THE POWER COMPANY LTD

Asset Management Plan Update 2017 - 2027

Publicly disclosed in March 2017

THEPOWERCOMPANYLTD

Update Overview

TPCL's Asset Management Plan update 2017-27 is presented as the sections shown below under contents, which have been updated from TPCL's Asset Management Plan 2016-26. The headings shown in the contents retain the same numbering as the previous AMP for convenient referencing. Updates are highlighted by a green shaded background generally to indicate where project implementation timeframes have varied from those indicated in the previous AMP, where new projects have been added to the capital or maintenance programmes or where projects have been completed and therefore do not form part of the updated work plan for future years

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4. Development Planning

4.3. Development Programme

New Connections

This budget provides allowance for new connections to the network including subdivisions where a large number of customers may require connection. Each specific solution will depend on location and customer requirements.

Planning for new connections uses averages based on historical trending, modified by any local knowledge if appropriate however customer requirements are generally unpredictable and quite variable. Larger customers especially, which have the greatest effect on the network, tend not to disclose their intentions until connection is required (perhaps trying to avoid alerting competitors to commercial opportunities), so cannot be easily planned for in advance.

Various options are considered generally to determine the least cost option for providing the new connection. Work required depends on the customer's location relative to existing network and the capacity of that network to supply the additional load. This can range from a simple LV connection at a fuse in a distribution pillar box at the customer's property boundary, to upgrade of LV cables or replacement of overhead lines with cables of greater rating, up to requirement for a new transformer site with associated 11kV extension if required. Even small customers can require a large investment to increase network capacity where existing capacity is already fully utilised.

Distributed generation as a network alternative tends to be intermittent so cannot be relied on without energy storage which would make an installation uneconomic. Some schemes may be becoming cost competitive with supply from the network however the upfront cost is generally not attractive to most customers and generally a connection to the network is still desired as backup, supplementation and sometimes the ability to sell surplus energy. Customers may be encouraged to better manage diversity of load within their facilities where details are known and there is perceived benefit to the customer or network.

Forecast costs reduced for future years to align with current year actual costs and activity as connections expenditure has been reducing due to the dairy conversion slowdown and this trend is expected to continue.

Cost $0.5M - $2.5M per annum on-going; CAPEX - Consumer Connections.

Mataura Valley Milk

This development was previously identified as a contingent project in section 4.7. The development is now going ahead and this project covers the extension of the network to supply the new Mataura Valley Milk (MVM) dairy factory at McNab.

The supply to the site will require two new 33kV cables from South Gore to the MVM site at McNab. The cables will operate at 11kV but 33kV cables have been installed to accommodate any increased supply requirement in the future. The cables will be supplied by two new 11kV circuit breakers added to the South Gore 11kV switchboard. Differential protection will be installed between South Gore and McNab utilising a fibre optic cable installed in the cable trench.

A 33kV line circuit breaker will be installed on the 33kV overhead line between Gore GXP, South Gore substation and Conical Hill substation just downstream of South Gore substation. This new circuit breaker will improve the reliability of supply to South Gore by reducing the impact of 33kV line faults downstream of South Gore.

A new substation site will be developed at McNab which will have a Portacom switchroom and 5 way 11kV switchboard. The substation site will allow space for two 33/11kV transformers and 33kV switchgear to accommodate any increased supply requirement in the future.

The 11kV network around the MVM plant installed as part of this project will be an 11kV cable ring supplying 6 Ring Main Units (RMUs) and 8 distribution transformers. The RMUs will be fully automated enabling remote operation from PowerNet system control.

Cost $1.0M - $7.5M per annum 2017/18 to 2018/19; CAPEX – Customer Connections.

Oreti Valley Project (OVP)

A significant amount of the work planned for the OVP has been delayed due to delays in completing the Centre Bush Substation design. There were clearance issues identified during the design of the Centre Bush to Mossburn line. These clearance issues have meant that the proposed extension bracket methodology to convert the existing 33kV line to 66kV is not able to be used. The methodology proposed is to replace the majority of the poles on the Centre Bush to Mossburn Line. This pole replacement has increased the overall cost of the project substantially.

Load growth has made the existing 33kV subtransmission backups to Centre Bush, Dipton, Lumsden and Riversdale marginal. The network is constrained by the amount of load and the length of 33kV line from Heddon Bush (for backup to Riversdale) or Gore GXP (for backups to Centre Bush, Dipton and Lumsden) under backup scenarios. A further constraint exists in that the capacity of the 15MVA 66/33kV transformer at Heddon Bush is exceeded when supplying Riversdale at peak times.

To resolve the above issues consideration was given to the use of 33kV voltage regulators to improve voltage for backup scenarios. However, given the transformer constraint at Heddon Bush, increased losses and higher system impedances caused by use of 33kV regulators, this option was discounted. The chosen solution to resolve the backup issues and provide for future load growth is to extend the 66kV network along the Oreti valley so it includes Centre Bush, Dipton, Lumsden and Mossburn substations. The southern connection is proposed at Winton to avoid all 66kV lines going through Heddon Bush substation.

The initial connection out of Winton substation is planned to be a new 66kV crossing the Oreti River to the west of the substation and heading north along Riverside Road to Centre Bush Substation. This line has been completed and the upgrade of Centre Bush Substation to 66kV has commenced.

Starting in 2016/17 the 33kV lines between Centre Bush and Mossburn will be upsized to 66kV. The first section to be completed will be Centre Bush to Dipton. Once this section is completed, work will commence on the upgrade of Dipton Substation to 66kV. The lines between Dipton and Lumsden and Lumsden and Mossburn will then be upgraded. The upgrade to 66kV at Lumsden will be timed to align with the completion of the 66kV lines into Lumsden from both Mossburn and Centre Bush.

Once the upgrade of Dipton Substation is completed, the 66/33kV transformer at Heddon Bush will become surplus and will be moved to spares. At this stage of the project, Lumsden will be supplied at 33kV by a single subtransmission line from Gore GXP until the remainder of the project is completed. This risk is acceptable as 11kV backups from Athol, Mossburn and Riversdale can supply all load normally supplied by Lumsden.

Work planned includes:

- Add an additional 66kV bay off the Winton Substation to supply the new 66kV line up the Oreti Valley.
- New 66kV line out of Winton to the west across the Oreti River and north to Centre Bush substation.
- Upgrade Centre Bush with a new 66/11+11kV 5/7.5MVA transformer[1] and new 22kV indoor switchboard with 4 feeder CBs. The additional feeder will supply along the now free 33kV line back to Heddon Bush area. Feeder upgrading to 22kV will be possible.
- Incorporate dual protection on the lines to maintain less than 200ms clearance of faults, as required for the White Hill Wind Turbines. This protection requires redundant communications paths, the design has been completed and will use digital microwave radios operating in a ring configuration.
- Reinsulate the 33kV lines from Centre Bush to Mossburn to 66kV.
- Upgrade Dipton by replacing the transformer with a new 66/11+11kV 5MVA unit and upgrade protection on the 66kV by having digital differential on the two sides of the substation but no 66kV line circuit breakers.
- Upgrade Lumsden by replacing the transformer with a 66/11+11kV 5MVA unit (ex Ohai) and replace the existing outdoor 11kV switchgear with a new 22kV indoor switchboard.
- The reinsulated 66kV line to Lumsden will connect into Mossburn substation by the spare 66kV bay.

Cost $5.0M - $12.5M per annum 2017/18 to 2018/19; CAPEX – System Growth

Planned outcome is shown in the diagram below**:**

[1] 66/11+11kV transformer can be connected to provide 11kV or 22kV output by parallel or series connecting the two 11kV windings.

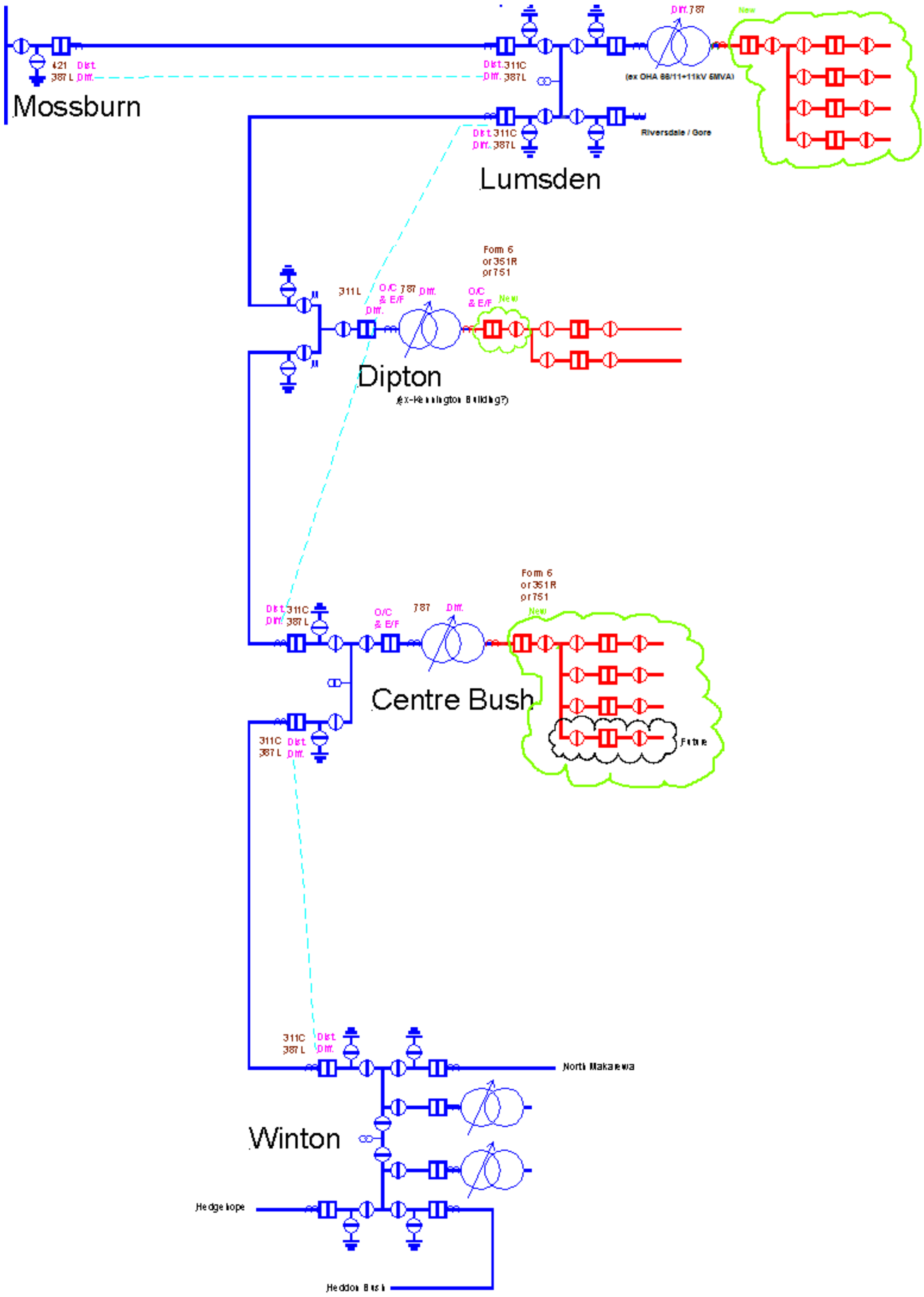

Figure 1 - Completed Oreti Valley Project Single Line Diagram

Waikiwi Substation Upgrade

Project completed in 2016/17. See previous AMP for project details.

Riversdale Substation Upgrade

Load growth has exceeded the capacity trigger point of 5MVA which aligns with the existing single 33/11kV 5MVA transformer. This growth has also eroded the 11kV backups between Lumsden and Riversdale Substations. The bulk of the growth on Riversdale had come from increased irrigation in the Waipounamu and Freshford areas. This irrigation growth is forecast to exceed the capacity of the existing 11kV network to deliver acceptable voltage. There are 2 existing 11kV regulators installed on the feeder already and one approaching its 3MVA capacity. Additional or larger regulators in conjunction with reconductoring to a larger sized conductor was considered as an option, however was determined to be not optimal due to increased losses and the limited gains achieved by reconductor. A new 11kV feeder heading into the affected area was also considered, however difficulty in obtaining a new line route due to the geography of the area and the length of line to be constructed (>6km) has meant that this option was discounted.

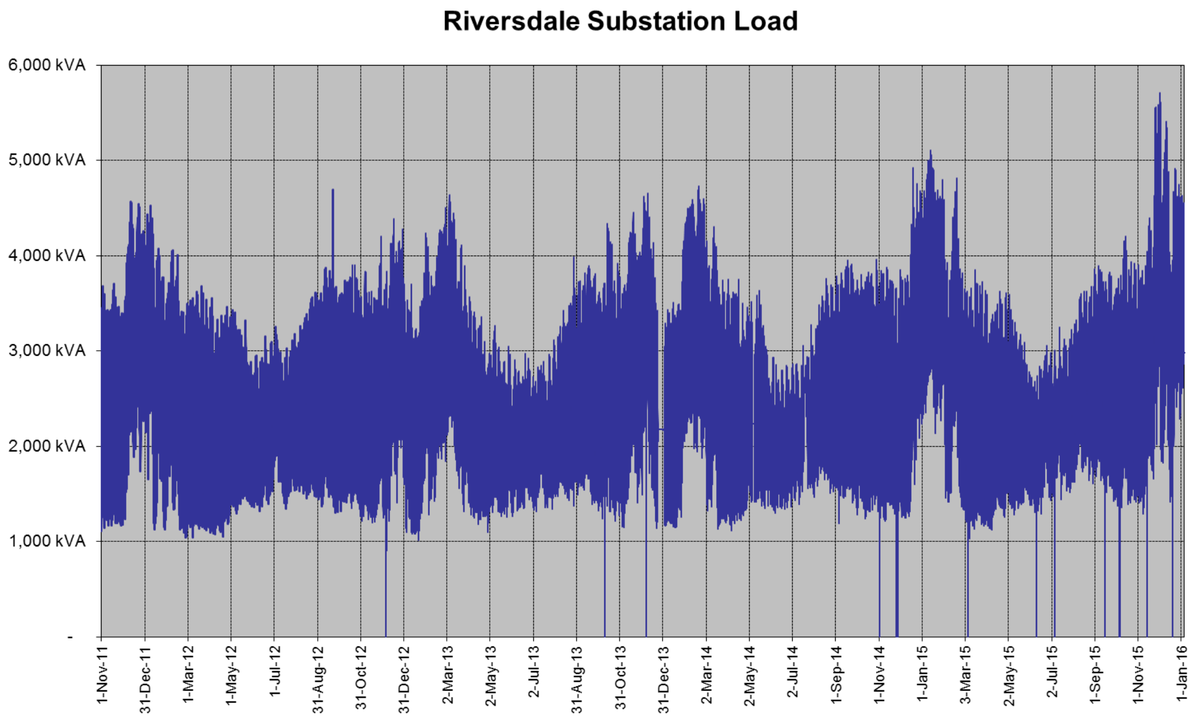

Figure 2 - Riversdale Substation Load Profile

Transfer of load to a new substation around Balfour (which is approximately halfway between Riversdale and Lumsden) would alleviate the transformer capacity trigger and improve the 11kV backups between Riversdale and Lumsden. However, the new substation at Balfour would not provide a solution to the load growth being experienced north of Riversdale in the Waipounamu and Freshford areas and as such has been removed as a project.

Figure 3 - Present Riversdale substation

The proposed solution is to install a new 66/22kV 6/12MVA unit and 22kV indoor switchboard with four feeders, two incomers and a bus coupler. The new transformer would operate in parallel with the existing 33/11kV 5MVA unit. The new switchboard would have 2 feeders operating at 11kV and 2 operating at 22kV with the bus coupler remaining open. Backup between the 2 transformers will be achieved by the use of 11/22kV autotransformers installed at tie-points between the 11kV and 22kV feeders. A diagram of the proposed solution is shown in Figure 4.

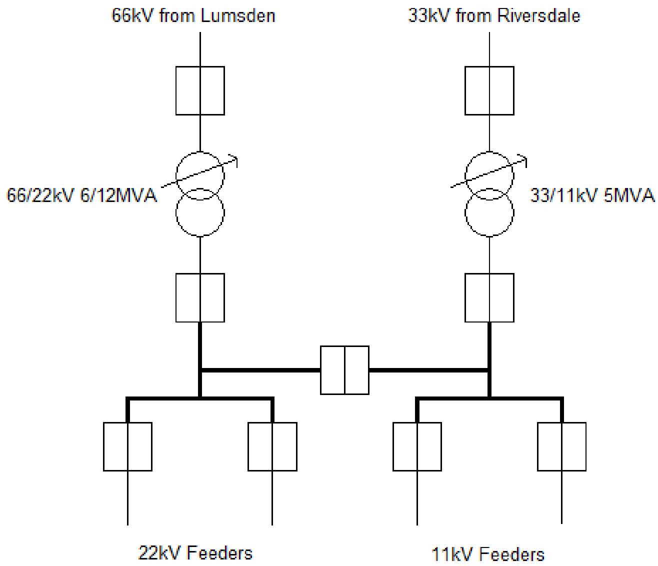

Figure 4 - Proposed Riversdale Single Line Diagram

A separate project will upgrade the two feeders heading north of Riversdale to 22kV in preparation for supply at 22kV from the upgraded Riversdale substation. Autotransformers will be used to reduce the voltage from 22kV to 11kV at the end of the upgraded sections to allow 11kV supply to the remainder of the feeder. If growth occurs before the upgrade is completed, 11/22kV autotransformers may be installed to allow operation of sections at 22kV as required as an interim measure.

The upgraded substation will be future-proofed by modifying the foundation for the existing transformer so a second 66/22kV 6/12MVA unit can be installed at a later date once conversion to 22kV has progressed on all four feeders.

Concept design has been completed. Detailed design will be completed in 2016/17 with construction to occur in 2017-2019.

Project construction deferred to 2018/19 -2019/20 due to forecast load growth not occurring as planned a result of economic drivers including reduced dairy conversions and irrigation projects.

Cost $0.5M - $5.0M per annum 2016/17 to 2019/20; CAPEX – System Growth

Riversdale 22kV Line Upgrades

Project deferred by two years due to forecast load growth not occurring as planned. This project will now become part of Lumsden / Riversdale 22kV line upgrades project with an increased budget and adding additional time to that project.

Load growth north of Riversdale is forecast to exceed the capacity of the existing 3MVA 11kV voltage regulator at Elders Corner. A larger regulator is considered not optimal as the existing conductor upstream and downstream of the regulator would also need to be upgraded to allow for additional load.

It is planned to supply 2 feeders out of Riversdale substation at 22kV following the proposed upgrade. These feeders will have 11kV insulators replaced with 22kV insulators ahead of supply conversion to 22kV. Autotransformers will be used to reduce the voltage from 22kV to 11kV at the end of the upgraded sections. This allows for 11kV supply to continue to the remainder of the feeder. If growth occurs before the Riversdale substation upgrade is completed, 11/22kV autotransformers may be installed at the start of the feeders to allow operation of sections at 22kV if required as an interim measure.

Cost Under $0.5M 2016/17; CAPEX – System Growth

Transpower Edendale Transformer Upgrade

Additional capacity forecast to be required at Edendale is in 2021 and this project will cover the Transpower upgrades required. The cost of this upgrade will be recovered through increased Transpower charges.

Transpower North Makarewa 220/66kV Transformer

Additional capacity forecast to be required at North Makarewa is in 2024 and this project will cover the installation of a new 220/66kv transformer by Transpower. The cost of this upgrade will be recovered through increased Transpower charges.

Edendale Supply Transformers and Substation Upgrade

Project completed in 2016/17. See previous AMP for project details.

Mobile Substation

Project completed in 2016/17. See previous AMP for project details.

Neutral Earthing Resistor (NER) project

As part of compliance with the new EEA Guide to Power System Earthing Practice 2009, Neutral Earthing Resistors (NERs) are being installed at each zone substation to limit earth fault currents on the 11kV network. While NERs alone will not ensure network safety they will generally significantly reduce the earth potential rise which may appear on and around network equipment when an earth fault occurs. TPCL considers NERs to be effectively a requirement of the EEA guide as when cost is considered to be distributed over all affected earth sites downstream of the zone substation this per site cost is quite low.

The aim of the project is to achieve safety of the public under earth fault conditions by reducing the earth potential rise (EPR) at the site under acceptable limits. This is achieved by either reducing the earth resistance, clearing the fault quicker or limiting the fault current.

Historic practice was to have an earth resistance under 10Ω (ohms) and protection operation of under 5 seconds. As some locations having poor ground resistivity achieving under 10Ω was found to be impractical and the level of EPR with 10Ω was still not low enough to mitigate the hazard.

This project plans to install a resistance in the neutral point that will greatly reduce the earth fault current and limit the EPR to acceptable levels. All zone substations will have an NER installed to limit the current to under 200A.

Cost $0.5-2.5M per annum 2016/17 to 2018/19; CAPEX – Other Reliability, Safety and Environmental

Replace Xiria Switchgear Gorge Road

The existing Xiria switchgear at Gorge Road has been determined to be not fit-for-purpose as Zone Substation switchgear following an internal review. This project will replace this switchgear with new fit-for-purpose switchgear.

Cost $0.1-1.5M per annum 2018/19 to 2019/20; CAPEX – Other Reliability, Safety and Environmental

Distribution Automation

To improve reliability it is planned to continue automating and remotely controlling field circuit breakers and load break switches. The project will increase the number of these and integrate with an Outage Management System to achieve automated fault detection, isolation and restoration. This will minimise the number of customers affected by a fault.

The project will target the installation of new field reclosers and remote operable vacuum load break switches on worst performing feeders from a SAIDI and SAIFI perspective. The aim is to allow automatic restoration and reduce average length of 11kV distribution network to one device per 75km.

Cost Under $0.5M per annum 2016/17 and 2017/18; CAPEX – Quality of Supply

Substation Safety

Arc flash hazards have been identified around indoor MV switchgear at zone substations, presenting a risk of harm to personnel inside substation buildings, especially during operation of the switchgear.

The project will retrofit arc flash detection through the use of modern protection relays to all indoor switchboards. This will reduce the hazard for personnel to under the levels provided by 8cal/cm^2 overalls required to be worn by all staff when entering zone substations. Additional PPE was considered as an alternative, but was determined to be suboptimal as each employee would require a full 40cal/cm^2 suit and the bulky PPE to achieve this level of protection creates additional hazards for personnel.

Project timeline extended out to 2020/21 to align with expected time to complete this work.

Cost Under $0.5M per annum 2016/17 and 2020/21; CAPEX – Other Reliability, Safety and Environmental

Tower Anti-Climb Guards

Project completed in 2016/17. See previous AMP for project details

Asset Relocation Projects

This budget captures costs for general minor relocation works required such as shifting a pole or pillar box to a more convenient location. Costs budgeted represent a long term average with actual spend being reactive and typically above or below budget in any year.

Cost Under $0.5M per annum on-going; CAPEX – Asset Relocations

Supply Quality Upgrades

This covers projects to remedy poor power quality. Most cases of poor power quality on TPCL's network are reports or measurements of low voltage. Voltage is either then measured (or calculated to vary) outside of regulatory limits.

Each of the below options / situations are considered and an appropriate solution implemented.

- Installation of 11kV regulators.
- Up-sizing of components (Conductor, Transformer).
- Demand side management. (Planning an Irrigation ripple control channel.)
- Power factor improvements. (Ensuring customer loads are operating effectively.)
- Harmonic filtering / blocking. (Ensuring customers are not injecting harmonics.)
- Motor starter faults / settings remedied. (Ensuring customer equipment is working and configured appropriately.)

Costs budgeted represent a long term average with actual spend being reactive typically being above or below in any year. The years 2016/17 through 2020/21 have increased budget to manage an increase in upgrades foreseen as the rollout of smart meters on the TPCL network progresses and identifies voltage constraints.

Cost Under $0.5M per annum on-going; CAPEX – Quality of Supply.

Network Improvement Projects

Projects to improve reliability through installation of remotely controlled field circuit breakers and load break switches or closing short gaps between adjacent 11kV circuits..

Cost Under $0.5M per annum on-going from 2018/19; CAPEX – Quality of Supply

New Invercargill to Colyer Rd 33kV Line

Timeline changed due to lack of growth and lower interest from developers than forecast.

Should development occur in the Awarua industrial zone, additional capacity will likely be required. It is proposed to begin planning and design to build a new heavy 33kV line from Invercargill to the new Colyer Road substation.

Construction is estimated to occur from 2020/21 (subject to development in the Awarua industrial zone)

Cost $1.5-3.0M per annum 2020/21 to 2022/23; CAPEX -System Growth.

Kelso Transformer Upgrade

Load growth is forecast to exceed the capacity of the transformer at Kelso Substation in 2022. Planning is to design for the replacement of the single 33/11kV 5MVA power transformer at Kelso substation with a 33/11kV 6/12MVA transformer.

Consideration was given to load transfers to keep load under 5MVA however backup capability on 11kV from neighbouring substations is limited by voltage drop so load transfer is not practical.

Consideration was also given to adding a second transformer. However, this would require new switchgear and changes to existing spare transformer pad. The security standard does not require 2 transformers and the mobile substation can be deployed to allow maintenance or upgrade. This was considered likely to be more expensive and not an efficient use of capital

Cost $0.2 - $1.5M per annum 2018 to 2020, System Growth.

Kennington 2nd 33kV line

Load growth is forecast to exceed the ability of the 11kV network to provide backup to Kennington should a fault affect the single 33kV line from Invercargill to Kennington.

Kennington was upgraded to a dual transformer site in 2013 and load on the site has increased after planned transfers from neighbouring substations.

A tee off from the Invercargill to Gorge Road 33kV line is proposed. The tee off will be constructed as 33kV over existing 11kV line routes in the road corridor.

Cost $0.1-1.0M 2017/18 and 2018/19; CAPEX - System Growth

Glenham Transformer Upgrade

Load growth is forecast to exceed the capacity of the transformer at Glenham Substation in 2026. However, as the substation provides 11kV backup to the adjacent Gorge Road and Tokanui substations, the project will occur ahead of load growth to ensure some backup capacity is retained. Planning is to design for the replacement of the single 33/11kV 1.5MVA power transformer at Glenham substation with a new 33/11kV 3MVA transformer or refurbished 5MVA transformer.

Cost $0.2 - $1.5M 2018/19 and 2019/20; CAPEX - System Growth.

Lumsden/Riversdale 22kV Line Upgrades

Load growth has eroded backup capability between Lumsden and Riversdale substations. Both substations are being upgraded to be able to supply 22kV and this project intends to upgrade key sections of line between the two substations to improve MV backups.

Autotransformers will be used to change the voltage between 22kV and 11kV at the ends of the upgraded sections.

Project deferred due to forecast load growth not occurring. Project timeline increased by one year and cost increased to incorporate Riversdale 22kV line upgrades.

Cost Under $0.5M per annum 2018/19 to 2022/23; CAPEX – System Growth

Gorge Road Transformer Upgrade

Load growth is forecast to exceed the capacity of the transformer at Gorge Road Substation in 2019. Planning is to design for the replacement of the dual 33/11kV 1.5MVA power transformers at Gorge Road substation with new 33/11kV 3MVA transformers or refurbished 5MVA transformers.

Cost $0.1M - $1.0M per annum 2018/19 and 2019/20; CAPEX – System Growth

66kV Supply From Gore GXP

This project will create a 66kV supply point at Gore GXP by installing a 33/66kV step up transformer adjacent to the Gore GXP site. This 66kV supply point will be used to provide a second 66kV supply to the Riversdale substation. The existing Gore to Riversdale line (operating at 33kV) has had a project to reinsulate to 66kV completed in 2016/17. This project will also need to upgrade the 33/11kV transformer at Riversdale to 66/22kV.

Under $2.5M - $5.0M 2021/22; System Growth.

Unspecified Projects

The unspecified projects budget is an estimate of costs for projects that are as yet unknown but from experience are considered likely to arise in the longer term (six to ten year time frame). Certainty for these estimates is obviously quite low.

$2.5M - $5.0M per annum 2022/23 onwards; System Growth.

4.4. Contingent projects

The following projects are contingent on uncertain events. These have been excluded from TPCL’s spend plans until they become certain.

Mataura Valley Milk

Project now going ahead as per details in section 4.3

New milk processing plant at the old saleyards site in McNab. This will likely require a new substation and reinforcement of the 33kV network.

Additional Milk Processing

Additional Milk Processing plants at existing or new sites.

Coal to Liquid Plants

Possible major new industry that may require a new substation and subtransmission lines, most likely would be onto the Transpower 220kV network.

Mines

Possible mineral extraction with power required to operate the mine and/or process the material. Possible resources include coal, lignite, silicon, gold, or platinum.

Oil Refineries

Possible major new industry that may require a new substation and subtransmission lines, most likely would be onto the Transpower 220kV network.

Wind farms

Possible large (>5MW) wind farms that may require new subtransmission lines and/or zone substations.

Gore Ripple Plant Replacement

Change in network loadings are forecast to overload this plant. The Transpower 220/110kV 'hard tee' project will significantly change the upstream network impedance and extra load due to Mataura Valley Milk may cause the existing injection plant to fail. Installation of Smart Meters in the region was planned to supersede the need for the Injection Plant but delays with the roll out could require an upgrade or replacement of the Injection Plant. However, the smart meter project will focus in this region to allow a transition from ripple injection to smart meter load control.

4.7. TPCL's Forecast Capital Expenditure

The forecast capital expenditure for TPCL is shown in Table 38. These figures are also provided in the information disclosure schedule 11a included in Appendix 3.

Table 38: TPCL's Forecast Capital Expenditure

CAPEX: Consumer Connection ($000)	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Customer Connections (≤ 20kVA)	936	936	936	936	936	936	936	936	936	936
Customer Connections (21 to 99kVA)	468	468	468	468	468	468	468	468	468	468
Customer Connections (≥ 100kVA)	535	535	535	535	535	535	535	535	535	535
Distributed Generation Connection	5	5	5	5	5	5	5	5	5	5
New Subdivisions	108	108	108	108	108	108	108	108	108	108
Mataura Valley Milk	5,145	1,187	-	-	-	-	-	-	-	-
	7,197	**3,239**	**2,051**	**2,051**	**2,051**	**2,051**	**2,051**	**2,051**	**2,051**	**2,051**

CAPEX: System Growth ($000)	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
OVP-Centre Bush to Mossburn 66kV Line	3,663	4,246	-	-	-	-	-	-	-	-
OVP-Dipton Substation Upgrade	2,402	-	-	-	-	-	-	-	-	-
OVP-Centre Bush Substation Upgrade	1,434	-	-	-	-	-	-	-	-	-
OVP-Lumsden Substation Upgrade	2,800	2,014	-	-	-	-	-	-	-	-
Riversdale Substation Upgrade	84	3,057	3,909	-	-	-	-	-	-	-
TPNZ Edendale 110kV Transformer Upgrade	-	-	-	-	-	-	-	-	-	-
New Invercargill to Colyer Rd 33kV Line	-	-	-	2,635	1,917	1,917	-	-	-	-
TPNZ North Makarewa 220/66kV Transformer	-	-	-	-	-	-	0	-	-	-
Kelso Transformer Upgrade	-	203	1,364	-	-	-	-	-	-	-
Kennington 2nd 33kV Line	108	1,006	-	-	-	-	-	-	-	-
Glenham Transformer Upgrade	-	191	1,220	-	-	-	-	-	-	-
Lumsden / Riversdale 22kV Line Upgrades	-	455	347	347	347	347	-	-	-	-
Gorge Road Transformer Upgrade	-	96	986	-	-	-	-	-	-	-
Unspecified Projects	-	-	-	-	-	3,636	3,636	3,636	3,636	3,636
OVP-Microwave Radio Ring Scheme	204	380	-	-	-	-	-	-	-	-
66kV supply from Gore GXP	-	-	-	-	2,390	-	-	-	-	-
	10,694	**11,648**	**7,826**	**2,983**	**4,654**	**5,901**	**3,636**	**3,636**	**3,636**	**3,636**

CAPEX: Asset Replacement and Renewal ($000)	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
General Distribution Replacement	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221
Transformer Replacment	1,414	1,414	1,414	1,414	1,414	1,414	1,414	1,414	1,414	1,414
11kV Line Replacement	4,426	4,426	5,110	5,110	5,110	5,110	5,110	5,110	5,110	5,110
Subtransmission Line Replacement	39	39	196	196	196	196	196	196	196	196
Zone Substation Minor Replacement	90	90	90	90	90	90	90	90	90	90
RTU Replacement	133	133	133	133	133	133	133	133	133	133
Regulator Replacement	-	-	-	316	-	-	-	-	-	-
Relay Replacement	67	108	87	87	26	26	26	26	26	26
Communications Replacement	212	249	-	-	-	-	-	-	-	-
General Technical Replacement	28	28	28	28	28	28	28	28	28	28
Seismic Remedial Distribution	343	53	53	53	-	-	-	-	-	-
Power Transformer Refurbishment	108	203	-	322	167	203	221	322	221	221
Seaward Bush Transfomer Replacement	-	-	-	501	623	-	-	-	-	-
Mataura Transformer Replacement	-	-	501	623	-	-	-	-	-	-
Orawia Substation Upgrade	613	-	-	-	-	-	-	-	-	-
Gore to Riversdale Pole Replacement	-	-	-	-	-	-	-	-	-	-
North Makarewa RTU & Relay Replacement	101	482	-	-	-	-	-	-	-	-
Makarewa Switchboard Replacement	-	-	-	-	-	-	-	182	1,567	-
Bluff Switchboard Replacement	-	-	-	-	-	-	-	182	1,155	-
Hillside Transformer Replacement	-	-	203	726	-	-	-	-	-	-
Gore Ripple Plant Replacement	0	-	-	-	-	-	-	-	-	-
	8,794	**8,445**	**9,038**	**10,822**	**9,010**	**8,422**	**8,440**	**8,905**	**11,162**	**8,440**

CAPEX: Asset Relocations ($000)	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Line Relocations	54	54	54	54	54	54	54	54	54	54
	54	**54**	**54**	**54**	**54**	**54**	**54**	**54**	**54**	**54**

CAPEX: Quality of Supply	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Supply Quality Upgrades	271	271	271	271	135	135	135	135	135	135
Mobile Substation site made ready	179	358	358	358	358	-	-	-	-	-
Distribution Automation	479	-	-	-	-	-	-	-	-	-
Network Improvement Projects	-	108	108	108	108	108	108	108	108	108
	929	**737**	**737**	**737**	**602**	**244**	**244**	**244**	**244**	**244**

CAPEX: Legislative and Regulatory ($000)	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
-	-	-	-	-	-	-	-	-	-	-
	-	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

CAPEX: Other Reliability, Safety and Environment ($000)	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Earth Upgrades	134	134	134	134	134	134	134	134	134	134
NER Installations	660	660	-	-	-	-	-	-	-	-
Substation Safety	216	216	216	216	-	-	-	-	-	-
Township Undergrounding	-	-	-	-	-	-	-	-	-	-
Replace Xiria Switchgear Gorge Road	-	96	1,033	-	-	-	-	-	-	-
	1,010	**1,105**	**1,383**	**350**	**134**	**134**	**134**	**134**	**134**	**134**

Network Capital Expenditure Total ($000)	**28,677**	**25,228**	**21,089**	**16,998**	**16,505**	**16,806**	**14,559**	**15,024**	**17,281**	**14,559**

5. Lifecycle Planning

5.2. Routine Corrective Maintenance & Inspection

Network assets are inspected routinely with the frequency dependant on the criticality of the assets and the outcome focussing on failure avoidance. Recognising that some deterioration is acceptable, inspections are intended to identify components which could lead to failure or deteriorate beyond economic repair within the period until the next inspection.

Deterioration is noted and may trigger corrective maintenance if economic, especially where deterioration can be "nipped in the bud", for example touching up paint defects before rust can take hold. Other forms of deterioration are unable to be corrected (or improved) for example pole cracks or rotting and noting these issues may become a trigger for replacement or renewal depending on the extent of deterioration i.e. loss of structural integrity.

Inspections are not able to cover all assets such as cables buried underground and may be limited by the availability of outages or the added effort (labour cost) required to remove covers. Therefore for the most part routine inspections are limited to what can be viewed from a walkover of the assets.

Testing supplements network inspections and although it typically requires additional time and skilled staff, testing has strong advantages over visual inspection if cost effective. It is generally possible to gain greater detail around asset condition and often allows collection of condition data without the need to remove covers for inspection. Testing may be destructive or non-destructive. For example insulation resistance (IR) testing gives an ohmic value for insulation under test whereas very low frequency (VLF) testing is "pass-fail" where a pass proves integrity of insulation but a fail will cause a fault which needs to be repaired.

TPCL's Maintenance Approach

Most technical equipment such as transformers, switchgear and secondary assets are maintained in line with manufacturer's recommendations as set out in their equipment manuals. Experience with the same types of equipment may provide reason to add additional activities to this routine maintenance. Visual inspections and testing also determine reactive maintenance requirements to maintain the serviceable life of equipment which are not routine but across a large asset base provide an ongoing need for additional maintenance resource.

Overhead line inspections are an economic means to prevent a large proportion of potential faults so the basic approach is to inspect these assets and perform preventative maintenance over the most cost effective period that achieves the desired service levels. A certain frequency of failure is accepted on overhead lines where this remaining proportion of failures becomes uneconomic to repair. This recognises customers' acceptance of a low number of outages and the increasing cost for diminishing returns in attempting to reduce fault frequency.

As cables are underground they are unable to be inspected and testing is generally not cost effective and difficult to obtain accurate results to predict time to failure. Cables are therefore often run to failure however as the relatively young cable network ages and fault frequency begins to increase a more preventive strategy will be employed based on testing to determine condition for critical cables.

In terms of cost efficiency, failures are relatively acceptable for lines and cables compared to the more technical assets. Significant serviceable life can be restored by repairing a fault due to the distributed nature of these assets and the relatively minor (i.e. localised) effect of faults. Asset criticality must allow for the occurrence of outages however increased security (redundancy) is often applied as more effective than attempting to determine time to failure and performing preventative maintenance.

Table 39 sets out the maintenance approaches applicable to each network asset category and the frequency with which these maintenance activities are undertaken.

Table 39: Maintenance Approach by Asset Category

Asset Category	Sub Category	Maintenance Approach	Frequency
Subtransmission	O/H	Condition Monitoring through periodic visual inspection. Tightening, repair or replacement of loose, damaged, deteriorated or missing components.	5 yearly
	U/G	Generally run to failure and repair. Inspection of visible terminations as part of zone substation checks and otherwise opportunistic inspection if covers removed for other work. Sheath insulation IR tested. Testing generally in conjunction with fault repair but may be initiated if anything untoward is noted during other inspections or work; may use IR, PI, TR, PD, VLF.	Annual
	Distributed Sub Transmission Voltage Switchgear (ABSs)	Condition Monitoring through periodic visual inspection. Tightening, repair or replacement of loose, damaged, deteriorated or missing components. Lubrication of moving parts.	5 yearly
Zone Substations	Sub Transmission Voltage Switchgear	Condition Monitoring through periodic visual inspection checking for; operation count, gas pressure, abnormal or failed indications and general condition. Testing; Contact Resistance, Partial Discharge, Insulation Resistance, CB operation time, Cleaning of contacts, Thermal Resistivity viewed soon after unloading, VT/CT IR and characteristics. Corrective maintenance as required after any concerning inspection or test results.	Monthly 5 Yearly
	Power Transformers	Condition monitoring through periodic inspections. Winding resistances, Insulation resistance, Function checks on auxiliary devices (Buchholz, pressure relief, thermometers). Tap changer servicing; mechanism and contacts inspected – replacements as necessary, DC resistance across winding each tap, diverter resistors resistances Predictive maintenance - oil analysis (dissolved gasses, furan) to estimate age and identify internal issues arising or trends; frequency increased if issues and trends warrant. Oil processed as necessary. Clean up and repair of corrosion, leaks etc and replacement of deteriorated or damaged components. Replacement of breathers when saturated. Paper sample may be taken to estimate age for aged transformers in critical locations at Engineers instruction or otherwise during major refurbishment work at unit's half-life. Swept frequency test at start of life and after significant events such as relocation, repaired fault, refurbishment done to check for internal movement of components.	Monthly Annual Operation Count Bi-Annual Non-periodic
	Distribution Voltage Switchgear	Condition Monitoring through periodic visual inspection checking for; operation count, gas pressure, abnormal or failed indications and general condition.	Monthly

Asset Category	Sub Category	Maintenance Approach	Frequency
		Testing; Contact Resistance, Partial Discharge, Insulation Resistance, CB operation time, Cleaning of contacts, Thermal Resistivity viewed soon after unloading, VT/CT IR and characteristics. Corrective maintenance as required after any concerning inspection or test results.	5 Yearly Non-periodic
	Other (Buildings, RTU, Relays, Batteries, Meters)	Monthly sub checks include inspection of auxiliary and other general assets for anything untoward; structures, buildings, grounds and fences for structural integrity and safety and general upkeep; rusting, cracked bricks, masonry or poles and weeds etc. Maintenance repairs and general tidying as necessary. Protection relays are tested typically with current injection to verify operation as per settings. Any alarms or indications from electronic equipment or relays reset and control centre notified for remediation. Relays recertified by external technicians as regulations require. Otherwise any other equipment visually inspected for anything untoward.	Monthly 5 yearly Non-periodic
Distribution Network	O/H	Condition Monitoring through periodic visual inspection. Tightening, repair or replacement of loose, damaged, deteriorated or missing components.	5 yearly
	U/G	Generally run to failure and repair. Inspection of visible terminations as part of zone substation checks and otherwise opportunistic inspection if covers removed for other work. Testing generally in conjunction with fault repair but may be initiated if anything untoward is noted during other inspections or work; may use IR, PI, TR, PD, VLF.	Reactive or opportunistic 5 yearly if visible
	Distributed Distribution Voltage Switchgear	Condition Monitoring through periodic visual inspection. Tightening, repair or replacement of loose, damaged, deteriorated or missing components. Function tests to verify operation as per settings; for any switchgear controlled by relays.	5 yearly
Distribution Substations	Distribution Transformers	Condition monitoring through periodic inspections. Infrared thermal camera inspection units 500kVA and larger. Clean up and repair of corrosion, leaks etc. Some units have breathers; replaced when saturated. Winding resistances, Insulation resistance for older units if shut down allows. DGA for critical end of life units.	6 monthly or if <150kVA 5 yearly Opportunistic Non-Periodic
	Distribution Voltage Switchgear (RMUs)	Condition monitoring visual inspection to assess deterioration or corrosion. Some minor repairs may be made but generally inspection determines when replacement will be required. Threshold PD tests to identify significant partial discharge. Periodic servicing undertaken including wipe down of epoxy insulation and oil replacement in critical switchgear. Some removed oil tested for dielectric breakdown as occasional spot check of general condition.	6 monthly 5-10 yearly
	Other	Inspection of enclosures for structural integrity and safety compromised by rusting or cracked brick or masonry. O/H structures included in distribution network inspections.	6 monthly
LV Network	O/H	Condition Monitoring through periodic visual inspection.	5 yearly

Asset Category	Sub Category	Maintenance Approach	Frequency
		Tightening, repair or replacement of loose, damaged, deteriorated or missing components.	
	U/G	Run to failure and repair.	Reactive
	Link and Pillar Boxes	External inspection for damage, tilting sinking etc. Internal components run to failure and repair. Some opportunistic inspections when opened for other work.	5 yearly
Other	SCADA & Communications	Generally self-monitored with alarms raised for failures or downtime. 24/7 control room initiate response.	Reactive
	Earths	Five yearly inspections to check locational risk, check for standard installation and any corrosion, deterioration or loosening of components. Testing is done to confirm connection resistances and electrode to ground resistance is sufficiently low.	5 yearly
	Ripple Plant	Inspection along with other assets at GXP for signs of deterioration or damage of components; oil leaks, corrosion etc. Reactive remedial actions will follow for any issues found.	Monthly

Maintenance and Inspection Programmes

Budget descriptions for routine corrective maintenance and inspection activities are set out in Table 40 and forecasts are provided in at the end of this section. These budgets tend to be ongoing at similar levels year after year but may be adjusted from time to time to allow for improvements in maintenance practice.

Table 40: Routine and Corrective Maintenance and Inspection Budget Descriptions

Budget	Description	Expenditure Range/Type
Routine Distribution Inspections, Checks & Maintenance	Five yearly network inspections (20% inspected annually), other routine tests and minor maintenance works on distribution assets.	Cost Under $1.0M on-going; OPEX
Distribution Minor Work, Inspection, Check & Maintenance	Generally reactive work undertaken to correct issues found during the routine distribution inspection. Also a general budget for all minor distribution work.	Cost Under $0.5M on-going; OPEX
This budget has been renamed “Planned Maintenance” to reflect that the budget covers planned work carried out on functional assets, in response to issues found during inspection.		
Routine Technical Inspections, Checks & Maintenance	Routine inspection and testing of assets at zone substations. Includes such things as oil DGA, breakdown, moisture and acidity, operation counts, protection testing etc. Also covers responses to maintenance triggers, such as oil processing or recalibration of relays.	Cost Under $1.0M on-going; OPEX
Technical Planned Maintenance	Routine maintenance at zone substations such as grounds, fence and building maintenance, rust repair and paint touch-ups. Routine maintenance at distribution substation assets such as cleaning, paint touch-ups and enclosure repairs. Routine maintenance for Ring Main Units such as cleaning, paint touch-ups and enclosure repairs. Includes reactive work undertaken to correct issues found during the routine technical inspection. Also a general budget for all minor technical work.	Cost Under $1.5M on-going; OPEX.
Partial Discharge Survey	Routine partial discharge condition monitoring surveying of subtransmission cables, terminations and equipment to identify abnormal discharge levels before failure occurs.	Cost Under $0.5M on-going; OPEX
Infra-Red Survey	Routine Infra-Red condition monitoring survey of bus-work, connections, contacts etc for abnormal heating as indication of poor electrical contact between current carrying components which may lead to voltage quality issues and/or failure of equipment.	Cost Under $0.5M on-going; OPEX
Supply Quality Checks	Investigations into supply quality which are generally customer initiated.	Cost Under $0.5M on-going; OPEX
Spare Checks and Minor Maintenance	A budget for checks to confirm what equipment is kept in spares and perform minor maintenance required to ensure spares are ready for service.	Cost Under $0.5M on-going; OPEX

Budget	Description	Expenditure Range/Type
Seismic Checks	A one off budget to complete checks to determine what remedial strengthening work is required to ensure seismic resilience for network equipment generally at distribution substations.	Cost Under $0.5M 2017-18; OPEX
Customer Connections	Operational portion of expenditure for the customer connections process is captured in this budget.	Cost Under $0.5M on-going; OPEX
Earth Testing	Routine testing of earthing assets and connections to ensure safety and functional requirements are met completed for all earths on a five yearly basis.	Cost Under $0.5M on-going; OPEX

Reactive Maintenance

The former Incident Response budget (Service Interruptions and Emergencies category) has been separated into two components; the "Reactive Maintenance" budget the component that covers permanent repairs carried out on faulted assets that have temporarily been made safe/functional.

This separation implements the final paragraph in the Information Disclosure Determination's definition of Service Interruptions & Emergencies: "Planned follow-up activities resulting from and event which were unable to be permanently repaired in the short term are to be included under routine and corrective maintenance and inspection".

Cost Under $1.5M on-going; OPEX

Systemic Issues

There are no systemic issues presently being investigated. Examples of past investigations and outcomes are shown below. Some of these examples represent learnings from issues found on other networks managed by PowerNet but which are common to the TPCL network.

- Kidney strain insulators: Replaced with new polymer strains.
- DIN LV fuses: Sourced units that can be used outdoor.
- Parallel-groove clamps: Replaced with compression joints.
- Non-UV stabilised insulation: Exposed LV now has sleeve cover, with new cables UV stabilised.
- Opossum faults: Extended opossum guard length.

5.3. Asset Replacement and Renewal

The overall objective for replacement and renewal programmes is to get the most out of the network assets by replacing assets as close as possible to their economic end of life. This is balanced by the need to manage workforce resources in the short term and delivery of desired service levels over the long term.

Inspection and testing programmes identify assets that are reaching the end of their economic life while critical assets may be replaced on a fixed time basis. For example 11kV switchboards at zone substations are replaced at the end of their expected 45 year life. Less critical assets or assets provided with redundancy as part of security arrangements may be run to failure and replaced reactively. Assets such as cables may be run to failure several times and repaired before the fault frequency increases to a point that complete replacement is more economic. This approach requires monitoring of failure rates.

Apart from whole of lifecycle cost analysis there are several additional drivers for replacement (though they can often be reduced to a cost analysis) including operational or public safety, risk management, declining service levels, accessibility for maintenance, obsolescence and new technology providing options for additional features or alternative solutions. Replacement of assets may also be heavily influence by the development drivers discussed in section Development Criteria.

Table 11 sets out the approach to making decisions around when to undertake replacements or renews applicable to each network asset category.

Table 11: Replacement and Renewal Decisions by Asset Category

Asset Category	Sub Category	Replacement and Renewal Decision Approach
Subtransmission	O/H	Reactive replacements after failure due to external force. Poles replaced when structural integrity indicated as low by pole scan or visual inspection. Generally poles cross arms, pins, insulators, binders and bracing etc. replaced when inspection indicates deterioration that could cause failure prior to next inspection and maintenance is uneconomic. Conductor replaced when reliability declines to an unacceptable level or repairs become uneconomic.
	U/G	XLPE cables replaced when reliability declines to an unacceptable level or repairs become uneconomic. Oil cables may be damaged beyond economic repair depending on nature of failure.
	Distributed Sub Transmission Voltage Switchgear (ABSs)	When inspection indicates deterioration sufficient to lose confidence in continued reliable operation and maintenance is considered uneconomic.
Zone Substations	Sub Transmission Voltage Switchgear	Replaced at end of standard life (fixed time), may be delayed in conjunction with condition monitoring to achieve strategic objectives. Significant damage from premature failure could require replacement.
	Power Transformers & Regulator Transformers	After failure causing significant damage that is not economic to repair. Paper, Furan or DGA analysis indicating insulation at end of life. Tank and fittings deteriorating, lack of spare parts and not economic to maintain for aged units. Not economic to relocate (transport and installation costs) after aged transformers displaced e.g. for a larger unit.
	Distribution Voltage Switchgear	Replaced at end of standard life (fixed time), may be delayed in conjunction with condition monitoring to achieve strategic objectives. Significant damage from premature failure could require replacement.
	Other (Buildings, RTU, Relays, Batteries, Meters)	Instrumentation/Protection at end of manufacturers stated life (fixed time) or when obsolete/unsupported or otherwise along with other replacements as economic e.g. protection replaced with switchboard or transformer. Batteries replaced prior to the manufacturers stated life expectancy (typically 10 years) or on failure of testing.

Asset Category	Sub Category	Replacement and Renewal Decision Approach
		Buildings and fences when not economic to maintain after significant accumulating deterioration or seismic resilience concerns. Bus work and conductors when not economic to maintain. Greater than Standard Life and maintenance required.
Distribution Network	O/H	Reactive replacements after failure due to external force. Poles replaced when structural integrity indicated as low by pole scan or visual inspection. Generally poles cross arms, pins, insulators, binders and bracing etc. replaced when inspection indicates deterioration that could cause failure prior to next inspection and maintenance is uneconomic. Conductor replaced when reliability declines to an unacceptable level or repairs become uneconomic.
	U/G	XLPE or paper lead cables replaced when reliability declines to an unacceptable level or repairs become uneconomic.
	Distributed Distribution Voltage Switchgear	Replaced at end of standard life (fixed time), may be delayed in conjunction with condition monitoring to achieve strategic objectives. Significant damage from premature failure could require replacement.
Distribution Substations	Distribution Transformers	Often replaced if rusting is advanced or other deterioration/damage is significant and maintenance becomes uneconomic. Otherwise units generally run to failure but transformers supplying critical loads may be replaced early based age or as part of other replacements at site. Units removed from service <100kVA and older than 20yrs are scrapped otherwise tested and if satisfactory recycled as stock.
	Distribution Voltage Switchgear (RMUs)	Replaced at end of standard life (fixed time), may be delayed in conjunction with condition monitoring to achieve strategic objectives. Significant damage from premature failure could require replacement.
	Other	Instrumentation/Protection at end of manufacturers stated life (fixed time) or when obsolete/unsupported or otherwise along with other replacements as economic e.g. protection replaced with switchboard or transformer. Batteries replaced prior to the manufacturers stated life expectancy (typically 10 years) or on failure of testing. Enclosures not economic to maintain after significant accumulating deterioration or seismic resilience concerns.
LV Network	O/H	Reactive replacements after failure due to external force. Poles replaced when structural integrity indicated as low by pole scan or visual inspection. Generally poles cross arms, pins, insulators, binders and bracing etc. replaced when inspection indicates deterioration that could cause failure prior to next inspection and maintenance is uneconomic. Conductor replaced when reliability declines to an unacceptable level or repairs become uneconomic.
	U/G	Generally run to failure. Replaced when condition declines to an unreliable level e.g. embrittlement of insulation.

Asset Category	Sub Category	Replacement and Renewal Decision Approach
	Link and Pillar Boxes	Replaced if damaged or deterioration is advanced and could lead to failure before next inspection (or if public safety concerns exist).
Other	SCADA & Communications	RTUs or radios at end of manufacturers stated life (fixed time) or when obsolete/unsupported or otherwise along with other replacements as economic.
	Earths	Replaced when inspections find non-standard arrangements, deteriorated components or test results are not acceptable.
	Ripple Plant	Becoming obsolete as smart meters are installed across the network. Run to failure but security provided by backup plant.

Non-Routine Replacement and Renewal Projects

Replacement and renewal projects that are not ongoing are described in Table 42 and often represent one-off replacement or renewal of significant assets that have reached end of life or a significant milestone in its life. Other projects may target a number of assets of similar age that will be replaced or renewed as part of short or medium term programme.

Table 42: Non-routine Replacement and Renewal Projects

Project and Description	Cost and Timing
Riversdale to Lumsden 33kV Replacement: The 33kV line from Riversdale to Lumsden will reach its Standard Life in 2010 and limitations exist in transporting power though this line. This line will be insulated at 66kV for future voltage upgrade. This project is largely complete, with the final sections being completed after crop harvest early in 2016/17.	CAPEX Cost Under $0.5M 2016/17
Project completed in 2016/17	
Counsel Rd Sth to Invercargill 33kV Replacement: The line is nearing its Standard Life and renewal is expected during 2016/17. This full line runs from Invercargill to Winton and was purchased from Transpower. It is insulated at 110kV and based on inspection and forecast renewals in the section from Counsel Rd Nth to Winton only 10 percent of the poles in this section are expected to need renewal.	CAPEX Under $0.5M 2016/17
Project completed in 2016/17	
Hillside to Te Anau 66kV Replacement: Line condition inspection has been completed. Of 109 poles, 18 have been assessed as needing renewal within 2 years. 2 red tagged poles have been replaced with 4 more planned before the end of 2015/16. This leaves 12 poles to be replaced in 2016/17.	CAPEX Under $0.5M 2016/17
Project completed in 2016/17	
Mataura Transformer Replacement: The two 33/11kV 10MVA power transformers at Mataura are nearing their 'end-of-life' (50 years at 2015). Oil testing has shown that paper age is currently sufficient for a few more years' service but will be monitored annually. Project will plan for replacement of these units with 33/11kV 6/12MVA transformers – one new and one refurbished (ex Waikiwi). Design and refurbishment of ex Waikiwi transformer to be completed in 2016/17 to cover urgent replacement in case of transformer fault. Transformer replacements forecast for 2017/18 and 2018/19 but may be deferred based on ongoing condition monitoring.	$0.25-$0.75M per annum 2016/17 to 2018/19
Project deferred to 2019/20-2020/21 based on results of condition monitoring	
Seaward Bush Transformer Replacement: The two 33/11kV 10MVA power transformers at Seaward Bush are nearing their 'end-of-life' (50 years at 2015). Oil testing has shown that paper age is currently sufficient for a few more years' service but will be monitored annually. Project will plan for replacement of these units with 33/11kV 6/12MVA	$0.25-$0.75M per annum 2016/17 to 2019/20

Project and Description	Cost and Timing
transformers – one new and one refurbished (ex Waikiwi). Design and refurbishment of ex Waikiwi transformer to be completed in 2016/17 to cover urgent replacement in case of transformer fault. Transformer replacements forecast for 2018/19 and 2019/20 but may be deferred based on ongoing condition monitoring.	
Project deferred to 2020/21-2021/22 based on results of condition monitoring	
Hillside Transformer Replacement: The three single phase transformers at Hillside reach end of life (60 years) in 2017. Project will design for a replacement 3 phase 66/11+11kV 3MVA transformer. The replacement of the transformers may be deferred until condition indicates end of life or one transformer fails and spare single phase transformer is utilised.	$0.25-$0.75M per annum 2019/20 to 2020/21
Makarewa Switchboard Replacement: The Makarewa 11kV Switchboard reaches its expected life of 45 years in 2025/26. Design to be completed in 2024/25 ahead of replacement in 2025/26.	CAPEX $0.2-$2.0M per annum 2024/25-2025/26
Bluff Switchboard Replacement: The Bluff 11kV Switchboard reaches its expected life of 45 years in 2025/26. Design to be completed in 2024/25 ahead of replacement in 2025/26. The new CB6 (installed in 2015) for connection of Flat Hill wind farm will be retained.	CAPEX $0.2-$1.5M per annum 2024/25-2025/26
Ohai Substation Upgrade: This project is to upgrade and renew multiple secondary systems at Ohai Substation. Work to be completed includes • Renewal of voltage regulation relays • Renewal of RTU • Upgrade of incomer protection relays • Installation of arc flash protection of 11kV switchboard • Installation of NER Design has been completed in 2015/16 with construction to occur in 2016/17.	CAPEX Under $0.5M 2016/17
Project completed in 2016/17	
Seismic Remedial - Zone Substations: Ongoing project completing seismic strengthening following inspections of zone substations. Most work is now complete and this project is in its final year	CAPEX Under $0.5M 2016/17
Project completed in 2016/17	
Seismic Remedial Distribution: This project will implement seismic remedial solutions at TPCL's distribution substations following seismic assessments. Various options will be available depending on the site characteristics and include strengthening of buildings, enclosures or structures or replacement with self-contained freestanding equipment. There are a limited number of distribution substations in TPCL's network so work will also consider the strength of overhead structures with large distribution transformers. Remedial work will be spread across five years to manage workload; beginning in 2016/17 and being completed in the 2020/21 year.	CAPEX Cost Under $0.5M per annum 2016/17 to 2020/21
Communications Replacement: Equipment is becoming obsolete with manufacturers' ending support. This project will replace the total communications network with a modern scheme to provide the required communication for TPCL. The chosen scheme will be a combination of higher speed digital microwave radio (DMR) to replace the existing microwave links, and high speed point-to-multipoint broadband radio to zone substations. The overall aim is to achieve a minimum of 1Mbps (Megabit-per-second) speed over Internet Protocol to all of TPCL's zone substations.	CAPEX Cost Under $0.25M per annum 2016/17 to 2018/19

Ongoing Replacement and Renewal Programmes

The remaining replacement and renewal budgets are for ongoing work that tends to require about the same expenditure year after year. These budgets are listed and described in Table 43 and expenditure forecasts are provided in Table 38 (CAPEX) and Table 44 (OPEX)

Table 43: Replacement and Renewal Programmes

Budget	Description	Expenditure
General Distribution Replacement	On-going replacements of distribution assets. These are identified through routine inspection. Covers the following: • Red tagged pole replacement • Increasing road crossing height • Minor distribution renewals and upgrades	Annual CAPEX Cost Under $1.5M
Transformer Replacement	On-going replacements of distribution transformers which are generally identified during distribution inspections and targeted inspections based on age. Some removed units are refurbished.	Annual CAPEX Cost Under $1.5M
11kV Line Replacement	On-going replacements of 11kV line assets. These are identified through routine inspection. As work is planned based on feeders, this renewal and refurbishment covers distribution lines, cables, dropouts and ABS's.	Annual CAPEX Cost Under $5.0M
Subtransmission Line Replacement	On-going replacements of subtransmission line assets. These are identified through routine inspection.	Annual CAPEX Cost Under $0.2M
Zone Substation Minor Replacement	Minor work discovered during previous years inspections are combined by sites into projects. Covers on-going replacement of minor components at zone substations such as LTAC panels and battery banks.	Annual CAPEX Cost Under $0.1M
RTU Replacements	This project will replace an average of three sites over each 2 year period. The Siemens RTU's have now been replaced (or will be replaced as part of other projects) so focus is now on the Harris RTU's. Some substation projects will include the RTU replacement and have costs included. i.e. Waikiwi, Centre Bush, Dipton, Lumsden and Riversdale. This was chosen as the present units are becoming unreliable and full remote operation is required to meet the service levels. Rate of renewal could be increased if unreliability reaches unacceptable levels.	Annual CAPEX Cost Under $0.25M
Regulator Replacement	Replacement of voltage regulators as they reach the condition where maintenance and repair become uneconomic. This project will have replaced all end-of-life phase regulators with modern single phase regulators in 2016/17. The mobile regulator will be renewed in 2020/21.	CAPEX Cost Under $0.25M 2016/17 Under $0.5M 2020/21
Relay Replacement	On-going testing and fault investigation sometimes highlight protection and control relays that are not performing as desired; this programme allows renewal of these with modern protection and control relays (includes Voltage Regulating Relays) Some replacements will occur with other replacement projects, i.e. Switchboard replacement projects	Annual CAPEX Cost Under $0.2M
General Technical Replacement	General replacement of technical items at Zone Substations such as DC systems and batteries.	Annual CAPEX Cost Under $0.1M

Budget	Description	Expenditure
Power Transformer Refurbishment	A budget to allow refurbishment work on large power transformers. Generally this work only insures that the power transformer will achieve its expected life.	Annual CAPEX Cost varies but generally $0.2-0.35M per annum
General Distribution Refurbishment	Refurbishment works for plant other than that located at distribution substations which won't impact on the valuation of the distribution asset. Covers items like crossarms, insulators, strains, re-sagging lines, stay guards, straightening poles, pole caps, ABS handle replacements etc.	Annual OPEX Cost Under $1.5M
Subtransmission Refurbishment	A budget to allow refurbishment work that doesn't impact on the valuation of the subtransmission assets. This covers items like crossarms, insulators, strains, re-sagging lines, stay guards, straightening poles, pole caps, ABS handle replacements etc.	Annual OPEX Cost Under $0.1M
Zone Substation Refurbishment	A budget to allow refurbishment works that won't impact on the valuation of the substation assets. Covers items like earth sticks, safety equipment, buildings, battery systems etc.	Annual OPEX Cost Under $0.1M
Power Transformer Refurbishment	A budget to allow refurbishment works that won't impact on the valuation of the power transformers. Covers items like painting.	Annual OPEX Cost Under $0.25M
Transformer Refurbishment	Refurbishment of distribution transformers such as rust repairs, paint touch-up, oil renewal, replacement of minor parts such as bushings, seals etc.	Annual OPEX Cost Under $0.1M

5.4. TPCL's Forecast Operation Expenditure

The forecast operational expenditure for TPCL is shown in Table 44. These figures are also provided in the information disclosure schedule 11b included in Appendix 3. Three further categories not described earlier complete TPCL's forecasted operational expenditure budget as follows.

Vegetation Management

Annual tree trimming in the vicinity of overhead network is required to prevent contact with lines maintaining network reliability. The first trim of trees has to be undertaken at TPCL's expense as required under the Electricity (Hazards from Trees) Regulations 2003. While some customers have received their first free trim, some are disputing the process and additional costs are occurring to resolve the situation. As TPCL's network is mostly overhead, tree issues are substantial and therefore costs are considerable. This OPEX cost is budgeted at $1.32M per annum ongoing.

Service Interruptions and Emergencies

This budget provides for the provision of staff, plant and resources to be ready for faults and emergencies. Fault staff respond to make the area safe, isolate the faulty equipment or network section and undertake repairs to restore supply to all customers. This OPEX cost is budgeted at $2.87 million per annum.

The former Incident Response budget has been separated into two components; the "Incident Response" budget that remains is the component that covers actions immediately taken to make the site safe and restore power to customers. Any follow-up actions necessary to make permanent repairs are now covered by the new "Reactive Maintenance" budget described in section 5.2.

This separation implements the final paragraph in the Information Disclosure Determination's definition of Service Interruptions & Emergencies: "Planned follow-up activities resulting from and event which were unable to be permanently repaired in the short term are to be included under routine and corrective maintenance and inspection".

The distinction between "Incident Response" and "Incident Additional Time" budgets has been removed as it reflects and internal charging structure that is no longer in force.

Non-Network Operation Expenditure

Non-network operational expenditure is forecast to increase over the AMP period due to the development of an Outage Management System (OMS) by PowerNet. It is planned that OMS will be deployed in a multi-year implementation in 3 major stages. Stage 1 will implement the core OMS, Stage 2 will involve integrating the OMS to other systems including SCADA, the Asset Management System (Maximo), the customer notification system (TVD avalanche) and customer information system. Stage 3 will involve taking the OMS into the field with mobility.

It is expected that the OMS will provide a number of benefits including

- increased outage data accuracy
- reduced fault location identification time
- greater access to information (both in the field and in the control room)
- operating efficiencies
- improved operational safety
- increased customer engagement
- improved auditing functionality

The capital expenditure of the OMS will be reflected in the charges to TPCL (by PowerNet) in the Systems Operations and Network Support non-network operational expenditure category.

Cost Under $0.5M per annum 2018/19 onward; Non-Network OPEX

Table 44: TPCL's Forecast Operational Expenditure

OPEX: Routine and Corrective Maintenance and Inspection ($000)	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Routine Dist Insp Check & Mtce	929	929	929	929	929	929	929	929	929	929
Distribution Planned Maintenance	302	298	298	298	298	298	298	298	298	298
Distribution Earthing Maintenance	456	456	456	456	456	456	456	456	456	456
Subtransmission Tower Inspections	218	-	-	-	-	-	-	-	-	-
Distribution Reactive Maintenance	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221
BS Communications Routine Inspection and Checks	78	78	78	78	78	78	78	78	78	78
Technical Routine Inspections and Checks	615	605	605	605	605	605	605	605	605	605
Technical Planned Maintenance	1,242	1,242	1,242	841	841	841	841	841	841	841
Technical Reactive Maintenance	87	87	87	87	87	87	87	87	87	87
Infrared Survey	16	16	16	16	16	16	16	16	16	16
Partial Discharge Survey	55	55	55	55	55	55	55	55	55	55
Supply Quality Checks	16	16	16	16	16	16	16	16	16	16
Spares Checks and Minor Maintenance	33	33	33	33	33	33	33	33	33	33
Seismic Checks - Distribution	63	-	-	-	-	-	-	-	-	-
Connections Minor Maintenance	95	95	95	95	95	95	95	95	95	95
	5,427	**5,132**	**5,132**	**4,731**	**4,731**	**4,731**	**4,731**	**4,731**	**4,731**	**4,731**

OPEX: Asset Replacement and Renewal ($000)	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
General Distribution Refurbishment	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022
Subtransmission Refurbishment	91	91	91	91	91	91	91	91	91	91
Zone Substation Refurbishment	38	38	38	38	38	38	38	38	38	38
Power Transformer Refurbishment	205	26	26	26	26	26	26	26	26	26
Transformer Refurbishment	40	40	40	40	40	40	40	40	40	40
	1,396	**1,216**	**1,216**	**1,216**	**1,216**	**1,216**	**1,216**	**1,216**	**1,216**	**1,216**

OPEX: Service Interruptions and Emergencies ($000)	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Incident Response Distribution	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221
Incident Response - Communications	50	50	50	50	50	50	50	50	50	50
Incident Response - Technical	350	350	350	350	350	350	350	350	350	350
	1,621	**1,621**	**1,621**	**1,621**	**1,621**	**1,621**	**1,621**	**1,621**	**1,621**	**1,621**

OPEX: Vegetation Management ($000)	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Vegetation Management	1,341	1,341	1,341	1,341	1,341	1,341	1,341	1,341	1,341	1,341
	1,341	**1,341**	**1,341**	**1,341**	**1,341**	**1,341**	**1,341**	**1,341**	**1,341**	**1,341**

Network Operational Expenditure Total ($000)	**9,786**	**9,311**	**9,311**	**8,909**	**8,909**	**8,909**	**8,909**	**8,909**	**8,909**	**8,909**
System Operations and Network Support	1,633	2,038	2,137	2,150	2,150	2,150	2,150	2,150	2,150	2,090
Business Support	3,746	3,845	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917
Non-Network Operational Expenditure Total ($000)	**5,379**	**5,883**	**6,054**	**6,067**	**6,067**	**6,067**	**6,067**	**6,067**	**6,067**	**6,007**
Operational Expenditure Total ($000)	**15,164**	**15,194**	**15,365**	**14,977**	**14,977**	**14,977**	**14,977**	**14,977**	**14,977**	**14,917**

Appendix 3 – Disclosure Schedules

Company Name: **The Power Company Limited**
AMP Planning Period: **1 April 2017 – 31 March 2027**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8	for year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
9	**11a(i): Expenditure on Assets Forecast**	$000 (in nominal dollars)										
10	Consumer connection	1,885	7,197	3,304	2,136	2,179	2,225	2,269	2,315	2,361	2,408	2,456
11	System growth	4,489	10,694	11,881	8,150	3,169	5,048	6,528	4,103	4,185	4,269	4,354
12	Asset replacement and renewal	9,795	8,794	8,614	9,412	11,496	9,772	9,317	9,524	10,249	13,103	10,107
13	Asset relocations	147	54	55	56	57	58	60	61	62	63	64
14	Reliability, safety and environment:											
15	Quality of supply	3,052	929	752	768	783	653	269	275	280	286	292
16	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	1,782	1,010	1,127	1,440	372	145	148	151	154	157	160
18	**Total reliability, safety and environment**	4,834	1,939	1,879	2,208	1,155	798	418	426	435	443	452
19	**Expenditure on network assets**	21,150	28,677	25,733	21,963	18,056	17,901	18,591	16,428	17,292	20,287	17,434
20	Expenditure on non-network assets	-	-	-	-	-	-	-	-	-	-	-
21	**Expenditure on assets**	21,150	28,677	25,733	21,963	18,056	17,901	18,591	16,428	17,292	20,287	17,434
22												
23	*plus* Cost of financing											
24	*less* Value of capital contributions	1,131	1,231	3,231	1,282	1,307	1,335	1,362	1,389	1,417	1,445	1,474
25	*plus* Value of vested assets											
26												
27	**Capital expenditure forecast**	20,019	27,446	22,502	20,681	16,749	16,566	17,230	15,039	15,875	18,842	15,960
28												
29	Assets commissioned	8,770	22,167	28,834	15,016	12,596	12,188	15,600	12,507	12,614	15,587	12,076

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
31	for year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
32		$000 (in constant prices)										
33	Consumer connection	1,885	7,197	3,239	2,051	2,051	2,051	2,051	2,051	2,051	2,051	2,051
34	System growth	4,489	10,694	11,648	7,826	2,983	4,654	5,901	3,636	3,636	3,636	3,636
35	Asset replacement and renewal	9,795	8,794	8,445	9,038	10,822	9,010	8,422	8,440	8,905	11,162	8,440
36	Asset relocations	147	54	54	54	54	54	54	54	54	54	54
37	Reliability, safety and environment:											
38	Quality of supply	3,052	929	737	737	737	602	244	244	244	244	244
39	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment	1,782	1,010	1,105	1,383	350	134	134	134	134	134	134
41	**Total reliability, safety and environment**	4,834	1,939	1,843	2,120	1,087	736	378	378	378	378	378
42	**Expenditure on network assets**	21,150	28,677	25,228	21,089	16,998	16,505	16,806	14,559	15,024	17,281	14,559
43	Expenditure on non-network assets	-	-	-	-	-	-	-	-	-	-	-
44	**Expenditure on assets**	21,150	28,677	25,228	21,089	16,998	16,505	16,806	14,559	15,024	17,281	14,559
45												
46	**Subcomponents of expenditure on assets (where known)**											
47	Energy efficiency and demand side management, reduction of energy losses											
48	Overhead to underground conversion											
49	Research and development											

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
52	for year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
53	**Difference between nominal and constant price forecasts**	$000										
54	Consumer connection	-	-	65	85	128	173	218	263	310	357	405
55	System growth	-	-	233	324	186	394	627	467	549	633	718
56	Asset replacement and renewal	-	-	169	374	674	762	895	1,083	1,344	1,942	1,666
57	Asset relocations	-	-	1	2	3	5	6	7	8	9	11
58	Reliability, safety and environment:											
59	Quality of supply	-	-	15	31	46	51	26	31	37	42	48
60	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
61	Other reliability, safety and environment	-	-	22	57	22	11	14	17	20	23	26
62	**Total reliability, safety and environment**	-	-	37	88	68	62	40	48	57	66	75
63	**Expenditure on network assets**	-	-	505	874	1,058	1,396	1,786	1,869	2,268	3,006	2,875
64	Expenditure on non-network assets	-	-	-	-	-	-	-	-	-	-	-
65	**Expenditure on assets**	-	-	505	874	1,058	1,396	1,786	1,869	2,268	3,006	2,875

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
67	for year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22
68	**11a(ii): Consumer Connection**						
69	*Consumer types defined by EDB**	$000 (in constant prices)					
70	Customer Connections (≤ 20kVA)	763	936	936	936	936	936
71	Customer Connections (21 to 99kVA)	327	468	468	468	468	468
72	Customer Connections (≥ 100kVA)	763	535	535	535	535	535
73	Distributed Generation Connection	5	5	5	5	5	5
74	New Subdivisions	27	108	108	108	108	108
	Mataura Valley Milk	157	5,145	1,187	-	-	-
75	**include additional rows if needed*						
76	**Consumer connection expenditure**	1,885	7,197	3,239	2,051	2,051	2,051
77	*less* Capital contributions funding consumer connection	1,131	4,318	1,943	1,231	1,231	1,231
78	**Consumer connection less capital contributions**	754	2,879	1,295	821	821	821
79	**11a(iii): System Growth**						
80	Subtransmission	1,365	3,755	5,101	-	2,108	1,534
81	Zone substations	2,612	6,939	6,092	7,479	527	2,773
82	Distribution and LV lines	-	-	455	347	347	347
83	Distribution and LV cables	-	-	-	-	-	-
84	Distribution substations and transformers	-	-	-	-	-	-
85	Distribution switchgear	-	-	-	-	-	-
86	Other network assets	512	-	-	-	-	-
87	**System growth expenditure**	4,489	10,694	11,648	7,826	2,983	4,654
88	*less* Capital contributions funding system growth	-	-	-	-	-	-
89	**System growth less capital contributions**	4,489	10,694	11,648	7,826	2,983	4,654

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
92	for year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22
93	**11a(iv): Asset Replacement and Renewal**	$000 (in constant prices)					
94	Subtransmission	645	39	39	196	196	196
95	Zone substations	1,131	1,140	1,043	1,043	2,827	1,068
96	Distribution and LV lines	4,551	3,930	3,930	4,443	4,443	4,443
97	Distribution and LV cables	518	305	305	305	305	305
98	Distribution substations and transformers	1,074	1,757	1,468	1,468	1,468	1,414
99	Distribution switchgear	1,690	1,412	1,412	1,583	1,583	1,583
100	Other network assets	187	212	249	-	-	-
101	**Asset replacement and renewal expenditure**	9,795	8,794	8,445	9,038	10,822	9,010
102	*less* Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
103	**Asset replacement and renewal less capital contributions**	9,795	8,794	8,445	9,038	10,822	9,010

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
106	for year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22
107	**11a(v):Asset Relocations**						
108	*Project or programme**	$000 (in constant prices)					
109	Line Relocations	147	54	54	54	54	54
110	[Description of material project or programme]						
111	[Description of material project or programme]						
112	[Description of material project or programme]						
113	[Description of material project or programme]						
114	**include additional rows if needed*						
115	All other project or programmes - asset relocations						
116	**Asset relocations expenditure**	147	54	54	54	54	54
117	*less* Capital contributions funding asset relocations	-	-	-	-	-	-
118	**Asset relocations less capital contributions**	147	54	54	54	54	54

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
121	for year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22
122	**11a(vi):Quality of Supply**						
123	*Project or programme**	$000 (in constant prices)					
124	Supply Quality Upgrades	223	271	271	271	271	135
125	Mobile Substation site made ready	2,350	179	358	358	358	358
126	Distribution Automation	479	479	-	-	-	-
127	Network Improvement Projects	-	-	108	108	108	108
128	[Description of material project or programme]						
129	**include additional rows if needed*						
130	All other projects or programmes - quality of supply						
131	**Quality of supply expenditure**	3,052	929	737	737	737	602
132	*less* Capital contributions funding quality of supply	-	-	-	-	-	-
133	**Quality of supply less capital contributions**	3,052	929	737	737	737	602

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
136	for year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22
137	**11a(vii): Legislative and Regulatory**						
138	*Project or programme**	$000 (in constant prices)					
139	[Description of material project or programme]						
140	[Description of material project or programme]						
141	[Description of material project or programme]						
142	[Description of material project or programme]						
143	[Description of material project or programme]						
144	**include additional rows if needed*						
145	All other projects or programmes - legislative and regulatory						
146	**Legislative and regulatory expenditure**	-	-	-	-	-	-
147	*less* Capital contributions funding legislative and regulatory						
148	**Legislative and regulatory less capital contributions**	-	-	-	-	-	-

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
150	for year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22
151	**11a(viii): Other Reliability, Safety and Environment**						
152	*Project or programme**	$000 (in constant prices)					
153	Earth Upgrades	109	134	134	134	134	134
154	NER Installations	1,542	660	660	-	-	-
155	Substation Safety	131	216	216	216	216	-
156	Township Undergrounding	-	-	-	-	-	-
157	Replace Xiria Switchgear Gorge Road	-	-	96	1,033	-	-
	[Description of material project or programme]						
158	**include additional rows if needed*						
159	All other projects or programmes - other reliability, safety and environment						
160	**Other reliability, safety and environment expenditure**	1,782	1,010	1,105	1,383	350	134
161	*less* Capital contributions funding other reliability, safety and environment	-	-	-	-	-	-
162	**Other reliability, safety and environment less capital contributions**	1,782	1,010	1,105	1,383	350	134

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
165	for year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22
166	**11a(ix): Non-Network Assets**						
167	**Routine expenditure**						
168	*Project or programme**	$000 (in constant prices)					
169	[Description of material project or programme]						
170	[Description of material project or programme]						
171	[Description of material project or programme]						
172	[Description of material project or programme]						
173	[Description of material project or programme]						
174	**include additional rows if needed*						
175	All other projects or programmes - routine expenditure						
176	**Routine expenditure**	-	-	-	-	-	-
177	**Atypical expenditure**						
178	*Project or programme**						
179	[Description of material project or programme]						
180	[Description of material project or programme]						
181	[Description of material project or programme]						
182	[Description of material project or programme]						
183	[Description of material project or programme]						
184	**include additional rows if needed*						
185	All other projects or programmes - atypical expenditure						
186	**Atypical expenditure**	-	-	-	-	-	-
187							
188	**Expenditure on non-network assets**	-	-	-	-	-	-

![THE POWER COMPANY LTD]

Company Name	**The Power Company Limited**
AMP Planning Period	**1 April 2017 – 31 March 2027**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref												
7		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8	for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	4,235	1,621	1,654	1,688	1,722	1,758	1,793	1,829	1,866	1,903	1,941
11	Vegetation management	1,390	1,341	1,368	1,397	1,425	1,455	1,484	1,513	1,544	1,575	1,606
12	Routine and corrective maintenance and inspection	2,673	5,427	5,235	5,345	5,025	5,131	5,233	5,338	5,445	5,554	5,665
13	Asset replacement and renewal	1,448	1,396	1,241	1,267	1,292	1,319	1,345	1,372	1,400	1,428	1,456
14	**Network Opex**	9,746	9,786	9,497	9,697	9,464	9,663	9,856	10,053	10,254	10,459	10,668
15	System operations and network support	1,572	1,633	2,079	2,225	2,284	2,332	2,379	2,426	2,475	2,524	2,503
16	Business support	3,765	3,746	3,922	4,080	4,161	4,248	4,333	4,420	4,509	4,599	4,691
17	**Non-network opex**	5,336	5,379	6,001	6,305	6,445	6,580	6,712	6,846	6,983	7,123	7,193
18	**Operational expenditure**	15,082	15,164	15,498	16,001	15,909	16,243	16,568	16,899	17,237	17,582	17,862
19		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
20	for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	4,235	1,621	1,621	1,621	1,621	1,621	1,621	1,621	1,621	1,621	1,621
23	Vegetation management	1,390	1,341	1,341	1,341	1,341	1,341	1,341	1,341	1,341	1,341	1,341
24	Routine and corrective maintenance and inspection	2,673	5,427	5,132	5,132	4,731	4,731	4,731	4,731	4,731	4,731	4,731
25	Asset replacement and renewal	1,448	1,396	1,216	1,216	1,216	1,216	1,216	1,216	1,216	1,216	1,216
26	**Network Opex**	9,746	9,786	9,311	9,311	8,909	8,909	8,909	8,909	8,909	8,909	8,909
27	System operations and network support	1,572	1,633	2,038	2,137	2,150	2,150	2,150	2,150	2,150	2,150	2,090
28	Business support	3,765	3,746	3,845	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917
29	**Non-network opex**	5,336	5,379	5,883	6,054	6,067	6,067	6,067	6,067	6,067	6,067	6,007
30	**Operational expenditure**	15,082	15,164	15,194	15,365	14,977	14,977	14,977	14,977	14,977	14,977	14,917
31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and demand side management, reduction of											
33	energy losses	125	125	125	125	125	125	125	125	125	125	125
34	Direct billing*											
35	Research and Development											
36	Insurance	303	303	303	303	303	303	303	303	303	303	303
37	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
38												
39		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
40	for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	-	32	67	101	137	172	208	245	282	320
43	Vegetation management	-	-	27	56	83	113	142	172	202	233	265
44	Routine and corrective maintenance and inspection	-	-	103	213	294	400	503	607	714	823	934
45	Asset replacement and renewal	-	-	24	50	76	103	129	156	184	212	240
46	**Network Opex**	-	-	186	386	555	753	947	1,144	1,345	1,550	1,759
47	System operations and network support	-	-	41	89	134	182	228	276	325	374	413
48	Business support	-	-	77	162	244	331	416	503	591	681	773
49	**Non-network opex**	-	-	118	251	378	513	645	779	916	1,055	1,186
50	**Operational expenditure**	-	-	304	636	932	1,266	1,591	1,923	2,261	2,605	2,945

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Company Name	**The Power Company Limited**
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SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref					Asset condition at start of planning period (percentage of units by grade)						
7											
8											
9	**Voltage**	**Asset category**	**Asset class**	**Units**	**Grade 1**	**Grade 2**	**Grade 3**	**Grade 4**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
10	All	Overhead Line	Concrete poles / steel structure	No.	-	5.00%	70.00%	5.00%	20.00%	3	5.00%
11	All	Overhead Line	Wood poles	No.	-	5.00%	70.00%	5.00%	20.00%	3	15.00%
12	All	Overhead Line	Other pole types	No.	-	5.00%	70.00%	5.00%	20.00%	3	5.00%
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	5.00%	70.00%	5.00%	20.00%	3	5.00%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	N/A	-	-	-	-	N/A	
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km		-	100.00%	-	-	4	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	N/A	-	-	-	-	N/A	
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	N/A	-	-	-	-	N/A	
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km		-	100.00%	-	-	4	-
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	N/A	-	-	-	-	N/A	
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	N/A	-	-	-	-	N/A	
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	N/A	-	-	-	-	N/A	
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	N/A	-	-	-	-	N/A	
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	N/A	-	-	-	-	N/A	
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	5.00%	90.00%	5.00%	-	4	5.00%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	N/A	-	-	-	-	N/A	
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.		-	100.00%	-	-	4	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.		5.00%	90.00%	5.00%	-	4	5.00%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	N/A	-	-	-	-	N/A	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.		2.00%	90.00%	8.00%	-	3	2.00%
30	HV	Zone substation switchgear	33kV RMU	No.	N/A	-	-	-	-	N/A	
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	N/A	-	-	-	-	N/A	
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	2.00%	90.00%	8.00%	-	4	2.00%
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	7.00%	86.00%	7.00%	-	4	7.00%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	100.00%	-	-	4	10.00%
35											
36					Asset condition at start of planning period (percentage of units by grade)						
37											
38	**Voltage**	**Asset category**	**Asset class**	**Units**	**Grade 1**	**Grade 2**	**Grade 3**	**Grade 4**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.		8.00%	90.00%	2.00%	-	4	10.00%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1.00%	4.00%	70.00%	5.00%	20.00%	3	10.00%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	1.00%	4.00%	70.00%	5.00%	20.00%	3	10.00%
42	HV	Distribution Line	SWER conductor	km	1.00%	4.00%	70.00%	5.00%	20.00%	3	5.00%
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	75.00%	5.00%	20.00%	3	-
44	HV	Distribution Cable	Distribution UG PILC	km	-	2.00%	73.00%	5.00%	20.00%	3	2.00%
45	HV	Distribution Cable	Distribution Submarine Cable	km	N/A					N/A	
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	3.00%	92.00%	5.00%	-	4	3.00%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	N/A					N/A	
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1.00%	6.00%	67.00%	6.00%	20.00%	2	7.00%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	N/A					N/A	
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	3.00%	94.00%	3.00%	-	4	5.00%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	-	3.00%	74.00%	3.00%	20.00%	3	10.00%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	1.00%	96.00%	3.00%	-	4	10.00%
53	HV	Distribution Transformer	Voltage regulators	No.	-	5.00%	90.00%	5.00%	-	4	5.00%
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	N/A	-	-	-	-	N/A	
55	LV	LV Line	LV OH Conductor	km	1.00%	4.00%	70.00%	5.00%	20.00%	3	5.00%
56	LV	LV Cable	LV UG Cable	km	1.00%	4.00%	70.00%	5.00%	20.00%	3	5.00%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	1.00%	4.00%	70.00%	5.00%	20.00%	3	5.00%
58	LV	Connections	OH/UG consumer service connections	No.	1.00%	4.00%	70.00%	5.00%	20.00%	3	10.00%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	2.00%	94.00%	4.00%	-	4	10.00%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	2.00%	94.00%	4.00%	-	4	10.00%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	100.00%	-	-	4	-
62	All	Load Control	Centralised plant	Lot	-	20.00%	80.00%	-	-	3	20.00%
63	All	Load Control	Relays	No.	-	-	18.00%	2.00%	80.00%	3	50.00%
64	All	Civils	Cable Tunnels	km	N/A					N/A	

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Company Name	**The Power Company Limited**
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SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

7 **12b(i): System Growth - Zone Substations**

sch ref	*Existing Zone Substations*	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
8										
9	Athol	1	-	N	1	-	-	-	No constraint within +5 years	
10	Awarua	5	-	N	1	-	12	67%	No constraint within +5 years	
11	Awarua Chip Mill	1	-	N	1	-	-	-	No constraint within +5 years	
12	Bluff	5	13	N-1	1	37%	13	42%	No constraint within +5 years	
13	Centre Bush	4	-	N	2	-	-	-	No constraint within +5 years	
14	Colyer Road		12	N-1	2				No constraint within +5 years	
15	Conical Hill	2	5	N-1	2	45%	-	-	No constraint within +5 years	
16	Dipton	2	-	N	1	-	-	-	No constraint within +5 years	
17	Edendale Fonterra	24	46	N-1	-	53%	46	74%	No constraint within +5 years	
18	Edendale	7	12	N	1	56%	12	60%	No constraint within +5 years	
19	Glenham	2	-	N	1	-	-	-	No constraint within +5 years	Upgrade planned
20	Gorge Road	3	2	N-1 switched	1	206%	-	-	Transformer	Upgrade planned
21	Heddon Bush	8	-	N	6	-	N/A	-	No constraint within +5 years	Removed to spares
22	Hedgehope	2	-	N	1	-	-	-	No constraint within +5 years	
23	Hillside	1	-	N	1	-	-	-	No constraint within +5 years	
24	Isla Bank		-	N	2	-			No constraint within +5 years	
25	Kelso	5	-	N	2	-	-	-	Transformer	Upgrade planned
26	Kennington	6	12	N-1 switched	2	48%	12	40%	No constraint within +5 years	
27	Lumsden	3	-	N	2	-	-	-	No constraint within +5 years	
28	Makarewa	7	12	N-1 switched	2	54%	12		No constraint within +5 years	
	Mataura	6	10	N-1	2	64%	12	50%	No constraint within +5 years	
	Monowai	0	-	N	-	-	-	-	No constraint within +5 years	
	Mossburn	2	2	N-1 switched	2	139%	-	-	No constraint within +5 years	
	North Gore	9	10	N-1	8	86%	10	77%	No constraint within +5 years	
	North Makarewa	50	45	N-1	-	110%	45	110%	Transformer	Expect some additional DG in Area
	Ohai	3	5	N-1 switched	1	54%	-	-	No constraint within +5 years	
	Orawia	3	-	N	2	-	-	-	No constraint within +5 years	
	Otatara	4	-	N	4	-	-	-	No constraint within +5 years	
	Otautau	5	-	N	3	-	-	-	No constraint within +5 years	
	Riversdale	5	-	N	3	-	5	118%	Transpower	Upgrade planned
	Riverton	5	8	N-1	2	64%	8	70%	No constraint within +5 years	
	Seaward Bush	9	10	N-1 switched	1	85%	12	67%	No constraint within +5 years	Upgrade planned
	South Gore	11	12	N-1	8	95%	12	77%	No constraint within +5 years	
	Te Anau	6	12	N-1	1	47%	12	51%	No constraint within +5 years	
	Tokanui	1	-	N	1	-	-	-	No constraint within +5 years	
	Underwood	13	20	N-1	4	65%	20	61%	No constraint within +5 years	
	Waikaka	1	-	N	1	-	-	-	No constraint within +5 years	
29	Waikiwi	10	23	N-1	2	45%	23	58%	No constraint within +5 years	
	Winton	10	12	N-1	3	83%	12	90%	No constraint within +5 years	

[1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

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Company Name	**The Power Company Limited**
AMP Planning Period	**1 April 2017 – 31 March 2027**

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref

7	**12c(i): Consumer Connections**						
8	*Number of ICPs connected in year by consumer type*			**Number of connections**			
9		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10	for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**
11	*Consumer types defined by EDB**						
12	Customer Connections (≤ 20kVA)	216	225	225	225	225	225
13	Customer Connections (21 to 99kVA)	20	25	25	25	25	25
14	Customer Connections (≥ 100kVA)	6	5	5	5	5	5
15	Subdivsions	-	5	5	5	5	5
16							
17	**Connections total**	242	260	260	260	260	260
18	**include additional rows if needed*						
19	**Distributed generation**						
20	Number of connections	20	30	30	30	30	30
21	Capacity of distributed generation installed in year (MVA)	0	0	0	0	0	0

22	**12c(ii) System Demand**						
23		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24	**Maximum coincident system demand (MW)** — for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**
25	GXP demand	80	80	81	82	83	83
26	*plus* Distributed generation output at HV and above	57	57	57	57	57	57
27	**Maximum coincident system demand**	137	137	138	139	140	140
28	*less* Net transfers to (from) other EDBs at HV and above	2	2	2	2	2	2
29	**Demand on system for supply to consumers' connection points**	135	135	136	137	138	138
30	**Electricity volumes carried (GWh)**						
31	Electricity supplied from GXPs	562	563	566	568	571	574
32	*less* Electricity exports to GXPs	55	50	50	50	50	50
33	*plus* Electricity supplied from distributed generation	268	240	240	240	240	240
34	*less* Net electricity supplied to (from) other EDBs	15	18	18	18	18	18
35	**Electricity entering system for supply to ICPs**	759	735	737	740	743	746
36	*less* Total energy delivered to ICPs	707	725	728	731	734	737
37	**Losses**	52	10	9	9	9	9
38							
39	**Load factor**	64%	62%	62%	62%	62%	62%
40	**Loss ratio**	6.9%	1.3%	1.3%	1.2%	1.2%	1.2%

Note: These forecasts are presented using the SAIDI/SAIFI calculation method detailed in the Electricity Distribution Services Default Price-Quality Path Determination 2015. As such they correlate with the Compliance Statement and the majority of publications in the public domain, but do not correlate with Schedule 10 of year-end disclosures. A rough correlation with Schedule 10 may be obtained through multiplying the Class B figures in rows 11 and 14 by a factor of 2

Company Name	**The Power Company Limited**
AMP Planning Period	**1 April 2017 – 31 March 2027**
Network / Sub-network Name	

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9	for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	46.4	36.0	37.0	37.0	37.0	37.0
12	Class C (unplanned interruptions on the network)	92.9	120.2	117.6	117.0	116.4	115.8
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.18	0.18	0.18	0.18	0.18	0.18
15	Class C (unplanned interruptions on the network)	2.02	2.60	2.54	2.53	2.52	2.51

Company Name	**The Power Company Ltd**
AMP Planning Period	**1 April 2015 – 31 March 2025**
Asset Management Standard Applied	**PAS 55: 2008**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Maturity Level Description
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	2	The asset management policy is authorised by top management, is widely and effectively communicated to all relevant employees and stakeholders, and used to make these persons aware of their asset related obligations.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	2	All linkages are in place and evidence is available to demonstrate that, where appropriate, the organisation's asset management strategy is consistent with its other organisational policies and strategies. The organisation has also identified and considered the requirements of relevant stakeholders.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the	2	The asset management strategy takes account of the lifecycle of all of its assets, asset types and asset systems.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	2	Asset management plan(s) are established, documented, implemented and maintained for asset systems and critical assets to achieve the asset management strategy and asset management objectives across all life cycle phases.
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	2	The plan(s) are communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan(s) and there is confirmation that they are being used effectively.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	3	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)?	2	The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	3	Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the	3	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	2	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and	2	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	2	The organisation can demonstrate that plan(s) are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system process(es).
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	2	Competency requirements are in place and aligned with asset management plan(s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	2	Competency requirements are identified and assessed for all persons carrying out asset management related activities - internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to asset management requirements.
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	3	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process(es). Pertinent asset information requirements are regularly reviewed.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	2	The organisation has established documentation that comprehensively describes all the main elements of its asset management system and the interactions between them. The documentation is kept up to date.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	1	The organisation has determined what its asset information system should contain in order to support its asset management system. The requirements relate to the whole life cycle and cover information originating from both internal and external sources.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite	2	The organisation has effective controls in place that ensure the data held is of the requisite quality and accuracy and is consistent. The controls are regularly reviewed and improved where necessary.
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	2	Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	2	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how	2	Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across	3	Effective process(es) and procedure(s) are in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are	2	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process for confirming the process(es)/procedure(s) are effective and if necessary carrying out modifications.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	2	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	2	The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2	The organisation can demonstrate that its audit procedure(s) cover all the appropriate asset-related activities and the associated reporting of audit results. Audits are to an appropriate level of detail and consistently managed.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and	2	Mechanisms are consistently in place and effective for the systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit.
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of	1	Continuous improvement process(es) are set out and include consideration of cost risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	3	The organisation actively engages internally and externally with other asset management practitioners, professional bodies and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments.

Appendix 4 – Directors Approval

We, Douglas William Fraser and Donald Owen Nicolson, being Directors of The Power Company Limited certify that, having made all reasonable enquiry, to the best of our knowledge-

a) The following attached information of The Power Company Limited prepared for the purposes of clause 2.6.3 and 2.6.6 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

c) The forecasts in Schedules 11a, 11b, 12a, 12b and 12c are based on objective and reasonable assumptions which both align with The Power Company Limited's corporate vision and strategy and are documented in retained records.

D W Fraser

D O Nicolson

Date: 29/03/2017