Retail Price Consistency Assessment (RPCA) Report

For the period starting 1 July 2026

1 EXECUTIVE SUMMARY

1.1 Clause 13.236W of the Code requires Meridian Energy Limited to provide an RPCA report in the form specified by the Electricity Authority. This document is the report explaining Meridian Energy Limited's RPCA methodology and results, as required by the Authority's specified form. This report should be read in conjunction with the four .csv files containing the relevant data.

1.2 The aggregate nation-wide margin across Meridian Energy Limited is positive, indicating that an 'as efficient' retailer with a similar hedging strategy can profitably operate and compete in the New Zealand retail electricity market.

1.3 Margins are calculated by comparing forecast revenues against forecast costs for the reporting period. Notional wholesale electricity costs for all regions, brands, and segments are built up as a portfolio of historical ASX baseload contracts, super peak contracts, and bilateral contracts actually purchased by Meridian Energy Limited for the reporting period to best fit the relevant load shapes.

1.4 The chosen methodology is objectively justifiable, clearly linked to observed market prices, could be achieved in practice by any retailer, and is easily repeatable for consistency through time, reducing compliance costs.

1.5 Lower notional wholesale electricity costs than those used in this RPCA would be achievable in practice by any retailer willing to take a more active and nuanced approach to contracting, for example by:

(a) using current ASX futures prices for the new customer segment;

(b) transacting bilateral contracts other than those transacted by Meridian Energy Limited; or

(c) adopting a purchase strategy that buys more contract volume when prices are lower (rather than always purchasing volumes equally).

1.6 Consistent with the Authority's RPCA Guidance, all prices and costs presented in this report exclude GST.

1.7 This RPCA covers all domestic customers and any business customers with annual consumption of 40 MWh or less. Export of distributed generation (such as rooftop solar), including both payments to customers and revenue received from the market, has been excluded from the RPCA assessment. This was due to export credits and volumes distorting the relationship between retail prices and underlying costs.

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3 RPCA MARGINS

Nation-wide margins

3.1 The table below sets out nation-wide margin results by brand (Meridian and Powershop) and customer segment (existing and new).

Brand	Segment	Margin $/MWh
MERI	Existing	$4.14
MERI	New	$14.06
PSNZ	Existing	-$2.63
PSNZ	New	$5.13
Total (Weighted)		**$2.72**

3.2 The nation-wide total weighted average margin for Meridian Energy Limited is $2.72/MWh. Margins are larger for the Meridian brand and the Powershop new segment. The only negative margin is for the Powershop brand in the existing segment, which includes legacy fixed-rate plans entered into at historical prices. The positive margin of the Powershop new segment demonstrates that an 'as efficient' retailer with a similar hedging strategy is able to profitably operate in the New Zealand retail electricity market and compete for new customers.

3.3 Lower ASX futures prices are expected to increasingly feature in the 'as if' portfolio of notional contracts that approximates an electricity cost for the purposes of this assessment. Therefore, future RPCA reports are expected to show higher margins under the chosen methodology. It would not be consumer welfare enhancing to raise retail prices now to deliver positive nation-wide margins for the Powershop existing segment under this assessment only to soon lower those retail prices again. Therefore, Meridian Energy Limited considers the negative margin reported for that brand and segment to be objectively justifiable.

Network reporting region margins

3.4 Margin results by network reporting region, brand, and segment are set out in the chart below.

[redacted]

3.5 There are several network reporting regions in which the margin for at least one brand or segment is negative.

3.6 Reasons include:

(a) The methodology to calculate the notional electricity cost includes large, lower-cost, long-term OTC contracts where Meridian is the buyer. Because of Meridian's physical generation in the South Island, it is generally only a buyer in the North Island. The methodology allocates those OTC contracts to North Island customers lowering the notional electricity cost component for those customers. This methodology was chosen because it is easily repeatable, can be automated, and is based on market prices that Meridian can easily validate. However, it does mean notional electricity costs for South Island network reporting regions on average are higher and South Island margins therefore appear lower.

(b) The existing customer segment contains a mix of legacy and current rates. Legacy fixed energy plans and fixed rate plans generally have lower margins due to energy and network cost components varying from the actual cost increases observed over the tenure of the fixed rate plan. These lower margins reflect contractual commitments made at historical prices and do not represent current pricing decisions. The prevalence of legacy fixed energy plans and fixed rate plans in each network reporting region accounts for much of the variability in brand margins, for example see Central Otago.

(c) Retail Costs per MWh are impacted by customer type and load. Where volumes per consumer differ greatly, the per MWh cost to serve will be significantly different. Network reporting regions with more high-volume customers (e.g. agricultural regions) generally have lower cost to serve.

(d) Retail Costs per MWh for New customers include an allocation of anticipated acquisition credits paid to customers and likely offer uptake. The cost of such credits is allocated to the forecast month of acquisition for Meridian (reflecting payment of acquisition credits at customer sign-up) and across 12 months for Powershop (reflecting monthly allocation of acquisition credits for the first 12 months) rather than spread over the expected tenure of the new customers, the effect being lower margins for new segments than would otherwise be the case.

4 RETAIL PRICE COMPONENT

Nation-wide retail price

4.1 Nation-wide retail prices for each brand and segment are set out in the table below.

Brand	Segment	Price $/MWh
MERI	Existing	$352.59
MERI	New	$372.31
PSNZ	Existing	$353.79
PSNZ	New	$375.87
Total (Weighted)		**$355.98**

4.2 Prices for each network reporting region, brand, and segment are calculated by taking total expected mass market revenue, less any discounts, and less any rural sales partner commissions in accordance with the relevant contractual arrangements over the reporting period. Revenue is then divided by expected MWh of consumption for the same network reporting region, brand, and segment over the same period.

4.3 Nation-wide prices are a volume weighted average of network reporting region values to nation-wide values

Calculation of retail price components

4.4 Forecast revenues and volumes are based on information available on the 1 July 2026 assessment date. Forecast revenues and volumes assume:

(a) Existing customer forecasts are based on historical consumption patterns and current pricing plans.

(b) New customers, and customers rolling off existing contracts are assumed to adopt the prevailing market rates aligned with the customer type.

(c) Customer growth assumptions are based on ICP growth targets in business plan at the assessment date.

(d) Customer gains are treated as customers in the new segment, while customer losses are offset against the customer numbers in the existing customer segment.

(e) Other retail revenue streams, including field services, credit card fees and paper bill fees, are included.

(f) For the purposes of the current RPCA, the energy component of prices (excluding the network component) for customers on variable rates is assumed to [redacted] That assumption will be reassessed for future RPCAs depending on decisions as to any actual price changes which will be made closer to 1 April 2027. Note that:

(i) Customers on fixed-rate or fixed-energy plans do not receive changes in the energy component of prices until their plan ends.

(ii) When a customer's fixed-rate or fixed-energy plan ends, the customer is assumed to roll onto the prevailing applicable pricing plan.

5 NON-ELECTRICITY COST COMPONENTS

Retail costs

5.1 Nation-wide retail costs for each brand and segment are set out in the table below.

Brand	Segment	Retail costs $/MWh
MERI	Existing	$20.04
MERI	New	$33.13
PSNZ	Existing	$27.72
PSNZ	New	$36.91
Total (Weighted)		**$24.64**

5.2 Retail costs are based on current approved budgets and include all fully allocated retail operating costs from Meridian Energy Limited financial data.

5.3 Retail costs also include the cost of bad debt based on historical write-off experience.

5.4 Costs are allocated to brands (MERI, PSNZ) and marketing segments (RES, SME, AGRI, CLB) on a per ICP or per MWh basis depending on the cost type. Costs are then allocated at a per ICP level. This is done across all ICPs, the RPCA mass market consumers represent a subset of this total.

Retail shared and common costs

5.5 Nation-wide shared and common costs for each brand and segment are set out in the table below.

Brand	Segment	Shared costs $/MWh
MERI	Existing	$5.24
MERI	New	$5.29
PSNZ	Existing	$6.42
PSNZ	New	$6.32
Total (Weighted)		**$5.70**

5.6 Shared and common costs are unallocated operating expenses that are allocated to revenue-generating business units based on each business unit's proportion of the forecast total operating costs and stay-in-business cost of capital.

5.7 Shared and common costs are allocated to brands (MERI, PSNZ) and marketing segments (RES, SME, AGRI, CLB) on a per ICP basis. Costs are then allocated at a per ICP level. This is done across all ICPs, the RPCA mass market consumers represent a subset of this total.

5.8 The shared and common costs allocated to mass market customers under the RPCA are included in the retail costs above.

Metering costs

5.9 Nation-wide metering costs for each brand and segment are set out in the table below.

Brand	Segment	Metering costs $/MWh
MERI	Existing	$12.38
MERI	New	$12.57
PSNZ	Existing	$13.07
PSNZ	New	$13.83
Total (Weighted)		**$12.72**

5.10 National metering costs are based on actual per ICP metering costs from MEPs, with allowances for annual CPI adjustments.

5.11 Metering costs are allocated to each network reporting region, brand, and segment based on number of ICPs.

Network costs

5.12 Nation-wide network costs for each brand and segment are set out in the table below.

Brand	Segment	Network costs $/MWh
MERI	Existing	$153.67
MERI	New	$156.57
PSNZ	Existing	$147.74
PSNZ	New	$160.77
Total (Weighted)		**$152.41**

5.13 Network costs (including lines rental rebates and ancillary costs) are calculated at an ICP level based on the actual network pricing methodology disclosed by the relevant network companies.

5.14 The individual network cost components are aggregated by each network reporting region, brand, and segment to provide the overall volume weighted network costs per MWh.

5.15 Network prices are assumed to increase on 1 April each year. An 8% increase has been assumed across all networks except Orion (12%) and Electricity Ashburton (9%) where more specific price change forecasts are available from those networks. Customers on fixed-rate plans do not incur network price increases until their plan expires.

5.16 Network costs include lines rental rebate revenue and ancillary network charges (frequency keeping costs allocated to wholesale purchasers).

Levies

5.17 Nation-wide levy costs for each brand and segment are set out in the table below.

Brand	Segment	Levy costs $/MWh
MERI	Existing	$1.80
MERI	New	$1.81
PSNZ	Existing	$1.84
PSNZ	New	$1.85
Total (Weighted)		**$1.82**

5.18 Levy costs are calculated at an ICP level, based on the rates published by the Electricity Authority. These costs are then aggregated for each network reporting region, segment, and brand.

6 EXPECTED ELECTRICITY COST COMPONENT

Nation-wide electricity costs

6.1 Nation-wide notional expected electricity costs for each brand and segment are set out in the table below.

Brand	Segment	Electricity costs $/MWh
MERI	Existing	$160.56
MERI	New	$154.17
PSNZ	Existing	$166.04
PSNZ	New	$157.38
Total (Weighted)		**$161.67**

6.2 The nation-wide notional expected electricity costs are the load weighted average of the network reporting region notional electricity costs.

Calculation of load profile

6.3 Load profiles are based on the latest half hour profile shapes from the reconciliation manager (i.e. sales volumes), which are used to create a forecast half hourly shape for each GXP, network reporting region, brand and segment as well as the business day and non-business day profiles.

Methodology for 'as if' hedging

6.4 For each network reporting region, brand, and segment, standard ASX baseload and super peak contracts are notionally purchased to best cover the retail load shape required.

6.5 These contracts are notionally purchased for each segment by calculating the expected number of times a product will be available for Meridian to buy, then notionally buying an equal quantity every time the market is made (e.g. incremental ASX baseload purchases for the three years of market making sessions ahead of the first RPCA period). Notional purchase prices are the ASX settlement prices for each session, and for super peak, if a trade occurred, the last trade for the session (115 products), or if there is a valid bid and offer (255 products), the average of the last of each, otherwise the last bid or offer (0 products).

6.6 For products that are expected to be available to purchase in the future, the remaining target volume is notionally purchased at Meridian's best estimate of the future price, which is usually the latest price, but if there is not yet a price – for example 2027 months April to June then a ratio between the quarterly price which does exist, and the months is used.

6.7 The methodology also includes in the "as if" portfolio eleven large long-term contracts that Meridian itself has purchased for the relevant reporting period (for example the PPA that Meridian executed with Harmony Energy / First Renewables for the Tauhei solar farm). These contracts were included because:

(a) they were at the time of purchase expected to be lower cost than standard products;

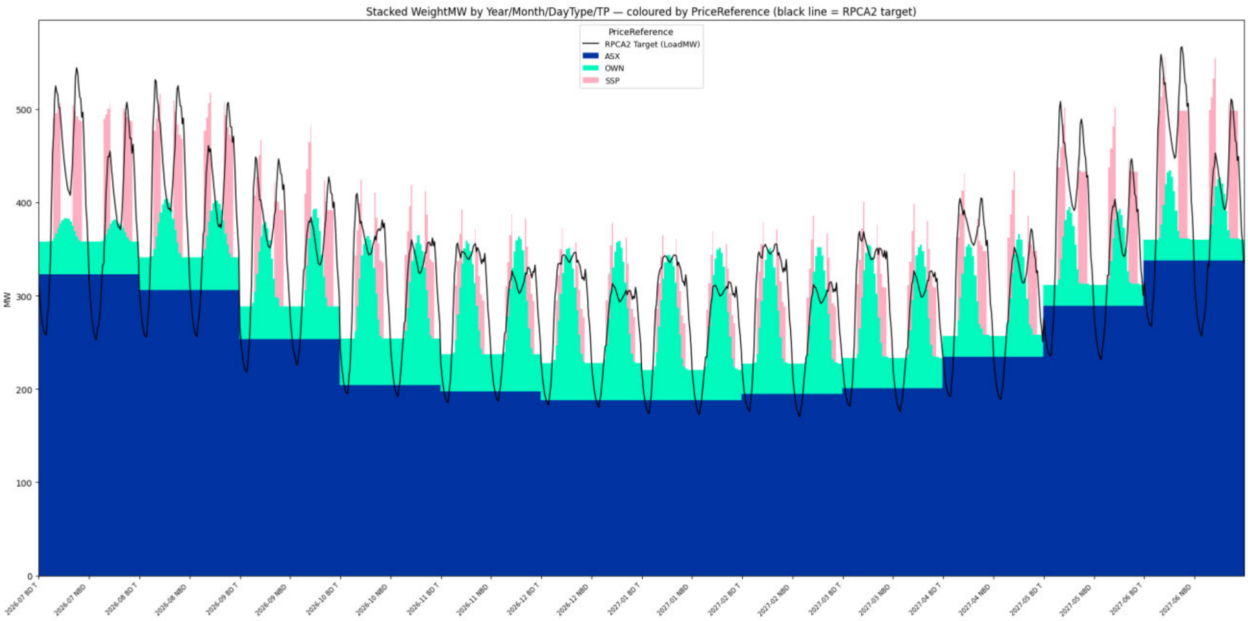
(b) similar contracts can equally be purchased by any retailer;

(c) the market prices of the contracts can be easily validated using Meridian’s own data since it is the purchaser of these contracts for its own portfolio in reality; and

(d) the methodology is easily repeatable for future RPCAs.

6.8 The quantity of ASX baseload and super peak contracts that are notionally purchased is adjusted around these larger contracts. The methodology ensures the notional purchases of the standard products assume only the information that Meridian had available to it at the time of each notional purchase.

6.9 Because the relevant load shapes are not perfectly covered by the eleven large contracts, plus ASX baseload and super peak contracts, there are some overs and unders in the purchased contracts. The Ordinary Least Squares method is used to find the best fit of the available contracts to the load shape. The methodology also prescribes that the volume of over and under purchases of contracts will net out over the reporting period. This is presented in the chart below showing the average business day then the average non-business day for each month. The volumes in over-hedged periods (bars above the black line) balance the volumes in under-hedged periods (bars below the black line) once the relative count of business and non-business days per month is accounted for.



6.10 The resulting ‘as if’ contract portfolio is one that any retailer could have acquired in practice to best fit the relevant load shapes.

Pricing of unhedged load

6.11 Because the methodology delivers the best contract fit and nets out the volume of over and under purchases, no assumptions are made regarding pricing of unhedged load.

Location adjustment

6.12 All standard contracts are notionally purchased at the OTA and BEN nodes for North Island and South Island customers respectively. The large contracts actually purchased by Meridian and used in the ‘as if’ portfolio use the actual node of each contract.

6.13 Nodal adjustments are applied to calculate the notional electricity cost for each network reporting region. Nodal adjustments are modelled on the estimated average nodal price difference between each grid node and the relevant island reference node for the reporting period based on historically observed differences. Grid nodes are then aggregated to network reporting region using a load weighted average. The nodal adjustment cost is added to the notional electricity cost.

6.14 To account for losses between the grid node and ICP the total purchase cost for each grid node is inflated to reflect local losses based on network pricing code. The notional electricity cost is scaled up by total purchases divided by total sales.

7 APPENDICIES

Commercial toolkit used for the RPCA

7.1 Meridian Energy Limited's retail forecasting and analytics toolkit has been used as a key input into the RPCA analysis.

7.2 The toolkit is a mature, proven and business-critical platform that underpins customer profitability analysis, load forecasting, financial planning and commercial decision-making across the retail business. It provides a consistent and trusted view of future customer volumes, revenues, costs and margins at an individual ICP level, enabling informed decision making by the Retail, Strategy and Portfolio, and Finance business units.

7.3 The toolkit combines data from core operational systems, market settlements, network tariffs, metering services, registry information and customer movements to create detailed forecasts of customer consumption, revenue, and cost outcomes.

7.4 A key strength of the platform is its highly granular ICP-level modelling capability. By forecasting profitability at the lowest practical level and then aggregating results across customers, segments, products and networks, it provides a robust and transparent forecast view for Meridian Energy Limited. This enables detailed performance analysis, pricing decisions, margin management and targeted commercial activity.

7.5 In addition to forecasting future performance, the platform provides a comprehensive view of retail profit and loss, incorporating revenues, network charges, metering costs, bad debt, operating costs and margin outcomes. These outputs support financial reporting, business planning and performance monitoring across the organisation.

7.6 The toolkit provides a forecast view based on available information and a range of underlying assumptions. It is not a guarantee of actual performance. As a forward-looking model, actual customer volumes, revenues, costs and margins may differ from forecast outcomes due a range of factors that are uncertain by nature.

Guide to comments in the RPCA electricity cost file (RPCA3)

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