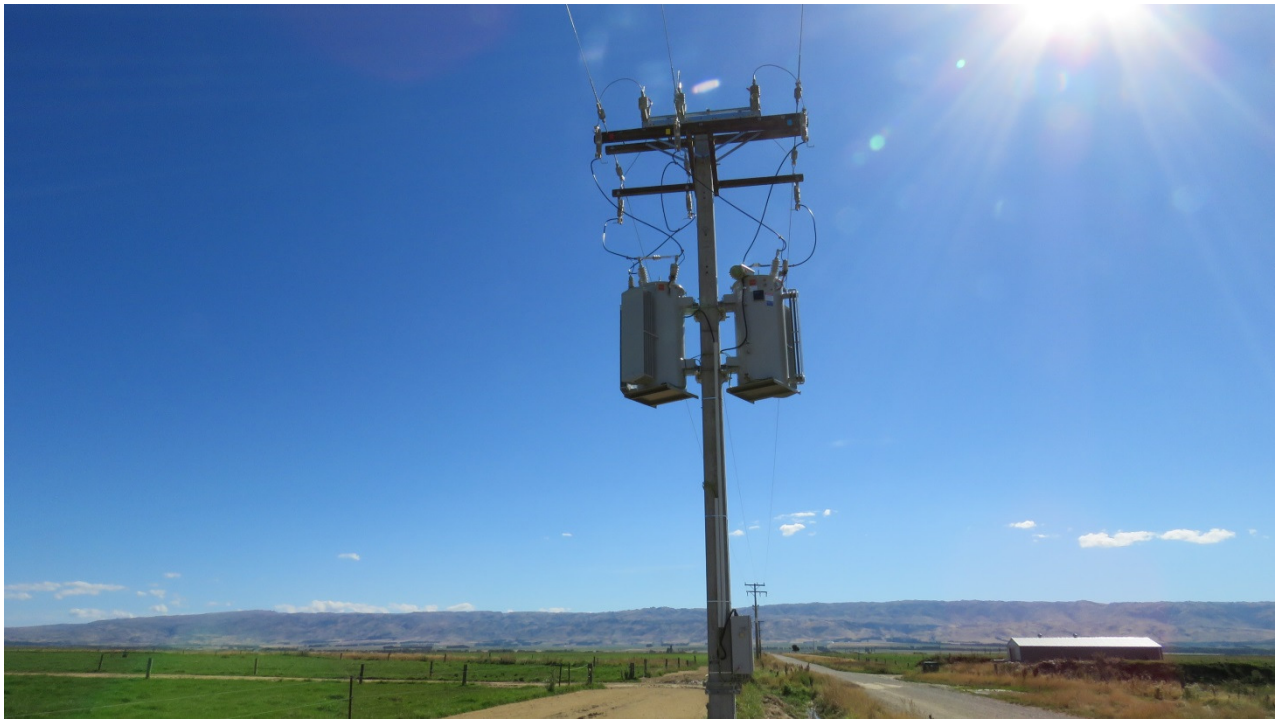

Carr Road Regulator February 2017

Asset Management Plan Update 2017 - 2027

Publicly disclosed in March 2017

Update Overview

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

Contents

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Liability Disclaimer

The information and statements made in this AMP are prepared on assumptions, projections and forecasts made by OtagoNet Joint Venture (OJV) and represent OJV's intentions and opinions at the date of issue (31 March 2017). Circumstances may change, assumptions and forecasts may prove to be wrong, events may occur that were not predicted, and OJV may, at a later date, decide to take different actions to those that it currently intends to take. OJV may also change any information in this document at any time.

OtagoNet Joint Venture accepts no liability for any action, inaction or failure to act taken on the basis of this AMP.

4.4. Development Programme

4.4.1. Current Projects

New Connections and Easements

The Customer Connections line items are an allowance for new connections to the network other than large development projects. Each specific solution will depend on location and consumer requirements. Some subdivision developments are occurring but we receive little or no prior notification of these. Requests to Developers and Regional Authorities provided only minimal information on subdivisions occurring.

The budgeted cost of $1.26M p.a. (Consumer Connection) is based on past experience and known development has been included in the plan.

A modest allowance has been made to connect Distributed Generation to the network. A budgeted cost of $12k p.a. (System Growth) is made for new easements and is based on past experience.

> The budget for individual Customer Connections has been reduced to $1.09M, to reflect the trend of actual spending. No other material changes.

Major New Connections Projects

Rapid growth areas as described in section 4.2.2 (refer to OtagoNet's 2016-2026 Asset Management Plan) require a corresponding expansion of the local distribution network. The rate of expansion is somewhat unpredictable as the timing and speed of developments are largely driven by commercial factors outside of OJV's ability to monitor.

$2-3M p.a. has been budgeted under Consumer Connection in the short term for projects that have relative certainty; plus an allowance of approx. $1.25M p.a. in the medium to long term where the location and/or scale of projects is relatively unknown.

> The budget has been increased for Major New Connections Projects in the short term to $2.5-3.6M p.a. and approx. $2M p.a. for projects in the medium to long term, due to increased projections of new subdivision development projects.

Clydevale Transformer Upgrade and New Switchgear

Increasing loads from new irrigation are now pushing the load capacity of the existing single transformer and there is limited load transfer ability away from the substation. In addition there are concerns with the condition and reliability of the old KFE outdoor circuit breakers. The project is to install a new 5 MVA transformer and place new indoor 11 kV switchgear.

Available options include

- Replace the transformer but keep the existing switchgear.
- Place dual transformers to meet the security criteria.
- No non-asset solutions available.

A replacement transformer is required for load growth. Replacing the old 11 kV CBs at the same time as the transformer replacement is the lowest cost option in the long term.

$1.5M in total has been budgeted under System Growth. The project was targeted for completion in the 2015/16 financial year; however the failure of the original site transformer has delayed some aspects of the project, causing approx. $870k of carry-over into 2016/17.

This project has now been completed.

Puketoi Area Upgrade

Accelerated load growth is occurring in the region due to spray irrigation and, to a lesser extent, dairy conversion. The Patearoa zone substation transformer is at the end of its nominal life. The nearby Waipiata feeder has voltage issues arising from load growth that could be solved by a tie point shift, if sufficient capacity were available at Patearoa.

An initial review indicated a requirement for a new zone substation; however a more detailed analysis has shown that the extra load can be supported more economically off an upgraded Patearoa zone substation using 11 kV voltage regulators.

Available options include

- Develop a new zone substation at or near Puketoi off the 66 or 33 kV lines.
- Upgrade Patearoa substation capacity and maintain feeder voltage via:
  - Field regulators, or
  - Reconductoring, or
  - 22 kV conversion.
- No non-asset solutions available.

The most economic option is to upgrade Patearoa substation capacity and install field regulators as load grows. $1.6M over two years is budgeted under System Growth. The upgrade is planned to be completed in time for the 2016/17 irrigation season.

This project has been split into two projects because of their differing time frames: 'Patearoa Substation Upgrade' and 'Puketoi Area Regulators'.

The Patearoa Substation Upgrade has been deferred until 2018/19 due to slower than expected load growth. Condition monitoring of the substation transformer indicates continued reliable operation.

Feeder load growth is being closely monitored and any emerging voltage issues will be mitigated with regulators. The first Puketoi area regulator was installed in early 2017. Current projections indicate that a second regulator will be required in 2019/20. A total of $122k has been allocated under System Growth for the second regulator.

Chrystalls Beach SWER line upgrade

Load growth on the Elderlee 1 feeder is starting to cause voltage issues at the coastal settlements of Chrystalls Beach and Bull Creek. These coastal settlements are at the end of a stretch of light SWER line that is now exposed to 7.5 A peak load current. The bulk of the voltage drop occurs over this SWER line. The SWER line is old and in poor condition.

Available options are to refurbish the SWER line and:

- Supply settlements along the coast from Toko Mouth via 3-phase upgrade, or
- Upgrade SWER conductor to Flounder, or
- Install battery bank near the coast for peak shaving, or
- Install generator near the coast for peak shaving, or
- Install SWER regulator
- No non-asset solutions.

Replacing SWER conductor to Flounder offers an efficient means of improving the voltage without undue incremental cost.

$336k has been allocated over 2016/17/18 under System Growth to improve voltage to customers whilst restoring the condition of the SWER line.

No material change.

Remarkables Substation

The land that the Remarkables Substation is built on is the subject of an agreement to purchase, but the purchase has not yet been completed due to delays in the subdivision process. These issues are expected to be resolved in the short term.

The existing internet-based communications from the substation is prone to failure and an improved communications system is warranted.

$538k has been allocated over 2016/17/18 under System Growth to fulfil the agreement for land purchase and establish more reliable communications to the site.

The substation land purchase has not progressed due to ongoing delays with the developer's subdivision process. The land purchase is now targeted for completion in the 2018/19 year.

The microwave radio backbone that will provide more reliable communications to Remarkables Substation is being installed by The Power Company Ltd in Southland; it has not yet been completed so the communications upgrade has been rescheduled for 2017/18.

Barnego Rd Subtransmission Upgrade

Load growth has led to a length of subtransmission line between Balclutha GXP and the Charlotte St substation exceeding its rated current at maximum demand and when the other Charlotte St/ Balclutha GXP line is out of service.

While most of the subtransmission conductor between Balclutha GXP and Charlotte St substation is Cochin or Hare, a short length of one line is constructed with lighter Raven conductor. This conductor exceeds its current rating when required to pass the full Charlotte St maximum demand.

A workaround exists in that Charlotte St can be partially backfed via Finegand with current load levels and protection settings. However the Raven conductor is an unnecessary weakness that can be removed from an otherwise strong subtransmission network at minimal cost.

Available options include

- Do nothing and continue to backfeed via Finegand when subtransmission faults require.
- Reconductor to Hare or equivalent

Reconductoring results in a stronger, simpler network at minimal cost.

$59k is budgeted under System Growth to remove a vulnerability to conductor overloading without unnecessary complication to system operation or protection setting. The project is scheduled for completion by 2019.

This project has been completed.

Gimmerburn Area Upgrade – Substation Upgrade and Lines

The abrupt load growth in the Puketoi area (see above) is largely driven by Otago Regional Council initiatives promoting more water-efficient (but more electrically demanding) irrigation schemes. The same initiatives apply to similar land in the Gimmerburn area some 15 km to the north. A similar level of load growth is therefore expected in the Gimmerburn area in the short to medium term.

An initial review indicated a requirement for a new zone substation; however a more detailed analysis has shown that the extra load can be supported more economically off an upgraded Patearoa zone substation. At this point the load on Patearoa would be sufficient to justify upgrade to an N-1 level of security. This upgrade involves conversion to a dual transformer site, completion of a subtransmission ring between Patearoa/ Ranfurly/Waipiata zone substations, and installation of a new Patearoa feeder to feed the Gimmerburn area.

Available options include

- Support the load from the existing substations (but the ability for this is limited).
- Reinforce feeders from existing substations to supply the load
- Develop a new zone substation on Maniototo Rd off the 66 kV line.

- Upgrade Patearoa substation capacity and security, and connect a portion of the Gimmerburn load to Patearoa. The most efficient approach would have the side effect of improving security of supply to the Waipiata 33 kV bus to N-1.
- No non-asset solutions.

Upgrading Patearoa substation to supply Gimmerburn is the only option that keeps zone substation 11 kV busbar security in the area at acceptable levels.

$3.95M is budgeted under System Growth. The timeframe of the project is dictated by actual Gimmerburn load growth. According to current projections the upgrade will occur over 2019-2021.

No material change.

11 kV Reclosers and SCADA Automation

Reliability improvement may be economically provided by the installation of line reclosers that automatically sectionalise lines under fault conditions, thereby restoring service to unaffected parts with only momentary interruption.

The 11 kV network is largely radial with few feeder interconnections, and any faults on the feeder interrupt all customers on the feeder until the fault is found and repaired.

The installed cost of reclosers is approximately $50k each which provides relatively cheap reliability improvement. On feeders with no downstream tie point a communications-free sectionaliser will provide only slightly lower benefits at a cost of approx. $30k each.

The opportunity also exists to replace existing old, unsupported hydraulic SWER reclosers on the network.

Available options include

- Do nothing and continue with the current reliability performance.
- Install reclosers where they are economically viable and replace end-of-life reclosers
- No non-asset solutions available.

Install reclosers where they are economically viable including SCADA modifications.

$1.6M is budgeted over five years under Quality of Supply. Planned timeframe for installation is 2015-19.

No material change.

Quality Remedies

Various works to remedy poor power quality usually identified from voltage complaint investigations and where an appropriate solution is identified including:

- Installation of 11kV regulators.
- Up-sizing of components (conductor, transformer).
- Demand side management.
- Power factor improvements. (Ensuring consumer loads are operating effectively.)
- Harmonic filtering / blocking. (Ensuring consumers are not injecting harmonics.)
- Motor starter faults / settings remedied. (Ensuring consumer equipment is working and configured appropriately.)

An on-going budget of $179k p.a. has been allocated under Quality of Supply.

A reducing trend in expenditure on Quality Remedies has resulted in a reduced budget of $45k from 2017 onwards.

Surge Arrestor Replacement due Transpower NER

Many existing subtransmission-voltage surge arrestors are chosen to operate at less than the line-to-line voltage of the circuit. This selection of rating maximises the extent to which lightning surges are "clipped", thus minimising voltage stress on the protected equipment.

However Transpower are installing 33 kV NERs at the Balclutha GXP. The presence of an NER means that downstream surge arrestors can be legitimately held at line-to-line voltage for the maximum fault clearing time of the GXP feeder protection system.

Each surge arrestor at risk of inappropriate operation must therefore be replaced with a new unit with a higher rating. A 2015 analysis has shown that most affected surge arrestors will operate correctly with the NER installed, but a few require replacement.

Available options include

- Accept occasional inappropriate surge arrestor operation
- Replace surge arrestors

Replacing at-risk subtransmission surge arrestors with models having a rating appropriate for an upstream NER is the most appropriate solution. $47k has been budgeted under Reliability to replace the vulnerable surge arrestors in 2016.

More surge arrestors than initially identified have been found to need replacement with a new unit with a higher rating. The increased number of arrestors and the requirement to shut the power off in most cases to effect the replacements has delayed completion. A total of $24k has been budgeted to complete the surge arrestor replacements in 2017/18.

Elderlee St Arc-Flash Upgrade

The Elderlee St substation has the only indoor switchboard on the network that has not yet had arc-flash protection installed. Arc flash hazards present a risk of harm to personnel inside substation buildings, especially during operation of the switchgear.

Available options include

- Additional Personal Protective Equipment (PPE) requirements
- Operational controls
- Protection improvements including arc-flash detection retrofit
- Panel reinforcement to contain arc-flash

An engineering solution is preferable to an administrative or PPE solution according to the Hierarchy of Hazard Control. The most appropriate engineering solution will be determined prior to installation.

$118k has been budgeted for this project under Safety in the 2016/17 year.

Project timeline extended to 2017/18 to align with resource availability.

Feeder Protection Upgrade for Minimum Fault Level

When a fault occurs and a failure is experienced in the primary protection, the secondary protection must be sufficiently sensitive to isolate the fault at the minimum possible fault level. Feeder extensions, reconfigurations, etc. can reduce the minimum fault level below levels that can be adequately covered by existing protection.

A protection review has identified two feeders where backup protection may not operate reliably if a fault occurs at minimum fault level. The minimum fault current is too low to be able to eliminate the problem simply through adjusting protection settings on existing devices.

Available options include

- Install new recloser to take on the role of secondary protection
- Install used but serviceable KFE recloser to take on the role of secondary protection
- Install fuses on problem laterals to take over the role of primary protection
- Upgrade conductor to increase minimum fault level
- No non-asset solutions.

Installing a used KFE recloser provides good protection at minimal material charge.

$44k has been allocated in 2016/17 under Safety to install sufficient reclosers that backup protection on the distribution network operates reliably for all fault levels.

The reused KFE recloser as proposed has been found to have protection grading issues at one location where the main feeder protection is also a KFE recloser. Alternative methods of providing backup protection are being investigated.

The second feeder's protection is a more sophisticated numerical relay and the possibility of employing a negative sequence protection element to provide the required protection is under investigation, as it would have a much lower lifetime operating cost than installing an ageing KFE recloser.

Determining the best reliable and cost effective solution to these issues has delayed implementation, which is now programmed for 2017/18.

Substation Structure Seismic Upgrades

A structural report has identified a number of substation buildings and outdoor structures that do not meet current building structural requirements under earthquake loading. There will be a range of work required at many substations, with the work prioritised and planned for completion over the next five years. More detailed engineering work is required to plan the remedial work noting that:

- There will be options for improving the building and structure integrity and each substation will require investigation and recommendations for consideration.
- As well as improving the strength of existing structures, consideration must be given to the age of the structures and their possible future replacements with indoor equipment.
- No non-asset solutions are available.

$1M has been allocated over 4 years with initial design work to be completed in 2016/17.

No material change.

Substation NER Installation

'Substation NER Installation' and '33 kV Transformer Circuit Breakers' were reported in the 2016 AMP as separate projects. Because 33 kV transformer circuit breakers will be installed concurrently with each NER, these two projects have been consolidated into one project 'Substation NERs and 33 kV Transformer Circuit Breakers'.

As part of compliance with the new EEA Guide to Power System Earthing Practice 2009, Neutral Earthing Resistors (NERs) are being installed where necessary on zone substations to limit earth fault currents on the 11kV network. While NERs alone will not ensure network safety they significantly reduce the earth potential rise appearing on and around network equipment when an earth fault occurs.

The new EEA Guide sets a higher standard for distribution earthing than was previously applicable. OtagoNet considers that the cost of building/upgrading individual earth sites in compliance with the Guide can be significantly reduced by the relatively low-cost installation of an NER at the upstream substation.

Available options include

- Do nothing and accept the higher overall cost of building distribution earths compliant with the EEA Guide.
- Install Petersen Coils and carry out the necessary network upgrades to allow sustained operation with phase-ground voltage at phase-phase levels.
- Install NERs.
- No non-asset solutions.

The NER installation is considered to provide the best cost-benefit ratio.

$1.7M is budgeted over seven years under Safety, including design work undertaken in 2015/16.

The scope of the NER and transformer protection that will be required has expanded following design and review, resulting in an increased budget of $2.9M over seven years for the new combined project 'Substation NERs and 33 kV Transformer Circuit Breakers'.

33 kV Transformer Circuit Breakers

Two out of seven 5MVA transformers do not have 33 kV circuit breakers for transformer protection at present, and rely on 33 kV fuses only. None of the 15 smaller 2.5 MVA transformers have circuit breakers.

Single transformers may be damaged by slow fuse clearing times with little protection for earth faults and dual transformer sites may be vulnerable to additional damage from back feeding into a transformer fault.

The installation of an NER reduces the fault current of 11 kV winding faults, thus reducing the level of protection provided by 33 kV transformer fuses. A 33 kV CB offers greater sensitivity to 11 kV winding faults particularly when used with a transformer differential protection scheme.

The 33 kV breakers were originally planned to be installed 2020-25 and were listed in the 2015 AMP as a contingent project. However the timeframe of the NER programme and the reliance of transformer fusing on solid earths has brought forward the project timeframe.

Available options include

- Retain fuses, do not install NER, and accept the do-nothing consequences of the NER project
- Retain fuses, install NER, and accept increased damage to the transformer and possibly nearby equipment in the event of an 11 kV winding fault
- Install 33 kV CBs and differential transformer protection
- No non-asset solutions.

Installing circuit breakers protects the transformer whilst permitting installation of an NER.

$203k p.a. has been budgeted over 6 years under Safety for a staged implementation in tandem with the NER project.

This budget for this project has been consolidated into the 'Substation NERs and 33 kV Transformer Circuit Breakers' project, see above.

Milton 33 kV Ring Protection Upgrade

The 33kV ring feed switching design from Balclutha through Glenore and Kiness only provides N-1 reliability to Elderlee Street but not to other substations teed off it. The present protection only uses directional protection relays and there have been some spurious openings of the ring in association with other faults.

A replacement system would have greater selectivity using end to end communications. The load and importance in the adjacent substations has grown and now includes the 7.65MW wind farm connection and the new Milburn substation which would benefit from an enhanced protection scheme.

Available options include

- Reroute Milburn supply to be fed directly from Elderlee St substation rather than Kiness. Install circuit breakers with distance protection on the Balclutha/Milton/ Glenore ring.
- Install distance relays only at the new Elderlee Street substation.
- Do nothing and accept nuisance trips that reduce reliability and result in voltage disturbances and/or actual loss of supply.

The enhanced protection system will yield the full reliability potential from the line assets employed which alternative options will not.

$347k has been budgeted under Reliability to improve network robustness toward 33 kV line faults. Target for completion is 2018.

Increased expenditure on Major New Connections projects, the prioritised installation of a replacement Palmerston ripple injection plant in the 2017/18 year together with capital expenditure targets have resulted in this reliability project being deferred two years. Construction is now targeted for 2019/20 with design work commencing in 2018/19.

Clydevale 33 kV Ring

The load and customer numbers in the Clydevale area are increasing with highlighted importance on a reliable supply to the individual dairy farms and the Gardians diary factory.

There are two 33 kV lines supplying Clydevale via Greers and Clifton respectively, with the first line having a tee off to supply the Greenfield substation. The second line is in poor condition, is not

reliable as a backup and only has basic manual switching involving hours of driving to achieve restoration after a fault on one line.

This project is to upgrade the switching configuration and ring protection around the Clydevale and Greenfield dairy factory to make the network more robust to single 33 kV line faults.

Available options include

- Replace manual switches at Clifton, Greers, Clydevale and Greenfield with SCADA operated circuit breakers for timely restoration, one line at a time.
- Extend the circuit breakers with additional directional protection and run the ring closed for resilience to the first fault.
- Do nothing and accept worsening SAIDI and SAIFI figures and increasingly unhappy customers.
- No non-asset solutions.

Upgrading the ring protection yields the most reliability from the existing 33 kV network in the area. Network performance will be increased with better SAIDI and SAIFI results. The closed ring will reduce losses and improve quality of supply to all customers in the area.

$463k is budgeted under Reliability. The project is targeted for completion by 2022.

No material change.

4.4.2. Considered Projects

Expected projects for year six to ten (YE 31 March 2022 to 2027) are as follows. These projects have little if any certainty.

Note that some projects that are on-going throughout this period are detailed above.

There are no Development Programme projects planned for the period YE 31 March 2022 to 2027. Projects that are planned for this period are classified under Asset Replacement and Renewal; refer to subsection 5.3.1 - Non-Routine Replacement and Renewal Projects.

4.4.3. Contingent Projects

The following contingent projects have been identified. In addition some customer related work may be expected from our largest current customers; for example requests for increased transformer or subtransmission line capacity. These have been excluded from OJV's spend plans until they been requested by the customer and have become certain.

Milton (Elderlee Street) Substation

This substation feeding Milton had been approaching its N-1 capacity. However the capacity driver for an upgrade has been removed by the recent closure of timber mills in the area, combined with new load transfer capability from the construction of the Milburn substation to the northeast.

There have been indications that significant industrial expansion could take place in the Milburn area in the medium term. Should this expansion take place, the load transfer capability from Milburn substation will be reduced and capacity may again become a constraint upon Elderlee St substation.

This project has therefore become contingent upon sufficient industrial expansion in the area being confirmed.

Secondary drivers for replacement include that the present substation is not ideally situated, being in a residential area with potential noise issues and limited room for expansion or renewal. The existing substation building has been identified as below current building seismic strength requirements. The existing 33kV lines cross industrial land and the railway and future 33kV line easements for the Milburn ring extension will be difficult to obtain.

Available options include

- Redevelop on a new site away from the residential area.
- Redevelop on the existing site with a new substation and indoor sound proofed transformers
- Replace the transformers only with 7.5MVA units and add bus protection.
- No non-asset solutions are available.

With sufficient industrial growth, replacement on a new site becomes the best strategic solution with the lowest risk.

$4.43M would be allocated for this project under System Growth.

No material change.

Palmerston Area Ripple Injection Plant

The plant is at the end of its service life with spares are no longer being supported and reliability is compromised.

The value of load control to OJV is doubtful given the change to the lower South Island regional demand grouping, however, the ripple receivers are owned by the retailer and are required for day/night rate switching, limiting other options.

The upcoming 33 kV reconfiguration in the area means the ripple signal will be too attenuated towards the Halfway Bush 33 kV bus and so the ripple plant injection point must be re-located.

Recent developments have raised the possibility that smart meters and/or load interruption relays controlled by the smart meter network may be able to be installed throughout the Palmerston area within the remaining life of the ripple plant.

The feasibility of the smart meter solution will not be able to be confirmed within the planning year. The ripple plant replacement is contingent upon the smart meter solution proving not to be feasible.

Available options include

- Install replacement ripple plant at the future Waikouaiti substation.
- Consider if replacement is justified as the main benefactor is the Retailer with their receivers being used more to control tariff options rather than the Network controlling load.
- Consider alternatives to ripple injection for load control in association with smart meters. Consider daylight switches for the main network use to control street lights.

A replacement ripple plant will be installed if a smart meter solution proves infeasible.

$510k would be allocated under Asset Replacement and Renewal for this project.

To mitigate the risk of failure a new containerised ripple injection plant will be purchased for Quarry Road substation (Merton substation replacement) under Asset Replacement and Renewal in 2017/18, and temporarily installed at Palmerston.

Clydevale Ring Reinforcement

There have been indications that significant industrial expansion requiring supply at 33 kV could occur in the Clydevale area in the medium term.

The existing subtransmission network in the area is incapable of delivering this extra load. Approximately half the Clydevale Ring will require reinforcement should the industrial expansion take place.

Available options include

- Reinforce Clydevale ring
- No non-asset solutions

$1.15M would be allocated for this project under System Growth.

No material change.

Waitati Tee Reinforcement

The Waitati Tee was recently built to provide one branch of an N-1 security of 33 kV supply to a point just north of the Waitati substation. The other branch is the original 33 kV line from Merton.

The Merton substation replacement project, scheduled for completion in 2020, will reuse this 33 kV line from Merton at 11 kV – thus removing one branch of the Waitati N-1 supply. By that time the second 110 kV line between Halfway Bush (HWB) and Palmerston (PAL) will have been converted to 33 kV, offering a second source of 33 kV supply in the Waitati area.

The Waitati substation relocation will ultimately utilise both HWB-PAL lines for an N-1 supply, and is currently scheduled for completion in 2022. However until condition testing uncovers condition-based drivers for replacement, the Waitati relocation will be driven only by reliability and calendar age of assets, and may be delayed if projects with more urgent drivers (i.e. growth- or condition-driven projects) arise.

Should it become apparent that the Waitati relocation will be delayed significantly beyond the Merton replacement, Waitati Tee reinforcement is required to preserve N-1 reliability of supply to Waitati using the second HWB-PAL line.

Available options include

- Connect HWB-PAL 2 to the Waitati Tee to preserve N-1 supply to the tee point after the completion of the Merton relocation
- Do nothing and accept reduced reliability to the tee point after the completion of the Merton relocation

HWB-PAL 2 will be connected to the Waitati Tee if it becomes apparent that the period of reduced reliability will be extended. $80k would be allocated under Reliability for this work.

No material change.

4.5. OJV's Forecast Capital Expenditure

The forecast capital expenditure for OJV is shown in Table 36. These figures are also provided in the information disclosure schedule 11a included in Appendix 1.

Table 36: OJV's Forecast Capital Expenditure

CAPEX: Consumer Connection ($000)	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
Customer Connections (≤ 20kVA)	303	303	303	303	303	303	303	303	303	303
Customer Connections (21 to 99kVA)	290	290	290	290	290	290	290	290	290	290
Customer Connections (≥ 100kVA)	502	502	502	502	502	502	502	502	502	502
Major New Connections Projects	3,608	2,952	2,479	2,759	2,880	4,694	1,965	2,950	2,965	2,965
	4,700	**4,046**	**3,573**	**3,853**	**3,974**	**5,788**	**3,059**	**4,044**	**4,059**	**4,059**

CAPEX: System Growth ($000)	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
Patearoa Substation Upgrade	147	1,352								
Puketoi Area Regulators			122							
Chrystalls Beach SWER line upgrade	171									
Gimmerburn Area Upgrade - substation upgrade and lines			1,684	2,249						
Easements	12	12	12	12	12	12	12	12	12	12
Remarkables Sub	179	463								
General ESL MV Network Growth	163	218								
Unspecified System Growth Projects							936	1,333	1,333	1,333
	673	**2,045**	**1,818**	**2,261**	**12**	**12**	**948**	**1,345**	**1,345**	**1,345**

CAPEX: Asset Replacement and Renewal ($000)	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
LV Line Replacement and Renewal	733	733	733	733	733	733	733	733	733	733
SWER Line Replacement and Renewal	488	488	488	488	488	488	488	488	488	488
11 kV Line Replacement and Renewal	2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930
33 kV Line Replacement and Renewal	1,849	1,849	1,849	1,849	1,849	1,849	1,849	1,849	1,849	1,849
HWB-PAL 2 110/33 kV Conversion	6	381								
Quarry Road Substation	691			875	3,780		180			
Glenore substation rebuild			118	560						
Owaka 11 kV switchgear replacement				100	532					
Port Molyneux 11 kV switchgear replacement						45	581			
Clinton 11kV bus indoor conversion						316	316			
Halfway Bush - Palmerston 33kV towers replacement		30	30	1,186						
Palmerston Substation Rebuild Taieri Peak Rd					158	2,196				
Waitati Tee and future substation						928	2,544			
Elderlee St switchgear replacement						35	555			
Zone Substation Minor Replacement	34	34	34	34	34	34	34	34	34	34
Distribution - General	59	59	59	59	59	59	59	59	59	59
Unspecified Replacement & Renewal Projects							804	2,638	2,638	2,638
	6,791	**6,505**	**6,241**	**8,814**	**10,564**	**9,614**	**11,073**	**8,732**	**8,732**	**8,732**

CAPEX: Asset Relocations ($000)	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
Network Chargeable	121	121	121	121	121	121	121	121	121	121
Unspecified Asset Relocation Projects								242	242	242
	121	**121**	**121**	**121**	**121**	**121**	**121**	**363**	**363**	**363**

CAPEX: Quality of Supply ($000)	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
Reclosers with SCADA integration	363	363	363							
Supply Quality Upgrades	45	45	45	45	45	45	45	45	45	45
Unspecified Quality of Supply Projects								242	242	242
	409	**409**	**409**	**45**	**45**	**45**	**45**	**288**	**288**	**288**

CAPEX: Legislative and Regulatory ($000)	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
	0	0	0	0	0	0	0	0	0	0

CAPEX: Other Reliability, Safety and Environment ($000)	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
Surge arrestor replacement due Transpower NER	24									
Elderlee St arc-flash upgrade	117									
Feeder protection upgrade for minimum fault level	44									
Substation clearances and fence improvements	33									
Substation structure seismic upgrades	359	359	255							
Substation NERs and 33kV Transformer Circuit Breakers	498	498	498	498	498					
Milton 33kV ring protection upgrade		28	330							
Clydevale 33 kV ring rebuild and protection				59	417					
Replacement of OH structures with Ground Mounted	182	182	182	182	182	182	182	182	182	182
Earth refurbishment from earth testing, incl. SWER	182	182	182	182	182	182	182	182	182	182
Transformer Fusing	341									
SCADA Integration to common platform	109	109								
Unspecified Reliability/Safety/Environment Projects							398	835	835	835
	1,886	**1,357**	**1,446**	**920**	**1,278**	**363**	**761**	**1,199**	**1,199**	**1,199**

AMP Total Network CAPEX ($000)	14,580	14,483	13,608	16,014	15,995	15,944	16,009	15,971	15,986	15,986

5.2. Routine Corrective Maintenance & Inspection

5.2.2. Maintenance and Inspection Programmes

Budget descriptions for routine corrective maintenance and inspection activities are set out in Table 38 and forecasts are provided in Table 41 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 38: Routine and Corrective Maintenance and Inspection Budget Descriptions

Budget	Description	Expenditure Range/Type
Line Condition Survey	Five yearly network inspections (20% inspected annually), other routine tests and minor maintenance works on overhead line assets.	Cost Under $0.5M on-going; OPEX
Distribution Minor Maintenance	Generally reactive work undertaken to correct issues found on distribution lines during the routine line condition survey. Also a general budget for all minor distribution work.	Cost Under $0.5M on-going; OPEX
This budget has been renamed "Distribution Planned Maintenance" to reflect that the budget covers planned work carried out on functional assets, in response to issues found during inspection.		
Zone Substation Minor Maintenance	Routine inspection and testing of assets at zone substations. Includes such things as oil DGA, breakdown, moisture and acidity, operation counts, protection testing etc. Also covers responses to maintenance triggers, such as oil processing or recalibration of relays. Also a general budget for all minor technical work.	Cost Under $0.5M on-going; OPEX
This budget has been consolidated with "General Zone Substation Maintenance" and renamed "Technical Planned Maintenance" to reflect that the budget covers planned work carried out on functional assets, in response to issues found during inspection.		
Voltage Complaint Investigation	Investigations into supply quality which are generally customer initiated.	Cost Under $0.5M on-going; OPEX
This budget has been renamed "Supply Quality Checks".		
Transmission Line Minor Maintenance	Generally reactive work undertaken to correct issues found on subtransmission lines during the routine line condition survey. Also a general budget for all minor subtransmission work.	Cost Under $0.5M on-going; OPEX
Earth Testing and Review	Routine testing of earthing assets and connections to ensure safety and functional requirements are met. Completed five yearly (20% annually).	Cost Under $0.5M on-going; OPEX

Budget	Description	Expenditure Range/Type
Load Control Equipment **Radio Equipment** **SCADA Equipment**	Routine inspection and testing of the applicable substation equipment	Cost Under $0.5M on-going; OPEX
"Radio Equipment" budget only - "Load Control Equipment" & "SCADA Equipment" budgets have been consolidated into "Technical Planned Maintenance" (see above).		
General Zone Substation Maintenance	Routine maintenance at zone substations such as grounds, fence and building maintenance, rust repair and paint touch-ups.	Refer to Technical Planned Maintenance (see above)
This budget has been consolidated with "Zone Substation Minor Maintenance" and renamed "Technical Planned Maintenance" (see above).		
Earth Testing	Routine testing of earthing assets and connections to ensure safety and functional requirements are met completed five yearly, next due 2017/18.	Cost Under $0.5M 2017/18 and five yearly thereafter; OPEX

Reactive Maintenance

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

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

Cost Under $0.5M on-going; OPEX

Routine Technical Inspections, Checks and Maintenance

Infrared Survey

Partial Discharge Survey

These new budgets have been separated out from the former "Zone Substation Minor Maintenance" budget to provide better visibility of the cost of routine inspections and condition monitoring of technical assets.

Cost Under $0.2M on-going; OPEX

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 nominal life. Less critical assets or assets provided with redundancy as part of security arrangements may be run to failure and replaced reactively. Assets such as cables may be run to failure several times and repaired before the fault frequency increases to a point that complete replacement is more economic. This approach requires monitoring of failure rates.

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

Table 39 sets out the approach to making decisions around when to undertake replacements or renews applicable to each network asset category.

Table 39: 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	Cables replaced when reliability declines to an unacceptable level or repairs become uneconomic.
	Distributed Sub Transmission Voltage Switchgear (ABSs)	Replacement when inspection indicates deterioration sufficient to lose confidence in continued reliable operation and maintenance is considered uneconomic.
Zone Substations	Sub Transmission Voltage Switchgear	Replaced at end of standard life (fixed time), may be delayed in conjunction with condition monitoring to achieve strategic objectives. Significant damage from premature failure could require replacement.
	Power Transformers and Regulators	Replacement after a 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

Asset Category	Sub Category	Replacement and Renewal Decision Approach
		economic to maintain for aged units. Not economic to relocate (transport and installation costs) after aged transformers displaced e.g. for a larger unit.
	Distribution Voltage Switchgear	Replaced at end of standard life (fixed time), may be delayed in conjunction with condition monitoring to achieve strategic objectives. Significant damage from premature failure could require replacement.
	Other (Buildings, RTU, Relays, Batteries, Meters)	Instrumentation/Protection at end of manufacturers stated life (fixed time) or when obsolete/unsupported or otherwise along with other replacements as economic e.g. protection replaced with switchboard or transformer. Batteries replaced prior to the manufacturers stated life expectancy (typically 10 years) or on failure of testing. Buildings and fences when not economic to maintain after significant accumulating deterioration or seismic resilience concerns. Bus work and conductors not economical to maintain.
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	Cables replaced when reliability declines to an unacceptable level or repairs become uneconomic.
	Distributed Distribution Voltage Switchgear	Replaced at end of standard life (fixed time), may be delayed with condition monitoring to achieve strategic objectives. Significant damage from premature failure could require replacement.
Distribution Substations	Distribution Transformers	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 on age or as part of other replacements at site. Units removed from service <100kVA and older than 20yrs are scrapped; other units testing satisfactory recycled as spares.
	Distribution Voltage Switchgear (RMUs)	Replaced at end of standard life (fixed time), may be delayed 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

Asset Category	Sub Category	Replacement and Renewal Decision Approach
		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 concerns exist).
Other	SCADA & Communications	RTU/Radio 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	Run to failure with redundant coupling cells at Ranfurly and Palmerston and spares available for converters

5.3.1. Non-Routine Replacement and Renewal Projects

Replacement and renewal projects that are not ongoing are listed below; these 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.

The expenditure forecasts for these budgets are provided in Table 36(CAPEX) and Table 41 (OPEX).

Halfway Bush-Palmerston Second 33 kV Conversion

The configuration of the pre-existing northern 33 kV network towards Dunedin was less than optimal with the lowest reliability being effectively at the end of the OtagoNet network, yet at the closest point to the Halfway Bush point of supply.

An opportunity arose to purchase the two Transpower Halfway Bush-Palmerston lines at a fair price to enable OJV to further develop or modify the supply to increase reliability and efficiency, both of this point of supply and the downstream 33 kV network and zone substations. A large part of these gains were to arise from shifting the point of supply to Halfway Bush and converting these 110kV lines to 33 kV, which allows a redundant 33 kV supply into zone substations supplying Waitati and Waikouaiti.

The first stage was to convert one of the 110 kV lines to 33 kV and this work has already been completed. The second stage is to convert the second line to 33 kV. The conversion must be undertaken in two stages because until Transpower upgrade the Halfway Bush 33 kV bus, scheduled for completion in 2018, they are unable to supply both lines at 33 kV.

$398k is budgeted as CAPEX under Asset Replacement & Renewal. The conversion will occur immediately after Transpower complete the conversion of their Halfway Bush bus; this work is currently scheduled for 2018.

Transpower's estimate of the cost of work at Halfway Bush has resulted in the budget being reduced slightly to $387k.

Merton Substation Replacement (Waikouaiti)

This project has been renamed 'Quarry Road Substation', in accordance with the location of the land purchased for the new substation.

The present Merton substation feeding the Waikouaiti area is reaching the N-1 capacity of the transformers, and the 11kV and 33kV structures have deteriorating wooden poles and components. The supply security is below the EEA guidelines as there are insufficient 11kV back-feeds available for loss of the single 33kV supply.

The substation is low lying alongside the Waikouaiti River and is prone to flooding and is at risk from tsunami or liquefaction following a seismic event. The substation is beside SH1 to the south of Waikouaiti, its major load centre, meaning there is only one line route to the main loads.

A further opportunity exists with the recent purchase of the Transpower 110kV lines that run past this substation, allowing for improved security of supply and reduced losses with more direct supply than the existing configuration.

Available options include

- Redevelop on the existing site with new transformers and indoor switchgear, raised above possible flood levels.
- Build a second substation on the south side of Waikouaiti to provide greater reliability and less dependence on this substation.
- Redevelop the substation on a more secure site closer to the load
- No non-asset solutions available.

Redeveloping on a new site is the best strategic solution with the lowest future risk.

$4.8M is budgeted as CAPEX under Asset Replacement and Renewal with the project planned for completion in 2020.However the substation cannot be completed until the second Halfway Bush-Palmerston line 33 kV conversion (below) has been carried out.

Increased expenditure on Major New Connections projects, rescheduling of System Growth projects together with capital expenditure targets have resulted in this Asset Replacement and Renewal project being deferred two years. Design work has commenced and will be completed in 2017/18 and construction is now targeted for 2021/22. If System Growth projects are able to be deferred due to lower than forecast load growth, this project could be brought forward.

A replacement for the Palmerston ripple injection plant has been added to the project scope, increasing the budget to $5.43M. As there are age related reliability concerns with the Palmerston injection plant, to mitigate the risk of failure a new containerised plant will be purchased for Quarry Road substation in 2017/18 and temporarily installed at Palmerston. The addition of the ripple injection plant to the Quarry Road project requires additional switchgear and protection to increase the security of the substation 33 kV bus.

The second 33kV supply that has been established into Waitati has also improved the supply security at Merton, with the addition of new remote controlled switches. Ongoing condition monitoring of the substation assets indicates that continued service is viable, and the risk of flood impacting on the security of supply is considered to be very low.

A total of $180k has been allowed to decommission Merton substation in 2022/23, at which time the remaining 11 kV feeders will be transferred from Merton to Quarry Road substation.

Glenore Transformer, Oil Containment and Overhead Structure

The existing substation transformer is the oldest on the network (although it is not currently showing signs of pending failure) and is not currently bunded. The 11 kV overhead structure is also ageing and has seismic concerns. The 33 kV bus will be required to support extra breakers under the transformer fuse replacement project and the Milton Ring project.

Available options include

- Install replacement 2.5 MVA transformer on bund to contain any oil spill. Replace seismically vulnerable 11 kV bus with indoor switchroom. Install 33 kV CB on transformer incomer.
- As above but replace the transformer with 1.5 MVA only and replace it with 2.5 MVA as required by load growth. Nonstandard size and cost differential between units small, so not supported.
- As per first bullet point but rebuild the 11 kV overhead structure and install outdoor circuit breakers on the same site. Cost likely to be higher than standardised indoor solution, with no increased safety or environmental benefits.
- As per directly above but retain the existing single 11 kV feeder rather than splitting the feeder which requires a more complex bus.
- Decommission substation, upgrade the interconnecting 11kV lines from Lawrence, Milton and Kaitangata and provide additional voltage regulation. Implementation costs similar but lower benefits with higher losses and worse reliability.
- Rebuild on a new site (which has been identified) away from the river.

- No non-asset solutions.

From a financial perspective the case for decommissioning the substation vs replacing the transformer and retaining the single 11 kV feeder is about even. However replacement and retention of the single feeder offers superior SAIDI/SAIFI performance and greater capacity in the area, and is therefore the preferred option.

$561k (excluding the Transformer which has already been purchased) is budgeted as CAPEX under Replacement and Renewal. Timing is flexible as a full backfeed option exists; current planning is to complete work in 2021.

No material change.

Owaka 11 kV Indoor Switchgear

The outdoor switchgear and bus arrangement is at end of life, has seismic strength and clearance issues and may require additional land for the substation to give adequate clearance to the fences if it was retained. The coastal location increases the vulnerability of the outdoor switchgear to corrosion and salt pollution.

Available options include

- Replace with new outdoor switchboard
- Replace with new indoor switchboard
- Redevelop on a new site with more space
- No non-asset solutions

An indoor conversion offers the best benefit-cost especially given the coastal location. Redevelopment on a different site is not warranted. Cost $612k as CAPEX under Asset Replacement and Renewal – target completion 2022.

No material change.

Port Molyneux 11 kV Indoor Switchgear

The outdoor switchgear and bus arrangement is at end of life, has seismic strength and clearance issues and may require additional land for the substation to give adequate clearance to the fences if it was retained. The coastal location increases the vulnerability of the outdoor switchgear to corrosion and salt pollution.

Available options include

- Replace with new outdoor switchboard
- Replace with new indoor switchboard
- Redevelop on a new site

- No non-asset solutions

An indoor conversion offers the best benefit-cost especially given the coastal location. Redevelopment on a different site is not warranted. Cost $606k as CAPEX under Asset Replacement and Renewal – target completion 2022.

The clearance issues have been addressed, the outdoor switchgear condition remains serviceable and the seismic risk in the short term is manageable. Due to an expected increase in Major New Connections projects expenditure in the 2020-22 period, this project's budget has been deferred for two years. Completion is now targeted for 2023/24.

Clinton 11 kV Indoor Switchgear

The outdoor switchgear and bus arrangement is at end of life, has seismic strength issues and many of the air break switches are no longer supported. Available options include

- Replace with new outdoor switchboard
- Replace with new indoor switchboard
- Redevelop on a new site
- No non-asset solutions

An indoor conversion offers the best benefit-cost and improves the aesthetics of a substation located directly next to State Highway 1. Redevelopment on a different site is not warranted. Cost $612k as CAPEX under Asset Replacement and Renewal – target completion 2022.

The outdoor switchgear is still in a serviceable condition, there is a small stock of air break switch spare parts and the seismic risk in the short term is manageable. Due to an expected increase in Major New Connections projects' expenditure in the 2020-22 period, this project's budget has been deferred for two years. Completion is now targeted for 2023/24.

Palmerston Substation Rebuild Taieri Peak Rd

The Palmerston 33/11 kV substation has dual transformers but is only supplied by a single 33 kV circuit. The 11 kV feeder arrangements are also sub optimal and on an old and difficult to maintain outdoor structure. There are minor clearance issues associated with the 11 kV cable terminations, and substation controls and ripple injection plant are within the contractor's depot building.

Available options include

- Relocate Palmerston zone substation to newly acquired Palmerston 110/33 kV substation.
- Keep the existing substation and route a second 33 kV incomer.
- No non-asset solutions available.

Relocation of the substation allows for increased supply security whilst addressing the condition and safety issues of the existing substation.

$2.32M is budgeted as CAPEX under Asset Replacement and Renewal. The project is currently scheduled for completion by 2023 however this timeframe may be deferred if higher priority (e.g. growth-related) projects arise.

No material change.

Waitati Zone Sub Relocation

Reliability for customers off the Waitati substation is the poorest on the network. The existing substation is flood prone and is located within a residential area. The supply security is below the EEA guidelines as there are insufficient 11kV back-feeds available for loss of the single 33kV supply. Both the transformer and switchgear are approaching end of life although at present, condition testing is not indicating that end of life is imminent. Reconfiguration of the Palmerston GXP supply allows for redundant 33kV line circuits to be provided into Waitati.

Available options include

- Do nothing and continue with poor reliability due to 33kV line faults.
- Redevelop on the existing site to allow for the dual 33kV circuits.
- Redevelop on a new site.

Redeveloping on a new site is the best strategic solution with the lowest future risk. $3.05M has been allocated as CAPEX under Asset Replacement and Renewal for work over 2021/22/23, however the timing of the project is flexible and may be adjusted if projects with more urgent drivers (i.e. growth- or condition-driven projects) arise.

A second 33kV supply has been established into Waitati improving the supply security. Ongoing condition monitoring of the assets indicates continued reliable service, and the risk of flood impacting on the security of supply is considered to be very low.

This project has been deferred by one year due to an expected increase in Major New Connections projects expenditure in the 2020-22 period.

The cost of decommissioning the old Waitati substation site and associated 33 kV supply lines has been added to the CAPEX cost of the Waitati Zone Sub relocation project. The allocation in 2022/23/24 under Asset Replacement and Renewal has increased to $3.47M.

Elderlee St Switchgear Replacement

The 11 kV indoor switchgear at Elderlee St is approaching end of life.

The Elderlee St switchroom is one of the network buildings highlighted as requiring seismic reinforcement. However space within the switchroom is very tight and disrupted by concrete pillars, both of which are likely to complicate a traditional steel reinforcement seismic solution. Options for seismic reinforcement will be investigated however at this stage the most likely scenario is for a replacement switchroom to be built to 100% NBS to house the replacement switchgear.

As described under "Contingent Projects", future industrial load growth may require this substation to be relocated from its current site. The replacement switchroom would therefore be a "PortaCom" style building that can be easily relocated to the new site should the need arise.

Available options include

- Reinforce existing switchroom and replace switchgear
- Replace switchgear and switchroom
- No non-asset solutions

At this stage the replacement portable switchroom appears to offer the best combination of economy, seismic strength and futureproofing. This recommendation may change pending the outcome of a detailed seismic assessment on the existing switchroom.

$570k has been as CAPEX allocated under Asset Replacement and Renewal to replace the end-of-life equipment whilst ensuring adequate switchroom seismic strength and allowing for the possibility of a future relocation to a new site. Current target for completion is 2022.

Following a detailed seismic assessment to be carried out in 2017, the benefit/cost of the options outlined above will be analysed. Current condition monitoring of the switchgear indicates that continued service is feasible in the medium term. Pending a determination on the future of the building, the project will be scoped accordingly. In the interim the project has been deferred by two years.

Decommissioning Works

The development programme for OJV includes the relocation of two substations that are approaching end of life and are in suboptimal locations. After completion of the relocation, the former substation sites must be decommissioned and restored to their original condition. Any lines made redundant by the shift should similarly be removed. The cost of this work appears as operational expenditure in the network budget.

It should be noted that the existing site for a third future relocation, Palmerston, will not require decommissioning due to its dual use as a depot and yard.

Estimated costs:

- $495k decommissioning of Merton substation and associated 33kV supply lines
- $54k decommissioning of (compact) Waitati substation

as OPEX under Asset Replacement and Renewal.

These decommissioning works have been included with the respective CAPEX projects under Asset Replacement and Renewal.

Halfway Bush-Palmerston 33 kV Towers Replacement

Condition monitoring indicates that a number of steel lattice towers are approaching replacement criteria. These towers support dual circuits mainly through suburban Dunedin. Further condition assessment is to be carried out, but due to their location and the criticality of the towers to the security of supply to Palmerston, Waikouaiti and Waitati, $1.25M has been allowed for tower replacements in 2020/21 with design and consenting in 2018-20.

5.3.2. 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 40 and expenditure forecasts are provided in Table 36(CAPEX) and Table 41(OPEX).

Table 40: Replacement and Renewal Programmes

Budget	Description	Expenditure
Line Replacement & Renewal (LV, SWER, Distribution, Subtransmission)	Work previously identified through condition assessment that is either on-going or planned over the next 5 years. Completion of this work is dependent on customer requirements, land access permission and priority re-assignment as further network condition information becomes available.	Over $5M on-going; CAPEX
Substation Minor Capital Work	On-going replacement of minor components at zone substations such as LTAC panels and battery banks.	Annual CAPEX Cost Under $0.5M
"Substation Minor Capital Work" has been renamed "Zone Substation Minor Replacement".		
Customer Connections	Operational portion of expenditure for the customer connections process is captured in this budget.	Cost Under $0.5M on-going; OPEX
33 kV Pole Maintenance	A budget specifically allocated for maintenance arising from the accelerated inspection program on 33 kV poles	Refer to 5.2.2
This budget has been consolidated into Transmission Line Minor Maintenance (under 5.2.2 Maintenance and Inspection Programmes).		
Network Chargeable Maintenance	Maintenance carried out at least partially at customer expense, e.g. pole shifts or third-party damage repairs.	Cost Under $0.5M on-going;

Budget	Description	Expenditure
		OPEX
Maintenance Identified on Distribution Line Survey	Covers priority maintenance works discovered during detailed condition inspections.	Cost Under $0.5M on-going; OPEX
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 CAPEX Cost Under $0.5M

Zone Substation Refurbishment

Power Transformer Refurbishment

These new budgets have been separated out from the former "Zone Substation Minor Maintenance" budget to provide better visibility of the cost of refurbishing existing assets.

Cost Under $0.1M on-going; OPEX

5.4. OJV's Forecast Operational Expenditure

The forecast operational expenditure for OJV is shown in Table 41. These figures are also provided in the information disclosure schedule 11b included in Appendix 1. Two further categories not described earlier complete OJV's forecasted operational expenditure budget as follows.

5.4.1. 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 OJV's expense as required under the Electricity (Hazards from Trees) Regulations 2003. While most customers have received their first free trim, some are disputing the process and additional costs are occurring to resolve the situation. This OPEX cost is budgeted at $1.08M per annum.

An additional $11k has been budgeted for tree trimming advertisements.

5.4.2. Service Interruptions and Emergencies

This budget provides for the provision of staff, plant and resources to be ready for faults and emergencies. Faults staff respond to make the area safe, isolate the faulty equipment or network section and undertake repairs to restore supply to all customers. This OPEX cost is budgeted at $0.98M per annum.

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

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

Cost Under $1.1M on-going; OPEX

Non-Network Operation Expenditure

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

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

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

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

Table 41: OJV's Forecast Operational Expenditure

OPEX: Asset Replacement and Renewal ($000)	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
Network Chargeable Maintenance	33	33	33	33	33	33	33	33	33	33
Maintenance Identified on Distribution Line Survey	177	177	177	177	177	177	177	177	177	177
Distribution Transformer Refurbishment	67	67	67	67	67	67	67	67	67	67
Zone Substation Refurbishment	27	27	27	27	27	27	27	27	27	27
Power Transformer Refurbishment	43	43	43	43	43	43	43	43	43	43
	346	**346**	**346**	**346**	**346**	**346**	**346**	**346**	**346**	**346**

OPEX: Vegetation Management ($000)	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
Vegetation Management	1,107	1,107	1,107	1,107	1,107	1,107	1,107	1,107	1,107	1,107
	1,107	**1,107**	**1,107**	**1,107**	**1,107**	**1,107**	**1,107**	**1,107**	**1,107**	**1,107**

OPEX: Routine and Corrective Maintenance and Inspection ($000)	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
Routine ESL Dist Insp Check & Mtce	7	8	10	11	12	14	15	16	18	19
Customer Connections Maintenance	7	7	7	7	7	7	7	7	7	7
Transmission Line Minor Maintenance	13	13	13	13	13	13	13	13	13	13
Line Condition Survey	317	317	317	317	317	317	317	317	317	317
Distribution Planned Maintenance	336	336	336	336	336	336	336	336	336	336
Technical Planned Maintenance	445	446	448	349	356	357	359	360	361	363

Distribution Reactive Maintenance	81	81	81	81	81	81	81	81	81	81
Technical Reactive Maintenance	31	31	31	31	36	36	36	36	36	36
Earth Testing and Review	55	66	66	77	77	77	77	77	77	77
Radio Equipment	33	33	33	33	33	33	33	33	33	33
Routine Tech Insp Check and Mtce	119	119	119	119	119	119	119	119	119	119
Infrared Survey	12	12	12	12	12	12	12	12	12	12
Partial Discharge Survey	10	10	10	10	10	10	10	10	10	10
Supply Quality Checks	13	13	13	13	13	13	13	13	13	13
Spares Checks and Minor Maintenance	7	7	7	7	7	7	7	7	7	7
	1,486	**1,500**	**1,502**	**1,416**	**1,429**	**1,432**	**1,435**	**1,438**	**1,440**	**1,443**

OPEX: Service Interruptions and Emergencies ($000)	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
Incident Response - Distribution	1,002	1,002	1,007	1,007	1,014	1,014	1,014	1,014	1,014	1,014
Incident Response - Technical	90	90	96	96	102	102	102	102	102	102
Sub Transmission Line Faults	92	92	92	92	92	92	92	92	92	92
	1,184	**1,184**	**1,195**	**1,195**	**1,207**	**1,207**	**1,207**	**1,207**	**1,207**	**1,207**

Operational Expenditure Total ($000)	**4,123**	**4,137**	**4,150**	**4,064**	**4,090**	**4,092**	**4,095**	**4,098**	**4,101**	**4,103**
System Operations and Network Support	596	736	789	795	795	795	795	795	795	769
Business Support	1,630	1,630	1,630	1,630	1,630	1,630	1,630	1,630	1,630	1,630

AMP Total Operational Expenditure ($000)	**6,348**	**6,499**	**6,570**	**6,489**	**6,515**	**6,518**	**6,521**	**6,524**	**6,526**	**6,503**

Appendix 1 – Disclosure Schedules

Schedule 11a – Capital Expenditure Forecast

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												
7		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8	for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
9	**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10	Consumer connection	4,248	4,700	4,127	3,721	4,093	4,310	6,402	3,451	4,654	4,765	4,860
11	System growth	2,088	673	2,086	1,893	2,401	13	13	1,070	1,548	1,579	1,610
12	Asset replacement and renewal	5,582	6,791	6,635	6,500	9,363	11,457	10,636	12,495	10,050	10,251	10,456
13	Asset relocations	32	121	124	126	129	131	134	137	418	427	435
14	Reliability, safety and environment:											
15	Quality of supply	245	409	417	426	48	49	50	51	331	338	345
16	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	1,733	1,886	1,384	1,506	977	1,386	402	859	1,380	1,407	1,436
18	**Total reliability, safety and environment**	1,978	2,295	1,801	1,932	1,025	1,435	452	910	1,711	1,745	1,781
19	**Expenditure on network assets**	13,928	14,580	14,773	14,172	17,011	17,346	17,637	18,063	18,381	18,767	19,142
20	Expenditure on non-network assets	-	-	-	-	4,249	-	-	-	-	-	-
21	**Expenditure on assets**	13,928	14,580	14,773	14,172	21,260	17,346	17,637	18,063	18,381	18,767	19,142
22												
23	*plus* Cost of financing											
24	*less* Value of capital contributions	567	729	743	759	774	790	806	822	839	855	872
25	*plus* Value of vested assets											
26												
27	**Capital expenditure forecast**	13,361	13,851	14,030	13,413	20,486	16,556	16,831	17,241	17,542	17,912	18,270
28												
29	Assets commissioned	13,757	14,737	15,625	12,294	22,100	18,273	16,343	19,528	18,381	18,767	19,142
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 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
32		**$000 (in constant prices)**										
33	Consumer connection	4,248	4,701	4,046	3,573	3,853	3,975	5,788	3,059	4,044	4,059	4,059
34	System growth	2,088	672	2,046	1,818	2,261	12	12	948	1,345	1,345	1,345
35	Asset replacement and renewal	5,580	6,792	6,506	6,243	8,815	10,564	9,614	11,073	8,732	8,732	8,732
36	Asset relocations	32	121	121	121	121	121	121	121	363	363	363
37	Reliability, safety and environment:											
38	Quality of supply	246	408	408	408	45	45	45	45	288	288	288
39	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment	1,733	1,888	1,357	1,446	920	1,278	363	761	1,199	1,199	1,199
41	**Total reliability, safety and environment**	1,979	2,296	1,765	1,854	965	1,323	408	806	1,487	1,487	1,487
42	**Expenditure on network assets**	13,927	14,582	14,484	13,609	16,015	15,995	15,943	16,007	15,971	15,986	15,986
43	Expenditure on non-network assets	-	-	-	-	4,000	-	-	-	-	-	-
44	**Expenditure on assets**	13,927	14,582	14,484	13,609	20,015	15,995	15,943	16,007	15,971	15,986	15,986
45												
46	**Subcomponents of expenditure on assets (where known)**											
47	Energy efficiency and demand side management, reduction of energy losses											
48	Overhead to underground conversion	2	61	61	61	61	61	61	61	182	182	182
49	Research and development											
50												

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
for year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
Difference between nominal and constant price forecasts	$000										
Consumer connection	-	(1)	81	148	240	335	614	392	610	706	801
System growth	-	1	40	75	140	1	1	122	203	234	265
Asset replacement and renewal	2	(1)	129	257	548	893	1,022	1,422	1,318	1,519	1,724
Asset relocations	-	-	3	5	8	10	13	16	55	64	72
Reliability, safety and environment:											
Quality of supply	(1)	1	9	18	3	4	5	6	43	50	57
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	-	(2)	27	60	57	108	39	98	181	208	237
Total reliability, safety and environment	(1)	(1)	36	78	60	112	44	104	224	258	294
Expenditure on network assets	1	(2)	289	563	996	1,351	1,694	2,056	2,410	2,781	3,156
Expenditure on non-network assets	-	-	-	-	249	-	-	-	-	-	-
Expenditure on assets	1	(2)	289	563	1,245	1,351	1,694	2,056	2,410	2,781	3,156

11a(ii): Consumer Connection

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22
*Consumer types defined by EDB**	$000 (in constant prices)					
Major New Connections Projects	2,660	3,607	2,952	2,479	2,759	2,881
Other New Connections	1,588	1,094	1,094	1,094	1,094	1,094
*include additional rows if needed						
Consumer connection expenditure	4,248	4,701	4,046	3,573	3,853	3,975
less Capital contributions funding consumer connection	557	656	656	656	656	656
Consumer connection less capital contributions	3,691	4,045	3,390	2,917	3,197	3,319

11a(iii): System Growth

Subtransmission	67	-	-	657	877	-
Zone substations	1,546	322	1,775	943	1,259	-
Distribution and LV lines	453	187	53	96	125	12
Distribution and LV cables	22	163	218	-	-	-
Distribution substations and transformers	-	-	-	-	-	-
Distribution switchgear	-	-	-	122	-	-
Other network assets	-	-	-	-	-	-
System growth expenditure	2,088	672	2,046	1,818	2,261	12
less Capital contributions funding system growth						
System growth less capital contributions	2,088	672	2,046	1,818	2,261	12

11a(iv): Asset Replacement and Renewal

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22
	$000 (in constant prices)					
Subtransmission	1,669	1,894	2,127	1,879	3,087	2,123
Zone substations	115	604	168	153	1,412	3,777
Distribution and LV lines	3,748	4,249	4,166	4,166	4,271	4,619
Distribution and LV cables	16	15	15	15	15	15
Distribution substations and transformers	16	15	15	15	15	15
Distribution switchgear	16	15	15	15	15	15
Other network assets						
Asset replacement and renewal expenditure	5,580	6,792	6,506	6,243	8,815	10,564
less Capital contributions funding asset replacement and renewal	10	-	-	-	-	-
Asset replacement and renewal less capital contributions	5,570	6,792	6,506	6,243	8,815	10,564

11a(v):Asset Relocations

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22
*Project or programme**	$000 (in constant prices)					
**include additional rows if needed*						
All other project or programmes - asset relocations	32	121	121	121	121	121
Asset relocations expenditure	32	121	121	121	121	121
less Capital contributions funding asset relocations	-	73	73	73	73	73
Asset relocations less capital contributions	32	48	48	48	48	48

11a(vi):Quality of Supply

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22
*Project or programme**	$000 (in constant prices)					
Reclosers with SCADA integration	239	363	363	363	-	-
**include additional rows if needed*						
All other projects or programmes - quality of supply	7	45	45	45	45	45
Quality of supply expenditure	246	408	408	408	45	45
less Capital contributions funding quality of supply						
Quality of supply less capital contributions	246	408	408	408	45	45

11a(vii): Legislative and Regulatory

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22
*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	-	-	-	-	-	-

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22

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

	*Project or programme**	$000 (in constant prices)					
	Substation clearances and fence improvements	153	33	-	-	-	-
	Substation structure seismic upgrades	60	359	359	255	-	-
	Substation NERs and 33kV Transformer Circuit Breakers	427	498	498	498	498	498
	Milton 33kV ring protection upgrade	-	-	28	330	-	-
	Transformer Fusing	730	341	-	-	-	-
	**include additional rows if needed*						
	All other projects or programmes - other reliability, safety and environment	363	657	472	363	422	780
	Other reliability, safety and environment expenditure	1,733	1,888	1,357	1,446	920	1,278
less	Capital contributions funding other reliability, safety and environment						
	Other reliability, safety and environment less capital contributions	1,733	1,888	1,357	1,446	920	1,278

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22

11a(ix): Non-Network Assets

	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**						
	Balclutha Depot	-	-	-	-	4,000	-
	**include additional rows if needed*						
	All other projects or programmes - atypical expenditure						
	Atypical expenditure	-	-	-	-	4,000	-
	Expenditure on non-network assets	-	-	-	-	4,000	-

Schedule 11b – Operational Expenditure Forecast

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
7												
8	for year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
9	**Operational Expenditure Forecast**	$000 (in nominal dollars)										
10	Service interruptions and emergencies	1,234	1,184	1,208	1,245	1,269	1,309	1,336	1,362	1,390	1,417	1,446
11	Vegetation management	1,180	1,107	1,129	1,153	1,176	1,200	1,224	1,249	1,274	1,299	1,325
12	Routine and corrective maintenance and inspection	1,476	1,486	1,530	1,565	1,504	1,550	1,584	1,619	1,654	1,691	1,728
13	Asset replacement and renewal	225	346	353	361	368	376	383	391	399	407	415
14	**Network Opex**	4,115	4,123	4,220	4,324	4,317	4,435	4,527	4,621	4,717	4,814	4,914
15	System operations and network support	598	596	751	822	845	863	880	898	916	934	921
16	Business support	1,492	1,629	1,658	1,698	1,732	1,768	1,803	1,839	1,876	1,914	1,952
17	**Non-network opex**	2,090	2,225	2,409	2,520	2,577	2,631	2,683	2,737	2,792	2,848	2,873
18	**Operational expenditure**	6,205	6,348	6,629	6,844	6,894	7,066	7,210	7,358	7,509	7,662	7,787

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
19												
20	for year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
21		$000 (in constant prices)										
22	Service interruptions and emergencies	1,234	1,184	1,184	1,195	1,195	1,207	1,207	1,207	1,207	1,207	1,207
23	Vegetation management	1,180	1,107	1,107	1,107	1,107	1,107	1,107	1,107	1,107	1,107	1,107
24	Routine and corrective maintenance and inspection	1,476	1,486	1,500	1,502	1,416	1,429	1,432	1,435	1,438	1,440	1,443
25	Asset replacement and renewal	225	346	346	346	346	346	346	346	346	346	346
26	**Network Opex**	4,115	4,123	4,137	4,150	4,064	4,089	4,092	4,095	4,098	4,100	4,103
27	System operations and network support	598	596	736	790	796	796	796	796	796	796	769
28	Business support	1,492	1,629	1,626	1,630	1,630	1,630	1,630	1,630	1,630	1,630	1,630
29	**Non-network opex**	2,090	2,225	2,362	2,420	2,426	2,426	2,426	2,426	2,426	2,426	2,399
30	**Operational expenditure**	6,205	6,348	6,499	6,570	6,490	6,515	6,518	6,521	6,524	6,526	6,502

31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and demand side management, reduction of											
33	energy losses	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
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	134	140	140	140	140	140	140	140	140	140	140

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

38

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
39												
40	for year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
41	**Difference between nominal and real forecasts**	$000										
42	Service interruptions and emergencies	-	-	24	50	74	102	129	155	183	210	239
43	Vegetation management	-	-	22	46	69	93	117	142	167	192	218
44	Routine and corrective maintenance and inspection	-	-	30	63	88	121	152	184	216	251	285
45	Asset replacement and renewal	-	-	7	15	22	30	37	45	53	61	69
46	**Network Opex**	-	-	83	174	253	346	435	526	619	714	811
47	System operations and network support	-	-	15	32	49	67	84	102	120	138	152
48	Business support	-	-	32	68	102	138	173	209	246	284	322
49	**Non-network opex**	-	-	47	100	151	205	257	311	366	422	474
50	**Operational expenditure**	-	-	130	274	404	551	692	837	985	1,136	1,285

Schedule 12a – Asset Condition

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	Voltage	Asset category	Asset class	Units	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
9											
10	All	Overhead Line	Concrete poles / steel structure	No.	2.58%	4.99%	17.34%	54.94%	20.16%	3	5.00%
11	All	Overhead Line	Wood poles	No.	7.41%	23.24%	6.78%	38.90%	23.67%	3	15.00%
12	All	Overhead Line	Other pole types	No.	-	-	-	-	-	N/A	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	8.39%	10.59%	1.12%	50.32%	29.57%	3	15.00%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	45.56%	47.72%	6.71%	-	3	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	84.02%	15.98%	4	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	-	-	N/A	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	-	-	N/A	-
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	-	-	N/A	-
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-	-	N/A	-
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-	-	N/A	-
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-	-	N/A	-
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-	-	N/A	-
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-	-	N/A	-
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	51.35%	35.14%	13.51%	-	3	8.11%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	100.00%	-	-	-	3	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	100.00%	-	3	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	15.15%	54.55%	30.30%	-	3	9.09%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	N/A	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	10.00%	85.56%	4.44%	-	3	11.11%
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	100.00%	-	4	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-	N/A	-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	100.00%	-	-	3	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	3.92%	5.88%	90.20%	-	3	-
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	12.12%	83.33%	4.55%	-	3	16.67%
35											

36					Asset condition at start of planning period (percentage of units by grade)						
37	Voltage	Asset category	Asset class	Units	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
38											
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	8.51%	78.72%	12.77%	-	3	8.51%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	8.04%	15.05%	21.48%	48.15%	7.27%	3	10.00%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	N/A	-
42	HV	Distribution Line	SWER conductor	km	2.68%	17.42%	3.53%	61.22%	15.16%	3	10.00%
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	-	38.65%	61.35%	N/A	5.00%
44	HV	Distribution Cable	Distribution UG PILC	km	-	-	-	9.40%	90.60%	N/A	-
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	-	-	N/A	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	17.65%	11.76%	70.59%	-	3	-
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	-	100.00%	-	4	-
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	-	20.37%	74.89%	4.74%	-	2	10.00%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	-	-	-	N/A	-
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	-	39.13%	60.87%	-	3	-
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	1.55%	0.79%	18.85%	2.10%	76.72%	3	2.50%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	-	-	12.72%	87.28%	4	-
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	70.59%	29.41%	-	3	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	-	-	-	N/A	-
55	LV	LV Line	LV OH Conductor	km	8.98%	17.11%	7.13%	66.78%	-	2	15.00%
56	LV	LV Cable	LV UG Cable	km	-	-	-	10.58%	89.42%	N/A	-
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	-	-	-	-	100.00%	N/A	-
58	LV	Connections	OH/UG consumer service connections	No.	-	-	-	-	100.00%	N/A	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	18.18%	39.90%	41.92%	-	3	7.07%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	4.62%	58.46%	36.92%	-	3	24.62%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	-	-	N/A	-
62	All	Load Control	Centralised plant	Lot	-	50.00%	25.00%	25.00%	-	3	25.00%
63	All	Load Control	Relays	No.	-	-	-	-	-	N/A	-
64	All	Civils	Cable Tunnels	km	-	-	-	-	-	N/A	-

Schedule 12b – Capacity Forecast

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**

8

	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	Charlotte Street	5.3	5	N-1	3	106%	5	106%	Transformer	Over N-1 but load transfer available
10	Clarks Junction	0.3	-	N	-	-	-		No constraint within +5 years	
11	Clinton	2.0	-	N	1	-	-		No constraint within +5 years	
12	Clydevale	3.0	-	N	1	-	-		No constraint within +5 years	Capacity increase to 5 MVA N-security site underway
13	Deepdell	0.1	-	N	-	-	-		No constraint within +5 years	
14	Elderlee Street	4.6	5	N-1	3	92%	5	95%	No constraint within +5 years	Load transfer available to Milburn and Glenore
15	Finegand	1.1	-	N	1	-	-		No constraint within +5 years	
16	Glenore	0.6	-	N	1	-	-		No constraint within +5 years	
17	Golden Point	2.9	-	N	-	-	-		No constraint within +5 years	Load transferred to Macraes end 2013, now standby substation only
18	Greenfield	1.7	-	N	-	-	-		No constraint within +5 years	
19	Hindon	0.2	-	N	-	-	-		No constraint within +5 years	
20	Hyde	0.8	-	N	1	-	-		No constraint within +5 years	
21	Kaitangata	1.4	-	N	1	-	-		No constraint within +5 years	
22	Lawrence	1.2	-	N	1	-	-		No constraint within +5 years	
23	Linnburn	0.8	-	N	-	-	-		Other	Temporary sub to be made obsolete by Patearoa sub expansion
24	Merton	2.4	2.5	N-1	2	96%	-		No constraint within +5 years	Over N-1 capacity, replacement Waikouaiti substation planned
25	Middlemarch	0.9	-	N	1	-	-		No constraint within +5 years	
26	Milburn	2.2	-	N	3	-	-		No constraint within +5 years	
27	North Balclutha	2.8	-	N	3	-	-		No constraint within +5 years	
28	Oturehua	0.2	-	N	-	-	-		No constraint within +5 years	
29	Owaka	1.4	-	N	1	-	-		No constraint within +5 years	
30	Paerau	0.3	-	N	-	-	-		No constraint within +5 years	
31	Paerau Hydro	12.5	15	N-1	-	83%	15	83%	No constraint within +5 years	
32	Palmerston	2.6	2.5	N-1	1	104%	2.5	108%	Transformer	Relocation to Transpower site planned (beyond 5 yrs) monitor growth. Load transfer available to Merton.
33	Patearoa	1.8	-	N	1	-	7.5	52%	Transformer	Site expansion and second subtransmission supply planned
34	Port Molyneux	0.6	-	N	1	-	-		No constraint within +5 years	
35	Pukeawa	0.5	-	N	-	-	-		No constraint within +5 years	
36	Ranfurly	2.1	2.5	N-1	1	84%	3	88%	No constraint within +5 years	Monitor growth
37	Remarkables	4.4	12.5	N-1	-	35%	12.5	51%	No constraint within +5 years	
38	Stirling	3.9	-	N	1	-	-		No constraint within +5 years	
39	Waihola	1.1	-	N	1	-	-		No constraint within +5 years	
40	Waipiata	1.4	-	N	1	-	-		No constraint within +5 years	Planned load transfer to Patearoa
41	Waitati	1.5	-	N	1	-	-		No constraint within +5 years	
42	Wedderburn	0.2	-	N	-	-	-		No constraint within +5 years	

43 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

Schedule 12c – Demand Forecast

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

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

sch ref

7 **12c(i): Consumer Connections**

8 *Number of ICPs connected in year by consumer type*

		Number of connections					
9		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10	for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**
11	*Consumer types defined by EDB**						
12	Consumer Connections <20 kVA	329	395	525	425	375	375
13	Consumer Connections <21-99 kVA	18	25	25	25	25	25
14	Consumer Connections >100 kVA	9	13	18	18	13	13
15							
16							
17	**Connections total**	356	433	568	468	413	413
18	**include additional rows if needed*						
19	**Distributed generation**						
20	Number of connections	30	35	35	35	35	35
21	Capacity of distributed generation installed in year (MVA)	0.09	0.15	0.15	0.15	0.15	0.15

22 **12c(ii) System Demand**

23		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24	**Maximum coincident system demand (MW)** for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**
25	GXP demand	56	57	58	59	59	60
26	*plus* Distributed generation output at HV and above	7	7	7	7	7	7
27	**Maximum coincident system demand**	63	64	65	66	66	67
28	*less* Net transfers to (from) other EDBs at HV and above	-	-	-	-	-	-
29	**Demand on system for supply to consumers' connection points**	63	64	65	66	66	67
30	**Electricity volumes carried (GWh)**						
31	Electricity supplied from GXPs	353	356	358	361	363	366
32	*less* Electricity exports to GXPs	-					
33	*plus* Electricity supplied from distributed generation	91	92	92	93	94	94
34	*less* Net electricity supplied to (from) other EDBs	-	-	-	-	-	-
35	**Electricity entering system for supply to ICPs**	444	448	450	454	457	460
36	*less* Total energy delivered to ICPs	422	426	428	432	434	437
37	**Losses**	22	23	23	23	23	23
38							
39	**Load factor**	80%	80%	79%	79%	79%	78%
40	**Loss ratio**	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%

Schedule 12d – Reliability Forecast

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

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.

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

sch ref	for year ended	*Current Year CY* 31 Mar 17	*CY+1* 31 Mar 18	*CY+2* 31 Mar 19	*CY+3* 31 Mar 20	*CY+4* 31 Mar 21	*CY+5* 31 Mar 22
8							
9	**SAIDI**						
10	Class B (planned interruptions on the network)	63.3	74.0	74.0	74.0	74.0	74.0
11	Class C (unplanned interruptions on the network)	176.4	164.7	160.8	156.8	154.8	154.8
12							
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.37	0.32	0.32	0.32	0.32	0.32
15	Class C (unplanned interruptions on the network)	2.18	2.33	2.30	2.27	2.25	2.25

Schedule 13 – Asset Management Maturity Assessment Tool

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

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

Q No.	Function	Question	Score	Maturity Description
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	2	The organisation has an asset management policy, which has been authorised by top management, but it has had limited circulation. It may be in use to influence development of strategy and planning but its effect is limited.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	2	Some of the linkages between the long-term asset management strategy and other organisational policies, strategies and stakeholder requirements are defined but the work is fairly well advanced but still incomplete.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	2	The long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	2	The organisation is in the process of putting in place comprehensive, documented asset management plan(s) that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy.
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	2	The plan(s) are communicated to most of those responsible for delivery but there are weaknesses in identifying relevant parties resulting in incomplete or inappropriate communication. The organisation recognises improvement is needed as is working towards resolution.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	3	Asset management plan(s) consistently document responsibilities for the delivery actions and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement of asset plan actions is appropriate.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	2	The organisation has arrangements in place for the implementation of asset management plan(s) but the arrangements are not yet adequately efficient and/or effective. The organisation is working to resolve existing weaknesses.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	3	Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	2	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	2	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	2	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan but the work is incomplete or has not been consistently implemented.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	2	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	2	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	3	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process(es). Pertinent asset information requirements are regularly reviewed.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	2	The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	1	The organisation is aware of the need to determine in a structured manner what its asset information system should contain in order to support its asset management system and is in the process of deciding how to do this.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	2	The organisation has developed a controls that will ensure the data held is of the requisite quality and accuracy and is consistent and is in the process of implementing them.
64	Information management	How has the organisation ensured its asset management information system is relevant to its needs?	2	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	2	The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	2	The organisation is in the process ensuring that outputs of risk assessment are included in developing requirements for resources and training. The implementation is incomplete and there are gaps and inconsistencies.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	2	The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements, but the information is not kept up to date, inadequate or inconsistently managed.
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	3	Effective process(es) and procedure(s) are in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	2	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process for confirming the process(es)/procedure(s) are effective and if necessary carrying out modifications.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	2	The organisation is developing coherent asset performance monitoring linked to asset management objectives. Reactive and proactive measures are in place. Use is being made of leading indicators and analysis. Gaps and inconsistencies remain.
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non-conformances is clear, unambiguous, understood and communicated?	2	The organisation is in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/authorities.
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2	The organisation is establishing its audit procedure(s) but they do not yet cover all the appropriate asset-related activities.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non-conformance?	2	The need is recognized for systematic instigation of preventive and corrective actions to address root causes of noncompliance or incidents identified by investigations, compliance evaluation or audit. It is only partially or inconsistently in place.
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	1	A Continual Improvement ethos is recognised as beneficial, however it has just been started, and or covers partially the asset drivers.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	3	The organisation actively engages internally and externally with other asset management practitioners, professional bodies and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments.

Appendix 2 – Directors Approval

We, Alan Bertram Harper and Ross Lindsay Smith being directors of companies which are parties to the OtagoNet Joint Venture certify that, having made all reasonable enquiry, to the best of our knowledge-

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

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

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

A B Harper

R L Smith

Date: 29 March 2017