Document 7
Asset Category – 11kV Switchgear
SPN

Asset Stewardship Report 2014

Brian Matthews

Approved by Richard Wakelen / Barry Hatton

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Document History

Version	Date	Details	Originator	Revision Class	Section Update
1.0	19/02/2014	Original document	Brian Matthews		
1.1	19/02/2014	Volumes and costs amended. RIGS rows updated. Appendices 8, 9 and 10 added	Brian Matthews	Major	1.1, 1.3, 2.1, 7.4, App 5
1.2	19/02/2014	Appendix 9 expanded	Brian Matthews	Major	App 9
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1.4	24/02/2014	HI and risk profiles updated	Brian Matthews	Major	7.2, 7.8, App 2
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1.9	05/03/2014	HIs aligned to final profile	Brian Matthews	Minor	7.8, App 2
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Preface

UK Power Networks uses Asset Stewardship Reports ('ASR') to describe the optimum asset management strategy and proposals for different groups of assets. This optimised asset management strategy and plan details the levels of investment required and the targeted interventions and outputs needed. Separate ASRs define the most efficient maintenance and inspection regimes needed and all documents detail the new forms of innovation which are required to maximise value, service and safety for all customers and staff throughout the ED1 regulatory period. Outline proposals for the ED2 period are also included.

Each DNO has a suite of approximately 20 ASR's. Although asset policy and strategy is similar for the same assets in each DNO the detailed plans and investment proposals are different for each DNO. There are also local issues which must be taken into account. Accordingly each DNO has its own complete set of ASR documents.

A complete list of titles of the ASR's, a summary of capex and opex investment is included in '**Document 20: Asset Stewardship Report: Capex/Opex Overview'**. This document also defines how costs and outputs in the various ASR's build up UK Power Networks 'NAMP' (Network Asset Management Plan) and how the NAMP aligns with Ofgem's ED1 RIGs tables and row numbers.

Where 'HI' or asset 'Health Index' information is included please note predicted ED1 profiles are before any benefits from 'Load driven investment.'

This ASR has also been updated to reflect the feedback from Ofgem on our July 2013 ED1 business plan submission. Accordingly to aid the reader three additional appendices have been added. They are;

1. **Appendix 8 - Output NAMP/ED1 RIGS reconciliation:** This section explains the 'line of sight' between the UKPN Network Asset Management Plan (NAMP) and the replacement volumes contained in the Ofgem RIGS tables. The NAMP is the UKPN ten year rolling asset management investment plan. It is used as the overarching plan to drive both direct and indirect Capex and Opex interventions volumes and costs. The volume and cost data used in this ASR to explain our investment plan is taken from the UK Power Networks NAMP. Appendix 8 explains how the NAMP outputs are translated into the Ofgem RIGS tables. The translation of costs from the NAMP to the ED1 RIGS tables is more complex and it is not possible to explain this in a simple table. This is because the costs of a project in the 'NAMP' are allocated to a wide variety of tables and rows in the RIGS. For example the costs of a typical switchgear replacement project will be allocated to a range of different Ofgem ED1 RIGs tables and rows such as CV3 (Replacement), CV5 (Refurbishment) CV6 (Civil works) and CV105 (Operational IT Technology and Telecoms). However guidance notes of the destination RIGs tables for NAMP expenditure are included in the table in the Section 1.1 of the Executive Summary of each ASR.

2. **Appendix 9 – Efficiency benchmarking with other DNO's:** This helps to inform readers how UK Power Networks is positioned from a benchmarking position with other DNO's. It aims to show why we believe our investment plans in terms of both

volume and money is the right answer when compared to the industry, and why we believe our asset replacement and refurbishment investment proposals are efficient and effective and in the best interest for our customers.

3. **Appendix 10 – Material changes since the July 2013 ED1 submission:** This section shows the differences between the ASR submitted in July 2013 and the ASR submitted for the re-submission in March 2014. It aims to inform the reader the changes made to volumes and costs as a result of reviewing the plans submitted in July 2013. Generally the number of changes made is very small, as we believe the original plan submitted in July 2013 meets the requirements of a well justified plan. However there are areas where we have identified further efficiencies and improvements or recent events have driven us to amend our plans to protect customer safety and service.

We have sought to avoid duplication in other ED1 documents, such as 'Scheme Justification Papers', by referring the reader to key issues of asset policy and asset engineering which are included in the appropriate ASR documents.

Contents

1.0 Executive Summary SPN 11kV Grid and Primary Switchgear

1.1 Scope

This document details UK Power Networks' non-load related expenditure (NLRE) replacement and refurbishment proposals for 11kV grid and primary switchgear for the RIIO-ED1 period. Indicative proposals for the ED2 period are also included.

There are 2,922 items of 11kV grid and primary switchgear in SPN, with an estimated MEAV of £299m. The proposed investment is including civils £3.9m per annum; this equates to an average annual 1.3% of the MEAV for this asset category.

Replacement costs for these assets are held in the Networks Asset Management Plan (NAMP) and in sections of the RIGs tables identified in Table 1. Note that the work associated with the replacement of 11kV Primary circuit breakers is mapped to several different RIGS tables and rows. Appendix 8 provides more information of the NAMP to RIGS mapping.

A full list of abbreviations is included in Section 6.0 of *Document 20: Capex Opex overview*.

INVESTMENT TYPE	ED1 COSTS	NAMP LINE	RIGS REFERENCE*
Asset Replacement	£8.0m	1.50.01	Additions CV3 Row 33 – 6.6/11kV CB (GM) Primary Removals CV3 Row 157 – 6.6/11kV UG Cable CV3 Row 161 – 6.6/11kV CB (GM) Primary
Asset Refurbishment	£4.9m	1.50.01	CV5 Row 19 – 6.6/11kV CB (GM) Primary
Operational FT	£1.0m	1.50.01	CV105 Row 6
Legal and Safety	£1.4m	1.50.01	CV8 multiple rows

Table 1 – Investment summary

Source: 19th February 2014 NAMP Table J Less Indirect

* Expenditure on this asset type is also included in CV6 civils and CV3 6.6/11kV UG cable

1.2 Investment Strategy

The investment strategy for RIIO-ED1 is detailed in *EDP 00-0012 Asset Lifecycle Strategy – Major Substations* and is based on achieving an optimal balance between maintenance, refurbishment and replacement by:

- Maintaining a constant risk level throughout the period by replacing or refurbishing assets when they reach HI4 or HI5
- Ensuring that the circuit breaker operating mechanism performance remains satisfactory by identifying deteriorating trends in circuit breaker trip times and refurbishing or replacing the assets as necessary
- Managing the deteriorating circuit breaker partial discharge performance of GEC type VMX by replacing assets as necessary.

1.3 Innovation

We have developed and deployed a new retrofit CB truck employing the minimum number of moving parts. During ED1, 90 switchpanels will be retrofitted with new trucks, which will save approximately £5.4m compared with traditional replacement strategies. In addition, the installation of online PD monitoring at 10 sites will enable the replacement of approximately 100 switchpanels to be deferred, saving around £10m.

1.4 Risks and Opportunities

	Description of similarly likely opportunities or risks arising in ED1 period	Uncertainties (£m)
Opportunity	Use refurbishment options 10% more often than planned	(2.6)
Risk	Cannot undertake refurbishment options for 10% of the time	2.6
Risk	Cost of refurbishment rises by 20% for 20% of planned refurbishment interventions in ED1 period	0.2

Table 2 – Risks and opportunities

2.0 Description of 11kV Grid and Primary Switchgear Population

2.1 11kV Grid and Primary Switchgear

There are 2,922 circuit breakers installed in 265 grid and primary substations operating at voltages from 6.6kV to 11kV. Switchboards in SPN range in size from rural three-panel boards to 33 panels in major cities. All are installed indoors. Table 3 shows the breakdown of types.

Arc interruption medium	Withdrawable	Fixed pattern
Oil	1,581	0
SF_6	50	2
Vacuum	832	457
Total	**2,463**	**459**

Table 32 – Breakdown of 11kV grid and primary switchgear by type

Source: ARP model Ph 1 11kV GP Sgr 25 July 2012

The age profile for the 11kV grid and primary switchgear is shown in Figure 1. The switchgear in SPN is the oldest in the UK Power Networks area, with an average age at the start of ED1 of 33 years, while the oldest 10% has an average age of 53 years at the start of ED1.

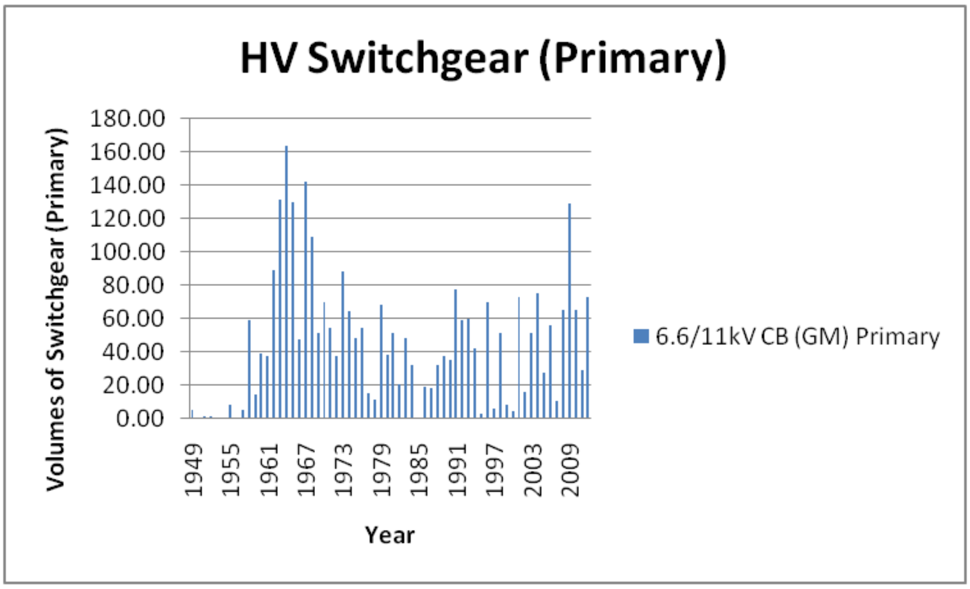


Figure 1 – 11kV grid and primary switchgear age profile at the start of ED1

Source: 2012 RIGs submission V5

Note: For withdrawable equipment, the profile is based on the age of the circuit breaker truck rather than the housing. There were 96 withdrawable vacuum circuit breakers manufactured between 1997 and 2010 and installed as retrofits into 1950s and 1960s oil CB housings.

With no interventions, the average age at the end of ED1 rises to 42 years and the oldest 10% rises to 67 years.

If the proposed retrofit and replacement interventions are carried out, at the end of ED1 the average age will remain at 33 years, with the oldest 10% rising slightly to 61 years.

Figure 2 – Reyrolle ‘C’ switchgear at Addington Local substation

Figure 2 shows part of a Reyrolle type ‘C’ switchboard at Addington Local substation. This was installed in 1952, with an extension in 1966, and is scheduled for replacement in 2018. The drivers for replacement are partial discharge and poor mechanism performance.

All 11kV grid and primary switchgear NLRE replacements and retrofit projects proposed for ED1 are listed under NAMP Line 1.50.01 and detailed in Appendix 7. The corresponding RIGs lines are shown in table 4.

RIGs Table	Row (additions)	Row (removals)	Description
CV3	29	157	6.6/11kV UG Cable
CV3	31		Building EHV
CV3	33	161	6.6/11kV CB (GM) Primary
CV5	19		6.6/11kV CB (GM) Primary

Table 4 – RIGs categories

3.0 Investment Drivers

The high-level investment drivers for 11kV grid and primary switchgear are detailed in EDP 00-0012, *Asset Lifecycle Strategy Major Switchgear*.

3.1 Defects

3.1.1 Defects used as replacement drivers

The switchgear defects used in the ARP model to help calculate the overall Health Index are shown in Table 5. As defects are found or cleared, they are recorded in the Ellipse asset register using the handheld device (HHD). Defects can be captured either on an ad hoc basis or at each inspection and maintenance.

Measure	Inspection	Maintenance
Compound leak	Yes	Yes
Control cubicle	If present	If present
External connections	If present	If present
Gasket	Yes	Yes
Oil level	Yes	Yes
Oil sight glass	Yes	Yes
Partial discharge	Yes	Yes
SF_6 gas pressure	Yes	Yes
Shutter mechanism	No	Yes

Table 5 – Defects used in the switchgear ARP models

In calculating the Health Index, the ARP model counts the total number recorded against individual items of plant, not just those currently outstanding. Each of these defects is described in more detail below.

- Compound leak – To provide an impulse voltage rating, bitumen compound was used as an insulation medium in busbars, CT chambers and cable termination boxes on most older metal-clad switchgear. If any compound leaks out, the impulse rating is reduced, with the risk of a disruptive failure if the equipment is subject to an overvoltage.
- Control cubicle – This records defects in the small wiring, auxiliary fuses and terminal blocks associated with the control of the circuit breaker. These defects can prevent the CB from operating correctly, with a resultant impact on Customer Interruptions (CIs) and Customer Minutes Lost (CMLs).
- External connection – For 11kV circuit breakers, this records defects with the primary isolating contacts. A problem here can result in overheating and eventual disruptive failure.
- Gasket – For oil-filled switchgear, this records a defective gasket, i.e. one that is allowing fluid to leak. No action is needed immediately, but, if left unchecked, this can result in a low oil level.

- Oil level – For oil-filled switchgear, this shows that the oil level is low and needs to be topped up. If left unchecked, this can result in a disruptive failure.
- Oil sight glass – For oil-filled switchgear, this shows that the oil sight glass is unreadable, broken or missing. If left unchecked, it can result in a disruptive failure.
- Partial discharge – This shows that partial discharge has been detected using the UltraTEV device, which, if left unchecked, could result in a disruptive failure. See Section 2.6 for more detail.
- SF_6 gas pressure – SF_6 gas is used as an insulating medium. If the pressure falls below the rated value, the equipment could fail disruptively if left in service.
- Shutter mechanism – For withdrawable switchgear only, this records defects with the mechanism used to cover the busbar and circuit spouts when the breaker is withdrawn from its housing. Broken mechanisms represent a serious risk to operator safety.

3.1.2 Analysis of defects

An analysis of all switchgear defects used in the ARP model is shown in Figures 3 and 4.

Figure 3 shows how old the asset was when the defect was recorded. It highlights two things: the number of defects increases as the plant ages; and defects generally occur between 30 and 55 years of age, which corresponds with the range of average asset life settings in the ARP model.

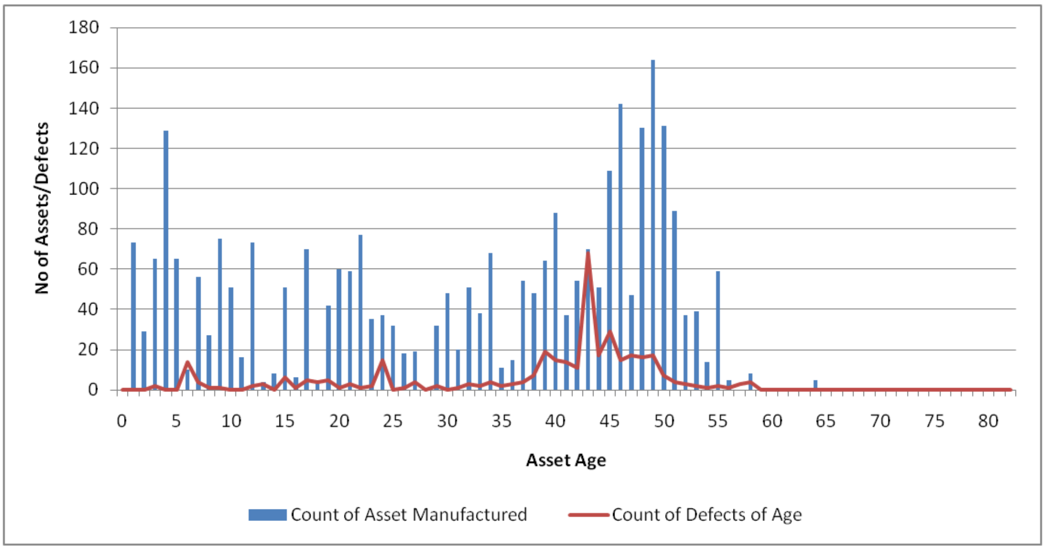


Figure 3 – Switchgear defects by age of asset

Source: Ellipse Defect extract 'SPN Defect Analysis v2' 19_02_2013

Figure 4 shows the number of 11kV switchgear defects reported since 2007, when the Ellipse asset register was introduced. The large number of defects recorded the first years is probably due to a backlog of defects being captured on the hand held devices for the first time, whilst the figures for 2009 onwards more accurately reflects the number of defects recorded for the first time. It shows a rising trend, excluding 2007 and 2008.

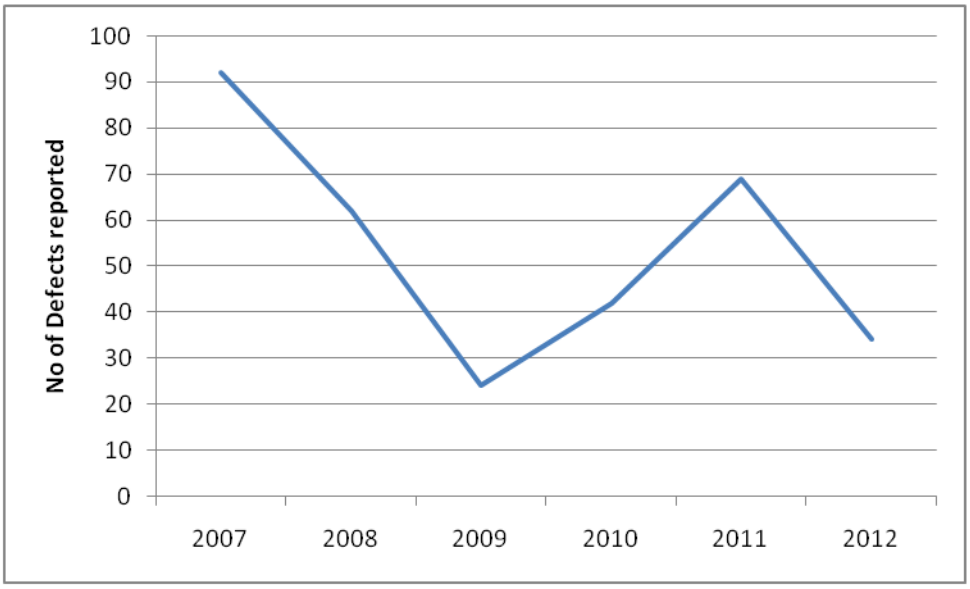


Figure 4 – Number of defects reported per year

Source: Ellipse Defect extract ‘SPN Defect Analysis v2’

3.1.3 Examples of defects

Figure 5 – Compound leak from C4X bushing at Moulescoombe substation

Figure 5 shows a compound leak from a South Wales type C4X bushing caused by an overheating connection. The CB has been repaired, but continuing mechanism problems at this site mean that the circuit breakers will be retrofitted with vacuum units in ED1.

Figure 6 – Compound leak from busbar at Hurstpierpoint substation

Figure 6 shows a compound leak onto the top plate of a Brush VSI OCB from an overheating busbar connection at Hurstpierpoint substation. Repairs have been carried out, but further leaks have occurred and so the switchgear has been scheduled for replacement in ED1.

3.2 Condition

3.2.1 Substation inspection

The main source of asset external condition data is from substation inspectors. As such, during the first half of DPCR5, a review of the *Substation Inspectors' Handbook* was carried out and a new handbook was issued. All inspectors were required to undertake a two-day training course and pass the theory and practical examinations before being certified as competent inspectors.

Figure 7 – Substation inspector with handheld device

To ensure good quality data is captured and recorded in the asset register in a timely manner, handheld devices (HHD) are used on site at the point of inspection. When an inspection HHD script is run, the user answers a set of questions, specific to each asset type, about the condition. This allows defects to be recorded, reviewed and cleared.

3.2.2 Maintenance

Maintenance fitters also use the same HHD technology to record their assessments of the internal and external condition of the assets being maintained. This assessment is made twice, to provide condition data "as found" and "as left".

3.2.3 Examples of condition data

Examples of condition data used in the ARP model are shown in Table 6. These are collected at inspection and maintenance.

Measure	Inspection	CB operation	Maintenance
CB initial trip time	No	Yes	Yes
CB last trip time	No	No	Yes
Condition of bushing	If visible	No	Yes
Condition of isolating contact	No	No	Yes
Ductor reading	No	No	At full maintenance
External condition of housing	Yes	No	Yes
Oil containment	Yes	No	Yes
Oil test breakdown	No	No	At full maintenance
Operation of switchgear	No	Yes	Yes

Measure	Inspection	CB operation	Maintenance
Overall internal condition	No	No	At full maintenance

Table 6 – Condition points used in switchgear ARP models

EMS 10-0002 Inspection and Maintenance Frequency specifies the inspection and maintenance frequencies for all plant. Inspection is currently carried out every four months; CB operation every one or two years, depending on the function of the CB; and maintenance of the CB mechanism takes place every six years, with full maintenance after three to six fault trips or 12 years, whichever comes first.

Condition is recorded as 1 (as new), 2 (normal for age, no work needed), 3 (remedial work needed) or 4 (replacement needed). Ductor and CB times are recorded in microhms/mS.

3.3 Asset Age/Obsolescence

By the start of RIIO-ED1 in 2015, 33% of the population will be more than 45 years old. Without any intervention, this figure will increase to 50% by the end of ED1.

In the ARP model, ‘average initial life’ is defined as the life at which an item of plant is expected to show increased levels of deterioration and not the point at which it is replaced. For 11kV switchgear, the average initial life varies between 20 years and 55 years, depending on the equipment type and design with the mean ‘average initial life’ for SPN being 48 years.

Note: The basic HI is capped so that switchgear with no adverse condition or defect data cannot rise above the equivalent of Ofgem HI3, irrespective of age.

The majority of the 11kV switchgear population are no longer supported by the manufacturer.

A spares/obsolescence factor is used in the ARP model calculating asset criticality:

1 – Still in production, supported by the manufacturer, all parts available.
2 – No longer in production, supported by the manufacturer, most parts still available.
3 – No longer in production, not supported by the manufacturer, limited parts available
4 – No longer in production, not supported by the manufacturer, no parts available.

3.4 Fault Rate

The rates for HV switchgear faults since 2007 are shown in Figure 8. These are presented as the number of faults recorded per item of switchgear per year. The fault-reporting system does not make it possible to distinguish between 11kV grid and primary switchgear and 11kV distribution switchgear, so all 31,630 assets are included. ‘All faults’ includes every fault resulting in an interruption of supply, irrespective of length or cause. The proportion of faults attributed to ageing and wear rate has risen during this period.

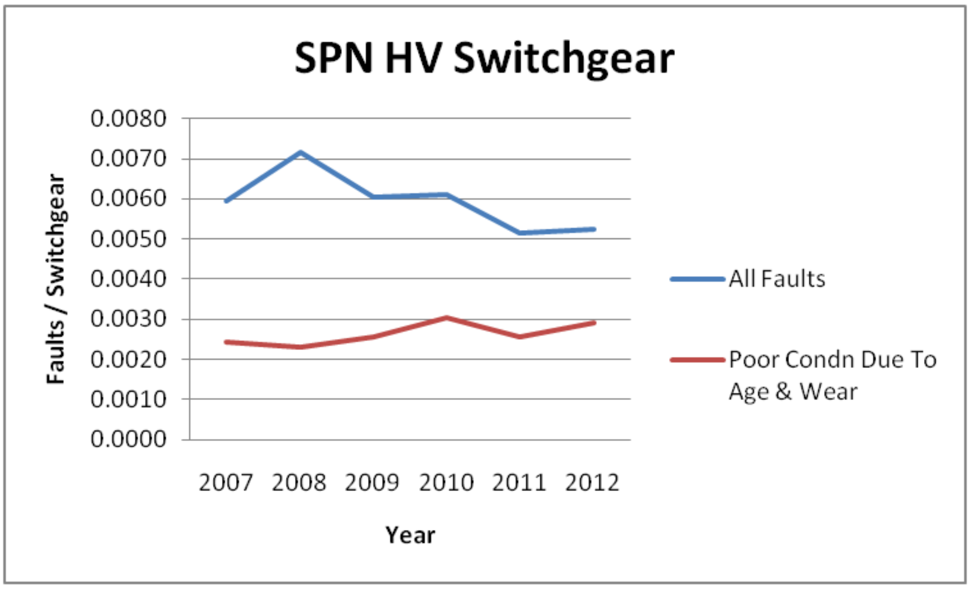


Figure 8 – SPN fault data

Source: Fault Analysis Cube ‘SPN Fault Rates’

3.5 Mechanism Performance

The main function of a circuit breaker is to clear fault current promptly when called on to operate, so it is important to monitor the way the operating mechanism performs and intervene if trip times start to increase. Within UK Power Networks, two measures are used to monitor circuit breaker performance. The first is a subjective measurement based on the ‘feel’ of the mechanism when it is operated; the second is an objective measurement of the initial trip time in mS. Both have been captured in Ellipse since 2007.

For circuit breaker operation, ‘satisfactory’ means that the mechanism operates freely first time without undue resistance, while ‘unsatisfactory’ means the mechanism is stiff, fails to operate first time or doesn’t operate at all. Ideally, there should be less than 1% ‘unsatisfactory’ operations recorded.

The initial trip time is measured using an approved timer such as the Kelman Profile or Bowden timer.

Grouping the results by equipment type highlights the fact that certain switchgear types are suffering more mechanism issues than others. There are similar volumes of Reyrolle ‘C’ gear (580) and ‘LMT’ (658) installed in SPN.

Figures 9 to 11 show that Reyrolle ‘C’ gear is starting to suffer an increasing number of both unsatisfactory operations and initial trip times. Consequently, this equipment is being targeted for retrofit or replacement in ED1.

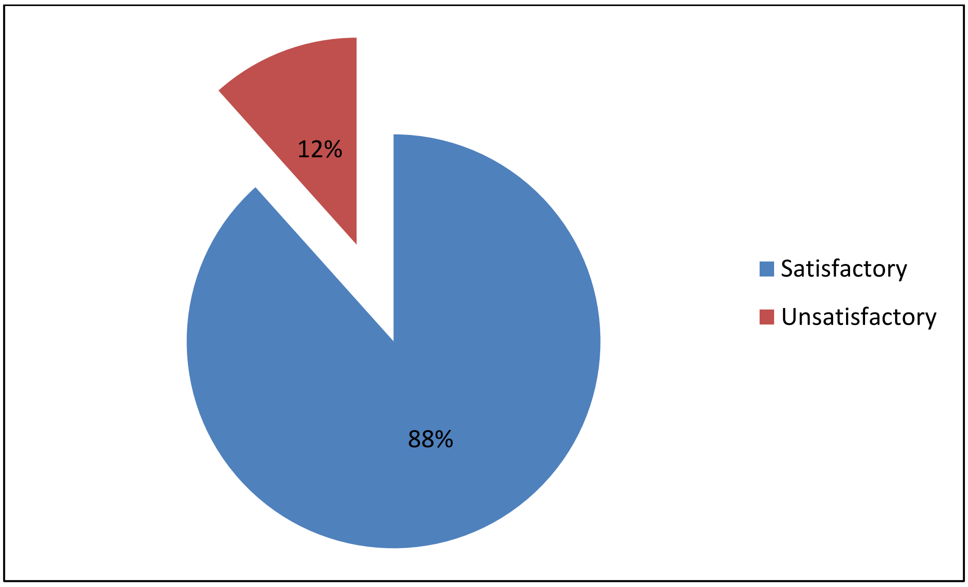


Figure 9 – CB operation history for Reyrolle 'C' gear in SPN

Source: Ellipse CBOPERATION condition point extract 22_01_2013

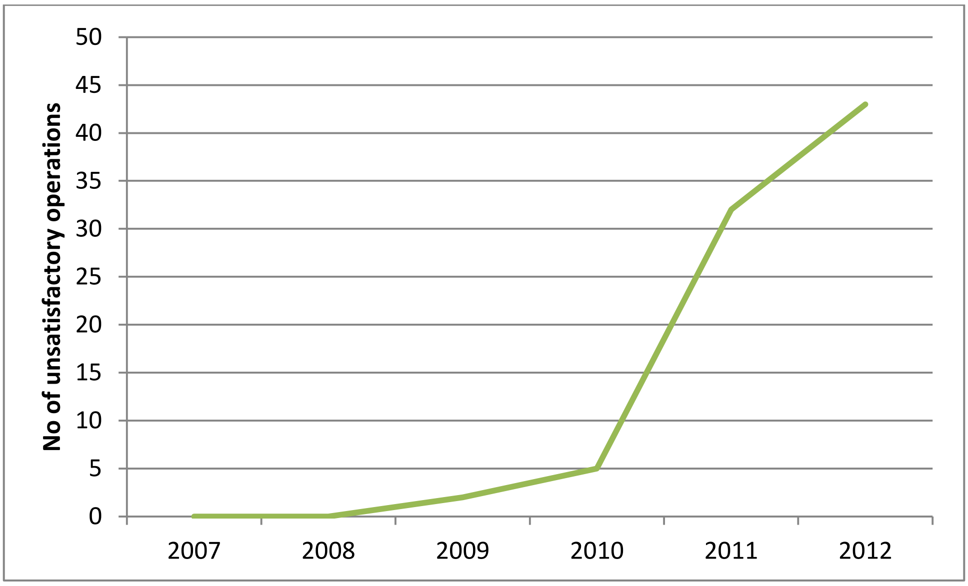


Figure 10 – Reyrolle 'C' gear: Rising trend in unsatisfactory CB operations

Source: Ellipse CBOPERATION condition point extract 22_01_2013

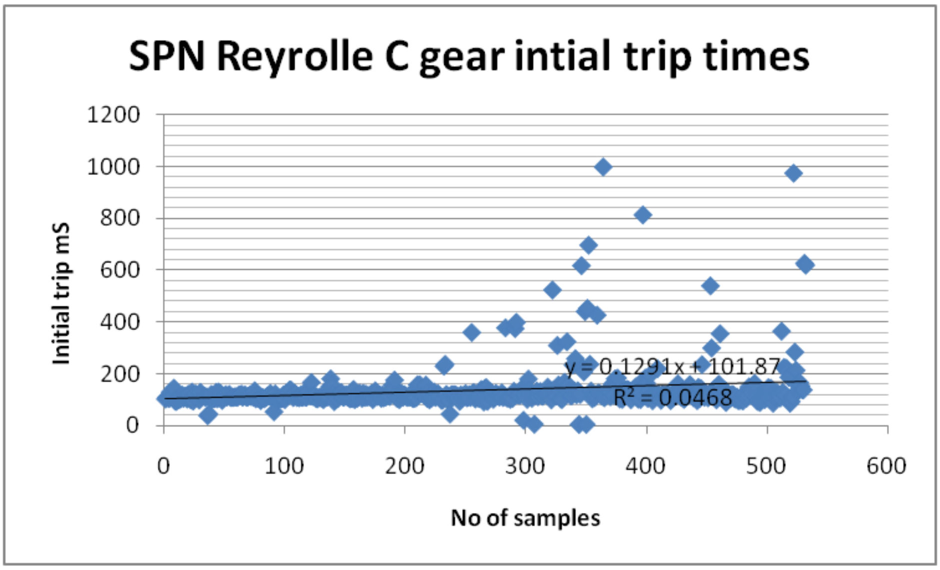


Figure 11 – CB trip times for Reyrolle 'C' gear

Source: Ellipse TRIPVALU1 condition point extract 14_01_2013

Figure 11 shows a rise from an average trip time of 101mS at the start of 2007 to 170mS at the end of 2012, an increase of 68%. As a result, it is proposed to retrofit or replace 281 'C' gear switchpanels in RIIO-ED1. By comparison, over the same period, Reyrolle type 'LMT' has suffered a smaller number of unsatisfactory operations and the CB trip times have remained relatively stable, rising from an average of 46mS at the start to 54mS at the end. There will be 138 'LMT' switchpanels retrofitted or replaced in RIIO-ED1.

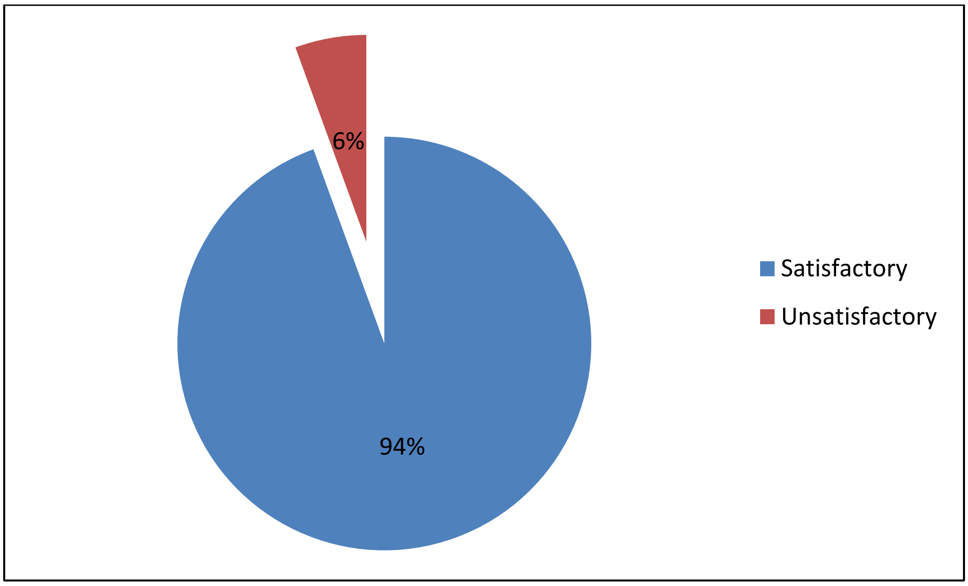


Figure 12 – CB operation history for Reyrolle 'LMT'

Source: Ellipse CBOPERATION condition point extract 22_01_2013

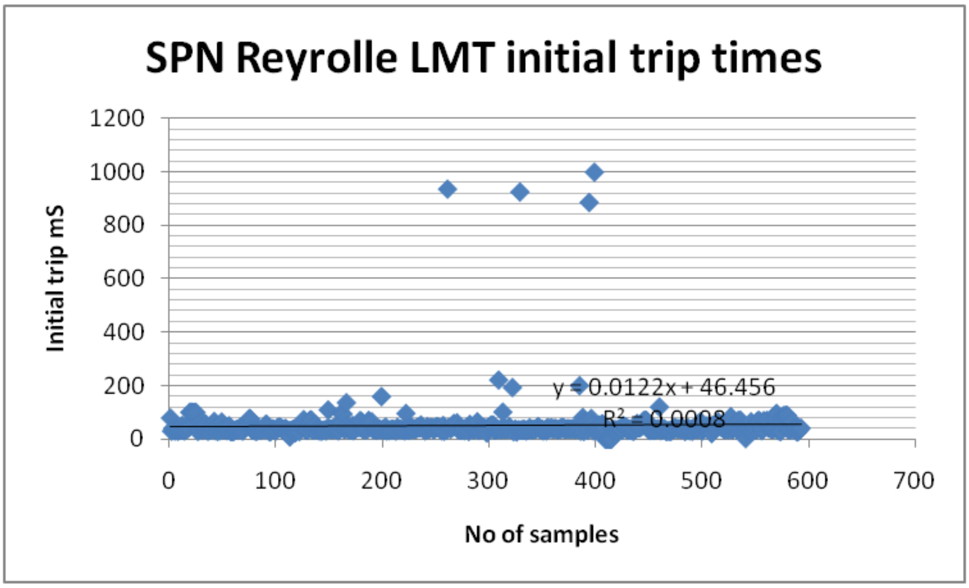


Figure 13 – CB trip times for Reyrolle 'LMT'

Source: Ellipse TRIPVALU1 condition point extract 14_01_2013

Many of the non-oil circuit breakers have 'sealed for life' operating mechanisms that are not readily accessible for normal maintenance. These will have to be stripped down and rebuilt when they reach their end-of-life, which the manufacturers estimate to be between 25 and 30 years. Much of the Hawker Siddeley VMV and VMH equipment will reach this age during ED1. Figures 14 and 15 suggest that some will need factory refurbishment. It is likely that refurbishments will be needed on other types of non-oil switchgear, so NAMP 1.50.01.8510 has been created as a provision for unspecified mechanism overhauls. Initially, it has been assumed that 10% of withdrawable pattern non-oil circuit breakers will require mechanism overhaul when they reach 25 years old.

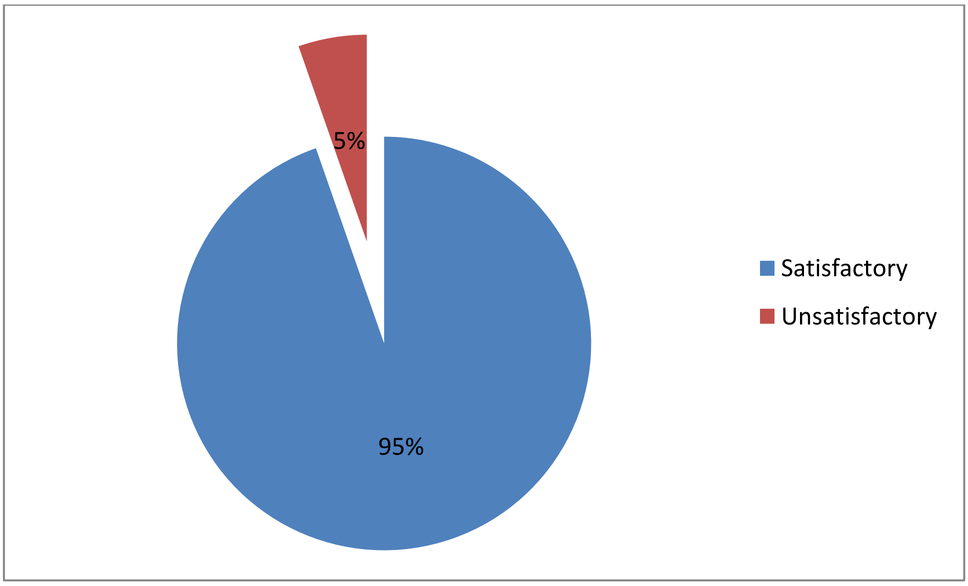


Figure 14 – CB operation history for Hawker Siddeley VMV/VMH

Source: Ellipse CBOPERATION condition point extract 22_01_2013

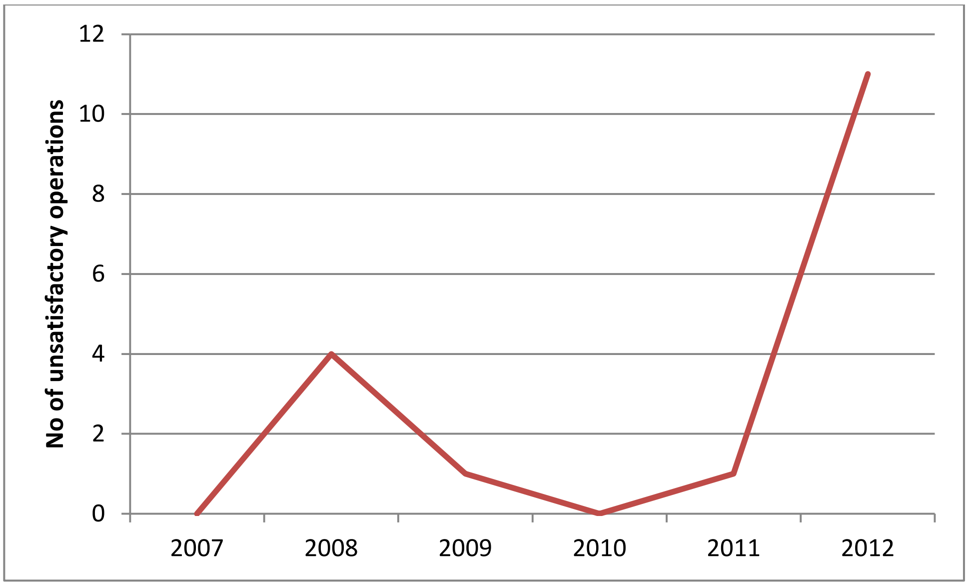


Figure 15 – Hawker Siddeley VMV/VMH: Rising trend in unsatisfactory CB operations

Source: Ellipse CBOPERATION condition point extract 22_01_2013

3.6 Partial Discharge Performance

3.6.1 Background

Partial discharge can occur within voids in the insulation, across the surface of the insulation (tracking) or in the air around a conductor (corona). Switchgear operating at 11kV should essentially be free of partial discharge, so detecting it is a very useful indicator of the health of the insulation.

Increasing levels of PD often indicate deteriorating switchgear insulation, which, if left uncorrected, could lead to disruptive failure with serious public and operator safety implications.

At every inspection, checks are made for PD activity using the UltraTEV instrument. A discharge defect is recorded in Ellipse if the TEV activity is over 29dB or any ultrasonic activity is present. EA Technology used the national database of TEV readings to determine that a reading over 29dB places the equipment in the top 5% of discharge activity and so most at risk from disruptive failure. Figure 16 shows the percentage of discharge defects recorded at the last inspection for different types of switchgear.

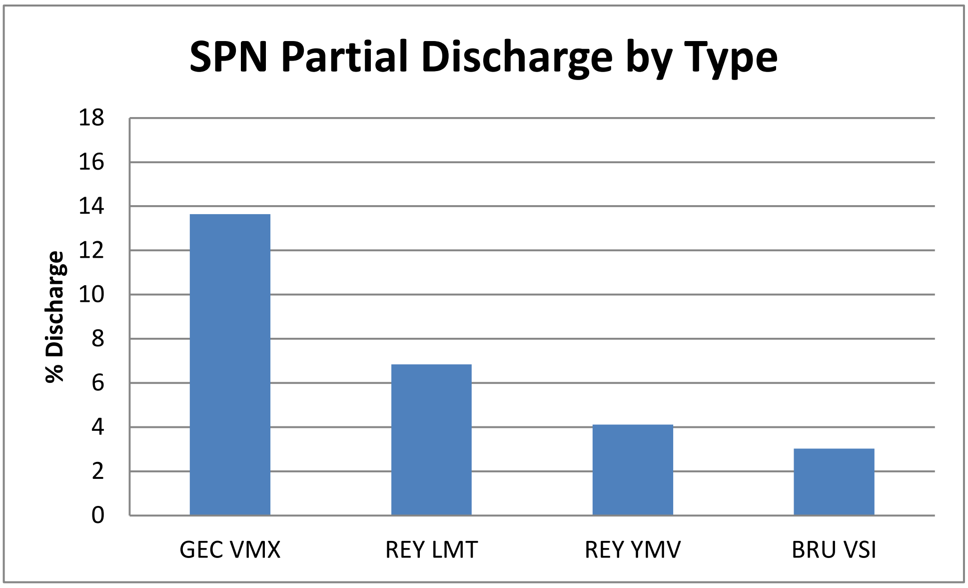


Figure 16 – Partial discharge history by switchgear type

Source: Ellipse Defect Visibility – Measure (DISCHARGE) 22_01_2013013

Certain types of switchgear, such as the Reyrolle LMT, are prone to discharge, but can safely be left in service because the insulation materials are sufficiently robust to prevent total breakdown. Others, such as the GEC VMX, must be promptly refurbished or replaced before a disruptive failure occurs. Figures 19 and 20 show the results of a disruptive failure.

Examples of output from the online PD monitoring system can be found in Section 5.2.

3.6.2 GEC type VMX circuit breakers

There are issues with the long-term reliability of this type of switchgear. It is a vacuum CB using cast-resin mouldings and is prone to partial discharge problems, which, if left unchecked, will result in a disruptive failure. Figure 17 shows the failures reported nationally via the ENA National Equipment Defect Reporting Scheme (NEDeRS) system.

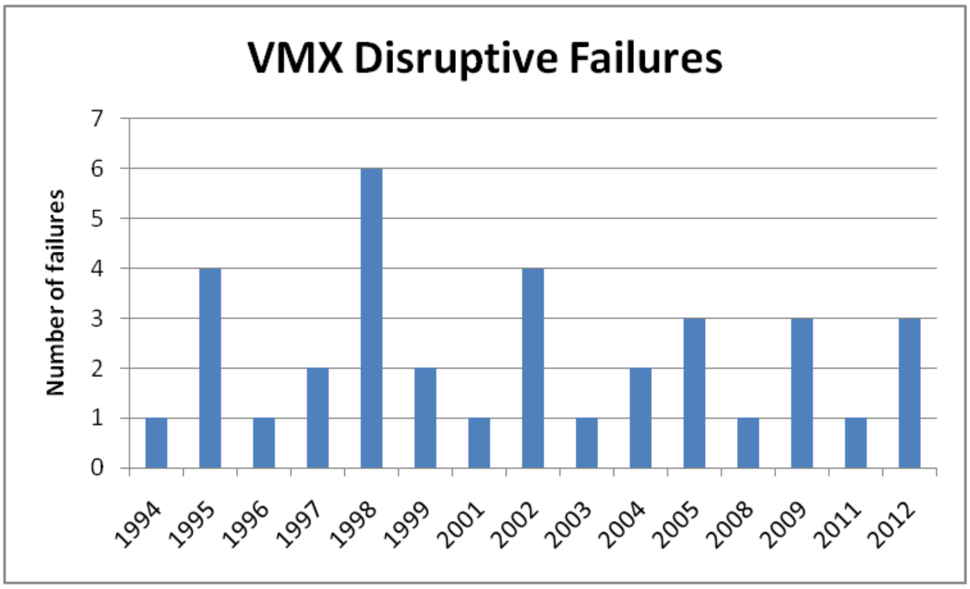


Figure 17 – GEC VMX: Disruptive failures reported via NEDeRS

Source: NEDERS website 11_02_2013

In SPN, there are 293 GEC VMX units. Several modifications intended to improve the partial discharge performance have had varying degrees of success, but there are still issues with 19 units – refer to Figure 18.

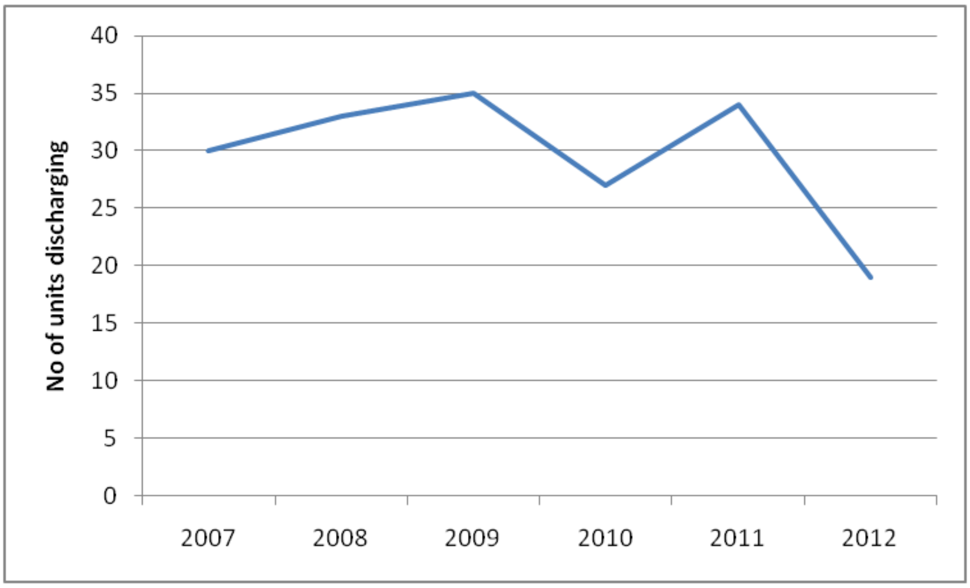


Figure 18 – GEC VMX: Number of CBs discharging by year in SPN

Source: Ellipse CONDISC condition point extract 22_01_2013

Keeping the substation environment as clean and as dry as possible can reduce the inception of discharge. Even so, discharge still occurs and is expected to continue to occur in the future. Past experience has shown that refurbishing VMX units that have started to discharge does not work effectively because the tracking damages the cast-resin material, so the only effective solution is replacement. For this reason, provision has been made to replace some of the VMX population over the ED1 period.

Figure 19 – GEC VMX: Tracking inside circuit spout

Figure 20 – GEC VMX: Failed 11kV panel

Figure 19 shows the inside of a cast-resin circuit isolating spout from a unit which has failed disruptively at a Marconi substation in Chelmsford (EPN). Signs of tracking can be seen from the isolating contact down to the edge of the spout.

Figure 20 shows the results of a circuit breaker that failed disruptively at Southwark Street substation in LPN. In this case, tracking had been taking place in the moulding that transmits drive to the vacuum bottles. Discharge had been recorded beforehand, but repairs were delayed.

3.7 Non-oil Circuit Breaker Issues

3.7.1 SF_6 gas tightness

Gas pressure is checked at each inspection and maintenance. Generally, 11kV circuit breaker designs are proving to be gas-tight and there is no evidence yet of ageing of seals.

3.7.2 Vacuum bottle performance

All vacuum circuit breaker manufacturers suggest a bottle life of 25 years, but practice suggests that this is very conservative and bottles will last considerably longer. However, the first 11kV vacuum circuit breakers are now 40 years old and we have had vacuum bottle failures on the oldest Reyrolle LM23V units.

The current age profile of vacuum CBs in SPN is shown in Figure 21.

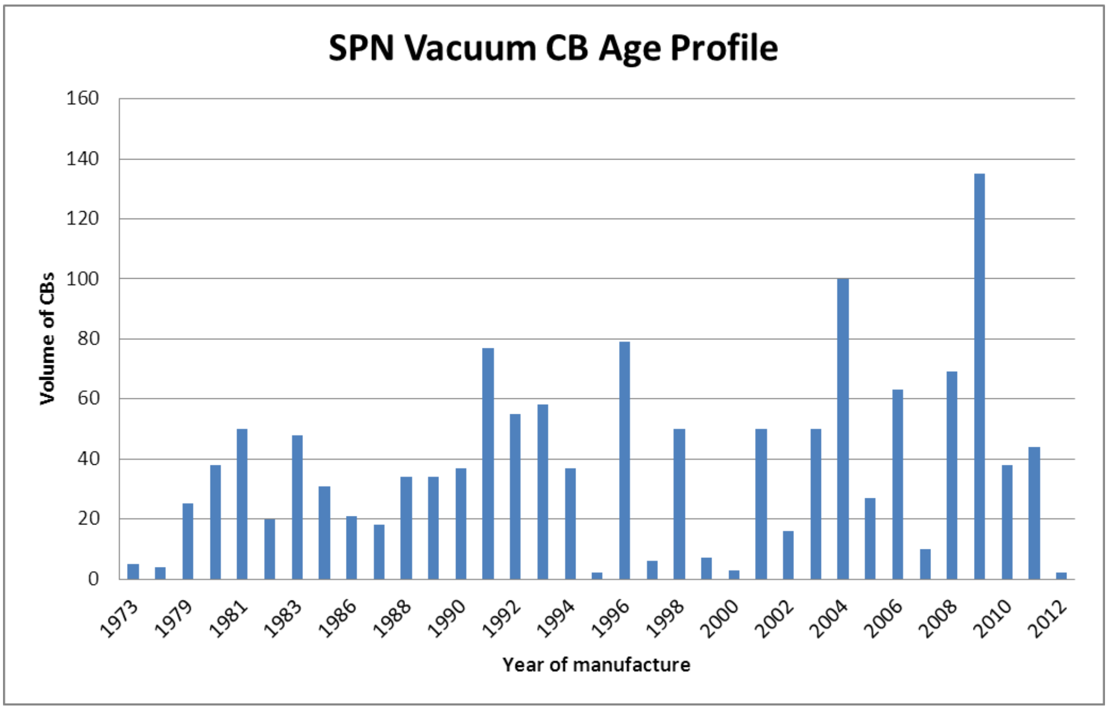


Figure 21 – Vacuum CB age profile

Source: ARP model Ph 1 11kV GP Sgr 25 July

At the end of ED1, there will be 261 vacuum CBs in SPN aged 35 years or greater, so NAMP line 1.50.01.8510 has been created to allow refurbishment of up to 20 11kV grid and primary CBs per year in ED1.

4.0 Asset Assessment

4.1 Asset Health

An innovative asset-health modelling tool, the Asset Risk and Prioritisation (ARP) model, has been developed for several asset categories, including 11kV grid and primary switchgear. The methodology behind the modelling is the same for all asset categories, but the switchgear model has been tailored specifically to use the data collected to assess against the identified investment drivers for switchgear.

The general methodology for the ARP model can be found in *Commentary Document 15: Model Overview*. The switchgear ARP models use age, location information and condition data to calculate a Health Index for an asset. An initial HI is calculated based on the year of manufacture, expected average asset life, the environment the asset is installed in and the duty of the switchgear during its life. The environmental factors considered are the distance from coast, whether it's indoors or outdoors, and the level of pollution. The function of the switchgear, whether it is a feeder, bus section or transformer breaker, is used to account for the duty. An average asset life is assigned per make and model of switchgear to show the expected time from when the asset was manufactured until it shows signs of increased deterioration. It is not the time from when the asset is commissioned until it is decommissioned. This initial HI is capped at HI3.

A factor value is then calculated using condition, defects and switchgear reliability data. The condition and defect data is inputted into the model and is obtained from the asset register, Ellipse. The reliability is assigned based on the make and model of the switchgear. There are two condition points that force the HI to a minimum of HI5, regardless of asset age – namely the external condition of housing and the number of SF_6 top-ups.

This factor value is then combined with the initial HI to produce the current HI of the asset.

4.2 Asset Criticality

The ARP model can also be used to calculate the criticality of a particular switchgear asset. This is then output in the form of a Criticality Index 1 to 4, with 1 being the least critical and 4 being the most. A detailed methodology for calculating the Criticality Index can be found in *Commentary Document 15: Model Overview*.

In the switchgear ARP model, five main areas are considered when calculating the criticality of an asset(s); network performance, safety, operational expenditure, capital expenditure and environment. A number of key factors are considered in each of these areas.

For network performance, the key factors are the number of customers that the substation feeds and the function of the asset. The function of bus section breaker is the most critical, and that of a feeder breaker is the least.

The factors considered for the safety criticality specific to switchgear are the arc extinction method and whether the switchgear is internal arc rated. Oil switchgear is considered the most hazardous method of arc extinction as far as the operator is concerned, and therefore is the most critical. Similarly, switchgear that isn't internal arc rated is considered more critical than switchgear that is.

The operational and capital expenditure sections both consider the criticality between assets in terms of the difference in maintenance costs between makes and models of switchgear and the difference in capital expenditure for different voltage levels.

Finally, the environment section considers the effects that different types of insulation have on the environment. Oil switchgear is again considered the most critical, with the level increasing with the volume of oil.

4.3 Network Risk

The network risk in monetary terms can be calculated in the ARP model using the probability of failure, the criticality and the consequence of failure, although the methodology is still under development. The probability of failure is calculated using the current Health Index of the item of switchgear, and the criticality is calculated as described in the previous section. The consequence of failure is the average cost to either repair or replace the item of switchgear following one of four failure modes – refer to Table 7.

Failure mode	Description
Failure to trip	No repair needed
Minor	Can be repaired in house
Significant	Can be repaired using external resource
Major	Beyond repair – disruptive failure or sent away for repair

Table 7 – ARP model failure modes

Although no repair is needed for the failure-to-trip mode, a post-fault maintenance will be carried out to investigate the cause of the stuck circuit breaker. Stuck or slow operating breakers have a big impact on customers, as they result in increased CIs and CMLs. This is because the circuit breaker upstream will operate if a feeder circuit breaker fails to trip or is slow to trip during a fault. The circuit breaker upstream will usually be the transformer breaker that feeds the bus section, meaning the bus section will be lost. The loss of the bus section will affect more customers than if just the original feeder was lost.

4.4 Data Validation

All data used in the ARP model is subject to validation against a set of data requirements. The requirements ensure data is within specified limits, up to date and in the correct format for use in the model. On completion of the validation process, an exception report is issued, providing details of every non-compliance and allowing continual improvement of data quality to be achieved.

An example of this is the circuit breaker trip times that are used in the model. These values have to be between 10 and 1,000mS, otherwise they are disregarded and not used in the model. There is also an age limit on the condition data – no data recorded more than five years ago is used. This is to ensure that the outputs of the model are describing the current asset rather than its past state.

4.5 Data Verification

A sampling approach to data verification follows each data upload to ensure accurate transfer into the models.

4.6 Data Quality

The completeness, accuracy and timeliness of the data used in the ARP model are routinely checked. For the results of the data used in the 11kV grid and primary switchgear, refer to Table 8.

The score is colour coded as follows.

- Green – Score of 85% or greater
- Amber – Score of 65% or greater
- Red – Score of less than 65%

Area	Result
Completeness	71%
Accuracy	89%
Timeliness	97%

Table 8 – Data CAT scores

Source: Source: ARP Switchgear CB data quality report 08_02_2013

The completeness score is a combination of switchgear nameplate data and condition data. Information used on the nameplate includes the year of manufacture, operating voltage, circuit breaker function, and any other information that will remain constant during an asset's life. Condition data is recorded by substation inspectors, as described in Section 2.2, and will change with time. The completeness of any data used in the network risk section of the model is also included, such as customer numbers.

The completeness of the nameplate information is 96% and there has been investment in improving this area during DPCR5. The completeness of condition data is 52% – the result of a large variation in completeness between different condition measures. As with the nameplate information, there has been a project during DPCR5 to improve the completeness of the condition data, and this has led to new condition points being created. Due to this, in some cases the condition point may not be populated until the next maintenance, which may not be fully complete until 2020.

The accuracy score is a measure of the reliability and correctness of the condition data stored in Ellipse. This is calculated by comparing the condition measure recorded by the UK Power Networks with the same measure recorded by an independent third party, SKM.

The timeliness score shows the percentage of assets that have condition data recorded within the expected time period, as stated in EMS 10-0002, *Inspection and Maintenance Frequency Schedule*. UK Power Networks' asset risk methodology is to use asset data and defect data to drive a need for specific funding for the refurbishment or replacement of those assets in RIIO-ED1. This has required a comprehensive increase in asset condition data. As a consequence, UK Power Networks is prepared to carry the risk associated with missing asset and condition data.

5.0 Intervention Policies

5.1 Interventions: Description of Intervention Options

Four categories of interventions have been considered for 11kV grid and primary switchgear: enhanced maintenance, refurbishment, retrofit and replacement. These are summarised in Table 9 and explained in more detail later in this section.

Note: The intervention policy for protection relays and instrumentation is included in *Commentary Document 13: Protection and Control*.

Option	Description	Advantages	Disadvantages
Enhanced maintenance	Decrease interval between maintenance interventions or introduce new maintenance intervention.	Usually cost-effective over short periods compared with replacement options.	Ties up maintenance resources. Not effective if mechanism wear is the issue.
Refurbishment	Replace complete operating mechanisms or refurbish gas systems of SF_6 units.	No civil costs. Can often be achieved on site.	Maintenance costs not reduced. Need to maintain existing CO_2 systems in switchrooms. Support from OEM often limited. May be type test issues if third parties used. At 11kV,

Option	Description	Advantages	Disadvantages
			cost tends to be similar to retrofit truck.
Retrofit CB truck	Replace entire CB truck with new vacuum unit.	No civil costs. CO_2 systems in switchrooms can be decommissioned. No (11kV) cabling costs. Reduction in maintenance costs if oil breaker replaced. Can extend the life of switchpanel by at least 25 years. No jointing needed.	Use of resin bushings in old housings can result in PD issues. Limited to certain types of equipment only. Needs careful design.
Replacement	Replace complete switchboard.	No compatibility issues with existing housings. Longest potential life (40+) of all interventions. Maintenance costs reduced.	Usually incurs some civil costs. Longer outages as cables need to be transferred to the new board.

Table 9 – Summary of intervention policies

5.1.1 Enhanced maintenance

Where condition and defect data show that mechanism performance is unsatisfactory, the first intervention considered is enhanced maintenance. Typically, this would be to alter the mechanism maintenance frequencies detailed in EMS 10-0002 or introduce additional mechanism maintenance between scheduled full maintenance. This can be successful if the underlying problem is inadequate lubrication. However, if wear is an issue, refurbishment is the better option.

5.1.2 Refurbishment

When several components have started to wear in an operating mechanism, it can become unreliable, either failing to close or failing to open. The entire mechanism can be replaced with one that has been refurbished by either the original manufacturer or a third party. Not all manufacturers offer this service and it may prove more economical to replace the entire circuit breaker truck with a retrofit device.

5.1.3 Retrofit CB truck

For withdrawable circuit breakers only, fitting a replacement vacuum CB in an existing oil CB housing has many advantages: the maintenance commitment is substantially reduced, especially the post-fault maintenance needed regularly on units protecting overhead line feeders; the new operating mechanism usually places a much less onerous duty on the substation battery; and remote control facilities can be easily incorporated.

UK Power Networks has been at the forefront of retrofit technology since the mid 1990s, with 1,622 units already installed, accounting for 14.1% of the 11kV grid and primary switchgear population.

Retrofit is only done on switchboards where the fixed portions are in good condition. A partial discharge survey is carried out to ensure there are no PD issues with the busbars, CT chamber and cable box. If the spot check PD shows any activity, a temporary online monitor may be installed for a few months.

5.1.4 Replacement

If refurbishment or retrofit is not appropriate, replacement is considered. Switchboards are not necessarily replaced like for like, as the opportunity may be taken to consolidate the number of switchpanels. Double busbar switchboards are only used in urban areas with interconnected LV load.

5.2 Policies: Selecting Preferred Interventions

The process used for selecting interventions for all categories of switchgear is shown in Figure 22. All 11kV grid and primary switchgear is part of a switchboard. Where more than 50% of the panels on a switchboard are HI4 or HI5 at the end of ED1, intervention will be considered, with a retrofit solution being the preferred option where this is available.

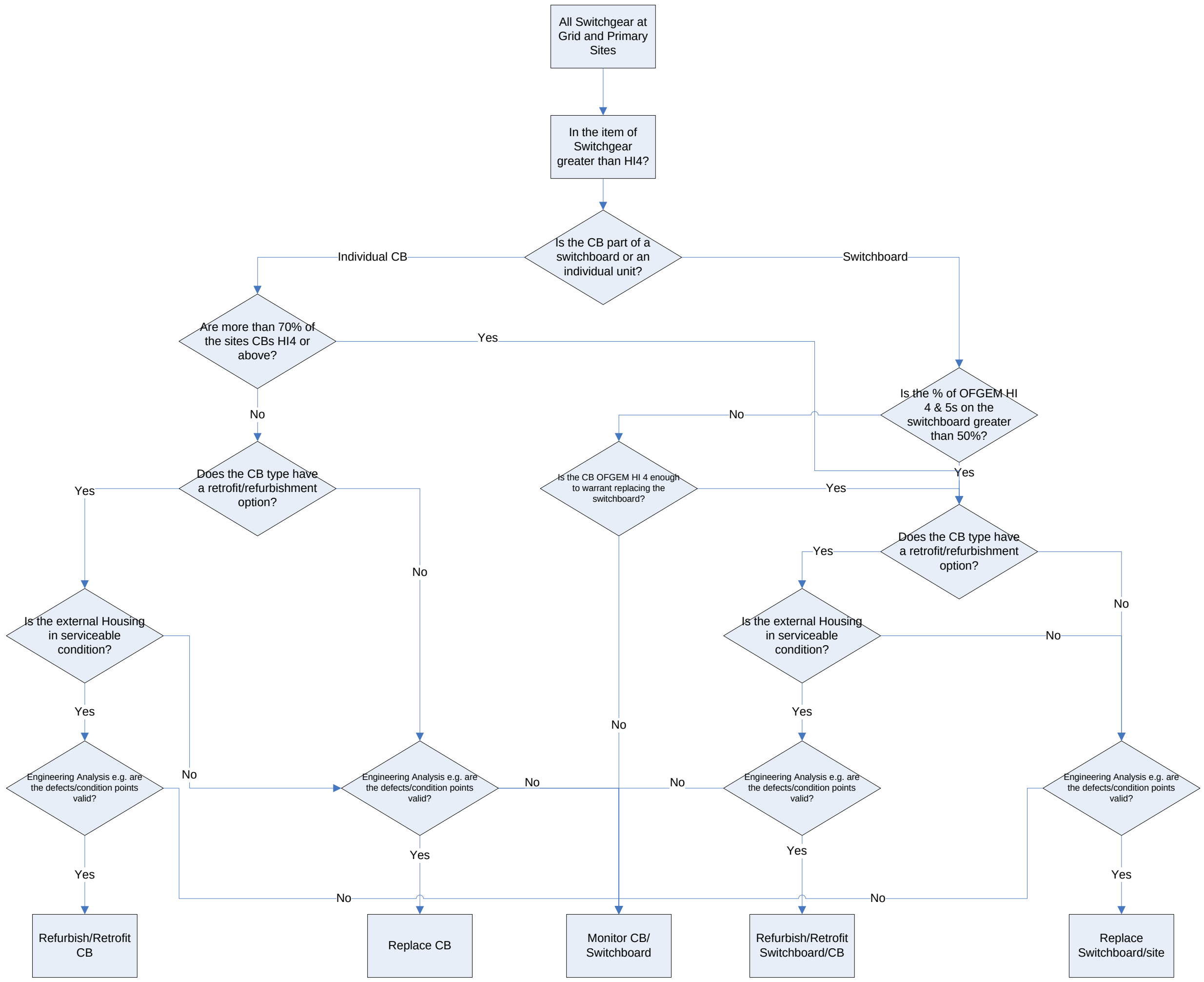


Figure 22 – Intervention decision flow chart

By implementing this programme of retrofitting, we will be able to manage the deterioration of the switchgear, addressing failure modes that would, if left untreated, result in asset replacement. This will extend the life of the plant, reduce whole-life costs and improve reliability and network risk while minimising short-term expenditure.

This capital expenditure programme – both replacement and retrofit interventions – will provide significant benefits to our operational expenditure. Oil switchgear has increased maintenance frequency and is likely to be less reliable and require more defect repair, so by replacing it with non-oil switchgear, the maintenance requirements will reduce.

6.0 Innovation

6.1 Retrofit Circuit Breaker Design

New designs of retrofit CB for AEI type QA/QF are currently being developed using a cassette module circuit breaker magnetic actuator breaker cassette module operating mechanisms with very few moving components, which should improve long-term reliability.

In conjunction with Siemens, a new design of retrofit circuit breaker for the Reyrolle 'C' gear has been designed based on the Sion circuit breaker cassette. The first installation nationally is in progress in LPN.

Figure 23 – Siemens Sion-C retrofit CB

Retrofit is only being carried out on switchboards where the fixed portions are in good condition. A partial discharge survey is carried out to ensure there are no PD issues with the busbars, CT chamber and cable box. If the spot check PD shows any activity, a temporary online monitor may be installed for a few months to determine whether retrofit is viable.

6.2 Use of Online PD Monitoring Equipment

UK Power Networks is using online monitoring equipment to monitor the PD performance of grid and primary switchboards. This enables expenditure to be deferred, while minimising the risk of disruptive failure.

The company providing the monitoring service sends text or e-mail alerts to flag any significant increases or decreases in the level of activity, or changes in the nature of activity. These are validated by on-site testing, and replacement or refurbishment action is then taken as appropriate.

In SPN, 12 of the 11kV switchboards suffering from partial discharge activity have been fitted with permanent online PD monitoring equipment.

Figure 24 shows typical screen shots from the online PD monitoring system, displaying activity on a Reyrolle type LMT switchpanel at Brighton Town substation over a six-month period from July 2012 to January 2013. The switchpanel has known discharge activity in the cast-resin CTs, but this is not deteriorating, as can be seen from the relatively flat upper graph showing TEV values in dB. The middle graph shows the substation humidity, and the lower one is the switchroom temperature. This installation has enabled us to defer replacement while closely monitoring PD levels.

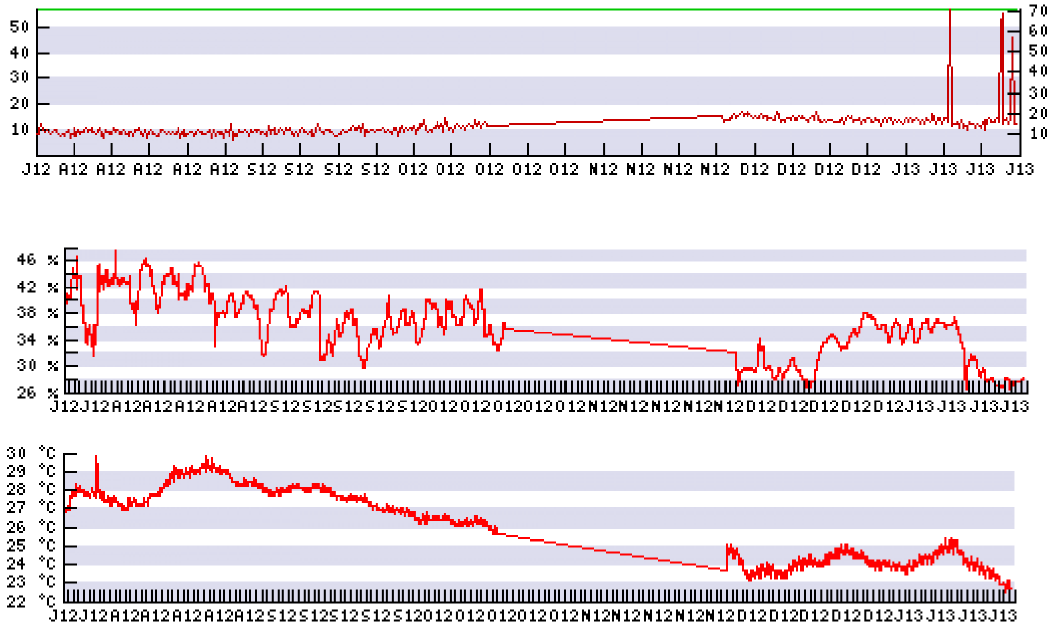


Figure 24 – Online PD monitoring results

Source: IPEC iSM 22_01_2013

7.0 ED1 Expenditure Requirements for 11kV Grid and Primary Switchgear

7.1 Method

An overview of the method used to construct the RIIO-ED1 NLRE investment plans is shown in Figure 25.

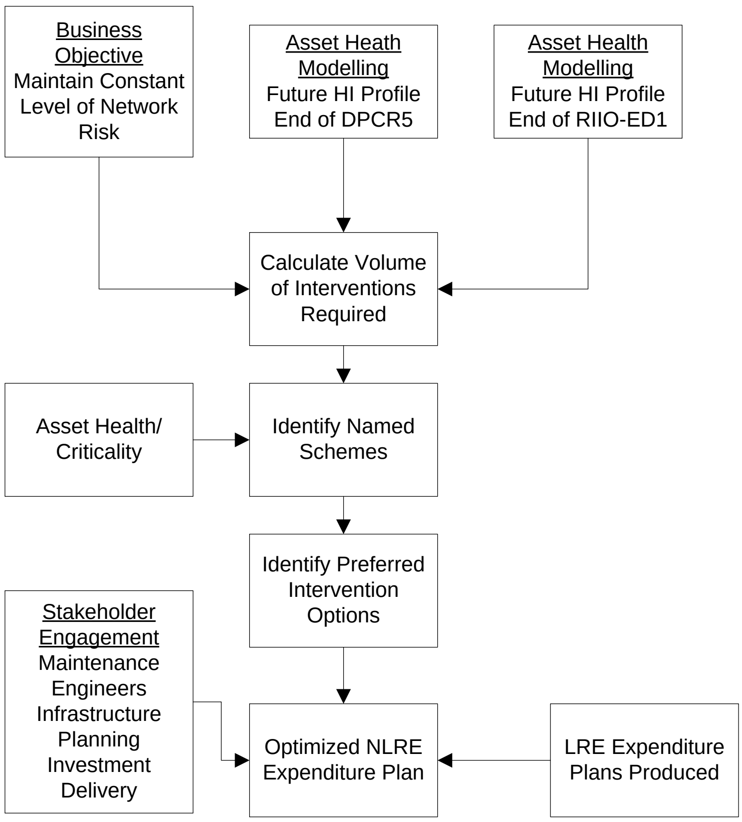


Figure 25 – Constructing the NLRE plan

7.2 Constructing the Plan

7.2.1 Intervention volumes

The business objective throughout the planning process for RIIO-ED1 NLRE was to maintain an approximately constant level of risk within each asset category. To achieve this, the ARP model was used to determine the HI profiles at the end of DPCR5 and the end of RIIO-ED1 in order to project how the number of HI4s and HI5s would increase without investment. This provided the basis for the volume of interventions required during RIIO-ED1. These sites were then assessed individually to see what level of intervention, if any, was appropriate based on the type of switchgear.

7.2.2 Intervention types

For withdrawable switchgear, retrofitting was the preferred option if an approved design currently exists or is scheduled for approval during ED1. For retrofits, only those circuit breaker trucks identified as HI4 or HI5 at the end of ED1 have been put into the plan, rather than all trucks on the switchboard.

7.2.3 Optimising the plan

Stakeholder engagement was an important part of the process to finalise the RIIO-ED1 plan. Maintenance engineers were consulted as they are most familiar with the assets. They ensured that the data being used in the ARP model reflected their own assessments of each asset's condition. There was also detailed consultation with those involved in constructing the RIIO-ED1 LRE expenditure plans to ensure the optimal investment for maximum achievement.

7.2.4 HI profiles

The HI profiles for the start and end of ED1, with and without investment, are given in Figure 26. The HI profiles are derived from condition related investment only and exclude the contribution from load related expenditure. Note that the 'without investment' HI figures include investment during the DPCR5 period.

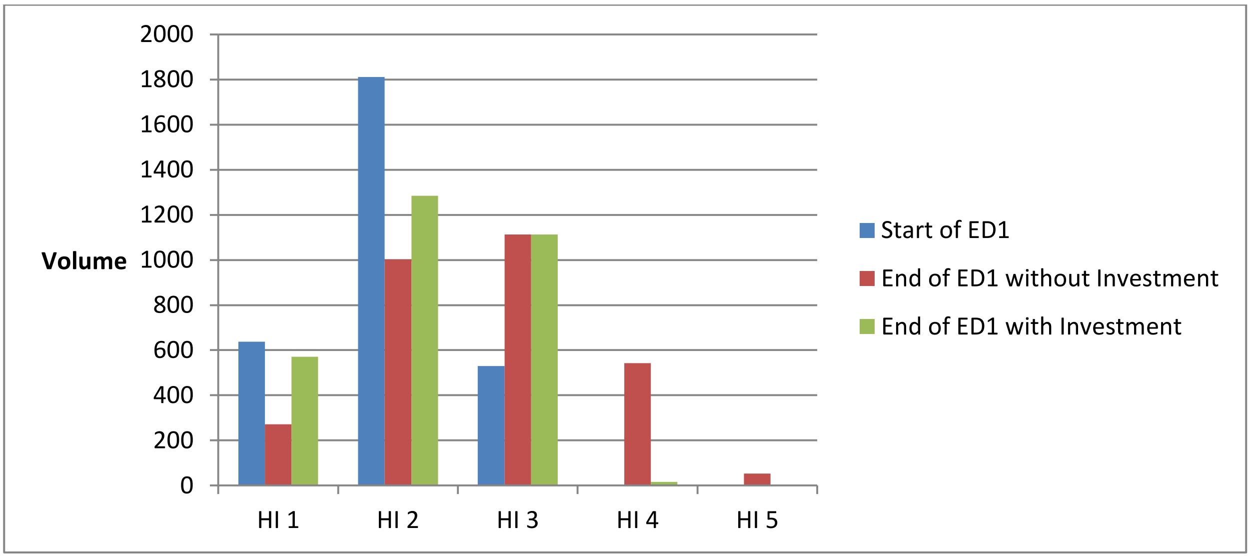


Figure 26 – HI profiles

Source: 21 February 2014 ED1 RIGS

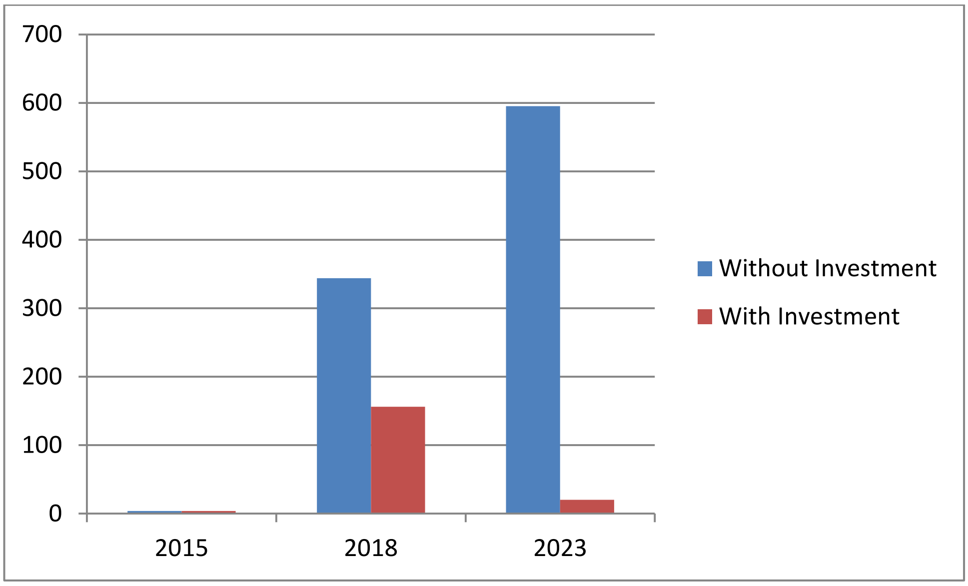


Figure 27 – Sum of HI4 and HI5

Source: 21 February 2014 ED1 RIGS

Figure 27 illustrates the effect of investment on the predicted number of HI4 and HI5 circuit breakers through the ED1 period. The number will rise through ED1, from 4 at the start of the period to 24 at the end, but this rise represents just 0.6% of the installed population.

Consideration was given to replacing or retrofitting more units during ED1 to maintain a level or reducing number of HI4 and HI5 circuit breakers. The remaining units are spread across a large number of substations which made replacement of the whole switchboard unattractive as it would have meant replacing relatively healthy units and retrofitting was discounted because it was felt that the level of risk did not warrant investment at this stage.

7.3 Additional Considerations

The Network Asset Management Plan (NAMP) has been used to ensure that the proposed switchgear projects are not duplicated in the Non Load Related LRE and Load Related plans. Similarly, to optimise time spent at site, the NAMP was used to ensure transformer replacements are timed to coincide with switchgear replacements where practicable.

7.4 Asset Volumes and Expenditure

Proposed asset replacement and retrofit volumes for ED1 are shown in Figure 28 along with volumes for DPCR4 and DPCR5 for comparison. In total, there are 587 interventions proposed during ED1, which represents 20% of the installed population.

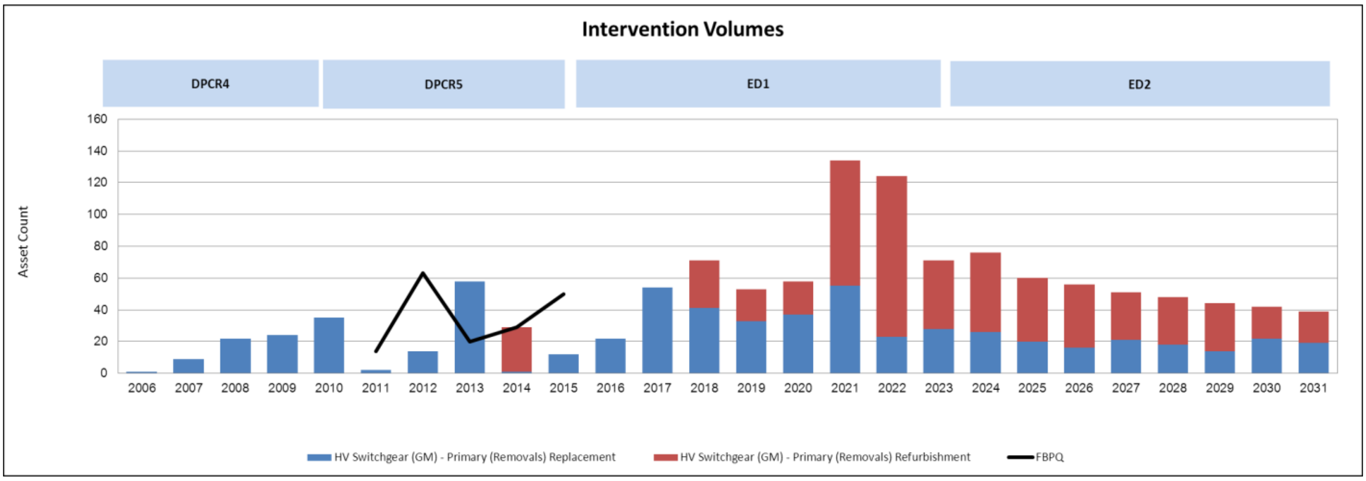


Figure 28: SPN 11kV Grid & Primary Switchgear intervention volumes

Sources:

- DPCR4 volumes: Table NL3 (DPCR5 FBPQ)
- DPCR5 volumes: First three years – RIGs CV3 table
- DPCR5 volumes: Last two years – 14 June 2013 NAMP (Table O)
- DPCR5 FBPQ volumes: SPN FBPQ Mapping NAMP data
- ED1 volumes: 19 February 2014 NAMP (Table O)
- ED2 volumes: Analysis from Statistical Asset Replacement Model (SARM1)

Note: Volumes for DPCR4 are not readily available as both distribution and grid/primary 11kV CBs were reported together in RRP. However, it has been assumed that, for SPN, 30% of the 11kV CB (GM) removals were at grid and primary sites with the remainder being distribution switchgear.

The proposed asset replacement and refurbishment expenditure for ED1 is shown in Figure 29, along with expenditure for DPCR4 and DPCR5 for comparison.

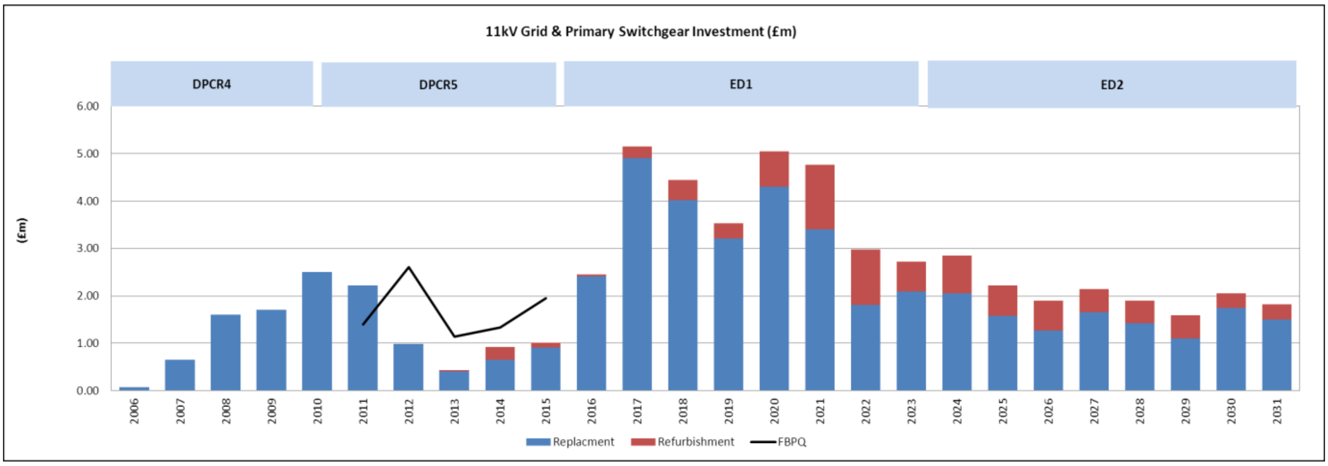


Figure 29 – SPN 11kV Grid & Primary Switchgear intervention expenditure

Sources:

- DPCR4 costs: Table NL1 (DPCR5 FBPQ
- DPCR5 costs: First three years – RIGS CV3 table
- DPCR5 costs: Last two years – 14 June 2013 NAMP (Table JLI)
- DPCR5 FBPQ costs: SPN FBPQ Mapping NAMP data
- ED1 costs: 19 February 2014 NAMP (Table JLI)
- ED2 costs: Volumes from SARM 1 * UCI of £79k for replacement and UCI of £16k for refurbishment

The actual and forecast level of investment in DPCR5 is below the level submitted in the FBPQ submission. The use of improved risk management techniques has allowed some expenditure to be deferred. An example of this is the new CB timing facility in the Enmac control system will be used to monitor CB trip time trends and will ensure that intervention expenditure is better targeted during ED1

7.5 Commentary

In order to tackle the two main problem areas of deteriorating CB mechanism performance on the ageing Reyrolle 'C' gear population and poor partial discharge performance of GEC VMX, it is necessary to increase the volume of interventions compared with DPCR4 and DPCR5.

The average volume of circuit breaker panels replaced per year rises from 23 (2 sites) in DPCR5 to 34 (3 sites) in ED1; for retrofits, the rise is from 11 to 35 circuit breakers per year.

Whilst a significant proportion of 11kV switchgear in SPN advances past the ARP average asset life of 59 years during ED1 and becomes subject to the degradation algorithm, this is not the sole reason for the increase in volumes. The ARP model will not move an asset beyond HI3 on age alone, it needs adverse condition data or defects to progress to HI4 or HI5.

During the second half of ED1, the bulk of the work is installing retrofit CB trucks into fixed portions that remain in good condition. This work is relatively simple to deliver compared with complete switchboard replacement.

By ED2, the split between refurbishment and replacement work changes from a two-thirds/one-third split at the start to a 50/50 split at the end of the period. Most of the switchboards that can be retrofitted will have been completed by the end of ED2.

Removing 559 11kV oil circuit breakers during ED1 will have an impact on the I and M opex budget, specifically on the following NAMP lines:

- 4.24.01 Maint Full 11/6.6kV OCX TSC
- 4.24.05 Maint Mech 11/6.6kV OCB TSC
- 4.06.10 Maint Full 11/6.6kV OCB Feeder
- 4.06.06 Maint Mech 11/6.6kV OCB Feeder

Based on an analysis of Maintenance Scheduled Task predictions from the Ellipse database, a total of 12% is expected to be saved across these lines.

7.6 Sensitivity Analysis and Plan Validation

An independent report has been carried out by Decision Lab to understand how the Health Index profile of assets may change if the average asset life does not turn out as predicted.

Average life change	**2015** percentage HI profile				
	HI1	HI2	HI3	HI4	HI5
-4	21.2	44.1	32.0	2.4	0.2
-2	21.3	53.5	24.5	0.7	0.0
-1	21.3	57.2	20.9	0.5	0.0
0	21.5	60.2	18.1	0.1	0.0
1	21.5	62.2	16.3	0.1	0.0
2	21.5	66.2	12.2	0.0	0.0
4	21.5	72.2	6.2	0.0	0.0

Average life change	**2023** percentage HI profile				
	HI1	HI2	HI3	HI4	HI5
-4	19.2	34.9	32.6	9.9	3.5
-2	19.8	38.6	35.1	5.3	1.2
-1	20.0	39.2	37.1	2.8	0.9
0	20.3	40.5	37.4	1.6	0.3
1	21.2	42.2	35.1	1.2	0.3
2	21.7	45.1	32.1	1.0	0.0
4	25.2	50.2	24.6	0.1	0.0

Table 3 – Results of sensitivity analysis

Source: Decision Lab analysis Appendix 6

In Table 10, each average asset life change of years +/- 1, 2 and 4 is represented as a percentage of the current population. With each change in average asset life, there is a subsequent movement in the percentage of population in each Health Index. An average asset life at 0 represents the current population split within each Health Index with intervention strategies applied. The two tables range from the start of ED1 (2015) and the end of ED1 (2023).

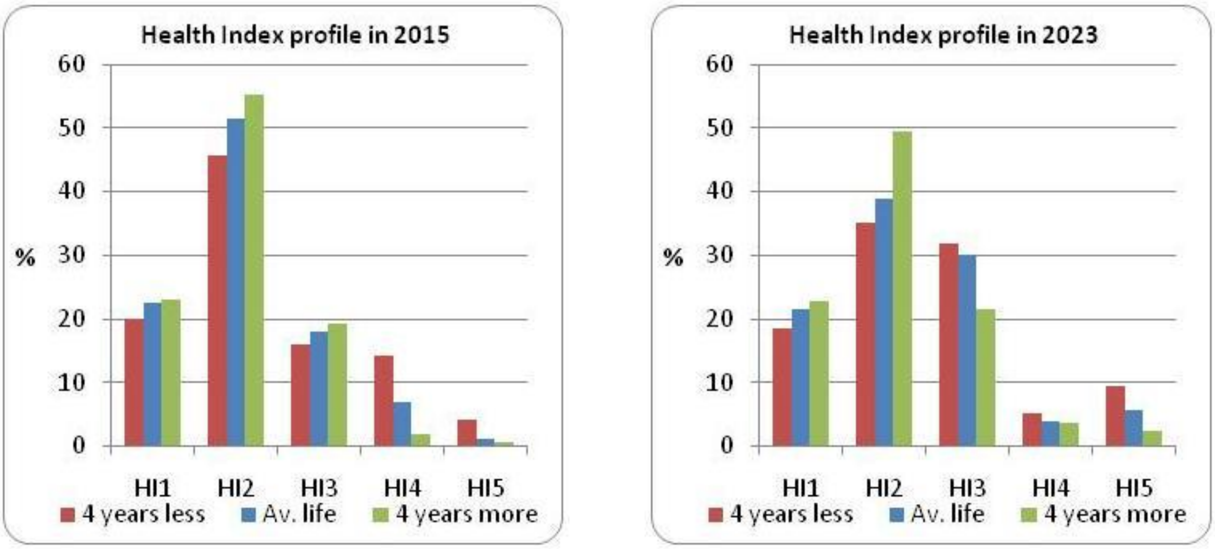


Figure 30 – Results of sensitivity analysis

Source: Decision Lab analysis Appendix 6

Figure 30 illustrates the effect on the 2023 age profile of changing the average asset life by + /– four years, while Figure 31 represents summed HI4s and HI5s as a percentage of the population showing the change at each average asset life iteration comparing 2015 and 2023.

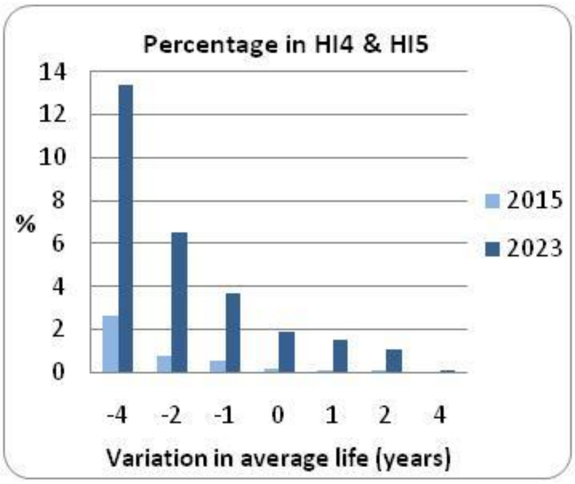


Figure 31 – Effect of average asset life variation on volumes of HI4 and HI5

Source: Decision Lab analysis Appendix 6

SPN has a substantial population of switchgear that is either approaching or beyond the average asset life used in the ARP model. This makes it the most sensitive of the three licence areas to a reduction in the average asset life. For example, a reduction of four years will increase the number of HI4s and HI5s in 2023 by 11.5%.

The full results are shown in Appendix 6.

7.7 Model Testing

The ARP model had undergone rigorous testing to ensure it met the defined requirements prior to acceptance. There were four distinct subsets to the testing process: algorithm testing, software testing, data flow testing and user and methodology testing. Each test is designed to capture potential errors in specific parts of the system. The completion of all tests provides assurance that a thorough evaluation has been carried out to ensure correctness and validity of the outputs.

7.7.1 Algorithm testing

The ARP model comprises a set of algorithms implemented within the database code. The tester in a spreadsheet mimics each algorithm, with the results compared to those of the ARP algorithm for a given set of test data inputs. The test data comprised data within normal expected ranges, low-value numbers, high-value numbers, floating point numbers, integers, negative numbers and unpopulated values. In order to pass the test, all results from the ARP algorithm are required to match the spreadsheet calculation.

7.7.2 Software testing

A number of new software functions used in the model required testing to ensure they performed correctly. A test script was created to identify the functional requirement, the method to carry out the function and the expected outcome. In order to pass the test, the achieved outcome had to match the expected outcome.

7.7.3 Data flow testing

Data flow testing was carried out to ensure that data presented in the ARP upload files passes into the model correctly. Data counts from the ARP model upload files were compared with data successfully uploaded to the model. To pass the test, counts of the data had to match within specified tolerances.

7.7.4 User and methodology testing

The aim of the user and methodology testing is to ensure that the models are fit for purpose. A test script has been created to check that displays operate correctly and that outputs respond appropriately to changes in calibration settings.

7.8 Network Risk Sensitivity

As mentioned in section 4 of this document, the ARP model is able to produce a criticality index (C1 to C4) for each individual asset, although this is a very new concept and is still being developed. The Criticality Index can be used with the Health Index to give an indication of the level of risk that can be seen on the network. Table 12 and Table 13 show the HI and criticality matrix for 2015 and 2023 with investment during ED1.

The single high-criticality HI4 asset in 2023 is a bus section circuit breaker where the remainder of the switchboard is HI3 or less and so do not justify investment in this period.

Asset categories	Criticality	Units	Estimated Asset Health and Criticality Profile 2015					Asset Register
			Asset Health Index					2015
			HI1	HI2	HI3	HI4	HI5	
11kV grid and primary switchgear	Low	No. CB	494	947	398	4	0	1843
	Average	No. CB	99	627	103	0	0	829
	High	No. CB	44	244	29	0	0	317
	Very High	No. CB	0	0	0	0	0	0

Table 4 – 2015 HI and criticality matrix

Source: 21 February 2014 ED1 RIGS

The total volumes for 2015 and 2023 differ slightly as the number of CBs removed and installed as part of a project are not always identical.

Asset categories	Criticality	Units	Estimated Asset Health and Criticality Profile 2023					Asset Register
			Asset Health Index					2023
			HI1	HI2	HI3	HI4	HI5	
11kV grid and primary switchgear	Low	No. CB	394	823	620	2	4	1843
	Average	No. CB	129	348	358	1	0	836
	High	No. CB	48	133	135	1	0	317
	Very High	No. CB	0	0	0	0	0	0

Table 5 – 2023 HI and criticality matrix

Source: 21 February 2014 ED1 RIGS

7.9 Whole Life Cost

Before a project is approved for implementation an estimate of the whole life cost is produced which quantifies purchase, installation and maintenance costs over a nominal 30 year period. An example is given in Appendix 4.

8.0 Deliverability

The volume of work proposed in ED1 is considerably higher than that achieved in DPCR4 or DPCR5. However, around 50% is retrofit work, which can be achieved largely by third parties. And as it is spread evenly across the network, access and outage availability issues are not anticipated.

EDS 08-0105 specifies the maximum number of any type of distribution switchgear that may be installed on the network to avoid operational difficulties in the event of a type defect.

All ED1 projects have been created in the Network Asset Management Plan (NAMP). The majority of projects are for specifically named schemes, but where this is not possible, a financial provision has been created.

Appendix 1 – Age Profiles

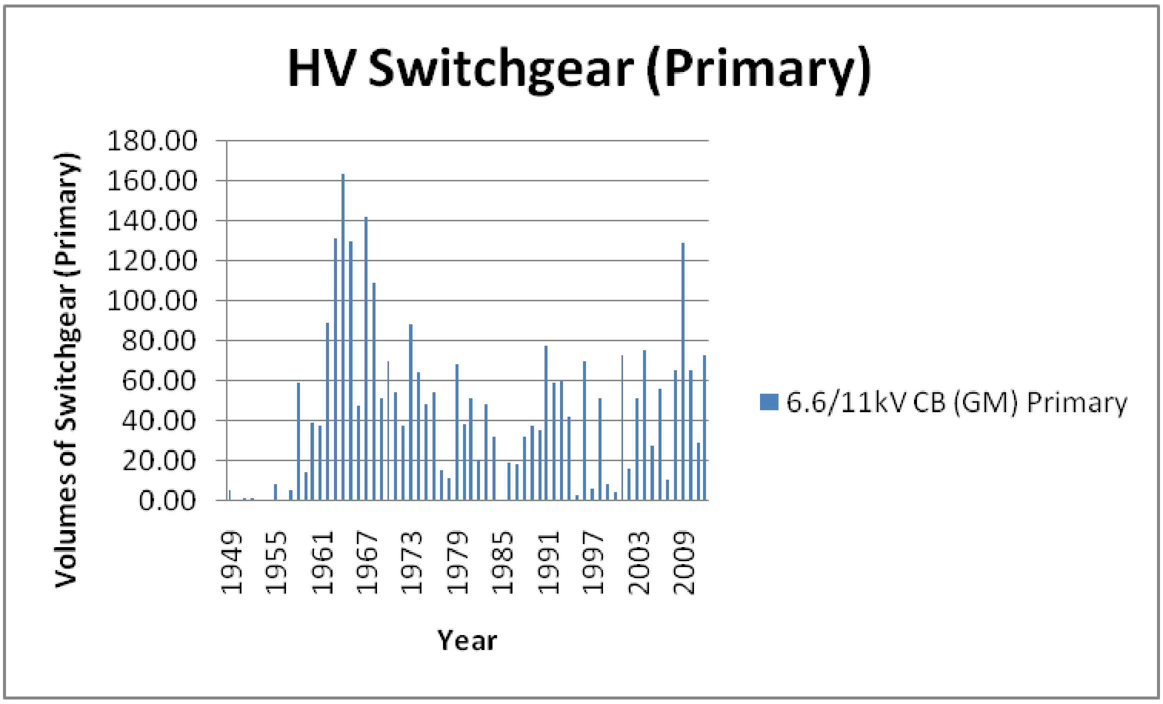


Figure 32 – 11kV Grid and Primary switchgear age profile at the start of ED1

Source: 2012 RIGs submission V5

The age profile for the 11kV grid and primary switchgear is shown in Figure 32. The switchgear in SPN is the oldest in the UK Power Networks area, with an average age at the start of ED1 of 33 years, while the oldest 10% has an average age of 59 years at the start of ED1.

Appendix 2 – HI and Criticality Profiles

Asset categories	Criticality	Units	Estimated Asset Health and Criticality Profile 2015					Asset Register
			Asset Health Index					2015
			HI1	HI2	HI3	HI4	HI5	
11kV grid and primary switchgear	Low	No. CB	494	947	398	4	0	1843
	Average	No. CB	99	627	103	0	0	829
	High	No. CB	44	244	29	0	0	317
	Very High	No. CB	0	0	0	0	0	0

Asset health and criticality – 2015 Yr1

Asset categories	Criticality	Units	Estimated Asset Health and Criticality Profile 2023					Asset Register
			Asset Health Index					2023
			HI1	HI2	HI3	HI4	HI5	
11kV grid and primary switchgear	Low	No. CB	394	823	620	2	4	1843
	Average	No. CB	129	348	358	1	0	836
	High	No. CB	48	133	135	1	0	317
	Very High	No. CB	0	0	0	0	0	0

Asset health and criticality – 2023 Yr10

Appendix 3 – Fault Data

SPN							
Assets		**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
	All faults	188	226	191	193	163	166
	Corrosion	1	4	4	9	3	0
	Deterioration due to ageing or wear (excluding corrosion)	76	69	77	87	78	92
	Deterioration due to ageing or wear (including corrosion)	77	73	81	96	81	92
Assets		**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
	All faults	0.0059	0.0071	0.0060	0.0061	0.0052	0.0052
	Poor condition due to age and wear	0.0024	0.0023	0.0026	0.0030	0.0026	0.0029

Table 6 – SPN fault data

Source: Fault Analysis Cube ‘SPN Fault Rates’

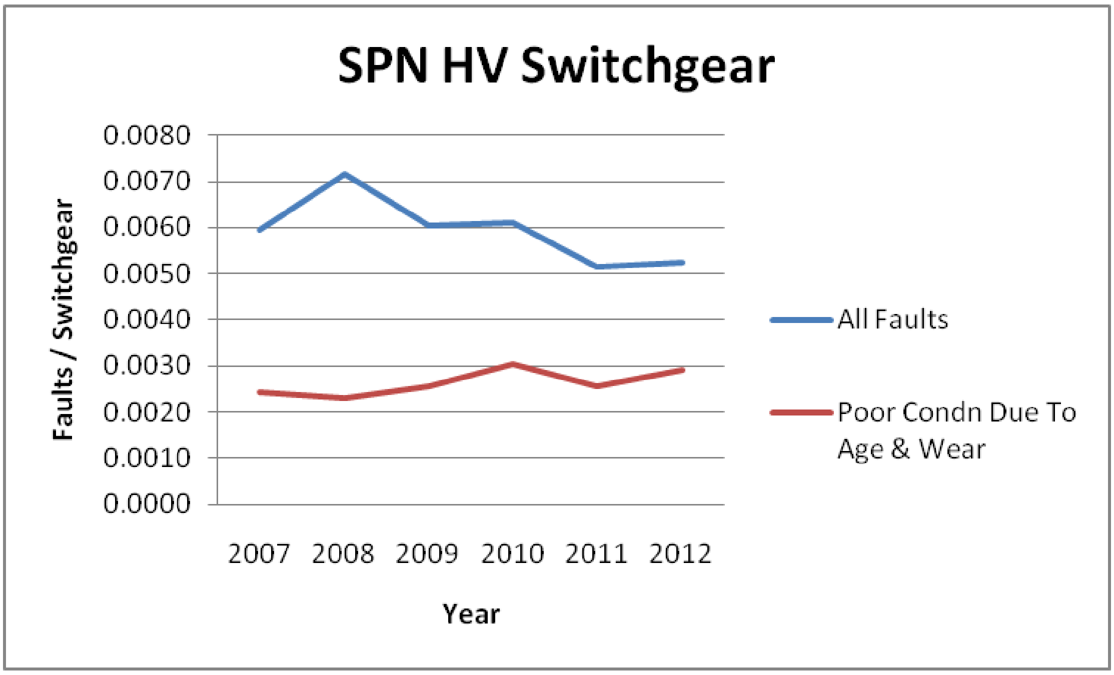


Figure 33 – SPN fault data

Source: Fault Analysis Cube ‘SPN Fault Rates’

Appendix 4 – WLC case study

Whole life cost description	Brighton Town 11kV CB: replacement v refurbishment analysis.
Starting assumption (same for all scenarios)	The OCBs are 40 years old at the beginning of the scenario, that it has a current new purchase cost of £109k/panel and an average useful operating life of 55 years. Switchboard is 34 panels and can be replaced without major civil works.

Scenario 1	At end of life a replacement vacuum CB is purchased.
Assumptions specific to this scenario	At year 15 a replacement CB is purchased.

Description of costs/(income) items	Year 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	Totals
Notional purchase cost of a 40 year old oil OCB switchboard (15 yrs remaining service life)	1,277																														1,277
I&M costs of original oil CB board	10	10	10	10	10	10	10	10	10	10	10	10	10	5																	135
Purchase of replacement vacuum CB in year 15														1,851	1,851																3,703
I&M costs of replacement vacuum CB															1	1	1	1	1	10	1	1	1	1	1	10	1	1	1	1	28
Residual value of replacement vacuum CB baord at end of scenario (i.e.: 30 years remaining life)																														-2,468	-2,468
Net cash flow	1287.1	10	10	10	10	10	10	10	10	10	10	10	10	1856	1852	0.5	0.5	0.5	0.5	10	0.5	0.5	0.5	0.5	0.5	10	0.5	0.5	0.5	-2467.9	2,674

Discount rate: Select 6.85%	6.85%
Discounted whole life cost	**2367**

Scenario 2	Housing is retrofitted with a vacuum CB truck to extend life by 20 yrs.
Assumptions specific to this scenario	Refurbishment intervention adds 20 years to the asset life.

Description of costs/(income) items	Year 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	Totals
Notional purchase cost of a 40 year old oil OCB switchboard (15 yrs remaining service life)	1,277																														1,277
I&M costs of original oil CB	10	2																													12
Purchase of retrofit CB trucks in Yr 1 & 2	287	287																													575
I&M costs of replacement vacuum CB	1	1	1	1	1	10	1	1	1	1	1	10	1	1	1	1	1	10	1	1	1	1	2	2							44
Purchase of replacement vacuum CB board in in Yr 23/24																							1,851	1,851							3,703
I&M costs of new board																							1	1	1	1	1	10	1	1	17
Residual value of replacement panel at end of scenario (i.e.: 38 years remaining life)																														-3,208	-3,208
Net cash flow	1575.3	289.8	0.5	0.5	0.5	10	0.5	0.5	0.5	0.5	0.5	10	0.5	0.5	0.5	0.5	0.5	10	0.5	0.5	0.5	0.5	1854	1854	1	1	1	10	1	-3207	2,419

Discount rate: Select 6.85%	6.85%
Discounted whole life cost	**2091**

Appendix 5 – NLRE Expenditure Plan

Investment (£'m)	DPCR4 (FBPQ)					DPCR5 (Actual and Forecast from RIgs)				
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
FBPQ						1.39	2.60	1.14	1.33	1.95
Replacment	0.08	0.65	1.60	1.70	2.50	2.22	0.98	0.40	0.65	0.90
Refurbishment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.28	0.11

Investment (£'m)	ED1 Plan								ED2 Plan							
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
FBPQ																
Replacment	2.41	4.91	4.02	3.21	4.31	3.40	1.81	2.10	2.05	1.58	1.26	1.66	1.42	1.11	1.74	1.50
Refurbishment	0.04	0.24	0.42	0.32	0.75	1.36	1.17	0.63	0.80	0.64	0.64	0.48	0.48	0.48	0.32	0.32

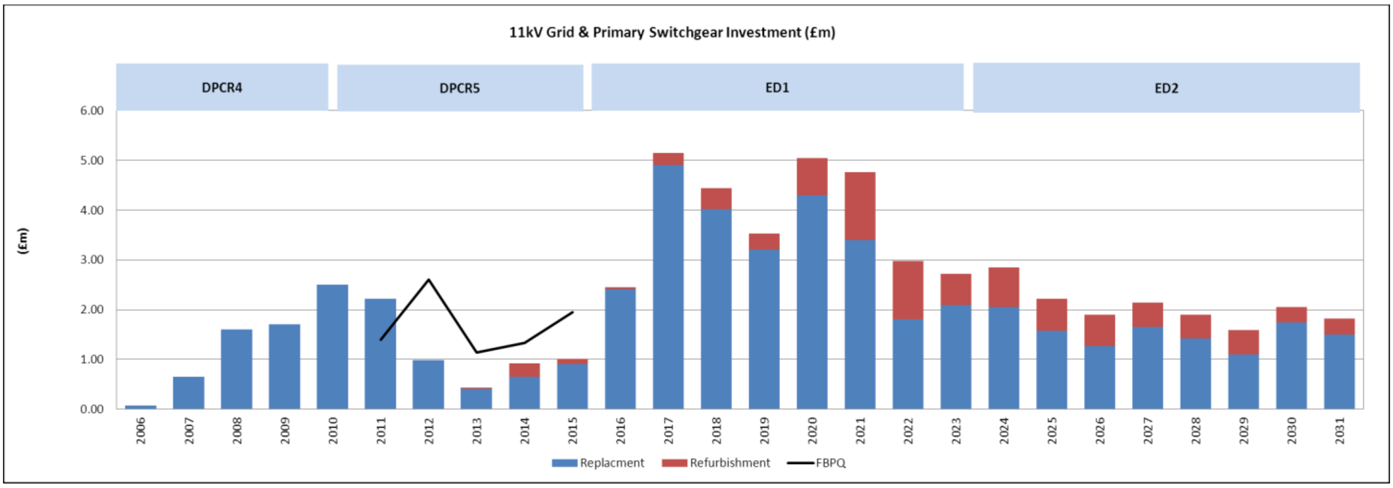


Figure 34: SPN 11kV Grid & Primary switchgear expenditure

Sources:

- DPCR4 costs: Table NL1 (DPCR5 FBPQ)
- DPCR5 costs: First three years – RIGs CV3 table
- DPCR5 costs: Last two years – 14 June 2013 NAMP (Table JLI)
- DPCR5 FBPQ costs: EPN FBPQ Mapping NAMP data
- ED1 costs: 19 February 2014 NAMP (Table JLI)
- ED2 costs: Volumes from SARM1 * UCI of £79k for replacement and UCI of £16k for refurbishment

Volumes	DPCR4 (FBPQ)					DPCR5 (Actual and Forecast from RIgs)				
Year end	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
HV Switchgear (GM) - Primary FBPQ (Removals only)						14	63	20	29	50
HV Switchgear (GM) - Primary (Removals) Replacement	1	9	22	24	35	2	14	58	1	12
HV Switchgear (GM) - Primary (Removals) Refurbishment	0	0	0	0	0	0	0	0	28	0

Volumes	ED1 Plan								ED2 Plan							
Year end	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
HV Switchgear (GM) - Primary FBPQ (Removals only)																
HV Switchgear (GM) - Primary (Removals) Replacement	22	54	41	33	37	55	23	28	26	20	16	21	18	14	22	19
HV Switchgear (GM) - Primary (Removals) Refurbishment	0	0	30	20	21	79	101	43	50	40	40	30	30	30	20	20

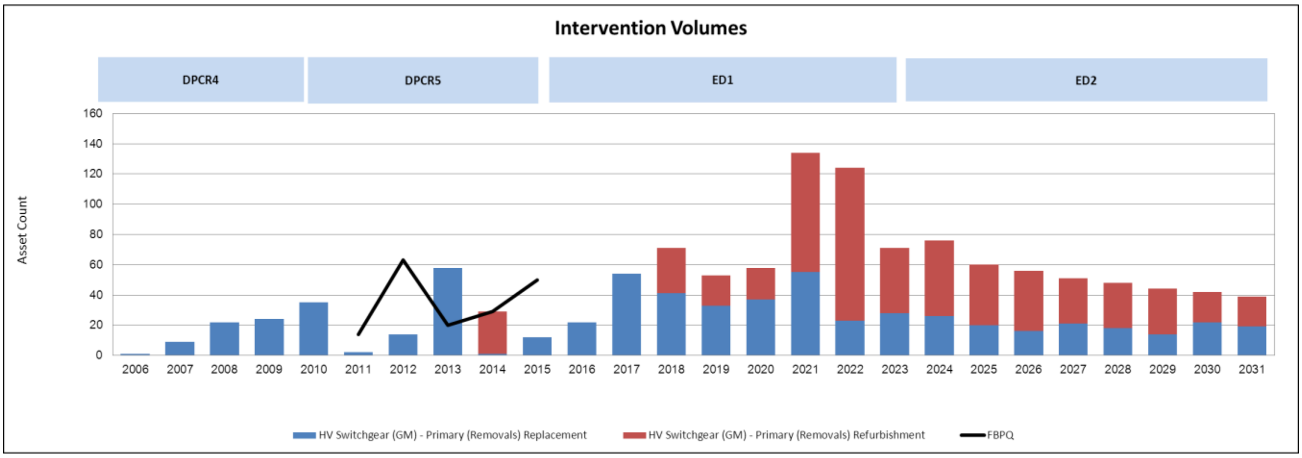


Figure 35: EPN 11kV Grid & Primary switchgear replacement volumes

Sources:

- DPCR4 volumes: Table NL3 (DPCR5 FBPQ)
- DPCR5 volumes: First three years – RIGs CV3 table
- DPCR5 volumes: Last two years – 14 June 2013 NAMP (Table O)
- DPCR5 FBPQ volumes: EPN FBPQ Mapping NAMP data
- ED1 volumes: 19 February 2014 NAMP (Table O)
- ED2 volumes: Analysis from Statistical Asset Replacement Model (SARM1)

Appendix 6 – Sensitivity Analysis

Sensitivity Analysis:

Asset Risk and Prioritisation Model for SPN HV Primary Switchgear (written by Decision Lab)

Introduction

This is a report on the sensitivity analysis conducted on the Asset Risk and Prioritisation (ARP) Model developed by EA Technology and used to support the asset replacement and investment strategy for SPN HV primary switchgear, which is included in the ED1 plan.

The objective is to understand how the Health Index profile of assets may change if the average asset life does not turn out as predicted.

An input to the ARP model is the starting asset population in each Health Index, which is different in each region. Therefore sensitivity analysis has been done on a region-by-region basis.

The Asset Risk and Prioritisation Model

The ARP model uses database information about each individual asset, and models many parameters to predict the Health Index of each asset in the future. Significant parameters are age, location, loading and current average asset life.

Sensitivity Analysis

Variation in average asset life can occur, but this is significantly less than the variation in individual asset lives.

Standard average asset lives are used in the ARP model. These range from 20 to 55 years. In 2012, about 86% had a current average asset life in the range of 45 to 55 years. This study covered the full population of SPN HV primary switchgear.

Using 2012, asset data and the replacement plans up to 2023, the ARP model was used to predict the Health Index of each asset at the beginning and end of ED1. This was then repeated, varying each current average asset life by +/- 1, 2 and 4 years.

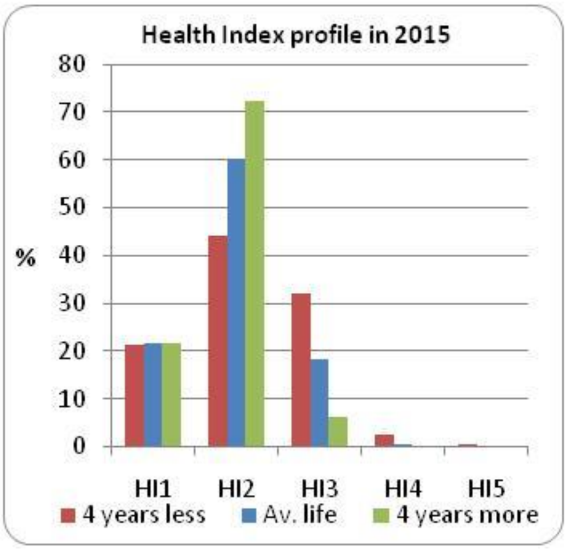
All results are shown below as the percentages of the population.

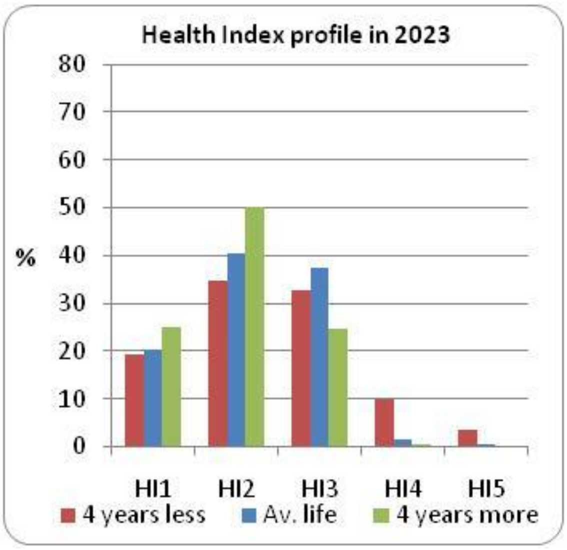
Average life change	2015 percentage HI profile				
	HI1	HI2	HI3	HI4	HI5
-4	21.2	44.1	32.0	2.4	0.2
-2	21.3	53.5	24.5	0.7	0.0
-1	21.3	57.2	20.9	0.5	0.0
0	21.5	60.2	18.1	0.1	0.0
1	21.5	62.2	16.3	0.1	0.0
2	21.5	66.2	12.2	0.0	0.0
4	21.5	72.2	6.2	0.0	0.0

Average life change	2023 percentage HI profile				
	HI1	HI2	HI3	HI4	HI5
-4	19.2	34.9	32.6	9.9	3.5
-2	19.8	38.6	35.1	5.3	1.2
-1	20.0	39.2	37.1	2.8	0.9
0	20.3	40.5	37.4	1.6	0.3
1	21.2	42.2	35.1	1.2	0.3
2	21.7	45.1	32.1	1.0	0.0
4	25.2	50.2	24.6	0.1	0.0

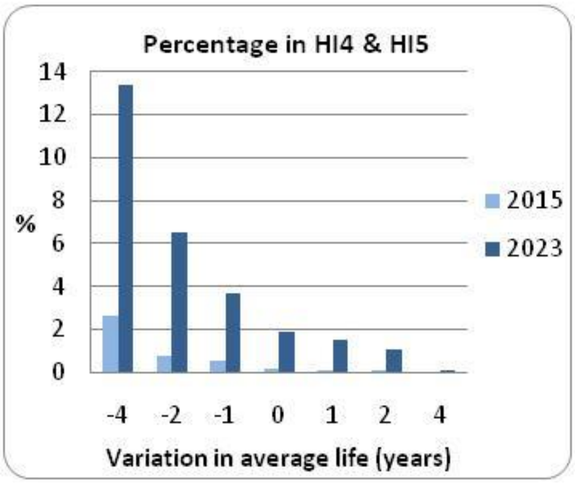
As the percentages above are rounded, the sum of a row may be 0.2% above or below 100%.

The upper and lower and current average asset life cases are charted below.





For all cases modelled, the sum of assets in Health Indices HI4 and HI5 is plotted below.



The results show:

- Variations in asset life will affect the proportions of HI4 and HI5 assets in 2015 and 2023.
- In 2015, if average asset life is four years longer, the proportion of HI4 and HI5 assets will reduce only from 0.1% to 0.0%; if four years shorter, it will increase to 2.6%.
- In 2023, if average asset life is four years longer, the proportion of HI4 and HI5 assets will reduce from 1.9% to 0.1%; if four years shorter ,it will increase to 13.4%.

Conclusion

The ED1 replacement plan for SPN HV primary switchgear is moderately sensitive to a variation in average asset life of up to four years.

Appendix 7 – Named Schemes

Ref	Project ID	DNO	Description	Switchgear type	Volume
1.50.01	3256	SPN	Addington Local - Replace 11kV Switchgear	C gear	17
1.50.01	7821	SPN	Angmering 33kV - Replace 11kV Switchgear	C gear	10
1.50.01	7919	SPN	Ashford East - Retrofit 11kV Switchgear	C4X	11
1.50.01	4163	SPN	Ashtead Primary - Replace 11kV Switchgear	C gear	9
1.50.01	7920	SPN	Barming - Retrofit 11kV Switchgear	LMT	8
1.50.01	7822	SPN	Biggin Hill 33kV - Retrofit 11kV Switchgear	C gear	6
1.50.01	7921	SPN	Broadoak - Retrofit 11kV Switchgear	C gear	3
1.50.01	4160	SPN	Burgess Hill Primary - Retrofit 11kV Switchgear	C gear	6
1.50.01	7823	SPN	Caterham 33/11kV - Replace 11kV Switchgear	C gear	12
1.50.01	7922	SPN	CERL - Retrofit 11kV Switchgear	C gear	10
1.50.01	7923	SPN	Chartham - Retrofit 11kV Switchgear	VSI	8
1.50.01	7924	SPN	Chatham Hill - Replace 11kV Switchgear	VMX	19
1.50.01	4158	SPN	Chatham West Primary - Retrofit 11kV Switchgear	C gear	16
1.50.01	7927	SPN	Cobham (Kent) 33/11kV - Retrofit 11kV Switchgear	LMT	8
1.50.01	7926	SPN	Cobham (Surrey) 33/11KV - Retrofit 11kV Switchgear	LMT	10
1.50.01	4159	SPN	Cowfold Primary - Replace 11kV Switchgear	C gear	8
1.50.01	7824	SPN	Crawley Ind Est West - Retrofit 11kV Switchgear	LMT	14
1.50.01	7812	SPN	Eastchurch Prison 33/6.6kV - Replace 6.6kV Switchgear	VMX	8
1.50.01	8965	SPN	Epsom 33/11kV Retrofit 11kV Switchgear	C gear	12
1.50.01	4167	SPN	Ewell Primary - Retrofit 11kV Switchgear	C gear	13
1.50.01	4165	SPN	Farningham Primary - Retrofit 11kV Switchgear	C gear	8
1.50.01	7826	SPN	Forest Row 33kV - Retrofit 11kV Switchgear	LMT	8
1.50.01	3135	SPN	Future provision - Replace 11kV Switchgear	Unknown	8
1.50.01	7925	SPN	Gravesend West - Retrofit 11kV Switchgear	C gear	3
1.50.01	7932	SPN	Hampton 33/11kV - Retrofit 11kV Switchgear	LMT	8
1.50.01	3258	SPN	Hangleton 33/11kV S/S - Retrofit 11kV Switchgear	C gear	10
1.50.01	7813	SPN	Herne Bay 33/11kV - Replace 11kV Switchgear	VMX	13
1.50.01	7814	SPN	Hurstpierpoint 33kV - Replace 11kV Switchgear	VSI	11
1.50.01	7827	SPN	Little Common 33/11kV - Replace 11kV Switchgear	C gear	12
1.50.01	7828	SPN	Margate 33/11kV - Retrofit 11kV Switchgear	LMT	10
1.50.01	7829	SPN	Meads - Retrofit 11kV Switchgear	C4X	11
1.50.01	7830	SPN	Medway Local 33/11kV - Retrofit 11kV Switchgear	LMT	5
1.50.01	7831	SPN	Minster 33/6.6kV - Replace 6.6kV Switchgear	C4X	7
1.50.01	7832	SPN	Molesey 33/11kV - Retrofit 11kV Switchgear	LMT	9
1.50.01	7833	SPN	Moulsecoomb 33/11kV - Retrofit 11kV Switchgear	C4X	12
1.50.01	7933	SPN	Newick 33/11kV - Retrofit 11kV Switchgear	C4X	5
1.50.01	7835	SPN	North Chessington 33kV - Retrofit 11kV Switchgear	C gear	7
1.50.01	7816	SPN	North Shoreham 33kV/11kV - Replace 11kV Switchgear	VMX	10
1.50.01	7836	SPN	North Worthing 33kV - Replace 11kV Switchgear	C gear	12
1.50.01	4155	SPN	Nutfield Primary - Replace 11kV Switchgear	C gear	12
1.50.01	4154	SPN	Ocklynge Primary - Replace 11kV Switchgear	C gear	12

1.50.01	7837	SPN	Peacehaven 33kV - Retrofit 11kV Switchgear	LMT	8
1.50.01	7838	SPN	Petts Wood 33kV - Retrofit 11kV Switchgear	LMT	6
1.50.01	4164	SPN	Queens Park Primary - Replace 11kV Switchgear	C gear	13
1.50.01	7840	SPN	Rainham - Replace 11kV Switchgear	C gear	13
1.50.01	7841	SPN	Ramsgate 33/11kV - Replace 11kV Switchgear	C gear	13
1.50.01	7842	SPN	Rusthall 33kV - Retrofit 11kV Switchgear	C4X	7
1.50.01	7843	SPN	Seaford - Replace 11kV Switchgear	C4X	9
1.50.01	4161	SPN	South Hove Primary - Replace 11kV Switchgear	C gear	19
1.50.01	7844	SPN	South Orpington 33kV - Replace 11kV Switchgear	C gear	11
1.50.01	7845	SPN	Southwick 33kV - Replace 11kV Switchgear	C gear	10
1.50.01	7846	SPN	Spurgeons Bridge - Retrofit 11kV Switchgear	LMT	18
1.50.01	7929	SPN	St Helier 33/11kV - Retrofit 11kV Switchgear	LMT	11
1.50.01	7847	SPN	St Peters 33/11kV - Replace 11kV Switchgear	C gear	12
1.50.01	7819	SPN	Sundridge 33kV - Replace 11kV Switchgear	VMX	9
1.50.01	7928	SPN	Tonbridge East 33/6.6KV - Retrofit 11kV Switchgear	LMT	15
1.50.01	7848	SPN	Twickenham 33/11kV - Retrofit 11kV Switchgear	C gear	8
1.50.01	8967	SPN	Warehorne 33kV/11kV - Replace 11kV Switchgear	VMX	4

Table 7 – SPN 11kV grid and primary switchgear: summary of interventions

Type	Retrofit	Replace	Total
C Gear	102	195	297
LMT	138	0	138
C4X	46	16	62
VMX	0	63	63
VSI	8	11	19
Unknown	0	8	8
Total	**294**	**293**	**587**

Table 8 - SPN summary of interventions by type

Note that further details of project 7924 (Chatham Hill 33/11kV Substation - Replace 11kV Switchgear) are given in a separate NLRE Scheme Justification Paper.

Appendix 8 – Output NAMP/ED1 Business Plan Data Table Reconciliation

Outputs	Asset Stewardship Reports										Business Plan Data Table										
Investment description	NAMP Line	2015 /16	2016 /17	2017 /18	2018 /19	2019 /20	2020 /21	2021 /22	2022 /23	**Total**	RIG Table	RIG Row	2015 /16	2016 /17	2017 /18	2018 /19	2019 /20	2020 /21	2021 /22	2022 /23	**Total**
HV Switchgear (GM) - Primary (Removals) Replacement	1.50.01	22	54	41	33	37	55	23	28	293	CV3	161	22	54	41	33	37	55	23	28	**293**
HV Switchgear (GM) - Primary (Removals) Refurbishment	1.50.01	0	0	30	20	21	79	101	43	294	CV5	19	0	0	30	20	21	79	101	43	**294**
										0											**0**
										0											**0**
										0											**0**
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										0											**0**
										0											**0**
Total		**22**	**54**	**71**	**53**	**58**	**134**	**124**	**71**	**587**			**22**	**54**	**71**	**53**	**58**	**134**	**124**	**71**	**587**

Table 9: Output NAMP/ED1 Business Plan Data Table Reconciliation

Source: 19th February 2014 NAMP Table O
21st February 2014 ED1 Business Plan Data Tables

Appendix 9 – Efficiency benchmarking with other DNO's

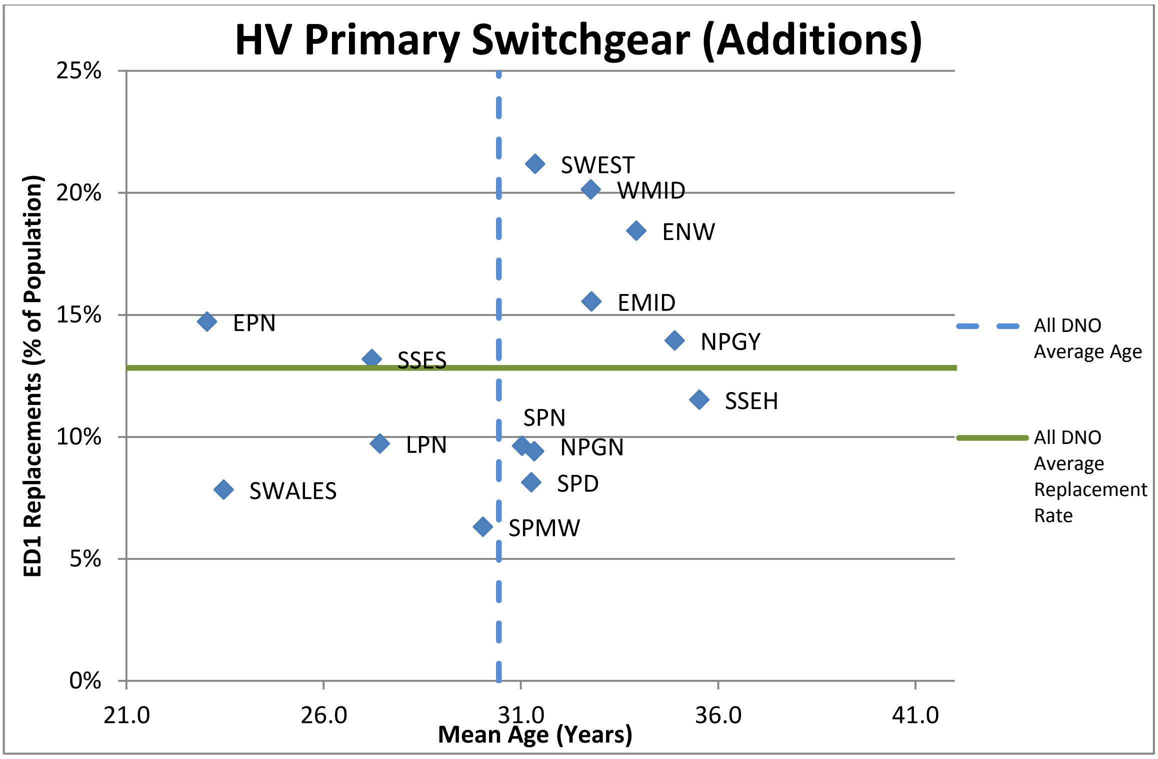

Figure 36 Efficiency Benchmarking

Source: DNO Datashare_2013

The graph above shows that the proposed replacement volumes in SPN are well below the industry average which reflects the UKPN policy of only replacing switchgear in poor condition rather than replacing on the basis of age alone.

Appendix 10 – Material changes since the July 2013 ED1 submission

Changes between the July 2013 submission and the March 2014 re-submission are summarised and discussed below.

Asset type	Action	Change type	2013 submission	2014 submission	Difference (Reduction)	Comment
6.6/11kV CB (GM) Primary	Replace (CV3)	Volume (additions)	289	300	11	Warehorne
		Volume (removals)	289	293	4	Warehorne
		Investment (£m)	7.9	8.0	0.12	Warehorne
		UCI (£k)	27.2	26.6	(0.6)	
6.6/11kV CB (GM) Primary	Refurbish (CV5)	Volume	282	294	12	Epsom
		Investment (£m)	4.69	4.93	0.24	Epsom
		UCI (£k)	16.6	16.8	0.2	

Table 10: Material changes since the July 2013 ED1 submission

Source: ED1 Business Plan Data Tables following the OFGEM Question and Answer Process
21st February 2014 ED1 Business Plan Data Tables

Switchgear – 6.6/11kV CB (GM) Primary

Between the time of the original submission and the current resubmission two additional sites have been identified as requiring intervention in ED1. The GEC VMX switchboard at Warehorne now requires replacement following an increase in partial discharge activity, and the switchboard at Epsom now requires retrofitting to resolve operating mechanism reliability issues. These two projects have increased the investment and reduced the overall UCI for both CV3 Row 33 and CV5 Row 19.