Shaping Subtransmission to 2030

South West – Report July 2016

WESTERN POWER DISTRIBUTION

Serving the Midlands, South West and Wales

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1 – Executive summary

As part of a wider trend across Great Britain, WPD's South West licence area has experienced unprecedented growth in the connection of distributed generation (DG), especially Solar PV. There is now over 1.9GW of generation connected to WPD's South West network, of which nearly 1.2GW is Solar PV. This contrasts against an annual maximum demand of around 2.6GW and minimum demand of less than 1.0GW.

Initially we were able to minimise connection costs for generation customers by using the capacity inherent in a network designed to support demand. As this capacity was used up, DG connection applications resulted in requirements to reinforce our network. While some customers have agreed to contribute to the cost of reinforcement in order to connect to our network, customers have sought alternative connection arrangements. Where these have not been available customers have generally preferred to pursue connections elsewhere in the South West or in other DNO licence areas with little or no reinforcement cost.

As a wider consequence of the rapid connection of DG to our network at all voltage levels, limits are being reached on key parts of our network and National Grid's network. The most significant of these was the F-route restriction. 132kV circuits interconnecting Bridgwater and Seabank GSPs were approaching overload, in part due to through-flows from DG and transmission-connected generation across the South West of England. Interactivity with National Grid and WPD's wider plan to enable the connection of Hinkley Point C power station meant that most new applications to connect medium and large DG in the South West were subject to a connection delay of 3 to 6 years.

A solution has since been devised whereby some of the 132kV works required to connect Hinkley Point C are being brought forward to alleviate the F-route restriction early. Meanwhile, National Grid's responses to WPD South West's Statement of Works (SoW) submissions highlighted that DG output in the South West is further limited by the capability of transmission network components both in the South West and further afield.

This report documents the processes that WPD is following to avoid DG or demand connections being unnecessarily delayed by another restriction similar to the F-route. With the assistance of Regen SW, we have developed scenarios for the growth of DG and demand in the South West from 2015 to 2030. These scenarios correspond to National Grid's Future Energy Scenarios: No Progression, Slow Progression, Consumer Power and Gone Green. Although they cover the growth of several types of generation and the electrification of transport and heating, they are dominated throughout by the growth of Solar PV. Developers have proved very capable of deploying Solar PV across the South West, but its growth brings significant challenges. Its output is dictated by weather and seasons, and is not coincident with times of peak demand for electricity. Without electricity storage or output curtailment on a vast scale, there will inevitably be a limit to how much Solar PV can usefully contribute to Great Britain's energy needs.

The scenarios were used as inputs to network studies, analysing the impact of future DG and demand connection on the subtransmission (i.e. BSPs, 132kV and GSPs) components of the WPD South West network. In these studies we have moved away from traditional 'edge-case' modelling, where only the network condition which is deemed to be most onerous is analysed. Instead we have analysed network behaviour throughout the day for:

- A generation-dominated summer peak day;
- A demand-dominated winter peak day; and
- A typical spring or autumn day.

This methodology highlighted that while many of the most onerous conditions occur at the expected peaks; this is not always the case. In particular, some thermal constraints are met first in spring or autumn rather than summer or winter. Reactive power constraints are often met when the network is lightly loaded. WPD's expected transition to become a Distribution System Operator will require more analysis of this type to manage the network in real time.

The studies confirmed the justification for WPD's planned subtransmission reinforcement projects such as the F-route, but also identified the requirement for further reinforcement by 2020. Most significantly, the K-route circuits interconnecting Alverdiscott and Indian Queens GSPs are affected by similar through-flow issues to the F-route. Normally interconnected 132kV and 33kV networks are a frequent limiting factor in these and other studies; it is recommended that the practicalities and economies of operating these networks are re-examined.

Looking beyond 2020 to 2025 and 2030, the scenarios diverge but further reinforcement is required under every scenario. Under the No Progression scenario this is limited to the replacement of Landulph GT2 with a larger unit. In contrast the Gone Green scenario triggers:

- An additional GSP in the vicinity of Pyworthy BSP to allow Alverdiscott and Indian Queens GSPs to be deloaded and split apart;
- Around 30 GTs to be replaced with larger units;
- A new BSP in the vicinity of Alverdiscott GSP to allow Barnstaple and East Yelland BSPs and the associated 132kV circuits to be deloaded; and
- The reconductoring or reinforcement of other 132kV circuits.

It is expected that some – but not all – of this reinforcement could be alleviated by using Active Network Management (ANM) or other measures to curtail the output of DG to prevent network overstressing. It is important to note that ANM is not capable of mitigating all types of network constraints; furthermore it does not have an unlimited ability to mitigate constraints unless significant pre-fault curtailment of output is applied to avoid protection operation or equipment damage prior to the operation of ANM.

While the forecast reinforcement requirements were dominated by the connection of DG, the electrification of transport and heating also has an impact. The studies are particularly sensitive to electric vehicle usage patterns, which may change dramatically as electric vehicles enter the mainstream.

While National Grid has not yet studied the impact of our scenarios on their network, they have committed to start these studies in September 2016. It is clear from the SoW process that DG can no longer be connected in the South West without transmission constraints or reinforcement. The initial constraints are for infrequent and unlikely combinations of outages, but as more generation connects it will have to be constrained for more frequent and likely first-circuit-outage conditions.

It is our intention to revisit these studies and the underlying scenarios on a two-yearly basis.

2 – Objective of this report

The overall aim of this report is to:

- Assess the potential growth in Distributed Generation by fuel type, general location and year of connection against potential demand changes that may result due to changes in end use such as electrification of transport and heating;
- Identify thermal and voltage constraints that may occur on our 132kV network which will limit the ability of those connections to take place;
- Assess options for reinforcement; and
- Provide recommendations for 'low regret' investment, noting the Ofgem consultation on 'quicker and more efficient connections' that raised questions on the role of strategic reinforcement funded by the wider customer base.

Given the uncertainty in the growth of distributed generation and changes in demand, the study has been undertaken using a scenario based approach to seek to identify an envelope of likely outcomes and understand the changes needed within that envelope.

We have used the four background Energy Scenarios developed by NGET in their Future Energy Scenarios for 2015 as a framework to assess the potential DG and demand changes on the S West distribution network.

3 – Background

South West network area

WPD South West covers an area of approximately 14,400 square kilometres and extends from Bristol and Bath in the north east, along the peninsula to Land’s End, some 300 kilometres to the south west, and comprises the counties of Devon and Cornwall, the unitary authority of the Isles of Scilly, large parts of Somerset and Avon and a small part of Dorset. The area is largely rural but includes the towns and cities of Bath, Bristol, Exeter, Plymouth, Taunton, Torquay and Weston-Super-Mare as well as many other costal resorts. A prominent feature of the area is the length of coastline, with no part of WPD South West being more than 40 kilometres from the sea. The area includes two large National Parks, Dartmoor and Exmoor, along with a number of Areas of Outstanding Natural Beauty, Heritage Coastline and numerous Sites of Special Scientific Interest.

Current network

The distribution network in the South West is supported by a 400kV transmission ring that runs around the peninsula providing connection at eight Grid Supply Points (Axminster, Exeter, Abham, Landulph, Indian Queens, Alverdiscott, Taunton and Bridgwater) with a further 3 GSPs (Seabank, Iron Acton and Melksham) connecting the northern end of the area. Large transmission connected generation is located at Seabank in Bristol, Hinkley Point in Somerset, Langage in South Devon and Indian Queens in Cornwall. There is an extensive 132kV network which operates in parallel between the GSPs. The overall configuration of the network in shown in Figure 1.

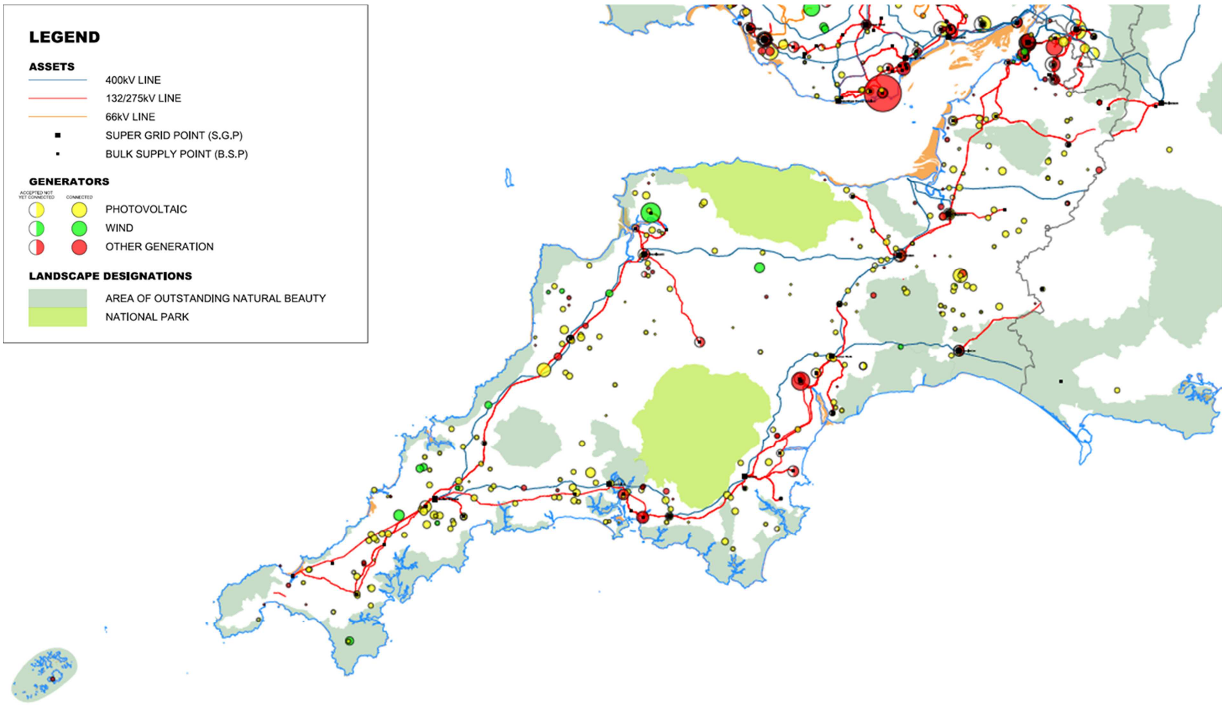

Figure 1: Network in S West showing 400kV and 132kV networks together with generation in excess of 1MW capacity

Demand usage of the network

Current forecast units distributed and historic system maximum demands are shown in Table 1 and Figure 2.

Table 1: Forecast units distributed in South West (more detailed breakdown available in published CDCM models)

	Rate 1 (Peak/Red) units (MWh)	Rate 2 (Off-peak/Amber) units (MWh)	Rate 3 (Green) units (MWh)	MPANs	Import capacity (kVA)	Reactive power units (MVArh)
Domestic	4,930,712	699,441	–	1,459,793	–	–
Other LV NHH (incl. unmetered)	2,088,842	391,495	159,041	150,642	–	–
Other LV HH	70,201	502,329	435,446	4,421	529,352	80,641
HV (incl. LV substation)	214,201	1,521,478	1,579,682	2,637	1,291,753	262,097
LV generation	75,664	1,104	1,217	772	–	4,273
HV generation	357,020	88,958	126,758	269	–	5,655
Total	**7,736,639**	**3,204,804**	**2,302,144**	**1,618,533**	**1,821,105**	**352,666**

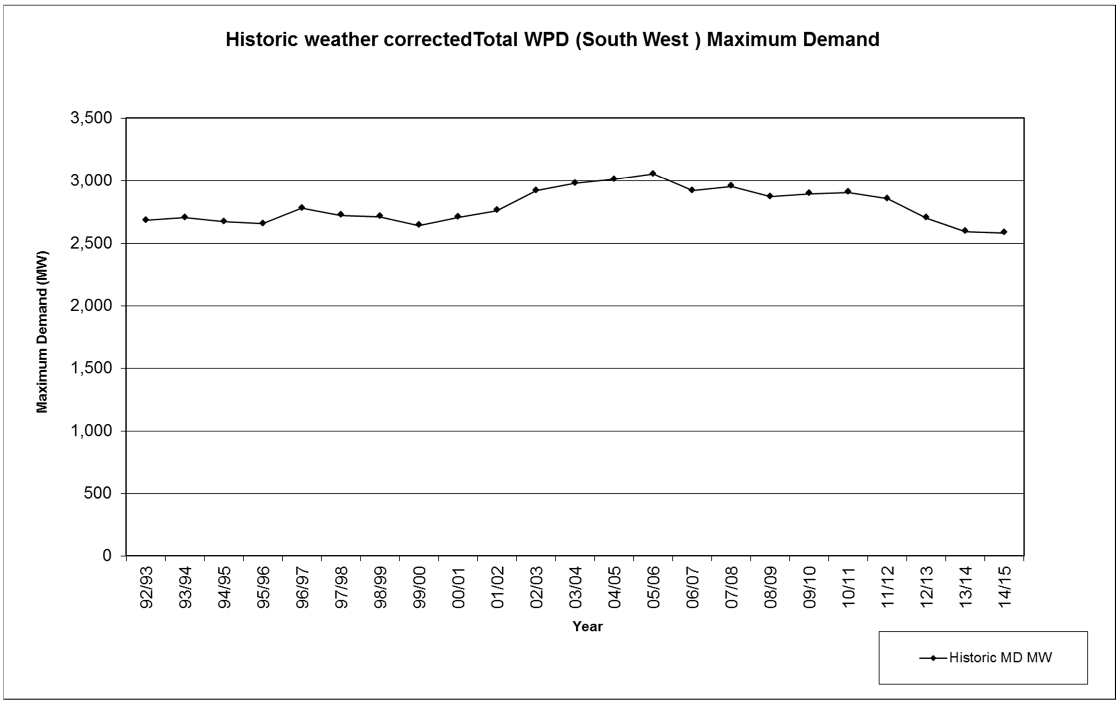

Figure 2: South West historic system maximum demand

The studies undertaken have used three representative days for each year studied:

- A winter peak demand day;
- A summer 'maximum generation' day – i.e. low demand with high levels of DG output; and
- A typical spring/autumn day – i.e. period when there are planned outages.

Using data from the settlement system the contribution to demand on these typical days from different segments of demand has been estimated and is shown in Figure 3, Figure 4, Figure 5, and Figure 6.

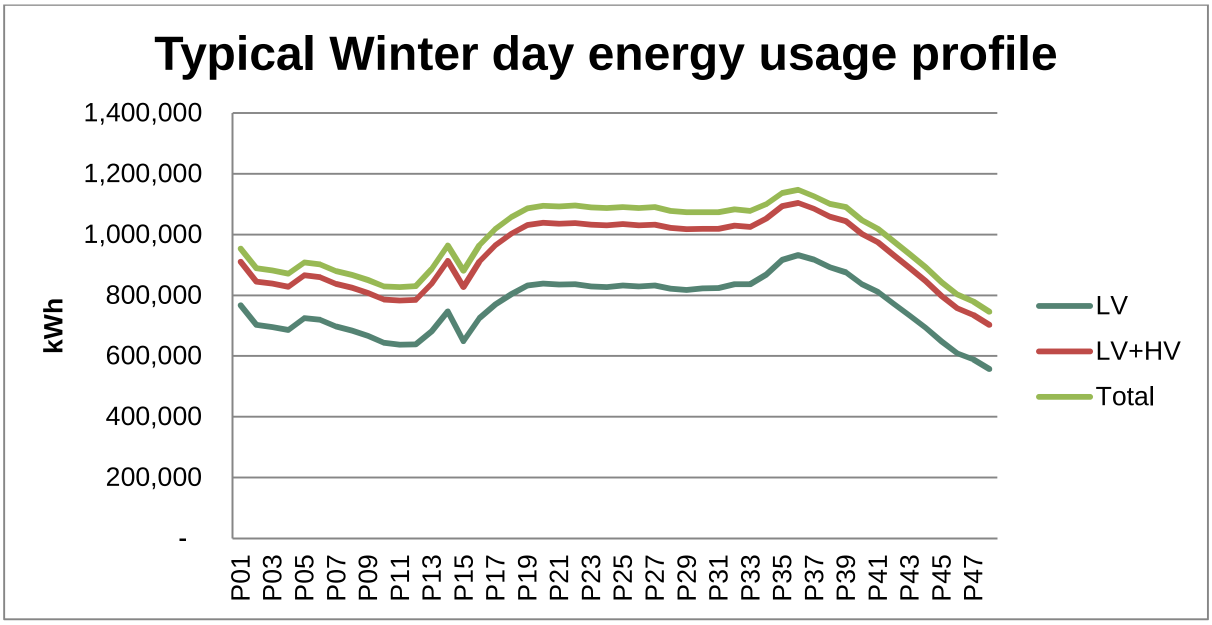

Figure 3: Typical Winter day energy usage profile

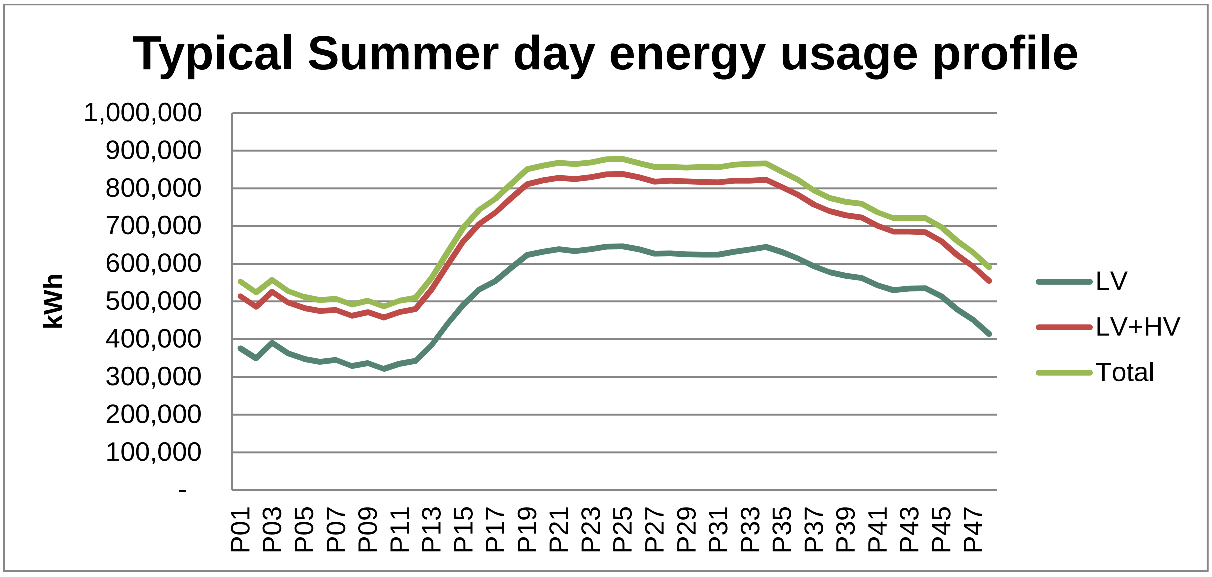

Figure 4: Typical Summer day energy usage profile

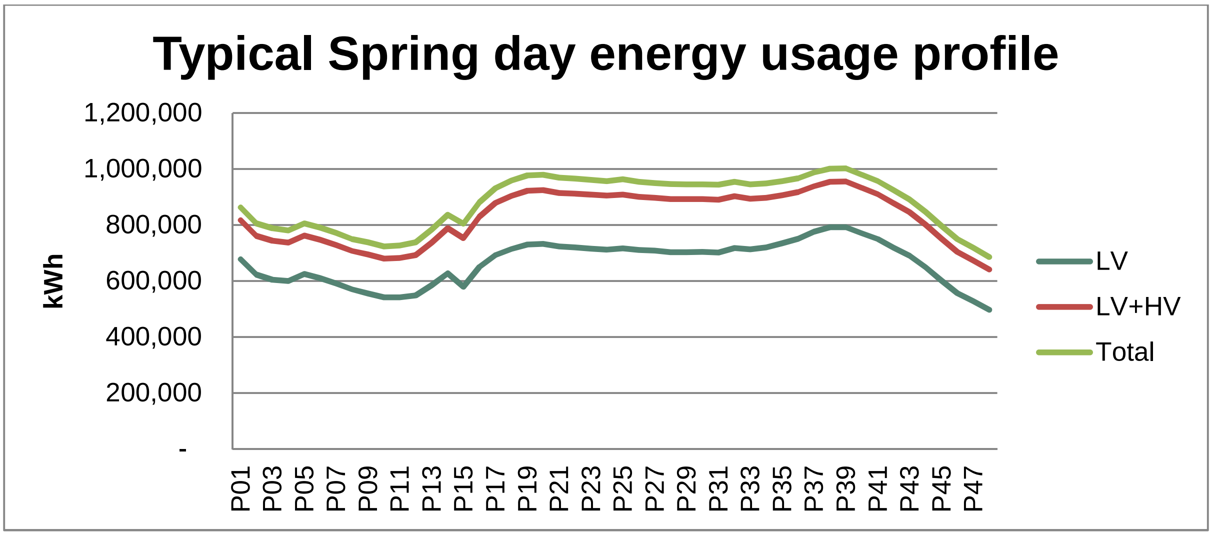

Figure 5: Typical Spring day energy usage profile

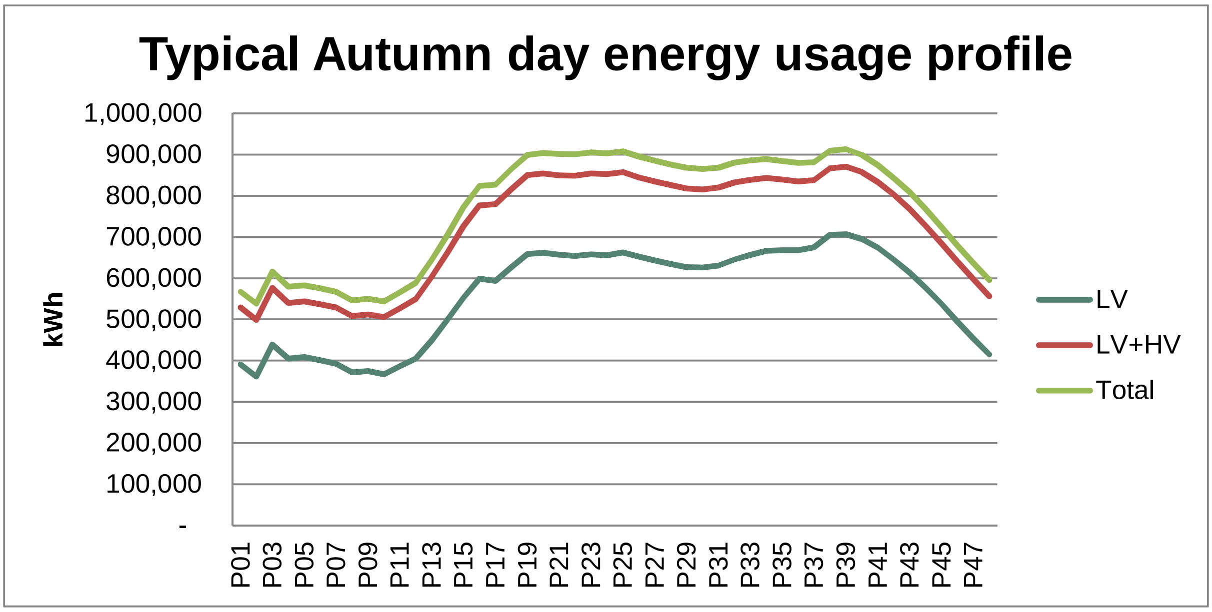

Figure 6: Typical Autumn day energy usage profile

A large proportion of energy usage in the South West is at LV; until the Smart Meter rollout is complete and controllable domestic demand technologies are adopted, opportunities for DSM in the South West are expected to be limited. A number of innovation projects are underway to further explore this area.

Growth in Distributed Generation

At privatisation, in 1990, there were virtually no generators connected to the distribution network. Those that existed were mainly embedded within customer-owned internal networks and primarily used for standby purposes. Since the early 1990's there has been a moderate growth of onshore wind generation supported by various subsidy arrangements.

In addition, NGET have developed various contracted services which has led to the growth in diesel- and gas-fuelled distribution-connected plant to provide these services, generally being required to operate at or around times of peak national demand.

Since around 2010, there has been a significant growth in solar PV connections, both in the volume of small roof top systems and large, MW scale, ground mounted systems.

More recently there has been a growing interest in the connection of storage. This has been driven by the falling cost of storage, reduced subsidies for renewable technologies, the growing value of flexibility in timing of import/export to the network and NGET seeking frequency support services.

The current position in terms of distributed generation in the South West is shown in Table 2. This shows the breakdown between those connected to the distribution network, those with accepted contracts to connect and those with outstanding offers for connection.

Table 2: Connected, Accepted and Offered distributed generation in WPD South West at the end of June 2016.

Generator type	Capacity [MVA]			
	Connected	**Accepted**	**Offered**	**Total**
Photovoltaic	1,186.1	442.7	58.5	1,687.2
Wind	254.7	66.4	1.4	322.5
Landfill Gas, Sewage Gas, Biogas & Waste Incineration	82.6	43.8	0.8	127.1
CHP	42.2	16.3	11.6	70.1
Biomass & Energy Crops	-	0.2	0.0	0.2
Hydro, Tidal & Wave Power	4.8	-	-	4.8
Storage	-	75.5	418.8	494.3
All other generation	390.9	264.9	605.6	1,261.4
Grand Total	**1,961.2**	**909.7**	**1,096.7**	**3,967.5**

Issues resulting from the growth in DG on the South West network to 2016

F-route constraint and planned reinforcement

In March 2015, we announced that due to the significant growth in acceptances for DG connection to the network it had reach a point where a critical circuit (F-route) at the boundary between the S West peninsula and the main interconnected transmission network had reached the limit of its capacity. This part of the 132kV network is due to be substantially reconfigured as part of the planned transmission works for the connection of Hinkley Point C. There is some uncertainty around the timing of the transmission works and this caused difficulties in being able to confirm construction dates and subsequent connection timescales for further DG in the peninsula.

We have already started on works to reconfigure and split the F-route by the addition of switchgear at a substation part way along this route. This brings forward a small part of the works that will be needed to facilitate the transmission works associated with the connection of Hinkley Point C power station.

Fraddon deficiency and planned reinforcement

As a result of large amounts of connected and committed generation at all voltage levels within the Cornwall region, reinforcement of the grid transformers at Fraddon BSP and associated 132kV circuits is required.

It is planned to install the following equipment at Fraddon BSP:

- Two new grid transformers;
- Two new indoor 33kV boards;
- Four new 132kV cables;
- A new 132kV line circuit breaker; and
- A new dual termination tower.

It is also planned to reprofile the four 132kV overhead line circuits between Indian Queens GSP and Fraddon BSP, increasing their ratings without reconductoring.

When complete these works will provide increased DG capacity at 33kV and below in mid-Cornwall.

J-route deficiency and planned reinforcement

As a result of large amounts of connected and committed generation at all voltage levels within the North Devon area, reinforcement of the 132kV J-route is required. The circuit from East Yelland disconnector 303 to Barnstaple GT2 will be recrimped to remove a ratings restriction.

SoW related limitations

All changes to demand or generation on the distribution network have some effect on the transmission system. National Grid’s Connection and Use of System Code has a requirement in it to seek National Grid’s assessment of the impact and any necessary works that they need to undertake where it is deemed that there will be an impact. The initial assessment is carried out via a Statement of Works which confirms whether NGET work or connection conditions will be required. Where works are required, a modification application is made to NGET. NGET then specifies the precise works or conditions needed before connection can take place.

This process was put in place prior to the substantial growth in DG and whilst originally designed to address the impact of single large DG plant being connection onto distribution networks, it has been used to assess the cumulative impact of large numbers of smaller DG plant.

Two bulk statement of works applications have been made to NGET for the South West which, after subsequent modification applications have led to the following conditions being imposed:

- Each generator connection must have a reactive capability between 0.95 power factor leading and 0.95 power factor lagging. The initial power factor setting will be:
    - 0.95 leading on DG capable of significant output overnight, and
    - 0.98 to 0.99 leading on DG only capable of generating during the day.
- Emergency disconnection facility to be provided to allow WPD to de-energise on instruction from National Grid.
- Installation of a South West Operational Tripping Scheme to allow management by National Grid of the levels of generation under certain combinations of transmission outages when export flows from the South West are high. The timing of the installation of this scheme (1 September 2019) and associated enabling transmission works will result in some connections being allowed before completion of those works (but with constraint during planned outages), while other connections need to wait for the transmission works to be completed.
- The enabling transmission works associated with the above are the hotwiring of the Hinkley Point – Melksham 1 and 2 circuits to increase their thermal rating (due by 31 October 2017), re-conductoring of the Fleet – Lovedean OHL circuits to increase their capacity (due by 31 October 2020) and re-conductoring the Bramley – Fleet OHL to increase capacity (due by 31 October 2021).
- Installation of an active network management (ANM) at Alverdiscott GSP (due by 31 October 2017) to manage flows within the rating of the SGTs at Alverdiscott.

4 – Scenarios

National Grid produces Future Energy Scenarios (FES) each year which provides:

- A range of credible futures.
- An output of an annual stakeholder consultation process regarding the future of the energy landscape.
- A document covering the model inputs to the scenario analysis, new technologies, social and economic developments, government policies and progress against targets.
- A set of scenarios which can be used to frame discussions and perform stress tests.
- A set of scenarios that are projected out from the present to 2050.
- Scenarios which form the starting point for all transmission network and investment planning. They are also used in analysis to identify future operability challenges and potential solutions to meet those challenges.
- A document covering developments in electricity generation and demand, and gas supply and demand.

In order to assess the future challenges facing the South West distribution network, WPD commissioned Regen SW to produce a set of forecasts for the growth of DG and demand in the South West. Forecasts were made for four scenarios:

- No Progression,
- Slow Progression,
- Consumer Power, and
- Gone Green.

These scenarios are named after and correspond to the economic scenarios developed by National Grid in the FES. Each scenario was forecast for each year from baseline in 2015 to 2030.

Technologies covered by the analysis include electricity generation, demand and storage as listed below:

Key distributed generation, storage and demand technologies assessed	
Electricity Generation Technologies • Solar PV – ground mounted • Solar PV – roof mounted • Onshore wind – large scale • Onshore wind – small scale	• Conventional and STOR DG capacity • Gas, diesel and gas CHP **Electricity Demand Technologies**

• Anaerobic digestion – electricity production
• CHP
• Heat pumps (communal/commercial)
• Hydropower
• Emerging and new DG technologies
    o Geothermal
    o Tidal stream
    o Wave energy
    o Floating wind
	• Electric vehicles
	• Heat pumps (domestic)
	
	Energy (electricity) storage
	
	• Energy storage 'network support'
	• Energy storage 'generation support'
	• Energy storage 'own use'

Forecasting the long term growth of any generation or demand technology is both difficult and complex owing to the multiple variables that can affect the market and determine growth. This is mitigated by forecasting for each of a diverse range of credible scenarios.

For each DG and demand technology, the growth assessment was split into three distinct phases:

1. Baseline – WPD and Regen SW's databases of Connected DG were correlated and confirmed to give a baseline at October 2015 with a high degree of accuracy;
2. Pipeline – WPD's database of Accepted-not-yet-Connected DG was combined with an assessment of the DECC planning database, current market conditions and recent policy changes, to give a forecast shared between all scenarios of what is expected to connect by 2017 or 2020 depending on technology; and
3. Scenario projection – each FES scenario was assessed and interpreted to take into consideration the specific local resources, constraints and opportunities for that technology in WPD's South West licence area under that scenario.

Focusing on the specific geographical region of the South West, with access to existing baseline data and a good knowledge of the local industry and growth factors, enabled the analysis, by Regen SW, to be taken down to the geographic area supplied by each BSP, which is the key level at which strategic investment decisions need to be made that have longer lead times.

The results of the assessment are presented in each of the technology chapters in the Regen SW report and provide a projection of annual capacity deployment, by technology and scenario, for the period from 2015 to 2030.

A summary of the DG forecasts is shown in Figure 7 and Figure 8. From the baseline capacity of circa 1.5GW at October 2015, capacity grows circa 5 GW by 2030 under the most ambitious Gone Green scenario. Growth estimates for the other scenarios, Consumer Power, Slow Progression and No Progression are lower. However, even under the lowest No Progression scenario, there is an expected growth pathway to 2.5 GW of DG capacity by 2030.

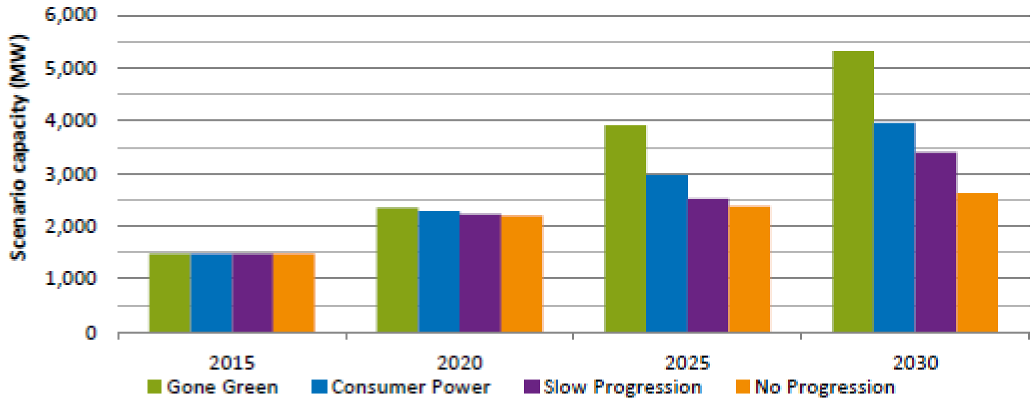

Figure 7: DG capacity growth 2015 to 2030 under the four scenarios

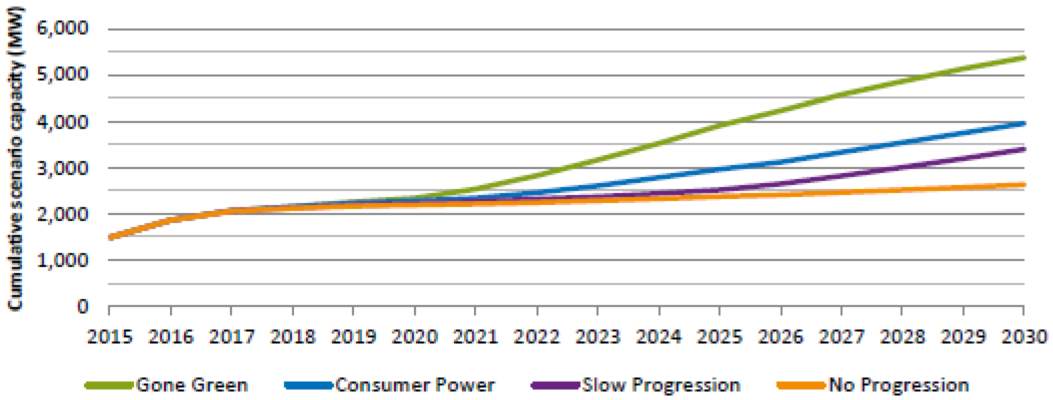

Figure 8: Total distributed generation capacity growth in WPD South West licence area from 2015 to 2030 under each scenario

The complete Regen SW report, *Distributed generation and demand study – Technology growth scenarios to 2030, South west licence area, January 2016* is available from our website.

5 – Network modelling technique and inputs

An analysis technique was devised to assess the impact of the four scenarios on WPD South West's subtransmission network. The subtransmission network was focussed upon because of the long timescales required to reinforce it.

Traditionally distribution networks are assessed by 'edge-case' modelling, where only the network condition which is deemed to be most onerous is analysed. As the installed capacity and behaviour of both demand and DG is rapidly developing, it has become difficult to predict what network condition will be most onerous.

For this project, a broader approach was taken. The network was assessed for each of the four scenarios, at five-year intervals from the baseline in 2015. To cover a range of likely onerous cases, each half-hour of three representative days was assessed:

- A winter peak demand day;
- A summer 'maximum generation' day – i.e. low demand with high levels of DG output; and
- A typical spring/autumn day – i.e. period when there are planned outages.

A half-hourly power profile for each representative day was developed for each demand and DG category. The profiles are described in 'Demand and Generation Profiles' below. The profiles were combined with the forecasts for demand and DG at BSP level. All demand and DG was modelled at the lower voltage (33kV or 11kV) busbars of the BSPs.

For each combination of scenario, year, day and half-hour the network was assessed for thermal and voltage violations under intact and credible outage conditions.

Although the works to enable the connection of Hinkley Point C power station will have a major impact on the 132kV network in the area, it is not an area which is forecast to require significant reinforcement under any scenario by 2025. The works have been designed to provide comparable network capacity and security to the existing network. Since much of the impact is heavily dependent on the design and behaviour of National Grid's network and Hinkley Point C itself, it was decided to postpone the 2025 post-Hinkley Point C studies until National Grid begin their studies in cooperation with WPD. Instead the studies up to 2025 pre-Hinkley Point C were prioritised. The 2030 studies were expected to build upon the results of the 2025 post-Hinkley Point C studies, so have not yet been carried out.

Program Summary

WPD South West's subtransmission and primary distribution networks are normally analysed using Siemens PSS/E. PSS/E's load flow tools are designed to analyse a single snapshot of a network (and optionally perform contingency analysis on that snapshot), rather than analysing the network for a multitude of scenarios, years, days and times of day.

For this project a custom power system analysis program was written in Python 2.7 to analyse that multitude of conditions. The program uses PSS/E 33 as its core analysis engine to perform the actual load-flow calculations, and uses some of PSS/E's built-in contingency analysis tools for efficiency. The processes followed by the program are summarised in Figure 9.

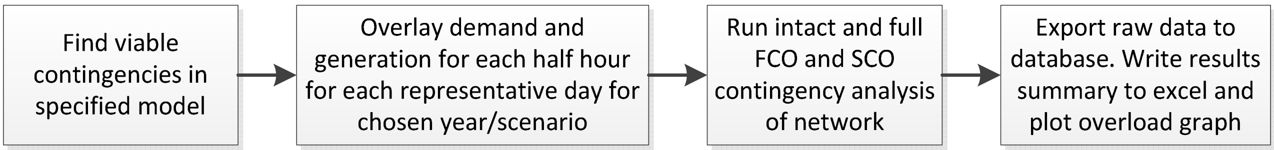

Figure 9: Simplified summary of program

The following inputs were combined for each half hour, day, year and scenario studied:

- An appropriate network model;
- The underlying demand capacity on each BSP;
- The forecast capacity of each DG and new demand on each BSP;
- Half-hourly profiles for each type of demand and DG; and
- The appropriate ratings of network components.

For each half hour, day, year and scenario studied, the program returns:

- MVA flow on all branches of interest for all network conditions detailed in 'Contingency Analysis' below;
- Voltage exceedances for all nodes of interest for all network conditions detailed in 'Contingency Analysis' below;
- Lost load (i.e. the amount of demand disconnected) for all network conditions detailed in 'Contingency Analysis' below;
- MW/MVAr flows at the interface between WPD and National Grid for the intact network; and
- Any issues with network model convergence.

These results are processed within the program and exported to a results database. A separate 'report writer' program was written to summarise the results in tabular and graphical formats for further evaluation.

A limitation of the program was that in a very small minority of studied conditions PSS/E was unable to converge (i.e. calculate valid results). Where this occurred the condition was evaluated separately to ensure that it did not indicate an issue with the network model or the network itself.

Contingency Analysis

The demand and generation capacity of a network is not normally limited by its characteristics under normal running conditions, but by its characteristics under abnormal running conditions. Abnormal running arrangements occur due to faults, maintenance, network construction and other reasons. WPD's network is required to comply with ER P2/6 for demand security, and must safely cope with credible fault conditions beyond the scope of ER P2/6. There is currently no standard for providing security of supply to DG. Contingency analysis is the analysis of the network under abnormal conditions to confirm that the network complies with these requirements.

Circuit breakers were included in the network model in order to determine the protective zones bounded by circuit breakers which are deenergised under fault conditions. A limitation of the contingency analysis is the assumption that planned outages would always apply to the same zones as faults, rather than using isolators, links or jumpers to allow part of the zone to be brought back into service for the bulk of the duration of the outage. The following conditions were modelled:

1. The intact (normal running) network – 'BASE';
2. The network following each First Circuit Outage as defined by ER P2/6 – 'FCO';
3. The network following each Second Circuit Outage (i.e. combination of any two First Circuit Outages) as defined by ER P2/6 – 'SCO'; and
4. The network following each outage of a busbar that is not within a wider circuit protective zone – 'BUSBAR'.

For the majority of the network, only 132kV protective zones and those encompassing Grid Transformers were assessed. The assessment of 275kV and 400kV contingencies including those affecting SGTs were excluded from the analysis due to the limited availability of information on National Grid's network, with the exception of 400kV contingencies around the Alverdiscott/Indian Queens area, which were modelled to demonstrate the sensitivity of interconnected 132kV networks to transmission outages.

Modelling Limitations

1. Flows on the WPD network can be significantly influenced by the transmission network due to the degree of parallel running. Better results are obtained by having accurate data about the transmission network in the South West together with a representation of the GB transmission network. To date we have a 2015 model of the transmission network that we have used for all studies. NGET models are going to be made available based upon the ETYS. They will represent 3, 5 and 10 years into the future, but will not directly correspond to the FES scenarios. Discussions are ongoing with NGET to obtain further models for future years to check whether this has a significant impact on the results obtained to date.
2. No model of battery storage behaviour was available, so their impact was excluded from the studies.

3. No data was available on the charging behaviour of large populations of fast-charging, high-capacity EVs with a broad range of users. EV charging profiles were derived from the Electric Vehicles Insight Report of the Customer-Led Network Revolution project. This was based on a trial involving 143 domestic EV owners that took place in 2014. It is possible that increases in power and energy consumption per EV will plateau at some point (despite improvements in charging speed and battery capacity) as EV capabilities come to match the demands of EV users, but it is not known when this will happen or at what level. The EV profiles used in the studies peaked at just 0.9kW per EV after diversity.
4. 275kV and 400kV contingencies have only been modelled for the 400kV circuits from Taunton to Landulph via Alverdiscott and Indian Queens. Given the heavily interconnected nature of the South West 132kV network, it is likely that some of the most onerous conditions for the network have not been studied.
5. Only load-flow studies have been carried out, assessing steady-state voltage and power flows. No fault level, power quality, protection or stability studies have been carried out.
6. Post-fault corrective actions such as auto-close schemes, auto-changeover schemes and generator intertripping or constraint have not been modelled. This means that the impact of some contingencies may be overstated in the raw results. To mitigate this, key intertripping schemes have been modelled manually to assess their impact.

Demand and Generation Profiles

To model the daily and seasonal variation in power flow, it was necessary to develop power profiles for the various categories of demand and DG connected to the network. Each profile was normalised around the unit of measure used for that type of demand or DG:

- Underlying demand is measured in MW of peak demand;
- EVs and heat pumps are measured in number of units installed; and
- Each type of DG is measured in MW of installed capacity.

The profiles for underlying demand, Solar PV and Onshore Wind were derived from measured flows on WPD South West's network. The other profiles were derived from various sources as described below. A particular focus was placed on the Solar PV profiles due to the high level of Solar PV both currently installed on the network and forecast out to 2030 under all scenarios.

Demand Profiles

Underlying demand

The underlying demand profiles for the South West are shown in Figure 10. The maximum daily load curve peaks at approximately 2,600 MW for the whole South West region. The specific load curve for each BSP will vary depending on a number of factors such as population density and levels of industry in the area. A representative sample of BSPs were categorised into urban, rural and mixed and their historic demand was used to generate demand profiles for the 3 distinct BSP types. Each BSP in the South West was then categorised based on the population density of the area fed by the BSP.

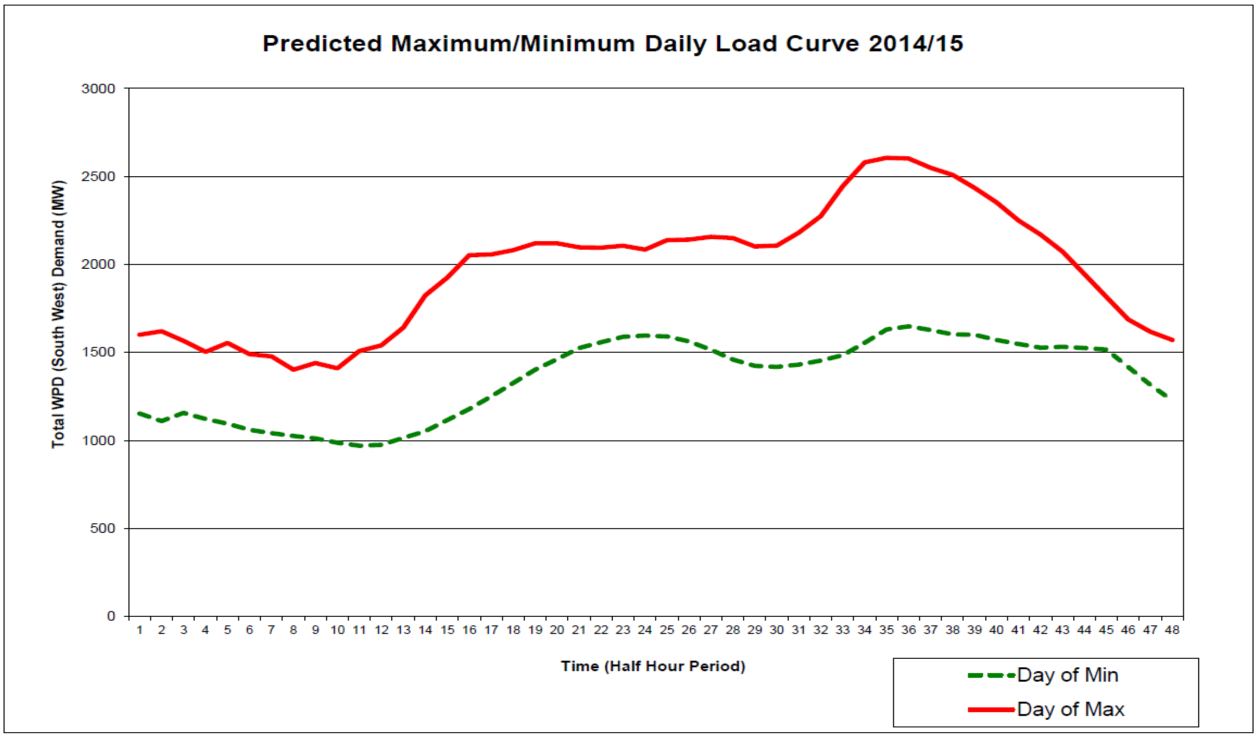

Figure 10: South West Demand Profiles

Heat Pumps

The profiles for heat pumps were derived from the Electricity North West Limited (ENWL) Network Innovation Allowance (NIA) funded study: Managing the Impact of Electrification of Heat, dated March 2016.

The study considered various types of heat pump as follows:

- Lower temperature air source heat pump (ASHP)
    - Seasonal performance factor of 2.5-3.0
    - Generates flow temperatures of up to 55 degrees C
    - Suitable for well insulated buildings and new builds
- Higher temperature ASHP
    - Seasonal performance factor of 2.3-3.0
    - Generates flow temperatures of up to 80 degrees C
    - Suitable for older dwellings with a moderate thermal demand
- Hybrid ASHP
    - Lower temperature ASHP plus a boiler
    - Switches between fuel sources, based on efficiency/running costs
    - Suitable for older dwellings with larger thermal demand

Ground source heat pumps were not considered in the ENWL study. Due to space requirements for the ground source loop, these are expected to be less prevalent.

Outside air temperature is a critical factor influencing heat pump load profiles. Profiles were derived for the ‘average’ peak winter day and the ‘1 in 20’ (extreme) peak winter day. On an average peak winter day, the back-up electrical heater is not required and the electrical demand of the heat pump peaks at approximately 2.5 kW. During a 1-in-20 peak winter day, the back-up electric heater is needed for large portions of the day resulting in an additional 3 kW of peak demand on very cold days. The 1-in-20 undiversified day was used in the winter peak demand studies to represent the worst case demand from heat pumps. The profiles assumed there was no demand in summer from heat pumps during the max gen studies.

Electric Vehicles (EVs)

EV charging profiles were derived from the Electric Vehicles Insight Report of the Customer-Led Network Revolution project. This was based on a trial involving 143 domestic EV owners that took place in 2014.

The daily profile of weekday charging load averaged across all participants exhibits a significant evening peak of 0.9 kW per EV at around 21:00. The daytime profile is consistent with the EVs being used primarily as commuting vehicles, where the evening peak correlates with household occupancy as commuters return home and plug-in to charge their EVs. The evening peak begins to drop after 22:00, indicating that some vehicles are fully charged by this time. A large seasonal variation in EV consumption was found, with the January peak charger demand of 0.9 kW, steadily reducing to 0.45 kW by June. This is likely to be due to additional lighting and heating requirements as well as reduced battery performance in colder weather.

The Regen SW report considers two different charging profiles, derived from the FES report, dated July 2015. The FES report assumed that a Time Of Use Tariff (TOUT) will be applied for the Gone Green and Consumer Power scenarios from 2020, while uninhibited charging was assumed for the Slow Progression and No Progression scenarios up to 2035. The TOUT results in a two-hour delay in peak demand as shown in Figure 11.

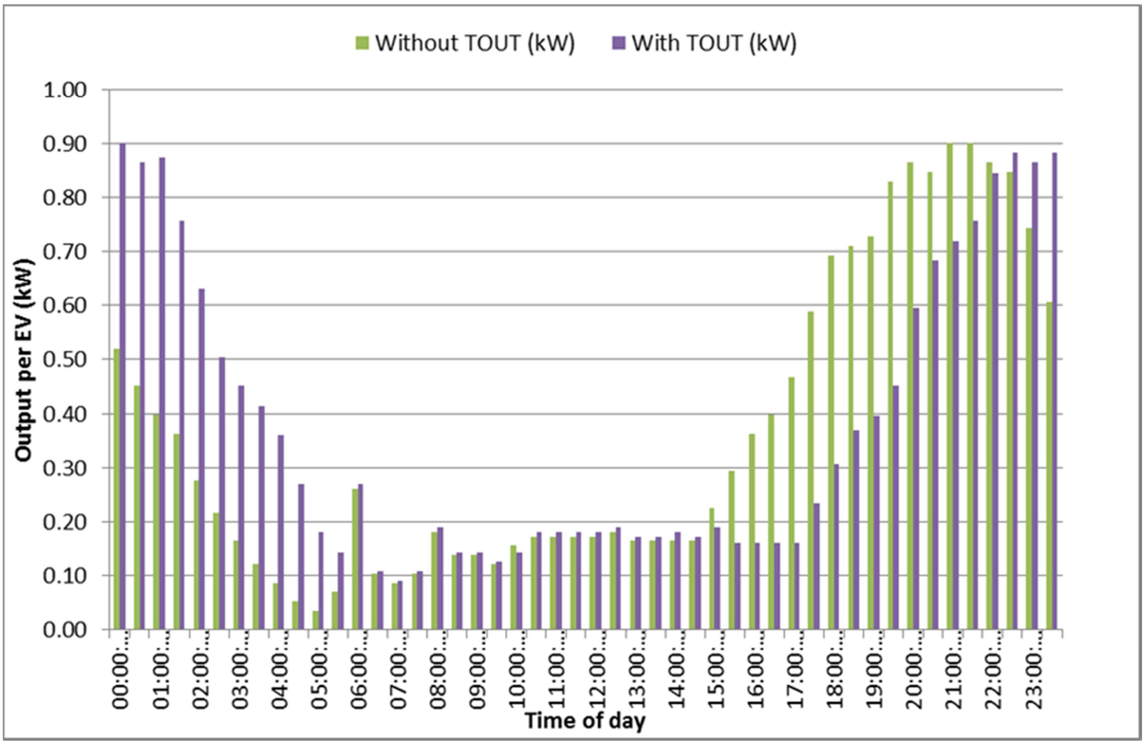

Figure 11: EV Winter Profile (per EV)

Generation Profiles

Solar PV

Data from a sample of the existing solar PV plants was used to generate the profiles. The sample comprised twelve of the largest solar PV plants, with a total installed capacity of 161.5MW. The total installed capacity of solar PV currently connected to WPD's network in the South West is 965MW. The geographical spread of solar PV plants in the sample is shown in Figure 12.

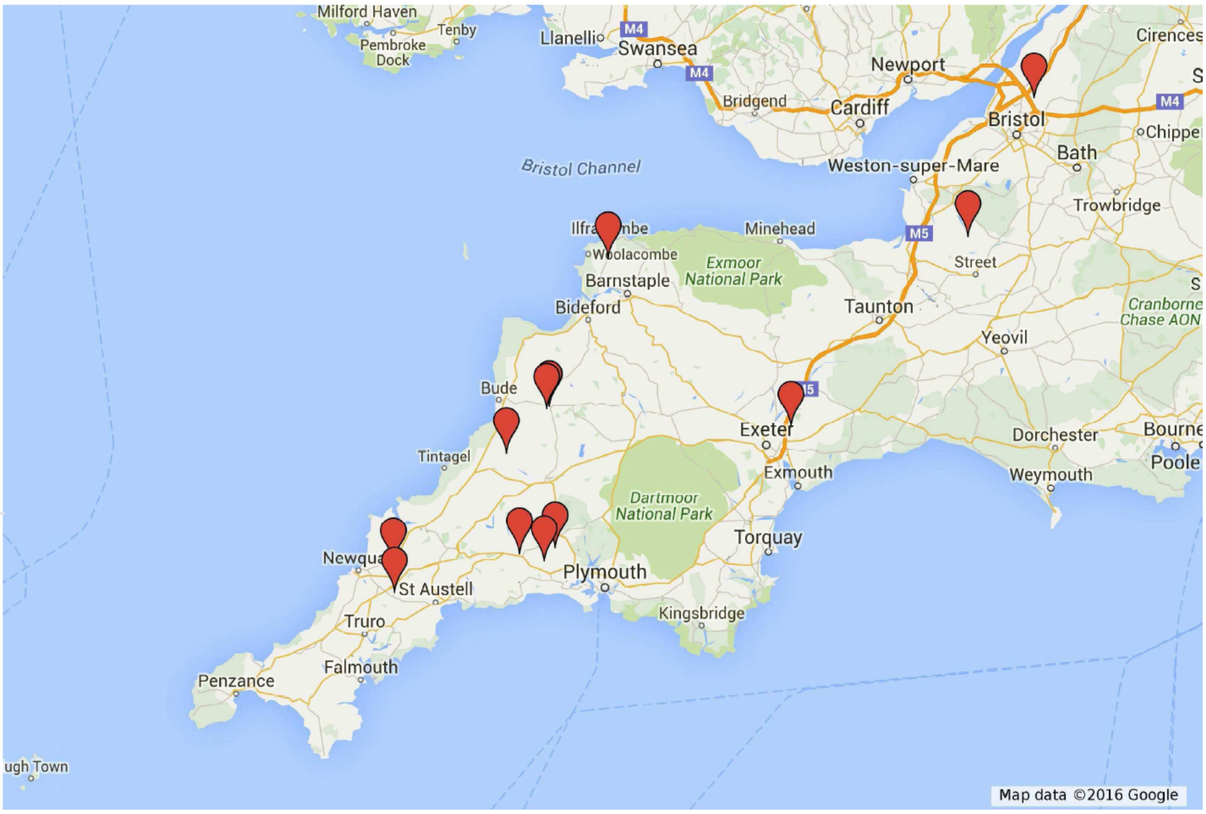

Figure 12: geographical spread of solar PV plants in sample

The half-hourly MW data was aggregated and then normalised to produce three characteristic profiles for:

1. Summer (May-August) Maximum by half hour
2. Winter (December-February) Minimum by half hour
3. Spring-Autumn (March-April and September-November) Average by half hour

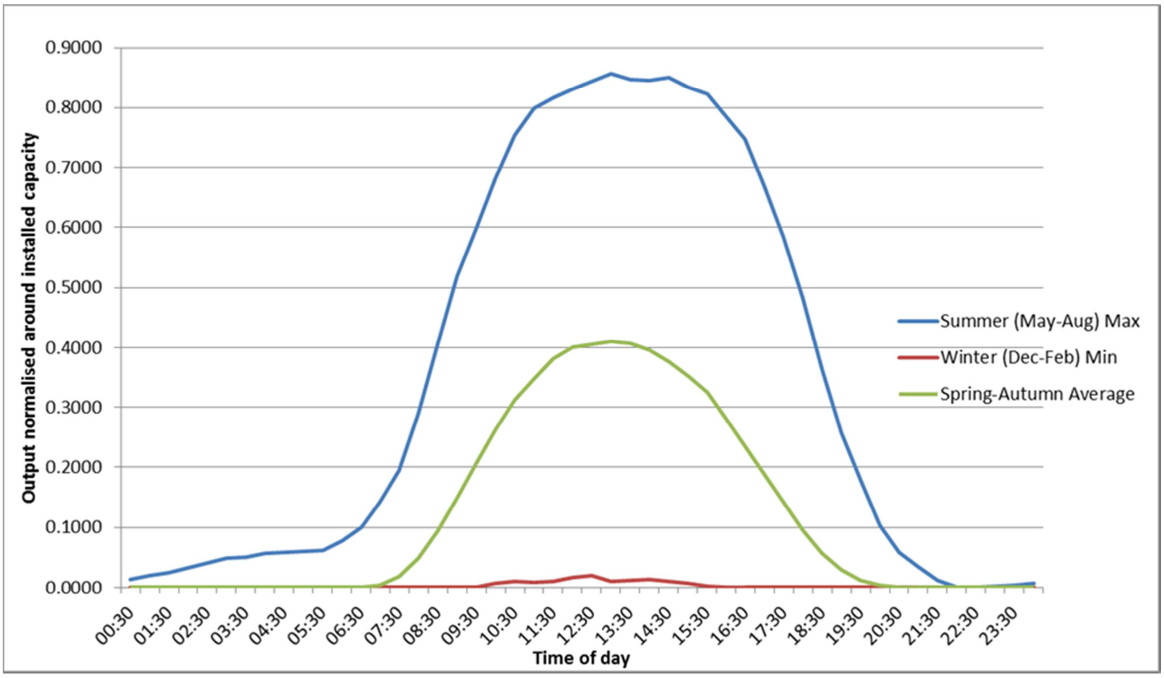

Figure 13: Normalised Solar PV Profiles (to be applied to installed capacity)

The installed capacities in the Regen SW study were multiplied by the profiles to obtain half hourly export from the solar PV plants.

Onshore Wind

The onshore wind plants used in the sample are shown geographically in Figure 14. They ranged in size from 4 MW to 66 MW with a sample size of nine sites.

The assumptions made for the wind profiles for each of the representative days were:

- Winter (December-February) - Minimum by half hour
- Spring-Autumn (March-April and September-November) - Average by half hour
- Summer (May-August) - Maximum by half hour

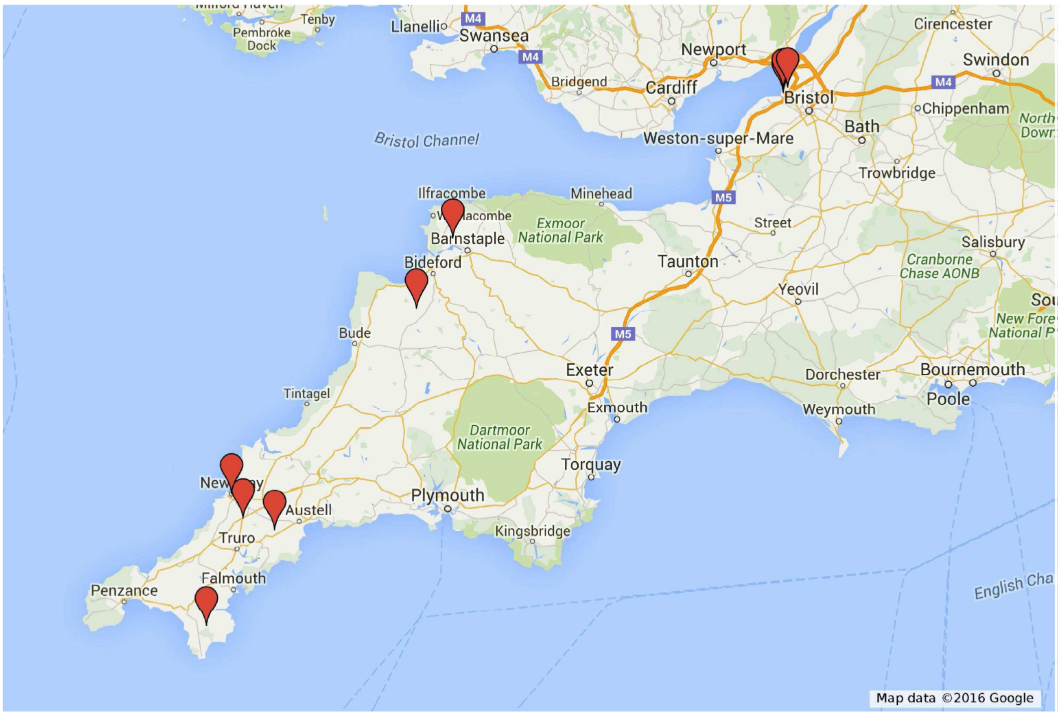

Figure 14: Geographic spread of onshore windfarms in sample

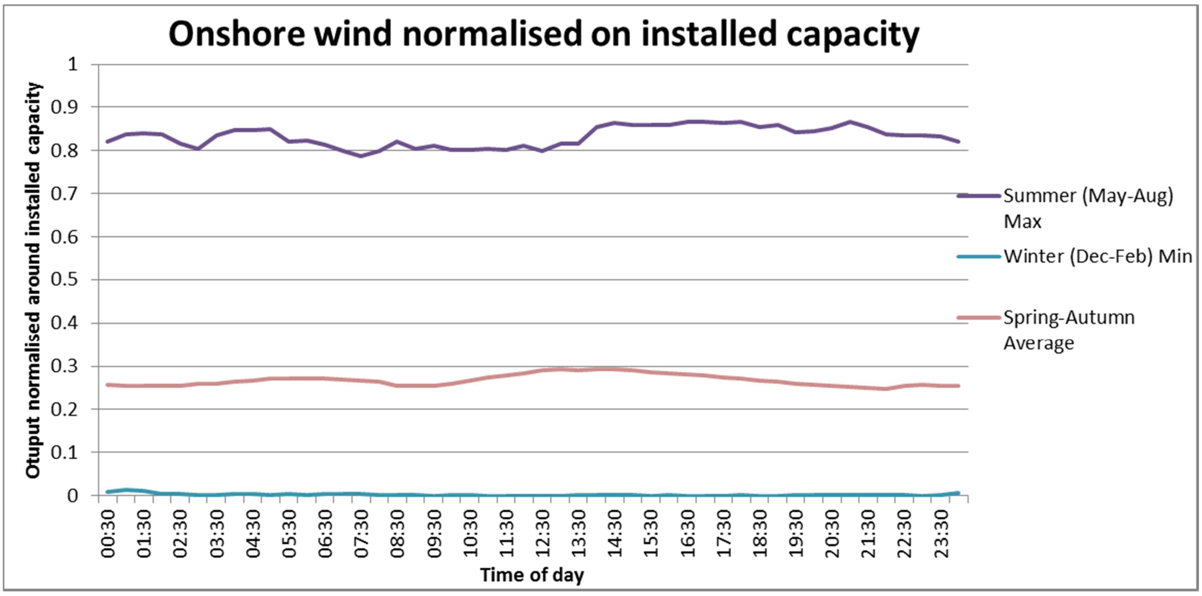

Figure 15: Normalised Wind Profiles (to be applied to installed capacity)

Other Generation

The remaining DG types modelled were:

- Anaerobic digestion
- Deep geothermal
- Energy from waste
- Hydropower
- Offshore and marine (split into floating, tidal and wave)

- Other generation (non-renewable distributed generation)
- Short-term Operating Reserve (STOR)

Insufficient data was available to derive profiles from measured flows for these technologies. In the case of infrequently-dispatched non-intermittent generation such as STOR, measured flows may not reflect the potential network impact. Instead, a flat (continuous output) profile was assumed for each representative day, representing the realistic behaviour that would have the worst impact upon the network. These were calculated as follows.

STOR

- Summer – Continuous output at installed capacity
- Winter – Zero output
- Spring/autumn – Continuous output at 0.2 times installed capacity

All other types

- Summer – Continuous output at installed capacity
- Winter – Zero output
- Spring/autumn – Continuous output at 0.8 times installed capacity

6 – Results

2015 – Validation of base case

The 2015 studies validated the modelling technique and our existing understanding of the performance of the network. They showed a network approaching its limits in some areas (particularly the F-route and Alverdiscott-Indian Queens group), but not yet overstressed.

While the raw results of the studies did show some overloading and unacceptable voltages, this was all in situations well beyond the requirements of P2/6. The studies highlighted the need to ensure that for credible contingencies beyond the scope of P2/6 we minimise the risk of equipment damage or danger and contain the potential loss of supply to demand customers. These contingencies could include busbar faults or the loss of two GTs feeding into a BSP group with three or more GTs.

2020 – Preparing for pipeline

The results with the forecast generation and demand for 2020 against the 2015 network confirmed the justification of the 132kV reinforcement schemes which are currently planned to be completed before 2020:

1. Splitting the F-route and reconfiguring the Bridgwater/Seabank/Taunton 132kV group;
2. Establishing GT3 and GT4 at Fraddon BSP; and
3. Recrimping the J-route circuit from East Yelland disconnector 303 to Barnstaple GT2 to remove a ratings restriction.

The forecast growth of generation to 2020 is dominated by currently Accepted-not-yet-Connected schemes under all scenarios, while the forecast growth of heat pump and electric vehicles to 2020 is limited. All four scenarios therefore have very similar results, dominated by generation rather than demand increases. Potential reinforcement schemes have been suggested for each reinforcement requirement.

Localised 132kV and BSP reinforcement

Various localised 132kV reinforcement requirements have been identified, each required under every scenario:

Table 3: 2020 localised reinforcement requirements and potential reinforcement schemes

Affected network	Potential reinforcement scheme required by 2020
132kV circuit from Marsh Barton power station to Sowton tee-off	Reconductor affected circuit (~7.2km) replacing 175mm² ACSR (Lynx) @ 50°C with 300mm² AAAC (Upas) @ 50°C
Landulph/St Germans BSP group and associated 132kV circuits	Install second GT at Landulph BSP and split 33kV network between Landulph and St Germans BSPs

Affected network	Potential reinforcement scheme required by 2020
132kV circuit from Indian Queens to St Germans/St Austell tee	Recrimp and reprofile 175mm² ACSR (Lynx) @ 50°C on affected circuit (~2.2km) for unrestricted 65°C operation
Pyworthy/North Tawton BSP group	Replace existing 22.5/45MVA Pyworthy GT1 with 60/90MVA unit

Alverdiscott/Indian Queens GSP group

Reinforcement requirement

A much wider reinforcement requirement has been identified in the Alverdiscott/Indian Queens GSP group, particularly the K-route (the 132kV circuits which interconnect Alverdiscott and Indian Queens GSPs) and Alverdiscott GSP itself. The network is required to withstand the combined impact of:

1. Through flows from generation elsewhere in the GSP group and outside the GSP group (similar to F-route; heavily dependent upon 400kV running arrangements);
2. Substantial growth in 33kV, 11kV and LV connected generation downstream of the BSPs connected to the K-route and beyond Alverdiscott GSP; and
3. Six large 132kV generators connected to the K-route and beyond Alverdiscott GSP.

The network is most constrained by the ratings of the circuits forming the K-route, particularly the 132kV cables crossing the river Torridge at the northern end of the K-route. It is also constrained by the ratings of the SGTs at Alverdiscott GSP and the ability to control voltage in the Alverdiscott area during SGT outages.

Reinforcement options

A potential reinforcement scheme required by 2020 would comprise:

1. Reprofiling existing 300mm² AAAC (Upas) on both sides of the K-route from Indian Queens to St Tudy (~30km) from 50°C to 75°C;
2. Reconductoring from 175mm² ACSR (Lynx) @ 50°C to 300mm² AAAC (Upas) @ 75°C on both sides of the K-route from St Tudy to Alverdiscott (~70km);
3. Overlaying both 132kV cables crossing the river Torridge with cables that match the rating of 300mm² AAAC (Upas) @ 75°C (likely to be 1600mm² Cu XLPE);
4. Replacing the fixed 60MVAr 132kV Capacitor at Alverdiscott GSP with a variable reactive source such as a Statcom or SVC capable of controlling voltage with a range of ±60MVAr; and
5. Installing intertripping or another suitable mechanism to reliably and promptly enforce all contractual constraints against the 132kV generators connected to the K-route and beyond Alverdiscott GSP.

It should be noted that even following this reinforcement some network components are very close to their capacity, particularly the SGTs at Alverdiscott GSP. The 2025 studies assume that this reinforcement has taken place, but their results show that the reinforcement will not be sufficient by 2025 under most scenarios without the use of ANM to manage future generators.

Given the limitations associated with operating 132kV networks normally interconnected between GSPs, increasing the capacity of the interconnectors without any means to control through-flow may not be the most appropriate long-term reinforcement solution. An alternative reinforcement scheme with better long-term benefits would be to establish a two SGT GSP in the vicinity of Pyworthy BSP to allow Alverdiscott and Indian Queens GSPs to be deloaded and split apart.

Interim reinforcement

An interim reinforcement scheme may be necessary to mitigate immediate issues due to the long lead time for major 132kV reinforcement. This would include reprofiling the existing 175mm² ACSR (Lynx) from 50°C to 75°C on both sides of the K-route from St Tudy to Alverdiscott (~70km) rather than immediately reconductoring. This would have very limited benefits unless the rating of the Torridge cables can be increased. Initial assessment of the existing Torridge cables suggests that no significant uprating of the existing cable is achievable. Overlaying the cables to match the rating of 175mm² ACSR (Lynx) @ 75°C would remove this pinch point but requires substantial work. If the cables were overlaid it is recommended they are rated at a minimum to match 300mm² AAAC (Upas) @ 75°C due to the continued generation growth in the Alverdiscott/ Indian Queens group. While an interim reinforcement scheme would increase the capacity of some network components, detailed analysis would be required to assess the benefits and limitations of the interim scheme compared to the more extensive schemes proposed above. Interim works may be required to provide network capacity on a timely basis where the lead-times for the optimal scheme are unacceptable.

Abham/Exeter/Landulph GSP group reinforcement requirements

The studies showed marginal overloading in both 132kV cables from Abham GSP to the tee-off point for Totnes BSP. These cables are a key limiting link in the 132kV circuits interconnecting Abham, Exeter and Landulph BSPs. It is suspected that this overloading is at least in part due to through flows from generation west of the cables (including generation in the Alverdiscott/Indian Queens GSP group), and that it will be heavily exacerbated by 400kV outages. These 400kV outages have not yet been studied, awaiting detailed information on the running arrangements of 400kV switchgear in the area.

2025 – Divergent scenarios

In 2025 the four scenarios diverge in their forecasts of new demand and DG. At one extreme the No Progression scenario contains only gentle growth from 2020 to 2025, and triggers only limited reinforcement. At the other extreme the Gone Green scenario is dominated by the expansion in Solar PV from under 2GW to more than 3GW, and triggers several major reinforcement projects across the South West.

Hinkley Point C power station is expected to be completed in the mid-2020s, so the state of the network in 2025 will be considered for both 'Pre-Hinkley Point C' and 'Post-Hinkley Point C' branches. Hinkley Point C is planned to be a 3.2GW nuclear power station at the existing Hinkley Point nuclear site. Since Hinkley Point C will have approximately double the combined capacity of Hinkley Point A (decommissioning) and Hinkley Point B (in service) power stations, major works will be required on both National Grid and WPD's networks. They include:

- Building a 400kV dual circuit route from Hinkley Point power station to Seabank power station near Bristol;
- Dismantling the 132kV F-route and parts of the G, N and AT 132kV routes, and so breaking 132kV interconnection between Bridgwater and Seabank GSPs;
- Undergrounding parts of the G, N, W, AT and BW 132kV routes;
- Establishing a two SGT GSP at Sandford in Somerset on the new Hinkley Point to Seabank 400kV route;
- Converting Bridgwater GSP from 275kV operation to 400kV operation; and
- Installing a second SGT at Taunton GSP.

2025 – Pre-Hinkley Point C

No Progression scenario

Under No Progression there is only gentle growth in demand and DG from 2020 to 2025. Keeping the SGTs at Alverdiscott GSP and part of the K-route within their ratings becomes heavily dependent upon the intertripping of 132kV generators for unplanned outages. If this intertripping cannot be relied upon, extensive reinforcement similar to the other scenarios (detailed below) would be required.

The only other reinforcement requirement identified is:

1. Landulph GT2 (22.5/45MVA) overloads (107%) for the loss of GT1 (40/60MVA) despite the 2020 reinforcement. Replacement of GT2 with a 40/60MVA unit is sufficient to support the group under the highest reverse flows seen during FCOs.

Slow Progression

In addition to the requirements of No Progression, the following reinforcement requirements were identified under Slow Progression:

1. The SGTs at Alverdiscott are overloaded for certain SCO conditions even after the intertripping of 132kV generators. Since the overload is only to 107% of rating, it may be possible to manage this through the use of ANM.
2. The 132kV circuit on the J-route from East Yelland disconnector 303 to Barnstaple GT2 overloads for the loss of the other 132kV circuit into Barnstaple, since this

outage transfers all of Barnstaple BSP onto the circuit which is already supplying a large 132kV generator.

3. The following GTs are overloaded under FCO conditions:
    a. St Germans GT1 and GT2, and
    b. Tiverton GT1 and GT2.

Consumer Power

In addition to the requirements of Slow Progression, the following reinforcement requirements were identified under Consumer Power:

1. Many sections of the K-route are overloaded, and the worst post-intertripping overload of an Alverdiscott SGT increases to 136% of rating.
2. The 132kV circuits suppling Exeter City BSP, Sowton BSP and a large 132kV generator overload for the outage of the circuit from Exeter Main circuit breaker 205 to Exeter City GT2 and Exeter Main GT2.
3. The following GTs are overloaded under FCO conditions:
    a. Landulph GT1 (installed as reinforcement in 2020),
    b. Exeter City GT2 and GT3,
    c. Barnstaple GT1 and GT2,
    d. St Tudy GT1 and GT2, and
    e. Pyworthy GT2.

Gone Green

The Gone Green scenario has a much greater impact on the network than any other scenario. In addition to the requirements of Consumer Power, the following reinforcement requirements were identified under Gone Green:

1. The SGTs at Indian Queens GSP are overloaded to 135% of rating under certain SCO conditions.
2. The majority of K-route is significantly overloaded under FCO conditions. Under certain SCO conditions it is overloaded beyond 150% of rating, despite the extensive reinforcement proposed for 2020.
3. Circuits in the West Cornwall 132kV network are overloaded:
    a. The 132kV circuit on the A-route from Indian Queens circuit breaker 305 to tower A148 at Fraddon (Fraddon/Camborne tee) for both FCO and SCO conditions, highest overload 120%, and
    b. The 132kV circuit on the CC-route from Rame mesh corner 1 to tower BM119 (Fraddon/Hayle tee) for SCO conditions, highest overload 115%.
4. Circuits in the East Cornwall 132kV network supplying St Austell and St Germans BSPs from Indian Queens and Landulph GSPs are overloaded for a variety of FCO and SCO conditions.
5. The following GTs are overloaded under FCO conditions:
    a. Truro GT1 and GT2,
    b. Taunton GT3,

c. Totnes GT1 and GT2,
d. Fraddon GT1 and GT2,
e. Hayle GT1 and GT2,
f. Street GT1, and
g. Bridgwater GT1, GT2 and GT3.

Potential reinforcement schemes

Since the appropriate reinforcement for any particular network component is heavily scenario-dependent, general descriptions of the reinforcement options in each network area are given.

The reinforcements proposed assume limited scope for ANM and similar measures to alleviate reinforcement requirements. The results from a detailed study may highlight a number of the proposed reinforcements would not be necessary as they could be managed by ANM. Generators connecting between now and 2025 in areas with known network constraints are likely to accept an alternative offer (with ANM) rather than a conventional connection offer.

The primary aim of this strategic report is to ensure major reinforcement requirements are identified with sufficient notice to ensure that they do not delay the quick and efficient connection of demand and DG. It is expected that smaller 132kV and BSP reinforcement schemes with short lead-times will be developed in detail as they are required.

WPD's preferred standard ratings for 132/33kV GTs are 40/60MVA and 60/90MVA. In general it has been assumed that where appropriate, overloaded GTs will be reinforced by direct replacement with a larger standard-rating unit.

Alverdiscott GSP and K-route

Where ANM and intertripping cannot manage overloads on the K-route and the SGTs at Alverdiscott GSP, a potential reinforcement option is to establish a GSP with two SGTs in the vicinity of Pyworthy BSP. The 132kV network in the area would be arranged so that:

1. Alverdiscott GSP supplies Barnstaple BSP, East Yelland BSP, North Tawton BSP and some 132kV generators;
2. Pyworthy GSP supplies Pyworthy BSP and several 132kV generators; and
3. Indian Queens GSP supplies St Tudy BSP, the West Cornwall and East Cornwall 132kV networks, and some 132kV generators.

Circuits between the three GSPs would be retained but operated normally-open, so preventing through-flow overloads.

If this new arrangement results in insufficient SGT capacity at Indian Queens GSP, additional SGTs at Indian Queens or the transfer of St Germans BSP on to Landulph GSP could be considered.

Barnstaple and East Yelland BSPs and associated 132kV circuits

Under Slow Progression, reprofiling or reconductoring the affected circuits is expected to be sufficient. Under Consumer Power, the GTs at Barnstaple BSP would also need to be replaced with 60/90MVA units.

Under Gone Green, the limits of reinforcing the existing circuits and GTs are exceeded. A potential scheme would be to establish a BSP with two GTs in the vicinity of Alverdiscott GSP and transfer part of the 33kV network in the area onto the new BSP. This would allow East Yelland and Barnstaple BSPs and the 132kV circuits to be deloaded, reducing or eliminating the need to reinforce them.

Exeter City and Sowton BSPs and associated 132kV circuits

A potential reinforcement scheme would be to re-establish a third 132kV circuit into Exeter City supplying a third GT. It is expected that this could use existing tower lines for at least part of the route from Exeter Main GSP to Exeter City BSP, but would require a new 132kV cable for the final kilometre into Exeter City. Additional 132kV switchgear would be required at Exeter Main GSP. This scheme would allow the remaining GTs at Exeter City and the 132kV circuits to be partially deloaded, reducing or eliminating the need to directly reinforce them.

West Cornwall 132kV circuits

The overloads may be eliminated by reconductoring the affected sections. If this is insufficient, there are two reinforcement schemes that may be beneficial:

1. Separating the Rame/Hayle/Fraddon circuit into a Rame/Hayle circuit and a Rame/Fraddon circuit. This would require around 500m of 132kV cable or overhead line from Rame BSP to tower BM119, and additional 132kV switchgear at Rame BSP.
2. Establishing a fifth 132kV circuit into the West Cornwall network, from Indian Queens GSP to Camborne BSP. This would require a cable or overhead line from Indian Queens to Fraddon, and rebuilding the A-route from single-circuit to double-circuit construction from Fraddon to Camborne. Additional 132kV switchgear would be required at Camborne BSP and Indian Queens GSP.

East Cornwall 132kV circuits

There is scope for reconductoring the 132kV circuits from Indian Queens GSP to St Austell BSP to increase their rating.

Given the length of the 132kV circuit from the St Germans/St Austell tee to St Germans BSP, reconductoring may not be the most appropriate option. Instead a second circuit from Landulph GSP to St Germans BSP could be established by rebuilding the B-route from single-circuit to double-circuit construction. The 132kV circuit from the St Germans/St Austell tee to St Germans BSP would then be held normally open at St Germans. This would improve load-share between the GTs at St Germans BSP, break the loose-couple between Indian Queens and Landulph GSPs, and deload Indian Queens GSP.

Bridgwater/Street BSP group

At present three GTs at Bridgwater BSP and one GT at Street BSP run in parallel to feed the 33kV network in the area. A second GT could be established at Street BSP, fed from the second circuit of the AP-route from Bridgwater GSP. This circuit is currently operated at 33kV as an interconnector between the two BSPs. Additional 132kV switchgear would be required at Bridgwater GSP, as would a 132kV cable from the GSP to the start of the AP-route 800m away. This would allow the interconnection between the two BSPs to be held normally open, alleviating fault level constraints and improving network operability.

2025 – Post-Hinkley Point C

Although the works to enable the connection of Hinkley Point C will have a major impact on the 132kV network in the area, it is not an area which is forecast to require significant reinforcement under any scenario by 2025. The works have been designed to provide comparable network capacity and security to the existing network. Since much of the impact is heavily dependent on the design and behaviour of National Grid's network and Hinkley Point C itself, it was decided to postpone the 2025 post-Hinkley Point C studies until National Grid begin their studies in cooperation with WPD. Instead the studies up to 2025 pre-Hinkley Point C were prioritised.

The following areas of interest have been identified, and should be assessed in the studies:

1. The fault level in the South West will increase with the connection of Hinkley Point C, so a detailed assessment is required to determine if this will cause any fault levels issues such as switchgear overstressing.
2. The National Grid boundaries that constrain transmission capacity in the South West will move and be redefined.
3. The planned network arrangement will create a new 132kV parallel running arrangement between Sandford and Seabank GSPs. There is a risk that this will result in overloads due to through-flow similar to those being dealt with on the F-route.
4. The installation of a second SGT at Taunton GSP may change the behaviour of the 132kV parallel running arrangement between Bridgwater and Taunton GSPs. There is a risk that this will result in overloads due to through-flow similar to those being dealt with on the F-route.

2030 – Further divergent scenarios

The 2030 studies were expected to build upon the results of the 2025 post-Hinkley Point C studies, have not yet been carried out.

The level of generation in the 2030 No Progression scenario shows very small growth over the levels seen in 2025 No Progression, so the levels of reinforcement required under this scenario in 2030 is likely to be limited.

Slow Progression and Consumer Power experience a growth of generation from 2025 to 2030, reaching similar levels seen in Gone Green 2025. A number of the network issues identified in Gone Green 2025 are expected be to seen in the other scenarios at some point between 2025 and 2030. The severity of these overloads and the period when they occur will depend on the generation mix and levels of demand at times of peak generation.

Gone Green 2030 shows a continued rapid growth of generation to an installed capacity in excess of 5.3 GW in the South West, dominated by Solar PV. While it may be possible to reinforce the network to allow all of this generation to operate unconstrained, the benefits of doing so must be considered. It is likely that Solar PV output would need to be constrained due to a lack of coincident demand in the wider network, rather than the constraints of the network itself.

7 – The balance between reinforcement and network management

Our demand security standard (P2/6) is a licence condition and whilst it defines the contribution that DG makes to demand security of supply, there is no standard for the security of connection of DG to the network or its ability to export to the network. P2 is currently under review, but to date there is limited support from stakeholders to define minimum standards for DG connections. The only standard that sets security of supply standards for generation is the National Electricity Transmission System Security and Quality of Supply Standard (SQSS). The core requirement of SQSS is that a credible event should not lead to the loss of more than 1320MW of generation. This is unlikely to affect the connection of DG on the WPD network in most cases.

Underlying assumptions

Our networks shall, as a minimum:

1. Comply with ER P2/6 (Demand Security of Supply); and
2. Minimise the risk of equipment damage or danger and contain the potential loss of supply to demand customers for any credible FCO or SCO condition beyond the requirements of P2/6. Credible outages include busbar faults, faults during planned outages and, by operational rearrangement of the network or other control action a further fault following a fault.

The balance

There is a balance between the cost of conventional reinforcement and the impact of DG output curtailment ANM or other automated responses. This is driven by two factors:

1. The cost of curtailment of the generator output, which is outside the scope of this document (at present this risk is carried by the generator as a trade-off for the lower cost of initial connection or faster connection time) ; and
2. The technical capabilities of the ANM scheme and the network it is managing.

Technical capabilities

Network complexity

Not all distribution networks are necessarily suitable for ANM. For instance, managing the flows on a radial network affected by a small number of generators is more straightforward than managing the flows on an interconnected network affected by a large number of geographically diverse generators which may even be connected to different Network Operators' networks.

Network monitoring and control

Distribution networks are traditionally operated passively, and have limited facilities for remote monitoring and control. In particular, very few circuits are fitted with directional power flow monitoring. In addition to the installation of monitoring and control equipment at generator sites, monitoring equipment will need to be installed across the network to allow the ANM system to appropriately manage network behaviour.

Operating timeframe and network transient ratings

For this study, it is assumed that an ANM scheme can operate in 3 minutes, from stimulus to resolution, taking into account:

1. Measurement
2. Communication of measurement
3. Calculation and determination of instructions
4. Communication of instructions
5. Generator ramp-down (and last-ditch trip)

3 minute transient ratings for both current and voltage can be determined for network components including:

1. Switchgear
2. Transformers
3. Overhead lines
4. Cables
5. Protection equipment

These ratings should take into account the current/voltage applied before and after the transient period, and the frequency of events that utilise the transient ratings. It is likely that in order to provide thermal headroom for transient ratings, the normal ratings of some network components will have to be reduced.

Where network behaviour would result in voltages or flows that exceed the 3 minute ratings of equipment, ANM will not be capable of managing the constraint by post-event curtailment. Instead pre-event curtailment or conventional reinforcement will be required. Pre-event curtailment of generator output is likely to reduce the energy output of generators much more than post-event curtailment.

8 – Recommendations

Low regret reinforcement schemes

It is recommended that all reinforcement requirements identified in the 2020 studies are assessed in further detail, and appropriate reinforcement schemes developed as required. The affected network areas are:

1. 132kV circuit from Marsh Barton power station to Sowton tee-off;
2. Landulph/St Germans BSP group and associated 132kV circuits;
3. 132kV circuit from Indian Queens to St Germans/St Austell tee;
4. Pyworthy/North Tawton BSP group;
5. Alverdiscott/Indian Queens GSP group; and
6. Abham/Exeter/Landulph GSP group.

Given the further requirements identified in the 2025 studies, it is recommended that serious consideration is given to a GSP in the vicinity of Pyworthy BSP to alleviate issues in the Alverdiscott/Indian Queens GSP group. This is likely to be a better long-term solution than reinforcing the interconnecting circuits between Alverdiscott and Indian Queens. It is recommended that a Modification Application is made to National Grid to fully understand the costs, timescales and wider implications of this project.

The studies have highlighted the extent to which the network is reliant upon the curtailment of generator output by means such as intertripping or ANM to provide cost-effective generator connections. It is recommended that:

1. The technical capabilities of these schemes and the networks they manage are investigated further so that their limitations can be better understood; and
2. Serious consideration is given to installing such schemes to enforce existing contractual constraints. This would help to minimise the risk of equipment damage or danger and contain the potential loss of supply to demand customers.

Assessing the future of interconnected networks

132kV networks running in parallel between multiple GSPs are a frequent limiting factor in these and other studies. The difficulty is that flows in these networks are influenced by a wide range of factors, often outside of WPD’s control. There are three broad categories of reinforcement option:

1. Continue to allow uncontrolled through-flow, increasing the capacity of affected circuits and transformers. Increasing the capacity of a component often decreases its impedance, and so exacerbates rather than solving the issue.
2. Break the interconnection under normal running. This solves the issue of through-flow, but often triggers further reinforcement to bolster the infeed to the newly separated networks.

3. Install equipment to control the power flow on circuits subject to through-flow. At subtransmission in Great Britain this equipment is usually a series reactor, which offers only limited control over power flow. Quadrature boosters – which allow the real power flow in a circuit to be increased or decreased – have seen some use at transmission in Great Britain, but are large and expensive devices. A newer option is power electronic devices. As part of the 'Network Equilibrium' Tier 2 Low Carbon Networks Fund project, WPD is installing a Flexible Power Link. This device allows the controlled transfer of real power between two separate 33kV networks, and provides independent controllable reactive compensation to each network. Such devices are in an early stage of development and several challenges remain, not least their limited ability to provide fault infeed.

It is recommended that option 2 should be preferred over option 1 to avoid expensive reinforcement with limited benefits. As option 3 develops, it should be given consideration as it offers some benefits of both interconnected and non-interconnected networks.

Further modelling

It is recommended that these studies are repeated in cooperation with National Grid, taking into account:

1. More appropriate models of the transmission network, taking into account the conditions being modelled;
2. Transmission network contingencies to assess their impact on WPD's interconnected networks; and
3. The impact of these scenarios on National Grid's own network. Where it is decided that it is more appropriate to curtail generator output than to reinforce National Grid's network, the level and impact of this curtailment should be assessed.

National Grid has committed to start these studies in September 2016.

As our understanding of the behaviour of battery storage develops, it should be incorporated into future studies. Similarly, any data on the charging behaviour of large populations of fast-charging, high-capacity EVs with a broad range of users should be used to refine the EV charging profiles used in these studies.

It is intended that these studies and the underlying scenarios will be revisited on a two-yearly basis. The scope of future studies could be broadened to include:

1. Fault level;
2. Protection;
3. Dynamics; and
4. Power quality.

9 – Definitions and references

References

External documents

P2

Engineering Recommendation P2 (*Security of Supply*), currently in its sixth revision (P2/6). P2/6 gives requirements for security of supply towards demand customers which form a condition of WPD's licence. P2 is currently under review by a working group of the ENA.

P27

Engineering Recommendation P27 (*Current Rating Guide for High Voltage Overhead Lines Operating in the UK Distribution System*). Used in conjunction with ST:SD8A/2 to determine the ratings applicable to overhead lines.

Electricity Act 1989 as amended

Section 9 of the Electricity Act (*General duties of licence holders*) states that:

1. *It shall be the duty of an electricity distributor—*
   a. *to develop and maintain an efficient, co-ordinated and economical system of electricity distribution;*
   b. *to facilitate competition in the supply and generation of electricity.*
2. *It shall be the duty of the holder of a licence authorising him to transmit electricity—*
   a. *to develop and maintain an efficient, co-ordinated and economical system of electricity transmission; and*
   b. *to facilitate competition in the supply and generation of electricity.*

Future Energy Scenarios (FES) 2015, 2016

Annual report published by National Grid which sets out possible scenarios for the future development of energy generation and consumption in Great Britain.

System Operability Framework (SOF) 2015

Annual report published by National Grid which describes challenges to the operability of Great Britain's electricity transmission system, and how these would develop over time under the scenarios set out in the FES report.

Network Options Assessment (NOA) 2016

New report published by National Grid giving recommendations on whether to proceed with key projects to develop Great Britain's electricity transmission system.

ENA Active Network Management Good Practice Guide

Report published by the ENA to give consistent guidance on the application of ANM schemes.

Insight Report Electric Vehicles

Report published by the Customer-Led Network Revolution project (reference CLNR-L092) in December 2014, describing research into the charging behaviour of electric vehicle users.

Western Power Distribution documents

1. ST:SD8A/2 (*Relating to Revision of Overhead Line Ratings*), used in conjunction with ER P27 to determine the ratings applicable to overhead lines;
2. ST:SD8C/1 (*Relating to 132kV, 66kV and 33kV Medium Power Transformer Ratings*).

General definitions, initialisms and acronyms

Term	Acronym / initialism	Definition
Super Grid Transformer	SGT	A transformer that steps voltage down from 400kV or 275kV to 132kV, 66kV or 33kV
Grid Transformer	GT	A transformer that steps voltage down from 132kV to 66kV, 33kV or 11kV.
Primary Transformer	–	A transformer that steps voltage down from 66 or 33kV to 11kV or 6.6kV
Distribution Transformer	–	A transformer that steps voltage down from 11kV or 6.6kV to LV
Bulk Supply Point	BSP	A substation comprising one or more grid transformers and associated switchgear
Grid Supply Point	GSP	A substation comprising one or more super grid transformers and associated switchgear
Primary Substation	–	A substation comprising one or more primary transformers and associated switchgear
Distribution Substation	–	A substation comprising one or more distribution transformers and associated switchgear
Subtransmission	–	The sections of an electrical distribution network which provide the interface between transmission and primary or secondary distribution. In WPD's South West network the GSPs, 132kV circuits and BSPs are considered to be subtransmission.
Primary Distribution	–	The sections of an electrical distribution network which provide the interface between transmission and primary or secondary distribution. In WPD's South West network the 33kV circuits and primary substations are considered to be primary distribution.

Secondary Distribution	–	The final section of an electrical distribution network which provides the interface between subtransmission or primary distribution and most final customers. In WPD's South West network the 11kV, 6.6kV and LV circuits and the distribution substations are considered to be secondary distribution.
First Circuit Outage	FCO	P2/6 defines a First Circuit Outage as: *…a fault or an arranged Circuit outage…* Also referred to as N-1 in some contexts.
Second Circuit Outage	SCO	P2/6 defines a Second Circuit Outage as: *…a fault following an arranged Circuit outage.* Also referred to as N-1-1 or N-2 in some contexts.
Static VAr Compensator	SVC	A device capable of providing fast-acting reactive power to the network
Demand Side Management	DSM	
Active Network Management	ANM	The ENA Active Network Management Good Practice Guide summarises ANM as: *Using flexible network customers autonomously and in real-time to increase the utilisation of network assets without breaching operational limits, thereby reducing the need for reinforcement, speeding up connections and reducing costs.*
Energy Networks Association	ENA	Taken from the ENA website: *…Represent the 'wire and pipes' transmission and distribution DNOs for gas and electricity…Influence regulation and the wider representation in UK, Ireland and the rest of Europe…*
Engineering Recommendation	ER	National standard engineering document published by the ENA
Distributed Generation	DG	Generation connected to a distribution network. Sometimes known as Embedded Generation.
Statement of Works	SoW	The process under which DNOs request that National Grid assesses the potential impact of the connection of DG upon the National Electricity Transmission System.
Aluminium Conductor, Steel Reinforced	ACSR	Family of overhead line conductors, each of which combines steel strands for mechanical strength with aluminium strands for electrical conductivity. ACSR is the conductor traditionally used for transmission and subtransmission lines in Great Britain. Each ACSR conductor is named after a species of mammal.
All Aluminium Alloy Conductor	AAAC	Family of overhead line conductors, each of which is composed of strands of an aluminium alloy which combines mechanical strength with electrical conductivity.

		Reconductoring from ACSR to a slightly larger AAAC often allows a significant improvement in circuit capacity without requiring major modifications to towers. AAAC is now commonly used for new build and refurbishment of transmission and subtransmission lines in Great Britain. Each AAAC conductor is named after a species of tree.
Time Of Use tariff	TOUT	National Grid's FES 2016 defines a Time Of Use Tarriff as: *A charging system that is established in order to incentivise residential consumers to alter their consumption behaviour, usually away from high power demand times.*
National Grid	NGET	–
Hotwiring	–	Hotwiring is a technique used by National Grid to increase the rating of a circuit. National Grid define hotwiring as: *…the ability to operate a circuit at a higher temperature than its original design by using Aerial Laser Survey methods to assess circuits' limiting factors.*
Electric Vehicle	EV	A vehicle which uses electric motors as its method of propulsion
Air Source Heat Pump	ASHP	Air source heat pumps absorb heat from the outside air. This heat can then be used to produce hot water or space heating

Seasons

For the derivation of demand and generation profiles, application of equipment ratings and similar purposes, the seasons of the year were assumed to be as follows in accordance with ST:SD8A/2:

- Spring: March and April;
- Summer: May to August;
- Autumn: September to November; and
- Winter: December to February.

Grid Transformer ratings

The ratings applied to Grid Transformers were derived from ST:SD8C/1.

Cooling methods

Term	Acronym	Definition
Oil Forced, Air Forced	OFAF	Transformer cooled by thermosiphon flow of its insulating oil assisted by oil pumps and external air flow forced by fans.
Oil Forced, Air Natural	OFAN	Transformer cooled by thermosiphon flow of its insulating oil assisted by oil pumps and natural convection of external air.

Oil Natural, Air Forced	ONAF	Transformer cooled by the natural thermosiphon flow of its insulating oil and external air flow forced by fans.
Oil Natural, Air Natural	ONAN	Transformer cooled by the natural thermosiphon flow of its insulating oil and natural convection of external air.

Note: OFAF, OFAN and ONAF are collectively referred to as 'Forced' ratings.

Rating categories

Term	Acronym	Definition
Continuous Maximum Rating	CMR	The allowable sustained loading of a transformer for given cooling conditions that leads to a yearly average winding hot-spot temperature of 98°C (and so unity ageing) under the following ambient temperature conditions: • Maximum yearly average 20°C • Maximum monthly average 30°C • Absolute maximum 40°C Also known as the sustained rating.
Cyclic rating	–	The allowable peak loading of a transformer for given cooling conditions and season or ambient conditions that leads to a peak hot-spot temperature of 120°C for a typical daily load curve.

Applied ratings

Nameplate rating [MVA]	Final Forced cooling method	CMR_{ONAN}	CMR_{Forced}	$Cyclic_{Winter\ ONAN}$	$Cyclic_{Winter\ Forced}$
15/30	OFAF	15	30	39	42
22.5/45	OFAF	22.5	45	58	63
30/60	OFAF	30	60	78	84
37.5/75	OFAF	37.5	75	97	105
45/90	OFAF	45	90	117	126
40/60	ONAF	40	60	78	84
60/90	ONAF	60	90	117	126

Notes:

1. *No Spring or Autumn ratings are tabulated in ST:SD8C/1, so Summer ratings were applied to the Spring/Autumn studies.*
2. *No ONAN Cyclic ratings are tabulated for transformers fitted with forced cooling in ST:SD8C/1, so a notional ONAN Cyclic rating was approximated by:*

$$Cyclic_{ONAN} = Cyclic_{Forced} \frac{CMR_{ONAN}}{CMR_{Forced}}$$