A whole system analysis

Joint network study for the south west transmission and distribution system

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1 EXECUTIVE SUMMARY

This report is a culmination from a joint whole system study by National Grid Electricity System Operator and Western Power Distribution (WPD) on WPD's south west licence area. This area has high potential for solar and wind renewables. Conventional transmission and distribution capacity issues were a limit on the predicted volume of distributed energy resources (DER). Within the south west, the study analysed the electricity transmission and distribution network covering the north of Cornwall to Devon in detail. This study aimed to:

- Identify network issues as the DER level increases.
- Find the most economical solution for the consumer taking into account distribution, transmission, build /operational solutions and value of lost generation.
- Inform the energy industry on potential regulatory changes to incentivise to most efficient behaviour in the changing environment.
- Inform process for future assessments.

Steady state power flow and dynamic system analysis shows that there are potential network issues beyond 2020 if the growth of DER progresses under the most extreme gone green scenario. This report highlights credible non-build/build solutions for those issues. The main findings include:

- There is a risk of fast voltage collapse and uncontrolled tripping of DER (G59 under voltage protection setting under current policy) for transmission circuit fault outage combinations. This is when DER dispatch goes beyond 1.7GW (equates to 2.6GW of installed capacity) in the whole of the south west area. There is a need to have dynamic MVAr support beyond this level of generation dispatches.
- The study found there are significant interactions between transmission fault / outage combinations and the configuration / loading on the 132 kV network. Many of the generation dispatch conditions which cause the distribution network to exceed ratings will also cause similar increases in the transmission network. The investment decisions must be linked in order to achieve the most economic whole system outcomes.
- The configuration of the 132 kV distribution network will be one of the defining factor of thermal and voltage limits. It will also have an impact on the effectiveness and complexity of Active Network Management (ANM) systems.
- Potential fault level issues have been identified in Indian Queens and Exeter. Studies indicate that Running Arrangement (RA) changes and distribution network operator (DNO) network configuration changes can help manage fault levels.

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2 BACKGROUND

The number of distributed energy resources (DER) connecting to the electricity distribution network in the south west of England and Wales is increasing. Forecasting the long term growth of DER is complex because of the multiple variables that can affect the market and determine growth. Western Power Distribution (WPD) have produced a forecast in collaboration with Regen[1], as shown in figure 1 below. It shows the level of DER capacity could reach as high as ~5 GW by 2030 when installed, as indicated in the worse gone green future energy scenario.

The energy scenarios derived from National Grid's national scenario and use regional data. They are based on the methodology used in the economic scenarios developed by National Grid in Future Energy Scenario (FES) document. This forecast used WPD connection data and local market intelligence to provide a more accurate regional forecast. The last WPD energy scenarios for the south west region were published in 2016 in the WPD South West report which was called *Shaping sub-transmission to 2030*. This was the best data available at the time of this analysis.

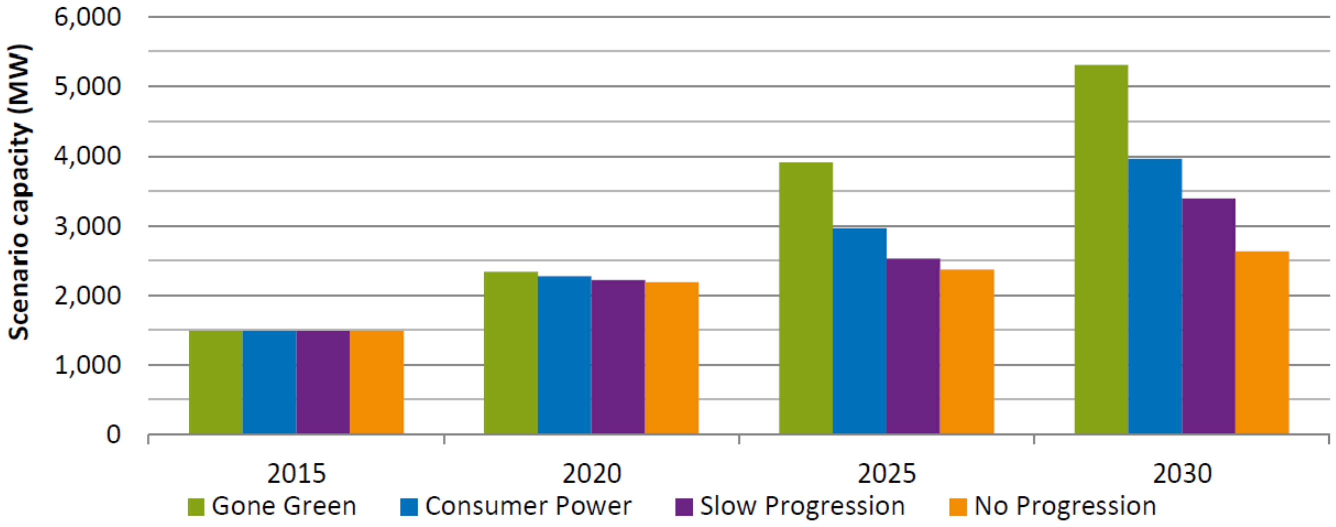


Figure 1: WPD SW Renewable DER Growth - 2015 to 2030

The transmission and distribution network in this area is not designed to cope with this level of DER growth. There is a need to understand the impact of the growth and come up with a strategy to operate the network in a safe, secure and economic way in the future.

[1] Regen SW is a not-for-profit organisation which promotes renewable energy and energy efficiency in the South West of England. More detail on https://www.regensw.co.uk/

3 INTRODUCTION

The aim of this document is to analyse the system progressively up to the year 2030. It makes recommendations for the most efficient solutions for consumer costs and the range of generation scenarios considered credible. The forecasted distributed energy resources (DER) growth is based on best information at the time of forecast. The growth of DER in the years 2020, 2025 and 2030 scenarios may not occur exactly on their respective dates and each scenario is considered equally probable.

The network studies for the Regional Development Plan in the south west have been carried out for the years 2020, 2025 and 2030. The gone green future energy scenarios have been imposed onto the network models to represent the distributed generation growth. This is because these scenarios represent the biggest potential increase in network power flows. This will demonstrate the worst possible issues on the network and will identify the regional development and network reinforcement required to accommodate the highest possible levels of generation growth. However the solution recommended will be based on an economic analysis.

3.1 The Whole System Approach

The concept of whole system planning is to approach the technical issues as a single entity (System Operator, Transmission Owner and Distribution System Operator/Distribution Network Owners). The objective is to find the most economical and efficient solution for the energy consumer. Asset build and operational solutions are considered. The operational solutions may be commercial or code based, to find the lowest cost solution. . All solutions are costed on an equal basis regardless of who would take that cost under current regulation.

Originally it was north Cornwall and north Devon considered for the exercise. Electrically this area is covering Indian Queens, Alverdiscott and the route leading up to Taunton but not including Taunton bus bars and grid supply points (GSP). The area is rich in potential renewable generation resources, but as the network is nearing full capacity. During the study significant interactions between the capacity available in the key study area and the south Cornwall and Devon network were discovered. In order to get the correct economic conclusion it became necessary to expand the study area. Electrically this includes Landulph, Abham and Exeter GSP's.

Figure 2: The Geographical Area of the Study

4 STUDY METHODOLOGY AND ASSUMPTIONS

This part of the network is dominated by photovoltaic PV installations. In the future, the PV growth forecast developed by WPD and Regen in 2015 shows this growth trend to continue in this area (see figure 3 below).

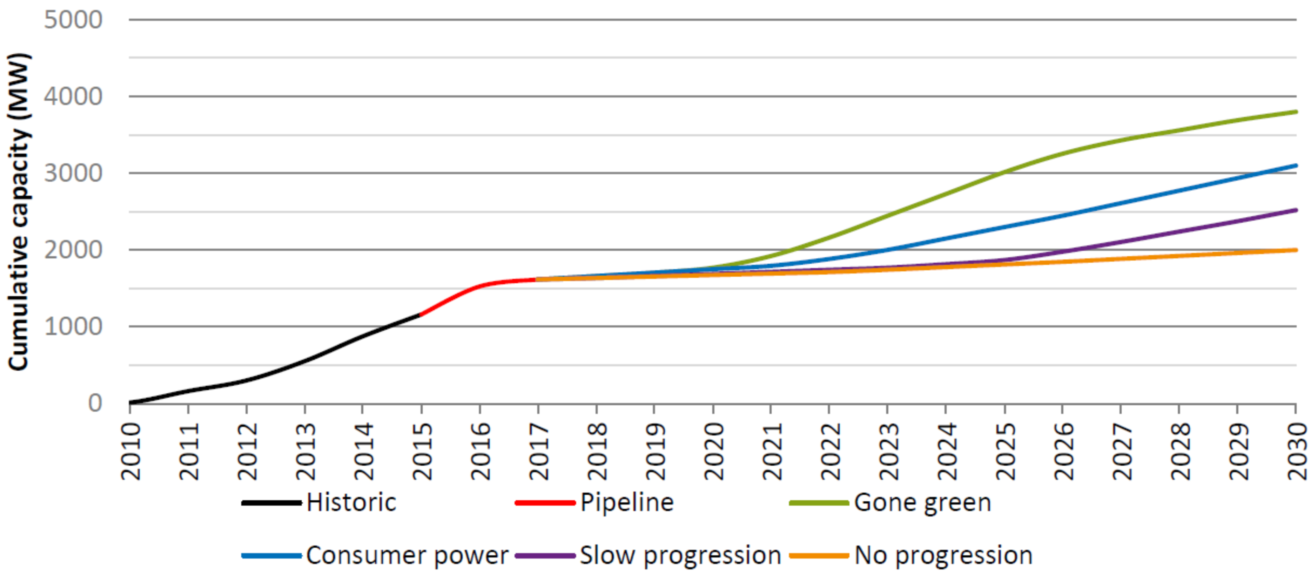


Figure 3: WPD SW PV Growth - 2010 to 2030

The attrition rate of WPD's pipeline has significantly affected the outturn in the short term – with PV currently sitting around 1.35 GW vs 1.6G W in the prediction. However, the longer term is based on what the future costs of deploying the technology might be and the availability of land etc. While Solar has reduced, the storage assumptions have increased. The longer term predictions are close to reality, depending on the scenario. In short, 2020 has been affected, but 2025 and 2030 will be affected less.

To analyse a typical worst case scenario, the summer solar peak period was selected for the study. The rest of Great Britain's (GB's) wide generation despatch, for the area outside the south west region, was as forecasted by 2016 Future Energy Scenarios (FES) ranking order. This was the best estimate available at the time of the study.

The local generation and demand was adjusted as per Western Power Distribution's data. This is explained in sections 4.1, 4.2 and 4.3 below for each of the study points. Interconnector and other large generation within and nearby the area were dispatched as follows;

- Langage 900MW
- Marchwood 900 MW
- Hinkley B 0 MW
- Hinkley C 0 MW
- IFA2 1000MW
- FAB Link 0MW

The above credible combination is most challenging for thermal and voltage issues within the whole system study zone. It has been elected to be studied in detail.

4.1 Network model

National Grid used DIgSILENT power factory's offline model to drive GB's wide base network. This base network was updated with data input from WPD and the National Grid transmission operator as follows for each scenario:

- Distribution and transmission network updates, including appropriate reinforcements for the scenario under consideration and running arrangements
- Technology wise generation modelled at 132kV and 33kV levels. Any generation below 33kV is lumped at a 33kV level. Wind, solar, battery, wave and other thermal technology type generation are modelled separately to allow scaling of the network.
- Active and reactive power demand (gross) at each bulk supply points (BSPs) updated.

WPD used the PSSE offline model that covers the entire WPD (south west) area. The committed reinforcement projects which are due for completion by relevant scenarios have been included in the study. The modelling has taken into account the inter-tripping schemes that are installed, committed or commercially available for the scenario studied.

Provisions are made for the transmission reactive compensations to be on outage during the summer outage period. This means the study did not rely on 100% availability of the reactive compensation to manage the system voltage from transmission point. WPD assumed that the 132kV capacitor at Alverdiscott has been switched out for the studies.

The 132kV and 400kV network configuration is shown figure 4.

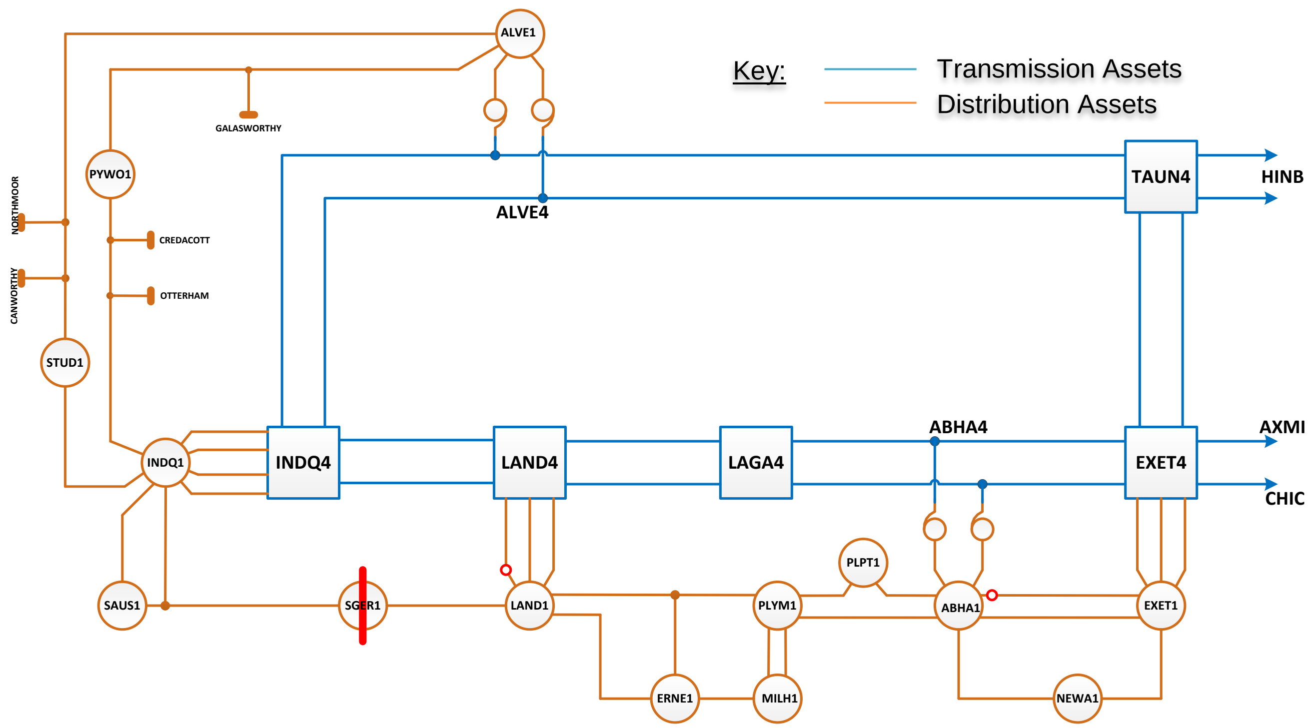


Figure 4: 400kV and 132kV network around 2020

4.2 Methodology – Calculation of DER Diversity Factors

In order to model the maximum simultaneous generator output across the south west realistically, generation diversity factors (load factors) were calculated for different generator technology types. The installed capacity for each generator technology type was multiplied by its respective diversity factor. This was to obtain a realistic power export (dispatch) for each generator technology. This method yields more realistic power flows when compared to the traditional method of modelling generator output as 1pu of installed capacity.

Diversity factors for the following generator technologies were calculated:

- Hydro
- Landfill Gas
- Medium CHP
- Mini CHP
- Mixed
- Onshore Wind
- Photovoltaic
- Waste Incineration
- Small CHP
- Other

These are the generator categories listed in WPD's recording database.

The generator diversity factors are derived from generator export meter readings. This is for sites with an installed capacity greater than 1MW in the WPD south west licence area. The export meter readings from all generators were combined to produce an annual total generator output profile for the region between 01/04/2016 – 01/04/2017, shown in figure 5. The total generation output for each half an hour was plotted and was normalised against the total installed generation capacity.

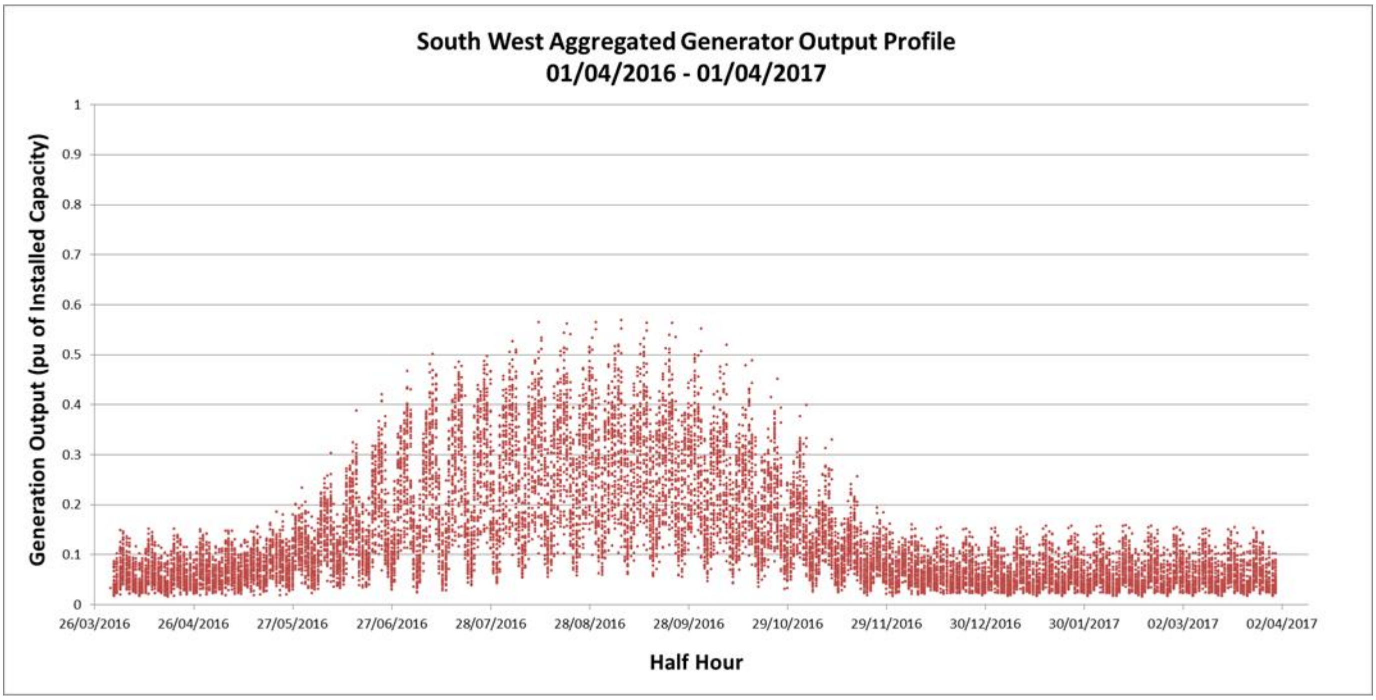


Figure 5: Aggregated Generator Output Profile

Using the same generator export data, the annual generation persistence curves was plotted for the south west region, shown in figure 6. The persistence curve is created by reordering the aggregated half hourly meter readings in descending order.

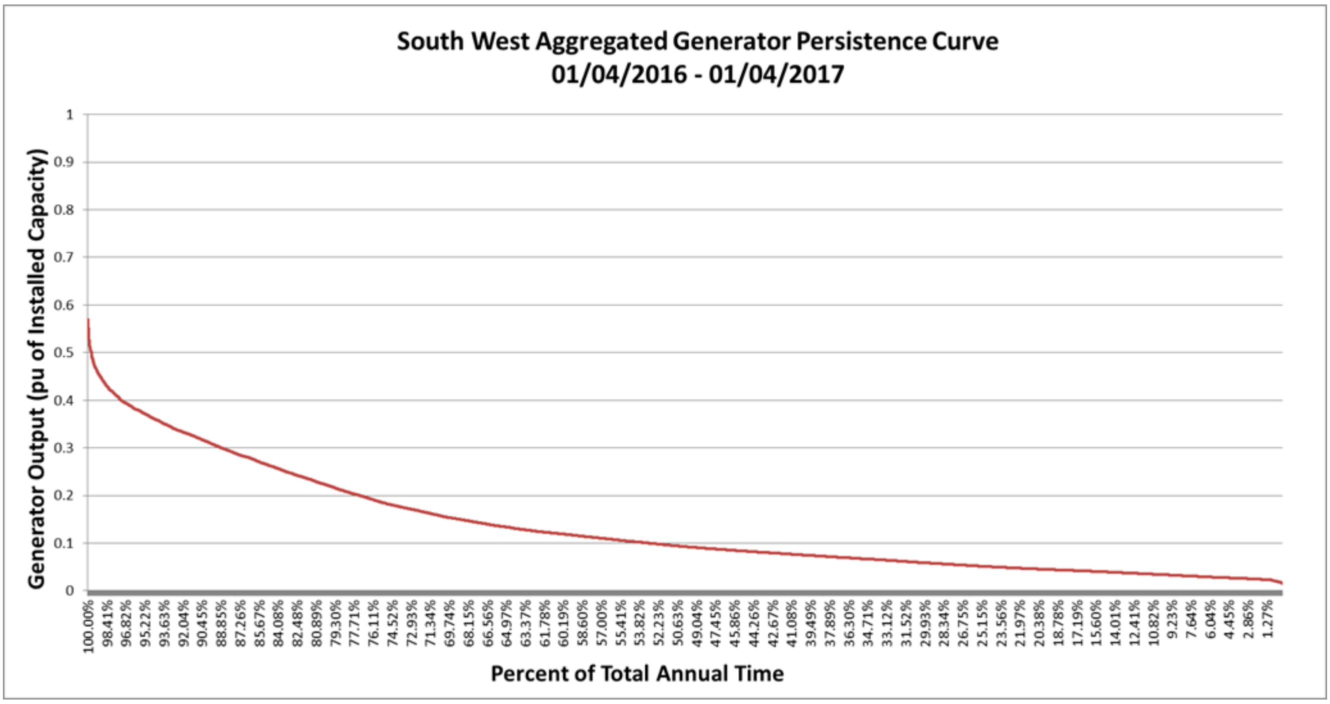


Figure 6: Aggregated Generator Persistence Curve

Using the annual aggregated generation output profile and the aggregated generator persistence curve, the top 50 highest generation output half hours were selected and plotted, shown in figure 7. Due to the amount of solar generation in the region, the top 50 highest output half hours occur in the summer. This sample data also represents the most significant power flows on the distribution network.

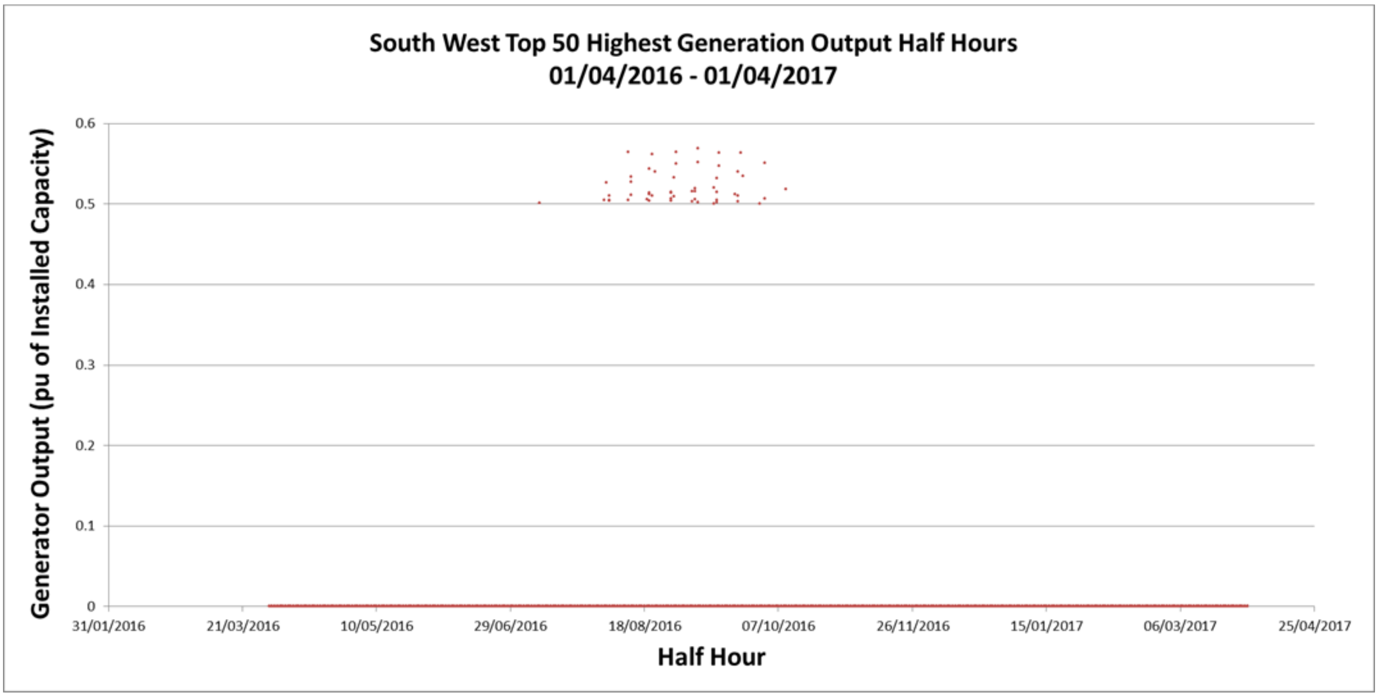


Figure 7: Top 50 Highest Generation Output Half Hours

The top 50 highest half hours account for 0.3% of the total annual time, and 0.98% of the total annual generated energy. The top 50 highest generator output half hours were used as the sample data for calculating the generator diversity factors. How the generator diversity factors were calculated is explained in the following steps.

Step 1

For each of the top 50 highest generator output half hours, the generation output for each of the generator technologies was found. For example, the highest day from data sample, broken down generator technology type, is shown in table 1. The generation power output for each technology type is expressed as pu (per unit) of the respective installed capacity.

Generator Technology Type	Generator Output (pu of Generator Installed Capacity)
Hydro	25.45 %
Landfill Gas	21.84 %
Medium CHP	12.00 %
Mini CHP	34.04%
Mixed	10.39 %
Onshore Wind	53.13 %
Other	23.82 %
Photovoltaic	75.22 %
Small CHP	3.34 %
Waste Incineration	39.74 %

Table 1

Step 2

From the top 50 highest generator output half hours, the highest generation output for each technology type was chosen. Table 2 shows the final generation technology type diversity factors.

Generator Technology Type	Generator Output (pu of Generator Installed Capacity)
Hydro	39.60 %
Landfill Gas	48.99 %
Medium CHP	12.00%
Mini CHP	35.76 %
Mixed	12.46 %
Onshore Wind	59.93 %
Other	23.82 %
Photovoltaic	86.70 %
Small CHP	15.43 %
Waste Incineration	41.27 %

Table 2

4.3 DER Dispatch from 2020 to 2030

This section summarises the generation technology types, installed capacities and diversity factors that have been imposed on WPD's south west 2020, 2025 and 2030 network models.

2020 Installed Capacities & Dispatch

Listed below are the generator technologies, installed capacities and diversity factors that have been imposed on WPD's south west network model. The generation dispatch levels are also shown.

Note: These figures represent WPD's committed connections for 2020

Generator Technology Type	Installed Capacity (MW)	Diversity	Dispatch (MW)
Hydro	6.12	39.60%	2.42
Landfill Gas	187.30	48.99%	91.76
Medium CHP	9.50	12.00%	1.14
Mini CHP	3.56	35.76%	1.27
Mixed	5.85	12.46%	0.73
Onshore Wind	324.00	59.93%	194.17
Other	695.60	23.82%	165.69
Photovoltaic	1394.00	86.70%	1208.60
Small CHP	16.80	15.43%	2.59
Battery Storage	188.45	-50.00%	-94.23
Total	2831.18		1574.15

Table 3

2025 Installed Capacities & Dispatch

Listed below are the generator technologies, installed capacities and diversity factors that have been imposed on WPD's south west network model. The generation dispatch levels are also given.

The generator technology types considered in the 2020 model have been rationalised into five generation technology types for the 2025 model. They are:

- Hydro
- Landfill Gas
- Medium CHP
- Mini CHP
- Mixed
- Small CHP
- Other, which has been grouped into the 2025 'Other' generation type.

  The 2025 'wind included both onshore and offshore wind. 'Wave' is a new generation technology type and includes both tidal and wave generation.

Note: These figures represent WPD's 4GW 2025 gone green energy scenario

Generator Technology Type	Installed Capacity (MW)	Diversity	Dispatch (MW)
Battery Storage	291.45	-50.00%	-145.72
Wind	551.79	60.00%	331.07
Other	1000.21	30.00%	300.06
Photovoltaic	2693.00	87.00%	2343.00
Wave	30.00	50.00%	15.00
Total	4566.45		2843.41

Table 4

2030 Installed Capacities & Dispatch

Listed below are the generator technologies, installed capacities and diversity factors that have been imposed on WPD's south west network model. The generation dispatch levels are also shown. The generation technology types and generation diversities are the same as those used in the 2025 model.

Note: These figures represent WPD's 5GW 2030 gone green" energy scenario

Generator Technology Type	Installed Capacity (MW)	Diversity	Dispatch (MW)
Battery Storage	415.5	-50.00%	208.07
Wind	833	60.00%	500
Other	1197	30.00%	359
Photovoltaic	3514	87.00%	3056
Wave	230	50.00%	115
Total	6191.5		3821.3

Table 5

5 NETWORK ISSUES

A number of steady state and dynamic analysis' were carried out to understand the network issues. The studies were carried out for three different distributed energy resources (DER) dispatch levels in 2020, 2025 and 2030 as explained in the section 4.3 above. All credible single and double circuit faults within the study zone are simulated under intact network and outage conditions. From the steady state simulation results, any fault/outage combination that indicates a voltage issue has been analysed using a dynamic simulation. The study looked to identify following issues within the study zone:

1. Thermal issues: any fault that may overload any of the remaining ccts/assets.
2. Voltage issues:
   a. Steady state voltage violation – any voltage violation three minutes after fault clearance
   b. Voltage step changes – any voltage step changes outside the limit three minutes after fault clearance
   c. Fast voltage collapse – the study zone lacks dynamic voltage support (i.e. synchronous generators or Static Var Compensators (SVCs)). Under certain scenarios the voltage can reduce to zero within few hundred milliseconds from fault occurring, and not recover.
3. G59 under voltage violation - The Energy Networks Association's (ENA) G59 recommendation advises small embedded generators on certain protection settings. One of the recommended protection settings is to disconnect generator if the connection point voltage drops below 0.8pu of nominal voltage and stays there for 500ms or longer.

From a system operation point of view, issues 1 and 2 above are visible and controllable (existing or future control systems). Potential DER disconnection in the G59 under voltage protection is not visible to the GB System Operator. Under a fault scenario, controlled generation reduction will help manage the system. Uncontrollable generation loss would not. The uncontrolled nature of G59 under voltage protection tripping of generators means that the infeed risk cannot be controlled. This causes a risk to frequency and national loss of supply. Also some of the under voltage tripping will be outside the group concerned, i.e. Taunton and Bridgwater GSP's. This will add to infeed loss risk without reducing the thermal or voltage issue within the study zone. This will also interact with the N-3 intertripping that would be required to solve the thermal issues.

The sections below highlight worst credible issues likely to occur in transmission and distribution networks. The conditions that will trigger the issues are likely to persist for about 10% of time in a given year, i.e. high DER output coupled with an outage. During the rest of the year, the issues are likely to be a lot less severe or none at all. Appendix A1 details the full set of studies and findings.

5.1 Transmission Issues

From the studies, the following outage and fault combination was found to be the worst case from a transmission point of view across the scenarios.

- Outage: INDQ-ALVE-TAUN 1 400kV
- Fault: EXET-ABHA-LAGA DC

Under this condition the transmission network becomes a radial network from Langage to Taunton. All the Langage and DER generation under a high generation scenario has the remaining INDQ-ALVE-TAUN – 2 400kV cct to the rest of the system. This single cct is about 90km long and incur significant I^2X losses under this scenario. This leads to a voltage dip in the system.

The issues are G59 under voltage or fast voltage collapse and thermal overloads in the transmission and distribution network. If the voltage collapse is not contained it will lead Langage machines becoming unstable and pole slip.

The voltage trace below (figure 8) shows typical voltage behaviour for the above n-3 condition. This trace is recorded when the DER output within the study zone is about 1.2GW and all three Langage machines are on with 900MW output. When the DER output increases further, the post fault voltage dip becomes bigger and eventually collapses altogether.

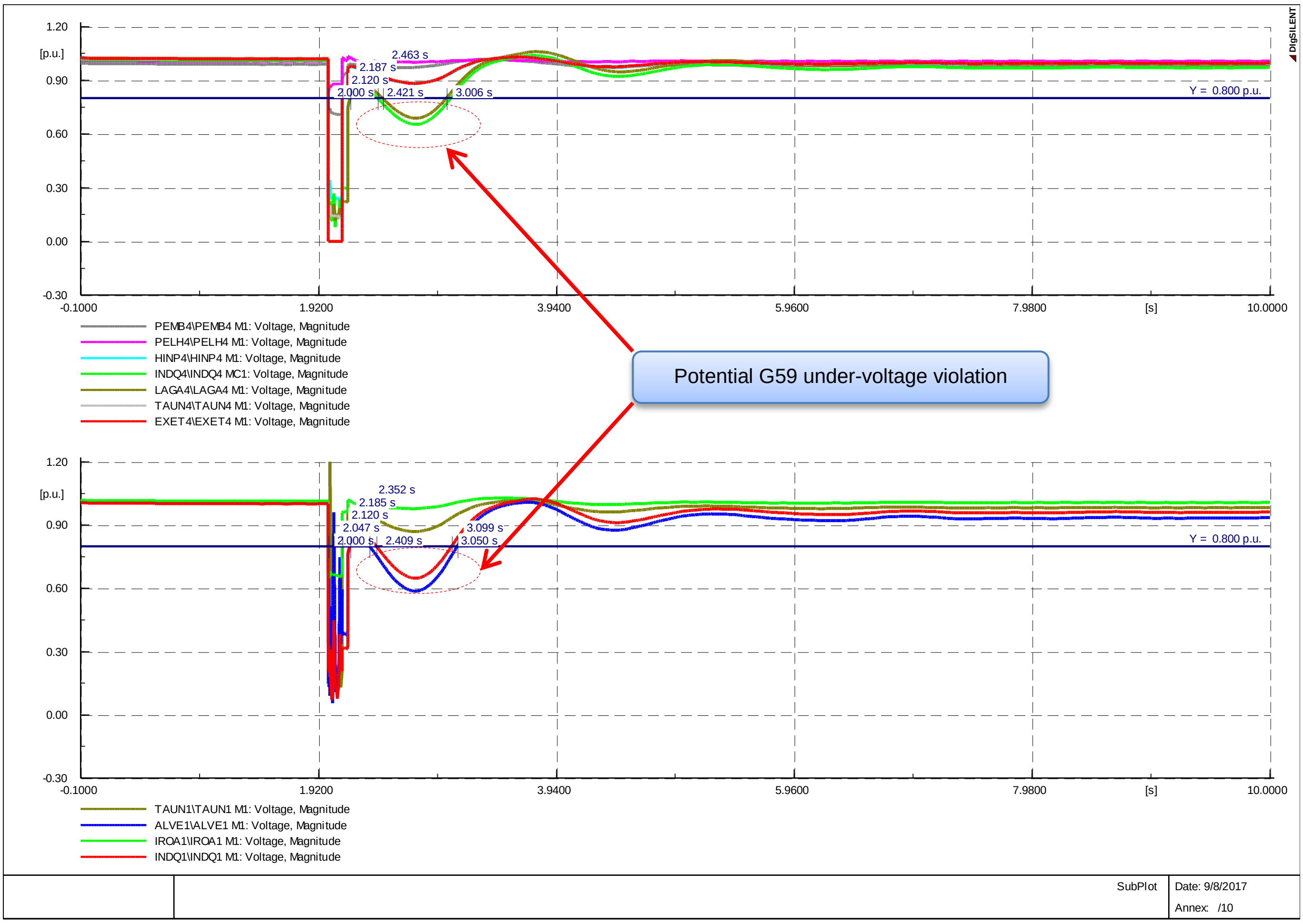


Figure 8: 132kV (below) and 400kV (above) Voltage traces for the above N-3 condition

Under this condition the thermal issues are:

1. WPD cct between LAND and EXET overloading
2. ALVE Super Grid Transformer 2 (SGT2) overloading
3. ALVE – TAUN 2 400kV cct overloading

The overload in thermal issues 1 and 2 above are distribution overloads caused by a transmission fault. This is due to the interconnected nature of distribution network from ALVE to EXET making a parallel route (see figure 4). The transmission network is required to secure for this credible N-3 event, but for distribution networks it is over and above the current standard.

However studies indicate that from a voltage perspective, having a parallel 132kV network provides more strength and significantly reduces a transmission related fast voltage collapse (that should be secured). This shows a clear interaction between transmission and distribution networks. Significant whole system advantages can be gained by proper coordination of transmission, distribution overload capability and overload protection the DNO has to protect their network.

These issues are tested for different 132kV network configurations to understand impact of different DER output levels. In all cases the Langage machines are all on with total output of 900MW. The finding are summarised as follows:

Under current network condition

DER output (in the study zone)	Network issues	Comments
600Mw	• No issues identified	Beyond this level the DNO ccts will start to overload
850MW	• DNO cct thermal overloads	No post fault actions required for voltage control up to this level of output
1.3GW	• DNO cct thermal overloads • G59 under voltage issue	At this level the remaining SGT at ALVE will be closer to 100% loading.

Under DNO network split between EXET and LAND at Plymouth and Plymton 132kV substations

DER output (in the study zone)	Network issues	Comments
700MW	• G59 under voltage	This limit achieved without post fault reactive switching
800MW	• G59 under voltage	This limit is achieved with post fault reactive switching
1.0GW	• G59 under voltage issue • voltage collapse and LAGA machine stability	This limit achieved with post fault reactive switching At this level, the ALVE –TAUN cct will overload into 10min rating. There will not be any DNO cct overloads.

Under DNO network split between INDQ and ALVE

This split configuration does not affect the total output of the DER very much. Under this split the ALVE network becomes radial. The generation minus demand in the group cannot exceed the single transformer rating under the above outage condition.

This arrangement makes any generation curtailment 100% effective on the overload. Under this configuration the proposed active network management will become easier to implement,

5.2 Distribution Issues

2020

Detailed distribution network studies confirmed that there are no significant issues (n-1 and n-2 conditions) on the distribution network for the 2020 scenario in addition to the interactive issues summarised above.

2025

Summer (50% of winter peak demand) studies (n-1 and n-2 conditions) with a diverse embedded generation dispatch indicate potential overloads on a number of 132kV interconnection circuits. This is between Alverdiscott and Indian Queens GSPs with some of the 132/33kV transformers.

The potential loadings are in excess of the available post fault ratings and further work is required to determine if increased post fault ratings over a shorter timescale are possible.

Re-conductoring the 132kV overhead sections (approximately. £14 million) of the circuits with larger conductor at a higher operating temperature will provide a significant increase in the 24 hour post-fault rating. Some curtailment of generation will be required post fault. In addition there will be the cost of replacing the 132/33kV transformers at WPD's sites with larger units.

Network studies were repeated simulating active network, management with and without the use of post fault (24 hour) ratings. The results are shown in Appendix A2.

Further network studies were undertaken with the 132kV network split between Alverdiscott and Indian Queens GSPs. The results indicate an increased potential overload on the Alverdiscott SGTs, however a shorter length of 132kV circuits experience overloads. The approximate cost of re-conductoring these circuits is approximately £7.3 million. There would also be the additional cost of replacing the 132/33kV transformers at WPD's sites with larger units (as with the parallel network).

2030

Studies were undertaken for the 2030 scenario (parallel operation between Alverdiscott & Indian Queens) The results show loadings in excess of the existing 24 hour post- fault ratings. Re-conductoring of the 132kV overhead sections of the circuits with larger conductor at a higher operating temperature is insufficient to manage the increased loadings.

Network studies were repeated simulating active network management with and without the use of post fault (24 hour) ratings. Results are shown in Appendix A2.

6 POSSIBLE SOLUTIONS / OPTIONS

There are number of different options that have been identified to address the aforementioned network issues. The ones listed below are the most credible solutions. One or more solutions (in combination) can be used to resolve network issues.

1. Alverdiscott Active Network Management (ANM)
2. N-3 intertrip
3. Pre-fault curtailment
4. Commercial storage in place of curtailment
5. 132kV Split between ABHA-LAND
6. Post fault 132kV Split between ABHA-LAND
7. Split ALVE - INDQ 132kV route (K route) pre/post fault
8. Protective reactive switching
9. DER MVAr dispatch
10. Exeter fault levels -
11. Uprate LAND-ABHA-EXET 132kV route
12. Uprate ALVE - INDQ 132kV route (K route)
13. Install new SVC/STATCOM
14. Renew/review existing Sync Comp within area
15. Uprate/Additional ALVE SGTs
16. New GSP at Pyworthy
17. Alverdiscott – Taunton reconductoring

The following sections describe each of the options in more detail. A cost benefit analysis (CBA) has been carried out for each option to understand the economics.. Different curtailment requirement are summarised in Appendix B.

6.1 Alverdiscott ANM

WPD are already installing an active network management (ANM) system in Alverdiscott GSP to prevent / control overloads on the distribution system and local SGTs. It will utilise the Last-In, First-Out (LIFO) commercial mechanism to determine which generator to curtail. The LIFO stack means that the last generator to apply for connection is the first to be curtailed when it is necessary. The generator will not get paid for any curtailment, or have to pay for distribution reinforcements, which traditionally would have been required to ensure operability under all conditions. There is a case study assessment on the curtailment strategies in the Western Power Distribution system operability document which gives an explanation with an example network.

The ANM is set up to facilitate the operational solution, replacing a build solution. This is already underway. Therefore, the whole system study does not to determine if it should go ahead or not. LIFO is the current method of curtailing generation and is extremely cost effective for the first generators in the stack, who are likely to see little curtailment at all and may save significant costs. But as more generation connects to the network and later generators pick up significant curtailment, it can remove the developer’s business case and it becomes a barrier to entry. This is because the next generator cannot afford the constraints or the reinforcement costs individually. By considering the cost of curtailment in the whole system CBA (if renewables are subsidised this will generally be the subsidy price) it is possible to demonstrate where the correct point to reinforce the network is. This information can be used to inform regulatory debate and to indicate where the continued use of LIFO will be a potential blocker for the levels of generation in the scenarios. However it can be used to actively manage thermal overloads pre or post fault.

WPD have identified three curtailment strategies that could be applied by ANM and other schemes that manage generator output.

Full pre-event curtailment: Generators are curtailed sufficiently to ensure that the network is steady-state compliant prior to the next event, and will be steady-state compliant immediately following any next event.

Post-event curtailment: Following an event the generators are curtailed immediately to return the network to steady state compliance.

Partial pre-event curtailment: Generators are curtailed sufficiently to ensure that the network is steady-state compliant prior to the next event, and will be short-term compliant for a specified recovery timeframe immediately following any next event. Following an event it is necessary to further curtail generators to restore steady-state compliance.

Power curtailment does not give a full picture of the advantages and disadvantages of the three strategies. The energy curtailed under each strategy would depend on the profiles of the generators and demands connected to the network, and the likelihood of any credible faults on the network. The Regional Development Plan (RDP) aims to ascertain how much energy would be curtailed under each of the strategies defined to inform the most appropriate way for WPD to manage distribution constraints in future. Alverdiscott SGT constraints are planned to use the partial pre-event curtailment method, utilising the SGT's short-term ratings that are available for the timescales ANM communications are available for.

6.2 N-3 Intertrip

Intertripping some of the DER as a post fault action, following a double circuit fault, during a planned outage of another transmission circuit will help manage the thermal overloads. The operational time of the scheme (in the order of up to 30 seconds), is not fast enough to solve fast voltage collapse or Langage generator stability. N-3 intertripping of DER is achieved by the proposed National Grid South West Operation Tripping Scheme. This will detect a fault and send a trip signal to WPD's ANM. This will disconnect the required volume of generation on a per GSP basis.

As this N-3 intertrip scheme is believed to be the most efficient solution, it is included in the Bilateral Connection Agreement between WPD and National Grid and in connection offers to WPD customers. These offers predate the proposal for general visibility and control of all relevant DER. Therefore they are required to ensure the network is operable under those conditions. It is included as part of the Whole System Planning Process for completeness.

6.3 Pre-Fault curtailment

Assuming that visibility and control of all new and existing DER participating to 1MW is achieved as per the RDP aim, pre-fault curtailment of generation against all network issues becomes the counter factual option. For constraints that occur infrequently with high reinforcement costs, this is likely to be the economic option. The cost of the frequent constraints options gives an indication of the limitations of reinforcement costs.

6.4 Commercial storage in place of curtailment

If storage was used to completely resolve the capacity issues, the volume of energy that needs to be stored will be similar to the pre-fault curtailment. The energy is stored in storage and released when there is no constraint. If a consistent pattern that is repeated is demonstrated in the constraints (to enable a storage provider to justify their capital investment) then a storage service will be more economical than curtailment payments. While it would be difficult for the RDP to show exactly how economic a storage solution is, the RDP studies can identify typical patterns of energy that could be stored.

6.5 Pre-fault 132kV split between ABHA-LAND

Splitting the network between ABHA and LAND pre-fault will avoid the 132kV overloads. However this will push more generation through the 400kV network and contribute to voltage collapse. Studies indicate that splitting this network will push ~300MW more through the remaining INDQ-AVE-TAUN – 2 cct. This causes more I^2R loss in the line and reduces the voltage limit. This option requires difficult network reinforcements to allow the distribution network in Plymouth to be secured without reliance on circuits from paralleled GSPs.

6.6 Post-fault 132kV split between ABHA-LAND

Post -fault split between ABHA and LAND on the 132kV network is beneficial to manage dynamic voltages. This could be achieved using an auto switching scheme. Studies indicate that making the split in approximately 500ms following the fault clearance will be sufficient. This is because at this point the voltage swings started to settle, so the voltage limit will be higher. However to give a safety margin, splitting the network at 1 second following the fault clearance will be better.

This option avoids costly reinforcements required to operate the networks permanently split instead the networks would be split post-fault using over current protection. This protection would segregate the network and not trip load.

6.7 Split ALVE - INDQ 132kV route (K route) pre/post-fault

A split between INDQ and ALVE will make the ALVE group radial with two SGTs at ALVE. Under any scenario the generation minus demand in the group cannot exceed the SGTs capacity. Designing an ANM to manage this configuration will be simpler and will affect a lower number of consumers. This is because with this split, the group will become radial and any curtailment will be 100% effective on the SGT loading and will only affect customers in 1 GSP. With the GSPs coupled via the K-route, the average effectiveness with 1 Alverdiscott SGT in service in around 50%. (In other words the curtailment volumes would be higher).

In the worst condition one Alverdiscott SGT is on outage. Without splitting this route the generation is curtailed to keep the SGT loading below 84% pre-fault in the anticipation of faults so that the short term ratings can be utilised. Splitting the K-route removes this requirement and the SGT can be loaded to 100% pre-fault.

6.8 Protective reactive switching

Studies indicate that one of the major issues as the embedded generation output increases is for the N-3 scenario explained in section 5.1; there will be a fast voltage collapse on the transmission network. This is because when the EXET-ABHA-LAGA DC fault happens, while one INDQ-ALVE-TAUN – 1 is out all of the embedded generation in the area and Langage has one remaining INDQ-ALVE-TAUN cct to get out. From Langage, this route is about 150 km long. This causes a lot of I^2R losses on the line and contributing to the voltage collapse.

The lack of any dynamic voltage support in the area makes it difficult to manage this situation. By switching in or out, available reactive equipment within protection timescales in the area is one way to replicate (to a certain extent) dynamic voltage support. Potential candidates for this are shunt reactor 2, MSC5 at INDQ4 and ALVE1 MSC1.

Keeping INDQ4 SR 2 in-service pre-fault and tripping it when the fault happens will help avoid voltage collapse and G59 under voltage issue. Studies show that under the worst planned outage conditions, when the DER output goes above 1.7GW across whole of the south west, there will be a requirement to have this support.

Combining protective reactive switching with post-fault 132kV split between Landulph and Abham is a very economical way to provide post fault voltage support to the area.

6.9 DER MVAr dispatch

Reactive capabilities of the embedded generators can help to manage pre and post-fault voltages. Studies indicate that operating embedded generators in non-unity power factor mode helps to maintain the voltage levels. Most of the time pre-fault high volts are an issue on this part of the network and new embedded generation are instructed on a slightly leading power factor to compensate. While this improves the voltage profile for low to typical DER outputs, at very high DER outputs it is detrimental to the post fault voltage performance of the network. For example, setting power factor at 0.98 lag for the worst outage in the worst 2025 scenario helped to increase the post fault voltage stability limit by about 100MW. While this does not incur any additional voltage issues at that cardinal point, it would if the same power factor was applied for the majority of the year. Currently the only way to change DER power factor is by the owner sending an engineer to site. But changing the power factor as the load shape changes within day is not practical.

Providing dynamic voltage support for transmission faults would have an increased benefit, i.e. the generators Automatic Voltage Regulator (AVR) sensing a disturbance in the volts and adjusting the MVAr output accordingly.. The ability to manage volts in this way is limited due to the location of the embedded generators in the distribution network, the ability to manage the interaction with distribution tap changers and to control generation.

The timescales to resolve the issues with DER voltage control and dispatch are beyond those that allow a useful service to be provided as part of the RDP and therefore it has not been possible to derive any cost benefit as part of this whole system planning exercise. It is recommended that future work should progress to demonstrate the great potential this option shows.

6.10 Exeter and Indian Queens fault levels

Fault level studies have been undertaken to determine the adequacy of switchgear with the projected connection of further embedded generation. Two sites have been identified where there is potential overstressing of plant: Indian Queens 132kV & Exeter Main 132kV substations. Detailed fault level study results can be found in appendix A3.

Exeter 132kV substation

At Exeter Main the 132kV circuit breakers have a rating of 25kA 3-phase and 31.5kA 1-phase. However the site rating is reduced to at 21.9kA (3-phase) due to the isolator rating and at 25.7kA (1-phase) due to earthing tape rating. National Grid’s circuits that were installed at the same time as the majority of WPD’s circuits are believed to have the same site infrastructure issues. CB250 is also a known limiting factor.

Two running arrangements have been identified which could resolve the switchgear overstressing. A running arrangement, which was implemented recently with an SGT on open-standby, improves some critical network loadings under high DER conditions. It also allows access to the busbars for maintenance. However, high demand or low DER conditions can increase the critical network loading conditions between Landulph and Plymouth. Operating the site in an asymmetric split with all three SGTs on load will marginally reduce the potential overloads in the Plymouth area during times of high demand/low DG conditions.

Indian Queens 132kV substation

At Indian Queens WPD’s 132kV circuit breakers have a limiting rating of 25kA 3-phase and 31.5kA 1-phase. The site rating is reduced to at 21.9kA (3-phase) and 26.3kA (1-phase) due to isolators & Holtom[2] bus bar rating. Peak ‘make’ ratings are two and a half times the short circuit break current rating. National Grid’s circuits that were installed at the same time as the majority of WPD’s circuits are believed to have the same site infrastructure issues.

Study results show that if the site continues to operate with four SGTs on a solid bus bar, the potential overstressing could occur from the worst 2020 scenario. Operating the site on a symmetrical bus coupler split will resolve the fault level problems. The symmetry in this running arrangement means that it is possible to remain split for the planned or fault outage of one SGT. It is possible to run the site solid on three SGTs. This is possible in the lower generation scenarios. As generation connections move towards the higher scenarios it will require the network splitting between Indian Queens and Alverdiscott to achieve acceptable fault levels.

This indicates it is likely to be able to operate the critical sites within fault levels for all scenarios up to 2025, except the worst scenario in 2030. Investment in switchgear is only likely to be required in the worst 2030 scenario.

[2] Holtom is a type of bus-bar from a particular manufacturer.

With no clear process available to provide a managed operational fault level solution using ANM that ensures the safety of personnel and apparatus, a cost benefit analysis approach to managing faults levels is not appropriate. When the contracted background goes beyond that studied in the 2025 WPD gone green background, work is likely to be required to connect generation in or near to these GSPs. This could be reviewed in the future.

6.11 Uprate LAND-ABHA-EXET 132kV route

This will involve re-conductoring the 132kV overhead lines (currently 175 sq.mm 'LYNX' conductor) with 300 sq.mm 'UPAS' conductor with an operating temperature of 75 degrees Celsius. This will give 206MVA post-fault continuous rating in the summer. This rating is sufficient to avoid overloading under most scenarios.

The length of the overhead line circuits between Exeter & Abham is 138km plus 62 km between Abham & Plymouth. There are also four circuits with cable sections at Abham totalling 7.9 km.

The 132kV cable between Ernesettle & Milehouse is overloaded and consideration will need to be given to either overlay this cable or construct a new 132kV circuit between Landulph & Milehouse.

6.12 Uprate ALVE - INDQ 132kV route (K route)

This will involve re-conductoring the 132kV overhead lines (currently 175 sq.mm 'LYNX' conductor) with 300 sq.mm 'UPAS' conductor with an operating temperature of 75 degrees Celsius. The total circuit route length is 106.7km.

6.13 SVC/STATCOM

A new SVC or a STATCOM will give dynamic voltage control in the area. This will be much more flexible compared to the protective reactive switching option explained in section 6.8.. However the cost of a new SVC /STATCOM will be much higher and it will be difficult to justify the cost benefit.

As the level of DER dispatch increases, studies indicate that a requirement for additional dynamic voltage control equipment in the area is likely to arise for 2030 scenarios. Again it will not be economic to install a new SVC/ or STATCOM because the N-3 scenario, where it is needed, is a much lower probable event.

6.14 Renew contract of INDQ synchronous compensator

A synchronous compensator at Indian Queens is currently contracted to provide voltage support in the area. The contract has been renewed periodically in the past. Indications are that the contract could be renewed in the future.

The benefit of continue having this service available will be similar to protective reactive switching or a new SVC/STATCOM. However the capabilities are limited as the reactive power support range is -74Mvar to +132MVar. This is compared to -225Mvar to 0Mvar for reactive switching or ±225MVAr for a SVC. The best option is using this synchronous compensator with reactive switching.

6.15 Add or uprate ALVE SGTs

Under current network conditions when one SGT at ALVE is out of service, the remaining SGT will start to become overloaded pre-fault once the DER output goes above 390MW generation within Boundary1 (figure 9).

Studies indicate that the limiting factor for boundary 1 is the rating of ALVE SGTs. There are two options to remove/reduce this limitation. One is to improve the cooling systems in the existing SGTs and increase the pre and post-fault ratings. This has been done elsewhere in the system and a similar 240MVA SGTs rating was increased to 276MVA. Replacing the existing SGTs with higher rated ones was considered. However due to the location of the ALVE 400kV substation, it will be difficult to transport physically bigger units to the substation.

The other option is to add another 240MVA SGT at ALVE. This will involve additional switchgear at the substation, particularly at the 400kV substation where it would be necessary to introduce bussing between the two SGT tee points to avoid the loss of the third unit for the first fault or planned outage.

6.16 New GSP at Pyworthy

The proposal for a new GSP at Pyworthy is aimed at relieving constraint in ALVE and INDQ distribution group. A new GSP has been modelled with two new 240MVA SGTs T'ed off the INDQ- ALVE – TAUN no 2 cct.

Studies indicate this solution will help ease the thermal issues at the Alverdiscott GSP (figure 9). However, this big investment is not improving the wider thermal or voltage issues in the region. It is making boundary voltage limits slightly worse. This is because more MW is injected in to transmission line towards INDQ which causes more I^2R losses under the worst N-3 scenario as explained in section 5.1.

6.17 Alverdiscott – Taunton re-conductoring

Under the N-3 scenario explained in section 5.1, Alverdiscott – Taunton cct will overload. Re-conductoring this section of the circuit is considered to resolve the issue. However the low probability N-3 event happening during high DER output, coupled with Langage machines that are on, make this re-conductoring extremely difficult to justify. As this is a thermal overload issue and not voltage or stability, it will be much more economical to use N-3 intertrip to solve this.

7 ECONOMIC ANALISIS

7.1 Introduction

A cost benefit analysis (CBA) has been performed to investigate the most economical whole system recommendation to future network challenges in the study zones (Devon and Cornwall region). Power system studies identified thermal and voltage vulnerabilities on the transmission and distribution networks. These vulnerabilities have broken the region down into two boundaries (see figure 9) for this CBA based on the ability to flow power around the network. National Grid has an economic analysis tool (BID3) which is designed to analyse the economics of traditional power system boundary capabilities.

BID3 is used by National Grid to perform long term constraint cost forecasts, of which the limitations of the modelling have been proven to be acceptable. Inevitably, as this study conducted at a finer level of detail and closer to the point of consumption, adjustments will be required. This study has used a custom tool[3] (based on BID3) to calculate the constraint costs in the specific region of interest and used various sensitivities to prove the robustness of the assessment and support the recommendations.

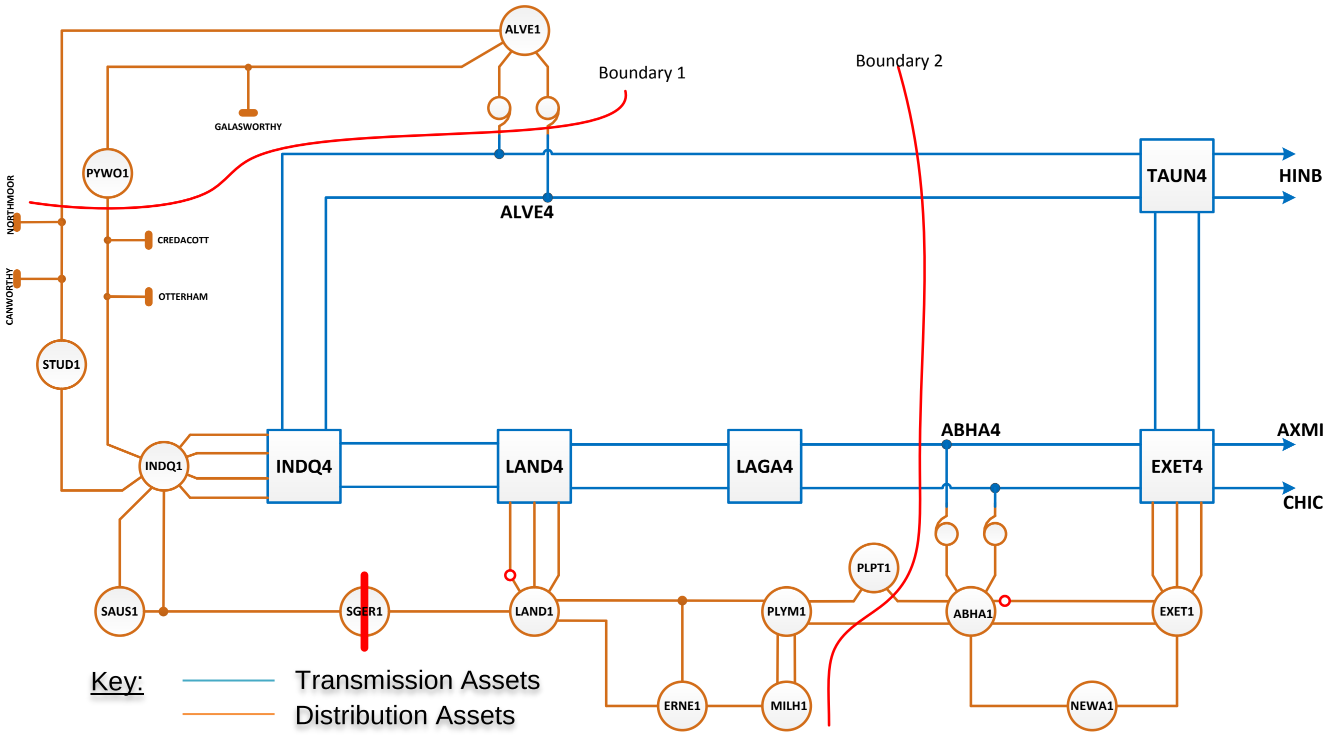


Figure 9: Boundary for economic analysis

The economic model was used to analyse power flows across boundaries one and two identified in the region and to quantify any power flows which exceeded the defined boundary capabilities. These high flows needed to be constrained. The constrained volumes were then converted to costs through the application of a bid and offer price. The model calculated a forecast of constraints for every option across a period of 40 years and applied a discounting rate to convert all costs to a present value. Similarly, the capital expenditure (CAPEX) of each option was converted to a present value based on the Spackman approach, where the costs are discounted at the social time preference rate. They are also inflated at a rate proportional to the weighted average cost of capital to reflect the cost of finance incurred by a developer.

[3] Further details in the Whole System study process Report, available on WPD and National Grid's RDP web pages:
www.westernpower.co.uk/RDP
https://www.nationalgrid.com/uk/publications/regional-development-programmes

7.2 Scenarios

As explained in section 2, WPD have provided four scenarios of local generation capacities. These have been based on the 2015 Future Energy Scenarios of Gone Green, Consumer Power, Slow Progression and No Progression. Generation capacities for the years 2018, 2025 and 2030 were provided and a linear interpolation was performed to create a range of capacities to input into the constraint model.

The scenarios studied consider a range of possible generation mixes for the south west region. Gone Green has the most aggressive level of capacity growth whereby the scenario considers that there is a high level of green ambition and the economic prosperity to match, leading to high levels of renewable generation nationally at both the distribution and transmission level. Consumer power similarly assumes a high economic prosperity in GB however, with less focus on green ambition and more on consumer convenience. This also leads to an aggressive growth in capacities.

7.3 Bid and Offer Prices

Bid and offer prices are derived from data from the National Economic Database for thermal plant, which creates a bid and offer price based on historic average market prices. For certain plant (e.g. nuclear) there is no sufficient historic data to create an accurate bid or offer price owing to a reluctance to participate in the balancing mechanism. For these exceptions, and where no other information is available, a bid and offer price is generally assumed to retain a merit order position which would reflect the balancing market participation.

For renewable generators, a bid price is assumed based on the Renewable Obligations levels. It is assumed that the opportunity cost for a renewable generator would be proportional to their level of Renewable Obligation Certificates (ROCs) and so to be kept whole if they were required to be bid off, they would require compensation to the level of the ROC.

Although it is acknowledged that there is currently no specific balancing cost for embedded generation, the above levels have been applied for embedded generators to be representative of the social cost of not having that generation, with the Renewable Obligations acting as a proxy for society's value of renewable generation.

For the main assessment it has been assumed a bid-offer stack of £99.50/MWh (bid price ~£45/MWh, offer price ~£54.50).

7.4 Options and Capital Cost

The following options have been selected for this CBA, out of the options listed in section 6. Options such as uprating ALVE-TAUN section of overhead line has not been included as it is obvious the benefit of it is very small compare to the capital cost of about £ ~70million.

Option	Estimated CAPEX
N-3 intertrip	£1.32m
Abham to Landulph pre-fault split	£15.00m
Abham to Landulph post-fault split	-
Alverdiscott to Indian Queens pre-fault split	£4.50m
Protective Reactive Switching	£0.20m
Uprate 132kV route from Landulph to Exeter	£20.00m
Uprate 132kV route from Alverdiscott to Indian Queens	£14.00m
Install SVC/STATCOM	£31.00m
Renew synchronous compensation at Indian Queens	-
Uprate Alverdiscott Super Grid Transformer (SGT)	£0.50m

Install a 3rd SGT at Alverdiscott	£13.00m
New Grid Supply Point (GSP) at Pyworthy	£30.00m

Table 6: Options and CAPEX

Estimates have been provided by the relevant network owner. Where no value is included it is assumed that the cost would be negligible. Prices are assumed to be 2017 base. For calculation of CAPEX a Weighted Average Cost of Capital (WACC) was assumed at 4%.

It is assumed that in the background to the above options is an operational ANM system to provide a level of visibility and control at the transmission and distribution level. Without a level of visibility and control at the distributed level the economical assessment of options becomes limited.

7.5 Analysis

In order to analyse the benefits of each of the proposed options, power system studies on the area have been performed considering an intact network and two outage conditions. This has then been applied such that each boundary has an annual capability, a July capability (assuming outages on the EXET-ABHA-LAGA circuits), and an August capability (assuming outages on the INDQ-ALVE-TAUN circuits). Listed below are the driving (lowest) capabilities for each of the options and conditions which have been used for this analysis.

Option	Annual (MW)	July (MW)	August (MW)
Base condition (do nothing)	346	346	213
Uprate 132kV route from Alverdiscott to Indian Queens	392	392	213
Uprate Alverdiscott Super Grid Transformer (SGT)	395	395	230
Install a 3rd SGT at Alverdiscott	588	588	392
New Grid Supply Point (GSP) at Pyworthy	No limit	No limit	510

Table 7: Capabilities of different options on Boundary 1

Option	Annual (MW)	July (MW)	August (MW)
Base condition (do nothing)	1291	1104	760
N-3 intertrip	1518	1518	1284
Abham to Landulph pre-fault split	1284	1043	1210
Abham to Landulph post-fault split	1290	1150	1284
Alverdiscott to Indian Queens pre-fault split	1291	1104	760
Uprate 132kV route from Landulph to Exeter	1537	1388	1200

Table 8: Capabilities of different options on Boundary 2

There were originally three additional options to be considered, namely Protective Reactive Switching, installing a new SVC/STATCOM and renewing the synchronous compensation at Indian Queens. These have not been included as they initially provide no capability above the base level and so wouldn't provide any savings. This is because the base capability is driven by thermal limitations of Boundary 1 and Boundary 2 whereas these additional options were mainly to address voltage constraints. It should be noted however that in combination with other reinforcements that alleviate the thermal constraints, these reinforcements may become economical.

Power system studies have found the curtailment effectiveness for boundary 1 constraints of the options above is around 50% on average i.e. for each 1MW of flow across boundary 1, 2MW would be required to be constrained to resolve the issue due to power flows and location of generation. The only exception to this is the Alverdiscott to Indian Queens split which has been proven to be 100% effective. As such, in the modelling all options bar the Alverdiscott to Indian Queens split have received a cost weighting on their flows across boundary 1 to reflect the average additional cost to resolve the constraint.

7.6 Study Output

By analysing the spread of savings compared to the capability tables, it can be seen that the options which provide capability to Boundary 1 provide the greatest levels of saving. Indeed it can be seen that the options which focus on Boundary 2 provide little to no savings. This is because the natural flows in Boundary 2 under the economic dispatch tool do not produce boundary flows which exceed the determined boundary limits even under the base case. Economic dispatch assumed that the local CCGTs in the system would be out of merit in the period which creates the network challenges (i.e. high wind high solar conditions). As such the options which improve this boundary capability provide no benefit. For the Options on Boundary 1, some of the options improve all year capability (e.g. SGT uprating or upgrades) whilst others only improve capability during the outage conditions (e.g. pre-fault splitting). It is important to note that although it is unlikely that local CCGTs are dispatched at periods of high wind and solar, national energy markets may not always outturn the theoretical ideal solution and so this scenario still needs to be considered on an engineering security basis.

Across the other scenarios the generation levels generally only breach the boundary limits during summer peaks where the system is more vulnerable. This effect is particularly apparent if you were to compare the savings available for the N-3 intertrip and the uprating of the Alverdiscott SGTs (excluding the Gone Green scenario). The N-3 intertrip provides additional capability during summer outage periods owing to the ability to allow higher volumes pre-fault due to the response available if a fault were to occur.

By performing a least worst regrets analysis across the scenarios and options it can be seen that installing a 3rd SGT at Alverdiscott is the economically recommended option.

Regrets (£m)	GG	CP	SP	NP
N-3 intertrip	30.35	2.09	0.00	1.40
Abham to Landulph pre-fault split	59.18	28.25	19.78	16.24
Abham to Landulph post-fault split	42.94	12.01	3.53	0.00
Alverdiscott to Indian Queens pre-fault split	29.61	8.11	5.46	4.84
Uprate 132kV route from Landulph to Exeter	64.59	33.66	25.19	21.66
Uprate 132kV route from Alverdiscott to Indian Queens	35.85	19.55	17.40	15.16
Uprate Alverdiscott SGT	14.55	0.00	0.29	0.51
Install a 3rd SGT at Alverdiscott	0.00	1.20	10.88	14.04
New Grid Supply Point (GSP) at Pyworthy	18.41	19.61	29.29	32.45

Table 9: Regrets table for the central case

By analysing the above table, it can also been observed that the uprating of the Alverdiscott SGTs comes a close second in terms of the recommendations. This is being largely driven by the Gone Green scenario which provides higher levels of constraint than the other scenarios owing to higher generation capacities. It is important to note that it must be assumed that each of the scenarios remain credible and equally probable in order to provide an unbiased analysis. Nonetheless, it can be informative to remove a driving scenario to understand the potential implications of the recommendation.

By removing gone green as a scenario, the least worst regret recommendation would move to the uprating of the Alverdiscott SGT with the N-3 intertrip scheme providing a close second recommendation. The installation of a 3rd SGT would fall down the ranks to a 5th favoured recommendation. This is due to the lower regrets of all of the other options which removing the high savings available under Gone Green would yield. This demonstrates the need for greater certainty of the generation levels before any of the recommendations are committed firmly. As such further analysis will be required in the future to confirm the recommendations. This revision of the CBA should have greater certainty of future generation levels and so the spread of capacity across scenarios should in theory be smaller, providing greater clarity and certainty to the recommendation.

7.7 Conclusion and recommendations

The cost benefit analysis concludes that the installation of a 3rd SGT at Alverdiscott is economical. This has not yet however considered any timing effects of when such work would be most economical. It has been observed from the analysis that this solution would not be justified until higher capacities of generation are active in the late 2020's to early 2030's. It is therefore recommended that this CBA is reviewed again once more certainty is obtained on generation capacities (i.e. 2020 or 2025).

This recommendation should not impact any progress that is made on the basis of system security or other engineering judgment.

It is recommended that regional and national assumptions that feed into scenarios are reviewed and in future CBA's of this type assess the difference in regional and national capacities closely in order to identify a suitable range of credible scenarios.

It is also recommended that further studies are performed by the NGESO to identify possible ways of scaling analysis completed within BID3 to more efficiently assess future CBA's of this type. Specifically a process for adjusting zones to match regional zones can be refined following this work and the ability of the re-dispatch module to return sensible results at the resolution required needs to be further investigated.

8 GLOSSARY

ABHA	Abham Grid Supply Point
ALVE	Alverdiscott Grid Supply Point
ANM	Active Network Management
BSP	Bulk Supply Point
Cct	Circuit
DER	Distributed Energy Resources – Electricity generators and storage assets connected to the electricity distribution network. Also referred as embedded generation.
DNO	Distribution Network Operator
ETYS	Electricity Ten Year Statement
EXET	Exeter Grid Supply Point
FES	Future Energy Scenarios
G59	ENA Engineering recommendation for under and over voltage limits for embedded generators
GSP	Grid Supply Point
IFA2	Interconnector to France No2
INDQ	Indian Queens Grid Supply Point
LAGA	Langage Grid Supply Point
LAND	Landulph Grid Supply Point
N-3	Outage and a double circuit trip condition
NGESO	National Grid Electricity System Operator
PV	Photovoltaic – solar power electricity generation
SGT	Super Grid Transformer
SO	System Operator – National Grid is the electricity System Operator for Great Britain
STATCOM	Static Compensator
SVC	Static Var Compensator
TAUN	Taunton Grid Supply Point
TO	Transmission Owner – National Grid is the electricity transmission owner in England and Wales

9 APPENDIX A1: TRANSMISSION STUDY RESULTS

At the initial stage, steady stage studies are carried out covering the whole of South West area. Contingency analyses were carried out on each scenario under intact and outage conditions. For outage analysis, the following outages were taken one by one and all the trips (single cct and double cct) in the transmission system in South West and South East were simulated.

- Hinkley Point - Melksham - 1
- Indian Queens - Alverdiscott - Taunton - 1
- Indian Queens – Landulph - Langage - 1
- Langage - Abham - Exeter - 1
- Chickerell - Axminster - 1
- Chickerell - Exeter - 1
- Bramley - Fleet - 1
- Melksham - Bramley – 1
- Lovedean – Fleet -1

Under intact condition the worst faults and thermal overloads are listed below.

Fault	O/L cct	Comments
INDQ-ALVE-TAUN 2 (ALVE SGT2)	ALVE4 SGT1	When one SGT at ALVE is lost the other will overload when the DER level reaches about 2.6GW. In 2025 scenario for this fault the SGTs are overloading by ~30%.
INDQ-ALVE-TAUN 1 (ALVE SGT1)	ALVE4 SGT2	
INDQ-ALVE-TAUN DC	All INDQ4 SGTs	In 2025 scenario for this fault the INDQ SGTs are overloading by ~20%.
HINP-MELK 1 or 2	HINP-MELK 2 or 1	40% overload is likely in 2030 scenario when Hinkley B machines are in service.
Any fault that take out one SGT at INDQ	Remaining SGTs	In 2030 scenarios up to 5% overload is observed. This is highly dependent on distribution network configuration.

On top of the above thermal overloads, for INDQ-ALVE-TAUN DC fault about -15% voltage step changes are observed at INDQ4 and LAND4 substations. In this case the study did not simulate the Automatic Reactive Switching (ARS) schemes in the area.

The top outage fault combinations within the study zone are listed below.

Outage	Fault	O/L cct	Comments
INDQ – ALVE –TAUN -1	EXET-ABHA-LAGA DC (ABHA MSC1)	ALVE4 SGT 2, ALVE – TAUN 2 and DNO ccts	This is the worst N-3 combination explained in section 5.1 .
	ALVE SGT2 or INDQ – ALVE –TAUN -2	INDQ4 SGT s	In 2025 scenario for this fault the INDQ SGTs are overloading by ~20%. This overload increases as the generation level increase. This is highly dependent on DNO network configuration
INDQ- LAND- LAGA -1	INDQ-ALVE-TAUN DC	INDQ4 SGT s	About 4% overload observed in 2025 scenario and increases further with the generation
LAGA -ABHA- EXET 1	INDQ-ALVE-TAUN DC	LAGA -ABHA- EXET 2	30% overload observed in 2025 scenarios and increases further with the generation

The following table shows thermal overloads for the N-3 condition explained in section 5.1. The DER output within the study zone is 1.2 GW.

Overloaded Elements	Base Flow	Base PFC(%)	New Flow	New PFC(%)	PFC Limit	6-Hr Limit	20-Min Limit	10-Min Limit	OVER LOAD
C82K: ABHA11-EXET11	22	24	128	144	89	89	89	89	*>89
C80M: PLPT11-TOTN1B	29	29	136	137	99	99	99	99	*>99
C81M: PLYM11-TOTN1A	26	27	131	133	99	99	99	99	*>99
C87J: EXET11-NEWA11	15	17	118	133	89	89	89	89	*>89
C84K: NEWA11-PAIG1A	24	24	127	129	99	99	99	99	*>99
C82M: PLPT11-PLYM11	6	7	112	125	90	90	90	90	*>90
C86M: ERNE11-LAND11	70	39	211	117	180	180	180	180	*>180
ALVE4B-TAUN4-2	412	37	1256	113	1110	1110	1220	*1420	>1420
ALVE4 SGT 2	-211	-88	-264	-110	240	246	255	255	*>240

The following table shows the effectiveness of various generators on the thermal overloads for above N-3 condition. This effectiveness is calculated under intact 132kV network conditions.

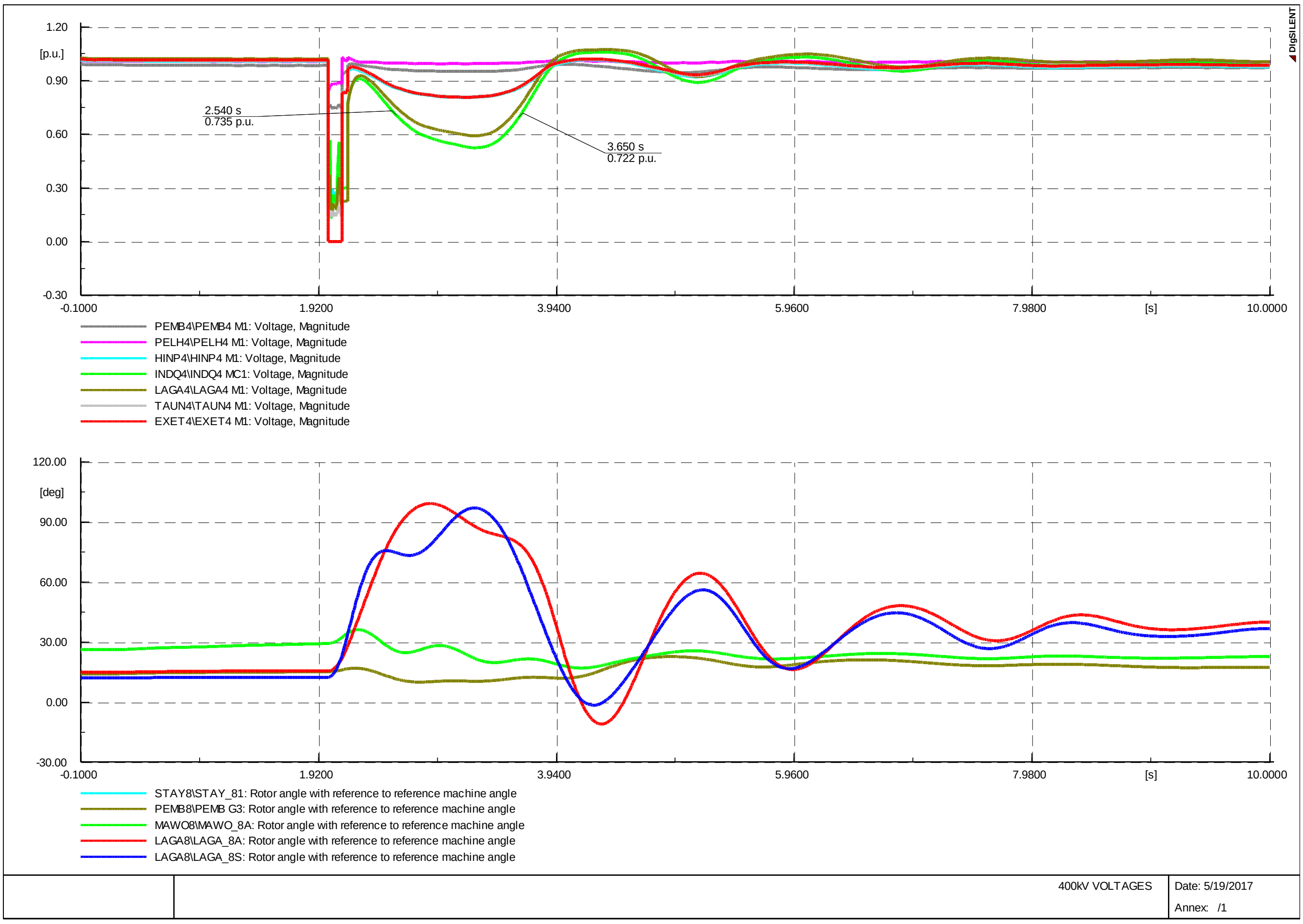
Overloaded Elements	Loading		Effectiveness of Gen Behind… (%)					LAGA (%)
	%	MVA	ALVE (PYWO, STUD)	INDQ (FRAD)	LAND	ABHA (PLPT)	EXET	
C82K: ABHA11-EXET11	144	128	15	16	21	29	-6	16
C80M: PLPT11-TOTN1B	137	136	14	15	21	33	-6	16
C81M: PLYM11-TOTN1A	133	131	13	15	21	18	-6	16
C87J: EXET11-NEWA11	133	118	13	15	21	22	-6	16
C84K: NEWA11-PAIG1A	129	127	13	15	21	22	-6	16
C82M: PLPT11-PLYM11	125	112	13	14	21	-66	-6	15
C86M: ERNE11-LAND11	117	211	20	22	29	-31	-8	23
ALVE4B-TAUN4-2	113	1256	150	147	107	77	21	140
ALVE4 SGT 2	-110	-264	70	31	16	10	2	20

In the case of ALVE 4B – TAUN4 -2 overload above the effectiveness of Langage generation and generation behind Alverdiscott GSP are more than 100%. This is because in power factory, effectiveness is given MVA loading reduction per MW generation reduced, calculated by dividing MVA loading with voltage. In the case of ALVE4B-TAUN4-2 overload, the voltage is also changing significantly when the generation is reduced. This is why it is possible to have more than 100% effectiveness. If the voltage profile remains the same then the effectiveness cannot be more than 100%.

When the DER output further increased under the same N-3 condition as explained in section 5.1, and at around 1.3GW DER level within the study zone, the remaining ALVE SGT2 will load to 100% pre-fault. Post fault of EXET-ABHA-LAGA DC the following will overload.

Overloaded Elements	Base Flow	Base PFC(%)	New Flow	New PFC(%)	PFC Limit	6-Hr Limit	20-Min Limit	10-Min Limit	OVER LOAD
C82K: ABHA11-EXET11	24	-26	137	-154	89	89	89	89	*>89
C87J: EXET11-NEWA11	-18	-20	-128	-144	89	89	89	89	*>89
C80M: PLPT11-TOTN1B	33	-33	142	-143	99	99	99	99	*>99
C81M: PLYM11-TOTN1A	29	-29	135	-137	99	99	99	99	*>99
C84K: NEWA11-PAIG1A	-24	-24	-135	-136	99	99	99	99	*>99
C82M: PLPT11-PLYM11	-6	-6	-114	-127	90	90	90	90	*>90
ALVE4 SGT 2	-239	-100	-296	-123	240	240	240	240	*>240
ALVE4B-TAUN4-2	446	-40	1329	-120	1110	1110	1220	*1420	>1420
C86M: ERNE11-LAND11	-70	-39	-213	-118	180	180	180	180	*>180

The following simulation plot shows the voltage and rotor angle traces for the same condition.



10 APPENDIX A2: DISTRIBUTION STUDY RESULTS

2025 Studies

Summer (N-1) studies indicate overloads on the following circuits based upon 50% winter peak demand and diversified embedded generation.

Circuit	% loading on sustained rating
Alverdiscott-Galsworthy	112
Galsworthy-Pyworthy	108
Otterham-Indian Queens	100
Barnstaple 132/33kV transformer	147
St Tudy 132/33kV transformer	149
Alverdiscott 400/132kV SGT	134

Summer (N-2) studies indicate overloads on the following circuits based upon 50% winter peak demand and diversified embedded generation.

Circuit	% Loading on sustained rating
Alverdiscott 400/132kV SGT	167
Alverdiscott-Galsworthy	142
Galsworthy-Pyworthy	138
Pyworthy-Cedar	142
Cedar-Otterham	143
Otterham-Indian Queens	150
Pyworthy 132/33kV transformer	151
Barnstaple 132/33kV transformer	147
North Tawton 132/33kV transformer	126

The overhead line sections have a 24 hour post fault rating of 107% on the basis of a pre-fault loading being less than 90% of the sustained rating.

The above results show that the existing 24 hour post-fault overhead line rating is insufficient. Further work is required to determine if increased post fault ratings over a shorter timescale are possible.

Re-conductoring the overhead line sections with 300 UPAS at 75 degree operation provides an increase of 46% of the existing continuous and 57% in the post fault (24 hour) ratings. The 24 hour post-fault rating of the new conductor is sufficient to manage the above overloads. The estimated cost of re-conductoring is in the order of £14 Million (139km of circuit, 97 towers strengthened & 12 towers replaced). In addition, there is the cost of transformer replacement at Pyworthy, Barnstaple & North Tawton with units of an increased rating.

The network studies were repeated simulating Active Network Management on the basis of pre-event curtailment and partial pre-event curtailment. By utilising any post-fault (short time) ratings that are available it is possible to use partial pre-event curtailment where less generation is curtailed in anticipation of a fault as circuit ratings are increased albeit for a restricted time.

The following table shows the required MW curtailment for worst scenarios by generator technology:

MW Curtailment (2025)

Curtailment	PV	Tidal	Wind	TOTAL
Pre-event (Assumes no post fault rating available)	157.1	2.1	21.8	181.0
Partial pre-event (with post fault rating available)	104.3	0	6.4	110.7

2025 Studies - 132kV network split between INDQ and ALVE

Further network studies have been undertaken with the 132kV network split between Alverdiscott and Indian Queens with open points between Pyworthy and Cedar Wind Farm and between Alverdiscott and Northmoor Solar Park. Otterham and Cedar Wind Farms plus Northmoor and Canworthy Solar Parks along with St Tudy are fed from Indian Queens. Galsworthy Wind Farm and Pyworthy are being fed from Alverdiscott.

N-1 Studies (summer)

First circuit outage (fault) studies have been undertaken for the winter peak demand scaled at 50% with the above diversity factors for the various network running conditions as follows:

Circuit	% loading on Sustained rating
Alverdiscott 400/132kV SGT	153
Alverdiscott-Galsworthy	112
Galsworthy-Pyworthy	108
Northmoor-Pyworthy	104
Alverdiscott-Northmoor	104
St Tudy- Indian Queens	102
St Tudy 132/33kV transformer	149
Barnstaple 132/33kV transformer	147

N-2 Studies (summer)

Second circuit (arranged outage plus a fault) have been undertaken for the winter peak demand scaled at 50% with the above diversity factors for the various network running conditions as follows:

Circuit	% Loading on sustained rating
Alverdiscott 400/132kV SGT	166
Alverdiscott-Galsworthy	136
Galsworthy-Pyworthy	133
Alverdiscott-Northmoor	132
Northmoor-Pyworthy	133
Pyworthy 132/33kV transformer	154
Barnstaple 132/33kV transformer	147
North Tawton 132/33kV transformer	113
Indian Queens 400/132kV SGT	115

Both N-1 and N-2 summer credible outage conditions result in overloads, as indicated in the above tables. To overcome the potential overload the estimated cost of 132kV overhead line reinforcement (re-conductor with 300UPAS) is in the region of £7.3 Million (73km of circuit) and it is possible for the overhead line circuits to run within their continuous rating.

The network studies were repeated simulating Active Network Management on the basis of pre-event curtailment and partial pre-event curtailment. The following table shows the required MW curtailment for both scenarios by generator technology:

MW Curtailment (2025) split network

Curtailment	PV	Tidal	Wind	TOTAL
Pre-event (Assumes no post fault rating available)	153.2	2.1	21.7	177.0
Partial pre-event (with post fault rating available)	116.5	0	10.1	126.6

2030 Studies

Summer (N-1) studies indicate overloads on the following circuits based upon 50% winter peak demand and diversified embedded generation (parallel network between Alverdiscott & Indian Queens)

Circuit	% Loading on sustained rating
Alverdiscott 400/132kV SGT	183
Alverdiscott-Galsworthy	174
Pyworthy-Cedar	150
Cedar-Otterham	150
Otterham-Indian Queens	158
Indian Queens-St Tudy	103
Pyworthy 132/33kV transformer	123
St Tudy 132/33kV transformer	247
Barnstaple 132/33kV transformer	235
North Tawton 132/33kV transformer	157
East Yelland 132/33kV transformer	119
Indian Queens 400/132kV SGT	103

Summer (N-2) studies indicate overloads on the following circuits based upon 50% winter peak demand and diversified embedded generation.

% Circuit loading for N-2 outage conditions (2030)

Circuit	% Loading on sustained rating
Alverdiscott 400/132kV SGTs	233
Alverdiscott- Galsworthy	224
Pyworthy-Cedar	188
Cedar-Otterham	204
Otterham-Indian Queens	212
Pyworthy 132/33kV transformer	158
Barnstaple 132/33kV transformer	235
North Tawton 132/33kV transformer	174

As indicated for the 2025 studies, the existing 24 hour post-fault overhead line ratings are insufficient. If the overhead line circuits were re-conductored with 300 UPAS (75 degree operation) the 24 hour post-fault rating of the new conductor is insufficient to manage the above overloads.

The network studies were repeated simulating Active Network Management on the basis of pre-event curtailment and partial pre-event curtailment. The following table shows the required MW curtailment for both scenarios by generator technology:

MW Curtailment (2030)

Curtailment	PV	Tidal	Wave	Wind	TOTAL
Pre-event (Assumes no post fault rating available)	408.4	3.6	67.7	110.8	590.5
Partial pre-event (with post fault rating available)	332.21	2.1	47.4	57.5	439.2

11 APPENDIX A3: FAULT LEVEL STUDY RESULTS

Fault level studies found that under increasing DER level there will be overstress of the switchgear at Exeter and Indian Queens. 2020, 2025 and 2030 gone green level of installed capacity is imposed on the network and a complete fault level analysis is carried out for each scenario.

The following table shows the result of the fault level analysis carried out in DigSiLENT Power Factory offline model by National grid. WPD separately carried out the analysis in PSSE offline model. The stress levels in the WPD results are slightly lower consistently across the board. This was attributed to the software and modelling differences. However, the overstressed switchgears are the same.

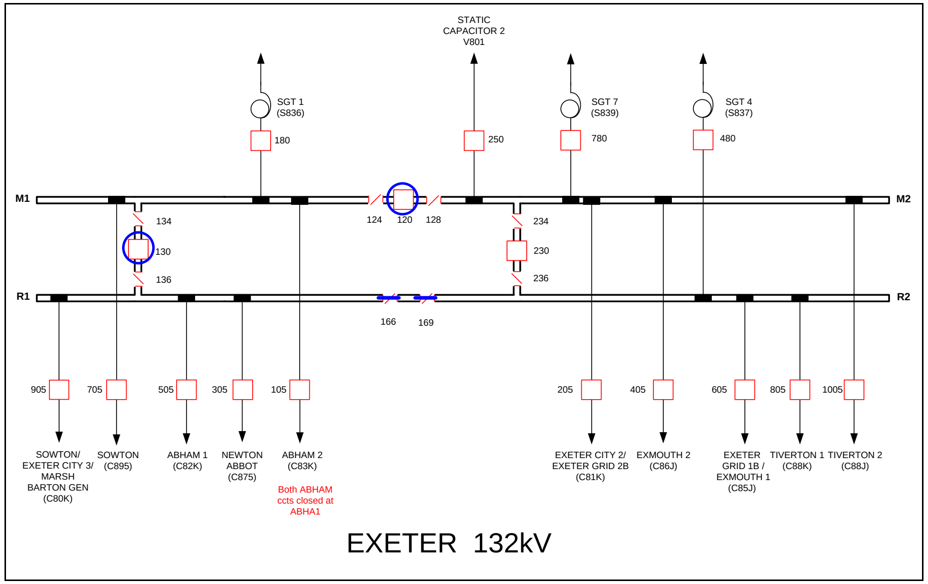
Report: 3 Phase Busbar Results (RT1)				……………….....……2020…………………………..				……………….....……2025…………………………..				……………….....……2030…………………………..			
				INITIAL PEAK		RMS BREAK		INITIAL PEAK		RMS BREAK		INITIAL PEAK		RMS BREAK	
FAULT NODE	REMOTE NODE	LINE CODE	CB CODE	CURRENT	% RATING	CURRENT	% RATING	CURRENT	% RATING	CURRENT	% RATING	CURRENT	% RATING	CURRENT	% RATING
EXET11			105	59.49	119.00%	22.19	119.80%	61.95	123.90%	23.09	122.30%	65.45	130.90%	24.32	128.50%
EXET11			120	59.49	119.00%	22.19	119.80%	61.95	123.90%	23.09	122.30%	65.45	130.90%	24.32	128.50%
EXET11			130	59.49	119.00%	22.19	119.80%	61.95	123.90%	23.09	122.30%	65.45	130.90%	24.32	128.50%
EXET11			230	59.49	119.00%	22.19	119.80%	61.95	123.90%	23.09	122.30%	65.45	130.90%	24.32	128.50%
EXET11			305	59.49	119.00%	22.19	119.80%	61.95	123.90%	23.09	122.30%	65.45	130.90%	24.32	128.50%
EXET11			505	59.49	119.00%	22.19	119.80%	61.95	123.90%	23.09	122.30%	65.45	130.90%	24.32	128.50%
INDQ11			120	59.64	119.30%	21.92	114.60%	64.17	128.30%	23.46	119.40%	69.01	138.00%	25.2	126.90%
INDQ11			130	59.64	119.30%	21.92	114.60%	64.17	128.30%	23.46	119.40%	69.01	138.00%	25.2	126.90%
INDQ11			505	59.64	119.30%	21.92	114.60%	64.17	128.30%	23.46	119.40%	69.01	138.00%	25.2	126.90%
INDQ11			605	59.64	119.30%	21.92	114.60%	64.17	128.30%	23.46	119.40%	69.01	138.00%	25.2	126.90%
INDQ11			705	59.64	119.30%	21.92	114.60%	64.17	128.30%	23.46	119.40%	69.01	138.00%	25.2	126.90%
INDQ11			1005	59.64	119.30%	21.92	114.60%	64.17	128.30%	23.46	119.40%	69.01	138.00%	25.2	126.90%
INDQ11			1005	59.64	119.30%	21.92	114.60%	64.17	128.30%	23.46	119.40%	69.01	138.00%	25.2	126.90%

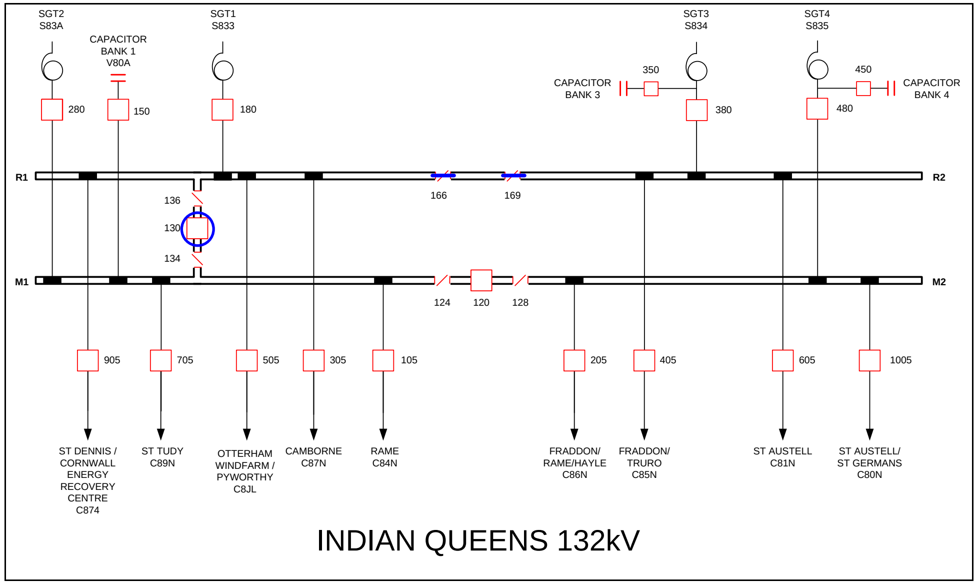
Report: 3 Phase Circuit Results (RT2)				……………….....……2020…………………………..				……………….....……2025…………………………..				……………….....……2030…………………………..			
				INITIAL PEAK		RMS BREAK		INITIAL PEAK		RMS BREAK		INITIAL PEAK		RMS BREAK	
FAULT NODE	REMOTE NODE	LINE CODE	CB CODE	CURRENT	% RATING	CURRENT	% RATING	CURRENT	% RATING	CURRENT	% RATING	CURRENT	% RATING	CURRENT	% RATING
EXET11	ABHA12	C83K	105	59.49	119.00%	22.19	119.80%	61.95	123.90%	23.09	122.30%	65.45	130.90%	24.32	128.50%
EXET11	NEWA11	C87J	305	55.39	110.80%	20.35	112.60%	57.58	115.20%	21.13	114.70%	60.77	121.50%	22.23	120.40%
EXET11	ABHA11	C82K	505	55.63	111.30%	20.4	112.80%	57.93	115.90%	21.22	115.00%	61.19	122.40%	22.34	120.80%
INDQ11	PYWO1*	C8JL	505	56.2	112.40%	20.46	107.90%	60.47	120.90%	21.89	112.60%	65.09	130.20%	23.55	119.80%
INDQ11	SAUS11	C81N	605	59.2	118.40%	21.79	114.10%	63.48	127.00%	23.25	118.80%	68.15	136.30%	24.95	126.10%
INDQ11	STUD11	C89N	705	56.3	112.60%	20.54	109.30%	60.01	120.00%	21.81	113.30%	64.28	128.60%	23.34	119.80%
INDQ11	SAUS1A	C80N	1005	57.51	115.00%	21.12	111.70%	61.5	123.00%	22.5	116.10%	66	132.00%	24.13	123.20%
INDQ11			1005	57.5	115.00%	21.2	110.80%	62.05	124.10%	22.73	115.70%	66.89	133.80%	24.47	123.20%

Report: 1 Phase Busbar Results (RT1)				2020				2025				2030			
				INITIAL PEAK		RMS BREAK		INITIAL PEAK		RMS BREAK		INITIAL PEAK		RMS BREAK	
FAULT NODE	REMOTE NODE	LINE CODE	CB CODE	CURRENT	% RATING	CURRENT	% RATING	CURRENT	% RATING	CURRENT	% RATING	CURRENT	% RATING	CURRENT	% RATING
EXET11			105	72.38	115.80%	27.98	117.50%	74.81	119.70%	29.03	120.00%	78.2	125.10%	30.3	125.00%
EXET11			120	72.38	115.80%	27.98	117.50%	74.81	119.70%	29.03	120.00%	78.2	125.10%	30.3	125.00%
EXET11			130	72.38	115.80%	27.98	117.50%	74.81	119.70%	29.03	120.00%	78.2	125.10%	30.3	125.00%
EXET11			230	72.38	115.80%	27.98	117.50%	74.81	119.70%	29.03	120.00%	78.2	125.10%	30.3	125.00%
EXET11			250	72.38	91.60%	28.16	94.40%	74.81	94.70%	29.25	96.10%	78.2	99.00%	30.54	100.30%
EXET11			305	72.38	115.80%	27.98	117.50%	74.81	119.70%	29.03	120.00%	78.2	125.10%	30.3	125.00%
EXET11			505	72.38	115.80%	27.98	117.50%	74.81	119.70%	29.03	120.00%	78.2	125.10%	30.3	125.00%
INDQ11			120	65.82	105.30%	25.25	104.70%	69.49	111.20%	26.7	108.60%	73.23	117.20%	28.13	113.60%
INDQ11			130	65.82	105.30%	25.25	104.70%	69.49	111.20%	26.7	108.60%	73.23	117.20%	28.13	113.60%
INDQ11			280	65.82	65.80%	25.25	84.20%	69.49	69.50%	26.7	89.00%	73.23	73.20%	28.13	93.80%
INDQ11			505	65.82	105.30%	25.25	104.70%	69.49	111.20%	26.7	108.60%	73.23	117.20%	28.13	113.60%
INDQ11			605	65.82	105.30%	25.25	104.70%	69.49	111.20%	26.7	108.60%	73.23	117.20%	28.13	113.60%
INDQ11			705	65.82	105.30%	25.25	104.70%	69.49	111.20%	26.7	108.60%	73.23	117.20%	28.13	113.60%
INDQ11			1005	65.82	105.30%	25.25	104.70%	69.49	111.20%	26.7	108.60%	73.23	117.20%	28.13	113.60%
INDQ11			1005	65.82	105.30%	25.25	104.70%	69.49	111.20%	26.7	108.60%	73.23	117.20%	28.13	113.60%

Report: 1 Phase Circuit Results (RT2)				2020				2025				2030			
				INITIAL PEAK		RMS BREAK		INITIAL PEAK		RMS BREAK		INITIAL PEAK		RMS BREAK	
FAULT NODE	REMOTE NODE	LINE CODE	CB CODE	CURRENT	% RATING	CURRENT	% RATING	CURRENT	% RATING	CURRENT	% RATING	CURRENT	% RATING	CURRENT	% RATING
EXET11	ABHA12	C83K	105	72.37	115.80%	27.98	117.50%	74.8	119.70%	29.03	120.00%	78.19	125.10%	30.3	125.00%
EXET11			250					74.81	94.70%	29.25	96.10%	78.2	99.00%	30.54	100.30%
EXET11	NEWA11	C87J	305	68.02	108.80%	25.92	111.10%	70.22	112.40%	26.85	113.40%	73.37	117.40%	28.01	118.00%
EXET11	ABHA11	C82K	505	68.35	109.40%	26.02	111.50%	70.67	113.10%	27	113.90%	73.89	118.20%	28.19	118.60%
INDQ11	PYWO1*	C8JL	505	62.85	100.60%	23.92	100.00%	66.34	106.10%	25.29	103.80%	69.96	111.90%	26.67	108.60%
INDQ11	SAUS11	C81N	605	64.72	103.60%	24.85	103.40%	68.13	109.00%	26.2	107.00%	71.67	114.70%	27.57	111.80%
INDQ11	STUD11	C89N	705	62.3	99.70%	23.71	100.00%	65.34	104.50%	24.92	103.20%	68.69	109.90%	26.2	107.70%
INDQ11	SAUS1A	C80N	1005	62.98	100.80%	24.11	101.20%	66.18	105.90%	25.38	104.60%	69.61	111.40%	26.7	109.30%
INDQ11			1005	64.28	102.90%	24.68	102.40%	68	108.80%	26.14	106.30%	71.77	114.80%	27.59	111.40%

The following RAs are proposed at Exeter and Indian Queens to alleviate the fault level issues. In addition to this there is another RA at Exeter with one SGT open standby also proposed with solid bus bars. These are found to be solving fault level up to 2025 Gone Green scenarios. As explained in section 6.10, further 132kVnetwork reconfiguration and investment in uprating switchgear would be required to manage higher 2030 scenarios.





12 APPENDIX B: CURTAILMENT REQUIREMENTS FOR VARIOUS OPTIONS

The table below shows a summary of curtailment requirement under the worst N-3 identified in section 5.1 of this report. For each study point i.e. 2020, 2025 and 2030, the worst possible DER background was imposed on the model as explained in section 4.3. Then, the study simulated the N-3 condition for each solution option individually and for each scenario. Each time, the study looked at how much generation reduction required within boundary 1 and 2 to make the network operable. Those are the numbers summarised below. Please note that this all assume Langage machines are all on with full output and in 2030 case FAB link is importing half full at 700MW.

For example, let's assume just pre-fault curtailment is implemented as the only solution for the network. Also assume we get the expected gone green generation background for 2025. Under this case to make the network compliant, 230MW generation has to be reduced behind boundary 1 and 670MW has to be reduced behind boundary 2. Because boundary 1 is nested within boundary 2 (please refer to figure 9 in section 7) any curtailment action taken for boundary1 will help boundary 2. This means after solving boundary 1 a further 440MW needs to be reduced to make boundary 2 compliant.

Please note this curtailment exercise has been carried out to inform issues around operability. We need to understand operability issues if we are ever get to these points and what it takes to make the network operable and the practicality of it.

From an economic point this has very low probability of happening. This is explained in section 4.2. From historic metered data, for ~90% of the time the DER output is likely to be below 30% of installed capacity. Even when they go above 50% dispatch they are likely to persist at that level for very few hours in a year. This means the volume of energy curtailment (i.e. MW level of curtailment multiplied by the time period) smaller and hence the cost of it.

Options	3GW (2020) / 2.0GW		4.85GW (2025) / 3.0GW		6.48GW (2030) / 4.0GW	
	Boundary 1	**Boundary 2**	**Boundary 1**	**Boundary 2**	**Boundary 1**	**Boundary 2**
Alverdiscott ANM	No requirement	Not Applicable	230MW Pre-fault to keep the loading of SGT2 below 84%	Not Applicable	500 MW pre-fault to keep SGT2 Loading below 84%	Not Applicable
N-3 intertrip	No requirement	Not possible because of short term rating unavailability on WPD ccts between EXET and LNAD	No requirement	Not possible because of short term rating unavailability on WPD ccts between EXET and LNAD	No requirement	Not possible because of short term rating unavailability on WPD ccts between EXET and LNAD
Pre-fault curtailment	No requirement	150MW Pre-Fault for DNO cct overloads	230MW Pre-fault to keep the loading of SGT2 below 84%	670MWPre-Fault for DNO cct overloads	500 MW pre-fault to keep SGT2 Loading below 84%	1250MW for Thermal O/L and voltage
Commercial storage in place of curtailment	No requirement	150MW Pre-Fault for DNO cct overloads	230MW Pre-fault to keep the loading of SGT2 below 84%	670MWPre-Fault for DNO cct overloads	500 MW pre-fault to keep SGT2 Loading below 84%	1250MW for Thermal O/L and voltage
Pre- fault 132kV Split between ABHA-LAND	No requirement	210MW pre-fault Voltage collapse ALVE-TAUN 400kV cct O/L into 10 min rating (260MW without protective reactive switching)	270MW Pre-fault to keep the loading of SGT2 below 84%	730MW pre-fault for voltage (850MW without reactive switching)	510MW Pre-Fault to keep SGT2 loading below 84%	1550MW pre-fault for voltage with (with reactive switching)

Post fault 132kV Split between ABHA-LAND	No requirement	210MW Post-fault ALVE-TAUN 400kV cct O/L into 10 min rating	230MW Pre-fault to keep the loading of SGT2 below 84%	720MW (250MW pre-fault to keep ALVE-TAUN cct O/L within 10min and voltage plus 470 post fault to reduce it further)	500 MW pre-fault to keep SGT2 Loading below 84%	1200MW Pre-fault for voltage with reactive switching 1600MW Pre-fault without reactive switching
Split ALVE - INDQ 132kV route (K route) pre/post fault	No requirement	120MW Pre-Fault for DNO cct overloads	130MW Pre-fault to keep the loading of SGT2 below 100%	570MW pre-fault for thermal overloads.(132kV cct between ABHA & EXET)	310MW Pre-fault to keep the loading of SGT2 below 100%	940 MW pre-fault for 132kV O/L 700MW pre-fault for voltage with reactive switching
Protective reactive switching	Not Applicable	150MW Pre-fault for G59 under voltage	Not Applicable	680MW Pre-fault for G59 under voltage	Not Applicable	1260MW Pre-fault for G59 under voltage
Uprate LAND-ABHA-EXET 132kV route	Not Applicable	Circuits should be capable of 120MVA	Not Applicable	ENER -LAND cct to 220MVA others at least 150MVA after 230MW pre-fault curtailment for ALVE SGT	Not Applicable	After total of 700MW pre-fault curtailment (500MW for ALVE SGT and 200MW to make the fault converge), the following O/L observed ENER-LAND - 205MVA Other routes max - 162MVA
Uprate ALVE - INDQ 132kV route (K route)	No requirement	Not Applicable	ccts should be capable of 260MVA for INDQ ALVE TAUN DC fault under intact network this is after about 90MVA pre-fault reduction	Not Applicable	After 360MW pre-fault reduction get the INDQ - ALVE- TAUN DC fault converge , the K route (INDQ-STUD) O/L 250MVA	Not Applicable
SVC/STATCOM	No requirement	No requirement	No requirement	Similar effect as reactive switching	No requirement	Similar effect as reactive switching also help with voltage step changes.
Renew contract of INDQ Sync comp	No requirement	Current contract runs out on Nov 2021	No requirement	Will be beneficial similar effect as reactive switching	No requirement	Will be beneficial similar effect as reactive switching
Uprate ALVE SGTs	No requirement	No requirement	Pre-fault loading 327MW	Not Applicable	Pre-fault loading 430MW	Not Applicable

New GSP at Pyworthy (double T)	No requirement	No requirement	No requirement	550MW pre-fault. Note: Pre Fault 200 MW (350 MW without reactive switching) for voltage collapse. Plus 350MW for Thermal (due to unavailability of WPD short term rating)	100MW pre-fault to keep SGT2 loading under 100%	1150 MW for thermal O/L of 132kV 910MW for voltage without reactive switching 700MW for voltage with reactive switching

13 APPENDIX C: ECONOMIC ANALYSIS RESULTS AND WORKED EXAMPLE

The Economics Assessment Team within National Grid System Operator has developed a number of methods for performing cost benefit analyses of network developments for a number of different purposes.

Despite elements of each of different purposes being unique, there is a common approach applied to determine which solution represents the most economical option for the GB consumer, taking into consideration uncertainty and characteristics of private sector investment in public services and infrastructure.

13.1 General Method

Step 1: Define a counterfactual case. This will be used as a base case to compare any additional costs or savings available when considering each of the possible options. Identifying benefits available when comparing to a counterfactual is often termed the Savings Approach. It is possible to perform a CBA without a counterfactual where you compare each option against each other and find the relative benefits or costs of each one.

Step 2: Forecast the level of constraint for each of the options, following technical studies which determine the extent of constraint on the network and the extent that each option impacts the constraint.

Step 3: Find the Present Value (PV) of the cost (capex) of each of the options (provided by the proposer of the option) by applying the Spackman Method[4] . This method involves amortising the cost of the investment, taking into consideration the cost of financing the investment at the Weighted Average Cost of Capital (WACC) for the company proposing to deliver the option. This finance adjusted capex is then discounted at the Social Time Preference Rate (STPR).

Step 4: Find the PV of the savings per option by first deducting the constraint costs of the counterfactual case from the option case to give a saving or cost for the option when compared to the counterfactual. Summing these savings over the life of the option and discounting the value by the STPR yields the PV of savings for each option.

Step 5: Find the Net Present Value (NPV) of each option by deducting the PV capex from the PV savings.

Step 6: Create a matrix of the NPV's across all of the options and scenarios modelled and then perform a Least Worst Regret analysis to identify the most economical option.

A worked example of the method is given below.

13.2 Worked example of General CBA Method

For illustrative purposes only, below is a worked example of steps 2, 3, 4, 5 and 6 in the general method above.

Constraints (£m)	2018	2019	2020	2021	2022
Counterfactual	100	120	140	150	150
Option 1	80	80	90	100	100
Option 2	60	70	70	70	80
Option 3	50	60	70	70	70
Option 4	60	70	70	70	80
Option 5	90	100	120	130	130

Table 10: Example table of constraint costs

Table 10: Example table of constraint costs shows the constraint costs for a selection of options over a number of years. For simplicity in this example, a lifetime of five years has been chosen. The constraint costs are calculated on an annual basis and the scenarios being analysed will respect capacity growth over years as well as any

[4] The Joint Regulators Group on behalf of UK's economic and competition regulators recommend a discounting approach that discounts all costs (including financing costs as calculated based on a Weighted Average Cost of Capital or WACC) and benefits at the Social Time Preference Rate (STPR). This is known as the Spackman approach. Further details of our assumptions regarding WACC and STPR are presented later in this document.

network developments assumed to be in the background for the cost benefit analysis (this typically includes the background assessed in the last NOA for transmission network boundaries).

CAPEX (£m, incl. finance)	2018	2019	2020	2021	2022	*Total*
Option 1	1	1	1	1	1	*5*
Option 2	2	2	2	2	2	*10*
Option 3	5	5	5	5	5	*25*
Option 4	3	3	3	3	3	*15*
Option 5	4	4	4	4	4	*20*

Table 11: Example table of financed capex costs

Table 11 shows a table of amortised capex costs which include the cost of finance in the annual values.

Savings (£m)	2018	2019	2020	2021	2022
Option 1	20	40	50	50	50
Option 2	40	50	70	80	70
Option 3	50	60	70	80	80
Option 4	40	50	70	80	70
Option 5	10	20	20	20	20

Table 12: Example table of savings calculated from the constraint costs

Table 12 shows the savings available for each option. This is calculated by deducting the constraints of each option found in Table 10 from the counterfactual.

Year	**2018**	**2019**	**2020**	**2021**	**2022**
STPR	0.97	0.93	0.90	0.87	0.84

Table 13: Table of social time preference rates for a 2017 price base

Table 13 shows the relevant discount rates to be applied for each year. These are calculated by applying a compound discount rate of 3.5% per year. These rates are then applied to the annual values for capex and savings to yield the present values presented in Table 14 and Table 15 respectively below. Deducting the capex from Table 14 from the savings in Table 15 gives the Net Present Value for each option, as shown in Table 16.

PV of CAPEX (£m)	2018	2019	2020	2021	2022	*Total PV*
Option 1	0.97	0.93	0.90	0.87	0.84	*4.52*
Option 2	1.93	1.87	1.80	1.74	1.68	*9.03*
Option 3	4.83	4.67	4.51	4.36	4.21	*22.58*
Option 4	2.90	2.80	2.71	2.61	2.53	*13.55*
Option 5	3.86	3.73	3.61	3.49	3.37	*18.06*

Table 14: Example calculated present value of capex

PV of Savings (£m)	2018	2019	2020	2021	2022	*Total PV*
Option 1	19.32	37.34	45.10	43.57	42.10	*187.43*
Option 2	38.65	46.68	63.14	69.72	58.94	*277.11*
Option 3	48.31	56.01	63.14	69.72	67.36	*304.53*
Option 4	38.65	46.68	63.14	69.72	58.94	*277.11*

Option 5	9.66	18.67	18.04	17.43	16.84	*80.64*

Table 15: Example calculated present value of savings

NPV (£m)	Scenario 1
Option 1	182.92
Option 2	268.08
Option 3	281.95
Option 4	263.57
Option 5	62.58

Table 16: Example table of net present values for a single scenario

For illustrative purposes, a number of additional scenarios have been added. In practice each scenario would have its own constraints and savings tables but the capex would typically be common for each option across scenarios (unless the scenario was a specific capex adjustment). The maximum NPV of each scenario has been highlighted in Table 17. This is used to produce the regrets in Table 18. As the NPV's represent the value that each option offers across each scenario, by subtracting the respective NPV from the maximum NPV for that scenario. This yields how much the consumer would regret (or the opportunity cost) if that option and scenario were to outturn in the future. If the best option for that scenario is chosen and that scenario outturns then the regret is zero as the best choice was made.

NPV (£m)	Scenario 1	Scenario 2	Scenario 3
Option 1	182.92	91.46	219.50
Option 2	268.08	134.04	321.70
Option 3	281.95	338.34	225.56
Option 4	263.57	395.35	237.21
Option 5	62.58	50.06	93.87

Table 17: Example NPV matrix for multiple scenarios and options

Regret (£m)	Scenario 1	Scenario 2	Scenario 3
Option 1	99.04	303.89	102.20
Option 2	13.87	261.31	0.00
Option 3	0.00	57.01	96.14
Option 4	18.39	0.00	84.49
Option 5	219.37	345.29	227.83

Table 18: Example regret matrix for multiple scenarios and options

Regret (£m)	Scenario 1	Scenario 2	Scenario 3	Worst regret	
Option 1	99.04	303.89	102.20	303.89	
Option 2	13.87	261.31	0.00	261.31	
Option 3	0.00	57.01	96.14	96.14	
Option 4	18.39	0.00	84.49	84.49	Least Worst regret
Option 5	219.37	345.29	227.83	345.29	

Table 19: Example identification of the Least Worst Regret option

Once the regrets have been calculated you next consider the worst regret provided by each option (i.e. the maximum looking across the options, as opposed to the scenarios). This informs you as to what the greatest opportunity cost is faced by selecting that option. The most economical recommendation is then the option that yields the lowest overall opportunity cost, or the least of the worst regrets. The Least Worst Regret method does have its limitations however it does provide a relatively conservative risk based decision making strategy. Other methods have been investigated however this method has been chosen as it provides a suitable level of protection for the GB consumer for network development considering the breadth uncertainties faced by the energy industry.