ElectraNet
electricity transmission

Asset Management Plan

May 2012

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Revision Record

Date	Version	Description	Author	Checked By	Approved By
31.05.12	1.0	Initial Version	David Boyce Asset Strategy Manager	Michael Dobbin Senior Manager Network & Asset Strategy	Rainer Korte Executive Network Strategy & Regulatory Affairs

Contents

1. Purpose and Scope

The purpose of this Asset Management Plan is to ensure that adequate resources and systems are provided to manage the regulated transmission network in South Australia to meet the objective of delivering safe, secure and reliable transmission services to customers at the lowest long-run cost. The Plan sets out the forecast asset replacement and maintenance expenditure requirements to achieve this objective in the 5-year regulatory period from 1 July 2013 to 30 June 2018.

The Asset Management Plan is developed within a strategic planning framework that includes taking direction from an organisational asset management policy, a long term vision of the network developed in consultation with stakeholders and Board-approved strategies for network development, asset management and information technology. The strategic planning framework is described in section 2.3 of this Plan.

ElectraNet applies a risk-based approach to its decision making to achieve an efficient balance of maintaining safety, security and reliability of supply at the lowest sustainable cost.

Figure 1.1 describes the asset lifecycle activities and asset management expenditure categories covered in this plan (with the exception of network augmentation which is addressed in Regional Development Plans and the Annual Planning Report published by ElectraNet for the information of market participants and other interested stakeholders).

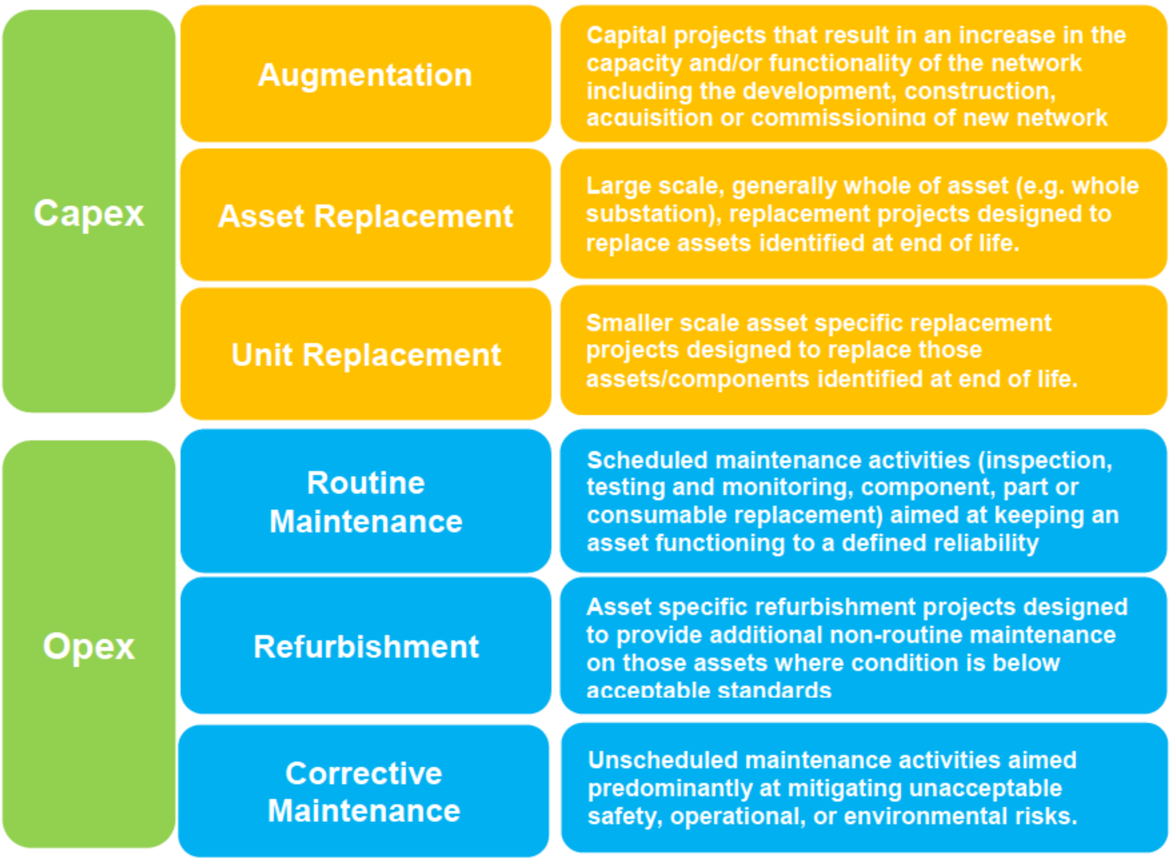

Figure 1.1: Asset lifecycle activities and expenditure categories

2. Definitions

Term	Definition
Asset Sustainability Ratio	Expresses net capital expenditure on renewal and replacement of existing assets as a percentage of the optimal level for such expenditure. A percentage less than 100 on an ongoing basis indicates that capital expenditure levels are not being optimised so as to minimise whole of life cycle costs of assets (having regard to the Infrastructure and Asset Management Plan) or that assets may be deteriorating at a greater rate than spending on their renewal or replacement.
Corrective Maintenance	Maintenance carried out after a failure has occurred, and intended to restore an item to a state in which it can perform its required function. (This may include breakdown or reactive maintenance).
Condition Based Maintenance	A maintenance technique that involves monitoring the condition of an asset and using that information to predict its failure. In other words it is preventive maintenance initiated as a result of knowledge of the condition of an item from routine continuous monitoring.
Defect	An imperfection within an asset that could potentially lead to the premature failure of the asset.
Economic Life	The length of time for which maintaining and operating the asset remains the lowest cost alternative for providing a nominated level of service.
Lifestyle Cost Analysis	A method of assessing which asset option, will be the most economical over an extended period of time.
Maintenance	Any activity performed on an asset with a view to ensuring that it is able to deliver an expected level of service until it is scheduled to be renewed, replaced or disposed of.
MGT	Mobile grazer terminal (a field data collection tool).
Network Asset	An asset that is considered to be part of a network. Network assets are interconnected assets that rely on each other to provide a service. If a network asset is removed the system may not function to full capacity.
Obsolescence	**T**he state of being which occurs when an asset is no longer wanted even though it may still be in good working order. Obsolescence frequently occurs because a replacement has become available that is superior in one or more aspects.
Operation	The act of utilising an asset. Asset operation will typically consume materials and energy.
OPSWAN	operational wide area network (the remote engineering interface to field devices)
Periodic Maintenance	Similar to, but more extensive than routine maintenance. Typically, periodic maintenance involves programmed clearing, programmed painting and programmed upgrades.
Planned Maintenance	Maintenance organised and carried out with forethought, control and the use of records to a predetermined plan.

Term	Definition
Preventative Maintenance	Maintenance carried out at predetermined intervals, or corresponding to prescribed criteria, and intended to reduce the probability of failure or the performance degradation of an item.
Proactive Maintenance	Scheduled maintenance programmed on the basis of condition data.
Reactive Maintenance	A form of maintenance in which equipment and facilities are repaired only in response to a breakdown or a fault.
Redundancy	A system in which critical components are duplicated, so that if one fails the other component can take over the function of the failed component.
Refurbishment	Works carried out to rebuild or replace parts or components of an asset, to restore it to a required functional condition and extend its life, which may incorporate some modification.
Reliability Centred Maintenance	Often known as RCM, is an industrial improvement approach focused on identifying and establishing the operational, maintenance, and capital improvement policies that will manage the risks of equipment failure most effectively
Remaining Useful Life	Estimated length of time remaining before it will need to be replaced.
Renewal	The replacement or refurbishment of an existing asset (or component) with a new asset (or component) capable of delivering the same level of service as the existing asset.
Replacement	The complete replacement of an asset that has reached the end of its life, in order to provide a similar or agreed alternative level of service
SCAR	System condition and risk (a process for assessing asset condition and associated risk)
TALC	Transmission asset lifecycle (a process for assessing asset life cycle)

3. Context

3.1 Transmission network

The regulated transmission system within South Australia consists of a 275 kV network, partially underpinned by interconnected 132 kV and 66 kV systems.

The sparse and remote nature of the country loads served by the transmission network is a significant cost driver for ElectraNet's business. The resulting network topology has a high degree of "radialisation" which can make attaining high levels of reliability challenging.

More detailed information about the transmission network can be found in the South Australian Annual Planning Report[1].

1 Available at www.electranet.com.au

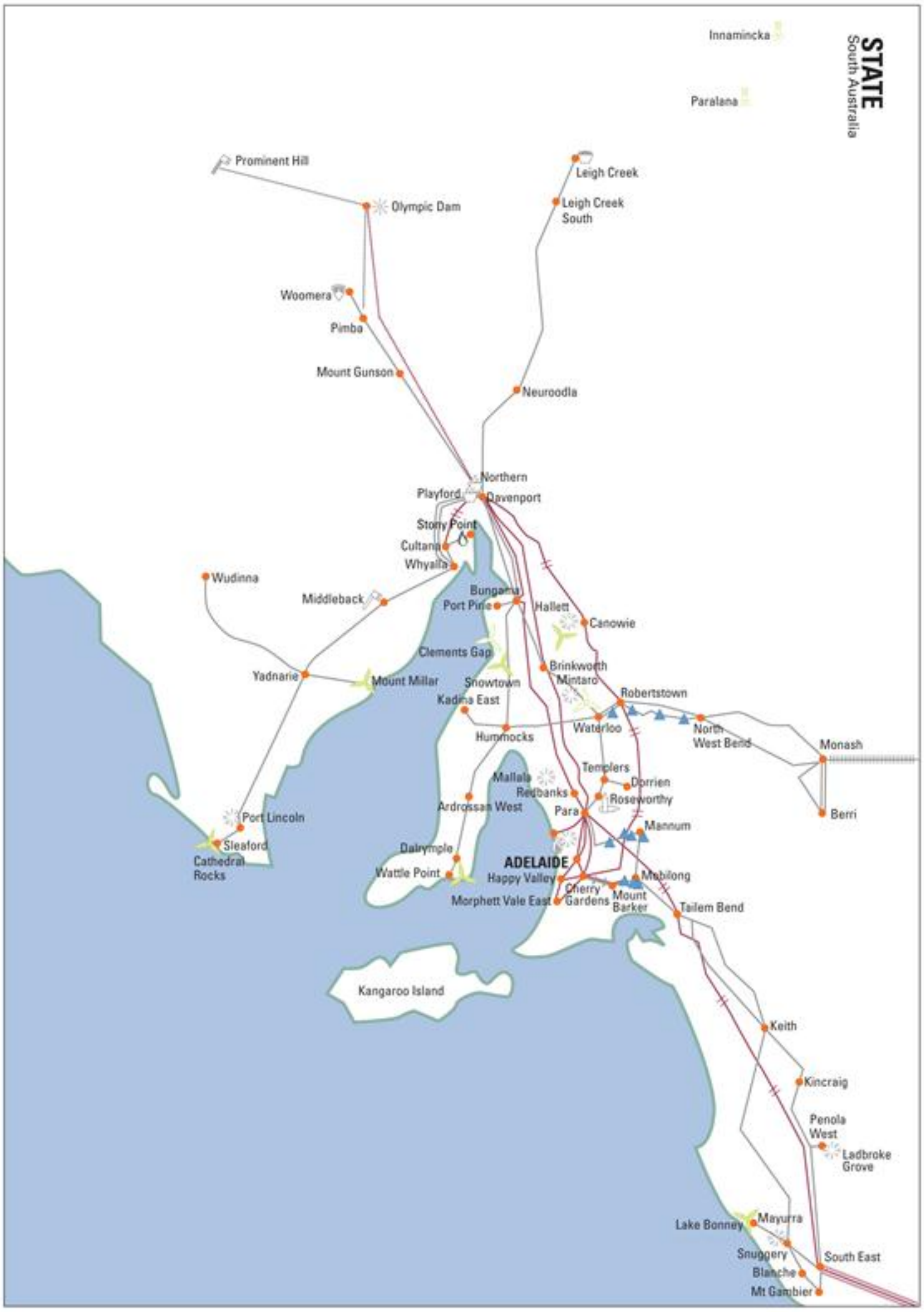

Figure 3.1: ElectraNet Transmission System Map

3.2 The regulatory framework

The Electricity Act 1996 (and regulations) and the National Electricity (South Australia) Act 1996 (and the National Electricity Law and National Electricity Rules made under that Act), together with the Essential Services Commission Act 2002, provide the basis for regulation of the electricity supply industry in South Australia.

The National Electricity Objective, as stated in the National Electricity Law is:

> *to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to –*

1. *Price, quality, safety, reliability, and security of supply of electricity; and*
2. *Reliability, safety and security of the national electricity system.*

ElectraNet is committed to achieve sustainable long-term performance in relation to the following objectives;

- Delivering a safe and reliable supply of electricity to customers and the community;
- Delivering transmission services to customers at lowest long-run cost;
- Meeting statutory obligations under the National Electricity Rules, Electricity Transmission Code and other relevant Legislation; and
- Providing fair and reasonable returns to shareholders.

3.3 Strategic planning framework

The Asset Management Plan is developed within a strategic planning framework illustrated in Figure 3.2.

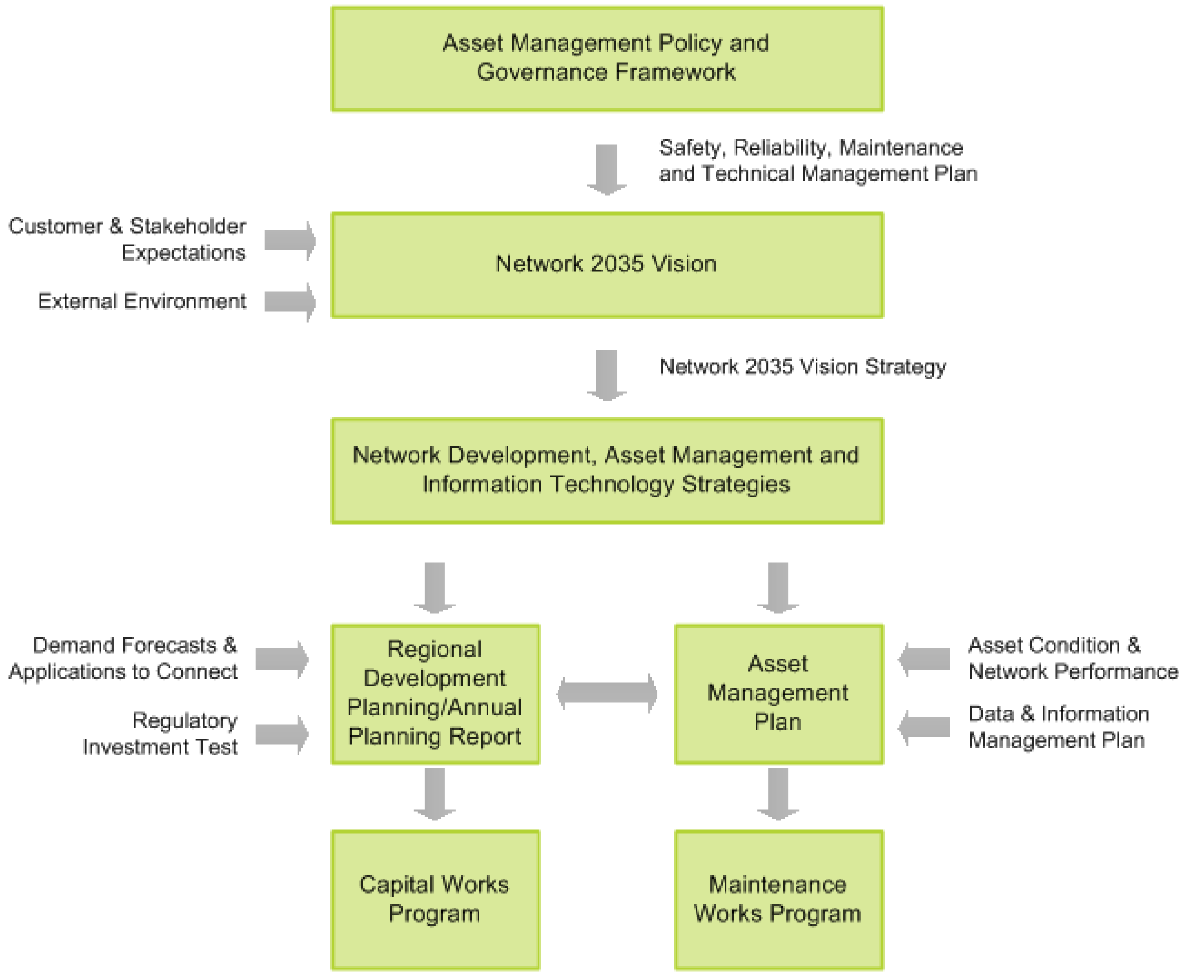

Figure 3.2: Asset Management Planning Framework

Table 3.1 describes the key asset management planning documents that are developed within this strategic planning framework.

Table 3.1: Asset Management Planning Documents

Document	Description	Approval by
Asset Management Policy	An organisational policy that sets out ElectraNet's asset governance framework and gives direction to operational policies and procedures used in the broader business to manage transmission network assets and deliver safe, secure and reliable transmission services to customers at lowest long-run cost. The policy also sets out ElectraNet's commitment to continuous improvement in asset management.	Management in consultation with the Board
Network 2035 Vision	A long term vision of the network developed in collaboration with stakeholders that sets out a framework for development of the transmission network over the long-term. The Vision includes a set of guiding principles that guide integrated decision making on the management and development of the transmission network.	Board
Network 2035 Vision Strategy	Sets out the framework for implementation of the Network 2035 Vision, the guiding principles and the resulting strategic priorities in the forecast regulatory period.	Board
Network Development Strategy	Sets out the strategic priorities for network development in the forecast regulatory period and how ElectraNet plans to deliver on these priorities.	Board
Asset Management Strategy	Sets out the strategic priorities for asset management in the forecast regulatory period and how ElectraNet plans to deliver on these priorities.	Board
Information Technology Strategy	Sets out the strategic priorities for information technology to support the delivery of transmission services in the forecast regulatory period and how ElectraNet plans to deliver on these priorities.	Board
Annual Planning Report	The medium to long term network development plan for the South Australian transmission network that is published for the information of market participants and other interested stakeholders. The Annual Planning Report is supported by a Telecommunications Development Plan.	Management
Asset Management Plan	The plan that sets out the asset management framework over the medium to long term and specific asset plans for substation, transmission line and telecommunication assets.	Management

Document	Description	Approval by
Safety, Reliability, Maintenance and Technical Management Plan (SRMTMP)	This plan is maintained as a condition of ElectraNet's transmission licence and demonstrates that ElectraNet has management practices in place to ensure: • the safe design, installation, commissioning, operation, maintenance and decommissioning of electricity infrastructure owned and/ or operated by ElectraNet; • that ElectraNet complies with the safety and technical requirements imposed by or under the applicable legislation, codes and licenses; and • that ElectraNet complies with good electricity industry practice. ElectraNet's compliance with the SRMTMP is subject to an annual audit requirement.	Essential Services Commission of South Australia on recommendation of the Technical Regulator

The Asset Management Plan should be read in conjunction with the other key asset management planning documents described above.

3.4 Transmission network assets

3.4.1 Substations

Substation assets include both substation plant and secondary systems assets with a total replacement value of approximately $2bn. ElectraNet operates and maintains 86 substations, which include 10,673 MVA of installed transformer capacity. Substation assets are summarised by voltage level in Table 3.2.

Table 3.2: Summary of Substation Assets

Voltage Substations	Number of Substations	Number of CBs	Number of Transformers	MVA
275 kV	28	181	42	7,557
132 kV	55	194	104	3,116
66 kV	3	66	0	0
Total	86	441	146	10,673

There are a range of equipment types in each asset category. Recent asset replacement and augmentation projects have introduced a significant number of new assets in the early life phase with transformers and isolators representing assets with a greater population towards end of life.

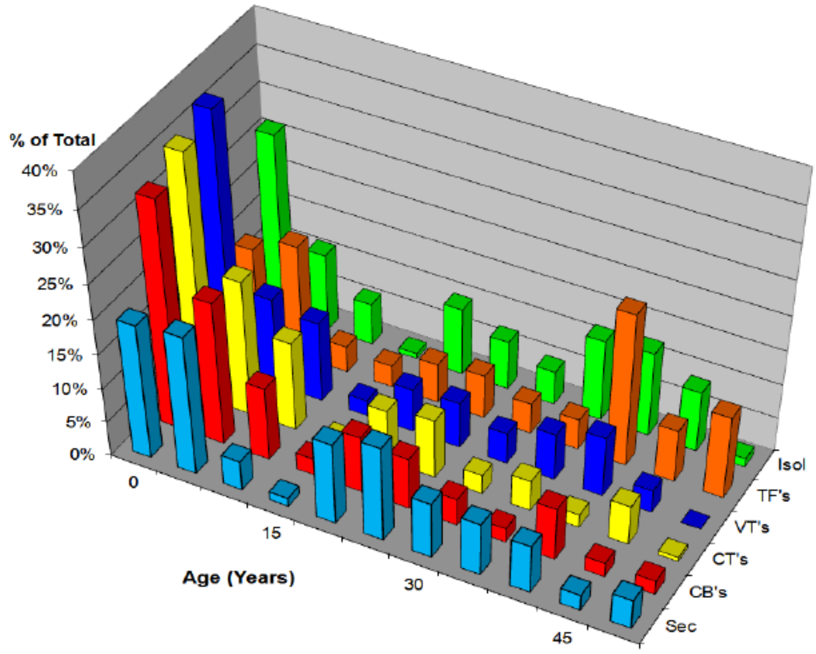

Figure 3.3: Substation Primary Plant Asset Profile

3.4.2 Substation asset sustainability

In order to assess the adequacy of asset replacement over the asset lifecycle the substation asset renewal profile (based on an average technical life of approximately 45 years) is modelled below. The capital expenditure profile for asset replacement is compared with actual and planned replacement programmes.

The profile below shows, that apart from some differences in timing, actual and planned replacement has been will be adequate based on forecast expenditure levels to sustain the asset and network reliability (i.e. the replacement profile, based on the current understanding of end of technical life of the assets shows that the overall level of replacement is reasonable as indicated by the overlapping profiles).

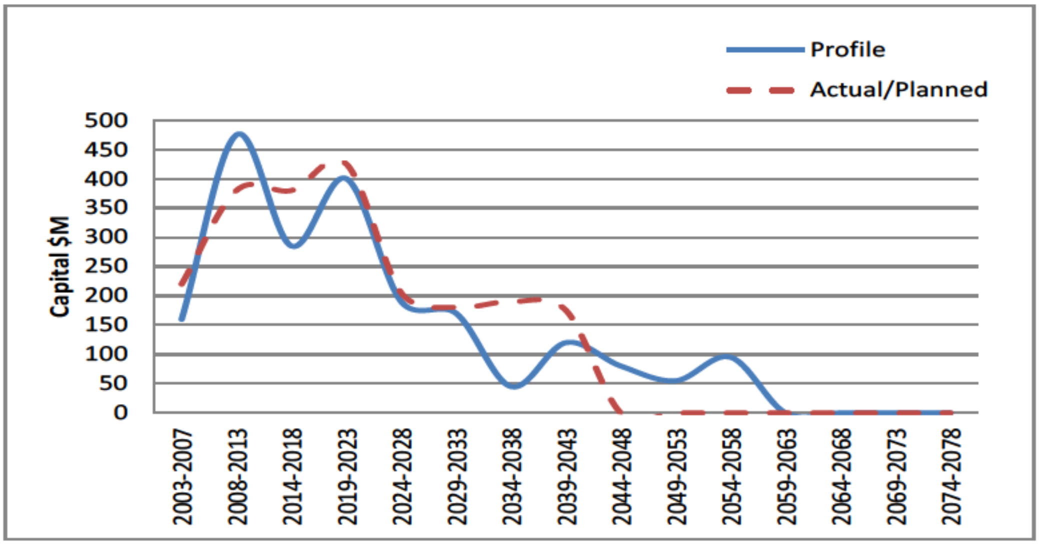

Figure 3.4: Substation Asset Replacement Capital Profile

3.4.3 Transmission lines

The transmission network consists of approximately 5,600 circuit kilometres of transmission lines that operate at nominal voltages of 275 kV, 132 kV and 66 kV with a total replacement value of approximately $3.5b. The length of lines for each voltage is given in Table 3.3.

Table 3.3: ElectraNet - Transmission Line Summary

Transmission Lines	
275 kV ElectraNet Feeders (Number)	41
132 kV ElectraNet Feeders (Number)	66
66k V ElectraNet Feeders (Number)	11
Total No. of ElectraNet Feeders	**118**
275 kV Circuit Length (km)	2,543
132 kV Circuit Length (km)	3,005
66 kV Circuit Length (km)	23
Total Circuit Length of ElectraNet Lines (km)	**5,572**
Route Length of Single Circuit Pole Line (km)	1,212
Route Length of Double Circuit Pole Line (km)	279
Route Length of Single Circuit Tower Line (km)	2,132
Route Length of Double Circuit Tower Line (km)	995
Route Length of Triple Circuit Pole Line (km)	24
Route Length of UG Cable (66, 132 & 275kV) (km)	28
Total Route Length of ElectraNet Lines (km)	**4,670**

132 kV transmission lines represent the majority of higher age profile assets.

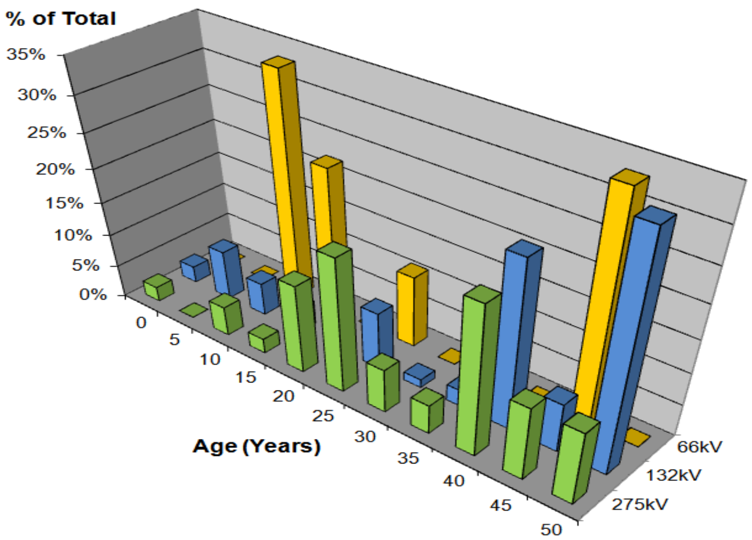

Figure 3.5: Transmission Line Asset Profile

3.4.4 Transmission line asset sustainability

In order to assess the adequacy of replacement and renewal over the asset lifecycle the transmission line asset renewal profile is modelled below. The capital expenditure profile for asset replacement is compared with actual and planned replacement programmes.

The figure indicates that transmission line asset replacement planning is required from approximately 2025 (based on indicative assumptions) in order to adequately sustain the asset. The current asset management plan is based on a program of transmission line component refurbishment in order to manage those elements of the transmission line asset with shorter life cycles.

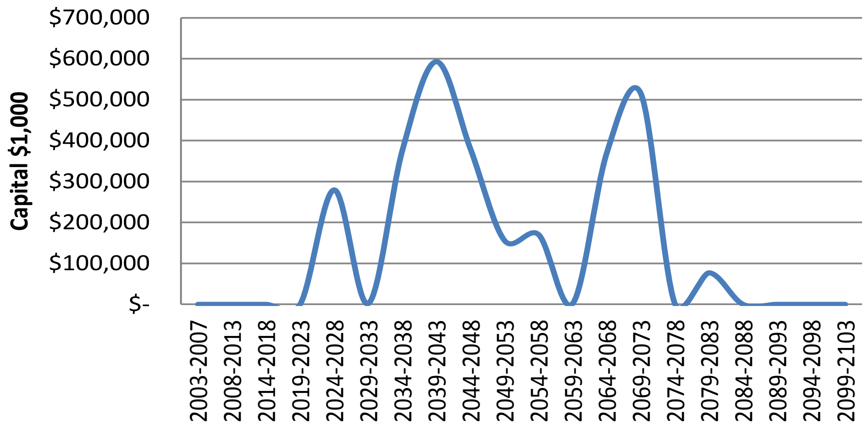

Figure 3.6: Transmission Line Asset Replacement Profile

3.4.5 Telecommunications

ElectraNet operates a substantial telecommunications network (estimated replacement value $75m) for the operational support of the electricity transmission system. The telecommunications network requires a level of availability adequate to meet the objective of providing efficient transmission services to customers and the meet the operational requirements of the power system.

The predominant services carried are:

- Protection and control signalling
- Data links for SCADA/RTU connections
- Operational speech services
- Network weather data

The infrastructure of the network consists of:

- Radio links (digital PDH)
- Power line carrier (analogue and digital)
- Fibre optic cable (predominantly OPGW)
- Pilot cable (owned by others - with and without digital multiplexing)

Table 3.4: Communications Sites & Weather Stations

Telecommunications Statistics	
ElectraNet sites	37
Other Sites used by ElectraNet	20
Total Sites	**57**
Weather Station Statistics	
ElectraNet Weather Station Sites	26

Figure 3.7: Telecommunications Asset Profile

3.5 Transmission network performance

The transmission network is a single entity made up of many network assets. The relationship between transmission network performance and network assets is the basis for understanding the threshold for unacceptable asset performance.

3.5.1 Asset reliability

As the transmission network is an interconnected meshed network with some radial connections, where radial connections are generally relatively small loads:

- Single asset failures in most cases do not directly materially affect transmission performance indices;
- Single asset failures may expose the network to significant risk of constraint or load shedding considering the next contingency;
- Multiple, coincident asset failures are likely to affect performance indices as they will involve the loss of more than one element of the network.

Considering the above it may be concluded that:

- Transmission network performance indices are lagging indicators of asset reliability (that is, asset performance has deteriorated across a range of assets before a material impact is evident);

- The threshold for unacceptable asset risk is aggregate asset reliability where coincident asset failure is becoming likely;
- The ability to quickly restore the network following an asset failure is increasingly critical in order to minimise exposure to next contingency events particularly in more heavily loaded sections of the network;
- It is possible to effectively operate and maintain the network with a number of unreliable assets however at some point aggregate unreliability will affect network performance as well as long run asset maintenance effort and associated cost.

The Asset Management Plan is based on:

- Understanding asset risk in order to manage exposure to aggregate asset unreliability, coincident asset failure and associated long run maintenance effort and cost;
- Developing network control and protection assets to provide levels of response that support remote fault diagnosis and restoration in order to meet required levels of performance.

3.5.2 Performance metrics

Network performance measures used for asset management purposes are the number of system events with loss of customer load of greater than 0.2 and 1.0 system minutes.

Performance profiles based on these two indicators are shown in Figure 3.8 and Figure 3.9 to identify emerging trends.

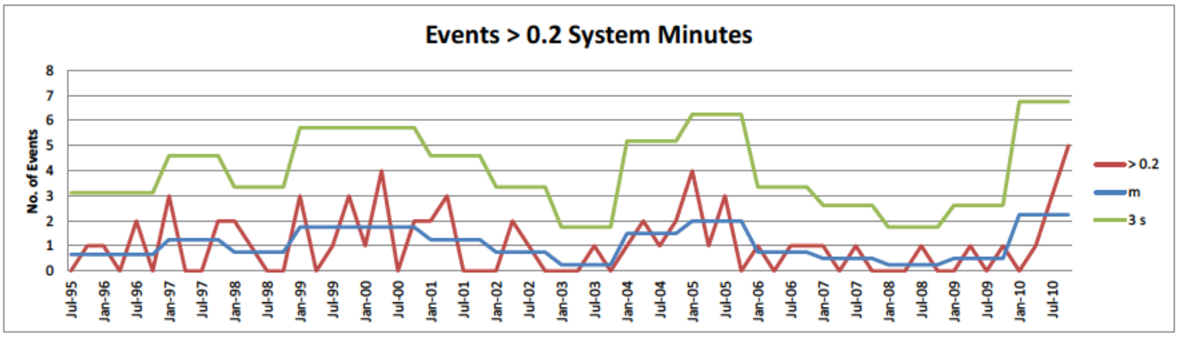

Figure 3.8: ElectraNet – Number of LOS Events Greater Than 0.2 System Minutes

Figure 3.8 shows Network Events >0.2 System Minutes since 1995, including the annual mean and three standard deviations plots. It shows a recently increasing trend. In 2010, a number of events were driven by severe storm activity impacting on the Eyre Peninsula transmission system. An investigation of line reliability and performance is currently underway with the aim of improving lightning protection of the effected line.

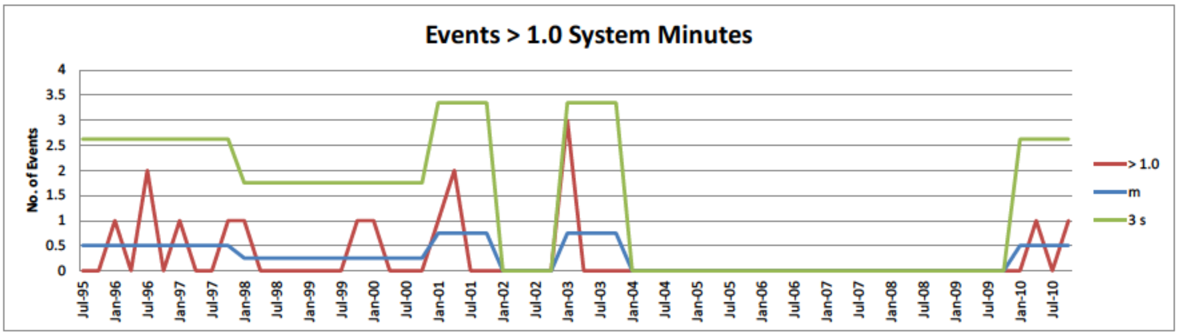

Figure 3.9 ElectraNet - Number of LOS Events Greater Than 1.0 System Minutes

Two > 1.0 system minute events shown in 2010 are also related to transmission line outages following storm activity (one event related to Eyre Peninsula, the other to the non-regulated Olympic Dam 275kV transmission line[2]). Time taken to respond to the outages has resulted in the >1.0 system minute event.

Plant Events are defined as equipment failures that result in a protection system operation on the network, which may or may not result in lost customer load. Figure 3.9 shows the number of plant events as well as the annual mean and three standard deviations for the trend. The plant events indicator reflects more general asset performance issues and shows a generally consistent trend during the previous two regulatory periods.

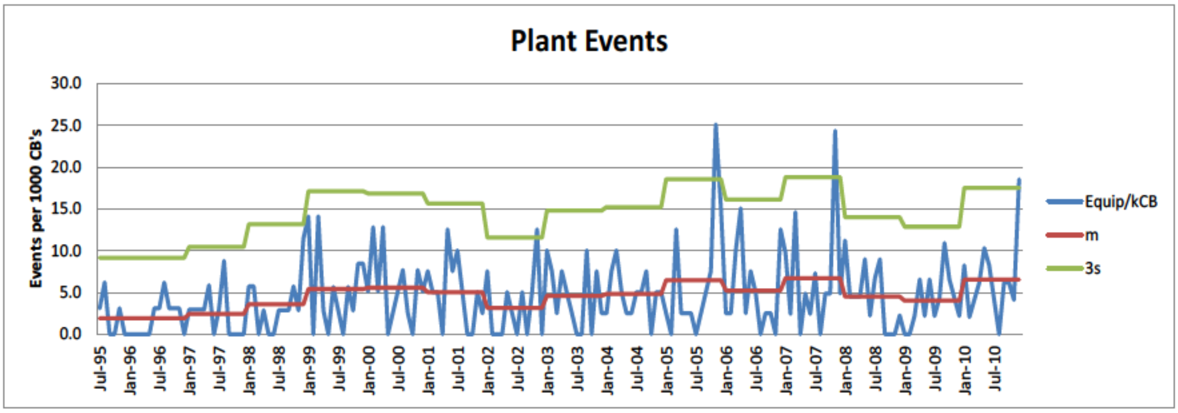

Figure 3.10: Number of Asset (Plant Failure) Events

Plant events by category are shown in Figure 3.11. A large percentage of plant events result from equipment mal-operation (e.g. related to configuration management and performance of control and protection systems). The increasing trend in 2010 is driven by an increasing rate of mal-operations and communication system faults. Improved device configuration management systems and processes have been identified to address the root cause of this problem.

2 Response determined by the asset owner BHP Billiton

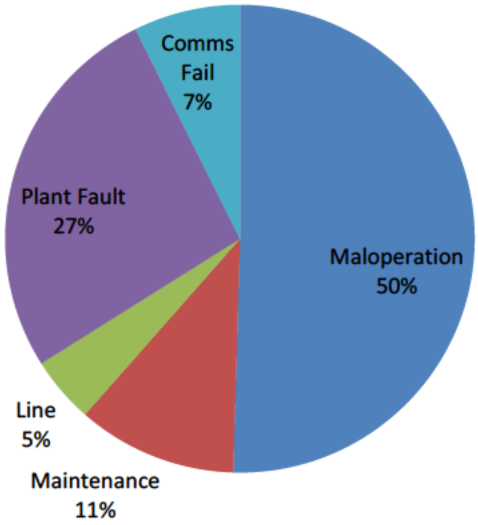

Figure 3.11: Plant Events 2007 - 2010

3.6 ElectraNet business model

In accordance with its obligations under the National Electricity Rules and associated South Australian legislation, ElectraNet operates and maintains the Transmission Network as well as planning and managing the medium to long term development and replacement of the Network and associated network assets.

Asset management functions are carried out internally, based on information relating to asset condition, performance and capacity. All field work (construction and maintenance) is outsourced to construction and maintenance service providers. A key aspect of the ElectraNet business model for asset management is that planning and decision making processes are remote from the assets and that decisions are based on information gathered by service providers. The business model is outlined in Figure 3.12.

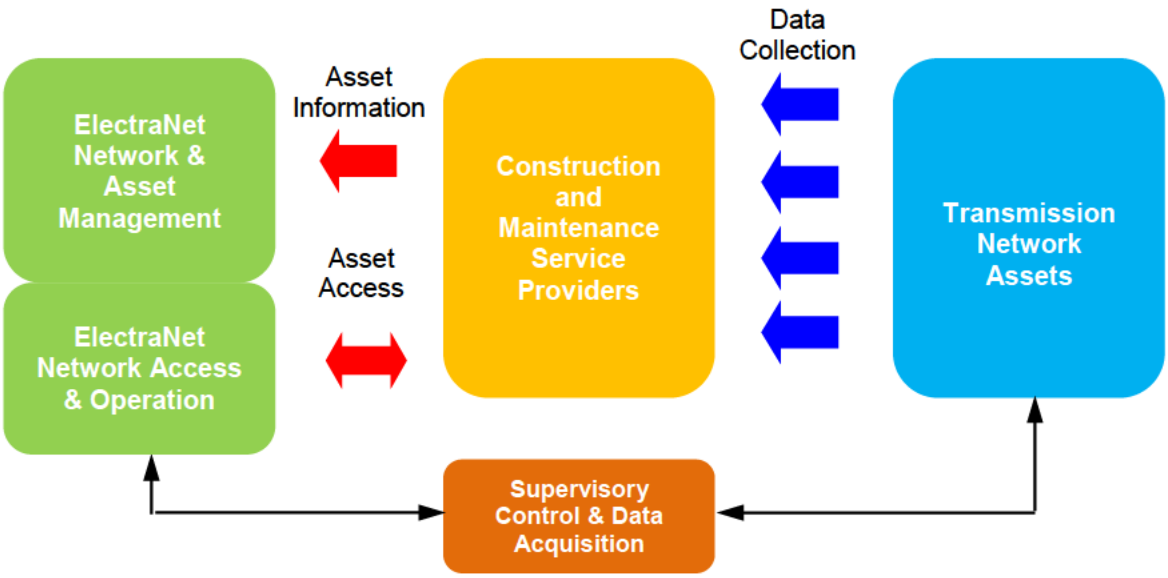

Figure 3.12: ElectraNet Business Model

A key aspect of the model is:

- Data is generated/collected by the service providers;
- Data is provided directly to ElectraNet's Asset Management System (SAP is the Asset Management System);
- There is an expectation that the service provider has the capacity to interpret asset condition in the process of collecting asset data.

All asset management decisions are made on the basis of data and information provided by service providers. ElectraNet recognises that asset data is in fact an asset in its own right and it is, therefore, important that the integrity of data collection is a key focus of the Asset Management Plan.

3.7 Previous regulatory period

This Asset Management Plan builds on the previous plan that has applied in the 5-year regulatory period from 1 July 2008 to 30 June 2013.

3.7.1 Asset data collection and analysis processes

Development of the Asset Management Plan relies upon collections of data and information accumulated over the life of the asset which may in some cases exceed 50 years. Ultimately the quality of the plan and its recommendations depends on underlying data and information.

> *Good asset management needs to manage the risks associated with incomplete and inaccurate data and disparate systems whilst still facilitating investment decisions that are as effective as possible.*[3]

In developing plans that effectively balance risk and investment, questions such as the following are typical:[4]

- *"What is the residual life of aged asset populations?"*
- *"Are remedial measures available which would extend the life and if so for what cost and for what benefit in terms of years of life extension?" or*
- *"If existing maintenance practices and costs are continued, what failure rates can be expected and therefore what investment in spare components will be needed?"*

This Asset Management Plan is based upon significant improvements to underlying asset management systems that improve the effectiveness of the plan by:

- Providing asset condition data based on documented inspection guidelines in order to maintain consistency and integrity of the data;
- Linking defect management to a documented risk management framework;
- Improving asset condition inspection and life cycle analysis;

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- Defining and applying asset end of life assessment criteria.

Improvement to asset data and information is an ongoing process. This plan represents the outcome of improvement work conducted in the regulatory period from 2007-08 to 2012-13. Data and information is more mature in some areas compared to others, for example:

- Collection and classification of substation asset defect data is well advanced due to the relatively short maintenance inspection cycle;
- Collection and analysis of transmission line condition information is in earlier stages due to the long inspection cycles associated with these assets (note acceleration of inspection programmes has been applied where possible, however this data and process is less mature than substations).

Development of the Plan is based on the following specific work undertaken to improve asset data collection and analysis processes during the 2007-08 to 2012–13 regulatory period:

SAP Asset data improvement

- Improved quality of Asset Condition Data and Information;
- The establishment of improved field data collection tools and process;
- Revision of Asset Management Policy and Procedure to support improved data collection and analysis.

Improved risk management

- Defined response criteria for asset defects based on a documented risk framework;
- Verification of transmission line easement vegetation profiles;
- Verification of transmission line ratings.

Improved condition assessment

- Development and implementation of transmission line and substation condition assessment guides;
- Development and implementation of transmission line component condition assessment and testing.

Transmission Asset Life Cycle analysis

- A framework for assessing overall asset condition (health) of transmission assets during the asset life cycle.

3.7.2 Managing substation risk

A key focus of the Asset Management Plan for the regulatory period from 2007-08 to 2012-13 was managing substation asset risk. Key objectives were to:

- Manage asset risk in order to limit further increase in maintenance effort and associated aggregate asset reliability risk;
- Implement substation routine maintenance plans based on industry best practice;
- Improve overall network functionality by replacing substation secondary systems with digital control and protection schemes and deployment of OPSWAN;
- Meet the requirements of the SA Transmission Code (augmentation of some sites was required to meet new code requirements);
- Replace substation assets where unacceptable levels of asset safety or defect performance were identified; and
- Undertake planned maintenance on asset types not previously covered by the maintenance plan for substation plant.

In this period implementation of improved asset inspection and data collection processes, increases to planned maintenance and replacement of poorly performing assets has produced a clearer understanding of substation asset performance and future asset risk.

Based on the asset information now available substation asset risk is more fully understood and this provides the basis for future risk mitigation work (corrective maintenance, opex refurbishment and capex asset replacement).

3.7.3 Transmission lines

The focus of the Asset Management Plan in relation to transmission lines was to transition from defect inspection to condition based maintenance of transmission lines. Key objectives were to:

- develop and implement condition based maintenance plans for transmission lines based on industry best practice;
- undertake condition assessment of high risk lines;
- improve understanding of transmission line asset life cycle analysis.

In this period implementation of condition based maintenance, detailed condition assessment of high risk lines and application of structured life cycle analysis has revealed an increasing requirement for transmission line refurbishment projects.

Due to long inspection cycles the full extent of transmission line risk and associated mitigating strategies will not be fully understood until well into the 2013-14 to 2017-18 regulatory period.

3.7.4 Network 2035 Vision

The Network 2035 Vision and guiding principles have been developed to provide the guiding framework for development of the Asset Management Strategy and this Asset Management Plan.

An external environment study and an associated risk analysis were undertaken in the development of this Vision. A key outcome of this analysis is that the future environment will be more dynamic and less stable in nature leading to greater uncertainty in forward planning.

The Network 2035 Vision is for ElectraNet to own and operate a modern network which:

- Has the optimised balance of lowest whole of life cost against net long term benefits;
- Has an optimum network topology whilst leveraging current voltage levels;
- Is capable of handling dynamically changing power flow directions;
- Comprises assets that are flexible, modular and plug in/plug out;
- Can operate all primary assets to thermal limits;
- Has full remote monitoring and control of all assets;
- Requires minimal maintenance;
- Achieves continual quality of supply improvements;
- Minimises environmental impact; and
- Is not reliant on any particular maintenance, construction or equipment provider.

The external environment study and an associated risk analysis undertaken in the development of this Vision have also indicated a need to improve data and information management systems supporting the following aspects of asset management:

- Operating Manual (process safety);
- Device configuration and security management;
- Training and competency assessment;
- Outage management;
- Transmission line rating;
- Transmission line asset inspection; and
- Telecommunications network performance.

This Asset Management Plan and the accompanying Data and Information Management Plan recognise and address the identified need for improved data and information management systems.

4. Asset Management Fundamentals

4.1 Asset management overview

In general all assets exhibit asset life behaviours that form the basis for critical asset management decisions, these are:

Potential Failure - Condition of the asset changes (slow deterioration) to a point where resistance to failure is compromised (a potential failure)

Functional Failure - Condition of the asset continues to change following a potential failure (the rate of change is dependent on a wide range of internal and external factors) to a point where failure occurs (functional failure)

End of Technical Life – Condition of the asset and external supporting frameworks (for example availability of spare parts, technical obsolescence, operational performance) continue to deteriorate to a point where it is no longer fit for purpose (end of technical life). End of technical life may be reached before reaching functional failure.

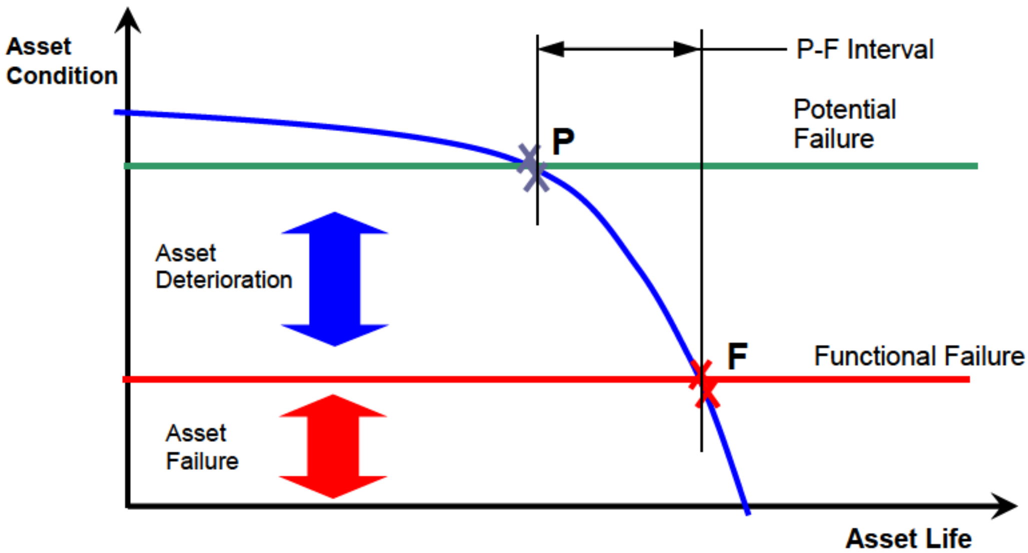


Figure 4.1: Asset Life Condition Curve

Note:

- The time taken to cross the P-F interval varies widely depending on factors both internal and external to the asset
- The shape of the curve is indicative only and will vary widely.

Entering the asset "end of technical life" period is not usually defined by a single event but rather is the culmination of a number of unrelated and independent events, these events are time driven.

While the culmination of these end of life events may not in itself result in the catastrophic failure of the asset, there is a significant risk that, in conjunction with a broad enough group of assets in a similar time condition, failure of fitness for purpose will decrease performance and increase unit costs. A typical asset end of life profile is developed below.

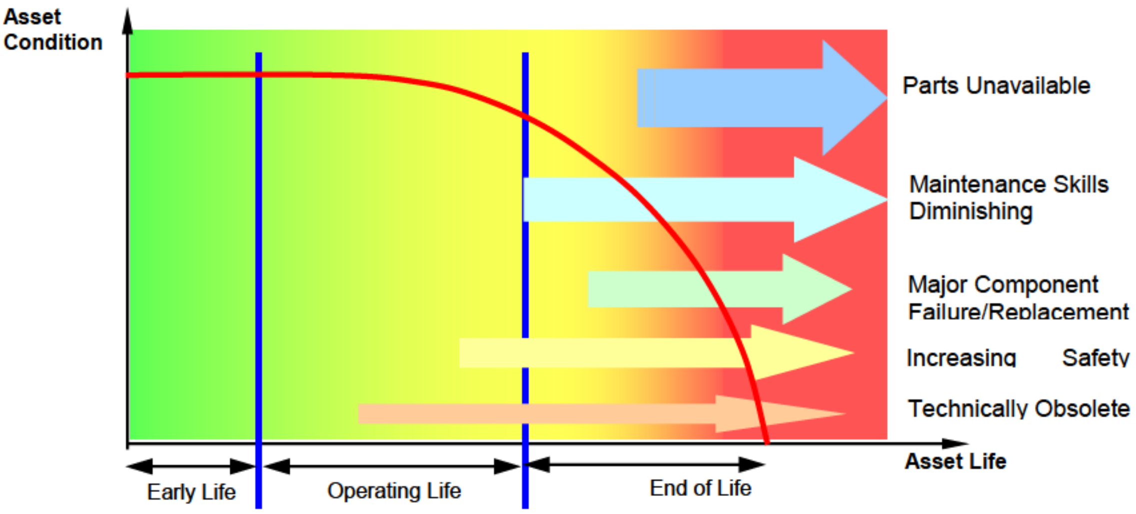


Figure 4.2: Asset End of Life Profile

The primary purpose of the asset management process is to manage the asset life cycle by:

- Understanding the P-F interval for each asset (or at least discover assets within the P-F interval with time to intervene before the failure point is reached);
- Understanding asset condition and the remaining life of the asset;
- Understanding asset failure modes and their consequences; and
- Determining the most appropriate response to changing asset condition in order to appropriately manage cost and risk.

4.2 Managing the asset life cycle

A combination of routine and defect maintenance responses are used to manage the asset lifecycle:

- Routine and Condition Based Maintenance plans have been developed based on manufacturer's recommendations and reliability centred maintenance (RCM) analysis – ideally the routine maintenance plan would maintain all assets at the point just prior to potential failure;
- Defect Maintenance is ideally responding to assets within the P-F interval and to gain information that may allow cost effective improvement to routine or condition based maintenance;
- Refurbishment Projects are planned where the most cost effective manner of dealing with deterioration of a group of assets is to perform additional one off refurbishment; and

- Condition Monitoring is used to track the rate of deterioration and provide the basis for asset condition assessment.

SAP is the asset management system used to collect, manage and analyse all asset maintenance, defects and response, the figure below shows the relationship of the asset life cycle to maintenance response and SAP data collection.

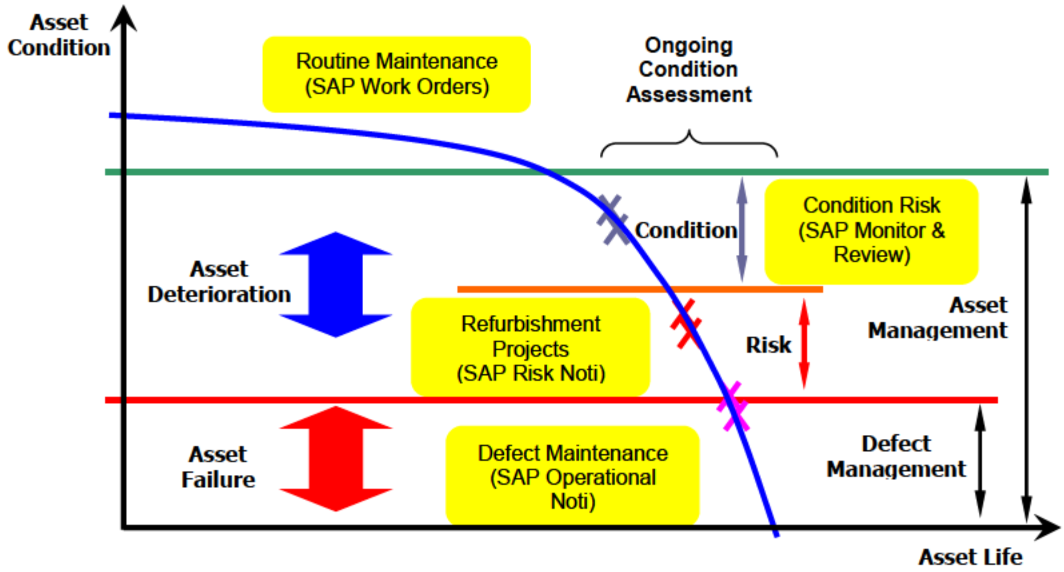


Figure 4.3: Managing the Asset Life Cycle

4.3 Understanding asset end of life

Traditionally Transmission Network Service Providers (TNSP's) have not developed a well-defined understanding of transmission asset end of technical life as:

- The vast majority of world-wide transmission assets are only now reaching the end of their technical and economic lives, therefore relevant statistical data and experience is still to be gained;
- Transmission equipment by its nature operates infrequently, which inherently limits the ability of TNSP's to collect statistically valid reliability and performance data;
- In high growth areas, TNSPs have focussed on managing rapid demand growth, which has led to augmentation works replacing equipment populations before they reached end of life.

As a result, there are no universally understood or agreed measures of transmission equipment reliability on which to base equipment replacement decisions.

ElectraNet has developed the Transmission Asset Life Cycle (TALC) assessment framework to provide an indicator of asset health and beginning of the end of life phase of the asset life cycle. TALC is a combination of the technical health of the asset and its strategic importance in the network (related to the value of load at risk).

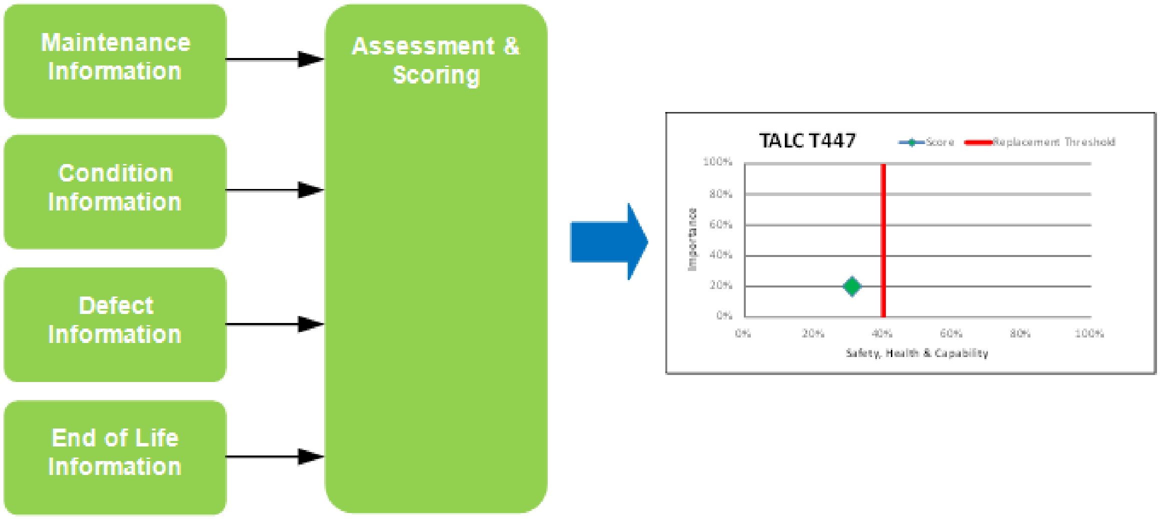


Figure 4.4: TALC Assessment Framework

4.4 Failure modes and consequences

Each asset may have more than one failure mode which means there may be multiple P-F intervals relating to an individual asset. Similarly each of these failure modes will have different failure rates and consequences. A different response is required for the range of possible failures and associated consequences.

ElectraNet has developed System Condition and Risk (SCAR) assessments of all common failure modes for substation and transmission line assets in order to define the most likely consequence and, therefore, the required response time and effort (cost) to address asset defects. Asset defects are categorised by consequence as follows:

- Sudden, very short time frame failures (in most cases the prime consequence is safety or environmental impact);
- Failure rates less than 12 months (the prime consequence is most likely to have an operational impact);
- Failure rates exceeding 12 months (usually associated with eventual failure of the asset).

Combinations of these consequences can exist for a single failure mode.

The risk profile developed by application of SCAR coding of defects is a leading indicator of future network reliability and availability.

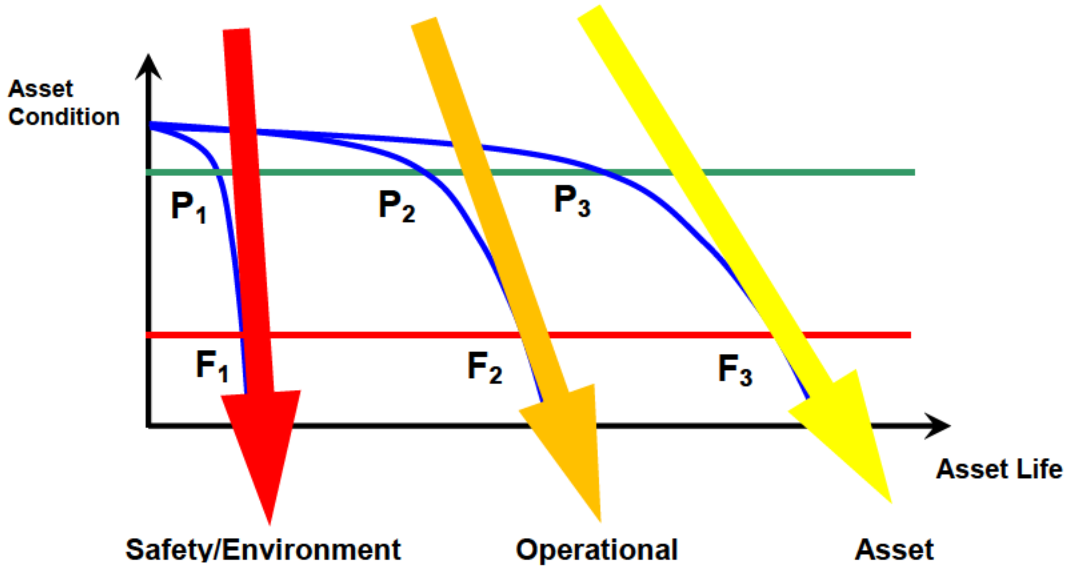


Figure 4.5: Asset Failure Basic Consequences

4.5 Asset management response

The aim of asset management is to maintain required levels of performance with the lowest possible long run maintenance effort (unit cost). Influences impacting asset performance/condition and cost are shown in the figure below and may be summarised as follows:

- Asset Deterioration represents changes in asset condition that eventually lead to higher cost and decreasing performance;
- Routine Maintenance is designed to counteract the effects of deterioration of the asset – ideally this is the most efficient response and should match asset condition;
- Asset Refurbishment is used to re-set asset condition (where routine maintenance is not adequate by itself) to a point where cost and performance are acceptable and routine maintenance will then be effective;
- Defect Maintenance is a reactive response to impending asset failure, it is the least efficient response and if allowed to dominate will lead to increasing unit cost and poor performance.

Ongoing efforts to improve efficiency in all maintenance activities will over time improve unit cost.

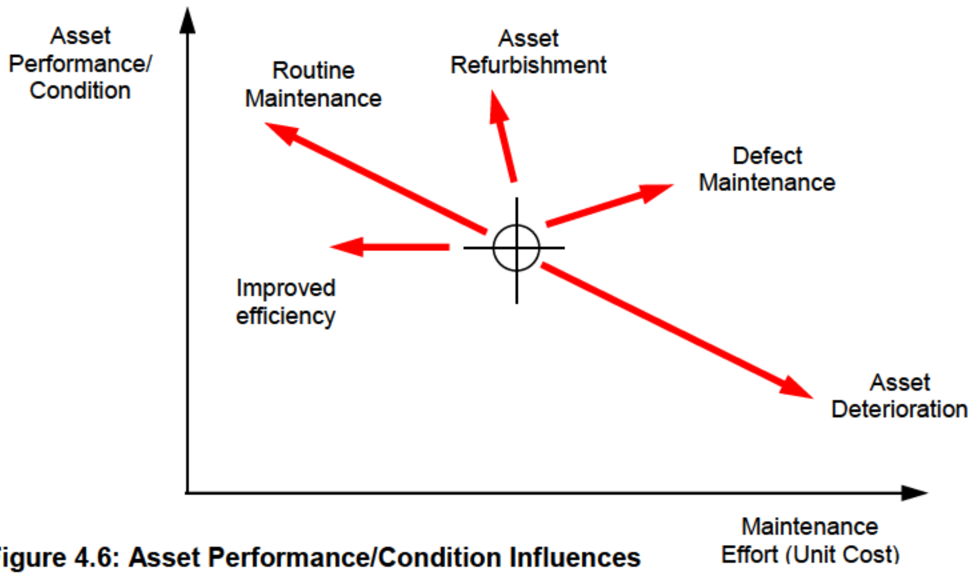


Figure 4.6: Asset Performance/Condition Influences

As the asset moves through its lifecycle the relative effectiveness of maintenance on the asset changes. Therefore, maintenance decisions change as represented in Figure 4.7.

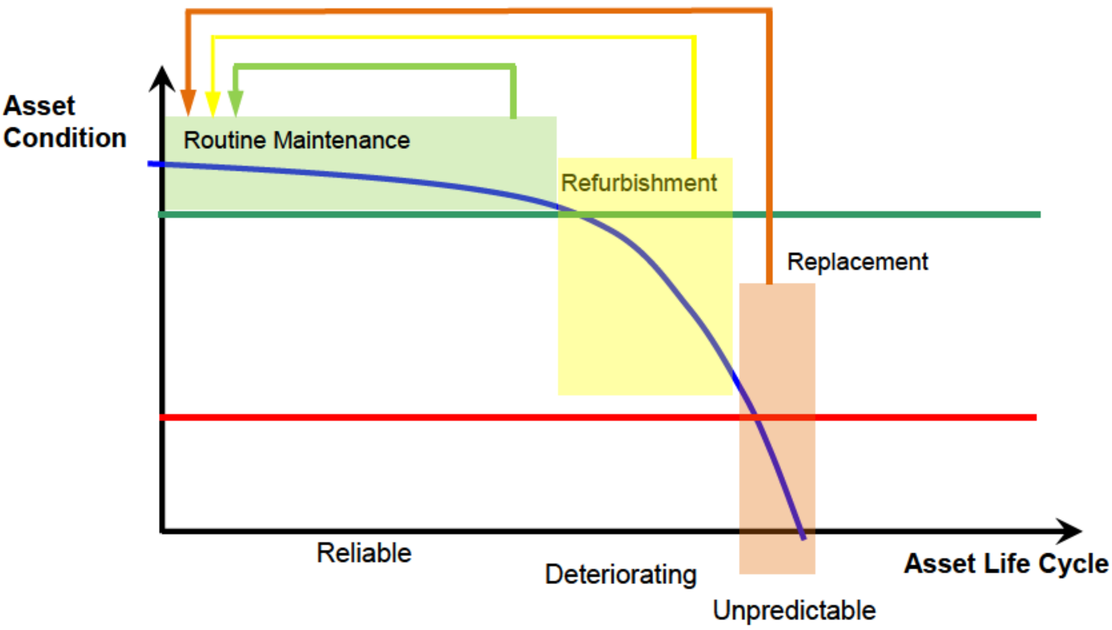


Figure 4.7: Asset Management Actions

The Asset Management Plan is developed based on the following asset management decisions for each asset:

- Asset Profile – assessment of plant/equipment profiles to confirm life cycle performance/cost (TALC – Equipment Profiles);
- Maintenance Plan – review of routine maintenance plans in order to optimise routine maintenance (Reliability Centred Maintenance analysis);

- Refurbishment Plan – review of plant/equipment defect profiles in order to identify problems common to groups of plant and it is cost effective to reset asset condition for ongoing routine maintenance (System Condition and Risk – Defect Analysis);
- Replacement Plan – identify assets approaching end of technical life where refurbishment is no longer cost effective, unpredictable behaviour is unacceptable (TALC – Life cycle assessment).

4.6 Investment decisions

The framework for making investment decisions is described below and is managed in the larger context of minimising the life cycle cost of the asset while maintaining acceptable levels of risk (associated with safety and performance of the network).

4.6.1 Routine maintenance

Routine maintenance costs for an asset are determined at the time of purchase of an asset as each asset brings with it a requirement to undertake routine maintenance in order to ensure that its performance is maintained for its working life.

In general the main characteristics of routine maintenance are:

- The lifecycle cost is largely determined at the time of purchase of the asset based on its design and manufacturers recommendation;
- Optimisation of routine maintenance cost (as more experience of the asset performance is gained) may be possible using optimisation techniques such as reliability centred maintenance (RCM);
- Routine maintenance is the most cost efficient method for maintaining the asset as the routine nature of the work makes it possible to optimise the maintenance plan and make the best use of resources;
- Routine maintenance costs are fixed costs.

4.6.2 Asset refurbishment

Asset refurbishment is work specifically undertaken to restore the condition of assets in the case that routine maintenance by itself is unable to do so. The cost of refurbishment work is specific to the task being undertaken.

In general the main characteristics of asset refurbishment are:

- Refurbishment work is undertaken where likelihood of accelerated end of technical life is significant and the early replacement of the asset is not the least cost option;
- Optimisation of refurbishment project cost may is possible by packaging work associated with similar or common assets into single work packages;
- Refurbishment projects, particularly for packaged works, are an efficient form of investment as work plans may be optimised to make the most efficient use of resources (and to identify those assets that may be replaced by other projects such as augmentation);

- The number and size of refurbishment projects (but is significantly influenced by the long run effectiveness of the routine maintenance plan and the asset age profile);
- Asset refurbishment projects are a variable cost.

4.6.3 Corrective maintenance

Corrective maintenance is scheduled in response to asset defects and associated levels of risk (safety, environmental or operational). Only defects that have high levels of risk and short response timeframes (less than 12 months) are classified as corrective. Defects with lower risk and longer response times are either packaged as refurbishment projects, asset replacement projects or scheduled to align with routine maintenance tasks.

In general the main characteristics of corrective maintenance are:

- Corrective maintenance is conducted in response to defects with unacceptable levels of long run risk;
- Defect maintenance by its nature is reactive and is therefore unplanned and relatively less efficient both in terms of allocation of funds and resources;
- The number and nature of asset defects is related to the long run effectiveness of the asset management framework and may severely lag changes to asset management practice;
- Costs associated with corrective maintenance are specific to the defect;
- Corrective maintenance is a variable cost.

4.6.4 Asset replacement

Asset replacement improves the asset risk profile (risks associated with safety, environment and performance as well as the ability to effectively manage the assets in the long run).

In general asset replacement decisions are made when:

- Assets have reached the end of their technical lives;
- Asset performance has become unpredictable and has unacceptable long run risk; and
- Asset refurbishment is no longer cost effective;

Asset replacement changes the routine/ corrective cost ratio (a reflection of long run asset risk). A high level measure of whether efficient levels of asset replacement are being undertaken is the asset sustainability profile, which is based on indicative asset lives. Ideally an asset sustainability ratio of one is maintained over time (indicating optimal replacement is undertaken based on the best understanding of useful life).

It is important to note that all asset replacement projects are aligned where possible with augmentation projects in order to gain efficiency of scale and reduce capital cost.

4.6.5 Cost optimisation

The aim of the Asset Management Plan is to minimise asset lifecycle cost while maintaining acceptable levels of performance and risk. The diagram below sets out the mechanisms incorporated into the asset management plan to optimise investment and funding decisions based on whole of life cost, performance and risk.

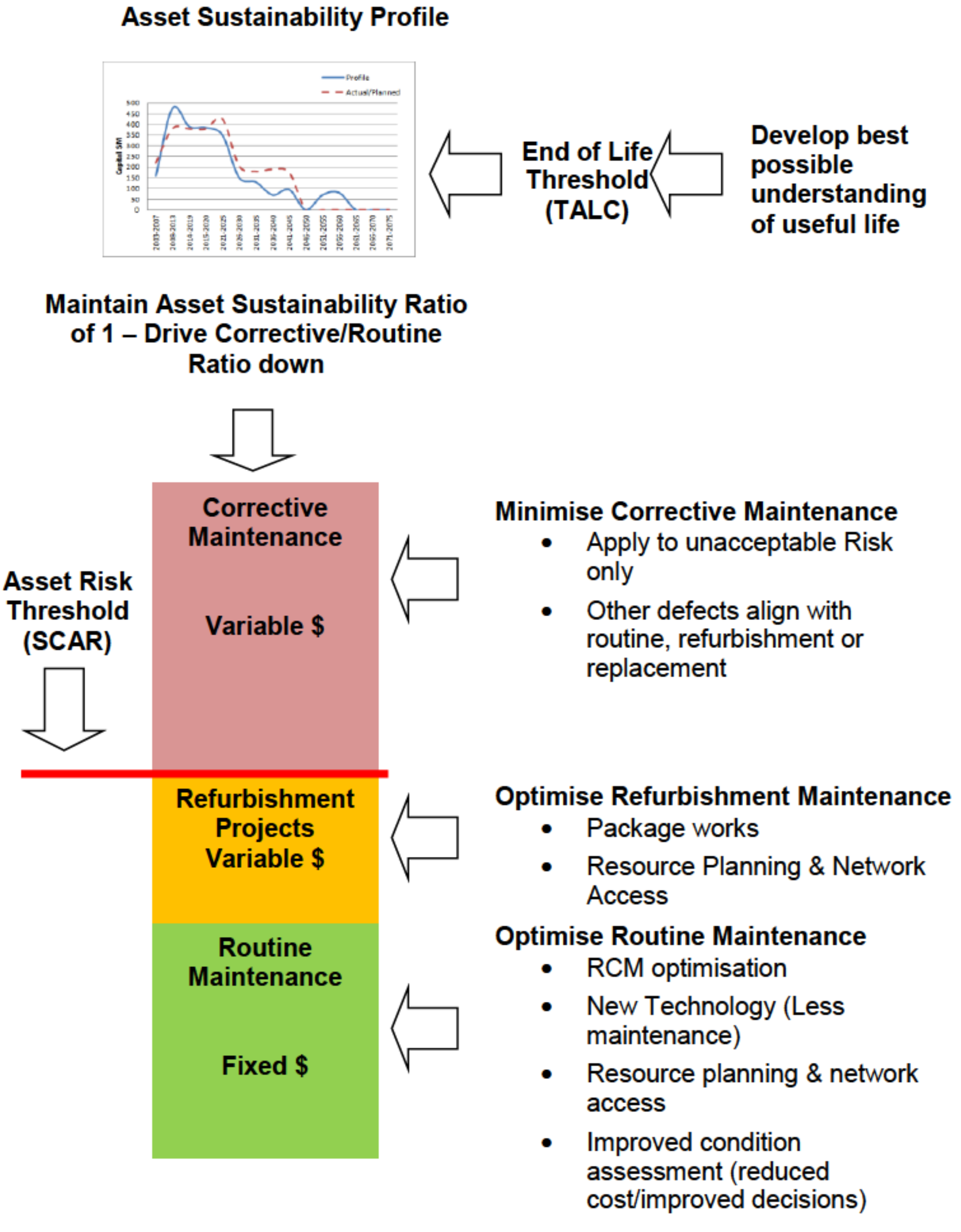


Figure 4.8: Asset Management Plan - Cost Optimisation Framework

5. Asset Management Framework

The Asset Management Plan is based on understanding and managing the lifecycle of each of the transmission network assets in order to maintain acceptable levels of risk and performance at the lowest possible long run cost.

The asset management process is described by the diagram shown below showing a series of planning, action and analysis steps, each associated with understanding and managing each of the assets that make up the transmission network.

The condition of each asset (or components of larger assets) changes over time depending on a wide range of factors including environment, maintenance history, design and the skills available to maintain those assets.

- The asset management process is designed to understand risk and cost associated with changing asset condition and the response appropriate to that risk
- The Asset Management Plan is the result of understanding the asset condition and defining a coordinated response for the future management of the asset.

Figure 5.1: Asset Management Process

Each of the frameworks and associated processes used to develop the asset management plan are described in more detail the following sections:

- Maintenance Policy and Procedure
- Refurbishment Planning
- Defect Management Process

- Capital Project Development
- Long Run Risk assessment

5.1 Maintenance policy and procedure

In 2005, ElectraNet began implementation of a new transmission network maintenance policy and procedure framework based on that used by Powerlink Queensland. This framework was developed using reliability centred maintenance and asset condition monitoring techniques and was applied directly to the South Australian transmission network with modifications to meet local statutory and environmental conditions as required.

The following maintenance policy frameworks are in place:

- Transmission Lines – Condition assessment based on routine inspection of transmission line components with inspection and test of selected components based on age and performance;
- Primary Plant – Routine maintenance plan based on reliability centred maintenance analysis;
- Secondary Systems – Routine testing of protection schemes where the test regime is based on the scheme technology;
- Communications – Routine maintenance of communication systems based on reliability centred maintenance where the maintenance regime is based on system technology.

Maintenance policy and associated procedural documentation is currently under review with emphasis on:

- Development of task lists for all routine maintenance in order to improve task and associated data management definition;
- Development of electronic checklists in line with the task list in order to structure data collection and provide a consistent framework for data analysis and asset condition and performance reporting;
- Reformatting of all documents (from Powerlink to ElectraNet document format);
- The expected completion of this review by June 2012.

Routine review of maintenance policy is based on asset performance using asset lifecycle performance reporting. These performance indicators are based on:

- Improved provision of maintenance and condition data from maintenance tasks, provided by task-list and checklist implementation;
- Improved provision of asset defect data (SAP Notifications) provided by implementation of System Condition and Asset Risk (SCAR) coding and field inspection tools;
- Development of SAP Asset Condition reporting tools.

The maintenance policy and procedure framework also includes specification for maintenance tasks, data collection and management, the overall structure is set out below, a full document list is provided in Appendix A Maintenance Policy and Procedure Listing

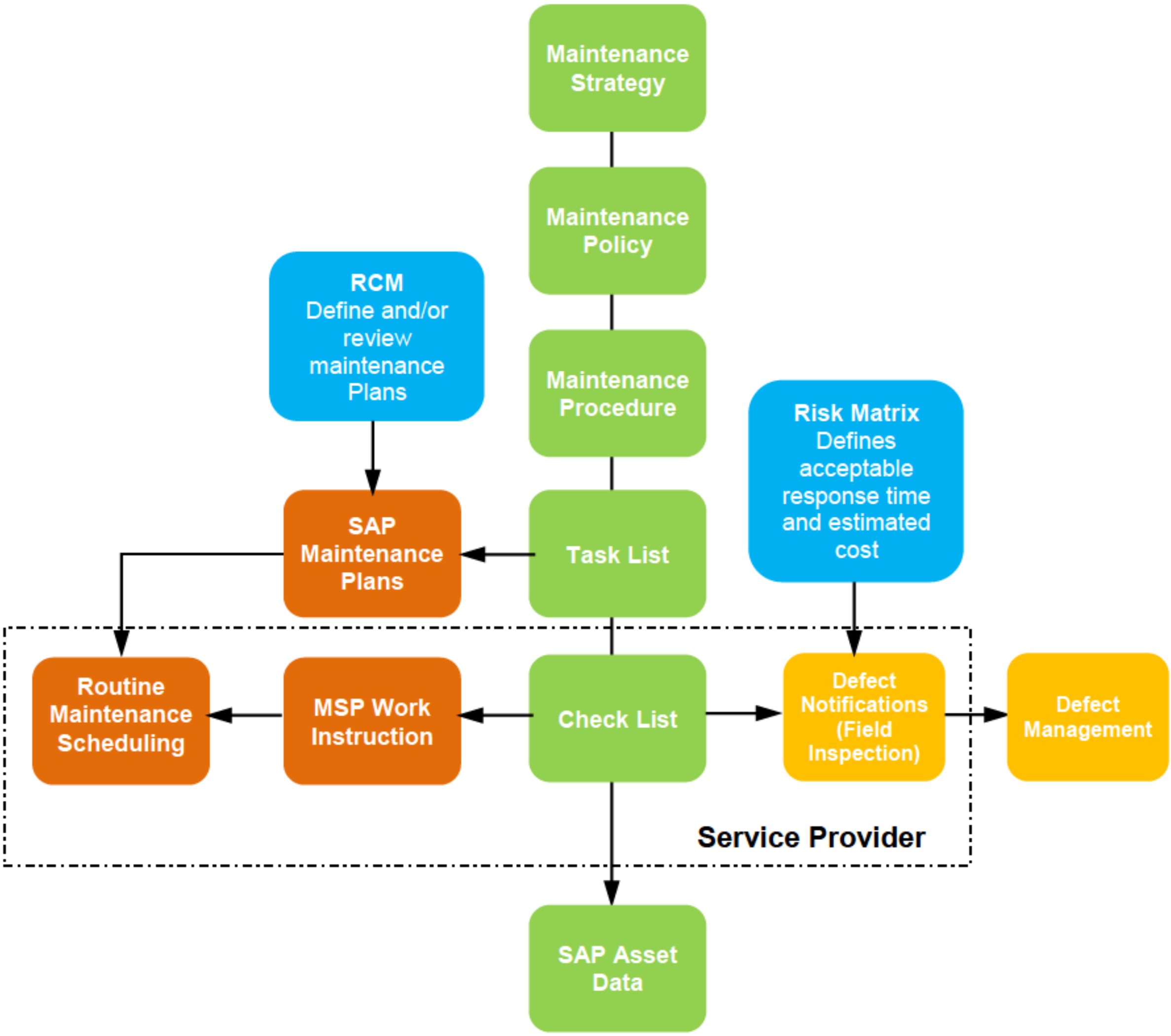


Figure 5.2: Maintenance Policy and Procedure Framework

5.2 Refurbishment planning

Refurbishment projects are determined by grouping asset defects and identifying the most cost efficient approach to effectively resolve defects while maintaining acceptable levels of asset safety, environmental performance, operational and asset risk.

Asset defect project lists are developed from SCAR coded non-immediate asset defects shown diagrammatically below.

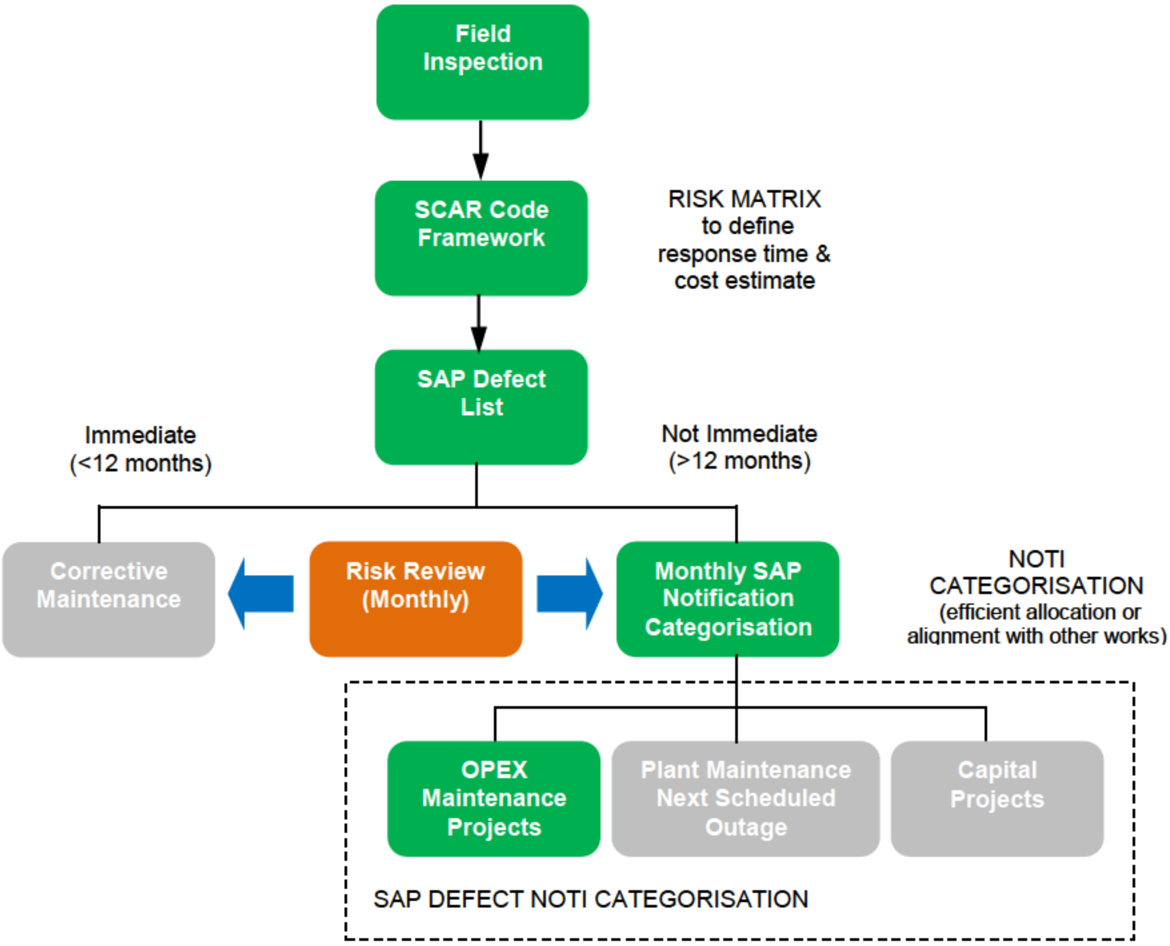


Figure 5.3: Refurbishment Project Development

OPEX refurbishment project briefs are developed for each maintenance project for the purpose of:

- Identifying the most efficient project framework and timing for undertaking the refurbishment work;
- Developing a detailed scope and estimate;
- Obtaining approval to proceed.

Note the SAP Defect Notification Categorisation process enables efficient allocation or alignment with other works of the non-immediate defects. This allows, where possible, the non-immediate defects to be planned to be completed during the next scheduled maintenance of the asset or addressed by other capital projects.

5.3 Defect management

Asset defects are managed in accordance with the risk associated with specific asset defects. The decision making process for classification of asset risk, response time and cost estimate is defined in the System Condition and Risk (SCAR) risk management process outlined below.

The SCAR risk matrix is designed to drive efficient cost by grouping as many asset defects as possible to future maintenance or capital projects. Only safety, environmental, operational and high risk asset defects are allocated to immediate defect response. The SCAR risk matrix is based on ElectraNet's corporate risk framework.

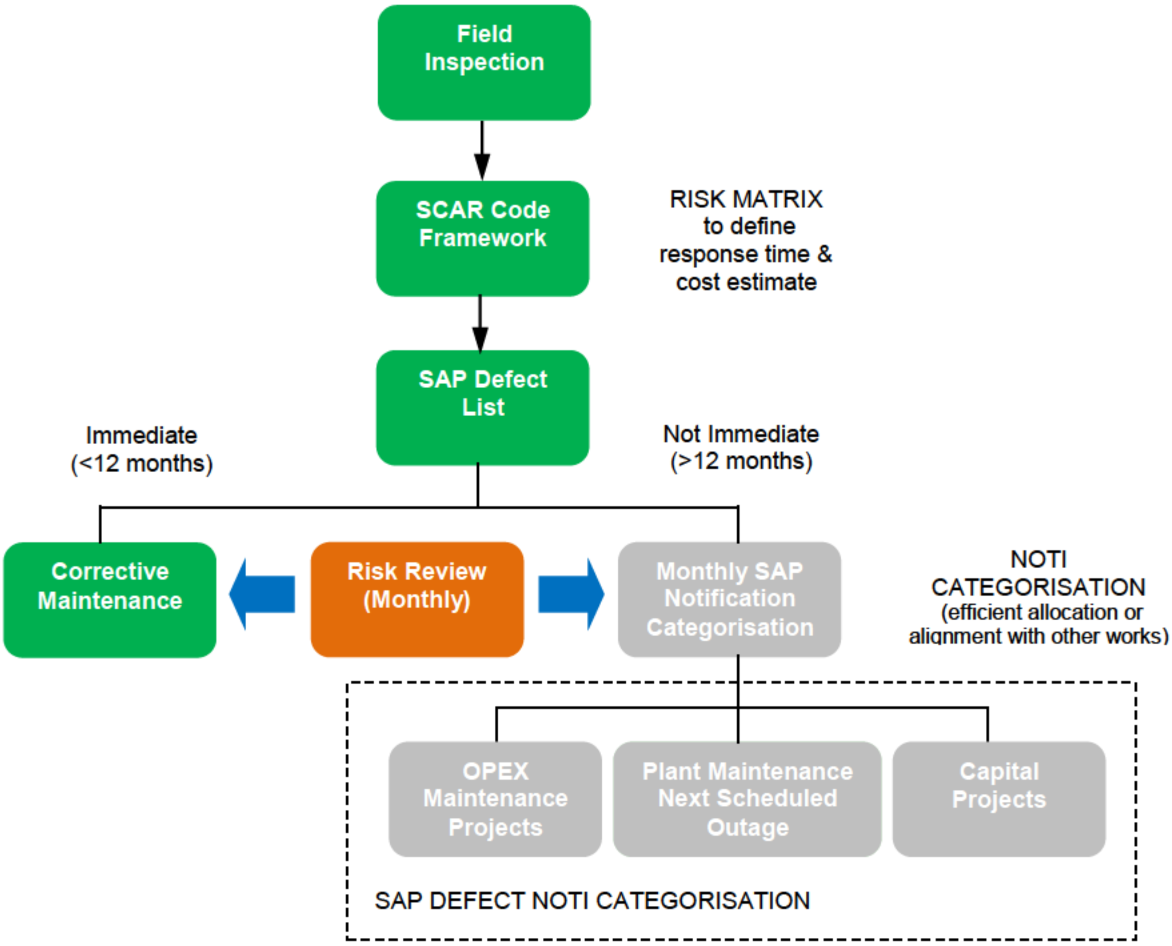
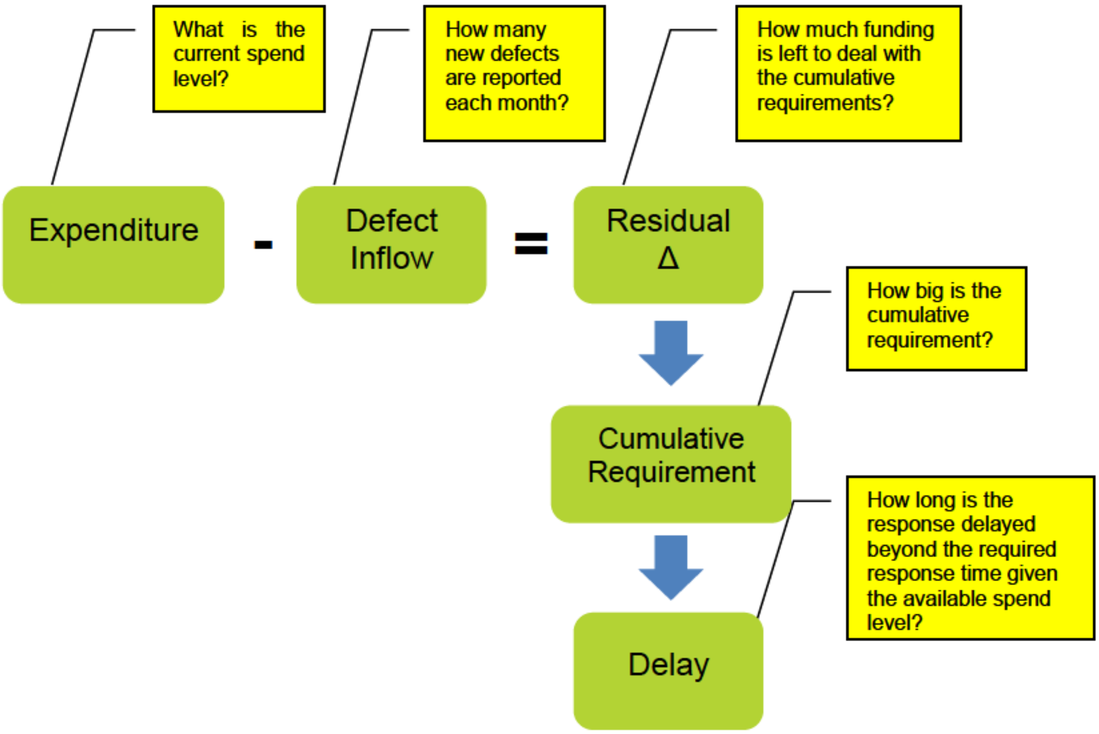


Figure 5.4: Defect Management Process

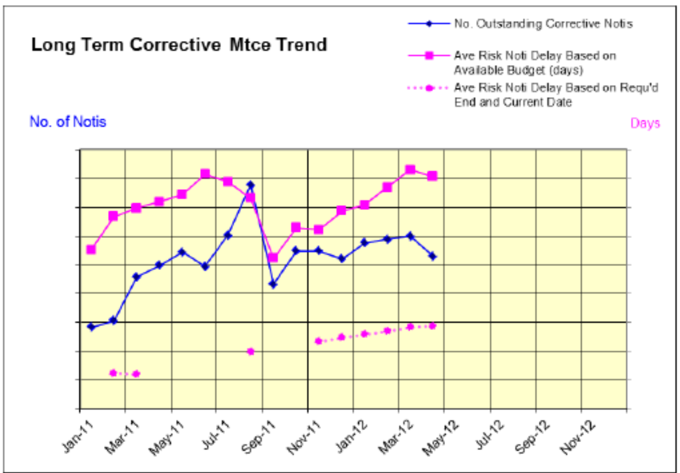
SCAR coding of all SAP asset defect notifications provides a consistent view of asset defect profiles, SCAR coding also provides an estimate of cost for each defect code therefore allowing a financial estimate of the accumulated defect effort to be characterised by:

- Asset defect budget – estimated cost to deal with immediate defect profile;
- Asset defect delay – a measure of risk exposure relating to the available budget time to respond compared to the risk assessed time to respond.

The process shown diagrammatically in Figure 5.5.



Substation & Secondary System Monthly trend of SAP notification defect response and cumulative requirement



Substation & Secondary System Monthly trend of SAP notification defect budget and $ estimate incoming rate

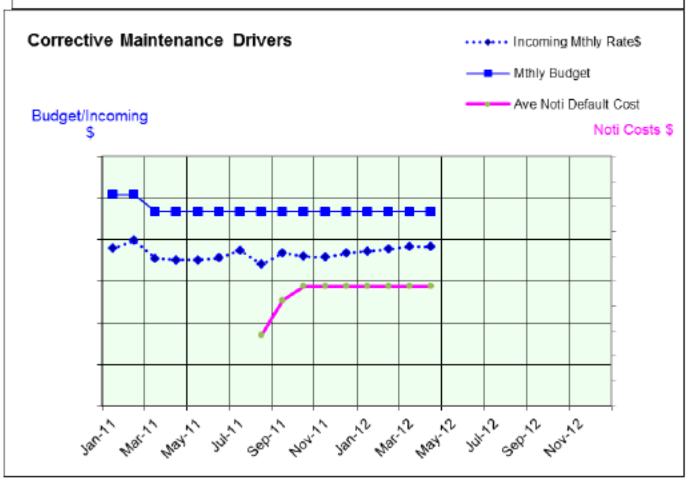


Figure 5.5: Defect Management Characterisation

All SAP defect notifications for Substation, Secondary System and Transmission Lines have been SCAR coded, this system of coding also allows the incoming rate of defects to be analysed and projected in order to estimate future corrective maintenance budgets.

5.4 Capital project development

The Asset Management Plan identifies four types of capital project, these are:

- Unit Asset Replacement Capital Project – where specific assets of a unit of property are identified to have reached end of life;
- Substation Replacement Capital Project – where a substation is identified as end of life;
- Transmission Line Capital Replacement – where a transmission line is identified to have reached end of life; and
- Communications Asset Replacement – where a communications asset is identified to have reached end of life.

Note that transmission network augmentation capital projects are identified in the Regional Development Plans and are summarised in the Annual Planning Report. Where possible asset replacement capital projects are planned to coincide with asset augmentation capital projects in order to improve the efficiency of project delivery.

Asset replacement capital projects are identified by determining asset end of life, timing of the project is then aligned with other capital projects as possible. The end of life decision process is summarised in Figure 5.6.

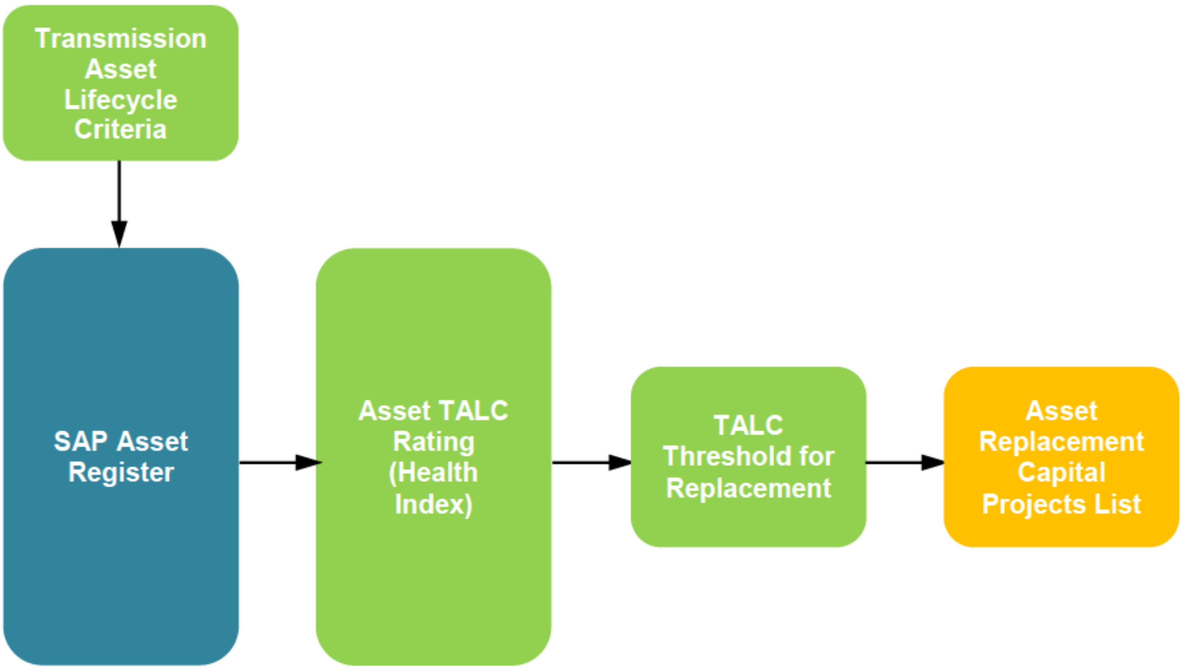


Figure 5.6: Asset End of Life Decision

Transmission Asset Life Cycle (TALC) has been developed to provide an indicator of asset health and signal when the end of life phase of the asset life cycle has begun. TALC is a combination of the technical health of the asset and its strategic importance in the network (related to the value at risk).

The process for undertaking a TALC assessment is set out in the following block diagram. This information is then used in the Asset Condition Assessment Report to summarise the overall lifecycle condition of the asset.

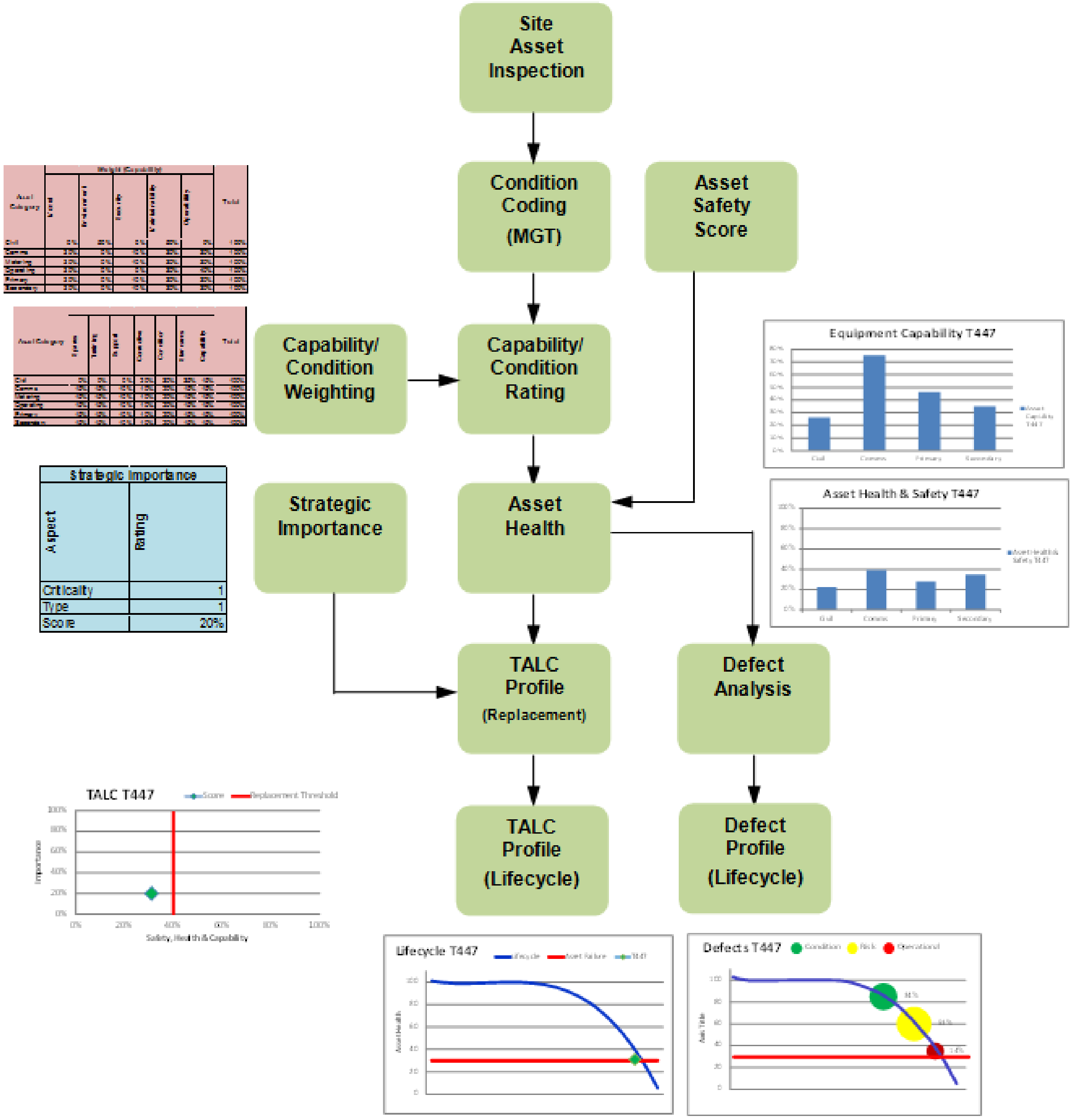


Figure 5.7: TALC Assessment Process

Each component is assessed based on the following criteria:

5.4.1 Substation Assets

Safety

Capability

- Model (evaluation of obsolescence)
- Environment
- Security
- Maintainability
- Operability

Asset Health

- Spare Parts
- Training (available maintenance skills)
- Support (available technical support)
- Corrective Maintenance Effort
- Condition
- Standards

Weightings are applied to each of the above categories based on the type of asset being assessed in order to ensure that relevant emphasis is given to the key aspects of the asset groups as follows:

- Civil
- Comms
- Metering
- Operating
- Primary
- Secondary

Note: Safety has 100% weighting under all conditions.

5.4.2 Transmission Line Assets

Condition of major components considering:

- The condition of line components at the time for the assessment;
- How long the asset can be expected to operate before failure (based on inspection, testing and assessment in accordance with international standards and practice.

Each assessment is based on a scoring system represented below:

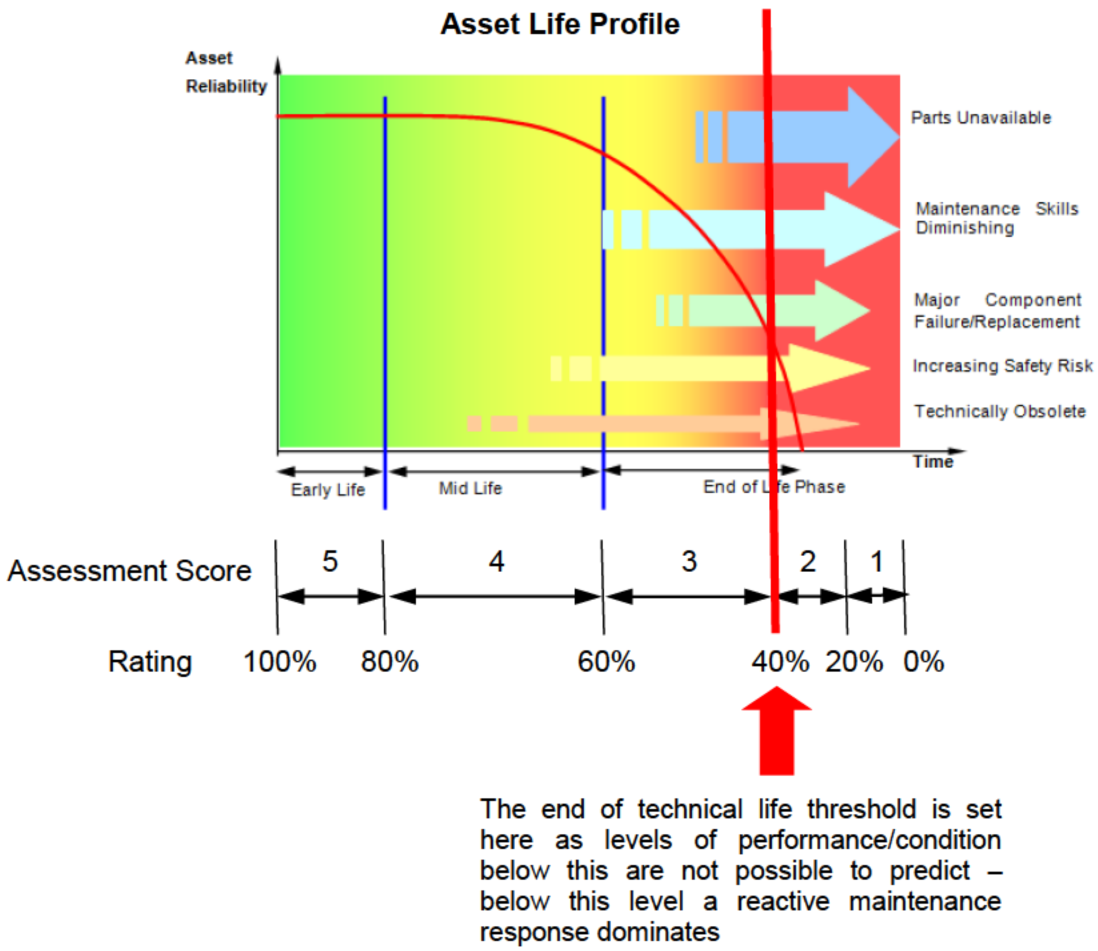


Figure 5.8: Asset End of Technical Life Threshold

The TALC framework provides a composite view of each major asset based on the sum of component scores as well as providing a view of each major component. The end of life threshold is the point at which asset behavior and performance becomes unpredictable and begins to dominate corrective maintenance effort and reduced reliability.

5.5 Long run risk – condition and cost

Identification of asset replacement and refurbishment thresholds is undertaken through application of SCAR and TALC. The aggregate asset risk analysis is used to evaluate the long run aggregate effect of asset replacement timing on defect maintenance effort and strategic functionality of the transmission network, a model is used to:

- Develop a prioritised project list based on SCAR (Refurbishment) and TALC (Asset Replacement) outcomes;
- Determine the timing of projects on the prioritised list in order to maintain an acceptable aggregate asset risk profile and meet network functionality requirements.

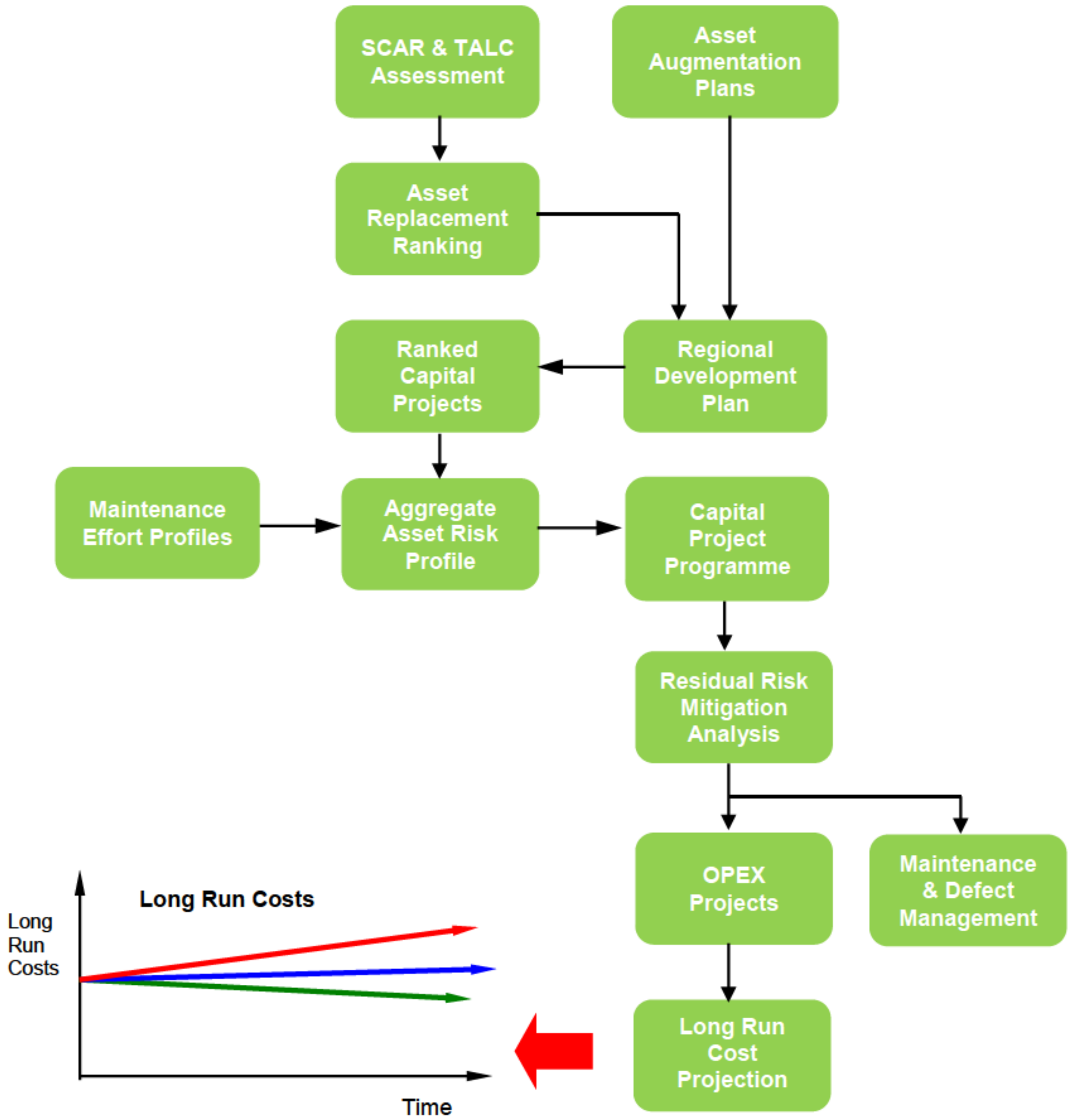


Figure 5.9: Risk Analysis

Asset maintenance effort may be characterised by the "bathtub curve" shown in Figure 5.10. As assets enter the end of life phase, performance begins to be dominated by maintenance issues, reducing MTBF and increasing time to repair.

There are two primary areas which present higher than desired levels of risk and cost. These areas are the "early life" period and the "end of life" period.

The cost implications associated with the early life period are largely managed through the procurement process which demands warrantee support for assets and construction workmanship. The partnering philosophy that ElectraNet has in place with its Dual Contractor arrangements further enhances ElectraNet's ability to transfer risk and get longer term commitment from service providers which mitigates cost impacts from early life failures.

The end of life phase is there area where the majority of ElectraNet's asset management focus must therefore be applied.

In order to model the effect of a particular asset replacement programme on long run costs, the asset maintenance effort profile is approximated using estimates of failure rates based on case studies of asset end of life (where failure is defined as any maintenance required outside the specified routine maintenance programme – unscheduled maintenance).

The Asset maintenance effort profile has been developed as described above, this profile then allows the incremental increase in corrective maintenance effort for each asset to be estimated in the period from the present to its scheduled replacement, providing the following estimates:

- The estimated OPEX Project spend to replace high risk assets
- The projected increase in defect maintenance costs if the high risk assets remain in service until a capital project replacement

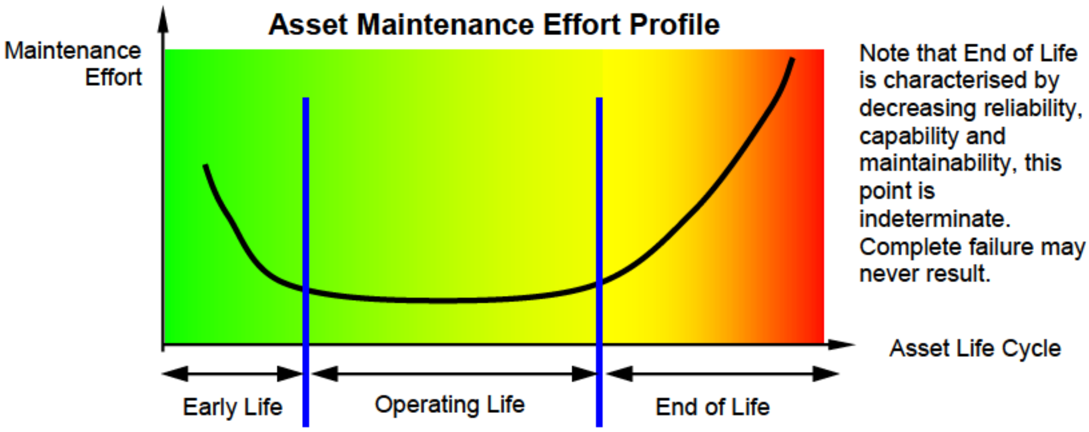


Figure 5.10: Asset Maintenance Effort Profile

The Asset Maintenance Profile is used:

- In the Asset Condition Assessment and scoring in order to be able to rank and support justification for asset replacement;
- To identify high risk assets for OPEX Projects;
- To develop an input for the modeling of long run maintenance costs.

The asset risk profile is based on a two dimensional risk model:

- **The Risk of Additional Maintenance Effort** - The asset risk model is based on estimating the effect of the asset maintenance effort profile on long run costs (that is the corrective maintenance costs associated with assets with decreasing MTBF and increasing MTTF). The key driver for the reliability estimates is the asset age at the projected time of replacement.
- **The Risk of Limited Secondary System Functionality** - A key element of these objectives is to drive improvement in performance by using new control and protection technology to provide the ability to remotely manage control and

protection maintenance and fault response in place of field attendance. The control and protection equipment technology profile (measured by equipment age) is used as an indicator of technology roll out by 2025.

The risk profile is based on estimating substation risk. The risk profile is developed in two stages, these are:

- The functionality and maintenance effort risks;
- The OPEX long run cost forecast consequence.

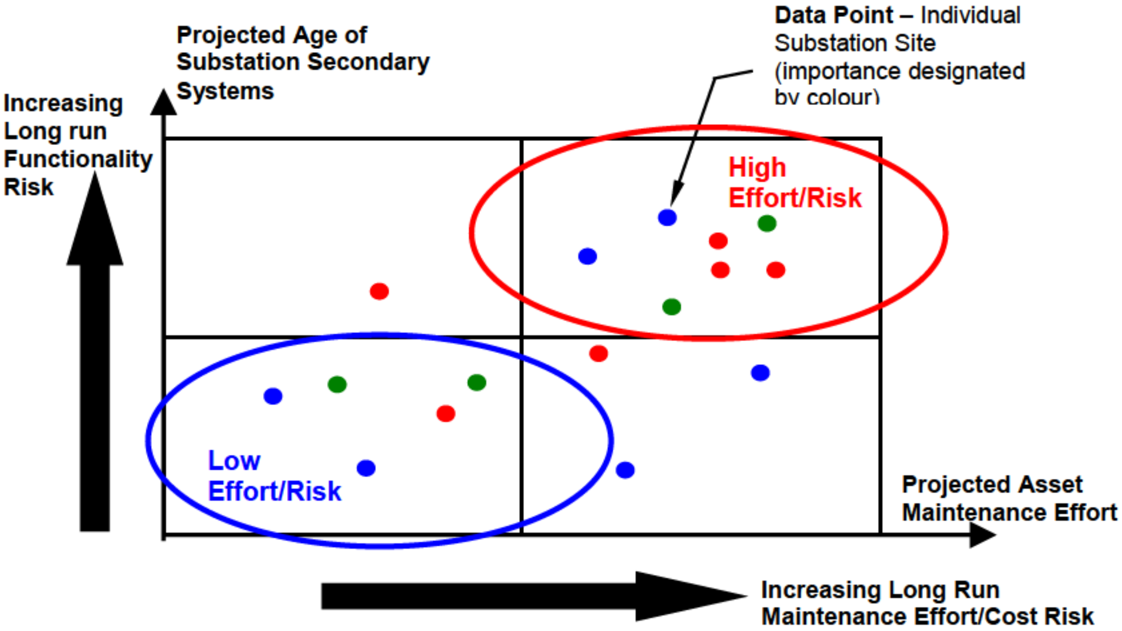


Figure 5.11: Development of the Long Run Substation Risk Profile – Example

The model output shown in Figure 5.11 shows:

- The projected risk of increased maintenance effort at each substation resulting from the underlying asset replacement programme – the model is intended to help answer the question *"Is the Asset Replacement Programme Timely by maintaining an acceptable long run corrective maintenance effort";*
- The projected profile of substation secondary system replacement (functionality) resulting from the underlying asset replacement programme – the model is intended to help answer the question *"Are adequate levels of functionality being built into the network in order to meet network performance targets".*

The transmission line risk model is a based on:

- Asset Health and Maintenance Effort;
- The OPEX long run cost forecast consequence.

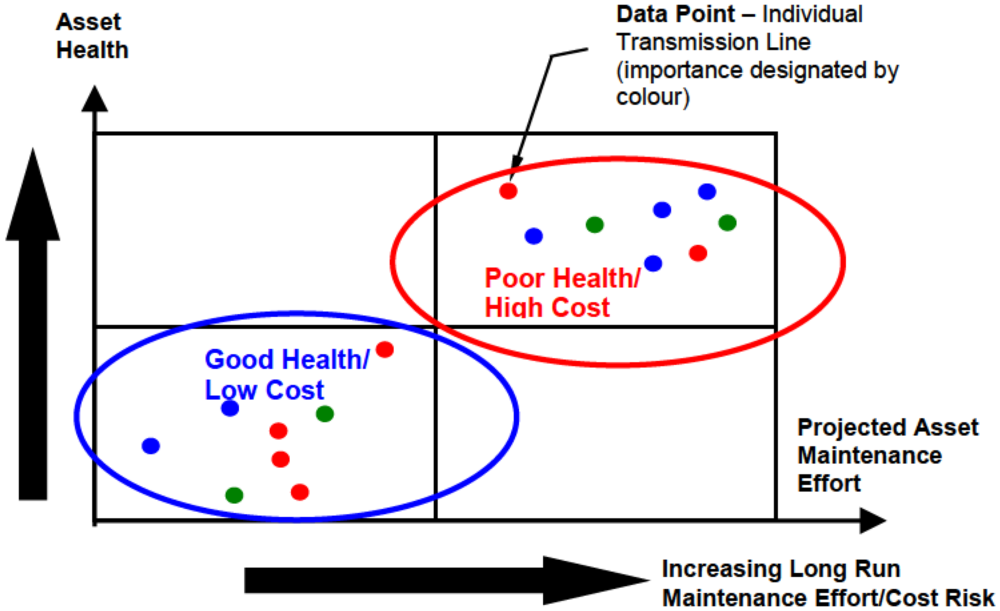


Figure 5.12: Development of the Long Run Transmission line Risk Profile – Example

The model output shown in Figure 5.12 shows:

- The relationship between maintenance effort and asset health – the model is intended to answer the question *"Is the maintenance effort being applied appropriate to the health of the asset"*.

6. Asset Plans

The details of the Asset Management Plan for the 2013-14 to 2017-18 regulatory period are set out in the following asset plans and associated projects.

Details of each plan are provided in the following sections. The Data and Information Management Plan is a separate document.

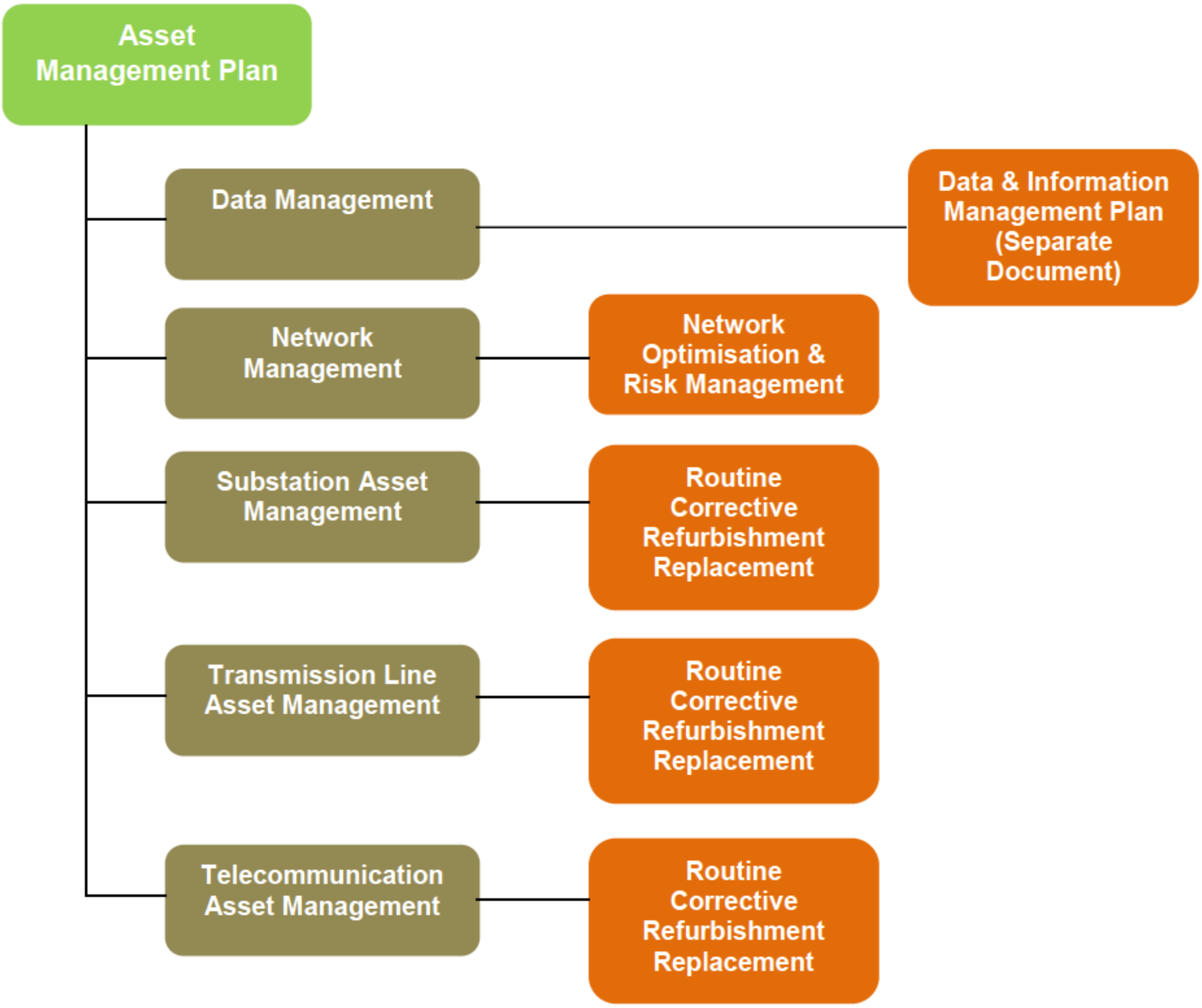


Figure 6.1: Asset Management Plans

6.1 Network optimisation and risk management

For the purpose of the asset management plan Network Optimisation and Risk Management (NORM) is defined as:

> *Those assets, asset information systems or asset management practices required to improve the operation and management of transmission network power flows, asset utilisation or asset management.*

The current status of NORM projects is summarised in Table 6.1.

Table 6.1: Summary of NORM Project Status

Project	Notes	Status
Remote monitoring of transmission network assets	Network control and protection IED communications	OPSWAN deployment and upgrades (CAPEX) – in progress
Automation of network control systems	Distributed control systems to provide the platform for increasing levels of automation	Project for configuration management and standardisation to be included in 2013 to 2018 period (CAPEX) IEC61850 deployment (as part of CAPEX Replacement or Augmentation projects) – in progress
Improve management of network power flows	Improved automation of voltage control schemes	Automation improvement project to be included in 2013 to 2018 period (CAPEX)
Improve network asset utilisation	Replace/modify under-rated substation assets limiting power flows	Project for replacing under-rated assets (minor plant - CAPEX) and secondary systems reconfiguration (OPEX) to be included in 2013 to 2018 period
	Improve automation of transformer dynamic rating	Project for deployment of transformer dynamic ratings to be included in 2013 to 2018 period (CAPEX)
Improve transmission line asset utilisation	Address line rating issues as improved line rating information is developed	ALS and line rating projects in place to improve line rating information (CAPEX) – In progress Project to provide allowance for management of line rating non-compliance to be included in 2013 to 2018 period (OPEX)
	Base line ratings on local weather conditions using regional weather stations	Project to provide regional weather stations to be included in 2013 to 2018 period (CAPEX)
	Improve dynamic line process	Project to provide time of day improvement to dynamic line rating automation to be included in 2013 to 2018 period (CAPEX)

Table 6.2: NORM Project Expenditure

Project	CAPEX ($2012/13)	OPEX ($2012/13)
Automation of network control system	$820,000	-
Improve management of network power flows	$3,600,000	-
Improve network asset utilisation	$360,000	$3,000,000
Improve transmission line asset utilisation	$2,000,000	$10,300,000
Total	$6,780,000	$13,300,000

6.2 Substation management plan

Implementation of the substation management plan (the substation management plan includes both substation primary plant and secondary systems) for the 2013–2018 regulatory period is based on the following considerations:

- Substation maintenance is now entering the second routine maintenance cycle (each routine maintenance cycle is approximately one regulatory period);
- Review of routine maintenance effectiveness will be conducted during this period using Reliability Centred Maintenance techniques, the aim of the review is to optimise routine maintenance effort and reduce long run unit costs;
- Refurbishment projects are based on high risk asset maintenance priority, two major plant refurbishment projects have also been included;
- Substation defect maintenance rates projections for 2013–2018 are based on current defect profiles; and
- Substation replacement projects focus on high cost radial sites with assets operating at the end of the asset life cycle.

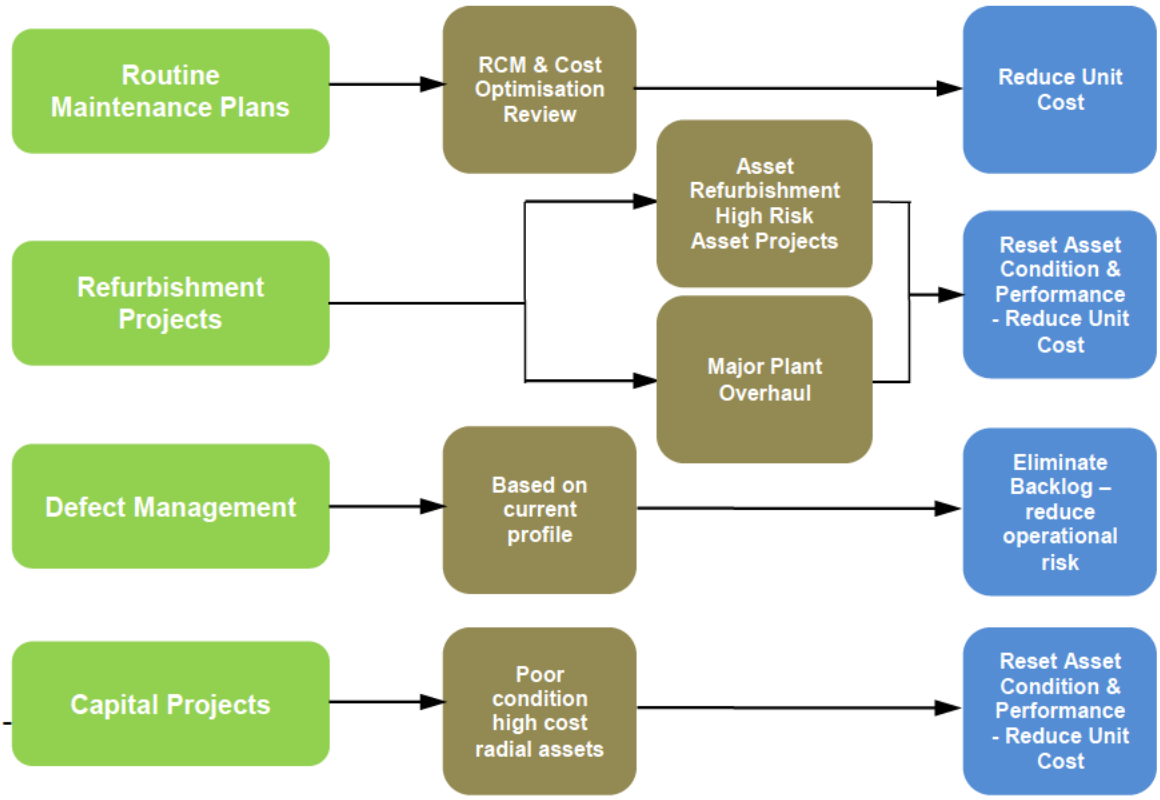


Figure 6.2: Substation Management Plan Summary

6.2.1 Substation asset profile

Substation functionality and maintenance effort profile at the end of the 2008–2013 period is estimated based on the current asset replacement and refurbishment program and updating substation condition assessment inspection data and scoring based on TALC criteria. A summary of the analysis is shown in Figure 6.3 below.

Sites with poor functionality and high effort risk (highlighted) have been identified as asset replacement projects for the following regulatory period. The aggregate effect on the overall substation asset functionality and maintenance effort performance is demonstrated on the following pages.

Note timing of replacement at some sites has been modified based on specific issues at that site, please refer to Table 6.8 for further detail.

Where high risk unit assets are identified specific replacement of those assets is identified in Table 6.4.

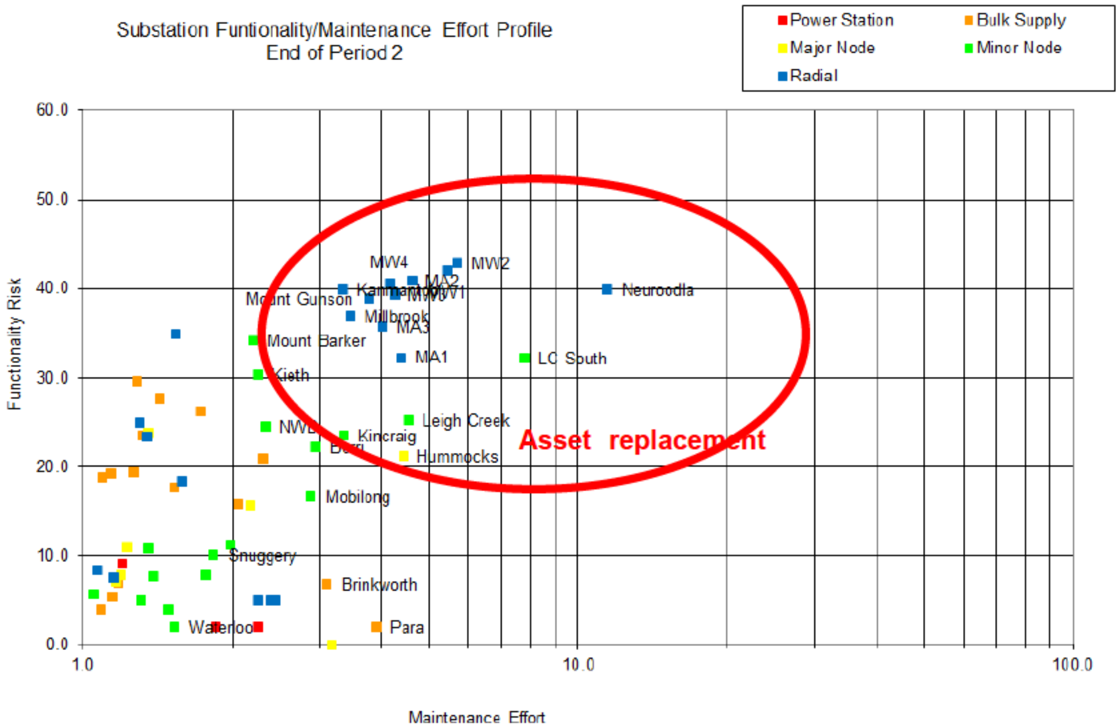


Figure 6.3: Substation Functionality and Effort Profile (Current)

6.2.2 Substation routine maintenance

Substation management includes all aspects of substation maintenance with the exception of telecommunications maintenance which is covered separately. Management of substation assets is represented in Figure 6.4 showing the overall relationship between maintenance policy, asset performance and strategic review.

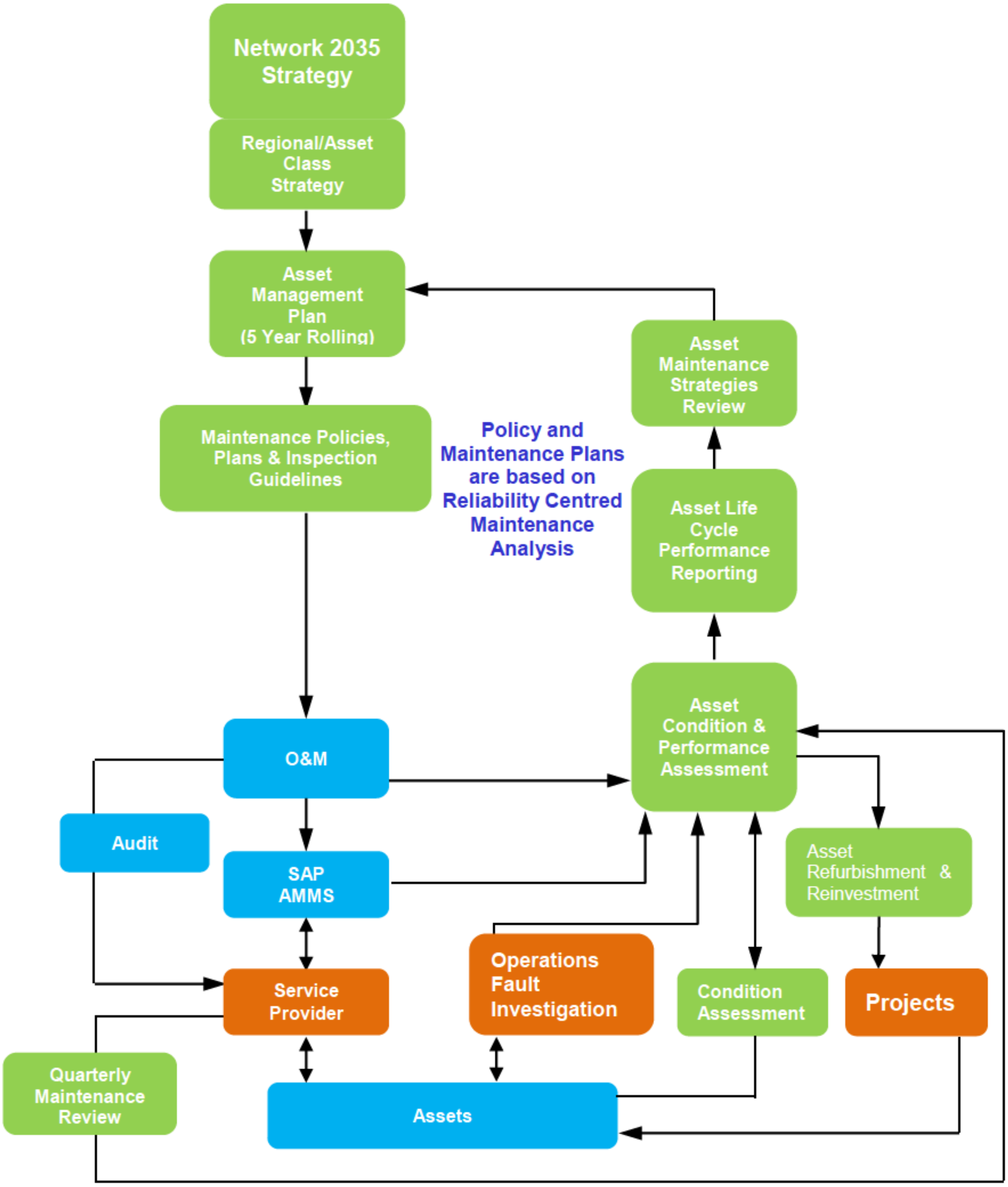


Figure 6.4: Asset Management Cycle - Substations

Current status of the maintenance plan is as follows:

- Powerlink maintenance plans have been implemented for a period of approximately five years;
- Considering the overall maintenance frequency of these plans most equipment is now completing the first maintenance cycle (up to six years);

- No material change to the maintenance plan is proposed, during the 2013–18 regulatory period a Reliability Centred Maintenance Review of all Substation Maintenance Plans is proposed in order to further optimise the maintenance plan.

Table 6.3: Substation Routine Maintenance Plan – Cost Estimate

Routine Maintenance	5yr Estimate ($2012/13)
Primary Plant Routine Maintenance Plan	$36,600,000
Secondary Systems Routine Maintenance Plan	$7,200,000
Total	$43,800,000

6.2.3 Substation refurbishment projects

Secondary systems refurbishment and plant overhaul projects identified using the SCAR coding process are summarised in Table 6.4, Table 6.5 and Table 6.6. Further detail is shown in Appendix E.

Table 6.4: Substation Refurbishment Projects – High Risk

Project	Estimate ($2012/13)
Substation Refurbishment – High Risk	$23,200,000
Total	$23,200,000

Table 6.5: Secondary Systems Refurbishment Projects – High Risk

Project	Estimate ($2012/13)
Secondary Systems Refurbishment – High Risk	$1,100,000
Total	$1,100,000

Table 6.6: Plant Overhaul Projects – High Risk

Project	Estimate ($2012/13)
Plant Overhaul – High Risk	$9,600,000
Total	$9,600,000

6.2.4 Substation corrective maintenance

Based on the current incoming rate of defect notifications, accumulated defects and the projected replacement of unreliable assets, the defect rate for the next regulatory period is estimated from the current incoming defect notification rate shown in Figure 6.5 below.

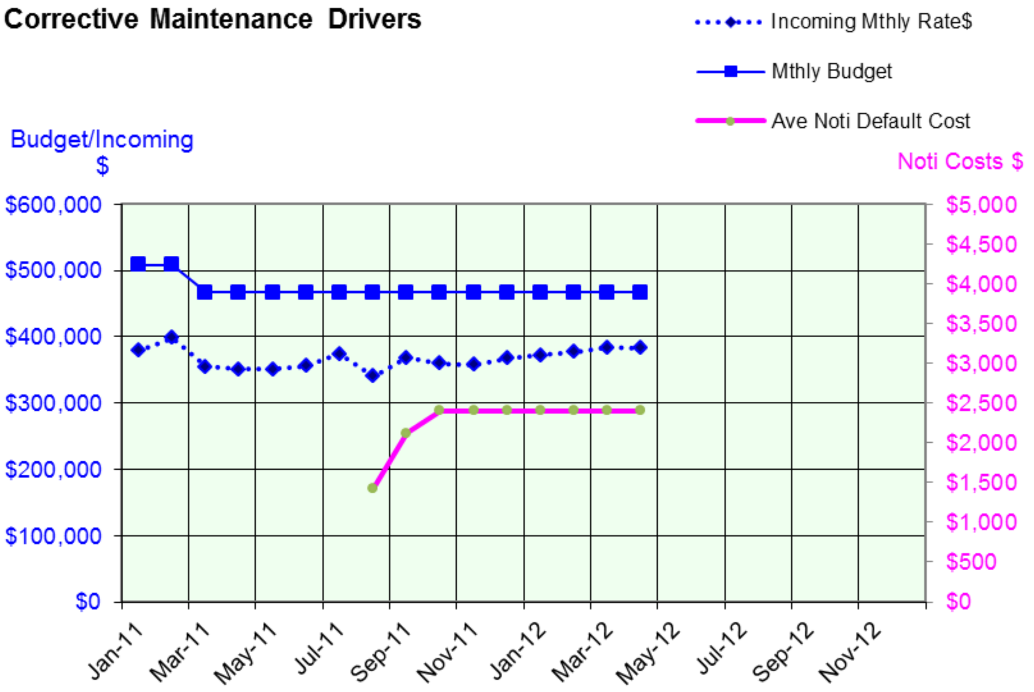


Figure 6.5: Incoming Substation and Secondary Systems Defect Rate

Figure 6.5 above shows:

- The estimated value of incoming monthly defect notifications compared to the current expenditure level;
- The expenditure level is currently higher than the incoming rate in order to deal with the accumulated corrective effort of defect notifications (it is estimated that with the current expenditure level the accumulated corrective effort will be completed by 2014-15).

To adequately manage the incoming defect notifications for Substations and Secondary Systems requires an ongoing annual budget of $4,500,000 ($2011-12).

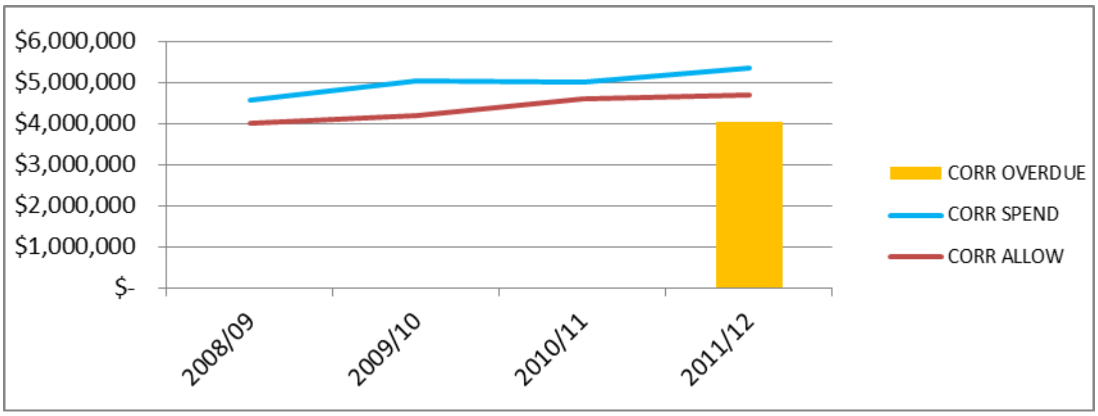


Figure 6.6: Substation and Secondary Systems Accumulative Requirement to Annual Expenditure

To address the accumulated corrective effort a total budget of $2,500,000 ($2011-12) over two years (2013-14 – 2014-15) is required.

Note that ElectraNet has throughout the current regulatory period already reprioritised its maintenance effort over and above this category allowance to address higher asset risk issues – to the extent possible with available resources.

Table 6.7: Substation and Secondary Systems Defect Maintenance Cost Estimate

Defect Maintenance	Annual Estimate Yr1 ($2012/13)	5 Yr Estimate ($2012/13)
Substation Defect Maintenance (Ongoing)	$4,100,000	$21,100,000
Substation Defect Maintenance (Accumulated – Yr1 and 2 only)	$1,100,000	$2,300,000
Secondary Systems Defect Maintenance (Ongoing)	$720,000	$3,700,000
Secondary Systems Defect Maintenance (Accumulated – Yr1 and 2 only)	$210,000	$430,000
Total	$6,130,000	$27,530,000

Refer to Appendix C for a full discussion of the SCAR framework and forecast estimation.

6.2.5 Substation capital projects

Substation replacement projects for the 2013 to 2018 regulatory period are summarised as follows:

Table 6.8 Substation Replacement Projects

Substation	Region	Comment on replacement driver	Estimate ($2012/13)
Millbrook substation	Eastern Hills	Asset replacement - condition based	$13,400,000
Kanmantoo substation	Eastern Hills	Poor Condition of Substation assets and emergency transformer deployed in 2011	$14,400,000
Kincraig substation	South East	Poor asset condition and augmentation transformer capacity (2013-2018)	$41,600,000
Baroota substation	Mid North	Poor Condition of Substation assets and connection point reclassification	$17,600,000
Neuroodla substation	Upper North	Primary and secondary assets at end of life	$11,200,000
Morgan / Whyalla #1 substation	Riverland	Primary and secondary assets at end of life	$23,300,000

Substation	Region	Comment on replacement driver	Estimate ($2012/13)
Morgan / Whyalla #2 substation	Riverland	Primary and secondary assets at end of life	$16,300,000
Morgan / Whyalla #3 substation	Riverland	Primary and secondary assets at end of life	$12,700,000
Morgan / Whyalla #4 substation	Riverland	Primary and secondary assets at end of life	$13,100,000
Mannum / Adelaide No.1 substation	Eastern Hills	Primary and secondary assets at end of life	$17,500,000
Mannum / Adelaide #2 substation	Eastern Hills	Primary and secondary assets at end of life	$15,900,000
Mannum / Adelaide #3 substation	Eastern Hills	Primary and secondary assets at end of life	$12,000,000
Mount Gunson substation	Upper North	Primary and secondary assets at end of life	$11,400,000
10509 Whyalla Terminal Substation Replacement	Eyre	Poor Condition of Substation assets & connection point reclassification	$33,100,000 (WIP _ 2008-13) $8,800,000 (WIP _ 2014-18)
10503 Waterloo Substation Replacement	Mid North	Poor Condition of Substation assets & connection point reclassification	$21,900,000 (WIP _ 2008-13) $4,800,000 (WIP _ 2014-18)
Keith Substation	South East	Poor asset condition and augmentation transformer capacity (2013-2018)	$18,800,000 (WIP _ 2013-18) $15,200,000 (WIP _ 2019-23)
Leigh Creek Substation	Upper North	Delayed pending long term future of supply point	_
Leigh Creek South Substation	Upper North	Delayed pending long term future of supply point	_

The Unit Asset Replacement program is aimed at efficiently addressing plant and equipment risk at the unit level to enable the overall substation asset to achieve its full intended service life, avoiding the need for full asset replacement.

Table 6.9: Substation Unit Asset Replacement

Project	Estimate ($2012/13)
Unit Asset Replacement (Primary Plant & Secondary Systems)	$35,400,000
Total	$35,400,000

Table 6.10: Secondary System Replacements

Project	Estimate ($2012/13)
Para 275kV Secondary Systems Replacement	$31,500,000
Para SVC Secondary Systems Replacement	$16,700,000
NGM CT, VT & Meter Replacement	$16,700,000
Asset Condition Online Monitoring Equipment Replacement	$12,000,000
Total	$76,900,000

6.2.6 Long run substation asset profile

Timing of capital replacement projects determines long run maintenance effort and functionality risk. The objective is to maintain an acceptable level of risk which is reflected by the maintenance effort and asset functionality. Modelling of these profiles based on the proposed capital replacement plan for the next three regulatory periods is shown below.

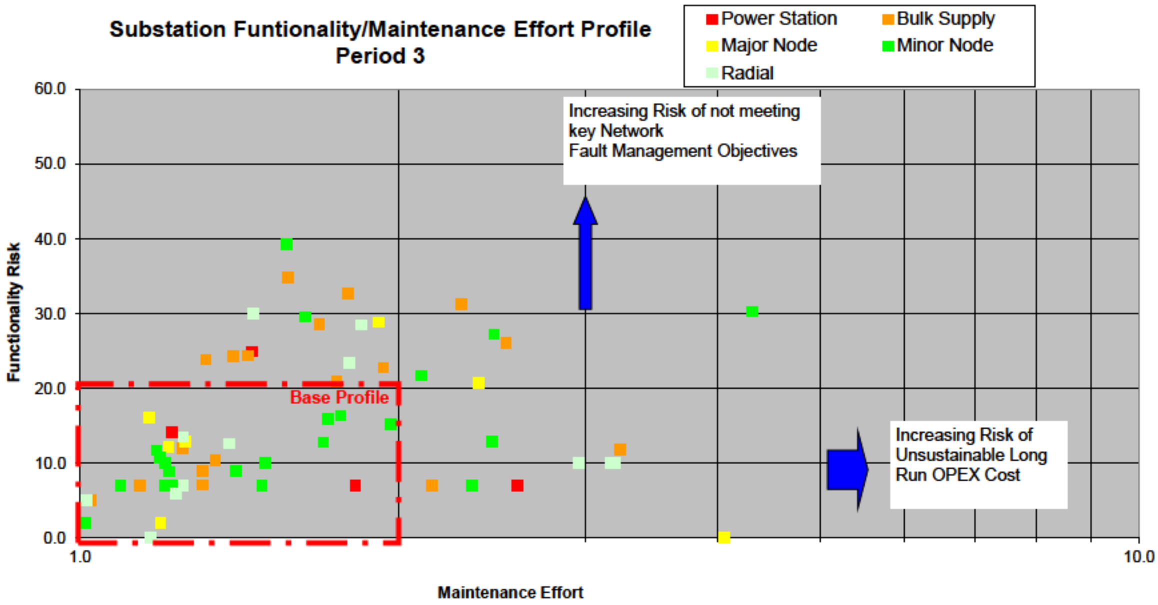


Figure 6.7: Substation Asset Profile (2013-14 to 2017-18)

Figure 6.7 above shows the effect of asset replacement programs for the 2013-14 to 2017-18 regulatory period indicating an overall reduction in high maintenance effort/poor functionality assets (compared to Figure 6.3 which shows the current position)

The following figures show the effect of future replacement programs based on replacement at end of technical life.

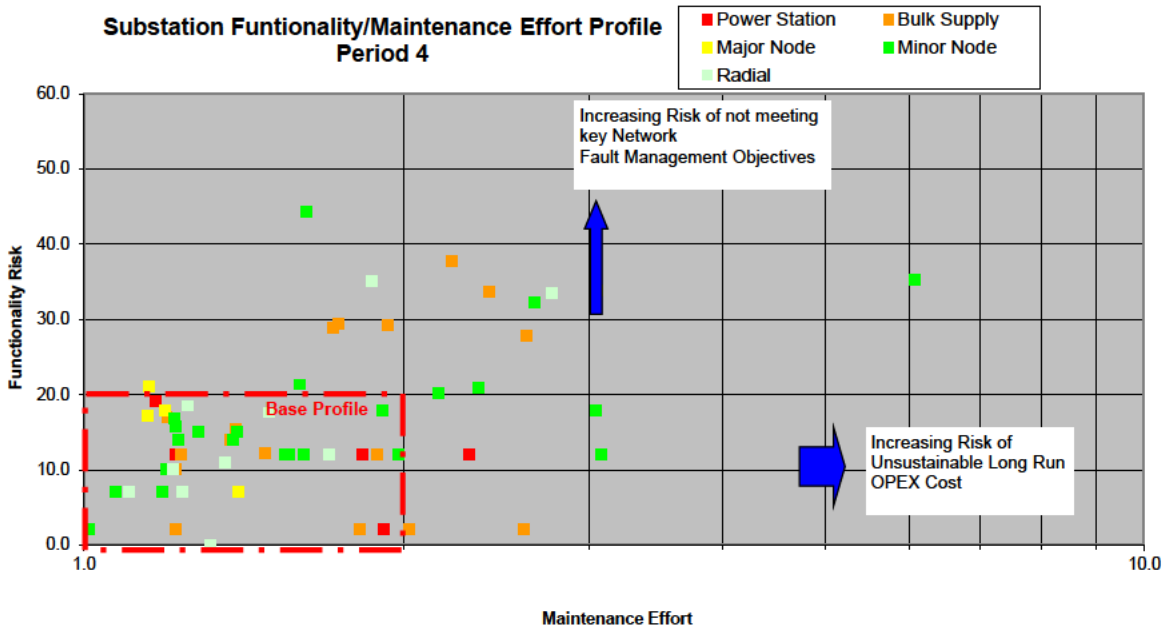


Figure 6.8: Substation Asset Profile (2018-19 to 2022-23)

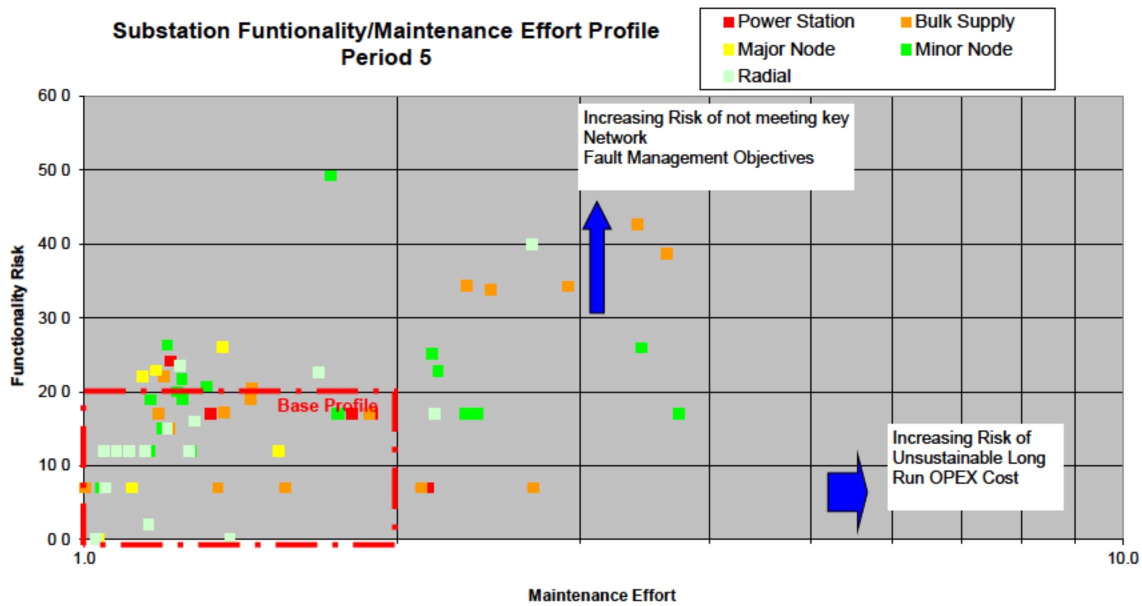


Figure 6.9: Substation Asset Profile (2023-24 to 2028-29)

Aggregating the diagrams above, the long run effect of the substation asset replacement program is shown in the figure below indicating a long run reduction in maintenance effort (corrective). In later periods the need to replace secondary systems begins to dominate functionality risk.

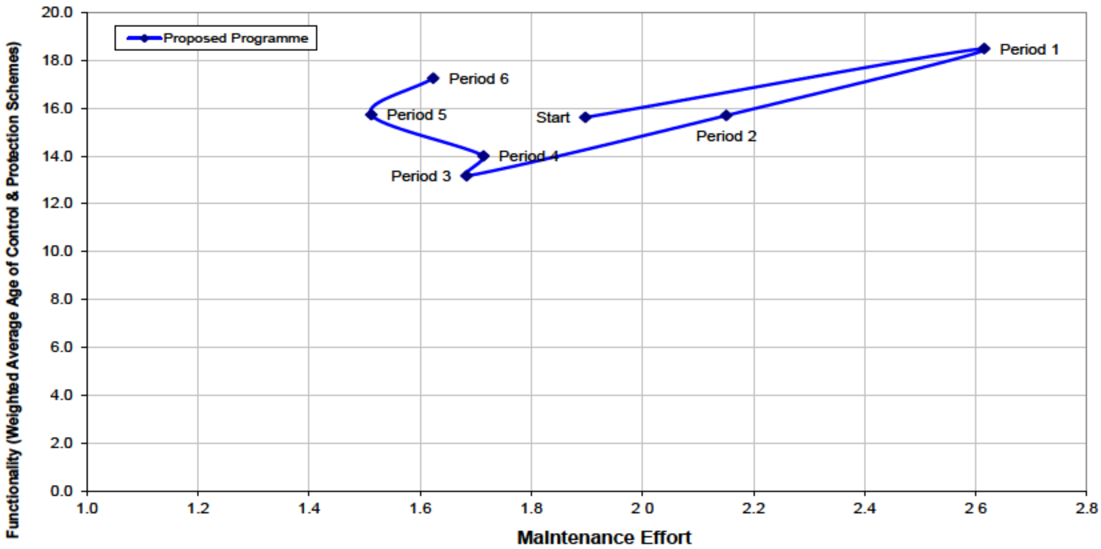


Figure 6.10: Asset 20 Year Risk Profile

6.2.7 Substation maintenance expenditure profile

A summary of substation and secondary systems operating expenditure for the current and following periods is shown below indicating:

- A sustained routine maintenance effort;
- An increased refurbishment maintenance effort (driven by large asset overhaul, isolator refurbishment and transformer oil containment and maintenance requirements);
- An initially increasing defect maintenance effort required to mitigate accumulated corrective maintenance requirements.

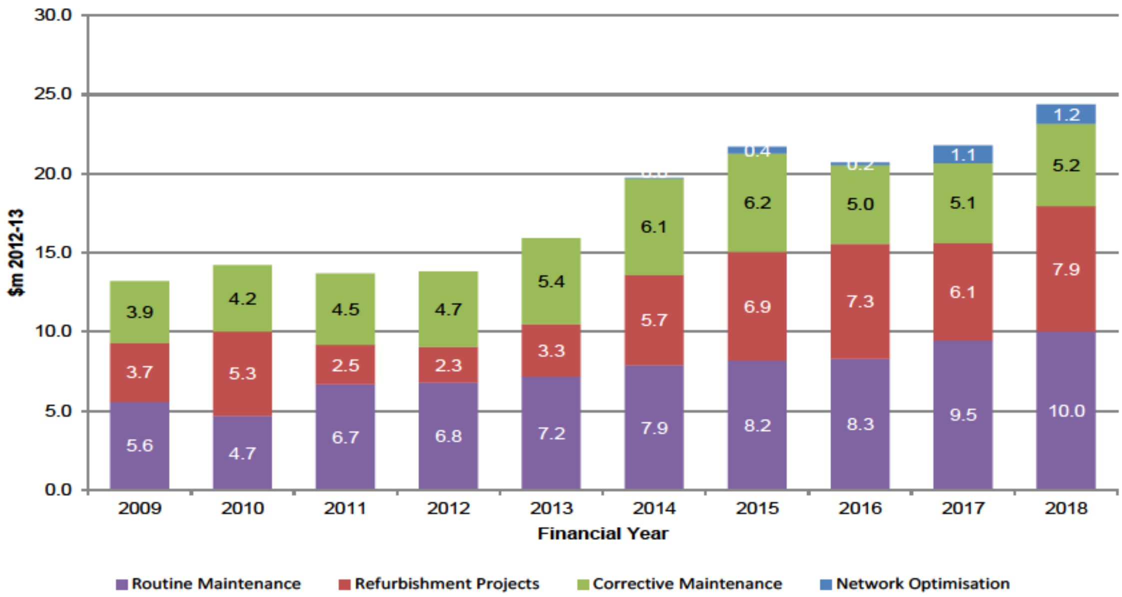


Figure 6.11: Substation maintenance expenditure profile

6.3 Transmission line management plan

Implementation of the Transmission Line Management Plan for the 2013–2018 regulatory period is based on the following considerations:

- Transmission Line maintenance will complete the 1st routine maintenance cycle during the 2013-14 to 2017-18 regulatory period;
- Condition assessments conducted during the current period indicate the need to bring forward inspection of line components on some transmission lines (the increased inspection requirement is based on the need to collect and analyse component condition data in order to fully assess the P-F interval as quickly as possible given the indicators of asset deterioration);
- Refurbishment projects are based high risk asset maintenance priority, identified by condition assessment already completed;
- Defect maintenance rates projections for 2013-14 to 2017-18 are based on current defect profiles – an increased annual defect maintenance spend to $6m per annum is indicated;
- Substation replacement projects focus on replacement of line insulation identified by line voltage drop tests completed during the current condition assessment program.

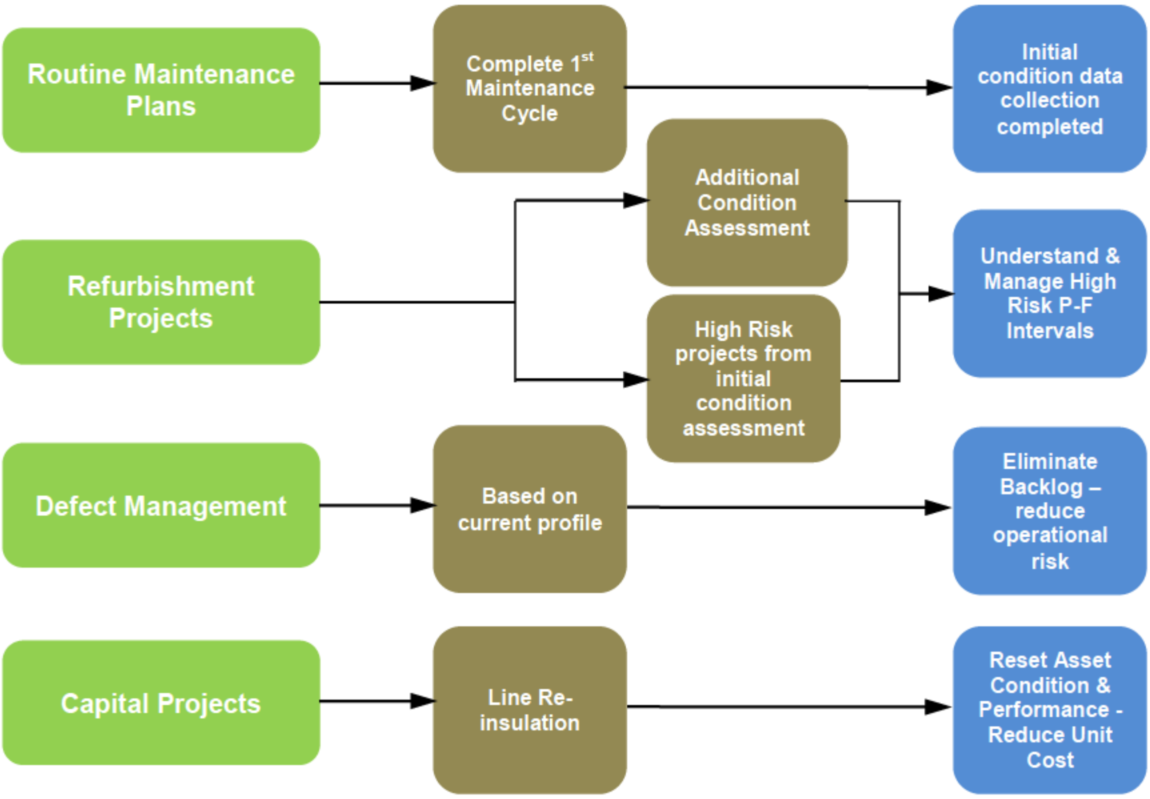


Figure 6.12: Transmission Line Management

6.3.1 Condition assessment

The aim of condition assessment is to establish where on the lifecycle curve the various components that make up a transmission line fit, to provide an estimate of both the general condition and the expected remaining life of components that make up the asset.

An estimate of where a component is on its technical life cycle requires the input of any three of the following typical parameters:

- Environmental aggressiveness
- Age of component
- Current condition
- Replacement criteria

The following graph shows the interdependency of each parameter. This approach is used as the basis for all transmission line condition assessments (note this approach takes into account the environmental conditions, these usually are the main drivers of transmission line asset deterioration).

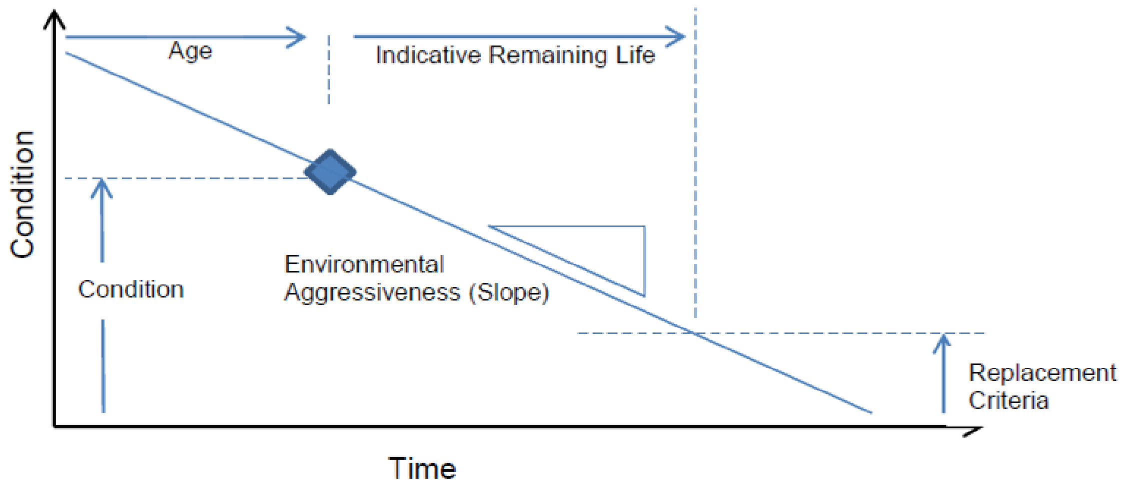


Figure 6.13: Simple (Linear Degradation) Condition Assessment Model

6.3.2 Transmission line asset profile

Condition and maintenance costs for each transmission line feeder have been assessed by:

- Undertaking a detailed condition assessment of those feeders known to have asset component deterioration based on all currently available data and field inspection reports;
- Undertaking a desktop assessment of current information for all feeders with no significant component deterioration;
- Identifying defect maintenance cost/km for each feeder using SAP defect notification work order costs (for the previous five year period).

A summary of the transmission line asset profile is shown below indicating the condition score and corrective maintenance cost for all feeders. Analysis of the assessment and proposed response are discussed in the following section.

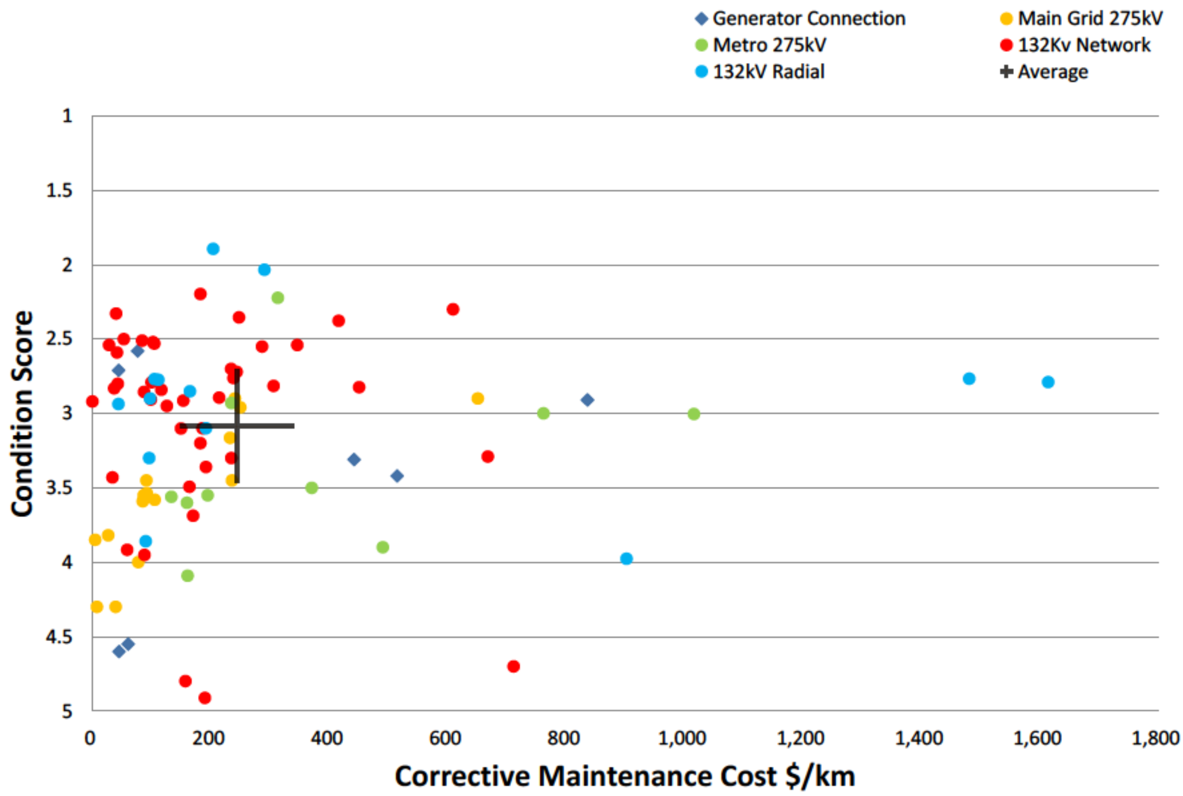


Figure 6.14 Transmission Line Asset Profile

Note:

- A condition score of 5 indicates good condition and high confidence in assessment data
- A condition score below 3 indicates component deterioration and/or low confidence in assessment data.

As systematic collection and analysis of transmission line asset data has commenced in the current regulatory period and is yet to complete a full maintenance cycle, response to the transmission line asset profile is as follows:

- Where condition data clearly indicates component deterioration approaching end of life, component replacement/refurbishment projects have been developed in order to mitigate functional failure risk;
- Where confidence in condition data is poor, specific condition assessment projects (in addition to routine maintenance inspection) have been developed in order to correctly determine remaining life and to understand the P-F interval;
- For those feeders showing good condition scores but above average defect costs further assessment of performance is required.

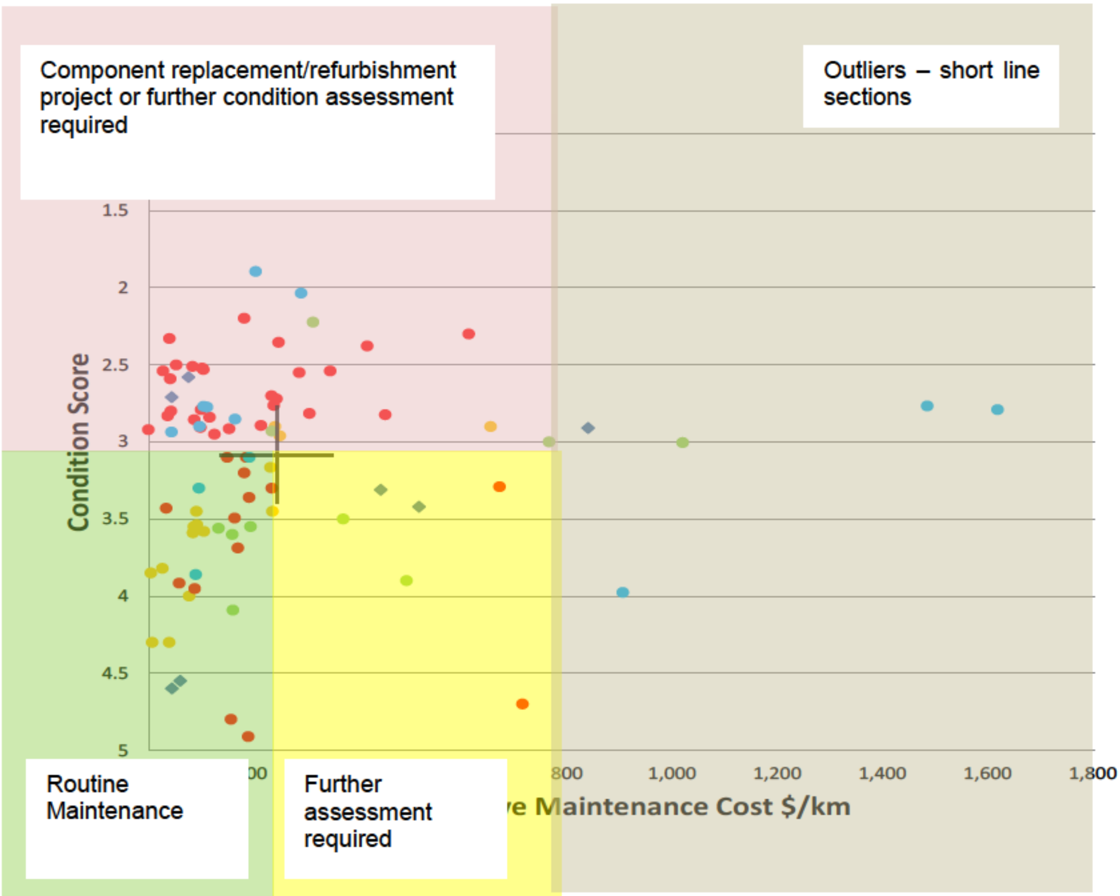


Figure 6.15: Transmission Line Asset Profile Analysis

Figure 6.14 indicates the response to asset condition incorporated in the asset management plan for each segment of the condition/cost chart:

- Low condition scores indicate the need for detailed field assessment and potential refurbishment;
- High condition scores indicate continuing routine maintenance only is required;
- Higher unit cost assets indicate need for specific investigation.

6.3.3 Transmission line routine maintenance plans

Routine maintenance includes all aspects of transmission line maintenance including easements and vegetation management. Management of transmission line assets is represented in Figure 6.16 showing the overall relationship between maintenance policy, asset performance and strategic review.

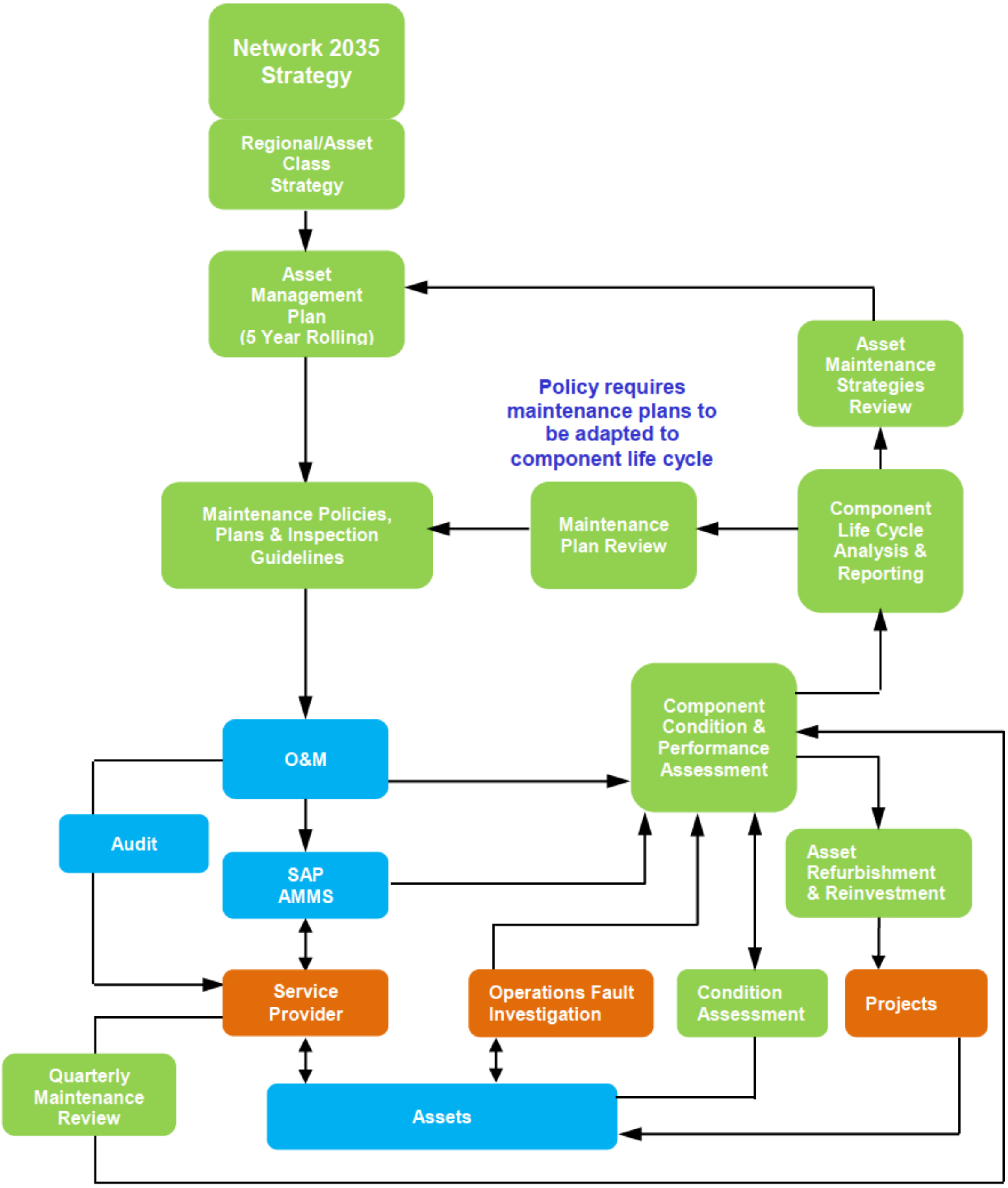


Figure 6.16 Asset Management Cycle - Transmission Lines

Current status of the maintenance plan is as follows:

- Powerlink maintenance plans have been implemented for a period of approximately two years;
- Considering the overall maintenance frequency of these plans most assets will not complete the first maintenance cycle until part way through the 2013-2018 Regulatory Period;

- Based on a review of inspection practice, fire start risk and asset condition transmission line pre-bushfire season aerial inspection tasks have been increased;
- No material change to maintenance plans is proposed; during the 2013-18 regulatory period analysis of condition assessment data will be used to further optimise the maintenance plan.

Table 6.11: Transmission Line Routine Maintenance Plan Estimated Cost

Routine Maintenance	5yr Estimate ($2012/13)
Transmission Line Routine Maintenance Plan	$22,000,000
Vegetation Management	$7,000,000
Total	**$29,000,000**

6.3.4 Transmission line corrective maintenance

As full development of SCAR coding and deployment to MGT was only completed in December 2011 a well-developed defect maintenance trend is not yet available. Preliminary cost and defect information for incoming defect rates are shown in the figure below.

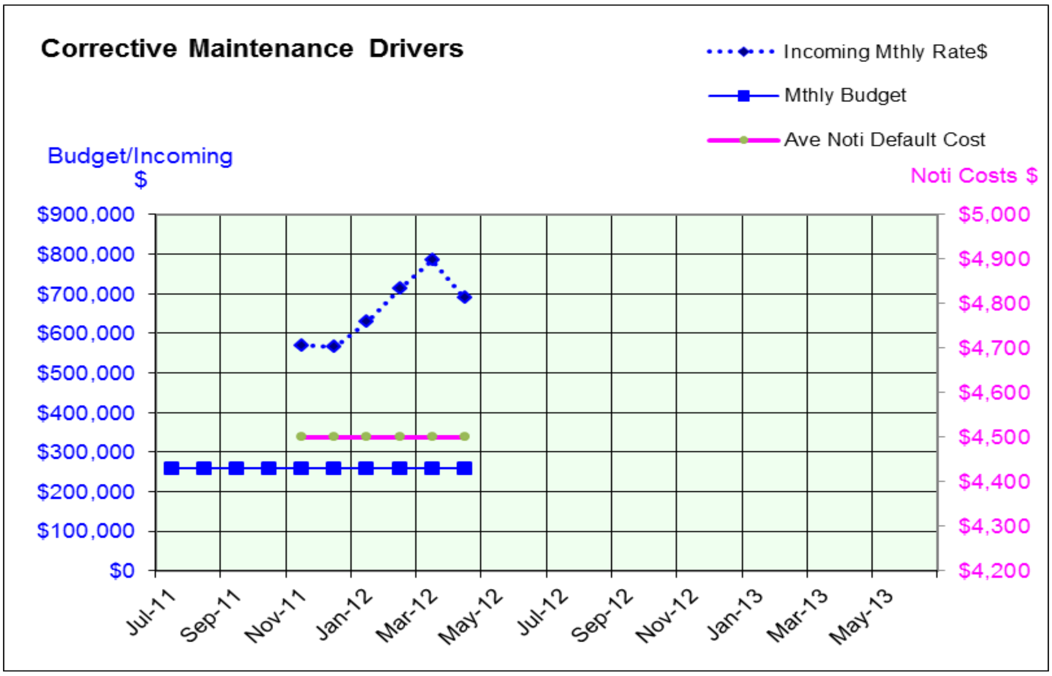


Figure 6.17 Incoming Transmission Lines Defect Rate

Figure 6.17 indicates that:

- The estimated value of incoming monthly defect notifications is greater than that of the current expenditure level;
- The current annual expenditure is adequate to deal with incoming Operational, Safety and Environment (urgent high risk defect notifications) only;

- To adequately manage the incoming defect notifications for asset risk notis (known as R defect notis) requires an additional annual expenditure of $3,000,000 ($2011-12).

To adequately manage the incoming defect notifications for Transmission Lines requires an ongoing annual budget of $6,000,000 ($2011-12).

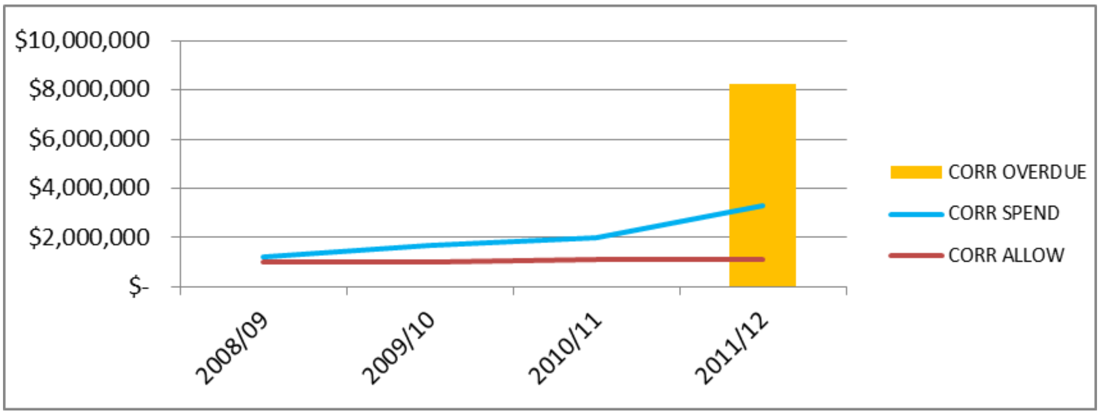


Figure 6.18: Transmission Lines Accumulative Requirement to Annual Expenditure

To address the accumulated corrective effort a total budget of $6,000,000 ($2011-12) over three years (2013-14 – 2015-16) is required.

Note that ElectraNet has throughout the current regulatory period already reprioritised its maintenance effort over and above this category allowance to address higher asset risk issues – to the extent possible with available resources.

Table 6.12: Transmission lines defect maintenance cost estimate

Defect Maintenance	Annual Estimate Yr1 ($2012/13)	5 Yr Estimate ($2012/13)
Transmission Lines Defect Maintenance (Ongoing)	$6,400,000	$33,200,000
Transmission Lines Defect Maintenance (Accumulated – Yr1, 2 and 3 only)	$2,100,000	$6,500,000
Total	$8,500,000	$39,700,000

Refer to Appendix C for a full discussion of the SCAR framework and methodology for developing expenditure forecasts.

6.3.5 Transmission line asset refurbishment

The Asset Refurbishment Plan has been generated by utilising asset condition assessment information to identify OPEX Maintenance Projects to undertake replacement/refurbishment of groups of asset components based on risk and cost justification. The Asset Refurbishment Plan has also been based on the overhead transmission line functional element groups. Refer Appendix L.

Underground HV Cable Management Plan has been specifically developed to address asset risks which are specific to underground HV cables of both oil-filled and XLPE cable types. Refer Appendix O.

Separate from managing asset condition risk, the Asset Rating & Risk Management Plan and an Easement Management Plan aim to provide asset information for ElectraNet to manage its legal and regulatory risk by being able to demonstrate compliance with its legal obligations of managing its transmission lines according to the SA Electricity Act and Regulations as well as relevant industry guidelines. Refer Appendix I and Appendix N respectively.

Due to the long cycle time of routine maintenance and therefore asset condition data collection, a Transmission Line Condition Assessment Plan has been developed to accelerate condition assessment information collection and analysis on high risk assets. This information directly informs the Transmission Line Refurbishment Plan via an efficient and timely process. The Transmission Line Condition Assessment Plan has also been based on the overhead transmission line functional element groups so to match the structure of the refurbishment plan. Refer Appendix M.

Together these Plans allow a structured risk managed and cost efficient approach to transmission line management.

A summary of the OPEX Projects to be conducted as per the various Plans are summarised below, a more detailed description of each plan is shown in the appendices:

Table 6.13: Transmission Line Refurbishment Projects – High Priority

Project	Estimate ($2012/13)
Transmission Line Refurbishment	$6,700,000
Total	**$6,700,000**

Table 6.14: Underground Cable Refurbishment Projects – High Priority

Project	Estimate ($2012/13)
Underground Cable Refurbishment	$660,000
Total	**$660,000**

Table 6.15: Asset Rating and Risk Management Projects – High Priority

Project	Estimate ($2012/13)
Asset Rating and Risk Management	$290,000
Total	**$290,000**

Table 6.16: Transmission Line Condition Assessment Projects – High Priority

Project	Estimate ($2012/13)
Transmission Line Condition Assessment	$15,200,000
Total	**$15,200,000**

Table 6.17: Easement Management Projects – High Priority

Project	Estimate ($2012/13)
Easement Management	$4,300,000
Total	**$4,300,000**

6.3.6 Transmission line removal

Specific transmission lines have been identified for decommissioning and removal and are summarised below. Refer to Appendix J for full discussion.

Table 6.18: Transmission Line Decommissioning and Removal Projects - High Priority

Project	Estimate ($2012/13)
Line Decommissioning and Removal	$2,400,000
Total	**$2,400,000**

6.3.7 Transmission line capital projects

No transmission line replacement projects are proposed for the 2013-14 to 2017-18 regulatory period. However, line re-insulation projects have been identified for a number of transmission feeders where the insulator components have reached end of technical life.

Table 6.19: Transmission Line Capital Project List

Project	Estimate ($2012/13)
F1910/1911 Para To Davenport Line Hazard Mitigation (Re-insulation)	$34,100,000
F1827 Tailem Bend to Keith No 2 Line Refurbishment (Re-insulation)	
F1804 Brinkworth to Mintaro Line Refurbishment (Re-insulation)	
F1905 Magill to Happy Valley Line Refurbishment (Re-insulation)	
F1844 Cultana to Stony Point Line Refurbishment (Re-insulation)	
F1864 Penola West to South East Line Refurbishment (Re-insulation)	
F1914 Magill/East Terrace Underground Cable Pit Construction	$21,800,000
Total	**$55,900,000**

6.3.8 Transmission line maintenance expenditure profile

A summary of transmission operating expenditure for the current and following period is shown below indicating:

- A sustained routine maintenance effort (based on the full implementation of condition based routine maintenance);
- An increased refurbishment maintenance effort (driven by accelerated condition assessment and tower/footing refurbishment requirements);
- An initially increasing corrective maintenance effort required to mitigate accumulated asset defect corrective requirements.

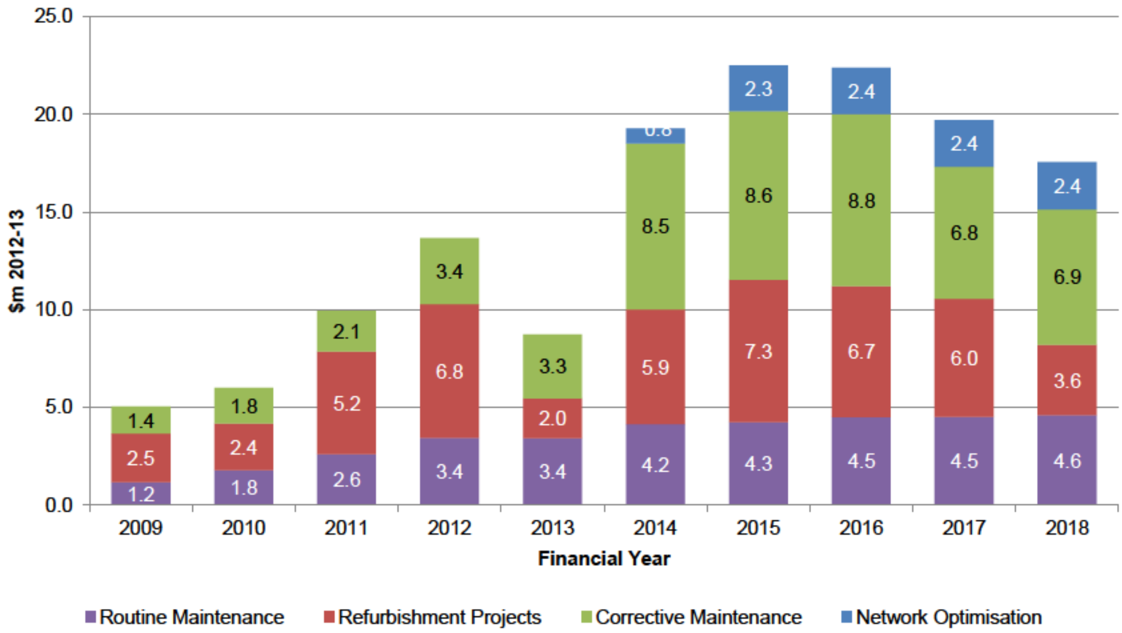


Figure 6.19: Transmission Line Maintenance Expenditure Profile

6.4 Telecommunications management plan

The Telecommunications Management Plan is based on the Telecommunications Strategic Development Plan, the overall structure of which is shown below.

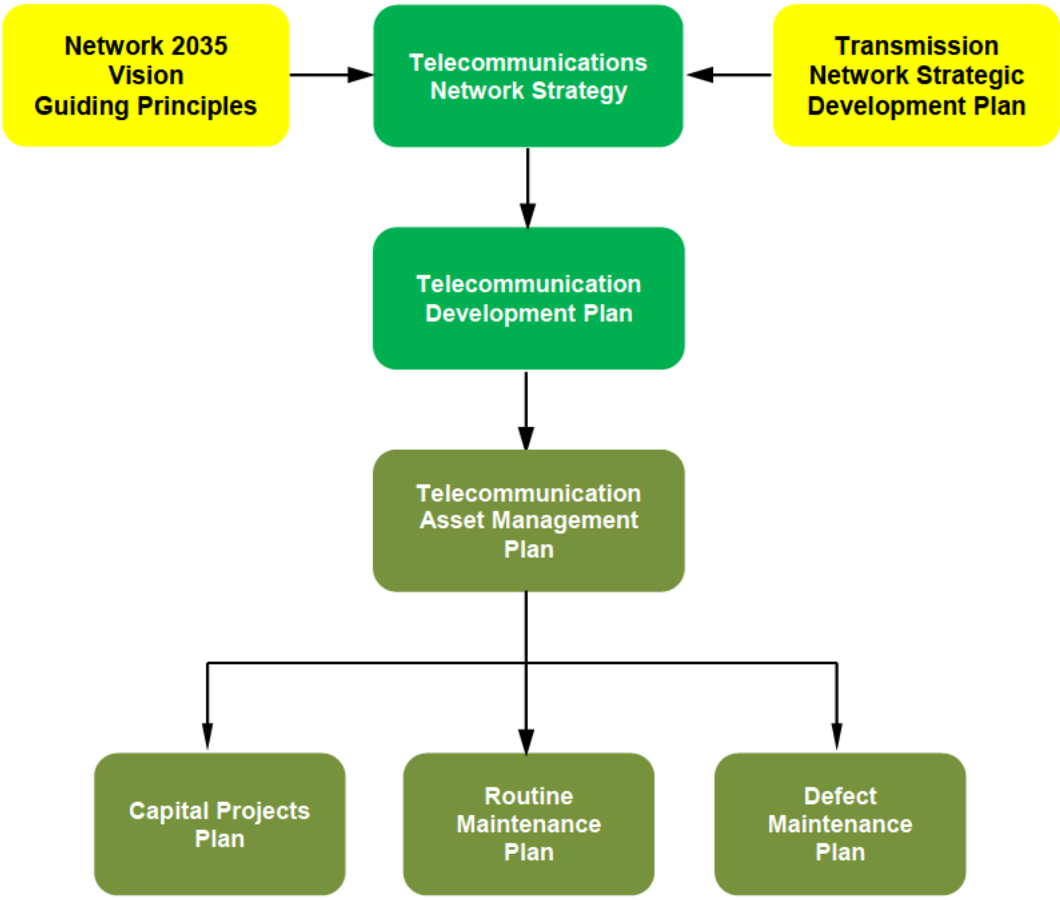


Figure 6.20 Telecommunications Management Planning Structure

Development of the telecommunications network is driven by:

- The requirement to provide specific levels of service across the transmission network (e.g. link reliability and availability for protection signalling);
- Transmission Network augmentation projects.

The Asset Management Plan considers augmentation to develop required new capacity and to maintain service level requirements of the communications network; as well as routine, refurbishment and defect maintenance requirements.

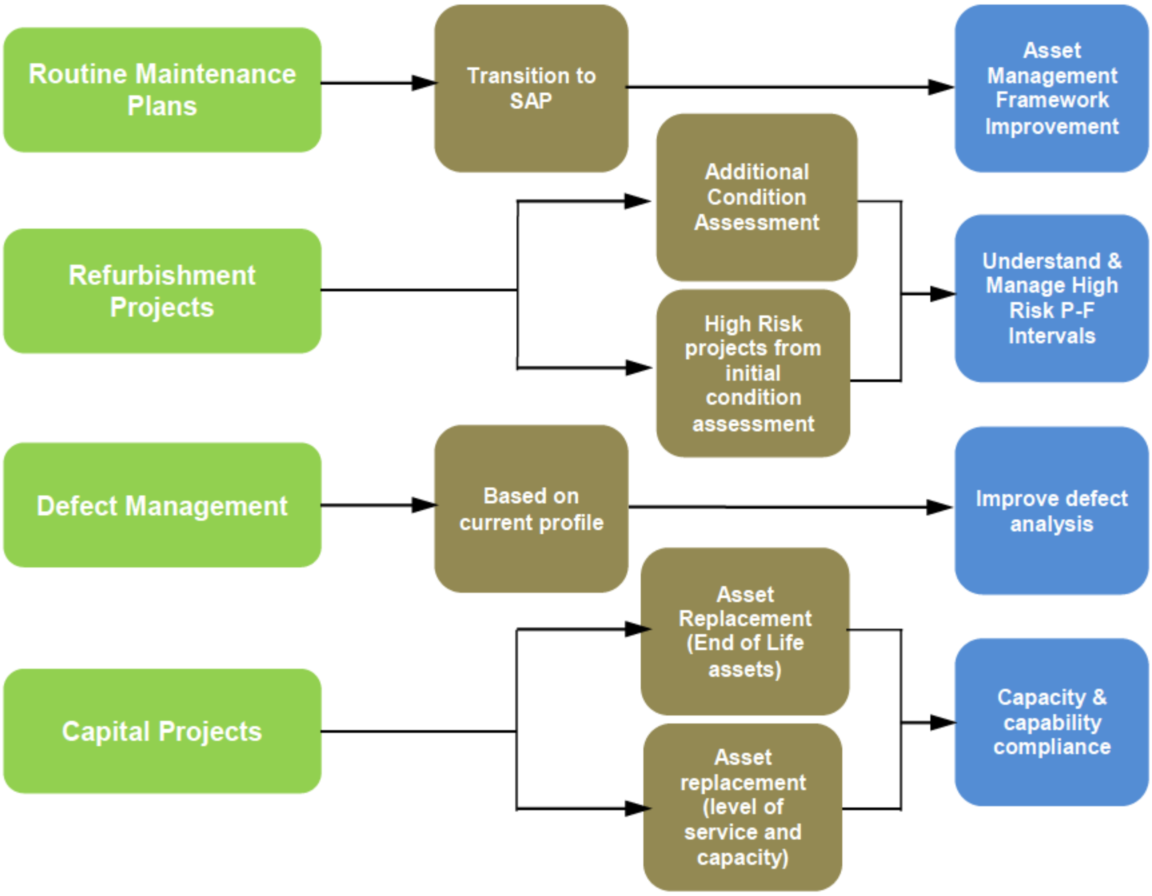


Figure 6.21: Telecommunication Asset Management

6.4.1 Communication asset profile

The overall profile of communication network assets is represented below, the main aspects of the profile are:

- Asset capability is becoming increasing important as more efficient communication protocols become available and significant increases in traffic volume and associated performance requirements impact on existing assets;
- Assets at end of life will impact on the ability of the network to provide reliable services and meet increasing performance requirements (link reliability and availability).

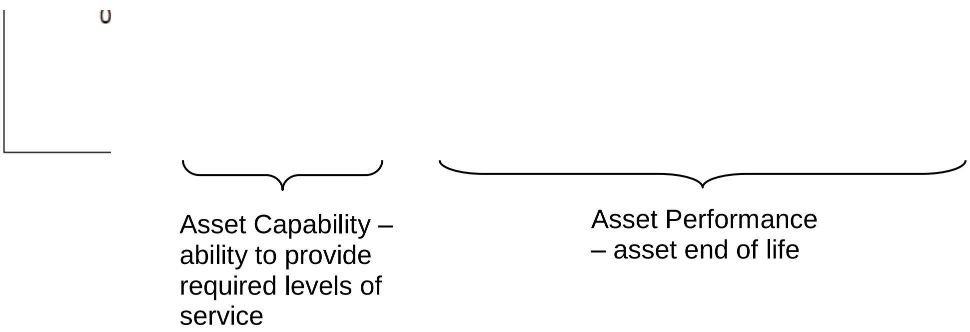


Figure 6.22 Communication Network Asset Profile

6.4.2 Telecommunications routine maintenance

Routine maintenance of telecommunication assets is based on routine maintenance cycles for main equipment types. Most of the electronic card and rack based assets are maintained on a defect basis as required.

The basic routine maintenance framework is set out below.

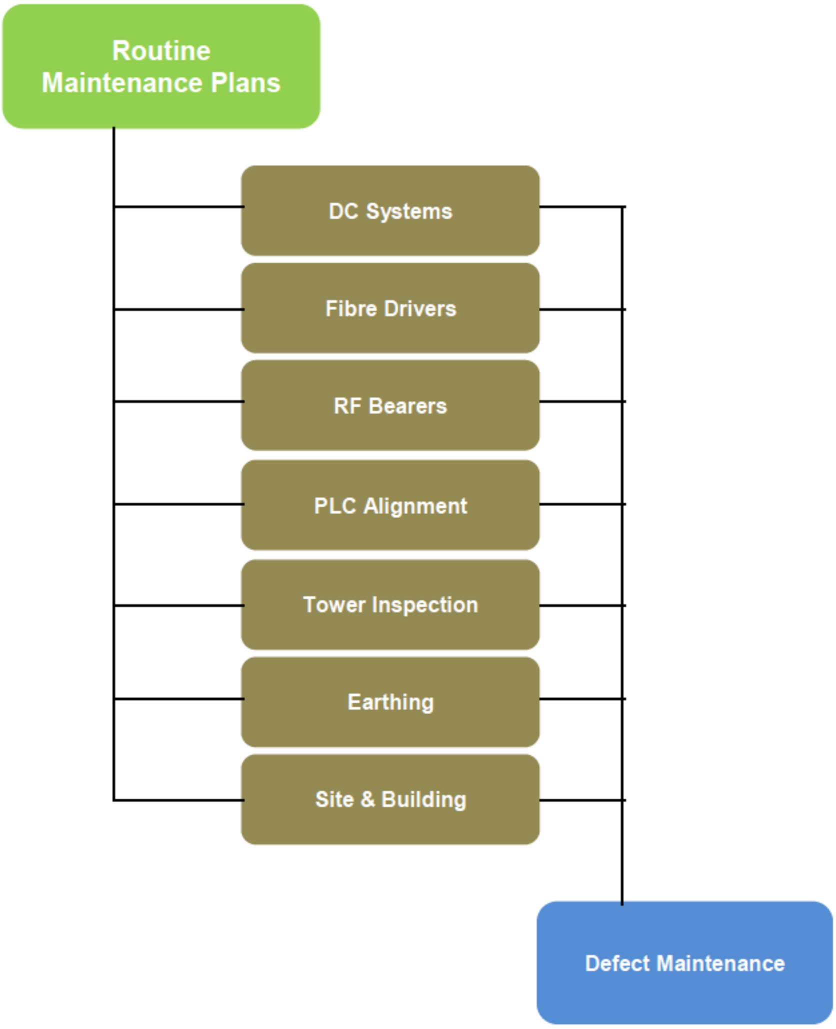


Figure 6.23 Telecommunications Routine Maintenance Framework

Table 6.20: Telecommunications Routine Maintenance Estimate

Routine Maintenance	5yr Estimate ($2012/13)
Telecommunications Routine Maintenance Plan	$8,100,000
Total	**$8,100,000**

6.4.3 Telecommunications asset refurbishment

The Telecommunications Refurbishment Plan is generated by utilising asset condition assessment information to identify OPEX Maintenance Projects to undertake replacement/refurbishment of groups of asset components (generally related to communication tower structure safety and maintenance).

The OPEX Maintenance Projects to be conducted per project type are summarised below:

Table 6.21: Telecommunications Refurbishment Projects

Refurbishment Projects	Estimate ($2012/13)
Telecommunications Refurbishment Projects	$1,100,000
Total	**$1,100,000**

6.4.4 Telecommunications Defect Management

Defect maintenance rate is estimated on a per annum basis according to the current defect profile.

Table 6.22: Telecommunications Defect Maintenance Cost Estimate

Defect Maintenance	Annual Estimate Yr 1 ($2012/13)	5 Yr Estimate ($2012/13)
Telecommunications Defect Maintenance	$270,000	$1,400,000
Total	**$270,000**	**$1,400,000**

6.4.5 Telecommunications Capital Projects

Capital projects are based on asset replacement at end of life (refer to Telecommunications Asset Management Plan) or network augmentation projects (refer to Telecommunication Development Plan).

Table 6.23: Telecommunications Capital Projects

Project	Estimate ($2012/13)
Asset Replacement (End of Life)	
Tel Asset Replacement - Metro Region	
Tel Asset Replacement - Mid North Region	
Tel Asset Replacement - South East Region	
Tel Asset Replacement - Eyre Region	
Tel Asset Replacement - Upper North Region	
Tel Asset Replacement - Eastern Hills Region	
Tel Asset Replacement - Riverland Region	$14,700,000
Asset Replacement (Capability)	
South East Substation to Heywood Telecommunications Bearer	
Yadnarie - Port Lincoln Backbone Telecommunications Links	
Riverland Telecommunications Bearer	
Barn Hill telecoms Bearer Replacement	$18,400,000
Total	**$33,100,000**

6.5 Research and development

ElectraNet routinely undertakes an internal and external SWOT analysis to identify current business risks that have changed or emerging risks. The outcomes from this process may drive Research and Development - Engineering Investigations (R&D) to determine the most appropriate risk mitigation strategy.

Current investigations and recent industry events has identified the R&D works to be conducted in the 2013-2018 period – refer to Appendix S.

Table 6.24: Research and Development Projects Cost Estimate

Research and Development Projects	Estimate ($2012/13)
Research and Development Plan	$430,000
Total	**$430,000**

6.6 Summary of Asset Management Plan forecasts

The asset management plan expenditure forecasts are shown diagrammatically below for each asset category.

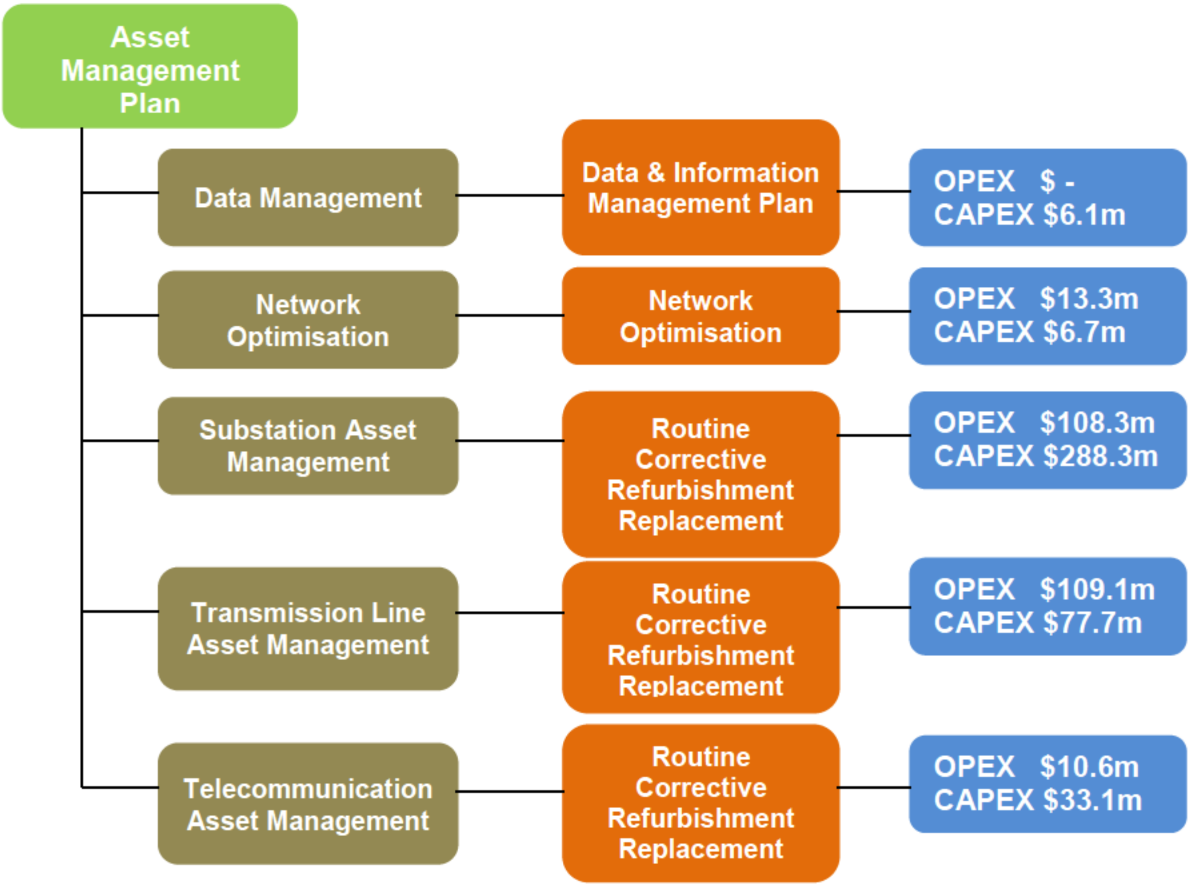


Figure 6.24: Asset Management Plan Outcomes ($2012/13)

Appendix A Maintenance Policy and Procedure Listing

The Asset Management document structure is shown below. The following tables provide a listing of asset management documents for substation, transmission line and telecommunications.

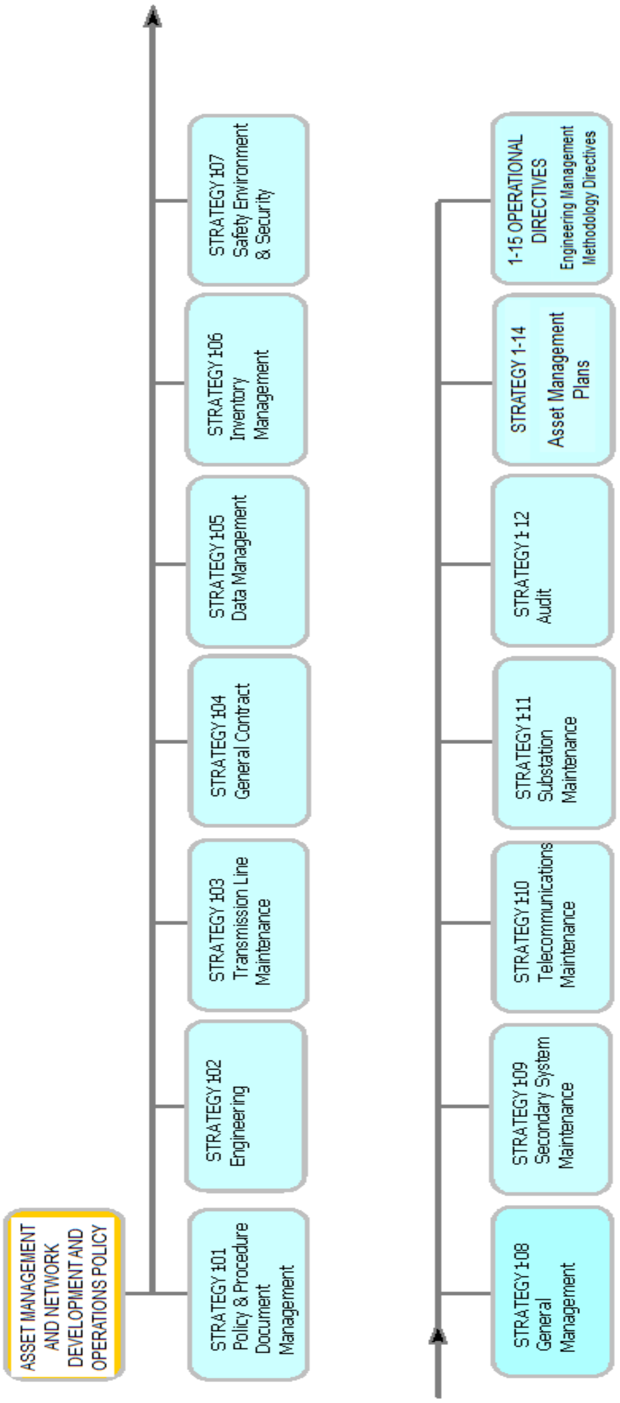


Figure A.1: Asset Management Planning Document Structure

Table A.1: Asset Management – Substation Maintenance

Type	Document	Title
Strategy	**1-11**	**Strategy Substation Maintenance**
Policy	**1-11-OP01**	**Policy Substation Maintenance - Circuit Breakers**
Procedure	1-11-P01	Procedure Substation Maintenance - Circuit Breakers SF6
Procedure	1-11-P53	Procedure Substation Maintenance - Circuit Breakers Oil
Procedure	1-11-P68	Procedure Substation Maintenance - Circuit Breakers - 11kV Reyrolle
Policy	**1-11-OP02**	**Policy Substation Maintenance - Power Transformers & Reactors**
Procedure	1-11-P02	Procedure Substation Maintenance Power Transformers & Reactors
Procedure	1-11-P03	Procedure Substation Maintenance Power Transformers & Reactors - Testing
Procedure	1-11-P04	Procedure Substation Maintenance Power Transformers & Reactors - On-Load Tap Changers
Procedure	1-11-P05	Procedure Substation Maintenance Power Transformers & Reactors - Air Cored Reactors
Procedure	1-11-P70	Procedure Substation Maintenance Power Transformers & Reactors - Doble Tests
Policy	**1-11-OP03**	**Policy Substation Maintenance - Instrument Transformers**
Procedure	1-11-P06	Procedure Substation Maintenance - Instrument Transformers
Policy	**1-11-OP04**	**Policy Substation Maintenance - Isolators & Earth Switches**
Procedure	1-11-P07	Procedure Substation Maintenance - Isolators & Earth Switches
Policy	**1-11-OP05**	**Policy Substation Maintenance - Structures**
Procedure	1-11-P08	Procedure Substation Maintenance - Structures Climb Inspection
Procedure	1-11-P64	Procedure Substation Maintenance - Structures Ground-line Inspection
Policy	**1-11-OP06**	**Policy Substation Maintenance - Insulators**
Procedure	1-11-P09	Procedure Substation Maintenance - Post Insulators
Procedure	1-11-P10	Procedure Substation Maintenance - Insulator Washing.
Procedure	1-11-P11	Procedure Substation Maintenance - Insulator Swabbing
Policy	**1-11-OP07**	**Policy Substation Maintenance - Overvoltage Equipment**
Procedure	1-11-P12	Procedure Substation Maintenance - Overvoltage Equipment
Policy	**1-11-OP08**	**Policy Substation Maintenance - Ac Auxiliaries**
Procedure	1-11-P13	Procedure Substation Maintenance - Diesel Generator
Procedure	1-11-P14	Procedure Substation Maintenance -Ac Auxiliaries - LV Switchboards
Procedure	1-11-P47	Procedure Substation Maintenance -Ac Auxiliaries - Station Supply Transformers
Policy	**1-11-OP09**	**Policy Substation Maintenance - Dc Auxiliaries.**
Procedure	1-11-P15	Procedure Substation Maintenance Dc Auxiliaries - Battery Banks
Procedure	1-11-P58	Procedure Substation Maintenance Dc Auxiliaries - Battery Chargers
Policy	**1-11-OP10**	**Policy Substation Maintenance - HV Cables**
Procedure	1-11-P16	Procedure Substation Maintenance HV Cables

Type	Document	Title
Policy	**1-11-OP11**	**Policy Substation Maintenance - Capacitors**
Procedure	1-11-P17	Procedure Substation Maintenance - Capacitor Bank
Policy	**1-11-OP12**	**Policy Substation Maintenance - Static Var Compensators**
Procedure	1-11-P18	Procedure Substation Maintenance - Static Var Compensators
Procedure	1-11-P49	Procedure Substation Maintenance - SVC Card Replacement
Policy	**1-11-OP13**	**Policy Substation Maintenance - Earthing**
Procedure	1-11-P19	Procedure Substation Maintenance - Earth Grid Testing
Procedure	1-11-P20	Procedure Substation Maintenance - Portable Earth Leads
Procedure	1-11-P60	Procedure Substation Maintenance - Earthing - Fault Level Signs
Policy	**1-11-OP14**	**Policy Substation Maintenance - Buildings**
Procedure	1-11-P73	Procedure Substation Maintenance -Buildings
Procedure	1-11-P21	Procedure Substation Maintenance - Air Conditioners
Policy	**1-11-OP15**	**Policy Substation Maintenance - Property**
Procedure	1-11-P22	Procedure Substation Maintenance - Vegetation Management
Procedure	1-11-P23	Procedure Substation Maintenance - Cleaning
Procedure	1-11-P24	Procedure Substation Maintenance - Water & Sewer
Procedure	1-11-P25	Procedure Substation Maintenance - Environmental Management Plan
Procedure	1-11-P26	Procedure Substation Maintenance - Ladders & Platforms
Procedure	1-11-P27	Procedure Substation Maintenance - Cranes & Hoists
Procedure	1-11-P28	Procedure Substation Maintenance - Switching Sticks
Procedure	1-11-P61	Procedure Substation Maintenance - Property - Work Area Equipment
Procedure	1-11-P65	Procedure Substation Maintenance - Property - Electric Gates
Policy	**1-11-OP16**	**Policy Substation Maintenance - Power Line Carrier**
Procedure	1-11-P29	Procedure Substation Maintenance - Power Line Carrier
Policy	**1-11-OP17**	**Policy Substation Maintenance - Site**
Procedure	1-11-P30	Procedure Substation Maintenance - Routine Inspection
Procedure	1-11-P31	Procedure Substation Maintenance Inspection - Thermographic
Procedure	1-11-P32	Procedure Substation Maintenance Site - Hazardous Material Inspection
Procedure	1-11-P52	Procedure Substation Maintenance Site - Pre Dawn Inspection
Policy	**1-11-OP18**	**Policy Substation Maintenance - Pressure Vessel**
Procedure	1-11-P33	Procedure Substation Maintenance - Pressure Vessels Inspection
Procedure	1-11-P34	Procedure Substation Maintenance - Pressure Vessels Sf6
Procedure	1-11-P35	Procedure Substation Maintenance - Pressure Vessels Pneumatic
Procedure	1-11-P36	Procedure Substation Maintenance - Pressure Vessels - Water
Policy	**1-11-OP19**	**Policy Substation Maintenance - Oil Containment**
Procedure	1-11-P37	Procedure Substation Maintenance - Oil Containment
Policy	**1-11-OP20**	**Policy Substation Maintenance - Fire and Security**

Type	Document	Title
Procedure	1-11-P38	Procedure Substation Maintenance - Fire & Security - Fire Protection Systems
Procedure	1-11-P39	Procedure Substation Maintenance - Fire & Security - Building Security & Fire Detection
Procedure	1-11-P48	Procedure Substation Maintenance - Fire & Security - Fire Extinguishers
Procedure	1-11-P59	Procedure Substation Maintenance - Fire & Security - Perimeter and Security Cameras
Policy	**1-11-OP21**	**Policy Substation Maintenance - Air Systems**
Procedure	1-11-P40	Procedure Substation Maintenance - Air Systems
Policy	**1-11-OP22**	**Policy Substation Maintenance - Oil Management**
Procedure	1-11-P41	Procedure Substation Maintenance - Oil in Service
Procedure	1-11-P42	Procedure Substation Maintenance - New Oil Management
Procedure	1-11-P43	Procedure Substation Maintenance - Oil Testing
Procedure	1-11-P50	Procedure Substation Maintenance - Oil Disposal
Policy	**1-11-OP23**	**Policy Substation Maintenance - SF6 Gas Management**
Procedure	1-11-P44	Procedure Substation Maintenance - SF6 Gas in Service
Procedure	1-11-P45	Procedure Substation Maintenance - New SF6 Gas Management
Procedure	1-11-P46	Procedure Substation Maintenance - SF6 Gas Testing
Policy	**1-11-OP24**	**Policy Substation Maintenance Busbars**
Procedure	1-11-P56	Procedure Substation Maintenance Busbars
Policy	**1-11-OP25**	**Policy Substation Maintenance Hybrid Switchgear**
Procedure	1-11-P57	Procedure Substation Maintenance Hybrid Switchgear - PASS
Procedure	1-11-P54	Procedure Substation Maintenance - Circuit Breakers Vacuum
Procedure	1-11-P68	Procedure Substation Maintenance - Indoor Switchgear -Snuggery Vacuum CB
Procedure	1-11-P69	Procedure Substation Maintenance - Indoor Switchgear - Roseworthy
Procedure	1-11-P66	Procedure Substation Maintenance - Outdoor Switchgear - GIS

Table A.2: Asset Management - Secondary Systems

Type	Parent Document	Document	Title
Strategy	**1-09**	**1-09**	**Strategy Secondary Systems Maintenance**
Policy	**1-09**	**1-09-OP01**	**Policy Secondary Systems Maintenance - Protection**
Procedure	1-09-OP01	1-09-P01	Procedure Secondary Systems Maintenance - Digital Relays
Procedure	1-09-OP01	1-09-P02	Procedure Secondary Systems Maintenance - Electronic Relays
Procedure	1-09-OP01	1-09-P03	Procedure Secondary Systems Maintenance - Electromechanical Relays
Policy	**1-09**	**1-09-OP02**	**Policy Secondary Systems Maintenance - Metering**

Type	Parent Document	Document	Title
Procedure	1-09-OP02	1-09-P04	Procedure Secondary Systems Maintenance - National Grid Metering
Policy	1-09	1-09-OP03	Policy Secondary Systems Maintenance - Power System Monitoring
Procedure	1-09-OP03	1-09-P05	Procedure Secondary Systems Maintenance - Power System Monitoring Power Quality
Procedure	1-09-OP03	1-09-P06	Procedure Secondary Systems Maintenance -Power Systems Monitoring Power System Performance
Procedure	1-09-OP03	1-09-P07	Procedure Secondary Systems Maintenance - Power System Monitoring - Travelling Wave Fault Locators
Policy	**1-09**	**1-09-OP04**	**Policy Secondary Systems Maintenance - Asset Condition Monitoring**
Procedure	1-09-OP04	1-09-P09	Procedure Secondary Systems Maintenance - Asset Condition Monitoring Power Transformers
Procedure	1-09-OP04	1-09-P10	Procedure Secondary Systems Maintenance - Asset Condition Monitoring CVT Secondary Voltage
Policy	**1-09**	**1-09-OP05**	**Policy Secondary Systems Maintenance - Site**
Procedure	1-09-OP05	1-09-P13	Procedure Secondary Systems Maintenance - Site Routine

Table A.3: Asset Management - Transmission Line Maintenance

Type	Parent Document	Document	Title
Strategy		**1-03**	**Strategy Transmission Line Maintenance**
Policy	**1-03**	**1-03-OP01**	**Policy Transmission Line Maintenance - Conductor**
Procedure	1-03-OP01	1-03-P01	Procedure Transmission Line Maintenance Conductor Joint Resistance
Procedure	1-03-OP01	1-03-P02	Procedure Transmission Line Maintenance Conductor Thermography
Policy	**1-Mar**	**1-03-OP02**	**Policy Transmission Line Maintenance - Insulator**
Procedure	1-03-OP02	1-03-P03	Procedure Transmission Line Maintenance - Insulator Insitu Inspection
Procedure	1-03-OP02	1-03-P04	Procedure Transmission Line Maintenance - Insulator Washing
Procedure	1-03-OP02	1-03-P05	Procedure Transmission Line Maintenance - Insulator Sampling & Testing
Policy	**1-03**	**1-03-OP03**	**Policy Transmission Line Maintenance - Towers**
Procedure	1-03-OP03	1-03-P06	Procedure Transmission Line Maintenance Tower Inspection
Procedure	1-03-OP03	1-03-P25	Procedure Transmission Line Maintenance Tower Footing Inspection
Procedure	1-03-OP03	1-03-P30	Procedure Transmission Line Maintenance Tower Cathodic Protection

Type	Parent Document	Document	Title
Policy	**1-03**	**1-03-OP04**	**Policy Transmission Line Maintenance - Poles**
Procedure	1-03-OP04	1-03-P07	Procedure Transmission Line Maintenance Pole Stobie Ground-line Inspection
Procedure	1-03-OP04	1-03-P08	Procedure Transmission Line Maintenance - Pole Concrete Inspection
Procedure	1-03-OP04	1-03-P57	Procedure Transmission Line Maintenance -Tubular Steel Pole Inspection
Procedure	1-03-OP04	1-03-P19	Procedure Transmission Line Maintenance Pole Stobie Inspection
Policy	**1-03**	**1-03-OP05**	**Policy Transmission Line Maintenance - Earth**
Procedure	1-03-OP05	1-03-P09	Procedure Transmission Line Maintenance Earth Earth-wire Inspection
Procedure	1-03-OP05	1-03-P10	Procedure Transmission Line Maintenance - Earth Footing Impedance
Policy	**1-03**	**1-03-OP06**	**Policy Transmission Line Maintenance - Circuit**
Procedure	1-03-OP06	1-03-P11	Procedure Transmission Line Maintenance - Circuit Pre-Bushfire Inspection Ground
Procedure	1-03-OP06	1-03-P12	Procedure Transmission Line Maintenance Circuit Bushfire Patrol Aerial
Procedure	1-03-OP06	1-03-P13	Procedure Transmission Line Maintenance Circuit Pre-Bushfire Inspection Aerial
Procedure	1-03-OP06	1-03-P14	Procedure Transmission Line Maintenance - Circuit Inspection Ground
Procedure	1-03-OP06	1-03-P15	Procedure Transmission Line Maintenance - Circuit Patrol Pre-Dawn
Procedure	1-03-OP06	1-03-P16	Procedure Transmission Line Maintenance - Circuit High Vehicle Management
Procedure	1-03-OP06	1-03-P37	Procedure Transmission Line Maintenance - Aerial Post Fault Patrol
Procedure	1-03-OP06	1-03-P38	Procedure Transmission Line Maintenance - Circuit Pre-Bushfire Inspection Ground
Procedure	1-03-OP06	1-03-P51	Procedure Transmission Line Maintenance - De-Energised Lines
Policy	**1-03**	**1-03-OP07**	**Policy Transmission Line Maintenance Easement**
Procedure	1-03-OP07	1-03-P24	Procedure Transmission Line Maintenance Easement Entry
Procedure	1-03-OP07	1-03-P21	Procedure Transmission Line Maintenance - Easement Electrical Safety
Procedure	1-03-OP07	1-03-P22	Procedure Transmission Line Maintenance - Easements Weeds & Animals
Procedure	1-03-OP07	1-03-P23	Procedure Transmission Line Maintenance - Easement Right Of Way
Policy	**1-03**	**1-03-OP08**	**Policy Transmission Line Maintenance - UG Cable (XLPE)**

Type	Parent Document	Document	Title
Procedure	1-03-OP08	1-03-P45	Procedure Transmission Line Maintenance - UG Cable (XLPE) 275kV Routine Inspection
Procedure	1-03-OP08	1-03-P46	Procedure Transmission Line Maintenance - UG Cable (XLPE) 275kV Cable
Procedure	1-03-OP08	1-03-P47	Procedure Transmission Line Maintenance - UG Cable (XLPE) 275kV Support & Monitor Systems
Procedure	1-03-OP08	1-03-P48	Procedure Transmission Line Maintenance - UG Cable (XLPE) 275kV Spares
Procedure	1-03-OP08	1-03-P49	Procedure Transmission Line Maintenance - UG Cable (XLPE) 66&132kV Cable
Policy	**1-03**	**1-03-OP09**	**Policy Transmission Line Maintenance - Emergency Restoration**
Procedure	1-03-OP09	1-03-P50	Procedure Transmission Line Maintenance ERS Deployment
Procedure	1-03-OP09	1-03-P52	Procedure Transmission Line Maintenance ERS Shared Arrangements
Procedure	1-03-OP09	1-03-P18	Procedure Transmission Line Maintenance Emergency Restoration Hydraulic Engine & Trailer
Procedure	1-03-OP09	1-03-P17	Procedure Transmission Line Maintenance Emergency Restoration Tools & Equipment
Procedure	1-03-OP09	1-03-P53	Procedure Transmission Line Maintenance ERS Deployment Trials
Procedure	1-03-OP09	1-03-P54	Procedure Transmission Line Maintenance ERS Stobie Poles
Policy	**1-03**	**1-03-OP10**	**Policy Transmission Line Maintenance - Guidelines (General)**
Policy	**1-03**	**1-03-OP11**	**Policy Transmission Line Maintenance Aerial Services**
Procedure	1-03-OP11	1-03-P26	Procedure Transmission Line Maintenance Aerial Services Administration
Procedure	1-03-OP11	1-03-P27	Procedure Transmission Line Maintenance Aerial Services Job Planning
Procedure	1-03-OP11	1-03-P28	Procedure Transmission Line Maintenance Aerial Services Route Management
Procedure	1-03-OP11	1-03-P29	Procedure Transmission Line Maintenance Aerial Services Pre-Flight Briefing
Procedure	1-03-OP11	1-03-P36	Procedure Transmission Line Maintenance Aerial Services Post Flight Debriefing
Procedure	1-03-OP11	1-03-P39	Procedure Transmission Line Maintenance Aerial Services Review & Audit
Policy	**1-03**	**1-03-OP12**	**Policy Transmission Line Maintenance Vegetation**
Procedure	1-03-OP07	1-03-P20	Procedure Transmission Line Maintenance Easement Vegetation Management
Policy	**1-03**	**1-03-OP13**	**Policy Transmission Line Maintenance - UG Cable (Oil)**
Procedure	1-03-OP13	1-03-P31	Procedure Transmission Line Maintenance - UG Cable (Oil) - Alarm & Pressure Test

Type	Parent Document	Document	Title
Procedure	1-03-OP13	1-03-P32	Procedure Transmission Line Maintenance - UG Cable (Oil) - Sheath Resistance Test
Procedure	1-03-OP13	1-03-P33	Procedure Transmission Line Maintenance - UG Cable (Oil) Pressure Gauge Calibration
Procedure	1-03-OP13	1-03-P40	Procedure Transmission Line Maintenance - UG Cable (Oil) 275kV Routine Inspection
Procedure	1-03-OP13	1-03-P41	Procedure Transmission Line Maintenance - UG Cable (Oil) 275kV Cable Oil Sampling & Testing
Procedure	1-03-OP13	1-03-P42	Procedure Transmission Line Maintenance - UG Cable (Oil) 275kV Support & Monitor Systems
Procedure	1-03-OP13	1-03-P43	Procedure Transmission Line Maintenance - UG Cable (Oil) 275kV Spares
Procedure	1-03-OP13	1-03-P55	Procedure Transmission Line Maintenance - UG Cable Earth Impedance

Table A.4: Asset Management - Telecommunications Maintenance

Type	Parent Document	Document	Title
Strategy	**1-10**	**1-10**	**Strategy Telecommunications Maintenance**
Policy	**1-10**	**1-10-OP01**	**Policy Telecoms Maintenance - Structures**
Procedure	1-10-OP01	1-10-P01	Procedure Telecoms Maintenance - Structure Inspection.
Procedure	1-10-OP01	1-10-P14	Procedure Telecoms Maintenance - Tower Safety Inspection.
Policy	**1-10**	**1-10-OP03**	**Policy Telecoms Maintenance - Property**
Procedure	1-10-OP03	1-10-P03	Procedure Telecoms Maintenance Property - Cleaning.
Policy	**1-10**	**1-10-OP04**	**Policy Telecoms Maintenance - AC Auxilaries**
Policy	**1-10**	**1-10-OP07**	**Policy Telecoms Maintenance - Site**
Policy	**1-10**	**1-10-OP08**	**Policy Telecoms Maintenance - Fire & Security**
Procedure	1-10-OP07	1-10-P12	Procedure Telecoms Maintenance Site - Fire & Security - Building Security & Fire Protection
Procedure	1-10-OP08	1-10-P13	Procedure Telecoms Maintenance Site - Fire & Security - Fire Extinguishers

Appendix B Transmission Asset Life Cycle (TALC)

PURPOSE

The Transmission Asset Life Cycle describes the criteria for assessing asset life cycle for transmission network assets and provides a framework for assigning an asset life cycle score to specific asset types.

SCOPE

All major components for substation and transmission line assets.

DEFINITIONS

Asset Failure - Defined as any maintenance required outside the specified routine maintenance programme – unscheduled maintenance.

B1 Introduction

> *Good asset management needs to manage the risks associated with incomplete and inaccurate data and disparate systems whilst still facilitating investment decisions that are as effective as possible.*[5]

Traditionally Transmission Network Service Providers (TNSP's) have not developed a well-defined understanding of transmission asset end of life behaviour, this is because:

- The vast majority of world-wide transmission assets are now only reaching the end of their technical and economic lives, therefore relevant statistical data and experience is still to be gained
- Due to the nature of transmission networks and the high level of reliability required, TNSP's have been conservative in their asset life cycle approach, which is to avoid operating equipment in the end of life period by replacing it rather than adopting a more sophisticated statistical analysis and understanding of equipment reliability.
- Transmission equipment by its nature operates infrequently, this inherently limits the ability of TNSP's to collect statistically valid reliability and performance data.
- TNSP's have recently focussed on managing rapid growth of load which has led to augmentation works replacing equipment populations before they reached end of life.

As a result of there are no universally understood or agreed measures of transmission equipment reliability on which to base equipment replacement decisions.

Transmission Asset Life Cycle (TALC) has been developed to provide a framework for systematically identifying where an asset is in its life cycle and more importantly when it is likely to reach end of life in order to make the most effective investment decisions can be made.

The main elements used to describe the transmission asset life cycle are shown in Figure B.1 below.

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[5] Asset Management of Transmission Systems and Associated CIGRE Activities (Working Group C1.1 December 2006) page 12

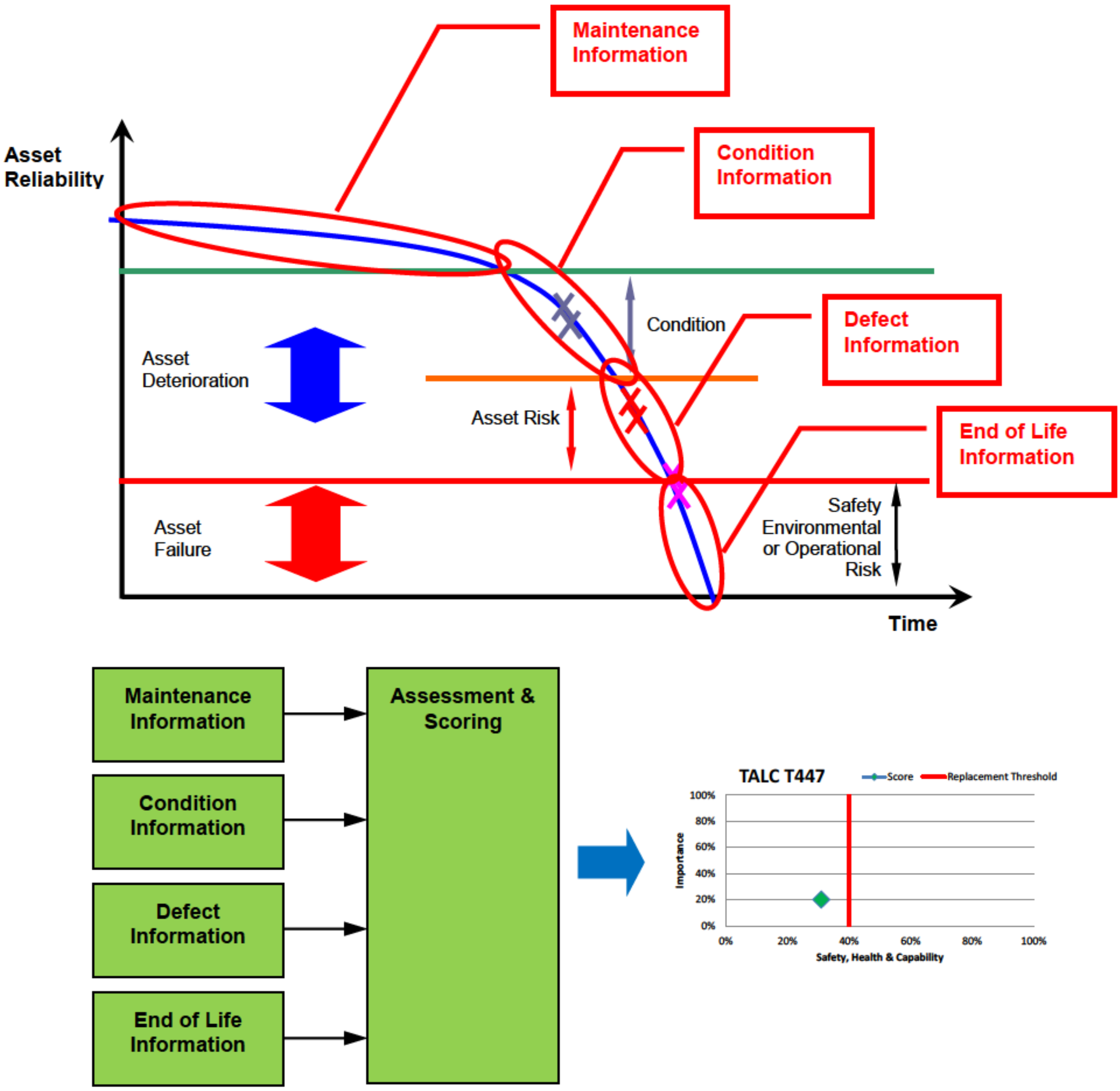


Figure B.1: Transmission Asset Lifecycle

B2 Asset end of life and risk

Entering the asset "end of life" period is not usually defined by a single event but rather is the culmination of a number of unrelated and independent events. These events are time driven. While the culmination of these end of life events may not in itself result in the catastrophic demise of the asset, there is a significant risk that, in conjunction with a broad enough group of assets in a similar time period, that these events will drive the long run operation and maintenance costs into an unsustainable upward trend. A typical asset life profile is developed in Figure B.2.

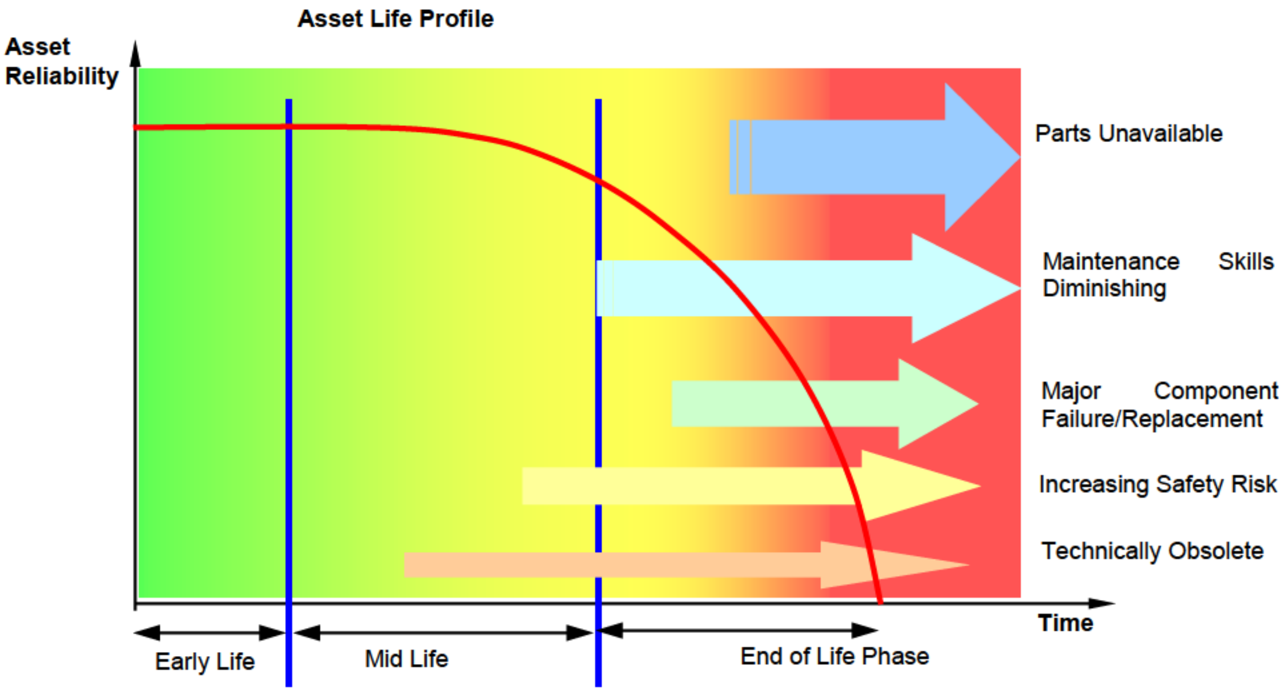


Figure B.2: Asset Life Profile

Although it is technically possible to keep assets working almost indefinitely, they will become less reliable over time as equipment is no longer supported and technological obsolescence sets in. The asset risk model is based on estimating the effect of the asset reliability on long run costs (that is, the risk of decreasing asset reliability causing increased corrective maintenance and the consequence of increasing long run cost that may become unsustainable).

B3 Asset life cycle indicators

During the life of an asset a number of events occur that indicate the maturity of the asset life cycle, these are described in the tables below.

Table B.1 Asset Life Cycle Indicators - Substation Plant

Life Cycle	Attribute	Indicator
Early Life Phase	Safety	Meets current safety standards/design
	Spare Parts	Short Lead Time
	Training	Fully Qualified Trainers
	Technical Support	Provided by Manufacturer
	Corrective Maintenance	Negligible
	Condition Assessment	No deterioration
	Standards	See Table B.9 Asset Standards Criteria
	Capability	Fully meets capability Table B.7 Substation Asset – Strategic Capability

Life Cycle	Attribute	Indicator
Mid Life Phase	Safety	Does not meet current safety standards/design, some operational controls are required
	Spare Parts	Longer Lead Times
	Training	Specialist trainers limited availability
	Technical Support	Limited Technical Support
	Corrective Maintenance	Condition based – driven by specific operating conditions
	Condition Assessment	Some deterioration but no significant remedial action required
	Standards	See Table B.9 Asset Standards Criteria
	Capability	Generally meets capability Table B.7 Substation Asset – Strategic Capability
End of Life Phase	Safety	Does not meet safety standards, significant operational controls are required
	Spare Parts	Only available from other spare or redundant units
	Training	Maintenance skills limited to small pool of skilled personnel (at best)
	Technical Support	None-manufacturer may now not exist
	Corrective Maintenance	Increasing corrective maintenance effort close to or at knee point of bathtub curve
	Condition Assessment	Measureable/observable deterioration requiring significant remedial action
	Standards	See Table B.9 Asset Standards Criteria
	Capability	Does not meet capability – refer Table B.7 Substation Asset – Strategic Capability

Table B.2 Asset Life Cycle Indicators - Transmission Lines

Attribute	Item	Indicator
Conductors	Conductor	Assessment is provided in two parts: The condition of line components at the time of the assessment (based on lines coding guide) How long the plant can be expected to operate before failure (based on inspection, testing and assessment in accordance with international standards and practice)
	Mid-span Joints	
	Hardware	
Earth wire	Conductor	
	Mid-span Joints	
	Earth wire Hardware	
Structure	Structure	
	Earthing	
	Foundations	
	Signage	

Attribute	Item	Indicator
Insulation	Suspension Insulators	
	Suspension Hardware	
	Tension Insulators	
	Tension Hardware	

B4 Asset end of life indicators

When an asset is purchased it comes with a number of features, these are:

- The technical performance (rating, operating characteristics, etc.)
- The maintenance performance (a defined reliability associated with a fixed routine maintenance programme, therefore the maintenance effort for this asset is defined)

There are a number of events that combine to indicate the end of life period, they are characterised by:

- Incremental reductions in mean time between failure (MTBF) - where a failure is defined as any event that requires any unscheduled maintenance to be performed. That is, the asset has now begun to require maintenance effort in addition to that originally specified (i.e. maintenance is now becoming reactive).
- Incremental increases in mean time to repair (MTTR) – new assets are supported by the manufacturer both in terms of spare parts and maintenance training and information, eventually however, they cease to be supported. As support for equipment diminishes, parts become harder to source and verify, the skills associated with fitting and testing the equipment also reduce as older equipment becomes a smaller percentage of the total asset base, thus personnel are less familiar with this equipment.

Note that these incremental changes in reliability may not be reflected in short run costs (for example it may cost the same to repair an asset in the end of life phase however the mean time to repair may be significantly longer awaiting parts or particular skills – the extended MTTR is an increased risk to the long run costs as out of service equipment forces more effort into managing the system around it).

B5 Asset maintenance effort

Asset maintenance effort may be characterised by the “bathtub curve” shown in Figure B.3. As assets enter the end of life phase, performance begins to be dominated by maintenance issues, reduced MTBF and increasing MTTR.

There are two primary areas which present higher than desired levels of risk and cost. These areas are the “early life” period and the “end of life” period.

The cost implications associated with the early life period are largely managed through the procurement process which demands warrantee support for assets and construction workmanship. The partnering philosophy that ElectraNet has in place with its Dual Contractor arrangements further enhances ElectraNet’s ability to transfer risk and get longer term commitment from service providers, which mitigates cost impacts from early life failures.

The end of life phase is the area where the majority of ElectraNet's asset management focus must therefore be applied.

In order to model the effect of a particular asset replacement programme on long run costs, the asset maintenance effort profile is approximated using estimates of failure rates based on case studies of asset end of life.

B6 Asset safety

Assets may no longer meet current design standards, the likelihood of sudden catastrophic failure increases or the asset does not meet all aspects current functional safety performance.

B7 Asset maintenance effort profile

The Asset maintenance effort profile has been developed as described above. This profile then allows the incremental increase in corrective maintenance effort for each asset to be estimated in the period from the present to its scheduled replacement, providing the following estimates:

- The estimated OPEX Project spend to replace high risk assets
- The projected increase in defect maintenance costs if the high risk assets remain in service until a capital project replacement

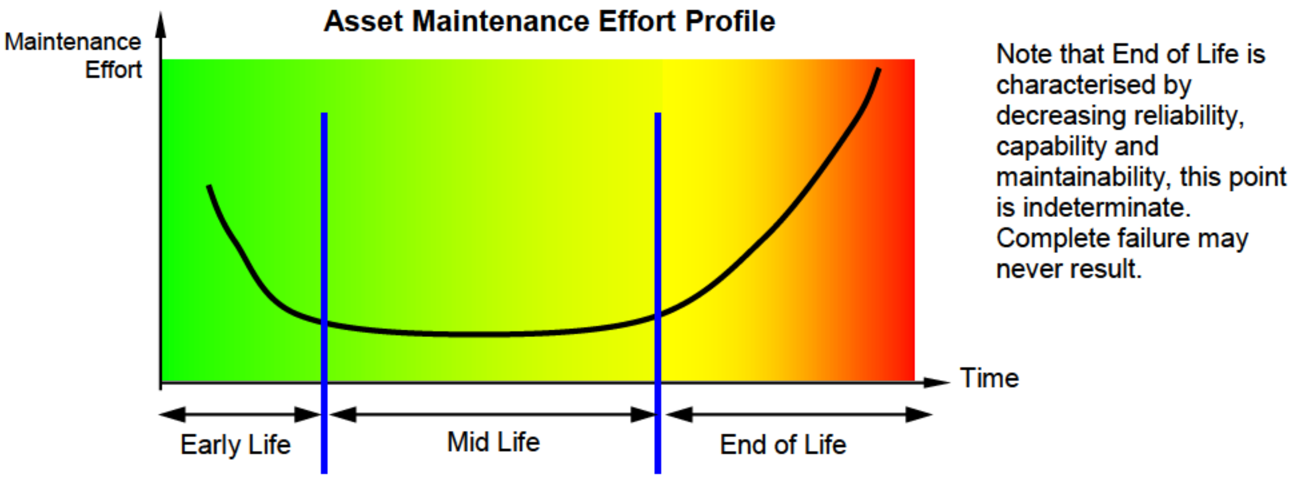


Figure B.3: Asset Maintenance Effort Profile

The Asset Maintenance Profile is used:

In the TALC Assessment and scoring

- To identify poorly performing assets requiring refurbishment
- To develop an input for the modeling of long run maintenance costs

The TALC framework will provide a composite view of each major asset based on the sum of component scores as well as providing a view of each major component.

B8 Transmission Asset Life Cycle

Transmission Asset Life Cycle (TALC) has been developed to provide an indicator of asset health and signal when the end of life phase of the asset life cycle has begun. TALC is a combination of the technical health of the asset and its strategic importance in the network (related to the value at risk).

The process for undertaking a TALC assessment is set out in the following block diagram. This information is then used in the Asset Condition Assessment Report to summarise the overall lifecycle condition of the asset.

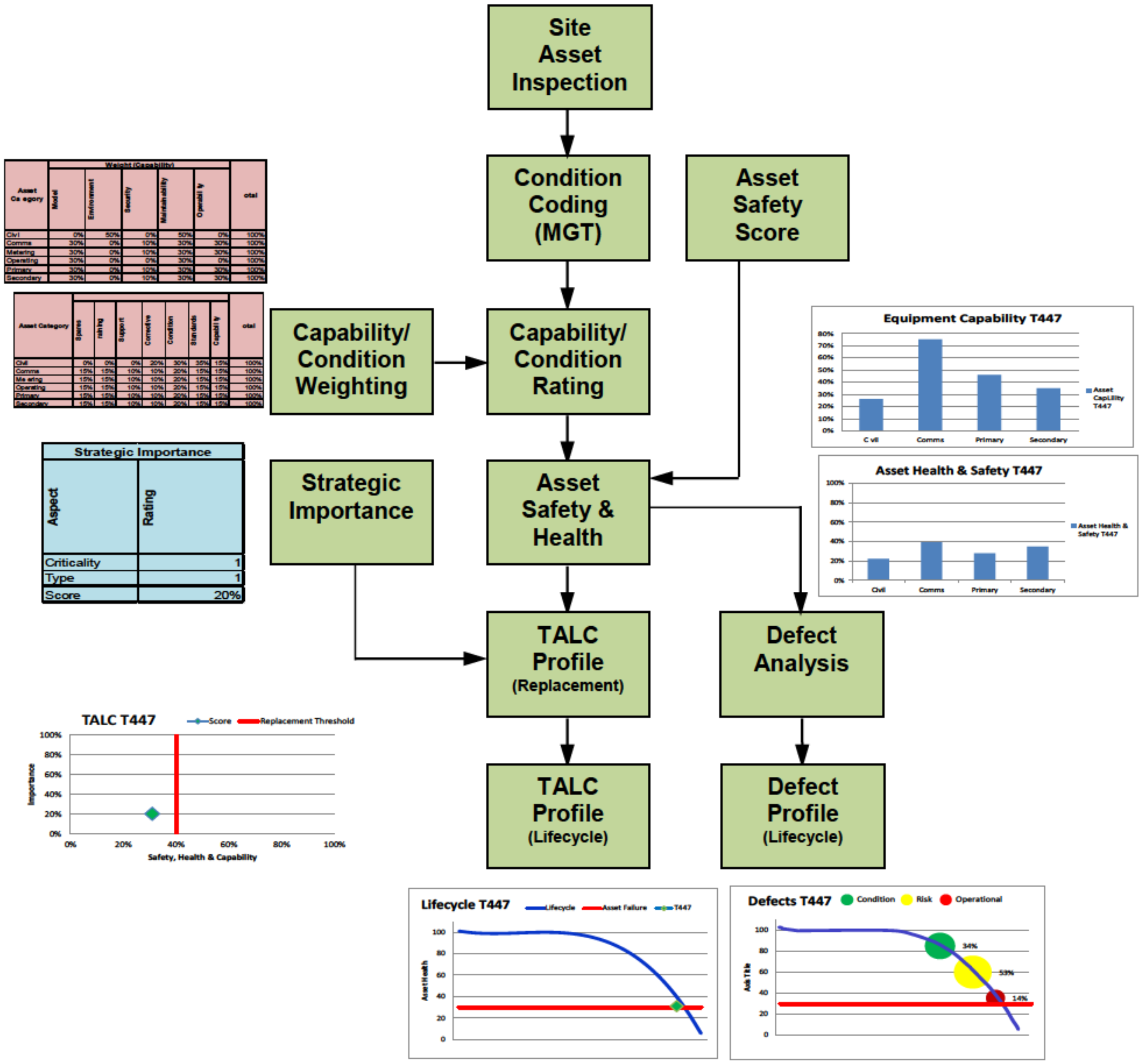


Figure B.4: TALC Assessment Process

B9 Asset Assessment

Each component is assessed based on the following criteria:

B9.1 Substation Assets

Safety

Capability

- Model (evaluation of obsolescence)
- Environment
- Security
- Maintainability
- Operability

Asset Health

- Spare Parts
- Training (available maintenance skills)
- Support (available technical support)
- Corrective Maintenance Effort
- Condition
- Standards

Weightings are applied to each of the above categories based on the type of asset being assessed in order to ensure that relevant emphasis is given to the key aspects of the asset groups as follows:

- Civil
- Comms
- Metering
- Operating
- Primary
- Secondary

Note: Safety has 100% weighting under all conditions.

B9.2 Transmission Line Assets

Condition of major components considering:

- The condition of line components at the time for the assessment

- How long the asset can be expected to operate before failure (based on inspection, testing and assessment in accordance with international standards and practice.

B10 End of Technical Life Criteria

Each assessment is based on a scoring system represented below:

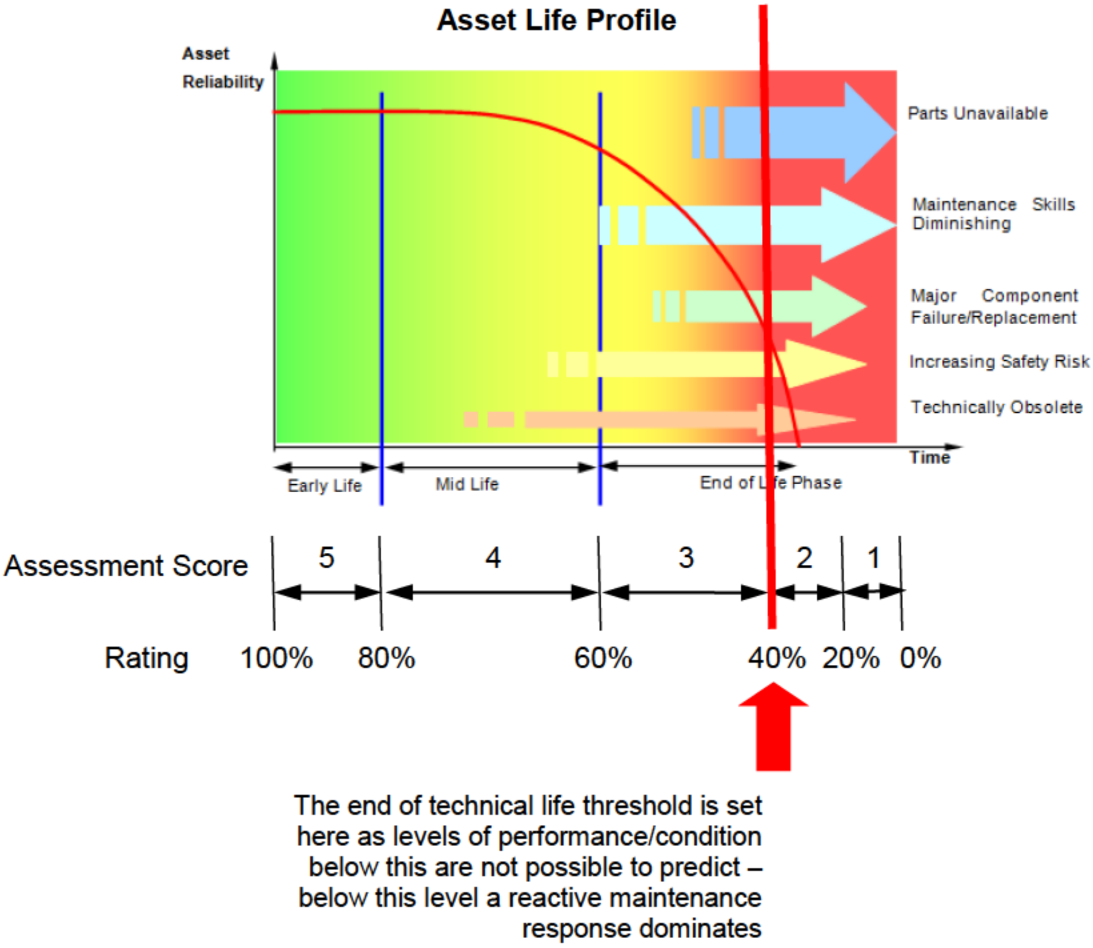


Figure B.5: Asset End of Technical Life Threshold

The TALC framework provides a composite view of each major asset based on the sum of component scores as well as providing a view of each major component. The end of life threshold is the point at which asset behavior and performance becomes unpredictable and begins to dominate corrective maintenance effort and reduced reliability

Scoring and rating criteria are shown in the appendices:

An example TALC assessment is shown below.

B11 Example TALC Assessment - Substation

An example of the application of TALC assessment of a substation site (Mannum Adelaide No.2 PS) is shown below, an example of a transmission line assessment is shown in Figure B.6.

Equipment Capability T447						Asset	Rating (1-5)					Weight					Score					Total	
Description	Barcode	Make	Model	Serial No	Startup Date	Category	Model	Environment	Security	Maintainability	Operability	Model	Environment	Security	Maintainability	Operability	Model	Environment	Security	Maintainability	Operability	Asset Score (1-5)	Asset Health
CURRENT TRANSFORMER	022521000006734	ABB			01/01/1968	Primary	5		4	3	5	30%	0%	10%	30%	30%	1.5	0.0	0.4	0.9	1.5	4.3	83%
CURRENT TRANSFORMER	022521000007074	AEI	TYPE C	111329	01/01/1968	Primary	5		4	3	5	30%	0%	10%	30%	30%	1.5	0.0	0.4	0.9	1.5	4.3	83%
CURRENT TRANSFORMER	022521000007072	ABB			01/01/1968	Primary	5		4	3	5	30%	0%	10%	30%	30%	1.5	0.0	0.4	0.9	1.5	4.3	83%
CURRENT TRANSFORMER	022521000006731	ABB			31/12/1967	Primary	5		4	3	5	30%	0%	10%	30%	30%	1.5	0.0	0.4	0.9	1.5	4.3	83%
CURRENT TRANSFORMER	022521000006732	ABB			31/12/1967	Primary	5		4	3	5	30%	0%	10%	30%	30%	1.5	0.0	0.4	0.9	1.5	4.3	83%
CURRENT TRANSFORMER	022521000006738	ABB			31/12/1967	Primary	5		4	3	5	30%	0%	10%	30%	30%	1.5	0.0	0.4	0.9	1.5	4.3	83%
SURGE ARRESTOR	022521000006735	ABB	Pexilim P120-XV1		01/01/1968	Primary	5		4	3	5	30%	0%	10%	30%	30%	1.5	0.0	0.4	0.9	1.5	4.3	83%
SURGE ARRESTOR	022521000006736	ABB	Pexilim P120-XV1		01/01/1968	Primary	5		4	3	5	30%	0%	10%	30%	30%	1.5	0.0	0.4	0.9	1.5	4.3	83%
SURGE ARRESTOR	022521000006737	ABB	Pexilim P120-XV1		01/01/1968	Primary	5		4	3	5	30%	0%	10%	30%	30%	1.5	0.0	0.4	0.9	1.5	4.3	83%
SURGE ARRESTOR	022521000007078	ABB	Pexilim P120-XV1		31/12/1967	Primary	5		4	3	5	30%	0%	10%	30%	30%	1.5	0.0	0.4	0.9	1.5	4.3	83%
SURGE ARRESTOR	022521000007077	ABB	Pexilim P120-XV1		31/12/1967	Primary	5		4	3	5	30%	0%	10%	30%	30%	1.5	0.0	0.4	0.9	1.5	4.3	83%
SURGE ARRESTOR	022521000007076	ABB	Pexilim P120-XV1		31/12/1967	Primary	5		4	3	5	30%	0%	10%	30%	30%	1.5	0.0	0.4	0.9	1.5	4.3	83%
LINE TRAP	022521000007079				01/01/1968	Primary	2		1	2	3	30%	0%	10%	30%	30%	0.6	0.0	0.1	0.6	0.9	2.2	30%
LINE TRAP	022521000006728				01/01/1968	Primary	2		1	2	3	30%	0%	10%	30%	30%	0.6	0.0	0.1	0.6	0.9	2.2	30%
ISOLATOR	022521000006730	ETSA	DR-P		01/01/1968	Primary	1		1	1	1	30%	0%	10%	30%	30%	0.3	0.0	0.1	0.3	0.3	1.0	0%
GANGED INTERRUPTOR	022521000006729				01/01/1968	Primary	1		1	1	1	30%	0%	10%	30%	30%	0.3	0.0	0.1	0.3	0.3	1.0	0%
ISOLATOR	022521000006983	ETSA			01/01/1968	Primary	1		1	1	1	30%	0%	10%	30%	30%	0.3	0.0	0.1	0.3	0.3	1.0	0%
ISOLATOR	022521000006982	ETSA			01/01/1968	Primary	1		1	1	1	30%	0%	10%	30%	30%	0.3	0.0	0.1	0.3	0.3	1.0	0%
BUS -					30/11/1999	Primary	2		3	1	1	30%	0%	10%	30%	30%	0.6	0.0	0.3	0.3	0.3	1.5	13%

Figure B.6: Example Equipment Capability Assessment (Part Example of Table)

Equipment Safety & Health T447						Asset	Rating (1-5)								Weighting							Score							Total		
Description	Barcode	Make	Model	Serial No	Startup Date	Category	Safety	Spares	Training	Support	Corrective	Condition	Standards	Capability	Spares	Training	Support	Corrective	Condition	Standards	Capability	Spares	Training	Support	Corrective	Condition	Standards	Capability	Asset Score (1-5)	Asset Health	Safety, Health & Capability
CURRENT TRANSFORMER	022521000006734	ABB			01/01/1968	Primary	4	2	3	2	3	5	2	4 3	15%	15%	10%	10%	20%	15%	15%	0 3	0 5	0.2	0.3	1.0	0.3	0.6	3.2	55%	41%
CURRENT TRANSFORMER	022521000007074	AEI	TYPE C	111329	01/01/1968	Primary	4	2	3	2	3	2	2	4 3	15%	15%	10%	10%	20%	15%	15%	0 3	0 5	0.2	0.3	0.4	0.3	0.6	2.6	40%	30%
CURRENT TRANSFORMER	022521000007072	ABB			01/01/1968	Primary	4	2	3	2	3	2	2	4 3	15%	15%	10%	10%	20%	15%	15%	0 3	0 5	0.2	0.3	0.4	0.3	0.6	2.6	40%	30%
CURRENT TRANSFORMER	022521000006731	ABB			31/12/1967	Primary	4	2	3	2	3	2	2	4 3	15%	15%	10%	10%	20%	15%	15%	0 3	0 5	0.2	0.3	0.4	0.3	0.6	2.6	40%	30%
CURRENT TRANSFORMER	022521000006732	ABB			31/12/1967	Primary	4	2	3	2	3	2	2	4 3	15%	15%	10%	10%	20%	15%	15%	0 3	0 5	0.2	0.3	0.4	0.3	0.6	2.6	40%	30%
CURRENT TRANSFORMER	022521000006738	ABB			31/12/1967	Primary	4	2	3	2	3	2	2	4 3	15%	15%	10%	10%	20%	15%	15%	0 3	0 5	0.2	0.3	0.4	0.3	0.6	2.6	40%	30%
SURGE ARRESTOR	022521000006735	ABB	Pexilim P120-XV1		01/01/1968	Primary	4	5	3	5	5	4	3	4 3	15%	15%	10%	10%	20%	15%	15%	0 8	0 5	0.5	0.5	0.8	0.5	0.6	4.1	77%	58%
SURGE ARRESTOR	022521000006736	ABB	Pexilim P120-XV1		01/01/1968	Primary	4	5	3	5	5	4	3	4 3	15%	15%	10%	10%	20%	15%	15%	0 8	0 5	0.5	0.5	0.8	0.5	0.6	4.1	77%	58%
SURGE ARRESTOR	022521000006737	ABB	Pexilim P120-XV1		01/01/1968	Primary	4	5	3	5	5	4	3	4 3	15%	15%	10%	10%	20%	15%	15%	0 8	0 5	0.5	0.5	0.8	0.5	0.6	4.1	77%	58%
SURGE ARRESTOR	022521000007078	ABB	Pexilim P120-XV1		31/12/1967	Primary	4	5	3	5	5	4	3	4 3	15%	15%	10%	10%	20%	15%	15%	0 8	0 5	0.5	0.5	0.8	0.5	0.6	4.1	77%	58%
SURGE ARRESTOR	022521000007077	ABB	Pexilim P120-XV1		31/12/1967	Primary	4	5	3	5	5	4	3	4 3	15%	15%	10%	10%	20%	15%	15%	0 8	0 5	0.5	0.5	0.8	0.5	0.6	4.1	77%	58%
SURGE ARRESTOR	022521000007076	ABB	Pexilim P120-XV1		31/12/1967	Primary	4	5	3	5	5	4	3	4 3	15%	15%	10%	10%	20%	15%	15%	0 8	0 5	0.5	0.5	0.8	0.5	0.6	4.1	77%	58%
L NE TRAP	022521000007079				01/01/1968	Primary	4	2	3	3	3	2	2	2 2	15%	15%	10%	10%	20%	15%	15%	0 3	0 5	0.3	0.3	0.4	0.3	0.3	2.4	35%	26%
L NE TRAP	022521000006728				01/01/1968	Primary	4	2	3	3	3	2	2	2 2	15%	15%	10%	10%	20%	15%	15%	0 3	0 5	0.3	0.3	0.4	0.3	0.3	2.4	35%	26%
ISOLATOR	022521000006730	ETSA	DR-P		01/01/1968	Primary	3	1	2	1	1	1	1	1 0	15%	15%	10%	10%	20%	15%	15%	0 2	0 3	0.1	0.1	0.2	0.2	0.2	1.2	4%	2%
GANGED INTERRUPTOR	022521000006729				01/01/1968	Primary	3	1	2	1	1	1	1	1 0	15%	15%	10%	10%	20%	15%	15%	0 2	0 3	0.1	0.1	0.2	0.2	0.2	1.2	4%	2%
ISOLATOR	022521000006983	ETSA			01/01/1968	Primary	3	1	2	1	1	1	1	1 0	15%	15%	10%	10%	20%	15%	15%	0 2	0 3	0.1	0.1	0.2	0.2	0.2	1.2	4%	2%
ISOLATOR	022521000006982	ETSA			01/01/1968	Primary	3	1	2	1	1	1	1	1 0	15%	15%	10%	10%	20%	15%	15%	0 2	0 3	0.1	0.1	0.2	0.2	0.2	1.2	4%	2%
BUS -					30/11/1999	Primary	3	2	2	1	2	1	1	1 5	15%	15%	10%	10%	20%	15%	15%	0 3	0 3	0.1	0.2	0.2	0.2	0.2	1.5	12%	6%
CURRENT TRANSFORMER 3 3K	022521000015927	STEMAR	BCT3/160	268592	13/06/2002	Primary	4	2	2	3	3	3	3	4 0	15%	15%	10%	10%	20%	15%	15%	0 3	0 3	0.3	0.3	0.6	0.5	0.6	2.9	46%	35%
CURRENT TRANSFORMER 3 3K	022521000015928	STEMAR	BCT3/160	268590	13/06/2002	Primary	4	2	2	3	3	3	3	4 0	15%	15%	10%	10%	20%	15%	15%	0 3	0 3	0.3	0.3	0.6	0.5	0.6	2.9	46%	35%
VOLTAGE TRANSFORMER	022521000005843	ENDURANCE		L5490	31/12/1967	Primary	4	2	2	1	3	2	1	3 3	15%	15%	10%	10%	20%	15%	15%	0 3	0 3	0.1	0.3	0.4	0.2	0.5	2.0	26%	20%
VOLTAGE TRANSFORMER	022521000005844	ENDURANCE		L5487	31/12/1967	Primary	4	2	2	1	3	2	1	3 3	15%	15%	10%	10%	20%	15%	15%	0 3	0 3	0.1	0.3	0.4	0.2	0.5	2.0	26%	20%
FUSE	022521000005847	ETSA			01/01/1968	Primary	3	2	2	1	3	2	1	1 3	15%	15%	10%	10%	20%	15%	15%	0 3	0 3	0.1	0.3	0.4	0.2	0.2	1.7	19%	9%
Trip Input/Output Card 1200-32	10011577	DEWAR	DM 1200	02048144	01/01/2007	Secondary	4	3	3	3	4	3	3	2.4	15%	15%	10%	10%	20%	15%	15%	0 5	0 5	0.3	0.4	0.6	0.5	0.4	3.0	50%	38%
Trip Input/Output Card 1200-32	10011576	DEWAR	DM 1200	02048145	01/01/2007	Secondary	4	3	3	3	4	3	3	2.4	15%	15%	10%	10%	20%	15%	15%	0 5	0 5	0.3	0.4	0.6	0.5	0.4	3.0	50%	38%
Trip Input/Output Card 1200-32	10011575	DEWAR	DM 1200	02048084	01/01/2007	Secondary	4	3	3	3	4	3	3	2.4	15%	15%	10%	10%	20%	15%	15%	0 5	0 5	0.3	0.4	0.6	0.5	0.4	3.0	50%	38%
RS422 Processor Card 1200-25	10011574	DEWAR	DM 1200	07036475	01/01/2007	Secondary	4	3	3	3	4	3	3	2.4	15%	15%	10%	10%	20%	15%	15%	0 5	0 5	0.3	0.4	0.6	0.5	0.4	3.0	50%	38%
Power Supply Card 1200-42	10011573	DEWAR	DM 1200	02048202	01/01/2007	Secondary	4	3	3	3	4	3	3	2.4	15%	15%	10%	10%	20%	15%	15%	0 5	0 5	0.3	0.4	0.6	0.5	0.4	3.0	50%	38%
Monitor Main Card 1200-10B	10011571	DEWAR	DM 1200	03048223	01/01/2007	Secondary	4	3	3	3	4	3	3	2.4	15%	15%	10%	10%	20%	15%	15%	0 5	0 5	0.3	0.4	0.6	0.5	0.4	3.0	50%	38%
Relay Card 1200-12	10011572	DEWAR	DM 1200	02048027	01/01/2007	Secondary	4	3	3	3	4	3	3	2.4	15%	15%	10%	10%	20%	15%	15%	0 5	0 5	0.3	0.4	0.6	0.5	0.4	3.0	50%	38%

Figure B.7 Example Equipment Safety & Health (Part Example of Table)

Table B.3 Weighting Criteria for Capability Assessment

Asset Category	Weight (Capability)					Total	Asset Capability (Average for each asset group)	Asset Capability T447
	Model	Environment	Security	Maintainability	Operability			
Civil	0%	50%	0%	50%	0%	100%	25%	22%
Comms	30%	0%	10%	30%	30%	100%	43%	43%
Metering	30%	0%	10%	30%	30%	100%	81%	
Operating	30%	0%	0%	30%	40%	100%	100%	
Primary	30%	0%	10%	30%	30%	100%	46%	46%
Secondary	30%	0%	10%	30%	30%	100%	35%	35%
						Average	55%	37%

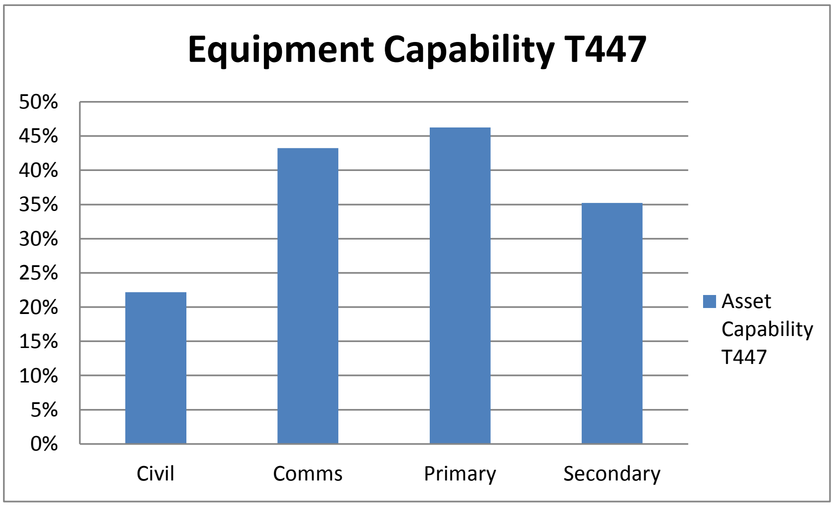


Figure B.8 Asset Capability Profile

Table B.4 Weighting Criteria for Asset Health Assessment

Asset Category	Spares	Training	Support	Corrective	Condition	Standards	Capability	Total	Asset Health & Safety (Average for each asset group)	Asset Health & Safety T447
Civil	0%	0%	0%	20%	30%	35%	15%	100%	22%	22%
Comms	15%	15%	10%	10%	20%	15%	15%	100%	39%	39%
Metering	15%	15%	10%	10%	20%	15%	15%	100%	65%	
Operating	15%	15%	10%	10%	20%	15%	15%	100%	98%	
Primary	15%	15%	10%	10%	20%	15%	15%	100%	28%	28%
Secondary	15%	15%	10%	10%	20%	15%	15%	100%	35%	35%
								Average	48%	31%

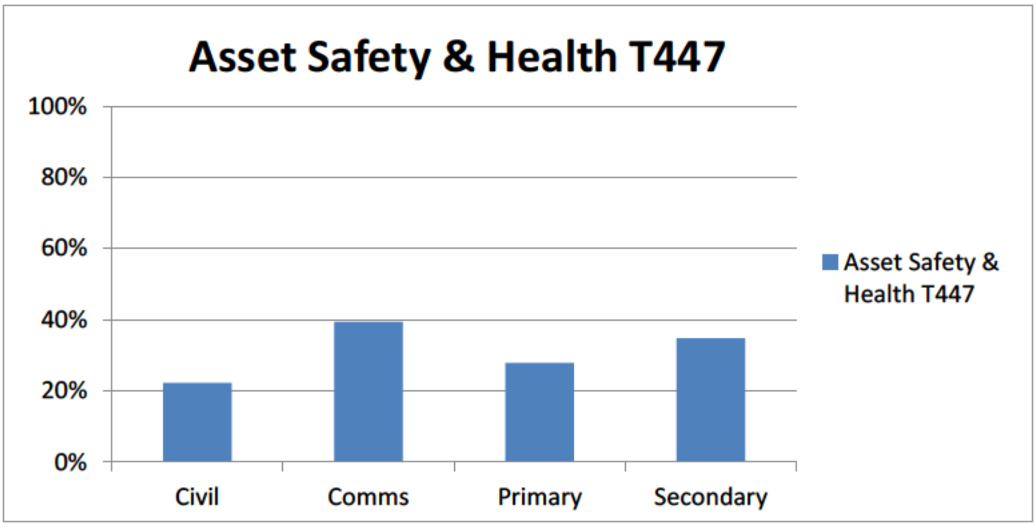


Figure B.9: Asset Safety & Health Profile - Example

Strategic Importance	
Aspect	**Rating**
Criticality	1
Type	1
Score	20%

<u>Note</u>

Scoring based on tables 9-1 and 9-2.

Connection category is radial = 1.

Connection ETC type is Category 1 = 1.

Figure B.10: Site Strategic Importance Rating - Example

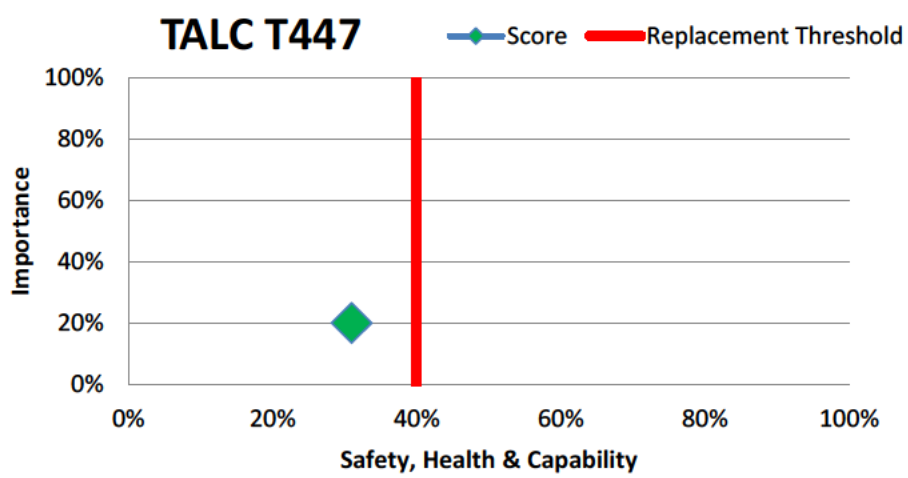
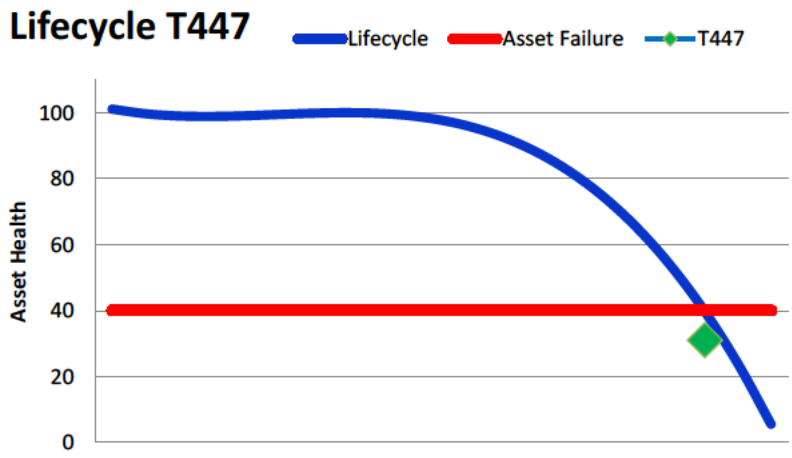


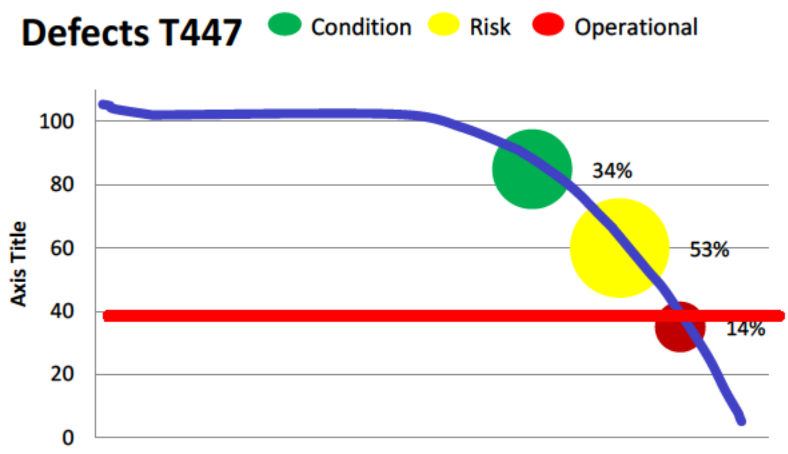
Figure B.11: TALC Profile - Example



Note

Asset failure (red line set at Asset Health 40%) indicates the point where the asset is in the end of life period and is likely to experience increasing failures.

Figure B.12: TALC Profile (Lifecycle)



Note

The defect profile represents all SCAR coded defects for the asset (both complete and active).

Figure B.13: Defect Profile - Example

Appendix 1 – Condition Scoring Substations

A scoring matrix shown below is used to develop an asset health score for each substation plant item or transmission line component

Table B.5 Substation Plant Condition Scoring Matrix - Example

Attribute	Weight	Rating	Score
Safety			
Spare Parts			
Training			
Technical Support			
Corrective Maintenance			
Condition Assessment			
Standards			
Capability			
Asset Health Score			

Scores are developed following site inspection and condition assessment by experienced personnel based on the following rating criteria:

Table B.6 Substation Plant/Transmission Line Rating Criteria - Life Cycle Indicators

Phase	Rating	Assessment Criteria
Early Life Phase	5	Asset fully meets manufacturers specification and performance
First half of Mid Life	4	Although the indicator shows early life phase characteristics there is evidence of transition to mid-life (some observable or measureable deterioration has occurred)
Second Half of Mid Life	3	Asset performance has observable or measureable deterioration – performance is no longer in line with best performing assets.
End of Life Threshold	2	Although the indicator shows mid-life phase characteristics there is evidence of transition to end of life.
End of Life Phase	1	Asset performance has become unacceptable.

Table B.7 Substation Asset - Strategic Capability

Life Cycle	Aspect	Impact	Rating
Early Life Phase	Model	Model is current and still in production	5
	Environment	Meets all aspects of current environmental performance standards	
	Security	Meets availability and reliability performance	
	Maintainability	Highest maintainability performance	
	Operability	Meets all operating protocols	
Mid Life Phase	Model	No longer latest technology but still in production	4-3
	Environment	Does not meet some environmental performance standards	
	Security	Availability and reliability are acceptable but do not meet best performance standards	
	Maintainability	Maintainability is acceptable but does not meet best performance	
	Operability	Operating protocols are acceptable but limit operational flexibility.	
End of Life Phase	Model	No longer in production	2-1
	Environment	Does not meet environmental performance standards	
	Security	Availability and reliability are not in accordance with acceptable performance	
	Maintainability	Asset is difficult to maintain	
	Operability	Operating protocols are limiting efficient and effective operation of the asset	

Table B.8: Asset Life Cycle Indicators – Substation Plant

Life Cycle	Attribute	Indicator	Rating
Early Life Phase	Safety	Meets current safety standards/design	5
	Spare Parts	Short Lead Time	
	Training	Fully Qualified Trainers	
	Technical Support	Provided by Manufacturer	
	Corrective Maintenance	Negligible	
	Condition Assessment	No deterioration	
	Standards	See Table B.9 Asset Standards Criteria	
	Capability	Fully meets capability Table B.7 Substation Asset – Strategic Capability	

Life Cycle	Attribute	Indicator	Rating
Mid Life Phase	Safety	Does not meet current safety standards/design, some operational controls are required	4-3
	Spare Parts	Longer Lead Times	
	Training	Specialist trainers limited availability	
	Technical Support	Limited Technical Support	
	Corrective Maintenance	Condition based – driven by specific operating conditions	
	Condition Assessment	Some deterioration but no significant remedial action required	
	Standards	See Table B.9 Asset Standards Criteria	
	Capability	Generally meets capability Table B.7 Substation Asset – Strategic Capability	
End of Life Phase	Safety	Does not meet safety standards, significant operational controls are required	2-1
	Spare Parts	Only available from other spare or redundant units	
	Training	Maintenance skills limited to small pool of skilled personnel (at best)	
	Technical Support	None-manufacturer may now not exist	
	Corrective Maintenance	Increasing corrective maintenance effort close to or at knee point of bathtub curve	
	Condition Assessment	Measureable/observable deterioration requiring significant remedial action	
	Standards	See Table B.9 Asset Standards Criteria	
	Capability	Does not meet capability – refer Table B.7 Substation Asset – Strategic Capability	

Table B.9: Asset Standards Criteria

Performance	Rating	Assessment Criteria
Assessment criteria for Table B.8 Asset Life Cycle Indicators – Substation Plant	5	Fully meets specified standard
	4	Generally meets specified standard and fully meets older acceptable standard
	3	Fully meets older (acceptable) standard
	2	Partly meets older acceptable standard
	1	Does not meet any acceptable standard

APPENDIX 2 – CONDITION SCORING TRANSMISSION LINES

Table B.10: Transmission Line Condition Scoring Matrix

Attribute	Condition Score (1-5)	Life Score (1-5)
Conductor		
Mid-span Joints		
Hardware		
Conductor		
Mid-span Joints		
Earth wire Hardware		
Structure		
Earthing		
Foundations		
Signage		
Suspension Insulators		
Suspension Hardware		
Tension Insulators		
Tension Hardware		

Table B.11: Transmission Line Condition Score Criteria

Score	Condition	Description	SCAR
1	Poor condition	Plant elements are in poor condition and failure is impending. Plant will become unreliable*. Replacement required	O
2	Fair condition	Plant elements are sound but showing signs of deterioration and may cause plant to become unreliable.	R
3	Satisfactory condition	Plant elements are sound but show some minor deterioration. But, will not affect plant reliability.	C
4	Good condition	Plant elements are in good condition and will maintain expected level of reliability	-
5	Very good condition	Plant elements suit modern specification.	-

Table B.12: Asset Lifecycle Indicators - Transmission Lines

Attribute	Item	Indicator
Conductors	Conductor	Assessment is provided in two parts: The condition of line components at the time of the assessment (based on lines coding guide)
	Mid-span Joints	
	Hardware	

Attribute	Item	Indicator
Earth wire	Conductor	How long the plant can be expected to operate before failure (based on inspection, testing and assessment in accordance with international standards and practice)
	Mid-span Joints	
	Earth wire Hardware	
Structure	Structure	
	Earthing	
	Foundations	
	Signage	
Insulation	Suspension Insulators	
	Suspension Hardware	
	Tension Insulators	
	Tension Hardware	
Line	Strategic Capability	See Table B.14 Transmission Line Asset - Strategic Capability

Table B.13: Transmission Line Remaining Life Score Criteria

Score	1	2	3	4	5
Remaining Life	5-10 years	10-15 years	15-20 years	20-30 years	30-50 years

Table B.14: Transmission Line Asset - Strategic Capability

Aspect	Impact
Safety	The asset must maintain specified levels of safety at all times
Environment	The asset must meet environmental performance standards
Security	In the case of line security it is possible to assess the condition of the plant and redefine the point at which the plant no longer meets is performance requirement in order to extend plant life, over a newly defined remaining life.
Maintainability	The factors considered in providing a measure of maintainability of a transmission line are: Spares availability: Can spares be sourced in a timely manner and are the stock holdings appropriate. Access to plant: Is their suitable contingency in the system to allow maintenance to be performed. Can maintenance be performed without interruption to the plant function (i.e. live line work capability). Resources: Are there skilled people available to perform maintenance and will they respond in an appropriate time frame. As plant ages it is likely that the skills to maintain it will become unavailable.
Operability	Assets are required to meet operating protocols

APPENDIX 3 – CRITICALITY CRITERIA

Criticality of major assets is determined by considering the importance of the connection based on:

The type of connection and location within the network

Connection classification in accordance with the SA Electricity Transmission Code

Table B.15: Asset Criticality Criteria

Asset criticality Category	Rating	Substation	Line
Assessment of the criticality of the customer connection importance, and the significance of an outage or constraint on that connection	5	Generator	Generator
	4	Major 275 Network	Metro
	3	Major Nodes	Main Grid
	2	132 Nodes	132kV Main
	1	Radial	132kV Radial

Table B.16 Connection Type Criteria

Connection (ETC type)	Rating	Substation	Line
Electricity Transmission code connection obligation - provides indication of risk of constraint	5	ETC Category 5	Metro
	4	ETC Category 4	Main Grid
	3	ETC Category 3	275kV
	2	ETC Category 2	132kV Main
	1	ETC Category 1	Radial
	0	ETC Category 0	Node Only

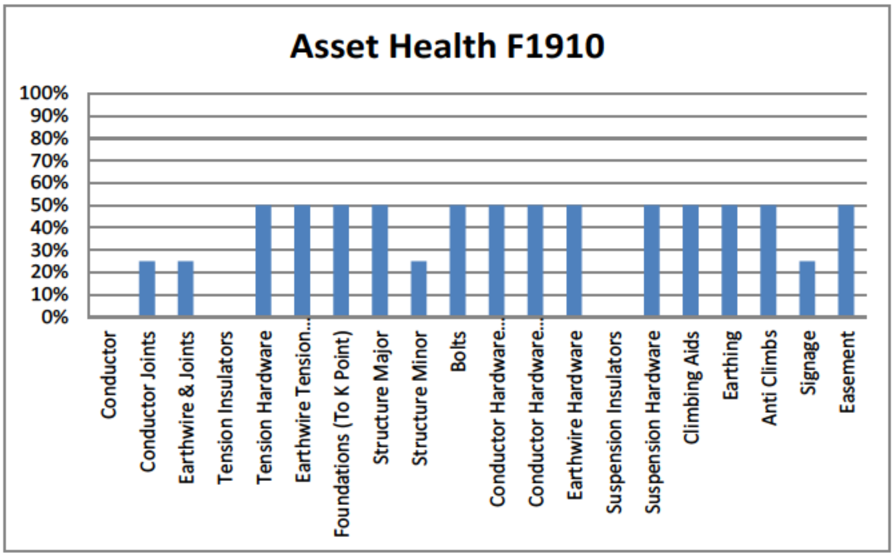
APPENDIX 4 – TRANSMISSION LINE ASSESSMENT EXAMPLE

Table B.17: Line Asset Health Score

F1910	Component	Install date	•1 (Poor) •2 (Fair) •3 (Reasonable) •4 (Good) •5 (Excellent - As New)
Conductor Systems			
Conductor	ASCR (Greased)	1950	1
Conductor Joints	ASCR (Greased)	1960	2
Earthwire & Joints	SC/AC	1960	2
Tension Insulators	Porcelain - Disc	1960	1
Tension Hardware	Strain	1960	3
Earthwire Tension Hardware	Strain	1960	3
Support Systems			
Foundations (To K Point)	Concrete Unreinforced	1960	3
Structure Major	Tower - Major Steel	1960	3
Structure Minor	Tower - Minor Steel	1960	2
Poles	NIL	1960	
Bolts	Tower - Minor Steel	1960	3
Conductor Hardware (Dampers)	Dampers	1980	3
Conductor Hardware (Armour Rod	Armour Rods	1980	3
Earthwire Hardware	Strain	1960	3
Suspension Insulators	Porcelain - Disc	1960	1
Suspension Hardware	Hot End	1960	3
Subcomponent Systems			
Climbing Aids	Tower - Minor Steel	1965	3
Earthing	Earthing	1960	3
Anti Climbs	Wire Cage	1960	3
Signage	Etched Metal	1965	2
Communications	NIL	1960	
Easement	Livestock	1960	3

Note:

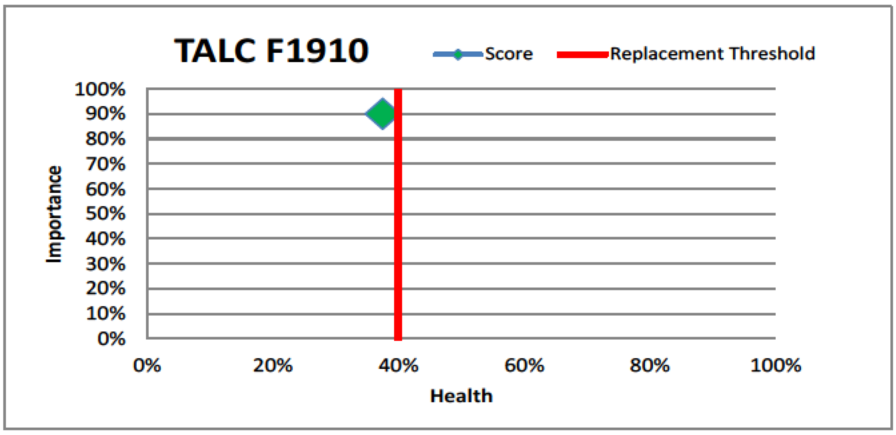
Asset health scores are weighted by an assessment of data confidence (not shown)



Note

Asset health for each component group is determined for the transmission line

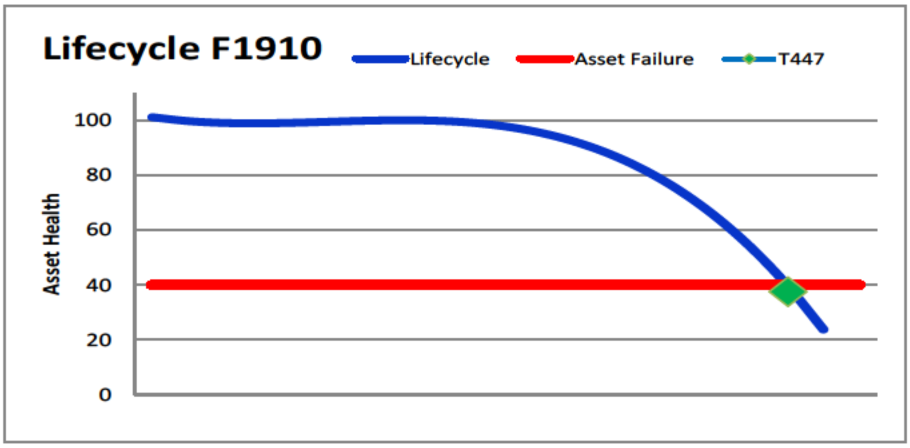
Figure B.14 Line Asset Health (Example)



Note

The TALC score for represents the aggregate asset health and importance – replacement of asset components is indicated by the threshold

Figure B.15 Line TALC Example



Note

The lifecycle profile indicates approach to failure (this may be driven by specific asset components)

Figure B.16 Line Lifecycle Example

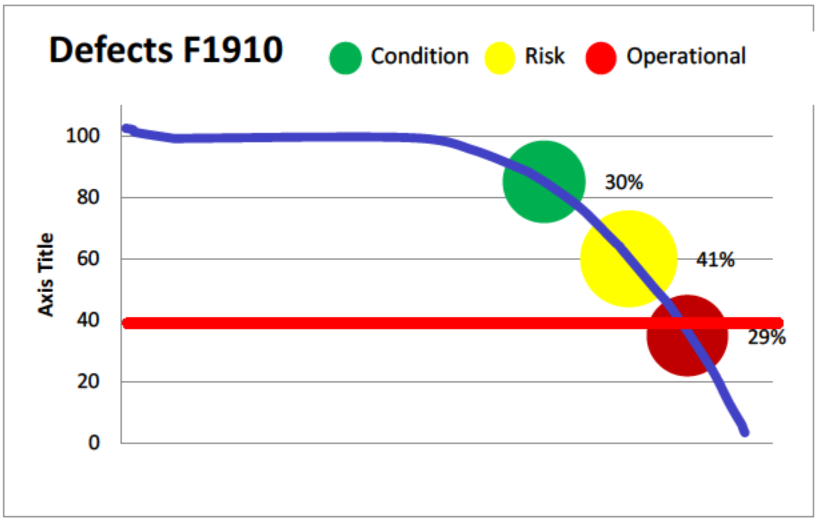


Figure B.17 Line Defect Profile Example

Note

The defect distribution shown represents the percentage of all asset defects (SCAR Coded) in each category – it provides an indication of the relationship between potential and actual defects (this may be component driven)

Appendix C System Condition and Risk (SCAR)

C1 Introduction

Substation Condition and Asset Risk (SCAR) Coding for asset inspection has been developed to provide:

- A structured process for assessing and coding the condition of an asset using SAP Notifications.
- A consistent maintenance response to the asset condition based on an underlying risk profile

The SCAR Codes then allow multiple categories of asset risk to be developed and managed, these are:

- Operational, safety and environmental risk – these categories of risk require immediate (up to 3 months) attention and are managed through the reactive, corrective maintenance process.
- Asset risk – this category of risk requires non urgent attention (up to next scheduled maintenance – 5 years) and is managed through amalgamating the work with the next scheduled opportunity of planned routine maintenance, or actioned through an OPEX Maintenance Project or Capital Replacement and Augmentation Project process.

SCAR Codes have been developed for each asset type and include:

- An underlying risk assessment (that determines the response time frame)
- An estimate of cost

Note the underlying risk assessment is driven by the SCAR Risk Matrix which is based on ElectraNet's corporate risk framework.

All SAP Notifications will include fields that identify:

- The Asset Risk Category (e.g. O, R, S, H, E etc)
- The response time frame (e.g. NWD, ABED)
- The Planned completion date (based on SCAR Risk Matrix)
- The Scheduled completion date (based on allocated maintenance stream and available budget)
- The estimated cost (based on SCAR Coding estimates)
- The allocated maintenance stream (i.e. corrective, OPEX Project, Capital Project)
- The specific project identifier (e.g. Bulk Oil Circuit Breaker Replacement)
- Project Timing (e.g. March 2010)

In order to support the above requirements development of the SCAR Coding Risk Matrix has been completed in conjunction with the Mobile Grazer Terminal (MGT) for field data assessment and SAP interface. The process for implementing SCAR and MGT is discussed below.

C2 Process

SCAR Coding introduces a consistent risk based view of asset condition and defect response timing, the overall process is shown in Figure C.1.

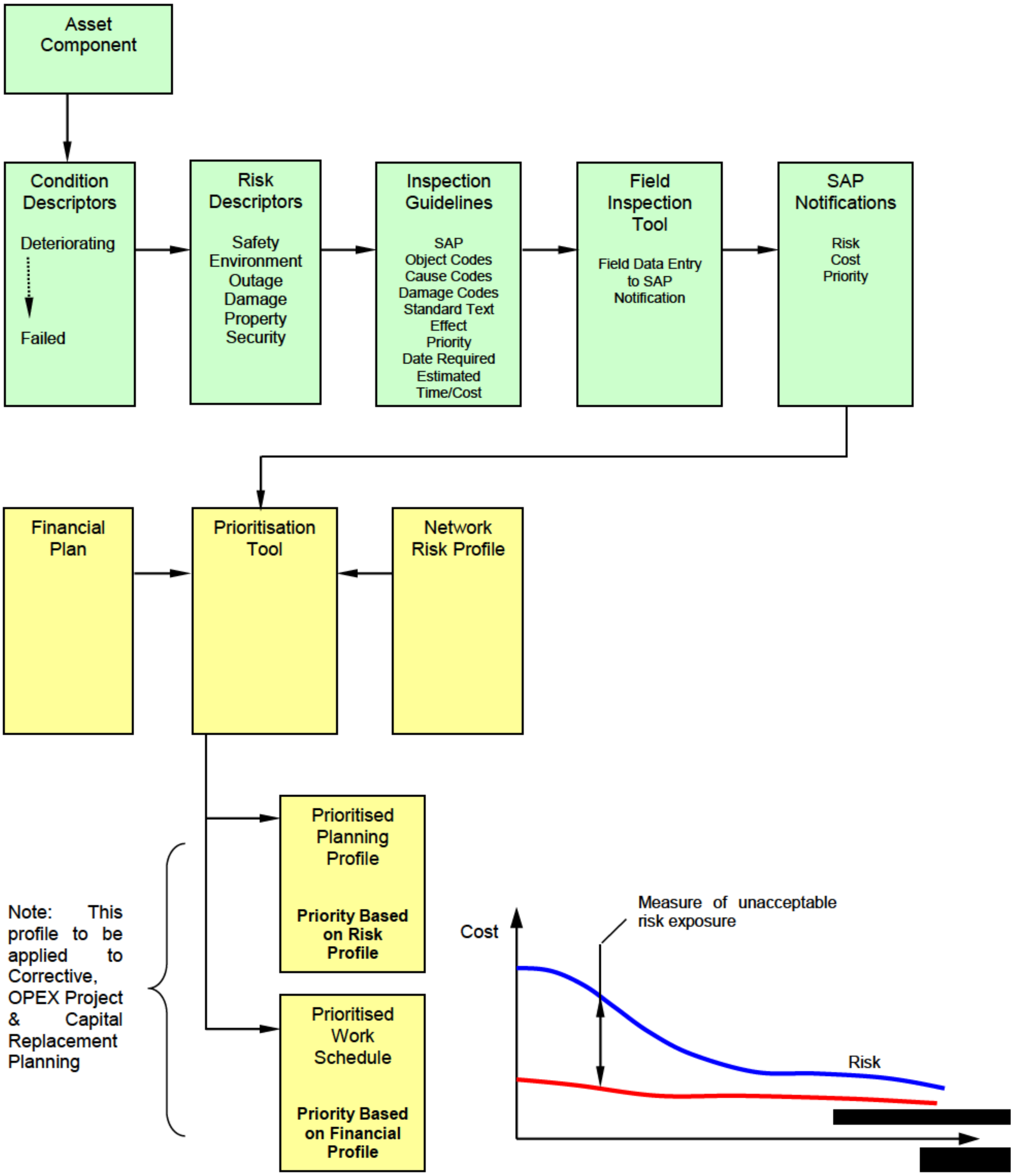


Figure C.1: Asset Risk and Response Prioritisation

C3 Risk assessment

A risk assessment of all anticipated plant failure and deterioration modes has been undertaken and documented using the SCAR Coding Matrix (a hierarchical representation of the plant asset structure). An example showing substation plant structure is shown below.

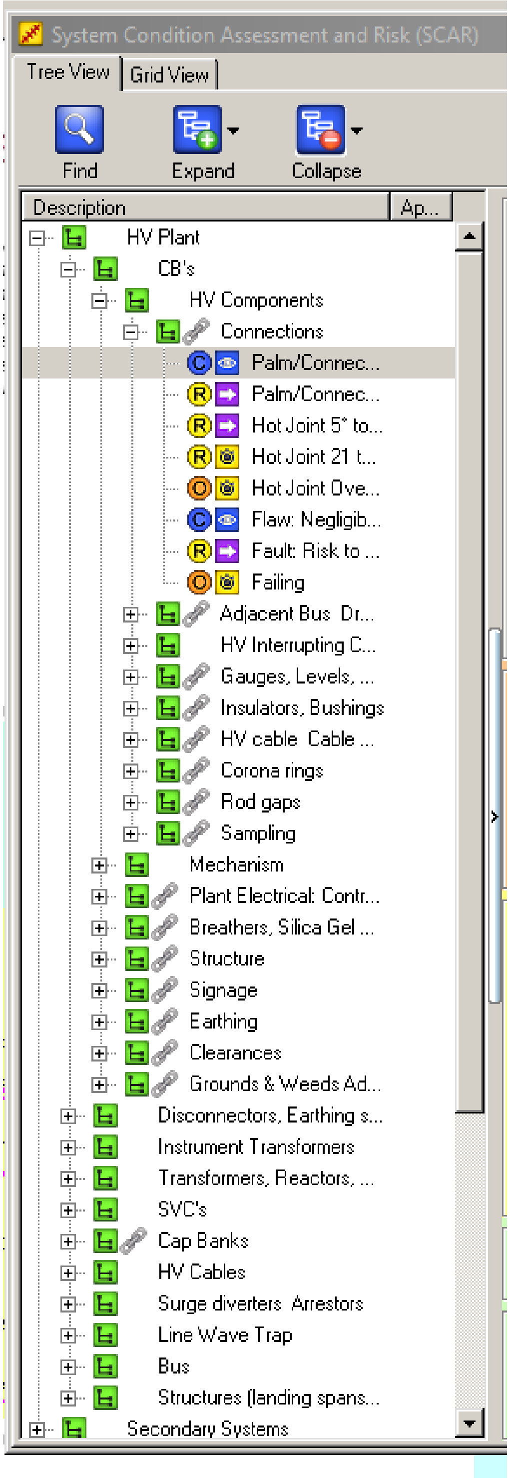
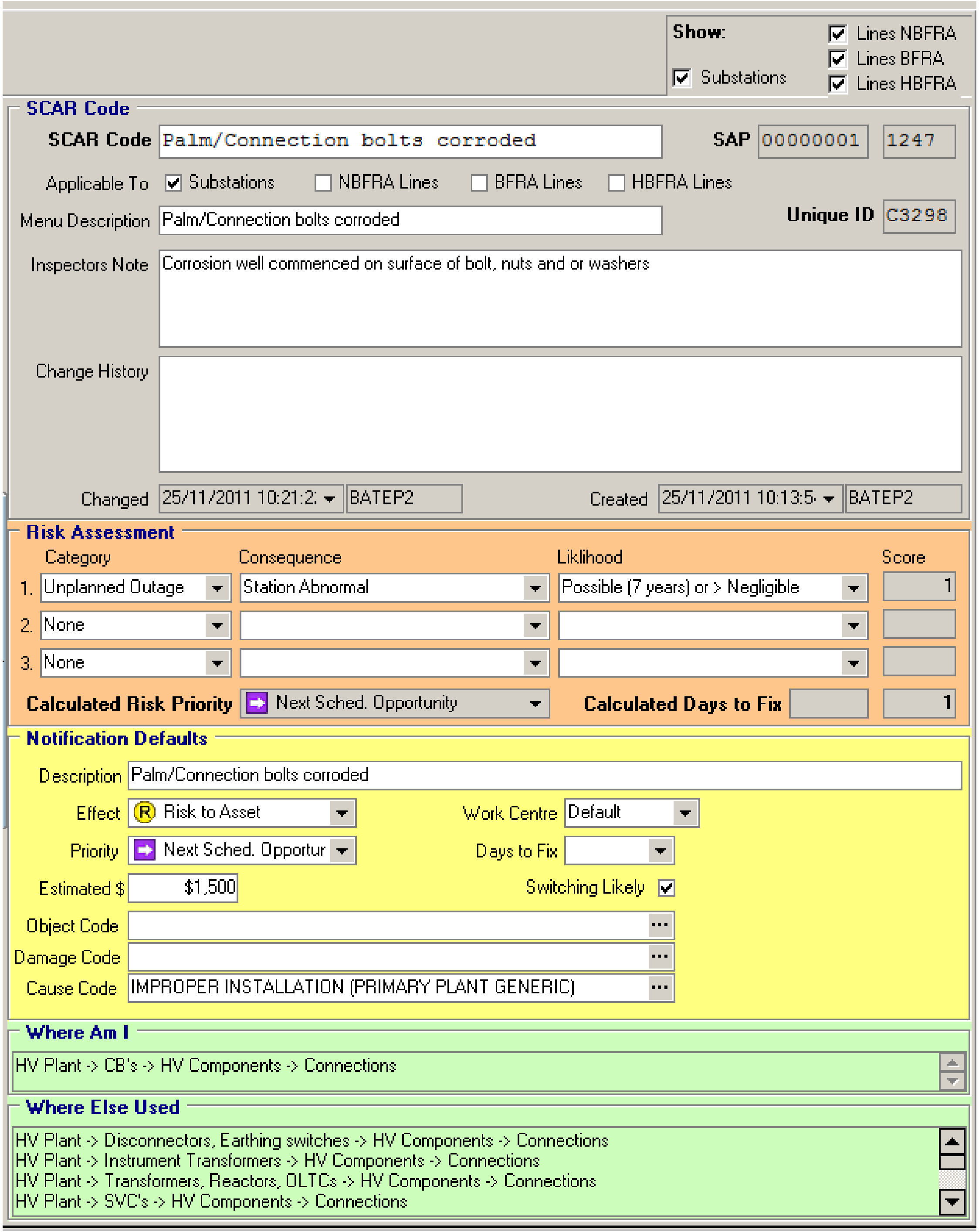


Figure C.2: Example SCAR Coding - Plant Structure

For each plant asset item inspector's notes, risk assessment and SAP notification details are documented where:

- Response time is based on risk and consequence
- Noti data is defined by the plant and failure mode being assessed
- A cost estimate is provided based on previous history



Show: Lines NBFRA, Lines BFRA, Substations, Lines HBFRA

SCAR Code

SCAR Code: Palm/Connection bolts corroded | SAP 00000001 | 1247

Applicable To: Substations, NBFRA Lines, BFRA Lines, HBFRA Lines

Menu Description: Palm/Connection bolts corroded | Unique ID C3298

Inspectors Note: Corrosion well commenced on surface of bolt, nuts and or washers

Change History:

Changed 25/11/2011 10:21:2 BATEP2 | Created 25/11/2011 10:13:5 BATEP2

Risk Assessment

	Category	Consequence	Liklihood	Score
1.	Unplanned Outage	Station Abnormal	Possible (7 years) or > Negligible	1
2.	None			
3.	None			

Calculated Risk Priority: Next Sched. Opportunity | Calculated Days to Fix: 1

Notification Defaults

Description: Palm/Connection bolts corroded

Effect: Risk to Asset | Work Centre: Default

Priority: Next Sched. Opportur | Days to Fix:

Estimated $: $1,500 | Switching Likely

Object Code:

Damage Code:

Cause Code: IMPROPER INSTALLATION (PRIMARY PLANT GENERIC)

Where Am I

HV Plant -> CB's -> HV Components -> Connections

Where Else Used

HV Plant -> Disconnectors, Earthing switches -> HV Components -> Connections
HV Plant -> Instrument Transformers -> HV Components -> Connections
HV Plant -> Transformers, Reactors, OLTCs -> HV Components -> Connections
HV Plant -> SVC's -> HV Components -> Connections

Figure C.3: Example SCAR Matrix - Documentation

Implementation of SCAR coding provides a prioritised list of SAP notifications based on the underlying asset risk matrix and response times. The prioritised SCAR list then provides the basis for identifying the appropriate strategy for the asset. An example of the application of this process is shown in figures 9.1 and 9.2.

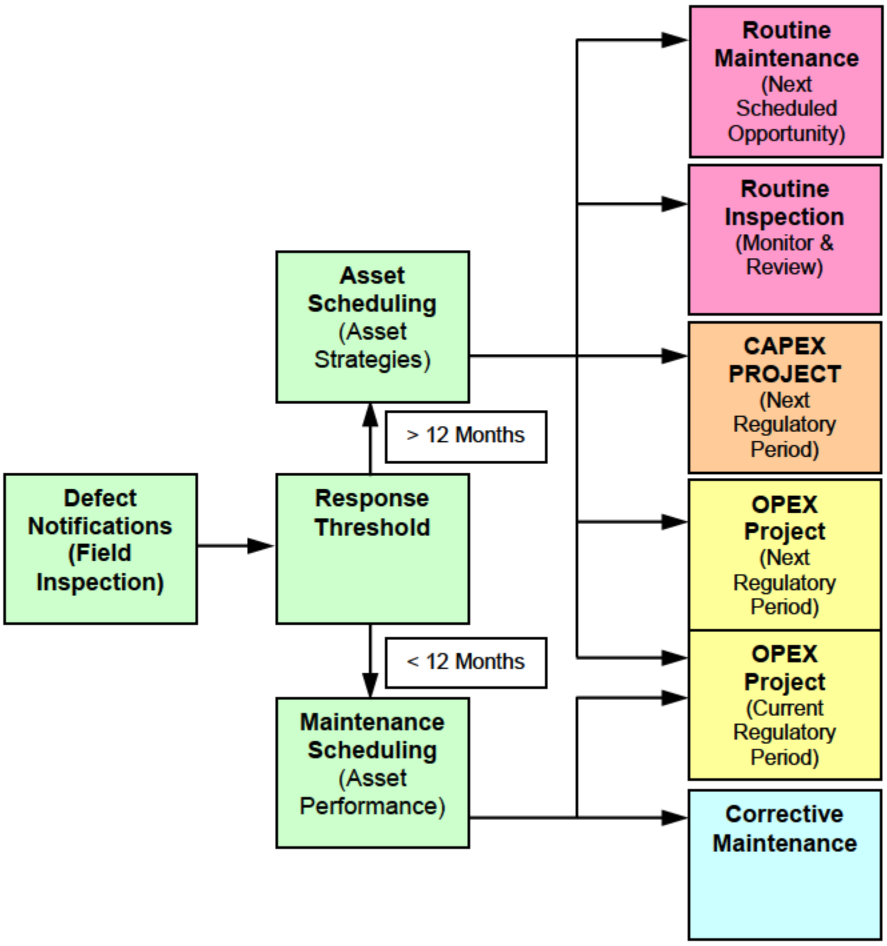


Figure C.4: SCAR Prioritisation – Application

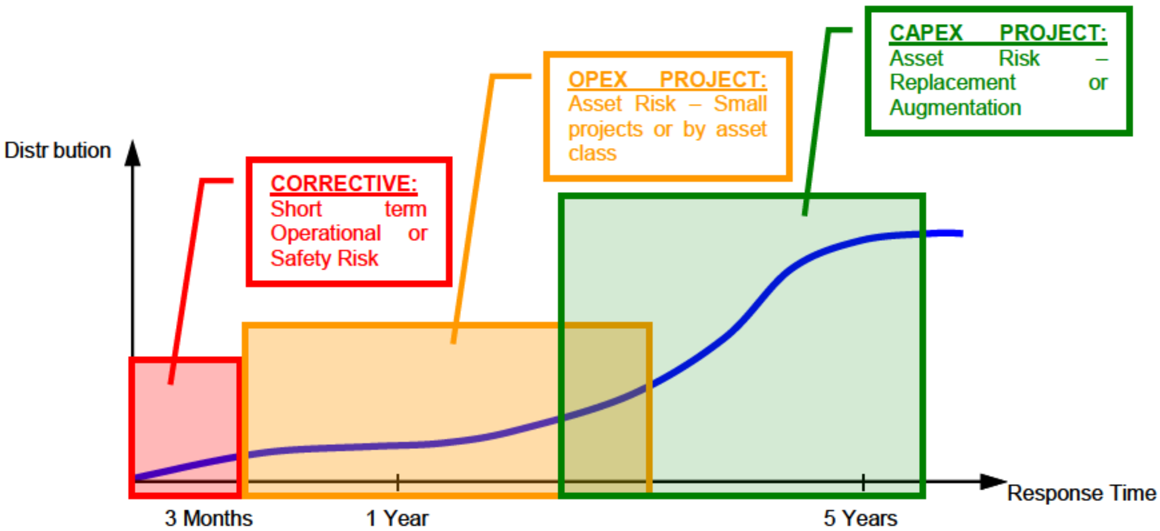


Figure C.5: SCAR Prioritisation - Structure

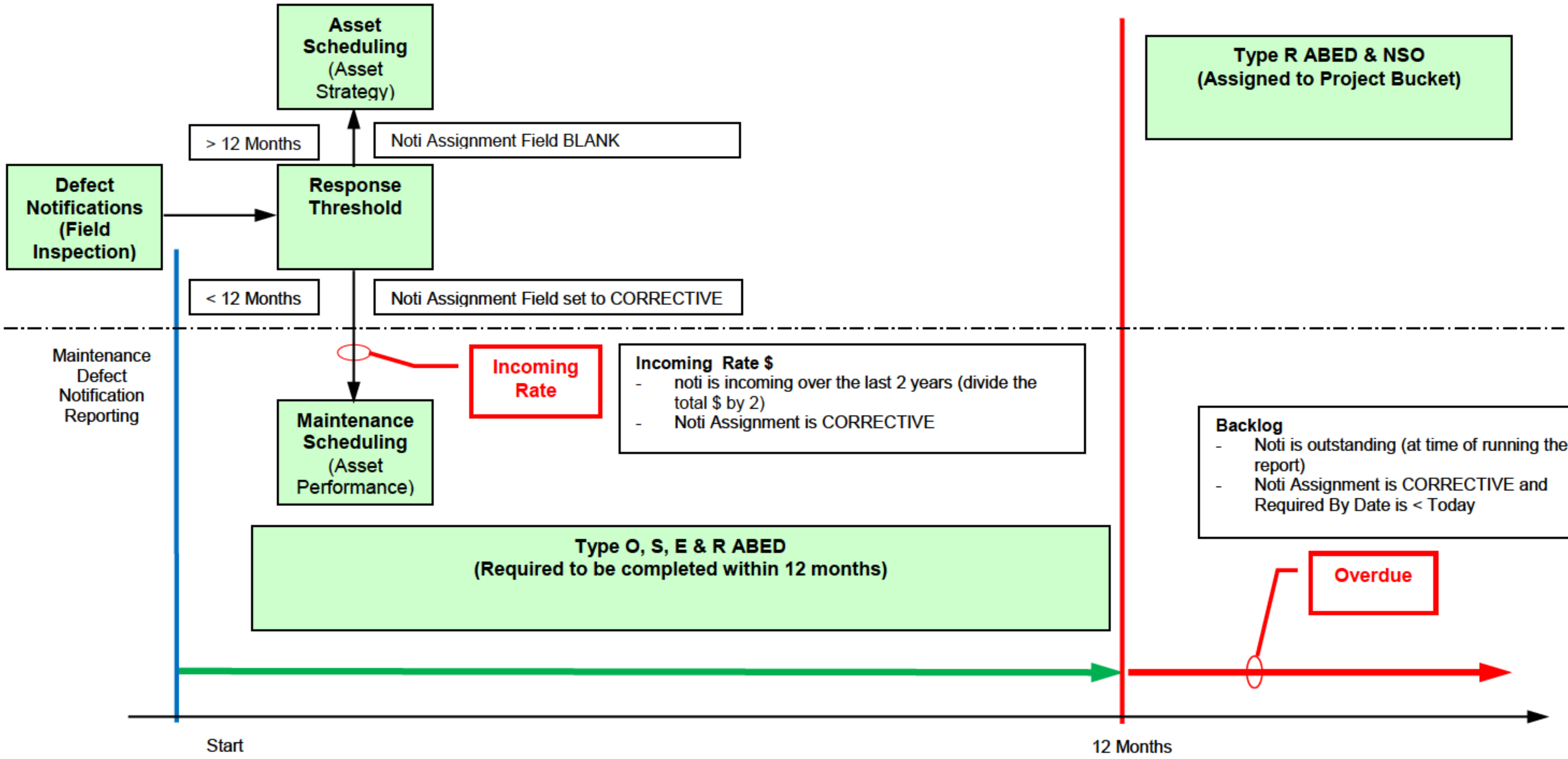


Figure C.6: SCAR Prioritisation - Reporting

C4 Corrective forecasting

The SCAR Prioritisation reporting enables forecasting of the estimated value of each defect category given the recorded incoming rate.

C4.1 Substations and secondary systems

Table C.1: Substation and Secondary Systems Defect Incoming Rates

Defect Category	Outstanding	Late (Days)	Current Annual Expenditure ($2011/12)	Incoming Rate PA ($2011/12)
R Notis	1644	297		$2,597,861
O Notis	234	299		$1,332,500
S Notis	61	80		$485,471
E Notis	16	163		$156,470
All	1965	288	$5,600,000	$4,597,602
Residual Expenditure available to address Accumulative Effort				$1,002,398
Difference between Expenditure and Incoming (mthly)				$83,533
Indicative Months to fully address Accumulated Effort				57

The table above shows:

- The current expenditure level is higher than estimated value of incoming defect notifications annual rate
- The expenditure level is currently higher than the incoming rate in order to deal with the accumulated corrective effort (late days) of defect notifications (it is estimated that with the current expenditure provided the accumulated corrective effort will be completed by 2014/15).

To adequately manage the incoming defect notifications for Substations and Secondary Systems requires an annual expenditure of $4,500,000 ($2011/12).

To address the accumulated corrective effort an additional expenditure of $2,500,000 ($2011/12) over 2 years is required.

C4.2 Transmission lines

Table C.2: Transmission Line Defect Incoming Rates

Defect Category	Outstanding	Late (Days)	Current Annual Budget	Incoming Rate PA($)
R Notis	4342	256		$4,071,711
O Notis	975	270		$2,804,170
S Notis	15	143		$53,100
Z Notis	0	0		$2,371
All	5360	257	$3,100,000	$8,281,487
Residual Expenditure available to address Accumulative Effort				($5,181,487)
Difference between Expenditure and Incoming (mthly)				($431,791)
Indicative Months to fully address Accumulated Effort				n/a

The table above shows that:

- The current annual expenditure is adequate to deal with incoming Operational, Safety and Environment (urgent high risk defect notifications) only.
- There is no financial resource available to address the incoming defect notifications for asset risk (R defect notis).
- There is no financial resource available to address the corrective accumulative requirement.
- To adequately manage the incoming defect notifications for urgent high risk defect notifications only requires an annual expenditure of $3,000,000 ($2011/12).

To adequately manage the incoming defect notifications for asset risk (R defect notis) requires an additional annual expenditure of $3,000,000 ($2011/12). Together with the urgent high risk defects totals an annual expenditure of $6,000,000 ($2011/12).

To address the accumulated corrective effort an additional expenditure of $6,000,000 ($2011/12) over 3 years is required.

Appendix D Asset Maintenance Effort

For the purpose of estimating maintenance effort for substation long run risk the underlying modelling assumptions are based on maintenance effort curves for primary plant.

Previously three case studies have been developed to understand the amount of maintenance effort associated with primary plant assets at, or near end or technical life. It should be noted that effort is a measure of the number of times that asset problems are responded to outside the scheduled maintenance programme for a modern equivalent asset.

The following data represents the relative number of primary plant defects related to either equipment type or age profile and is used to estimate the Asset Risk Failure Profile.

Circuit Breakers – Older circuit breaker performance for both routine and defect maintenance is compared with current circuit breaker technology, in this case a modern ABB type LTB SF6 circuit breaker.

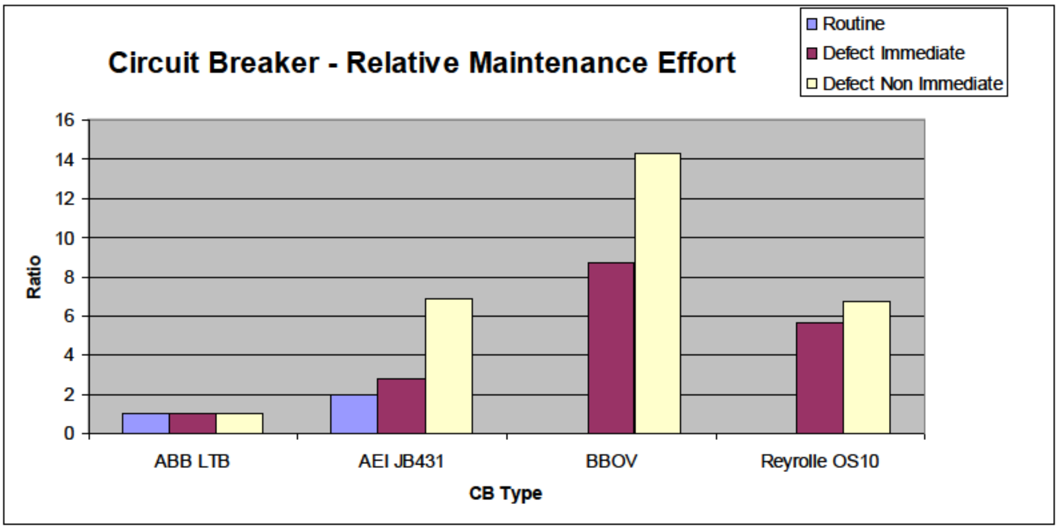


Figure D.1: Circuit Breaker Relative Maintenance Effort

The measures of relative maintenance effort and age are used to develop the shape of the maintenance effort profile shown in Figure D.2. The relative effort profile is then used to predict the incremental increase in maintenance effort for circuit breakers over the next three regulatory periods (during the period they remain in service until replacement).

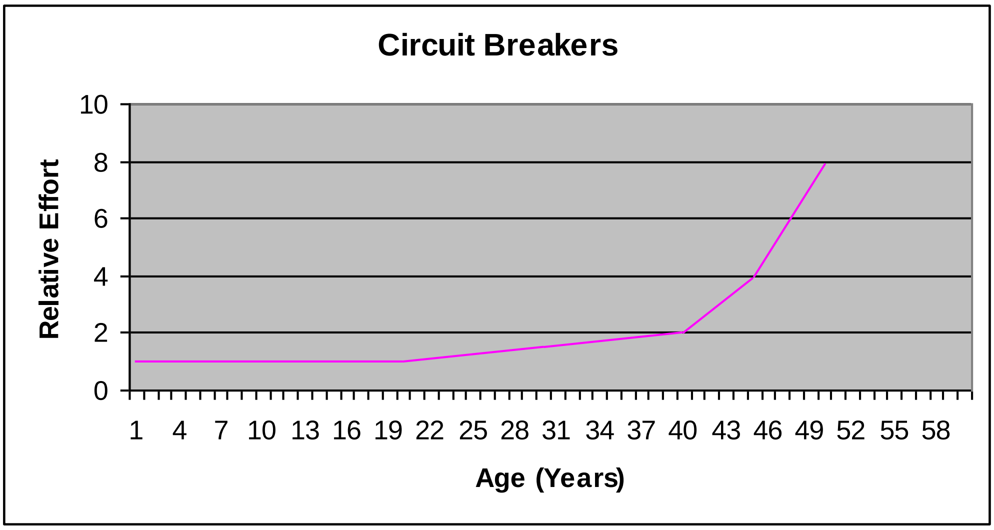


Figure D.2: Circuit Breaker Relative Maintenance Effort Profile

Validation of the modelling assumption is based on Asset data from SAP showing actual maintenance effort performance of the circuit breaker population as a function of age.

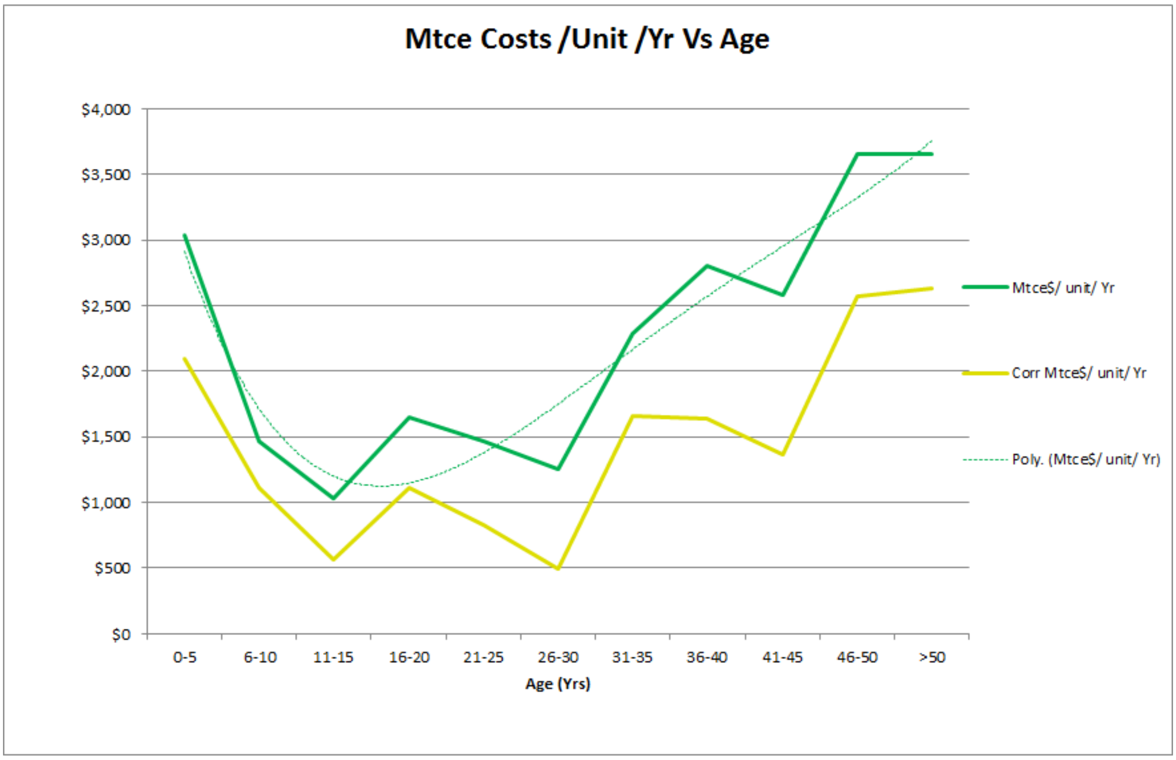


Figure D.3: SAP Data - Circuit Breaker Total Maintenance Cost

Isolators – There is a population of approximately 1500 isolators in the transmission network, the number of defects per isolator is shown for each ten year age group.

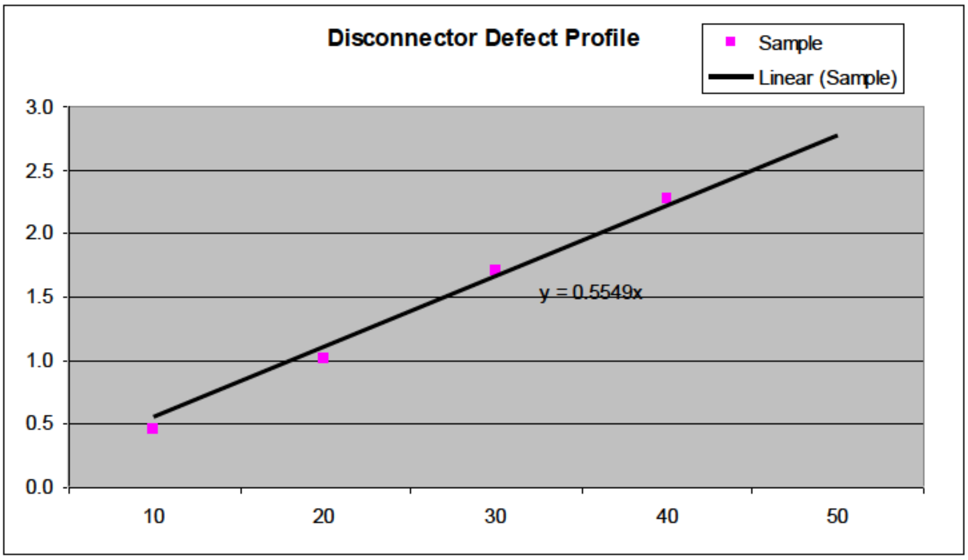


Figure D.4: Isolator Relative Maintenance Effort

Note that the average isolator effort has doubled by the end of technical life (40 years).

Validation of the modelling assumption is based on Asset data from SAP showing actual maintenance effort performance of the isolator population as a function of age.

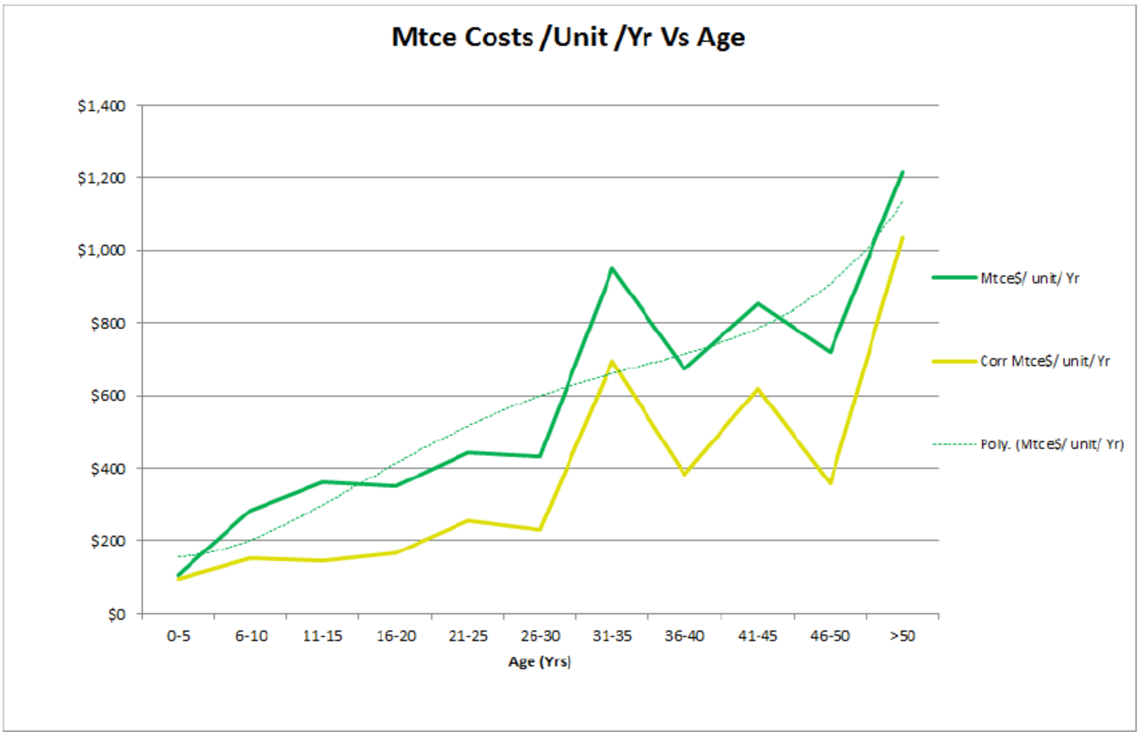


Figure D.5: SAP Data - Isolator Total Maintenance Cost

Current Transformers – Very little maintenance is required for current transformers which is generally limited to condition monitoring through gas in oil analysis and routine inspection, however due to their construction and relatively high levels of electrical stress they have the potential for sudden catastrophic failure.

As a result of the relatively large volumes of oil enclosed within the porcelain shells, the failure of the primary insulation system of a current transformer almost invariably results in an explosion and fire and accordingly can pose significant risk to personnel and adjacent plant and equipment.

Failure rates related to current transformer average age profile are shown, (note that failures are defined as any condition that results in the unit being removed from service). In general our experience with current transformer maintenance, monitoring and replacement indicates:

- Most current transformer faults (detected by dissolved gas analysis) occur in units older than 30 years or very early in the life of the unit (typically less than 10 years).
- New maintenance standards have introduced shorter sampling frequencies and a reduced acetylene limit of 5ppm which has increased the condemning rate of older current transformers with measurable acetylene levels.
- The on-going maintenance strategy is to limit the age of current transformers to 40 years due to the unacceptable consequence of catastrophic failure and the difficulty in detecting the much more likely sudden deterioration of aged units.

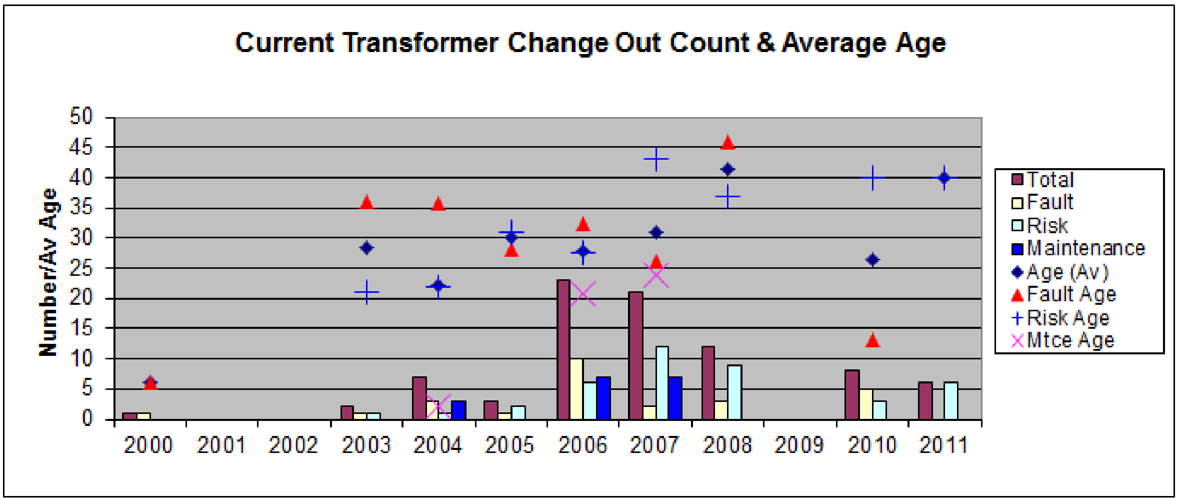


Figure D.6: Current Transformer Failure Profile

SAP maintenance data for instrument transformers shows the effect of higher maintenance and fault issues in early life, mid-life (30+ years) and end of life (40+ years).

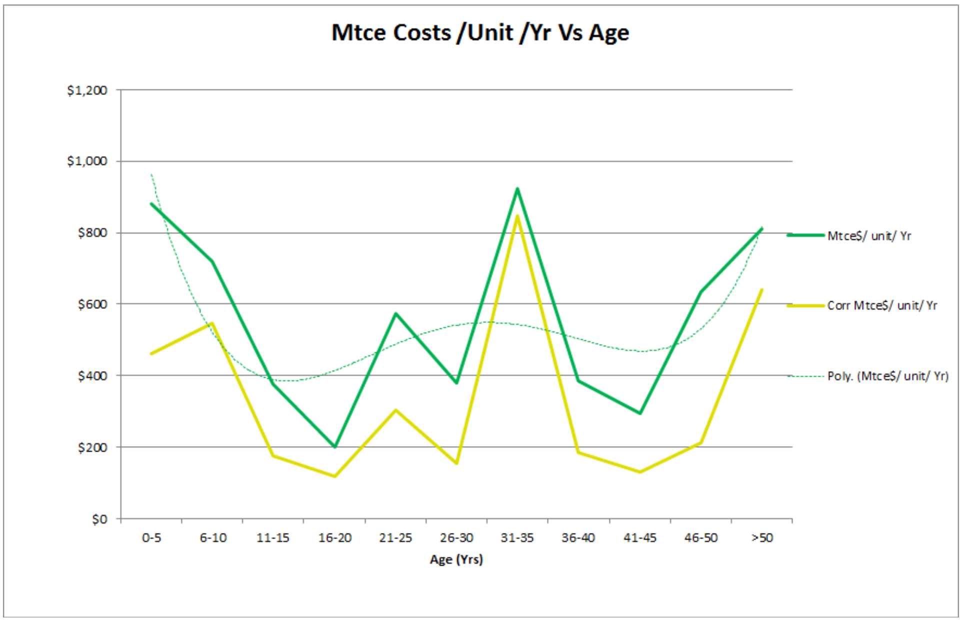


Figure D.7: SAP Data - Instrument Transformer Total Maintenance Cost

Capacitor voltage transformer failure characteristics indicate a recent population of early life failures, this appears to relate to poor quality manufacturing. The total CVT population is approximately 1000 units. The failure rate in 2010 was 0.1%.

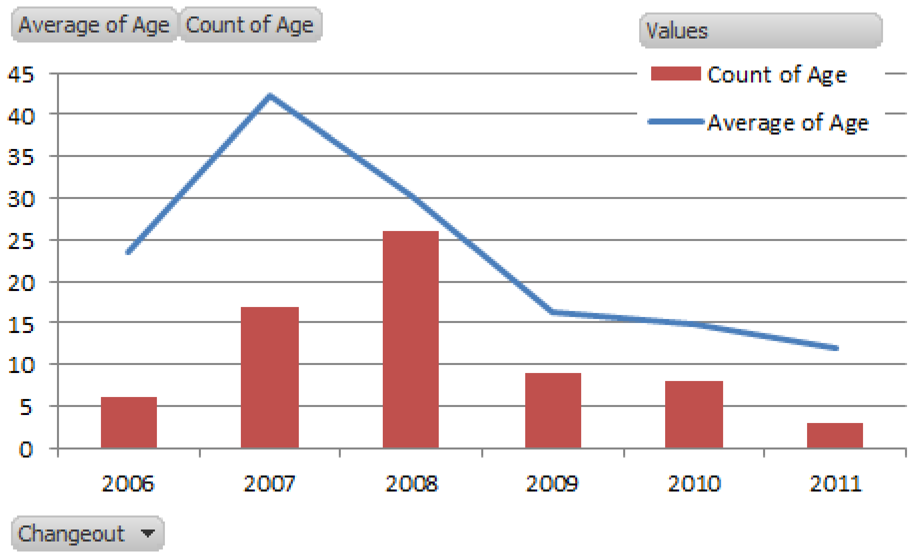


Figure D.8: CVT Failure Rates and Average Age

Appendix E Network Optimisation and Risk Management

Network Optimisation and Risk Management (NORM) projects scheduled for the 2013-2018 period are as follows:

Table E.1: NORM Project Expenditure – CAPEX ($2011/12)

Project	Project Name	CAPEX ($2011/12)
Automation of network control system	11865 Network Configuration Management Upgrade	[redacted]
Improve management of network power flows	11646 Upper North Voltage Control Scheme	[redacted]
	11647 Eyre Peninsula Voltage Control Scheme	[redacted]
Improve network asset utilisation	11620 Dynamic Constraint Systems	[redacted]
Improve transmission line asset utilisation	11620 Dynamic Constraint Systems	[redacted]
	11824 Weather Stations For Dynamic Line Rating	[redacted]
Total		[redacted]

Table E.2: NORM Project Expenditure – OPEX ($2011/12)

Project	Project Name	Project Ref	OPEX ($2011/12)
Improve network asset utilisation	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
Improve transmission line asset utilisation	[redacted]	[redacted]	[redacted]
Total			[redacted]

Appendix F Substation Refurbishment

Substation refurbishment projects are based on addressing significant asset condition deterioration that is beyond the scope of routine maintenance. Projects are identified by:

- An analysis of the defect backlog by asset group is shown below. Substation defects are recorded and grouped by asset type.
- Known specific asset condition and risk issues

F1 Defect analysis

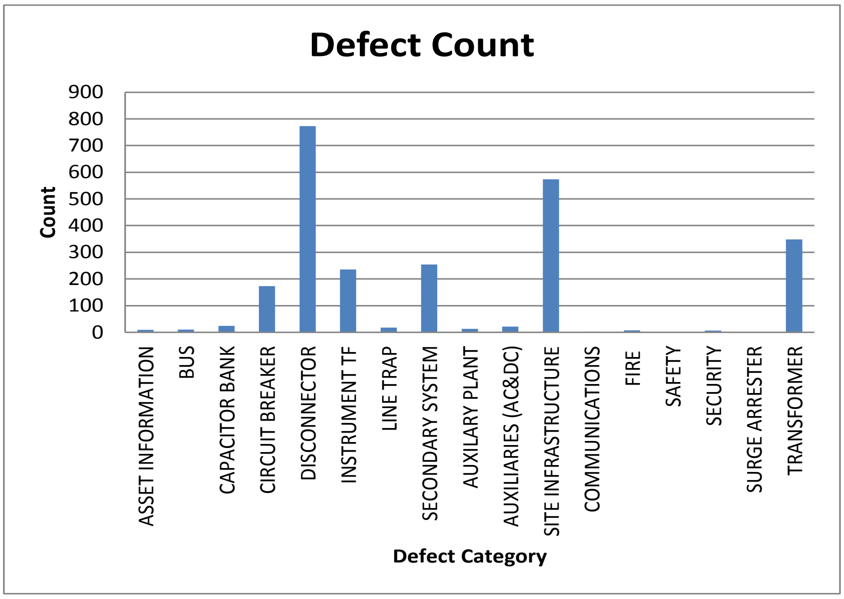


Figure F.1: Summary of Substation Defects by Group

Table F.1: Asset Refurbishment (based on defect analysis)

Group	Refurbishment Plan
Circuit Breaker	Minor defects - defer to routine maintenance
Isolator	Large range of major defects – establish overhaul programme
Instrument TF	Minor defects – defer to unit asset replacement & routine maintenance
Secondary System	Minor defects – defer to routine maintenance
Site Infrastructure	Large range of major defects – establish site civil remediation project
Transformer	Large range of defects – establish TF minor refurbishment project

F2 Condition and risk analysis

F2.1 Gas insulated switchgear

ElectraNet has 275 kV Gas Insulated Switchgear (GIS) at Northfield, Kilburn and East Terrace Substations that was installed during the 1980's. The GIS equipment is located in the open and is beginning to show evidence of physical deterioration.

Condition of substation GIS has been reviewed and identified for major overhaul based on:

- The equipment is currently at mid life
- Deterioration of protective coating and seals
- Poor condition of compressors and control equipment

F2.2 Transformer oil containment

Oil containment and treatment of discharge from transformer bunds is an area of environmental risk that requires the following actions in addition to routine maintenance:

- Replacement of redundant plate separator/oil blocking units
- Construction of transformer bunds (un-bunded transformers)

F2.3 Battery charger upgrade

A number of battery charger systems of various manufacturers and technology generations have reached the end of their practical life. The reliability, availability of spares and/or components, and manufacturer support/knowledge base represents an operational risk that requires the following actions in addition to routine maintenance:

- Replacement of identified high risk battery charger units

F2.4 Secondary system HMI upgrade

ElectraNet substations currently employ technology that enables users to view the status of components of plant within the substation through what has become to be known as a 'Human Machine Interface' or HMI. A number of these screen-based systems of a certain manufacturer and technology generation are now at their end-of-life phase and do not possess facility for spares and technical support. The fault trend with this unit is currently increasing to the point where a replacement with current technology is now warranted.

- Replacement of identified high risk HMI units

F3 Substation refurbishment projects

Substation refurbishment projects are recommended as follows:

- Substation Refurbishment Projects – High Risk
- Secondary Systems Refurbishment – High Risk
- Plant Overhaul Projects – High Risk

Table F.2: Substation Refurbishment Projects – High Risk

Project	Project Ref	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]		[redacted]

Table F.3: Secondary System Refurbishment Projects – High Risk

Project	Project Ref	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]
[redacted]		[redacted]

Table F.4: Plant Overhaul Projects – High Risk

Project	Project Ref	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]		[redacted]

Listed below are refurbishment or overhaul projects of lower priority that have been deferred from, or action requirements will be monitored, during the 2013- 2018 period.

Table F.5: Substation Refurbishment Projects – Medium/Low Risk

Project	Project Ref	Risk	Response	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]				[redacted]

Table F.6: Plant Overhaul Projects – Medium/Low Risk

Project	Project Ref	Risk	Response	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]				[redacted]

Appendix G Transformer Management Plan

The Transformer Management Plan is based on:

- Undertaking non-intrusive condition assessment of all power transformers as part of the routine maintenance task and identifying Asset Refurbishment Projects to mitigate unacceptable asset risk
- Understanding transformer end of life through the internal condition assessment of older power transformers through a programme of internal inspection.
- Maintaining a transformer re-deployment plan in order to identify potential capital efficiencies available from the redeployment of existing transformers made available through capital projects.

G1 Condition assessment

ElectraNet maintains a condition assessment programme for power transformers based on:

- Monitoring the quality of transformer insulating oil
- Monitoring transformer insulating oil fault indicator dissolved gas levels
- Monitoring the condition of the paper insulation (Degree of Polymerisation – a measure of the remaining life of the solid insulation)

A routine transformer test programme has been implemented to monitor:

- Transformer Bushing insulation condition
- Transformer winding electrical characteristics
- Transformer winding insulation characteristics

Routine substation inspection and maintenance programmes require:

- External inspection of the transformer
- Testing of cooling systems (pumps and fans)
- Maintenance of tap changers
- Maintenance of cooling and auxiliary systems

In general the outcomes of the condition assessment process may be classified as follows:

- **No Issues Identified** – all parameters and associated trends are within acceptable limits, therefore it is concluded that reliable operation of the unit will continue
- **Indicator Gases Identified** – An internal fault in the transformer is developing, based on the type and rate of gas generation the timing for taking the unit out of service can be predicted. Units with gassing problems are considered to be unreliable in the longer term.

- **Paper Insulation Degradation** – An indication that the transformer has reached end of life, replacement of the transformer is required.
- **Transformer Bushing Tests** – Trends or test values outside acceptable parameters indicate the requirement for bushing replacement. Older bushings of particular types with known insulation issues may require replacement.
- **Electrical and Winding Insulation Tests** – are indicators of developing or actual internal problems or faults, usually changes will occur following a major adverse event such as high through fault current to a nearby fault or a transient voltage rise. Generally older transformer units with loose winding supports or degraded solid insulation are susceptible to these types of faults.

Most condition assessment information is an indicator of a transformer fault that is either developing of has occurred. Paper insulation condition is the main indicator of solid insulation remaining life, note that there are no reliable indicators of the internal winding supporting structures, such as winding clamps and supports (elements that are critical in the performance of a transformer during a fault).

Transformer condition monitoring does not provide an accurate prediction of the remaining transformer life, but rather is an indicator that end of life has been reached.

G2 Transformer end of life

The nominal life of transmission network power transformers operating under design conditions is understood to be 45 years. In practice the actual end of life (assuming no earlier catastrophic events) may occur in relatively broad band of time outlined in Figure G.1. This behaviour is known from a small population of transformers installed when the transmission network was first established approximately sixty years ago.

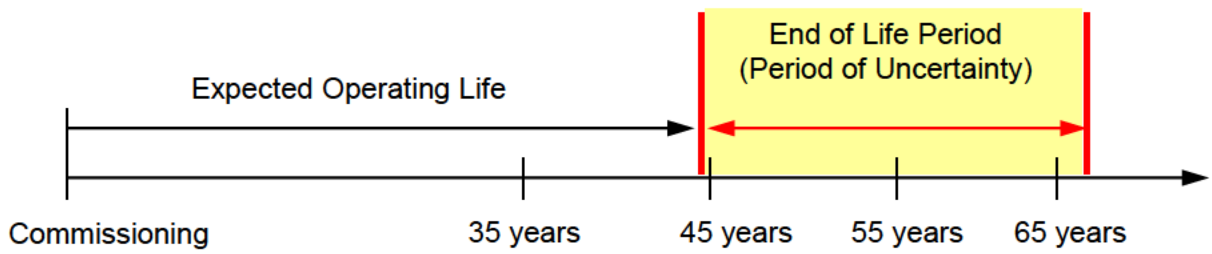


Figure G.1: Transformer End of Life

As reliable statistical analysis of transformer end of life performance in the period of uncertainty shown above has not been developed internal inspection of transformers representative of this group are undertaken.

G3 Transformer re-deployment plan

This Transformer Redeployment Plan is based on capital projects and their associated timings as identified in the 2011 Annual Planning Report. Additionally, the first five years of the Plan aligns with the capital projects in the current 5-year ElectraNet Business Plan.

It should be noted that the redeployment opportunities identified in this Plan are based on known condition issues associated with the existing transformers. Actual Redeployment and reuse would be based on a case by case basis, after a full condition assessment has been made. This assessment is to give due consideration to any remaining life and the associated refurbishment costs.

The plan chronologically identifies:

- The transformer's current location;
- The transformer's ID;
- The transformer's rating;
- The transformation voltages;
- The year the transformer replacement is planned;
- The limitation driving the transformer replacement;
- The location of potential redeployment or if earmarked to be scrapped;
- The redeployment year; and,
- If reuse is considered viable, the recommended interim storage location.

G4 Transformer refurbishment plan

During the 2008–2013 regulatory period a programme of internal inspection of transformers in the 35 to 45 year age range was undertaken in order to assess remaining life and refurbishment cost. Based on project costs and inspection information the following conclusions were reached:

Major internal inspection and refurbishment of transformers was in general not cost effective for small transformers (60 MVA and less) at of marginal cost benefit for larger transformers (note this marginal benefit was offset by operational difficulties associated with gaining access to the units for this work to be undertaken).

Internal inspection represented a cross section of typical transformers in the ElectraNet network, the inspection indicated remaining technical lives in the order of twenty years.

Based on the above, transformer refurbishment will be limited to only minor external work related to leaks, bushings and control systems.

ElectraNet has approximately 158 power transformers in the transmission network, 46% of these units have been in service for more than 30 years.

Until 2008 ElectraNet major overhaul of power transformers has not been routinely undertaken, this has resulted in a large backlog of routine maintenance and defects. Although a routine maintenance plan has now been implemented, the routine maintenance task is not designed to deal with the large backlog.

This project is to provide a power transformer minor refurbishment programme specifically developed to reduce the maintenance backlog by targeting transformers in service for more than 30 years.

Table G.1: Transformer Refurbishment Projects - Summary

Project	Project Ref	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]
[redacted]		[redacted]

The site locations and numbers of transformers are detailed in the table below.

Table G.2: Transformer Refurbishment Projects - Detail

SSD	Substation	Number of Transformers at Site	Total Substation Cost ($2011/12)
[redacted]	[redacted]	[redacted]	[redacted] [redacted]
[redacted]	[redacted]	[redacted]	[redacted] [redacted]
[redacted]	[redacted]	[redacted]	[redacted] [redacted]
[redacted]	[redacted]	[redacted]	[redacted] [redacted]
[redacted]	[redacted]	[redacted]	[redacted] [redacted]
[redacted]	[redacted]	[redacted]	[redacted] [redacted]
[redacted]	[redacted]	[redacted]	[redacted] [redacted]
[redacted]	[redacted]	[redacted]	[redacted] [redacted]
[redacted]	[redacted]	[redacted]	[redacted] [redacted]
[redacted]	[redacted]	[redacted]	[redacted] [redacted]
[redacted]	[redacted]	[redacted]	[redacted] [redacted]
[redacted]	[redacted]	[redacted]	[redacted] [redacted]
[redacted]	[redacted]	[redacted]	[redacted] [redacted]
[redacted]	[redacted]	[redacted]	[redacted] [redacted]
[redacted]	[redacted]	[redacted]	[redacted] [redacted]
[redacted]	[redacted]	[redacted]	[redacted] [redacted]
[redacted]	[redacted]	[redacted]	[redacted] [redacted]
[redacted]	[redacted]	[redacted]	[redacted] [redacted]
[redacted]	[redacted]	[redacted]	[redacted] [redacted]
[redacted]	[redacted]	[redacted]	[redacted] [redacted]
[redacted]	[redacted] [redacted]	[redacted]	
		[redacted]	[redacted]

Appendix H Substation Capital Replacement Plan

Substation functionality and maintenance effort profile at the end of the 2008 – 2013 period is estimated based on the current asset replacement and refurbishment program and updating substation condition assessment inspection data and scoring based on TALC criteria.

Sites with poor functionality and high effort risk have been identified as asset replacement projects for the following regulatory period. The long run effectiveness of the proposed capital works program is designed to manage the aggregate effect on the overall substation asset functionality and maintenance effort performance to acceptable and sustainable levels.

Note timing of replacement at some sites has been modified based on specific issues at that site. Refer to Table H.1 Substation Replacement below for further detail.

Where high risk unit assets are identified specific replacement of those assets is identified in Table H.2 Substation Unit Asset Replacement.

Substation replacement projects for the 2013 to 2018 regulatory period are summarised as follows:

Table H.1 Substation Replacement Projects

Project	Region	Comment on replacement driver	Estimate ($2011/12)
10505 Millbrook Pump Station	Eastern Hills	Asset replacement - condition based	[redacted]
11005 Kanmantoo Substation Upgrade	Eastern Hills	Poor Condition of Substation assets & emergency transformer deployed in 2011	[redacted]
10619 Kincraig Substation Replacement and Transformer Upgrade	South East	Poor asset condition & augmentation transformer capacity (2013-2018)	[redacted]
10618 Baroota Substation Upgrade	Mid North	Poor Condition of Substation assets & connection point reclassification	[redacted]
11504 Neuroodla Asset Replacement	Upper North	Primary & secondary assets at end of life	[redacted]
11316 Morgan Whyalla Pump Station No 1	Riverland	Primary & secondary assets at end of life	[redacted]
11317 Morgan Whyalla Pump Station No 2	Riverland	Primary & secondary assets at end of life	[redacted]
11318 Morgan Whyalla Pump Station No 3	Riverland	Primary & secondary assets at end of life	[redacted]
11319 Morgan Whyalla Pump Station No 4	Riverland	Primary & secondary assets at end of life	[redacted]
11313 Mannum Pump Station No 1	Eastern Hills	Primary & secondary assets at end of life	[redacted]

Project	**Region**	**Comment on replacement driver**	**Estimate ($2011/12)**
11314 Mannum Pump Station No 2	Eastern Hills	Primary & secondary assets at end of life	[redacted]
11315 Mannum Pump Station No 3	Eastern Hills	Primary & secondary assets at end of life	[redacted]
11505 Mt. Gunson Substation Replacement	Upper North	Primary & secondary assets at end of life	[redacted]
10509 Whyalla Terminal Substation Replacement	Eyre	Poor Condition of Substation assets & connection point reclassification	[redacted]
10503 Waterloo Substation Replacement	Mid North	Poor Condition of Substation assets & connection point reclassification	[redacted]
11305 Keith Substation Rebuild	South East	Poor asset condition & augmentation transformer capacity (2013-2018)	[redacted]
Total			[redacted]

The following substation replacement projects have been deferred.

Table H.2: Substation Replacement Projects - Deferred

Project	**Region**	**Comment on replacement driver**	**Estimate ($2011/12)**
Leigh Creek Substation	Upper North	Delayed pending long term future of supply point	-
Leigh Creek South Substation	Upper North	Delayed pending long term future of supply point	-

The Unit Asset Replacement program is aimed at efficiently addressing plant and equipment risk at the unit level to enable the overall substation asset to achieve its full intended service life, avoiding the need for full asset replacement.

Table H.3: Substation Unit Asset Replacement

Project	**Estimate ($2011/12)**
11890 Unit Asset replacement	[redacted]
Total	[redacted]

The site locations and individual assets are detailed in the table below.

Table H.4: Substation Unit Asset Replacement – Asset Type Summary

Asset Type	Number of Sites	Number of Assets
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Table H.5: Secondary Systems Replacement

Project	Estimate ($2011/12)
Para 275 kV Secondary Systems Replacement	[redacted]
Para SVC Secondary Systems Replacement	[redacted]
NGM CT, VT & Meter Replacement	[redacted]
Asset Condition Online Monitoring Equipment Replacement	[redacted]
Total	[redacted]

Appendix I Transmission Line Asset Rating

The Asset Rating and Risk Management Plan aims to provide accurate and repeatable geo-referenced asset information to enable ElectraNet to *demonstrate compliance* with its legal obligations of managing its transmission lines according to the SA Electricity Act and Regulations.

The Asset Rating and Risk Management Plan consists of a field data capture and analysis schedule, and subsequent Business Risk Mitigation and Asset Rating and Identification Projects to be conducted.

I1 Field data capture - asset surveying systems

Three surveying systems are to be used as part of the Field Data Capture Schedule. These are:

- Asset photography;
- Ground survey; and
- Airborne Laser Survey (ALS).

Asset photography, captured either from an aerial platform or from ground, provides time-stamped records of the installed assets and is used for asset data audits, asset change identification, and as inputs into field works planning. Asset photography is generally captured in conjunction with other field works so to minimise costs.

Ground Survey means a traditional topographical survey using traditional survey techniques. Ground surveys are predominantly used for ALS validation spot check works as part of the quality assurance process.

Airborne Laser Survey (ALS) uses LiDAR (Light Detection and Ranging) system, which is an optical remote sensing technology, mounted on an airborne platform to determine the range and/or other information of a distant target. This is combined with an inertial position and orientation system with integrated airborne GPS, together with simultaneous capture of high resolution digital camera imagery and environmental data. ALS is used for larger line segment or complete Built Section line and easement fully detailed survey/validation works. The outcomes of ALS are used for Business Risk Mitigation and Asset Rating and Identification Projects.

I2 ALS data capture methodology

Current ALS data analysis techniques allow for comparative analysis between asset surveys given the line assets geometry has not been significantly modified between surveys, i.e. by line uprate projects. Therefore following an initial data capture and analysis effort, only comparative analysis is required to identify changes, i.e. land use, vegetation clearance, easement encroachments, and the like.

I3 ALS data capture schedule

Initial data capture has been conducted in the 2008-2013 Period according to risk priority:

- Low Spans Risk Management
- Vegetation Clearance Audits in High Bushfire Risk Zones
- Network Development Strategy (Asset Rating)

Cyclic 5-year resurvey program will be scheduled according to the most cost efficient method over the time period.

All surveys will be co-ordinated with Lines Augmentation projects requiring asset surveys for engineering or as-built documentation so to optimise surveying effort and cost.

I4 Asset rating and network risk mitigation projects

The Network Risk Mitigation Projects are grouped as follows:

- Low Spans Risk Management projects;
    - Independent audit of surveyed lines for low span violations according to Schedule 2 of the SA Electricity Act (completed in 2008-13 Period), and
    - Land Use Survey for input into ESAA C(b)1 Low Spans Risk Management process (as per the Management of Low Spans process below)
- Independent Vegetation Clearance Audits, according to Part 5 Clearance of Vegetation from Power lines of the SA Electricity Act (ongoing, business as usual);
- Independent Easement Encroachment Audits, including identification of any developments/encroachments in the line easement that are in violation of the SA Electricity Act and Regulations (ongoing, business as usual);
- ALS Quality Assurance Project, including tolerance/sensitivity analysis and ground survey validation (completed in 2008-13 Period); and
- ERS Anchor Proof Loading systems development and field trials (completed in 2008-13 Period).
- Emergency Restoration Structure (ERS) systems development and field trials. This includes;
    - Systems/process development for using Lindsey ERS and Stobie Pole systems,
    - Systems/process field trials using Lindsey ERS and Stobie Pole systems, and
    - Lindsey ERS and Stobie Pole systems documentation update.

The estimated cost for the ERS systems development and field trial is shown in the table below.

Table I.1: Network Risk Mitigation Projects – High Risk

Project	Project Ref	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]
Total		[redacted]

Other Network Risk Mitigation projects will be further assessed and monitored during the 2013-2018 regulatory period and the lower priority projects deferred until the following 2019-2023 period. Medium/low priority projects are listed below.

Table I.2: Tower Refurbishment Projects– Medium/Low Priority

Project	Project Ref	Risk	Response	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total				[redacted]

The Asset Rating Projects are grouped as follows:

- Line Thermal Capacity Confirmation projects;
- Dynamic Line Rating Parameter Validation projects.

These projects have been identified as part of the Network Optimisation and Risk Management (NORM) set of projects. Refer Appendix E for the full project listing.

I5 Management of Low Spans

The clearance heights for aerial lines set out in Schedule 2 to the Regulations under the SA Electricity Act are NOT statutory requirements for aerial lines installed prior to 1 July 1997. ElectraNet has the choice of operating lines above clearance height or accepting the risk of operating at reduced height.

Regulations should be complied with by either applying the clearance heights OR undertaking a comprehensive risk management assessment using ESAA C(b)1.

Identification of low spans and the priority decision process to address them is shown below.

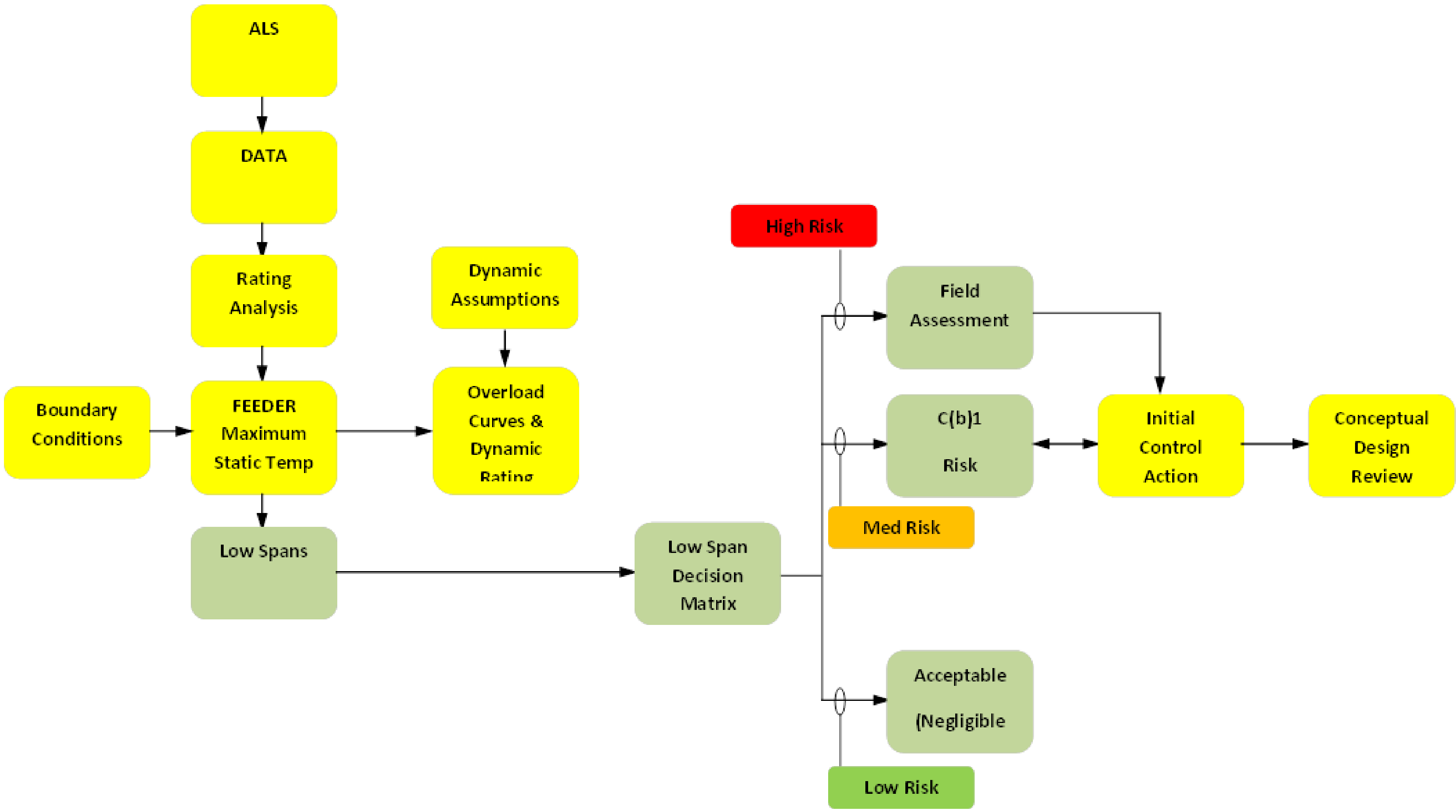


Figure I.1: Low Span Priority Decision Process

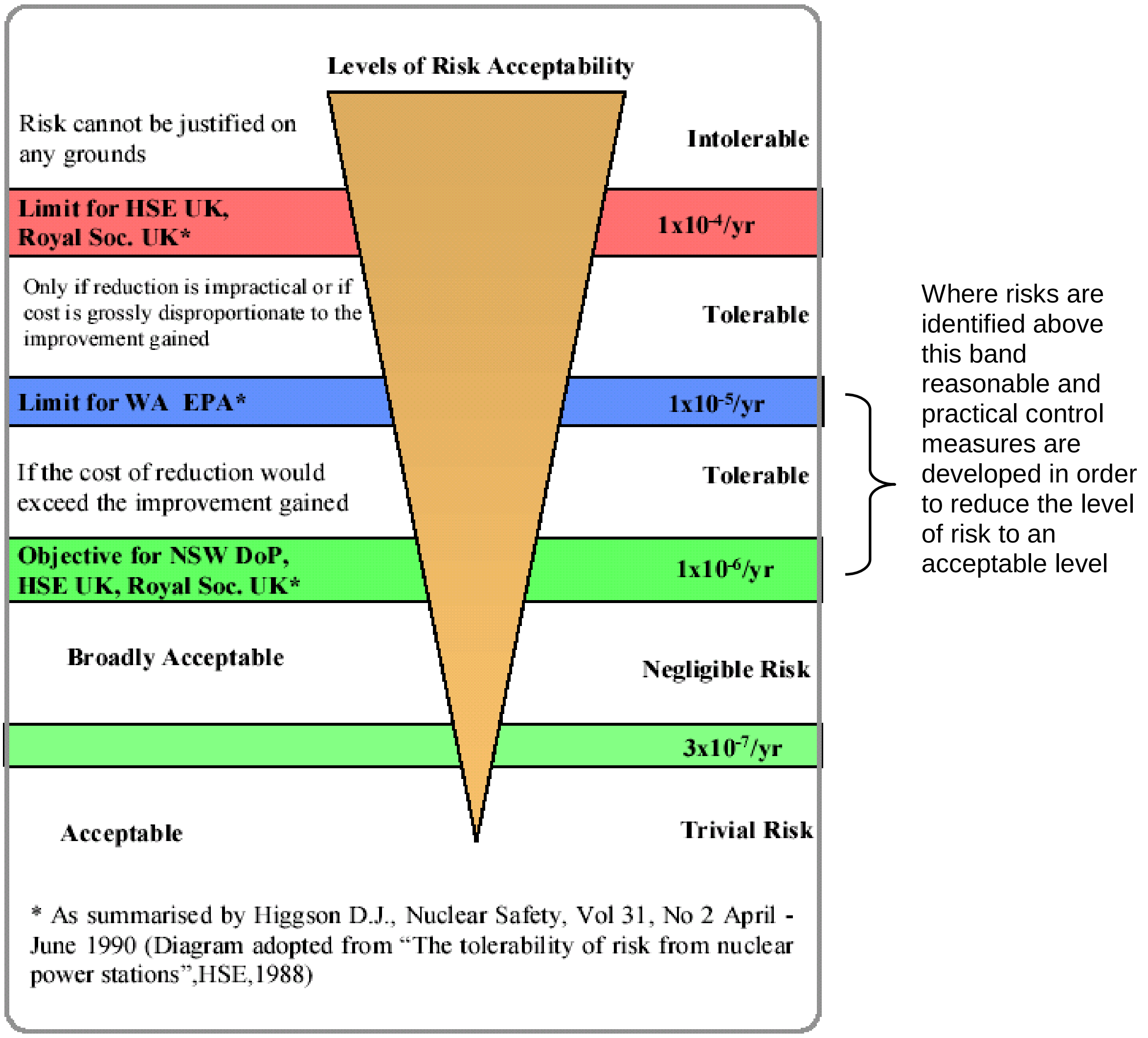


Figure I.2: ESAA C(b)1 Risk Definitions

Where lines are up rated or low spans are identified the risk and associated control measures must be considered by taking into account the line whole of life. Development of the business case to support risk control recommendations is based on the process shown below.

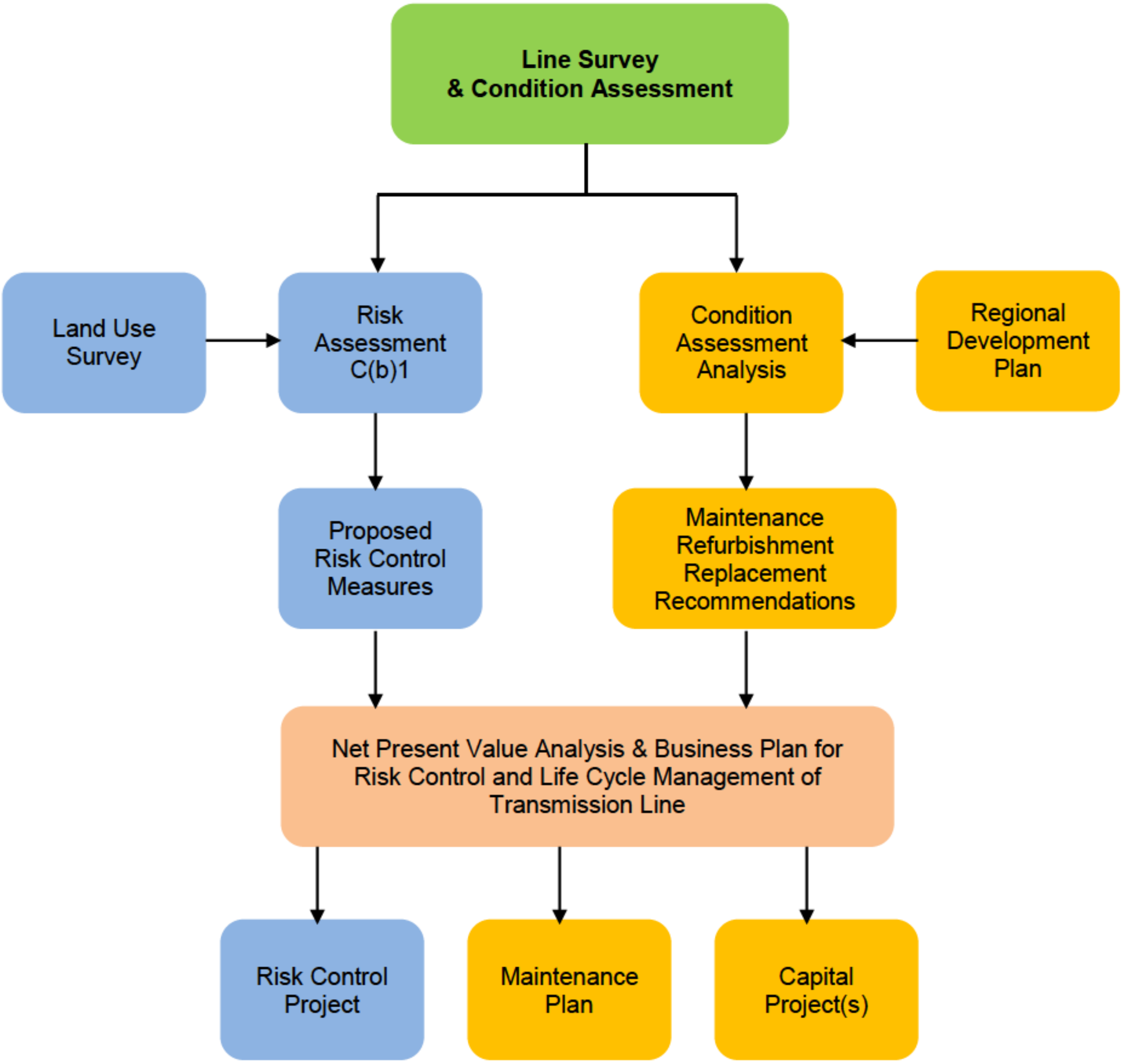


Figure I.3: Low Span Risk Mitigation Process

A project has been identified as part of the Network Optimisation and Risk Management (NORM) set of projects to address Line Remediation and Risk Management issues. Refer Appendix E for the full project listing.

Appendix J Transmission Line Removal

Decommissioning and removal of transmission lines is conducted in accordance with Policy 1-02-OP49 Transmission Line Decommissioning and Disposal. Lines currently decommissioned are shown in the table below.

Table J.1: Decommissioned Transmission Lines

Description	Length (km)
F1712 TIPS - NEW OSBORNE NO 1 (DE-ENERGISED)	1.40
F1713 TIPS – LEFEVRE (DE-ENERGISED)	1.40
F1819 WATERLOO-ROBERTSTOWN 1 (NOT ENERGISED)	26.11
F1823 NORTHFIELD - PARA (LINE TURNED BACK AT TOWER 7)	1.98
F1830 NORTHFIELD - ANGAS CREEK (ISOLATED)	13.65

J1 Planned line decommissioning

The following lines are planned for decommissioning:

- 1712 TIPS – New Osborne No1 (Port River High Crossing Section [De-energised])
- 1713 TIPS – LeFevre (Port River High Crossing Section [De-energised])
- 1712 TIPS – New Osborne No1 (Underground Cable Section [De-energised])
- 1713 TIPS – LeFevre (Underground Cable Section [De-energised])
- 1808 Davenport to Whyalla No1
- 1809 Davenport to Whyalla No2
- 1830 Northfield to Angas Creek (Isolated and turned back at Paracombe)
- 1836 Tailem Bend to Keith No1
- 1837 Keith to Snuggery

J2 Decommissioning plan – TIPS to New Osborne/LeFevre

F1712/1713 Port River High Crossing Section [De-energised]

The 66 kV feeders 1712 and 1713 Port River High Crossing became redundant to network requirements following the installation of the Pelican Point Power Station and associated network augmentation works on the LeFevre peninsula. Network planning studies to date have not identified an economic driver for retaining the asset, nor forecast to in a reasonable timeframe, so the asset will be dismantled in the 2007-2012 regulatory period.

The estimated cost for decommissioning and removal is shown in the table below.

Table J.2: Decommissioning Estimate Feeders 1712 & 1713 Port River High Crossing

Project	Project Ref	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]
Total		[redacted]

F1712, 1713, 1714 & 1715 Redundant Underground Cable Sections [De-energised]

The 66 kV feeders 1712 and 1713 have become redundant to network requirements following the augmentation of the 1714 and 1715 TIPS – New Osborne #3 & #4 66kV feeder underground cable sections installed in the 2007-2012 regulatory period. Further the 66 kV feeders 1714 and 1715 redundant cable sections were left in place.

These de-energised cable sections have been drained of insulating oil and capped at the power station (AGL) boundary fence as full asset removal was not practical at that time. These cables now represent an environmental hazard to the sensitive adjacent waterways as monitoring their condition has become unfeasible due to other planned works in the power station. A decommissioning and removal project has been scheduled in the 2013-2018 regulatory period to address this risk.

The estimated cost for decommissioning is shown in the table below.

Table J.3: Decommissioning Estimate Feeders 1712, 1713, 1714 & 1715 Redundant Underground Cable Sections

Project	Project Ref	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]
Total		[redacted]

The TIPS 66kV Cable Over/Under Station was also de-energised and become redundant following the augmentation of the 1714 and 1715 TIPS – New Osborne #3 & #4 66kV feeder underground cable sections installed in the 2007-2012 regulatory period. This equipment does not pose an immediate safety, environmental or asset risk. The TIPS 66 kV Cable Over/Under Station will be further assessed and monitored during the 2013-2018 regulatory period. Dismantling and removal of the assets is to be deferred until the following 2019-2023 period.

The estimated cost for decommissioning is shown in the table below.

Table J.4: Decommissioning Estimate TIPS 66kV Cable Station Removal

Project	Project Ref	Risk	Response	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total				[redacted]

J3 Decommissioning Plan – 1830 Northfield to Paracombe

The 132 kV feeder 1830 became redundant to network requirements following a network augmentation in the Eastern Hills 132kV network that utilised the Paracombe to Angas Creek segment of F1830 to connect to a new line from Para. ElectraNet has no future plans for reuse or to re-energise this line section due to its location.

Further, some of the structures on this line also carry ETSA Utilities assets. ETSA Utilities, via the Joint Planning meetings, has requested to take over ownership of those sections of line from Northfield Substation up to and including structure F1830-0031. This transfer, while not included in the scope of this project, represents an efficient economic outcome as part of the asset will continue to be utilised by another regulated entity.

This asset also presents significant access issues to perform inspection and maintenance tasks to manage public safety and asset risk due to the line route traversing across residential housing allotments and nature conservation areas in the Hills face zone for the section of the line from structure F1830-0031 to Paracombe.

Given the above the asset has been scheduled for de-commissioning and removal in the 2013-2018 regulatory period.

The estimated cost for decommissioning is shown in the table below.

Table J.5: Decommissioning Estimate Feeder 1830

Project	Project Ref	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]
Total		[redacted]

J4 Decommissioning Plan – Davenport to Whyalla

The 132 kV feeders 1808 and 1809 will become redundant to network requirements when replacement of Whyalla Terminal Substation and commissioning of a second 275 kV circuit from Davenport to Cultana are completed.

Condition assessment of these lines shows that they are towards end of life, in particular the Spencer Gulf crossing towers and foundation on Davenport to Whyalla No1 line. Considering the above the decommissioning plan is to:

- The end of the feeders near Cultana will be terminated on structures adjacent the substation but will be positioned so that connection to Stony Point and Yadnarie lines is possible.
- Both feeder segments will be re-energised from the Davenport to Whyalla No2 Line exit at Davenport
- These feeders will be retained for use as an emergency bypass for the Davenport to Cultana 275 kV double circuit line until a second line is constructed in the future.
- Gulf crossing towers will be further assessed and monitored during the 2013-2018 regulatory period. Dismantling and removal and the two feeders connected electrically on the western side of the Gulf in will be deferred until the following 2019-2023 period.

The estimated cost for decommissioning is shown in the table below.

Table J.6: Decommissioning Estimate Feeders 1808 & 1809

Project	Project Ref	Risk	Response	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total				[redacted]

J5 Decommissioning Plan – South East 132 kV No1 Line

Condition assessment indicates substantial refurbishment of major components of both feeders Tailem Bend to Keith and Keith to Snuggery is required as follows:

- Tower Foundation refurbishment
- Line Re-insulation
- Conductor Replacement

A market benefit test is currently in progress to assess possible market benefit project opportunity to increase interconnector capacity from South Australia to Victoria.

Preliminary results indicate that decommissioning and removal of the Tailem Bend to Keith and Keith to Snuggery 132 kV lines will provide a positive benefit by removing operating constraints associated with the limited capacity of these feeders and also reducing system losses.

At present no cost benefit has been identified to show that refurbishment of these lines should be undertaken in preference to decommissioning and removal. It is proposed that should the outcome of the market benefit test be positive then these feeders be decommissioned and dismantled in the regulatory period 2013–2018. Otherwise the decommissioning and dismantling works will be deferred until the following 2019-2023 period. Decommissioning estimates are shown below.

Table J.7: Decommissioning Estimates Feeders 1836 & 1837

Project	Project Ref	Risk	Response	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total				[redacted]

Appendix K Transmission Line Fire Start Risk Management

There is a potential risk that a fire start may be caused by an ElectraNet transmission line asset failure. While analysis of current transmission line asset inspection and maintenance history provides some data to predict how and when failures on the network will occur, prediction of potential failures could be improved by having a full set of inspection data, which is collected over relevant maintenance cycles.

Prior to this regulatory period, aerial and climbing inspections have been primarily focused on corrective maintenance rather than undertaking programs of systematic inspection and verification of asset condition, which would provide a fuller set of data.

Currently, a key element of managing bushfire risk involves taking lines out of service when very adverse weather conditions arise. This approach results in the effective management of risk but results in lower service levels to affected electricity consumers.

An improved risk-based approach is based on an inspection plan that maximises the likelihood of proactively discovering potential functional failures before they occur. This includes full implementation of modern/ contemporary condition-based inspection programs.

Based on the above, the following initiatives have been implemented in the current regulatory period in relation to fire start risk:

- The aerial inspection program has increased to include a full inspection and verification of the condition of all insulator strings (annually in all bushfire risk areas prior to bushfire season);
- Increased aerial inspection programs will continue to be undertaken until inspection and defect data indicates that potential failure of critical asset components is adequately addressed; and
- Tower inspection procedures have been amended to now require the maintenance provider to systematically inspect, verify and record the condition of critical asset components.

Appendix L Transmission Line Asset Refurbishment Plan

The Asset Refurbishment Plan is generated by utilising asset condition assessment information to identify OPEX Maintenance Projects to undertake replacement/refurbishment of groups of asset components based on risk and cost justification. High priority projects for transmission lines are summarised below.

Table L.1: Transmission Line Refurbishment Project Summary – High Priority

Project	Estimate ($2011/12)
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
Total	[redacted]

Medium to low priority projects for transmission lines are summarised below. The subject of these projects will be further assessed and monitored during the 2013-2018 regulatory period. As such these projects have been deferred until the following 2019-2023 period.

Table L.2: Transmission Line Refurbishment Project Summary – Medium/Low Priority

Project	Estimate ($2011/12)
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
Total	[redacted]

The transmission line asset has been broken down into the following functional element groups to enable appropriate condition risk analysis to be performed and OPEX Maintenance Projects identified. These functional element groups are:

- Conductor systems;
- Structures;
- Insulator and Insulator Hardware Systems; and
- Foundation Systems.

The OPEX Maintenance Projects to be conducted per the functional element groups are summarised below:

Figure L.1: Transmission Lines OPEX Maintenance by Functional Element

Feeder	Description	CA Required	Conductor	Insulator	Structure	Foundations	Subcomponents
1701	OCPL - NEW OSBORNE No1	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1702	OCPL - NEW OSBORNE No2	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1703	NEW OSBORNE - LEFEVRE NO 1	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1704	MONASH - BERRI	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1705	T PS NORTH - TIPS No1	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1706	T PS NORTH - TIPS No2	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1707	LEFEVRE - NEW OSBORNE NO 2	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1712	T PS - NEW OSBORNE NO 1 (DE-ENERGISED)	New Level 1 CA	Routine Task	Routine Task	Lines050- High	Routine Task	Routine Task
1713	T PS - LEFEVRE	New Level 1 CA	Routine Task	Routine Task	Lines050- High	Routine Task	Routine Task
1714	T PS - NEW OSBORNE No3	New Level 1 CA	Routine Task	Routine Task	Lines050- High	Routine Task	Routine Task
1715	T PS - NEW OSBORNE No4	New Level 1 CA	Routine Task	Routine Task	Lines050- High	Routine Task	Routine Task
1801	YADNARIE - WUD NNA	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1802	BUNGAMA - PORT P RIE	5 Yr CA Update	Routine Task	Routine Task	Lines050- High	Routine Task	Routine Task
1803	HUMMOCKS - ARDROSSAN WEST	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1804	MINTARO - CLARE NORTH	New Level 1 CA	Routine Task	CAPEX 11446	Routine Task	Routine Task	Routine Task
1805	WATERLOO - MINTARO	5 Yr CA Update	Routine Task	Lines051- High	Routine Task	Routine Task	Routine Task
1806	WATERLOO-WATERLOO EAST	5 Yr CA Update	Routine Task	Lines030- High	Routine Task	Routine Task	Routine Task
1807	NORTH WEST BEND - MONASH No2	5 Yr CA Update	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1808	DAVENPORT - WHYALLA No 1	5 Yr CA Update	Routine Task	Routine Task	Lines050- High	Routine Task	Routine Task
1809	DAVENPORT - WHYALLA No 2	5 Yr CA Update	Routine Task	Routine Task	Lines050- High	Routine Task	Routine Task
1810	WHYALLA - YADNARIE	5 Yr CA Update	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1811	YADNARIE - PORT L NCOLN	5 Yr CA Update	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1812	DAVENPORT-PIMBA	5 Yr CA Update	Routine Task	Routine Task	Routine Task	Lines025- High	Routine Task
1813	DAVENPORT-LEIGH CREEK	5 Yr CA Update	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1816	HUMMOCKS - BUNGAMA	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1818	BUNGAMA-BRINKWORTH	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1819	WATERLOO-ROBERTSTOWN 1 (NOT ENERGIS	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1820	NORTH WEST BEND - MONASH No1	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1821	TEMPLERS - WATERLOO	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1822	PARA - ROSEWORTHY	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1823	NORTHFIELD - PARA (L NE TURNED BACK AT	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1825	CHERRY GARDENS-MOUNT BARKER	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1826	MT BARKER - MOB LONG (MTBK-No 3 PUMP)	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1827	TA LEM BEND - KEITH 2	5 Yr CA Update	Routine Task	CAPEX 11445	Routine Task	Routine Task	Routine Task
1828	KEITH - KINCRAIG	5 Yr CA Update	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1829	SOUTH EAST - MOUNT GAMBIER	5 Yr CA Update	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1830	NORTHFIELD - ANGAS CREEK (ISOLATED)	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1831	K NCRAIG - PENOLA WEST	5 Yr CA Update	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1832	ANGAS CREEK-MANNUM	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1833	MANNUM-ADELA DE PUMP STATION No1	5 Yr CA Update	Lines002- High	Routine Task	Routine Task	Routine Task	Routine Task
1834	MANNUM - MOB LONG	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1835	MOBILONG - TAILEM BEND	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1836	TA LEM BEND - KEITH 1	5 Yr CA Update	Lines002- High	Routine Task	Routine Task	Routine Task	Routine Task
1837	KEITH - SNUGGERY	5 Yr CA Update	Lines002- High	Routine Task	Lines034- High	Routine Task	Routine Task
1838	SNUGGERY - BLANCHE	5 Yr CA Update	Routine Task	Lines051- High	Lines034- High	Lines056- High	Routine Task
1839	BLANCHE - MOUNT GAMBIER	5 Yr CA Update	Routine Task	Lines051- High	Lines034- High	Lines056- High	Routine Task
1840	PLAYFORD P S - NORTHERN P S TIE	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1841	HUMMOCKS - KADINA EAST	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1843	CULTANA - WHYALLA	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1844	CULTANA - STONY POINT	5 Yr CA Update	Routine Task	CAPEX 11448	Routine Task	Routine Task	Routine Task
1845	MOBILONG - No 1 PUMP STATION	5 Yr CA Update	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1846	ROBERTSTOWN - NORTH WEST BEND 1	5 Yr CA Update	Routine Task	Lines051- High	Routine Task	Routine Task	Routine Task
1847	ROBERTSTOWN - NWBEND 2 (ROBTN TO No 3	5 Yr CA Update	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1848	ARDROSSAN WEST-DALRYMPLE .	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1849	ROBERTSTOWN-NWBEND2 (No3 TO No2 PUMI	5 Yr CA Update	Routine Task	Lines030- High	Routine Task	Routine Task	Routine Task
1850	MT BARKER-MOBILONG(No3 PS TO KANMANT	5 Yr CA Update	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1851	MT BARKER-MOBILONG(No3 PS TO No2 PS)	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1852	MT BARKER-MOBILONG (No2 PS TO MOBILON	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1853	ROBERTSTOWN-NWBEND2(No2 PS TO No1 PS	5 Yr CA Update	Routine Task	Lines030- High	Routine Task	Lines056- High	Routine Task
1854	ROBERTSTOWN-NWBEND2(No1 PS TO NW BE	5 Yr CA Update	Routine Task	Lines030- High	Routine Task	Routine Task	Routine Task
1855	WATERLOO EAST-ROBERTSTOWN (No4 PS-R	5 Yr CA Update	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1856	BUNGAMA-BAROOTA	5 Yr CA Update	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1857	P MBA-WOOMERA	5 Yr CA Update	Routine Task	Routine Task	Routine Task	Lines025- High	Routine Task
1861	HUMMOCKS-WATERLOO	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1864	PENOLA WEST - SOUTH EAST	5 Yr CA Update	Routine Task	CAPEX 11444	Routine Task	Routine Task	Routine Task
1865	MONASH - BERRI No1	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1866	MONASH - BERRI No2	5 Yr CA Update	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1868	SNUGGERY - MAYURRA	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1869	PARA - ANGAS CREEK	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1870	SLEAFORD - PT L NCOLN	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1871	YADNARIE - MT M LLAR 132kV	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1872	SOUTH EAST - SNUGGERY 132KV	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1873	TEMPLERS - DORR EN	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1874	ROSEWORTHY - DORR EN	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1884	PLAYFORD - DAVENPORT No2	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1886	CLARE NORTH - BRINKWORTH	New Level 1 CA	Routine Task	CAPEX 11446	Routine Task	Routine Task	Routine Task
1887	REDH LL - CLEMENTS GAP W NDFARM	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1888	WATERLOO EAST-ROBERTSTOWN (WATERL(	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task

Feeder	Description	CA Required	Conductor	Insulator	Structure	Foundations	Subcomponents
1901	PELICAN POINT - PARAF ELD GARDENS WES	New Level 1 CA	Routine Task	Routine Task	Lines050- High	Routine Task	Routine Task
1902	T PS - PARA (No4)	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1903	T PS - CHERRY GARDENS	New Level 1 CA	Routine Task	Lines051- High	Routine Task	Routine Task	Routine Task
1905	MAGILL - HAPPY VALLEY	New Level 1 CA	Routine Task	CAPEX 11447	Routine Task	Routine Task	Routine Task
1906	CHERRY GARDENS - HAPPY VALLEY	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1907	CHERRY GARDENS-MORPHETT VALE EAST	5 Yr CA Update	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1908	HAPPY VALLEY - MORPHETT VALE EAST	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1910	BR NKWORTH - DAVENPORT (EAST CCT)	5 Yr CA Update	Routine Task	CAPEX 11441	Routine Task	Routine Task	Routine Task
1911	PARA - BR NKWORTH (EAST CCT)	5 Yr CA Update	Routine Task	CAPEX 11441	Routine Task	Routine Task	Routine Task
1912	T PS - MAG LL	5 Yr CA Update	Routine Task	Routine Task	Routine Task	Lines056- High	Routine Task
1913	PARA - MAGILL No1	5 Yr CA Update	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1916	NPS - DAVENPORT No1	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1917	NPS - DAVENPORT No2	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1918	PARA - BUNGAMA	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1919	DAVENPORT - CANOW E	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1920	DAVENPORT - BELAL E	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1921	PARA - TUNGK LLO	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1922	TA LEM BEND - SOUTH EAST No1	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1923	TA LEM BEND - SOUTH EAST No2	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1924	PELICAN POINT - LEFEVRE	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1925	LEFEVRE - T PS	New Level 1 CA	Routine Task	Routine Task	Lines050- High	Routine Task	Routine Task
1926	CANOWIE - ROBERSTOWN	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1930	SOUTH EAST - HEYWOOD No1	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1931	SOUTH EAST - HEYWOOD No2	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1932	T PS - K LBURN	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1933	KILBURN - NORTHFIELD	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1934	T PS - NORTHF ELD	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1935	DAVENPORT - CULTANA No1	New Level 1 CA	Routine Task	Routine Task	Lines050- High	Routine Task	Routine Task
1936	DAVENPORT - CULTANA No2	New Level 1 CA	Routine Task	Routine Task	Lines050- High	Routine Task	Routine Task
1937	PLAYFORD - DAVENPORT No1	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1938	ROBERTSTOWN - TUNGK LLO	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1940	PARAF ELD GARDENS WEST - PARA	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1941	BUNGAMA - DAVENPORT	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1942	TUNGK LLO - TA LEM BEND	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1943	TUNGK LLO - CHERRY GARDENS	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1944	CHERRY GARDENS - TA LEM BEND	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1945	PARA - ROBERTSTOWN	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1946	MOKOTA - ROBERTSTOWN	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task
1951	BELALIE - MOKOTA	New Level 1 CA	Routine Task	Routine Task	Routine Task	Routine Task	Routine Task

L1 Conductor systems

No Conductor System refurbishment or replacement projects have been identified for the 2013-2018 Regulatory Period.

L2 Structures

Refurbishment/replacement works for transmission line structures have been determined from condition assessment programs focussing on structure member, structure fastener, and ground line interface corrosion.

L2.1 Tower Refurbishment/Replacement

The following projects have been identified by condition assessment programs for refurbishment or replacement works and form the prioritised project list below. High priority projects have been recommended for funding as below the table below.

Table L.3: Tower Refurbishment Projects

Project	Project Ref	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]
Total		[redacted]

Tower assets will be further assessed and monitored during the 2013-2018 regulatory period and the lower priority projects deferred until the following 2019-2023 period. Medium/low priority projects are listed below.

Table L.4: Tower Refurbishment Projects– Medium/Low Priority

Project	Project Ref	Risk	Response	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total				[redacted]

L2.2 Stobie Pole Refurbishment/Replacement

No Stobie Pole high priority refurbishment/replacement projects have been identified for the for the 2013-2018 Regulatory Period.

Stobie pole and spun concrete pole assets will be further assessed and monitored during the 2013-2018 regulatory period and the lower priority projects deferred until the following 2019-2023 period. Medium/low priority projects are listed below.

Table L.5: Stobie Pole Refurbishment/Replacement Projects – Med/Low Priority

Project	Project Ref	Risk	Response	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total				[redacted]

L3 Insulator and insulator hardware systems

Refurbishment/replacement works for transmission line insulators & insulator hardware systems have been determined from condition assessment programs focussing on aged insulator systems with known failures.

L3.1 Insulator system replacement

The following insulator systems have been identified by condition assessment programs for replacement works and form the prioritised project list below:

Table L.6: Insulator Replacement Project– High Priority

Project	Project Ref	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]
Total		[redacted]

Line re-insulation projects have been identified for a number of transmission feeders where the insulator components have reached end of technical life.

Table L.7: Transmission Line Re-Insulation (CAPEX) Project List

Project	Estimate ($2011/12)
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
Total	[redacted]

L4 Foundation systems

Refurbishment/replacement works for transmission line structure foundation systems have been determined from condition assessment programs utilising detailed tower footing inspections, non-destructive testing and subsequent analysis of tower structural integrity under expected wind-loading conditions. High priority projects are recommended below.

The prioritised project list is below:

Table L.8: Foundation Refurbishment Project– High Priority

Project	Project Ref	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]
Total		[redacted]

The outcomes of the F1812/57 Footing Repair project will drive the need for further refurbishment works for F1812/57 in the following 2019-2023 Regulatory Period.

L5 Earthing systems

Refurbishment/replacement works for transmission line structure earthing systems have been determined from condition assessment programs.

No transmission line structure earthing systems refurbishment or replacement projects have been identified for the 2013-2018 Regulatory Period

Transmission line structure earthing systems will be further assessed and monitored during the 2013-2018 regulatory period and the lower priority projects deferred until the following 2019-2023 period. Medium/low priority projects are listed below.

Table L.9: Structure Earthing Refurbishment Projects – Med/Low Priority

Project	Project Ref	Risk	Response	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total				[redacted]

Appendix M Transmission Line Condition Assessment Plan

Condition assessment information is used for identifying OPEX Maintenance Projects to undertake replacement/refurbishment of groups of asset components based on risk and cost justification.

The transmission line asset has been broken down into the following functional element groups to enable appropriate condition risk analysis to be performed. These functional element groups are:

- Conductor systems;
- Structures;
- Insulator and Insulator Hardware Systems; and
- Foundation Systems

The Condition Assessment Projects to be conducted per the functional element groups are summarised below. High priority projects are recommended.

Table M.1: Condition Assessment Project Summary – High Priority

Project	Project Ref	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
Total		[redacted]

M1 Engineering support

In addition to the field Condition Assessment works, engineering support to create condition assessment reports encompassing all functional element groups for each feeder in the system.

Table M.2: Engineering Support Projects

Project	Project Ref	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]
Total		[redacted]

M2 Conductor systems

Conductor/Joint thermal chain analysis has been planned to assess the condition of transmission line thermal chains via multiple complementary methods. These are:

- Mid-span joint resistance testing
- Dead-end joint thermography
- Conductor material assessment

M2.1 Mid-span joint resistance testing

Prior to the establishment of a routine maintenance task to systematically test the resistance of mid-span joints on a sample basis, a risk prioritised testing program has been developed. The risk considerations are:

- Line uprate projects (past or planned future);
- Line criticality (HBFRA, public safety [joints in spans across roads], load, generation);
- Environment;
- Age;
- Defect/Condition Assessment history.

From the prioritised list, access to the mid-span joints is planned as follows:

Table M.3: Mid Span Joint Access Method

Location	Access Method
Rural	Aerial platform
Urban	Ground-based platform

A risk based program has been developed based on initial testing methodology, results and analysis performed in the 2007-2012 period.

Table M.4: Mid-Span Joint Testing Projects

Project	Project Ref	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
Total		[redacted]

A prerequisite for the mid-span joint testing program is identification and recording of each mid-span joint in the transmission line network. This work will be carried out as part of the Asset Identification program conducted as part of the Lines Asset Rating & Risk Management Plan.

M2.2 Dead-end joint thermography

Prior to the establishment of a routine maintenance task to systematically perform thermography on dead-end joints on a sample basis, a risk prioritised testing program has been developed. The risk considerations are:

- Line uprate projects (past or planned future);
- Line criticality (HBFRA, public safety [spans across roads/rail], load, generation);
- Environment;
- Age;
- Defect/Condition Assessment history.

The prioritised list will be co-ordinated with the mid-span joint testing program.

From the prioritised list, access to the dead-end joints is planned as follows:

Table M.5: Dead End Joint Access Method

Location	Access Method
Rural	Aerial platform
Urban	Ground-based

A risk based program has been developed based on initial testing methodology, results and analysis performed in the 2007-2012 period.

Table M.6: Dead End Joint Testing Projects – High Priority

Project	Project Ref	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]
Total		[redacted]

M2.3 Conductor material testing

Production of Conductor Condition Life Assessment Models encompassing construction techniques, corrosion assessments, physical damage/defects analysis, environmental conditions, and material life-cycle aging is planned. Earth Wires are to be included as part of the assessment.

This process will be started using the following methods:

- High level desktop planning study
  - prioritise areas of interest
  - assessment criteria
  - test methods
- Field trial non-destructive testing (NDT)
- Analyse conductor removed during Project Works

The recommended high priority conductor assessment and testing projects is shown below.

Table M.7: Conductor Material Testing

Project	Project Ref	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]
Total		[redacted]

The outcomes of the above works will drive the future conductor and earth wire condition assessment projects in the 2019-2023 period.

Table M.8: Conductor Material Testing – Medium/Low Priority

Project	Project Ref	Risk	Response	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total				[redacted]

M3 Structures

Structure member, structure fastener, and Groundline interface corrosion are the main factors in determining refurbishment/replacement works for transmission line structures.

M3.1 Tower condition assessment

Tower condition assessments will be driven by the establishment of a routine maintenance task to systematically perform the condition assessments on a sample basis. The routine task schedule will be prioritised according to the following risk considerations:

- Environment;
- Age;
- Defect/Condition Assessment history.

Tower condition assessments will be conducted as per 1-03-P06 Procedure A&O Transmission Line Maintenance Tower Inspection.

Earth wire condition assessment will also be undertaken in conjunction with tower condition assessments, where earth wires are installed. Earth wire condition assessments will be conducted as per 1-03-P09 Procedure A&O Transmission Line Maintenance Earth Wire Inspection.

A specific *special structure* condition assessment project has been scheduled to accelerate the tower condition assessment program due to the asymmetrical risks these structures present compared to standard design structures. The recommended high priority special structure condition assessment project is shown below.

Table M.9: Tower Condition Assessment – High Priority

Project	Project Ref	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]
Total		[redacted]

M3.2 Stobie pole groundline condition assessment

Stobie Pole groundline condition assessments will be driven by the establishment of a routine maintenance task to systematically perform the condition assessments on a sample basis. The routine task schedule will be prioritised according to the following risk considerations:

- Environment;
- Age;
- Defect/Condition Assessment history.

Stobie Pole groundline condition assessments will be conducted as per 1-03-P07 Procedure A&O Transmission Line Maintenance Pole Stobie Groundline Inspection.

M3.3 Stobie pole condition assessment

Stobie Pole condition assessments will be driven by the establishment of a routine maintenance task to systematically perform the condition assessments on a sample basis. The routine task schedule will be prioritised according to the following risk considerations:

- Environment;
- Age;
- Defect/Condition Assessment history.

Stobie Pole condition assessments will be conducted as per 1-03-P19 Procedure A&O Transmission Line Maintenance Pole Stobie Inspection.

M4 Insulator and insulator hardware systems

The continued safe operation of a transmission line is dependent on the quality of the conductor support by insulators on structures. The insulators provide the critical linkage between conductors and structures and are required to perform under onerous concurrent electrical and mechanical stresses.

To achieve this overall objective mitigation of the following risks must be addressed:

- line component failure which may result in dropped conductors
- Insulator flashovers which may result in dropped conductors or system interruptions

Prior to the establishment of a routine maintenance task to systematically perform insitu insulator inspection and testing on a sample basis, a risk prioritised testing program has been developed. The risk considerations are:

- Insulator type (porcelain);
- Environment (HBFRA);
- Age;
- Defect/Condition Assessment history.

Insitu Insulator Inspection and Live Line Voltage Profiling will be conducted as per 1-03-P03 Procedure A&O Transmission Line Maintenance Insulator Insitu Inspection.

Earth wire condition assessment will also be undertaken in conjunction with insitu insulator inspections, where earth wires are installed. Earth wire condition assessments will be conducted as per 1-03-P09 Procedure A&O Transmission Line Maintenance Earth Wire Inspection.

A risk prioritised program is currently being conducted in the 2007-2012 period. The continuation of this program is shown below.

Table M.10: Insulator Testing Program – High Priority

Project	Project Ref	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]
Total		[redacted]

M5 Foundation Systems

The foundation systems of towers are an integral part of the overall structural integrity of a tower. Degradation of tower footings can lead to future footing failures resulting in the potential total collapse of the tower structure under expected wind-loading conditions.

Prior to the establishment of a routine maintenance task to systematically perform detailed tower footing inspections and non-destructive testing on a sample basis, a risk prioritised testing program has been developed. The risk considerations are:

- Environment (Geotechnical);
- Age;
- Defect/Condition Assessment history.

Tower footing inspections will be conducted as per 1-03-P25 Procedure A&O Transmission Line Maintenance Tower Footing Inspection.

A risk prioritised program is currently being conducted in the 2007-2012 period. The continuation of this program is shown below.

Table M.11: Foundation System Testing Program – High Priority

Project	Project Ref	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]
Total		[redacted]

Appendix N Transmission Line Easement Management Plan

The Easement Management Plan aims to investigate, analyse and document risk mitigation measures to enable ElectraNet to *demonstrate compliance* with its legal obligations of managing its transmission line easements according to the SA Electricity Act and Regulations, as well as meeting relevant industry guidelines according to ENA C(b)1. The specific focus areas relating to easement management are:

- Entry to Easements;
- Animal and Plant Control and Heritage Site Management;
- Vegetation Clearance;
- Electrical Safety – Clearance of Public Structures;
- Electrical Safety – Equipotential Rise of area adjacent to structure during fault conditions;
- Electrical Safety – Clearance to other Electrical Infrastructure; and
- Easement Maintenance (Right of Way).

The Easement Management Plan consists of Business Risk Mitigation Projects to be conducted. These are summarised below, these projects are not recommended due to low risk:

Table N.1: Easement Risk Mitigation Projects

Project	Project Ref	Risk	Response	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total				[redacted]

N1 Entry to easements

The risk of adverse consequences from not meeting and demonstrating compliance, with respect to landholder complaints and claims for property/stock damage, will be managed by the establishment and auditing of a routine Entry to Easement task to systematically document easement entry requests on a per access basis.

All access to easements will be conducted as per 1-03-P24 Procedure A&O Transmission Line Maintenance Easement Entry.

No Entry to Easement projects have been identified for the current 2008-2013 Regulatory Period.

N2 Animal and plant control and heritage site management

The risk of adverse consequences from not meeting and demonstrating compliance, with respect to requirements set by relevant Government Authorities and landholder complaints and/or claims for property/stock damage, will be managed by the establishment and auditing of information systems for identifying restricted areas and required practices to access and minimise impact on them.

The environmental management systems and associated practices will be conducted as per 1-03-P22 Procedure A&O Transmission Line Maintenance Weeds, Animals and Heritage.

No Animal and Plant Control and Heritage Site Management projects have been identified for the current 2008-2013 Regulatory Period.

N3 Vegetation clearance

Vegetation management must be conducted in a manner that demonstrates full compliance with the requirements of the Electricity Act – Part 5 Clearance of Vegetation from Power-lines (general requirements for the clearance of vegetation) and Electricity (Principles of Vegetation Clearance) Regulations 2010 (specific requirements for the clearance of vegetation).

Vegetation management on transmission line easements is aimed at preventing contact or electrical flashover between live high voltage conductors and easement vegetation. The primary driver is public safety, particularly to prevent possible fire starts. Fire starts due to flashover or contact with vegetation represent an extreme risk to ElectraNet where the consequence of a fire start under adverse conditions may result in multiple fatalities and property loss in the order of hundreds of millions of dollars. To mitigate this risk it is necessary to develop a vegetation management process that demonstrates compliance.

To achieve this risk mitigation objective by way of a vegetation management process the following factors must be addressed:

- Modelling the position of High Voltage conductors under all foreseeable operating conditions
- Location and recording the position of vegetation relative to the conductor
- Individual validation of the cutting profile for each item of vegetation
- Recording of all critical profile dimensions for each item of vegetation
- Auditing of the validation, field inspection and cutting process

This process is documented as 1-03-P20 Procedure A&O Transmission Line Maintenance Easement Vegetation Management.

N4 Electrical safety – clearance of public structures

The risk of adverse consequences from a development occurring within an easement or adjacent to infrastructure without adequate consent, which then needs to be modified, will be managed by improving communication with Local Councils to ensure development approvals are obtained. It is expected that this risk mitigation strategy will enable integration with Local Government process to reduce risk of substantial oversight.

All development assessments will be conducted as per 1-03-P21 Procedure A&O Transmission Line Maintenance Easement Electrical Safety.

No Electrical Safety – Clearance of Public Structures projects have been identified for the current 2013-2018 Regulatory Period. All works to communicate with Local Councils and to integrate with Local Government process will be carried out by Network Services: Land Development BU.

N5 Electrical safety – equipotential rise of area adjacent to structure during fault conditions

Equipotential rise (EPR) of area adjacent to structure during fault conditions represents a public safety risk/duty of care issue resulting in a possible fatality if not managed appropriately. ENA C(b)1 documents guidelines on demonstrated risk based management of EPR on transmission line structures. Significant works have already been performed in line with this guideline in preparation to construct and implement an EPR Risk Management Plan.

To further this work, field evaluation of structure footing earth resistances must be carried out to determine the risk exposure in the environmental areas, as detailed in the 1-03-G02 Guideline A&O Transmission Line Maintenance Inspection Coding. Structure earth footing impedance testing and assessment will be carried out as a routine maintenance task according to 1-03-P10 Procedure A&O Transmission Line Maintenance Earth Footing Impedance.

The outcomes of the routine maintenance task and subsequent analysis will drive the future EPR Risk Management Plan works including data gathering, assessment, or asset modification projects.

No Electrical Safety – Equipotential Rise of area adjacent to Structure during Fault Conditions projects have been identified for the 2013-2018 Regulatory Period.

N6 Electrical safety – spacing of conductors between different circuits

Conductors of different circuits on different supports (unattached crossings) must have sufficient separation to prevent circuit to circuit or phase to phase contact or flash-over to minimise public safety/duty of care and asset risk. To mitigate this risk it is necessary to develop a undercrossing management process that evaluates and demonstrates compliance to relevant industry guidelines according to ENA C(b)1.

Current transmission line survey information has highlighted multiple instances of under-crossings (distribution lines crossing under higher voltage transmission lines) that have been recommended to be investigated to determine if adequate clearance is present under the terms of ENA C(b)1.

Development of an undercrossing management process in conjunction with ETSA Utilities, plus evaluation of the recommended undercrossing sites will be by the prioritised project list is below, high priority projects are recommended.

Table N.2: Undercrossing Management Projects – High Priority

Project	Project Ref	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]
Total		[redacted]

The outcomes of the Undercrossing Analysis will drive the future data gathering, assessment, or asset modification projects.

N7 Easement maintenance (right of way)

The risk of adverse consequences from inadequate access track or gate maintenance, which results in a breach of duty of care relating to safety or the environment, will be managed by demonstrating adequate levels of maintenance. This will be achieved via routine access track and gate maintenance inspections conducted according to 1-03-P14 Procedure A&O Transmission Line Maintenance Circuit Inspection Ground. Access track and gate condition will be assessed according to 1-03-G02 Guideline A&O Transmission Line Maintenance Inspection Coding.

Given the above the following Business Risk Mitigation Projects listed below are not recommended due to low risk. The outcomes of the routine access track and gate maintenance inspections will drive the future data gathering, assessment, or asset modification projects in the 2019-2023 period.

Table N.3: Easement Maintenance (Right of Way) Projects – Medium/Low Priority

Project	Project Ref	Risk	Response	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total				[redacted]

Appendix O Underground HV Cable Management Plan

The Underground HV Cable Management Plan is generated by utilising asset condition assessment information to identify OPEX Maintenance Projects to undertake replacement/refurbishment of groups of asset components based on risk and cost justification.

The Underground HV Cable Management Plan aims to address asset risk for both oil-filled and XLPE cable types. The OPEX Maintenance Projects to be conducted are summarised below:

O1 Underground HV Cable Emergency Restoration Plans

A review of the capability of ElectraNet's current Maintenance Service Providers (MSPs) and of the industrial service market in Australia/New Zealand to adequately enact emergency restoration of ElectraNet's underground HV cables in a timely manner has identified as a significant risk. This risk was also identified during the planning stages of the Adelaide Central Reinforcement (ACR) Project with respect to the selection of a 275 kV XLPE cable to form the F1949 TIPS – City West line. The ACR Project will address the emergency restoration risk specifically for the F1949 TIPS – City West line.

The required service definition, identification of suitable service providers and establishment of service agreements for oil-filled cables is to form the Underground HV Cable Emergency Restoration Plan.

O2 Underground HV Oil-Filled Cables

Refurbishment/replacement works for underground HV Oil-Filled cables have been determined from defect analysis and condition assessment programs focussing on cable instrumentation and other auxiliary systems.

The prioritised underground HV Oil-Filled cables project list is shown below, high priority projects are recommended below:

Table O.1 Cable Auxiliary Replacement Projects – High Priority

Project	Project Ref	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
Total		[redacted]

The outcomes of the Cable Auxiliary Replacement Projects will provide input into future requirements for the management of underground HV Oil-Filled cables. These potential projects for the 2019-2023 regulatory period are listed below:

Table O.2 Cable Auxiliary Replacement Projects – Medium/Low Priority

Project	Project Ref	Risk	Response	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total				[redacted]

Appendix P Telecommunications Management Plan

P1 Telecommunications refurbishment plan

The Telecommunications Refurbishment Plan is generated by utilising asset condition assessment information to identify OPEX Maintenance Projects to undertake replacement/refurbishment of groups of asset components based on risk and cost justification.

The OPEX Maintenance Projects to be conducted per project type are summarised below:

Table P.1: Telecommunications Refurbishment Projects

Project	Project Ref	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
Total		[redacted]

The outcomes of the Telecommunications Refurbishment Projects will drive the future data gathering, assessment, or asset modification projects in the 2019-2023 period.

P2 Telecommunication systems

Refurbishment/replacement works for telecommunication systems have been determined from condition assessment programs focussing on asset risk.

The risk considerations are:

- No manufacturer support;
- Spares in use are from re-covered systems;
- Capacity;
- Age;
- Defect/Condition Assessment history.

The Telecommunications prioritised project list is below:

Table P.2: Telecommunications Capital Projects

Project	Estimate ($2012/13)
Asset Replacement (End of Life)	
Tel Asset Replacement - Metro Region	[redacted]
Tel Asset Replacement - Mid North Region	[redacted]
Tel Asset Replacement - South East Region	[redacted]

Project	Estimate ($2012/13)
Tel Asset Replacement - Eyre Region	[redacted]
Tel Asset Replacement - Upper North Region	[redacted]
Tel Asset Replacement - Eastern Hills Region	[redacted]
Tel Asset Replacement - Riverland Region	[redacted]
Asset Replacement (Capability)	
South East Substation to Heywood Telecommunications Bearer	[redacted]
Yadnarie - Port Lincoln Backbone Telecommunications Links	[redacted]
Riverland Telecommunications Bearer	[redacted]
Barn Hill telecoms Bearer Replacement	[redacted]
Total	[redacted]

Appendix Q Weather Station Management Plan

Q1 Weather station refurbishment plan

The Weather Station Refurbishment Plan is generated by utilising asset condition assessment information to identify OPEX Maintenance Projects to undertake replacement/refurbishment of groups of asset components based on risk and cost justification.

Q1.1 Weather station systems

Refurbishment/replacement works for weather station systems has been determined from condition assessment programs focussing on system accuracy/calibration and maintainability risk.

The risk considerations are:

- No manufacturer support/obsolete equipment;
- Unmaintainable (location access or instrument/device);
- Instrument accuracy inadequate for intended network rating application;
- Instrument installation location poor (instrument readings effected by mounting structure);
- Defect/Condition Assessment history.

Where possible the Weather Station Instrumentation Replacement works will be done in conjunction with the EC.11824 Weather Stations For Dynamic Line Rating CAPEX Project in 2013-2018 to optimise deployment and commissioning costs. As such no individual refurbishment/replacement projects for weather station systems are planned for the 2013-2018 regulatory period.

Appendix R Building Management Plan

An assessment of the functionality and condition of all substation buildings has been undertaken with the intent of developing a building management plan in order to specifically address:

- Development of long term maintenance plans for buildings
- Identifying the capacity of existing buildings to meet operational requirements and to determine the need for building replacement
- Enable joint planning of long term building asset management with ETSA Utilities where those assets have common use or may be transferred to ETSA following removal of all operational functions.

The building management programme prioritised project list is shown below, high priority projects are listed.

Table R.1: Building Maintenance Projects – High Priority

Project	Project Ref	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
Total		[redacted]

Other projects identified but of lower priority will have their requirements monitored or the projects deferred into the following 2019-2023 regulatory period. These projects are listed below:

Table R.2: Building Maintenance Projects – Medium/Low Priority

Project	Project Ref	Risk	Response	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total				[redacted]

Appendix S Research and Development

ElectraNet routinely undertakes an internal and external SWOT analysis to identify current business risks that have changed or emerging risks. The outcomes from this process may drive Research and Development - Engineering Investigations (R&D) to determine the most appropriate risk mitigation strategy.

Current investigations and recent industry events has identified the R&D works to be conducted in the 2013-2018 period.

Table S.1: R&D Projects – High Priority

Project	Project Ref	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]
Total		[redacted]

The outcomes of the R&D engineering investigation will drive the future data gathering and assessment Vegetation Management process improvements.

Other projects that have been identified but of lower priority will have their requirements monitored or the projects deferred into the following 2019-2023 regulatory period. These projects are listed below:

Table S.2: R&D Projects – Medium/Low Priority

Project	Project Ref	Risk	Response	Estimate ($2011/12)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total				[redacted]

Appendix T Summary of Performance Measures

To monitor the performance outcomes of the asset management framework, ElectraNet has been developing a set of performance indicators. The key outcomes can be grouped into five categories:

- Physical assets are available as required to deliver service at their intended standard;
- Maintenance is conducted both cost and time efficiently
- Stakeholder/customer satisfaction
- Investment in physical assets is protected (economic lives are extended where appropriate and asset values are optimised)
- Exposure to risk is appropriately managed

Typical performance indicators under consideration for each of the above outcomes categories are listed in the following tables.

Table T.1: Performance Indicators - Asset Availability

Performance Standard (Defined Success)	Performance Indicators & Measures	Basis of Measurement
Assets are available within appropriate levels of downtime and/or service disruption	Downtime as a proportion of total operating time (%)	Target
No. of breakdown call-outs on critical services per month	Target / trend (To review planned to reactive maintenance balance)	
Cost of major defects / unit asset	Trend over time (To consider asset replacement, changed usage or cost of service delivery)	
Assets meet performance requirements from Asset Strategy for: • Utilisation • Capacity • Functionality	Asset utilisation operational constraint index (asset availability unconstrained) Asset capacity index (full feeder capacity is available) Asset functionality (level of service) index (defined levels of service availability)	
Total defect costs / annual expenditure	Trend over time (An indicator of adequacy of maintenance expenditure)	
Assets perform at their specified standard	No of service interruption per month	Trend over time (To revise level of maintenance)
Asset life cycle managed for long term service delivery	Age profile of assets	
Age / unit asset	Target / trend (To monitor portfolio age profile and life cycle maintenance profile)	
End of Life Profile	Target / Trend (To monitor portfolio age profile and life cycle maintenance profile)	

Performance Standard (Defined Success)	Performance Indicators & Measures	Basis of Measurement
Assets comply with appropriate health and safety requirements	OH&S defects reported / period	Target (To manage liabilities and maintenance response and comply with WH&S legislation)
Reduction of accidents over time	No. of accidents/injuries attributable to asset defects per period % workforce injured	Trend over time (To manage liabilities and maintenance response)

Table T.2 Performance Indicators - Time and Cost

Performance Standard (Defined Success)	Performance Indicators & Measures	Basis of Measurement
Cost of maintenance is reasonable	Maintenance costs compared between facilities or assets	Target / trend Trend (To identify / manage highest cost assets)
Maintenance cost per unit of service delivery ($ per user)	Target (to measure service cost, to manage service strategy and maintenance strategy)	
Maintenance cost to facility replacement cost (%)	Target (Indicates adequacy of maintenance expenditure)	
Maintenance cost to total operational cost (%)	Target (Indicates significance of assets to service delivery. To manage service strategy and maintenance strategy)	
Maintenance cost to 5 year moving average maintenance cost (%)	Target / trend (To manage life cycle maintenance)	
Majority of maintenance is programmed rather than emergency	Cost of responsive maintenance / cost of planned maintenance Cost of responding to defects in key categories	Target (To manage maintenance strategy) Trend (To identify and manage risks)
Ratio of emergency maintenance cost to total maintenance cost (emergency maintenance index)	Target / trend (to manage risks and maintenance strategy)	
Ratio of breakdown call-outs per period to average call-out rate (%).	Trend over time (To manage maintenance strategy and contracts)	
Response time is appropriate	Average time taken to respond to work requests	Target / trend (To manage maintenance strategy)
Number of outstanding work orders to number of work orders received during period (%).	Trend over time (To manage maintenance strategy and allocation)	

Table T.3: Performance Indicators - Stakeholder/Customer Satisfaction

Performance Standard (Defined Success)	Performance Indicators & Measures	Basis of Measurement
Stakeholders, customers and community perceive maintenance to be: Cost efficient Timely Of an appropriate standard	% clients surveyed annually (for key stakeholder categories) who express satisfaction regarding: Economy Timeliness Condition of assets (stakeholder sentiment index)	Target / trend (To manage maintenance strategy)
Ratio of actual maintenance expenditure to budgeted maintenance expenditure (%)	Target / trend (To manage expenditure priorities and maintenance expenditure)	

Table T.4: Performance Indicators - Asset Value Protected

Performance Standard (Defined Success)	Performance Indicators & Measures	Basis of Measurement
Asset maintenance completed in the period planned.	Cost of maintenance due / average annual maintenance expenditure	Target (To manage maintenance strategy and allocation)
Asset continues to support service delivery	Cost of refurbishment awaiting funding / average annual refurbishment expenditure	Target / trend (To manage asset strategy, maintenance strategy and allocation)
Asset values maintained	Asset valuations completed / total assets in portfolio Change in portfolio values / time	Target (To identify outstanding valuations) Trend (To meet reporting responsibilities. To indicate investment level)
Asset management strategies implemented	Asset Management Plans/Policy endorsed	Target

Table T.5: Performance Indicators - Risk Management

Performance Standard (Defined Success)	Performance Indicators & Measures	Basis of Measurement
Risks are identified and contingency plans are in place Plans address service and asset risks.	Risk management plans being implemented Risk management plans updated per year.	Target (To ensure identified risks are managed) Target (To ensure current risks are identified) Target (To manage corporate governance risks)
% of identified management issues being implemented	Target (To monitor continuous improvement)	

T1 Performance Trends

An example of specific performance trends with commentary is discussed below.

T1.1 OPEX Corrective Ratio

Review of corrective/routine maintenance performance profiles (below) show changing ratios as substation asset replacement and transmission line asset condition monitoring programmes established in the current regulatory period begin to take effect.

Corrective/Routine maintenance spend profiles for substations and transmission lines are shown below for the period since 2004.

The substation trend shows:

- A high ratio of corrective to routine maintenance (this is a reflection of a high number of substation assets approaching end of technical life);
- A levelling/reduction of the defect trend over time (the asset replacement programme currently in progress will reduce the long run corrective/routine ratio);
- An increase in routine maintenance trend over the period – resulting from the introduction of additional routine maintenance tasks to cover plant not previously subject to routine maintenance (with a resultant increase in corrective maintenance);
- As current asset replacement programmes and additional effort to reduce accumulated corrective work is completed, a significant reduction in the corrective to routine maintenance ratio is expected.

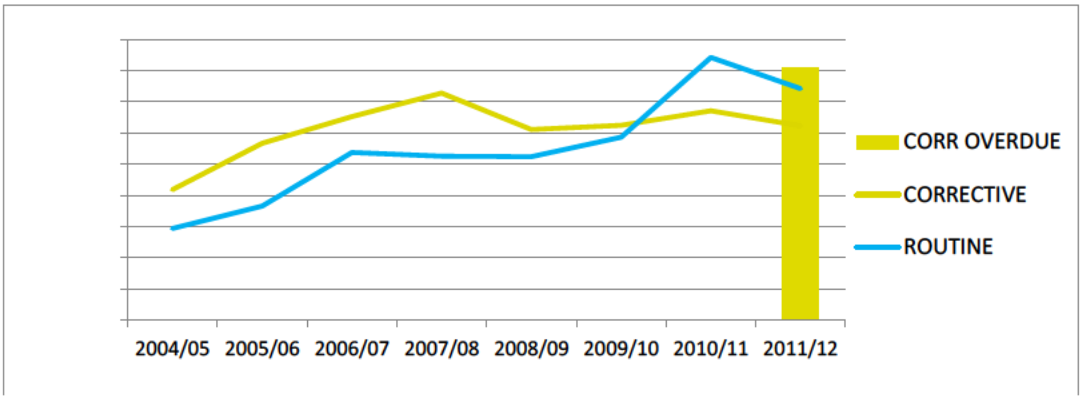


Figure T.1: Substation Corrective/Routine Maintenance Cost Trend

The transmission line trend shows:

- A low ratio of corrective to routine maintenance (this is a reflection of the limited condition inspection previously undertaken on the line asset components);
- An increasing corrective maintenance trend (resulting from an improved maintenance plan based on condition inspection);
- An increase in routine maintenance (as condition monitoring and inspection plans are introduced);

- As condition monitoring programmes are implemented it is expected that the corrective/routine maintenance profile will increase into the next regulatory period when the first maintenance cycle is completed – this will then provide the basis for planning the reduction in corrective/routine effort through asset replacement/refurbishment programmes.

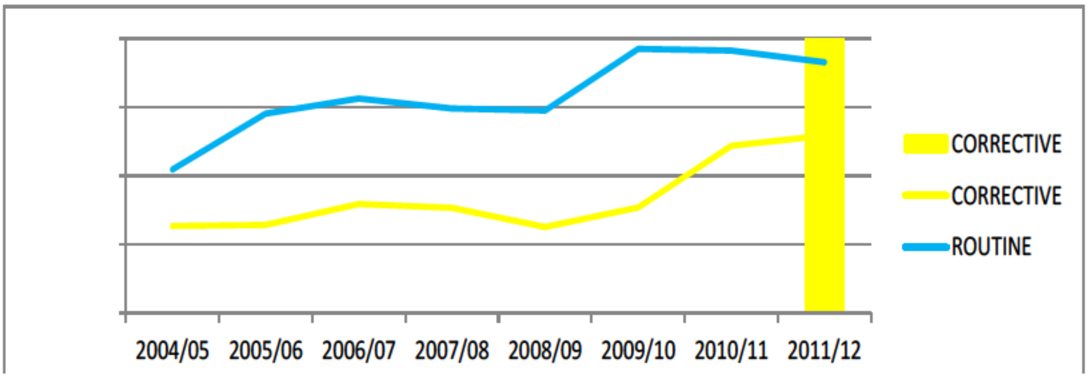


Figure T.2: Transmission Line Corrective/Routine Maintenance Cost Trend

T2 Performance Ratios

Performance Ratios utilised to monitor asset management outcomes on an asset category basis are described below.

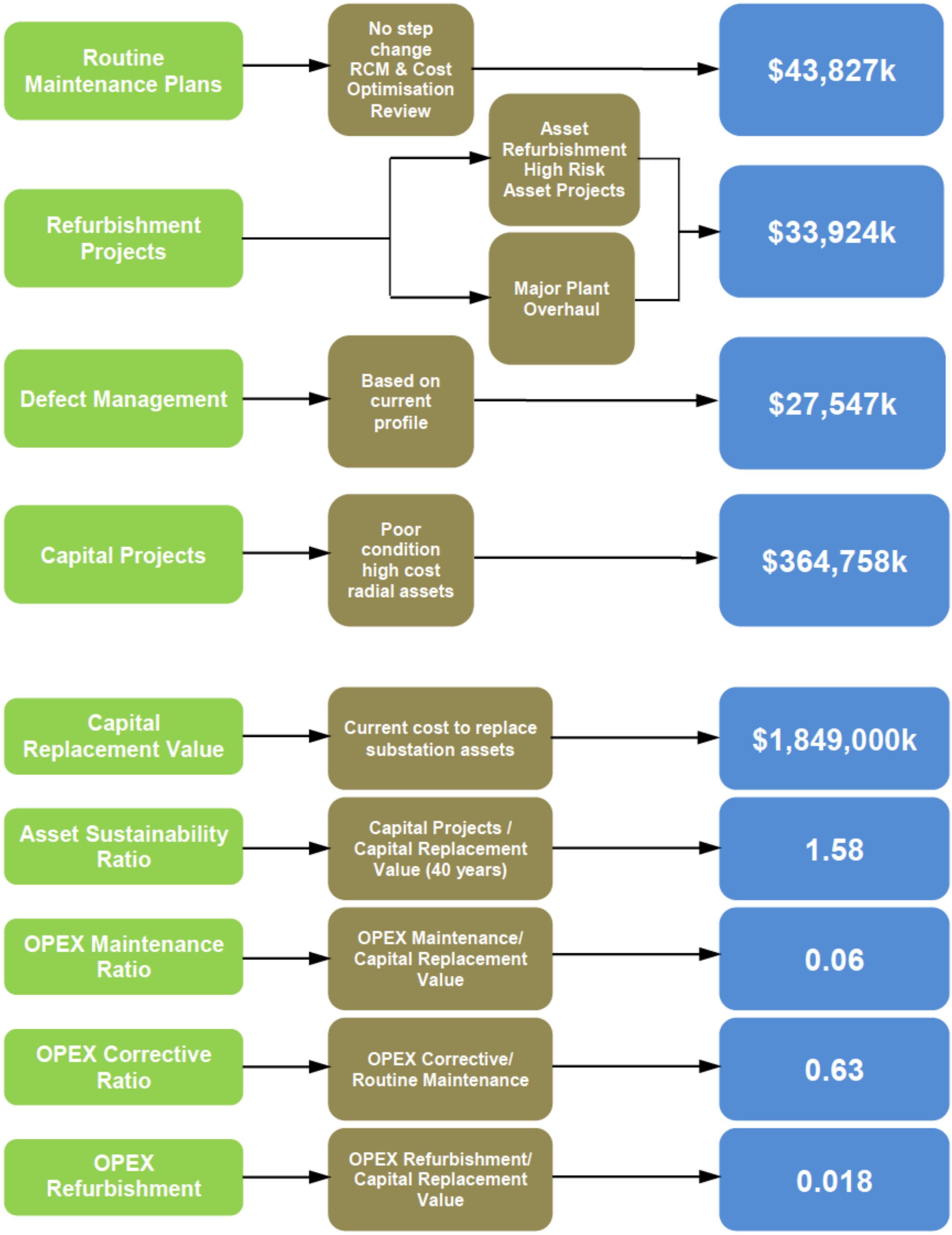


Figure T.3: Substation and Secondary Systems Asset Management Outcomes ($2012/13)

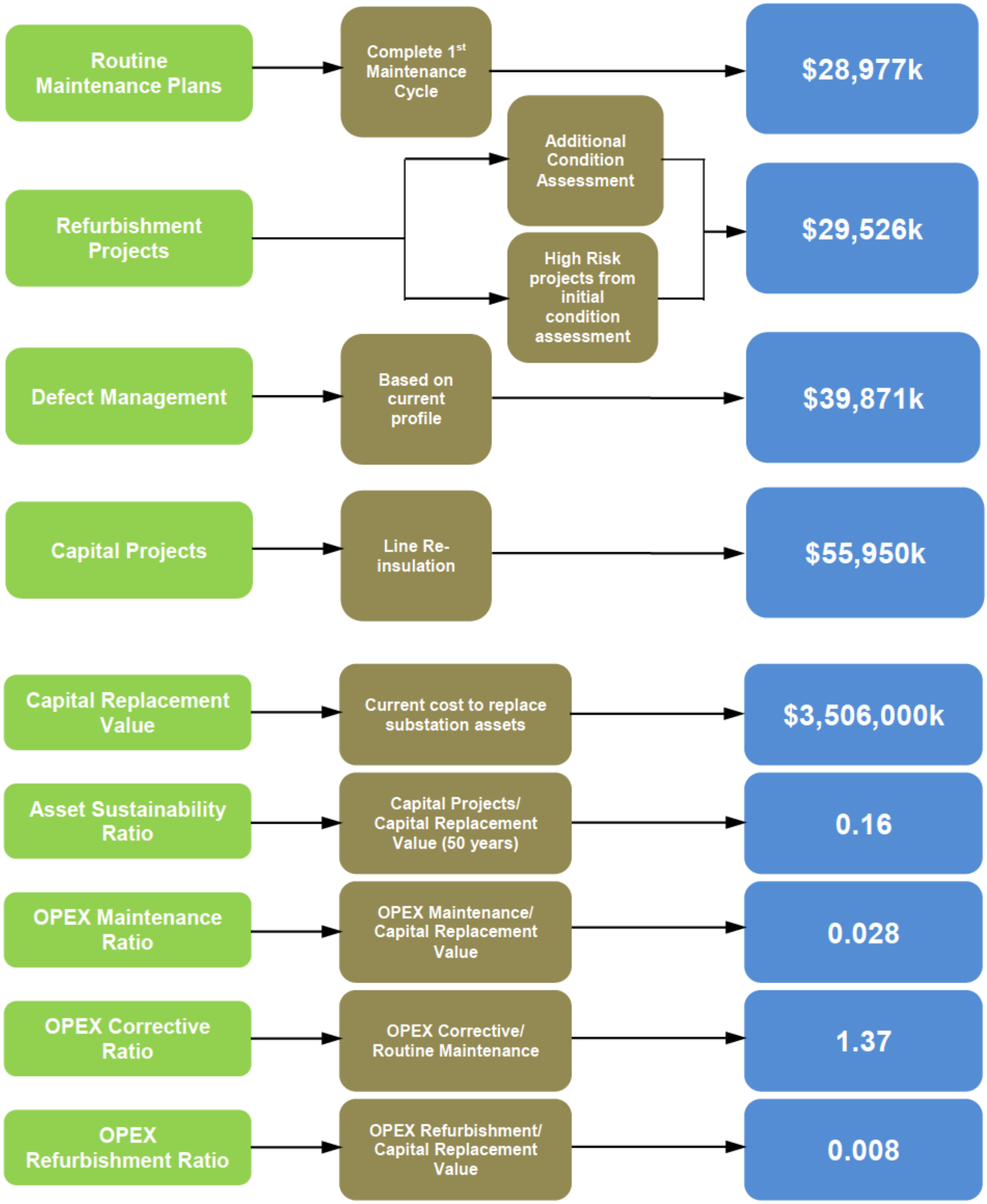


Figure T.4: Transmission Line and Easements Asset Management Outcomes ($2012/13)

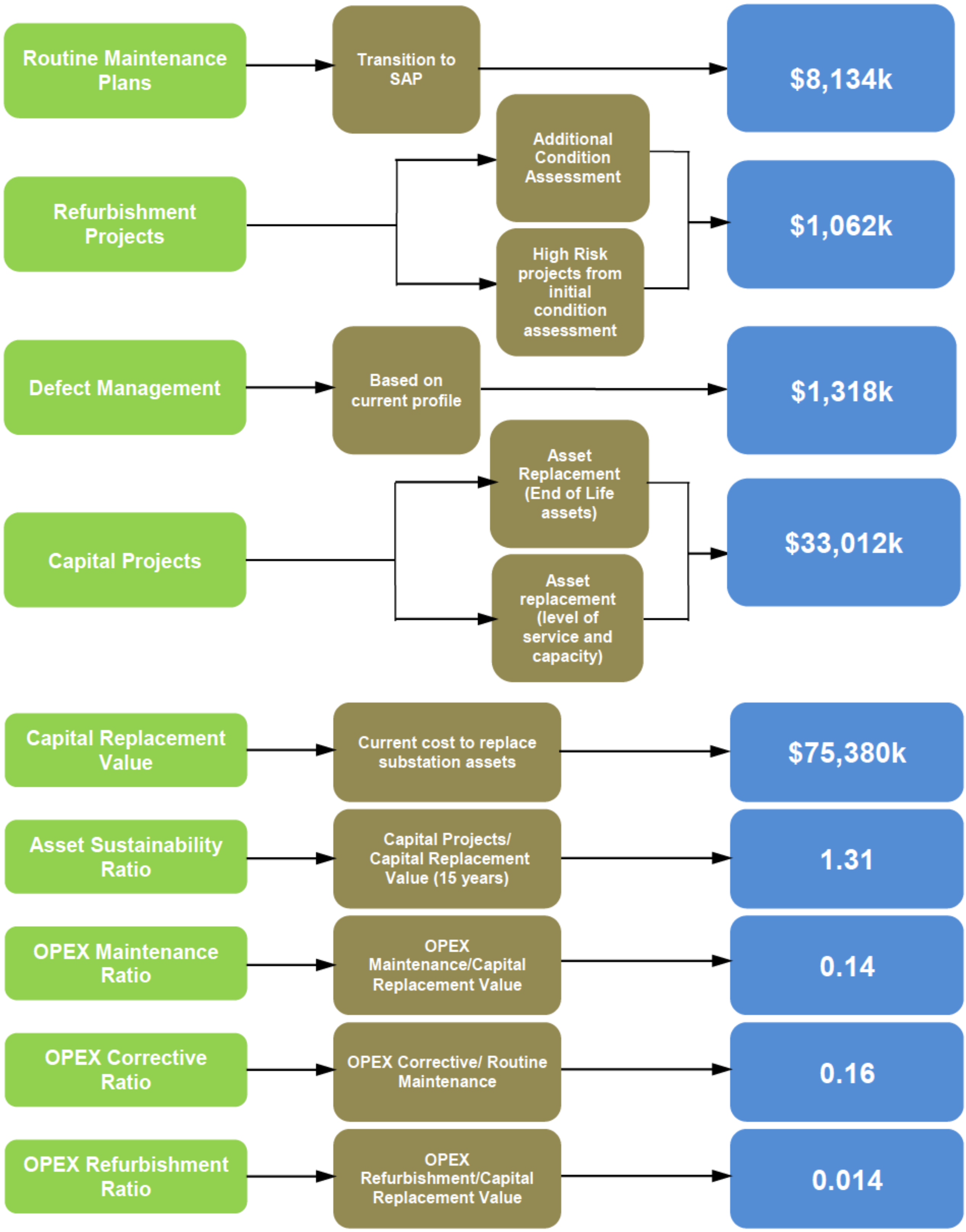


Figure T.5: Telecommunications Asset Management Outcomes ($2012/13)