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Regional Development Plan learnings relevant to investment planning processes

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Executive Summary

The number of distributed energy resources (DER) connecting to the electricity distribution network in GB is increasing, leading to system issues such as high volts. Forecasting the long-term growth of DER is complex because of the multiple variables that can affect the market and determining at what voltage levels to implement solutions to solve the issues arising from this is key to maintaining a co-ordinated, efficient and economical electricity network.

Two Regional Development Programmes (RDPs) were set up between National Grid and UK Power Networks (UKPN) in the South East and National Grid and Western Power Distribution (WPD) in the South West to consider whole system analysis of the issues in these areas. In undertaking this whole system analysis challenges were encountered in the process of bringing together transmission and distribution network modelling and solutions to determine the best course of action. This report documents the key learnings from these programmes most relevant to the investment planning process and which can be explored further through the case studies being delivered through Work Stream 1 Product 1 of the ENA Open Networks project. This report does not look to presuppose future system architecture.

The key findings and recommendations for further industry follow up are summarised as follows:

1. The RDPs have demonstrated the value in enhanced data sharing to better facilitate NGESO modelling the effect of the distribution system on the transmission system, and likewise for DNOs to be able to model the effects of the transmission system on distribution networks. The RDPs have shown how well managed interaction can also add significant value. To enable this, consistent modelling of the combined transmission system and distribution system is essential, as is the ability to model this interaction under changing conditions, E.g. changing solar output. It is suggested that the Week 24 data should be reviewed to align with RDP modelling techniques, which will also align with the data for the trial reassessment process under RDP Appendix G. **Action for Open Networks, Work Stream 1, Product 12 to consider**.
2. The RDPs have demonstrated the benefits of a deep application of connect and manage to avoid tying the connection of small DER to significant transmission reinforcement works. Where volumes of DER are involved the consistent application of the Wider System Cancellation Fee across DER and transmission connections is required. The rules for the inclusion of DER in the wider application fee calculation and for application of that fee to DER should be reviewed to obtain a more consistent approach. **Action for NGESO Market Change Electricity**.
3. Incentive setting for RIIO T2 and ED2 should take note of whole system findings to ensure future incentives encourage the most efficient “Whole System” investments to be built. It was seen under the studies that further SGT capacity at specific sites is the most efficient solution but to build that capacity under current regulation the costs would be split between all the new users involved with each user having to take the risk of increased costs if other prospective “connectees” pull out, which they are generally not able to take; it is therefore unlikely that the SGT capacity would be built. **Action for Charges Futures Forum - Network Access Taskforce.**
4. Inconsistency of demand and generation data has caused rework, delays and uncertainty throughout the RDP process. Significant improvements were made in the disaggregation of load and generation at lower voltages, and on agreed assumptions. Further work is required to agree a consistent approach to the provision of data and also to better align the DNO Regional FES and NG national FES. This will ensure improved outcomes for both

distribution and transmission systems and particularly for “Whole System” interactions. **Action for Open Networks, Work Stream 1, Product 5 to consider.**

5. The best approach to managing the impact of distribution constraints on embedded NGESO services is still to reach consensus in the industry. This is so that network constraints do not interfere with access to ESO services. It should be noted that the approach agreed for trial in the UKPN SE coast is different to that in the WPD South West RDP. The findings from the UKPN and WPD RDP trials should be used to inform the debate on the best approach to take account of related activities and requirements such as TERRE. **Action for Open Networks, Work Stream 1, Product 13 to assess the outcomes of real time conflict of service trials.**
6. Solutions for managing high volts were considered in the form of installing reactors at lower voltages. Comparison of the cost effectiveness of reactors installed at transmission and at a number of distribution voltages narrowed down the range of credible options, but greater confidence in costs for distribution connected plant is required to confirm the conclusions. Further consideration needs to be given to increased distribution losses along with detailed modelling of the distribution network. **Action for Open Networks, Work Stream 1, Product 1 to assess the findings and gain additional cost data for distribution level reactors.**
7. The whole system analysis in these RDPs has been a learning activity and taken much time and resource. A process is now required to be able to update the recommendations of the whole system study as backgrounds change. This will need to be faster and less resource intensive and will need a suitable trigger to indicate the need to re-start the analysis. **Action for Open Networks, Work Stream 1, Product 1 to consider.**

1 Introduction

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

The techniques and processes used within the RDPs will be replicated across other network areas as appropriate, resulting in innovative approaches being deployed much more rapidly. Initially the RDPs have been set up on a project basis, but as the techniques and findings of the RDPs move into regular practice, it is envisaged that the RDP approach will continue to develop into a series of Business as Usual (BAU) developments.

The learnings from the Western Power Distribution (WPD) and UK Power Networks (UKPN) RDPs form the basis of the pathfinding projects currently underway to further develop processes for a regional Network Options Assessment approach for high voltage issues. This report outlines the key learnings from each of these RDPs in terms of investment planning processes and the recommendations to be taken forward. The outputs and recommendations of this report are based on the current system architecture, noting that this may evolve in the future.

2 Western Power Distribution RDP

2.1 Whole System Regional Network Options Assessment and Investment Recommendations

The RDP between National Grid and Western Power Distribution (WPD) was set up to address issues driven by large volumes of distributed energy resource. Conducting a detailed joint transmission and distribution network analysis showed benefits in understanding network security issues under conditions not previously experienced and enabled the investigation of a range of build and operational solutions to show under what conditions "Whole System" solutions benefit the consumer and DER project developers. A whole-system study of an area of north Cornwall was also conducted and it aimed to identify network issues such as the DER level increases, whilst finding the most economical solution for consumers taking into account distribution/transmission build and non-build solutions. A Network Options Assessment (NOA) Cost Benefit Analysis (CBA) process has been used to demonstrate the most efficient way to manage the Whole System interactions on the network and find the correct balance between operational solutions and investment in network infrastructure on both the Distribution and Transmission side of the boundary. The key learnings from this programme relating to investment planning processes are detailed below. Further observations and recommendations can be found in the full set of published reports on the RDPs.

1. The original brief for the Whole System NOA study was to cut the geographical area down to a more manageable area, namely North Cornwall and Devon which is rich in renewable potential but is known to be near capacity by conventional means. The results of the studies showed T / D interactions which made it necessary to extend the area considered for Whole System interactions to cover South Cornwall and Devon in order to get the correct economic solution for the original area. This has been combined with the wider RDP results to obtain the optimum transmission solution for the complete SW Peninsula area. Note that the

analysis of the distribution system has been more limited outside the original Whole System area.

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

2.2 Study Findings and Management of the Network in the SW Peninsula

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

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

Key findings can be found below:

1. Although the analysis indicates capacity is likely to be adequate to at least 2020 and possibly beyond, a large quantity of the transmission capacity available is already allocated to contracted parties. An increase in interest could potentially lead to viable developers getting delayed connection offers as a result of the allocation process. Early adoption of revisions to the DER connection package towards a “deep Connect and Manage” approach should alleviate this issue, particularly when combined with the measures below which together enable increased operational solutions.
2. Sunny days in spring and summer do present a significant challenge to both transmission and distribution, particularly when windy and / or coincident with low consumer demand. Analysis shows that the loadings in the peak solar condition are for a relatively short time period in the year and therefore there is an economic balance to be obtained in managing the generation to the network capability rather than building new network to meet the peak requirement. In the short term investment in systems to better control generation on the distribution network, sometimes to resolve transmission issues and developing the functionality of the existing networks to actively work together will therefore be important.
3. A new single stage connection offer process for applicants in this zone would remove the requirement to make offers subject to statement of works and enables generators to have all the distribution and transmission contractual terms in their initial offer. This results in quicker, more efficient connections for all customers.
4. The use of deep Connect and Manage with visibility and control of DER as Enabling Works, socialised transmission securities and the use of NOA processes to decide transmission reinforcements on a wider basis, provides more consistent outcomes to customers and a more manageable position for network companies. The DER are no longer tied into specific transmission works which means their risk profile is no longer affected by their place in the queue and will not affect their connection date. The reinforcements can be planned on a consistent industry best view thereby removing risks around speculative applications.
5. Commercial arrangements for DER flexibility will be developed to allow the appropriate level of participation, through multiple routes, without undue burden on infrequent participants.
6. The RDP has recommended the development of a Control System and processes for Transmission/Distribution operational interactions that will allow more efficient outcomes for customers and consumers.

2.3 Processes for Exchanging Model and Data Assumptions

Several challenges were observed during the RDP relating to data assumptions and model exchange which are applicable for investment planning processes. These revolved around consistency in forecasts between transmission and distribution, scenario setting, the assumptions made on the demands seen in study areas and establishing methodologies for Cost Benefit Analysis on both transmission and distribution.

2.3.1 Identifying scenarios for study

The accepted not yet connected connections database held by the DNO may include a significant amount of capacity which, whilst the DNO is committed to delivering, is not delivered through to energisation. By building the uptake scenarios from a local level upwards, the distribution of installations can be more accurately aligned to the current installed position and also include better forecasting predictions. Energy Supply Areas are created by using the boundaries of network assets, these will change as the network is reconfigured and augmented in time. This may mean it is not possible to identically compare ESAs in subsequent studies, thus care needs to be taken when selecting areas of study for future work in order to be able to have consistency between results.

There was also significant variation in scenarios between those developed for the transmission and distribution networks. In order to fully understand and quantify the impacts of demand and DER uptake on the whole electricity system, the scenarios being studied need to be decided and fixed. The volume and distribution of the various technologies need to be described in consistent terms in such a way that it is possible to repeat the studies for both transmission and distribution network studies and ensure the power flows are comparable.

A number of key learnings were identified to be taken forward in the development of consistent scenarios. These are:

- Choosing scenarios based upon the installed capacity, rather than a time period or economic/political outlook may reduce the number of scenarios required to be studied. Where the technology type of generation varies significantly between scenarios, then this approach will not hold true and should not be applied.
- Modelling every single technology type individually within each of the geographic areas chosen for the study will result in a significant number of nodes being created. Some rationalisation of the technologies will be required, but the level to which that grouping occurs should be carefully considered else it may limit the analysis carried out subsequently.
- Whilst the growth of renewables is likely to be the main focus, other generation types should also be considered as they may impact the total energy flows to a greater extent than the more intermittent technology types.
- The size of installed capacities for each technology type and the coincidence of dispatch with other types will inform the studies needed to determine maximum loading conditions.

2.3.2 Determining generation diversity factors

In order to realistically model the behaviour of generator output in the region being studied, generation diversity factors (load factors) need to be calculated for different generator technology types. As it is not practical to do annual time-series modelling to determine the maximum loading conditions, the dispatch studies being modelled need to be determined by selecting the current peak loading periods of the network and understanding the individual technology loading contributions.

Where there is a future energy scenario which predicts a deviation in the generation mix, the studies may need to be revisited to ensure they remain representative of the future maximum dispatch conditions. The coincidence of demand against generation peak also needs to be considered as a variable. Care needs to be taken to ensure the coincidence of generation and demand does not change across the timeline being studied, in so far that it would impact on the validity of the study.

2.3.3 Identifying and agreeing area of study

When using separate network models, it is not realistic to expect full alignment at the same granularity for all voltage levels, however, the differences in network models used can be mitigated by ensuring the voltage levels adjacent to the boundary are closely aligned in both transmission and distribution models. Any network models used for current practices should be expanded to include more detail of the adjacent network as the addition of such network information is no longer a restriction for present modelling tools and computing capability. It should be recommended that DNOs begin to move from purely considering power flows for strategic network studies, to considering energy flows across a wide time period.

2.3.4 Joint Modelling Methodology

Asset build and operational mitigations are both considered in order to find the lowest cost solution as seen by the consumer. All solutions shall be costed on an equal basis regardless of who, under current regulations, would bear the cost.

2.3.4.1 Distribution Modelling

Distribution network modelling should consider steady state flows across the distribution assets and ensures they remain within limits. Dynamic or transient studies are not currently undertaken by the DNO, however, operating the assets within the original designed capacity will ensure voltage step changes are within limits.

By using conventional network study tools to analyse the overloads observed for the various uptake scenarios under both intact and credible outage conditions, the circuits and assets in need of mitigation through curtailment or reinforcement can be identified. Studies should be undertaken with different diversities of generation output.

2.3.4.2 Transmission Modelling

All credible single and double circuit faults within the study zone should be simulated under intact network and outage conditions. From the steady state simulation results, any fault/outage combination that indicates a voltage issue is then further analysed using a dynamic simulation.

Studies should look to identify any issues relating to thermal violations, voltage violations or G59[1] under voltage violation.

2.3.5 Steady State nodal comparison

To ensure all the models are aligned and broadly representative of each other, the flows between nodes should be compared so that the results can be corroborated.

Reactive power consumption behaviour of the models needs to be compared and potentially adjusted to ensure that under different loading scenarios, both models behave similarly to enable comparison of study results.

2.3.6 Compare Exceedances, Challenge and Review Option Combinations

For efficient and economic whole system planning, conventional and non-conventional build techniques need to be assessed alongside non-build options.

New network build solutions can be assessed for suitability using conventional network study tools, but non-build and hybrid build/non-build solutions need new cost assessment processes to be developed. Both types of solution need to be compared using cost assessment techniques to understand which solutions are most economical to implement under certain scenarios.

New study tools for non-conventional build and non-network build techniques need to be developed to allow options to be assessed. The liquidity and cost of flexibility markets will define how applicable

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[1] ENA Engineering Recommendation

non-network build alternatives are, however replicable data for these markets can be difficult to coordinate. NOA tends to assume markets will deliver at an economic cost, however this assumption may not hold true for distribution constraints, as these will be more locational specific.

2.3.7 CBA for curtailment options

When considering the CBA on a whole system basis, the boundaries being considered need to be defined as there will be a separate assessment required for each boundary.

2.3.7.1 Distribution

The difference between the sum of all generation output of the Network Maximum Credible Loading Study[2] and the Network Minimum Curtailment Study[3] should provide the maximum requirement for generation curtailed. This can be combined with collated load duration information from the dominant generation source within the constraint area, to determine the likely number of half hours for which levels of generation dispatch above the network capacity may occur.

2.3.7.2 Transmission

To undertake a whole system options assessment, the process involves the following typical steps:

- Whole system technical studies
- Identify appropriate power flow boundaries from physical constraints of the whole system
- Where boundaries are nested, assess from extremities in toward the main interconnected network
- CBA process to assess favoured option
- Re-analyse boundaries to identify if any boundaries are improved/worsened by recommendation. Reiterate where needed
- Whole system recommendations.

This method will only work when considering a fairly consistent mix, dominated by non-dispatchable generation. When you add significant volumes of controllable generation that responds to market conditions, then can't rely on history to predict future constraints.

2.3.8 Recommendations from the WPD RDP

The following recommendations are made following the learning on processes and modelling:

1. It was determined that to fully understand and quantify the impacts of demand and DER uptake on the whole electricity system, the scenarios being studied need to be decided and fixed. The volume and distribution of the various technologies need to be described in consistent terms in such a way that it is possible to repeat the studies for both transmission and distribution network studies and ensure the power flows are comparable. It is recommended that it may be prudent to apply scenario modelling techniques on the accepted not yet connected database to provide a more realistic expectation of future

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[2] **Network Maximum Credible Loading Study:** In order to determine likely maximum curtailment requirements, this study analyses a credible maximum generation output profile, with coincident demand loadings. See WPD RDP Process Report Section 2.5.1

[3] **Network Minimum Curtailment Study:** This study reduces the output of generators affecting the circuits and assets in technical best order until the network remains within limits. See WPD RDP Process Report Section 2.5.1

generation levels.   These issues and recommendations are explored in more detail in the following sections.

2. It is recommended that the industry work together to determine a consistent methodology for determining future energy scenarios so that this methodology can best inform further whole system study work. Having a consistent methodology and better sharing of data would reduce the time spent within the first RDPs on aligning data and scenarios between Transmission and Distribution. This work is being progressed through the Energy Networks Association (ENA) Open Networks Project in the 2018 Work Stream 1 Product 5 and Work Stream 1 Product 12.
3. Any network models used for current practices should be expanded to include more detail of the adjacent network as the addition of such network information is no longer a restriction for present modelling tools and computing capability. It should be recommended that DNOs begin to move from purely considering power flows for strategic network studies, to considering energy flows across a wide time period.
4. Reactive power consumption behaviour of the models needs to be compared and potentially adjusted to ensure that under different loading scenarios, both models behave similarly to enable comparison of study results.
5. Regional and national assumptions that feed into scenarios should be reviewed and in future CBAs of this type assess the difference in regional and national capacities closely in order to identify a suitable range of credible scenarios. Alignment between scenarios is critical for the success of future CBAs of this type as discrepancies between them would render the CBA redundant.
6. One of the main learnings is that a mechanism for collaborating and understanding other areas is critical with greater need for interaction on quantifying issues and deciding best course of action.
7. It is recommended that further studies are performed by the NGSO to identify possible ways of scaling analysis completed within BID3(a pan-European power market modelling tool) to more efficiently assess future CBAs of this type, particularly to refine processes for adjusting dispatch zones to match regional zones.

3 UK Power Network RDP

An RDP was set up for the South East coast network because UK Power Networks (UKPN) and National Grid 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 Distributed Generation (DG) and Energy Storage. The key learnings of undertaking this RDP, which are relevant for investment planning processes are detailed further in the following sections. The full report will be published by UKPN on their website in Autumn 2018.

3.1 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 the transmission studies consistently modelling the complete 132kV network down to the first busbar below (in this case usually 66kV or 33kV.) 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 whole transmission and distribution 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 SoW 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.

3.2 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 do not build up to the detriment of those on the back end of the queue who end up with long delays and potentially prohibitively high costs to connect to the network. Hence the following recommendations are made:

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 GC week24 etc 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 socialise transmission wider securities to all players transmission and distribution 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 the visibility and control of smaller generation generally. This is recognised in other places such as the new 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 of the above need to be considered as a package to deliver the overall benefit.

3.3 Whole System and Management of SO 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.

3.4 IS Architecture

The RDP has demonstrated that in order to deliver the benefits of whole system working, significant developments are required to control room IS and communications between both TSO and DNO 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 but with a view to achieving standardisation as much as possible down the line. Further, although the RDPs are 'trial by doing' the implementation must be able to be relied upon and consistency in TSO control room interfaces must be sought as far as possible. This will require Open Networks coordination of learning outcomes.

3.5 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 the 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.

3.6 Effectiveness and cost of reactive compensation on DNO network

This study was carried out to investigate the cost and effectiveness of installing shunt reactors in the South East UKPN distribution network in order to mitigate high volts challenges. The driver behind this being the notion that reactive power compensation is more efficient when implemented closer to the source of reactive power gain.

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.

3.6.1 Reactive power effectiveness

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 efficient than the equivalent of transmission reactors and vice versa. The effectiveness was calculated using a number of base case scenarios (winter peak, 1pm summer solar peak, 6am summer minimum), which reflect the starting point of each study.

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 (6am summer minimum) when reactive compensation will most likely be required. 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.

A number of useful conclusions were drawn:

- The more reactive compensation capacity installed at the distribution level, the higher the effectiveness.
- The distribution connected 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 33kVand 132kV rather than 11kV.
- The dynamics of the distribution network as far as the reactive power is concerned (gain and losses) are highly dependent on the voltage level at which the compensation is applied.

3.6.2 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. As-built cost information for reactors of lower voltages were hard to obtain. Credible assumptions had to be made where information was not available and third party historical costs considered.

3.6.3 Recommendations for Further work

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 shall also be considered as multiple number of assets installed at different locations would generally be more expensive. Extensive studies to fully understand the impact of the proposed solutions on the distribution and transmission network (e.g. voltage behaviour) shall also be part of a more detailed assessment. Further work is required to gain greater confidence in the costs at distribution voltages. This work is being undertaken in association with Electricity North West and Northern Powergrid as part of the Open Network Project Workstream 1 Product 1 High Volts Case Studies.

3.6.4 Conclusion

The study showed that, due to economies of scale, higher voltage solutions tend to be more efficient. The 33kV and 132kV options could potentially be beneficial but only on a case-by-case basis, where cost and site implications are favourable. Key aspects to be looked at are more detailed costs, impact on voltage step change for routine switching and optimised design. The 11kV option was found to be uneconomical.

The key challenge identified was the fact that costs quoted by different organisations were not on an equivalent basis and, as such, special consideration needs to be given when comparing various options. A wider industry support in carrying out further analysis would help eliminate uncertainties surrounding costs and detailed specifications. Experience from other network operators would bring significant value to this project and help inform some of the critical elements of the study. This work is being undertaken in association with Electricity North West and Norhtern Powergrid as part of the Open Network Project Workstream 1 Product 1 High Volts Case Studies.

3.7 Lessons Learnt from the UKPN RDP

A summary of the recommendations from the UKPN RDP are as follows, which also includes area where work in ongoing into the implementation phase.

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 improvement of 6-12 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 much 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. Innovative control system (Distributed Energy Resource Management System (DERMS)-Active Network Management (ANM)) is under development to dispatch the flexibility required to allow DER to contribute to constraint markets and ensure the system remains operable.
7. Commercial arrangements and associated contracts for DER flexibility are in advanced stages of development to allow the appropriate level of participation without undue burden on infrequent participants.
8. Processes for Transmission and Distribution (T/D) operational interactions are under development.
9. A system for assessing and managing service conflicts has been defined and a plan to implement trials is being developed. These trials will provide the learnings for Open Networks Workstream 1 Product 13.
10. A process map for how services could be procured on a whole system and coordinated basis has been developed and will provide input into Open Networks Workstream 1 Product 2.
11. The benefits of the joint investigation of events affecting Transmission and Distribution were realised through analysis of inadvertent tripping of DER due to Vector Shift protection (Loss of Mains protection (LoM)) with the findings feeding into industry programmes to change from Vector shift protection to high setting RoCoF.
12. 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 findings from this analysis will feed into Open Networks Work Stream 1 Product 1 High Volts Case Studies. Further work is required to gain greater confidence in the costs at distribution voltages.
13. A high level IS and communications architecture has been developed to provide the control room visibility and control for operational Inter-tripping and Service Conflict Management.
14. Further work is still required to implement the control systems and interfaces within the Electricity Network Control Centre (ENCC), develop the commercial process and to inform the suitability of service conflict protocols in this use case.