# 2025 Interim Results Presentation

Meridian.

# Neal Barclay – Chief Executive

Meridian’s West Wind Farm near Wellington

# Key points

| WINTER INFLOWS | CUSTOMERS | RUAKĀKĀ BESS | RUAKĀKĀ SOLAR & MT MUNRO WIND |
|---|---|---|---|
| 1 IN 90 YEAR LOW WINTER INFLOWS | +4% CUSTOMERS SINCE JUNE | COMMISSIONING COMMENCED AT RUAKĀKĀ BESS | FINAL CONSENTS FOR RUAKĀKĀ SOLAR AND MT MUNRO WIND |
| **HEDGES** | **RETAIL** | **JOINT VENTURE** | **SIGNED** |
| $200M OF HEDGE COVER COSTS | +5% RETAIL REVENUE V 1H FY24 | WITH NOVA FOR 400MW TE RAHUI SOLAR FARM | SIA WITH NZ WINDFARMS, PPA FOR 150MW TAUHEI SOLAR FARM OFFTAKE |
| **EBITDAF [1]** | **DIVIDEND** | **NZ HOUSEHOLDS** | **REPLACEMENT** |
| -$186M -42% EBITDAF V 1H FY24 | 6.15cps flat INTERIM DIVIDEND | NEW RETAIL PROPOSITIONS NOW AVAILABLE TO HALF OF NZ HOUSEHOLDS | TRANSFORMERS AT MANAPŌURI AND WEST WIND |

[1]Earnings before interest, tax, depreciation, amortisation, unrealised changes in fair value of hedges and asset related adjustments.

# Changing fuel mix

$10B of new generation investment in the last 15 years by generators.

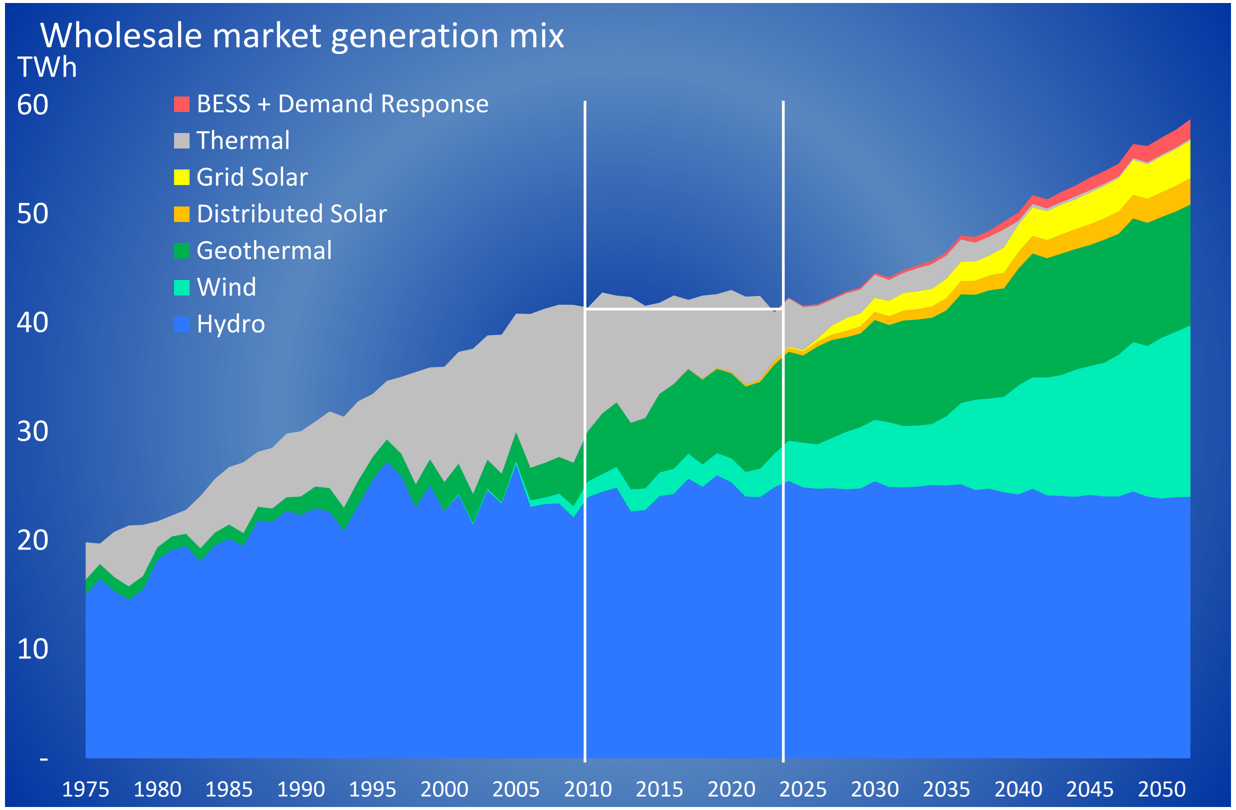
Through a period of flat electricity demand and uncertainty on the future of NZAS.

Geothermal, wind and some solar has met thermal capacity retirement.

Resulting in a more renewable electricity system, but one still dependent on thermal fuel storage to firm hydro drought.

That electricity system managed the record 2024 winter drought, despite a lack of available gas for generation.

And is now solving that structural issue of gas unavailability.

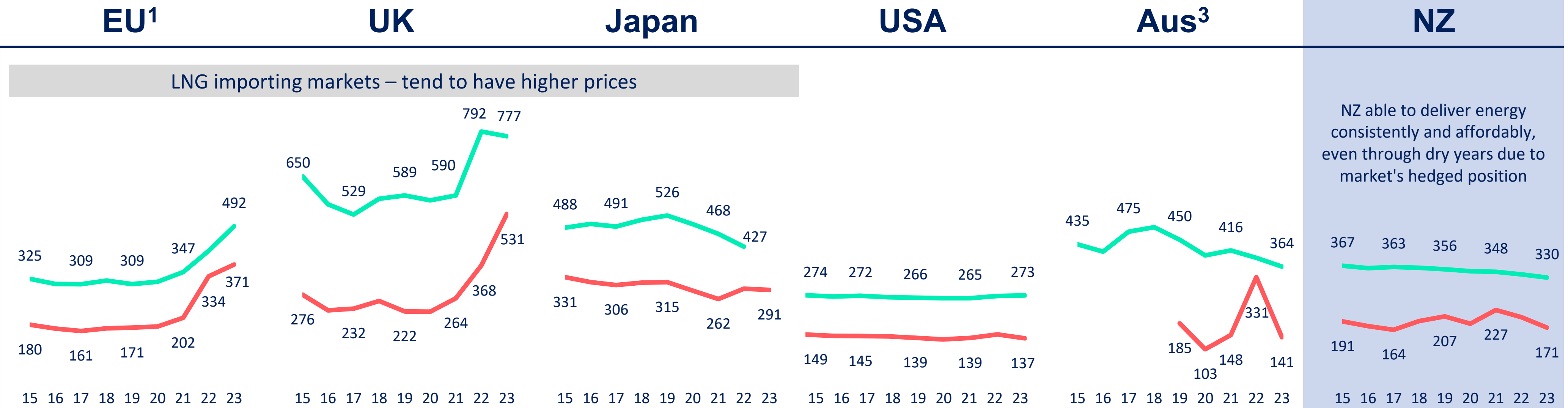



Source: Meridian

# A world class electricity system in NZ

**Affordability**

Real Ave. Electricity Price 2023 $NZ/MWh[2]




| | EU[1] | UK | Japan | USA | Aus[3] | NZ |
|---|---|---|---|---|---|---|
| **Security** | • Recent energy conservation, high LNG import dependency<br>• Nuclear decommissioning | • Declining gas reserves, LNG used to balance<br>• Aging infrastructure | • High LNG import dependence<br>• Nuclear decommissioning | • Aging energy infrastructure | • Gas supply shortage, drove 2021 domestic reservation policy | • Susceptible to 'Dry years' |
| WEC Security Score | 70.3 | 67.7 | 61.1 | 72.7 | 66.6 | 68.2 |
| **Sustainability** % Zero carbon electricity | ~40% | ~60% | ~30% | ~40% | ~35% | ~90% |
| **WEC rank[4]** | Fr=6 Ger=7 Ita=25 | 8 | 23 | 10 | 22 | 9 |

1. EU prices, reflect Generation Weighted Average Prices for combined Italy, Germany and France energy profiles
2. Nominal Enerdata prices adjusted to Real 2023 NZ$ using Reserve Bank of New Zealand inflation figures
3. Australian Industrial prices reflect wholesale prices + 45% transport premium
4. World Energy Council

Source: BCG, Meridian

Data sources: MBIE Quarterly Nominal Fuel Prices; CMEMWA - Energy Trilemma Report 2024, Enerdata Household and Industrial Electricity Prices, Reserve Bank of New Zealand, Ember National Energy Mix

# Fuel scarcity

Meridian experienced 1 in 90 year, record low May to mid-August inflows.

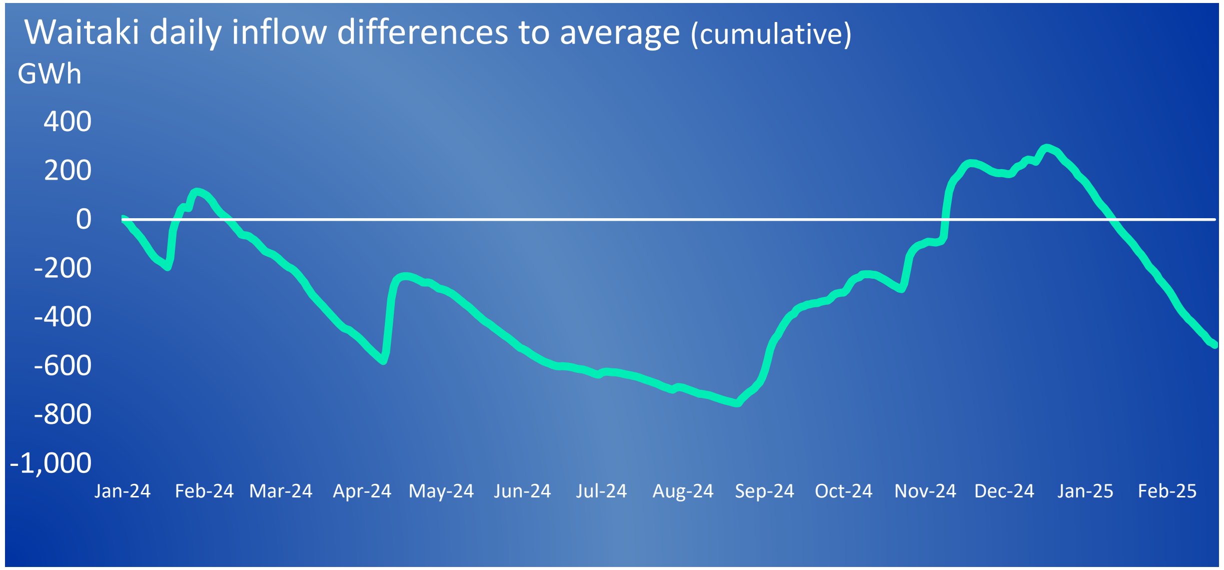
That was preceded by calm and dry conditions, and meant cumulative inflows were below average for much of 2024.

Largest NZAS Demand Response option was called.

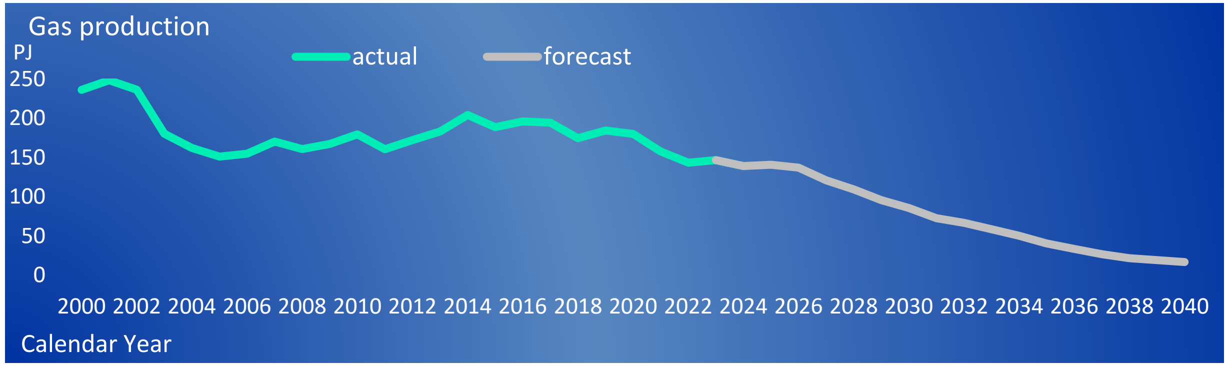
Lack of available gas for electricity generation saw existing hedge cover fail.

Large industrial gas demand reduction in the short term then followed.

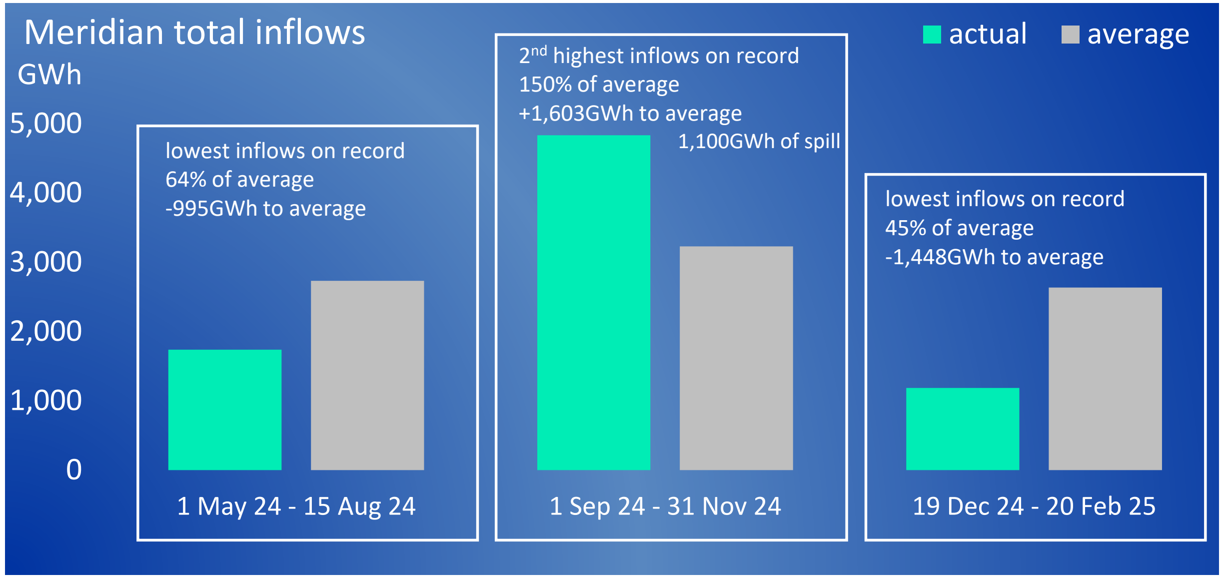
Including demand response, Meridian acquired 800GWh of hedges ($258/MWh average cost) to manage fuel scarcity.




Source: Meridian




Source: Ministry of Business, Innovation and Employment, Hīkina Whakatutuki




Source: Meridian

# Contingent storage

Contingent storage is fuel that physically exists in the system today.

It is intended to be available for generation at specific times to mitigate high risk of drought.

In November 2024, Meridian again requested amendments be made to make access to contingent storage practically available.

The existing buffer applied in calculating contingent storage release does not reflect actual risk of serious energy shortage.

The buffer was temporarily amended during September and October 2024 because of this inconsistency.

Meridian's request is to make this amendment permanent now, so the market can be confident contingent storage will be available when needed.

| Contingent storage | | |
|---|---|---|
| **Lake Tekapo** | **Lake Pūkaki** | **Lake Hawea** |
|  |  |  |
| 220GWh of additional storage available between October and March if storage falls below Contingent Storage Release Boundary.<br>Between April and November, the 220GWh is controlled storage. | 545GWh of additional hydro storage available;<br>▪ 331GWh if storage falls below Contingent Storage Release Boundary.<br>▪ 214GWh if the System Operator declares an Official Conservation Campaign. | 67GWh of additional storage if storage falls below Contingent Storage Release Boundary. |

Source: Transpower

# Regulatory focus – 2024 fuel scarcity

Government's focus is on initiatives many of which are already underway or part of existing policy programme.

Task Force programme is largely derived from the Electricity Authority's existing work programme.

Timeframes for the Task Force's programme are condensed. Consultation papers are expected in early 2025, with possible code changes from mid 2025.

Aside from contingent storage, little will immediately address the lack of, or reliability of available fuel in a significant drought.

The fundamental issue is how the electricity sector further responds to gas supply decline and low confidence in the future of gas industry.

A Government Policy Statement on electricity was released in October 2024.

Closely followed by terms of reference for the ministerial review of the electricity sector.

| Government focus | |
|---|---|
| **Action to bolster energy security** | **Next steps on Electrifying NZ** |
| Reverse the ban on offshore oil and gas exploration | Establishing a one stop shop fast track approvals and permitting regime |
| Remove regulatory barriers to the construction of facilities to import LNG as a stop gap | Amendments to the RMA to speed up resource consenting |
| Ease restrictions on electricity lines companies owning generation | Stronger national direction for renewable energy |
| Ensure access for gentailers to hydro contingency | A new regime for offshore wind |
| Improve electricity market regulation (via a sector review) | Updated regulatory settings for electricity networks and new connections |

| Energy Competition Task Force work programme | |
|---|---|
| **Package 1** | **Package 2** |
| Consider requiring gentailers to offer firming for PPAs | Requiring distributors to pay a rebate when consumers export electricity at peak times |
| Introduce standardised flexibility products | Require all retailers to offer time-of-use pricing |
| Look at benefits of virtual disaggregation | Require retailers to better reward consumers for supplying power |
| Investigate level playing field measures as a regulatory backstop | Reward industrial consumers for providing short-term demand flexibility |

# Transmission and distribution costs

Final Commerce Commission decision in November 2024 on regulated revenues for Transpower and distribution companies for the next 5 years.

Regulated revenue increases are significant, more than 40% above the current regulatory period.

Much of the increase is attributable to inflation and higher regulated cost of capital.

Remainder of the increase is attributable to increased network investment.

The Commission has applied smoothing to reduce the step change in costs to customers on 1 April 2025.

Cost increases are significant, with the Commission estimating increases of $120 to $300 for households in the next year (5% on average).

Transmission lines near New Zealand's Aluminium Smelter in Southland

# Transformer replacement

New transformer from existing supplier installed at Manapōuri.

Unit 6 returned to service in December 2024, with the first of seven new control and protection systems as part of the station’s Automation Upgrade Project.

Unit 4 remains out of service until the first of two new transformers are delivered in late 2025, from a new supplier.

Leased transformer installed at West Wind in October 2024, returning the farm to full capacity.

New West Wind transformer installed by late 2025.

Transportation of a transformer across Lake Manapōuri

And up the West Wind Farm access road

# Construction and development

First grid injection at Ruakākā Battery Energy Storage System, April 2025 operational date.

Ruakākā Solar consent finalised, final investment decision (FID) expected in March 2025.

Environment Court consent granted for Mt Munro Wind Farm.

JV with Nova for stage 1 of Te Rahui Solar Farm (200MW of 400MW), 50-50 offtake, FID expected in April 2025.

Te Rere Hau Wind Farm FID expected in June 2025.

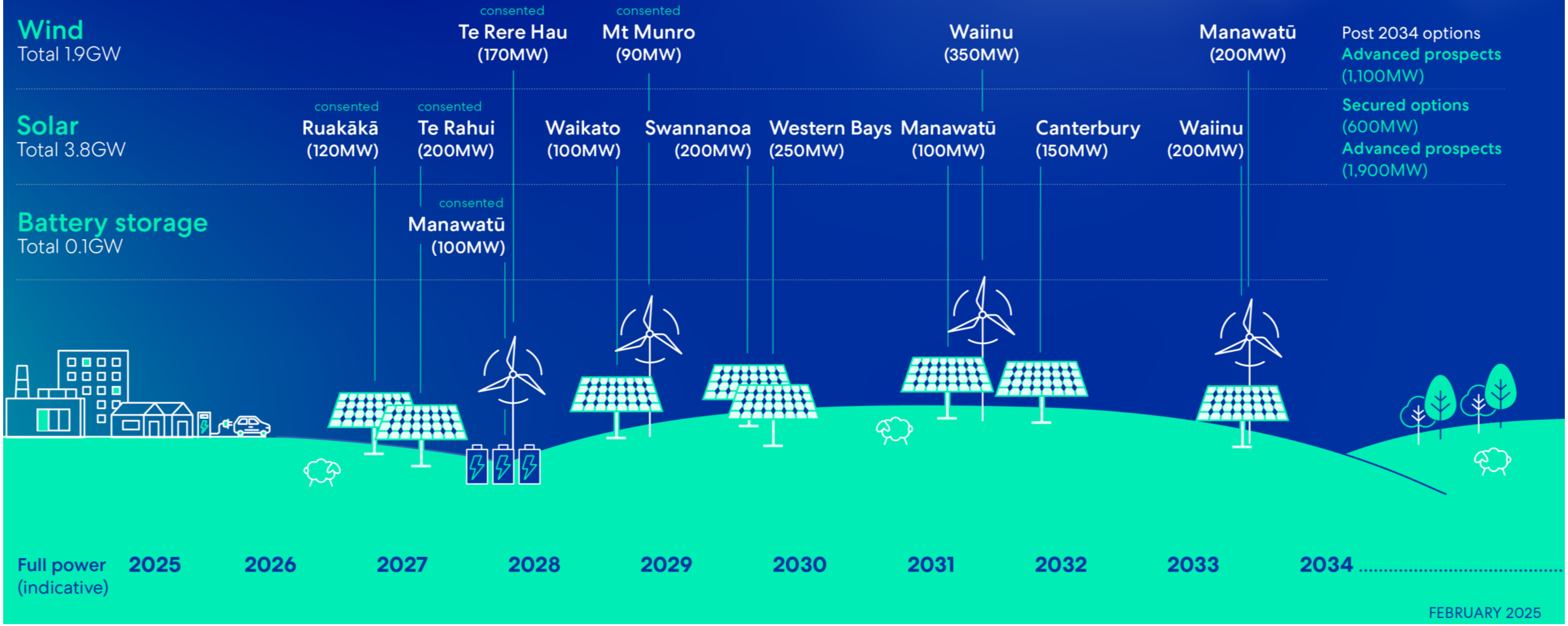
Scheme Implementation Agreement (SIA) signed with NZ Windfarms.

Power Purchase Agreement (PPA) signed for 150MW Tauhei Solar Farm offtake.

Meridian's Ruakākā Battery Energy Storage System near Whangārei

# Renewable development pipeline

**5.8GW (13.8TWh) of development options**
**2.6GW secured, 3.2GW in advanced prospects**



# Mike Roan – Chief Financial Officer

Benmore Hydro Station in the Waitaki Valley, South Canterbury

# Wholesale market operation

Wholesale electricity markets are inherently volatile.

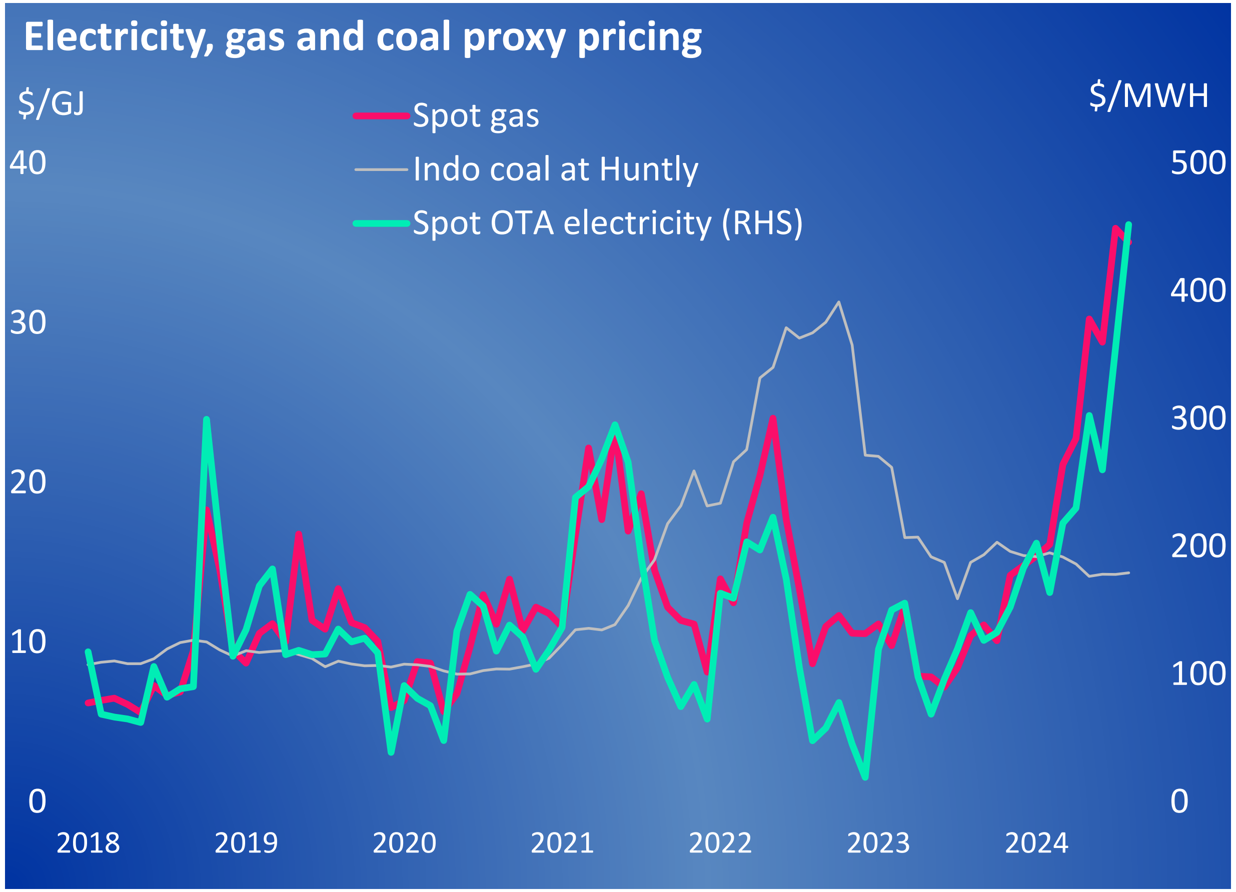
Particularly in this country, with the system's low storage hydro backbone and increasingly intermittent renewables.

High wholesale prices are part of how the system operates, signaling fuel scarcity.

And offering the financial incentive for more expensive forms of generation and demand response to be made available.

The winter 2024 drought has shown the extent of gas unavailability for electricity generation, particularly compared to previous low hydro inflows periods.

Spot gas prices are increasingly the driver of wholesale electricity prices, rather than hydro storage levels.



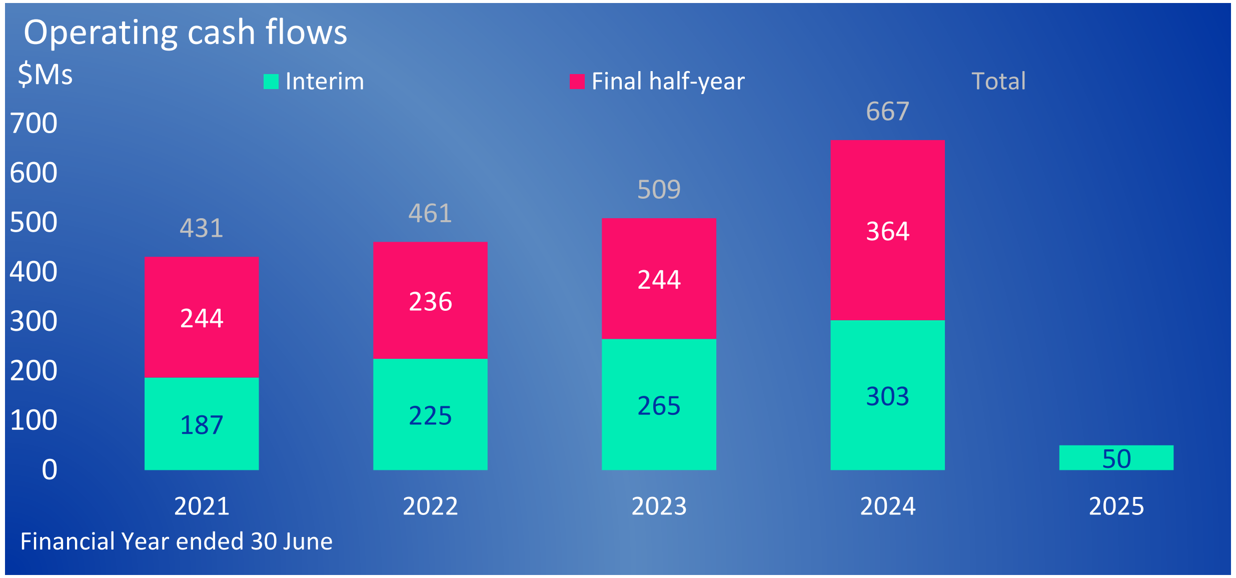

Source: Enerlytica

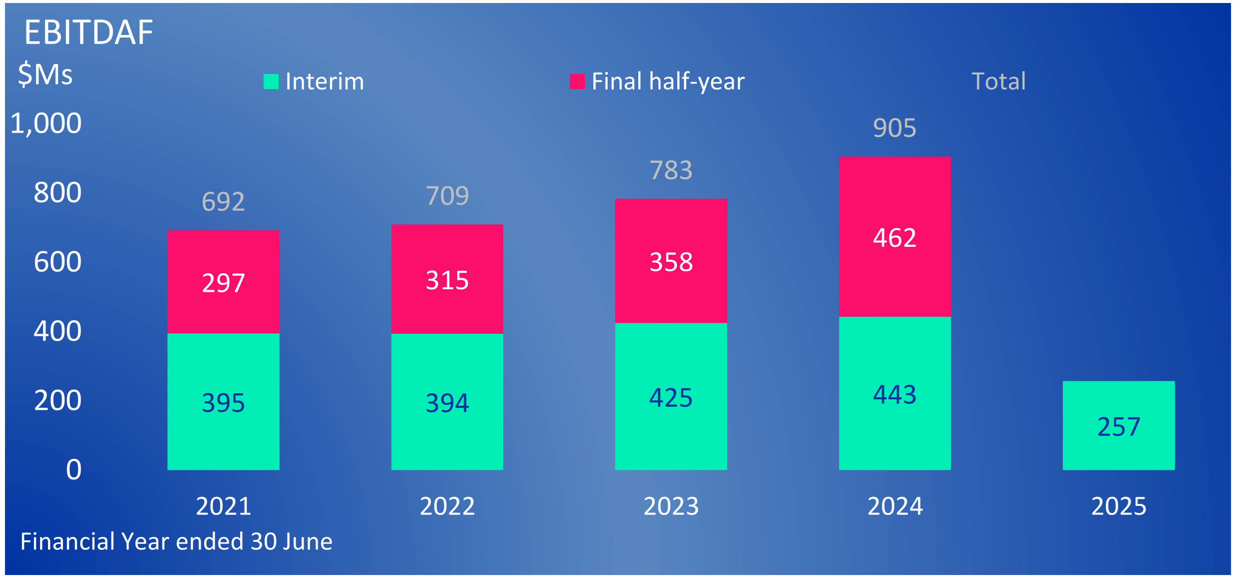
# Operating cash flow and EBITDAF

| Six months ended 31 December<br>$M | 2024 Operating cash flows | YoY change $M | YoY change % | | 2024 EBITDAF | YoY change $M | YoY change % |
|---|---|---|---|---|---|---|---|
| Receipts from customers | 2,410 | | | | | | |
| Interest received | 4 | | | | | | |
| Payments to suppliers and employees | (2,165) | | | +/- accruals +8 | **257** | -186 | -42% |
| Interest paid | (44) | -6 | | | | | |
| Income tax paid | (155) | -51 | | | | | |
| **Operating cash flows** | **50** | -253 | -83% | | | | |
| | | | | Energy margin | 444 | -185 | -29% |
| | | | | Other revenue | 26 | +10 | +63% |
| | | | | Transmission expense | (37) | -1 | +3% |
| | | | | Hosting expenses | (2) | +0 | +0% |
| | | | | Metering expense | (26) | -1 | +4% |
| | | | | Other operating expenses | (148) | -9 | +6% |

-83% decrease in operating cash flows.

-42% decrease in EBITDAF.



# Dividend

Interim ordinary dividend declared of 6.15cps (flat on 1H FY24), 85% imputed.

Dividend reinvestment plan will apply to this interim dividend at a 2% discount.


| Dividends declared | 1H FY25 | | 1H FY24 | |
|---|---|---|---|---|
| | cents per share | imputation | cents per share | imputation |
| Ordinary dividends | 6.15 | 85% | 6.15 | 80% |

**Dividend Reinvestment Plan Dates**

| | | | |
|---|---|---|---|
| Ex dividend date | 6 March | Strike price announced | 13 March |
| Record date | 7 March | Dividend paid/shares issued | 25 March |
| Elections close | 10 March | | |

# Movement in EBITDAF

1H FY25 EBITDAF -42% (-$186M) decrease on 1H FY24.

5% higher retail contracted sales revenue on 1% lower volumes.

-11% decrease in 1H FY25 hydro generation volumes.

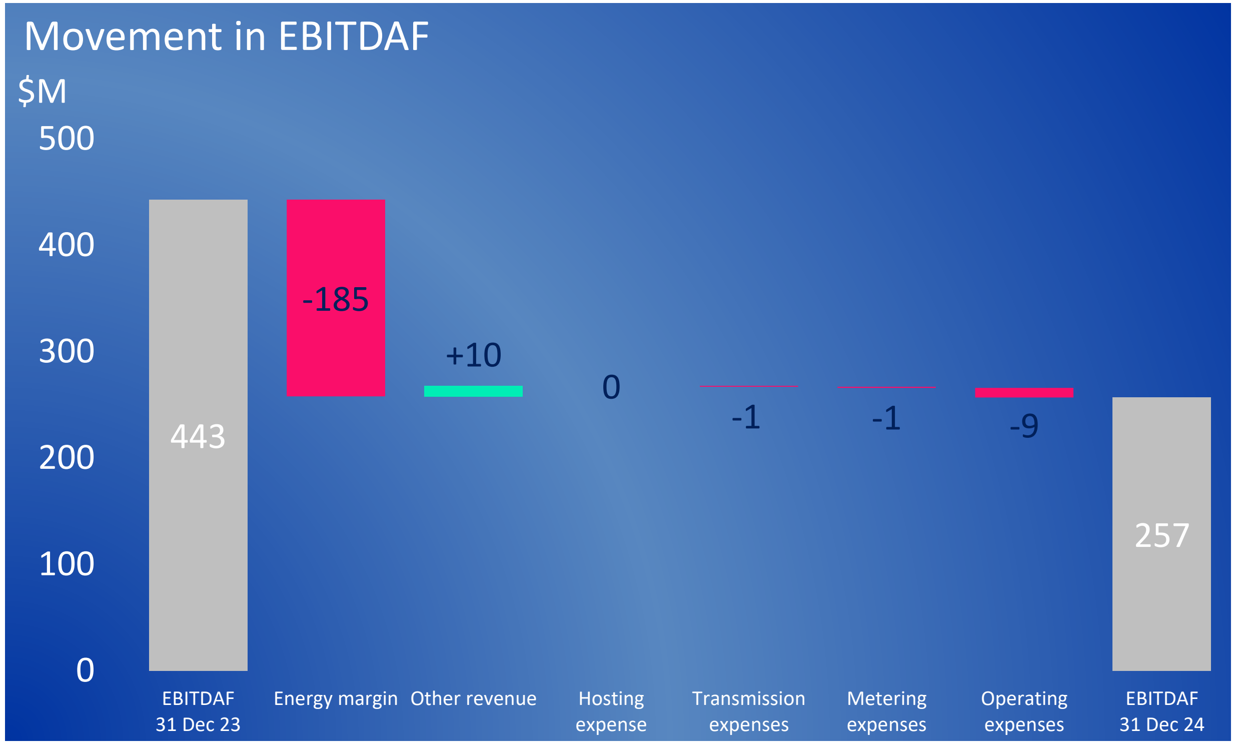
-24% decrease in 1H FY25 financial contract sales volumes.

Higher average cost paid to supply customers and financial contracts.

Significant hedge and demand response costs to manage record low winter inflows.

+$10M increase in other revenue from metering contract changes and transformer settlements.

+$9M (+6%) increase in 1H FY25 operating costs.



# Energy margin

5% revenue growth in mass market and corporate and industrial segments from higher average prices.

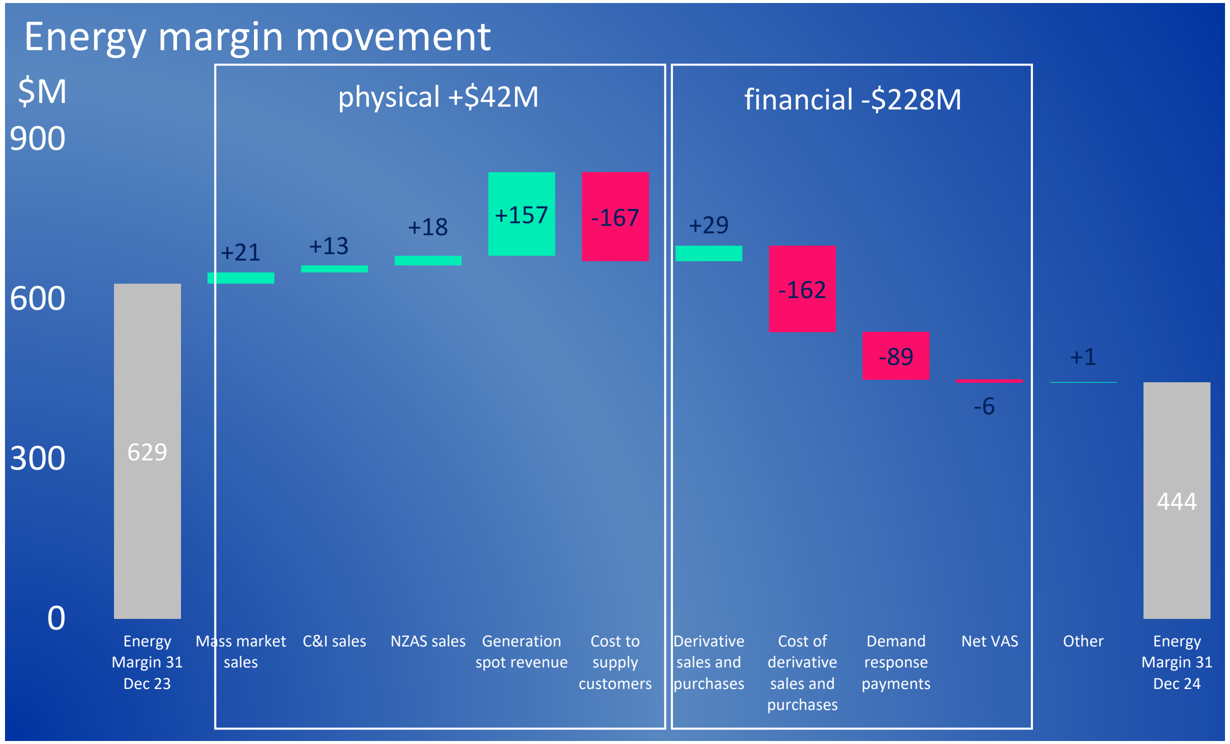
Winter fuel scarcity drove an -11% decrease in 1H FY25 hydro generation volumes.

Higher generation spot revenue and customer supply costs from higher wholesale prices.

24% lower financial contract sales volumes reflecting the lack of discretionary generation.

$200M in hedge costs and demand response to manage record low winter inflows.

$17M of close out costs largely due to market making costs through low market liquidity.




Refer to pages 37-38 for a further breakdown of energy margin

# Retail customers

## Mass market

+$21M (+5%) growth in mass market revenue from higher average sales price and large business volume growth.

Modest declines in other mass market segment sale volumes.

## Corporate

-4% decrease in corporate sales volume at a higher net average sales price.

Corporate sales revenue increased +$13M (+5%).

| Customer sales | Average price[1] ($/MWh) | Total sales volume (GWh) | North Island sales volume (GWh) | South Island sales volume (GWh) |
|---|---|---|---|---|
| **1H FY25** | | | | |
| Residential | | 941 | 522 | 419 |
| Small medium business | | 848 | 518 | 330 |
| Agricultural | | 700 | 221 | 479 |
| Large business | | 358 | 232 | 126 |
| Total mass market | $152 | 2,847 | 1,493 | 1,354 |
| Corporate | $143 | 1,903 | 971 | 932 |
| **1H FY24** | | | | |
| Residential | | 947 | 530 | 417 |
| Small medium business | | 850 | 521 | 329 |
| Agricultural | | 695 | 212 | 483 |
| Large business | | 330 | 212 | 118 |
| Total mass market | $146 | 2,822 | 1,475 | 1,347 |
| Corporate | $130 | 1,984 | 1,180 | 804 |

[1]Volume weighted average electricity price received from retail customers, less distribution costs

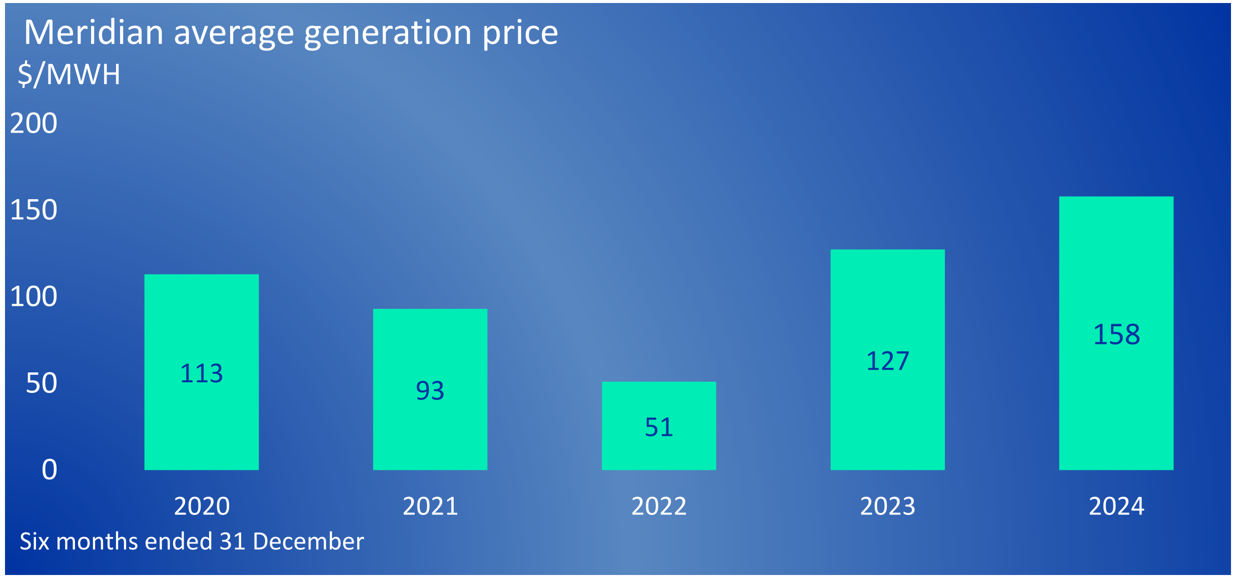
# Generation

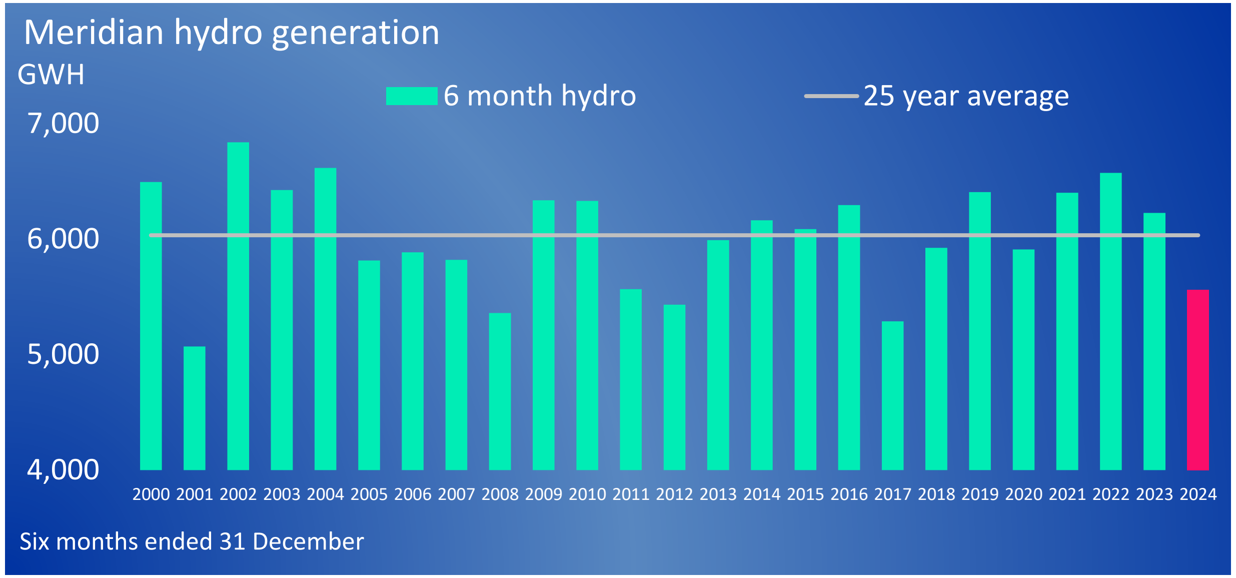
1H FY25 inflows were 126% of average, heavily skewed to spring and early summer inflows.

Winter fuel scarcity drove an -11% decrease in 1H FY25 hydro generation volumes.

Wind generation increased 306GWh (+42%), despite calm winter periods with additional Harapaki generation and return to full 143MW capacity at West Wind in October 2024.

Wholesale price volatility during 1H FY25 reflected fuel scarcity. Average daily prices in August 2024 ranged between $800MWh and $1MWh.



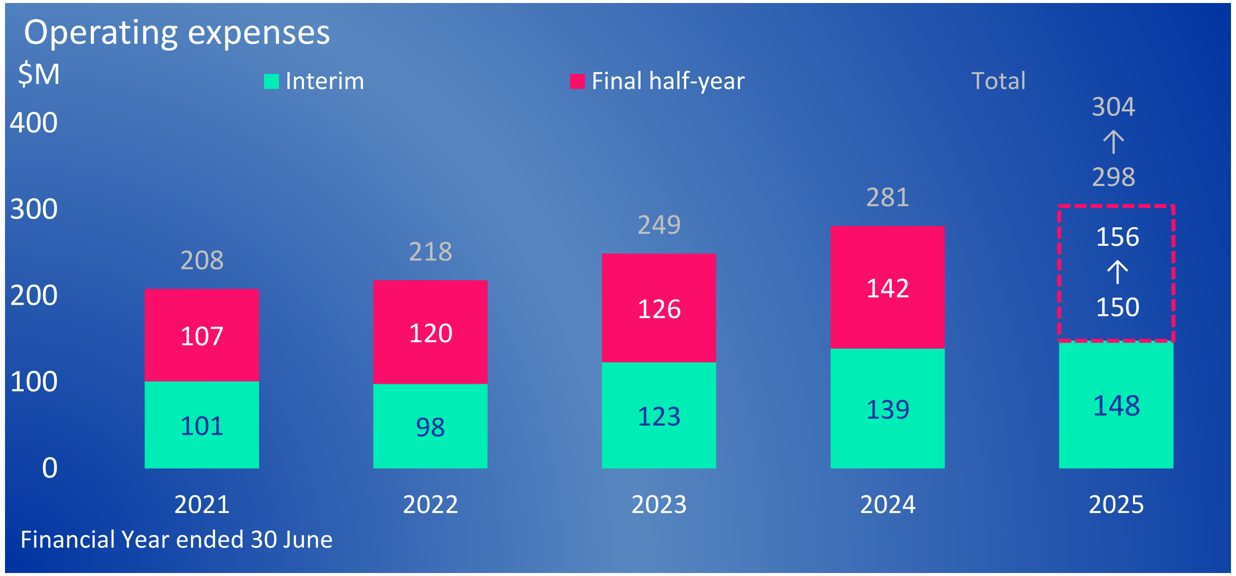



# Operating expenses

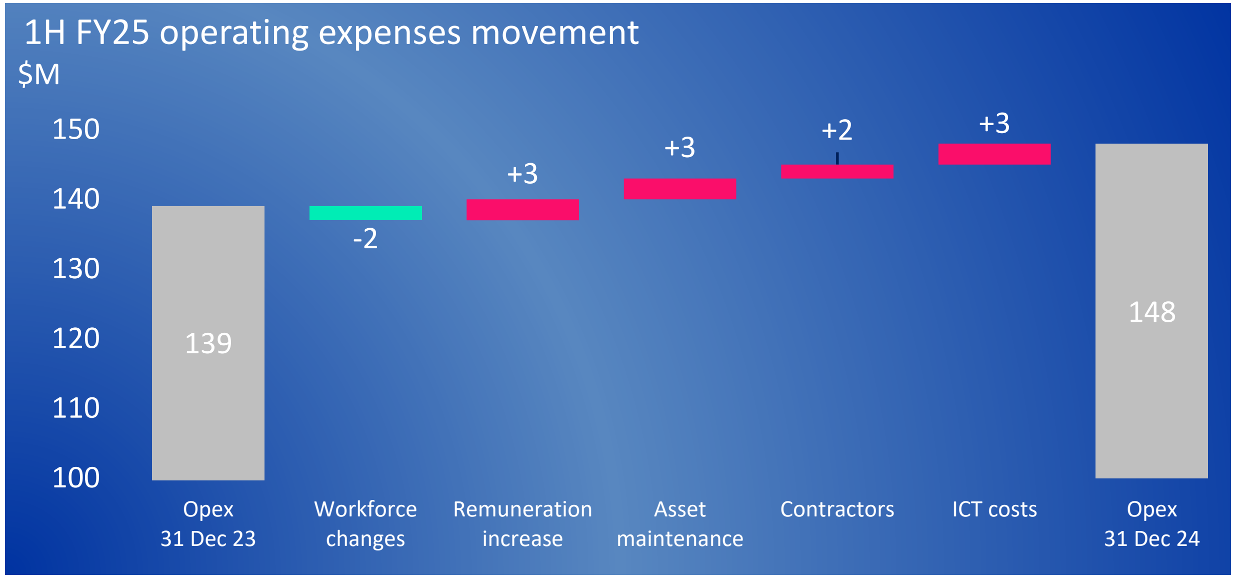
Operating expenses $9M (6%) higher than 1H FY24.

Growth in 1H FY25 from workforce changes, remuneration increases, transformer costs, retail transformation and finance and generation control system upgrades.

Expecting FY25 operating costs of between $298M and $304M (previous guidance between $302M and $308M).




| | FY25 Cost Guidance | | |
|---|---|---|---|
| | **Generation** | **Flux** | **Total** |
| Operating Costs | | $15M | $298M - $304M |
| Stay in Business | | | $75M - $90M |
| Growth | | | $145M - $160M |
| **Total Capital Expenditure** | | | **$220M - $250M** |
| Total Cash Costs | $125M - $130M | | |



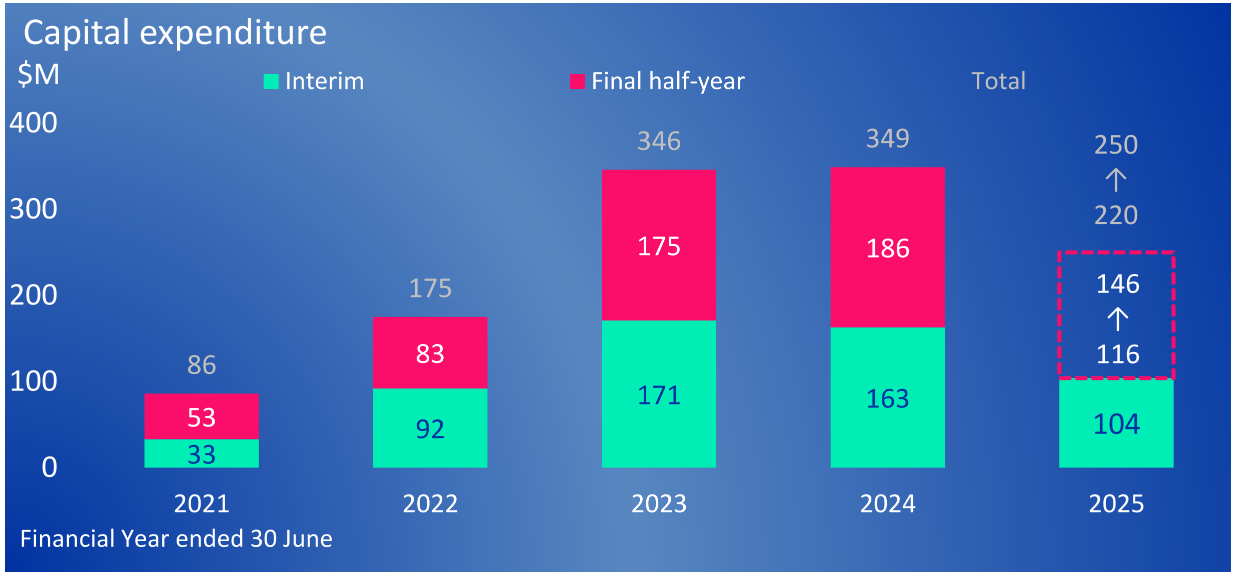
# Capital expenditure

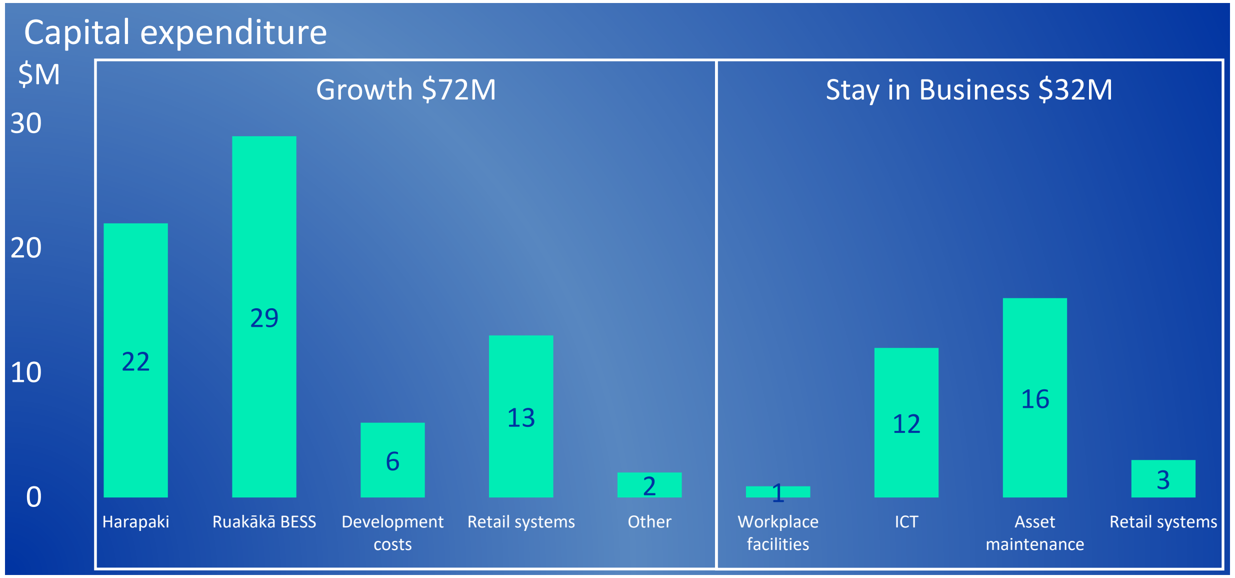
Capital expenditure of $104M in FY25.

$32M stay in business spend and $72M growth investment.

Spend in 1H FY25 from Harapaki completion, Ruakākā Battery, retail transformation, finance and generation control system upgrades, asset maintenance.

Expecting FY25 capital expenditure of between $220M and $250M (previous guidance between $295M and $325M).




# Below EBITDAF

-$154M decrease in NPBT[1] from the net change in fair value of hedges[2] (-$2M decrease in 1H FY24).

+$61M (+37%) increase in depreciation from June 2024 asset revaluation and Harapaki completion.

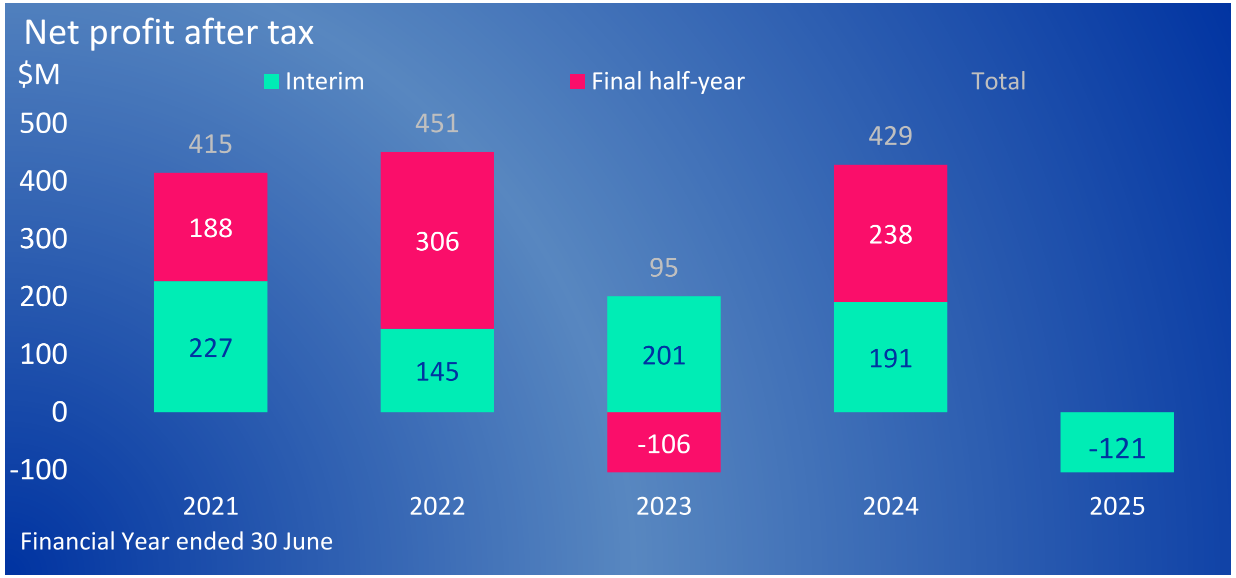
-$8M of asset related adjustments in 1H FY25, mainly impairments and transformer disposal losses.

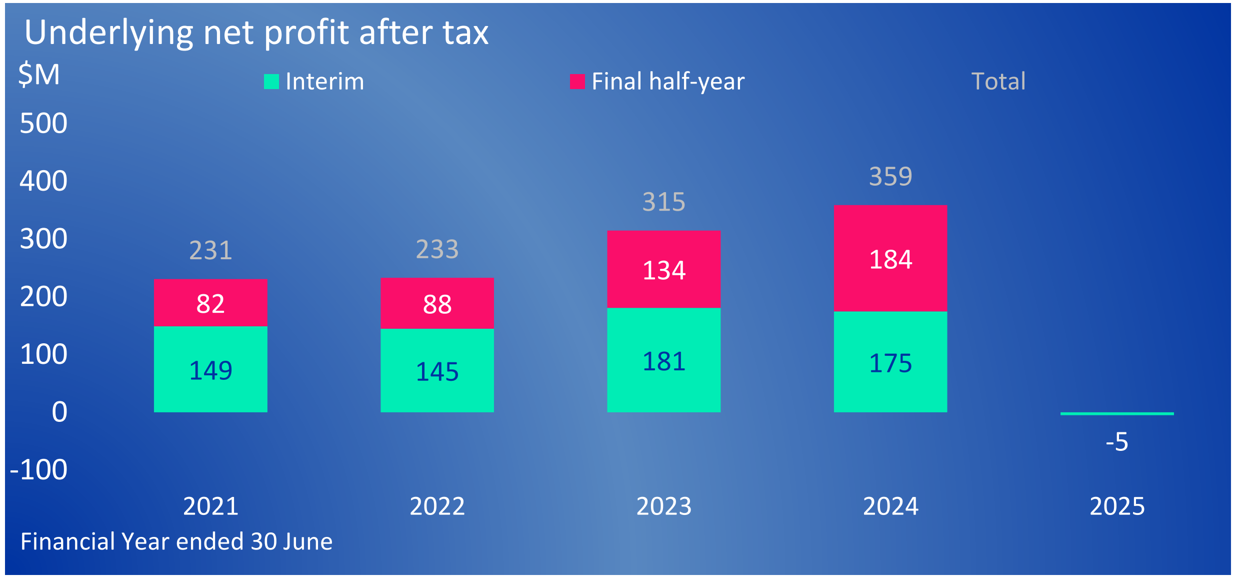
+$13M increase in net finance costs from higher funding costs and completed Harapaki capitalisation.

Negative tax expense on pre-tax losses.

Resulted in a -$121M net profit after tax.

-$5M underlying net profit after tax[3] largely from lower EBITDAF and tax with higher depreciation, financing costs.




[1]Net profit before tax

[2]Net changes in the fair value of unrealised energy hedges and treasury hedges

[3]Net profit or loss after tax adjusted for the effects of changes in fair value of unrealised hedges, electricity option premiums and other non-cash items and their tax effects

A reconciliation of NPAT to Underlying NPAT is on page 42

# Debt and funding

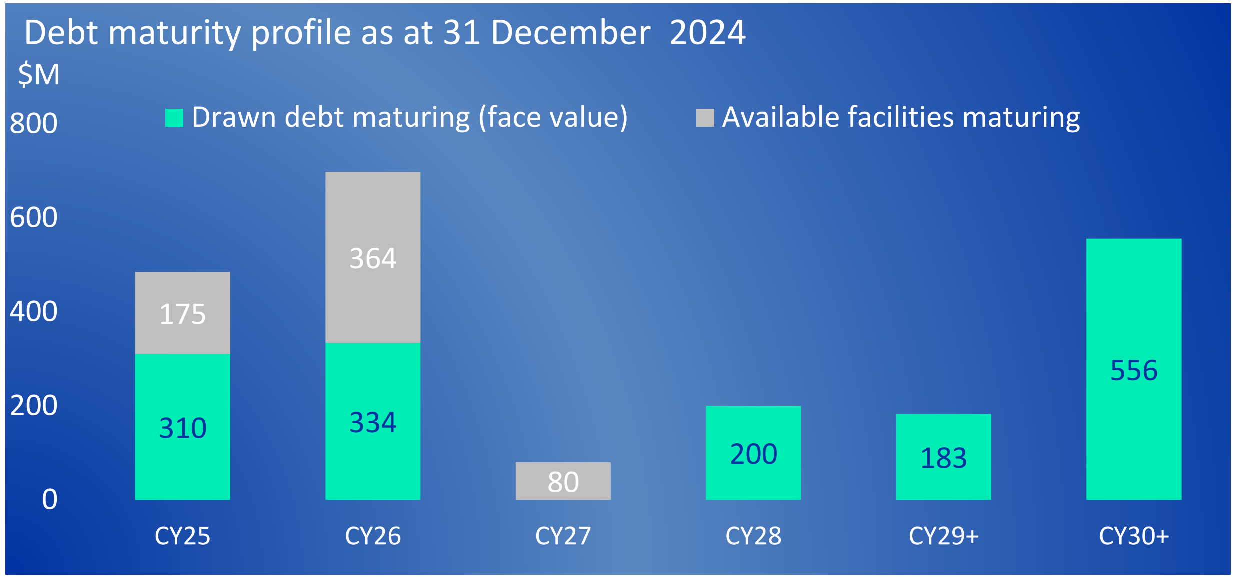
December 2024 total borrowings of $1,657M[1.]

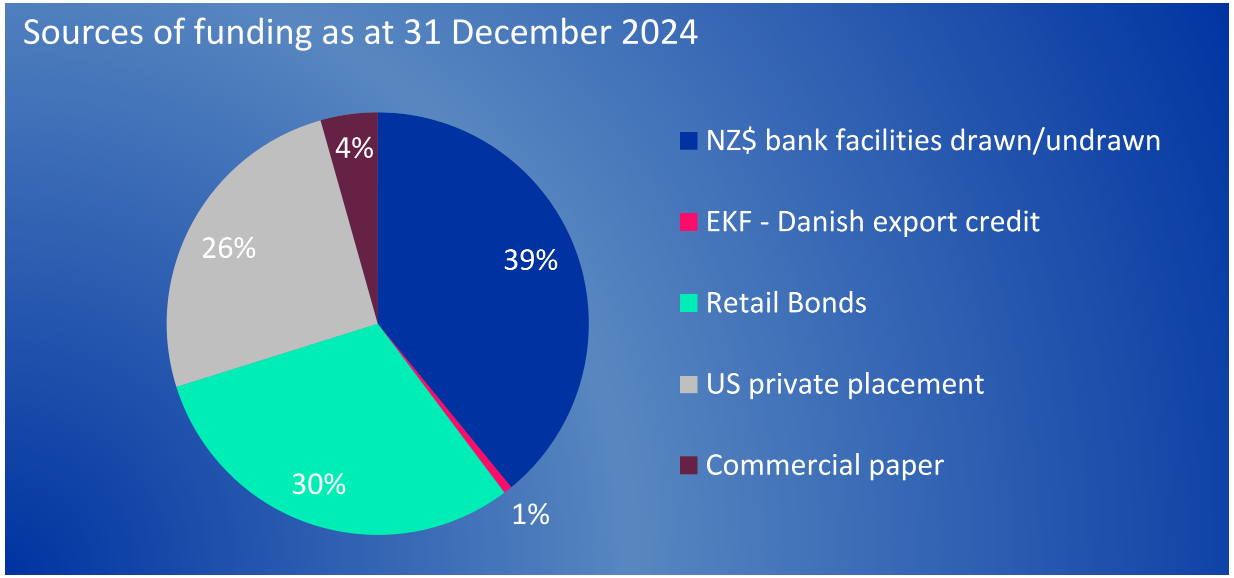
Total funding facilities of $2,302M, of which $719M were undrawn.

All facilities classified under Meridian's Green Finance Programme.

Net debt to EBITDAF at 2.2x (1H FY24: 1.3x).

Credit rating maintained at BBB+/Stable.




[1]Including $24M fair value adjustment

# Final thoughts

1H FY25 was challenging with record dry winter conditions.

Followed by record low inflows in the last two months.

Additional hedge and DR costs of $25M+ now expected in Q3.

680MW of development projects now consented representing $1B capital commitment.

Customer product set evolving.

Enhancing hydro storage is a solution to gas scarcity.

Manapōuri Hydro Station in the Fiordland National Park

# Questions

# Additional information

# Segment results

| $M | Wholesale | | Retail | | Other & unallocated | | Inter-segment | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **1H FY25** | 1H FY24 | **1H FY25** | 1H FY24 | **1H FY25** | 1H FY24 | **1H FY25** | 1H FY24 | **1H FY25** | 1H FY24 |
| Contracted sales | **291** | 296 | **704** | 670 | **-** | - | **-** | - | **995** | 966 |
| Cost to supply customers | **(1,631)** | (1,334) | **(653)** | (660) | **-** | - | **719** | 729 | **(1,565)** | (1,265) |
| Net cost of hedging | **(15)** | 51 | **-** | - | **-** | - | **-** | - | **(15)** | 51 |
| Generation spot revenue | **1,042** | 885 | **-** | - | **-** | - | **-** | - | **1,042** | 885 |
| Inter-segment electricity sales | **719** | 729 | **-** | - | **-** | - | **(719)** | (729) | **-** | - |
| Virtual asset swap margins | **(9)** | (3) | **-** | - | **-** | - | **-** | - | **(9)** | (3) |
| Other market revenue/(costs) | **(3)** | (5) | **(1)** | - | **-** | - | **-** | - | **(4)** | (5) |
| **Energy margin** | **394** | **619** | **50** | **10** | **-** | **-** | **-** | **-** | **444** | **629** |
| Other revenue | **2** | 2 | **13** | 9 | **16** | 10 | **(5)** | (5) | **26** | 16 |
| Hosting expense | **-** | - | **-** | - | **(2)** | (2) | **-** | - | **(2)** | (2) |
| Energy transmission expense | **(37)** | (36) | **-** | - | **-** | - | **-** | - | **(37)** | (36) |
| Energy metering expense | **-** | - | **(26)** | (25) | **-** | - | **-** | - | **(26)** | (25) |
| **Gross margin** | **359** | **585** | **37** | **(6)** | **14** | **8** | **(5)** | **(5)** | **405** | **582** |
| Employee expenses | **(16)** | (16) | **(20)** | (18) | **(32)** | (32) | **-** | - | **(68)** | (66) |
| Other operating expenses | **(40)** | (35) | **(21)** | (19) | **(23)** | (23) | **4** | 4 | **(80)** | (73) |
| Operating expenses | **(56)** | (51) | **(41)** | (37) | **(55)** | (55) | **4** | 4 | **(148)** | (139) |
| **EBITDAF** | **303** | **534** | **(4)** | **(43)** | **(41)** | **(47)** | **(1)** | **(1)** | **257** | **443** |

# EBITDAF reconciliation to the income statement

| Six months ended 31 December | 2024 | 2023 |
|---|---|---|
| **Income statement** | | |
| Energy sales to customers | **1,178** | 1,203 |
| Generation revenue | **1,051** | 892 |
| Energy related services revenue | **5** | 5 |
| Other revenue | **21** | 11 |
| **Total operating revenue** | **2,255** | **2,111** |
| Energy expenses | **(1,094)** | (1,136) |
| Energy distribution expenses | **(393)** | (363) |
| Energy transmission expenses | **(37)** | (36) |
| Hosting expenses | **(2)** | (2) |
| Electricity metering expenses | **(26)** | (25) |
| Employee expenses | **(68)** | (66) |
| Other expenses | **(80)** | (73) |
| **Total operating expenses** | **(1,700)** | **(1,701)** |
| Depreciation and amortisation | **(225)** | (164) |
| Asset related adjustments | **(8)** | 11 |
| *realised energy hedges* | ***(298)*** | *33* |
| *unrealised energy hedges* | ***(143)*** | *11* |
| Net change in fair value of energy hedges | (441) | 44 |
| Net finance costs | **(38)** | (25) |
| Net change in fair value of treasury hedges | **(11)** | (13) |
| **Net profit before tax** | **(168)** | **263** |
| Income tax expense | **47** | (72) |
| **Net profit after tax** | **(121)** | **191** |

| | 2024 | 2023 |
|---|---|---|
| **Segment earnings statement** | | |
| **Energy margin** | **444** | **629** |
| Other revenue | **26** | 16 |
| Energy transmission expense | **(37)** | (36) |
| Hosting expenses | **(2)** | (2) |
| Energy metering expense | **(26)** | (25) |
| **Gross margin** | **405** | **582** |
| Employee expenses | **(68)** | (66) |
| Other operating expenses | **(80)** | (73) |
| **EBITDAF** | **257** | **443** |

# Retail

<u>Customers</u>

+4% increase in customers since June 2024.

<u>Residential, business, agri segment</u>

-1% decrease in residential volumes.

Slight decrease in small business volumes.

+1% increase in agri volumes.

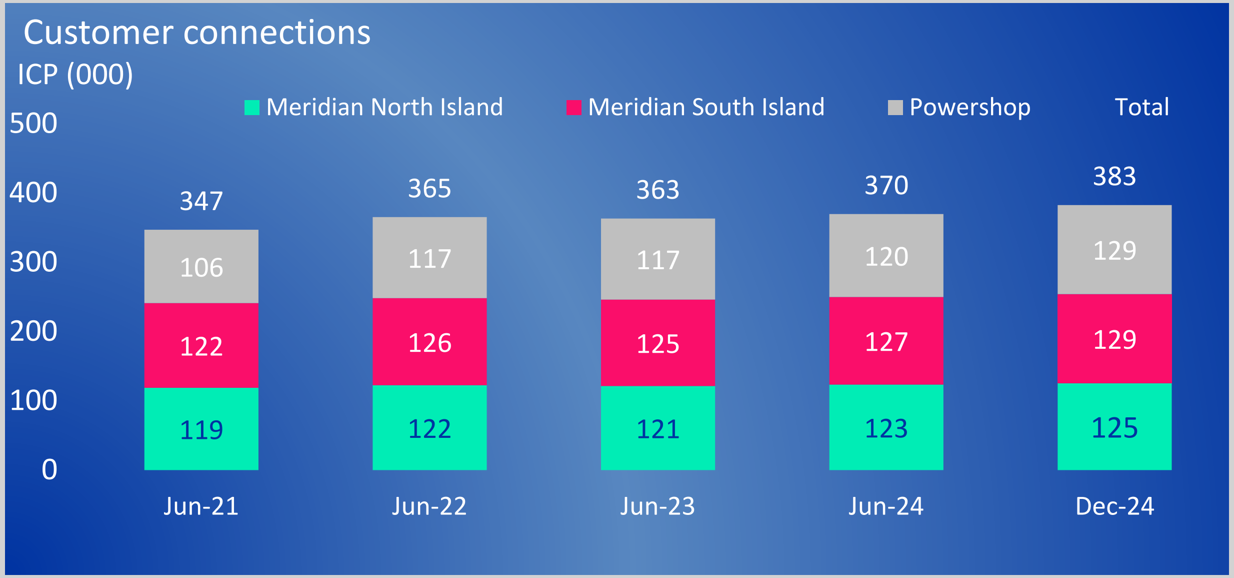
+8% increase in large business volumes.

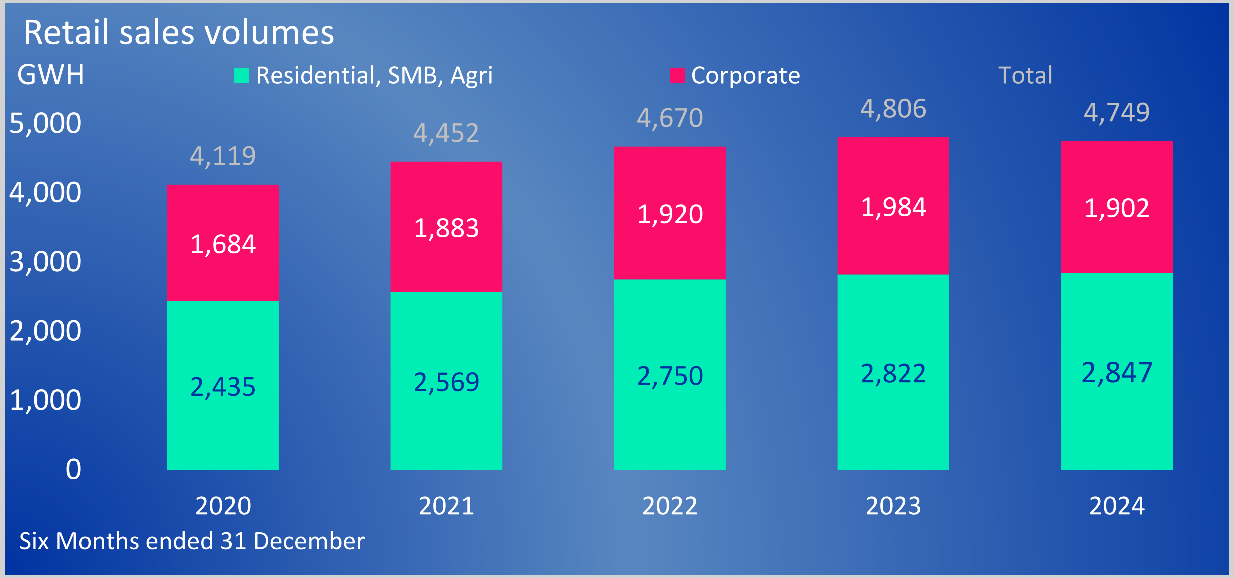
+4% increase in average sales price.

<u>Corporate segment</u>

-4% decrease in volumes.

+10% increase in average sales price.



# Hydrology

## Inflows

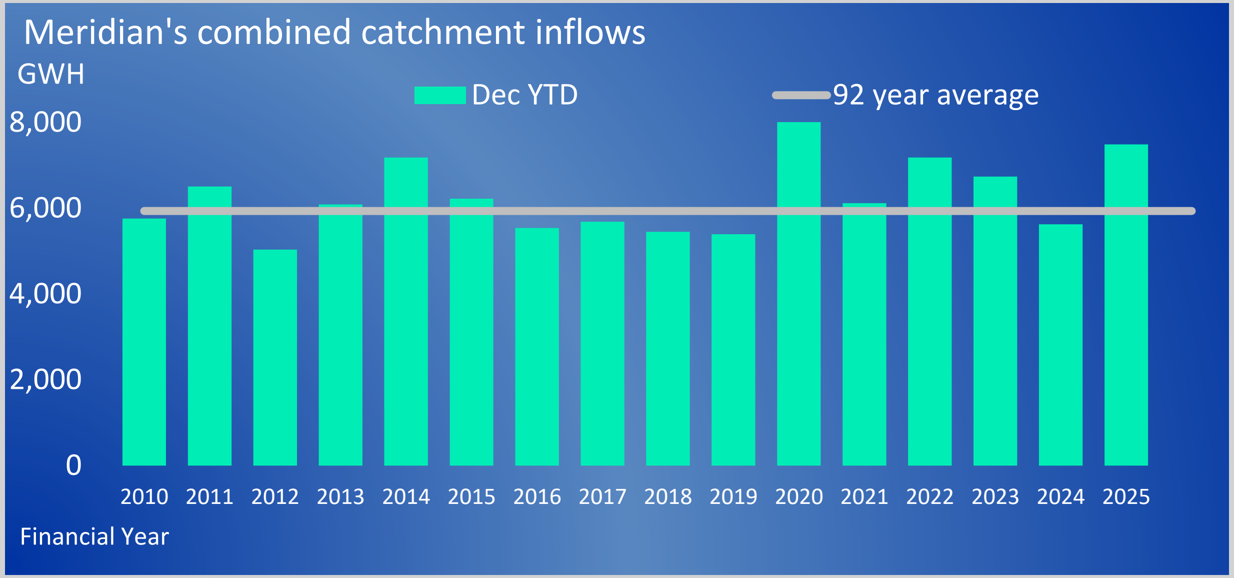
1H FY25 inflows were 126% of historical average.

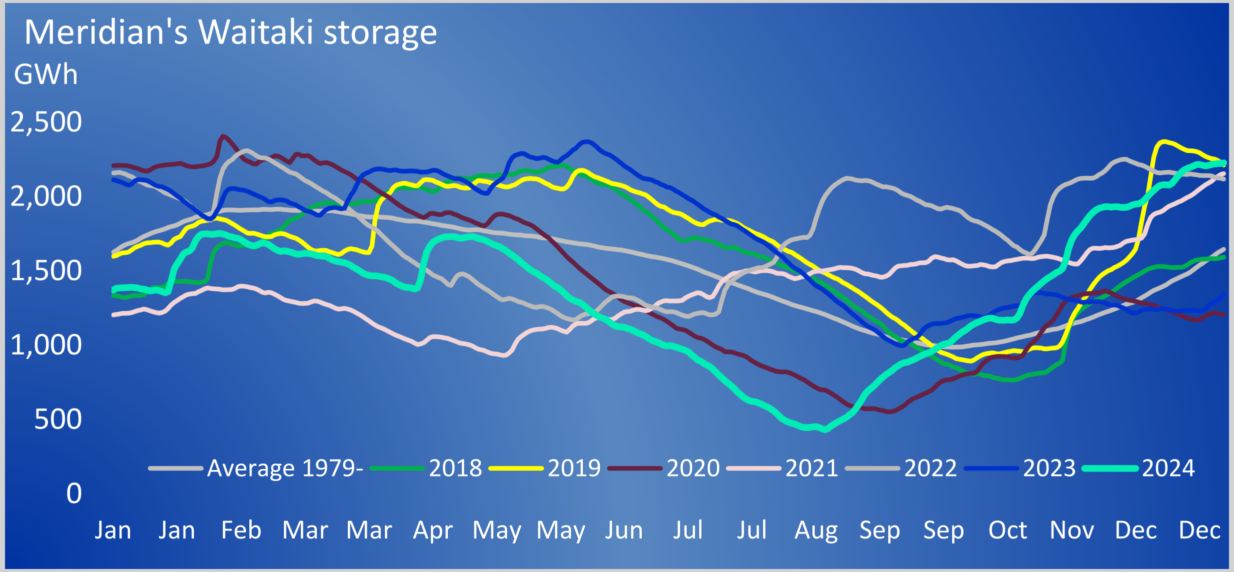
January 2025 inflows were 43% of average.

## Storage

Meridian’s Waitaki storage at 31 December 2024 was 135% of historical average.

By 31 January 2025, this position was 104% of average.



# Generation

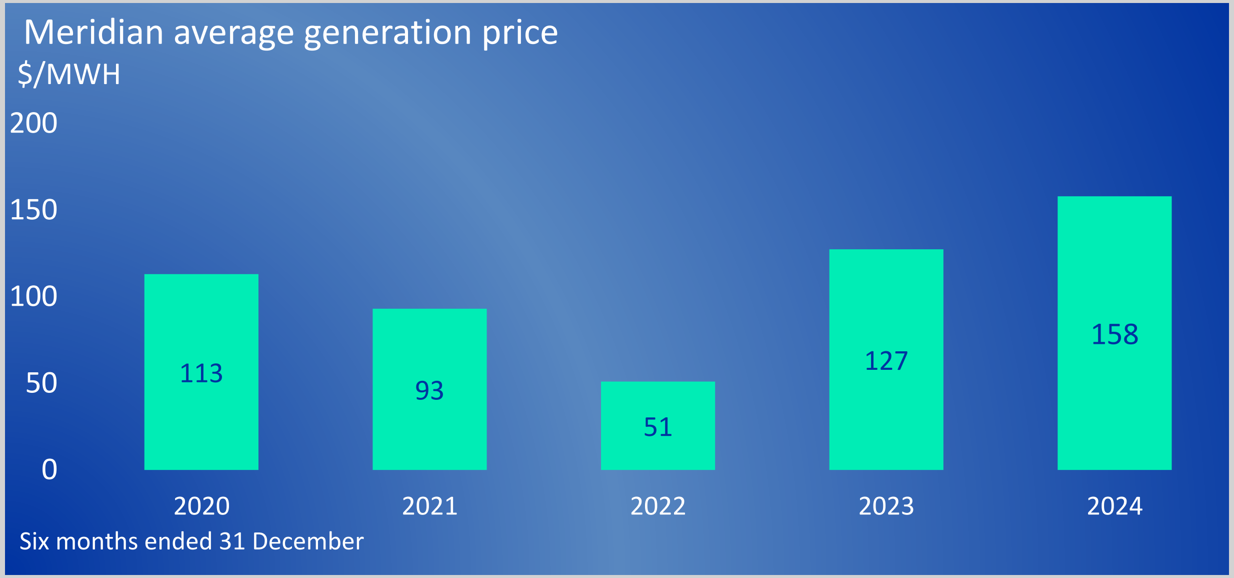
## Volume

1H FY25 generation was -5% lower than 1H FY24 with -11% lower hydro generation and +42% higher wind generation.

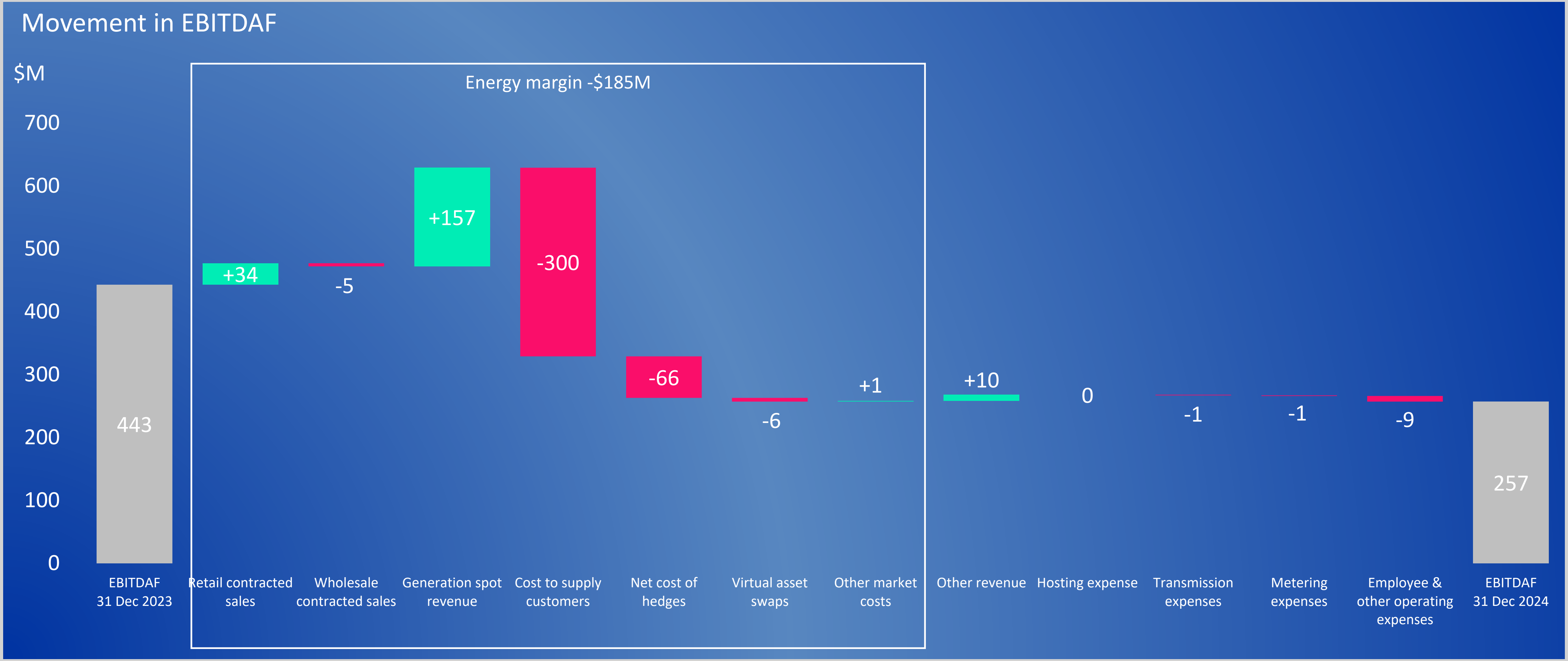
## Price

1H FY25 average price Meridian received for its generation was +25% higher than 1H FY24.

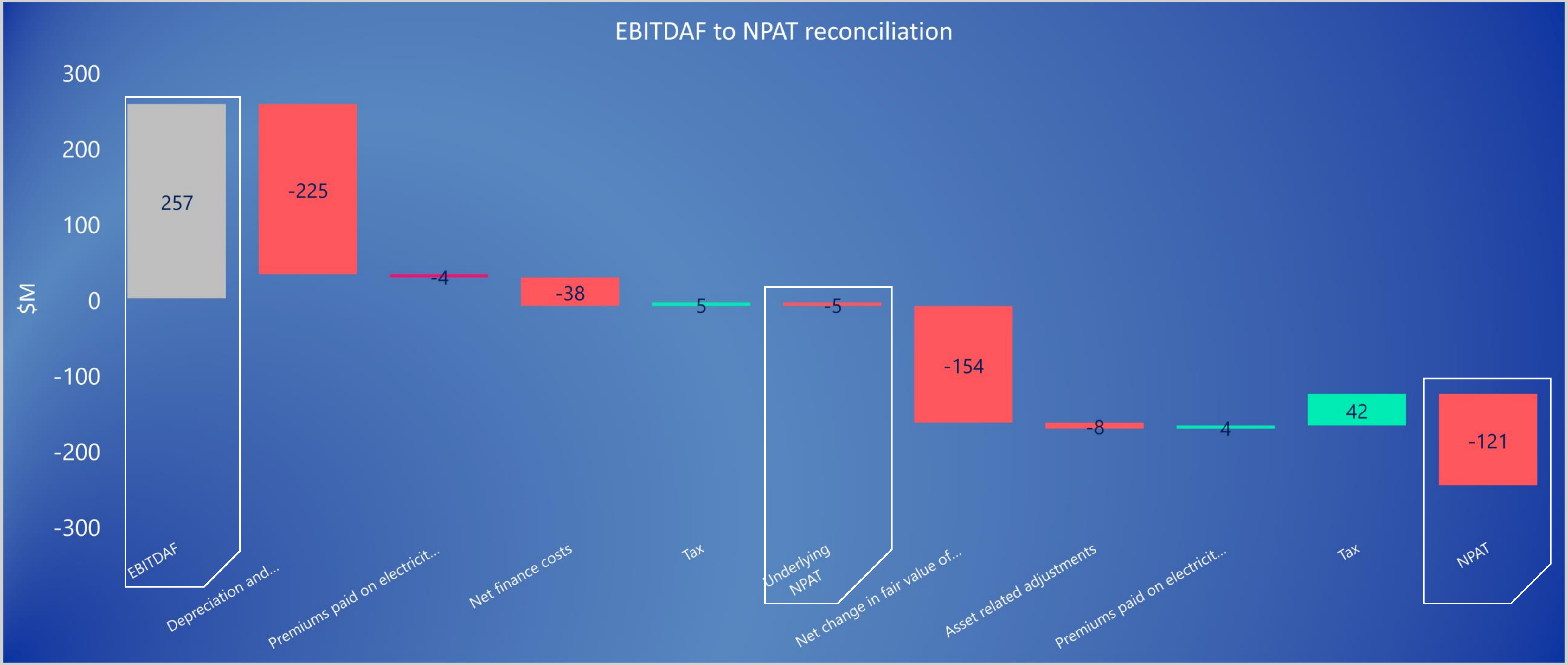
1H FY25 average price Meridian paid to supply customers was +40% higher than 1H FY24.

# 1H FY25 EBITDAF

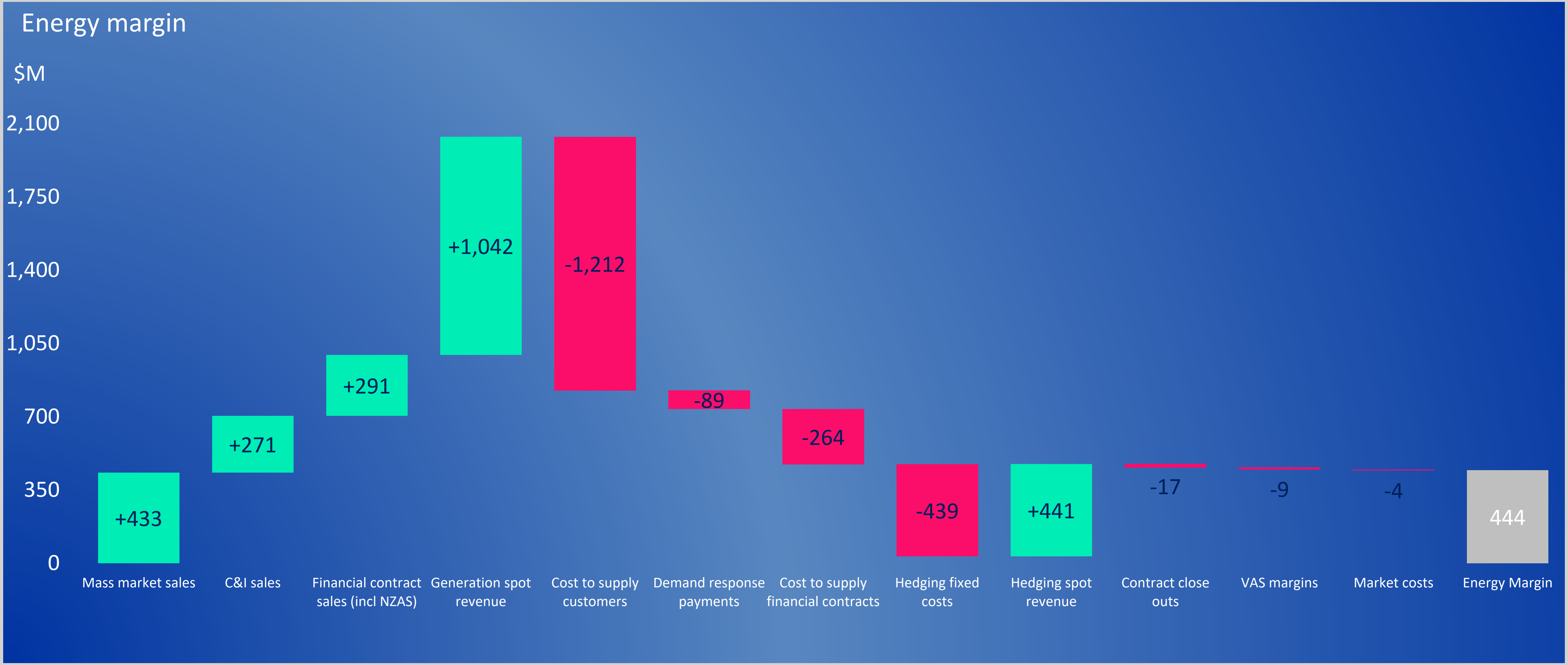


# EBITDAF to NPAT

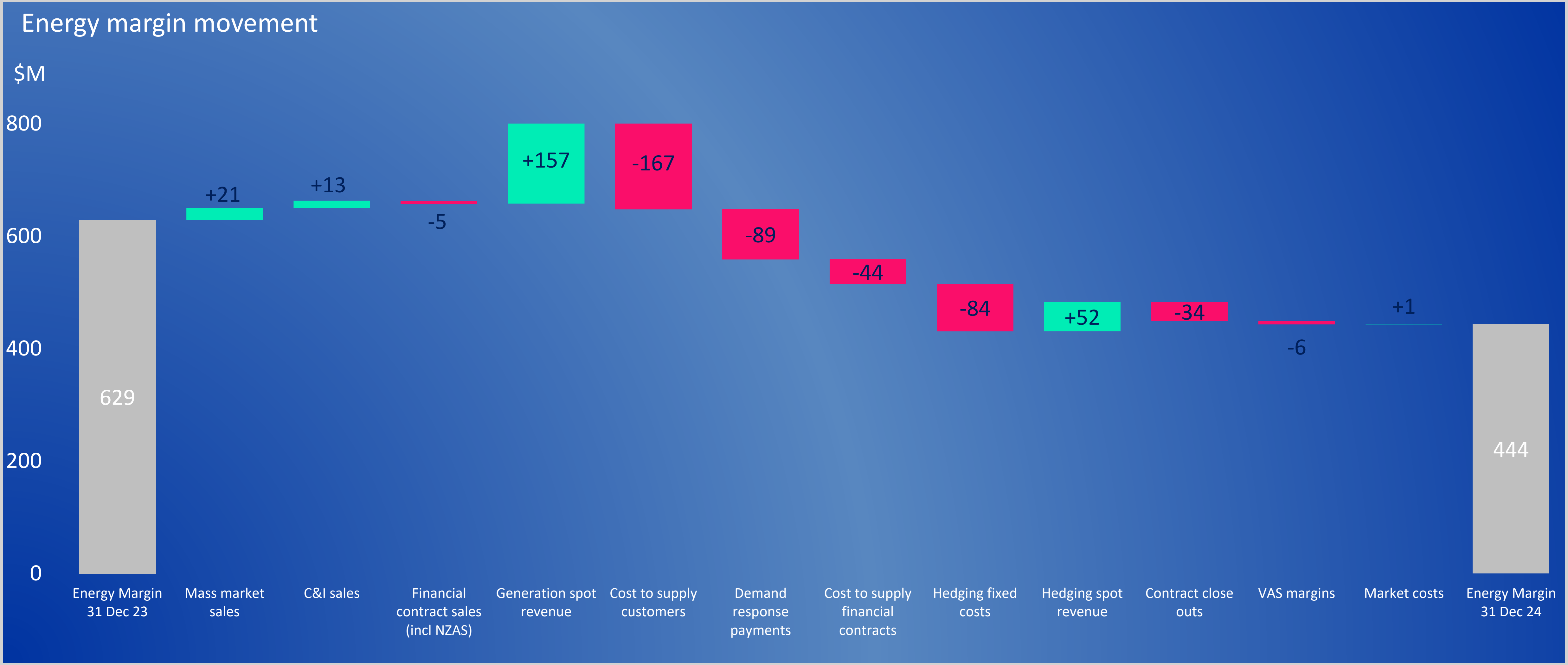



*Net changes in the fair value of unrealised energy hedges and treasury hedges

# Energy margin



# Energy margin



# Energy margin

| | 1H FY25 | | | 1H FY24 | | |
|---|---|---|---|---|---|---|
| | Volume | VWAP | NZD M | Volume | VWAP | NZD M |
| Res, business, agri sales | 2,847 | $152 | 433 | 2,822 | $146 | 412 |
| Corporate and industrial sales | 1,903 | $143 | 271 | 1,984 | $130 | 258 |
| Retail contracted sales | 4,749 | $148 | 704 | 4,806 | $139 | 670 |
| NZAS sales | 1,663 | | | 2,525 | | |
| Financial contract sales | 1,337 | | | 1,763 | | |
| Wholesale contracted sales | 3,000 | $97 | 291 | 4,289 | $69 | 296 |
| Cost to supply retail customers | 4,998 | -$182 | (911) | 5,108 | -$142 | (726) |
| Cost to supply wholesale customers | 1,663 | -$181 | (301) | 2,525 | -$126 | (319) |
| Demand response payments | | | (89) | | | - |
| Cost of financial contracts | 1,337 | -$198 | (264) | 1,763 | -$125 | (220) |
| Cost to supply customers | 7,998 | -$196 | (1,565) | 9,396 | -$135 | (1,265) |
| Hedging costs | 2,346 | -$187 | (439) | 2,860 | -$124 | (355) |
| Hedging spot revenue | 2,346 | $188 | 441 | 2,860 | $136 | 389 |
| Close-outs | | | (17) | | | 17 |
| Net cost of hedging | | | (15) | | | 51 |
| Hydro generation | 5,553 | | | 6,227 | | |
| Wind generation | 1,026 | | | 720 | | |
| Generation revenue | 6,579 | $158 | 1,042 | 6,948 | $127 | 885 |
| Virtual asset swap margins | | | (9) | | | (3) |
| Other | | | (4) | | | (5) |
| **Energy margin** | | | **444** | | | **629** |

# Energy margin

A non-GAAP financial measure representing energy sales revenue less energy related expenses and energy distribution expenses.

Used to measure the vertically integrated performance of the retail and wholesale businesses.

Used in place of statutory reporting which requires gross sales and costs to be reported separately, therefore not accounting for the variability of the wholesale spot market and the broadly offsetting impact of wholesale prices on the cost of retail electricity purchases.

Defined as:

Revenues received from sales to customers net of distribution costs (fees to distribution network companies that cover the costs of distribution of electricity to customers), sales to large industrial customers and fixed price revenues from financial contracts sold (contract sales revenue).

The volume of electricity purchased to cover contracted customer sales and financial contracts sold (cost to supply customers).

The fixed cost of derivatives used to manage market risks, net of spot revenue received from those derivatives, and demand response payments (net cost of hedging).

Revenue from the volume of electricity that Meridian generates (generation spot revenue).

The net margin position of virtual asset swaps with Genesis Energy and Mercury New Zealand.

Other associated market revenues and costs including Electricity Authority levies and ancillary generation revenues, such as frequency keeping.

# NZAS Demand Response Agreement

## Summary of demand response options

| Option | Equivalent reduced consumption (MWh per hour) | Exercisable Reduction from Meridian demand response agreement (MWh per hour) | Usual Ramp-Down Notice Period | DR Period (equivalent number of days) | Usual Ramp-Down Period (equivalent number of days) | Usual Ramp-Up Notice Period (equivalent number of days) | Usual Ramp-Up Period (equivalent number of days) | Maximum Calls |
|---|---|---|---|---|---|---|---|---|
| 1 | 25 | 18.75 | 3 Business Days | Minimum 10 days, maximum 150 days | 5 days | 3 days | 15 days | Unlimited, but the Option cannot be exercised more than 4 times in any 12-month period |
| 2 | 50 | 37.5 | 3 Business Days | Minimum 15 days, maximum 145 days | 10 days | 3 days | 30 days | Unlimited, but the Option cannot be exercised more than 2 times in any 18-month period |
| 3 | 100 | 75 | 3 Business Days | Minimum 22 days, maximum 137 days | 18 days | 5 days | 100 days | The Option cannot be exercised more than 8 times over the Term |
| 4 | 185 | 138.75 | 5 Business Days | Minimum 30 days, maximum 75 days | 25 days | 5 days | 200 days | The Option cannot be exercised more than 4 times over the Term |

Stand down periods apply between the exercise of Options.

# Fair value movements

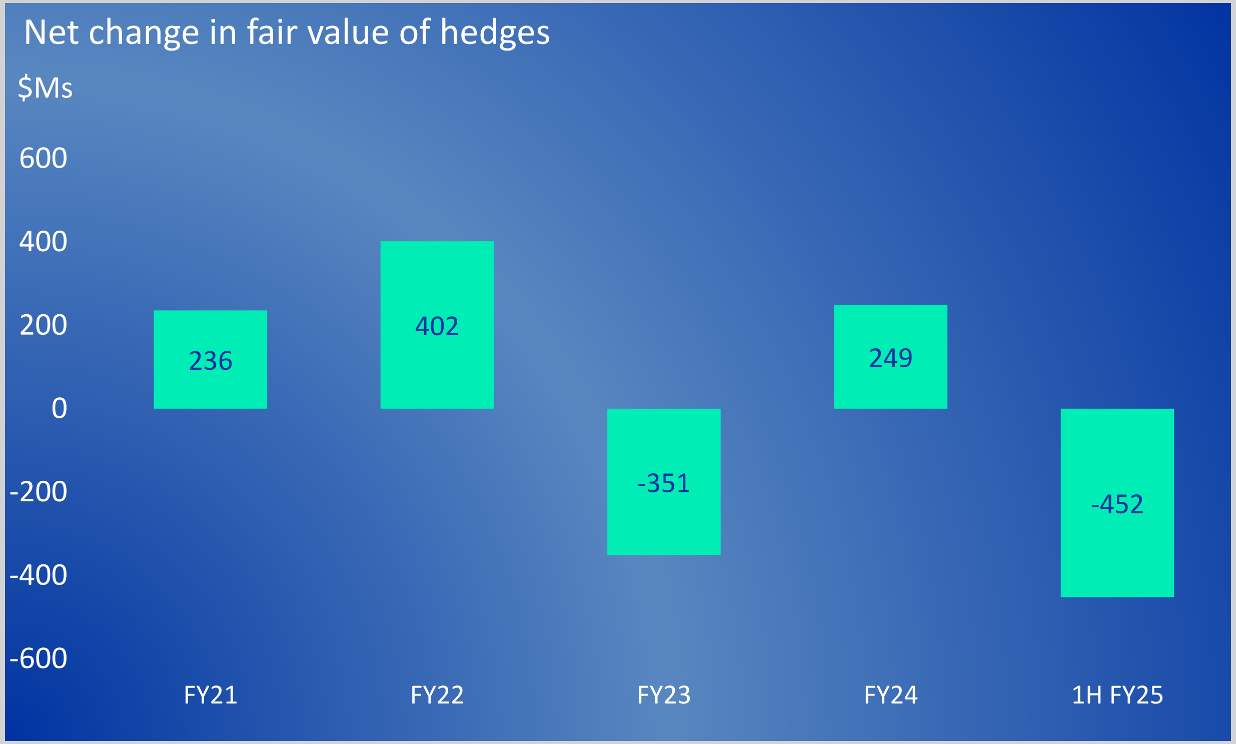
Meridian uses derivative instruments to manage interest rate, foreign exchange and electricity price risk.

As forward prices and rates on these instruments move, non-cash changes to their carrying value are reflected in NPAT.

Accounting standards only allow hedge accounting if specific conditions are met, which creates NPAT volatility.

$441M decrease in NPBT from fair value of energy hedges from higher forward electricity prices ($44M increase in 1H FY24).

$11M decrease in NPBT from fair value of treasury hedges from lower forward interest rates ($13M decrease in 1H FY24).



# Segment earnings statement

| **Segment earnings statement** | | |
|---|---|---|
| **Six months ended 31 December** | **2024** | **2023** |
| **$M** | | |
| Energy margin | 444 | 629 |
| Other revenue | 26 | 16 |
| Hosting expense | (2) | (2) |
| Energy transmission expense | (37) | (36) |
| Electricity metering expenses | (26) | (25) |
| Employee and other operating expenses | (148) | (139) |
| **EBITDAF** | **257** | **443** |
| Depreciation and amortisation | (225) | (164) |
| Asset related adjustments | (8) | 11 |
| Net change in fair value of energy hedges | (143) | 11 |
| Net finance costs | (38) | (25) |
| Net change in fair value of treasury hedges | (11) | (13) |
| **Net profit before tax** | **(168)** | **263** |
| Income tax expense | 47 | (72) |
| **Net profit after tax** | **(121)** | **191** |

# Underlying NPAT reconciliation

| Underlying net profit after tax | | |
|---|---|---|
| **Six months ended 31 December** | **2024** | **2023** |
| **$M** | | |
| Net profit after tax | (121) | 191 |
| Underlying adjustments | | |
| Hedging instruments | | |
| Net change in fair value of energy hedges | 143 | (11) |
| Net change in fair value of treasury hedges | 11 | 13 |
| Premiums paid on electricity options net of interest | (4) | (10) |
| Assets | | |
| Asset related adjustments | 8 | (11) |
| Total adjustments before tax | 158 | (19) |
| Taxation | | |
| Tax effect of above adjustments | (42) | 3 |
| **Underlying net profit after tax** | **(5)** | **175** |

# Cash flow statement

| **Cash flow statement** | | |
|---|---|---|
| **Six months ended 31 December** | **2024** | **2023** |
| **$M** | | |
| Receipts from customers | 2,410 | 2,044 |
| Interest received | 4 | 6 |
| Payments to suppliers and employees | (2,165) | (1,605) |
| Interest paid | (44) | (38) |
| Income tax paid | (155) | (104) |
| **Operating cash flows** | **50** | **303** |
| Purchase of property, plant and equipment | (104) | (143) |
| Purchase of intangible assets and investments | (20) | (12) |
| Purchase of other assets | (4) | (11) |
| **Investing cash flows** | **(128)** | **(166)** |
| Borrowings drawn | 256 | 167 |
| Borrowings repaid | (5) | (5) |
| Shares purchased for long term incentive | (6) | (2) |
| Lease liabilities paid | (1) | (1) |
| Dividends | (276) | (287) |
| **Financing cash flows** | **(32)** | **(128)** |
| **Net (decrease)/increase in cash and cash equivalents** | **(110)** | **9** |
| Cash and cash equivalents at beginning of the six months | 221 | 212 |
| **Cash and cash equivalents at end of the six months** | **111** | **221** |

# Balance sheet

| **Balance sheet** | | |
|---|---|---|
| **Six months ended 31 December** | **2024** | **2023** |
| **$M** | | |
| Cash and cash equivalents | 111 | 221 |
| Trade receivables | 297 | 458 |
| Customer contract assets | 13 | 13 |
| Financial instruments | 110 | 170 |
| Other assets | 75 | 42 |
| **Total current assets** | **606** | **904** |
| Property, plant and equipment | 12,059 | 9,031 |
| Intangible assets | 71 | 80 |
| Financial instruments | 236 | 99 |
| Other assets | 19 | 11 |
| **Total non-current assets** | **12,385** | **9,221** |
| Payables, accruals and employee entitlements | 243 | 458 |
| Customer contract liabilities | 18 | 15 |
| Current portion of term borrowings | 490 | 382 |
| Current portion of lease liabilities | 3 | 3 |
| Financial instruments | 118 | 64 |
| Current tax payable | - | 44 |
| **Total current liabilities** | **872** | **966** |
| Borrowings | 1,167 | 1,009 |
| Deferred tax | 2,857 | 2,071 |
| Lease liabilities | 27 | 28 |
| Financial instruments | 163 | 103 |
| Term payables | 60 | 63 |
| **Total non-current liabilities** | **4,274** | **3,274** |
| **Net assets** | **7,845** | **5,885** |

# Glossary

| | |
|---|---|
| Hedging volumes | buy-side electricity derivatives excluding the buy-side of virtual asset swaps |
| Average generation price | the volume weighted average price received for Meridian's physical generation |
| Average retail contracted sales price | volume weighted average electricity price received from retail customers, less distribution costs |
| Average wholesale contracted sales price | volume weighted average electricity price received from wholesale customers (including NZAS) and financial contracts |
| Combined catchment inflows | combined water inflows into Meridian's Waitaki and Waiau hydro storage lakes |
| Cost of hedges | volume weighted average price Meridian pays for derivatives acquired |
| Cost to supply contracted sales | volume weighted average price Meridian pays to supply contracted customer sales and financial contracts |
| Contracts for Difference (CFDs) | an agreement between parties to pay the difference between the wholesale electricity price and an agreed fixed price for a specified volume of electricity. CFDs do not result in the physical supply of electricity |
| Customer connections | number of installation control points, excluding vacants |
| GWh | gigawatt hour. Enough electricity for 125 average New Zealand households for one year |
| Historic average inflows | the historic average combined water inflows into Meridian's Waitaki and Waiau hydro storage lakes over the last 84 years |
| Historic average storage | the historic average level of storage in Meridian's Waitaki catchment since 1979 |
| HVDC | high voltage direct current link between the North and South Islands of New Zealand |
| ICP | New Zealand installation control points, excluding vacants |
| ICP switching | the number of installation control points changing retailer supplier in New Zealand, recorded in the month the switch was initiated |
| MWh | megawatt hour. Enough electricity for one average New Zealand household for 46 days |
| National demand | Electricity Authority's reconciled grid demand www.emi.ea.govt.nz |
| NZAS | New Zealand's Aluminium Smelter Limited |
| Retail sales volumes | contract sales volumes to retail customers, including both non half hourly and half hourly metered customers |
| Financial contract sales | sell-side electricity derivatives excluding the sell-side of virtual asset swaps |
| Virtual Asset Swaps (VAS) | CFDs Meridian has with Genesis Energy and Mercury New Zealand. They do not result in the physical supply of electricity |

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www.meridianenergy.co.nz/about-us/investors

All currency amounts are in New Zealand dollars unless stated otherwise.