2026 interim results presentation

Six months ended 31 December 2025

contact

16 February 2026

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Agenda

1H26 Highlights

Mike Fuge
Chief Executive Officer

Financial results & outlook

Matt Forbes
Chief Financial Officer

Supporting materials - Market context

Supporting materials - Financial results

1H26 highlights

contact

Delivering financial performance

+24% **EBITDAF**[1] $500M
up **$96M** YoY

+44% **NPAT** $205M
up **$63M** YoY

Interim Dividend

16cps

Delivering portfolio change

Manawa acquisition completed
>**80%** of identified cost synergies **secured in first 6 months**
(run-rate basis)

Manawa hydro and PPAs increased renewable output by **1.3TWh** in 1H26

Generation at new Te Huka 3 geothermal plant **0.2TWh** in 1H26

Delivering renewable energy growth

+26% Renewable generation YoY

97%
renewable in 1H26

Investment in Glorit solar approved
150MWac / 285GWh p.a.

TCC decommissioning
activities have commenced

Delivering for customers

Commenced electricity supply to **NZ Steel's new EAF**[2] (200GWh p.a)

AoG[3] **contract providing 2PJ** of gas to core community assets

Over **150,000 households** choosing discounted or free off-peak energy as at 31 December 2025

Delivering for shareholders

+11%

Annualised total shareholder return over 1H26[4]

MSCI

Continued representation within
DJSI and MSCI indices

Delivering for the market

Contracted 50MW Huntly Firming Option for 10 years to manage dry year risk, supporting security of supply

Investment in Glenbrook battery 2.0 approved, bolstering new renewable flexibility in the market

1. See slide 33 for a definition and reconciliation between statutory profit and the non-GAAP profit measure earnings before net interest expense, tax, depreciation, amortisation, change in fair value of financial instruments (EBITDAF). | 2. Electric Arc Furnace (EAF). | 3. All of Government (AoG). | 4. Annualised TSR (dividends reinvested) over 1H26 reflects the share price change for the half year plus dividends reinvested on the ex-dividend date. The resulting half year return is then expressed on an annualised basis to provide a like for like full year comparison.

1H26 New Zealand market context: Generation more than 90% renewable on strong hydro inflows

The market ended 1H26 in a strong stored fuel position across hydro lakes, gas and coal

Trading conditions dominated by strong hydro inflows:
Hydro inflows 128% of post market mean[1], leading to lower spot wholesale prices vs. 1H25. Market generation more than **90%** renewable.[2]

Energy storage & winter 2026:
1H26 ended with hydro lakes well above mean (129% of post market mean)[1], gas storage (AGS[3]) full and the Genesis coal stockpile at 1,131Kt (up 97% on 1H25), reducing fuelling risk for Winter 2026.

Gas scarcity remains:
Gas production for Q1 was ~16% (~5PJ) lower compared to the same period last year.[4]

Demand returns:
Demand was robust, up ~4% on 1H25, following record demand (1% normalised for NZAS[5] demand response).[6]

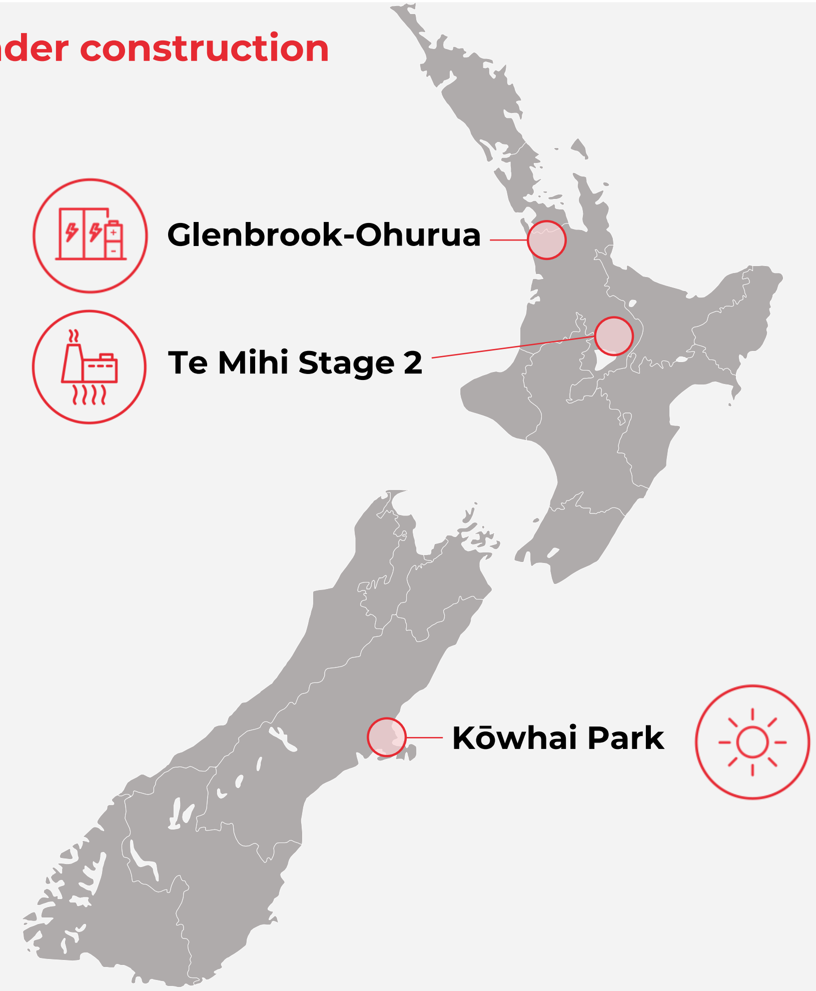
Cost & pricing pressures continue:
Lines cost increases from 1 April 2025.[7]

1. Source: NZX Hydro. 2. Source: EMI and MBIE. 3. Ahuroa Gas Storage Facility (AGS). | 4. Source: MBIE electricity & gas data. | 5. New Zealand Aluminium Smelters Ltd. On 1 July 2024, responding to dry market conditions Meridian called on its demand response contract with NZAS resulting in operations being turned down and demand for electricity being reduced temporarily in 1H25. | 6. Source: EMI and Contact. | 7. From 1 April 2025, Commerce Commission-approved changes to network charges began to take effect, increasing household bills by $10-$25 per month on average (depending on region and usage profile). Source: Commerce Commission.

Project execution: Concurrent renewable builds underway

Contact has 1.1TWh p.a. of renewable generation and 100MW battery capacity under construction

Under construction



Glenbrook-Ohurua Battery

100MW / 200MWh duration

Target online Q1 CY26

Target IRR ~8-9% at FID[1]

- Construction-complete
- Transpower and system integration nearing completion

Te Mihi Stage 2 Geothermal

101MW / ~830GWh p.a.

Target online Q3 CY27

Target IRR ~10% at FID[1]

- Site construction by EPC contractor progressing to schedule
- Cooling towers on site and supporting civils complete

Kōwhai Park Solar

150MWac / ~275GWh p.a.

Target online Q2 CY26

Target IRR ~12% at FID[2]

- Structural framework advanced (over 80% of tracker tubing installed)
- Over 50% of solar panels installed

Contact has maintained a continuous infrastructure build programme since 2021 with the Tauhara and Te Huka 3 geothermal plants now completed. This has led to strong continuity of its major projects execution expertise, key staff, suppliers and contractors.

1. Representing target ungeared project IRRs. | 2. Target Contact IRR includes joint venture returns and margin on acquired generation. Return on acquired generation will ultimately depend on sales channel and market conditions.

We have better clarity across key electricity market risks in New Zealand, providing confidence to grow and invest

Market evolution

Effect

Conclusion expected 2026

MAY 2024

NZAS extended operations

NZAS to remain operational under new long-term contract, alongside an innovative demand response agreement creating additional flexibility to improve New Zealand's energy security

All-of-government energy demand procurement

MBIE-led RFI[1] for government-wide electricity requirements, to be backed by new supply

AUG 2025

Huntly Firming Option signed

Agreement signed between major generators to manage dry year risk, supporting security of supply through the energy transition

LNG infrastructure procurement

MBIE-led procurement for supply of LNG infrastructure to support energy security

OCT 2025

Stable outcome from Government-led review

Government commissioned Frontier Economics report[2], found current market design and rules are facilitating market entry and investment in additional generation

Actions from Government-led review

Implementation of response expected to be complete mid 2026

NOV 2025

BCG: Energy to Grow report released

The report[3] shows **New Zealand is developing renewable generation at the fastest rate in its history** and highlights market challenges are largely due to the rapid decline of the gas market

Resource Management Act (RMA) reform

Planning and Environment Bills expected to pass by end of year, with stated goal of better enabling development of land, including provision of infrastructure to meet expected demand

New Zealand will have a general election on 7th November 2026 and the electricity sector is likely to remain in focus. While radical proposals may be floated, we expect mainstream parties to draw on the Government-led review and the BCG report to understand the challenges faced by the sector and the investment required.

1. Ministry of Business, Innovation and Employment (MBIE) Request for Information (RFI). | 2. 'Review of electricity market performance' by Frontier Economics, 2025. | 3. 'Energy to grow: securing New Zealand's future' by the Boston Consulting Group (BCG), 2025.

Financial results and outlook

Strong result with $500M EBITDAF reflecting investments in renewable generation

	Six months ended 31 December 2025 (1H26)[1]	Six months ended 31 December 2024 (1H25)	
EBITDAF	$500M[2]	↑	24% from $404M
Profit	$205M	↑	44% from $142M
Profit per share	20.9c	↑	17% from 17.9c
Operating free cash flow[3]	$249M	↑	80% from $138M
Operating free cash flow per share[3]	25.5c	↑	47% from 17.4c
Dividend declared (interim)	$159M	↑	24% from $128M
Dividend declared per share (interim)	16.0 c	→	No change 16.0 c
Stay-in-business (SIB) capital expenditure (cash)	$59M	↓	9% from $65M
Growth capital expenditure (cash)[4]	$166M	↓	7% from $179M

Key themes from the results

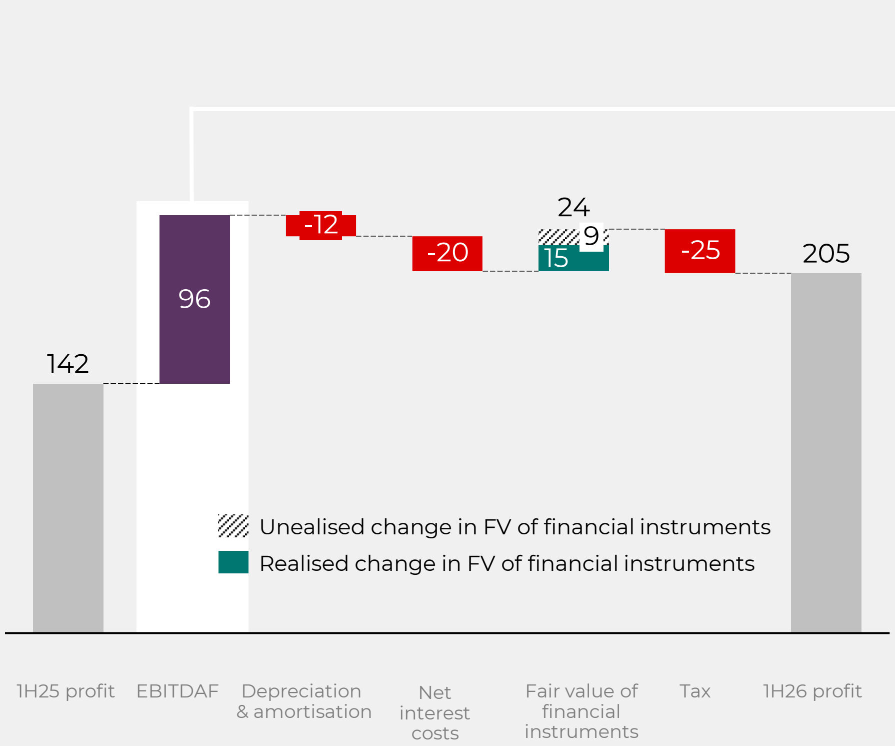
- Manawa acquisition adding 1.3TWh via hydro generation and PPA contracts
- Increasing sales to major users in the long-term inflation-protected, strategic fixed price sales channel
- Te Huka 3 plant online, supporting higher geothermal generation
- Delivering on the benefits of the Manawa acquisition (>80% of identified cost synergies secured in the first 6 months)
- Gas position secured and customers supported with long-term Greymouth contract
- 1H26 performance increases FY26 normalised and expected EBITDAF to $995M[5]

1. Includes Manawa from 11 July 2025. Prior period does not include Manawa. | 2. EBITDAF of $522M excluding Manawa transaction and integration costs of $22M. | 3. Refer to slide 17 for a reconciliation of operating free cash flow. | 4. Includes capitalised interest. | 5. $965M after Manawa transaction and integration costs.

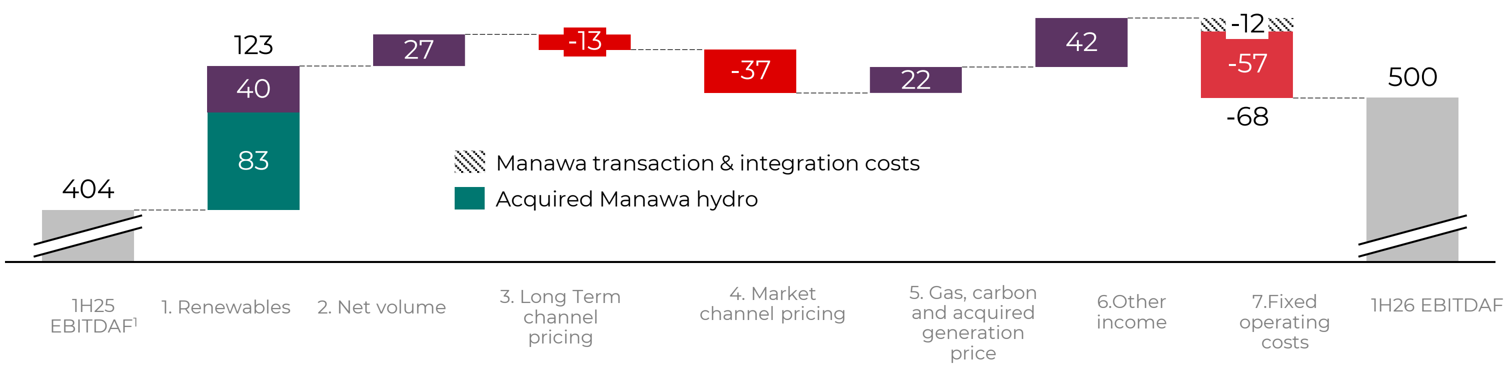
Profit of $205M for 1H26

EBITDAF up $96M (24%) on 1H25, reflecting the Manawa acquisition and increase in renewable generation

Profit, $M



EBITDAF, $M



1. Manawa generation (measured at GWAP).

2. Higher contracted sales volumes underpinned by higher generation and Manawa contracted sales acquired as part of the transaction.

3. Higher average price of strategic fixed price sales was offset by mix shift between Contact's retail and strategic fixed price sales channels

4. Hydro conditions in 1H26 led to a normalisation of CFD prices. These were elevated in 1H25 as risk management contracts reflected challenging market conditions.

5. Prior period gas and acquired generation prices were elevated by short-term Methanex gas, NZAS demand response and fuel scarcity conditions.

6. This now includes Manawa irrigation income.

   Prior period included losses on sale of excess Methanex gas.

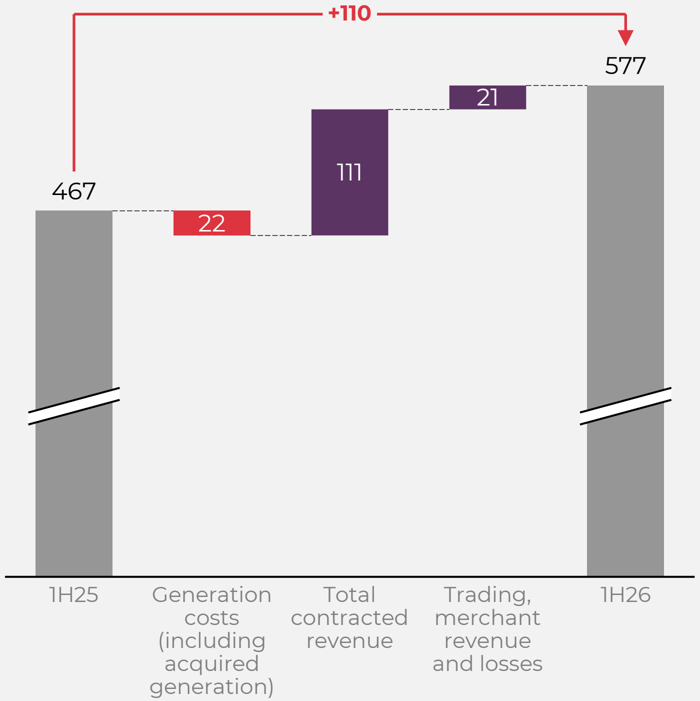
7. Manawa fixed costs, inflation impacts, non-recurrence of AGS provision unwind benefit, and transaction and integration costs ($12m higher than prior period).

1. 1H25 EBITDAF is the reported EBITDAF figure. This includes a $7M favourable unwind in the previously recognised AGS onerous contract provision. This provision was revalued and subsequently fully released in the full year FY25 results.

EBITDAF up by $96M on 1H25

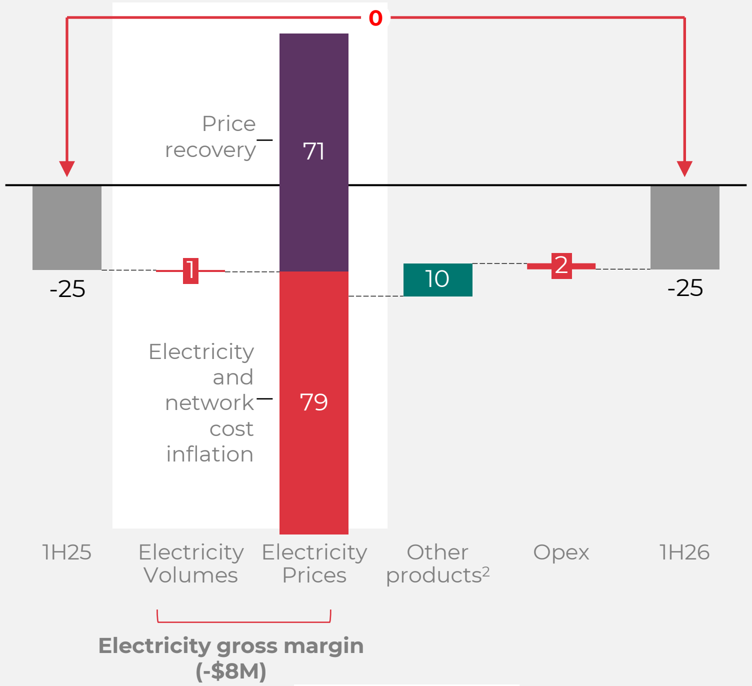
Business performance by segment

Wholesale EBITDAF[1], $M



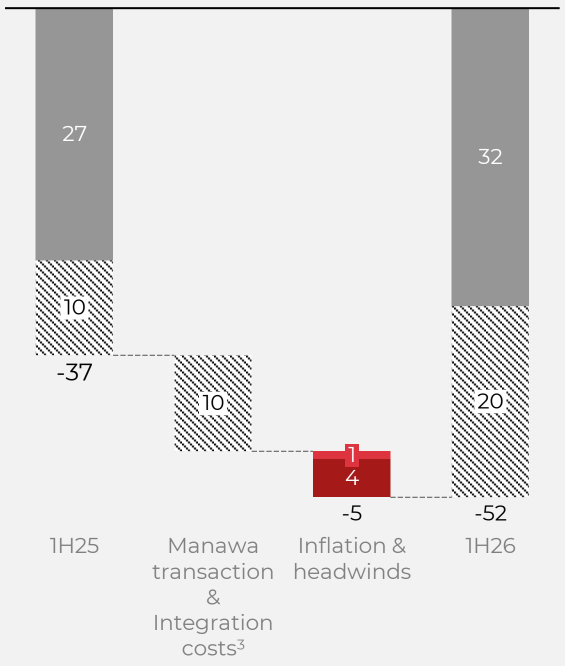
Refer to slides 12-14

Retail EBITDAF, $M



Refer to slide 15

Corporate / unallocated costs, $M

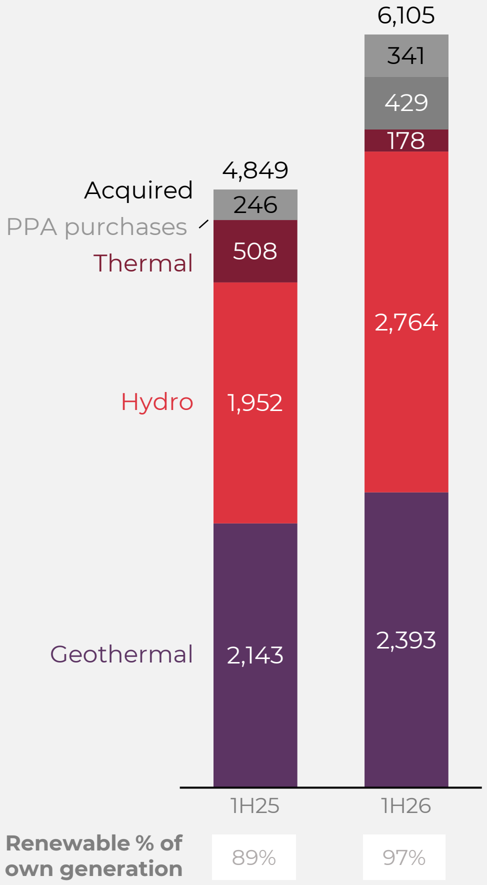


1. Simply Energy and Western Energy included within Wholesale EBITDAF. | 2. Other products includes retail gas and telco gross margins and other revenue / costs. | 3. This differs from the $12M movement referenced on slide 10 as $2M of integration costs were recognised within the wholesale business. 4. Includes higher incentive due to performance and costs associated with strategy development.

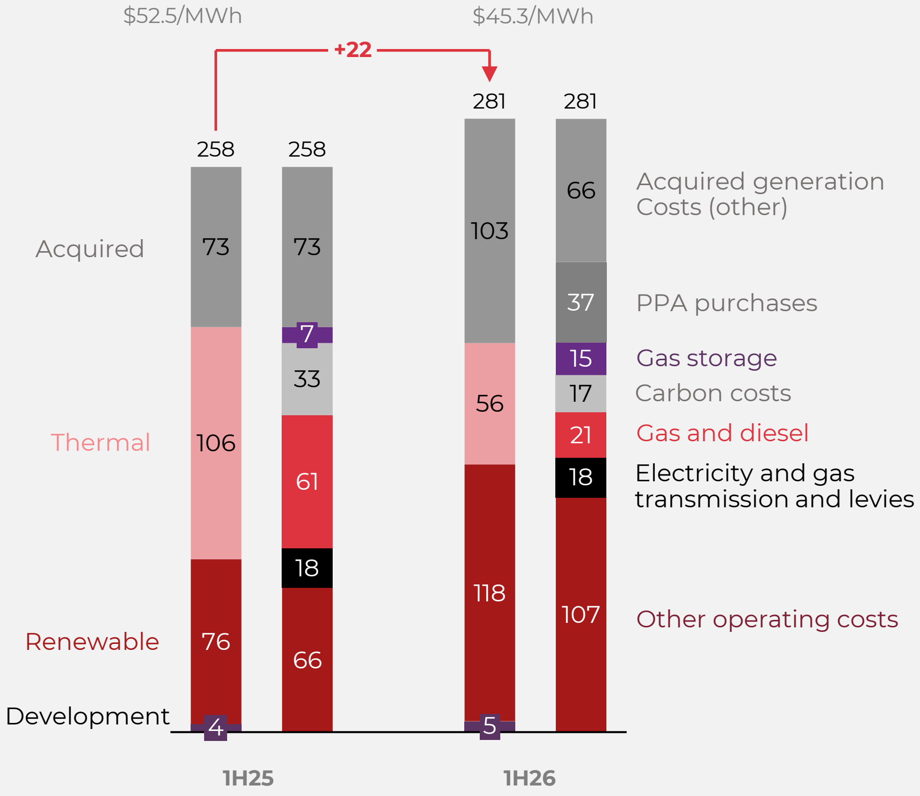
Generation costs

Costs up $22M with lower thermal costs offset by renewable generation and PPA additions

Electricity generated or acquired, GWh



Electricity generated or acquired costs, $M



Generation volumes

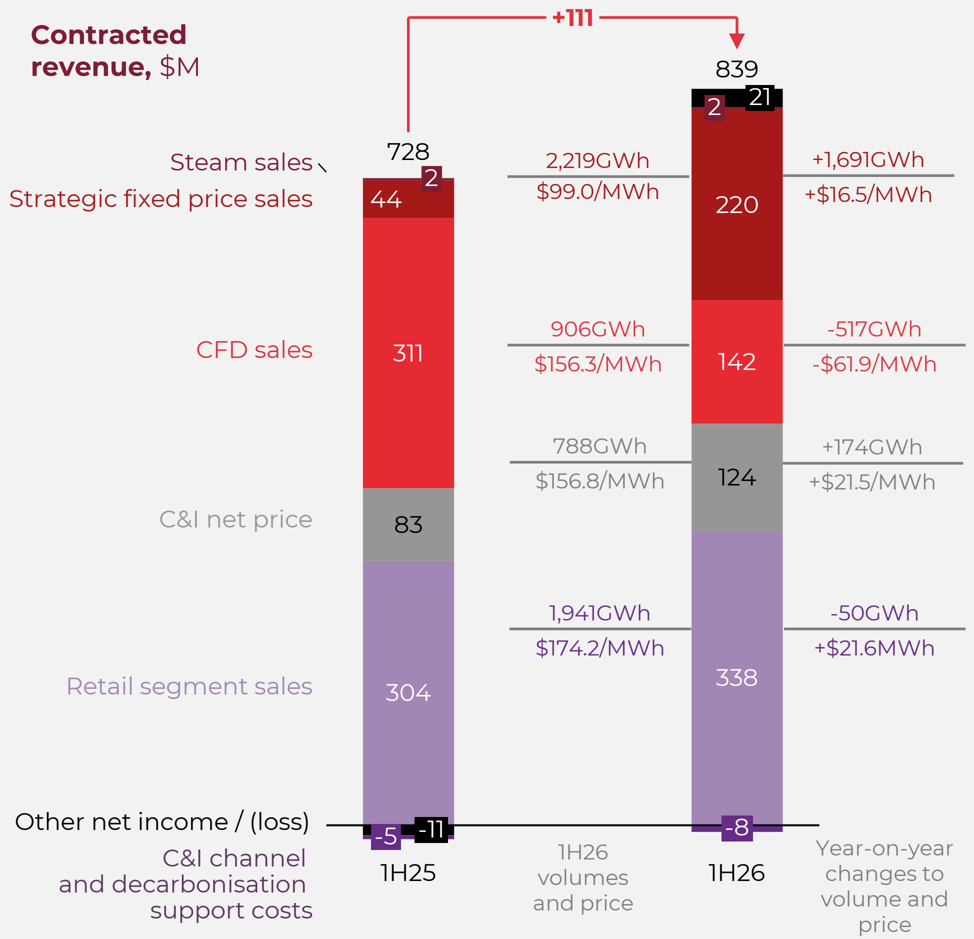
- Hydro generation of 2,764GWh was up 812GWh on 1H25 (+42%) with Manawa assets contributing 844GWh.
- Geothermal generation was up 250GWh (12%) on 1H25, attributable to Te Huka 3 being online for the full period and completion of a planned outage at Te Mihi in 1H25.
- 1H26 thermal generation volumes were down 330GWh on 1H25 (-65%). This was due to:
  - Higher thermal generation in 1H25 to make use of gas purchased from Methanex and to cover risk management CFD sales made in extreme dry conditions.
  - Reduced need within the portfolio due to increased generation from Manawa and geothermal plant.

Costs

- Renewable generation costs were up $43M (57%) owing to the inclusion of operational costs associated with Manawa, higher unit costs on geothermal carbon and higher operational costs associated with a full period of Te Huka 3.
- Thermal generation costs in 1H26 were significantly down on 1H25 from a combination of lower thermal generation volumes and a lower gas cost per unit (1H25: $15.2/GJ, 1H26: $13.6/GJ). The prior period included a benefit from the unwind of the AGS provision (+$7M).
- Despite lower cost fuel replacement CFDs, total acquired generation costs were significantly higher in 1H26 ($30M up on 1H25). This is due to the acquisition of Manawa's long-term wind and geothermal PPAs. Together these contracts added 429GWh of generation.

Wholesale contracted revenue

Strategic fixed price sales increased ~1.7TWh due to Manawa's long-term supply agreement with Mercury, a full period of Tauhara-linked PPAs[1] and higher NZAS volume

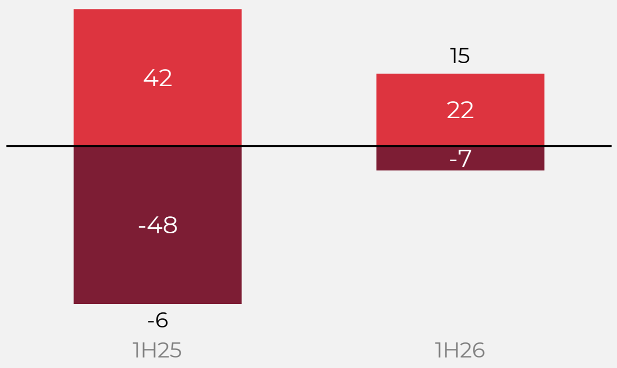


- Fixed price variable volume electricity sales to the Retail segment and C&I customers ended 124GWh higher than 1H25 (+$75M). The volume shift is attributed to C&I, from Manawa contracts acquired in the period, as Retail volumes reduced.
  - Pricing to C&I was up on last year aided by the inclusion of higher priced contracts from Manawa.
  - Transfer price to the Retail channel was up $21.6/MWh to $174.2/MWh reflecting higher wholesale prices over the three preceding years. This transfer price increase was not fully passed through in customer tariffs.
- Strategic fixed price sales were up 1,691GWh (320%) on 1H25 from a combination of:
  - The acquisition of the long-term Mercury CFD from Manawa (588GWh).
  - A full period of Tauhara-linked CFDs (240GWh marginal uplift on 1H25).
  - Increase in sales to NZAS (337GWh marginal uplift on 1H25).
  - An increase in long-term strategic CFDs in line with Contact's focus on this channel.
  - Pricing: Average pricing across this channel was $16.5/MWh higher as new long-term agreements better reflect Contact's long-run view of electricity pricing.
- CFD sales volumes were down 517GWh (36%) as a result of a significant risk management contract sold to Meridian in 1H25. Prices were down by $61.9/MWh reflecting the change in market conditions in 1H26 compared to the extreme dry conditions at the beginning of 1H25.
- Steam sales were steady in both volume and revenue compared to 1H25.
- Other net income was significantly higher on 1H25 (+$32M). This was due to the inclusion of irrigation net income from Manawa (+$5.6M), and a return to profitability on sale of gas not used for generation or stored (the loss on sale of excess gas purchased from Methanex was $18M in1H25).

1. Power Purchase Agreements (PPAs).

Wholesale trading and merchant revenue

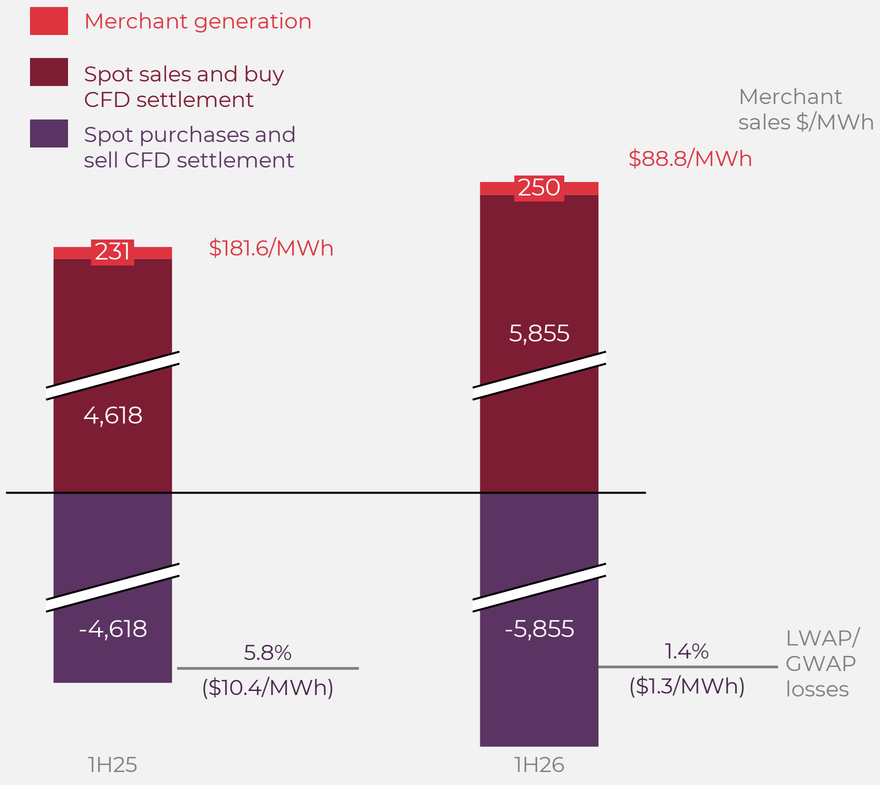
Trading EBITDAF, $M



Trading revenue

- **Merchant sales:** short-term sales channel available when spot prices exceed the opportunity cost of Contact generation.
- **LWAP / GWAP[1] losses:** locational price differences between where electricity is generated and purchased.

Long / short position, GWh



- Total merchant generation volume for the period was up marginally on 1H25 reflecting Contact's larger portfolio with the addition of the Manawa assets.
- Through the late winter months, Contact had a neutral–to-long position as the market called for additional thermal generation. In Q2, with large hydro inflows, this position shifted to being largely neutral (to slightly short) as surplus water was spilled at prices below Contact's cost of generation.
- The variation in the market between Q1 and Q2 combined in a way that significantly reduced Contact's location losses (LWAP / GWAP cost) for the period.
  - In Q1, higher and more consistent prices meant Contact's LWAP / GWAP costs were reduced and largely covered.
  - In Q2, high inflows saw spot prices drop to very low levels. This reduction in price resulted in very low absolute LWAP / GWAP spreads, significantly reducing Contact's overall LWAP / GWAP losses.

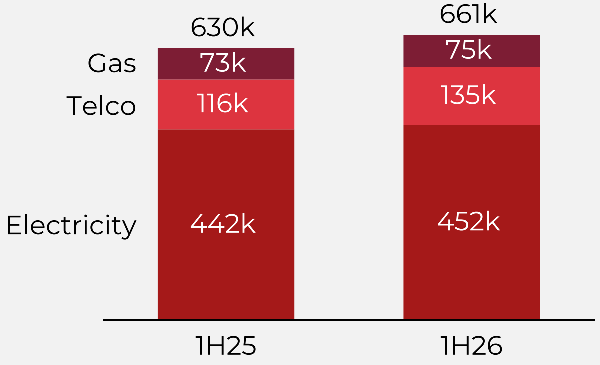
1. Location Weighted Average Price (LWAP) / Generation Weighted Average Price (GWAP).

Retail business performance

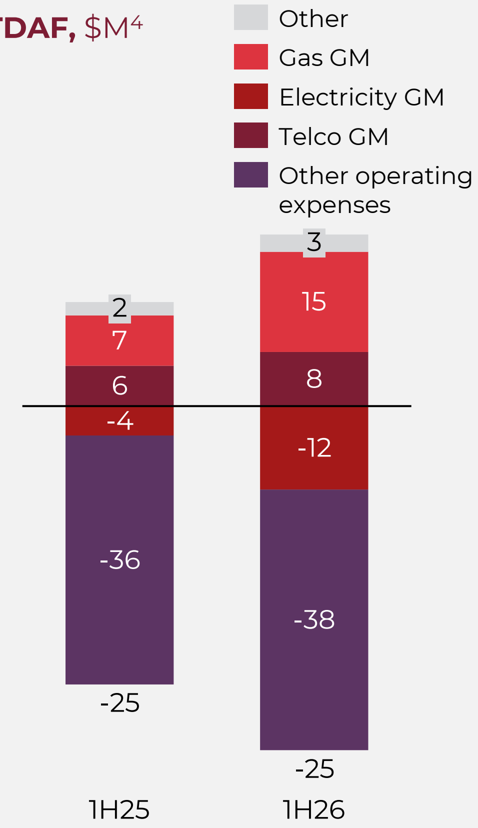
Electricity margins contract as wholesale electricity and lines costs rise faster than tariffs; Contact gaining connections via time-of-use and multi-product offerings

Revenue & Tariff, $M[1]	1H25	1H26		Variance	
	$M	$M	*Tariff[1]*	$M	*Tariff*
Electricity revenue	544	609	333	65	41
Gas revenue	52	83	46	31	3
Telco revenue	48	57	72	8	1
Other income	4	3		(1)	
Total revenue	**648**	**752**		**103**	
# of connections (closing)[2]	*630k*	*661k*			
Cost to serve / connection[3]	*$57*	*$58*			

Closing connections, 000's[2]



EBITDAF, $M[4]



	1H25	1H26
Electricity transfer price[5]	$153/MWh	$175/MWh
Networks, meters and levies[5]	$122/MWh	$145/MWh

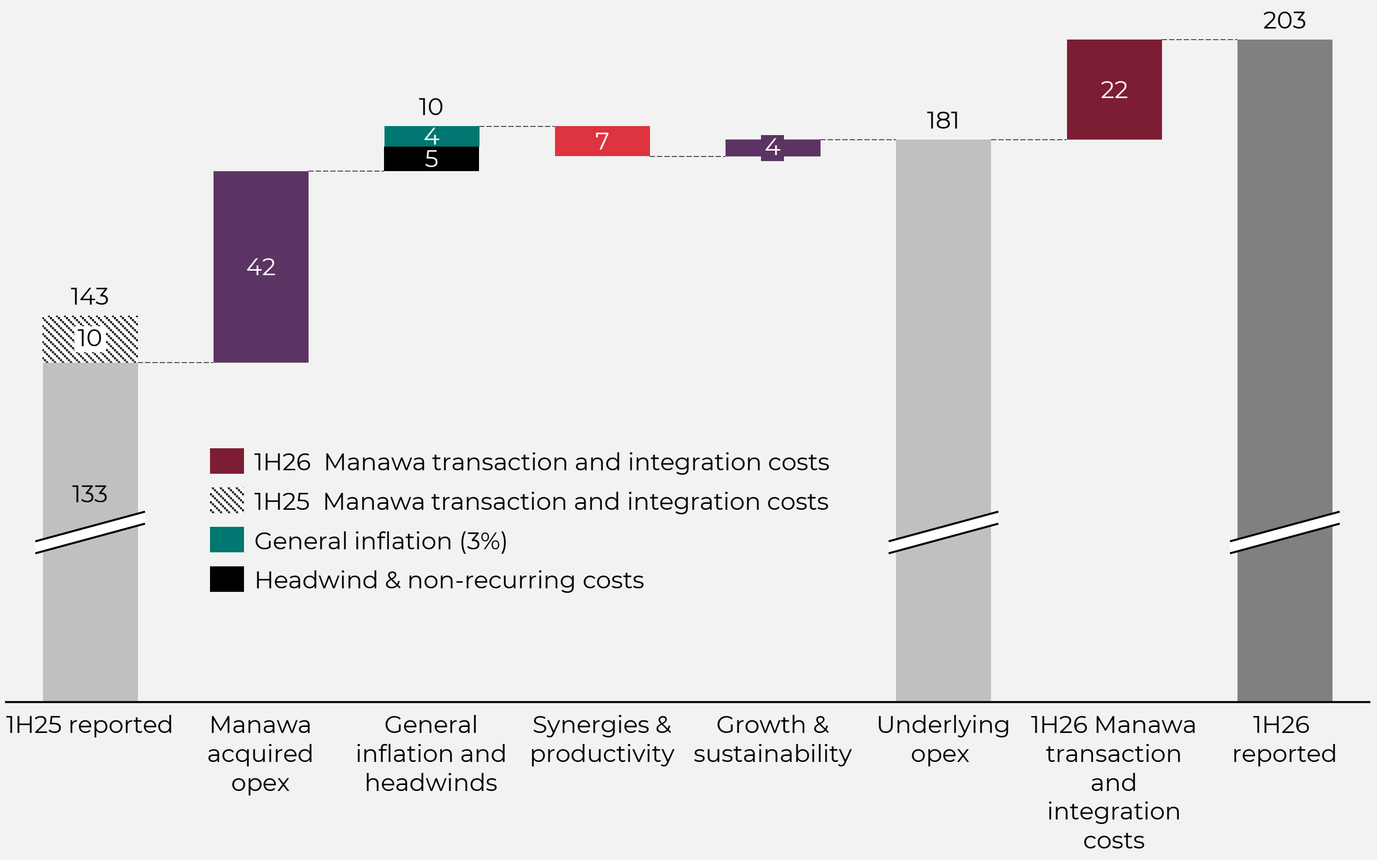
- Retail margins in line with 1H25, with unfavourable electricity margin, driven by high energy costs and rising lines costs, offset by improved gas and broadband margins.
  - Retail electricity margin decreased by $8M on 1H25 largely driven by the $79M increase in electricity input costs that were not fully passed through to customers.
- Contact's average retail electricity tariff increased by 14% reflecting price rises to fully recover lines costs and partially offset rising energy costs.
  - Around 90% of eligible customers received a price increase in the last 12 months, with higher average increases than in 1H25.
  - In-market acquisition price is ~9% higher than 1H25.
- As the energy industry decarbonises, cost pressure for retailers is expected to remain, as a result of:
  - Ongoing significant investment in lines infrastructure.[6]
  - Elevated wholesale futures prices over the medium term.

  Contact will continue to prudently reflect these costs in its retail tariffs to electricity consumers.
- Connections grew strongly since 2H25 through a focus on multi-product customers growing telco and Time of Use (ToU) electricity 'Good Plans' and securing the 'All of Government' gas contracts.
  - Total connections up 31k on 1H25 with telco up 19k and energy up 12k.
  - Multi-product customers up 7% on 1H25, driven by telco products alongside ToU 'Good Plans' growth.
- Cost to serve – up $1/connection, largely driven by wage inflation, partially offset by productivity improvements through continued growth in digitalised interactions.

1. Tariff is $/MWh for electricity, $/GJ for gas and $ per month per customer connection for Telco. | 2. Retail connections only, excludes Simply Energy. | 3. Reflects total operating costs (direct and indirect) / average connections. Includes customer acquisition costs. | 4. Gross Margin (GM) is Revenue less Cost of Goods (Networks, meters, levies, energy, carbon and telco). | 5. Input costs shown per MWh at the GXP. | 6. From 1 April 2025, Commerce Commission-approved changes to network charges began to take effect, increasing household bills by $10-$25 per month on average (depending on region and usage profile). Source: Commerce Commission.

Operating cost increase largely reflects the acquisition of Manawa

Other operating cost movement, $M



Manawa other operating costs

- $42M acquired Manawa related operational opex from 11 July 25.

Base movement

- $4M general inflation of 3% impacting operating costs. These have been seen across the business, including labour cost.
- $5M headwinds related to:
  - Higher generation business costs.
  - Higher incentive due to performance.
  - Costs associated with the strategy development.
  - Support for staff energy costs.

Synergies delivered

- $6M in-period Manawa related cost synergies achieved in 1H26 within opex (run-rate of $25M achieved on cost synergies within opex).
- $1M savings from productivity improvement in the retail business.

Growth and sustainability

- $2M incremental costs with Te Huka 3 online.
- $1M incremental investment related to retail connection growth.

Manawa related costs

- Transaction and integration related costs incurred were $12M higher than prior period (transaction costs +$5M, integration costs +$7M).

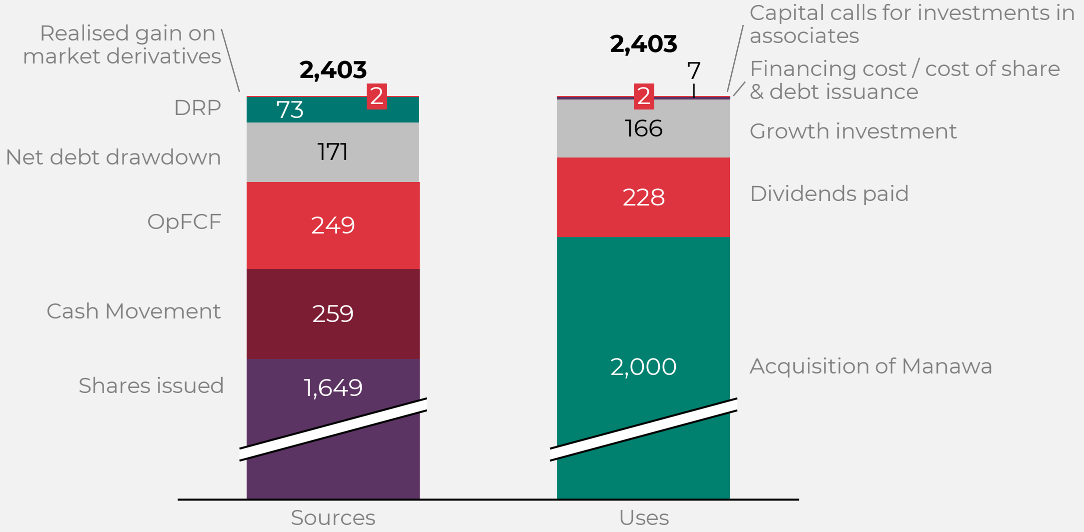
Cash flow and capital expenditure

Cash conversion for 1H26 driven by higher EBITDAF and reduced value of fuel inventory reflecting return of gas to Methanex

	6 months ended 31 December 2025 (1H26)	6 months ended 31 December 2024 (1H25)	Comparison against 1H25	
EBITDAF	$500M	$404M	↑	$96M
Working capital changes	($68M)	($80M)	↑	$12M
Tax paid	($67M)	($74M)	↑	$7M
Interest paid, net of interest capitalised	($61M)	($43M)	↓	($18M)
SIB capital expenditure	($59M)	($65M)	↑	$6M
Non-cash items included in EBITDAF	$4M	($4M)	↑	$8M
Operating free cash flow	$249M	$138M	↑	$111M
Operating free cash flow per share	25.5 c	17.4 c	↑	8.1c
Cash conversion (OpFCF / EBITDAF)	50%	34%	↑	16%

- Higher underlying EBITDAF reflecting Manawa acquisition and renewable growth.
- Working capital changes were $12M lower than in the prior year due to lower value and levels of stored gas, reflecting gas returned to Methanex, and lower net carbon asset / liability offset by net movement in debtors / payables.
- Interest paid, net of capitalised interest, was $18M higher than 1H25, mainly due to increased borrowing in support of the Manawa acquisition.
- 1H26 stay-in-business (SIB) capital expenditure includes previous accelerated programme ($6M), geothermal and hydro enhancement projects and integration ($8M), Wairakei extension ($6M) and risk-rated and improvement projects ($39M).

Sources and uses of cash, $M



Growth capital expenditure

Growth capital expenditure in 1H26 reflects Contact's continued commitment to renewable development

Growth capital expenditure – cash basis, $M

	Up to 30 June 2025	6 months ended 31 Dec 2025	Remaining under approvals at 31 Dec 2025	Total
Tauhara	905	20	6	931
Te Huka 3	292	8	5	305
Te Mihi Stage 2	201	75	435	712
Wind	21	4	4	29
Glenbrook-Ohurua battery	91	44	28	163
Capitalised interest	196	10	66[2]	272
Other[1]	-	5	-	5
Total	**1,707**	**166**	**544**	**2,417**

Investment in joint ventures and associates, $M

	Up to 30 June 2025	6 months ended 31 Dec 2025	Remaining under approvals at 31 Dec 2025	Total
Solar[3]	-	-	37	37
CO_2	6	1	2	9
Forestry	83	1	0	84
Total	**89**	**2**	**39**	**130**

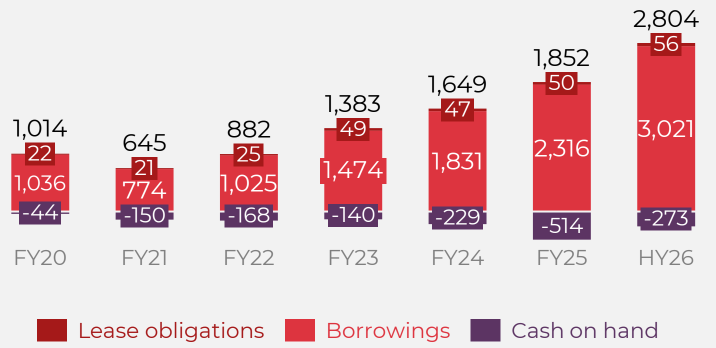
- Construction continued on three major renewable projects: the Glenbrook-Ohurua battery, the Kōwhai Park solar farm, and the Te Mihi Stage 2 geothermal plant.
- The totals shown reflect board-approved funding and include pre-FID sunk costs of $66M for Te Mihi Stage 2 geothermal and $5M for the Glenbrook-Ohurua battery.
- Tauhara geothermal plant is complete and underwent its first statutory outage in November 2025. Final costs in relation to that outage are still to be paid.
- Construction of Te Huka 3 geothermal plant is complete. Remaining spend reflects final milestone payments due post-completion.
- Contact does not currently have any wind projects under construction. The reported wind development spend reflects pre-FID activity only.
- For major growth projects, Contact capitalises interest from the point of FID—or from the commencement of significant pre-FID works—through to commissioning. The capitalisation rate reflects the average interest rate across the portfolio.
- Contact's investment in the Kōwhai Park solar farm is accounted for as an investment in joint ventures.

1. Relates to pre FID spend on renewable and battery opportunities. | 2. Relates to Te Mihi Stage 2 and Glenbrook-Ohurua battery development. | 3. Excludes pre-FID development expenses for solar which are captured within receivables.

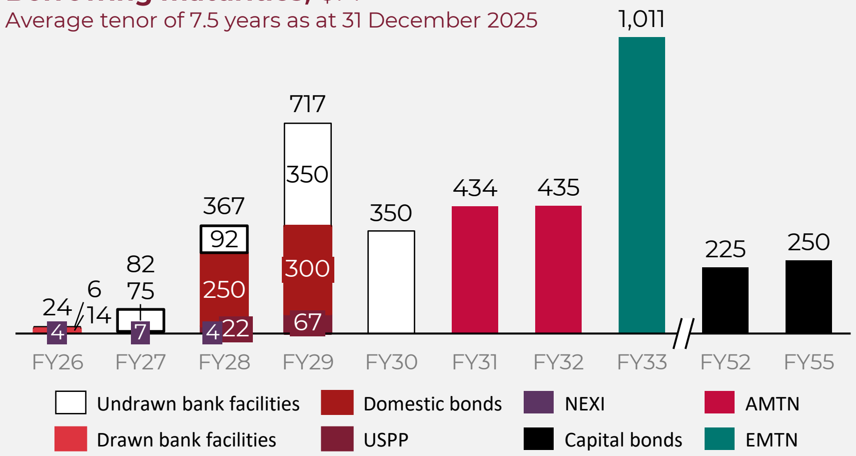
Diversified approach to funding

Underpins efficient access to capital and strong liquidity

Closing net debt, $M
Face value of borrowings less cash

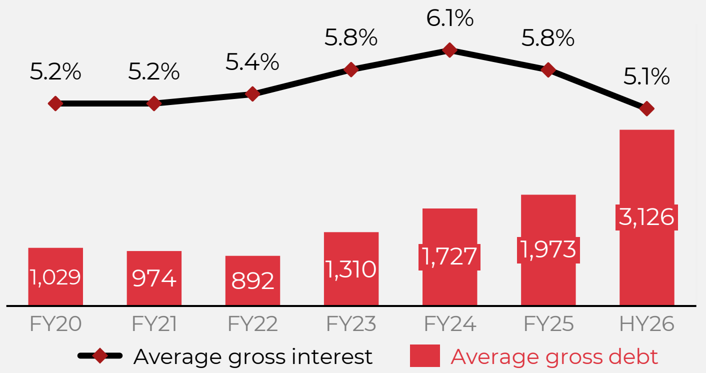


Borrowing maturities, $M
Average tenor of 7.5 years as at 31 December 2025

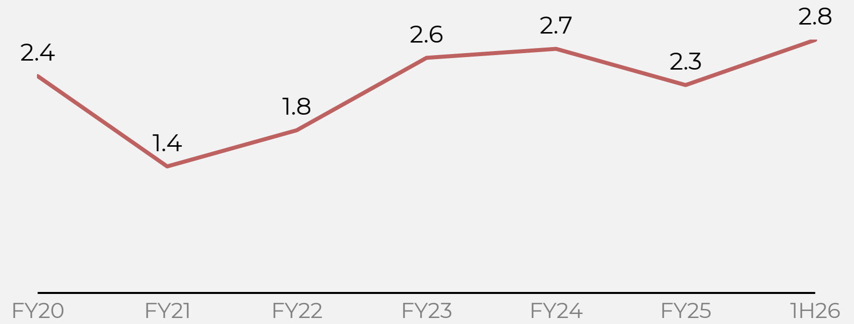


- As part of the Manawa acquisition, a $1.011B EMTN was issued resulting in an overall increase in gross debt. This debt was certified green against the Green Bond Principles under Contact's Sustainable Finance Framework.
- Contact targets a BBB investment grade credit rating with S&P. This requires net debt to EBITDAF to remain below 3.0x over a sustained period. Point estimate S&P net debt to EBITDAF is currently 2.8x at the half year[2]. Contact's EBITDAF outlook, DRP and capacity for further hybrid bonds allow this metric to be managed effectively.
- Following the acquisition of Manawa Energy, Contact has transitioned its $850M Sustainability-Linked Facilities into Green Loan Facilities[3] to better align with the Contact31+ strategy, reflect our significantly lower operating emissions, and focus funding on our renewable hydropower and geothermal assets under our DNV-verified Sustainable Finance Framework.

Interest rate, %
Weighted average gross interest[1] on average borrowings



Net debt to EBITDAF, X
Includes S&P adjustments[2]

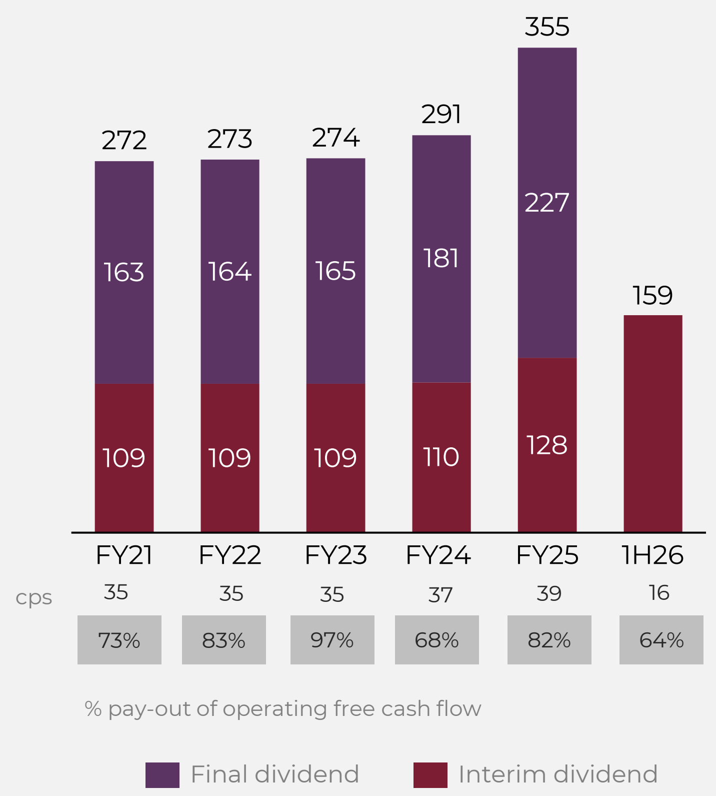


1. Gross interest includes all interest on borrowings, bank commitment fees and deferred financing costs. Unwind of leases, provisions and capitalised interest not included. | 2. Illustrated here on a point basis based on expected S&P adjustments. S&P provides an annual ratings analysis on full year information. The 1H26 ratio is Contact's indicative analysis based on adjustments equivalent to S&P's historic approach. S&P's approach can change at any time. For the 1H26 ratio, Contact's estimate of the equivalent S&P adjusted net debt at 31 December 2025 is $2,721m. This adjusts net debt for fair value adjustments, restoration of environmental provisions and hybrid bond credits. For the 1H26 ratio, Contact's estimate of the equivalent S&P adjusted EBITDAF is $974m based on FY26 normalised and adjusted EBITDAF after Manawa integration costs, before Manawa transaction costs, and adjusted for expected realised losses on market derivatives and share based compensation. | 3. Term also extended by 12 months.

Dividend for 1H26

Dividend of 16cps in 1H26 is consistent with an indicative 40cps total dividend for FY26[2]

Ordinary dividends declared, $M



Interim dividend for 1H26 of 16 cents per share

- Interim dividend of 16 cents per share is imputed to 56% or 9 cents per share for qualifying shareholders.
- Record date of 19 February 2026[1]; payment date of 25 March 2026.
- The NZD/AUD exchange rate used for the payment of Australian dollar dividends will be set on 12 March 2026.

Dividend reinvestment plan (DRP)

- Shareholders will have the option of full, partial or no participation. If a shareholder elects to participate, they will remain in the plan at the same participation level until they elect to terminate or amend their participation level.
- A 2% discount will be offered for the FY26 interim dividend as described below.
- The Board has exercised its discretion in exceptional or unusual circumstances to adjust the volume weighted sale price so that the DRP Strike Price will be set equal to the lower of (i) the DRP Strike Price calculated under the usual DRP methodology applying a 2% discount as contemplated under the terms of the DRP; and (ii) the New Zealand dollar Issue Price payable under the Retail Offer announced by Contact on 16 February 2026.
- Dividend reinvestment plan application forms must be in by 20 February 2026 to confirm participation in the plan.
- Trading period for setting the price for the DRP is 18 February 2026 to 24 February 2026. DRP strike price will be announced on 12 March 2026 and allotment of the new shares is expected to occur on 25 March 2026.

Dividend expectations

- Contact reaffirms its expectation to lift the total dividend in FY26 to 40cps and between 41 and 42cps in FY27.[2]
- Reliable ordinary dividends are expected to increase over time with growth in operating free cash flow.[2]

1. Contact has received a waiver from the NZX to enable it to shorten the five business days' notice period prescribed by the NZX Listing Rules between the announcement of this dividend and its Record Date. Any shareholders wishing to adjust their shareholdings prior to the Record Date for the dividend will need to make any trades prior to market close on 17 February 2026 in order for the adjustment to become effective by the Record Date. | 2. All future dividend decisions are at the discretion of the Board at the time. These are dependent on business and market conditions when each payment decision is made.

1H26 results: Normalised & expected performance

1H26 outperformance increases FY26 normalised & expected EBITDAF by $15M to $995M[1]

Equivalent to $965M on a reported basis after Manawa transaction and integration costs

1H26 assumptions that align to initial normalised & expected EBITDAF of $945M (reported) for FY26

1 Channel choices maximise long term value[2]		X	2 Net price[3] driven by best commercial practices	=	Total
Strategic fixed price	2,075GWh	x	$95/MWh	=	$197M
CFDs	850GWh	x	$155/MWh	=	$132M
C&I	875GWh	x	$165/MWh	=	$144M
Retail	2,000GWh	x	$164/MWh	=	$328M
Other income[4]					$50M
					$851M

3 Hydrology & asset availability optimise generation		X	4 Access to and price of fuel* drives financials & risk position	=	Total
Hydro	3,050GWh	x	$0/MWh	=	-$0M
Geothermal	2,475GWh	x	$4/MWh	=	-$10M
Thermal	138GWh	x	$215/MWh[5]	=	-$29M
Renewable PPAs	415GWh	x	$100/MWh	=	-$42M
Market acquired	100GWh	x	$260/MWh[6]	=	-$26M
					-$107M

5 Trading delivers value offsetting locational losses		6 Digitalisation & continuous improvement optimise fixed costs	
Length[7]	$68M	Transmission / Storage	-$45M
Location losses[8]	-$68M	Operating expenses – underlying	-$192M
Total		Opex - integration and transaction costs	-$28M
	-$0M		**-$265M**

Normalised & Expected 1H26 at start of year

Lower renewables
Renewable generation below mean (-369GWh) at expected thermal SRMC ($215/MWh)

Increased long-term channel price
Strategic fixed price sales price of $99/MWh in 1H26 ~$4/MWh higher than full year expectation

Lower market channel price
C&I and merchant sales prices were both lower, offset by higher CFD prices

Location losses
GWAP:LWAP spread was -$10/MWh lower than forecast
see slide 14 for further information

Gas, carbon, acquired generation price
Lower thermal unit costs (due to the lower heat rate of TCC), and lower acquired generation than expected

Net volume impact
Lower sales volumes were offset by meeting sales with more acquired & thermal generation at lower prices

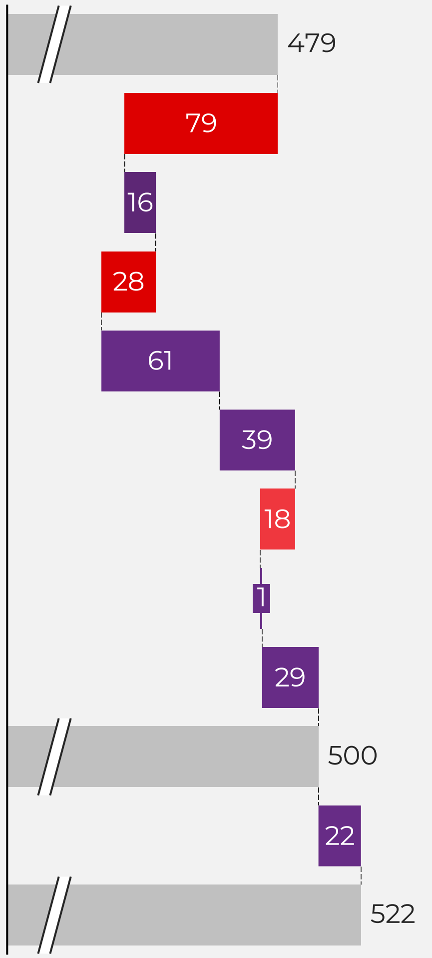
Other income
Other income was higher from improved margin on gas sales

Fixed costs
Transmission & storage costs were $12M lower than forecast, supported by LCE rebates. Integration & transaction costs were $6M lower than forecast.

Reported 1H26 EBITDAF

Manawa transaction & integration costs

1H26 EBITDAF normalised for Manawa transaction and integration costs



1. Normalised and expected EBITDAF assumes mean hydrology and wind for the year and assumes planned asset availability/capacity i.e. adjusts for planned in-year outages (e.g. geothermal statutory outages, hydro refurbishments).
2. All volumes are at the Grid Exit Point (GXP).
3. Net price is equal to tariff less pass-through costs (network, meters and levies) /MWh.
4. Steam sales, retail gas gross margin, broadband gross margin and other income.
5. Gas price of $16/GJ, carbon price of $80/unit and thermal portfolio heat rate (10.5GJ/MWh).
6. Acquired generation price includes premiums paid for HFO (operational from 1 Jan 2026) and NZAS demand response.
7. Length of 378GWh for 1H26 assumed.
8. Locational losses of 6.5% on spot purchases and settlement of CFDs sold at a wholesale price of $180/MWh.

* Fuel is natural gas and carbon costs

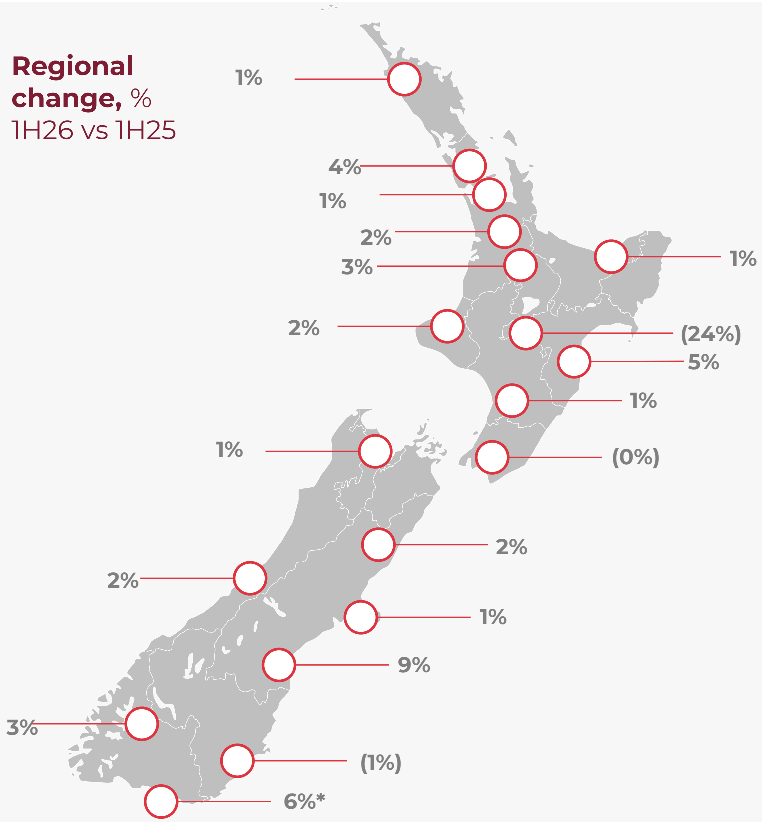
Supporting materials

Market context

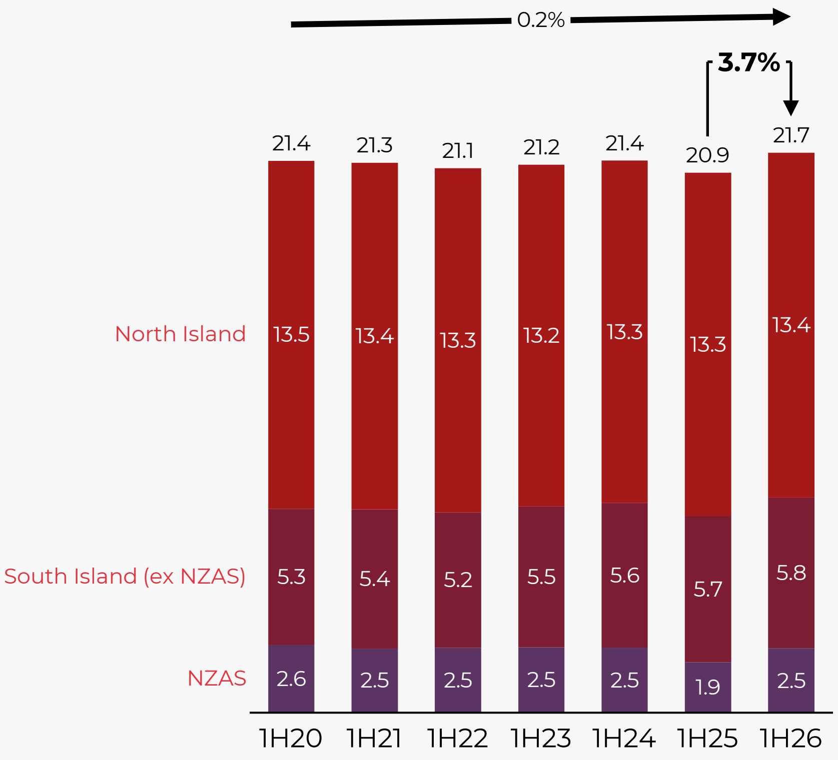
National electricity demand up ~4%

National New Zealand electricity demand up ~4% on 1H25 (up ~1% normalised for NZAS)

Regional change, % 1H26 vs 1H25



National electricity demand, TWh



Total national electricity demand increased by 0.8TWh (3.7% from 1H25).

- Demand at the Central North Island node was down 24% following the closure of the Winstone Karioi pulp mill and Tangiwai sawmill in August 2024, reflecting broader challenges in wood and paper processing without the protection of fixed price electricity hedging.
- Seasonal conditions at irrigation nodes, along with population growth, have resulted in a 9% increase in demand in South Canterbury.
- Adjusting for NZAS demand response – called by Meridian in 1H25 to support challenging hydro conditions – ***demand was up ~1%.***

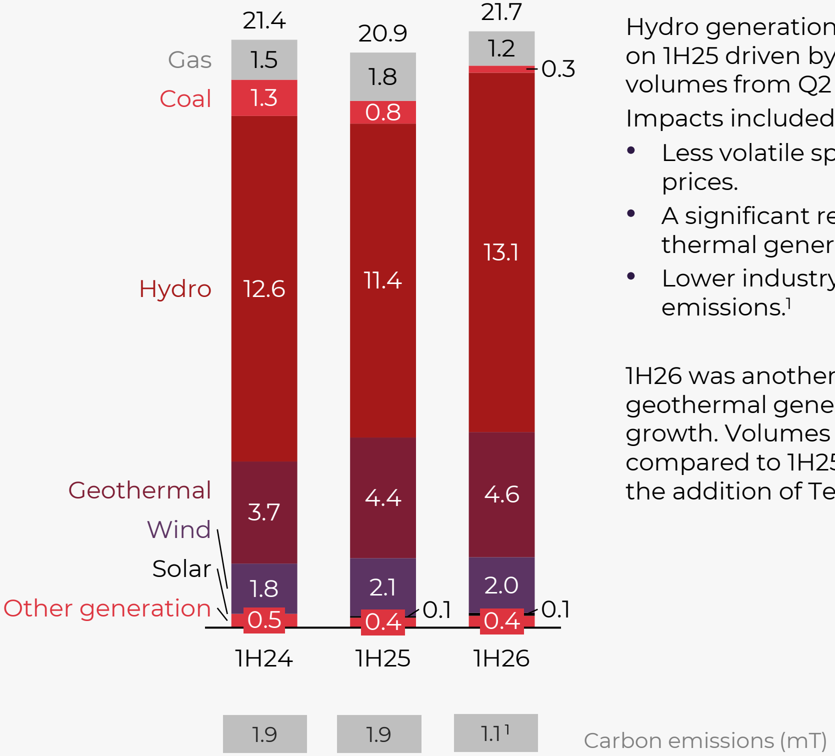
Source: EMI, Contact.
*Does not include NZAS

Source: EMI, Contact. EMI demand data is grossed up to account for losses in distribution networks.
NZAS: New Zealand Aluminium Smelters Ltd.

Generation >90% renewable backed by hydro and new geothermal

Significant reduction in thermal fuel consumption

Generation by type, TWh



Hydro generation was up 14.5% on 1H25 driven by high inflow volumes from Q2 1H26.

Impacts included:

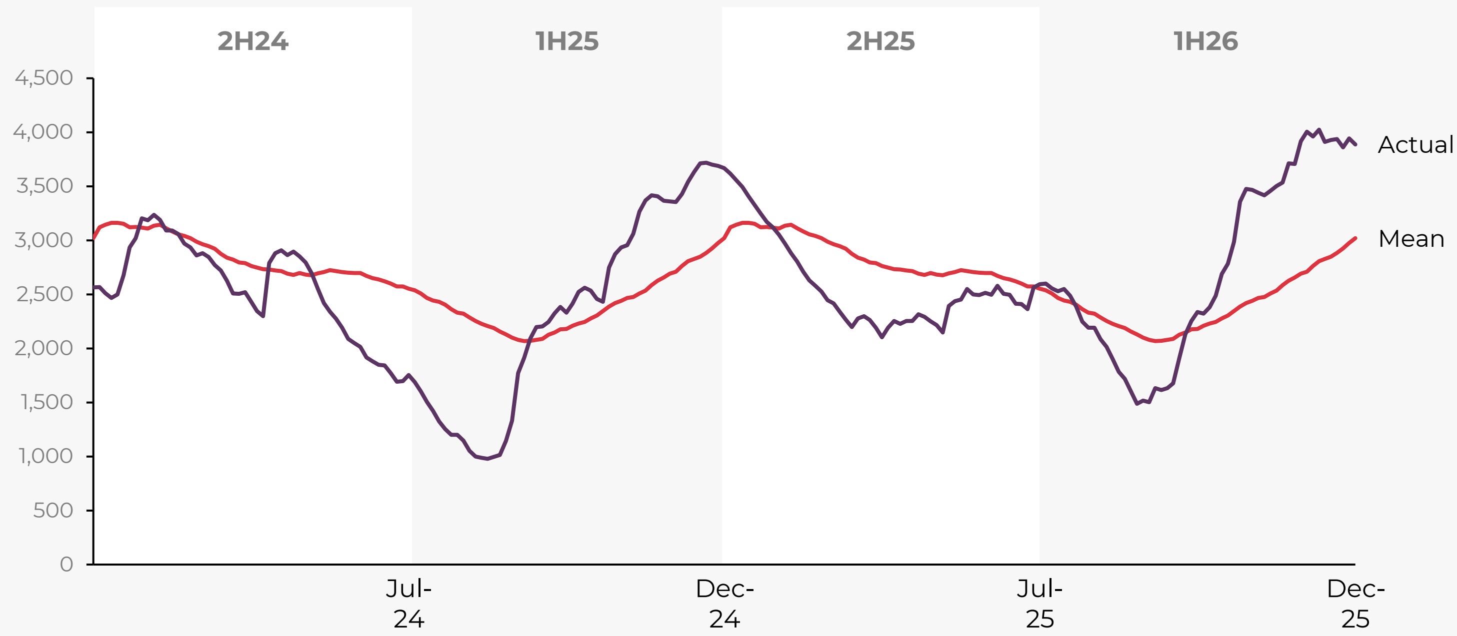
- Less volatile spot wholesale prices.
- A significant reduction in thermal generation.
- Lower industry carbon emissions.[1]

1H26 was another period of geothermal generation volume growth. Volumes were up ~4% compared to 1H25 backed by the addition of Te Huka 3.

Carbon emissions decreased in 1H26 due to an absolute reduction in thermal generation and a fuel mix away from diesel[2], gas and coal – which all saw volumes significantly lower than 1H25.

Source: EMI & MBIE

National hydro storage, GWh



National hydro storage levels began 1H26 just above historical mean. Levels declined through July, reaching their lowest point at the end of August. From early September, storage increased rapidly due to several heavy rainfall events, which continued into October and again in November, resulting in storage ending the period well above mean. The higher hydro storage and strong inflows reduced the need for gas by ~29% and coal by ~69%.

Source: NZX Hydro – mean represents post-market mean storage volumes.

1. Carbon emissions for 1H26 Oct-Dec quarter have been estimated using historic conversion rates with actual generation data. | 2. Diesel generation volume (0.37GWh) is included in other generation figures.

The market responds to changes in supply and demand through price signals across different time horizons

Short-term external factors that can influence the market include:

Hydro storage and inflow volumes

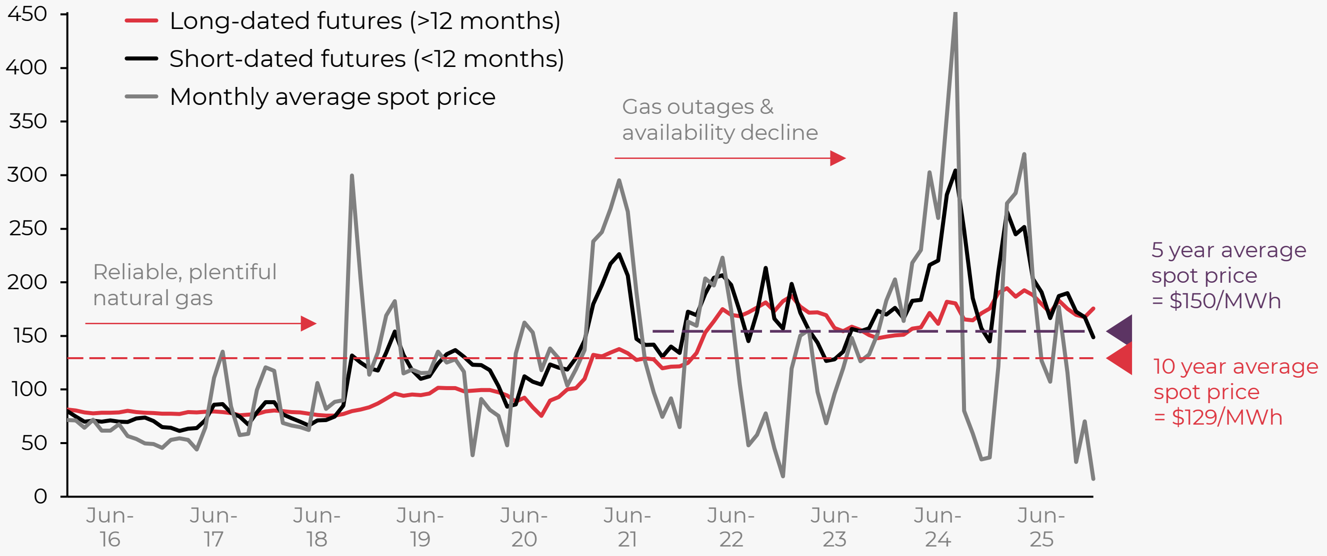
Gas prices / availability

Demand
(marginal demand sets price)

Long-term pricing is linked to the long-run marginal costs of new renewable projects, plus costs associated with firming renewable intermittency.

Contact expects the long-term wholesale price to revert to **$115-125/MWh[1].**

Wholesale and futures electricity pricing, $/MWh



Source: EMI wholesale pricing, OTA, to 31 December 2025.

Spot wholesale electricity prices in the period responded sharply to significant rainfall in Q2 with prices subdued as hydro and renewables replaced thermal in the national offer stack.

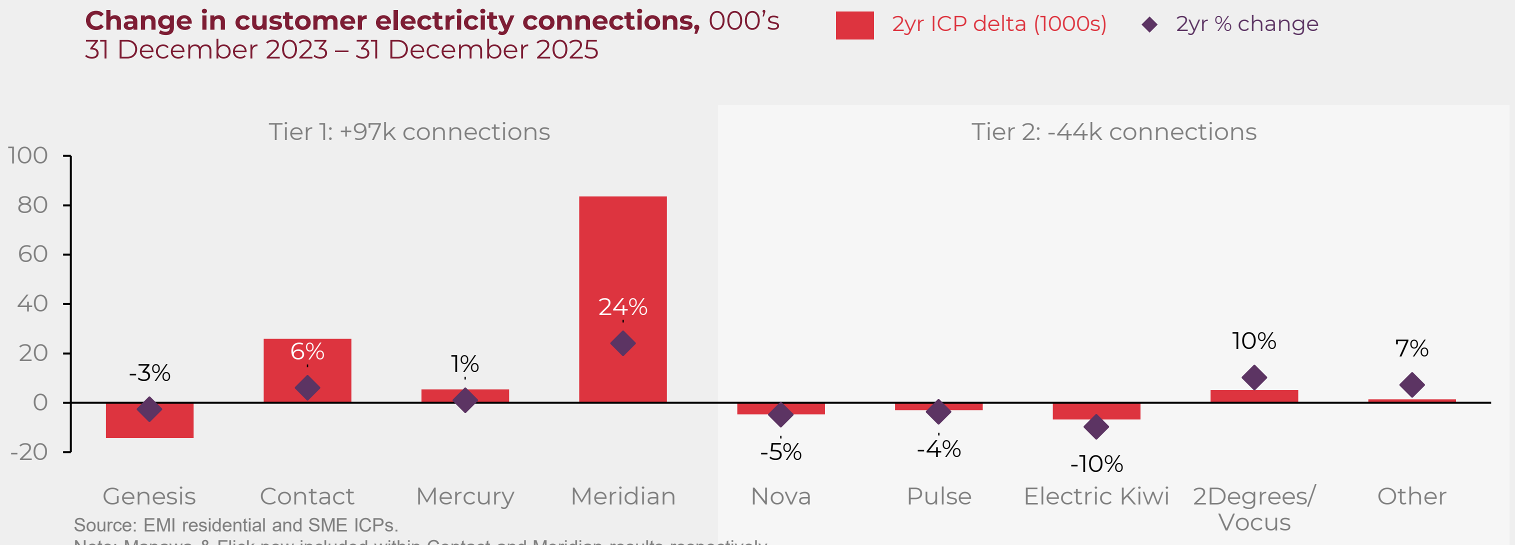
Short-dated futures (for CY26) followed spot prices lower as hydro lakes filled, reduced use of thermal pushed stored gas volumes in AGS up, and Genesis replenished it's coal stockpile (backed by the HFO), reducing the risk of fuel scarcity in Winter 2026. Long dated futures are reflecting the long-run marginal cost of developing renewable generation.

1. 2025 real – Otahuhu Node OTA, Auckland. This is a through-the-cycle measure in a balanced market. Prices achieved are a function of the market at a point in time.

Differences in retail strategies apparent

Electricity and lines costs continue to rise

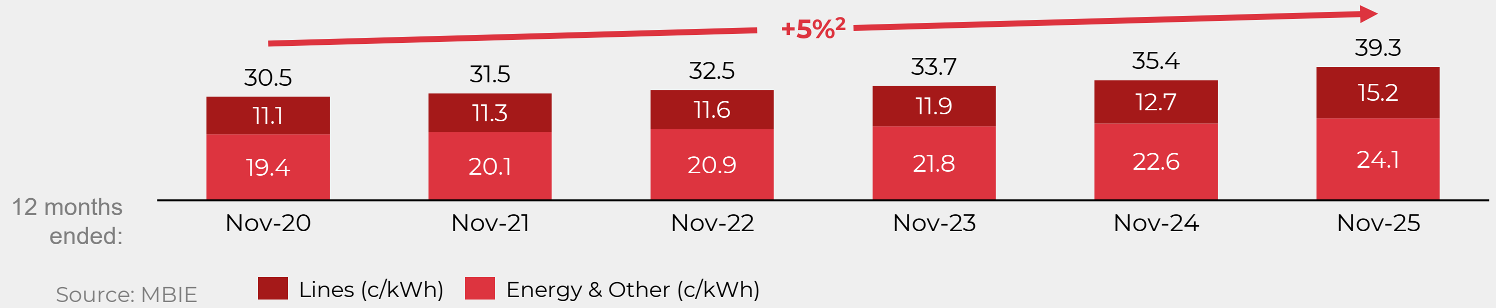
Change in customer electricity connections, 000's
31 December 2023 – 31 December 2025



Source: EMI residential and SME ICPs.
Note: Manawa & Flick now included within Contact and Meridian results respectively.

- Competition remains intense and market churn continues to reflect this with residential switching at ~21%[3].
- In May 2025 Meridian entered into an agreement to purchase Flick Electric. The deal resulted in Meridian adding ~41k ICPs and increasing market share to ~19%.
- Tier 1 retailers have a seen an increase in market share to ~87% in December 2025 (~84% December 2023).
- Tier 2 retailer growth rates have been mixed. This paired with the sale of Flick Electric has resulted in a collective decline in market share to ~13% (~16% December 2023).
- Since 31 December 2023, 2Degrees has grown connections by 5k (+10.0%) while Nova (-5k), Pulse (-3k) and Electric Kiwi (-7K) have seen a decrease in connections.
- Contact electricity connections are up +26k from December 2023 to December 2025, resulting in a ~20% market share.

Retail electricity tariff changes, c/kWh[1]



Source: MBIE

- Increasing wholesale energy and, more recently, network costs have resulted in a lift in residential electricity tariffs with the compound annual growth rate of 5% across the last five years to November 2025.
- Average tariff increases for the year to November 2025 of 11% were above consumer price inflation (~3.1%)[4], with residential price increases rising to cover both increasing lines costs and to continue the partial recovery of energy costs.
- Input cost pressure for retailers is expected to continue with ongoing significant network cost increases.

1. Inclusive of GST. | 2. Compound annual growth rate. | 3. EMI, 12 month rolling rate across residential ICPs and all switch types. | 4. Stats NZ CPI index increase in the 12 months to December 2025.

Supporting materials

Financial results

Guidance confirmation

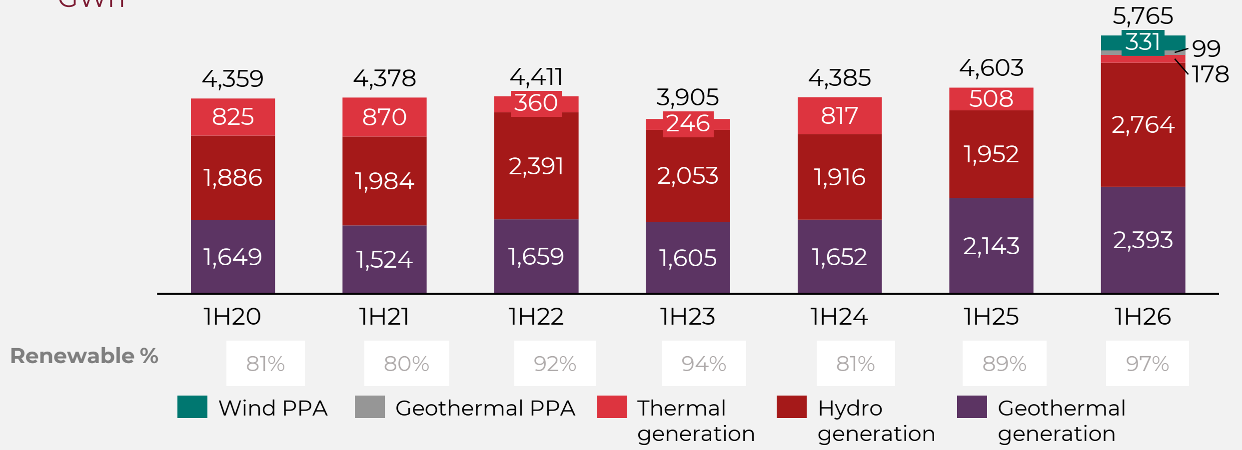
	Updated FY26 guidance	1H26 result	Change to prior guidance	
Stay in business (SIB) capex (cash)	**$170M - $185M**	**$59M**	-$5M	
SIB capital expenditure BAU	$115M - $125M	$39M	-	
SIB accelerated programme	$12M – $13M	$6M	-	
SIB capital expenditure Wairakei	$20M - $25M	$6M	-	
SIB capital expenditure enhancements and integration	$18M - $22M	$8M	-$5M	Reduction on deferment of geothermal well enhancements to FY27 and timing of cash payments for Highbank and Coleridge.
Growth capital expenditure (cash)[1]	$500M - $510M	$166M	+$110m	Increase due to approval of Glenbrook battery 2.0 and Tauhara 2 drilling.
Depreciation and amortisation	$280M - $290M	$142M	-	
Net interest (accounting)	$115M - $125M	$72M	-$35M	Reduction in interest expense and cash flow due to reduction in interest rates and impact of equity raise on short term borrowing requirements.
Cash interest (in operating cash flow)	$105M - $115M	$61M	-$35M	
Cash taxation	$120M - $130M	$67M	-$10M	Reduction in final FY24 tax cash payment due to utilisation of prior period tax credits.
Realised (gains) / losses on market derivatives not in a hedge relationship (cash)	$5M - $10M	-$1M	-$5M	Reduction in total losses in reflection of 1H26 actuals.
Corporate costs – ex Manawa	$60M - $70M	$32M	+$10M	Updated as guidance reflected Contact corporate costs only. Manawa corporate costs were all previously allocated to wholesale. As integration progresses, allocations may be updated.
Corporate costs - Manawa transaction and integration	$25M - $35M	$20M	-$5M	
Target ordinary dividend per share	40 cps (FY)	16cps (interim)	-	In line with target payout of 40 cps – Interim dividend 40% of the expected total.
Operating cash flow conversion	50%	50%	-	

1. Growth capital expenditure includes capitalised interest, and investments in joint ventures.

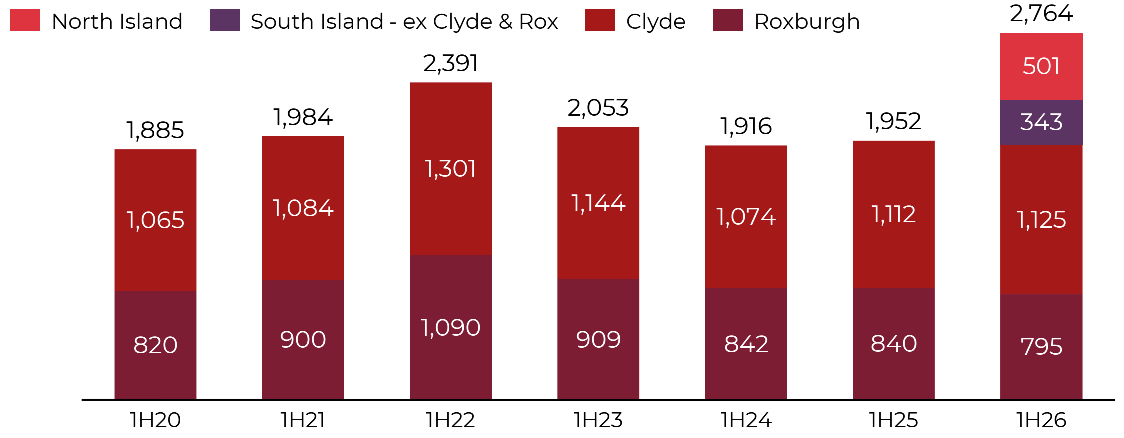
Operational data

Generation and sales position

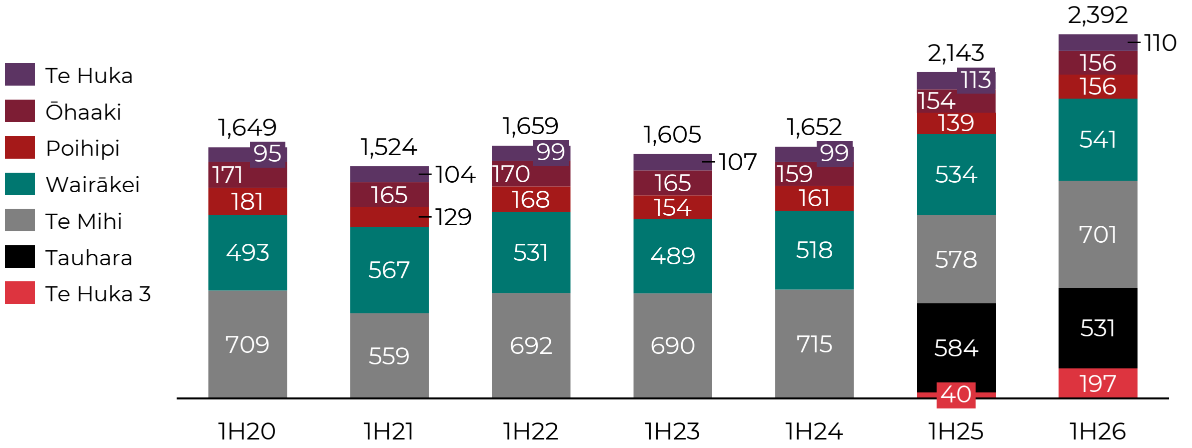
Contact generation output and long term PPA purchases sold to the national grid, GWh



Hydro generation, GWh

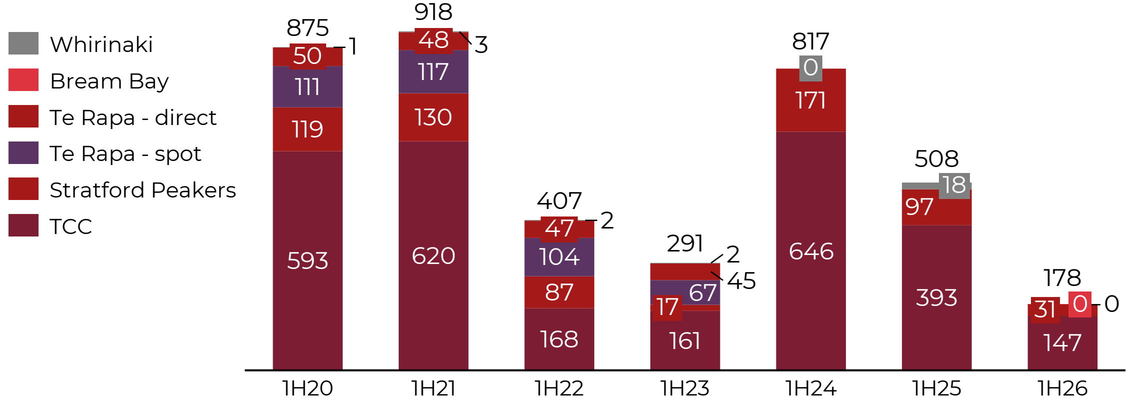


Geothermal generation, GWh



Geothermal generation was up 250GWh (12%) on 1H25, the uplift is attributable to Te Huka 3 being online for the full period and completion of the major statutory turnaround at Te Mihi in 1H25.

Thermal generation, GWh



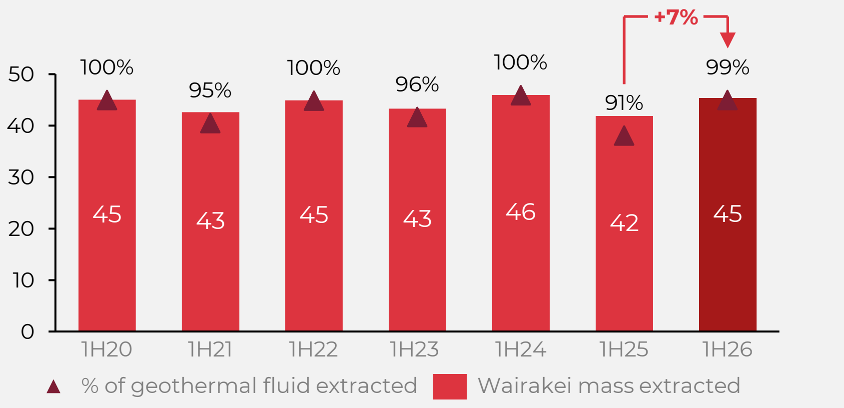
1H26 thermal generation volumes were down 330GWh, 65% lower than 1H25 due to significant hydro inflows in the second quarter of 1H25, in conjunction with new geothermal output, leading to reduced reliance on thermal generation.

Operational data

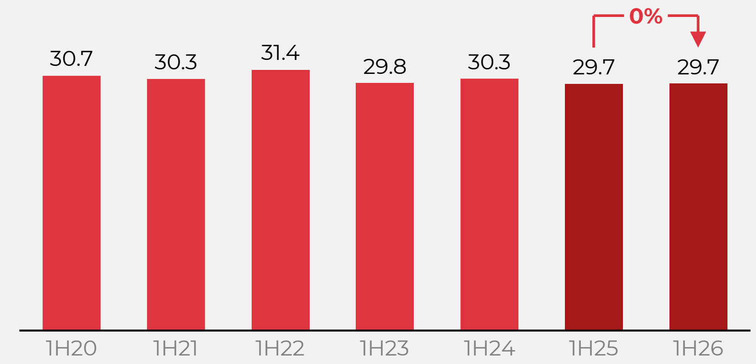
Plant and fuel performance

Geothermal fuel performance

Geothermal fuel extracted at Wairakei vs consented, mT



Wairakei, Poihipi and Te Mihi conversion effectiveness, MWh per kT extracted



Plant availability

Hydro

	Net capacity, MW	Availability[1]	Capacity factor	Electricity output, GWh	Pool revenue $/MWh	Pool revenue $M
1H22	784	83%	69%	2,391	90	215
1H23	784	87%	59%	2,053	52	107
1H24	784	93%	55%	1,916	123	235
1H25	784	92%	57%	1,952	129	252
1H26	1,295	91%	50%	2,764	100	275

Taranaki combined cycle (TCC)

	Net capacity, MW	Availability[1]	Capacity factor	Electricity output, GWh	Pool revenue $/MWh	Pool revenue $M
1H22	377	100%	10%	168	183	31
1H23	377	89%	10%	161	107	17
1H24	377	69%	39%	646	127	82
1H25	377	100%	23%	393	418	164
1H26	377	93%	9%	147	183	27

Whirinaki & Bream Bay

	Net capacity, MW	Availability[1]	Capacity factor	Electricity output, GWh	Pool revenue $/MWh	Pool revenue $M
1H22	158	98%	0%	2	783	1.8
1H23	158	97%	0%	2	274	0.4
1H24	158	100%	0%	0	0	0.0
1H25	158	95%	3%	18	667	12
1H26	167	97%	0%	0	219	0.1

Geothermal

	Net capacity, MW	Availability[1]	Capacity factor	Electricity output, GWh	Pool revenue $/MWh	Pool revenue $M
1H22	410	96%	92%	1,659	105	175
1H23	410	94%	89%	1,605	56	89
1H24	410	95%	91%	1,652	134	221
1H25	584	90%	80%	2,143	167	357
1H26	649	89%	83%	2,392	82	197

Stratford Peakers

	Net capacity, MW	Availability[1]	Capacity factor	Electricity output, GWh	Pool revenue $/MWh	Pool revenue $M
1H22	202	74%	10%	87	216	19
1H23	202	57%	2%	17	190	3
1H24	202	56%	19%	171	152	26
1H25	202	60%	11%	97	123	12
1H26	202	77%	3%	31	143	4

Upcoming geothermal statutory turnarounds (outages)[2]

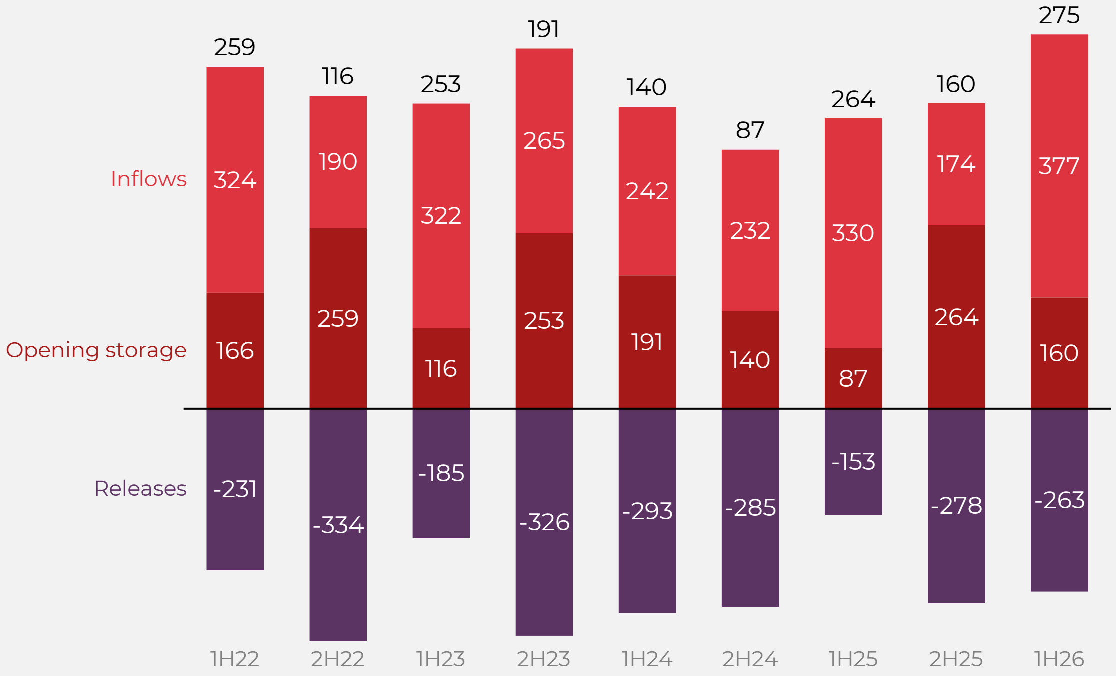
Plant	Impact, GWh	FY	Frequency & type
Tauhara	*113*	*26*	*Y1 Stat turnaround, complete*
Te Huka 3	37	26	Y1 Stat turnaround
Wairakei	25	26	4y Stat turnaround
Te Huka 1&2	25	27	4y Stat turnaround
Wairakei	320	27	4y Stat turnaround + ext works
Poihipi	31	28	4y Stat turnaround
Te Mihi Stage 2	73	28	Y1 Stat turnaround
Tauhara	169	28	Y3 Stat turnaround
Te Huka 3	37	28	Y3 Stat turnaround

1. Availability Factor calculation includes all station outages (Planned, Maintenance, Forced) but does not consider plant deratings. | 2. Statutory turnarounds occur after the first operating year of a new plant, again in operating year 3, and every four years thereafter. The table shows which plant have a major statutory turnaround in the next 3 calendar years. The GWh impact is an estimate based on understood scope at the time of publishing. Turnarounds in FY27 and FY28 are indicative.

Operational data

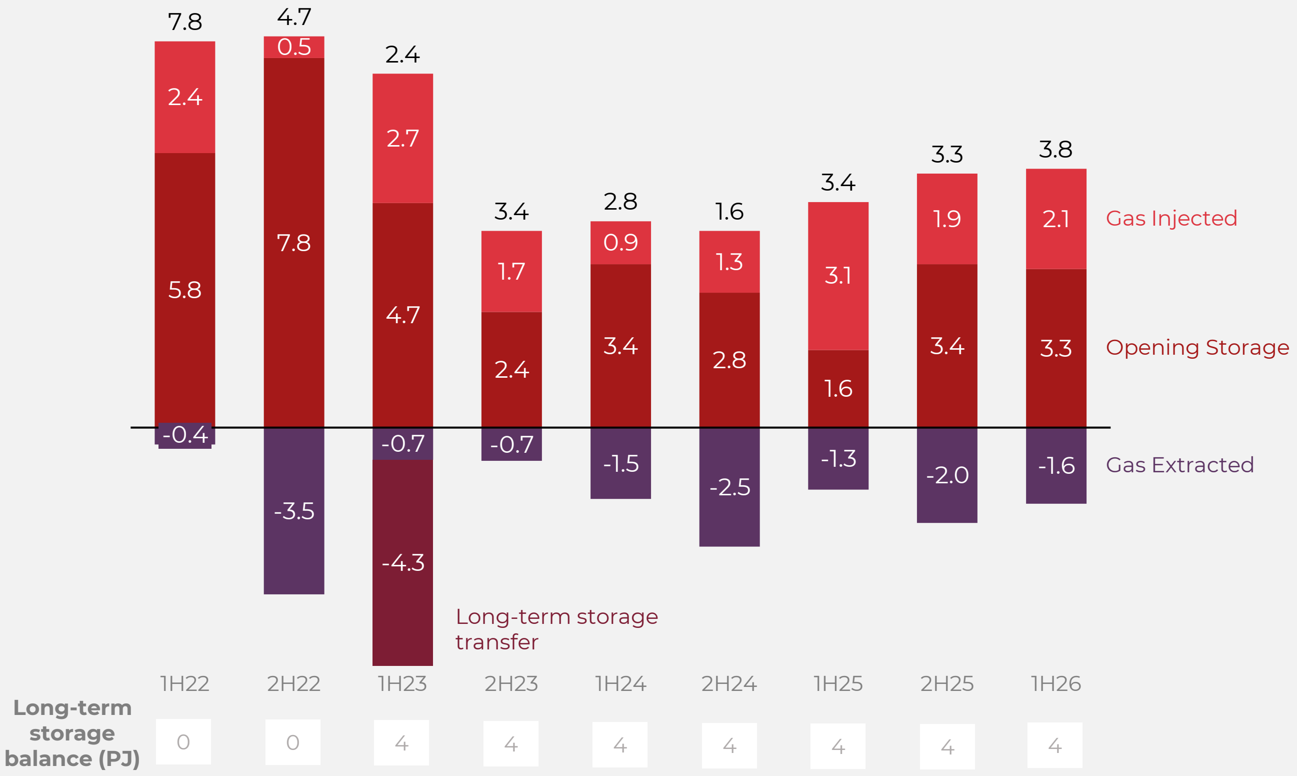
Fuel storage movements

Hawea storage, GWh
Closing storage



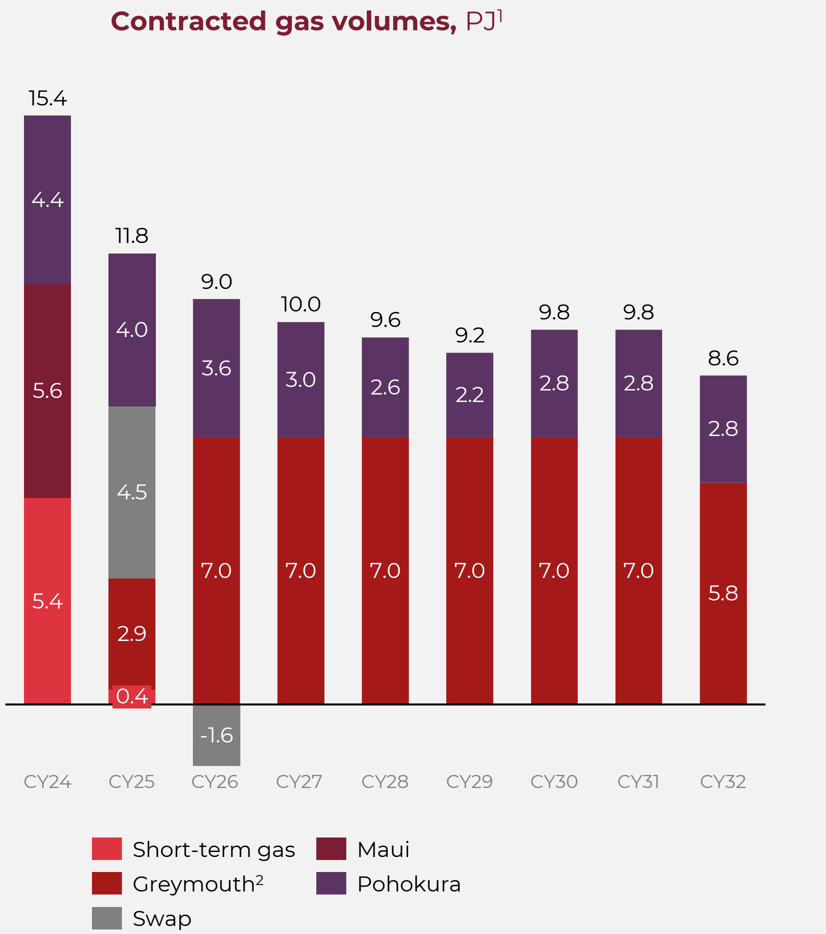
Source: NZX hydro

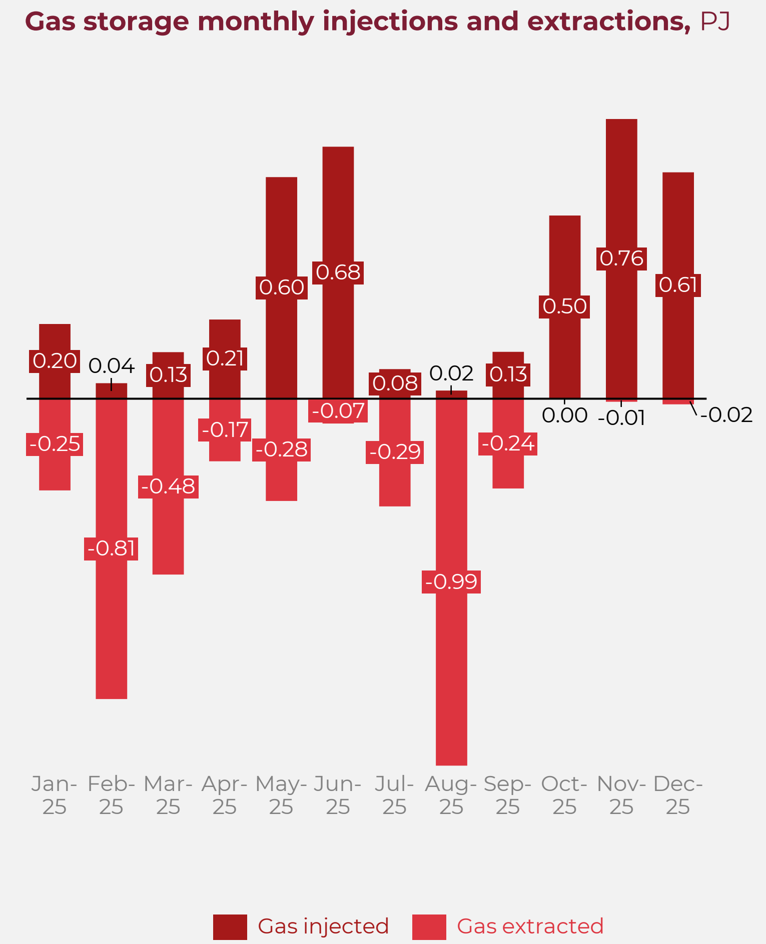
Gas storage, PJ
Closing storage (current)

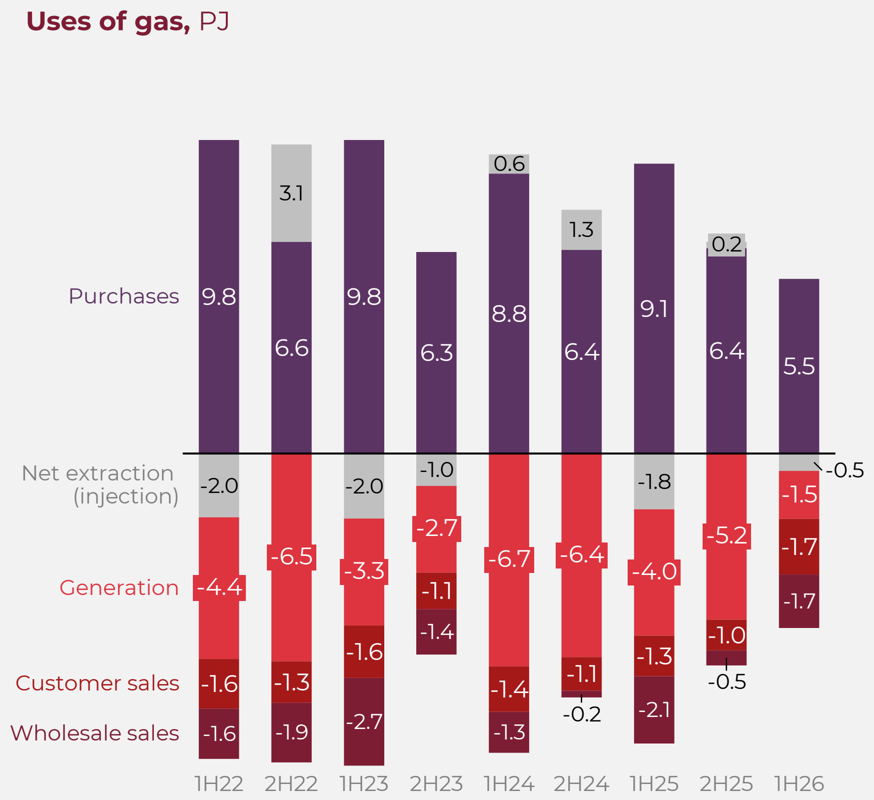


Operational data

Contracted and stored gas







1. CY26 – 32 reflect maximum volume of gas available under contracts. Forecasted volumes for these periods are not yet available. | 2. Greymouth Gas volumes illustrated based on maximum gas available at Contact's option up to October 2032. Forecasted volumes are not yet available.

Reconciliation between Profit and EBITDAF

EBITDAF is Contact's earnings before interest, tax, depreciation and amortisation, asset write-offs and impairments and changes in fair value of financial instruments.

EBITDAF is commonly used in the electricity industry so provides a comparable measure of Contact's performance.

Reconciliation of statutory profit back to EBITDAF:

	6 months ended 31 December 2025 (1H26)	6 months ended 31 December 2024 (1H25)	Variance on prior year	
			$M	%
Profit	**205**	**142**	**63**	**44%**
Depreciation and amortisation	142	130	12	9%
Change in fair value of financial instruments	(3)	21	(24)	N/A
Asset write-offs and impairments	-	-	-	N/A
Net interest expense	72	52	20	38%
Tax expense	84	59	25	42%
EBITDAF	**500**	**404**	**96**	**24%**

The adjustments from EBITDAF to reported profit and movements on 1H25 are as follows:

- **Depreciation and amortisation:** increased by $12M as a result of an increased fixed asset register from the purchase of Manawa. This has been partially offset by significantly lower usage of thermal assets compared to 1H25.
- **Change in fair value of financial instruments:** includes unrealised gain/losses associated the long-term contract Manawa struck with Mercury, the NZAS contract, and realised gains/losses on market making. See slide 34 for more detail.
- **Net interest expense:** significantly higher than 1H25 as a result of additional borrowing to complete the Manawa acquisition and a full period of interest no longer being capitalised on Te Huka 3.
- **Tax expense:** for the period increased by $25M as a result of higher profit before tax in 1H26 vs 1H25.

Reconciliation of change in fair value of financial instruments

Change in fair value of financial instruments	Realised / unrealised	1H26	1H25	Variance	Description
(A) Net market making	**Realised**	**1**	**(14)**	**15**	Realised gains or losses on the settlement of electricity derivatives entered into to meet Contact's market making obligations
– NZAS long-term sale CFD		(12)	(17)	5	NPV of the changes to the forecast forward wholesale price path vs the wholesale path when the contracts were agreed
– Kōwhai Park PPA (Contact buys)		2	3	(1)	
– Mercury CFD (Manawa)		10	-	10	
– Market making		3	4	(1)	Mark-to-market of open electricity derivatives in future periods
– Other non-hedged movements		(1)	3	(4)	
(B) Unrealised movements in non-hedge effective electricity derivatives	Unrealised	2	(7)	9	
Total change in fair value of financial instruments as per segment note (A+B)	**Realised and unrealised**	**3**	**(21)**	**24**	
Commercial hedges recognised in EBITDAF that do not qualify for hedge accounting					
– Financial Transmission Rights (FTR) settlements and Exchange for Physical (ASX)	Realised	(9)	(4)	(5)	Financial contracts that hedge portfolio sales that are settled in the period
– Net settlement of NZAS CFD in the period		(6)	(36)	30	Realised settlement (difference between the fixed contract and spot settlement)
– Net settlement of Mercury CFD in the period		10	-	10	
Change in fair value of financial instruments as per Income statement		(2)	(61)	59	

In the period, Contact acquired Manawa Energy and all of its associated long-term sales contracts. This included several major contracts for difference (CFD) that are not eligible for hedge accounting. The most significant of these is the sale of electricity to Mercury Energy.

As with Contact's existing CFDs ineligible for hedge accounting, movements in expected wholesale prices, when compared to forward wholesale prices when the contracts were entered into, drive changes in their recorded fair value.

These non-cash movements, which relate to future periods, are recognised in the current period in the change in fair value of financial instruments line item. These movements increase the volatility of Contact's reported Net Profit After Tax.

The primary change to wholesale price expectations in the period was the listing of the 2029 ASX contract from October 2025, which was higher than Contact's internally generated price path for the same period.

Historical financial information

	Unit	1H22	1H23[1]		1H24		1H25	1H26
			Underlying[2]	Reported	Underlying[2]	Reported	Reported[2]	
Revenue	$M	1,141	994		1,306		1,707	1,617
Expenses[3]	$M	819	737	857	981	952	1,263	1,112
EBITDAF	$M	322	257	137	334	362	404	500
Profit	$M	134	79	(7)	134	153	142	205
Operating free cash flow	$M	131	71		174		138	249
Operating free cash flow per share	cps	16.8	9.1		22.1		17.4	25.5
Dividends declared	cps	14.0	14.0		14.0		16.0	16.0
Total assets	$M	4,978	5,408		6,059		6,383	9,729
Total liabilities	$M	2,027	2,748		3,375		3,738	5,288
Total equity	$M	2,951	2,660		2,684		2,645	4,441
Gearing ratio[4]	%	19.3	30.6		38.4		38.6	37.7

1. In 1H24 Contact made reclassifications to better align with IFRIC guidance on IFRS 9 resulting in realised gains / losses from market derivatives not in a hedge relationship (includes market making activity) no longer being reported in operating income (EBITDAF). 1H23 Expenses, EBITDAF and operating free cash flow were restated accordingly. | 2. 1H23 and 1H24 figures were reported exclusive of the impacts of the AGS onerous contract provision. The provision was not recalculated in 1H25, however, the monthly unwind and interest impacts of the provision were included in the reported 1H25 figures. This provision was revalued and fully released in 2H25. | 3. Includes realised gains / (losses) on risk management derivatives not in a hedge relationship. | 4. Gearing ratio is calculated as: (Senior debt - including finance lease liabilities) / (Senior debt - including finance lease liabilities + Equity).

Wholesale segment

	1H26 Six months ended 31 December 2025			1H25 Six months ended 31 December 2024		
	Volume	GWAP		Volume	GWAP	
Note: this table has not been rounded and might not add	GWh	$/MWh	$M	GWh	$/MWh	$M
Electricity sales to Retail segment	**1,941**	**174**	**338**	**1,991**	**153**	**304**
Electricity sales to C&I	**1,044**	**139**	**146**	**777**	**124**	**97**
CfDs – Tiwai support sales	640			303		
PPAs	300			62		
CfDs - Long term sales & MCY	1,023			219		
CfDs and ASX - Short term sales	906			1,265		
Electricity sales – CFDs	**2,870**	**116**	**332**	**1,849**	**182**	**336**
Total contracted electricity sales	**5,855**	**139**	**816**	**4,618**	**160**	**737**
Steam sales	**131**	**18**	**2**	**127**	**20**	**2**
Other income			14			6
Net income on gas sales			-			(18)
Irrigation net income			6			-
Net income on electricity related services			1			1
Net other income			**21**			**(11)**
Total contracted revenue	**5,986**	**140**	**839**	**4,745**	**153**	**728**
Generation costs	5,335	(33)	(174)	4,603	(39)	(181)
Acquired generation cost	770	(133)	(103)	246	(297)	(73)
Generation costs (including acquired generation)	**6,105**	**(45)**	**(276)**	**4,849**	**(52)**	**(254)**
Spot electricity revenue	5,335	89	477	4,603	176	812
Settlement on acquired generation	770	84	65	246	280	69
Spot revenue and settlement on acquired generation (GWAP)	**6,105**	**89**	**542**	**4,849**	**182**	**881**
Spot electricity cost	(2,985)	(96)	(286)	(2,769)	(208)	(576)
Settlement on CFDs sold	(2,870)	(84)	(242)	(1,849)	(168)	(312)
Spot purchases and settlement on CFDs sold (LWAP)	**(5,855)**	**(90)**	**(527)**	**(4,618)**	**(192)**	**(887)**
Trading, merchant revenue and losses	***250***		***15***	***231***		***(6)***
Wholesale EBITDAF			**577**			**467**

Segmental performance

Retail segment

Residential electricity	unit	1H23	1H24	1H25	1H26
Average connections	#	381,222	386,540	400,518	409,937
Sales volumes	GWh	1,445	1,478	1,506	1,523
Average usage	MWh per ICP	3.8	3.8	3.8	3.7
Tariff	$/MWh	261.4	281.2	291.7	330.4
Network, meters and levies	$/MWh	-118.2	-122.1	-132.8	-153.9
Energy costs	$/MWh	-128.7	-149.9	-164.5	-186.0
Gross margin	**$/MWh**	**14.5**	**9.2**	**-5.6**	**-9.4**
Gross margin	$ per ICP	55	35	-21	-35
Gross margin	$M	21	14	-8	-14

Residential gas	unit	1H23	1H24	1H25	1H26
Average connections	#	66,796	67,658	70,322	70,377
Sales volumes	TJ	881	916	884	860
Average usage	GJ per ICP	13.2	13.5	12.6	12.2
Tariff	$/GJ	38.1	41.3	45.8	56.2
Network, meters and levies	$/GJ	-20.7	-20.8	-25.3	-28.2
Energy costs	$/GJ	-10.2	-9.7	-10.7	-15.7
Carbon costs	$/GJ	-4.2	-3.0	-4.3	-3.6
Gross margin	**$/GJ**	**3.0**	**7.8**	**5.6**	**8.7**
Gross margin	$ per ICP	39	106	70	107
Gross margin	$M	3	7	5	7.5

SME electricity	unit	1H23	1H24	1H25	1H26
Average connections	#	47,702	44,746	42,563	40,093
Sales volumes	GWh	421	392	355	309
Average usage	MWh per ICP	8.8	8.8	8.3	7.7
Tariff	$/MWh	249.2	276.6	294.4	343.8
Network, meters and levies	$/MWh	-113	-114	-121	-153
Energy costs	$/MWh	-129.8	-148.0	-161.7	-183.2
Gross margin	**$/MWh**	**6.4**	**14.6**	**11.7**	**7.2**
Gross margin	$ per ICP	56	128	98	55
Gross margin	$M	3	5	4	2

SME and C&I gas[2]	unit	1H23	1H24	1H25	1H26
Average connections	#	3,656	3,100	2,721	3,251
Sales volumes	TJ	635	465	336	925
Average usage	GJ per ICP	173.6	149.9	123.5	284.7
Tariff	$/GJ	23.1	29.5	34.7	37.3
Network, meters and levies	$/GJ	-8.4	-11.4	-12.8	-10.3
Energy costs	$/GJ	-10.2	-9.7	-10.7	-15.7
Carbon costs	$/GJ	-4.2	-3.0	-4.3	-3.6
Gross margin	**$/GJ**	**0.3**	**5.5**	**7.0**	**7.7**
Gross margin	$ per ICP	54	828	864	2,184
Gross margin	$M	0.2	3	2	7

Telco[1]	unit	1H23	1H24	1H25	1H26
Average connections	#	74,974	89,831	113,324	113,714
Tariff	$/cust/mth	70.4	72.2	71.2	71.9
Network, provisioning, modems	$/cust/mth	-62.8	-63.3	-62.5	-61.9
Gross margin	$/cust/mth	**7.6**	**8.9**	**8.7**	**10.1**
Gross margin	$M	4	5	6	8

Retail segment EBITDAF		1H23	1H24	1H25	1H26
Electricity Gross margin	$M	24	19	-4	-12
Gas Gross Margin	$M	3	10	7	15
Telco Gross Margin	$M	4	5	6	8
Total Gross Margin	**$M**	**31**	**34**	**9**	**10**
Other income	$M	5	4	4	3
Other direct costs	$M		-1	-2	0
Other operating costs	$M	-35	-37	-36	-38
Retail segment EBITDAF	**$M**	**1**	**-1**	**-25**	**-25**
Corporate allocation (50%)	$M	-11	-14	-19	-26
Retail EBITDAF	**$M**	**-10**	**-15**	**-44**	**-51**
EBITDAF margins (% of revenue)	%	-1.80%	-2.43%	-6.78%	-6.83%

[1] Telco includes both broadband and mobile from 1H24 (previously broadband only). | 2. C&I gas sales included with SME gas from 1H26.