THEPOWERCOMPANYLTD

Asset Management Plan Update 2019 - 2029

Publicly disclosed in March 2019

THEPOWERCOMPANYLTD

Update Overview

TPCL's Asset Management Plan update 2019-29 is presented as the sections shown below under contents, which have been updated from TPCL's Asset Management Plan 2018-28. 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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Enquiries

Enquiries, submissions or comments about this Asset Management Plan (AMP) can be directed to:

Network Assets Manager	
PowerNet Limited,	Phone (03) 211 1899,
PO Box 1642,	Fax (03) 211 1880,
Invercargill, 9840	Email amp@powernet.co.nz

Liability Disclaimer

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4. Development Planning

4.3. Development Programme

Current Projects (Year 1 – 2019/20)

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 fibre optic cables 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 six Ring Main Units (RMUs) and eight distribution transformers. The RMUs will be fully automated enabling remote operation from PowerNet system control.

33kV cables have been installed and are operating at 11kV supplied from South Gore Substation. McNab Substation construction was delayed due to issues confirming the site location and levels with resulting delays in completion of the civil design. The substation is under construction with completion forecast in June 2019 with final connection of McNab Substation to be aligned with MVM factory outages proposed for August 2019.

Cost $0.6M 2019/20; CAPEX – Customer Connections

Blue Sky Meats Upgrade

Blue Sky Meats have requested increased capacity for their abattoir at Morton Mains. This project enables the abattoir to take supply from two 11kV feeders to provide increased capacity whilst providing a lower level of supply should either feeder experience outages caused by faults or during planned maintenance. A new 11kV overhead supply, 11kV metering, two new 11kV Ring Main Units (RMUs), additional 11kV cabling and an additional 500kVA transformer will be installed during the upgrade. An automation scheme will ensure essential load remains energised in the event of outages on either 11kV supply.

Cost $0.6M 2019/20; CAPEX – Customer Connections

Oreti Valley Project (OVP)

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 (a new 66kV crossing the Oreti River to the west of the substation and heading north along Riverside Road to Centre Bush Substation) has been completed along with the upgrade of Centre Bush Substation to 66kV.

The 33kV lines between Centre Bush and Mossburn will be upsized to 66kV. The first section from Centre Bush to Dipton has been completed along with the upgrade of Dipton Substation to 66kV.

The lines between Dipton and Lumsden and Lumsden and Mossburn are to be completed in 2018/19 along with the upgrade to 66kV at Lumsden. The timing of completion of Lumsden will align with the completion of the 66kV lines into Lumsden from both Mossburn and Centre Bush.

The 66/33kV transformer at Heddon Bush will be relocated to Lumsden to provide a 33kV backup to Riversdale substation under a separate project.

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 200 millisecond 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 or rebuild 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.

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

- 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 from Mossburn to Lumsden will connect into Mossburn substation by the spare 66kV bay.

Dipton to Lumsden 66kV line upgrade has been completed and the Lumsden Substation 66kV upgrade had been partially completed allowing supply from the upgraded 66/11+11kV transformer and new 22kV indoor switchboard. The remaining works at Lumsden Substation are due to be completed in September 2019. The Lumsden to Mossburn section required significantly more pole replacements than forecast due to ground clearance issues identified during design. This has delayed completion of this line section until October 2019.

Cost $2.7M 2019/20; CAPEX – System Growth

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

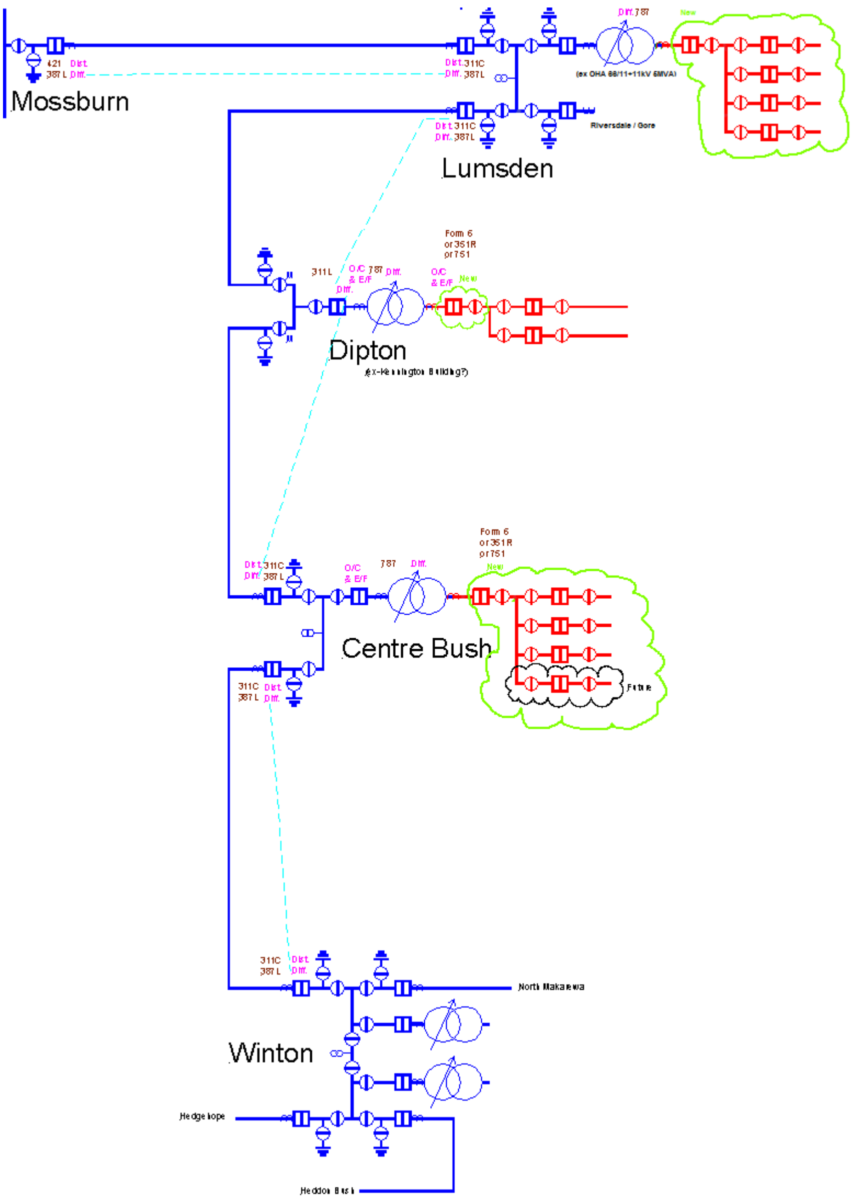

Figure 1 - Completed Oreti Valley Project Single Line Diagram

Riversdale Transformer Upgrade

Project completed in 2018/19. See previous AMP for project details.

Gorge Road Transformer Upgrade

Load growth has already exceeded the N-1 capacity of 1.5MVA at Gorge Road Substation. Load is approaching 2.5MVA. This project will replace the dual 33/11kV 1.5MVA power transformers at Gorge Road substation with a single refurbished 5MVA transformer.

Cost Under $0.1 - 1.5M per annum 2018/19 and 2019/20; CAPEX – System Growth

No material change.

22kV Upgrade Athol – Kingston

Load growth occurring in and around Kingston township is forecast to exceed the ability of the 11kV network to supply adequate voltage. There is an existing 11kV regulator at Fairlight and an additional regulator on the feeder from Athol to Kingston is not desirable. This project will mole plough sections of 22kV cable from Athol to Kingston which will initially operate at 11kV and reinsulate the remainder of the line to 22kV. After load growth exceeds the ability of 11kV to supply Kingston, Athol substation can be converted to 22kV supply with autotransformers used to step voltage back down to 11kV at points where 11kV will continue to be utilized.

This project has been deferred to meet the revised understanding of timing for the subdivision and development of water infrastructure in Kingston. Design will be completed in 2019/20 to enable the network upgrades to be completed in parallel with the subdivision development should it proceed earlier than forecast.

Cost $0.1 – 2.0M per annum 2019/20 to 2023/24; CAPEX – System Growth

Neutral Earthing Resistor (NER) project

As part of compliance with the 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.

Detection of NER open circuit faults has required fitment of Neutral Voltage Transformers (NVTs) at seven sites where NERs have already been installed. This work will be completed in 2019/20 along with commissioning of NERs at two sites where difficulty obtaining outages has resulted in deferral of completion into the 2019/20 year. An NER will also be installed at Glenham in 2019/20 under this project due to deferral of the transformer upgrade at that site which incorporated NER installation.
Cost $0.6M 2019/20; CAPEX – Other Reliability, Safety and Environment

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 (Personal Protection Equipment) 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.

Cost Under $0.5M per annum 2018/19 to 2021/22; CAPEX – Other Reliability, Safety and Environment

No material change.

Replace 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 Environment

No material change.

Riversdale 33kV Backup Supply

The Oreti Valley Project has resulted in the 33kV backup supply to Riversdale (from Heddon Bush via Centre Bush and Dipton) being removed. As the plan to upgrade Riversdale to 66kV supply has been removed from the AMP due to lower than forecast load growth, a backup 33kV supply to Riversdale is required. PowerNet’s supply security standard requires 25 minutes restoration time. Due to time involved in switching to achieve 11kV backups, a switched subtransmission supply is required to achieve the security standard.

This project will relocate the Heddon Bush 66/33kV transformer to the upgraded Lumsden Substation. A 33kV cable will then be installed from the transformer to the line supplying Riversdale Substation.

Delays in construction of Lumsden Substation due to re-allocation of contractor resource to other projects have had follow-on impacts on completion of this project. Completion is forecast in August 2019.
Cost $0.2M 2019/20; CAPEX – Other Reliability, Safety and Environment

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.

Forecast completion of Gorge Road Transformer Upgrade in 2019/20 combined with lower regional growth than forecast has resulted in deferral of this project until 2021/22. Design has been completed in 2018/19.
Cost $1.3M 2021/22; CAPEX - System Growth

Bluecliffs Remote Area Power Supply

A Remote Area Power Supply (RAPS) solution is proposed to supply 2 customers at the end of a remote section of line in the Bluecliffs area. The existing line is unable to be economically rebuilt due to expected ongoing erosion of ground around poles. The RAPS solution has the lowest capital cost and the lowest lifetime cost when compared to the alternative options of rebuilding the line along an alternative route or mole ploughing a cable. The project will install the RAPS and remove the remaining sections of the existing line.

Project delayed until 2019/20 due to delays in obtaining customer approval of the RAPS scheme and development of a suitable RAPS solution.
Cost $0.2M 2019/20; CAPEX – Other Reliability, Safety and Environment

Planned Projects (Years 2 – 5 2020/21 – 2023/24)

Lumsden / Riversdale 22kV Line Upgrades

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. In addition, load growth has also eroded backup capability between Lumsden and Riversdale substations. Lumsden being upgraded to be able to supply 22kV and Riversdale will have 22kV autotransformers installed on key feeders. This project intends to upgrade the lines north of Riversdale to 22kV and key sections of line between the two substations to improve MV backups.

Project start deferred to 2020/21 due to lack of load growth and customer enquiries.
Cost $0.4 - 0.5M per annum 2020/21 to 2028/29; CAPEX – System Growth

Transpower Edendale Transformer Upgrade

The load at Edendale GXP is approaching the continuous rating (30MVA) of Transpower's T1/T2 transformer at Edendale bank. This puts supply at risk in the event of one transformer being out of service. PowerNet has requested further information from Transpower about the summer and winter ratings of the transformers so as to understand the supply risk and possible mitigation measures.

Control measures include increased load control, tie point and load shifts to other GXPs, and Special Protection Schemes which will automatically shed load in the event of a transformer tripping.

Additional capacity is forecast to be required at Edendale in 2021 and this project will cover the Transpower upgrades required. The likely upgrade path is fans fitted to the T1 and T2 transformers. The cost and timeframe of this upgrade is to be confirmed in consultation with Transpower.

Kennington Second 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. Consideration will be given to moleploughing in a 33kV cable instead of the line upgrade as the rural nature of the proposed route means this may be more cost-effective.

> A 33kV cable is now planned as this is more cost effective. A scoping exercise has concluded three new 33kV circuit breakers are required compared to one allowed for in the initial estimate. A directional protection scheme will be developed at Kennington to ensure reliability meets security of supply requirements. These additional requirements have resulted in an increase in forecast cost of the project to $1.5M in 2019/20.
> Cost $1.5M 2019/20; CAPEX - System Growth

Considered Projects

Expected projects for year six to ten (YE 31 March 2024 to 2029) are as follows. These projects have little if any certainty.

Kelso Transformer Upgrade

Load growth is forecast to exceed the 5MVA capacity of the transformer at Kelso Substation in 2024. This project will add fans to the transformer to increase its capacity. This should provide for another 10 years of growth.

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 two 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 $0.1 - $0.2M per annum 2023 to 2025, System Growth.

> No material change.

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.

Cost $3.9M per annum 2024/25 onwards; System Growth

Routine / Ongoing Projects

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.

Cost $2.1M per annum on-going; CAPEX - Consumer Connections.

Asset Relocation Projects

This budget captures costs for relocation works when requested by authorities or customers 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

There are two known relocation projects for 2019/20 in addition to the above. These are detailed below.

Te Anau – Manapouri Pipeline 11kV Cable

The Southland District Council is installing a wastewater pipeline from Te Anau to Manapouri. The proposed route is immediately adjacent to an existing 11kV cable. The cable will be relocated and replaced due to a combination of service age and capacity.
Cost $0.1M; CAPEX – Asset Relocations

Fairlight Regulator Relocation

Fairlight Regulator will be relocated due to the ideal electrical location having shifted due to forecast changes in loading on the 11kV feeder it serves. The relocated regulator will be 22kV capable but operated at 11kV initially due to intent to convert the feeder to 22kV within the planning period.
Cost $0.4M; 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 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.

Mobile Substation Site Made Ready

This project provides connection points for the mobile substation at single transformer substations. The aim is to have each substation suitably arranged to allow the mobile substation to be connected for either maintenance activities or to cover transformer or other major equipment failures. The works will vary at each substation but could include additional land, fencing, gravel, earthing, HV connection / isolation point, MV connection / isolation point.

The single transformer substation sites will be converted ahead of the next scheduled maintenance activities which require a full substation offload. Nine substations remain to be made mobile substation ready.
Cost Under $0.1 -0.5M per annum 2019/20 – 2024/25; 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 $0.1M per annum on-going from 2018/19; CAPEX – Quality of Supply

Earth Upgrades

Ineffective earthing may create hazardous voltage on and around network equipment (Earth Potential Rise; EPR) during fault situations, affecting safety for the public and for staff. Poor earthing can also prevent protection systems from operating correctly, which may affect the safety and reliability of the network. Routine earth site inspection and testing identifies any sites that require upgrades.

Determining the most appropriate upgrade option can be quite complex, but the ultimate aim is to find the optimal trade-off between cost and risk reduction. Upgrade works may include additional earthing rods or banks, replacement of surface material (asphalt or gravel) to reduce risk, and installation of insulating fences or fence sections to reduce the risk of transfer to adjacent conductive fences.

Routine testing is completed five yearly.

> PowerNet have invested in two new earth rod drivers (one truck mounted, one excavator mounted) which enable a more cost-effective earth in hard ground conditions. These earth rod drivers are being deployed for new earths in known difficult areas and to upgrade existing known high resistance earths.
> Cost Under $0.8M 2019/20 $0.5M 2020/21 then $0.2M per annum on-going; CAPEX – Other Reliability, Safety and Environment

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.

Riversdale Substation Upgrade

If load growth occurs faster at Riversdale than forecast a substantial upgrade of the substation will be required. 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 2.

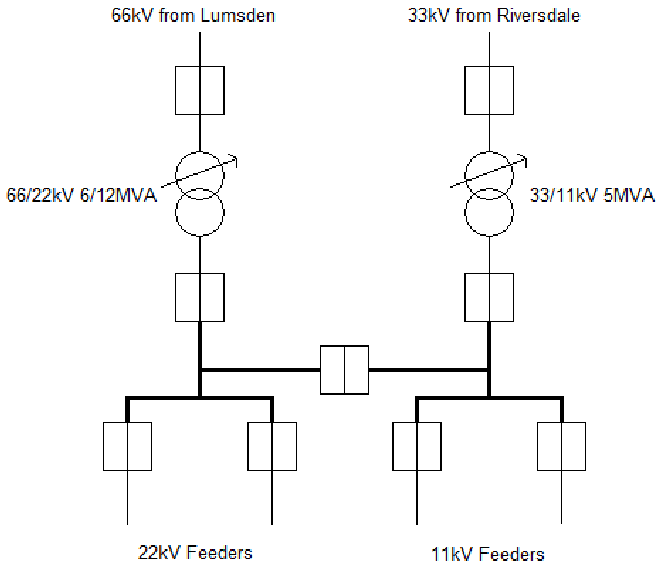

Figure 2 - Proposed Riversdale Single Line Diagram

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 been reinsulated to 66kV. This project will also need to upgrade the 33/11kV transformer at Riversdale to 66/22kV.

Colyer Road Third 33kV Line

Additional major load growth at Colyer Road would require a third 33kV subtransmission line from Invercargill GXP. As no approaches have been made from any developers recently this project has moved into contingent project.

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.

4.7. Non-network Development

IT Services

TPCL receives IT and management services support through its management services contract with PowerNet. Whilst it does not directly develop the GIS (Intergraph) or AMS (Maximo) systems, it does in conjunction with PowerNet develop interfaces and processes around these systems.

Lumsden Depot

The depot workshop at Lumsden was built in 1963 and the small office was added in the early 1970's. The buildings have had minimal maintenance over this time and are uneconomic to upgrade. The site is no longer fit for purpose and is potentially a health and safety hazard as parts of the current buildings contain asbestos and the layout of the site and facilities are not practical for modern day distribution work.

A new building is required at the depot, including storage for trucks and equipment, office space for the Depot Supervisor and Team Leader, kitchen and bathroom facilities and a common area/staff room for the team to congregate.

Cost $0.8M 2019/20

Training Line

Access roads to the training line at the Racecourse Road Depot will allow safety training to continue over the winter months without the risk of recovering stuck heavy vehicles. In the past the training line has been shut down in the winter months while the ground remained soft to any heavy/light vehicles. Year round access to the training line will allow the full scope of tasks such as heavy vehicle setup, plant certification, live line training and competency validation to continue throughout the winter months

Cost $35k 2019/20

TPCL's Forecast Capital Expenditure

The forecast capital expenditure for TPCL is shown in Table 44.

These figures are also provided in the information disclosure schedule 11a included in Appendix 3.

Table 44: TPCL's Forecast Capital Expenditure

CAPEX: Consumer Connection	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Customer Connections (≤ 20kVA)	981	981	981	981	981	981	981	981	981	981
Customer Connections (21 to 99kVA)	491	491	491	491	491	491	491	491	491	491
Customer Connections (≥ 100kVA)	561	561	561	561	561	561	561	561	561	561
Distributed Generation Connection	6	6	6	6	6	6	6	6	6	6
New Subdivisions	112	112	112	112	112	112	112	112	112	112
Blue Sky Meats Upgrade	619	-	-	-	-	-	-	-	-	-
Mataura Valley Milk	615	-	-	-	-	-	-	-	-	-
	3,385	**2,150**	**2,150**	**2,150**	**2,150**	**2,150**	**2,150**	**2,150**	**2,150**	**2,150**

CAPEX: System Growth	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
OVP-Centre Bush to Mossburn 66kV Line	1,313	-	-	-	-	-	-	-	-	-
OVP-Dipton Substation Upgrade	94	-	-	-	-	-	-	-	-	-
OVP-Centre Bush Substation Upgrade	-	-	-	-	-	-	-	-	-	-
OVP-Lumsden Substation Upgrade	1,108	-	-	-	-	-	-	-	-	-
Riversdale Substation Upgrade	-	-	-	-	-	-	-	-	-	-
Kelso Transformer Upgrade	-	-	-	-	31	100	-	-	-	-
Kennington 2nd 33kV Supply	1,456	-	-	-	-	-	-	-	-	-
Glenham Transformer Upgrade	-	-	1,335	-	-	-	-	-	-	-
Lumsden / Riversdale 22kV Line Upgrades	-	469	397	397	397	397	397	397	397	397
Gorge Road Transformer Upgrade	518	-	-	-	-	-	-	-	-	-
OVP-Microwave Radio Ring Scheme	152	-	-	-	-	-	-	-	-	-
22kV Upgrade Athol - Kingston	59	-	1,599	984	847	-	-	-	-	-
Easements	25	25	25	25	25	25	25	25	25	25
Unspecified Projects	-	-	-	-	-	3,927	3,927	3,927	3,927	3,927
	4,724	**494**	**3,356**	**1,406**	**1,300**	**4,448**	**4,348**	**4,348**	**4,348**	**4,348**

CAPEX: Asset Replacement and Renewal	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Transformer Replacement	745	745	745	745	745	745	745	745	745	745
Ground Mount Platform Transformers	688	688	688	688	688	688	688	688	688	688
11kV Line Replacement	6,759	6,600	6,600	6,600	6,600	6,600	6,600	6,600	6,600	6,600
Subtransmission Line Replacement	205	205	205	205	205	205	205	205	205	205
Zone Substation Minor Replacement	94	94	94	94	94	94	94	94	94	94
RTU Replacement	140	140	140	140	140	140	140	140	140	140
Regulator Replacement	-	332	-	-	-	-	-	-	-	-
Relay Replacement	183	56	56	56	56	56	56	56	56	56
Communications Replacement	269	269	76	76	76	76	76	76	76	76
General Technical Replacement	29	29	29	29	29	29	29	29	29	29
Seismic Remedial Distribution	337	-	-	-	-	-	-	-	-	-
Tower Inspection Remediation Works	-	113	-	-	-	-	-	-	-	-
ABS renewals	1,442	2,883	2,883	2,883	2,883	1,442	-	-	-	-
Counsell Rd N - Winton additional strain structures	-	-	-	-	-	-	-	-	-	-
Power Transformer Refurbishment	-	361	187	227	247	361	247	247	247	247
Orawia Substation Upgrade	-	-	-	-	1,219	-	-	-	-	-
North Makarewa RTU & Relay Replacement	334	-	-	-	-	-	-	-	-	-
Makarewa Switchboard Replacement	-	-	-	-	-	198	1,693	-	-	-
Bluff Switchboard Replacement	-	-	-	-	-	198	1,248	-	-	-
Gore Ripple Plant Upgrade	72	-	-	-	-	-	-	-	-	-
Seaward Bush RTU, Arc Flash & Structure Replacement	813	351	-	-	-	-	-	-	-	-
KF CB Replacement - Nobbs Hill & Upuk	-	-	-	-	-	-	-	-	-	-
KF CB Replacement - Pahia & Nobbs Hill	134	-	-	-	-	-	-	-	-	-
KF CB Replacement - Waimumu & Robsons	-	134	-	-	-	-	-	-	-	-
Transpower Gore ODID Preparatory works	54	-	-	-	-	-	-	-	-	-
RMU Renewals	249	249	249	124	124	124	124	124	124	124
Gore LV Link Box Renewals	175	-	-	-	-	-	-	-	-	-
Waikaka Transformer Replacement	-	-	-	-	-	-	-	-	-	-
	12,721	**13,247**	**11,952**	**11,868**	**13,107**	**10,956**	**11,945**	**9,004**	**9,004**	**9,004**

CAPEX: Asset Relocations	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Line Relocations	56	56	56	56	56	56	56	56	56	56
Te Anau Manapouri Pipeline	104	-	-	-	-	-	-	-	-	-
Fairlight Regulator Relocation	356	-	-	-	-	-	-	-	-	-
	516	**56**	**56**	**56**	**56**	**56**	**56**	**56**	**56**	**56**

CAPEX: Quality of Supply	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Supply Quality Upgrades	279	279	279	279	279	279	279	140	140	140
Mobile Substation Site Made Ready	503	129	-	129	-	259	-	-	-	-
Network Improvement Projects	140	113	113	113	113	113	113	113	113	113
	923	**522**	**392**	**522**	**392**	**651**	**392**	**253**	**253**	**253**

CAPEX: Legislative and Regulatory	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
	-	-	-	-	-	-	-	-	-	-
	-	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

CAPEX: Other Reliability, Safety and Environment	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Earth Upgrades	828	460	221	221	221	221	221	221	221	221
NER Installations	649	-	-	-	-	-	-	-	-	-
Substation Safety	250	227	453	-	-	-	-	-	-	-
Township Undergrounding	-	-	-	-	-	-	-	-	-	-
Replace Xiria Switchgear Gorge Road	462	-	-	-	-	-	-	-	-	-
Riversdale 33kV backup supply	221	-	-	-	-	-	-	-	-	-
Bluecliffs Remote Area Power Supply	183	-	-	-	-	-	-	-	-	-
Heat Pump Installation in Zone Substations	244	-	-	-	-	-	-	-	-	-
	2,836	**687**	**674**	**221**	**221**	**221**	**221**	**221**	**221**	**221**

Total Network CAPEX	25,104	17,156	18,581	16,222	17,226	18,482	19,113	16,033	16,033	16,033

CAPEX: Non-Network Assets	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Lumsden Depot	800	-	-	-	-	-	-	-	-	-
Training Line	35	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-
	835	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

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 preventative 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 45 sets out the maintenance approaches applicable to each network asset category and the frequency with which these maintenance activities are undertaken.

Table 45: 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 As occurs
	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 As discovered
	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 Engineer's 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 As discovered Half life After Significant Event
	Distribution Voltage Switchgear	Condition Monitoring through periodic visual inspection checking for; operation count, gas pressure, abnormal or	Monthly

Asset Category	Sub Category	Maintenance Approach	Frequency
		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.	5 Yearly
		Corrective maintenance as required after any concerning inspection or test results.	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.	Monthly
		Protection relays are tested typically with current injection to verify operation as per settings.	5 yearly
		Any alarms or indications from electronic equipment or relays reset and control centre notified for remediation.	
		Meters recertified by external technicians as regulations require.	
		Otherwise any other equipment visually inspected for anything untoward.	Non-periodic
Distribution Network	O/H	Condition Monitoring through periodic visual inspection.	5 yearly
		Tightening, repair or replacement of loose, damaged, deteriorated or missing components.	
	U/G	Generally run to failure and repair.	Reactive or opportunistic
		Inspection of visible terminations as part of zone substation checks and otherwise opportunistic inspection if covers removed for other work.	5 yearly if visible
		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.	
	Distributed Distribution Voltage Switchgear (ABSs)	Condition Monitoring through periodic visual inspection.	5 yearly
		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.	
Distribution Substations	Distribution Transformers	Condition monitoring through periodic inspections. Infrared thermal camera inspection units 500kVA and larger.	6 monthly or if <150kVA
		Clean up and repair of corrosion, leaks etc. Some units have breathers; replaced when saturated.	As discovered
		Winding resistances, Insulation resistance for older units if shut down allows.	Opportunistic
		DGA for critical end of life units.	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.	6 monthly
		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.	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

Asset Category	Sub Category	Maintenance Approach	Frequency
LV Network	O/H	Condition Monitoring through periodic visual inspection. Tightening, repair or replacement of loose, damaged, deteriorated or missing components.	5 yearly
	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 46 and forecasts are provided in Table 52 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 46: Routine and Corrective Maintenance and Inspection Budget Descriptions

Budget	Description	Expenditure Range/Type
Distribution Inspections	Five yearly network inspections (20% inspected annually), other routine tests and minor maintenance works on distribution assets.	Cost $1.4M on-going; OPEX
Distribution Planned Maintenance	Generally reactive work undertaken to correct issues found during the routine distribution inspection. Also a general budget for all minor distribution work.	Cost $0.3M on-going; OPEX
Technical Inspections	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 $0.6M 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 $1.4M 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 $64k 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 $18k on-going; OPEX
Supply Quality Checks	Investigations into supply quality which are generally customer initiated.	Cost $18k 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 $35k on-going; OPEX
Customer Connections	Operational portion of expenditure for the customer connections process is captured in this budget.	Cost Under $0.1M on-going; OPEX
Earth Testing	Routine testing of earthing assets and connections	Cost $0.5M on-going;

Budget	Description	Expenditure Range/Type
	to ensure safety and functional requirements are met completed for all earths on a five yearly basis.	OPEX

Systemic Issues

One potential systemic issue is currently being investigated. Grey porcelain insulators on EDE Air Break Switches manufactured between 1998 and 2014 have a potential defect which can result in water ingress. Over time this can cause the insulator to crack and break into pieces which can fall when the switch is operated. The investigation is proceeding and once completed appropriate remedial action will be taken to mitigate, repair, or replace the affected ABS's.

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.

Innovations That Defer Asset Replacement

There are a number of innovations that TPCL uses to defer asset replacement. These include;

- Thermal (Infrared) and Partial Discharge (Corona) camera inspections of Zone Substation equipment

- Mid-life refurbishment of power transformers
- Dissolved Gas Analysis (DGA) of large distribution transformers
- Thor hammer analysis of poles
- Automation of switchgear to enable faster restoration in the event of fault

Table 47 sets out the approach to making decisions around when to undertake replacements or renews applicable to each network asset category.

Table 47: 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 Subtransmission Voltage Switchgear (ABSs)	When inspection indicates deterioration sufficient to lose confidence in continued reliable operation and maintenance is considered uneconomic.
Zone Substations	Zone Substation HV 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.
	Medium 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. Buildings and fences when not economic to maintain after significant accumulating deterioration or seismic resilience

Asset Category	Sub Category	Replacement and Renewal Decision Approach
		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 Medium 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.
	Link and Pillar Boxes	Replaced if damaged or deterioration is advanced and could lead to failure before next inspection (or if public safety

Asset Category	Sub Category	Replacement and Renewal Decision Approach
		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 if security provided by backup plant.

Non-Routine Replacement and Renewal Projects

Replacement and renewal projects that are not ongoing are described in Table 48, Table 49, and Table 50 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.

No material change to these budgets except where otherwise indicated.

Table 18: Current (Year 1) Non-routine Replacement and Renewal Projects

Project and Description	Cost and Timing
Seaward Bush RTU, Arc Flash & Structure Replacement: The Seaward Bush substation has a number of secondary systems which were planned to be replaced as part of a Power Transformer renewal. The transformers have now been condition assessed in consultation with a transformer expert as having many years' service life remaining. This has led to the transformer renewal being removed as a project. The other renewal activities (RTU, arc flash and 33kV structure) are still planned and are combined in this project. The existing overhead 33kV bus structure will be replaced with two 33kV ring main units (RMUs) and short 33kV cable runs to poles adjacent to the substation. The 11kV switchboard will be retrofitted with arc flash detection sensors and new incomer CB protection relays to enable arc flash protection. The obsolescent Harris RTU will also be replaced with an SEL Axion or SEL 3530 RTU.	CAPEX $0.4-$0.8M per annum 2019/20 to 2020/21
Design to be completed in 2019/20 ahead of construction in 2019/20 and 2020/21.	
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 2019/20 year.	CAPEX $0.3M 2019/20
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 $0.3M per annum 2016/17 to 2027/28
Counsell Rd N – Winton Additional Strain Structures: Design for a full rebuild of the Counsell Rd N to Winton 66kV line was completed in 2014. Condition inspection of the line revealed that only 7 structures needed replacement. These were replaced and the completed design was archived. Review of the design has highlighted that four additional	CAPEX Cost Under $0.2M 2018/19

Project and Description	Cost and Timing
strain structures are required to bring the line up to the standard of AS/NZS 7000 for Overhead Lines. This project will replace the four identified existing suspension structures with new strain structures to improve the resilience of this line.	
Project completed in 2018/19	
North Makarewa RTU & Relay Replacement: The existing North Makarewa 33kV feeder protection relays (and injection plant CB relays) are at nominal end-of-life (45 years) in 2018. This project is to renew the existing relays on 33kV feeders (and injection plant) with SEL-751 protection relays. CB 1062 will also be replaced as part of this project as it is at nominal end-of-life and in poor condition. The obsolescent Harris RTU will also be replaced with an SEL 3530 RTU.	CAPEX $0.3M 2019/20
RTU installation started. Project completion deferred due to staff shortages and difficulties in recruiting new staff. Project will be completed in 2019/20.	
Gore Ripple Plant Upgrade: Changes in network loading and impedance 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. Delays with the smart meter roll out have meant that an upgrade of the converter panel at the Gore Ripple Plant is required.	CAPEX $0.1M 2019/20
Converter panel installed and commissioned in 2018/19. Difficulties in obtaining a new local controller to interface to the SCADA system has resulted in this component of the project being deferred until 2019/20.	
KF CB Replacement: The older Cooper KF circuit breakers are at nominal end of life with the six remaining units due for maintenance over the next 3-5 years. It is proposed to replace these circuit breakers ahead of their periodic maintenance. The replacement circuit breakers will have vacuum breaking and the upgrade will incorporate modern protection relays and SCADA radios. Two circuit breakers will be replaced per annum over the next 3 years.	CAPEX Cost Under $0.2M per annum 2018/19 to 2020/21
Waikaka Transformer Replacement: The power transformer at Waikaka has had some poor condition monitoring results and is suffering from some minor oil leaks. Given the condition of this unit it will be replaced with a spare 1.5MVA unit.	CAPEX Cost Under $0.2M
Project completed in 2018/19	
Transpower Gore ODID Preparatory Works: Transpower are converting the outdoor 33kV switchgear to an indoor switchboard. Ahead of this work TPCL will renew the termination structures opposite the Gore GXP and remove poles which are no longer required.	CAPEX $54k 2019/20
The Transpower project timing has meant some of this project will carry over into the 2019/20 year	
Ground Mount Platform Transformers: This project will renew large platform or pole mounted distribution transformers (greater than 100kVA) with ground mount units to minimise seismic risk. There are 145 of these transformers around TPCL's network. The program will target 10 per annum of 15 years. The general transformer replacement budget has been reduced over the duration of this project.	CAPEX $0.7M per annum 2019/20 to 2033/34
Tower Inspection Remediation Works: The subtransmission tower circuits will be inspected in 2019/20. Any capital renewal works will be completed in 2020/21.	CAPEX $0.1M 2020/21

Project and Description	Cost and Timing
Gore LV Link Box Renewals: The LV link boxes in Gore's CBD have been identified for renewal based on both condition and the desire to improve safety for our field staff when operating.	CAPEX $0.2M 2019/20

Table 49: Planned (Year 2 - 5) Non-routine Replacement and Renewal Projects

Project and Description	Cost and Timing
Orawia Substation Upgrade: The Orawia Substation control room building and transformer and overhead bus structures were identified as being at risk during seismic investigation. This project will replace the control room and make changes to the weight loading on the bus structures. Loading will be reduced by replacing pole mounted equipment with ground mounted equipment and replacing overhead conductor bus with either cable or conductor supported on dedicated equipment stands.	CAPEX $1.2M 2023/24
Orawia Substation has been made ready for the Mobile Substation allowing deferral of this project due to competing capital work priorities. Work is now proposed for the 2023/24 year.	
ABS Renewals: Air Break Switches have been identified for a substantial renewal program due to the failure rate and age of the ABS fleet. This program will replace around 300 ABS's with enclosed vacuum load break switches over 4 years. Project timeframe extended to 6 years to smooth resource requirements.	CAPEX $1.4-$2.9M per annum 2019/20 to 2024/25

Table 50: Considered (Year 6 – 10) Non-routine Replacement and Renewal Projects

Project and Description	Cost and Timing
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-$1.7M 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 $0.1-$1.2M per annum 2024/25-2025/26

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 51 and expenditure forecasts are provided in Table 44 (CAPEX) and Table 52 (OPEX). A redefinition of work programmes to more closely align to Information Disclosure Determination definitions has resulted in a transfer of some distribution work from Routine Maintenance to Replacement & Renewal. A one-off adjustment in 2018/19 adapts the OPEX budgets below for a change in the financial treatment of these costs under a revised network management agreement.

Table 2: Replacement and Renewal Programmes

Budget	Description	Expenditure
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	Annual CAPEX Cost $0.7M

Budget	Description	Expenditure
	refurbished.	
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. This budget also covers • Red tagged pole replacement • Increasing road crossing height • Minor distribution renewals and upgrades	Annual CAPEX Cost $6.6M – 6.8M
Subtransmission Line Replacement	On-going replacements of subtransmission line assets. These are identified through routine inspection.	Annual CAPEX Cost $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 $0.1M
RTU Replacements	This project will replace an average of three sites over each 2 year period. The focus is now on the Harris RTU's. Some substation projects will include the RTU replacement and have costs included. i.e. Seaward Bush, Lumsden. 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 $0.2M
Regulator Replacement	Replacement of voltage regulators as they reach the condition where maintenance and repair become uneconomic. The mobile regulator will be renewed in 2020/21.	CAPEX Cost $0.3M 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 $0.1-0.2M
General Technical Replacement	General replacement of technical items at Zone Substations such as DC systems and batteries.	Annual CAPEX Cost Under $29k
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
RMU Renewals	On-going renewal of Ring Main Units as required based on condition assessments.	Annual CAPEX Cost $0.3M
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 CAPEX Cost $0.7M
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 $0.1M

Budget	Description	Expenditure
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 $43k
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 $29k
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 $45k

5.4. TPCL's Forecast Operation Expenditure

The forecast operational expenditure for TPCL is shown in Table 52. These figures are also provided in the information disclosure schedule 11b included in Appendix 3. Two 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 $1.7M 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. Any follow-up actions necessary to make further repairs are charged to the appropriate Reactive Maintenance budget. This OPEX cost is budgeted at $3.9 million per annum.

Table 52: TPCL's Forecast Operational Expenditure

OPEX: Asset Replacement and Renewal	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
General Distribution Refurbishment	680	680	680	680	680	680	680	680	680	680
Subtransmission Refurbishment	101	101	101	101	101	101	101	101	101	101
Zone Substation Refurbishment	43	43	43	43	43	43	43	43	43	43
Power Transformer Refurbishment	29	29	29	29	29	29	29	29	29	29
Transformer Refurbishment	45	45	45	45	45	45	45	45	45	45
	898	**898**	**898**	**898**	**898**	**898**	**898**	**898**	**898**	**898**

OPEX: Vegetation Management	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Vegetation Management	1,713	1,713	1,713	1,713	1,713	1,713	1,713	1,713	1,713	1,713
	1,713	**1,713**	**1,713**	**1,713**	**1,713**	**1,713**	**1,713**	**1,713**	**1,713**	**1,713**

OPEX: Routine and Corrective Maintenance and Ir	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Distribution Inspections	1,393	1,393	1,393	1,393	1,393	1,393	1,393	1,393	1,393	1,393
Distribution Planned Maintenance	282	282	282	282	282	282	282	282	282	282
Earth Testing	515	515	515	515	515	515	515	515	515	515
Subtransmission Tower Inspections	266	-	-	-	-	-	-	-	-	-
Distribution Reactive Maintenance	282	282	282	282	282	282	282	282	282	282
BS Communications Routine Inspection and Checks	92	92	92	92	92	92	92	92	92	92
Technical Inspections	605	605	605	605	605	605	605	605	605	605
Technical Planned Maintenance	1,392	1,392	1,392	1,392	1,392	1,392	1,392	1,392	1,392	1,392
Technical Reactive Maintenance	98	98	98	98	98	98	98	98	98	98
Infrared Survey	18	18	18	18	18	18	18	18	18	18
Partial Discharge Survey	64	64	64	64	64	64	64	64	64	64
Supply Quality Checks	18	18	18	18	18	18	18	18	18	18
Spares Checks and Minor Maintenance	35	35	35	35	35	35	35	35	35	35
Transfomer Two-Pole Structure Inspections	38	-	-	-	-	-	-	-	-	-
Asbestos Inspections	-	-	-	-	-	-	-	-	-	-
Connections Minor Maintenance	107	107	107	107	107	107	107	107	107	107
	5,206	**4,901**	**4,901**	**4,901**	**4,901**	**4,901**	**4,901**	**4,901**	**4,901**	**4,901**

OPEX: Service Interruptions and Emergencies	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Incident Response - Distribution - Fixed Fee	496	496	496	496	496	496	496	496	496	496
Incident Response - Distribution - Unplanned	2,983	2,983	2,983	2,983	2,983	2,983	2,983	2,983	2,983	2,983
Incident Response - Communications - Fixed Fee	43	43	43	43	43	43	43	43	43	43
Incident Response - Communications - Unplanned	17	17	17	17	17	17	17	17	17	17
Incident Response - Technical - Fixed Fee	37	37	37	37	37	37	37	37	37	37
Incident Response - Technical - Unplanned	354	354	354	354	354	354	354	354	354	354
	3,931	**3,931**	**3,931**	**3,931**	**3,931**	**3,931**	**3,931**	**3,931**	**3,931**	**3,931**

Operational Expenditure Total	**11,748**	**11,443**	**11,443**	**11,443**	**11,443**	**11,443**	**11,443**	**11,443**	**11,443**	**11,443**
System Operations and Network Support	2,660	2,942	3,001	3,001	3,001	3,001	3,001	3,001	3,001	3,001
Business Support	3,724	3,715	3,784	3,784	3,784	3,784	3,784	3,784	3,784	3,784
AMP Total Operational Expenditure	**18,132**	**18,100**	**18,229**	**18,229**	**18,229**	**18,229**	**18,229**	**18,229**	**18,229**	**18,229**

Appendix 3 – Disclosure Schedules

Company Name	The Power Company Limited
AMP Planning Period	1 April 2019 – 31 March 2029

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 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	31 Mar 28	31 Mar 29
9	**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10	Consumer connection	4,347	3,385	2,172	2,196	2,222	2,251	2,283	2,317	2,354	2,394	2,437
11	System growth	5,545	4,724	499	3,427	1,453	1,361	4,721	4,685	4,760	4,841	4,928
12	Asset replacement and renewal	10,078	12,721	13,380	12,204	12,263	13,720	11,629	12,869	9,856	10,024	10,204
13	Asset relocations	111	516	57	57	58	59	59	60	61	62	63
14	Reliability, safety and environment:											
15	Quality of supply	639	923	527	401	539	411	691	423	277	281	286
16	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	2,402	2,836	694	689	228	231	235	238	242	246	251
18	**Total reliability, safety and environment**	3,041	3,759	1,220	1,089	767	642	926	661	519	527	537
19	**Expenditure on network assets**	23,121	25,104	17,327	18,973	16,764	18,033	19,618	20,592	17,550	17,848	18,169
20	Expenditure on non-network assets	-	835	-	-	-	-	-	-	-	-	-
21	**Expenditure on assets**	23,121	25,939	17,327	18,973	16,764	18,033	19,618	20,592	17,550	17,848	18,169
22												
23	*plus* Cost of financing	-	-	-	-	-	-	-	-	-	-	-
24	*less* Value of capital contributions	2,475	1,821	1,303	1,318	1,333	1,351	1,370	1,390	1,412	1,436	1,462
25	*plus* Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
26												
27	**Capital expenditure forecast**	20,646	24,119	16,024	17,655	15,430	16,682	18,248	19,202	16,137	16,412	16,707
28												
29	Assets commissioned	26,178	28,982	17,997	18,739	16,264	17,331	18,052	19,405	16,024	16,024	16,024
30		*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 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	31 Mar 28	31 Mar 29
32		**$000 (in constant prices)**										
33	Consumer connection	3,385	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150
34	System growth	5,545	4,724	494	3,356	1,406	1,300	4,448	4,348	4,348	4,348	4,348
35	Asset replacement and renewal	10,078	12,721	13,247	11,952	11,868	13,107	10,956	11,945	9,004	9,004	9,004
36	Asset relocations	111	516	56	56	56	56	56	56	56	56	56
37	Reliability, safety and environment:											
38	Quality of supply	639	923	522	392	522	392	651	392	253	253	253
39	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment	2,402	2,836	687	674	221	221	221	221	221	221	221
41	**Total reliability, safety and environment**	3,041	3,759	1,208	1,067	743	613	872	613	474	474	474
42	**Expenditure on network assets**	22,159	23,870	17,156	18,581	16,222	17,226	18,482	19,113	16,033	16,033	16,033
43	Expenditure on non-network assets	-	835	-	-	-	-	-	-	-	-	-
44	**Expenditure on assets**	22,159	24,705	17,156	18,581	16,222	17,226	18,482	19,113	16,033	16,033	16,033
45												
46	**Subcomponents of expenditure on assets (where known)**											
47	Energy efficiency and demand side management, reduction of energy losses	N/A	244	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
48	Overhead to underground conversion	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
49	Research and development	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Row			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
50													
52		for year ended	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	31 Mar 28	31 Mar 29
53	**Difference between nominal and constant price forecasts**		$000										
54	Consumer connection		962	1,234	22	45	72	101	132	166	203	243	287
55	System growth		-	-	5	71	47	61	273	336	411	492	579
56	Asset replacement and renewal		-	-	132	252	396	613	673	924	852	1,019	1,200
57	Asset relocations		-	-	1	1	2	3	3	4	5	6	7
58	Reliability, safety and environment:												
59	Quality of supply		-	-	5	8	17	18	40	30	24	29	34
60	Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
61	Other reliability, safety and environment		-	-	7	14	7	10	14	17	21	25	29
62	**Total reliability, safety and environment**		-	-	12	23	25	29	54	47	45	54	63
63	**Expenditure on network assets**		962	1,234	172	392	541	806	1,136	1,479	1,517	1,815	2,137
64	Expenditure on non-network assets		-	-	-	-	-	-	-	-	-	-	-
65	**Expenditure on assets**		962	1,234	172	392	541	806	1,136	1,479	1,517	1,815	2,137
66													

11a(ii): Consumer Connection

Row			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
67		for year ended	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
68	**11a(ii): Consumer Connection**							
69	*Consumer types defined by EDB**		$000 (in constant prices)					
70	Customer Connections (≤ 20kVA)		981	981	981	981	981	981
71	Customer Connections (21 to 99kVA)		491	491	491	491	491	491
72	Customer Connections (≥ 100kVA)		561	561	561	561	561	561
73	Distributed Generation Connection		6	6	6	6	6	6
	New Subdivisions		112	112	112	112	112	112
	Blue Sky Meats Upgrade		619	-	-	-	-	-
74	Mataura Valley Milk		615	-	-	-	-	-
75	**include additional rows if needed*							
76	**Consumer connection expenditure**		3,385	2,150	2,150	2,150	2,150	2,150
77	*less* Capital contributions funding consumer connection		2,475	1,821	1,290	1,290	1,290	1,290
78	**Consumer connection less capital contributions**		910	330	860	860	860	860

11a(iii): System Growth

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
79	**11a(iii): System Growth**						
80	Subtransmission	3,417	2,551	-	-	-	-
81	Zone substations	1,895	1,938	469	1,732	397	428
82	Distribution and LV lines	-	63	25	1,064	665	575
83	Distribution and LV cables	-	-	-	-	-	-
84	Distribution substations and transformers	-	15	-	400	246	212
85	Distribution switchgear	-	6	-	160	98	85
86	Other network assets	232	152	-	-	-	-
87	**System growth expenditure**	5,545	4,724	494	3,356	1,406	1,300
88	*less* Capital contributions funding system growth	-	-	-	-	-	-
89	**System growth less capital contributions**	5,545	4,724	494	3,356	1,406	1,300
90							

			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
92		for year ended	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
93	**11a(iv): Asset Replacement and Renewal**		**$000 (in constant prices)**					
94	Subtransmission		984	258	566	392	432	452
95	Zone substations		886	1,664	1,114	319	319	1,538
96	Distribution and LV lines		4,872	5,069	4,950	4,950	4,950	4,950
97	Distribution and LV cables		-	35	-	-	-	-
98	Distribution substations and transformers		1,220	1,771	1,433	1,433	1,433	1,433
99	Distribution switchgear		1,749	3,654	4,916	4,782	4,658	4,658
100	Other network assets		368	269	269	76	76	76
101	**Asset replacement and renewal expenditure**		10,078	12,721	13,247	11,952	11,868	13,107
102	*less* Capital contributions funding asset replacement and renewal		-	-	-	-	-	-
103	**Asset replacement and renewal less capital contributions**		10,078	12,721	13,247	11,952	11,868	13,107
104								

			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
106		for year ended	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
107	**11a(v): Asset Relocations**							
108	*Project or programme**		**$000 (in constant prices)**					
109	Line Relocations		111	56	56	56	56	56
110	Te Anau Manapouri Pipeline		-	104	-	-	-	-
111	Fairlight Regulator Relocation		-	356	-	-	-	-
112								
113								
114	**include additional rows if needed*							
115	All other project or programmes - asset relocations							
116	**Asset relocations expenditure**		111	516	56	56	56	56
117	*less* Capital contributions funding asset relocations		-	-	-	-	-	-
118	**Asset relocations less capital contributions**		111	516	56	56	56	56
119								

			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
121		for year ended	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
122	**11a(vi): Quality of Supply**							
123	*Project or programme**		**$000 (in constant prices)**					
124	Supply Quality Upgrades		168	279	279	279	279	279
125	Mobile Substation Site Made Ready		196	503	129	-	129	-
126	Network Improvement Projects		275	140	113	113	113	113
127								
128								
129	**include additional rows if needed*							
130	All other projects or programmes - quality of supply							
131	**Quality of supply expenditure**		639	923	522	392	522	392
132	*less* Capital contributions funding quality of supply		-	-	-	-	-	-
133	**Quality of supply less capital contributions**		639	923	522	392	522	392
134								

11a(vii): Legislative and Regulatory

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
*Project or programme**	$000 (in constant prices)					
**include additional rows if needed*						
All other projects or programmes - legislative and regulatory						
Legislative and regulatory expenditure	-	-	-	-	-	-
less Capital contributions funding legislative and regulatory						
Legislative and regulatory less capital contributions	-	-	-	-	-	-

11a(viii): Other Reliability, Safety and Environment

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
*Project or programme**	$000 (in constant prices)					
Earth Upgrades	560	828	460	221	221	221
NER Installations	1,225	649	-	-	-	-
Substation Safety	224	250	227	453	-	-
Township Undergrounding	-	-	-	-	-	-
Replace Xiria Switchgear Gorge Road	84	462	-	-	-	-
Riversdale 33kV backup supply	309	221	-	-	-	-
Bluecliffs Remote Area Power Supply	-	183	-	-	-	-
Heat Pump Installation in Zone Substations	-	244	-	-	-	-
**include additional rows if needed*						
All other projects or programmes - other reliability, safety and environment						
Other reliability, safety and environment expenditure	2,402	2,836	687	674	221	221
less Capital contributions funding other reliability, safety and environment	-	-	-	-	-	-
Other reliability, safety and environment less capital contributions	2,402	2,836	687	674	221	221

11a(ix): Non-Network Assets

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
Routine expenditure						
*Project or programme**	$000 (in constant prices)					
**include additional rows if needed*						
All other projects or programmes - routine expenditure						
Routine expenditure	-	-	-	-	-	-
Atypical expenditure						
*Project or programme**						
Lumsden Depot	-	800	-	-	-	-
Training Line	-	35	-	-	-	-
**include additional rows if needed*						
All other projects or programmes - atypical expenditure						
Atypical expenditure	-	835	-	-	-	-
Expenditure on non-network assets	-	835	-	-	-	-

Company Name	The Power Company Limited
AMP Planning Period	1 April 2019 – 31 March 2029

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		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 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	31 Mar 28	31 Mar 29
9	**Operational Expenditure Forecast**	$000 (in nominal dollars)										
10	Service interruptions and emergencies	3,939	4,475	4,520	4,569	4,624	4,684	4,750	4,821	4,898	4,982	5,071
11	Vegetation management	1,550	1,799	1,723	1,742	1,763	1,786	1,811	1,838	1,867	1,899	1,933
12	Routine and corrective maintenance and inspection	4,901	5,351	5,088	5,144	5,206	5,273	5,347	5,427	5,514	5,608	5,709
13	Asset replacement and renewal	986	1,407	1,421	1,437	1,454	1,473	1,493	1,516	1,540	1,566	1,595
14	**Network Opex**	11,376	13,032	12,752	12,892	13,047	13,216	13,401	13,602	13,820	14,055	14,308
15	System operations and network support	1,903	2,812	3,062	3,252	3,388	3,534	3,690	3,856	4,033	4,222	4,425
16	Business support	4,475	3,763	3,904	4,140	4,314	4,500	4,698	4,909	5,135	5,376	5,634
17	**Non-network opex**	6,378	6,575	6,967	7,392	7,702	8,034	8,387	8,765	9,168	9,599	10,059
18	**Operational expenditure**	17,754	19,607	19,718	20,284	20,749	21,250	21,788	22,367	22,988	23,653	24,367

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
20	for year ended	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	31 Mar 28	31 Mar 29
21		$000 (in constant prices)										
22	Service interruptions and emergencies	3,939	4,475	4,475	4,475	4,475	4,475	4,475	4,475	4,475	4,475	4,475
23	Vegetation management	1,550	1,799	1,706	1,706	1,706	1,706	1,706	1,706	1,706	1,706	1,706
24	Routine and corrective maintenance and inspection	4,901	5,351	5,037	5,037	5,037	5,037	5,037	5,037	5,037	5,037	5,037
25	Asset replacement and renewal	986	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407
26	**Network Opex**	11,376	13,032	12,625	12,625	12,625	12,625	12,625	12,625	12,625	12,625	12,625
27	System operations and network support	1,903	2,812	2,945	3,004	3,004	3,004	3,004	3,004	3,004	3,004	3,004
28	Business support	4,475	3,763	3,754	3,824	3,824	3,824	3,824	3,824	3,824	3,824	3,824
29	**Non-network opex**	6,378	6,575	6,699	6,828	6,828	6,828	6,828	6,828	6,828	6,828	6,828
30	**Operational expenditure**	17,754	19,607	19,324	19,453	19,453	19,453	19,453	19,453	19,453	19,453	19,453
31	**Subcomponents of operational expenditure (where known)**											
32–33	Energy efficiency and demand side management, reduction of energy losses	125	125	125	125	125	125	125	125	125	125	125
34	Direct billing*	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	Research and Development	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
36	Insurance	277	998	1,246	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271

37 ** Direct billing expenditure by suppliers that direct bill the majority of their consumers*

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
40	for year ended	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	31 Mar 28	31 Mar 29
41	**Difference between nominal and real forecasts**	$000										
42	Service interruptions and emergencies	-	-	45	94	149	209	275	346	423	507	596
43	Vegetation management	-	-	17	36	57	80	105	132	161	193	227
44	Routine and corrective maintenance and inspection	-	-	50	106	168	236	310	390	477	570	671
45	Asset replacement and renewal	-	-	14	30	47	66	86	109	133	159	187
46	**Network Opex**	-	-	126	267	421	591	776	977	1,195	1,429	1,682
47	System operations and network support	-	-	118	248	385	530	686	852	1,029	1,219	1,422
48	Business support	-	-	150	316	490	675	873	1,085	1,311	1,552	1,810
49	**Non-network opex**	-	-	268	564	875	1,206	1,559	1,937	2,340	2,771	3,232
50	**Operational expenditure**	-	-	394	831	1,296	1,797	2,335	2,914	3,535	4,200	4,914

Company Name	**The Power Company Limited**
AMP Planning Period	**1 April 2019 – 31 March 2029**

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	H1	H2	H3	H4	H5	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.	0.25%	0.16%	1.27%	88.76%	9.56%	-	3	6.00%
11	All	Overhead Line	Wood poles	No.	5.84%	8.10%	8.46%	76.04%	1.56%		2	12.00%
12	All	Overhead Line	Other pole types	No.	-	-	-	-	-	-	N/A	6.00%
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	5.00%	10.00%	63.00%	2.00%	20.00%	3	4.00%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	100.00%	-	-	2	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	100.00%	-	-	2	-
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	5.00%	85.00%	5.00%	5.00%	-	4	3.00%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	65.00%	35.00%	-	4	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	5.00%	15.00%	75.00%	5.00%	-	4	2.00%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	2.00%	15.00%	75.00%	8.00%	-	3	4.00%
30	HV	Zone substation switchgear	33kV RMU	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	2.00%	5.00%	78.00%	15.00%	-	4	2.00%
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	7.00%	10.00%	75.00%	8.00%	-	4	5.00%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	15.00%	81.00%	4.00%	-	4	6.00%
35												

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	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
36					Asset condition at start of planning period (percentage of units by grade)							
37												
38												
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	4.00%	8.00%	80.00%	8.00%	-	4	4.00%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1.00%	4.00%	10.00%	60.00%	5.00%	20.00%	2	6.00%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	-	N/A	-
42	HV	Distribution Line	SWER conductor	km	1.00%	4.00%	10.00%	60.00%	5.00%	20.00%	2	2.00%
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%	8.00%	65.00%	5.00%	20.00%	3	2.00%
45	HV	Distribution Cable	Distribution Submarine Cable	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	1.00%	7.00%	87.00%	5.00%	-	3	7.00%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1.00%	6.00%	15.00%	50.00%	3.00%	25.00%	2	25.00%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	3.00%	10.00%	84.00%	3.00%	-	3	4.00%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	-	3.00%	14.00%	60.00%	3.00%	20.00%	1	8.00%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	1.00%	6.00%	90.00%	3.00%	-	3	8.00%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	-	82.00%	18.00%	-	4	4.00%
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-
55	LV	LV Line	LV OH Conductor	km	1.00%	4.00%	10.00%	60.00%	5.00%	20.00%	2	2.00%
56	LV	LV Cable	LV UG Cable	km	1.00%	4.00%	10.00%	60.00%	5.00%	20.00%	2	2.00%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	1.00%	4.00%	10.00%	60.00%	5.00%	20.00%	1	3.00%
58	LV	Connections	OH/UG consumer service connections	No.	1.00%	4.00%	10.00%	60.00%	5.00%	20.00%	2	9.00%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	2.00%	4.00%	90.00%	4.00%		3	8.00%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	6.00%	4.00%	86.00%	4.00%	-	3	10.00%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	100.00%	-	-	4	-
62	All	Load Control	Centralised plant	Lot	-	16.00%	16.00%	68.00%	-	-	3	16.00%
63	All	Load Control	Relays	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-
64	All	Civils	Cable Tunnels	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-

Company Name: **The Power Company Limited**

AMP Planning Period: **1 April 2019 – 31 March 2029**

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
9	Athol	1	-	N	1	-	-	-	No constraint within +5 years	
10	Awarua Chip Mill	1	-	N	1	-	-	-	No constraint within +5 years	
11	Bluff	5	13	N-1	2	38%	13	40%	No constraint within +5 years	
12	Centre Bush	3	-	N	3	-	-	-	No constraint within +5 years	
13	Colyer Road	7	12	N-1	4	57%	12	65%	No constraint within +5 years	
14	Conical Hill	1	5	N-1	1	23%	5	0	No constraint within +5 years	
15	Dipton	1	-	N	1	-	-	-	No constraint within +5 years	
16	Edendale Fonterra	27	46	N-1	-	59%	46	65%	No constraint within +5 years	
17	Edendale	7	12	N-1	2	54%	12		No constraint within +5 years	
18	Glenham	1	-	N	1	-	-	-	No constraint within +5 years	
19	Gorge Road	2	2	N-1 switched	2	151%	-	-	Transformer	Dual 1.5MVA transformers upgradee to single 5MVA transformer
	Hedgehope	1	-	N	2	-	-	-	No constraint within +5 years	
	Hillside	1	-	N	1	-	-	-	No constraint within +5 years	
	Isla Bank	2	-	N	2	-	-	-	No constraint within +5 years	
	Kelso	4	-	N	2	-	-	-	No constraint within +5 years	
	Kennington	6	12	N-1 switched	4	48%	12	55%	No constraint within +5 years	
	Lumsden	3	-	N	3	-	-	-	No constraint within +5 years	
	Makarewa	4	12	N-1	2	32%	12	34%	No constraint within +5 years	
	Mataura	5	10	N-1	2	55%	10	62%	No constraint within +5 years	
	Monowai	0	-	N	-	-	-	-	No constraint within +5 years	
	Mossburn	2	-	N	2	-	-	-	No constraint within +5 years	
	North Gore	10	10	N-1	8	103%	10	95%	Transformer	Fans can be added to second transformer to increase firm capacity
	North Makarewa	46	45	N-1	-	102%	45	105%	Transformer	Expect some additional DG in area
	Ohai	2	-	N	2	-	-	-	No constraint within +5 years	
	Orawia	3	-	N	2	-	-	-	No constraint within +5 years	
	Otatara	4	-	N	3	-	-	-	No constraint within +5 years	
	Otautau	3	-	N	3	-	-	-	No constraint within +5 years	
	Riversdale	4	-	N	3	-	-	-	No constraint within +5 years	
20	Riverton	4	8	N-1	3	58%	8	62%	No constraint within +5 years	
21	Seaward Bush	6	10	N-1	4	62%	10	65%	No constraint within +5 years	
22	South Gore	9	12	N-1	8	77%	12	95%	Transformer	Additional load from Mataura Valley Milk has utilised existing spare capacity
23	Te Anau	6	12	N-1	1	47%	12	50%	No constraint within +5 years	
24	Tokanui	1	-	N	1	-	-	-	No constraint within +5 years	
25	Underwood	11	20	N-1	4	53%	20	54%	No constraint within +5 years	
26	Waikaka	1	-	N	1	-	-	-	No constraint within +5 years	
27	Waikiwi	10	23	N-1	2	44%	23	48%	No constraint within +5 years	
28	Winton	10	12	N-1	4	81%	12	85%	No constraint within +5 years	

29 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

Company Name: **The Power Company Limited**

AMP Planning Period: **1 April 2019 – 31 March 2029**

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			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
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 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
11	*Consumer types defined by EDB**							
12	Customer Connections (≤ 20kVA)		310	250	250	250	250	250
13	Customer Connections (21 to 99kVA)		26	25	25	25	25	25
14	Customer Connections (≥ 100kVA)		-	5	5	5	5	5
15	New Subdivisions		-	5	5	5	5	5
16								
17	**Connections total**		336	285	285	285	285	285
18	**include additional rows if needed*							
19	**Distributed generation**							
20	Number of connections		30	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 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
25	GXP demand		103					
26	*plus* Distributed generation output at HV and above		44					
27	**Maximum coincident system demand**		147	-	-	-	-	-
28	*less* Net transfers to (from) other EDBs at HV and above		1	2	2	2	2	2
29	**Demand on system for supply to consumers' connection points**		145	(2)	(2)	(2)	(2)	(2)
30	**Electricity volumes carried (GWh)**							
31	Electricity supplied from GXPs		632	636	639	642	645	648
32	*less* Electricity exports to GXPs		29	29	29	29	29	29
33	*plus* Electricity supplied from distributed generation		216	216	216	216	216	216
34	*less* Net electricity supplied to (from) other EDBs		14	15	15	15	15	15
35	**Electricity entering system for supply to ICPs**		806	808	811	814	817	821
36	*less* Total energy delivered to ICPs		754	758	762	766	770	773
37	**Losses**		51	50	49	49	48	47
38								
39	**Load factor**		63%	(4,612%)	(4,630%)	(4,648%)	(4,666%)	(4,684%)
40	**Loss ratio**		6.4%	6.2%	6.1%	6.0%	5.9%	5.7%

Company Name	The Power Company Limited
AMP Planning Period	1 April 2019 – 31 March 2029
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
9	for year ended	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
10	**SAIDI**						
11	Class B (planned interruptions on the network)	57.5	50.0	50.0	50.0	50.0	50.0
12	Class C (unplanned interruptions on the network)	149.3	131.5	129.5	127.6	125.7	123.8
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.26	0.26	0.26	0.26	0.26	0.26
15	Class C (unplanned interruptions on the network)	2.72	2.57	2.56	2.55	2.53	2.52

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, 12c, and 12d 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: 27/03/2019