National Grid Electricity Transmission Network Output Measures Methodology Network Asset Risk Annex

Issue 3

VERSION CONTROL

VERSION HISTORY

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30/04/18	1	Issue 1: OFGEM Submission
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29/6/18	3	Issue 3: Final Version

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GLOSSARY OF TERMS

Asset Risk	Term adopted that is synonymous with Condition Risk in the Direction
Asset Class	A group of assets with similar characteristics
Asset Management	Coordinated activity of an organization to realize value from assets[†]
Consequence	Outcome of an event affecting objectives[*]
Consequence of Failure	A consequence can be caused by more than one Failure Mode. This is monetised values for the Safety, Environmental, System and Financial consequences
Deterioration	Progressive worsening of condition
the Direction	Ofgem Direction document from April 2016
EoL Modifier	End of Life number that modifies or is modified to produce an End of life value
Event	Occurrence or change of a particular set of circumstances[*]
Failure	A component no longer does what it is designed to do. May or may not result in a fault
Failure Mode	A distinct way in which a component can fail
Fault	An asset no longer functions and intervention is required before it can be returned to service
Intervention	An activity (maintenance, refurbishment, repair or replacement) that is carried out on an asset to address one or more failure modes
Level of risk	Magnitude of a risk or combination of risks, expressed in terms of the combination of consequences and their likelihood[*]
Licensee(s)	One or more of the TOs
Likelihood	Chance of something happening[*]
Load Related	Works on a transmission system required due to an increase in demand and/or generation
Monetised Risk	A financial measure of risk calculated as a utility function
Network Risk	The sum of all the Asset Risk associated with assets on a TO network

[†]ISO 55000:2014

[*]Refer to Table 1 below for the source of these definitions

AAAC	All Aluminium Alloy Conductors
AAL	Anticipated Asset Life
ABCB	Air Blast Circuit Breaker
ACAR	Aluminium Conductor Aluminium Reinforced conductor
ACSR	Aluminium Conductor Steel Reinforced conductor
BS EN	British Standards European Norm
CAB	Conventional Air-Blast
CoF	Consequence of Failure
CUSC	Connection and Use of System Code
DGA	Dissolved Gas Analysis
EA	Equivalent Age
EoL Modifier/ EOLmod	End of Life Modifier
FMEA	Failure mode and effects analysis
GCB	Gas Circuit Breaker
HILP	High Impact Low Probability
HTLS	High Temperature Low Sag conductor
ISO	International Organization for Standardization
MITS	Main Interconnected Transmission System
MVArh	MegaVar Hours
MWh	Megawatt Hours
NETS SQSS	National Electricity Transmission System Security and Quality of Supply Standards
NGET	National Grid Electricity Transmission
NOMs	Network Output Measures
OCB	Oil Circuit Breaker
Ofgem	Office of gas and electricity markets
OHL	Overhead line
PAAF	Predicted Actual Age at Failure
PAB	Pressurised head Air Blast
PoF	Probability of Failure
RTM	Risk Trading Model
SO	System Operator
SSSI	Site of Special Scientific Interest
SVL	Sheath Voltage Limiter
TEC	Transmission Entry Capacity
TNUoS	Transmission Network Use of System
TO	Transmission Owner
VOLL	Value of Lost Load

*Refer to Table 1, below,for the source of these definitions

α	Tuning parameter for mapping end of life modifier to probability of failure
β	The maximum probability of failure which would be expected for an asset that has reached its anticipated asset life
φ	Weighting factor for design variation
A_k	A measure of risk associated with asset k
B_y	Cost of operation for a boundary
C_1	A scaling factor to convert age to a value in the range 0 to 100 in EOL calculations
C_i	An individual component parameter of end of life modifier
C_j	Monetised consequence j
C_{MVArh}	Average cost of procuring MVArh from generation sources
C_{SBP}	Annual average system buy price
C_{SMP}	Annual average system marginal price
C_{TNUoS}	Average TNUoS refund cost per MWh
C_{max}	Maximum score that a component parameter of end of life can be
D	Duration or Family specific deterioration
D_d	Circuit damage restoration time
D_f	Unrelated fault restoration time
D_{fm}	Duration of failure mode unavailability
D_m	Protection mal-operation restoration time
D_o	Outage restoration time
F_i	Failure mode i
G_c	Generation compensation payment cost
G_R	Cost of generation replacement
i	A given failure mode
j	A given consequence
k	A given asset or a family specific deterioration scaling factor
L	Customer connection or substation
MW_D	Annual average true demand of customers disconnected
MW_{GTEC}	The Transmission Entry Capacity of each disconnected generator
MW_w	Weighted quantity of disconnected generation
M_z	A multiplier coefficient
n	A given whole number
N_d	Probability of no damage to another circuit
N_f	Probability of no coincident fault to another circuit
N_l	Probability of not overloading remaining circuit
N_m	Probability of no protection maloperation of another circuit
N_o	Probability of no coincident outage
P	Probability
$P(C_j)$	Probability of consequence j occurring during a given time period
$P(C_j/F_i)$	Conditional probability of consequence j arising as a result of failure mode i occurring
P_d	Probability of damage to another circuit
$P(D_i)$	Probability of failure mode i being detected and action being taken before consequence j materialises
P_f	Probability of a coincident fault to another circuit
$P(F_i)$	Probability of failure mode i occurring during the next time interval
P_l	Probability of overloading remaining circuit
P_m	Probability of protection maloperation of another circuit

P_o	Probability of coincident outage
P_{oc}	Probability of disconnection
Q	Capacity of compensation equipment in MVAr
$R_{boundary}$	Boundary transfer risk cost
$R_{customer}$	Customer disconnection risk cost
R_F	Requirement factor for compensation equipment
R_{RC}	Reactive compensation risk cost
S_C	Particularly sensitive COMAH sites
S_E	Economic key point
S_i	Component score for OHL conductor samples
$S_t \ or \ S(t)$	The cumulative probability of survival until time t
S_T	Transport hubs
$S_{t+1} \ or \ S(t+1)$	The cumulative probability of survival until time $t+1$
t	A given time period
V	Vital infrastructure disconnection cost
V_C	Disconnection cost for COMAH sites
V_E	Disconnection cost for economic key point
V_T	Disconnection cost for transport hubs
W_{FAM}	Family weighting score for overhead line conductors used in EOL modifier calculations
X	Number of circuits supplying a connection after an asset failure
Z	The number of customer sites where X is at its minimum value, X_{min}

1. INTRODUCTION

This document should be read in conjunction with the common NOMs Methodology document.

1.1. NATIONAL GRID

National Grid Electricity Transmission (NGET) owns the high voltage electricity transmission system in England and Wales. It broadly comprises circuits operating at 400kV and 275kV, the system consists of approximately:

- 14,000 kilometres of overhead line
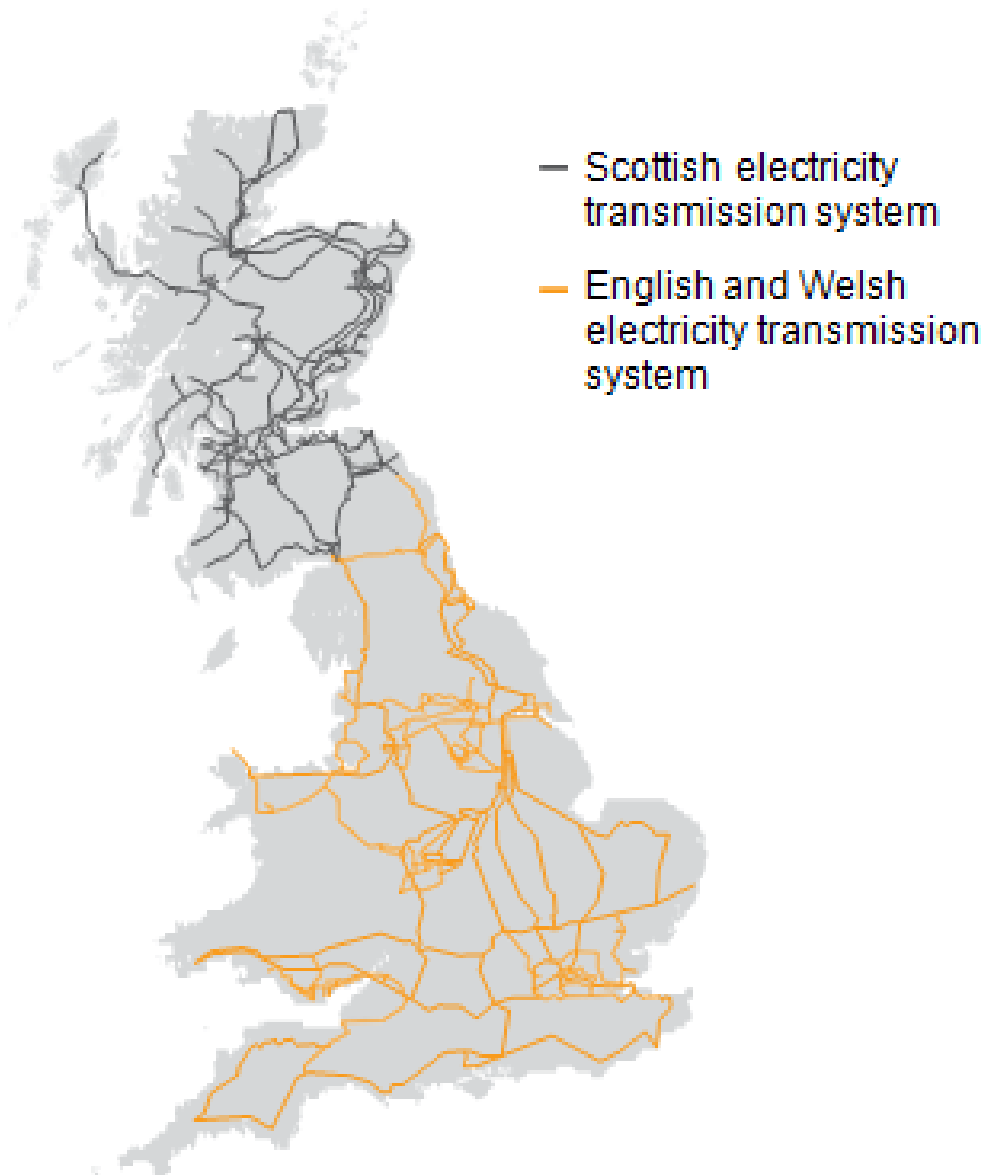- 600 kilometres of underground cable
- Over 300 substations.

Figure 1

1.2. INTRODUCTION TO RISK

Risk is part of our everyday lives. In our everyday activities such as crossing the road and driving our cars we take risks. For these everyday activities we often do not consciously evaluate the risks but we do take actions to reduce the chance of the risk materialising and/or the impact if it does.

For example we reduce the chance of crashing into the car in front by leaving an ample stopping distance and we reduce the impact should a car crash happen by fastening our seat belts. In taking these actions we are managing risk.

Organisations are focussed on the effect risk can have on achieving their objectives, for example, keeping their staff, contractors and the public safe, providing an agreed level of service to their customers at an agreed price, protecting the environment, making a profit for shareholders.

Organisations manage risk by identifying it, analysing it and then evaluating whether the risk should be modified.

To help organisations manage risk, the International Organization for Standardization (ISO) produced ISO 31000:2009 *Risk management - Principles and guidelines* which included a number of definitions, principles and guidelines associated with risk management which provide a basis for identifying, analysing and modifying risk. In addition, BS EN 60812:2006 *Analysis techniques for system reliability* provides useful guidance on the application of analysis techniques to risk management.

In this methodology relevant content from ISO 55001 *Asset management*, ISO 31000:2009 and BS EN 60812 has been used. This includes definitions associated with risk as defined in ISO Guide 73:2009 *Risk management - Vocabulary*.[1]

Risk	Effect of uncertainty on objectives
Risk management	Coordinated activities to direct and control an organization with regard to risk
Event	Occurrence or change of a particular set of circumstances
Likelihood	Chance of something happening
Consequence	Outcome of an event affecting objectives
Level of risk	Magnitude of a risk or combination of risks, expressed in terms of the combination of consequences and their likelihood

<div align="center">Table 1</div>

Risk is often expressed in terms of a combination of the associated likelihood of an event (including changes in circumstances) and the consequences of the occurrence.

Likelihood can be defined, measured or determined objectively or subjectively, qualitatively or quantitatively, and described using general terms or mathematically (such as a probability or a frequency over a given time period).

Similarly, consequences can be certain or uncertain, can have positive and negative effects on objectives and can be expressed qualitatively or quantitatively.

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A single event can lead to a range of consequences and initial consequences can escalate through knock-on effects.

The combination of likelihood and consequence is often expressed in a risk matrix where likelihood is placed on one axis and consequence on the other.

This combination is not necessarily mathematical as the matrix is often divided into categories on the rows and the columns and can be categorised in whatever form is applicable to the risks under consideration.

Sometimes this combination of likelihood and consequence is expressed mathematically as:

$$Risk = Likelihood \times Consequence$$

Equation 1

In this mathematical form whilst it is necessary for the likelihood and consequence to be expressed numerically for such an equation to work, the likelihood does not necessarily have to be a probability and the consequence may be expressed in any numeric form.

When using likelihood expressed as a probability and consequence expressed as a cost, using the risk equation this provides a risk cost. This risk cost enables ranking of the risk compared with others risks similarly calculated. This is true for any consequence expressed numerically on the same basis.

When considering a non-recurring single risk over a defined time period, the risk event has two expected outcomes, either the risk will occur resulting in the full consequence cost or the risk event will not occur resulting in a zero-consequence cost.

For this reason the use of summated risk costs for financial provision over a defined time period works best when there is a large collection of risks. This is because if only a small number of risks are being considered, a financial provision based on summated risk cost will either be larger or smaller than is actually required.

This is particularly the case for high-impact, low-probability (HILP) risks. It is generally unusual to have a large collection of HILP risks and so the summated risk cost does not give a good estimate of what financial provision is required. There are also particular considerations with respect to these risks when using risk cost to rank subsequent actions.

1.3.   INTRODUCTION TO NGET RISK CALCULATION METHODOLOGY

In order to ascertain the overall level of risk for NGET, the NOMs methodology will calculate Asset Risk for lead assets only, namely:

1. Circuit Breakers
2. Transformers and Reactors
3. Underground Cables
4. Overhead Line Conductor
5. Overhead Line Fittings

For reasons of economic efficiency, NGET does not consider every possible failure mode and consequence, only those which are materially significant. NGET's assessment of material significance is based upon their experience and consequential information set.

The NGET implementation of this methodology considers the failure modes which have been explored in detail and are supported by available data. The mapping of failure modes to consequences is complex and is supported by historical data, where this is available, and estimated, where it is not.

1.3.1. ASSET (A)

An asset is defined as a unique instance of one of the above five types of lead assets. Overhead line and cable routes will be broken down into appropriate segments of the route. Each asset belongs to an asset family and each asset family has one or more failure modes. A failure mode can lead to one or more consequences.

1.3.2. MATERIAL FAILURE MODE (F)

A failure mode is a distinct way in which an asset or a component may fail, material failure modes are only those failure modes that are considered to be materially significant and, as stated above, only material failure modes are considered in the risk calculation methodology. Failure means it no longer does what it is designed to do and has a significant probability of causing a material consequence. Each failure mode needs to be mapped to one or more failure mode effects.

A given failure mode (F_i) also needs to be mapped to at least one consequence (C_j) and a conditional probability that the given consequence will manifest should the failure occur $P(C_j|F_i)$.

1.3.3. PROBABILITY OF FAILURE P(F)

Probability of failure ($P(F_i)$) represents the probability that a failure mode will occur in the next time period. It is generated from an underlying parametric probability distribution, or failure, curve. The nature of this curve and its parameters (i.e. increasing or random failure rate, earliest and latest onset of failure) are provided by Failure Mode and Effects Analysis (FMEA). The probability of failure is influenced by a number of factors, including time, duty and condition. The detailed calculation steps to determine probability of failure are described within this document.

1.3.4. PROBABILITY OF DETECTION AND ACTION P(D)

There is a probability that the failure mode may be detected through inspection and action taken before there is a consequence, this is denoted by $P(D_i)$ for a given failure mode, i.

The probability of detection and action has been included at this stage for completeness. Further development in this area could be considered in future iterations of the calculation of asset risk; however, it is not currently included within the NGET calculations.

There are a number of techniques that may be used to detect certain failure modes and these have been captured in the FMEA:

Detection Technique	Activity
Periodic inspection	Routine inspection of asset at set intervals.
Alarm/indication/ metering	Automatic systems that monitor certain parameters on equipment and provide an automatic alert, e.g. cable oil pressure monitoring detects the possibility of an oil leak.
Sample monitoring	Periodic sampling to establish specific parameters to determine health of asset, e.g. oil sampling on transformers.
Continuous monitoring	Monitoring equipment installed on specific assets whereby data about their health is recovered, logged, trended and monitored autonomously.

	Alerts are generated when thresholds are breached, or when a parameter exceeds X% in a specified time frame, e.g. Mobile Transformer Assessment Clinic.
Periodic operation	Planned operation to ensure that the asset/components/mechanisms function as expected, e.g. periodic operation of circuit breakers.

<div align="center">**Table 2**</div>

1.3.5. CONSEQUENCE (C)

For the calculation of asset risk, each of the underlying system, safety, environmental and financial components are assigned a consequence, expressed as a financial cost. Each C_j has one or more F_i mapped to it. A Consequence can be caused by more than one Failure Mode, but a Consequence itself can only occur once during the next time period. For example, an Asset or a particular component is only irreparably damaged once.

1.3.6. PROBABILITY OF CONSEQUENCE P(C)

If Consequence *j* can be caused by *n* failure modes, then *P(Cj)* the probability of consequence *j* occurring in the next time interval is given by:

$$P(C_j) = 1 - \prod_{i=1}^{n}(1 - P(F_i) \times P(C_j|F_i) \times (1 - P(D_i))$$

<div align="center">**Equation 2**</div>

<div align="center">$where$:</div>

$P(C_j) = Probability\ of\ consequence\ j\ occurring\ during\ a\ given\ time\ period$

$P(F_i) = Probability\ of\ failure\ mode\ i\ occurring\ during\ the\ next\ time\ interval$

$P(C_j|F_i) = Conditional\ probability\ of\ Consequence\ j\ given\ F_i\ has\ occurred$

$P(D_i) = Probability\ of\ detecting\ failure\ mode\ i\ and\ acting\ before\ C_j\ materialises$

However, where failure modes and consequences have a one-to-one mapping, i.e. the given consequence will definitely occur if the failure mode occurs, the function *P(Cj|Fi)* is not required and the Probability of Failure is equal to the Probability of Consequence.

1.3.7. ASSET RISK

In the common NOMS Methodology document, Asset Risk is defined as:

For a given asset (A), a measure of the risk associated with it is the Asset Risk (AR), given by:

$$AR = \sum_{j=1}^{n} PoF_j \times CoF_j$$

<div align="center">**Equation 3**</div>

$where$:

$PoF_j = Probability\ of\ Failure\ j\ occurring\ during\ a\ given\ time\ period$

CoF_j = the monetised Consequence of Failure j

n = the number of failures associated with Asset

The NGET specific methodology modifies this slightly to:

For a given asset k, a measure of the risk associated with it is the Asset Risk (A_k), given by:

$$Asset\ Risk(A_k) = \sum_{j=1}^{n} P(C_j) \times C_j$$

$where$:

$P(C_j)$ = Probability of consequence j occurring during a given time period

C_j = the monetised Consequence j

n = the number of Consequences associated with Asset k

Figure 2 shows how the components interact and combine together to arrive at a value for Asset Risk.
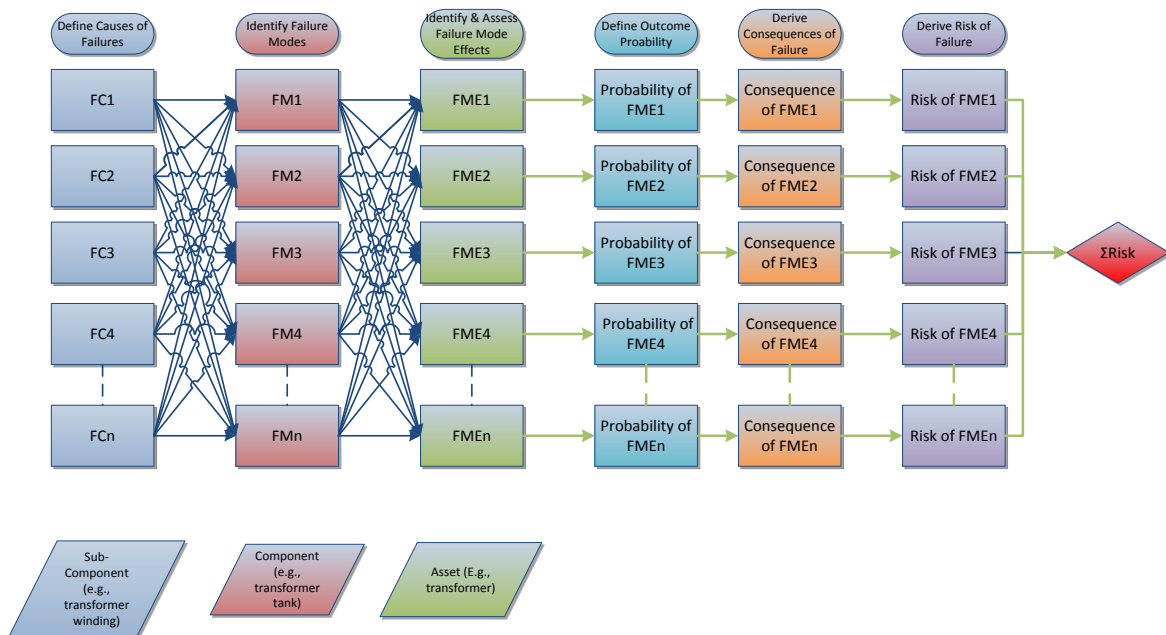

Figure 2

1.3.8. NETWORK RISK

As shown in Figure 2 & Equation 4, the asset risk is a function of the probability of each failure mode occurring and the impact of each of the consequences.

The network risk for NGET can be calculated by summing the asset risks associated with each of the lead assets as shown in Equation 5.

$$Network\ Risk = \sum_{k=1}^{n} A_k$$

Equation 5

2. METHODOLOGY FOR CALCULATING PROBABILITY OF FAILURE

Probability of failure represents the likelihood that a failure mode will occur in the next time period. It is denoted by $P(F_i)$, the probability of failure mode i occurring during the next time interval is given by:

$$P(F_i) = \frac{S_t - S_{t+1}}{S_t}$$

Equation 6

$where$:

$P(F_i) = the\ probability\ of\ failure\ mode\ i\ occurring\ during\ the\ next\ time\ interval$

$S_t = the\ cumulative\ probability\ of\ survival\ until\ time\ t$

$S_{t+1} = the\ cumulative\ probability\ of\ survival\ until\ time\ t+1$

S_t denotes the likelihood that failure does not occur until at least time t. It is generated from an underlying parametric probability distribution or failure curve. The nature of this curve and its parameters (i.e. increasing or random failure rate, earliest and latest onset of failure) are provided by the process known as Failure Mode and Effects Analysis (FMEA) as described in BS EN 60812. The probability of failure is influenced by time, duty and condition.

2.1. DEFINE CAUSES OF FAILURE

Failure may be defined and categorised in different ways. For the purposes of the FMEA approach NGET has adopted, it is usefult to consider three basic underlying types of failure:

1. Time-based failure (potential to functional failure)
   The patterns of failure are predictable with an interval between initiation (potential) and failure. Inspection activities may be available to identify the development of the failure cause after initiation. Time-based failures are represented within the model with an earliest and latest expected onset of the failure based on the time that has elapsed following the last intervention (for example, maintenance activity) which addresses the particular failure cause.

2. Utilisation failure
   Failure is based on duty with a predictable 'useful life' for the component. A preventative intervention can be undertaken, if this useful life is understood, which can be scheduled before failure occurs. For example, these asset types may have a known number of operations and are represented in the model by the number of expected operations to failure since the last intervention that addresses the particular failures.

3. Random failure
   These failures will have a constant failure rate, when observed over a large enough population or over a sufficient period of time. They are usually expressed as a percentage per annum for the population.

To avoid unnecessary levels of analysis, section 5.2.4 of BS EN 60812 recommends that the most likely causes for each failure mode should be identified. Therefore, rather than identifying every single possible cause for all failure modes, the level of detail should be reflective of the failure mode effects and their severity. The more severe the effects, the more accurate the identification and description needed to prevent unnecessary effort

to identify failure causes with little effect. The failure cause may usually be determined from analysis of failed assets, test units or expert opinion.

2.2.   IDENTIFY FAILURE MODES

There are a number of potential causes of asset failure. These can lead to many different failure modes, which in turn lead to one or more events.

Every asset will have many different failure modes, consideration of the range of failure modes associated with a circuit breaker for example, may resemble Figure 3 (purely illustrative and not to scale).
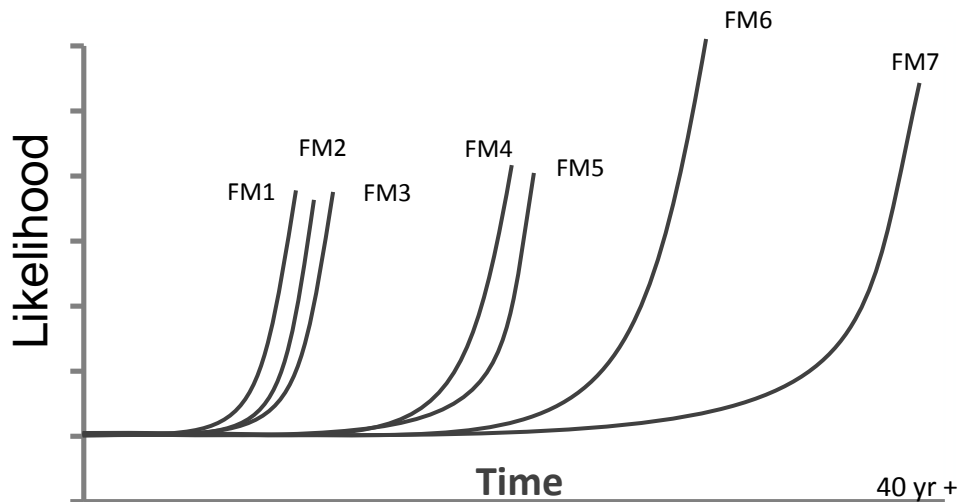
Figure 3

Examples of these failure modes might include:

FM1	Failure to trip
FM2	Failure to open
FM3	Failure to complete operation
FM4	Failure to close
FM5	Failure to respond to control signal
FM6	Flashover
FM7	Loss of Containment

Table 3

The level of detail in the analysis (and the number of relevant failure modes) is an important consideration. Section 5.2.2.3 of BS EN 60812 provides useful guidance in this area and recognises that the number of failure modes for consideration will be influenced by previous experience; less detailed analysis may be justified from a system based on a mature design, with good reliability, maintainability and safety record. In addition, the requirements of the asset maintenance and repair regime may be a valuable guide in determining the necessary level of detail.

2.2.1. UNDERSTANDING FAILURE MODES AND HOW INTERVENTIONS IMPACT ASSET RISK

Figure 4 shows a simplified and purely illustrative example of an asset that has 2 failure modes (FM1 and FM2). The blue line represents the asset's risk position with time:
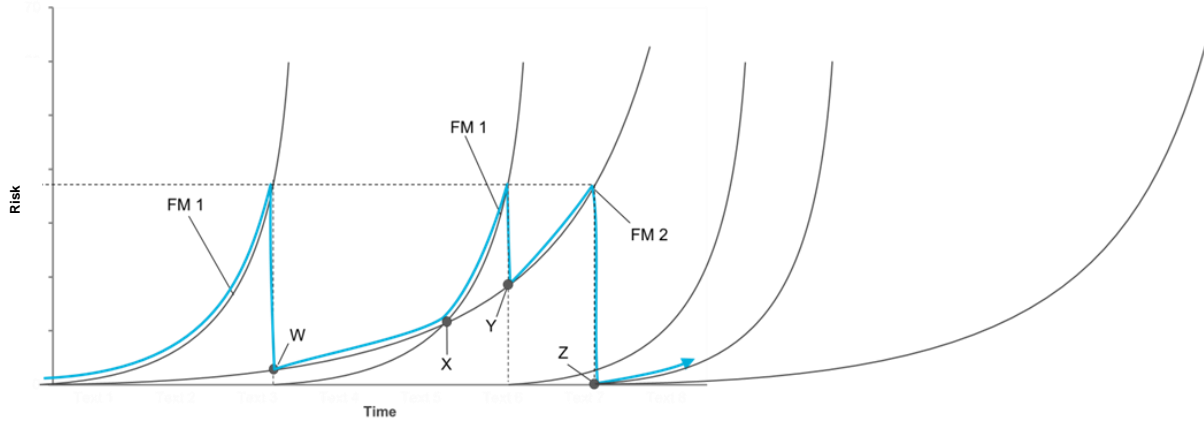
Figure 4

An intervention addresses one or more failure modes, either resetting or partially resetting that failure mode but leaving others unchanged.

As time progresses the asset risk increases because the probability of FM1 occurring increases. Eventually the risk reaches a specified level and an intervention is conducted which fully addresses FM1. However it does not affect FM2.

The asset risk then drops down onto FM2's curve at point 'W' as FM1 has effectively reset and so deterioration progresses along the degradation curve for FM2.

As the degradation curve for FM1 is much steeper than FM2 it intersects with FM1's curve at point 'X' and so a transition to being FM1 driven commences again. When the risk becomes too great, another intervention is undertaken returning the risk to point 'Y' on FM2's curve.

The risk then increases along FM2 until a limit is reached. At this point, because of the nature of FM2 (for example, it may be the degradation of a core component through wear) totally replacing the asset becomes necessary and this will therefore reset both failure modes to point 'Z'.

When carrying out an intervention, a number of factors need to be considered in addition to the asset risk; the intervention should address the relevant failure mode(s), whilst taking into account the cost of intervention as well as any constraints, such as outage availability for example.

2.2.2. EVENTS RESULTING FROM A FAILURE MODE

Each failure mode may result in one or more failure mode events. The events are categorised in a hierarchy of failure mode consequences, in terms of the impact of failure, and are comparable across the asset types. An example of a hierarchy of events, which is based on transformer failure modes, is shown in Table 4.

Event
01 - No Event
02 – Environment Noise
03 - Reduced Capability
04 - Alarm
05 - Unwanted Alarm + Trip
06 - Transformer Trip
07 - Reduced Capability + Alarm + Trip
08 - Fail to Operate + Repair
09 - Reduced Capability + Alarm + Loss of Voltage Control + Fail to Operate
10 - Overheating (will trip on overload)
11 - Cross Contamination of Oil
12 - Alarm + Damaged Component (Tap Changer) No Trip
13 - Alarm + Trip + Damaged Component (Tap Changer)
14 - Alarm + Trip + Tx Internal Damage
15 - loss of oil into secondary containment
16 - Alarm + Trip + Damage + State Requiring Replacement (Asset Replacement)
17 - Alarm + Trip + Disruptive Failure + External Damage (danger) + Replacement
18 - Alarm + Trip + Disruptive Failure + External Damage (danger) + Replacement+ Transformer Fire

Table 4

The same failure mode may result in different events. For example, Table 5 shows the potential events for the dielectric failure of a transformer bushing.

Asset Type	Item	Function	Failure Mode	Cause	Event
Transformer	Bushing	Carries a conductor through a partition such as a wall or tank and insulates it therefrom	Dielectric failure (oil, oil impregnated paper, resin imp paper, resin bonded paper, solid cast resin, SF6)	Water ingress/ treeing (partial discharge)	18 - Alarm + Trip + Disruptive Failure + External Damage (danger) + Replacement+ Transformer Fire
					17 - Alarm + Trip + Disruptive Failure + External Damage (danger) + Replacement
					14 - Alarm + Trip + Internal Damage
					05 - Unwanted Alarm + Trip

Table 5

In all instances of this failure mode, the transformer will trip and a component will be damaged, which will require investigation and repair. However, there is also a 50% chance of the transformer failing disruptively, i.e. that the transformer will need to be replaced rather than repaired.

Table 6 shows the same failure mode events as given in Table 4, this time with return to service time. Note that these are example times and that actual return to service times may vary for individual assets depending on, for example, the nature of the failure, availability of spare parts, resourcing issues or existing system constraints.

Event	Example Unplanned Return to Service (days)
01 - No Event	0
02 – Environment Noise	1
03 - Reduced Capability	1
04 - Alarm	1
05 - Unwanted Alarm + Trip	1
06 - Transformer Trip	1
07 - Reduced Capability + Alarm + Trip	1
08 - Fail to Operate + Repair	1
09 - Reduced Capability + Alarm + Loss of Voltage Control + Fail to Operate	1
10 - Overheating (will trip on overload)	1
11 - Cross Contamination of Oil	1
12 - Alarm + Damaged Component (Tap Changer) No Trip	5
13 - Alarm + Trip + Damaged Component (Tap Changer)	30
14 - Alarm + Trip + Tx Internal Damage	30
15 - loss of oil into secondary containment	15
16 - Alarm + Trip + Damage + State Requiring Replacement (Asset Replacement)	180
17 - Alarm + Trip + Disruptive Failure + External Damage (danger) + Replacement	180
18 - Alarm + Trip + Disruptive Failure + External Damage (danger) + Replacement+ Transformer Fire	180

Table 6

2.3. IDENTIFY & ASSESS FAILURE MODE EFFECTS

Failure Modes and Effects Analysis (FMEA) is a structured, systematic technique for failure analysis that is used to establish an asset's likelihood of failure. It involves studying components, assemblies and subsystems to identify failure modes, their causes and effects. NGET uses FMEA to examine the effectiveness of the its current risk management approach by considering these key elements relating to potential failure modes:

- What are the effects and consequences of the failure mode?

- How often might the failure mode occur?

- How effective is the current detection method?

- How effective are the interventions for the failure mode?

FMEA views the asset as an assembly of items, each item being the part of the asset that performs a defined function. When identifying failure modes, the items under consideration are usually sub-assemblies, but there may be discrete components. Some of the asset categories are single asset types which can be separated into an integrated set of items.

It is necessary to identify the consequences of each potential failure event to determine the risk.

Some illustrative guidance is provided by section 5.2.5 of BS EN 60812, which stresses the importance of considering both local and system effects – recognising that the effects of a component failure are rarely limited to the component itself.

2.4. DEFINE OUTCOME & PROBABILITY

The determination of Probability of Failure (PoF) can be especially challenging for highly reliable assets. BS EN 60812 provides useful guidance on how to develop an estimate for PoF.

Section 5.2.9 of BS EN 60812 recognises that it is very important to consider the operational profile (environmental, mechanical, and/or electrical stresses applied) of each component that contributes to its probability of occurrence. This is because, in most cases, the component failure rates and consequently failure rates of the failure modes under consideration increase proportionally with the increase of applied stresses with the power law relationship or exponentially. Probability of occurrence of the failure modes for the design can be estimated from:

- Data from the component life testing

- Available databases of failure rates

- Field failure data

- Failure data for similar items or for the component class

When probability of occurrence is estimated, the FMEA must specify the period over which the estimations are valid (such as the expected service life).

Section 5.3.4 of BS EN 60812 provides further guidance on the estimation of failure rates where measured data is not available for every asset and specific operation condition (as is generally the case for transmission assets). In this case, environmental, loading and maintenance conditions different from those relating to the "reference" failure rate data are accounted for by a modifying factor. Special care needs to be exercised to ensure that the chosen modifiers are correct and applicable for the specific system and its operating conditions.

As part of the FMEA approach, an end of life curve is derived for each asset. Some of these predicted deterioration curves may be theoretical as the actual mechanism may not have occurred in practice; these are based on knowledge of asset design and specific R&D into deterioration mechanisms. NGET makes use of the following sources of data in deriving deterioration curves:

- Evidence from inspection of failed and scrapped assets

- Results of condition assessment tests

- Results from continuous monitoring

- Historical and projected environmental performance (e.g. oil loss)

- Historical and projected unreliability

- Defect history for that circuit breaker family.

The end of life failure curves are expressed in terms of the data points corresponding to the ages at which 2.5%, and 97.5% of failures occur. The method for determining the end of life curves is explained in the failure modes and effects analysis section of NGET Licensee Specific Appendix, NARA Section 4.2 Risk Trading Model – Risk Methodology document.

Typically within each lead asset group there are separate end of life curves determined for each family grouping. Assignment to particular family groupings is through identification of similar life-limiting factors.

2.4.1. FACTORS THAT MAY INFLUENCE THE FAILURE MODE'S PROBABILITY OF FAILURE

2.4.1.1. DIFFERENTIATORS

There may be factors that change the shape of failure mode degradation curves depending on the asset or asset family. Examples of differentiating factors may include:

- Some families of an asset type may have a design weakness which could influence their failure mode and hence probabilities of failure
- Location specific reasons, such as proximity to coastal areas or heavily polluted industrial areas, may also influence the probability of failure for the asset

2.4.1.2. MODIFIERS

Modifiers change the rate at which an asset progresses along a curve. There may be variations in terms of the condition and duty on assets of a particular type, so while they will have the same failure modes, and hence the same degradation curves, they may proceed along the curve at a different rate.

This introduces the concept of equivalent age. An asset can be compared to another asset which was installed at the same time which might be at a different point of progression along the curve due to specific location and/or operational reasons.

By conducting inspections it is possible to understand where each asset lies on the curve and therefore the assets can be moved down the curve, effectively reducing their equivalent age, or vice versa, as shown in Figure 5. Assets are assessed to establish any modifying factors.
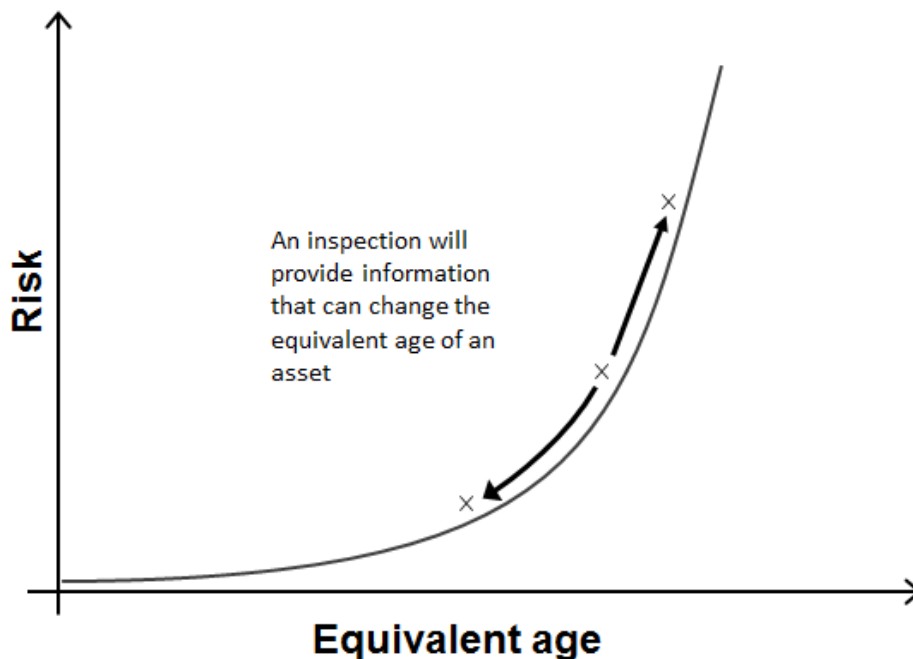

Figure 5

2.4.2. MAPPING END OF LIFE MODIFIER TO PROBABILITY OF FAILURE

The end of life probability of failure (PoF), which is the probability of end of life failure in the next year given that the asset is still surviving at the beginning of the year, is determined from the end of life (EOL) modifier. The EoL modifier is determined from the asset's current condition, duty, age and asset family information and, through the process described below, is converted to PoF.

A probability mapping function is required to enable mapping from an EOL modifier to a PoF. Figure 6 below illustrates distributions representing the end of life failure mode for a population of transformers. The 50% point on the cumulative distribution function (blue) indicates the anticipated asset life (AAL). The PoF at the AAL can be determined from the red curve in the figure below (approximately 10% per year). We can use this as an initial value in the mapping function, such that an EOL modifier of 100 is equivalent to a 10% PoF.

PoF cannot be utilised at an individual asset level to infer individual asset risk, and therefore the PoF values need to be aggregated across the asset population in order to support the calculation of risk. Over a population of assets at a given a PoF we have an expectation of how this PoF will continue to deteriorate over time, duty or condition. This is shown by the PoF curve in red.
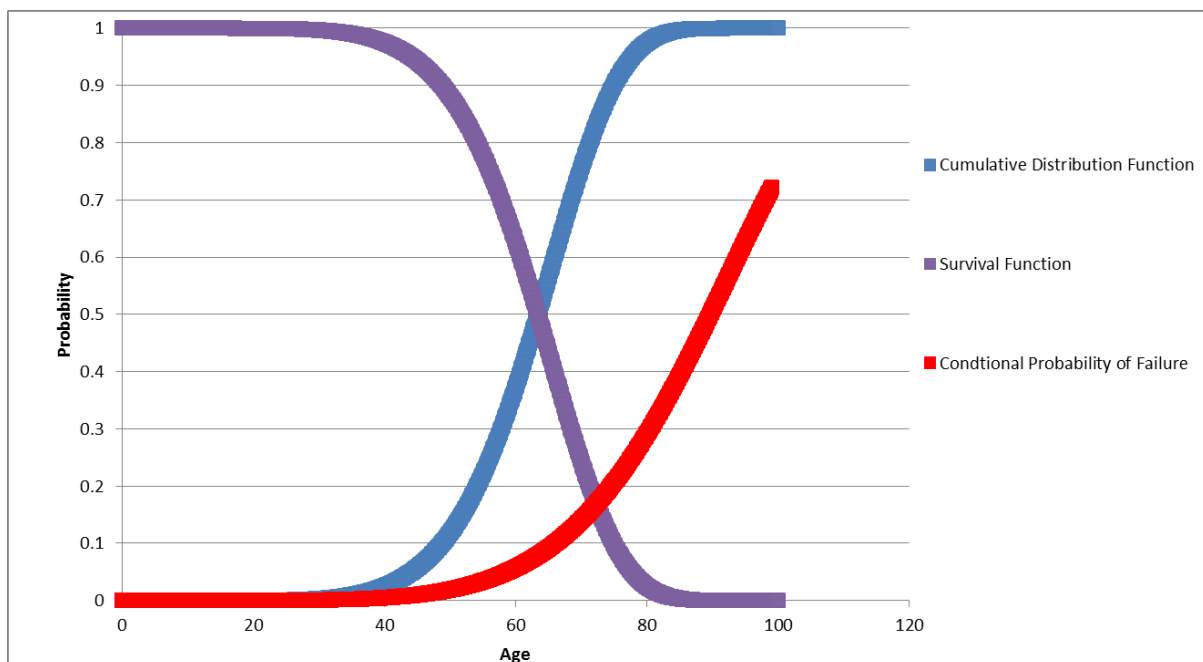
Figure 6

The development of a methodology that maps the EOL modifier to PoF needs to consider the actual number of failures experienced, it should then be validated against the expected population survival curve and it should satisfy the following requirements:

- High scoring young assets should be replaced before low scoring old assets. *The mapping function achieves this objective because high scoring assets will always reach their AAL quicker than those of low scoring assets.*

- When two assets of similar criticality have the same PoF then the older asset should be replaced first. *The mapping function will assign the same PoF to both assets, so they reach their respective AAL at the same time. In practice the planner could prioritise the older asset for replacement over the younger asset without penalty.*

- When an asset is not replaced the PoF should increase. *The EOL modifier score reflects the condition of the asset, and will therefore increase over time. This means the PoF will also increase.*

- A comprehensive and steady replacement programme will lead to a stabilisation of the population's average PoF. *The proposed methodology will satisfy this requirement as worsening PoF would be offset by replacements.*

- The PoF and resulting risks must be useful for replacement planning. *The proposed methodology is validated against the expected survival function, so should be compatible with existing replacement planning strategies.*

- Outputs should match observed population data. The expected survival function for the population is already identified based on known asset deterioration profiles and NGET experience. *The mapping to PoF method is validated against this expected population statistic.*

In the following example, the PoF mapping function is derived for a transformer, then the mapping curve parameters are systematically adjusted through a process of validation and calibration against the expected population's survival curve.

The mapping function is given by the following exponential function.

$$Conditional\ PoF = \exp(k * EOLmod^{\alpha}) - 1$$

The parameter α is tuned so that the deterioration profile over the population is consistent with the expected survival function for the relevant population of assets. The expected survival function is given by the FMEA earliest and latest onset of failure values, which have been determined though the transmission owner experience using all available information such as manufacturer data and understanding of asset design.

The parameter k scaling value ensures that for an EOL modifier score of 100 the expected PoF is obtained (given as β in the formula below). The formula is given by:

$$k = ln\frac{(1 + \beta)}{100^{\alpha}}$$

The PoF mapping function is shown in the figure below for a transformer with α=1.7 and β=10%.
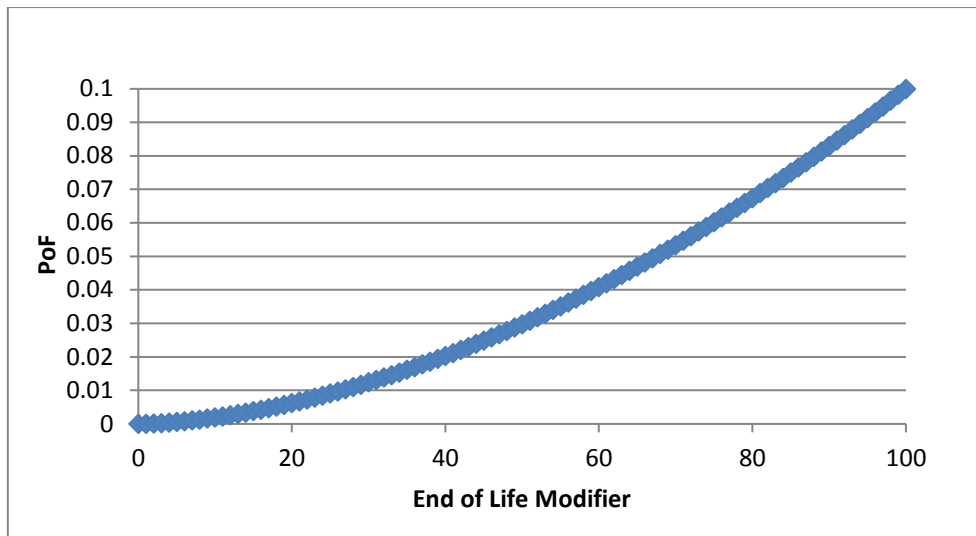
Figure 7

2.4.3. DETERMINING ALPHA (α) AND VALIDATION

To tune the parameters and validate the approach, the Predicted Actual Age at Failure (PAAF) for each asset needs to be determined so that a population survival curve may be determined. Using the PoF, an Equivalent Age (EA) is identified using the red curve in Figure 6 above. The PAAF calculation also needs actual Age and the AAL of the asset's population.

$$PAAF = \text{Age} + (\text{AAL - EA})$$

Equation 9

The EOL modifier score for an individual asset puts it on a PoF curve *n* years away from the AAL. This *n* years value can be interpreted as the difference between the AAL and the equivalent age of the asset (AAL – EA). Combining with actual age gives the PAAF, as shown in Equation 9.

The PAAF can then be used to generate a survival curve that indicates the percentage of the population that is still surviving at a given age. Figure 8 below shows an example modelled transformer survival curve based on PAAF (blue) overlaid with the expected survival curve generated from the FMEA curve (red). The modelled PoF is observed to give a near perfect fit to the expected survival curve up to 60 years old. The trend diverges from the expected survival curve. This section of the survival curve is not as well understood, as there is little operational experience at this older age range. The linear appearance of the older section of the modelled survival curve (blue) is driven by a large population of transformers that are all around a similar age of 49 years old and have a relatively even spread of EOL modifier scores.

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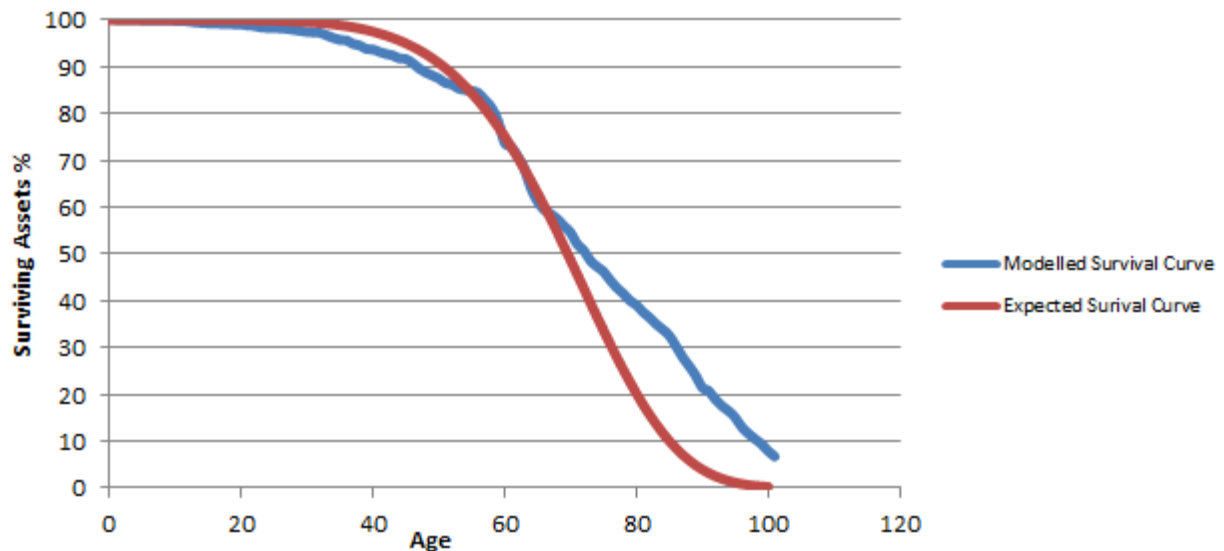
Figure 8

2.4.4. DETERMINING BETA (β) AND VALIDATION

Beta (β) sets the maximum PoF which would be expected for an asset that has reached its AAL. As described in the earlier section an initial value can be determined from the FMEA end of life failure curve earliest and latest onset values. A value of 10% was chosen for transformers, although there is a scope to tune this value using failure data. The total PoF across the population can be obtained by summing the individual PoFs; this is then compared to the observed failures noting that many assets are replaced before they fail. In the case of transformers the sum of PoF gives five transformer failures per year. The value for β can be tuned such that the number of failures is similar to what is actually observed, but any tuning needs to be performed in conjunction with the parameter α.

The parameters alpha (α) and beta (β) are both calibrated by considering population level statistics. In the same sense the PoF or risk is only meaningful when aggregated across the asset population.

2.4.5. OIL CIRCUIT BREAKER POF MAPPING EXAMPLE

The analysis described above was repeated for Oil Circuit Breaker (OCB) EOL modifier scoring data to validate and quantify the proposed method against expectation based on NGET experience. The EOL modifier values are mapped to a PoF using a similar function to that shown in Figure 8 above, noting that the value of α and β will be specific to this OCB asset type. For the purpose of implementing this methodology a PoF value of β=10% per year is assumed for an EOL modifier score of 100. An initial value of α is selected and it is assumed that it will be adjusted to provide the best fit.

Using the same method described above for transformers the PAAF for each OCB on the network is determined. Plotting these PAAF values as a survival curve, overlaid with the expected survival curve, allows quantification of the model against expected asset deterioration and provides a mechanism for tuning the mapping parameter α. The modelled survival curve shown in Figure 9 below has been produced with α=2.1 and β=10%.
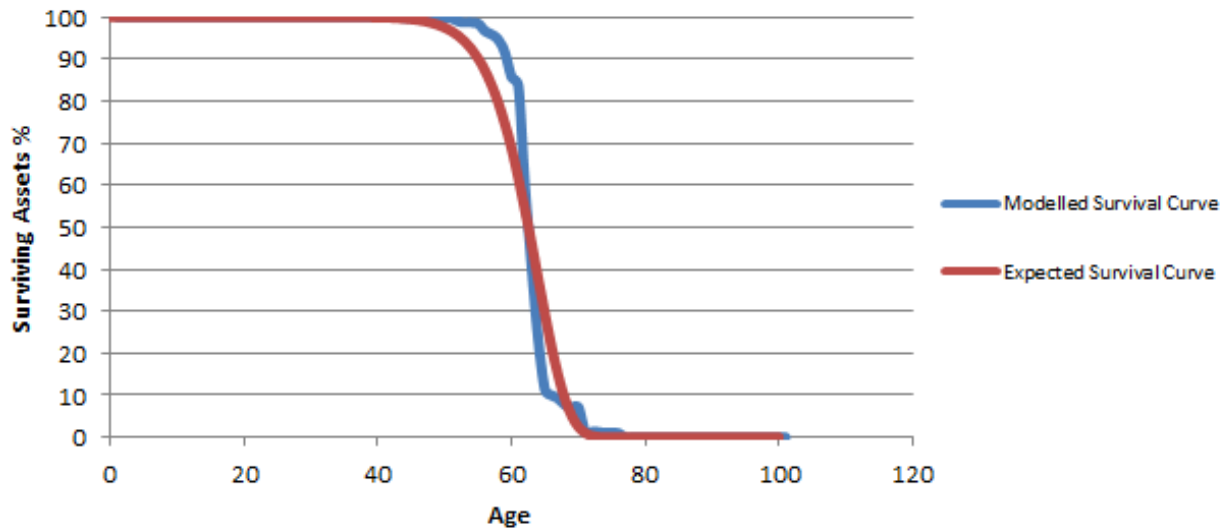
Figure 9

2.4.6. CALCULATING PROBABILITY OF FAILURE

As described above the PoF curve is based on two data points that correspond to the ages at which specific proportions of the asset's population is expected to have failed. Using these data points we can construct a cumulative distribution function *F(t)*. The survival function, or the cumulative probability of survival until time *t*, is given as: *S(t) = 1-F(t)*. The probability of failure, which is the probability an asset fails in the next time period given that it is not in a failed state at the beginning of the time period, is then given by the following formula, where *t* is equivalent age in the case of end of life failure modes:

$$PoF(t) = \frac{S(t) - S(t+1)}{S(t)}$$

Equation 10

In order to calculate the end of life PoF associated with a given asset, the asset will need to be assigned an EOL modifier. This EoL modifier is derived from values such as age, duty and condition information where it is available. In the absence of any condition information, age is used. The service experience of assets of the same design and detailed examination of decommissioned assets may also be taken into account when assigning an EoL modifier. Using the EoL modifier an asset's equivalent age can then be determined and mapped onto a specific point on the PoF curve.

The generalised EoL modifier (*EOLmod*) formula has the following structure for assets that have underlying issues that can be summed together:

$$EOLmod = \sum_{i=1}^{\substack{number\ of \\ components}} C_i$$

Equation 11

Or, for transformer assets that are single assets with parallel and independent failure modes, the following generalised EoL modifier formula is used:

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$$EOLmod = \left(1 - \prod_{i=1}^{\substack{number\ of \\ components}} \left(1 - \frac{C_i}{C_{max}}\right)\right) * 100$$

Equation 12

C_i = an individual component parameter of the end of life modifier

C_{max} = the max score that the component can get

For some of the lead asset types, the generalised formula will need to be nested to derive an overall asset EoL modifier. For example, in the case of overhead lines (OHLs), the maximum of the preliminary EoL modifier and a secondary EoL modifier are taken.

The EoL modifier will range from zero to 100, where 100 represents the worst health that an asset could be assigned. It is then necessary to convert the EoL modifier to a PoF to enable meaningful comparison across asset types.

As far as reasonably possible the scores assigned to components of the EoL modifier are set such that they are comparable e.g. are the same magnitude. This enables the EoL modifier between different assets in the same family to be treated as equivalent. The validation and testing of these scores is described in the testing section of the common NOMS Methodology document.

2.4.7. FORECASTING PROBABILITY OF FAILURE

Future PoF is estimated by following the appropriate failure curve. Depending on the type of failure mode the current position on the failure curve is identified using either age, equivalent age or last intervention date. The forecast is determined by following along this curve, usually at the rate of one year per year. Figure 10 illustrates the PoF for an asset highlighting the PoF at an equivalent age of 80.
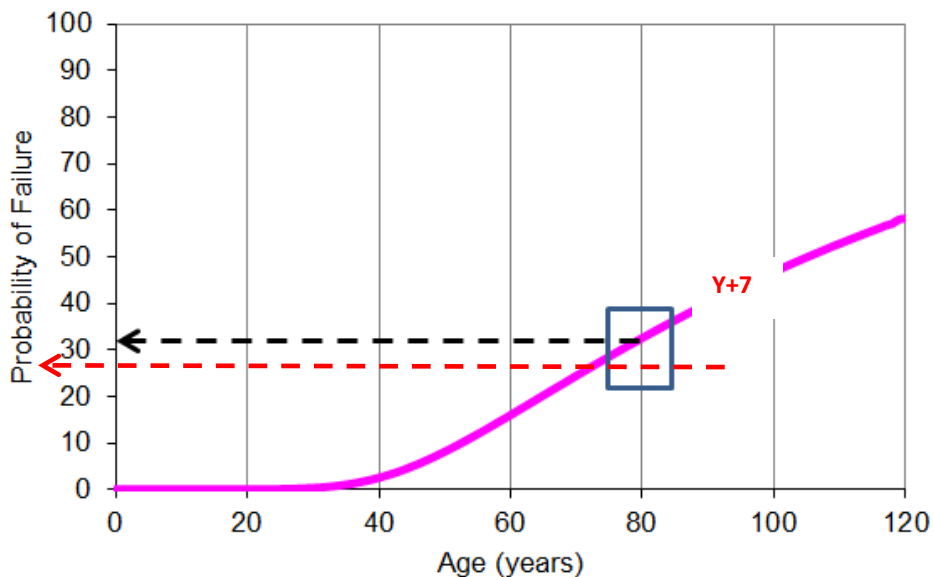
Figure 10

The forecast probability of failure in future years can then be obtained by following along the curve. For example the forecast for Y+7 would be the value given by the above curve at the equivalent age of 87. Note that in this case it is not the real age of the asset, but an equivalent age that has been determined through the process described in the above sections.

Where appropriate and enough historical data exists, a rate multiplier can be applied, so that for each annual time step in forecast time equivalent age is increased or decreased by the rate multiplier time step. The default value of the rate multiplier time step is set as 1.0 per year. This modelling feature will allow high duty assets to be forecast more accurately.

2.4.8. HIGH LEVEL PROCESS FOR DETERMINING END OF LIFE PROBABILITY OF FAILURE

The process illustrated below will be used to determine the PoF of each asset. This is done by translating through a probability mapping step, so that the appropriate end of life curve may be used to determine the probability of an asset having failed.
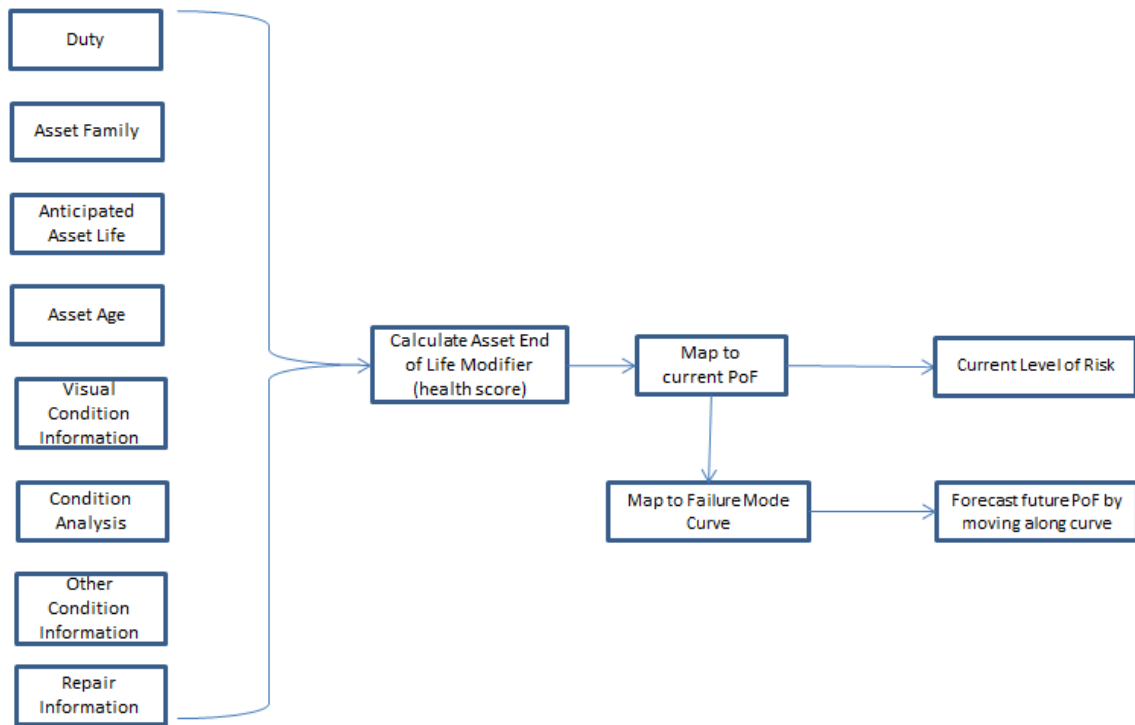
Figure 11

This process is shown in more detail for each asset type in section 8 .

3. CONSEQUENCE OF FAILURE

The consequences of failure (CoF) may fall into four categories:

Consequence	Description
System	The impact on the network of the failure and any subsequent intervention required
Safety	Impact of direct harm to public/personnel as a result of failure mode
Environment	Impact of failure mode taking into account the sensitivity of the geographical area local to the asset
Financial	Cost of the intervention needed to address and resolve the failure

Table 7

These categories reflect the impact of the various failure modes which are specific to the asset and the consequences are consistent for each class of failure mode. The impact of the various failure modes will vary depending on the type of failure. For example, for less disruptive failure modes there may be no impact from a safety perspective.

Safety and environmental consequences are specific to the asset and its physical location.

In a highly-meshed system, such as a transmission network, consideration of system effects becomes paramount. A comprehensive system of consequence evaluation must be derived, leading to a transparent, objective and tradeable measure of risk.

In considering the safety and environment consequences, the concept of exposure is needed. Exposure is based upon the asset's location, i.e. its proximity to a location where it has the potential to cause harm (whether to people or the environment).

Each consequence will be monetised and the price base for consequence of failure is defined in the NGET Licensee Specific Appendix Section 3 – Consequence of Failure document.

NGET states which failure modes have been included in the analysis and explains why the chosen failure modes are considered appropriate for the analysis.

It is the aim of this section to provide a quantified view in the terms of monetised consequence.

In taking the approach detailed below it is intended that the quantification forms an approximation to how this may play out in the real world. In this case an approximation is of much greater value, due to its simplified nature and the ease of comparison and benchmark. All quantities used will be externally verifiable and benchmarked, where practicable to do so, as part of Calibration, Testing and Validation.

The monetisation does not correspond to the actual costs that will be incurred. The data used in the models attempts to approach the correct orders of magnitude to avoid confusion it does not, however, guarantee this and can only be treated as abstract.

3.1. SYSTEM CONSEQUENCE

The system consequence of a failure or failure mode effect of an asset is an indication of the asset's importance in terms of its function to the transmission system as given by the disruption to that function caused by the failure. It is measured in terms of certain system related costs associated with system consequences incurred by the industry electricity sector if that asset were to experience a failure. These system costs incurred due to an asset failure can be divided into two categories, customer costs and System Operator costs. Regardless of

who initially pays these costs they are ultimately borne by electricity consumers. Customer costs are incurred as a result of the disconnection of customers supplied directly or indirectly (via a distribution network) by the transmission system. The cost for demand disconnections is expressed as the economic value that the user assigns to that lost load. In the case of generators being disconnected from the network there is a mechanism of direct compensation payments from the System Operator. The second category of costs are those that the System Operator incurs in undertaking corrective and preventative measures to secure the system after asset failures have occurred. These include generator constraint payments, response and reserve costs and auxiliary services costs.

Unlike the environmental, financial and safety consequences of asset failures, the existence and scale of network risk due to asset failures is dependent on the functional role that the failed asset plays in the transmission system. The transmission system is designed with a degree of resilience that seeks to ensure the impact of asset faults is contained within acceptable limits. It is the NETS SQSS that mandates a certain level of resilience that the design and operation of the transmission system must meet when faced with a range of scenarios and events. It is a license obligation of TOs that their networks comply with the NETS SQSS.

A range of negative system consequences (unacceptable overloading of primary transmission equipment, unacceptable voltage conditions or system instability) must be avoided for 'defined secured events' under certain network conditions. The required resilience is not absolute nor is it uniform across the network. The philosophy behind the NETS SQSS is that lower severity consequences are to be accepted for relatively high probability (and therefore high frequency) faults while more severe consequences are only to be accepted for lower probability events. Figure 12 represents this philosophy.

This approach is further influenced by other considerations such as the geographical location of the assets in question i.e. which TO License Area they are in, and for what timescales the network is being assessed (near term operational timescales vs. long term planning timescales). The level of resilience required also varies depending on the function of the part of the network in question. Parts of the network which connect demand, generation or make up part of the Main Interconnected Transmission System (MITS) all have distinct design requirements dependent upon their importance to the Transmission System and the total economic value of all the customers they supply.
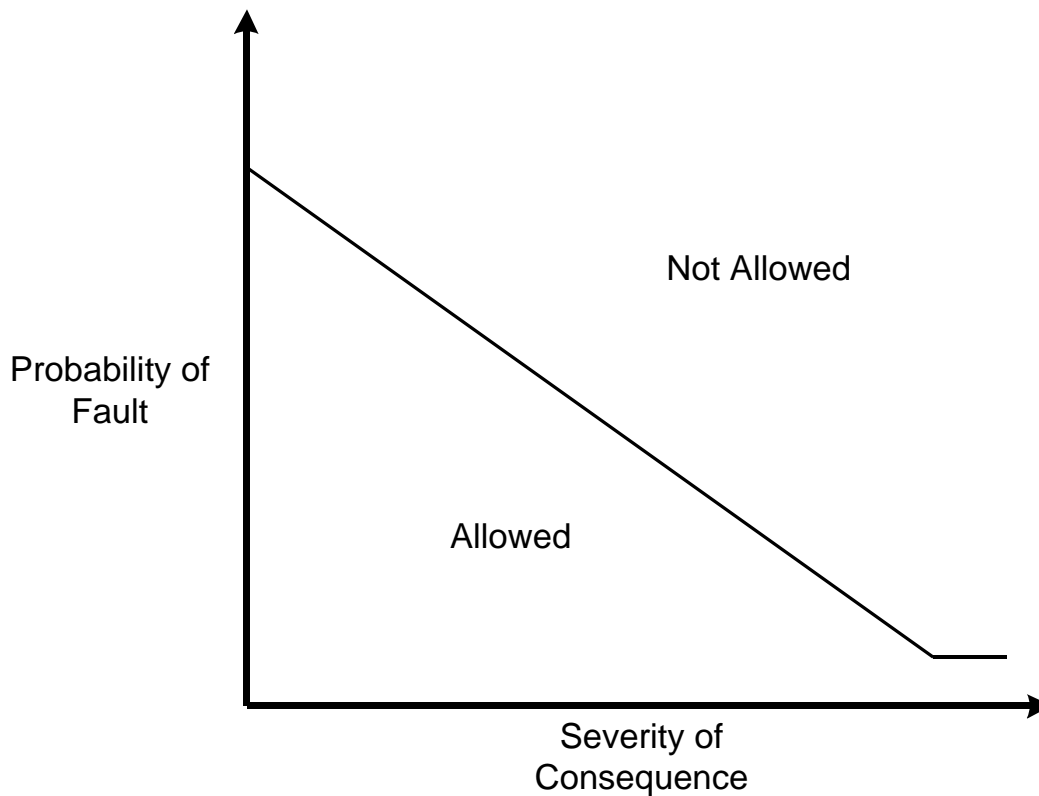
Figure 12

Events that the NETS SQSS requires a degree of resilience against are described as 'secured events'. These are events that occur with sufficient frequency that it is economic to invest in transmission infrastructure to prevent certain consequences when such events occur on the system. Secured events include faults on equipment and these events range from single transmission circuit faults (highest frequency) to circuit breaker faults (lowest frequency). When an asset fault occurs that results in the loss of only a single transmission circuit in an otherwise intact network, almost no customer losses are permitted and all system parameters must stay within limits without the SO taking immediate post-fault actions. While in the case of circuit breaker faults the NETS SQSS only requires that the system is planned such that customer losses are contained to the level necessary to ensure the system frequency stays within statutory limits to avoid total system collapse.

The key assumption that underpins this variation in permitted consequences of faults is that most faults are weather related and that faults caused by the condition of the asset are rare. This can be seen in that faults on overhead lines (often affected by wind and lightning) are relatively frequent events ($\approx$20% probability per 100 km 400 kV circuit per annum) while switchgear faults are relatively less frequent ($\approx$2% probability per 2-ended 400 kV circuit per annum). Another key assumption in the design of the SQSS is that faults are relatively short in duration. A vast majority of circuits have a post-fault rating that is time limited to 24 hours, it is expected that faults will be resolved within this time so that this rating will not be exceeded.

Asset failures driven by asset condition do not conform to these key assumptions, they occur in assets regardless of their exposure to the elements and they can significantly exceed 24 hours in duration. The system therefore cannot be assumed to be designed to be resilient against even a single asset failure. Even if system resilience is sufficient to avoid an immediate customer or operator cost, no asset fault or failure that requires offline intervention can be said to be free from a risk cost. At the very least, the unavailability of the asset reduces system resilience to further events and therefore increases exposure to future costs.

3.1.1. QUANTIFYING THE SYSTEM RISK DUE TO ASSET FAULTS AND FAILURES

Fundamentally the transmission system performs three functions. It receives power from generators, transports power where it is needed and delivers it to consumers. The system risk cost of a fault or failure can be quantified by combining the following costs:

1. The economic value assigned to load not supplied to consumers including directly-connected demand customers. Commonly described as Value of Lost Load (VOLL) in units of £/MWh

2. The cost of compensating generators disconnected from the transmission system, based on the market cost of generation (£/MWh), the size of the generator (MW) and the expected duration of disconnection (hours)

3. The cost of paying for other generators to replace the power lost from disconnected generation based on the market cost of replacement generation (£/MWh) and number of megawatt hours that require replacement

4. The increased cost in transporting power across the wider transmission network. This is comprised of:

    a. Constraint payments to generators due to insufficient capacity in part of the transmission system. This comprises the costs to constrain off generation affected by the insufficient capacity and the cost to constrain on generation to replace it. If there is insufficient replacement generation capacity, costs will include demand reduction.

    b. Payments to generators to provide auxiliary services which ensure system security and quality of supply e.g. the provision of reactive power.

The applicability and size of these cost sources are dependent upon the role of the failed asset in the system. Some assets are solely for the connection of generation or demand, while others will provide multiple functions.

The methodology for calculating these potential costs is split into three parts:

1. A customer disconnection methodology, incorporating the cost of disconnecting generation, total consumer demand and vital infrastructure sites (1, 2 and 3 above)

2. A boundary transfer methodology that estimates potential generator constraint payments (4a)

3. A reactive compensation methodology that estimates the cost of procuring reactive power to replace that provided by faulted assets (4b)

Each of these methodologies will be described in turn in the following sections. All three share a common structure that can be expressed by Equation 13.

$$Cost\ of\ System\ Impact\ = probability\ \ x\ duration\ x\ size\ x\ cost\ per\ unit$$

<div align="center">**Equation 13**</div>

The total cost of system impact of a failure mode of an asset will be the sum of the consequence costs that come from the three above costs.

3.1.2. CUSTOMER DISCONNECTION – CUSTOMER SITES AT RISK

With the exception of radial spurs, assets on the system will usually contribute towards the security of more than one substation that connects customers to the network. However, the fewer other circuits that supply a substation, the more important that asset is for the security of the site. In order to identify which sites are most at risk of disconnection because of the failure of a specific asset, the number of circuits left supplying a customer connection site after a failure of an asset, X, is defined;

$$X = number\ of\ parallel\ circuits\ supplying\ customer\ site(s)$$
$$- number\ of\ circuits\ tripped\ as\ a\ result\ of\ the\ Failure\ Mode\ Effect\ of\ the\ asset$$

<div align="center">**Equation 14**</div>

Circuit availability statistics indicate that the importance of a circuit decreases by around two orders of magnitude for each extra parallel circuit available. Given that the uncertainty of other inputs into these calculations will be greater than 1% it is a reasonable simplification to neglect all customer sites with values of X greater than the minimum value of X; $X_{min}=min(X)$.

Once there are four or more circuits in parallel supplying a site additional circuits do not necessarily decrease the probability of losing customers as the capacity of the remaining circuits will not be sufficient to meet the import/export of the customers at risk. In parts of the network where the number and rating of circuits connecting a substation are determined soley by the need to meet local demand, there is a significant risk that once two or three circuits have been lost cascade tripping of remaining circuits due to overloading will result.

Therefore:

For assets on circuits containing transformers down to 132 kV or below if $X_{min} > 3$ it will be treated as $X_{min} = 3$ for the purposes of calculating the Probability of Disconnection (P_{oc}) and Duration (D).

Otherwise for assets on circuits at 275 kV or below if $X_{min} = 4$ it will be treated as $X_{min} = 3$ for the purposes of calculating the Probability of Disconnection (P_{oc}) and Duration (D).

Otherwise if $X_{min} > 3$ then the risk of customer disconnection will be neglected as neglible.

As there will often be multiple customer connection sites with $X=X_{min}$, to ensure that the methodology is efficient and operable a variable Z, is introduced which is equal to the number of customer sites with $X=X_{min}$ for a given asset. Only the largest group of customer sites that would be disconnected by the loss of a further X_{min} circuits is considered explicitly while the extra risk of customer disconnection due to other combinations of circuit losses is approximated by the use of the risk multiplier coefficient M_Z:

$$M_Z = \frac{\sum Z + (Z-1) + (Z-2) + \dots}{Z}$$

<div align="center">**Equation 15**</div>

Intuitively $M_1 = 1$, and M_Z scales with increasing values of Z. Figure 13 illustrates an example of how M_Z is calculated with three customer sites (M_3):
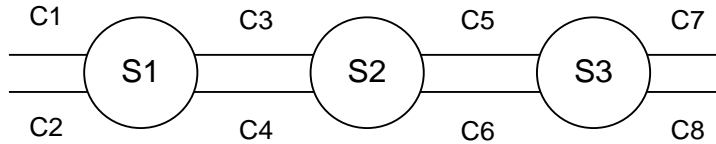
Figure 13

Three substations labelled S1, S2 and S3 are part of a double circuit ring with eight circuits labelled C1-C8. Each substation is immediately connected to the rest of the system by four circuits and could be disconnected from the system if these four immediate circuits were lost. However, each substation could also be disconnected by other combinations of four circuit losses also. For example S2 could be disconnected by the loss of C3, C4, C5 and C6, but also by losing C3, C4, C7 and C8 or C1, C2, C5 and C6 etc. More than one substation would be lost for these other combinations and all three substations would be lost for a loss of C1, C2, C7 and C8.

In order to calculate the total system consequence of a failure mode of an asset that is part of C1 we assume that the volume and cost per unit of customer connections are approximately evenly distributed among the substations (L for each substation) and that the probability (P) and duration (D) of each four circuit combination being lost is approximately equal. The relative consequence of a loss event is then determined only by the amount of customers lost. So a loss of S1 and S2 is twice the consequence of losing only S1. There is one combination of four circuit losses involving C1 that disconnected a single substation, one combination that disconnects two substations and one that disconnects all three. Therefore the risk cost is:

$$Risk\ cost = (1{\times}PDL) + (1{\times}2PDL) + (1\ {\times}3PDL) = 6\ PDL$$

Equation 16

Given the risk cost of losing all three sites at once is 3PDL so the risk cost can be expressed as a function of the risk cost of losing all three sites at once:

$$Risk\ cost = 6\ PDL = 2{\times}3PDL = 3PDLM_3$$

Equation 17

Therefore M_3 is equal to 2.

3.1.3. CUSTOMER DISCONNECTION – PROBABILITY

The probability of a generator or consumer being disconnected as a consequence of an asset failure is a function of a wide range of variables including the physical outcome of the failure , the local network topology, asset composition of circuits, asset loading, physical proximity of assets, protection configuration and operation options for restoration.. The probability of consequence is calculated as a function of five probabilities, shown in Table 8.

Probability	Symbol	Determination of Value
Coincident outage	P_o	TO statistics on planned unavailability of circuits
Damage to another circuit	P_d	TO historical experience of explosive/incendiary failures of failure mode
Maloperation of another circuit	P_m	TO statistics on protection maloperation
Coincident fault to another circuit	P_f	TO fault statistics
Overloading of remaining circuit	P_l	TO specific network design

Table 8

The probabilities P_o, P_d, P_m, P_f and P_l are determined separately by each TO according to their own methodology outlined in TO specific appendices.

The probabilities in Table 8 can be combined to create a probability tree for each value of X_{min} between 0 and 3. Below are the resulting equations for P_{oc}, the probability of disconnection.

$$\text{For } X_{min} = 0,\ P_{oc} = 1$$

Equation 18

$$\text{For } X_{min} = 1,\ P_{oc} = 1 - N_o N_d N_m N_f$$

Equation 19

$$\text{For } X_{min} = 2,\ P_{oc} = P_d^2 + 2P_d N_d P_o + 2P_d N_d N_o P_m + 2P_d N_d N_o N_m P_f + N_d^2 P_o P_m + N_d^2 P_o N_m P_f + N_d^2 N_o P_m P_f + N_d^2 N_o N_m P_f^2$$

Equation 20

$$\text{For } X_{min} = 3,\ P_{oc} = P_d^2 P_o + P_d^2 N_o P_m + P_d^2 N_o N_m P_f + P_d^2 N_o N_m N_f P_l + 2P_d N_d P_o P_m + 2P_d N_d P_o N_m P_f + 2P_d N_d P_o N_m N_f P_l +$$
$$2P_d N_d N_o P_m P_f + 2P_d N_d N_o P_m N_f P_l + 2P_d N_d N_o N_m P_f^2 + 4P_d N_d N_o N_m P_f N_f P_l + N_d^2 P_o P_m P_f + N_d^2 P_o P_m N_f P_l + N_d^2 P_o N_m P_f^2 +$$
$$2N_d^2 P_o N_m P_f N_f P_l + N_d^2 N_o P_m P_f^2 + 2N_d^2 N_o P_m P_f N_f P_l + N_d^2 N_o N_m P_f^3 + 3N_d^2 N_o N_m P_f^2 N_f P_l$$

Equation 21

Where N_o, N_d, N_m, N_f and N_l are the probabilities of no outage, no damage, no maloperation, no coincident faults and no overloading respectively.

The derivation method of the above probability equations can be followed in Figures 14 & 15, the probability tree diagram for the most complex of the four cases, $X_{min} = 3$.

Figure 14

Continued

3 circuits remaining

Probability of parallel outage (P_o)

2 circuits remaining

Probability of Maloperation (P_m)

1 circuit remaining

Probability of unrelated fault (P_f)

0 circuits remaining ($N_d^2 P_o P_m P_f$)

Probability of no unrelated fault (N_f)

1 circuit remaining

Probability of overloading circuit (P_l)

0 circuits remaining ($N_d^2 P_o P_m N_f P_l$)

Probability of no maloperation (N_m)

2 circuits remaining

Probability of two unrelated faults (P_f^2)

0 circuits remaining ($N_d^2 P_o N_m P_f^2$)

Probability of no second unrelated fault ($2P_f N_f$)

1 circuit remaining

Probability of overloading circuit (P_l)

0 circuits remaining ($2N_d^2 P_o N_m P_f N_f P_l$)

Probability of no parallel outage (N_o)

3 circuits remaining

Probability of Maloperation (P_m)

2 circuits remaining

Probability of two unrelated faults (P_f^2)

0 circuits remaining ($N_d^2 N_o P_m P_f^2$)

Probability of no second unrelated fault ($2P_f N_f$)

1 circuit remaining

Probability of overloading circuit (P_l)

0 circuits remaining ($2N_d^2 N_o P_m P_f N_f P_l$)

Probability of no maloperation (N_m)

3 circuits remaining

Probability of three unrelated faults (P_f^2)

0 circuits remaining ($N_d^2 N_o N_m P_f^3$)

Probability of two unrelated faults ($3P_f P_f N_f$)

1 circuit remaining

Probability of overloading circuit (P_l)
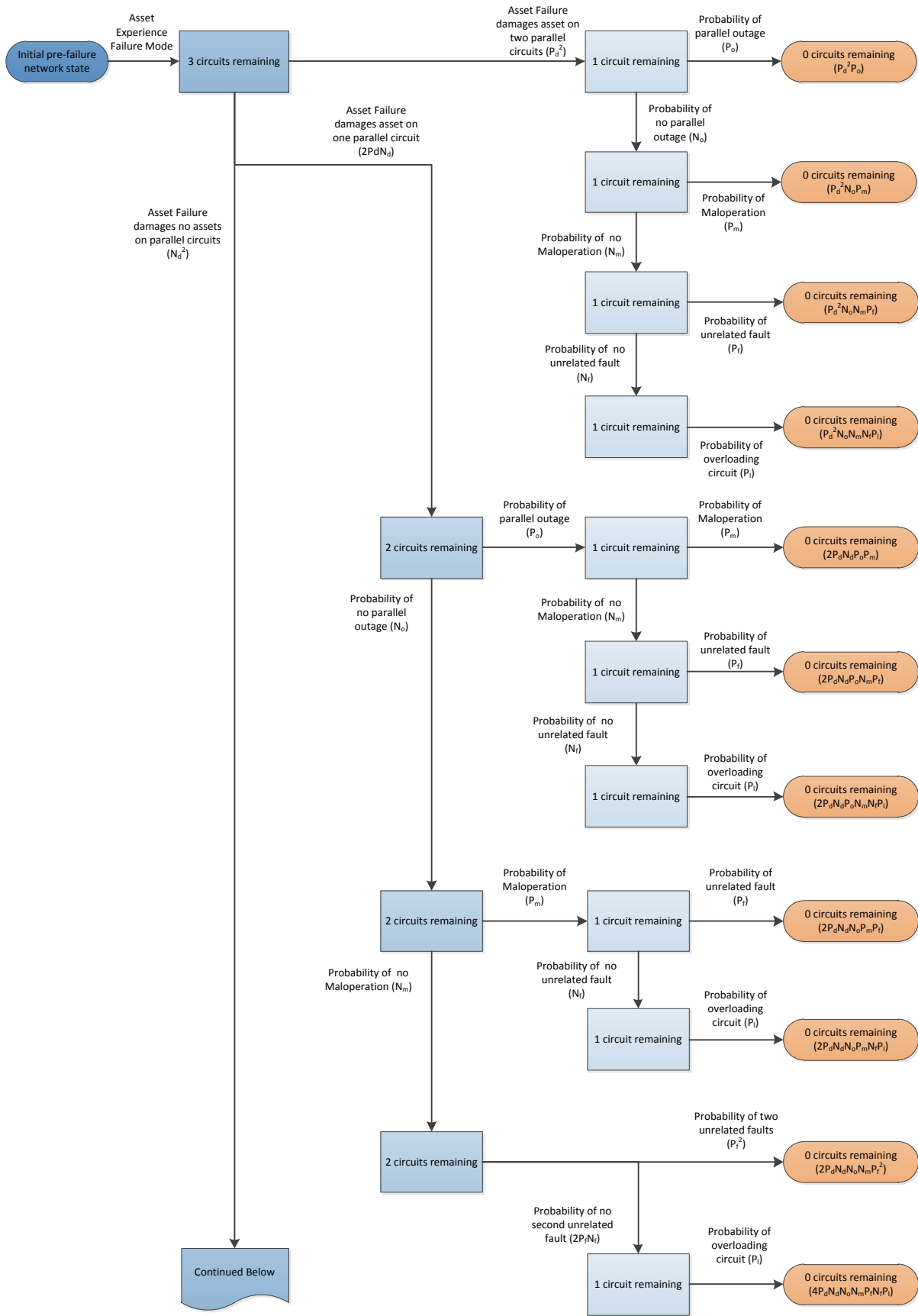
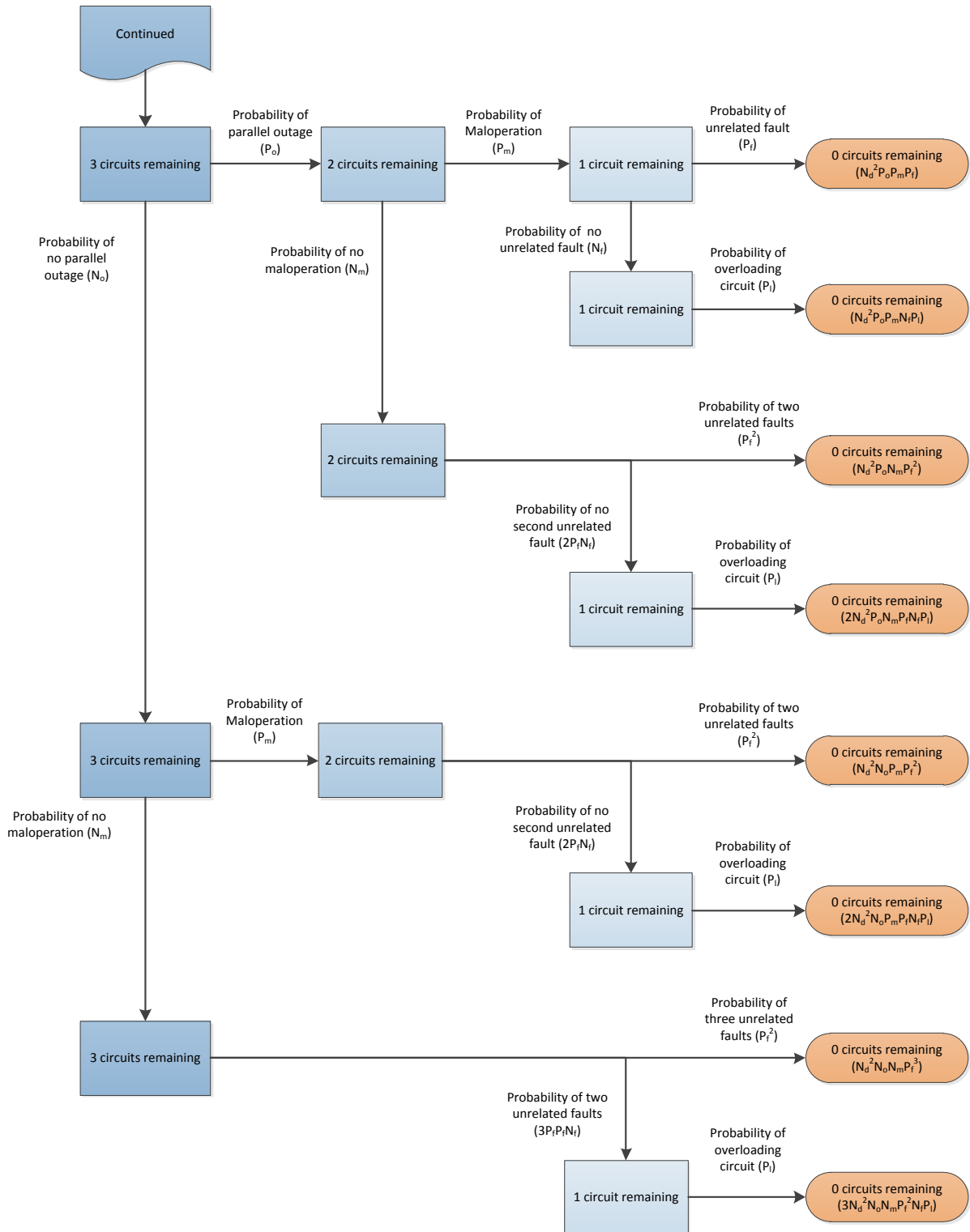0 circuits remaining ($3N_d^2 N_o N_m P_f^2 N_f P_l$)

Figure 15

3.1.4. CUSTOMER DISCONNECTION – DURATION

A similar approach is taken with the expected duration of such a disconnection event. This is dictated by the failure mode of the asset in question, and both operational and asset interventions available to restore supply to the customers. In order to calculate the duration of disconnection, six separate durations are introduced in Table 9.

Duration	Symbol	Determination of Value
Duration of failure mode unavailability	D_{fm}	TO experience of failure durations
Outage restoration time	D_o	TO statistics on planned unavailability of circuits
Circuit damage restoration time	D_d	TO historical experience of explosive/incendiary failures of failure mode
Protection mal-operation restoration time	D_m	TO statistics on protection maloperation
Unrelated fault restoration time	D_f	TO fault statistics
Circuit overload restoration time	D_l	TO historical experience of overload trips

<div align="center">Table 9</div>

The durations D_{fm}, D_o, D_d, D_m and D_f are determined separately by each TO according to their own methodology outlined in TO specific appendices. The duration of customer loss is calculated by weighting the probabilities of the event combinations outlined in the formulae for P_{oc} and multiplying by the shortest of the above durations that apply to that event combination. For example, if a failure mode with $X_{min} = 2$ and disconnection is due to a combination of the failure mode, a parallel outage and protection mal-operation then the minimum of D_{fm}, D_o and D_m is weighted with the other minimum durations of other disconnection combinations. Below are the equations for D for different values of X_{min}.

$$\text{For } X_{min} = 0, \; D = D_{fm}$$

<div align="center">**Equation 22**</div>

$$\text{For } X_{min} = 1, \; D = [min(D_{fm},D_o)P_o + min(D_{fm},D_d)P_d + min(D_{fm},D_f)P_f + min(D_{fm}, D_m)P_m] \, / \, P_{oc}$$

<div align="center">**Equation 23**</div>

$$\text{For } X_{min} = 2, \; D = [min(D_{fm},D_d)P_d^2 + min(D_{fm}, D_d, D_o)2P_dN_dP_o + min(D_{fm},D_d,D_m)2P_dN_dN_oP_m +$$
$$min(D_{fm},D_d,D_f)2P_dN_dN_oN_mP_f + min(D_{fm},D_o,D_m)N_d^2P_oP_m + min(D_{fm},D_o,D_f)N_d^2P_oN_mP_f + min(D_{fm},D_m,D_f)N_d^2N_oP_mP_f +$$
$$min(D_{fm},D_f)N_d^2N_oN_mP_f^2] \, / \, P_{oc}$$

<div align="center">**Equation 24**</div>

$$\text{For } X_{min} = 3, \; D = [min(D_{fm},D_d,D_o)P_d^2P_o + min(D_{fm},D_d,D_m)P_d^2N_oP_m + min(D_{fm},D_d,D_f)P_d^2N_oN_mP_f +$$
$$min(D_{fm},D_d,D_l)P_d^2N_oN_mN_fP_l + min(D_{fm},D_d,D_o,D_m)2P_dN_dP_oP_m + min(D_{fm},D_d,D_o,D_f)2P_dN_dP_oN_mP_f +$$
$$min(D_{fm},D_d,D_o,D_l)2P_dN_dP_oN_mN_fP_l + min(D_{fm},D_d,D_m,D_f)2P_dN_dN_oP_mP_f + min(D_{fm},D_d,D_m,D_l)2P_dN_dN_oP_mN_fP_l +$$
$$min(D_{fm},D_d,D_f)2P_dN_dN_oN_mP_f^2 + min(D_{fm},D_d,D_f,D_l)4P_dN_dN_oN_mP_fN_fP_l + min(D_{fm},D_o,D_m,D_f)N_d^2P_oP_mP_f +$$
$$min(D_{fm},D_o,D_m,D_l)N_d^2P_oP_mN_fP_l + min(D_{fm},D_o,D_f)N_d^2P_oN_mP_f^2 + min(D_{fm},D_o,D_f,D_l)2N_d^2P_oN_mP_fN_fP_l +$$
$$min(D_{fm},D_m,D_f)N_d^2N_oP_mP_f^2 + min(D_{fm},D_m,D_f,D_l)2N_d^2N_oP_mP_fN_fP_l + min(D_{fm},D_f)N_d^2N_oN_mP_f^3 +$$
$$min(D_{fm},D_f,D_l)3N_d^2N_oN_mP_f^2N_fP_l \,]/ \, P_{oc}$$

<div align="center">**Equation 25**</div>

3.1.5. CUSTOMER DISCONNECTION – SIZE AND UNIT COST

Once the largest group of customer sites with $X = X_{min}$ for a given failure mode of an asset has been identified the size of consequence of disconnection of this group must be fully quantified. The weighted quantity of generation disconnected, MW_W is given by:

$$MW_W = \sum \varphi MW_{GTEC}$$

<p align="center">**Equation 26**</p>

Where MW_{GTEC} is the Transmission Entry Capacity (TEC) of each disconnected generator and φ is the design variation weighting factor. This factor equals 1 for generators who are connected with standard SQSS levels of security. Its value for generators with lower than standard levels of security will be determined by each TO. TEC is used without any reference to load factor as this is how generator disconnection compensation is calculated as laid out in the Connection and Use of System Code (CUSC). Secondly the annual average true demand of customers disconnected, MW_D, is calculated by summing the peak demand and the embedded generation contribution during peak of all sites at risk. Both the peak demand and contribution of embedded generation is taken directly from DNO week 24 data submissions. The final inputs are the number of vital infrastructure sites of three different types supplied by sites at risk as shown in Table 10. These are demand sites of particular importance in terms of economic or public safety impact. There is no additional quantification of the risk of disconnection of customers or consumers for which the disconnection risks are considered High Impact Low Probability (HILP) events. The risk is treated on a per MW basis like any other consumer or customer.

The lists of sites that belong to the categories outlined in Table 10 are deemed sensitive and thus are not included here. The selection criteria and sources for the lists of sites can be found in the individual TO specific appendices. The costs of disconnection per site, per hour were calculated by collecting as much publicly available information as possible on the costs of historic disconnection events of comparable infrastructure sites across the developed world. These costs per minute or per event were converted into current sterling prices through exchange rate and price indexation conversion. An average for each category was then taken.

Vital Infrastructure Category	Symbol and Cost		
	Number of Sites	Cost per site per hour (£/hr)	Cost per site per disconnection event (£)
Transport Hubs	S_T	V_T	-
Economic Key Point	S_E	V_E	-
Particularly sensitive COMAH sites	S_C	-	V_C

<p align="center">**Table 10**</p>

The values for V_T, V_E and V_C are contained within the NGET Licensee Specific Appendices.

The final component of the risk cost, the per unit cost, is separately defined for the three above quantities of customer loss. *VOLL* in £/MWh is the same RPI indexed value as that used in the RIIO-T1 energy not supplied incentive (see NGET Licensee Specifc Appendix for value)

The cost of disconnection of generation is in two parts, firstly the generation compensation payment cost, G_C, in £/MWh varies with outage duration is based upon the CUSC methodology and uses cost information from System Operator.

<p align="center">For D ≤ 1.5h, $\ G_c = \ MW_W D C_{SBP}$</p>

<p align="center">**Equation 27**</p>

For 1.5 h < D ≤ 24h, $G_c = MW_W(1.5C_{SBP} + \{D - 1.5\}C_{SMP})$

For D > 24h, $G_c = MW_W(1.5C_{SBP} + 22.5C_{SMP} + \{D - 24\}C_{TNUoS})$

Where C_{SBP} is the annual average system buy price in £MWh^{-1}, C_{SMP} is the annual average system marginal price in £MWh^{-1} and C_{TNUoS} is the average Transmission Network Use of System (TNUoS) refund cost per MW per hour. C_{TNUoS} is calculated by divided the annual TNUoS charge for all generators by the total of TEC of all generators and again by 8760.

Secondly, the cost of generation replacement, G_{R*}, again dependent on D is defined as below.

For D ≤ 2h, $G_R = DC_{SMP}(0.42MW_W - 0.62MW_D)$

For D > 2h, $G_R = 2C_{SMP}(0.42MW_W - 0.62MW_D)$

For $G_R ≥ 0$, $G_{R*} = G_R$

For $G_R < 0$, $G_{R*} = 0$

This cost reflects the expense of the System Operator constraining on generation to replace that lost by the disconnection of generation. The equation multiples the duration of the disconnection and the annual average price to constrain on plant by the mismatch between the expected mismatch between generation and demand disconnected by the event. This mismatch is calculated by first taking the total TEC of generation connected to the customer sites in the group at risk, MW_W, and multiplying it by the system wide average generation load factor 0.42 (calculated by dividing the total energy generated in a year in MWh across the whole system by 8760 and then by the total TEC of all generation on the system). Secondly the peak adjusted demand, MW_D, of all customer sites in the group is multiplied by the average demand factor 0.62 (calculated by dividing the total annual transmission demand in MWh by 8760 and dividing again by the winter peak demand in MW). The difference between these two numbers is the mismatch, multiplied by the System Marginal Price in £MWh^{-1} and the duration up to a maximum of 2 hours. After 2 hours it would be expected that the market would have self-corrected for the generation mismatch.

The vital infrastructure site disconnection cost, V, is the numbers of different types of vital infrastructure sites multiplied by the cost per site and in the case of transport and economic key point sites multiplied by D.

$$V = D(V_T S_T + V_E S_E) + V_C S_C)$$

With all elements of the equation defined, the customer disconnection risk cost, $R_{customer}$, of a given asset failure mode of any asset can be defined by Equation 35.

$$R_{customer} = P_{oc}[G_C + G_R + 0.62DMW_D VOLL + V]M_z$$

A vast majority of lead assets will return a non-zero value for customer disconnection risk, the exceptions being shunt reactors and circuits which connect nodes with more than 4 circuits. These assets will have material risks for one of the next two elements of system consequence.

Note that in the future it may be possible to vary VOLL with the type of load lost but this is not included in the current methodology.

3.1.6. BOUNDARY TRANSFER

This methodology estimates the cost impact of having to pay generation constraint payments in order to restrict flows across a system boundary. Unlike the customer disconnection methodology, there is not a discrete disconnection event that either occurs or doesn't (within a given probability) but instead there is a year-round average cost per hour at which the boundary must be constrained which implicitly includes the probability of a constraint existing. The constraint cost per hour is dependent upon the number of circuits unavailable by the asset failure, Y. In the vast majority of cases this will be 1, but tower failures would usually result in two circuits being lost until the asset can be restored. Additionally the extra constraint cost that would result from unrelated unavailability on another circuit on the same boundary must be considered.

The derivation of average constraint costs will be based on flow and price information provided by the System Operator on an annual basis. The System Operator will run simulations of a full year of operation with each boundary in with intact, N-1 depletion, N-2 depletion and N-3 depletion capabilities resulting in four annual costs of operation for the boundary, B_Y, which is then calculated as follows:

$$B_1 = \frac{[(annual\ n-1\ cost) - (annual\ intact\ cost)]}{8760}$$

$$B_2 = \frac{[(annual\ n-2\ cost) - (annual\ intact\ cost)]}{8760}$$

$$B_3 = \frac{[(annual\ n-3\ cost) - (annual\ intact\ cost)]}{8760}$$

While a failure mode that renders Y circuits unavailable will incur costs at least the B_Y level, on average a proportion of the duration of the failure mode will be spent with Y+1 circuits unavailable, defined as P_{Y+1}. The proportion used is derived from historic fault and outage probabilities and durations. The probability of sustained boundary depletion beyond Y+1 circuits is assumed to be negligible.

These costs are multiplied by the duration of the unavailability of the asset until it is returned to service, D_{fm}, dependent upon historic precedent for the asset type and failure mode in question.

With the variables defined the methodology for determining the boundary transfer risk cost, $R_{boundary}$, of an asset failure mode of any asset can be described by Equation 39.

$$R_{boundary} = D_{fm}[B_Y(1 - P_{Y+1}) + B_{Y+1}P_{Y+1}]$$

<div align="center">**Equation 39**</div>

This methodology will return non-zero risk costs for all assets that belong to or affect circuits critical to the capability of one or more system boundaries with significant constraint implications.

Equation 39 can be illustrated with the example of B6, the boundary between the SPT and National Grid Electricity Transmission (NGET) areas. There are currently four circuits that make up this boundary. If a failure of an asset which makes up part of one of these circuits occurs then this circuit will be unavailable until the failure has been rectified, Y = 1 for this failure. The boundary will be at N-1 depletion until the failure is rectified and on average will spend some proportion, P_{Y+1}, of the duration of failure at a N-2 depletion level due to unrelated prior outages or other unrelated faults. The weighted average boundary constraint cost per hour is calculated by first multiplying B_1 by (1- P_{Y+1}), the proportion of time that the boundary is at N-1 depletion. Then B2 is multiplied by the proportion of time that the boundary will spend at N-2 depletion, P_{Y+1}. These two products are added together. This average boundary cost per hour is then simply multiplied by the average time taken to restore the circuits to service by repairing the failed asset, D_{fm}. This gives us the total expected boundary constraint for the failure mode of the asset.

3.1.7. REACTIVE COMPENSATION

The third methodology calculates the cost impact of having reactive compensation unavailable due to a fault or failure of any asset that would render the reactive compensation unusable. This could include circuit breakers, transformers and cables as well as the compensation itself. The purpose of reactive compensation is to produce or consume reactive power to aid control of system voltage. When compensation equipment is unavailable this reactive power control is either procured from generators instead or elements of the transmission system are de-energised, reducing system resilience. As a simplification the cost impact of a fault or failure can be quantified as the volume of reactive power not supplied multiplied by the cost per MVArh the SO must pay to buy the same service from generators. Therefore we have Equation 40Equation 39 to calculate the reactive compensation system risk cost, RRC, of an asset Failure Mode:

$$R_{RC} = R_F D_{fm} Q C_{MVArh}$$

<div align="center">**Equation 40**</div>

R_F is the requirement factor of the compensation equipment made unavailable or the proportion of the year that the compensation in question is required on a scale of 0 to 1. D_{fm} is the duration of unavailability due to the asset failure mode. Q is the capacity of the asset in MVAr and C_{MVArh} is the average cost of procuring of MVAr from generation sources.

C_{MVArh} will be calculated by taking an annual sum of all costs of generators to absorb MVArs including BM actions to bring plant into service and constrain others as well as the cost of providing the reactive absorption itself. This sum is divided by the total number of MVArhs that were absorbed by generators over the year.

3.2.   SAFETY CONSEQUENCE

When assets fail they have the potential to cause harm to both the general public and personnel who work on or near to the assets. In circumstances where this happens, there is a cost to society as a whole. The aim of this part of the methodology is therefore to capture the safety risks that deteriorating assets present to individuals who are exposed to their effects and the associated cost. In general the safety risk for an individual asset can be expressed as shown below:

$$Safety\ Risk = \sum_i \left(P\left(C_{saf,i}\right) \times C_{saf,i} \right)$$

Where:

$P\left(C_{saf,i}\right)$ = Probability of failure mode effect i occurring as a result of a failure event

$C_{saf,i}$ = Safety-related costs associated with asset failure resulting in failure mode effect i

For an individual asset the general expression for C_{saf} is as follows:

$$C_{saf} = Probability\ of\ Injury\ \times Cost\ of\ Injury\ \times Safety\ Exposure$$

Where:

Probability of Injury – the likelihood that an individual is injured when exposed to the effects of an asset failure

Cost of Injury – the cost associated with an individual sustaining an injury

Safety Exposure – modifier to reflect the number of people who are exposed to the effects of an asset failure

In reality, individuals exposed to asset failures can potentially sustain injuries of varying severity and the likelihood of these injuries occurring will depend on the asset under consideration, the type of failure that occurs and the effects associated with that failure. Moreover, the cost associated with different types of injury will vary. Taking into account these variables the 'Safety Cost' can be more formally expressed as shown below:

$$C_{saf,i} = \sum_j Probability\ of\ Injury_{j,i} \times Cost\ of\ injury_j \times Safety\ Exposure$$

Where:

i	=	Failure Mode Effect
j	=	Injury Type

3.2.1. FAILURE MODE EFFECT & PROBABILITY OF FAILURE MODE EFFECT

The failure mode effect represents the possible effects that NGET considers as a result of failure and the probability of failure mode effect represents its likelihood of occurrence. The effects that are considered by NGET and the calculation of their likelihood are described below.

3.2.2. INJURY TYPE & PROBABILITY OF INJURY

Individuals can sustain varying degrees of injury as a result of an asset failure. NGET proposes to categorise the severity of injury into the following types, using HSE definitions[2]:

1. Slight – Injury involving minor cuts and bruises with a quick and complete recovery
2. Serious - Slight to moderate pain for 2-7 days. Thereafter some pain/discomfort for several weeks. Some restrictions to work and/or leisure activities for several weeks/months. After 3-4 months return to normal health with no permanent disability.
3. Permanent Incapacitating Injury - Moderate to severe pain for 1-4 weeks. Thereafter some pain gradually reducing but may recur when taking part in some activities. Some permanent restrictions to leisure and possibly some work activities.
4. Fatality

The 'Probability of Injury' represents the likelihood that an individual is injured when exposed to the effects of an asset failure. Probabilities will be assigned to each 'Injury Type' considered. The probability assigned to each category will vary depending on the failure mode that occurs and the effects that occur as a result of the failure mode effect materialising. For less disruptive failures there may be no impact from a safety perspective and the probability of injury will be zero. In addition, because it is assumed that the probability of injury applies to an individual, the sum of probabilities across all injury types categories for a particular failure effect is less than or equal to unity (i.e. an individual's injuries can only be classified under a single category of injury).

3.2.2.1.   COST OF INJURY

Fixed costs will be assigned to the different injury types recognised by the HSE as per their website[3], which are inflated to a cost-base of 2016/17 in line with RPI[4].

Whilst the appraisal values reflect a broad range of cost categories, for simplicity of presentation the appraisal values can be divided into two main component costs:

- Human costs - representing a monetary estimate of the loss of quality of life, and loss of life in the case of fatal injuries
- Financial costs, which are the sum of the following:
  - Productivity costs including:
    - net lost income, taking into account of loss of output and earnings due to absence from work, and offsetting transfers from one party to another, e.g. benefits payments are a cost to Government, but an equal and opposite offsetting benefit to individuals
    - production costs, such as cost of recruitment and work reorganisation
  - The cost of Employer's Liability Compulsory Insurance, less compensation payouts to individuals
  - Health and rehabilitation costs, such as NHS costs
  - Administrative and legal costs, such as costs of administering benefits claims

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[2] http://www.hse.gov.uk/risk/theory/alarpcheck.htm
[3] http://www.hse.gov.uk/risk/theory/alarpcheck.htm
[4] https://www.ons.gov.uk/economy/inflationandpriceindices/timeseries/chaw/mm23

Each of these factors is discussed in the following sections. NGET anticipates that the 'Cost of Injury' will be calculated as below:

$$Cost\ of\ Injury_j = \sum Total\ Cost\ (Rounded) \times Disproportion\ Factor$$

Equation 44

The 'Total Cost (Rounded)' is reflected by the HSE values, as per their website, which are inflated to a cost-base of 2016/17 in line with RPI.

A disproportion factor recognises the high risk nature of the Transmission Industry. Such disproportion factors are described by the HSE guidance when identifying reasonably practicable costs of mitigation. This value is not mandated by the HSE but they state that they believe that "the greater the risk, the more should be spent in reducing it, and the greater the bias should be on the side of safety"[5].

The value of the disproportion factor is included in each Licensee Specific Appendix, as the disproportion factor reflects the organisation's risk appetite.

3.2.3. SAFETY EXPOSURE

Safety consequences are specific to individual assets and their physical location. Some assets will expose a greater number of people to their failure effects than others depending on the levels of activity near to the asset. The 'Probability of Injury' only considers whether an individual will be injured assuming they are exposed to the effects of an asset failure and does not consider whether it is likely that one or more individuals will be within the vicinity of an asset when it fails. In order to take into account the likely number of people exposed to the effects of an asset failure (e.g. where an event impacts multiple people at the same time) a 'Safety Exposure' modifier is incorporated into the 'Safety Cost of Failure Mode Effects' calculation.

Under the Electricity Safety Quality and Continuity Regulations 2002 (ESQCR), risk assessments must be carried out on NGET assets to assess the risk of interference, vandalism or unauthorised access to the asset by the public.

The overall safety exposure value is built from the following components:
- Location:
  - Proximity to areas that may affect its likelihood of trespass or interference
  - Personnel activity in the vicinity of the asset

Location/Exposure Risk Rating	
Low	Limited personnel access. No likely public access
Medium	Regular personnel/public activity in the vicinity of the asset
High	High levels of personnel/public activity in the vicinity of the asset
Very High	Constant personnel/public activity in the vicinity of the asset

Table 11

The values used for each safety exposure score (Low-Very High), are included in the Licensee Specific Appendix. The following factors have been taken into consideration:

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[5] http://www.hse.gov.uk/risk/theory/alarpcheck.htm

- Number of hours per annum of an individual staff member being in the vicinity of an asset on the system, due to:
  - Routine activities
  - Maintenance activities
  - Replacement activities
  - Switching activities
  - Meetings in substation buildings
  - Office base at substation buildings

- Number of hours per annum to an individual member of the public being in the vicinity of an asset, due to:
  - Domestic activity
  - Industrial activity
  - Rights-of-way
  - Agricultural activity
  - Educational activity
  - Commercial activity
  - Retail activity

The safety exposure factor takes an average value of hours per annum for an individual to be within the vicinity of an NGET asset. This presents an average safety exposure value for each of the four categories, reflective of a ratio of the number of hours per annum for an individual to be within the vicinity of an NGET asset compared to the number of hours in a year. The average value is taken due to the number of NGET sites, such that the sites included in each exposure category can vary significantly, and the category for 'Very High' exposure will contain the anomaly sites with extreme cases of public and staff exposure, significantly higher than the remaining sites within that category. The average value is used as the most appropriate representation of the exposure levels for the majority of sites within each relevant exposure category.

3.3.   ENVIRONMENTAL CONSEQUENCE

When assets fail they have the potential to impact on the geographical area local to the asset. The aim of this part of the methodology is to capture the different environmental effects that deteriorating assets present and the associated costs. In general the total environmental risk for an asset can be expressed as shown below:

$$Environmental\ Risk = \sum_i \left(P\left(C_{env,i}\right) \times C_{env,i} \right)$$

Equation 45

Where:

$P\left(C_{env,i}\right)$ = Probability of failure mode effect i occurring as a result of a failure event

$C_{env,i}$ = Environmental-related costs associated with asset failure resulting in failure mode effect i

For an individual asset the general expression for C_{env} is:

$$C_{env} = Probability\ of\ Environmental\ Impact \times Cost\ of\ Environmental\ Impact \times Environmental\ Exposure$$

<div align="center">**Equation 46**</div>

Where:

Probability of Environmental Impact – the likelihood that there is an environmental impact as a result of a particular asset failure mode effect

Cost of Environmental Impact – the costs arising from a failure event that has an impact on the environment

Environmental Exposure – modifier to reflect the sensitivity of the environment exposed to the effects of an asset failure event

In reality, the environment exposed to asset failures can potentially sustain varying severities of environmental impacts, and the likelihoods of these environmental impacts occurring is dependent on the asset under consideration, the type of failure that occurs and the effects associated with the failure. Consequently, the costs associated with different types of environmental impacts will vary. Taking into account these variables the 'Environmental Cost of Failure Mode Effect' can be formally expressed as shown below:

$$C_{env,i} = \sum_{j} Probability\ of\ Environmental\ Impact_{j,i} \times Cost\ of\ Environmental\ Impact_{j} \times Environmental\ Exposure$$

<div align="center">**Equation 47**</div>

Where:

i	=	Failure Mode Effect
j	=	Environmental Impact Type

3.3.1. FAILURE MODE EFFECT & PROBABILITY OF FAILURE MODE EFFECT

The failure mode effects represent the possible effects that NGET considers as a result of a failure event and the probability of failure mode effect represents its likelihood of occurrence. The environmental effects that are considered by NGET and the calculation of their likelihoods are described below.

The probability assigned to each environmental impact type, see section 1.1.2, will vary depending on the failure mode that occurs and the effects that result from the failure mode event materialising. For less disruptive failures there may be no impact on the environment, and the probability of environmental impact would then be zero. In addition, because it is assumed that the probability of impact applies to an individual site, the sum of probabilities across all impact type categories for a particular failure effect is less than or equal to unity (i.e. the environmental impact that occurs at a site can only be classified under a single impact type).

3.3.2. ENVIRONMENTAL IMPACT TYPE

The severity of the environmental impact, as a result of an asset failure can vary. NGET proposes to categorise the severity of different environmental impact types, by the following table:

Impact Type	Environmental Impact
Low	• Near Miss - An incident, which under different circumstances had the potential to cause harm or damage to the environment
Moderate	• Events resulting in environmental harm or damage • Prosecution or enforcement action by a regulatory body or adverse public perception is deemed unlikely
Significant	• Significant environmental harm or damage, incidents which are significant to us as a business and drive different decisions and/or behaviours. • National Grid receiving formal written notification of enforcement action from a regulatory authority • Regulators and similar bodies taking an active involvement in our activities as a result of the incident

Table 12

3.3.2.1.   COST OF ENVIRONMENTAL IMPACT

Costs will be assigned to the different environmental impact types, as detailed in the Licensee Specific Appendix. These include:

- Environmental cost per litre of oil
- Environmental cost per kg of SF_6 lost

  This is derived from:
  - Traded carbon price
  - Cost of SF_6 loss compared with the cost of carbon

- Environmental cost of fire
- Environmental cost per tonne of waste

The values are provided in the Licensee Specific Appendix.

3.3.3. ENVIRONMENTAL EXPOSURE

Due to the distributed nature of networks it is important that exposure is taken into account. Environmental consequences are specific to individual asset size and their physical location. Some assets pose a greater risk to the environment than others. In order to account for this an 'Environmental Exposure' modifier is incorporated into the 'Environmental Consequence of Failure Mode Effect' calculation. The environmental exposure values are included in the Licensee Specific Appendix.

3.3.3.1.   LOCATION FACTOR

Location factor allows for an adjustment to be made based on an assessment of the environmental sensitivity of the site on which an asset is located. The specific concerns will vary by asset type but include proximity to watercourses and other environmentally sensitive areas. The factor also recognises any mitigation associated with the asset. This factor is derived by combining separate factors relating to proximity to a watercourse or Site of Special Scientific Interest (SSSI).

Environmental Exposure Category	Criteria

Low	• Asset located in controlled environment
Medium	• Asset may be located in controlled, environment which may be located within 100m of environmentally sensitive area. • Distributed asset located greater than 100m from sensitive environment
High	• Distributed asset, all or part of which, is located within 100m of Source Protection Zone, abstraction or surface water course or SSSI

<div align="center">**Table 13**</div>

3.4. FINANCIAL CONSEQUENCE

The Financial Consequence of Failure is derived from an assessment of the typical replacement and repair costs incurred by the failure of the asset in each of its applicable Failure Modes and is multiplied by the probability of each Failure Mode effect.

$$Financial\ Risk\ (k) = \sum_i \left(P\left(C_{fin,i}\right) \times C_{fin,i}\right)$$

<div align="center">**Equation 48**</div>

Where:

$P\left(C_{fin,i}\right)$ = Probability that event i occurs

$C_{fin,i}$ = Financial consequence of the event's effect

The FMEA process identifies asset items and the failure events associated with them. Each failure event may result in one or more Failure Mode effects and each effect has consequences. The probability of the events resulting from each Failure Mode is determined through the FMEA process.

The Financial Consequence for each effect is derived from the average cost to repair or replace the asset (or assets, if the failure results in a disruptive failure where adjacent assets are damaged) based on existing repair and replacement data. The costs presented are the labour and repair costs as well as OMGS (Other Materials, Goods and Services), which are necessary to carry out the repair or replacement of the failed asset. Additional costs, associated with the failure but not incurred in carrying out the repair or replacement, such as environmental clean-up or formal incident investigation costs (undertaken following catastrophic failures, for example), are not considered as part of the Financial Consequence.

To illustrate, the following Failure Mode effects result from events associated with transformers. It is the event which has the consequence; hence the costings are derived for each event. In order to validate the costing, the Failure Modes which cause the event are also presented.

Event	Connected with Failure Mode/cause	Activities used to derive average cost (this table will show actual costs in the Licensee Specific Appendix following CTV)
01- No Event		
02- Environment Noise	Noise caused by anti vibration pads failing or faulty fans	Labour costs and component costs plus OMGS
03- Reduced Capability	Downratings due to pumps/fans failure or overheating caused by carbon build up on tap changers	Labour costs to investigate and repair. Component costs + OMGS
04- Alarm	Overheating alarm	Labour costs for alarm investigation
05- Unwanted Alarm + Trip	Unintentional operation of Buchholz or WTI	Labour costs for trip investigation
06- Transformer Trip	high res contacts on diverters	Labour costs for trip investigation
07- Reduced Capability + Alarm + Trip	Overheating due to WTI failure Contactor/control relay failure Pump failure Fan failure Incorrect valve position Blockages (sludging) cooler blockage external OR loss of oil due to tank corrosion	Labour costs to investigate and repair. Component costs + OMGS
08- Fail to Operate + Repair	Buchholz or WTI fail to trip or alarm, overheating on tap changers,	Labour costs to investigate and repair. Component costs + OMGS
09- Reduced Capability + Alarm + Loss of Voltage Control + Fail to Operate	Tap changer motor drive defects	Labour costs to investigate and repair. Component costs + OMGS
10- Overheating (will trip on overload)	Overheating due to carbon build up or high resistance contacts in tap changer or overheating due to WTI failure Contactor/control relay failure Pump failure Fan failure Incorrect valve position Blockages (sludging) cooler blockage external	Labour costs to investigate and repair. Component costs + OMGS
11- Cross Contamination of Oil	Gasket leak, drive seal failure, corrosion on diverters	Labour costs to investigate and repair. Component costs + OMGS
12- Alarm + Damaged Component (Tap Changer) No Trip	Diverter mechanism jams due to loose permali nuts	Labour costs to investigate and repair. Component costs + OMGS. May necessitate replacement of tap changer.
13- Alarm + Trip + Damaged Component (Tap Changer)	Selector/diverter fail to complete op or flashover. Diverter open circuit, loss of containment	Labour costs to investigate and repair. Component costs + OMGS. May necessitate replacement of tap changer.

14- Alarm + Trip + Transformer Internal Damage	Selector/diverter fail to complete operation or flashover. Diverter go open circuit, loss of containment - but in this case the transformer is damaged not just the tap changer	Labour costs to investigate and repair. Component costs + OMGS. Significant damage to the transformer windings.
15- loss of oil into secondary containment	Major oil leak, tank breach	Labour costs to investigate and repair. Component costs + OMGS.
16- Alarm + Trip + Damage + State Requiring Replacement (Asset Replacement)	End of Life owing to deterioration	Unit cost for replacement of the asset
17- Alarm + Trip + Disruptive Failure + External Damage (danger) + Replacement	Disruptive failure - potential for bushing porcelain projectiles	Replacement of the asset plus costs of replacing/repairing any adjacent assets damaged
18- Alarm + Trip + Disruptive Failure + External Damage (danger) + Replacement+ Transformer Fire	Transformer fire	Replacement of the asset plus costs of replacing/repairing any adjacent assets damaged by the fire

Table 14

4. RISK

4.1. METHODOLOGY FOR CALCULATION OF RISK

As stated in section 1.3.7, for a given asset (k), a measure of the risk associated with it is the Asset Risk (A_k), given by:

$$Asset\ Risk(A_k) = \sum_{j=1}^{n} P(C_j) \times C_j$$

Equation 49

$where$:

$P(C_j) = Probability\ of\ consequence\ j\ occurring\ during\ a\ given\ time\ period$

$C_j = the\ monetised\ Consequence\ j$

$n = the\ number\ of\ Consequences\ associated\ with\ Asset\ k$

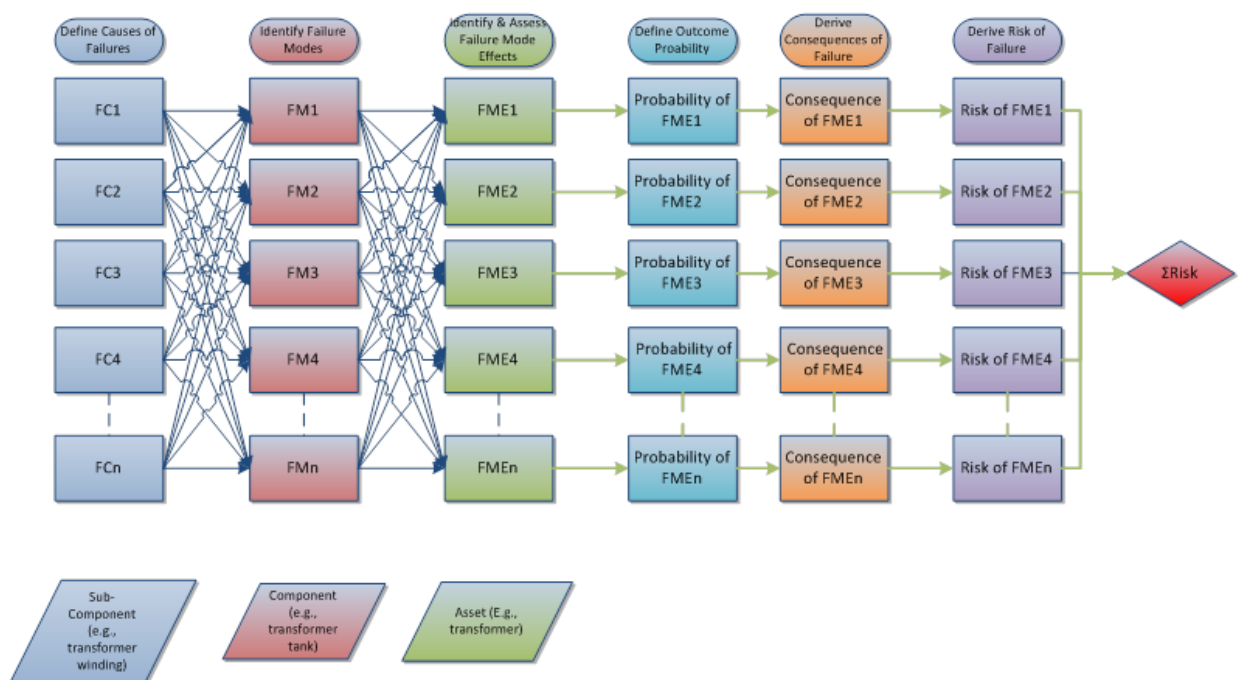Figure 2 shows how the components interact and combine together to arrive at a value for Asset Risk.

Figure 2

The Network Risk for NGET can be calculated by summing the Asset Risk associated with each lead asset as shown in Equation 50.

$$Network\ Risk = \sum_{k=1}^{n} A_k$$

BS EN 60812 describes the process for disaggregating systems into their component parts and assessing the probability of functional failures of each component and the consequences of such failures, then aggregating these quantities to obtain an estimate of the overall risk of the system. A failure mode is clearly immaterial if the cost of the analysis of the failure of a component is much greater than value of the risk represented by the failure of that component, because either the probability of failure of a component or the consequence of failure of a component is insufficiently large.

The available evidential and supporting data, suitable for FMEA analysis, is usually imperfect. This may be for a number of reasons, for example, some possible effects and consequences might be material, but have not yet occurred. Similarly, accurate data may not have been captured for failures, even though the effects and consequences have occurred. Effective application of FMEA therefore requires engineering expertise, both to envision material consequences that have not yet occurred and to estimate values which have not been measured and/or recorded and which cannot be reliably calculated from first principles.

There is a further requirement in the Ofgem Direction to enable the identification of all material factors contributing to real or apparent performance against targets.

A non-exhaustive list of these factors is identified in Paragraph 32 of the Direction. In practice, the effect of any of these factors will be a modification to one or more inputs to the methodology. By definition, any factor which does not result in a modification to one or more of the inputs does not contribute to real or apparent performance against targets as measured by this methodology.

For factors that do modify one or more inputs to the methodology, the methodology can be re-run incorporating these input changes and the outcomes compared with the outcomes produced before the changes are applied. Hence not only can factors be identified but also their relative materiality can be determined.

Therefore if NGET (or Ofgem) suspects that a factor (e.g. data revisions) or change in external environment (business, legal, site or situation) will contribute to real or apparent performance against targets, then the following tests can be made:

1. Check what impact the factor has on existing inputs to the methodology – if the impact is zero then the factor has been positively classified as non-material

2. If impact is non-zero then re-run the methodology with changed inputs and compare outputs with equivalent outputs with the un-changed inputs – The variation of output can be compared with the variations produced by other factors and ranked in terms of relative materiality

4.2. RISK TRADING MODEL

The NGET Risk Trading Model will calculate the monetised risk for each asset and aggregate to give the total Network Risk. It will reflect the processes and calculations described within this methodology and associated appendices.

The Risk Trading Model (RTM) is being developed with the aim that it will be used to assist in planning and prioritising work to be undertaken on high risk assets within the transmission network between a start year (Y_o) and an end year (Y_n) (e.g. for a price control period).

The scope of the RTM and its detailed methodology are defined in the NGET Licensee Specific Appendices

The development of the Risk Trading Model is ongoing. Its development is contingent upon a number of topics which will form part of the next phase of work, including Calibration, Testing & Validation. The development of the Risk Trading Model will ensure a consistent format for outputs and will be included within the detailed Implementation Plan in section 7 below.

5. DECISION MAKING

5.1. INTERVENTIONS

Certain types of intervention will address particular failure modes. These may be routine interventions, such as maintenance, or specific, such as planned replacements.

The available interventions for managing the performance of assets range from routine maintenance to full replacement.

These activities are undertaken to ensure the longevity and performance of the NGET network. Without effective management of these activities, and understanding the related interactions between them, NGET would, in time, experience deterioration of network outputs which would have a significant detrimental impact on the capability of the network.

Intervention plans are optimised to deliver an efficient level of network risk in line with customer, consumer and stakeholder expectations. In determining this efficient level, NGET evaluates the cost of interventions against the benefits these interventions deliver.

In determining an intervention plan in any period, NGET needs to assess the Asset Risks and decide exactly which interventions to undertake. This requires NGET to make a binary decision (e.g. to replace, or not to replace) where every asset has an Asset Risk contribution to the Network Risk. This process involves assessing all available interventions to decide the combination which most efficiently manages Network Risk.

The cost of these interventions is not equal to the reduction in Network Risk achieved by undertaking that intervention plan.

Table 15 identifies different types of intervention that would address failure modes, Figure 1616 (not to scale) illustrates which failure modes are addressed by the different intervention types.
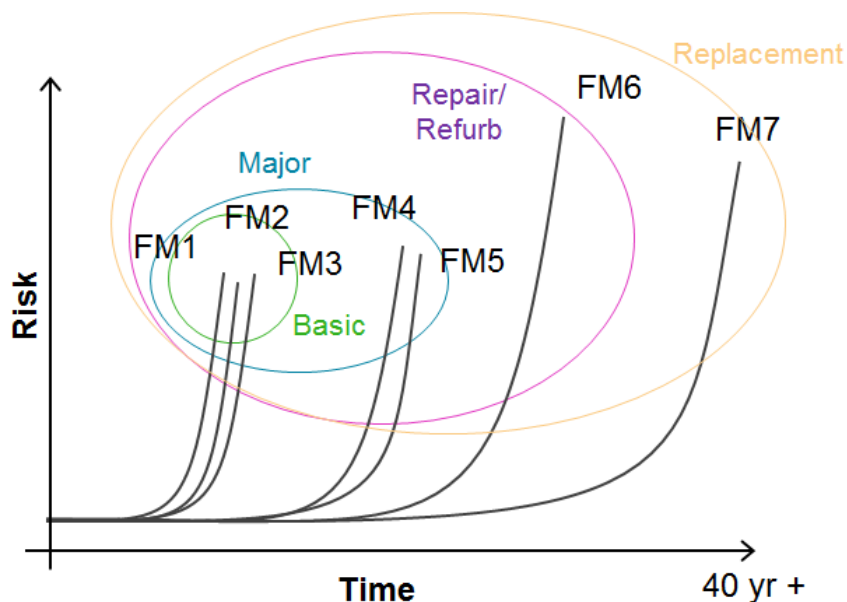

Figure 16

Failure Mode	1	2	3	4	5	6	7
Basic Maintenance	✔	✔	✔	✗	✗	✗	✗
Major Maintenance	✔	✔	✔	✔	✔	✗	✗
Repair	✔	✔	✔	✔	✔	✔	✗
Refurbishment	✔	✔	✔	✔	✔	✔	✗
Replacement	✔	✔	✔	✔	✔	✔	✔

Table 15

Several failure modes can happen within a similar time frame/ duty cycle, so the work to be carried out needs to be selected carefully in order to:

- Ensure that the relevant failure modes are adequately addressed
- Reduce the whole life cost
- Limit the impact of constraints such as outages and resources.

Interventions are determined by understanding how to prevent failure modes and the collection of data to predict failures. Knowing the asset's position on each failure mode curve enables NGET to make a targeted intervention specifically addressing those failure modes most contributing to the risk. Following the intervention the asset risk on the asset is reduced for that particular failure mode.

5.1.1. MAINTENANCE

The purpose of asset maintenance is to ensure that relevant statutory and legal requirements are met, such as those relating to safety and environmental performance, keeping assets in service, as well as allowing NGET to gather condition information so that performance risks are better understood and mitigated.

Through maintenance activities NGET can manage the natural deterioration of asset condition so that the assets remain operable throughout their anticipated technical life, reducing unplanned outages on the network as well as monitoring the condition of assets to improve understand of their performance. This then feeds into future asset intervention plans.

Maintenance is a fundamental tool in NGETs' management of network reliability, safety and environmental performance (and hence customer satisfaction). Reducing maintenance to zero, or reducing levels without undertaking impact assessments, would lead to a decline in the condition of assets (this effect is seen more rapidly than for under-investment in replacement), leading to increased unplanned events and in some cases bringing forward the need for asset replacement or increasing refurbishment activities.

Maintenance policy evolves as processes and practice are periodically reviewed. NGET reassess maintenance policy on an ongoing basis using the latest information available in order to ensure assets can achieve their anticipated asset lives and reduce the potential for unplanned disruption. Maintenance activity can uncover developing trends for defects, ensure rectification of unforeseen functional failure modes and can be the driver for further innovation in methodologies and techniques for future interventions .

When developing maintenance content, NGET has a systematic, structured method for cost/benefit evaluation. This includes understanding the asset's reliability for known failure modes, taking account of how the operating costs would be expected to increase during the time between interventions; identifying potential changes in performance; and consideration of the impact that a change to the intervention might have on the life of the asset. As part of the planning process, maintenance is bundled into efficient packages to optimise access to the network and the assets.

Maintenance activities are pro-active interventions which take place at regular intervals according to policy. Undertaking maintenance activities ensures that the assets function correctly and can identify issues with the assets which can be addressed prior to a failure mode occurring.

A basic maintenance will involve basic checks for function of particular components as well as activities such as visual inspections, checks for fluid/gas levels where appropriate.

An intermediate maintenance takes place at longer intervals than a basic and will include all activities undertaken for a basic maintenance but will include additional checks on specific components of the equipment.

A major maintenance will include all the activities undertaken for a basic and intermediate maintenance but will also include comprehensive and possibly intrusive work as well as more exhaustive checks. These take place less regularly than basic and intermediate levels and generally require a significantly longer outage to carry out the work.

Maintenance interventions are determined through maintenance policy for each asset type, according to the specific requirements for that asset. Manufacturer recommendations are taken into account, but not necessarily followed.

5.1.2. REPAIR

Repair is generally a reactive activity responding to a failure mode event when it has occurred or, in some cases, to prevent a particular failure mode if it can be detected before the event occurs. For some failure modes which cannot be detected on a routine basis, such as by maintenance or inspection, repair is the only available intervention once the failure mode has occurred. That is not to say that detection of the failure mode is not available and assets are monitored for known failure modes. For example, cable oil pressure is monitored and an alarm triggered if the pressure falls below a certain level. The failure mode is detected as the oil leak initiates but there are no routine interventions available to detect the occurrence of a leak before it occurs.

The only available option is to repair the cable when the oil leak is detected. Some failure modes, which lead to another failure mode, can be detected prior to failure, for example, sheath testing of cables will reveal defects in the oversheath which, if left unrepaired, will eventually lead to the corrosion of the sheath and subsequently an oil leak. A repair intervention can then be planned to mitigate this risk.

5.1.3. REFURBISHMENT

The decision to refurbish instead of replace an asset follows careful consideration of a number of criteria. For refurbishment to be technically feasible and cost-effective, the asset population size must be sufficiently large because the costs associated with developing the technical content of a refurbishment procedure, and the set-up costs to undertake the work, mean that it is difficult to make refurbishment of small populations cost-effective.

The ongoing lifetime cost of supporting a refurbished asset family must also be considered. It may be more cost-effective to replace highly complex units that require frequent intervention.

Continuing spares support must be considered. Whilst some spares can be re-engineered without significant risk, this is not appropriate for performance critical components. If such components are unavailable (or not available cost-effectively), refurbishment is unlikely to be a realistic option.

Additionally, the condition and deterioration mechanisms of the asset class must be well understood. If these criteria are met, and it is considered that refurbishment is a viable option, it would be expected that refurbishment activities would change the asset's condition and/or extend asset life.

5.1.4. REPLACEMENT

Individual assets or families, which are deemed to be a priority given their risk, trigger the need for replacement and capital investment. There may also be instances where the frequency of repair (and associated cost) is such that replacement is considered economic. To facilitate the development of an optimised replacement plan, priority ranked lists for replacement are created for each asset type.

5.1.5. HIGH IMPACT LOW PROBABILITY ASSETS

A High Impact Low Probability (HILP) asset will have an element of 'HILP' risk associated with it that is not the same as Asset Risk. An example of a HILP asset may be an asset associated with transmission network black start capabilities or an asset associated with connection of a nuclear site to the transmission network.

The HILP risk will be associated with an event that NGET wish to avoid (e.g. the tripping of a nuclear power station) but one that is also difficult to specifically quantify.

Application of the NOMs methodology, described in this NARA and associated supporting documentation, may result in HILP assets ending up lower down in a prioritised list of assets for intervention, based on their Asset Risk.

In instances like this, NGET may choose to intervene on a HILP asset in preference to an asset with an equal or higher Asset Risk and will justify each decision.

6. CALIBRATION, TESTING AND VALIDATION

The TOs have put together a detailed plan for Calibration, Testing and Validation (CTV).

The NOMs methodology has been designed to enable the parameters to be easily adjusted to reflect the results of the CTV exercises. The CTV exercises include scenarios and tests, and defined criteria are set out prior to the test and the results are compared against these criteria.

6.1. CALIBRATION

The purpose of calibration is to:

- Ensure that each TO produces credible CoF, EoL modifiers and PoF values that are representative of the impacts of actual asset failures.
- Ensure that each TOs input values and assumptions are consistent and comparable.

6.2. TESTING

The purpose of testing is to:

- Ensure that each TO has implemented correctly inline with the NOMs methodology.
- That the each TOs implementation of the NOMS methodology works across a suitable range of credible scenarios.

6.3. VALIDATION

The purpose of validation is to:

- Ensure that each TOs implementation of the NOMs methodology produces comparable results.
- Ensure that the NOMs methodology produces realistic and credible values.

6.4. DELIVERY OF CTV

The TOs will work together while undertaking the CTV exercises to compare results to ensure that the results are comparable and to share any data required to undertake the exercises.

A separate document will be produced once the CTV exercises have been completed which will:

- Detail the work carried out and the data sources used.
- List any calibration that has been applied as a result of the CTV.
- Demonstrate the comparability across TOs.

7. IMPLEMENTATION

NGET has been working to develop the NOMs methodology but is focused on upskilling our staff and embedding new ways of working into our business.
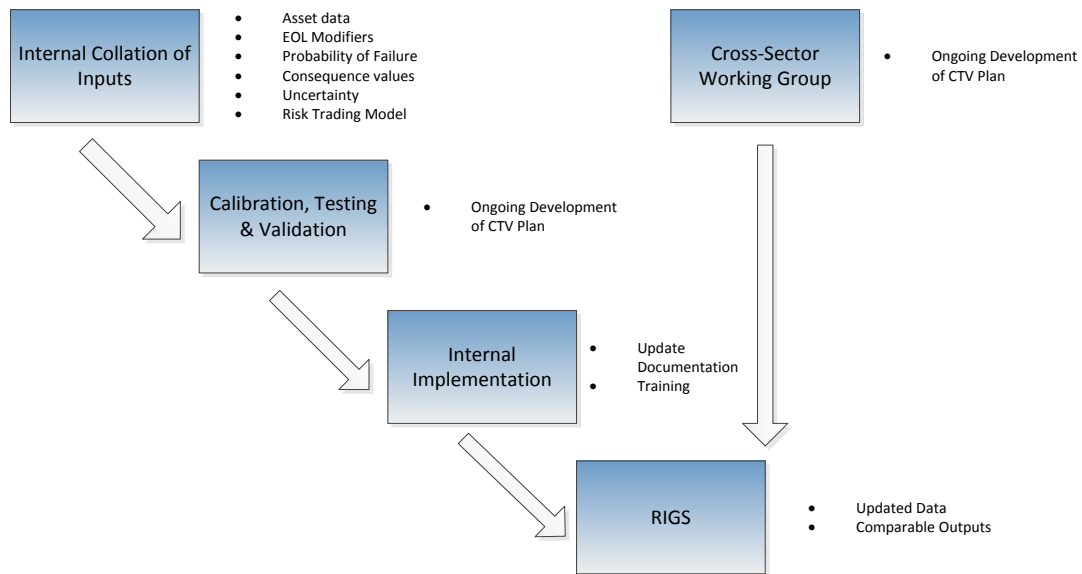
Figure 17

Process	Item	Description of Implementation Work Required	Planned Date for completion
Internal Collation of Inputs	Asset Data	Subject to approval of common methodology, NGET specific inputs to be collated in order to commence CTV process	See CTV detailed plan
	EOL Modifiers		
	Probability of Failure		
	Consequence Values		
	Uncertainty		
	Risk Trading Model		
Calibration, Testing and Validation	See CTV plan	Detailed plan to be submitted 15th Dec 2017. Ofgem feedback on CTV draft plans concerning tasks which are dependent upon having a finalised methodology noted.	See CTV detailed plan
Internal Implementation	Rebase targets	Develop and Issue Draft Updated Methodology to Ofgem	July 2018

		Methodology Final Submission	August 2018
		Rebased Final Targets – Ofgem Submission	September 2018
	Update process documentation	Technical documentation written in draft form for submission to Ofgem subject to successful CTV.	April 2018
		Subject to approval, roll out of technical documentation to business via internal governance process	April 2019
	Implement Training	Operational Staff Training, Planners Training	Complete
		Develop monetised risk game and roll out to operational staff, planning and asset management functions	Complete
		Use of a Risk Score in planning training	Complete
		Further training on monetised risk for asset replacement process	April 2019
RIGS	Comparable Outputs	Rebase targets comparison with old targets completed	September 2018
		Develop RIGS for reporting monetised risk	April 2019
		Run monetise risk model in parallel with Replacement Priority risk model and report both outputs in RRP	July 2019
Continuous Improvement		Continue to review inputs as part of asset management processes	ongoing
Cross Sector Working Group	Implementation of incentive mechanism	Review with Scottish TOs and Ofgem	
	Principles for under/over delivery	Review with Scottish TOs and Ofgem	
	HILP events	Review with Scottish TOs and Ofgem	

Table 16

8. ASSET SPECIFIC DETAIL

8.1. LEAD ASSETS

The following sections provide background and high level deterioration mechanisms for the lead assets.

8.1.1. CIRCUIT BREAKERS

8.1.1.1. BACKGROUND

Circuit breakers are different to other lead assets as they generally have limited condition information on an individual asset basis. To gather additional condition information on sub components which has the potential to affect the end of life (EoL) modifier, would require invasive work to assess the actual condition of a particular sub component. It is undesirable to do so in the majority of situations as it would require a system outage.

Technically effective or cost justified diagnostic techniques, including continuous monitoring, are limited for use on large populations and are not applicable for deterioration modes determining the end of life of most types of existing circuit breaker. In addition, the deterioration age range is related to the equipment's environment, electrical and mechanical duty, maintenance regime and application.

In this methodology a family specific deterioration component to the EoL modifier formula is introduced to account for missing condition information. Assignment to particular family groupings is through identification of similar life limiting factors. Family groupings are broadly split into interrupter mechanism types.

Known deterioration modes have been determined by carrying out analysis of materials and components during replacement, refurbishment, maintenance and failure investigation activities or following failures. The output of the analysis reports has been used to both inform and update the relevant deterioration models. Anticipated technical asset lives are based on the accumulated engineering knowledge of NGET's defect and failure statistics and manufacturer information. The method for mapping this knowledge to the end of life curve was presented in the functional modes and effects analysis section.

8.1.1.2. DETERIORATION

Circuit breakers are made up of a number of sub-components. These sub-components deteriorate at different rates, are different in relation to their criticality to the circuit breaker function and finally have different options regarding intervention

Although there is a correlation between age and condition, it has been observed that there is a very wide range of deterioration rates for individual units. The effect of this is to increase the range of circuit breaker condition with age, some circuit breakers becoming unreliable before the anticipated life and some showing very little deterioration well after that time.

8.1.1.3. AIR-BLAST CIRCUIT BREAKER TECHNOLOGY

As Air-Blast Circuit Breaker (ABCB) families approach their end of life an assessment is made regarding the relative economic impact of replacement or refurbishment taking into account factors such as technological complexity, population size and ongoing asset management capability for the design. Since most ABCB families are no longer supported by their original equipment manufacturer, the cost and feasibility of providing parts, skilled labour and ongoing technical support must be factored into the total cost of refurbishment. For this

reason, refurbishment may only be cost-effective for certain, large family types. For small families, the cost of establishing a refurbishment programme and maintaining appropriate knowledge and support will most often favour replacement.

Using the above approach, refurbishment has, in selected cases, proven to be an effective way to extend the Anticipated Asset Life (AAL) for Conventional Air-Blast (CAB) and Pressurised head Air Blast (PAB) circuit breakers.

The replacement of ABCBs is considered alongside the remaining lifetime of the associated site air system. If removal of the last ABCBs at a site allows the site air system to be decommissioned, early switchgear replacement may be cost beneficial when weighed against further expenditure for air system replacement and/or on-going maintenance.

8.1.1.4. OIL CIRCUIT BREAKER TECHNOLOGY

The life-limiting factor of principal concern is moisture ingress and the subsequent risk of destructive failure associated with the BL-type barrier bushing in bulk Oil Circuit Breakers (OCBs). A suitable replacement bushing has been developed that can be exchanged when moisture levels reach defined criteria, but at a high cost to the extent that is not economical to replace many bushings using this technology. Risk management of bushings has been achieved by routine oil sampling during maintenance, subsequent oil analysis and replacement of bushings where required. On this basis the AAL for this technology has been extended and detailed plans for replacement or refurbishment remain to be developed.

8.1.1.5. SF6 GAS CIRCUIT BREAKER TECHNOLOGY

The bulk of the Gas Circuit Breaker population (GCB) is relatively young compared to its AAL, and therefore many have not required replacement. A similar process to that followed for the ABCB families is being undertaken to identify refurbishment (i.e. life extension) opportunities. Where this is not technically-feasible or cost-effective, replacement is planned.

The GCB population includes a large number of small families, with variants and differing operating regimes, and so the identification of large-scale refurbishment strategies may not be cost-effective. Technical and economic evaluation as well as further development of refurbishment strategies will take place.

A significant number of SF6 circuit-breakers which are installed on shunt reactive compensation are subject to very high numbers of operations (typically several hundred per year). The "end of life" of these circuit-breakers is likely to be defined by number of operations ("wear out") rather than age-related deterioration. To assist with asset replacement planning, these circuit-breakers have been assigned a reduced asset life in this document based on a prediction of their operating regime. Different asset lives have been assigned depending on the circuit breaker mechanism type and/or if the circuit breaker has been reconditioned; in each case the asset life is based on an operating duty of 300 operations per year. It is currently proposed to recondition most types of high duty reactive switching circuit breaker when they have reached their anticipated asset life based on the number of operations they have performed. A more detailed asset specific strategy for replacement or refurbishment of these categories of circuit-breakers is being developed in terms of the actual number of operations and their forecast operating regime.

8.1.2. TRANSFORMERS AND REACTORS

8.1.2.1. BACKGROUND

Transformers and reactors share similar end of life mechanisms since they are both based on similar technologies. The same scoring method is therefore applied to calculate the EoL modifier. For simplicity within this section the term transformer is used to mean both transformer and reactor.

Transformers are assigned an EoL modifier according to the condition inferred from diagnostic results, the service history, and post mortem analysis of other similar transformers.

The health of the overall transformer population is monitored to ensure that replacement/refurbishment volumes are sufficient to maintain sustainable levels of reliability performance, to manage site operational issues associated with safety risks and to maintain or improve environmental performance in terms of oil leakage.

The process by which transformers are assigned an EoL modifier relies firstly on service history and failure rates specific to particular designs of transformers and secondly on routine test results such as those obtained from Dissolved Gas Analysis (DGA) of oil samples. When either of these considerations gives rise to concern, then where practicable, special condition assessment tests (which usually require an outage) are performed to determine the appropriate EoL modifier. Special condition assessment may include the fitting of a continuous monitoring system and the analysis of the data to determine the nature of the fault and the deterioration rate.

The elements to be taken into account when assigning an EoL modifier are:

1. Results of routine condition testing
2. Results of special condition assessment tests
3. Service experience of transformers of the same design, and detailed examination of decommissioned transformers
4. Results of continuous monitoring where available

The following additional condition indications shall be taken into account when deciding the repair/replacement/refurbishment strategy for a particular transformer:

1. Condition of oil
2. Condition of bushings
3. Condition of coolers
4. Rate of oil loss due to leaks
5. Condition of other ancillary parts and control equipment
6. Availability of spare parts particularly for tap-changers

8.1.2.2. TRANSFORMER AND REACTOR DETERIORATION

Thermal ageing of paper is the principal life limiting mechanism for transformers which will increase the failure rate with age. This failure mechanism is heavily dependent on design and evidence from scrapped transformers indicates a very wide range of deterioration rates. Knowledge of the thermal ageing mechanism, other ageing mechanisms and the wide range of deterioration rates are used to define the anticipated asset lives for transformers.

In addition to the above fundamental limit on transformer service life, experience has shown that a number of transformer design groups have inherent design weaknesses which reduce useful service life

The condition of transformers can be monitored through routine analysis of dissolved gases in oil, moisture and furfural content together with routine maintenance checks. Where individual test results, trends in test results or family history give cause for concern, specialist diagnostics are scheduled as part of a detailed condition assessment. Where appropriate, continuous monitoring will also be used to determine or manage the condition of the transformer.

Methods exist to condition assess transformers and indicate deterioration before failure, however the time between the first indications of deterioration and the transformer reaching a state requiring replacement is varied and can depend on factors such as the failure mechanism, the accuracy of the detection method, and the relationship between system stress and failure. For this reason the transformer models periodically require updating (supported by evidence from post-mortem analysis) as further understanding of deterioration mechanisms is acquired during the transformer life cycle.

8.1.2.3. INSULATING PAPER AGEING

The thermal ageing of paper insulation is the primary life-limiting process affecting transformers and reactors. The paper becomes brittle, and susceptible to mechanical failure from any kind of shock or disturbance. Ultimately the paper will also carbonise and cause turn to turn failure, both mechanisms leading to dielectric failure of the transformer. The rate of ageing is mainly dependent upon the temperature and moisture content of the insulation. Ageing rates can be increased significantly if the insulating oil is allowed to deteriorate to the point where it becomes acidic.

The thermal ageing of paper insulation is a chemical process that liberates water. Any atmospheric moisture that enters the transformer during its operation and maintenance will also tend to become trapped in the paper insulation. Increased moisture levels may cause dielectric failures directly or indirectly due to formation of gas bubbles during overload conditions.

The paper and pressboard used in the construction of the transformer may shrink with age which can lead to the windings becoming slack. This compromises the ability of the transformer windings to withstand the electromagnetic forces generated by through-fault currents. Transformer mechanical strength may be compromised if it has experienced a number of high current through faults during its lifetime and the internal supporting structure has been damaged or become loose.

End of life as a result of thermal ageing will normally be supported by evidence from one or more of the following categories:

1. Post-mortem (scrapping) evidence (including degree of polymerisation test results) from units of similar design and load history
2. High and rising furfural levels in the oil
3. High moisture content within the paper insulation
4. Evidence of slack or displaced windings (frequency response tests or dissolved gas results)

8.1.2.4. CORE INSULATION

Deterioration of core bolt and core-to-frame insulation can result in undesirable induced currents flowing in the core bolts and core steel under certain load conditions. This results in localised overheating and risk of Buchholz alarm/trip or transformer failure as free gas is generated from the localised fault. It is not normally possible to repair this type of fault without returning the transformer to the factory. Evidence of this end of life condition would normally be supported by DGA results together with evidence from decommissioned transformers of similar design. Insertion of a resistor into the core earth circuit can reduce or eliminate the induced current for a period of time.

8.1.2.5. THERMAL FAULT

Transformers can develop localised over-heating faults associated with the main winding as a result of poor joints within winding conductors, poor oil-flow or degradation of the insulation system resulting in restrictions to oil flow. This is potentially a very severe fault condition. There is not normally a repair for this type of fault other than returning the transformer to the factory. Evidence of this end of life condition would normally be supported by dissolved gas results together with forensic evidence from decommissioned transformers of similar design.

8.1.2.6. WINDING MOVEMENT

Transformer windings may move as a result of vibration associated with normal operation or, more commonly, as a result of the extreme forces within the winding during through fault conditions. The likelihood of winding movement is increased with aged insulation as outlined above. Where evidence of winding movement exists, the ability of the transformer to resist subsequent through faults is questionable and therefore the unit must be assumed not to have the strength and capability to withstand design duty and replacement is warranted. There is no on-site repair option available for this condition. Winding movement can be detected using frequency response test techniques and susceptibility to winding movement is determined through failure evidence and evidence of slack windings through dissolved gas results.

8.1.2.7. DIELECTRIC FAULT

In some circumstances transformers develop dielectric faults, where the insulation degrades giving concern over the ability of the transformer to withstand normal operating voltages or transient overvoltage. Where an internal dielectric fault is considered to affect the main winding insulation, irreparable damage is likely to ensue. This type of condition can be expected to worsen with time. High moisture levels may heighten the risk of failure. Evidence of a dielectric problem will generally be based on operational history and post-mortem investigations from units of similar design, supported by DGA. Various techniques are available to assist with the location of such faults, including partial discharge location techniques. If evidence of an existing insulation fault exists and location techniques cannot determine that it is benign, then the transformer should be considered to be at risk of failure.

8.1.2.8. CORROSIVE OIL

In certain cases high operating temperatures combined with oil containing corrosive compounds can lead to deposition of copper sulphide in the paper insulation, which can in turn lead to dielectric failure. This phenomenon may be controlled by the addition of metal passivator to the oil, however experience with this technique is limited and so a cautious approach to oil passivation has been adopted. Regeneration or replacement of the transformer oil may be considered for critical transformers or where passivator content is consumed quickly due to higher operating temperatures.

8.1.3. UNDERGROUND CABLES

8.1.3.1. BACKGROUND

Cable system replacements are programmed so that elements of the cable systems are replaced when the safety, operational or environmental risks of continued operation meet defined criteria.

Replacement of cable systems are based on a number of metrics including age. These metrics only include a few condition-related components since there is limited information that can be obtained on how deteriorated a cable actually is. Further condition information could be obtained by digging up and taking samples of a cable, but this is not practical, would be costly and could also cause further failures. Metrics such as the cost of repairs are taken into account when determining if a cable has reached the end of its life. While this is not the most desirable metric from an analytical perspective, it does reflect historical practice and is justifiable from a consumer value perspective.

The factors to be taken into account when determining an EoL modifier are:

1. Historical environmental performance
2. Historical unreliability
3. Risk of tape corrosion or sheath failure
4. Results of condition assessment and other forensic evidence
5. Service experience of cable systems of similar design
6. Number of defect repairs
7. Number of cable faults
8. Duty in terms of how much time annually a cable is running at or above its designed rating
9. Bespoke nature and issues associated with specific cable systems

8.1.3.2. DETERIORATION

End of technical life will generally be due to the deterioration of the main cable system; this may be associated with either mechanical or electrical integrity or withstand capability.

With the exception of cables vulnerable to reinforcing tape corrosion and cables where a known manufacturing defect has occurred (e.g. lead sheath deterioration), cable systems have generally given reliable operation and there is limited experience of long term deterioration mechanisms.

Cables can be split broadly into two classes for the purposes of understanding the end of life of this asset class, these are fluid filled cables and solid dielectric cables. In general the cable circuit will only meet the criteria for replacement where refurbishment as described above will not address condition and performance issues and guarantee compliance with statutory requirements.

8.1.3.3. END OF LIFE MECHANISMS AFFECTING BOTH TYPES OF CABLES

8.1.3.3.1. LEAD AND ALUMINIUM SHEATH DETERIORATION

Fatigue and intercrystalline cracking, and defects introduced during manufacture can cause oil leaks to develop. It is not generally possible to predict when a given cable section will fail as a result of this failure mode. Local repairs are not generally effective as sheath deterioration is usually distributed along the cable. End-of-life is reached where sheath deterioration is resulting in significant and widespread oil-loss (relative to duties in respect of recognised code of practice) along the cable length.

8.1.3.3.2. BONDING SYSTEM

Water ingress to link boxes causes deterioration of cross-bonding systems and leaves the link box and its Sheath Voltage Limiters (SVLs) vulnerable to explosive failure under fault conditions. Specific evidence shall be gathered through condition assessment to support end-of-life determination. This issue will in general be addressed by replacement of specific components during circuit refurbishment activity or enhanced routine maintenance.

8.1.3.3.3. COOLING SYSTEM

The life of a cable's cooling system is much shorter than the lifetime of the overall cable asset. Therefore mid-life intervention maybe required to replace the cable cooling system components. While this is not the end of the life of the cable it is an important consideration as the cable is not able to do what it was designed to do with a failed cooling system. Cooling systems tend to be unique to each cable route. Loss of the cooling capacity can typically reduce circuit rating by 40%. Most problems are experienced with the original control systems which are now obsolete. Aluminium cooling pipes are vulnerable to corrosion and plastic pipes are vulnerable to splitting, which can result in water leaks. Cooling control system and pumping equipment will also require replacement prior to the main cable system in line with circuit specific assessment. In general cooling pipework should be managed through maintenance to achieve the asset life of the main cable system.

8.1.3.4. FLUID FILLED CABLE END OF LIFE MECHANISMS

8.1.3.4.1. REINFORCING TAPE CORROSION

Reinforcing tapes are used to retain the oil pressure for cables with lead sheaths. Corrosion of the tapes in certain early BICC cables and AEI cables results in the tapes breaking, the sheath splitting and consequential oil leaks. Methods are being developed for predicting failure using corrosion rates determined through sampling in combination with known operating pressures, and also using degradation mechanism models. Local repairs are not considered effective mitigation as corrosion is usually distributed along the cable. End-of-life of the cable system is in advance of widespread predicted tape failure. The lead times for cable replacement schemes are considerably greater than the time to deteriorate from broadly acceptable to unacceptable cable system performance for this failure mode. This implies that pre-emptive action is required to minimise the likelihood of failure occurring. Acceptable performance is where the cable can be repaired on an ad-hoc basis; unacceptable performance is where the corrosion is distributed along a significant number of sections of the route.

8.1.3.4.2. STOP JOINT DETERIORATION

Stop-joint failure presents significant safety, reliability and environmental risk. End-of-life for stop joints will be justified based upon oil-analysis data or forensic evidence from similar designs removed from service. Stop joint deterioration can be addressed via refurbishment and would not alone drive replacement of the cable system.

8.1.3.4.3. CABLE JOINT DETERIORATION

In general cable joint deterioration can be addressed via refurbishment and would not alone drive replacement of the joint or cable system.

8.1.3.4.4. OIL-ANCILLARIES

Corrosion of oil tanks, pipework and connections, and pressure gauges can result in oil leaks and incorrect operation of the ancillaries. Specific evidence shall be gathered through condition assessment to support end-of-life determination. This issue will in general be addressed by replacement of specific components during circuit refurbishment activity or enhanced routine maintenance.

8.1.3.4.5.   ENVIRONMENTAL CONSIDERATIONS

NGET has a statutory obligation to comply with the Water Resources Act 1991/Water Resources (Scotland) Act 2013 and to fulfil its commitments with respect to its Environmental Statement.   Utilities demonstrate compliance with the requirement of the Act through adherence to the guidance provided.

A factor to consider in determining anticipated asset life is when it is no longer reasonably practicable to comply with the requirements of the above legislation and guidance, and maintain a sustainable level of circuit availability.

8.1.3.4.6.   SOLID XLPE FILLED CABLE END OF LIFE MECHANISMS:

Transmission circuits have been installed at at 132kV and 275kV since 1988 in the UK. Limited examples at lower voltages in substations exist back to 1968. There is limited service experience at 400kV. Provided high standards of manufacture and installation are available, the risk of early-life failures will be avoided. The existing asset lifetime estimates are largely based on the tests conducted at type registration, e.g. the time to fault when tested at voltages very much greater than that intended for operational use. Statistics were then used to justify the probability a cable would reach a specific age. End of life mechanisms have not been encountered in the UK at this time. The long-term deterioration mechanisms would benefit from further research and development.

Possible failure modes[6] that XLPE cables may exhibit are:

- Insulation deterioration due to natural ageing due to thermal cycling, mechanical aggression and defects.
- Polyethylene oversheaths have known risks of photo- and thermal-degradation into lactones, esters, ketones and carboxylic acid.
- Water treeing, arising from partial discharge in a cable. This failure mode arises mostly as a result of moisture ingress; which itself can arise from outer sheath damage, poor or non-existent water barriers or outer metallic sheath corrosion. It should be noted that moisture can penetrate even an intact oversheath; albeit Polyethlyene is a much better barrier than PVC as used on older cable technologies. The figure below illustrates this failure mode.
- Electric treeing due to a defect in the insulation, partial discharge or thermal ageing. Such a defect could also occur at cable joints; as the risk of contamination is considerably higher for such an assembly in the field rather than the clean-room conditions of the production line.
- Arcing from phase conductor to the outer sheath. Such a fault is unlikely without external influences, such as excessive mechanical force on the cable sheath, or deformation of the conductor and insulation.
- Thermal runaway, in the event that the material surrounding the cable does not posess the thermal conductivity and heat capacity appropriate to the losses encountered on the cable. Thermal runaway is possible as a result of third party influences; for example where burial depths are unintentionally increased without notification.

National Grid does not at this time have experience of all these failure modes. Circuit loadings inherent to design of the system to the SQSS in routine operation, are relatively low. The populations are also relatively young; the oldest example at transmission voltage in the UK dates from 1988.   The failure modes listed are highly interlinked, for example the condition and quality of the cable installation have bearing on the risk of water treeing and arcing. The deterioration of the insulation appears mostly to be associated with the age of the cable, though operational duty and installation environment also appear to have bearing on condition. Evaluation of

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[6] *EA Technology - Reducing Failure Rates and Better Management of Underground Cable Networks*

condition is, as noted above, problematic without destructive testing, there is therefore a strong desire to devise and deploy alternative means of evaluating condition rather than relying on age as an indicator alone.

8.1.4. OVERHEAD LINES

8.1.4.1. GENERAL APPROACH

Routes are fully refurbished, or have critical components replaced, to maintain reliability (including a level of resilience to extreme weather conditions), operational risk and safety performance. In addition, conductors should retain sufficient residual mechanical strength to facilitate safe replacement by tension stringing methods at end of life.

Technical asset lives for OHL components in various environments have been predicted using historical condition information from previous OHL replacement schemes, condition samples taken on existing assets, and an understanding of deterioration mechanisms.

Scoring assessments are made on sections of circuit that are typically homogenous in conductor type, installation date and environment.

8.1.4.1. DETERIORATION

8.1.4.1.1. CONDUCTORS

Conductor end of life condition is a state where the conductor no longer has the mechanical strength (both tensile and ductility) required to support the combination of induced static and environmental loads.

Two main deterioration mechanisms exist:

1. Corrosion, primary cause pollution either saline or industrial
2. Wind induced fatigue, common types
   a. Aeolian vibration (low amplitude high frequency oscillation 5 to 150 Hz)
   b. sub-conductor oscillation (bundles conductors only) produced by forces from the shielding effect of windward sub-conductors on their leeward counterparts
   c. galloping (high-amplitude, low-frequency oscillation)
   d. wind sway

Conductor fatigue is usually found at clamp positions where the clamp allows more interstrand motion within the conductor, leading to fretting of the internal layers. Loss of strand cross-section follows, then fatigue cracking, and finally strand breakage. This form of degradation is generally the life-limiting factor for quad bundles, clamping positions on twin bundles can also be affected

Conductor corrosion is also usually found at clamp positions. Interwoven conductor strands open up at these points allowing for easier ingress of corroding chlorides, sulphates and moisture etc. The zinc galvanising of the core wires is corroded, eventually exposing the underlying steel. A galvanic corrosion cell is then created where the aluminium wire is sacrificial. The loss of cross section of aluminium leads to greater heat transfer to the steel core increasing the risk of core failure. Additionally, some spacer clamps with elastomer bushings that contain carbon and have a low resistance also lead to galvanic corrosion of aluminium strands, reducing thickness, strength and ductility.

In addition end of life may be advanced, in rare instances, due to an unexpected load or events such as extreme wind ice or heat which overload (stress) the conductor beyond its design capability. Quality of the original

manufacturing could also be an issue (galvanising defects) but there is not much evidence for this in conductor condition assessment data.

8.1.4.1.2.   INSULATORS

The end of life occurs when the increased risk of flashover (loss of dielectric strength) reaches an unacceptable level due to condition, which may or may not result in mechanical failure of the string, or a decrease in mechanical strength due to corrosion of the steel pin.

8.1.4.1.3.   FITTINGS - SPACERS, SPACER DAMPERS AND VIBRATION DAMPERS

The functional end of life of spacers, spacer dampers and vibration dampers occurs at the point at which the conductor system is no longer protected, and conductor damage starts to occur.

These items are utilised to protect the conductor system from damage. The main deterioration mechanism is wear or fatigue induced through conductor motion. Corrosion in polluted environments can also be an issue particularly inside clamps

Wear damage to trunnions and straps of suspension clamps occurs due to conductor movement. The wear has been greatest in areas of constant wind, i.e. higher ground, flat open land and near coasts. For quad lines, in particular at wind exposed sites, wear can be extensive and rapid failures of straps, links, shackles and ball-ended eye links can occur. This is one of the best indicators of line sections subject to sustained levels of wind induced oscillation and hence where future conductor damage is likely to become a problem.

Most conductor joints for ACSR have been of the compression type, although bolted joints are used in jumpers. Overheating joints can arise from inadequate compression along the length of the joint, mainly due to either poor design or installation problems. These allow moisture penetration and oxidation of the internal aluminium surfaces between the joint and conductor. The resistive aluminium oxide reduces the paths for current flow and may cause micro-arcing within the joint. The consequence of this deterioration is that the joint becomes warm which further increases the rate of oxidation. Over a period of time, the resistive paths can result in excess current flowing in the steel core of the conductor, which can then overheat and rupture.

8.1.4.1.4.   SEMI-FLEXIBLE SPACERS

These are fitted in the span and the semi-flexibility comes from either elastomer liners, hinges or stranded steel wire depending on the manufacturer. End of life is defined by perishing of the elastomer lining or broken/loose spacer arms. These allow for excessive movement of the conductor within the clamp leading to severe conductor damage in small periods of time (days to months, depending on the environmental input). The elastomer lining of the Andre spacer type also causes corrosion of conductor aluminium wires due to its carbon content and subsequent galvanic corrosion. A common finding of conductor samples at these positions is strands with significantly poorer tensile and torsional test results. This is a hidden condition state unless it manifests in broken conductor strands that are visible on inspection.

Replacement of these spacers has been necessary on routes that are heavily wind exposed at approximately 25 years. There are many examples still in service beyond their anticipated life of 40 years where visual end of life characteristics have not yet been met. As the condition of the associated conductor within or near the clamp can remain hidden, certain families of this type of spacer such as the 'Andre' are identified for the increased risk they pose to conductor health.

8.1.4.1.5. SPACER DAMPERS

As the service history of spacer dampers is limited, extensive data on their long-term performance and end of life is not yet available. The spacer arms are mounted in the spacer body and held by elastomer bushes. This increased flexibility should provide the associated conductor system with more damping and greater resilience to wind induced energy. End of life criteria will be defined by broken/loose spacer arms that allow for excessive movement of the conductor/clamp interface.

8.1.4.1.6. VIBRATION DAMPERS

Stockbridge dampers have always been used for the control of Aeolian vibration, a minimum of one damper being installed at each end of every span on each subconductor. For long spans (where specified by the manufacture) two or more may be used. End of life is defined by loss of damping capability which is visually assessed in the amount of 'droop' in and wear of the messenger cable between damper bells. The useful life of a damper is constrained by wind energy input and corrosion of the messenger wire connection with the damper bells. In areas of high wind exposure there is evidence that dampers have required replacement after 10 to 15 years. There are however many more examples of dampers operating beyond their anticipated life with no visual signs of end of life.

8.2. LEAD ASSETS – PARAMETERS FOR SCORING

Examples of the methodology used for scoring against the parameters outlined below are contained within the NGET Licensee Specific Appendices

8.2.1. CIRCUIT BREAKER PARAMETERS

8.2.1.1. SCORING PROCESS

Circuit breakers will be assigned an end of life modifier according to the formula below. The maximum of the components as shown is determined, and it is capped at 100.

$$EOLmod = \max(AGE_{FACTOR}, DUTY_{FACTOR}, SF6_{FACTOR}, DEFECT_{FACTOR}, FAMILY_{FACTOR})$$

Equation 51

The EOL modifier is therefore determined based on the maximum of its constituent parts. AGE_FACTOR, DUTY_FACTOR, SF6_FACTOR and FAMILY_FACTOR are non-dimensional variables with possible values between 0 and 100.

$$AGE\_FACTOR = C_1 \times FSDP \times \frac{Age}{AAL}$$

Equation 52

- Age: Reporting year - Installation year (years)

- C1: a scaling factor to convert Age to a value in the range 0 to 100. The method for calculating C_1 is described at the end of this section

- *AAL* is the anticipated asset life determined through FMEA analysis. The end of life curve described in the Failure Modes and Affects analysis section can be used to determine *AAL*, which is the 50% point on the respective end of life failure mode curve. The process for deriving these failure mode curves, which we use to determine AAL, are themselves estimated using historical data and engineering expertise. Further explanation is available in the section of this methodology discussing FMEA.

- FSDP is a family specific deterioration correction function described below. This is a function multiplier to convert AGE from a linear function to an exponential function. This has the effect of decreasing the relative significance of lower values of AGE

- The AAL value is determined through interpretation of historic data associated with the type and manufacturer of the circuit breaker. Other factors can also influence the AAL including locational factors such as whether or not the asset is indoors or outdoors. Other locational factors such as proximity to high corrosion potential are not included as these are covered through maintenance activities to ensure that the asset achieves its Anticipated Life.

8.2.1.2. DUTY_FACTOR

The duty of each circuit breaker asset is determined using the following formula:

$$DUTY\_FACTOR = C_1 \times FSDP \times \max\left(\left(\frac{(OC)}{(MOC)}\right), \left(\frac{(FC)}{(MFC)}\right)\right)$$

Equation 53

Where:

- *OC* is the current asset operational count

- *MOC* is the expected max asset operational count over a lifetime. For older circuit breakers this is determined through liaison with suppliers, and for newer circuit breakers this is determined during type testing

- *FC* is the current accumulated fault current

- *MFC* is the max permissible fault current over a lifetime. The value for MFC is set to 80% of the value of the maximum rated value for the asset

FC and MFC are determined through liaison with suppliers who confirm operational limits for the mechanism and interrupter.

Note that the DUTY_FACTOR has been normalised to account for variations in the asset life of the circuit breaker family. This normalisation means that the end of life modifier of a circuit breaker from one family can be compared to the end of life modifier of a circuit breaker from a different family. Age and other duty related metrics are important due to the lack of more specific condition information.

8.2.1.3. FAMILY SPECIFIC DETERIORATION PROFILE (FSDP)

The Family Specific Deterioration profile accounts for the expected deterioration of an asset. This is needed as there is limited availability of Asset Specific condition information. This function is based on duty value D which is given by the following formula:

$$D = \max\left(\frac{OC}{MOC}, \frac{FC}{MFC}, \frac{AGE}{AAL}\right)$$

Equation 54

The family specific deterioration function is determined using the function:

$$FSDP = e^{k*D^2} - 1$$

Equation 55

This parameter k is determined such that when D=1.0 then *FSDP*=1.0. This gives a value of k=0.694. FSDP is capped at 1.0.

This function ensures that the impact of family specific deterioration is correctly considered in the health score formula.
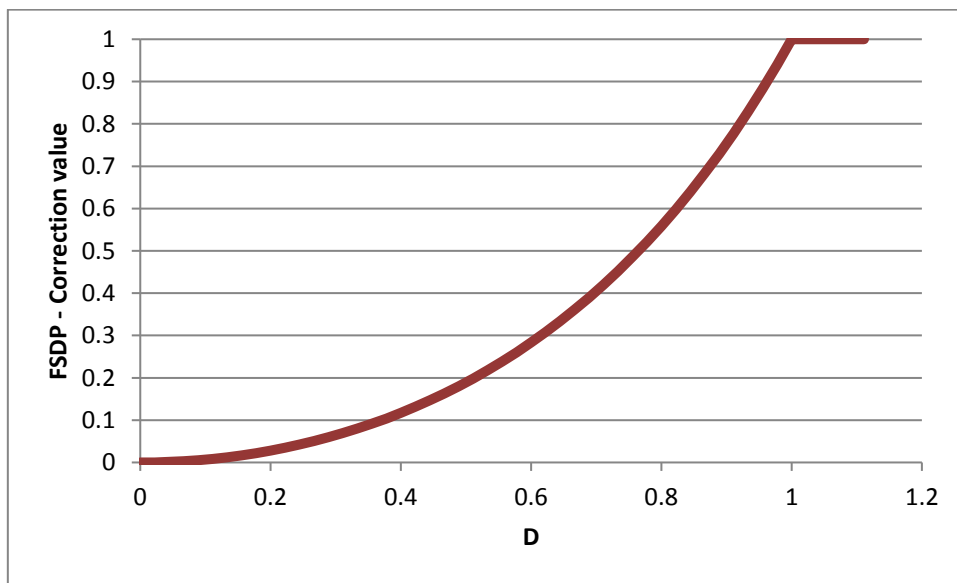
Figure 18

The curve will generate a value from 0 to 1 depending on the duty of the asset. This curve is used within this method due to the lack of condition information, and allows us to accelerate or suppress duty values depending on the deterioration we would expect for that asset family. Note that while the shape of the curve is fixed, the duty value (D) captures family specific factors such as anticipated asset life, maximum fault current and maximum number of operations.

8.2.1.4.   SF6_FACTOR (SF6)

The SF6_FACTOR calculation maps the reported leakage of a circuit breaker to a score of between either 0 or 100. A score of 100 is assigned where major leakage is deemed to have occurred. Leaking time is the time in years that the asset has had a non-zero $Leak_{mass}$, $Leak_{rate}$, or $Leak_{combined}$.

$$SF6_{FACTOR} = Max(Leak_{Mass}, Leak_{Rate}, Leak_{Combined}) + Leak_{Duration} * Leaking_{time}$$

Equation 56

$Leak_{mass}$ is a score dependent on the mass of SF6 leakage (kg) within the previous financial year.

Mass of Leakage (kg)	Significance	Leak$_{mass}$ Score
<10kg	Insignificant	0
>=10kg	Significant	60
>=50kg	Major Leakage	75

Leak$_{rate}$ a score dependent on proportion of total installed mass of SF6 that has leaked within the previous financial year

$$Leakage\ rate = \frac{Leak_{Mass}}{Asset\ SF6\ Inventory}$$

where Asset SF6 Inventory is the Reported volume of SF6.

Mass of Leakage (kg)	Significance	Leak$_{rate}$ Score
<5%	Insignificant	0
>=5%	Signifcant	60
>=10%	Major Leakage	75

Leak$_{combined}$=100 if both the mass of leakage is >=50kg and leakage rate is >=10%, otherwise Leak$_{combined}$=0

Leak$_{duration}$ ensures that a leaking asset for the last two or five (dependant on current severity of leak) years will be assigned a score of 100.

Leakage Duration	Leak$_{duration}$ Score
First year of leak	0
Leak mass score=60	8
Leak mass score=75	12.5

Any asset classified with EOL modifier of 60 or 75 due to SF6 leakage will undergo a significant intervention within a 5 year or 2 year timeframe respectively. It is expected that an asset classified with a health score of 75 today will reach a health score of 100 within 2 years, which has been set-up to reflect legislation that significant SF6 leakers should be repaired within 2 years. The decision over which type of intervention to carry out, *whether that is repair, reconditioning, refurbishment or replacement*, will be *cost justified* for the expected benefit to the consumer. This means that risk will be reduced through the most cost justified intervention, which may not necessarily be asset replacement.

Whilst there are pre-existing technologies that exist to carry out minor repairs to stop SF6 leaks, analysis of these repairs demonstrates that in the majority of instances they are temporary in nature and a further major intervention is then required to permanently repair the asset.

Broadly there are two functional requirements for a Gas Circuit Breaker. Firstly it must be able to break load, and secondly it must be able to retain the Insulating Medium. This is based on the requirements described in the Fluorinated Greenhouse Gases Regulations 2015, which places significant limits on permitted Leakage.

1. Operators of equipment that contains fluorinated greenhouse gases shall take precautions to prevent the unintentional release ('leakage') of those gases. They shall take all measures which are technically and economically feasible to minimise leakage of fluorinated greenhouse gases.

2. Where a leakage of fluorinated greenhouse gases is detected, the operators shall ensure that the equipment is repaired without undue delay. (Chapter 2 Article 3 Sections 2 and 3 from http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32014R0517&from=EN)

8.2.1.5.   DEFECT_FACTOR

This factor is currently set to zero awaiting improved classification in data collection process

8.2.1.6.   FAMILY FACTOR

Circuit breaker families that are exhibiting life limiting factors, which do not align to the other factors in the formulation, needs to be captured by the end of life modifier scoring process. As such a factor will be applied to drive intervention due to end of life to be approximately within a specific timeframe.

Asset family modifier	Score
Intervention within 2 years	80
Intervention within 5 years	60
Intervention within 10 years	35

Table 20

8.2.1.7.   PROCEDURE FOR DETERMINING C1

This value of this parameter is determined by calculating a value for EOL modifier from historical switchgear data. The C1 value is tuned so that a reasonable translation between historical AHI's, which were calculated under the previous RIIO-T1 volume based methodology, and EOL modifier is achieved. Assets that were classed as AHI1 previously should normally have a score of 100 under the new methodology. This approach is consistent with the theme of the direction, as it enables a translation from previously classified AHI's.

Based on this approach the parameter is fixed as $C1 = 5/6$.

8.2.1.8.   EOL MODIFIER CALCULATION EXAMPLE

The following table shows three assets with example data that will allow us to determine the EOL modifier

Component	Example Asset 1	Example Asset 2	Example Asset 3
Asset Operation Count (OC)	350	3000	350
Max Asset Operation Count (MOC)	5000	5000	5000
Accumulated Fault Current (FC)	400	400	1000
Max Permissible Fault Current (MFC)	1400	1400	1400
Anticipated Asset Life (AAL)	45	45	45
SF6 leakage (kg)	2	10	1
Age	40	20	15

Table 21

Applying the relevant formula presented in the above sections yields the following output.

	Example Asset 1	Example Asset 2	Example Asset 3
D (in FSDP)	0.89	0.6	0.71
FSDP	0.72	0.28	0.41
AGE_FACTOR	53.19	10.23	11.23
DUTY_FACTOR	16.73	13.94	24.16
SF6_FACTOR	0	60	0
EOL Modifier	53.2	60	24.2

Table 22

The EOL Modifier in example asset 1 is driven by age factor, example 2 is driven by SF6 factor and example 3 is driven by the duty factor (in particular the accumulated fault current).

The EOL modifier calculation proposed here facilitates a reasonable translation from the AHI's utilised within the existing RIIO-T1 methodology. An initial validation has been performed to calculate EOL modifier over a range of assets and then comparing to the AHI determined under the existing methodology.

It should be noted that placing a cap on the age related components of health score would substantially impair the translation from the previous AHI to health score.

8.2.2. TRANSFORMER AND REACTOR PARAMETERS

8.2.2.1. SCORING PROCESS

The scoring process needs to takes account of the four failure modes – dielectric, mechanical and thermal as well as issues with other components that may significantly impact the remaining service life. The end of life modifier is determined according to the following formula:

$$EOLmod = \left(1 - \left(1 - \frac{DCF}{100} \right) \left(1 - \frac{TCF}{100} \right) \left(1 - \frac{MCF}{100} \right) \left(1 - \frac{OCF}{100} \right) \right) * 100$$

Equation 58

The components of the end of life modifier are assigned using the scoring system described below. The component OCF (other component factor) is a factor that accounts for other issues that can affect transformer end of life. The maximum value of *EOLmod* is 100.

As far as possible National Grid uses actual condition indicators rather than extrapolating condition from load and temperature over time. This approach is more feasible with large transformers and is less dependent on the availability of historical data. The approaches are not mutually exclusive and loading data is important to the correct interpretation of some condition indicators such as oil test results

8.2.2.2. DIELECTRIC CONDITION FACTOR (DCF)

Dielectric condition is assessed using dissolved gas analysis (DGA) results. The score can be increased if the indication is that the individual transformer is following a trend to failure already seen in other members of the family. Where it is known that the indications of partial discharge are coming from a fault that will not ultimately lead to failure e.g. a loose magnetic shield then the score may be moderated to reflect this but the possibility of this masking other faults also needs to be taken into account.

Score	Dielectric Condition Criteria
0	All test results normal: no trace of acetylene; normal levels of other gases and no indication of problems from electrical tests.
2	Small trace of acetylene in main tank DGA or stray gassing as an artefact of oil type, processing or additives. Not thought to be an indication of a problem.
10	Dormant, intermittent or low level arcing/sparking or partial discharge fault in main tank.
30	Steady arcing/sparking or partial discharge fault in main tank.
60	Indications that arcing/sparking fault is getting worse.
100	Severe arcing/sparking or partial discharge fault in main tank – likely to lead to imminent failure.

Table 23

8.2.2.3. THERMAL CONDITION FACTOR (TCF)

Thermal condition is assessed using trends in DGA and levels of furans in oil. Individual Furfural concentration (FFA) results are unreliable because they can be influenced by temperature, contamination, moisture content and oil top ups, therefore a trend needs to be established over a period of time. The presence of 2 Furfural (2FAL) is usually required to validate the FFA result and the presence or absence of methanol is now being used to validate (or otherwise) conclusions on thermal score. Thermal condition is understood to include ageing and older, more heavily used and/or poorly cooled transformers tend to have higher scores. The score can be increased if the indication is that the individual transformer is following a trend to failure already seen in other members of the family.

Score	Thermal Condition Criteria
0	No signs of paper ageing including no credible furans >0.10ppm and methanol ≤0.05ppm. The credibility of furan results usually depends on the presence of 2 Furfural (2FAL).
2	Diagnostic markers exist that could indicate paper ageing (including credible furans in the range 0.10-0.50ppm) or are thought to be the result of contamination. The credibility of furan results usually depends on the presence of 2 Furfural (2FAL).
10	Indications or expectations that the transformer is reaching or has reached mid-life for example: credible furans in the range 0.51-1.00ppm or stable furans >1ppm possibly as a result of historic paper ageing. and/or DGA consistent with low temperature overheating e.g. raised levels of methane or ethane in the main tank.

	and/or
	Transformers with diagnostic markers resulting from oil contamination (e.g. furans, specifically 2FAL) that may mask signs of paper ageing.
30	Moderate paper ageing for example: credible furans consistently > 1ppm with a clear upward trend. and/or Significant overheating fault e.g. steadily rising trend of ethylene in main tank DGA.
60	Advanced paper ageing for example: credible furans > 1.5ppm showing a clear upward trend (even if the furan level has subsequently stabilised) or following the indications of a sister unit found to be severely aged when scrapped. and/or Significant and worsening overheating fault.
100	Very advanced paper ageing for example: credible furans >2ppm with an upward trend or following the indications of a sister unit found to be severely aged when scrapped. and/or Serious overheating fault.

<div align="center">**Table 24**</div>

Electrical test data may be used to support a higher thermal score where they show poor insulation condition. Electrical tests can provide further evidence to support the asset management plan for individual transformers e.g. where a significant number of oil tops ups have been required for a particularly leaky transformer and it is suspected that this is diluting the detectable Furans in the oil. However experience shows that not all poor thermal conditions can be detected by electrical tests which is why DGA data remains the focus for scoring the Thermal Condition Factor.

While age and AAL are not explicitly considered as part of the transformer EOL modifier scoring process, the thermal condition score is a fairly good indicator of the age of an asset. The DGA results obtained from oil samples will generally show signs indicating the aging of a transformer including increased levels of furans.

8.2.2.4. MECHANICAL CONDITION FACTOR (MCF)

Mechanical condition is assessed using Frequency Response Analysis (FRA) results.

Score	Mechanical Condition Criteria
0	No known problems following testing.
1	No information available.
3	Anomalous FRA results at last measurement which are suspected to be a measurement problem and not an indication of mechanical damage. and/or Corrected loose clamping which may reoccur.
10	Loose clamping or Following the indications of a sister unit found to have had compromised mechanical integrity/short circuit strength

	or A design known to have a poor short circuit design.
30	Suspected mechanical damage to windings. This does not include cases where the damage is confirmed.
60	Loose or damaged clamping likely to undermine the short circuit withstand strength of the transformer.
100	Confirmed mechanical damage to windings.

<center>**Table 25**</center>

Mechanical condition is assessed using Frequency Response Analysis (FRA) results; FRA is used to detect movement in the windings of the transformer, these data are supplemented by family history e.g. where post mortem analysis of a similar transformer has confirmed winding movement and DGA results (which indicate gas generation from loose clamping) as appropriate.

8.2.2.5   OTHER COMPONENT FACTOR (OCF)

The Other Components score uses an assessment of other aspects, this includes:

Tap-changers. Tap-changers are maintained and repaired separately to the transformer and defects are most likely repairable therefore tap-changer condition does not normally contribute to the AHI score. Where there is a serious defect in the tap-changer and it cannot be economically repaired or replaced this will be captured here.

Oil Leaks. During the condition assessment process transformers may be found to be in a poor external condition (e.g. severe oil leaks), this will be noted and the defect dealt with as part of the Asset Health process. The severity of oil leaks can be verified by oil top up data. Where there is a serious defect and it cannot be economically repaired, this will be captured here.

Other conditions such as tank corrosion, excessive vibration that cannot be economically repaired and audible noise which has resulted in complaints from stakeholders will be captured here.

Score	Other Component Criteria
0	No known problems.
2	Oil leaks (in excess of 2000 litres per annum over the past 3 years) that **can** be economically repaired but the volume of top ups may be diluting diagnostic gases.
10	Oil leaks (in excess of 2000 litres per annum over the past 3 years) that cannot be economically repaired. and/or Tap-changer that is known to be obsolete and spare parts are difficult to acquire or that is heavily used/incurs high maintenance costs.
30	Exceptional oil leaks (in excess of 10 000 litres per annum over the past 3 years) that cannot be economically repaired where the annual oil top up volume is likely to be diluting diagnostic markers. and/or Other mechanical aspects potentially affecting operation that cannot be economically repaired for example: tank corrosion, excessive vibration. or Justifiable noise complaint for which there may be a practicable means of mitigation,
60	Exceptional oil leaks (in excess of 15 000 litres per annum over the past 3 years) that cannot be economically repaired and where the effectiveness of the

	secondary oil containment system is in doubt and would be difficult or impossible to repair without removing the transformer.
	and/or
	Tap-changer that is known to be in poor condition and obsolete with no spare parts available.
100	Confirmed serious defect in the tap-changer that cannot be economically repaired or replaced.
	or
	Audible noise complaint which has resulted in a noise abatement notice, for which there is no practicable means of mitigation,

<div align="center">**Table 26**</div>

Where noise mitigation measures are planned the Other Component Score may be subject to review, for instance where efficiencies can be delivered by bringing forward a planned replacement and negating the need to take mitigating actions.

Oil quality is assessed using the results of four tests – acidity, interfacial tension, dissipation factor and resistivity. The oil quality score does not contribute to the AHI score, but it is used to prioritise transformers requiring oil replacement or regeneration.

8.2.2.6.   FAMILY SPECIFIC CONSIDERATIONS

Where individual test results, trends in test results or family history give cause for concern, specialist diagnostics are scheduled as part of a detailed condition assessment. Where appropriate, continuous monitoring will also be used to determine or manage the condition of the transformer. The EOL modifier scoring process will then be applied as described above, which can lead to an increase in the score applied to an asset.

Thermal condition is assessed using trends in DGA and levels of furans in oil, supplemented by family and operational history and electrical test data as appropriate. The score can be increased if the indication is that the individual transformer is following a trend to failure already seen in other members of the family. Following the scrapping of a transformer it may be necessary to review the thermal scores assigned to remaining sisters in a family.

Note that transformers share the same end of life failure mode group. Reactors are split into two end of life failure mode groups. A failure mode group has specific parameters for ealiest and latest onset of failure ages. The process for deriving these failure mode curves, are themselves estimated using historical data and expert opinion. Further explanation is available in the section of this methodology discussing FMEA.

8.2.3.   UNDERGROUND CABLE PARAMETERS

8.2.3.1.   SCORING PROCESS

The formula to determine the EOL modifier for cables, which is capped at a maximum of 100, is:

$$EOLmod = ACS + Sub\_ADJ$$

<div align="center">**Equation 59**</div>

Where ACS is the main asset condition score and Sub_Adj is the sub-asset condition score adjustment.

$$ACS = (AALc * GFR) + DUTY + \max(DEFECTS, \ SEVERITY) + ACCESS + \max(OIL, PROIL) + Main\_ADJ$$

Equation 60

The factors defined in this formula are described as listed below.

8.2.3.2.   CURRENT AGE VARIATION FROM ANTICIPATED ASSET LIFE AALC:

In the table below variation= age – anticipated asset life. The anticipated asset life is listed in the appendix section and reflects specific issues associated with a particular family.

Variation from anticipated asset life (*AALc*)	
>=Variation	Score
-100	0
-5	2
0	5
5	20
10	25
15	30

Table 27

8.2.3.3.   GENERIC FAMILY RELIABILITY (GFR)

This component is used to score any known generic family issues which can affect the anticipated life of the asset, that is, a design weakness may become apparent for a particular family of assets. For example it has been determined that type 3 cables have a known generic defect. Type 3 cables are AEI and pre-1973 BICC oil filled cables with lead sheath and polyvinyl chloride (PVC) over sheath and an additional risk of tape corrosion or sheath failure. This scoring takes account of the family design issues which are a risk to the anticipated asset life.

Generic Family Reliability (*GFR*)	
	Weighting
Evidence of design issue	3
Vulnerable to design issue	2
Vulnerability to design issue mitigated	1.5
Other	1

Table 28

8.2.3.4.   DUTY (DUTY)

This represents the operational stress that a cable route has undergone during the last 5 years. It is measured in terms of the hours the cable has operated at or above its maximum designed continuous rating during the last 5 years.

The England and Wales transmission owner will set this factor to zero, as cables are not operated at or even near maximum designed rating.

Duty – hours at or above max rating (DUTY)	
>= Hours	Score
0	0
24	5
48	10
120	15

Table 29

8.2.3.5. DEFECTS (DEFECTS)

This represents the total number of faults and defects raised against each asset over the last 10 complete financial years.

Number of Defects (DEFECTS)	
>= Number of Defects	Score
0	0
10	15
40	35
90	40

Table 30

8.2.3.6. SEVERITY (SEVERITY)

The severity of repairs to remedy faults and defects is quantified by the man-hours spent carrying out these repairs.

Repair Time in Hours (SEVERITY)	
>= Time	Score
0	0
500	5
950	20
1500	30
2350	40

Table 31

8.2.3.7. DAYS NOT AVAILABLE OVER LAST YEAR PERIOD APRIL/APRIL (ACCESS)

This score is determined from the total number of days out of service based on outages in the last financial year.

Access (*ACCESS*)	
>= Days	Score
0	0
50	2
100	5
200	10
300	20

Table 32

8.2.3.8. HISTORICAL OIL LEAKS IN LAST 10 YEARS SCORE (OIL)

This is the litres of oil leaked in the last 10 years.

Oil leaks last ten years (*OIL*)	
>= Litres	Score
0	0
1000	5
1500	10
2000	15

Table 33

8.2.3.9. PRO-RATA TO 1KM OIL LEAKS IN LAST 10 YEARS SCORE (PROIL)

This is the pro-rata to 1km litres of oil leaked in the last 10 years. This is quantity of oil lost over the last 10 years divided by the length of the cable.

It is important to include pro-rata oil leaks, so that signififant oil leaks from short cables are not missed due their relatively low volume compared to significant oil leaks from long cables.

Oil leaks last ten years (*PROIL*)	
>= Litres	Score
0	0
200	5
400	10
500	15

Table 34

8.2.3.10. MAIN CABLE INFORMATION (MAIN_ADJ)

The following condition scores will be applied when determining a cable EOL score. These factors tend to be bespoke to each cable route, so need to be included in the calculation as an adjustment component.

- Known presence of tape corrosion. (Score 10)

8.2.3.11. SUB-ASSET INFORMATION (SUB_ADJ)

The cable has a number of sub-asset upon which it is reliant for operation. These sub-assets also experience deterioration.

- Risk of failure of old style link boxes. (Score 5)

- Risk of stop joint failure. (Score 5)

- Risk of sheath voltage limiter (SVL) failure. (Score 5)

- Poor Condition of joint plumbs. Information about whether they have been reinforced. (Score 5)

- Known faults with oil tanks, oil lines, pressure gauges and alarms. (Score 5)

- Condition or faults with cooling system (if present). (Score 5)

- Occurrence of sheath fault (5) Multiple faults (10)

- Known issues with the cable's laying environment (Score 5)

8.2.4. OVERHEAD LINE CONDUCTOR PARAMETERS

8.2.4.1. SCORING PROCESS

Overhead Line Conductors are assigned an end of life modifier using a 2 stage calculation process. The first stage assesses each circuit section based on conductor type, time in operating environment and number of repairs. The second stage assesses information gathered from condition assessments. The overall end of life modifier is given by:

$$EOLmod = \begin{cases} PRE_{HS} & if \ VAL = 0 \\ SEC_{HS} & if \ VAL = 1 \end{cases}$$

Equation 61

Where:

PRE_{HS} is a 'Preliminary' or 'First Stage' score and

SEC_{HS} is a 'Secondary Stage' Score.

The maximum value of *EOLmod* is 100.

The preliminary health score PRE$_{HS}$ is effectively capped at 70, which ensures that an asset is never replaced on the basis of only age and repair information alone. If we believe an asset to be in a worst condition than PRE$_{HS}$ indicates then additional sampling would need to be performed on that asset.

The EOL modifier methodology in this section has been developed assuming an ideal situation where all data is available. However the methodology has been carefully designed to cope with situations where there are large gaps in or data, such that a meaningful score can still be generated.

8.2.4.2. PRELIMINARY STAGE

Each conductor is assigned to a 'family' which has an associated asset life. For ACSR conductors, this is based on:

a. Grease Type (Fully or Core-only greased). This can be derived from installation records and sampling of the conductor. This record is stored in our Ellipse Asset Inventory.

b. Conductor Type (e.g. Zebra or Lynx). This can be derived from installation records and sampling of the conductor. This record is stored in our Ellipse Asset Inventory.

c. Environment Category (A – 'Heavy Pollution', B – 'Some Pollution', C – 'No Pollution', d – 'Wind Exposed'. Sections may pass through different environments so the most onerous category experienced is assigned. This is based on mapping data and employs distance to the coast and polluting sources. Wind Exposed environments generally refer to heights above sea level of 150m (where high amplitude, low frequency 'conductor galloping' is more prevalent) as well as areas where wind induced oscillations have been observed by field staff.

AAAC/ACAR conductors are one family and have one asset life.

HTLS conductors are one family and have one asset life.

The preliminary end of life modifier is taken to be the maximum of an age based score and repair based score. If the repairs component of the equation is high it always requires further investigation, regardless of the age of the asset. The spread of repair locations is also significant. Clusters may appear on spans/ sections with local environment characteristics (e.g. turbulence level). For example, the damping or configuration of the conductor bundle may require intervention to prevent earlier failure of this part of the line.

Because the processes of corrosion, wear and fatigue reduce wire cross section and strength over time, 'Age' of a line in its respective operating environment is a significant part of the conductor assessment. Factors such as distance from the coast, altitude and corrosion from industrial pollution are taken into account in the process of determining AAL for each family of OHL conductor.

Our ability to detect all the condition states of a conductor is limited. This is a composite, linear asset where condition states remain hidden without intrusive analysis. The act of taking a sample is time consuming (average 3-4 days per line gang), can only be done in places where conductor can be lowered to the ground and introduces more risk to the system by the insertion of joints between new and old conductor. This means that a preliminary health score is needed to enable scores to be determined for assets that don't have sample data. This preliminary health score is necessarily based on factors such as family weighting, age and repairs, as these are the only sets of data known for all of our OHL conductor assets.

$$PRE_{HS} = W_{FAM} * \max(AGE_{SCORE}, REPAIR_{SCORE})$$

$$AGE_{SCORE} = \begin{cases} 0 & AGE - AAL \leq -8 \; or \; AGE \leq 5 \\ 35 & AGE - AAL \leq -3 \\ 2(AGE - AAL) + 41 & otherwise \end{cases}$$

$$REPAIR_{SCORE} = \begin{cases} 0 & REP = 0 \\ 10 & REP \leq 0.6 \\ 20(REP) & otherwise \end{cases}$$

Equation 62

REP= Number of conductor repairs in the span being assessed divided by the total number of spans on the route or section.

AGE=Reporting year – Installed year

AAL=Anticipated asset life of the family. This is obtained from the end of life FMEA end of curve for the family. Please see the failure modes section for a general explanation of how these curves are determined and what distribution is used.

Repairs range from a helical wrap of aluminium to a compression sleeve to the installation of new pieces of conductor (requiring joints) depending on damage severity. Within any given span, the most common areas of conductor repair on our network are at or adjacent to clamping positions, in particular spacers. On routes where the number of repairs is high, exposure to wind induced conductor motion is the common characteristic. This measure is an indication of the environmental input to a line, in particular wind exposure. It does not provide a complete picture, especially for latent processes of corrosion within a conductor and fretting fatigue that has not yet manifested in broken strands.

W_{FAM} is a family weighting score derived from OHL conductor sample data. The sample data is calculated according to the formula S_i in the following section. W_{FAM} ensures that the PRE_{HS} is a reasonable proxy for asset condition given the lack of actual sample data. W_{FAM} is capped inside a range from 1.0 to 2.0 to prevent PRE_{HS} from becoming too dominant. This means PRE_{HS} is effectively capped at 70.

$$W_{FAM} = \frac{Average\ Sample\ Score\ within\ family}{Average\ Sample\ Score\ across\ all\ OHL\ conductor\ assets}$$

Equation 63

8.2.4.3.   VALIDITY MULTIPLIER

To aim for condition data that is indicative of the whole circuit or section being assessed, a validity criterion is applied. All environment categories the circuit passes through must be assessed and at least one conductor sample per 50km is required.

Results of the secondary health score are only considered if the criterion for a 'valid' set of condition assessments described above is met. Note that a zero value of VAL implies that there is not enough condition information and therefore the preliminary health score will be used.

$$VAL = Criteria\ A * Criteria\ B$$

Equation 64

Validity Criteria A	Criteria A value
No. of Categories Assessed / No. of Environment Categories= 1	1
No. of Categories Assessed / No. of Environment Categories <1	0
Validity Criteria B	*Criteria B value*
No. of samples per 50 route km >=0.02	1
No. of samples per 50 route km <0.02	0

Table 35

8.2.4.4.   SECOND STAGE

On completion of the preliminary scoring, further condition indications will be reviewed to allow a second stage assessment of a conductor.

$$S_i = AH + VA + GL + DSS + GT + CL + DAS + TBL + TT$$

$$PCSI = \max_{All\ phase\ conductor\ samples}(S_1, S_2, S_3 \dots S_n)$$

$$SEC_{HS} = max(PCSI,\ COR) + \text{JNT}$$

The PCSI component is therefore determined by adding up the component scores for each phase conductor sample (S_i). This generates a total result for each phase conductor sample. The maximum total result across all phase conductor samples then gives the value if *PCSI*. This second stage assessment is the maximum of either *PCSI* or non-intrusive core corrosion rating.

A phase conductor sample requires a conductor to be lowered to the ground, where typically, a length is taken from the anchor clamp to the first 'spacer clamp' in the span. The test is destructive, this is cut out and then a new piece of conductor jointed in. The spacer clamp area is a corrosion, wear and fatigue location where the worst conductor degradation is usually witnessed. Other locations of interest within a conductor span are the area around a suspension shoe, dampers, any other clamping device and the bottom of the wire catenary.

Phase Conductor Sampling Interpretation (out of 100)	$AH + VA + GL + DSS + GT + CL + DAS + TBL + TT$
Presence of Aluminium Hydroxide (a corrosion product) (*AH*) (0-15)	
Significant – Area/Areas with full surface coverage of powder.	15
Present – Area/Areas with small clusters of powder or a small number of particles scattered over surface	10
None	0
Visual Assessment of Steel Core Galvanising (*VA*) (0-15)	
Loss – 10% + galvanising is missing/damaged	15
Small Loss – small areas of (no more that 10% of damaged/ missing galvanising	10
Good – Galvanising appears intact	0
Grease Level and Quality (*GL*) (0-10)	
Core Only Greased Dry	10
Core Only Greased Flexible	5
Fully Greased Dry	2.5
Fully Greased Flexible	0
Diameter of Steel Strands (*DSS*) (0-5)	
Less than 0%, or lower than the Min Spec of 3.18mm	5
Between 0 and 0.4 % (inclusive) Min Spec of 3.18mm	2.5
Greater than 0.4 % Min Spec of 3.18mm	0
Measurement of Galvanising Thickness on Outer and Inner Face of Steel Core Wire (*GT*) (0-5)	
Aluminium loss to steel core/evidence of rust	Score of 80 applied to COR factor
Average <5 microns	Score of 50 applied to COR factor
Average <20 microns	5 – Score of 30 applied to COR factor
Average >=20 microns	2
Average >=49 microns	0
Measurement of Corrosion Layer of Outer and Inner Face of Aluminium Strands (*CL*) (0-5)	
Average >=275	5

Average >100	2
Average >0	0
Diameter of Aluminium Strands (*DAS*) (0-5)	
Average >=275	5
Average >100	2
Average >0	0
Average Tensile Breaking Load of Outer Aluminium Strands (*TBL*) (0-20)	
<1120N	20
>=1120N	15
>=1280N	10
>=1310N	0
Torsion Test (Average Revolutions to Failure of Outer Aluminium Strands (*TT*) (0-20)	
<1 revolution to failure	20
>=1 revolution to failure	15
>=10 revolutions to failure	5
>=18 revolutions to failure	0

Table 36

Eddy current non-intrusive core corrosion rating measure the residual zinc coating of the steel core within ACSR. These employ a device that is required to be mounted on and propelled down a conductor wire. Changes in magnetic flux density detect loss of zinc and aluminium to the steel core.

Core Sample Interpretation	*Score (COR)*
Aluminium loss detected	80
Residual zinc coating of 5 microns or less ('Severe Corrosion')	50
Residual zinc coating of >5 to <=20 microns ('Partial Corrosion')	30
Minimum	0

Table 37

A 'Joint' factor is made up of a 'Tate' joint multiplier and infra red survey score.

A multiplier is assigned for OHL 'Tate' joints to reflect that this type of joint is inferior to a hexagonal compression. If 'Tate' joints are present then TATE=2, otherwise 1.

Infra Red Survey	*Score*
Hot Joints in Main Compression >2.5% of Tension Towers in last 5 years	10
Hot Joints in Compressed Jumper Palm >2.5% of Tension Towers in last 5 years	7.5
Hot Joints in Bolted Jumper Palm >2.5% of Tension Towers in last 5 years	5

Table 38

8.2.5. OVERHEAD LINES FITTINGS PARAMETERS

Overhead Line Fittings are assigned an EOL modifier using a 2 stage calculation process. The first stage is preliminary assessment based on age. The second stage is based on visual condition assessment (referred to as a 'Level 1'), an 'outage' or intrusive condition assessment ('Level 2'), current defects and failure history.

Scoring assessments are made on sections of circuit that are typically homogenous in conductor type, installation date and environment.

8.2.5.1 OHL FITTINGS FAILURE MODE GROUPING

OHL fitting assets are currently split into two different failure mode groups each of which has a different earliest and latest onset of failure value, and therefore a different AAL. These groupings are Quad Conductor Routes and Twin & Triple Conductor Routes.

8.2.5.2. OHL FITTINGS END OF LIFE MODIFIER

The formula to determine the EOL modifier of fittings is given below, and is capped at a maximum of 100.

$$EOLmod = \max(SPA, DAM, INS, PHF)$$

Equation 66

A maximum score of spacers, dampers, insulators and phase fittings is applied, since the conditional probability of the asset failing is determined by the weakest component. In this case the most deteriorated component is the component that has the highest EOL modifier component score.

The components of this formula will all be broken down and described in more detail below. The meaning of these components is:

1. Spacers (SPA)

2. Dampers (DAM)

3. Insulators (INS)

4. Phase Fittings (PHF). This category includes linkages (shackles, straps, dowel pins etc.) and Arcing Horns/Corona Rings.

The score for the NOMS reporting unit is calculated as below for each component class (spacers, dampers, insulators and phase fittings). It remains necessary to review the results for each tower and span across the NOMs reporting unit level to understand the distribution of condition across the system. A targeted intervention may be required within a component class or within a sub section of the OHL circuit or both. To guard against the averaging effect of large routes masking specific sections requiring attention, a threshold volume of 4.5km is used as below. This is equivalent to our smaller routes and is roughly three sections or 15 towers/spans. Our research shows distinct operating environments can be localised to a span or section. It is likely that intervention may be required on a small number of sections within a larger route.

The 'asset' below is defined as tower (for insulators, linkages and dampers) or span (spacers). Further explanation on how to apply the logic in the criteria column of the table is explained below in the preliminary assessment section.

Asset Health Score	Criteria
0	>=50% of Assets or 4.5 circuit km are New Assets, Less than 5 years Old
10	>=50% of Assets or 4.5 circuit km scoring 10 or more
20	>=50% of Assets or 4.5 circuit km scoring 20 or more
30	>=50% of Assets or 4.5 circuit km scoring 30 or more
40	>=50% of Assets or 4.5 circuit km scoring 40 or more
50	>=50% of Assets or 4.5 circuit km scoring 50 or more
60	>=50% of Assets or 4.5 circuit km scoring 60 or more
70	>=50% of Assets or 4.5 circuit km scoring 70 or more
80	>=50% of Assets or 4.5 circuit km scoring 80 or more
90	>=50% of Assets or 4.5 circuit km scoring 90 or more
100	>=50% of Assets or 4.5 circuit km scoring 100

Table 39

8.2.5.3.   PRELIMINARY ASSESSMENT

The Preliminary assessment of spacers, dampers, insulators and phase fittings is based on the age of the oldest components versus the anticipated life. The preliminary score for each of these components (SPA_{PRE}, DAM_{PRE}, INS_{PRE}, PHS_{PRE}) can be determined from the table below.

$$SPA_{PRE}, DAM_{PRE}, INS_{PRE}, PHS_{PRE} = \begin{cases} 0 & AGE - AAL \leq -13 \\ 300 & AGE - AAL \geq -3 \\ 30(AGE - AAL) + 390 & otherwise \end{cases}$$

Equation 67

8.2.5.4.   LEVEL 1 AND LEVEL 2 CONDITION ASSESSMENT

Each of the categories, spacers, dampers, insulators and phase fittings are assessed against condition statements. Each of these statements has a weighting which results in the overall End of Life modifier.

Level 1 is a visual condition assessment of fittings components. The usual method of data collection is by High Definition Camera mounted to a helicopter.

Level 2 is an 'outage' or 'intrusive' condition assessment. This extra degree of inspection is required on those components likely to produce 'false negative' or 'false positive' results when the level 1 approach is adopted. This includes wear to phase fittings and loss of dielectric strength in insulation. Only some of the components have level 2 information.

8.2.5.5.   SPACERS

$$SPA = \frac{(SPA_{PRE} * LVL1) + SPA_{OvCA}}{6}$$

Where:

SPA is the overall spacer score

SPA_{PRE} is the preliminary spacer score

LVL1 is a multiplier: if Level 1 condition assessment is available (=0), if Level 1 condition assessment is not available (=1)

SPA_{OvCA} is the overall Condition Assessment score for spacers which is a function of the % of assets falling into scores 0-100 following Level 1 condition assessment(SPA$_{LV1}$), Level 2 condition assessment from the route (SPA$_{LV2}$), latest defects from annual foot patrols (SPA$_{CDEF}$) and failures(SPA$_{FAIL}$). These are then multiplied by an operating environment modifier.

To calculate SPA_{OvCA} on NOMs Reporting Unit Level:

An SPA$_{CA}$ score is first calculated for all assets in each NOMs unit as described below. The SPA_{OvCA} value is then given by the maximum of:

a) The score where 50% or more of assets in that NOMs unit have this SPA$_{CA}$ score.

b) The maximum SPA$_{CA}$ score is obtained from circuits that are 4.5km or longer.

For an individual spans:

$$SPA_{CA} = \frac{\max(SPA_{LVL1}, SPA_{LVL2}, SPA_{CDEF}, SPA_{FAIL})}{6} * (ENV_{MOD})$$

where:

SPA_{FAIL} where ≥2.5% of population of family on the route has failed in last five years

$$ENV_{MOD} = \begin{cases} 1.2 & if\ A \\ 1.1 & if\ B \\ 1 & if\ C \\ 1.2 & if\ D \\ 1 & if\ not\ A, B, C\ or\ D \end{cases}$$

where:

Environment Modifier	Description
A	Heavy Pollution – 5 km of a coast or major estuary, or within 10km downwind of an older, low stack coal fired power station or adjacent to chemical plant.
B	Some Pollution – 5-15km from a coast or major estuary or in an industrial area or on high ground downwind of pollution source
C	No Pollution – Rural areas at least 15km from the coast
D	Wind Exposed – High ground >150 metres above sea level, or areas with known sub-conductor oscillation and/or galloping problems

Table 40

SPACER VISUAL CONDITION STATEMENTS SPA_{LVL1} & SPA_{CDEF}

Spacers	Good Condition	Dull Appearance	Black Appearance	Slight Oxidation Deposits Around Conductor Clamp and Locking Pins	Severe Oxidation Deposits Around Conductor Clamp and Locking Pins
Tight and Secure	100	200	300	400	500
Locking Pins Ineffective or Loose	600	600	600	600	600
Rubber Missing	600	600	600	600	600
Loose Arms	600	600	600	600	600
Clamps Loose	600	600	600	600	600
Clamps Open	600	600	600	600	600
Missing	600	600	600	600	600

Table 41

SPACER INTRUSIVE CONDITION STATEMENTS SPA$_{LVL2}$

Conductor Samples from Spacer Families on the Same Route and Environment	Good Condition	Dull Appearance	Black Appearance	Slight Oxidation Deposits Around Conductor Clamp and Locking Pins	Severe Oxidation Deposits Around Conductor Clamp and Locking Pins	Galvanic Corrosion between Rubber and Aluminium	Tensile Breaking Load <1310N but >=1114N Torsion Fail 5-15 Revs	Tensile Breaking Load <1114N Torsion Failure <5 Revs
Flattening/ Deformation of Conductor Wire	300	300	400	500	600	600	400	500
Heavy Fretting of Conductor Wires (>=50% of wire area indented in any layer)	300	300	400	500	600	600	400	500
Broken Conductor Wires	600	600	600	600	600	600	600	600

Table 42

8.2.5.6.   DAMPERS

$$DAM = \frac{(DAM_{PRE} * LVL1) + DAM_{OvCA}}{6}$$

Equation 70

where:

DAM is the overall damper score

DAM_{PRE} is the preliminary damper score

LVL1 is a multiplier: if Level 1 condition assessment is available (=0), if Level 1 condition assessment is not available (=1)

There is no Level 2 stage assessment for dampers.

DAM_{OvCA} is the overall condition assessment score for dampers which is a function of the % of assets falling into scores 0-100 following Level 1 condition assessment, latest defects from annual foot patrols and failures. These are then multiplied by an operating environment modifier.

To calculate DAM_{OvCA} on NOMs Reporting Unit Level:

An DAM$_{CA}$ score is first calculated for all assets in each NOMs unit as described below. The DAM_{OvCA} value is then given by the maximum of:

a) The score where 50% or more of assets in that NOMs unit have this DAM$_{CA}$ score.

b) The maximum DAM$_{CA}$ score is obtained from circuits that are 4.5km or longer.

For an Individual Span:

$$DAM_{CA} = \frac{\max(DAM_{LVL1}, DAM_{CDEF}, DAM_{FAIL})}{6} * (ENV_{MOD})$$

where:

DAM_{FAIL} where ≥2.5% of population of family on the route has failed in last five years

$$ENV_{MOD} = \begin{cases} 1.2 & if\ A \\ 1.1 & if\ B \\ 1 & if\ C \\ 1.2 & if\ D \\ 1 & if\ not\ A, B, C\ or\ D \end{cases}$$

where:

Environment Modifier	Description
A	Heavy Pollution – 5 km of a coast or major estuary, or within 10km downwind of an older, low stack coal fired power station or adjacent to chemical plant.
B	Some Pollution – 5-15km from a coast or major estuary or in an industrial area or on high ground downwind of pollution source
C	No Pollution – Rural areas at least 15km from the coast
D	Wind Exposed – High ground >150 metres above sea level, or areas with known sub-conductor oscillation and/or galloping problems

Table 43

DAMPER VISUAL CONDITION STATEMENTS DAM$_{LVL1}$& DAM$_{CDEF}$

Damper	Galvanising Weathered, Dull Appearance	Galvanised Coating Starting to Deteriorate	Light Rust, Majority of Galvanised Coating Missing	Heavy Rust	Heavy Corrosion, Pitting of Steelwork and Some Section Loss
0-20° Droop	100	100	200	200	300
20°-40° Droop	100	100	200	300	400
40° + Droop	600	600	600	600	600
Bell(s) missing, messenger wire broken or slipped	600	600	600	600	600

Slipped	600	600	600	600	600
Missing	600	600	600	600	600

Table 44

8.2.5.7.   INSULATORS

$$INS = \frac{(INS_{PRE} * LVL1) + INS_{OvCA}}{6}$$

Equation 72

Where:

INS is the overall insulator score

INS_{PRE} is the preliminary insulator score

LVL1 is a multiplier: if Level 1 condition assessment is available (=0), if Level 1 condition assessment is not available (=1)

INS_{OvCA} is the overall condition assessment score for insulators which is a function of the % of assets falling into scores 0-100 following Level 1 condition assessment, Level 2 condition assessment from the route, latest defects from annual foot patrols and failures. These are then multiplied by an operating environment modifier.

To calculate INS_{OvCA} on NOMs Reporting Unit Level:

An INS$_{CA}$ score is first calculated for all assets in each NOMs unit as described below. The INS_{OvCA} value is then given by the maximum of:

a) The score where 50% or more of assets in that NOMs unit have this INS$_{CA}$ score.

b) The maximum INS$_{CA}$ score is obtained from circuits that are 4.5km or longer.

For an Individual Span:

$$INS_{CA} = \frac{\max(INS_{LVL1}, INS_{LVL2}, INS_{CDEF}, INS_{FAIL})}{6} * (ENV_{MOD})$$

Equation 73

where:

INS_{FAIL} where ≥2.5% of population of family on the route has failed in last five years

$$ENV_{MOD} = \begin{cases} 1.2 & if\ A \\ 1.1 & if\ B \\ 1 & if\ C \\ 1.2 & if\ D \\ 1 & if\ not\ A, B, C\ or\ D \end{cases}$$

where:

Environment Modifier	Description
A	Heavy Pollution – 5 km of a coast or major estuary, or within 10km downwind of an older, low stack coal fired power station or adjacent to chemical plant.
B	Some Pollution – 5-15km from a coast or major estuary or in an industrial area or on high ground downwind of pollution source
C	No Pollution – Rural areas at least 15km from the coast
D	Wind Exposed – High ground >150 metres above sea level, or areas with known sub-conductor oscillation and/or galloping problems

Table 45

INSULATOR VISUAL CONDITION ASSESSMENT INS_{LVL1} & INS_{CDEF}

Insulator	Galvanising Weathered, Dull Appearance	Galvanised Coating Starting to Deteriorate	Light Rust on Bells, Majority of Galvanised Coating Missing	Heavy Rust on Bells	Bells Severely Corroded and Some Section Loss
No Pollution	100	200	200	300	300
Evidence of Light Pollution	200	300	300	300	400
Evidence of Heavy Pollution	300	300	300	300	400
Visible Burn Marks	400	400	500	500	500
Evidence of Crazing	600	600	600	600	600

Table 46

INSULATOR INTRUSIVE CONDITION ASSESSMENT INS_{LVL2} & INS_{CDEF}

Insulator Resistance Testing from Insulator Families on the Same Route and Environment	Galvanising Weathered, Dull Appearance	Galvanised Coating Starting to Deteriorate	Light Rust on Bells, Majority of Galvanised Coating Missing	Heavy Rust on Bells	Bells Severely Corroded and Some Section Loss to Pins <10% for 190kN <2.5% for 300kN	Loss of Steel Pin Area 10% for 190KN, 2.5% for 300kN	Loss of Steel Pin Area 40% for 190KN, 10% for 300kN
Evidence of Failed units							

but string or set do not meet 'failed' criteria of 3 in a single string or 6 in a bundle	300	300	300	400	400	500	500
A single String or Set fails Meggar Test Criteria (3 in a string or 6 in a bundle)	600	600	600	600	600	600	600

Table 47

8.2.5.8. PHASE FITTINGS

$$PHF = \frac{(PHF_{PRE} * LVL1) + PHF_{OvCA}}{6}$$

Equation 74

Where:

PHF is the overall phase fittings score

PHF_{PRE} is the preliminary phase fittings score

LVL1 is a multiplier: if Level 1 condition assessment is available (=0), if Level 1 condition assessment is not available (=1)

PHF_{OvCA} is the overall condition assessment score for phase fittings which is a function of the % of assets falling into scores 0-100 following Level 1 condition assessment, Level 2 condition assessment from the route, latest defects from annual foot patrols and failures. These are then multiplied by an operating environment modifier.

To calculate PHF_{OvCA} on NOMs Reporting Unit Level:

An PHF$_{CA}$ score is first calculated for all assets in each NOMs unit as described below. The PHF_{OvCA} value is then given by the maximum of:

a) The score where 50% or more of assets in that NOMs unit have this PHF$_{CA}$ score.

b) The maximum PHF$_{CA}$ score is obtained from circuits that are 4.5km or longer.

For an Individual Span:

$$PHF_{CA} = \frac{\max(PHF_{LVL1}, PHF_{LVL2}, PHF_{CDEF}, PHF_{FAIL})}{6} * (ENV_{MOD})$$

Equation 75

where:

PHF_{FAIL} where ≥2.5% of population of family on the route has failed in last five years

$$ENV_{MOD} = \begin{cases} 1.2 & if\ A \\ 1.1 & if\ B \\ 1 & if\ C \\ 1.2 & if\ D \\ 1 & if\ not\ A, B, C\ or\ D \end{cases}$$

where:

Enviroment Modifier	Description
A	Heavy Pollution – 5 km of a coast or major estuary, or within 10km downwind of an older, low stack coal fired power station or adjacent to chemical plant.
B	Some Pollution – 5-15km from a coast or major estuary or in an industrial area or on high ground downwind of pollution source
C	No Pollution – Rural areas at least 15km from the coast
D	Wind Exposed – High ground >150 metres above sea level, or areas with known sub-conductor oscillation and/or galloping problems

Table 48

PHF_{LVL1} is the Level 1 Condition Assessment score for phase fittings.

PHF_{LVL2} is the Level 2 Condition Assessment score for phase fittings.

Phase Fittings are made up of

1. Suspension Linkages: Shackle, Ball Ended Eye Link, Yoke Plate, Shoes, Maintenance Bracket, Weights, Straps. (LNK_{SUS})

2. Tension Linkages: Landing Pin, Shackle, Ball Ended Eye Link, Straps, Yoke Plate. (LNK_{TEN})

3. Arcing Horns and Corona Rings. (ARC)

4. Dowel Pins and Bolts. (DOW)

$$PHF_{LVL1} = \max((max(LNK_{SUS})), (max(LNK_{TEN})), ARC, DOW)$$

Equation 76

$$PHF_{LVL2} = \max((max(LNK_{SUS})), (max(LNK_{TEN})), DOW)$$

Equation 77

The *max(LNK_{SUS})* means maximum of all suspension linkages on the tower. *Max(LNK_{TEN})* means maximum of all tension linkages on the tower. There is no Level 2 assessment for Arcing Horns and Corona Rings

These have their own set of condition statements and scores as set out below.

PHF_{LVL1} & PHF_{CDEF} SUSPENSION AND TENSION LINKAGES, DOWEL PINS AND BOLTS

Phase and Earthwire Fittings (Suspension & Tension), Dowel Pins and Bolts	Galvanising Weathered, Dull Appearance	Galvanised Coating Starting to Deteriorate	Light Rust, Majority of Galvanised Coating Missing	Heavy Rust	Heavy Corrosion, Pitting of Steelwork and Some Section Loss
Minimal Wear 0-10%	100	200	300	300	400
Slight Wear 10-20%	200	300	300	400	500
Moderate Wear 20-40%	300	300	400	500	500
Heavy Wear 40-60%	400	400	500	600	600
Severe Wear >60%	600	600	600	600	600

Table 49

PHF_{LVL1} & PHF_{CDEF} ARCING HORNS AND CORONA RINGS

Arcing Horn/ Corona Ring	Galvanising Weathered, Dull Appearance	Galvanised Coating Starting to Deteriorate	Light Rust, Majority of Galvanised Coating Missing	Heavy Rust	Heavy Corrosion, Pitting of Steelwork and Some Section Loss
Tight and Secure	100	200	300	400	500
Missing Components, Locking Nuts etc	300	400	400	400	500
Loose	400	400	500	500	500
Missing	600	600	600	600	600
Incorrect Length	600	600	600	600	600

Table 50

PHF_{LVL2} & PHF_{CDEF} SUSPENSION AND TENSION LINKAGES, DOWEL PINS AND BOLTS

Intrusive assessment of Linkages from the same route and environment	Material Loss of Steel through corrosion < 20% Cross Sectional Area	Material Loss of Steel through corrosion >= 20% Cross Sectional Area	Material Loss of Steel through corrosion >= 40% Cross Sectional Area
Minimal Wear 0-10%	300	400	600
Slight Wear 10-20%	400	500	600
Moderate Wear 20-40%	500	600	600
Heavy Wear 40-60%	600	600	600

Severe Wear >60%	600	600	600
Missing/ Out of Plumb >20⁰/ Cracked Wedge Clamp	600	600	600

Table 51

8.2.5.9.   OVERALL END OF LIFE MODIFIER FOR OHL FITTINGS

The end of life modifier formula for fittings given at the beginning of this section is reproduced below with a mathematic summary of how each component is determined.

$$EOLmod = \max(SPA, DAM, INS, PHF)$$

Equation 78

Where:

$$SPA = \frac{(SPA_{PRE} * LVL1) + SPA_{OvCA}}{6}$$

Equation 79

$$DAM = \frac{(DAM_{PRE} * LVL1) + DAM_{OvCA}}{6}$$

Equation 80

$$INS = \frac{(INS_{PRE} * LVL1) + INS_{OvCA}}{6}$$

Equation 81

$$PHF = \frac{(PHF_{PRE} * LVL1) + PHF_{OvCA}}{6}$$

Equation 82

The overall condition assessment (OvCA) is determined from the underlying condition assessment (CA) for each span according to the logic described above.

For an Individual Span the condition assessment score is determined from the following formula:

$$SPA_{CA} = \frac{\max(SPA_{LVL1}, SPA_{LVL2}, SPA_{CDEF}, SPA_{FAIL})}{6} * (ENV_{MOD})$$

Equation 83

$$DAM_{CA} = \frac{\max(DAM_{LVL1}, DAM_{CDEF}, DAM_{FAIL})}{6} * (ENV_{MOD})$$

Equation 84

$$INS_{CA} = \frac{\max(INS_{LVL1}, INS_{LVL2}, INS_{CDEF}, INS_{FAIL})}{6} * (ENV_{MOD})$$

Equation 85

$$PHF_{CA} = \frac{\max(PHF_{LVL1}, PHF_{LVL2}, PHF_{CDEF}, PHF_{FAIL})}{6} * (ENV_{MOD})$$

Equation 86