networktasman

Your consumer-owned electricity distributor

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# NETWORK TASMAN LIMITED

# DEFAULT PRICE-QUALITY PATH COMPLIANCE STATEMENT

## Assessment for Year ended 31 March 2017 (Assessment Period Two)

**Pursuant to the Commerce Act**
**Electricity Distribution Services Default Price-Quality Path**
**Determination 2015**

**Dated 1 June 2017**

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**Supporting Information:**

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# 1 Directors' Certification

**Default Price-Quality Path Compliance Statement**

**Year Ended 31 March 2017**

We, M. J. McCliskie and Sarah-Jane Weir, being directors of Network Tasman Limited, certify that, having made all reasonable enquiry, to the best of our knowledge and belief, the attached Annual Compliance Statement of Network Tasman Limited, and related information, prepared for the purposed of the Electricity Distribution Services Default Price-Quality Path Determination 2015 are true and accurate.

**Director** **Director**

**Dated: 1 June 2017**

# 2 Default Price-Quality Path Compliance Statement

**a). Background**

Network Tasman Limited (**NTL**) is a Non Exempt Electricity Distribution Business as defined in section 54G of the Commerce Act 1986 and consequently is subject to Default Price-Quality Regulation. This statement provides an assessment of NTL's compliance with the requirements of the Electricity Distribution Services Default Price-Quality Path Determination 2015 (the **DPP Determination 2015**) for the year ended 31 March 2017.

**b). Information**

The audited information NTL has included in this statement has been prepared specifically to comply with the requirements of Clauses 8-11 of the DPP Determination 2015. This audited information includes:

- NTL's schedule of prices for 2016/2017 (Appendix 1)
- Calculation of the maximum allowable notional revenue compared with notional revenue, distribution prices and quantities (Appendix 2)
- Pass through revenue calculations (Appendix 3)
- Calculation of pass-through balance (Appendix 4)
- Applicability of recoverable costs for 2016/17 DPP compliance (Appendix 5)
- Pass-through and recoverable costs used to set prices (Appendix 6)
- Reliability data and assessment (Appendix 7)
- Two previous annual reliability assessments (Appendix 8)
- Reliability recording policies and procedures (Appendix 9)

**c). Price Path Compliance**

Network Tasman Limited ***fully complies with the default price pathway*** requirements specified in Clause 8 of the DPP Determination 2015 for the year to 31 March 2017. The following test confirms NTL's compliance.

**Test: Clause 8.3 of the DPP Determination 2015**

The Notional Revenue for a Non-exempt EDB (NTL) in the Assessment Period for the year to 31 March 2017 must not exceed the allowable notional revenue for the Assessment Period:

| | |
|---|---|
| **Test per Clause 8.3:** | **NR < ANR** |
| Where: | NR = Notional Revenue |
| | ANR = Allowable Notional Revenue |
| $ANR_{2016/17}$ | $28,391,747 |
| $NR_{2016/17}$ | $28,221,840 |
| **Result:** | **NR does not exceed ANR** |

This test confirms NTL compliance with the Default Price Path. Actual Notional Revenue $NR_{2017}$ was *$169,907 less* than the Allowable Notional Revenue $R_{2017}$ for the Assessment Period ended 31 March 2017. The supporting evidence for the test above is provided in Appendices 1 and 2. NTL's schedule of distribution prices is contained in Appendix 1. Calculation of the allowable notional revenue and notional revenue is in Appendix 2.

Notional Revenue in the DPP compliance assessment includes all revenue NTL has derived from supply of the following controlled, non-contestable line function services:

- Electricity conveyance services provided under Use of Systems Agreements with electricity retailers
- Electricity conveyance services provided under Direct Connection Agreements with major electricity consumers and embedded electricity generators
- Network development levies and connection fees charged to new electrical loads at the time of their connection to Network Tasman Limited's distribution network.
- Application fees for Small Scale Distributed Generation (SSDG)

The Allowable Notional Revenue for the year to 31 March 2017 was calculated using the following formula set out in Schedule 3B of the DPP Determination 2015:

$$ANR = (\sum DP_{2016}Q_{2015} + (ANR_{2016}\text{-}NR_{2016}))(1+\Delta CPI)(1\text{-}X)$$

## d). Quality Standard Compliance

Network Tasman Limited ***fully complies with the default quality standard*** in Clause 9 of *Determination 2015* for the assessment period ended 31 March 2017. In particular:

- NTL's assessed SAIDI value has not exceeded the SAIDI Limit
- NTL's assessed SAIFI value has not exceeded the SAIFI Limit

Under Clause 9 of the DPP Determination 2015, to comply for Assessment Two, NTL must either:

- Under 9.1a, comply with the annual reliability assessment; or
- Under 9.1b, have complied with the annual reliability assessments in each of the two preceding Assessment periods.

The following test confirms NTL's compliance under 9.1a.

**Figure 1: Quality standards compliance with clause 9.1a of the DPP Determination 2015**

**Test per 9.1a:**

SAIDI Assessed Value ≤ SAIDI Limit recalculated in accordance with Schedule 4B

| | |
|---|---|
| Assessed Value | 132.52 |
| SAIDI Limit | 157.79 |
| **SAIDI complies with assessment** | |

SAIFI Assessed Value ≤ SAIFI Limit recalculated in accordance with Schedule 4B

| | |
|---|---|
| Assessed Value | 1.248 |
| SAIFI Limit | 1.676 |
| **SAIFI complies with assessment** | |

NTL's annual reliability assessments for the previous two periods are contained in Appendix 8 which demonstrates that 9.1b of the DPP Determination 2015 is also satisfied.

**e). Transactions compliance**

On 1 December 2014, NTL acquired from Transpower the 66kV transmission line to the Cobb hydro-electric power station and connection assets at Motueka and Golden Bay. As per clause 10.6 of the DPP Determination 2015 relating to the purchase of system fixed assets from Transpower, NTL has recalculated the SAIDI and SAIFI limits, boundary values, caps and collars contained in Schedule 4A, according to the methodology specified in Schedule 4B in the annual reliability assessment. These values were recalculated in the preparation of Assessment One. Details of the recalculations are set out in Appendix 7. NTL has not undertaken any other transmission acquisition in the relevant period.

NTL has not undertaken an Amalgamation, Merger or Major Transaction (as defined in the Determination 2015) in the assessment period for the year ended 31 March 2017.

**f). Restructure of Prices Compliance**

NTL is required to disclose any restructuring of prices in the year to 31 March 2017 that requires specific disclosure and assessment in terms of Clause 11.7 and 11.8 of the DPP Determination 2015. The only pricing restructure was the introduction of price changes to Small Scale Distributed Generation (SSDG) application fee as per Schedule 6.5 of the Electricity Industry Participation Code which required the pricing structure set out in the table below:

| SSDG Application type | Units | Application fee |
|---|---|---|
| Part 1 (unapproved inverter) | $/SSDG | 200 |
| Part 1a (approved inverter) | $/SSDG | 100 |
| SSDG > 10kW and < 100kW | $/SSDG | 500 |
| SSDG > 100kW and <1000kW | $/SSDG | 1,000 |
| SSDG > 1000kW | $/SSDG | 5,000 |

While there was a price for >10kW, all SSDG was charged at the ≤ 10kW price of $173.91 per connection for Q2015. Post the change the fee for new connections ≤ 10kW with a pre-approved inverter are charged under Part1A ($100), and those without an approved inverter at $200. Since the change, all applications were of type Part 1a, therefore there was no need to estimate lagged quantities for the other applications types (as were all set to zero). NTL's >10 kW fee was replaced with the three mandated prices above, >10 kW and<100 kW, >100 kW and <1000 kW and >1000 kW.

**g). Recoverable Costs and Pass-Through Costs**

In accordance with the DPP Determination 2015 the recoverable and pass-through cost categories described below have been included in NTL's Default Price Path calculations.

**i)** **Recoverable Costs** $V_{2017}$ include the following cost categories:

- Charges billed by Transpower
    i. Connection charges
    ii. Interconnection charges
    iii. New Investment charges
- Avoided transmission charges paid to embedded generators

- Avoided Transpower charge liability as a result of a transmission asset acquisition
- Quality incentive adjustment
- Capex wash-up adjustment

A list of the recoverable costs described in the Electricity Distribution Services Input Methodologies Determination 2012 (as amended at December 2015), and their applicability to NTL's DPP assessment for the year ended March 2017 is set out in Appendix 5.

**ii)** **Pass Through Costs** $K_{2017}$ include the following costs categories:

- Local Authority *Rates* levied on NTL's systems fixed assets including lines, cables, electrical equipment and substation land and buildings.
- Electricity Authority *Levies* for the regulatory costs allocated to all EDB's under an industry levy formula determined by government.
- Commerce Act *Levies* for the funding of Commerce Commission EDB regulatory activities that are allocated to all EDB's under an industry levy formula determined by government.
- Electricity and Gas Complaints Commission *Levies* for funding the contribution all EDB's make towards the independent electricity and gas industry complaints resolution scheme.

A comparison of actual pass through and recoverable costs with those used to set prices is set out in Appendix 6.

**h). Methodology used to set prices for 2016/17**

Distribution prices

Distribution prices for the previous year (2015/16) were multiplied by the quantities for 2014/15 (ie, 2 year lagged quantities). This calculation showed what the notional revenue would be if prices remained constant. The resulting notional revenue did not exceed the allowable notional revenue and no price increase was applied aside from the price applicable for the large embedded generator.[1]

Pass-through Prices

Budgeted quantities for 2016/17 were set using analysis of historic trends as well as expectations regarding future growth. Prices for Group 6, Nelson Electricity and the large embedded generator were set directly through calculation of the transmission charges attributable to those consumers. Budgeted quantities for other customers were then multiplied by transmission prices from the previous year and the resulting revenue from all customers was compared with the sum of pass-through and recoverable costs. Prices were increased to reflect an increase in transmission charges.

The incentive associated with the avoided Transpower charge liability as a result of a transmission asset acquisition, which is included in the Recoverable Costs, is very significant. It was decided by NTL that full inclusion of that recoverable cost would not be required to earn a reasonable return.[2] As a result there is an under-recovery of recoverable costs in 2016/17.

[1] The charge for the large embedded generator increased as per the contractual agreement with that generator.

[2] Instead there was only a partial inclusion of the incentive in 2016/17 prices.

Similarly, it was decided that the pass-through balance from 2015/16 would not be recovered from 2016/17 prices.

**i). Pass-through balance for 2016/17**

The pass-through balance for 2016/17 is -$4,635,028 (see Appendix 4 for details as to how this was calculated). This means that the pass-through prices for 2016/17 under-recover recoverable and pass-through costs by approximately $4.6m.

As described above, this large negative pass-through balance occurs because NTL concluded that it did not need to fully include the incentive associated with transmission asset acquisition in its prices to achieve a reasonable return for the company, and similarly that it did not need to recover the pass through balance from the previous year of -$2.4m. This pricing approach reflects NTL's consumer ownership and dual focus on both operating a successful company and increasing consumer benefit.

**j). Network Tasman SAIDI & SAIFI Policies and Procedures**

NTL is required under Clause 11.5 (e) of the Determination 2015 to describe the policies and procedures used to record the SAIDI and SAIFI statistics for the Assessment Period ended 31 March 2017. This information is provided in Appendix 9.

# 3 Disclaimer

The information disclosed by Network Tasman Limited in this Default Price-Quality Path Compliance Statement 2017 has been prepared solely for the purposes of complying with the requirements of the *Commerce Act 1986* and the Determination 2015.

The information in this compliance statement relates only to the lines business activities covered by the DDP Determination 2015. NTL is involved in other activities that are not required to be reported on under the Determination.

The information in this compliance statement has not been prepared for any other purpose than that required by the Determination 2015 and Network Tasman Limited expressly disclaims any liability to any party who may rely on this information for any other purpose.

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# *Appendix 1: Schedule of NTL prices for 2016/17*

The following table sets out for each price during the year ended 31 March 2017, the total price, the distribution portion of the price and the pass-through portion of the price, as required by clause 11.4(d) of the DPP Determination 2015.

| PriceCode/ description | Units | Distribution Prices | Pass Through Price | Total Price |
|---|---|---|---|---|
| Streetlights (Watts) | c/W/day | 0.079 | 0.038 | 0.12 |
| 0UNM count | c/day | 35.00 | 18.00 | 53.00 |
| 0TBS count | c/day | 0.00 | 0.00 | 0.00 |
| 1 | c/day | 11.85 | 3.15 | 15.00 |
| 2LLFC | c/day | 11.85 | 3.15 | 15.00 |
| 2HLFC | c/day | 11.85 | 3.15 | 15.00 |
| 2 | c/kVA/day | 3.68 | 1.53 | 5.21 |
| HLF | c/kVA/day | 31.24 | 8.78 | 40.02 |
| 1ANY | c/kWh | 6.17 | 3.04 | 9.21 |
| 1DAY | c/kWh | 6.78 | 3.36 | 10.14 |
| 1NIT | c/kWh | 2.04 | 1.03 | 3.07 |
| 1OPK | c/kWh | 4.84 | 2.33 | 7.17 |
| 1WSR | c/kWh | 2.87 | 1.38 | 4.25 |
| 2ANY | c/kWh | 5.87 | 2.24 | 8.11 |
| 2DAY | c/kWh | 6.45 | 2.49 | 8.94 |
| 2NIT | c/kWh | 1.94 | 0.75 | 2.69 |
| 2OPK | c/kWh | 4.61 | 1.72 | 6.33 |
| 2WSR | c/kWh | 2.72 | 1.03 | 3.75 |
| 2LANY | c/kWh | 8.81 | 3.36 | 12.17 |
| 2LDAY | c/kWh | 9.38 | 3.62 | 13.00 |
| 2LNIT | c/kWh | 4.86 | 1.89 | 6.75 |
| 2LOPK | c/kWh | 7.57 | 2.82 | 10.39 |
| 2LWSR | c/kWh | 5.67 | 2.14 | 7.81 |
| 2HANY | c/kWh | 12.24 | 4.69 | 16.93 |
| 2HDAY | c/kWh | 12.81 | 4.95 | 17.76 |
| 2HNIT | c/kWh | 8.28 | 3.23 | 11.51 |
| 2HOPK | c/kWh | 11.02 | 4.13 | 15.15 |
| 2HWSR | c/kWh | 9.11 | 3.46 | 12.57 |
| HLFANY | c/kWh | 1.67 | 0.61 | 2.28 |
| HLFDAY | c/kWh | 1.81 | 0.67 | 2.48 |
| HLFNIT | c/kWh | 0.52 | 0.19 | 0.71 |
| HLFOPK | c/kWh | 1.30 | 0.48 | 1.78 |
| HLFWSR | c/kWh | 0.75 | 0.28 | 1.03 |
| GENA | c/kWh | *0.00* | *0.00* | *0.00* |
| Cat 3.1 Summer Day | c/kWh | 0.44 | 0.00 | 0.44 |
| Cat 3.1 Summer Night | c/kWh | 0.24 | 0.00 | 0.24 |
| Cat 3.1 Winter Day | c/kWh | 0.79 | 0.00 | 0.79 |
| Cat 3.1 Winter Night | c/kWh | 0.24 | 0.00 | 0.24 |
| Cat 3.1 RCPD $/kW/day | $/kW/day | 0.0319 | 0.3077 | 0.3396 |
| Cat 3.1 Anytime $/kVA day | $/kVA/day | 0.0901 | 0.0338 | 0.1239 |
| Cat 3.3 Summer Day | c/kWh | 1.35 | 0.00 | 1.35 |
| Cat 3.3 Summer Night | c/kWh | 0.71 | 0.00 | 0.71 |
| Cat 3.3 Winter Day | c/kWh | 3.45 | 0.00 | 3.45 |
| Cat 3.3 Winter Night | c/kWh | 0.71 | 0.00 | 0.71 |
| Cat 3.3 RCPD $/kW/day | $/kW/day | 0.0319 | 0.3077 | 0.3396 |

| PriceCode/ description | Units | Distribution Prices | Pass Through Price | Total Price |
|---|---|---|---|---|
| Cat 3.3 Anytime $/kVA day | $/kVA/day | 0.1164 | 0.0338 | 0.1502 |
| Cat 3.4 Summer Day | c/kWh | 1.35 | 0.00 | 1.35 |
| Cat 3.4 Summer Night | c/kWh | 0.71 | 0.00 | 0.71 |
| Cat 3.4 Winter Day | c/kWh | 3.45 | 0.00 | 3.45 |
| Cat 3.4 Winter Night | c/kWh | 0.71 | 0.00 | 0.71 |
| Cat 3.4 RCPD $/kW/day | $/kW/day | 0.0319 | 0.3077 | 0.3396 |
| Cat 3.4 Anytime $/kVA day | $/kVA/day | 0.1242 | 0.0338 | 0.1580 |
| Cat 3.5 Summer Day | c/kWh | 0.91 | 0.00 | 0.91 |
| Cat 3.5 Summer Night | c/kWh | 0.57 | 0.00 | 0.57 |
| Cat 3.5 Winter Day | c/kWh | 2.95 | 0.00 | 2.95 |
| Cat 3.5 Winter Night | c/kWh | 0.57 | 0.00 | 0.57 |
| Cat 3.5 RCPD $/kW/day | $/kW/day | 0.0319 | 0.3077 | 0.3396 |
| Cat 3.5 Anytime $/kVA day | $/kVA/day | 0.1164 | 0.0338 | 0.1502 |
| G3 Reactive Charge | c/kVar/day | 0.2545 | 0.0000 | 0.2545 |
| Cat 6.2 | $/year | 229,973 | 362,829 | 592,802 |
| Cat 6.1 | $/year | 214,575 | 1,815,008 | 2,029,583 |
| Large Embedded Generator | $/year | 1,308,853 | 318,948 | 1,627,801 |
| Nelson Electricity | $/year | 0 | 2,158,233 | 2,158,233 |
| NCA Admin G0 | $/ICP | 125 | n/a | 125 |
| NCA Admin G1 | $/ICP | 250 | n/a | 250 |
| NCA Admin G2 | $/ICP | 325 | n/a | 325 |
| NCA Admin G3 | $/ICP | 400 | n/a | 400 |
| SSDG < 10kW | $/SSDG | n/a | n/a | 0 |
| Part 1 | $/SSDG | 200 | n/a | 200 |
| Part 1a | $/SSDG | 100 | n/a | 100 |
| SSDG > 10kW and <100kW | $/SSDG | 500 | n/a | 500 |
| SSDG > 100kW and <1000kW | $/SSDG | 1,000 | n/a | 1,000 |
| SSDG > 1000kW | $/SSDG | 5,000 | n/a | 5,000 |
| NDL - Group 1 uncapped | $/kVA*km | 7.44 | n/a | 7.44 |
| NDL - Group 1 Capped | $/ICP | 3,250.00 | n/a | 3,250.00 |
| NDL - Group 2 | $/kVA*km | 18.32 | n/a | 18.32 |
| NDL Subdivision | $/ICP | 2,170.75 | n/a | 2,170.75 |

# *Appendix 2: Allowable notional revenue and notional revenue for year to 31 March 2017*

| **Allowable Notional Revenue for Assessment Two** | |
|---|---|
| ∑DP2016Q2015 = | $28,227,547 |
| ANR2016-NR2016 = | $33,962 |
| ΔCPI = | 0.0046 |
| X= | 0.00 |
| **ANR = (∑DP2016Q2015 + (ANR2016-NR2016))(1+ΔCPI)(1-X) =** | **$28,391,747** |

## Table 1: Calculation of Notional Revenue

| Price Code/description | Quantity Units | Price Units | Q2015 | Distribution Prices 2017 | Revenue |
|---|---|---|---|---|---|
| Streetlights (Watts) | Watts | c/W/day | 702,459 | 0.079 | 202,554 |
| 0UNM count | ICPs | c/day | 92 | 35.00 | 11,790 |
| 0TBS count | ICPs | c/day | 0 | 0.00 | 0 |
| 1 | ICPs | c/day | 35,093 | 11.85 | 1,517,851 |
| 2LLFC | ICPs | c/day | 24 | 11.85 | 1,050 |
| 2HLFC | ICPs | c/day | 1 | 11.85 | 43 |
| 2 | kVA | c/kVA/day | 114,630 | 3.68 | 1,539,705 |
| HLF | kVA | c/kVA/day | 2,896 | 31.24 | 330,176 |
| 1ANY | kWh | c/kWh | 169,875,848 | 6.17 | 10,481,340 |
| 1DAY | kWh | c/kWh | 1,675,244 | 6.78 | 113,582 |
| 1NIT | kWh | c/kWh | 4,496,909 | 2.04 | 91,737 |
| 1OPK | kWh | c/kWh | 516,356 | 4.84 | 24,992 |
| 1WSR | kWh | c/kWh | 60,292,325 | 2.87 | 1,730,390 |
| 2ANY | kWh | c/kWh | 65,093,216 | 5.87 | 3,820,972 |
| 2DAY | kWh | c/kWh | 17,701,618 | 6.45 | 1,141,754 |
| 2NIT | kWh | c/kWh | 7,654,543 | 1.94 | 148,498 |
| 2OPK | kWh | c/kWh | 226,507 | 4.61 | 10,442 |
| 2WSR | kWh | c/kWh | 3,812,739 | 2.72 | 103,707 |
| 2LANY | kWh | c/kWh | 129,659 | 8.81 | 11,421 |
| 2LDAY | kWh | c/kWh | 12,755 | 9.38 | 1,197 |
| 2LNIT | kWh | c/kWh | 15,445 | 4.86 | 751 |
| 2LOPK | kWh | c/kWh | 325 | 7.57 | 25 |
| 2LWSR | kWh | c/kWh | 24,370 | 5.67 | 1,381 |
| 2HANY | kWh | c/kWh | 2,271 | 12.24 | 278 |
| 2HDAY | kWh | c/kWh | 0 | 12.81 | 0 |

| Price Code/description | Quantity Units | Price Units | Q2015 | Distribution Prices 2017 | Revenue |
|---|---|---|---|---|---|
| 2HNIT | kWh | c/kWh | 0 | 8.28 | 0 |
| 2HOPK | kWh | c/kWh | 0 | 11.02 | 0 |
| 2HWSR | kWh | c/kWh | 0 | 9.11 | 0 |
| HLFANY | kWh | c/kWh | 4,332,433 | 1.67 | 72,352 |
| HLFDAY | kWh | c/kWh | 3,491,078 | 1.81 | 63,189 |
| HLFNIT | kWh | c/kWh | 1,474,604 | 0.52 | 7,668 |
| HLFOPK | kWh | c/kWh | 0 | 1.30 | 0 |
| HLFWSR | kWh | c/kWh | 38,459 | 0.75 | 288 |
| GENA | kWh | c/kWh | 1,089,825 | 0.00 | 0 |
| Cat 3.1 Summer Day | kWh | c/kWh | 4,326,185 | 0.44 | 19,035 |
| Cat 3.1 Summer Night | kWh | c/kWh | 1,818,015 | 0.24 | 4,363 |
| Cat 3.1 Winter Day | kWh | c/kWh | 3,182,244 | 0.79 | 25,140 |
| Cat 3.1 Winter Night | kWh | c/kWh | 1,354,065 | 0.24 | 3,250 |
| Cat 3.1 RCPD $/kW/day | kW | $/kW/day | 1,536 | 0.0319 | 17,884 |
| Cat 3.1 Anytime $/kVA day | kVA | $/kVA/day | 2,419 | 0.0901 | 79,552 |
| Cat 3.3 Summer Day | kWh | c/kWh | 3,910,261 | 1.35 | 52,789 |
| Cat 3.3 Summer Night | kWh | c/kWh | 1,739,069 | 0.71 | 12,347 |
| Cat 3.3 Winter Day | kWh | c/kWh | 1,988,941 | 3.45 | 68,618 |
| Cat 3.3 Winter Night | kWh | c/kWh | 810,430 | 0.71 | 5,754 |
| Cat 3.3 RCPD $/kW/day | kW | $/kW/day | 457 | 0.0319 | 5,321 |
| Cat 3.3 Anytime $/kVA day | kVA | $/kVA/day | 2,103 | 0.1164 | 89,348 |
| Cat 3.4 Summer Day | kWh | c/kWh | 42,744,747 | 1.35 | 577,054 |
| Cat 3.4 Summer Night | kWh | c/kWh | 14,944,275 | 0.71 | 106,104 |
| Cat 3.4 Winter Day | kWh | c/kWh | 32,577,301 | 3.45 | 1,123,917 |
| Cat 3.4 Winter Night | kWh | c/kWh | 11,501,026 | 0.71 | 81,657 |
| Cat 3.4 RCPD $/kW/day | kW | $/kW/day | 14,872 | 0.0319 | 173,163 |
| Cat 3.4 Anytime $/kVA day | kVA | $/kVA/day | 38,753 | 0.1242 | 1,756,790 |
| Cat 3.5 Summer Day | kWh | c/kWh | 5,576,915 | 0.91 | 50,750 |
| Cat 3.5 Summer Night | kWh | c/kWh | 2,482,601 | 0.57 | 14,151 |
| Cat 3.5 Winter Day | kWh | c/kWh | 4,123,628 | 2.95 | 121,647 |
| Cat 3.5 Winter Night | kWh | c/kWh | 1,853,395 | 0.57 | 10,564 |
| Cat 3.5 RCPD $/kW/day | kW | $/kW/day | 1,935 | 0.0319 | 22,530 |
| Cat 3.5 Anytime $/kVA day | kVA | $/kVA/day | 3,866 | 0.1164 | 164,251 |
| G3 Reactive Charge | kVAr | c/kVAr/day | 1423 | 0.2545 | 13,238 |
| Cat 6.2 | ICP | $/year | 1 | 229,973.00 | 229,973 |
| Cat 6.1 | ICP | $/year | 1 | 214,575.00 | 214,575 |
| Large Embedded Generator | ICP | $/year | 1 | 1,308,853 | 1,308,853 |
| Nelson Electricity | Connection | $/year | 1 | 0 | 0 |
| NCA Admin G0 | ICP | $/ICP | 2 | 125.00 | 250 |
| NCA Admin G1 | ICP | $/ICP | 507 | 250.00 | 126,750 |

| Price Code/description | Quantity Units | Price Units | Q2015 | Distribution Prices 2017 | Revenue |
|---|---|---|---|---|---|
| NCA Admin G2 | ICP | $/ICP | 50 | 325.00 | 16,250 |
| NCA Admin G3 | ICP | $/ICP | 12 | 400.00 | 4,800 |
| SSDG < 10kW | SSDG | $/SSDG | 92 | n/a | 0 |
| Part 1 | SSDG | $/SSDG | 0 | 200.00 | 0 |
| Part 1a | SSDG | $/SSDG | 0 | 100.00 | 9,200 |
| SSDG > 10kW and < 100kW | SSDG | $/SSDG | 0 | 500.00 | 0 |
| SSDG > 100kW and <1000kW | SSDG | $/SSDG | 0 | 1,000.00 | 0 |
| SSDG > 1000kW | SSDG | $/SSDG | 0 | 5,000.00 | 0 |
| NDL - Group 1 uncapped | kVA*km | $/kVA*km | 7,455 | 7.44 | 55,487 |
| NDL - Group 1 Capped | ICP | $/ICP | 3 | 3,250.00 | 9,750 |
| NDL - Group 2 | kVA*km | $/kVA*km | 9,035 | 18.32 | 165,506 |
| NDL Subdivision | ICP | $/ICP | 24 | 2,170.75 | 52,098 |
| **Total Notional Revenue NR** | | | | | **28,221,840** |

# Appendix 3: Pass-through revenue calculations

The calculation of pass-through revenue is contained in the following table in which 2016/17 pass-through prices ($PTP_{2017}$) are multiplied by 2016/17 quantities ($Q_{2017}$).

**Table 2: Calculation of Pass-through revenue**

| PriceCode/description | Quantity Units | Price Units | Q2017 | Pass Through Price | $P(V)_{2017}Q_{2017}$ |
|---|---|---|---|---|---|
| Streetlights (Watts) | Watts | c/W/day | 558,976 | 0.04 | 77,529.97 |
| 0UNM count | ICPs | c/day | 85 | 18.00 | 5,584.50 |
| 0TBS count | ICPs | c/day | 0 | 0.00 | 0.00 |
| 1 | ICPs | c/day | 35,749 | 3.15 | 411,024.13 |
| 2LLFC | ICPs | c/day | 37 | 3.15 | 425.41 |
| 2HLFC | ICPs | c/day | 2 | 3.15 | 23.00 |
| 2 | kVA | c/kVA/day | 120,518 | 1.53 | 673,032.77 |
| HLF | kVA | c/kVA/day | 3,218 | 8.78 | 103,127.25 |
| 1ANY | kWh | c/kWh | 177,450,736 | 3.04 | 5,394,502.38 |
| 1DAY | kWh | c/kWh | 1,907,057 | 3.36 | 64,077.12 |
| 1NIT | kWh | c/kWh | 4,419,404 | 1.03 | 45,519.86 |
| 1OPK | kWh | c/kWh | 436,912 | 2.33 | 10,180.04 |
| 1WSR | kWh | c/kWh | 61,785,579 | 1.38 | 852,640.99 |
| 2ANY | kWh | c/kWh | 65,013,710 | 2.24 | 1,456,307.10 |
| 2DAY | kWh | c/kWh | 16,787,597 | 2.49 | 418,011.17 |
| 2NIT | kWh | c/kWh | 7,921,016 | 0.75 | 59,407.62 |
| 2OPK | kWh | c/kWh | 257,779 | 1.72 | 4,433.79 |
| 2WSR | kWh | c/kWh | 3,678,732 | 1.03 | 37,890.94 |
| 2LANY | kWh | c/kWh | 197,206 | 3.36 | 6,626.12 |
| 2LDAY | kWh | c/kWh | 17,709 | 3.62 | 641.07 |
| 2LNIT | kWh | c/kWh | 13,274 | 1.89 | 250.88 |
| 2LOPK | kWh | c/kWh | 177 | 2.82 | 4.99 |
| 2LWSR | kWh | c/kWh | 42,705 | 2.14 | 913.89 |
| 2HANY | kWh | c/kWh | 6,243 | 4.69 | 292.80 |
| 2HDAY | kWh | c/kWh | 0 | 4.95 | 0.00 |
| 2HNIT | kWh | c/kWh | 0 | 3.23 | 0.00 |
| 2HOPK | kWh | c/kWh | 0 | 4.13 | 0.00 |
| 2HWSR | kWh | c/kWh | 1,016 | 3.46 | 35.15 |
| HLFANY | kWh | c/kWh | 5,060,318 | 0.61 | 30,867.94 |
| HLFDAY | kWh | c/kWh | 4,044,475 | 0.67 | 27,097.98 |
| HLFNIT | kWh | c/kWh | 1,666,851 | 0.19 | 3,167.02 |
| HLFOPK | kWh | c/kWh | 0 | 0.48 | 0.00 |

| PriceCode/description | Quantity Units | Price Units | Q2017 | Pass Through Price | $P(V)_{2017}Q_{2017}$ |
|---|---|---|---|---|---|
| HLFWSR | kWh | c/kWh | 34,536 | 0.28 | 96.70 |
| GENA | kWh | c/kWh | 2,828,885 | 0.00 | 0.00 |
| Cat 3.1 Summer Day | kWh | c/kWh | 4,359,894 | 0.00 | 0.00 |
| Cat 3.1 Summer Night | kWh | c/kWh | 1,809,313 | 0.00 | 0.00 |
| Cat 3.1 Winter Day | kWh | c/kWh | 3,007,389 | 0.00 | 0.00 |
| Cat 3.1 Winter Night | kWh | c/kWh | 1,295,466 | 0.00 | 0.00 |
| Cat 3.1 RCPD $/kW/day | kW | $/kW/day | 1,450 | 0.3077 | 162,850.23 |
| Cat 3.1 Anytime $/kVA day | kVA | $/kVA/day | 2,412 | 0.0338 | 29,756.84 |
| Cat 3.3 Summer Day | kWh | c/kWh | 3,888,798 | 0.00 | 0.00 |
| Cat 3.3 Summer Night | kWh | c/kWh | 1,725,422 | 0.00 | 0.00 |
| Cat 3.3 Winter Day | kWh | c/kWh | 2,089,711 | 0.00 | 0.00 |
| Cat 3.3 Winter Night | kWh | c/kWh | 843,363 | 0.00 | 0.00 |
| Cat 3.3 RCPD $/kW/day | kW | $/kW/day | 993 | 0.3077 | 111,524.33 |
| Cat 3.3 Anytime $/kVA day | kVA | $/kVA/day | 2,319 | 0.0338 | 28,609.50 |
| Cat 3.4 Summer Day | kWh | c/kWh | 45,108,939 | 0.00 | 0.00 |
| Cat 3.4 Summer Night | kWh | c/kWh | 15,810,534 | 0.00 | 0.00 |
| Cat 3.4 Winter Day | kWh | c/kWh | 35,109,862 | 0.00 | 0.00 |
| Cat 3.4 Winter Night | kWh | c/kWh | 12,605,606 | 0.00 | 0.00 |
| Cat 3.4 RCPD $/kW/day | kW | $/kW/day | 17,313 | 0.3077 | 1,944,431.69 |
| Cat 3.4 Anytime $/kVA day | kVA | $/kVA/day | 41,326 | 0.0338 | 509,838.86 |
| Cat 3.5 Summer Day | kWh | c/kWh | 5,164,171 | 0.00 | 0.00 |
| Cat 3.5 Summer Night | kWh | c/kWh | 2,256,059 | 0.00 | 0.00 |
| Cat 3.5 Winter Day | kWh | c/kWh | 4,431,814 | 0.00 | 0.00 |
| Cat 3.5 Winter Night | kWh | c/kWh | 1,975,078 | 0.00 | 0.00 |
| Cat 3.5 RCPD $/kW/day | kW | $/kW/day | 1,866 | 0.3077 | 209,571.39 |
| Cat 3.5 Anytime $/kVA day | kVA | $/kVA/day | 3,702 | 0.0338 | 45,671.57 |
| G3 Reactive Charge | kVAr | c/kVAr/day | 168 | 0.0000 | 0.0000 |
| Cat 6.2 | ICP | $/year | 1 | 362,828.69 | 362,828.69 |
| Cat 6.1 | ICP | $/year | 1 | 1,815,008.01 | 1,815,008.01 |
| Large Embedded Generator | ICP | $/year | 1 | 318,948 | 318,948 |
| Nelson Electricity | Connection | $/year | 1 | 2,158,233 | 2,158,233 |
| NCA Admin G0 | ICP | $/ICP | 0.00 | n/a | 0 |
| NCA Admin G1 | ICP | $/ICP | 0.00 | n/a | 0 |
| NCA Admin G2 | ICP | $/ICP | 0.00 | n/a | 0 |
| NCA Admin G3 | ICP | $/ICP | 0.00 | n/a | 0 |
| SSDG < 10kW | SSDG | $/SSDG | 0.00 | n/a | 0 |
| Part 1 | SSDG | $/SSDG | 0.00 | n/a | 0 |

| PriceCode/description | Quantity Units | Price Units | Q2017 | Pass Through Price | $P(V)_{2017}Q_{2017}$ |
|---|---|---|---|---|---|
| Part 1a | SSDG | $/SSDG | 0.00 | n/a | 0 |
| SSDG > 100kW and <1000kW | SSDG | $/SSDG | 0.00 | n/a | 0 |
| SSDG > 10kW and < 100kW | SSDG | $/SSDG | 0 | n/a | 0 |
| SSDG > 1000 kW | SSDG | $/SSDG | 0 | n/a | 0 |
| NDL - Group 1 uncapped | kVA*km | $/kVA*km | 0.00 | n/a | 0 |
| NDL - Group 1 Capped | ICP | $/ICP | 0.00 | n/a | 0 |
| NDL - Group 2 | kVA*km | $/kVA*km | 0.00 | n/a | 0 |
| NDL Subdivision | ICP | $/ICP | 0.00 | n/a | 0 |
| **$\sum PTP_{2017}Q_{2017}$** | | | | | **17,380,984** |

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# *Appendix 4: Calculation of Pass-through Balance*

**PTB = $\sum$PTP$_{2017}$Q$_{2017}$ - K$_{2017}$ - V$_{2017}$ - PTB$_{t-1}$(1+r)**

| | |
|---|---|
| $\sum$PTP$_{2017}$Q$_{2017}$ | $17,380,984 |
| K$_{2017}$ | $409,834 |
| V$_{2017}$ | $19,073,503 |
| PTB$_{t-1}$ | ($2,387,290) |
| r= | 6.09% |
| Pass Through Balance | ($4,635,028) |

**Pass-through Balance Reconciliation**

| **Assessment One** For YE March 2016 | | **Assessment Two** For YE March 2017 | | **Difference** |
|---|---|---|---|---|
| | P2016Q2016 | | P2017Q2017 | |
| $\sum$PTPt-1Qt-1 | 16,797,099 | $\sum$PTPtQt | 17,380,984 | 583,885 |
| Kt-1 | 330,381 | Kt | 409,834 | 79,452 |
| Vt-1 | 18,854,007 | Vt | 19,073,503 | 219,495 |
| PTB 1st assessment =0. | 0 | PTBt-1 | (2,387,290) | (2,387,290) |
| r = cost debt | 6.09% | r = cost debt | 6.09% | |
| PTBt-1 | (2,387,290) | PTBt | (4,635,028) | (2,247,738) |

# *Appendix 5: Applicability of recoverable costs for 2016/17 DPP compliance*

The recoverable costs that may be claimed under the DPP are set out in 3.1.3(1) of *Electricity Distribution Services Input Methodologies Determination 2012* as amended and consolidated as of 15 December 2015. An assessment of which of these are relevant to NTL's DPP calculation for the year ended 31 March 2017 is set out in the table below.

| **Subclause of 3.1.3(1)** | **Recoverable cost** | **Applicability to NTL for Assessment One** |
|---|---|---|
| (a)(i) | IRIS incentive adjustment | Not applicable in the current assessment period. |
| (a)(ii) | CPP transition | Not applicable. |
| (b) | Charges payable to Transpower for electricity lines services in respect of the transmission system | Applicable - connection and interconnection charges billed by Transpower. |
| (c) | Transpower NIA charge | Applicable. |
| (d) | Charges for System Operator services | Not applicable. |
| (e) | Transpower charges for transmission and NIA that have been avoided as a result of an acquisition of transmission assets | Applicable as a result of December 2014 acquisition by NTL of transmission assets from Transpower. |
| (f) | Distributed generation allowance | Applicable – Avoided Cost of Transmission (ACOT) payments. |
| (g) | Claw-back applied by the Commission. | Not applicable. |
| (h)-(l) | Relevant to CPP | Not applicable. |
| (m) | Energy efficiency and demand side management incentive allowance | Not applicable. |
| (n) | Catastrophic allowance | Not applicable. |
| (o) | Extended reserves allowance | Not applicable. |
| (p) | Quality incentive adjustment | Applicable – calculated in Assessment One (2015/16). |
| (q) | Capex wash-up adjustment | Applicable – source from Commerce Commission capex wash-up adjustment calculator |
| (r) | Transmission asset wash-up adjustment | Not relevant because transmission asset acquisition by NTL was completed prior to the commencement of the regulatory period. |
| (s) | 2013-15 NPV wash-up allowance | Not applicable – only relevant to Alpine, Centralines and Top Energy. |
| (t) | A reconsideration event allowance | Not applicable. |

# *Appendix 6: Pass-through and recoverable costs used to set prices*

Pass-through costs used to set prices are those contained in the Budget column of Table 3 below. Variation between actual and amount used to set prices is negligible for most of the pass-through costs, except the EA levy due to a budgeting error.

**Table 3: Pass-through costs used to set prices**

| Pass Through | Budget | Actual |
|---|---|---|
| Commerce Commission Levy | $72,000 | $68,704 |
| Electricity Authority | $105,018 | $122,796 |
| Electricity Gas Complaints Commission | $19,000 | $19,468 |
| Local Body Rates | $201,945 | $198,867 |
| | **$397,963** | **$409,834** |

Recoverable costs used to set prices are those contained in the Budget column of Table 4 below. There was no difference between the budget and actual recoverable costs, aside from the quality incentive adjustment. The budget for the quality incentive adjustment was set at $0 as it was unknown at the time that 2016/17 pricing was set.

**Table 4: Recoverable costs used to set prices**

| **Recoverable Costs $V_{2017}$** | | |
|---|---|---|
| | **Budget** | **Actual** |
| Transpower Transmission Charges for YE March 2017 | $13,267,974 | $13,267,974 |
| Avoided Transmission Charges (Embedded Generators) | $1,785,942 | $1,785,942 |
| Avoided Transmission Allowance (per Schedule 5E ) | $4,269,909 | $4,269,909 |
| Capex Wash-up Adjustment | ($256,285) | ($256,285) |
| Quality Incentive Adjustment | $0 | $5,961 |
| **Total Recoverable Costs** | **$19,067,541** | **$19,073,503** |

# *Appendix 7: Reliability data and assessment – 2016/17*

NTL purchased fixed assets from Transpower 2014, hence a recalculation of the quality measures are made as per Schedule 4B

Subsequent to the purchase of system fixed assets from Transpower, a Reference Dataset of interruptions during the reference period as per Schedule 4B 7a was used for recalculations.

| **Annual reliability assessment (Compliance test)** | | | |
|---|---|---|---|
| a. SAIDI. Assessed value =< SAIDI Limit | | **Initial** | **Recalculation** |
| | Assessed Value | 130.87 | 132.52 |
| | SAIDI Limit | 129.82 | 157.79 |
| | Test | 1.01 | 0.84 |
| b. SAIFI. Assessed value =< SAIFI Limit | | | |
| | Assessed Value | 1.192 | 1.248 |
| | SAIFI Limit | 1.422 | 1.676 |
| | Test | 0.838 | 0.744 |
| **1 Recalculation of Assessed values for test** | | | |
| **Recalculation of Boundary Values** | | **Initial** | **Recalculation** |
| SAIDI Unplanned Boundary Value | | 6.93 | 7.48 |
| SAIFI Unplanned Boundary Value | | 0.067 | 0.089 |
| *a boundary is the 23rd largest value in reference dataset* | | | |
| **$SAIDI_B$** | ∑daily $SAIDI_B$ values during assessment two | 70.03 | 70.03 |
| **$SAIDI_C$** | ∑daily $SAIDI_C$ values during assessment two(1) | 95.86 | 97.51 |
| **$SAIFI_B$** | ∑daily $SAIFI_B$ values during assessment two | 0.283 | 0.283 |
| **$SAIFI_C$** | ∑daily $SAIFI_C$ values during assessment two(1) | 1.050 | 1.106 |
| | Note 1. where any daily value > boundary value, use boundary value | | |
| | B = Planned, C = Unplanned | | |
| SAIDI Assessed Value | recalculation=$SAIDI_B$×0.5+$SAIDI_C$ | 130.874 | 132.523 |
| SAIFI Assessed Value | recalculation=$SAIFI_B$×0.5+$SAIFI_C$ | 1.192 | 1.248 |

## 2 Recalculation of Limits

Based on new reference dataset with aquired fixed asset outages included

| 2.1 Recalculate Targets. | | | | Initial | Recalculation |
|---|---|---|---|---|---|
| $Daily_{planned}$ | | | | | 623.82 |
| $Daily_{unplanned}$ | | | | | 969.01 |
| **SAIDITarget** | | | | **112.48** | **128.09** |
| $Daily_{planned}$ | | | | | 3.094 |
| $Daily_{unplanned}$ | | | | | 12.260 |
| **SAIFITarget** | | | | **1.230** | **1.381** |

*Daily planned/unplanned is sum of all values in Reference Dataset*
*Recalculated Targets are (DailyPlanned×0.5+DailyUnplanned)/10*

### 2.2 Recalculate Deviation per 4B

| | | | | | |
|---|---|---|---|---|---|
| SAIDIdeviation | | | | | 1.555 |
| SAIFIdeviation | | | | | 0.015 |

### 2.3 New limits

| | | | | | |
|---|---|---|---|---|---|
| SAIDI Limit | *Recalculation=(Target+(Sdeviation×√365)* | | | 129.82 | 157.79 |
| SAIFI Limit | *Recalculation=(Target+(Sdeviation×√365)* | | | 1.422 | 1.676 |

## 3 Recalculation for Quality Incentive Adjustment

*For information only in Assessment Two*

| | | | | | |
|---|---|---|---|---|---|
| SAIDI Collar | *Recalculation=(Target-(Sdeviation×√365)* | | | 95.14 | 98.39 |
| SAIFI Collar | *Recalculation=(Target-(Sdeviation×√365)* | | | 1.038 | 1.086 |
| SAIDI Cap | *= SAIDI Limit* | | | 129.82 | 157.79 |
| SAIFI Cap | *= SAIFI Limit* | | | 1.422 | 1.676 |

**a) Find $S_{SAIDI}$**

| | | | | |
|---|---|---|---|---|
| $SAIDI_{IR}$ | | | | 4,729 |
| SAIDItarget | | | | 128.092 |
| SAIDIassess | | | | 132.523 |
| **$S_{SAIDI}$= (SAIDIIR×(SAIDItarget-SAIDIassess)** | | | | **($20,955)** |

**b) Find $SAIDI_{IR}$**

| | | | | |
|---|---|---|---|---|
| SAIDIcap | | | | 157.792 |
| SAIDItarget | | | | 128.092 |
| REVrisk | 1% | 28,092,000 | | 280,920 |
| **$SAIDI_{IR}$=(0.5×$Rev_{Risk}$)/(SAIDIcap=SAIDItarget)** | | | | **$4,729** |

**c) Find $S_{SAIFI}$**

| | | | | |
|---|---|---|---|---|
| $SAIFI_{IR}$ | | | | 475,776 |
| SAIFItarget | | | | 1.381 |
| SAIFIassess | | | | 1.248 |
| **$S_{SAIFI}$= (SAIFIIR×(SAIFItarget-SAIFIassess)** | | | | **$63,270** |

| | | | Initial | Recalculation |
|---|---|---|---|---|
| **d) Find $SAIFI_{IR}$** | | | | |
| *SAIFIcap* | | | | 1.676 |
| *SAIFItarget* | | | | 1.381 |
| *REVrisk* | 1% | 28,092,000 | | 280,920 |
| **$SAIFI_{IR}=(0.5\times Rev_{Risk})/(SAIFIcap=SAIFItarget)$** | | | | **$475,776** |
| **e) Calculate incentive** | | | | |
| SSAIDI | | | | ($20,955) |
| SSAIFI | | | | $63,270 |
| **$S_{TOTAL}$ = SSAIDI + SSAIFI** | | | | **$42,315** |

Recalculated on 10yr reference dataset as per Schedule 4B

**Major Event Days**

| | |
|---|---|
| 14-Nov-2016 | Boundary exceeded for both SAIDI and SAIFI, due to effect of widespread earthquake |
| 22-Jan-2017 | Wind storm caused SAIDI to exceed boundary. Included damage to poles, insulators and bark on lines |
| 14-Oct-2016 | 33kV feeder tripped, cause unknown |

# *Appendix 8: Two previous annual reliability assessments*

The following annual reliability assessments for two previous assessment periods have been extracted from NTL's compliance statements.

## Annual Reliability Assessment 2015/16

The quality standards assessments for SAIDI and SAIFI below demonstrate that for the Assessment Period ended 31 March 2016, Network Tasman's:

- ***Assessed SAIDI value has not exceeded the SAIDI Limit***
- ***Assessed SAIFI value has not exceeded the SAIFI Limit***

when calculated in accordance with *Clause 9.1a of the DPP Determination 2015*.

**Figure 2: Quality standards compliance with clause 9.1a of the DPP Determination 2015**

**Test per 9.1a:**

SAIDI Assessed Value ≤ SAIDI Limit recalculated in accordance with Schedule 4B

| | |
|---|---|
| Assessed Value | 136.309 |
| SAIDI Limit | 157.792 |
| **SAIDI complies with assessment** | |

SAIFI Assessed Value ≤ SAIFI Limit recalculated in accordance with Schedule 4B

| | |
|---|---|
| Assessed Value | 1.287 |
| SAIFI Limit | 1.676 |
| **SAIFI complies with assessment** | |

## Annual Reliability Assessment 2014/15

The quality standards assessments for SAIDI and SAIFI below demonstrate that for the Assessment Period ended 31 March 2015, Network Tasman's:

- ***Assessed SAIDI value has not exceeded the SAIDI Limit***
- ***Assessed SAIFI value has not exceeded the SAIFI Limit***

when calculated in accordance with *Clause 9.2 of the Determination 2012*.

*Clause 9.2 Interruption Duration (SAIDI Classes B&C) Test 2014/15*

Test: $\frac{SAIDI_{Assessed\ 2015}}{SAIDI_{Limit}} \leq 1$

SAIDI $_{Assess\ 2015}$ 157.8

SAIDI $_{Limit}$ 162.5

Result: 0.9708 < 1

Result: SAIDI Limit has not been exceeded

*Clause 9.2 Interruption Frequency (SAIFI Classes B&C) Test 2014/15*

Test: $\frac{SAIFI_{Assessed\ 2015}}{SAIFI_{Limit}} \leq 1$

SAIFI $_{Assessed\ 2015}$ 1.40

SAIFI $_{Limit}$ 1.74

Result: 0.8021 < 1

Result: SAIFI Limit has not been exceeded

# *Appendix 9: Reliability Recording Policies and Procedures*

For the purposes of compiling annual SAIDI and SAIFI data:

1) A high voltage outage on the distribution network is defined as an event resulting in loss of supply to any number of consumers for a duration of more than one minute
2) Only those outages resulting in de-energisation of a high voltage feeder or conductor (6.6kV and above on NTL's network) are included in SAIDI & SAIFI statistics. Outages stemming from low voltage (400V) equipment are excluded.
3) Both planned (Class B) and unplanned (Class C) events are included within high voltage outage statistics
4) All high voltage outages are managed through Network Tasman's control room by a qualified NTL System Operator
5) The Faults and Maintenance Contract between NTL and its faults contractor, Delta, obligates both parties to manage all outage events centrally through the System Operator located in NTL's control room.
6) All HV fault switching operations are recorded by the System Operator in the Control Room Log at the time the activity takes place. This provides a detailed record of the switching events for future reference and record keeping.

Under fault conditions, customers affected by operation of a distribution system high voltage protection device can be divided into:

(a) Those within the core fault area (i.e. who won't have supply restored until the necessary line repairs are completed)
(b) Those outside the immediate fault area (i.e. who can have power restored through co-ordinated switching activity)

To calculate the customer minutes lost under each fault event, each event is approximated as a maximum two step restoration process. This is in keeping with the philosophy of fault restoration that relies on the following sequential process for supply restoration:

(a) Identification, isolation and minimisation of the core fault area.
(b) Restoration, through switching, of supply to areas not immediately within the core fault area
(c) Making repairs and restoration of the core fault area.

The switching and recording process is managed by a NTL System Operator using NTL's Geographical Information System (GIS). To record outage data the operator draws geographical selection polygons around all sections of the high voltage line affected by the fault event. The software is then used to select and identify all the distribution transformers within the fault area. A query is then made into NTL's customer connection database to find and list all customers (ICPs) connected to those transformers affected by the fault event.

This data is then used in the following formula to calculate the total customer minutes for a fault event:

Total No. of customers initially affected **x** (Time Unfaulted Area restored – Time of Initial Interruption)
+
No. of Fault area customers **x** (Time Fault Area restored – Time Unfaulted Area restored)

Planned and unplanned events rely on essentially the same recording process however by nature, planned interruptions can be identified down to a predetermined set of consumers within a known area in advance.
The total customer minutes for a planned interruption are thus calculated using the following formula:

> Total No. of customers interrupted **x** (Time Interrupted Area restored – Time of Initial Interruption)

The system operator records details of all outage events in the NTL Outage Database. This is an access database that remains on line in the control room. Each planned or unplanned event forms a one record entry into the database. The Outages Database is subject to NTL's normal electronic file backup and security protocols.

The Outage Database records the following data fields for each event:

- Date
- ID number of the protective device that has operated (allows identification of the HV feeder and area affected)
- Area: (Text description of area affected)
- Description; (Text description of fault cause and type – recorded once known)
- Outage type (Planned Shutdown or Fault)
- Area Class (Urban or Rural)
- Fault Class (Overhead or Underground)
- Fault Voltage (6.6kV, 11kV, 33kV, 66kV)
- Outage Region (Stoke, Motueka, Golden Bay, Kikiwa, Murchison)
- Time of Initial Interruption
- Time Unfaulted Area Restored
- Time Fault area restored
- Customers (ICPs) in Total Area ( recorded post event)
- Customers (ICPs) in Fault area (recorded post event)

Unless otherwise stated all data is recorded on line by the NTL System Operator at the time of the event.

The outage database supports the following NTL activities:

1) Queries on an as needed basis by NTL's Network and Operations Managers
2) Summary outage statistics are prepared and provided to NTL's CEO and Board of Directors on a monthly basis and are compared against expected values.
3) Annual outage statistics are prepared and independently audited for regulatory and financial reporting purposes.
4) Summary statistics are recorded on a cumulative basis and are used for comparative analysis and form a key input into NTL's annual Asset Management Planning process.
5) Annual data is also reported against reliability targets in NTL's SCI, Information Disclosure Statements and Annual Financial Statements.
6) The SCI targets are negotiated and agreed annually with the Network Tasman Trust.

# Independent Assurance Report

## To the directors of Network Tasman Limited and the Commerce Commission

The Auditor-General is the auditor of Network Tasman Limited (the company). The Auditor-General has appointed me, Ian Lothian, using the staff and resources of Audit New Zealand, to provide an opinion, on his behalf, on whether the Annual Compliance Statement for the year ended on 31 March 2017 on pages 2 to 24 has been prepared, in all material respects, with the Electricity Distribution Services Default Price-Quality Path Determination 2015 (the Determination).

## Directors' responsibilities for the Annual Compliance Statement

The directors of the company are responsible for the preparation of the Annual Compliance Statement in accordance with the Determination, and for such internal control as the directors determine is necessary to enable the preparation of an Annual Compliance Statement that is free from material misstatement.

## Our responsibility for the Annual Compliance Statement

Our responsibility is to express an opinion on whether the Annual Compliance Statement has been prepared, in all material respects, in accordance with the Determination.

## Basis of opinion

We conducted our engagement in accordance with the International Standard on Assurance Engagements (New Zealand) 3000 (Revised): Assurance Engagements Other Than Audits or Reviews of Historical Financial Information and the Standard on Assurance Engagements 3100: Compliance Engagements issued by the External Reporting Board. Copies of these standards are available on the External Reporting Board's website.

These standards require that we comply with ethical requirements and plan and perform our assurance engagement to provide reasonable assurance about whether the Annual Compliance Statement has been prepared in all material respects in accordance with the Determination.

We have performed procedures to obtain evidence about the amounts and disclosures in the Annual Compliance Statement. The procedures selected depend on our judgement, including the assessment of the risks of material misstatement of the Annual Compliance Statement, whether due to fraud or error or non-compliance with the Determination. In making those risk assessments, we considered internal control relevant to the company's preparation of the Annual Compliance Statement in order to design procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the company's internal control.

In assessing the disclosures about compliance with the price path in clause 8 of the Determination for the assessment period ended on 31 March 2017, our assurance

engagement included examination, on a test basis, of evidence relevant to the amounts and disclosures contained on pages 2 to 17 of the Annual Compliance Statement.

In assessing the disclosures about compliance with the quality standards in clause 9 of the Determination for the assessment period ended on 31 March 2017, our assurance engagement included examination, on a test basis, of evidence relevant to the amounts and disclosures contained on pages 3 to 6, and 18 to 24 of the Annual Compliance Statement.

Our assurance engagement also included assessment of the significant estimates and judgements, if any, made by the company in the preparation of the Annual Compliance Statement.

We believe that the evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

## Use of this report

This independent assurance report has been prepared solely for the directors of the company and for the Commerce Commission for the purpose of providing those parties with reasonable assurance about whether the Annual Compliance Statement has been prepared, in all material respects, in accordance with the Determination. We disclaim any assumption of responsibility for any reliance on this report to any person other than the directors of the company or the Commerce Commission, or for any other purpose than that for which it was prepared.

## Scope and inherent limitations

Because of the inherent limitations of a reasonable assurance engagement, and the test basis of the procedures performed, it is possible that fraud, error or non-compliance may occur and not be detected.

We did not examine every transaction, adjustment or event underlying the Annual Compliance Statement nor do we guarantee complete accuracy of the Annual Compliance Statement. Also we did not evaluate the security and controls over the electronic publication of the Annual Compliance Statement.

The opinion expressed in this independent assurance report has been formed on the above basis.

## Independence and quality control

When carrying out the engagement, we complied with the Auditor-General's:

- independence and other ethical requirements, which incorporate the independence and ethical requirements of Professional and Ethical Standard 1 (Revised) issued by the New Zealand Auditing and Assurance Standards Board; and

- quality control requirements, which incorporate the quality control requirements of Professional and Ethical Standard 3 (Amended) issued by the New Zealand Auditing and Assurance Standards Board.

We also complied with the independent auditor requirements specified in the Determination.

The Auditor-General, and his employees, and Audit New Zealand and its employees may deal with the company and its subsidiaries on normal terms within the ordinary course of

trading activities of the company. Other than any dealings on normal terms within the ordinary course of business, this engagement, the information disclosure regulation reports and the annual audit of the company's financial statements, we have no relationship with or interests in the company and its subsidiaries.

## Opinion

In our opinion:

- as far as appears from an examination, the information used in the preparation of the Annual Compliance Statement has been properly extracted from the company's accounting and other records, and has been sourced, where appropriate, from its financial and non-financial systems; and

- the Annual Compliance Statement of company for the year ended on 31 March 2017, has been prepared, in all material respects, in accordance with the Determination.

In forming our opinion, we have obtained sufficient recorded evidence and all the information and explanations we have required.

Ian Lothian
Audit New Zealand
On behalf of the Auditor-General
Christchurch, New Zealand
1 June 2017