur at high transfer levels when plant with naturally responding characteristics (e.g. Dungeness synchronous generation and / or saturated reactors) are out of service.

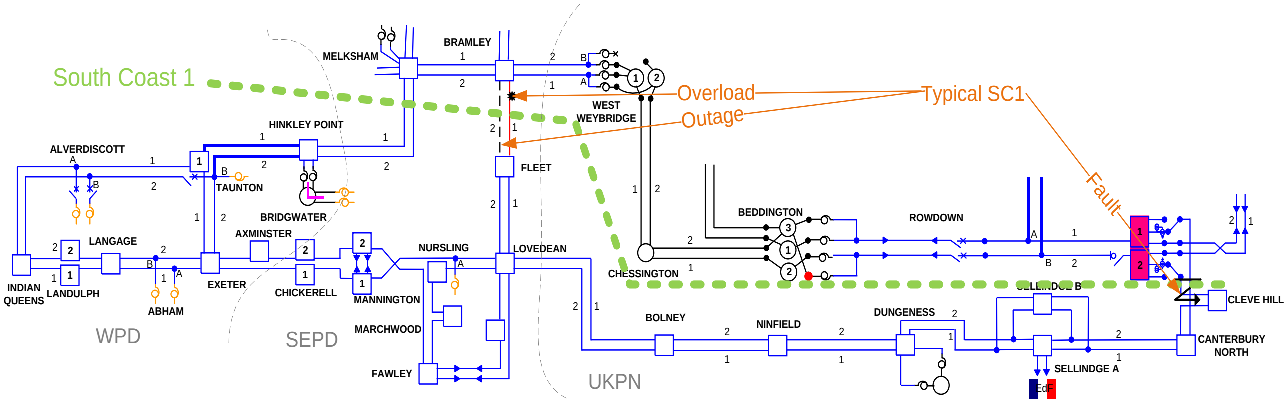


Figure 2.4 Diagram to show typical wider South Coast (SC1) Constraint.

Commercial:

- Resolve transmission and distribution queuing issues;
- Resolve capacity blocking and ensure transmission and distribution generation can access and secure on an equal basis;
- Manage energy storage and other flexibility effectively; and
- Ensure the market works fairly for both transmission and distribution generation.
- System Operability Framework (SOF) Issues (Not directly connected to SE coast or a blocker of connections, but RDP solutions help to resolve.)
- Insufficient controllable generation to balance and regulate the network; and
- Inadequate inertia to manage system frequency.

2.5 Overview of the Distribution Issue[2]

Figure 2.5.1 shows the South-East Coast distribution network and National Grid interface points (Grid Supply Points (GSPs)) considered under the Regional Development Programme.

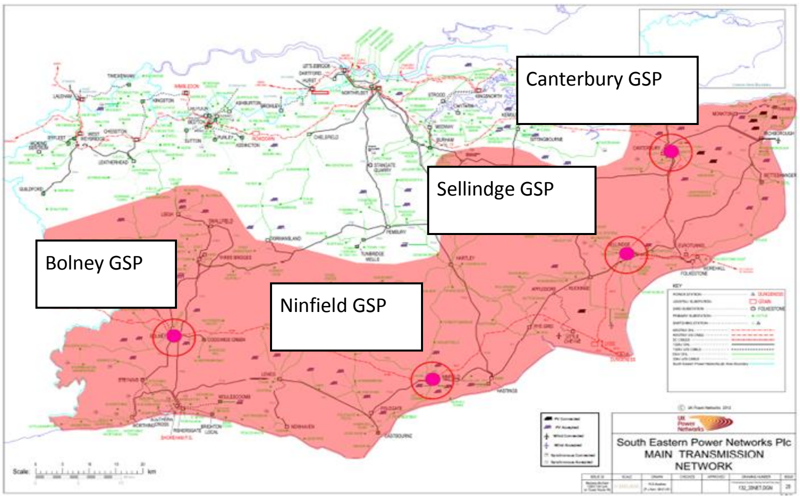


Figure 2.5.1 South East Coast Distribution Network

The South-East distribution network has seen a significant increase in generation connected over the past five years. This has resulted in distribution constraints emerging under certain load and generation patterns.

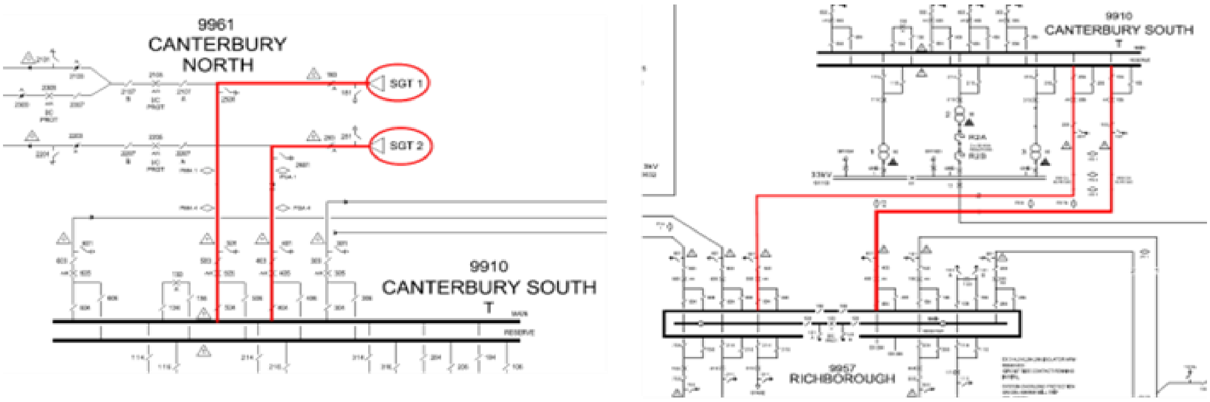


Figure 2.5.2 Overview of the South-East Coast distribution network issue

<u>PX Route – Canterbury South 132kV to Richborough 132kV (RH diagram Figure 2.5.2)</u>

This 132kV double circuit line connects the Canterbury South 132kV substation with Richborough 132kV. The latter is the point of connection for the offshore wind farm Thanet (300 MW). During

[2] RDP analysis was conducted on the network ahead of but was compatible with the creation of Richborough GSP (attributed to the NEMO enabling works)

certain outage conditions, the PX route can be overloaded. This overloading condition worsens depending on the direction of flow of the interconnectors and outages on the transmission network.

PMA/PGA Routes & Canterbury 400/132kV Super-Grid Transformers (SGTs) (LH Diagram Figure 2.5.2)

During key outage scenarios, it can be seen that the reverse power flow at Canterbury GSP and/or on its associated PMA/PGA 132kV circuits can exceed asset ratings. This is identified during outage planning; and DER curtailment pre-fault is necessary to avoid protection operation or damage to equipment.

Both areas present issues under outage conditions, particularly when considering the next fault. Both currently require significant constraints to be applied during operational timescales to resolve these issues, with a need to move towards faster control systems where additional DER export is to be considered.

Emerging constraints

There are a number of 132/33kV substations across the region with limited capacity, and an impending requirement to manage overloads should more DER connect.

The distribution system between Bolney - Ninfield; and Ninfield - Sellindge/Canterbury, is normally connected by loose couples at Lewes and Ruckinge 33kV, which depending on demand/generation across the region can have a significant effect on power flows in the area. Protection schemes are currently in place to ensure that overloads are prevented, however, these key pinch-points could be subject to overloads that would require managing should more DER connect in the area.

Following the NEMO works in 2019 it is anticipated that under outage conditions or when considered the next fault following an outage, constraints in the region would change and there may also be a need to apply curtailment to avoid damaging assets on the 132kV PF route between Ruckinge and Hastings.

2.6 Key areas of RDP Focus

This table indicates how the analysis under the RDP was broken down and the main outcomes.

Initiative	Main Objective	Outcome
DER Modelling Assumptions	To review, enhance and jointly agree the assumptions on generation and load in both the distribution and transmission network for the calculation of the key limiting factors including the voltage stability limit on the South-East Coast.	Revised modelling at transmission level and at distribution level. Modelled of the complete 132kV network to first busbar below 132kV. 1MW and above generation connected below 132 are represented by equivalent PV, Wind, thermal and battery generators at that bar. Work complete to study the limiting case for DER connections (high export from South East).
T/D Services Coordination (Service Conflicts)	To inform the procurement process for future ANM equipment and operational control protocols such that there is a management system in place to manage potential conflicting actions between the transmission and the distribution networks.	Principles for assessing service conflict in planning timescales were demonstrated with a successful case study. Trial agreed with DSO assessed approach and will be compared with TSO assessed trial in WPDs RDP area. Work ongoing to implement the IS architecture for the trial then feed learning into Open Networks.
Facilitating DER Services	Develop revised process for commercial services provision and future service procurement mechanisms. Seek to understand how services contracted from DER to resolve wider transmission system issues can most economically be connected in the distribution network	Work was complete to develop a joint NGESO/DSO process map on how coordinated service procurement could take place. Findings of the work have been fed into Open Networks for further development.
Getting more from ANM roll-out	To design Distribution ANM systems that enable visibility and control of DER for managing transmission constraints in the South East. The technical requirements of the ANM will be identified to satisfy both pre-fault commercial control and post-fault action delivery.	High level architecture at NGESO and UKPN developed for visibility and control including N-3 OTS. Supporting commercial framework in development with delivery plan in place. Further work on both will continue in the implementation phase.
Whole system network planning	Seek to prove the principles of whole system network planning by performing a cost-benefit analysis on high volts in the South Coast. To inform the necessary recommendations regarding processes to enable whole system network planning to be used going forward.	Assessed the cost/benefit of managing high volts comparing reactors connected at Transmission and Distribution voltage levels and fed to Open Networks. Further work required to gain greater confidence in distribution voltage installed costs.
Protection system stability	Determine the impact of current LoM protection settings on system stability after a fault. Determine how these undermine capacity and seek to address.	G59 under and over voltage protection impact for transmission faults studied for the area on a whole system basis. Interim approach for capacity release devised. Analyses of Vector Shift (VS) incidents informed a strategy to move c.800MW off VS in the Southern England in 2018.

3 Regional Planning

3.1 Our approach to joint T/D modelling & planning

There are a number of recent modelling and planning initiatives both within and outside of the RDP that if consistently applied can be used to improve the reliability and accuracy of our models:

1. Improvements in the offline transmission system load flow and stability model:
    a. New specific models now available to replace generic models for the transient behavior of various major components on the SE coast: IFA, Nemo, Saturable Reactor type SVCs and Statcoms.
    b. Enhancements to several dynamic models: Shoreham, London Array, NGTO SVCs
    c. DER above 1MW modeled separately from gross demand (split into directly connected demand and aggregated demand below 33kV) at the first 33kV busbar. Generation was 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, for generation connected at lower voltages this will always be an approximation on voltage performance.
    d. Operability review to ensure the proposed design can be operated in control timescales as intended and voltage profiles are both realistic and manageable. This is achieved by using the latest modelling techniques detailed above and more advanced dynamic modelling to replace current control room steady state modelling and processes.
2. Use of the BID3 (used for NOA) software to model more realistic pan European generation backgrounds, particularly to get interconnectors transfers aligned to the surrounding networks.
3. A better understanding of the application of European law on cross boarder flows and an improved understanding of what the European Code Requirement for management of interconnector capacity, Capacity Allocation and Congestion Management (CACM), could look like when fully implemented.
4. Consistency with the improved NOA process.
5. Adopting the key principle: The use of generation output curtailment or load increase (e.g. on storage assets), as an economic approach to manage constraints until reinforcement alleviates (see 3.2.1). UKPN and National Grid have developed a means by which this recommendation can be delivered, which involves ensuring new Distributed Energy Resource (DER) applications over 1MW are visible to the NGESO and controllable for managing both transmission and distribution network issues, allowing DER to be included in processes for managing transmission congestion.

3.2 Outputs of Planning Process

3.2.1 Major asset schemes in the future plan

A new route from the South-East Coast to South-East London would be the next in line transmission build solution for this area, given that all other cheaper thermal and voltage reinforcements are already built or under construction and were included in the background as far as the RDP studies were concerned. The 2016/17 NOA process did not trigger the proposed new transmission route and, at the time of RDP development, the same route was the Transmission “Enabling Works” holding off new DER connections in the area-an obvious inconsistency. A review of the need for this reinforcement to be enabling work for DER in the area was undertaken and it was decided that with the addition of visibility and control of the DER output it could be reclassified as wider works~~,~~ due to:

- The Seven Criteria in the CUSC that require the works to be classified as wider rather than enabling now being met, particularly:
    - The operability requirements (ability to operate the National Electricity Transmission System in a safe manner) stemming from Connect and Manage were ensured through the requirement of visibility and control placed on the new DER connections.
    - The Connect and Manage pre-fault criteria were re-assessed with more detailed data made available from and consistent with the NOA output and on that basis 4 FES scenarios showed compliance with the pre-fault criteria for the lead time of the proposed works.
    - Under Connect and Manage the contribution from each individual small DER connection must be considered against the system background that is reasonably expected rather than any contractual background.

- In addition:
    - The 2016/17 decision for the route not to be built hence holding DER connection for this route could would not also be logical, or economic and efficient. Even though subsequent NOA assessments came to different recommendations [3] the decision to classify as wider works is still seen as valid as the seven CUSC criteria are met and all NOA assessments consider in their options underlying DER growth and assess the constraint of generation flows in the area on a commercial basis until the route is built. Further, each individual small generation application is not yet proven to be uneconomic.

3.2.2 Compatibility with SQSS and Connect and Manage

The SQSS security standard should be applied to the network ahead of the economic standard, which is what NOA applies. 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 on 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. That is particularly important for the SE coast network because interconnectors can now bid into the capacity mechanism. It is therefore proposed to apply the SQSS security standard, by applying that generation that has won capacity market tenders to the study, rather than the SQSS generation background. In practice with a high demand in the 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.

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 do not require to be completed

[3] The 2017/18 NOA recommended to progress a feasibility study for one option for the new route, and for the 2018/19 NOA that option had been discounted due to access issues but an alternative option was recommended and approved as "proceed".

before connection provided the network also passes an economic test. The economic test is now NOA and so that is passed in this case.

Detail analysis 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 obtained 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 T's & C's. In this case, there is one action that requires action from the developer and DNO. That is the provision of N-3 intertripping to ensure post fault overloads can be managed in the most economical way.

It is therefore necessary to include the requirements for the N-3 intertrip in the NGESO-DNO BCA and the DNO – DER connection agreement (considered under 'Abnormal Conditions'). Also, a suitable operability scheme is required to trip the generation. It is proposed to interface the Sellindge OTS scheme to the ANM scheme controlling the DER to provide this functionality.

3.3 Identification of connections capacity and agreed approach to T/D capacity allocation

3.3.1 Capacity Available

Using the above approach, capacity levels consistent with the FES scenarios should be available. Each application would be considered under the principles of C&M, which requires the generation background to be set to those which ought reasonably to be foreseen to arise in the course of a year of operation. Detail of the application of FES scenarios to this zone are in Appendix A. In summary, scenarios with increased DER, on average showed lower South Coast constraints in the 2016/17 NOA. On that basis, there is no reason to put an immediate cap on the volume of DER that can connect. Although good management of new connections to the network is required to ensure provide the necessary data to allow effective management of the network under the Connect and Manage principles. FES assumptions will be updated annually using this connections data and other industry intelligence.

This group aligns with a standard NOA boundary and that will also be reassessed annually based on latest FES. It is unlikely this will result in any change to DER connection policy in the area. If it did the principles of C&M mean it would not apply to any existing contracted connection that progressed to connection within or close to their contract. Any change would only apply to new applications going forward.

For the SE-coast DER, a period in excess of 5 years is analyzed aligning with the likely consenting and build time of a new circuit route, that if deemed economically viable, would be built to relieve the capacity requirements on this part of the system. Large amounts of capacity are therefore assumed to be available after this time.

3.3.2 Fair Capacity Allocation / Securities

To ensure the allocation of capacity is consistent and that applications are fairly handled between transmission and distribution connections, and due process is in place to apply Connect and Manage principles fully, the transmission wider network cancellation fee will be consistently levied to all applicants. This was previously not effectively applied to DER in this area as it only starts for 4-years prior to trigger. In the traditional build then connect world, the trigger is the end date of works and therefore was aligned with firm access via a new circuit build in 2026 and therefore did not kick in until 2022, after all the DER applicants want to connect. Under the C&M regime, the trigger is each DER providing visibility and control and therefore is the individual DER applicant's connection date. The wider cancellation fee is a socialised cost per MW that represents the cost of cancelling wider transmission works (which are themselves socialised in the C&M 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 is 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. Conversely, if the generator's 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 the expected commitment from a DER 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 and 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 providing capacity at their requested date. This is resolved by the application of QMEC,[4] which is the new agreed industry standard on fairly administering queuing processes for DER.

3.3.3 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. Further work was required to achieve the ultimate goal- that a DER customer could always get an offer in 90-days inclusive of all the transmission and distribution contractual requirements and not subject 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 C&M 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 UKPN 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

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

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 B and illustrated in the diagram below.

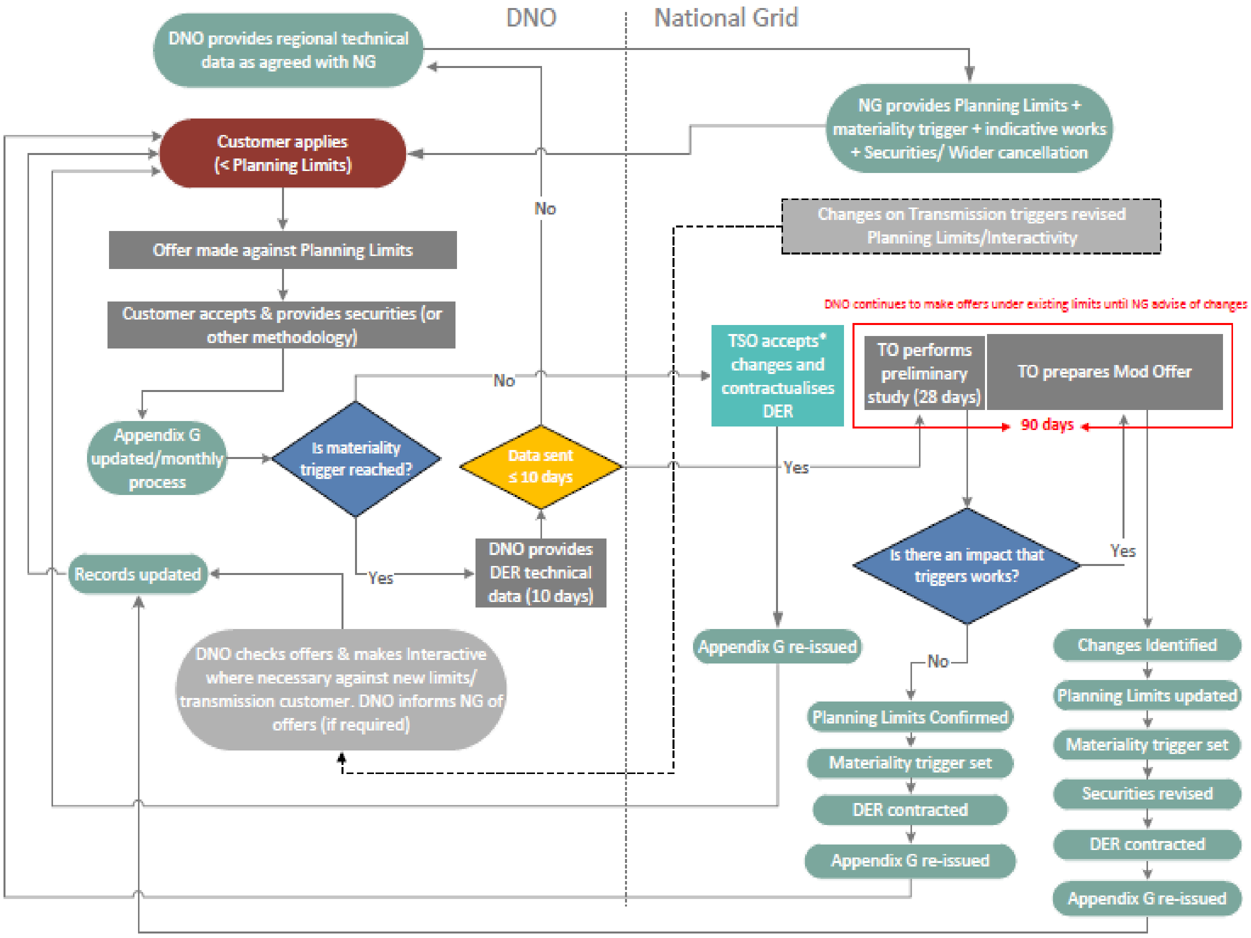


Figure 3.3.3 Revised T/D Appendix G Process

3.3.4 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 to 12mth period of uncertainty around whether to invest in their development (this is illustrated on the left of Figure 3.3.4 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 UKPN connection offer (right hand side of diagram below). This offer is usually with the customer within 70 days, but no longer than 90 days from application.

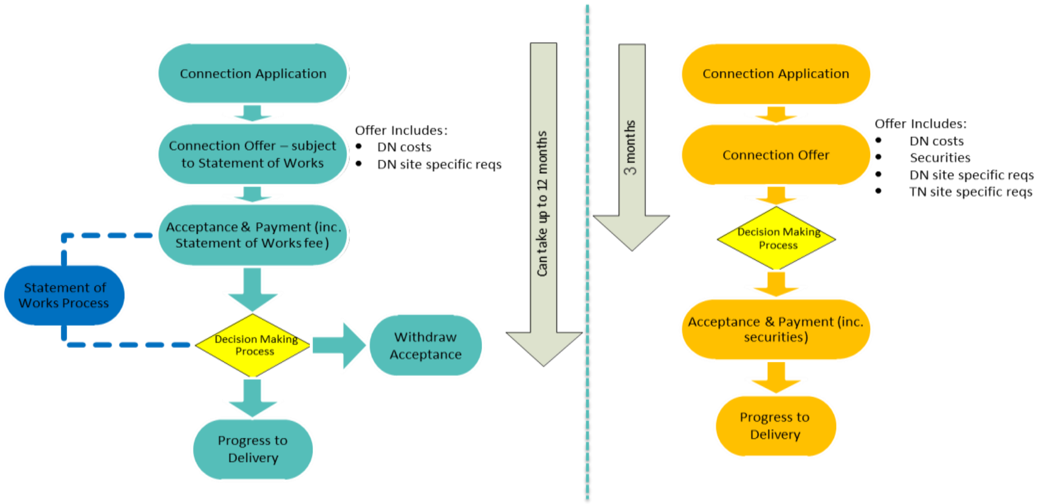


Figure 3.3.4 Changes to DER / DNO Connections Process and Contracts

Customers in this area will now receive a UKPN 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 Loss of Mains (LoM) protection to be provided in the form of High Setting RoCoF (for small generators); and
- 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.

Increasing the capacity for new DER connections on the SE coast network relies heavily on post fault fast auto-de-load of interconnectors to arrest voltage collapse, along with tripping of DER and other generation to remain in thermal limits after a fault. The volume of generation fast de-load / disconnection must be carefully controlled to be enough to resolve the voltage collapse / thermal overload issue, but must not exceed frequency containment policy. The unpredictable nature of Vector Shift protection presents the risk of not keeping the total loss within that required band. This is further aggravated by RoCoF relays being originally set to a policy of 0.125Hz/s with no specific time delay. On a low inertia network, typically seen under the high interconnector import / high renewable output conditions, that limit the capacity on the SE Coast network, the inertia of the network following an unplanned large generator loss is low presenting a risk that RoCoF on DER operates tripping the DER, and accelerating the frequency decline. Constraint management will at times of high transfer require a double circuit fault out of the South Coast group to be secured by the arming of 1000MW fast interconnector de-load to Operational Intertripping. To secure the coincident loss of infeed (interconnector and Vector shift) could present a frequency management (RoCoF) risk. It is not possible for the 1000MW fast de-load volume to be reduced on reliance of DER tripping on Vector Shift.

In the event of a combined loss exceeding RoCoF trigger levels, the frequency decline would eventually be arrested by Low Frequency Demand Disconnection (LFDD). The LFDD is in itself located upstream of much of the DER and will trip groups that include volumes of DER and so will need to disconnect significantly more demand blocks until it eventually finds a balance.

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.

3.4.2 Action Taken

OFGEM have approved Distribution Code working group DC0079's recommendation to implement, in the Distribution Code and Engineering Recommendation G59, a new LoM policy. From 1st February 2018, non-type tested generation commissioned after that date now needs to conform to a RoCoF setting of 1Hz/s with a 0.5s time delay and is no longer be permitted to employ Vector Shift as a method of LoM protection. Following network studies conducted under the RDP, UKPN made a proactive decision to adopt this new LoM policy ahead of the proposed code modification, for all new connections in and around this zone. The authority has also approved implementation of the new policy for all new type tested generation as of 1st July 2018. A retrospective code change and programme to remove Vector shift completely is in advance stages of discussion by the same working group.

UKPN and National Grid along with SEPD and WPD South West worked closely to analyse historic transmission faults dating back to March 2016 which had been observed to have noticeable increases in "transmission demand", i.e. DER MW losses. These were correlated against DNO data of DER sites observed to de-load and their expected method of protection. The results provided three useful outcomes:

- The losses were nearly entirely down to sites with either known Vector shift (VS) Protection or likely to have VS fitted (derived), reinforcing the need case for a move away from this type of protection;
- The losses allowed estimates for prediction of the extent to which Vector Shift losses would spread and therefor what capacity would be at risk for faults in the southern England transmission system; and
- The findings helped form the requirements for strategic volume change. A strategic volume, c.800MW, of plant across Southern England employing vector shift protection was changed across the three Southern Most DNO licence areas (UKPN, SSE and WPD), completing prior to Summer 2018. This significantly reduces the risk that following a transmission fault in the area a system RoCoF will exceed the 0.125Hz setting.

3.4.3 Control of Residual Risk

There is still a risk of spread outside the zone and operation of existing relays within the zone. There are 3 stages required to manage this risk to at least the level it would have been without further DER connections in this zone:

1. Prior to Nemo link commissioning. – Transfers from the SC2 group were thermally limited rather than voltage limited. The hotwiring of the remaining low rated circuits in the group has been completed. This together with the thermal uprating for Nemo / Eleclink that is already complete provides more capacity on the network. Although this does not remove the need for the intertrip it allows for the selection of a smaller volume, i.e. in practice smaller generators can be selected to the intertrip. The end effect leaving more bandwidth between the network thermal limit and the RoCoF trigger for uncertainty around Vector Shift.

2. Between commissioning Nemo and commissioning of Eleclink: Works for NEMO include new voltage compensation (Statcoms and fast switching MSC's) and a replacement of Sellindge Operational intertrip scheme, which can be set more flexibly, especially the time delay function. On completion of the new voltage compensation it is then possible to operate the network away from the voltage collapse limit and make use of time delayed intertrip. Time delaying the intertrip by a number of minutes moves the loss caused by the intertrip away from the potential loss caused by Vector Shift protection reducing the maximum instantaneous risk and therefore the RoCoF risk.
   Note the above 2 measures do not solve the underlying LoM issue, they mean the network can be operated such that any newly connected DER do not make the issue worse.

3. Following commissioning of Eleclink – Under this condition larger volumes of intertrip will be required at times of highest transfer. Initially the retrospective programme coming from DC0079 may not be completed prior to Eleclink commissioning and so fast de-load will be at times limited to ensure that the combined loss of intertrip plus vector shift loss is securable. It will also be prudent for the wider programme to target changes with higher risk, such as the South East, first.

3.4.4 Further Work

Further work in this area shall constitute the implementation of the wider programme of change from Vector shift or low setting RoCoF to high setting RoCoF.

3.5 Whole System Approach to the Contracting of Services Including Storage

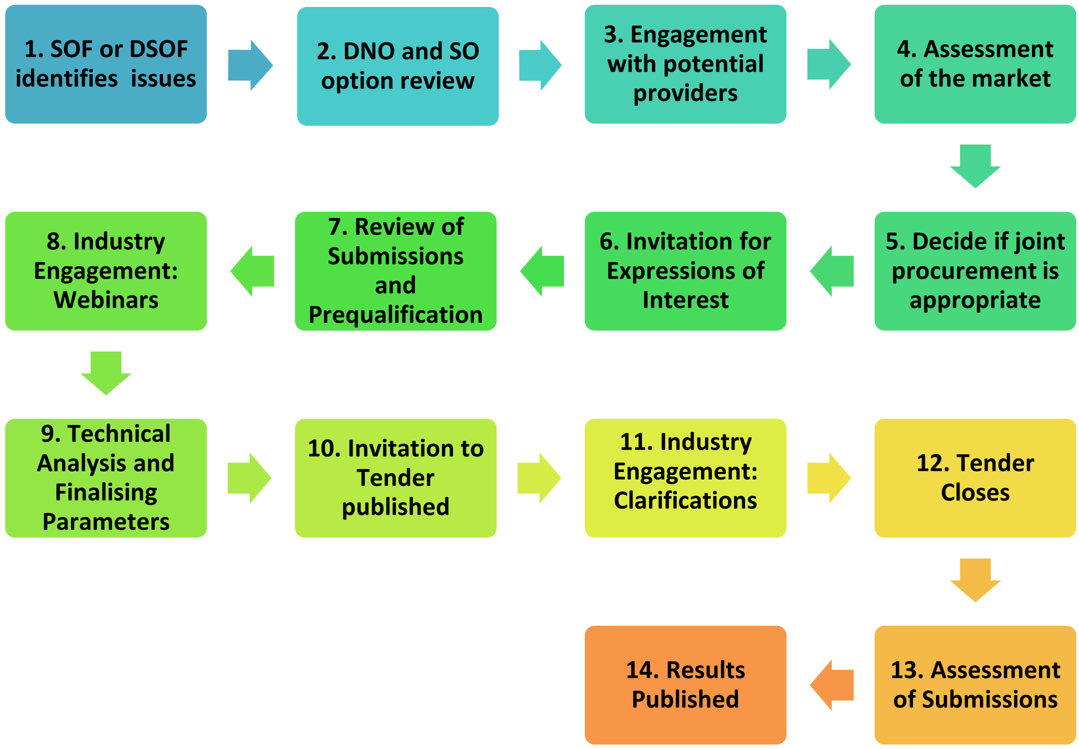
3.5.1 Approach

A review of the process for developing balancing and system services has taken place to understand how this process could be better coordinated between NGESO and DNOs to ensure that services developed by either party have a more optimum impact across the whole system. The recommendations from this work were fed into the Open Networks.

In reviewing this process, we have considered that either party might initiate a new service as both DNOs and NGESO look for new ways to manage operational challenges. With service providers becoming increasingly decentralised the likelihood of impacts being on both parties are increasing. Proposed process improvements are described below to highlight several opportunities where collaboration between DNOs and NGESO can lead to better outcomes for both parties.

The process for procurement should facilitate a level playing field for all capable technology types. A summary of the proposed process is included below a more detailed report on the findings will be provided by Open Networks.

3.5.2 Coordinated Service Development Process Model



Process step	Opportunity for whole system coordination
1. System Operability Framework (SOF) or Distribution System Operability Framework (DSOF) identifies issues	• Joint investigations to be included in publications • Consult specifically with DNOs on SOF topics and NGESO on DSOF topics • Arrange networks specific workshops to discuss topics following publication
2. DNO and NGESO option review	• Identification of shared service needs and synergies • Identification of restrictions and network impacts • Identification of potential providers across both transmission and distribution • Early management of network impacts
3. Engagement with potential providers	• Representation from both DNOs and NGESO • Clear RACI so that potential providers know which party they are best to speak with about different topics.
4. Assessment of the market	• Identification of potential from new connections to be stimulated and where • Consideration of indirect admin costs across both transmission and distribution
5. Decide if joint procurement is appropriate	• Coordinated procurement - Where we expect there to be some interaction (e.g. NGESO and DNO require a different service from the same assets) a coordinated procurement approach will be used; or • Joint procurement – Where there is a clear synergy (e.g. where distribution constraints align with transmission constraints) the DNO and NGESO will work together to procure a single service.
6. Invitation for expressions of interest	• Publication of heat-maps allows providers to see where there is most value to connect
7. Review of submissions and prequalification	• Check point with DNOs can be introduced to ensure connection applications are consistent with service requirements • Establish if there is any conflict of service provision

Process step	Opportunity for whole system coordination
8. Industry engagement and webinars	• Representation from both DNOs and NGESO • Clear RACI so that potential providers know which party they are best to speak with about different topics.
9. Final technical requirements and commercial arrangements agreed	• Where joint procurement is taking place as well as the technical parameters being agreed, the flow of payments between parties needs to be clearly mapped out. The service will need to be developed taking into account existing risk and reward frameworks and incentives and any need for changes to these. By this stage assessment, dispatch, visibility, settlement and systems development all need to be significantly developed.
10. Invitation to tender published	• Representation from both DNOs and NGESO • Clear RACI so that potential providers know which party they are best to speak with about different topics.
11.Industry Engagement: **Clarifications**	• Clear RACI so that potential providers know which party they are best to speak with about different topics.
12. Tender submission	• Where joint procurement is used a single but shared route should be agreed for the submission of tenders.
13. Assessment of service	• The interaction of services may need to be taken into consideration in the assessment of the value of the service
14. Results Published	• Currently the information published about contract acceptance does not include information about the specific location of the successful sites. Knowing what services connectees are participating in could allow DNOs to make better assumptions in how to efficiently manage the distribution network for network planning

3.6 Whole System Approach to Steady State System High Voltage Control using Static Plant.

3.6.1 Introduction and Scope

The Power Potential project considers an operational solution to high volts as opposed to asset based alternatives. For completeness, it was considered appropriate to perform a case study and cost benefit analysis on the effectiveness of asset based solutions on the distribution network, as mitigation to the High Volts issue. The scope was as follows:

- Estimate the "effectiveness" of reactive power compensation at different distribution voltage levels, namely 11kV, 33kV and 132kV.
- Collect cost information associated with the available options at 400kV, 132kV, 33kV and 11kV
- Analysis of above to compare transmission connected equipment to that connected at distribution voltage levels.
- Feed learning into 2018 Open Networks WS1 Product 1

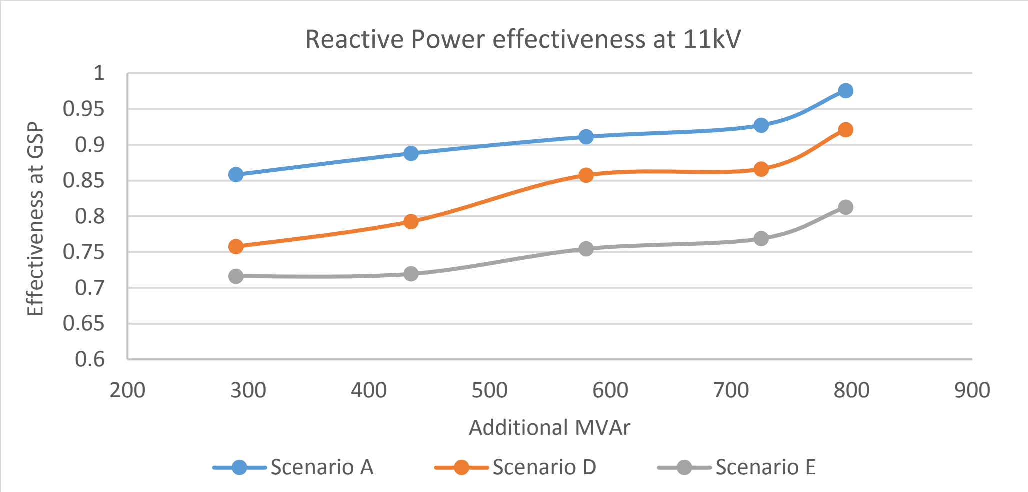
3.6.2 Reactive Power effectiveness

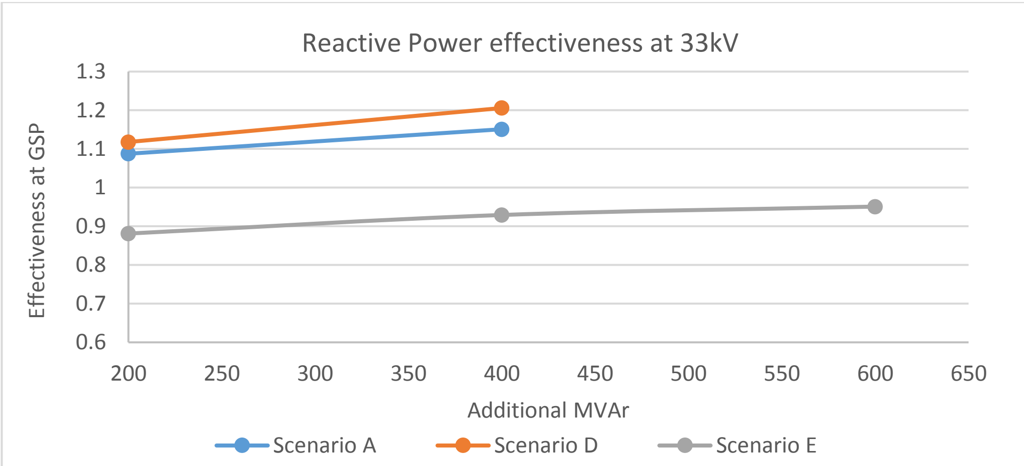
The first part of the study looked at the impact of installing reactors at different distribution voltage levels. The impact was reflected by the absolute change in MVAr power exchange at the HV side of four GSPs (Bolney, Ninfield, Sellindge and Canterbury North) after increasing the reactive power demand connected on 11kV, 33kV and 132kV bars in separate cases. By applying the increase at several bars of the same voltage, the study was deemed adequate to capture the cumulative effective of the solution and was considered equivalent of installing reactors of equal net size.

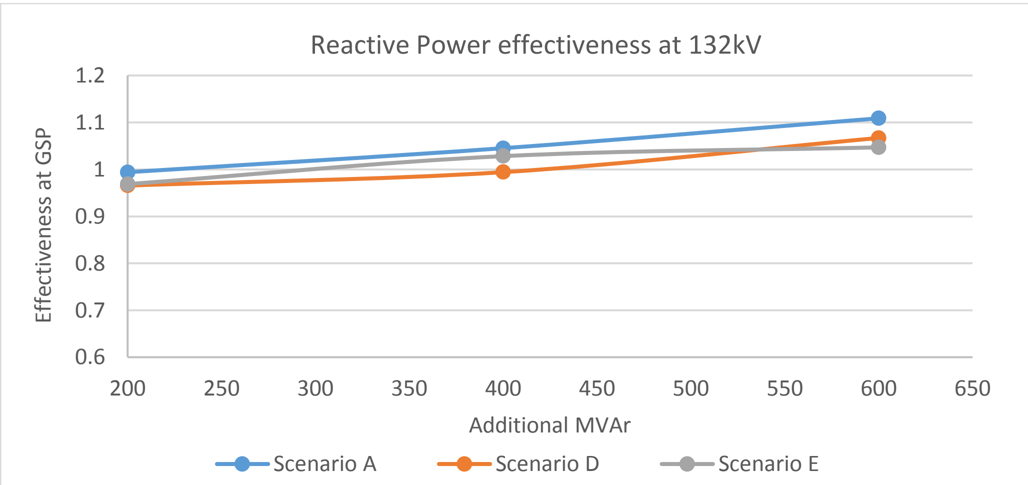
Installing reactors of equal size at the HV side of the SGTs was defined as having an effectiveness of 1. As such, effectiveness above 1 would mean that installing distribution reactors is more electrically effective than the equivalent of transmission reactors and vice versa. The effectiveness was calculated using a number of base case scenarios, which reflect the starting point of each study (i.e. before any MVAr were added). The selection of scenarios was aimed at capturing different cases of reactive power exchange between the distribution and transmission networks:

Scenario A Winter Peak, **Scenario D** 1pm Summer solar Peak, **Scenario E** 6am summer Minimum.

The following graphs represent the study results per voltage level. The vertical axis shows the effectiveness and the horizontal the number of additional MVAr distributed at the respective voltage levels.







The upper limit of the horizontal axis was restricted by the capability of the network model to converge after increasing the reactive power demand, for instance, when running the study at the 11kV level, additional MVAr above 800MVAr resulted in non-convergence.

Due to practical reasons the studies had to run using different models; 11kV ran on UKPN model and 33kV and 132kV ran on National Grid's model. This explains the differences observed in the scenarios between the graphs. Despite these differences though, a number of useful conclusions were drawn:

- The more reactors installed at the distribution level, the higher the overall effectiveness;

- The solution is more effective when the demand is high. However, leading reactive power compensation is most likely to be needed when the demand is low;
- Highest effectiveness is achieved when connecting reactors at 33kV and 132kV; and
- The dynamics of the distribution network as far as the reactive power is concerned (gain and losses) are highly dependent on the voltage level the compensation is applied at.

3.6.3 Costs

The study considered the costs associated with designing, procuring, installing and testing the reactors and necessary switchgear. Initially, Operation and Maintenance costs were left out of the study. The benchmark for comparing the different options was two 200MVAr, 400kV reactors from National Grid TO as built costs. As-built cost information for reactors of lower voltages were more difficult to obtain for distribution type connections. Existing information on 132kV installed reactors was used and extrapolations made where information was not readily available.

3.6.4 Results

The first part of the study showed that installing reactors at 33kV could potentially be a more effective solution as it presents high effectiveness (1.1-1.2) for two of the scenarios. However, the effectiveness is below 1 for the most onerous case (Scenario E) when reactive compensation will most likely be required. There was a similar trend for the 132kV option although in this case all scenarios demonstrate an effectiveness of 1.0-1.1. The effectiveness given by the 11kV option is well below 1 for all scenarios. Based on the above, when looking at Scenario D, then to get the equivalent of 400MVAr at the HV side of the SGTs (base case), would need one of the following:

<u>Option 1 – reactors at 11kV</u>

In this case and for an average effectiveness of 0.75 would need 400 / 0.75 / 5 = 107 x 5MVAr 11kV reactors. The cost of this option was significantly above the corresponding equivalent transmission solution (2x200MVAr reactors). Another implication with this option would be the size of the required breaker, which might be unlikely to fit into a primary substation.

<u>Option 2 – reactors at 33kV</u>

In this case and for an average effectiveness of 1 would need 400 / 1 / 25 = 16 x 25MVar 33kV reactors. The cost of this option was similar to the corresponding equivalent transmission solution (2 x 200MVAr reactors).

<u>Option 3 – reactors at 132kV</u>

In this case and for an average effectiveness of 1 would need 400 / 1 / 120 = 3.3 x 120MVar 132kV reactors. Following a bottom up approach to costs, the estimated cost of this option came out lower than the 400MVAr base cost. The Option 3 costs did not include additional complexities, such a requirement for “tap-able” reactors to limit step change which may be required for reactors above around 60MVArs connected at 132kV. However, analysis of a third party TO’s cost for similar size reactors with this option came out higher than the 400MVAr base cost.

3.6.5 Conclusions

From the above analysis, it is evident that, in general, economies of scale tend to favour higher voltage options. Cost variations in the assumptions for distribution connected equipment introduced significant challenges in achieving a robust decision – the difference between the third party cost and the bottom up approach differed markedly. For this study, Options 2 and 3 (reactors at 33kV and 132kV) may be more efficient but only on a case by case basis, depending on the chosen location and site/cost implications. Option 1 does not seem to be of any benefit under any of the scenarios studied, however further work that challenges the concept of traditional voltage regulation may arrive at a different conclusion in the future.

This study was carried out as part of the RDP project to investigate the merits of installing distribution reactors to resolve a transmission network issue. However, with the current planned works at this part of the network and the Power Potential project there is no immediate need for further reactive compensation in this area. Nevertheless, this work is a first attempt to carry out a whole system cost-benefit analysis and its main conclusions are useful for other projects and initiatives. Key learning derived is the challenge of comparing costs quoted by different organisations since they couldn't be demonstrated to be on an equivalent basis and this is essential in order to make a realistic comparison.

3.6.6 Recommendations for Further work

For the above analysis to be carried out, there were two simplifications made:

- Reactors at one voltage level only
  Reactive compensation equally distributed among all bars at the same voltage level

When proceeding with similar studies, it is recommended to analyse the effect of installing reactors at areas/substations with the highest effectiveness. A combination of reactors at 33kV and 132kV may be adopted. This approach will most likely result in higher efficiencies. At the same time, the implication of operating and maintaining the assets should also be considered as multiple numbers of assets installed at different locations would generally be more expensive.

In addition, the constraint of maximum size reactor, to avoid breaching the voltage step change limit (3%), could be overcome by installing multiple units only at the most efficient sites (higher effectiveness) but making sure they are switched on/off in steps. Extensive studies to fully understand the impact of the proposed solutions on the distribution and transmission network (e.g. voltage behaviour) should also be part of a more detailed assessment.

The conclusions, further work and learnings have been highlighted to ENA's 2018 Open Networks Work Stream 1 Product 1. Wider industry support in carrying out further analysis would help eliminate uncertainties surrounding costs and detailed specifications.

4 Operability Scheme Design

4.1 Introduction

The area to be covered by UKPN's planned ANM scheme will be Bolney, Ninfield, Sellindge, Canterbury and future Richborough GSPs. In effect this is the same area as, and is a similar approach to, the scheme being developed under the Power Potential project, without the MVAr calculations and dispatch. UKPN are designing a new system called Distributed Energy Resource Management System, "DERMS" for both Power Potential and to complement future applications of ANM.

The Distributed Energy Resource Management System (DERMS) is a software-based solution that increases the DSO operator's real-time visibility into its underlying distributed asset capabilities. By collating network information and DER technical/commercial data, the DERMS will calculate the optimum DER production dispatch that satisfies the MVAr and MW services requested by NGESO, at the lowest cost. The DERMS platform will provide visibility of network availability and act on instructions provided via UKPN and NGESO. The DERs will interface with the system via an on-site RTU and will receive signals to provide an increase or reduction in MW or MVAr, as needed.

The intention is to provide the RDP requirements by supplementing this with ANM technology to provide the required functionality for despatch of MW required by the new connection agreements - see 3.3.4. It should be noted that new connecting DER will have the alternative option of NGESO despatch, not via DERMS/ANM, where they choose to do so e.g. those through third party aggregators or DER offering additional NGESO services. Notwithstanding this, the DERMs/ANM and associated customer site equipment will still need to be in place to meet the DNO's own constraint management requirements.

To facilitate the requirements derived under the RDP and those associated with the management of distribution constraints (i.e. ANM), new software will be required over and above that being specified under the Power Potential project. It is intended that funding for both the RDP and ANM requirements is achieved through normal 'business as usual' charging methodologies. This is clearly separate from, and will not be supplemented by, the NIC funding associated with the Power Potential project.

4.2 NGESO Scheme Requirements

A despatch tool capable of interfacing with UKPN's ANM will be required. One option being considered is that the "Platform for Ancillary Service" (PAS) tool, developed by NGESO, as is the case for Power Potential.

4.3 Local operability schemes

4.3.1 Principles of MW dispatch

Consideration was given to establish the most appropriate way of coordinating the dispatch of DER for transmission and distribution services in real time. The key principles that were considered to apply are:

1. Under normal operation, security of the distribution network will always be maintained by the DNO's systems (DERMS/ANM).

2. Automated systems should indicate to the TSO where despatch of an embedded NGESO service will be prevented or nullified by the DNO/ANM. This system should at least provide visibility to NGESO of service availability close to real time and ideally hours ahead.

3. Further work is required to determine Transmission / Distribution processes and the action of DERMS under emergency conditions where it may be desirable for wider network security to take precedence over local security. Such emergency priority will likely be over and above the scope of the trial under this RDP.

4. The proposed South East Coast ANM should have the functionality to hold “spare” headroom or footroom to accommodate transmission services such as frequency response, where it is appropriate and agreed to do so. It is acknowledged that supporting commercial work would be required to make this acceptable and would be considered under a future phase of work.

To achieve the requirements of (2.) above, two options were considered and they are summarised below. The chosen option for this trial area was to deliver Option 1, in the UKPN South East RDP area, and to bench test, TSO-led. This approach was chosen as:

- Option 1 has a high degree of synergy with existing UKPN DERMS design and explores the idea that a DSO analysed approach may provide better optimisation/accuracy;
- Option 2 is planned to be trialled in WPD South West RDP area in roughly similar timescales which would allow a good comparison with this trial for Open Networks learning.

4.3.1.1 Option 1

Involves three possible stages with Stages 2 and 3 pursued if DSO industry direction merited. Stage 1 of this approach involves the NGESO systems providing UKPN’s ANM with a list of DER services and the order of priority under consideration for instruction, determined by system needs and priorities. This creates a pseudo LIFO (Last-In-First-Off) stack for ANM power system analysis at regular intervals, to determine the effective service capacity considering the expected impact of DNO ANM operation. The selected priority will affect the effective maximum availability of each service with reduction assigned using the pseudo LIFO stack. ANM can include in its assessment the impact of services procured by the DSO, such as Demand Side Respond and/or actions being taken for Flexible Connections. The result of the analysis is fed back to the NGESO control room and this could take various formats e.g. per DER, total service per GSP/area or both. An interface to the NGESO control room would be required and might look like the following table, and could be considered for incorporation into existing NGESO tools.

DER	Activate (ordered by priority)	Nominal service (MW)	Effective service (MW)
DER1	X	5	5
DER2		10	-
DER6	X	7	6
DER5	X	15	10
DER3		2	-
TOTAL		27	21

A possible advantage of this option is that the DNO ANM has a more complete and automated visibility of the distribution network state and DER impact on it, such as nested constraints and DER sensitivities. A challenge to address is that the volume of effective service depends on the selected order of DER to be dispatched. If NGESO's system priority changed a new priority order would need to be submitted by NGESO to ANM for ANM to respond to the new order.

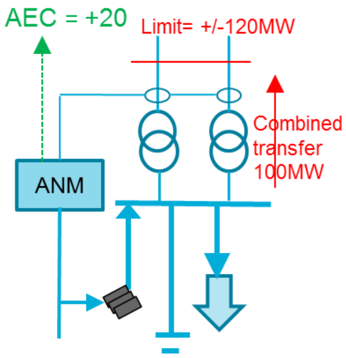
Possible future developments to this approach could be: Stage 2, a recommendation that maximises the available service or should the industry DSO model develop in such a way Stage 3. Stage 3 would involve the inputting of TSO to DER contract details into DERMS, such as pricing, volume and availability and DERMS optimises the available distribution connected services.

4.3.1.2 Option 2

ANM/DERMS dispatch DER services that are contracted with UKPN involvement (RDP and Power Potential), resolves D constraints and optimises T service options (Power Potential and RDP Constraint MW) it knows about. ANM also calculates constraint signals for headroom and footroom for each DNO active/near active group of constrained circuits and passes this information to NGESO probably via the ICCP data link - see below for service conflict signal details. Service's sensitivity to headroom and footroom are provided to the TSO probably as standing data sets. NGESO selects DER dispatch options from DERMS/ANM or from direct providers. Where services from direct providers are dispatched the NGESO operator /NGESO tool checks the net ability of the services to run against service conflict headroom / foot room signals, also utilising the service sensitivities, to ensure there is no conflict and the net service at the GSP will be provided.

The ENA Open Networks 2018 work identified two possible real time signals for sharing DSO constraint information with NGESO. The first signal would be sent from the ANM to NGESO for each significant distribution export constraint in the ANM area. The second signal is similar, but is for importing constraints (where generation is constrained on for security). It may be there are no import constraints in the zone and so this would be omitted:

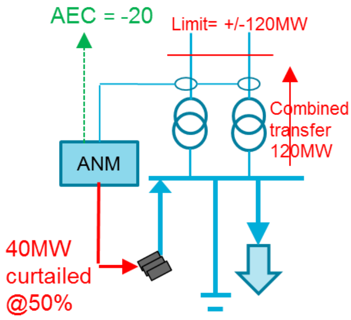
Signal 1-Additional Export Capacity MW (+/-)



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.



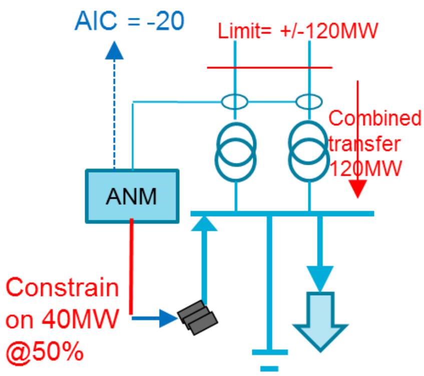
- -ve signal indicates volume of DER currently constrained off to meet limit (converted using each DER sensitivity to circuit transfer flow).

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. NGESO would calculate their contribution to the transfer enabling efficient call off of services.

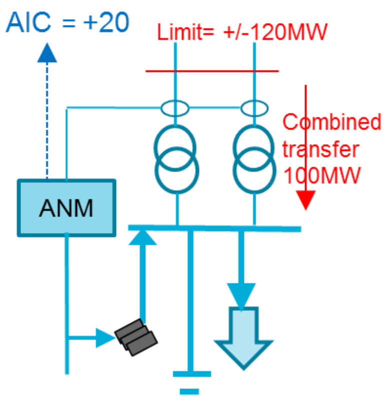
Signal 2- Additional Import Capacity MW (+/-)

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

4.3.1.3 Next Steps for Service Conflict Trials

The agreed trial of Option 1 in UKPN SE would explore the feasibility and advantages of this approach compared to Option 2 in WPD South West and will be assessed through the Open Networks forum.

4.3.2 Dispatch of N-3 to ANM 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 virtually all the time, because the probability of the fault is exceptionally 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. Section 3.4 of this report details how the intertrip interaction and challenges of LoM protection will be managed on an interim and enduring basis.

Normal protocol is the intertripping on a linear network such as the SE Coast is on a LiFo basis, unless there is a technical reason to do otherwise. In this case the speed of operation of an intertrip to DER via ANM will not be fast enough to prevent voltage collapse for double circuit faults and so a fast de-load of a VSC interconnector is required. This is also consistent with the connection terms and conditions of these VSC interconnectors and is a technical reason not to dispatch in LiFo order. For many faults under N-3 conditions, thermal overloads persist even following the complete de-load of one of the VSC interconnectors and further intertripping is required. In this case it is appropriate to use generation including DER in LIFO order.

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.

4.3.2.1 Procedure and principles for management of DER Inter-trip

The following design and communication principles have been agreed for its operation:

Prior to arming

1. ANM gives visibility of total generation available to be tripped per GSP to both control rooms via own control systems (NGESO’s IEMS and UKPN’s Power-On)_.

2. The NGESO control monitor the transmission system and decide whether arming the intertripping function is required amongst the options of interconnectors, Large Generating Units and the RDP DER.

Arming

1. NGESO make two arming requests - One to the NG TO control room with a specified delay for the TO OTS system, the second to UKPN (expected to be via ICCP). The UKPN request will comprise MW volume to be reduced per GSP and any additional required ANM delay.

2. ANM will determine which DER shall be tripped/de-loaded per GSP and when in order to achieve the requested response.

3. ANM sends real time information to NGESO via the ICCP link of total MW armed per GSP (the sum will change as DER output changes and hence NGESO needs visibility of how much will be tripped and when).

4. Following intertrip, ANM should not backfill the freed up capacity on any active distribution constraints. Consideration should be also given as to visibility/management of services delivering MVAR services under Power Potential which may also be armed to intertrip. Intertripping these services will lose their reactive support.

Tripping

1. When ANM receives a trip signal from OTS (with optional additional delay implemented by OTS), it will send trip/de-load signals to DER.

2. The time delay, excluding any additional selectable delay in OTS/ANM, between receiving the signal at Sellindge and tripping/de-loading the DER shall not exceed 30sec. If there is a system failure preventing this, suitable contingencies need to be in place. The health of comms/ equipment between Sellindge and the DER required for the N-3 intertrip will be monitored with remote alarm(s) at UKPN control centre, and if appropriate, at NGESO via ICCP link, to allow advance knowledge of failures and enactment of contingencies.

Dis-arm / Restore

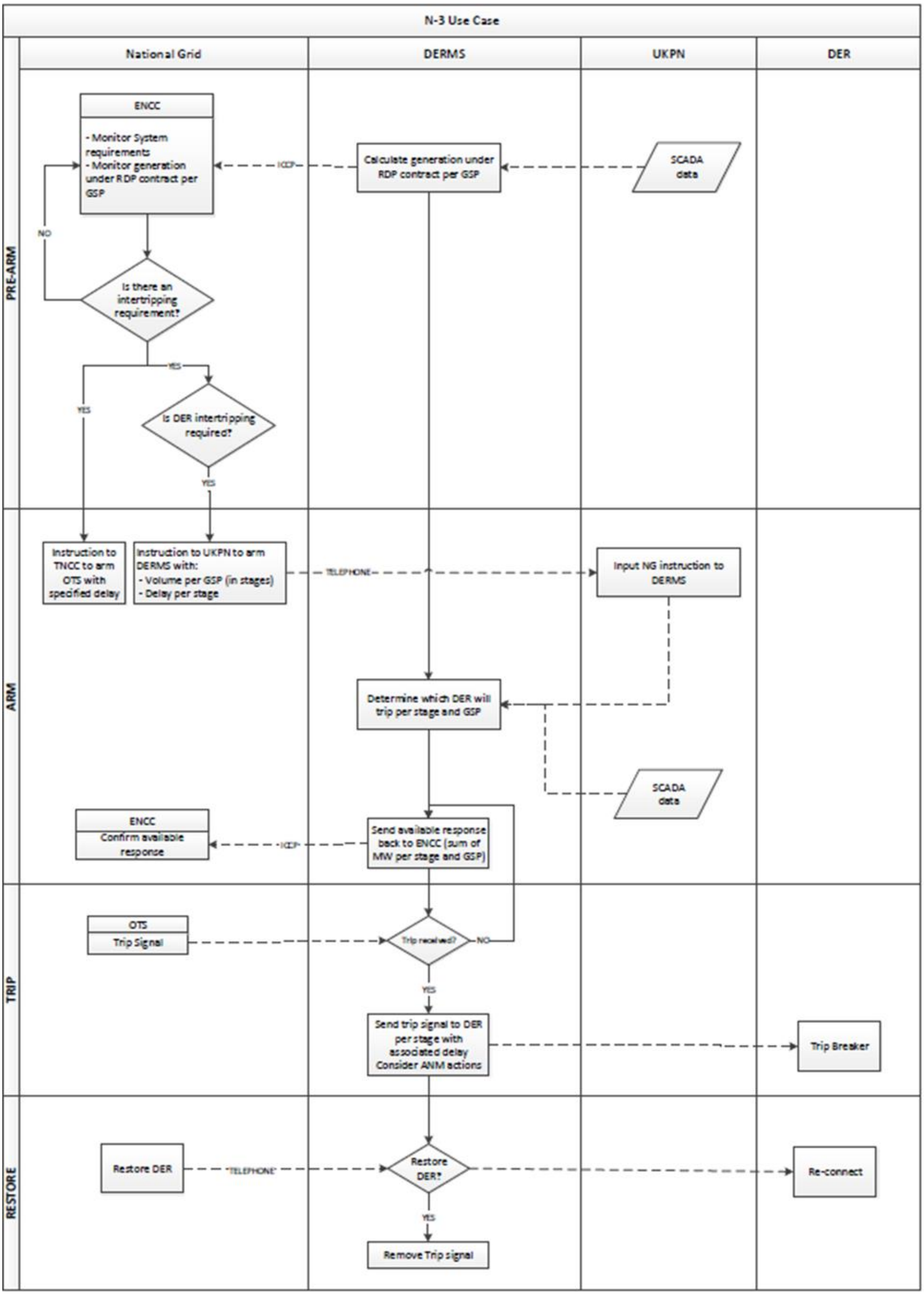
1. NGESO will dis-arm OTS and DERMS (via telephone to NG TO and ICCP to UKPN respectively). Dis-arming may be instructed regardless of an actual trip happening or not

2. After intertrip/de-load, DER reconnect/re-load is managed by ENCC through ICCP to UKPN taking into account system conditions.

Additional Notes

The OTS will present a dual redundant pair of, normally open volt-free contacts at Sellindge with the trip signal being a 2 second closed pulse trip signal. Reasonable endeavours to ensure that no single hardware, software, system, communication, interface or power supply failure or depletion of facility shall result in failure to trip within the specified time or an incorrect control action.

Initial draft of N-3 flow diagram:



Consideration is now being given to utilisation of ICCP for arming from NGESO to DSO to reduce telephone and manual burden.

4.3.3 Integration of Schemes into the Control Environment

An indicative overall architecture of the systems is shown in the figure on page 36, the elements of which require development as follows:

- The ICCP link between ENCC and UKPN is in place and will be used as a dual directional comms for exchange of data and for the control of NGESO to UKPN element of N-3 Intertrip arming. Work is required to link the required database points to the new screens described below.

- National Grid's control system IEMS system. The following development is required:
    - N-3 Intertrip to DER screen - For NGESO to view and arm aggregate available DER to be armed and information on the volume which is armed. Sources for this information will be from the onsite TO owned OTS, and from UKPN via the ICCP link.
    - DER aggregated visibility - To enhance visibility and forecasting of DER output, analogue outputs aggregated by GSP and by fuel type of MW output are envisaged. Aggregation should align with modelling principles described in 3.1.
    - The receipt of additional DNO network switch position signals along with DER visibility will drive enhancements in NGESO's exiting online contingency analyser (PNA, which exists in the IEMS suite).

- A MW dispatch tool is required at NGESO's ENCC this could be Platform for Ancillary Services or another system to be determined.

- UKPNs DMS system 'PowerOn' will require modifications to achieve the requirements of the RDP which will include:
    - Provision to NGESO via ICCP visibility and control of the N-3 I/T. The status of arming will be shared across the ICCP link, both directions.
    - Via ICCP sending of aggregated DER MW and DNO network status to NGESO.
    - Via ICCP the receipt of transmission circuit flows and switch positions to drive a new Distribution online contingency analyser.

- The under development DERMS/ANM has previously been described. To meet the requirements of the RDP will need the following developments:
    - Service conflict Option1 functionality previously described and an interface to receive priority information from the NGESO and feedback effective service will be required.
    - NGESO MW dispatch of DER for RDP - The MW dispatch will make use of the flexible connection equipment which in any case is required by the DNO for distribution constraint management.
    - N-3 Intertrip will be implemented through ANM. ANM will need to receive the intertrip signals from the Sellindge OTS, from two normally open contacts. To receive these signals into ANM suitable dual redundant comms will require installing between Sellindge Substation, where they are presented to the DNO, to the DERMS system. ANM will need to manage conflict by preventing backfill from ANM post intertrip and consideration given to Power Potential MVAr also being armed to Intertrip.
    - ANM control for distribution constraint management. This is not strictly an RDP development requirement but the equipment installed for flexible connection at the generator site, in the DERMS and the comms in between, will be additionally utilised for the N-3 I/T de-load/trip signals to the DER and for the NGESO RDP MW dispatch for transmission constraint management.

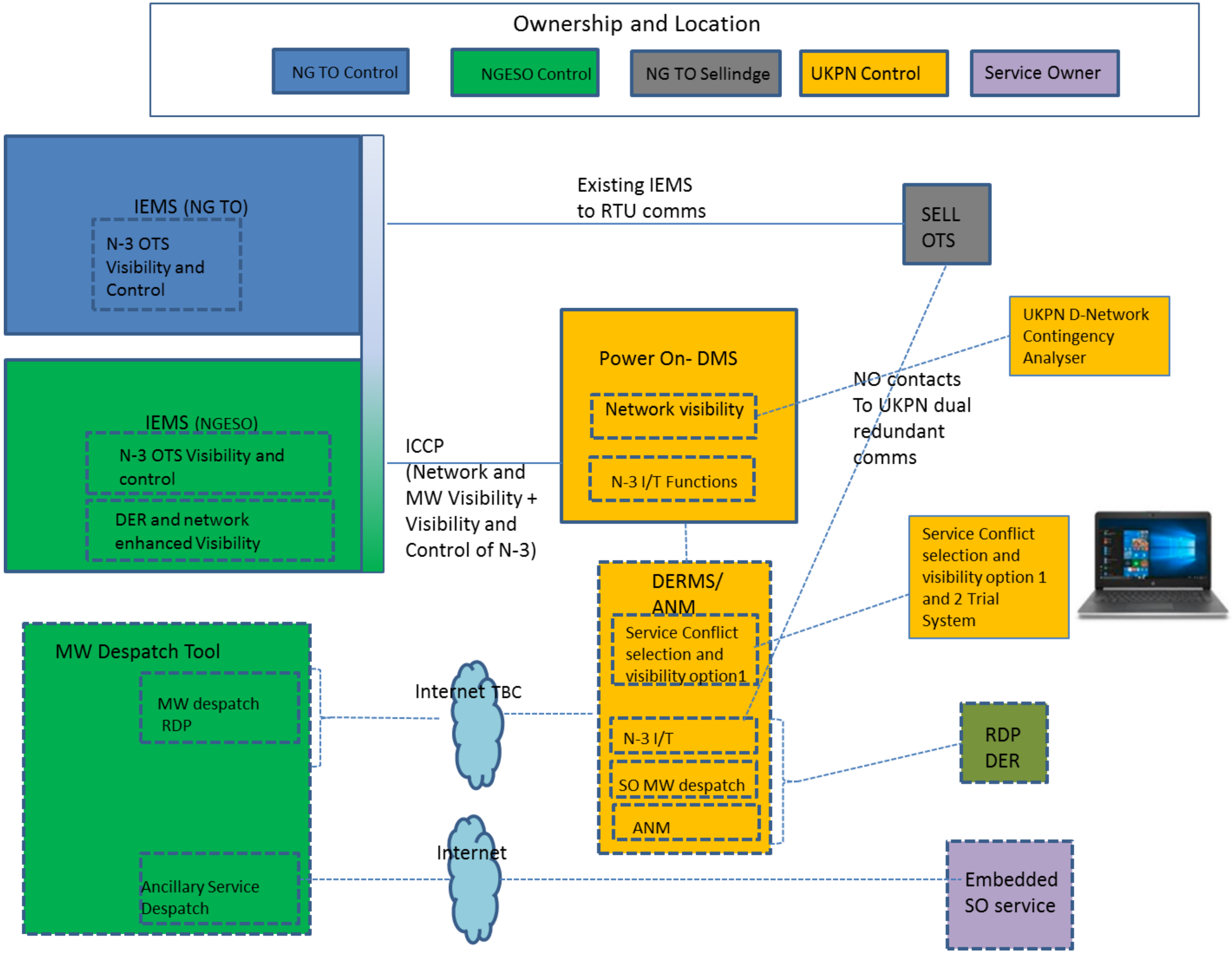


Figure 4.3.4 Indicative System Architecture

4.4 Commercial frameworks, curtailment funding and settlement approach

4.4.1 Effect on DER Project Developer

The effect of the arrangements detailed in this section on the DER developer have been considered throughout their development. The approach is to make any new requirements as simple and least burdensome as possible. A fact sheet has been written and published on both the UKPN and National Grid web sites and is copied in appendix B of this document 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 application. 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.

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

Initially, National Grid will seek curtailment prices from DER to allow them to be compensated for flexibility they provide to manage transmission constraints. It is proposed that these prices will be submitted to UK Power Networks 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 UKPN, 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 south coast is via a service-based, rather than asset-based approach, National Grid will require new DER to participate in procurement events for transmission constraint management services. 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 won't 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, and that necessary links are made with existing DER services procured by UKPN and NGESO, and future developments for the Power Potential project.

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

UK Power Networks 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 events for the South-East Coast GSPs. These will be joint UKPN/National Grid procurement events. Coordination between UK Power Networks and National Grid will take place to facilitate service stacking, as required. The full details will be established as 'RDP Procurement Principles'.

4.4.3 Approach to Distribution constraints

Given the existing and emerging constraints on the distribution network, it is proposed that all new DER connections should include an Active Network Management (ANM) capability. As per existing Flexible 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'). For this region, a pro-rata implementation is proposed as the Principles of Access (PoA). Under this PoA blocks of capacity will be defined (quotas). For those generators within a capacity quota, curtailment is shared across all generators that are subject to a constraint proportionally to their contribution to the constraint. Such constraints will be specified in the connection agreement, with any other/future distribution constraints conferring no such obligation on the DER.

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 utilised to manage local flexibility markets, allowing DERs to participate and enable UKPN to manage distribution constraints.

4.4.4 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 UKPN. Where additional or modified connection assets are required for a DER connection, UKPN would seek to recover these costs from the DER involved. Generally, the DER do not want to pay these costs so a flexible 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 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 BSuoS changes, in the same way as any other transmission balancing service would. In practice that will cover all occasions where transmission curtailment will influence the DER's business case.

4.4.5 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 plant, small and medium DER do not pay transmission charges in exchange for transmission access rights and therefore has no formal transmission access rights and no compensation when access is disconnected for events beyond the security standard for that class of plant.

4.5 Conflicts of Service Study

4.5.1 Service dispatch conflicts in the area

Currently, there are services, such as Enhanced Frequency Response, being procured by NGESO 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 possible steps to mitigate them.

4.5.2 Service conflicts - Overview

As many DNOs are accommodating increasing number of DER connected in their networks, they have been considering 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. The active power service from DERMS will build from the principle of using ANM to solve distribution constraints first and then offer additional flexibility upstream to National Grid. The DERMS software can be subject to the same service conflicts as an ANM which are described in this section.

The industry stakeholders, particularly through the Energy Networks Association (ENA) NGESO-DSO working groups, have identified the potential for ANMs to, at times, conflict with embedded NGESO services by negating service output. NGESO 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 A.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 NGESO service, Short Term Operating Reserve (STOR), within the ANM Zone not itself under ANM or DERMS control. Should the STOR service be called upon by NGESO 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.

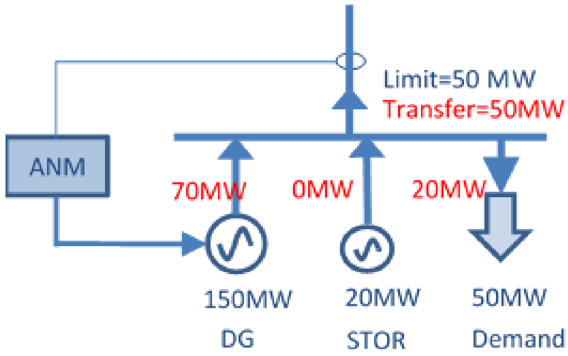


Figure A.4.2a Example embedded incremental service conflict

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 NGESO service, Enhanced Frequency Response (EFR), within the ANM Zone not itself under ANM or DERMS 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.

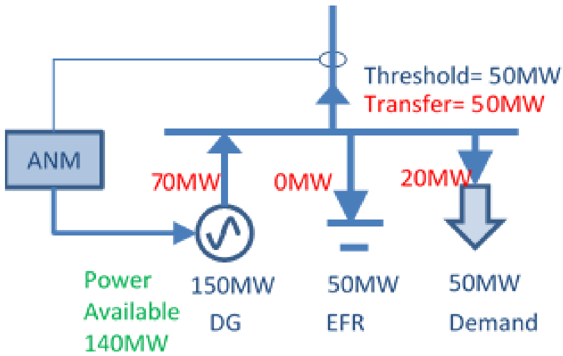


Figure 4.4.2b Example embedded decremental service conflict

What are the Consequences of the Problem?

NGESO will to continue to procure ancillary and balancing services from providers embedded in the distribution network. Furthermore, ANM type 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 DERMS, the risk of service conflicts can still materialise as some NGESO service providers are connected in the trial area. All Power Potential services procured by UKPN and RDP specific services procured by National Grid will be coordinated by the DERMS software to avoid conflict between those, however design allowances will need to be made to include the detection of other services being procured in the area and their possible conflict resolution.

4.5.3 Service Conflict – Planning timescales and Norwich Case Study.

The RDP was used to trial the use of UKPN curtailment assessment tools to determine a suitable process to assess service conflict volumes and the likely conditions where a service conflict is likely to occur. This trial is detailed in Appendix C, it was decided to use Norwich group for this trial rather than the south coast, because Norwich is the only real example of a complex ANM scheme and has all the data to represent a difficult case study readily available. The trial successfully showed that it is possible to assess service conflict in this way and the derived process could be used to determine the worth of contracting for a new service in an ANM area, or the effect of new connections / network reinforcements on the economics of existing services. The trial is being used to inform the ENA Open 2018 Networks WS1 product 2 work to set process in this area. It is envisaged that additional Grid Code data transfers DNO – NGESO and NGESO-DNO will be required to enable the trial process to be further developed and become part of BAU process. The additional data requirements are also needed to set up the real-time signalling discussed below.

5 Learning Points from RDP Process

5.1 Power System Modelling

As the volume of DER increases and the distribution network becomes more active, then its effect on the transmission network becomes more important. Historically some modelling of the distribution network within the transmission study has occurred, but this is not consistent tending to be based on the computer power available and what individuals views on importance was some time in the past. The RDP shows value in consistently modelling the complete 132kV network down to the first busbar below (in this case usually 33kV.) It is recommended this becomes normal practice throughout the network. In cases where there is no 132kV network and 66kV or 33kV is used instead, consideration should be given to the need to model the 66kV or 33kV network. Furthermore, studies conducted on the distribution network have shown that there is significant value in being able to accurately model the local transmission network and have visibility of transmission services embedded at distribution level, both in planning and operational timescales, especially where there is interconnection at 132kV.

Again as the volume of DER increase and the distribution network becomes more active, the number of operating conditions that need to be considered when planning the network increases significantly. The RDP trialled representing each 33kV node (or the first node below 132kV) with a Solar, Wind, Storage and Synchronous generator, lumping all generation connecting via that 33kV node sized above 1MW to the appropriate model on that node. The demand net of residual (below 1MW) generation is also modelled on that node on 1 of 4 cardinal points; Winter Peak, Summer Min AM (approx. 05:30hrs), Summer Min day time or Solar Max (approx. 13:00Hrs) and Access Period peak. This allows the network to be modelled considering different weather conditions at the key points to more accurately demonstrate the technical constraints of the network and what the network capability is. This is particularly important on networks where the limiting factor is dynamic in nature. In the case of this RDP it showed more capacity was available. Calculation of the residual demand at the 33kV node did cause problems and is a possible source of error, as direct metering of all the data required is not available.

From the above it is possible to derive a number of recommendations for further review and changes to industry codes and practices:

1) Adopt modelling, as a minimum, the complete 132kV network to the first busbar below as a transmission study standard, with consideration to extending this to 66kV or 33kV where there is no 132kV network.
2) Create the requisite data exchange mechanisms to provide visibility of local transmission network data and embedded transmission services
3) Look to align Statement of Works and week 24 data requirements around the ability to model each generator class at the first node below 132kV with 4 sets of demand data in all planning studies.
4) Look at what is required to determine database, metering and calculation requirements to ensure the residual 33kV or 66kV demands are accurately known.
5) Further investigate the potential for the same process for operational planning in operational planning timescales. This is complicated by the use of historic SGT metered demands to scale the study to the half hour involved.

5.2 Management of New Connections

The ability to manage the effect on transmission of the connection of small generation on a socialised basis has significant advantages in making sure that network connections are available for those that are really going to use them, while insuring full control of the network is maintained on a co-ordinated economic and efficient basis. The existing Connect and Manage rules can be used for this, but a much greater focus on the “and manage” is required than has previously been considered for DER. Socialising in this way helps to ensure that unrealistic queues to not build up to the detriment of those on the back end of the queue who end up with long delays and potentially unrealistic, for them, costs to connect to the network. Hence the following:

1) There would be benefits in the wider introduction of the data management processes trialled under this RDP’s revised App G process, this can considerably speed up the connection assessment process outcome for customers. To achieve this more widely the data requirements and process for the SoW process would need to change in line with this trial. The work done under this RDP has provided the basis for, and has been progressed under, the Open Networks Project Workstream 1 Product 7 (2017) and Product 9 (2018). For efficiency, existing data processes under the Grid Code week24 should also be aligned.
2) Queue Management and incentives to prevent lengthy queues and the ability to obtain a realistic view on network investments are important. A stringent implementation of QMEC is therefore vital to this process. As is the ability to apply socialised transmission wider securities to all players both transmission and distribution connected on a fair basis. While that has been achieved in this case, the CUSC rules on application of wider cancellation fee to DER are not helpful in achieving this goal and so it is recommended these are reviewed so it can be consistently applied everywhere.
3) As we move forward the ability to use operational measures to manage the network in an economic and efficient way needs to be extended to smaller power stations. The revised App G process trialled here makes it easy to contractually apply these to the relevant generation going forward as Site Specific Conditions. Further to this requirement there is a need to increase visibility and control of smaller generation generally. This is recognised in other places such as Requirements for Generators under the EU Codes. Coupling this with the role out of DNO ANM in a way that can be used to provide the means of control for

commercially procured flexibility, ensures operability of the network under all conditions. The methods of dispatch need not always align with the commercial procurement and settlement of flexibility.

Note all the above need to be considered as a package to deliver the overall benefit.

5.3 DER Protection Systems

The RDP has demonstrated that the historic lack of Whole System coordination between the generators' protection systems and the transmission system and that this can have a detrimental effect on the capacity available for connection. Current RoCoF, Vector Shift and potentially voltage protection all have issues. Action has been taken via the DC0079 work group to ban new Vector Shift and plans are being finalised to retrospectively resolve the remaining RoCoF and Vector Shift issues. The RDP shows if either of these are in place by the time Eleclink connects this will eliminate the risk and that a priority should be place on targeting Vector Shift in that area, although there a work around to allow new connections in the meantime.

In this case the RDP has also demonstrated that G59 under voltage protection can limit the network. In the studies to date for this zone, that limit is at around the same level as the total voltage collapse limit and so the fact nothing is proposed to be done about this protection is not currently limiting. That will not necessarily be the case for future operating scenarios and therefore remains a risk to be monitored.

5.4 Whole System and Management of NGESO Services

The RDP has shown a method to demonstrate how service conflict between transmission services and distribution constraints can be assessed in the planning timescales and has proposed two possible methods for real time control of these conflicts. Work needs to continue to ensure that planning data exchanges required for management of these issues are acceptable to all parties involved and are included in code. Conclusions on real time management of this issue are more difficult and so significant learning will be obtained by comparison of the two trial methods of real time management of these issues.

The Whole system work package demonstrated how coordination and efficiency can be achieved through an interactive process across transmission and distribution in procurement of services and such approach should be standardised through Open Networks and adopted in future significant procurement exercises, i.e. integrated into company procurement processes.

5.5 IS Architecture

The RDP has demonstrated that to deliver the benefits of whole system working, significant developments are required to control room IS and comms between both NGESO and DNO/DSO control rooms. One of the challenges is to implement the changes within BAU budgets accepting the trial nature of the work, and that industry consensus has not yet been reached - achieving standardisation as much as possible in time should be an aim. Further, although the RDPs are trial by doing the implementation must be able to be relied upon and consistency in NGESO control room interfaces must be sought as far as possible. This will require Open Networks coordination of learning outcomes.

5.6 General RDP Process

This RDP has successfully demonstrated that collaborative working in this way is effective in solving Whole System problems and progress has been made faster than by more conventional methods of working. This may well be a good method for resolving similar future problems quickly; the main blocker is getting support internally within the organisations to get the correct expert resources in a timely manner to ensure the level of progress can be maintained. This is particularly the case where a particular subject matter expert may not be directly involved in the project on a routine basis. A further learning on process and resource is that a two-stage process to RDP- Design and Implementation recognises the different resources and skill sets required to develop then implement an RDP. The resource for the implementation should not be underestimated.

Appendix A: South England RDP Capacity Release Document

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

Issue: Final V2

Date: 25/8/17

By: A Minton

Change log: V2 - Section on treatment of Large Embedded Generation added.

Issue

There is a need to find ways to offer additional capacity to DER on the SE-Coast. This area is currently part of the “Appendix G” trial.

Detailed dynamic network analysis is required to fully understand the network behaviour and risks in facilitating this.

NOA2 – has not recommended the build of a new South Coast circuit, designed to release capacity in this area. The current BCA’s that allow UKPN to connect DER in this area have restricted capacity and require this circuit to be built to remove that restriction. Furthermore some of the offered / connected generation has non-firm conditions based on the need for the line.

Summary

This paper details the approach that is required to allow future connections to DER developers in the South East coast group, linking with the NOA 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 UKPN to offer connections to DER developers. This will change the way in which the DNO 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 UKPN South Coast RDP applies to the network between, but not including Kemsley and Lovedean 400kV substations 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 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 Coast example, NOA2 has already determined that constrained operation of the network is economic for the 4 FES scenarios studied. It would also be possible to reinstate any build works for the proposed new south coast circuit with a 10-years lead time if deemed as economic, hence in this piece of work it is only necessary to consider the next 10-years. Additional DER connections on the 4 scenarios over the next 10-years are:

	2017	2026	2026	2026	2026		2026
	APP G*	NP	SP	CP	GG		average
Total Embedded	935	1515	1689	2280	1583		1767
Embedded Solar	332	650	866	1116	880		878
Embedded Wind	211	208	247	254	259		242
Embedded Battery	94	0.14	39	192	36		67
Embedded Fuel cell				2	1		1
Thermal	298	657	542	714	406		580

*APP G contracted position at March 2017, around 200MW is still to be connected and the materiality headroom is 130MW

It should be noted that the closest scenario to triggering the proposed new circuit is the scenario with the least new DER, as the constraint transfer is dominated by interconnector behaviour that exhibits lower volumes of import flows in FES scenarios with higher national DER volumes. It clearly is not possible to track potential new DER against national or, with the effect interconnectors have on this part of the network, international scenarios. There is also no reason to believe this zone will not reflect the national average. On the basis of this and the numbers above, it is not intended to put a hard capacity limit on the volume of generation that can economically connect to the zone via the SoW process. If the weighting of generation within the group changes in time, this should be reflected in the FES scenarios and picked up via the NOA process in the annual review.

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.)

UKPN 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. UKPN also have a material changes process which will reset a projects 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) <u>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</u>

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 3 outages; Canterbury – Kemsley, Canterbury –

Cleve Hill and Cleve Hill – Kemsley where this was not the case. For these outages the transfer limit out of the SE- Coast network has been calculated with the network optimised for the best performance. (QB's in Canterbury / Cleve Hill circuits selected to TAP 1*.) 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 the criteria would not be met. The SQSS deterministic criteria are designed to keep the network secure and provide the correct balance between asset build and constraint solutions. The economic cut off for build solutions was set such that assets are required to cover 95% of the time (2SD from mean). This is met in all except for 1 scenario in 1 year (Gone Green 2021 is 6.3%). On this basis this paper proposes to declare the network compliant against this criterion.

*Note there are usually good technical reasons not to use extreme QB taps pre-fault, these generally case overloads in the parallel network, or voltage issues for parallel faults. Studies showed that was not the case in this example.

2) <u>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</u>

Generally not an issue as the size of the DER power stations are small. (There may be some temporary issues around the performance of LoM protection until the GC079 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) <u>Enable the Company to operate the National Electricity Transmission System in a safe manner</u>

To operate in a safe manner NGESO 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, NGESO 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) <u>Resolve any fault level issues associated with the connection and/or use of system by the C&M Power Station</u>

Generally fault level has not been considered a risk in the SE-coast network. There will be a requirement to do fault level studies on actual and planned technical data to ensure the network remains safe. This needs to occur via the existing SoW and Appendix G 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 LEEMPS 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</u>

Provided the network can be operated in accordance with chapter 5 of the SQSS and any changes to coloured 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 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) Avoid any adverse impact on other Users

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 largely 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 Inter-trip 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 inter-trip 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 inter-trip 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 choose to accept. 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, it is suggested the adoption of retrospective invoicing for statement of work / project progressions is investigated.

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 need to be created. Once the DNO has received the new BCA no more offers on the original T+C's 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 T+C's.

See Appendix B 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, NGESO 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 T+C's. 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 so 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.

It is anticipated that changes to the Appendix G template will be required 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. Initially there may be a short period, before the commissioning of NEMO, when generation may connect with the provision of visibility and control at a later date, these will be considered delayed enabling works. 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 favourable terms than Large or BEGA plant. In fact the DER could do so on a purely speculative basis and continually delay without making any commitment, creating 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 behaviour in reserving capacity.

Visibility and Controllability

In order to ensure the transmission network can be safely operated, visibility and control (on commercial terms in this case) of DER is required by NGESO. 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 arrogation if the user choses that route. NGESO and UKPN are jointly developing an ANM control scheme and a commercial route to market for this service.

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 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 NGESO. Clearly one generator cannot have 2 places in a single queue. In the case of the 4 UKPN south coast GSP's developers should be informed that additional competency checks will be added to both the DNO connection application and the NGESO 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

A number of generators have already accepted offers with interim restrictions on generator availability under outage conditions applicable until 2026, when it was anticipated that a major reinforcement between a location west of Sellindge to South London would be built. There was always uncertainty around this investment. In recognition of this the works were defined in the BCA none specifically as “thermal overload relief works” and a clause was added to indicate that National Grid would review and define the exact nature of these works by 28/4/17. In effect we have done so via the regional development program and have concluded that an operational solution with visibility and control (on a commercial basis) is the most appropriate solution.

Ideally all the generation with non-firm conditions would transition onto the new “visibility and control” T+C’s. This may however cause additional retrospective costs to some players to provide this facility. Generally the developers fall into 2 categories: 1) Smaller mainly Solar providers many of which are already connected. 2) Larger mainly storage and thermal generators which are not yet connected. It is therefore proposed to offer 2 options to these customers: 1) Remain on the existing Non-firm connection under the “Design Variation” clauses in the SQSS, this will suit the smaller renewable providers that are mainly already connected. 2) Provide the control interface equipment and transition to the new arrangements. This will suit the larger more flexible providers who are largely not constructed. It is generally in this groups commercial interest to provide flexibility anyhow.

Appendix B: SE Coast Connections Commercial Factsheet

Connecting to UK Power Network's South East Coast network Information for Distributed Energy Resources (DERs)

Context

This fact sheet sets out what developers of Distributed Energy Resources (DER) need to know regarding the constraint management arrangements that will facilitate additional capacity to connect within the South East Coast distribution network from June 2017 (Bolney, Ninfield, Sellindge and Canterbury Grid Supply Points (GSPs).

There are three categories of constraint relevant to DERs connecting to the South East Coast:

- ***Transmission constraints:*** Following detailed study work as part of the 2016/17 Network Options Assessment (NOA) process, it has been determined by National Grid that it is not economically efficient to fully reinforce the network at this time, and that the use of flexibility is a lower-cost option. To enable this, National Grid requires access to flexibility within the South East Coast transmission and distribution network, and will be seeking to access that flexibility through a mechanism that will enable both transmission participants and DERs to receive compensation for any curtailed output (other than where qualified in the 'Summary' section of this document).

- ***Existing distribution constraints:*** In some, but not all, parts of the network there are distribution constraints. DERs wishing to connect behind these constraints will be offered either a standard connection (which may involve a delay whilst works are carried out and may require a contribution to the reinforcement of the distribution network) or a Flexible Connection. Such Flexible Connections will require curtailment according to pre-determined rules that will be incorporated into the connection agreement. In the future, DERs may also be given the opportunity to access a local flexibility market that will allow them effectively to "trade" their curtailment obligations where it is economically better for them to do so.

- ***Emerging distribution constraints:*** Even in areas of the distribution network that do not currently face constraints, it is expected that constraints will emerge. DERs connecting today will not be obliged to curtail in order to manage such constraints, but will be able to offer constraint management services to the Distribution Network Operator (DNO) and other DERs, perhaps through the local flexibility market.

We outline below the proposed operational and commercial arrangements to deliver this capacity. The principles that underpin these arrangements include:

- Maintaining the integrity and security of the transmission and distribution networks;
- Operating efficient, economic and coordinated transmission and distribution networks;
- Managing network constraints at least cost to consumers;
- Supporting DER investment decisions; and
- Providing DERs access to new and existing markets to allow them to build a viable business case.

Connecting to the distribution network

DERs will each have a connection agreement with UK Power Networks defining their operational requirements, including any technical capabilities that DERs will need to have, such as:

- Control & Visibility - to provide the relevant signals and control capabilities necessary to instruct changes in either your export or import of electricity;
- Loss of Mains protection – for small generators/storage connecting this will mean a requirement to use RoCoF. Vector Shift must not be used; and
- 0.95-0.95 lead/lag power factor capability – the ability, under instruction, to change your target power factor across the aforementioned range.

Given the existing and emerging constraints on the distribution network, it is proposed that all new DER connections (where HV/EHV connected and >200kW) should include an Active Network Management (ANM) capability. As per existing Flexible Connection regimes[5], 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 and the Principles of Access. Such constraints will be specified in the connection agreement, and any other distribution constraints will confer no such obligation on the DER.

If the distribution network is unconstrained, the DER will not be obliged to curtail if 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 UK Power Networks to manage constraints as required.

Managing transmission constraints

In order to connect to this region, because of the transmission constraints, DERs will need to provide adequate Control & Visibility to be able to participate in constraint management. The installation of ANM equipment would be sufficient to meet this requirement so there should be no additional obligation on DERs.

Initially, National Grid 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 to UK Power Networks as part of the connection process; and will represent 'back-stop' prices that will apply/endure should the DER not wish to participate in a future tender procurement process for transmission constraint management services. Once submitted to UK Power Networks, DERs will then be able to review and re-submit these prices if their circumstances change.

By ensuring DERs connecting in this region provide 'back-stop' curtailment prices and encouraging them to participate in market-based procurement events for constraint management services, it would be expected that National Grid's service needs can be met in an efficient and economic manner. This would avoid the risk of National Grid having to resort to emergency measures to maintain the integrity of the transmission system.

Recruitment & procurement approach for transmission constraint management

Recruitment and procurement will be based on the following principles:

[5] Reference Norwich and March Grid

- UK Power Networks and National Grid will work together to bring DERs into constraint management procurement events for the South East Coast GSPs (Bolney, Ninfield, Sellindge, Canterbury) as required;
- Procurement may be based on short-term specific requirements and/or longer-term more general requirements, as considered necessary;
- DERs (or their aggregators) may choose to post holding bids, which endure until subsequently changed, which reduces the operational burden placed on them, particularly if their commercial position remains consistent for a prolonged period of time; and
- UK Power Networks ANM system will facilitate the dispatch, based on the state of the network.

Stacking services and managing conflicts

Even if a DER has a financially firm connection agreement, if there are constraints on the distribution network, or if they are expected to emerge, then providing transmission constraint management or wider system service requires coordination between National Grid, UK Power Networks, DERs and aggregators. Coordination between UK Power Networks and National Grid will take place to ensure service stacking may occur on a case by case basis.

Summary

This paper is intended to provide DER developers with information regarding the constrained South East Coast network, and to give them confidence that they will be able to connect under terms that are acceptable to them. Whilst some questions remain, we are able to say that:

- Customers in the South East will be offered a new type of connection, allowing them continued access to generation capacity;
- Connecting DERs will be obliged to interface with UK Power Networks ANM system, to provide the Control & Visibility required to manage transmission constraints, and distribution constraints where they exist, and to future-proof the distribution system against emerging constraints;
- Initially, and in advance of market-based procurement, DERs will be required to submit 'back-stop' prices (as part of the connection process) to allow them to be compensated for flexibility they provide to manage transmission constraints;
- Subsequently, connecting DERs will be encouraged to participate in market-based procurement events for constraint management services, as part of the process to ensure constraint management services can be efficiently sought to safeguard the integrity of the transmission network in the region; and
- Provision of such constraint management services to manage a transmission constraint will be compensated by National Grid competitively and in an economic and efficient way.

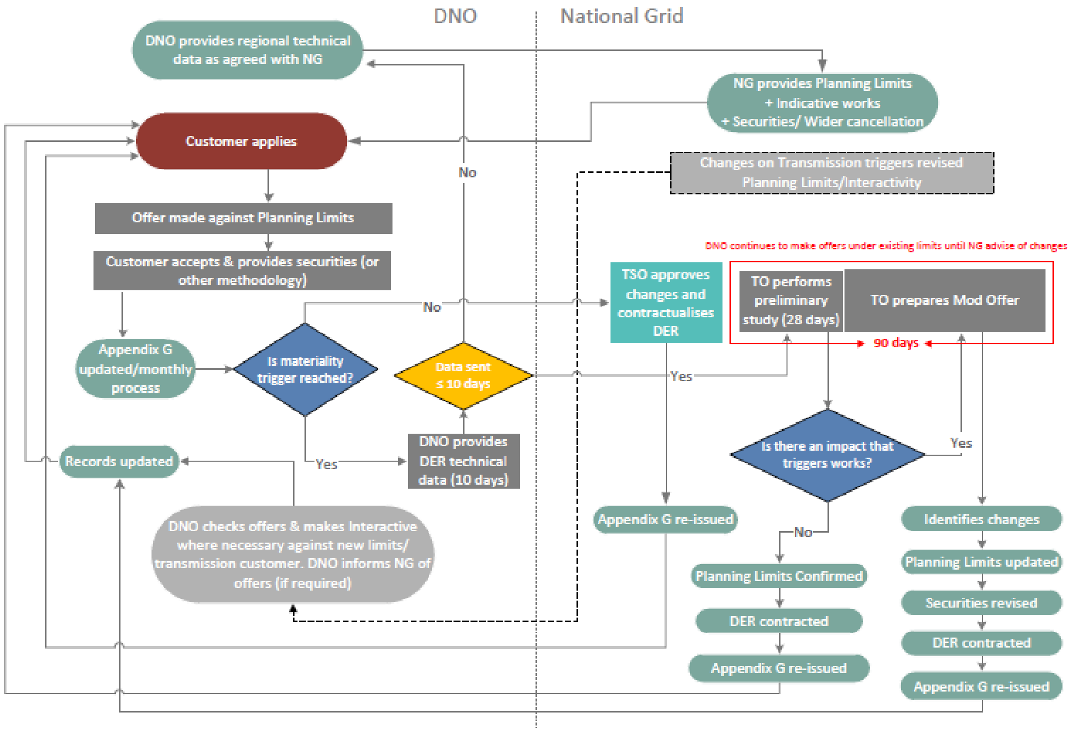
For clarity, areas that are currently subject to curtailment on an uncompensated basis are as follows:

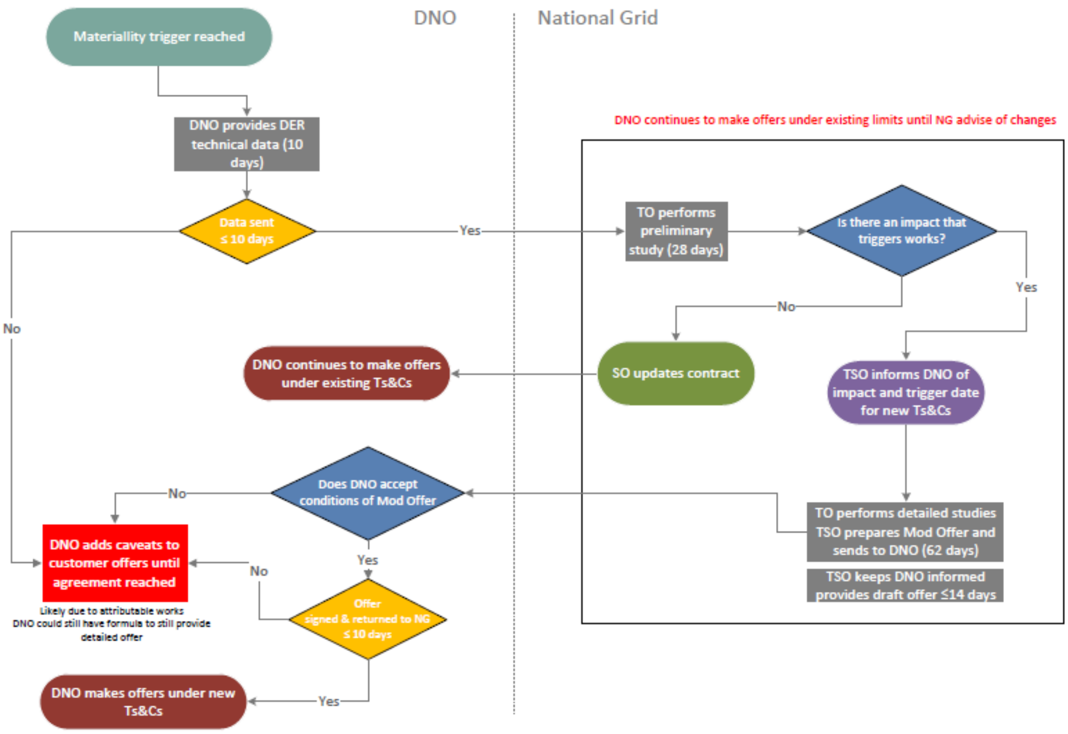
- Where the connection is via a single point of connection to the distribution network, the connection may be subject to long-term de-energisation during abnormal network conditions and/or during periods of network maintenance;
- Where there is an immediate and identified distribution constraint;
- Where there is an n-3 condition on the transmission network resulting from a double-circuit fault during a planned outage on the South Coast route, which requires the inter-

tripping of DER to secure. Curtailment assessment analysis shows this to be a less than 1 in 100 year event; and

- Where conditions on the Distribution System or Transmission System are more adverse than the operators are required to plan for, or are reasonable to plan for, and the disconnection of DERs is necessary to maintain system integrity and safety (this includes Emergency Disconnection).

Figures Appendix B: Diagrams Showing Revised Appendix G Process





DNO
National Grid
Materiallity trigger reached
DNO provides DER technical data (10 days)
Data sent ≤ 10 days
Yes
No
DNO continues to make offers under existing limits until NG advise of changes
TO performs preliminary study (28 days)
Is there an impact that triggers works?
Yes
No
SO updates contract
DNO continues to make offers under existing Ts&Cs
TSO informs DNO of impact and trigger date for new Ts&Cs
TO performs detailed studies TSO prepares Mod Offer and sends to DNO (62 days)
TSO keeps DNO informed provides draft offer ≤14 days
Does DNO accept conditions of Mod Offer
No
Yes
DNO adds caveats to customer offers until agreement reached
Likely due to attributable works
DNO could still have formula to still provide detailed offer
Offer signed & returned to NG ≤ 10 days
No
Yes
DNO makes offers under new Ts&Cs

Appendix C: Service Conflict Norwich Group Case Study

C.1 Current Curtailment Process

Figure C1 shows the curtailment assessment process used by UKPN for assessment of Flexible Connections[6]. The process begins with a planning engineer defining the intact network configuration and then, using power system analysis, the worst-case N-1 and N-2 network configuration. Worst case is defined as most constraining for the generation collectively. These three network configurations along with existing generation profiles and demand profiles are fed into the next stage of analysis which uses Power Factory and its DPL scripting language. For the 3 network configurations Power Factory/DPL is used to calculate the sensitivity of the generators against the limiting circuits. Further, 30 min interval annual base flows on the limiting circuits are calculated. These are the flows prior to adding in the impact of the flexible DER. UKPN has two types of curtailment implemented, LIFO and pro-rata.

The final step is the spreadsheet/VB analysis and is done for 10 months intact network, 1month of N-1 (in December) , 1month of N-2 (in June). The spreadsheet takes the output data from the previous analysis i.e. 30minute base flows on the constraining circuits and sensitivity factors of the LIFO generators and has as a further input data on flexible DER size and stack position and the MVA limit on the constraining circuit. UKPN's approach is to use 90% of rating to be conservative. UKPN's implementation of ANM is to allow flows up to the pre-fault rating and should there be a fault the ANM will curtail the generators in very short timescales to prevent overload- either by ANM control or by group or global trip depending on the severity of the overload.

This process described was developed post this trial to take place entirely in Power Factory/DPL environment, i.e. no longer requiring separate spreadsheet analysis. Also in this development generator sensitivity is calculated at every 30min interval rather than a single set of figures for a given network configuration.

[6] Integration into Power Factory DPL, described further down, now implemented post this trial.

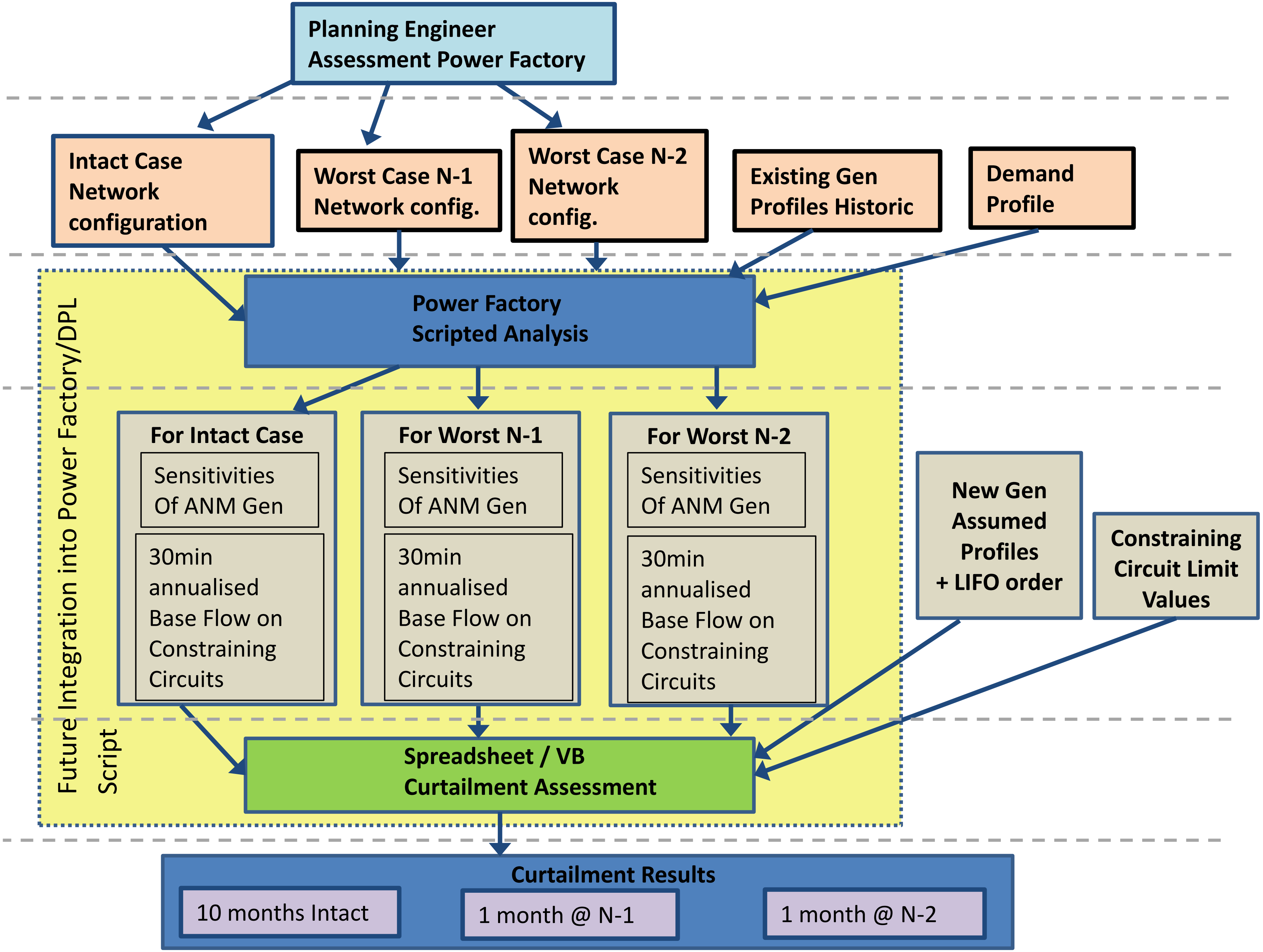


Figure C1 UKPN curtailment Assessment Process

C.2 UKPN Trial of Embedded NGESO Service Curtailment Assessment

C.2.1Area

For the trial, Norwich Flexible DER zone was chosen. A large offshore generator, 317MW, is connected at Sheringham Shoal. The remaining existing non-flexible generation in the area is made up of 97MW of PV across 9 installations and one 6MW onshore wind farm. The area is also impacted by a network outside of the Flexible zone which feeds in generation, less demand from Great Yarmouth thermal Power station (TEC 405MW) and Scroby Sands Offshore Wind Farm (60MW). UKPN's process is to model the demand in the flexible area based on historic profiles. Demand in the external area is modelled at minimum to be pessimistic i.e. impose the maximum through flow on to the Flexible zone.

The flexible, ANM controlled, DER for the area is made up of 104MW of PV across 14 installations and 20.5MW of CHP/Biomass.

The area contains 10 constraining circuits as listed in Table C1 which includes the Norwich SGTs. On some circuits, the sensitivity of the generators varies significantly e.g. Cct B has generators with sensitivity ranging from 0 to 28% .

	Cct A	Cct B	Cct C	Cct D	Cct E	Cct F	Cct G	Cct H	Cct I	Cct J
Gen1	50%	12%	12%	24%	24%	17%	22%	17%	17%	21%
Gen2	7%	16%	16%	21%	21%	18%	22%	16%	16%	22%
Gen3	-20%	11%	11%	26%	26%	17%	22%	18%	18%	21%
Gen4	19%	25%	25%	17%	15%	14%	23%	14%	19%	25%
Gen5	4%	16%	16%	16%	15%	16%	22%	16%	16%	23%
Gen6	3%	27%	27%	13%	12%	13%	23%	13%	18%	26%
Gen7	12%	16%	16%	20%	19%	18%	22%	16%	16%	23%
Gen8	1%	14%	14%	26%	25%	18%	22%	17%	17%	22%
Gen9	11%	28%	28%	13%	11%	13%	23%	13%	18%	25%
Gen10	1%	16%	16%	16%	15%	18%	22%	16%	16%	23%
Gen11	4%	14%	14%	21%	20%	16%	22%	16%	17%	22%
Gen12	2%	3%	3%	7%	6%	18%	22%	17%	17%	22%
Gen13	3%	3%	3%	5%	3%	12%	24%	12%	19%	28%
Gen14	25%	20%	20%	18%	17%	17%	23%	15%	18%	21%
Gen15	-2%	0%	0%	3%	-3%	11%	29%	11%	22%	24%
Gen16	5%	3%	3%	7%	6%	18%	22%	17%	18%	22%
Gen17	4%	16%	16%	20%	19%	18%	22%	16%	16%	23%

Table C1 ANM Generator Sensitivity vs Circuit for Norwich Area

C.2.2 Service Consider in the Trial

A hypothetical 20MW STOR with a contracted 24/7 full capability was used in the trial. The service was modelled at North Walsham 33kV and was chosen as significant levels of extra curtailment due to the service running at time of high solar were anticipated.

C.2.3 Assessment period

The service period was assumed to be starting 1/4/17 and to run through to 31/4/18- 1 financial year.

C.2.4 Calculation Methodology

Initially it was trialled with the service modelled as last in the LIFO stack and only curtailment on the service monitored as it was incorrectly believed that whether the service was ANM controlled or its LIFO position didn't matter. This would only be the case where all DER have the same sensitivity against a given circuit. It was decided to trial an alternative approach with the service non-ANM controlled and two curtailment runs done:

- Assessment 1- With the STOR service off 24/7/365
- Assessment 2-With the STOR service on 24/7/365

The equivalent availability of the service could then be calculated as follows (negative availability limited to zero)

Equivalent Service Availability= Service Size MW- Net Additional Curtailment due to service

=Service Size MW – (Net ANM Curtailment Assessment2- Net Curtailment Assessment 1)

Example for an incremental Service:

STOR Capacity= +20MW, and for a particular half hour the net curtailment with the STOR at full output is 55MW and with the STOR at zero the net curtailment is 50MW. Then Equivalent availability of the STOR service in that half hour = 20- (55-50)= 15MW. i.e. 75%.

Example for a decremental Service:

EFR Capacity= +/-20MW, and for a particular half hour the net curtailment with the EFR at full absorbtion is 40MW and with the EFR at zero the net curtailment is 50MW. Then Equivalent availability of the EFR service for absorbtion in that half hour = -20- (40-50)= -10MW. i.e. 50%.

C.2.5 Input Assumptions

Consideration was given as to what level of generation for future year assessment should be used-

- Just those that are contracted?
- % of open offers?
- All open offers?

For this trial, all accepted offers with a connection date within the year of assessment and 30% highest in the LIFO of open offers stack were chosen. See Table 1 for DER and Demand Assumptions

Table C2 Input Assumptions UKPN Trial

Aspect	UKPN's Normal CA Process	Assumed Profile for Service CA Trial
STOR	Treated as per plant type below as STOR contracts not known.	24/7/365 on, repeated with 24/7/365 off.
Synchronous broken into fuel type • CHP • Gas • Diesel	For existing thermal plant historic profile was used. For new thermal plant CHP 100% output assumed.	For existing thermal plant historic profile was used. For new thermal plant CHP similar historic profile was assumed.
Storage	50% generating output outside of "TRIAD Risk period". 100% generating output over "TRIAD Risk" Period assumed to be 16:00 to 18:30, between November and February.	There were none within this trial.
Solar	Profiled on a nearby representative generator corrected for metering and outages.	Profiled on a nearby representative generator corrected for metering and outages.
Wind	Profiled on a nearby representative generator corrected for metering and outages.	Profiled on a nearby representative generator corrected for metering and outages.
Demand	LTDS Demand inc. G83 modelling.	LTDS Demand inc. G83 modelling
Network Configuration	Intact 10months 1month, November of N-1 1 month, June, of N-2	12months Intact
Circuit Ratings	90% of full rating. Rating seasons: Winter Ratings October to March Summer Ratings April to September	100% of full rating. Rating seasons: Winter Ratings October to March Summer Ratings April to September

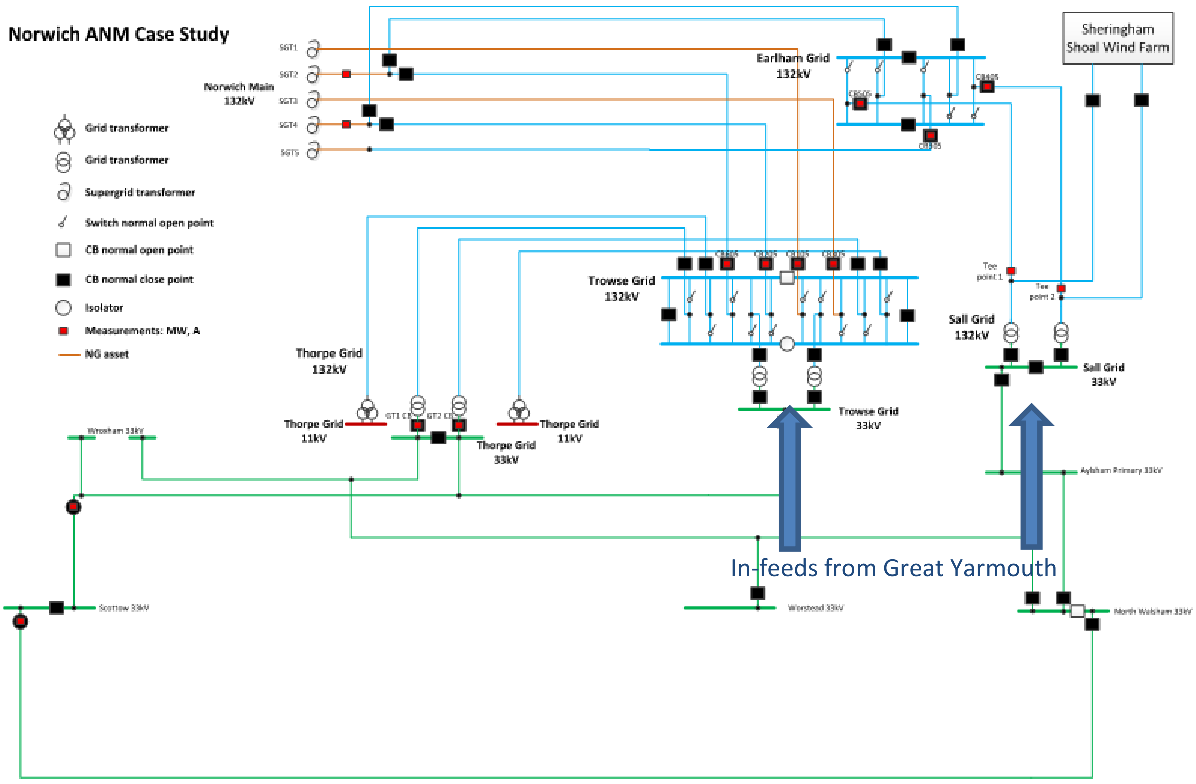


Figure C2 UKPN Curtailment Assessment Trial Area- Norwich Flexible Area

C.3 UKPN Trial Results

As described previously, the initial trial had the service set as last in the LIFO stack as it was believed that position of the Service in the LIFO stack didn't matter. After further consideration, the process described in C.2.4 was followed which found the net additional curtailment due to the service running.   The following data were provided as outputs from the trial upon which to do further analysis (30min interval over 1 year):

Inputs to UKPN's Curtailment Assessment

- A: Non-ANM Plant MW output (plus Fuel Type and Capacity)
- B: Prior to curtailment ANM Plant output MW (plus Fuel Type and Capacity)
- C: Demand MW for each load in flexible zone

Outputs from UKPN's Curtailment Assessment

- D: With Service Off 24/7/365: Post curtailment ANM Plant output MW
- E: With Service On 24/7/365: Post curtailment ANM Plant output MW

DNOs' curtailment assessments typically present results on the basis of energy, as this is of most interest to DER Developers. For service conflict, results presented in MW are most useful. Using the equation in C.2.4 the results in Figure C3 to C8 were obtained.

Figure C3 shows, on a sunny day in April, how due to relative sensitivity of the service to ANM controlled generation in the LIFO stack more MW can be curtailed due to the service running than the size of the service MW e.g. at 13:30 ~65MW of additional curtailment occurs due to the service running at its full output of 20MW. If the service ran at this time this would result in a net loss of 45MW to the system rather than the desired 20MW increase. (For the equivalent availability calculation, negative results were limited to zero.)

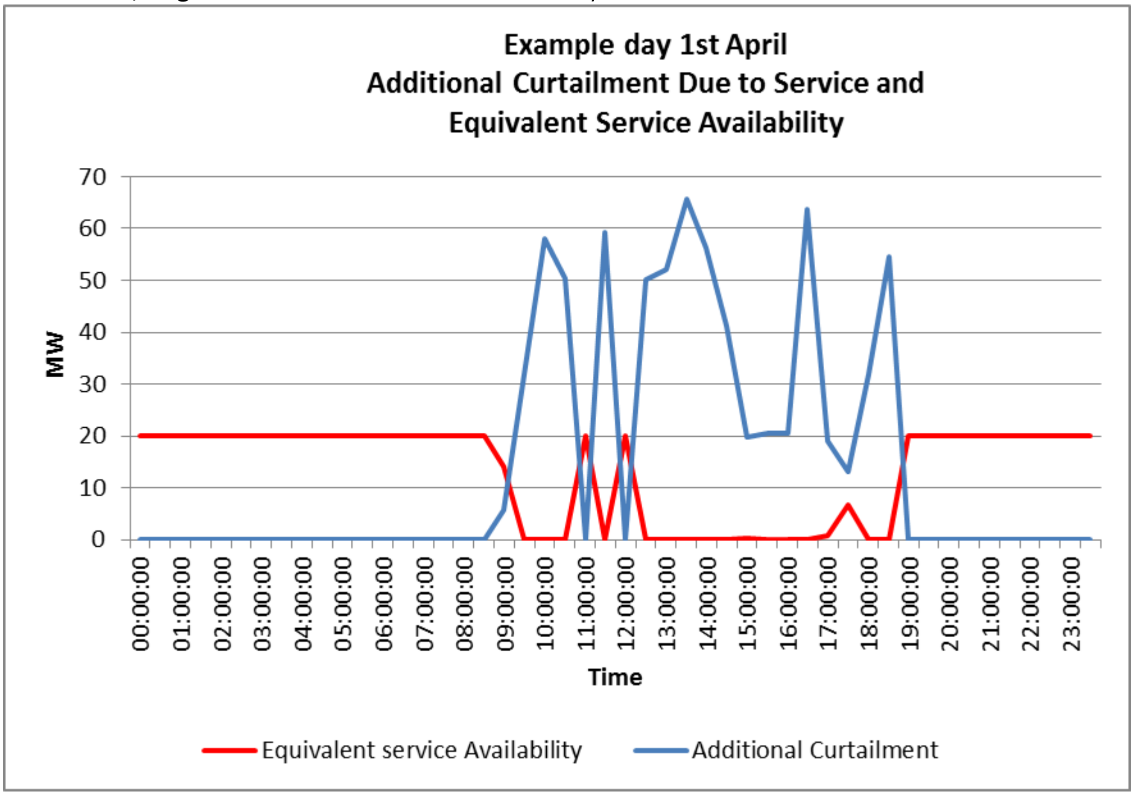


Figure C3

Alternatively, Figure C4 for 23rd August shows no additional curtailment occurs on this day due to the service running. It should be noted that a pessimistic location was chosen for the service hence significant reduced equivalent availability at times. Figure C5 and FigureC6 show average equivalent service availability by month and time of day over a year. FigureC7 and FigureC8 show average availability for two sample months, January and April.

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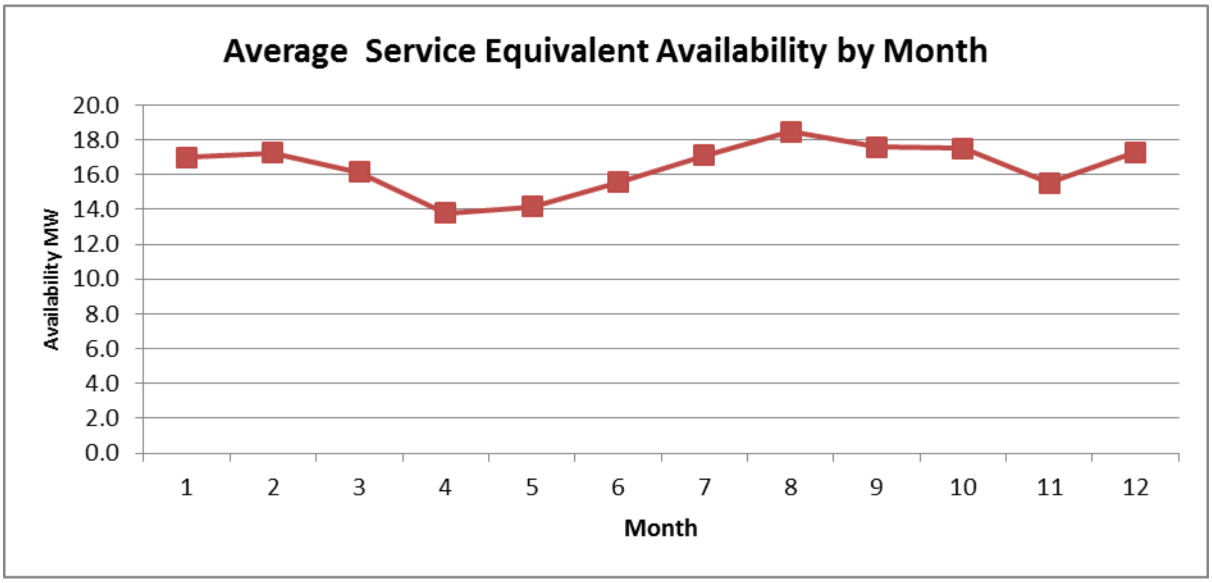

Figure C5

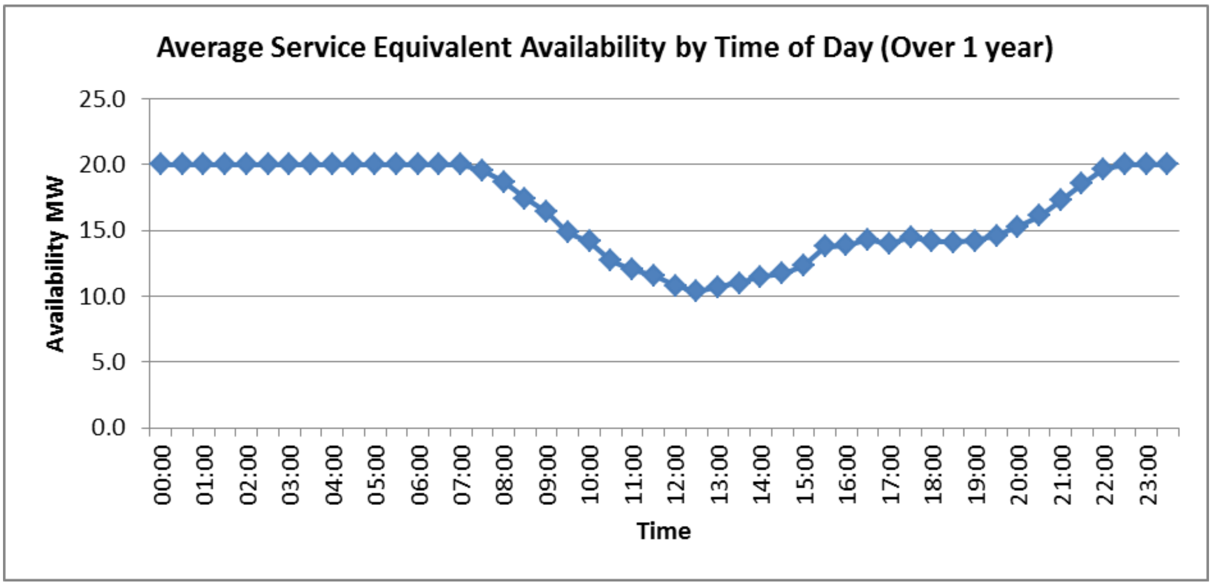

Figure C6

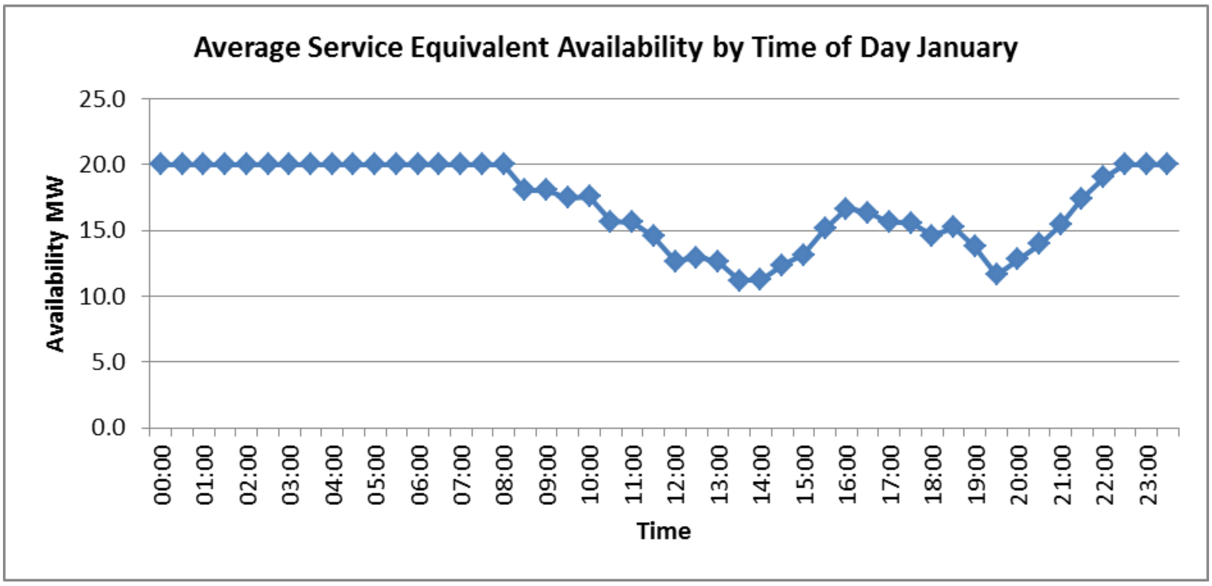

Figure C7

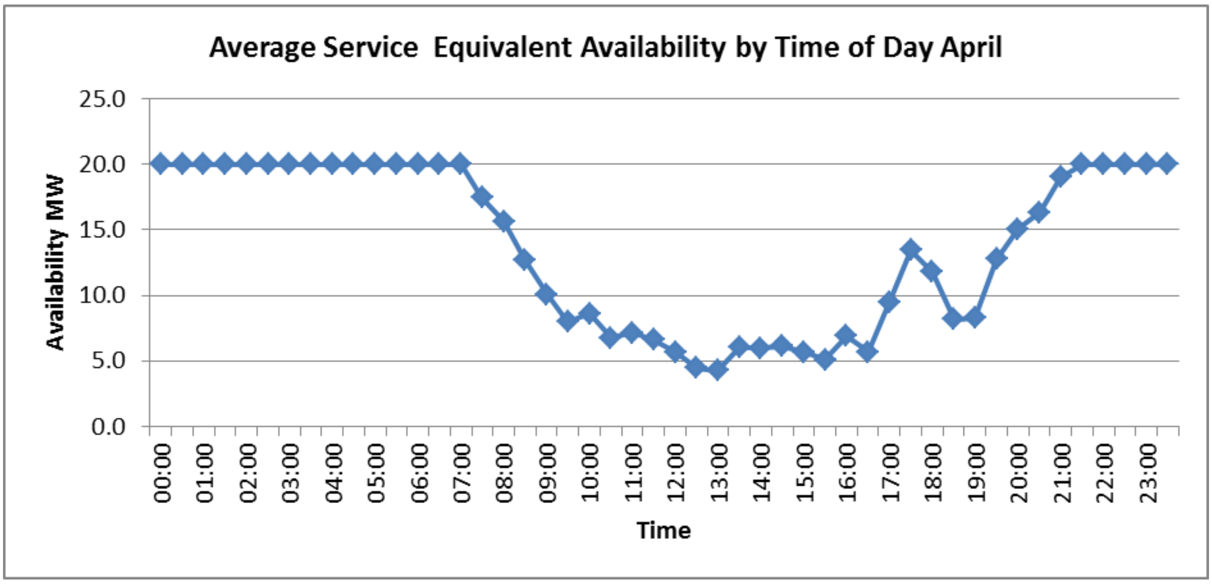

Figure C8

It was desired to explore whether it would be possible to forecast when curtailment occurs based on key indicators. To do this it was decided to group the monitoring variables that were understood to behave in the same fashion. As solar and wind follow the same profile these were grouped regardless of sensitivity. Similarly it was assumed that demand, on the whole, would roughly follow the same profile. Using this logic the following variable groups were chosen:

Explanatory Variables:

- Net Solar output MW (Both ANM Uncurtailed and non-ANM)
- Net Offshore Wind output MW
- Large Thermal output MW (Great Yarmouth)
- Flexible DER Thermal Plant output- No 28
- Net Demand MW

Predictor (Output) variable:

- Additional Curtailment MW Due to Service

The explanatory variables were put through a linear regression to determine the relationship between the Explanatory variables and the Predictor variable. The ratings in the UKPN area change between winter and summer ratings. Winter ratings apply for the months October to March and summer April to September. On this basis two separate regressions were performed for winter and summer as it was assumed there would be two different linear relationships depending on the season. From this regression, the accuracy, measured by the term R squared=0.72 which means that 72% of the variation could be explained, i.e. predicted by the chosen explanatory variables listed above. This was not quite as accurate as hoped however it does show some forecasting ability and for simpler constraints the accuracy would be much higher. FigureC9 shows an example forecast for October and FigureC10 shows an example forecast for April. It can be seen that the October forecast is reasonably accurate and the April forecast less so.

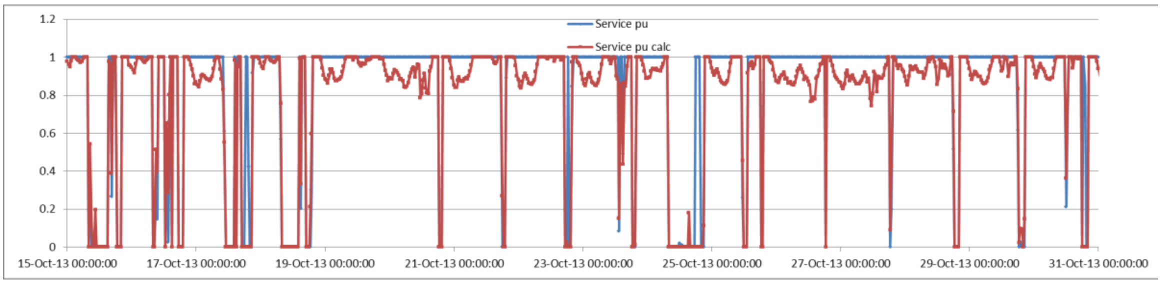

Figure C9

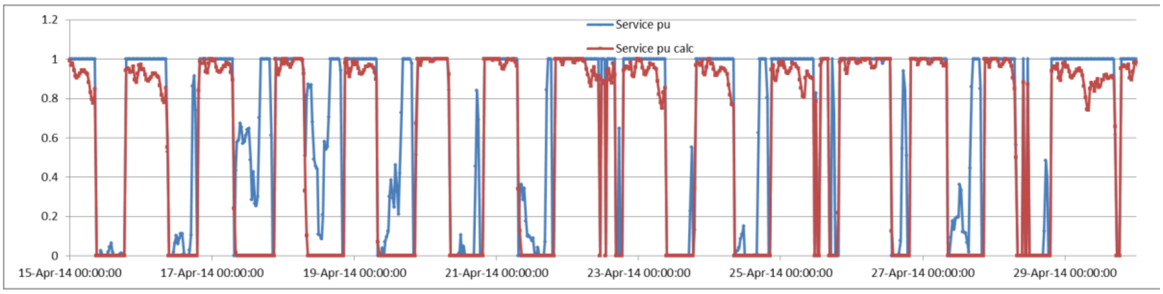

Figure C10