2025 full year results presentation

Twelve months ended 30 June 2025

18 August 2025

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Agenda

FY25 highlights

Delivering financial performance

▲ +17% **EBITDAF** (underlying)
$774m up **$111m** YoY

▲ +13% **NPAT** (underlying)
$261m up **$31m** YoY

▲ +5% **Dividend CPS**
39c up **2c** YoY

Delivering transformative portfolio change

MANAWA ENERGY

Transaction completed
11th July 2025

Integration underway

Delivering renewable energy growth

Stations online

Tauhara
174MW
1.45TWh

Te Huka 3
51MW
0.43TWh

$1.1b of projects under construction

Kōwhai Park | 168MWp Solar
Glenbrook-Ohurua | 100MW BESS
Te Mihi Stage 2 | 101MW Geothermal

Delivering for customers

Fonterra electrification
Contact to supply 540GWh p.a. at Whareroa by 2028 (~75% new demand)

Greymouth and OMV gas contracts
Secured up to 10PJ p.a. to CY2032

140,000 households
choosing discounted or free off-peak energy

Delivering for shareholders

MSCI

Added to the
MSCI Global Standard Index

Continued representation within
Dow Jones Sustainability Index

Delivering for the market

Secured access to ~6PJ Methanex gas, supporting the market in dry sequences

Medium-term gas supply
supporting generation needs & gas-reliant businesses

Taranaki Combined Cycle gas plant made available for winter 2025

Refreshed leadership, delivering growth

Leadership team refreshed to match the scale, complexity and ambition of the business

Mike Fuge
Chief Executive Officer

Changes
(During 2H FY25)

- Jack Ariel, Major Projects Director, retired.
- Matt Forbes appointed Chief Financial Officer.
- Carolyn Luey appointed Chief Retail Officer.

Chris Abbott
Chief Corporate Affairs Officer

Jan Bibby
Chief People Experience Officer

Matt Bolton
Manawa Integration Director

John Clark
Chief Generation Officer

Dorian Devers
Chief Renewable Growth Officer

Matt Forbes
Chief Financial Officer

Carolyn Luey
Chief Retail Officer

Tighe Wall
Chief Technology Officer

Summary of key financial performance measures

Building for the future, ready for today

Performance powered by geothermal expansion and resilient risk management

	Twelve months ended 30 June 2025 (FY25)		Twelve months ended 30 June 2024 (FY24)	
	Underlying[1]	*Reported*	Against underlying[1]	
EBITDAF[2]	$774m	*$872m*	↑	17% from $663m
Profit	$261m	*$331m*	↑	13% from $230m
Profit per share	32.7 c	*41.6 c*	↑	12% from 29.1 c
Operating free cash flow[3]	$434m		↑	2% from $424m
Operating free cash flow per share[3]	54.4 c		↑	1% from 53.9 c
Average ROIC[3]	4.9%		↑	From 3.7%
Dividend declared[4]	$355m		↑	22% from $292m
Dividend declared per share[4]	39.0 c		↑	5% from 37.0 c
Stay-in-business (SIB) capital expenditure (cash)	$110m		↓	29% from $156m
Growth capital expenditure (cash)[5]	$363m		↓	14% from $424m

	Market	contact
FY25	FY25 was shaped by challenging market dynamics: • **Two historically significant dry periods** reduced hydro output and increased reliance on thermal generation. • **Gas production fell 20% year-on-year**, deepening fuel scarcity. • **Spot and short-term futures prices spiked**, then eased as inflows recovered and Methanex gas was secured. • **Lines charges rose ~20%** from April 2025, adding further cost pressure.	Contact's diversified portfolio and proactive risk management supported strong performance in a volatile year: • **Geothermal output rose 34%,** with Tauhara and Te Huka 3 delivering 1.5TWh of reliable baseload energy. • **TCC was retained to support winter 2025**, despite being scheduled for closure. – **Combined with AGS storage**, this enabled Contact to secure Methanex gas and supply renewable-only generators during dry periods—helping stabilise the market.
Medium term	FY25 highlighted several medium-term challenges: • **Ongoing gas scarcity** with limited options to increase gas supply. • **Rising costs for long-term risk management** products. • **Growing seasonal price spreads**, especially between summer and winter. • **Increased price volatility** as more intermittent generation enters the market.	Contact is well-positioned for medium-term market conditions: • **Renewable build-out progressing** across solar, geothermal and battery projects. • **Manawa acquisition** adds portfolio flexibility and favourable market channel exposure. • **Long-term gas contracts to 2032** support intermittent generation and key customers. • **Strategic customer partnerships** support decarbonisation.

[1] In FY25, the release of the AGS onerous contract provision increased reported EBITDAF by $98m and profit by $71m. In FY24 the net movement in this provision added $12m to EBITDAF and $5m to profit. This is the only adjustment from reported to underlying performance.
All variances and commentary reflect year-on-year changes in underlying performance.

[2] Refer to slide 50 for a definition and reconciliation of Profit to EBITDAF.

[3] ROIC is four-year average. See slide 25 for the operating free cash flow reconciliation and for the basis of calculation of return on invested capital. For FY24, $46m of growth capex has been reclassified to stay-in business capex, ensuring that spend is classified according to which assets receive the most benefits under a revised scope of Te Mihi Stage 2.

[4] Relates to interim and final FY25 dividends declared.

[5] Includes capitalised interest.

Delivering on the plan

Impressive delivery of the FY25 strategic targets outlined at the start of the year

Strategic theme	FY25 operational plan	FY25 achieved
Grow Demand	New demand facilitated since FY21 to reach >120MW.	New demand facilitated and contracted since FY21 ~230MW (88MW online) up from 105MW.
	Achieve FID for CO_2.	CO_2 Final Investment Decision (FID) now targeted for FY26.
	Add 15MW of flexible demand.	15MW of additional flexible demand contracted, taking total contracted volume to 188MW (141MW online).
Grow renewable development	Achieve FID for Te Mihi Stage 2.	Achieved FID on Te Mihi Stage 2 geothermal station. Expected online in Q3 CY2027.
	Lodge consent for Stratford solar.	Consent lodged for Stratford solar.
	Achieve consent on Glorit solar.	Consenting process underway for Glorit solar. Earliest expected FID FY26.
	Achieve consent on Southland Wind.	Consent declined under COVID-19 Fast Track. Contact has been accepted under the new Fast Track Approvals Act and expects to lodge a substantive application shortly.
	Te Huka 3 online Q4 CY2024.	Te Huka 3 online December 2024 at 54MW operating capacity. Final commissioning completed June 2025.
	Glenbrook-Ohurua BESS[1] on-track for online Q1 CY2026.	Glenbrook-Ohurua BESS under construction. Expected online in Q1 CY2026.
	Kōwhai Park solar on track for online for Q2 CY2026.	Kōwhai Park solar under construction. Expected online in Q2 CY2026.
Decarbonise our portfolio	Additional investment in carbon offsets.	Purchased additional ~8% interest in Forest Partners (taking total to 22%).
	Close TCC[2] gas generation plant. Expected to close December 2024.	TCC made available for Winter 2025 to support security of supply. Closing 2025.
	Sustained entry into the DJSI.	Sustained inclusion in DJSI Asia-Pacific (one of only five New Zealand companies).
Create outstanding customer experiences	Electricity net price up by 2-3%.	Up >3%; full recovery of lines cost increases; partial recovery of rising wholesale costs.
	Multi-product customers >149k (up from 140k).	More than 149k multi-product customers, up ~7%.
	Target cost to serve <$123/connection.[3]	Cost to serve $116 / connection.
	Scale Hot Water Sorter programme to >20k homes (up from ~5k).	Reached >20k homes in the programme and shifted 4GWh residential demand off-peak in FY25.

Key: Complete / on-track | Minor delay and / or cost increase | Major delay and / or cost increase

[1] Battery Energy Storage System.
[2] Taranaki Combined Cycle.
[3] Includes customer acquisition costs.

Renewable projects under construction

Contact is currently leading the build of ~$1.1bn in renewable infrastructure across New Zealand

Te Mihi Stage 2 geothermal

Glenbrook-Ohurua BESS[1]

Kōwhai Park solar farm[4]

Key facts & progress updates

Te Mihi Stage 2 geothermal

Net capacity / annual generation	101MW / 0.8TWh
Total project costs	$712m[2]
Target schedule	Online in Q3 CY2027

Progress update

- Earthworks are nearing completion.
- The power station site has been handed over to the EPC contractor, with foundation trenching and excavation now underway.
- Wairakei extension works have commenced, including planning for major upgrades to electrical reticulation systems.

Glenbrook-Ohurua BESS

Battery capacity / storage	100MW / ~200MWh
Total project costs	Up to $163m[2]
Target schedule	Online in Q1 CY2026

Progress update

- All 28 transformers and 56 Megapacks are now installed on site.
- Electrical connections between Megapacks and transformers are well advanced.
- Balance of plant works—including switch and control rooms, cabling, and auxiliary transformers—are progressing well.
- Concrete foundations for key infrastructure are largely complete.

Kōwhai Park solar farm

Net capacity / annual generation	168MWp / 0.3TWh
Total project costs	$273m[3]
Target schedule	Online in Q2 CY2026

Progress update

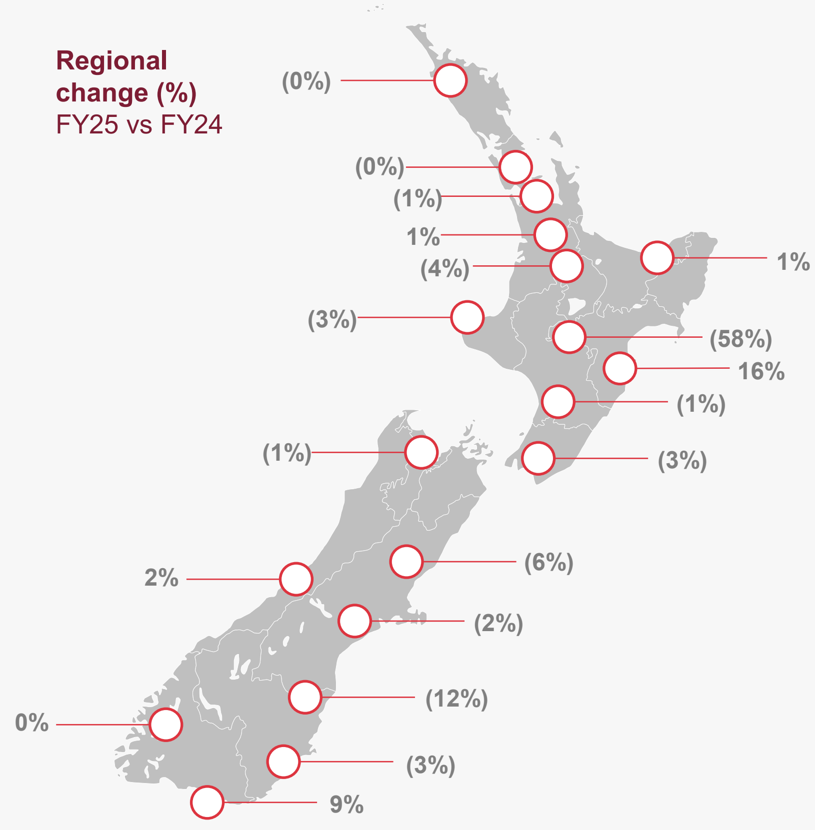
- Construction village and earthworks are well advanced.
- Most PV modules, trackers, and inverters are now on site.
- The first row of solar panels—the “golden row”—has been successfully installed.

[1] Battery Energy Storage System.
[2] Includes sunk cost of $66m and $5.4m for Te Mihi Stage 2 and Glenbrook-Ohurua BESS respectively. Excludes capitalised interest.
[3] Excludes financing costs of $43m. Includes development costs.
[4] The Kōwhai Park solar farm is part of Contact’s 50/50 JV with Lightsource bp.

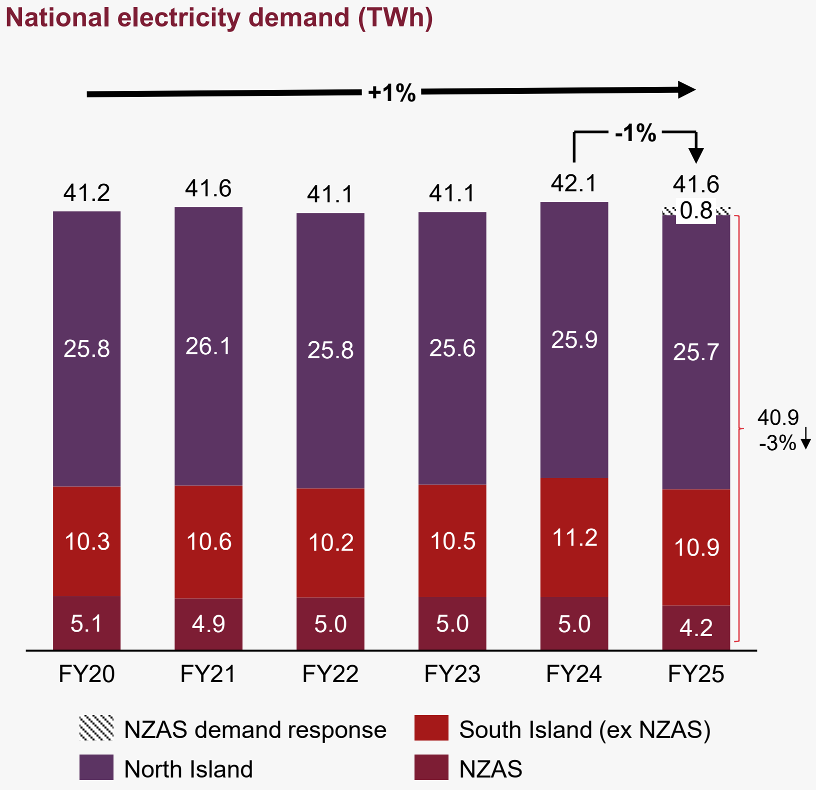
Market update

National electricity demand

NZ electricity demand down ~1% even when normalised for NZAS demand response



Source: EMI, Contact.
Does not include NZAS.



Source: EMI, Contact.
NZAS demand response is estimated by comparing total demand in FY25 against average demand at the Tiwai node over the preceding 4 years.

National electricity demand in FY25 reflected the impact of extreme weather and challenging conditions.

Overall demand was down ~3% year-on-year, driven by dry conditions and demand reductions from customers exposed to fuel scarcity though high prices.

Adjusting for NZAS demand response—called by Meridian to support lower hydro conditions—underlying demand fell ~1%.

Notable regional changes included:

- A 58% drop in demand at the central North Island node 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.
- A 12% decline in South Canterbury, concentrated in irrigation nodes, driven by high inflows between September and December 2024.
- A 16% increase on the East Coast, as Pan Pac's Whirinaki plant—closed after Cyclone Gabrielle in 2023—gradually resumed operations through 2H24 and 1H25.

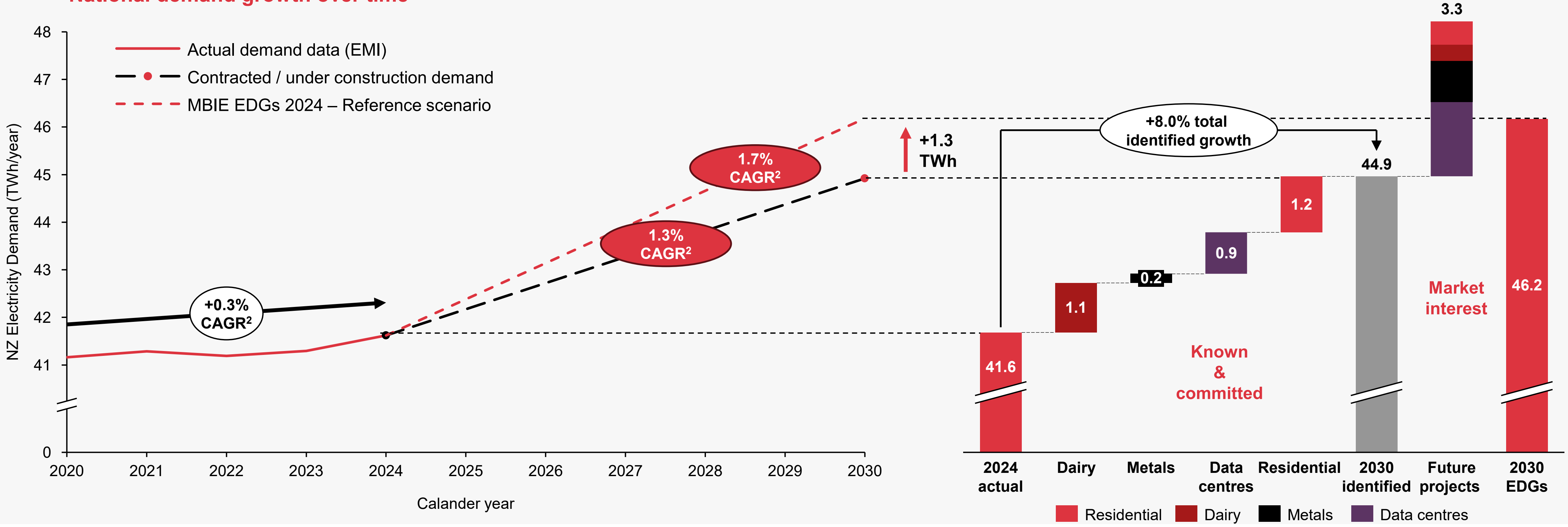
Market demand

Near term demand outlook is positive

Committed new load and consistent residential progression accounts for more than half of market growth expectations in the next 5 years

National demand growth over time[1]

Estimates of future demand by sector[3]



Future demand sources committed growth

Additional / faster industrial electrification

Additional and / or faster industrial decarbonisation resulting from higher cost and less available natural gas

Residential decarbonisation & EV uptake

Faster EV uptake and residential decarbonisation (heating / cooling)

Data centres

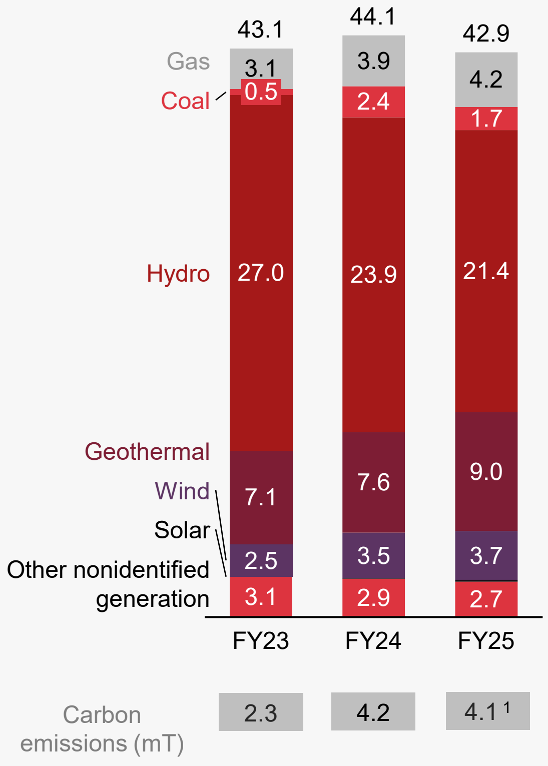
Data centre build out consistent with current pipelines / projections

[1] MBIE EDGs reference case used as a proxy for market expectations given its use by Transpower for capital investment planning. [2] Compound annual growth rate. [3] Forecast does not include assumptions around potential industrial demand loss or line losses.

Two historically significant dry periods

Lower hydro output offset by new geothermal production and lower demand

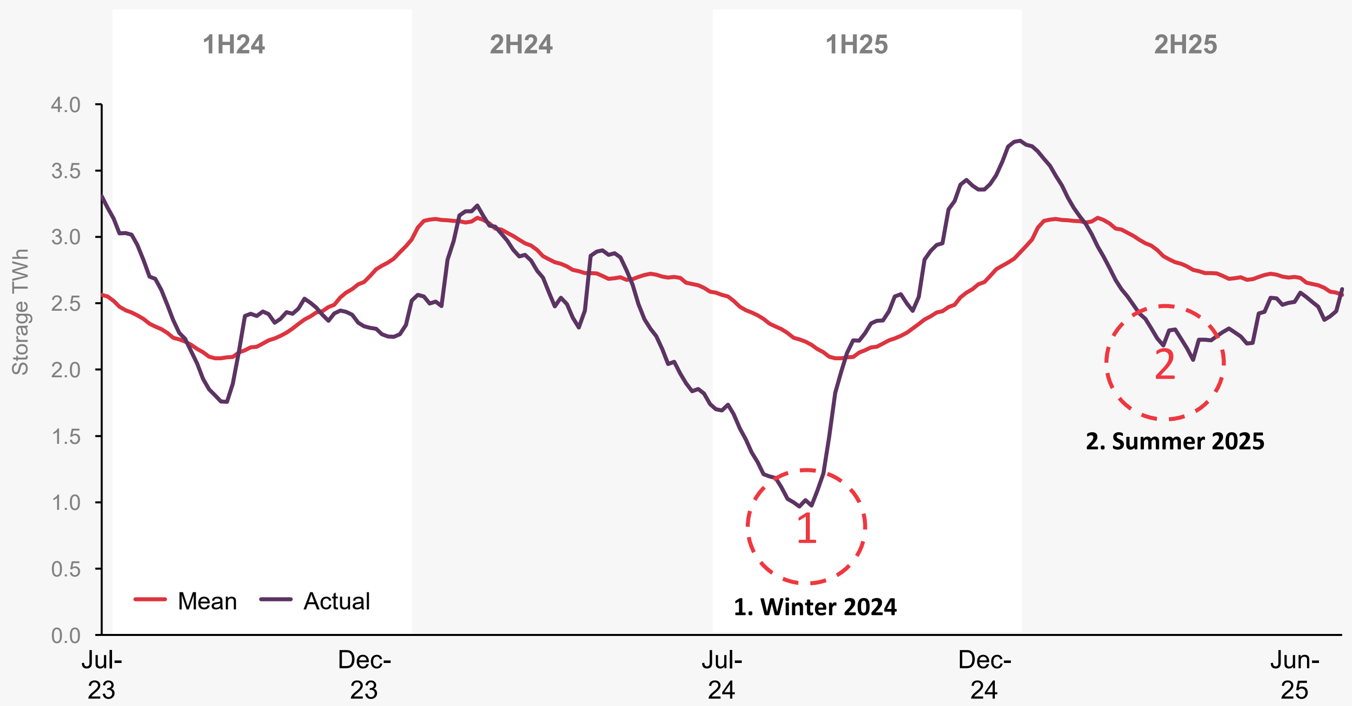
Generation by type (TWh)



Supply Commentary – Generation Mix FY25

- **Hydro generation** was down ~10% on FY24, 9% below the post-market mean and the lowest annual volume since 2008. This reflected two historically dry periods, including record-low inflows between January and March 2025.
- **Gas generation** increased to support the market, enabled by short-term gas from Methanex, which paused methanol production to make supply available.
- **Geothermal** rose with Tauhara and Te Huka 3 contributing 1.5TWh—geothermal delivers twice what wind does.
- **Solar** increased from 10GWh to 100GWh, ~0.2% of total market generation.
- FY25 highlighted the importance of flexible, dispatchable generation and strategic fuel reserves in managing volatility and supporting the transition to renewables.

National hydro storage



Hydro Storage – FY25 Summary

Hydro storage was highly volatile across the year:

- The financial year began with storage well below average due to low inflows in late FY24.
- Heavy rainfall in August lifted storage to a peak in December.
- From January to March, total inflows (across Taupo, Waitaki, Clutha and Te Anau) were the lowest in 99 years.
- With gas supply tight, the market conserved hydro storage ahead of winter 2025.

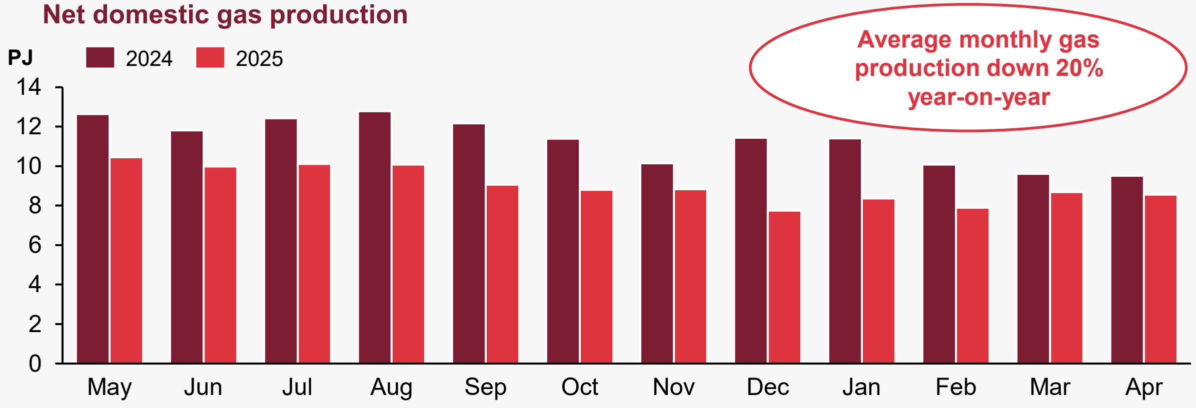
Source: EMI (generation data), MBIE (emissions data) and NZX Hydro data.

[1] Carbon emissions for FY25 Apr-Jun quarter has been estimated using historic conversion rates with actual generation data.

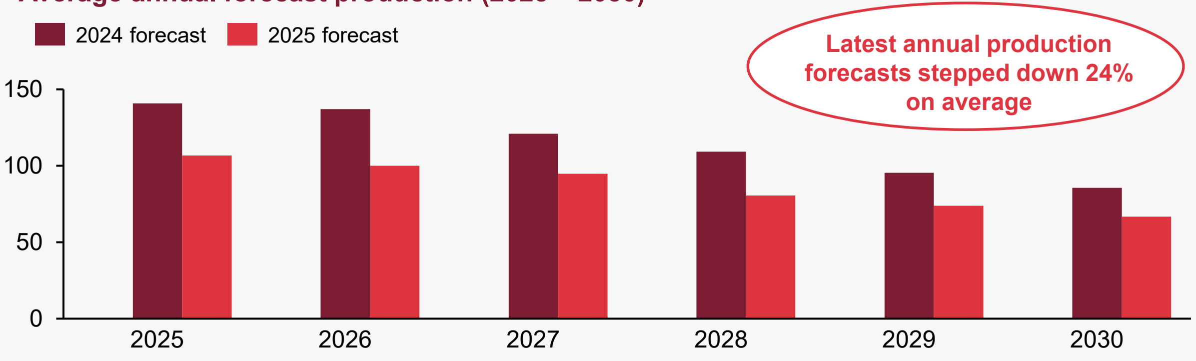
Volatile pricing driven by hydro and gas availability

Current gas deliverability forecasts point to continued steep decline

Net domestic gas production

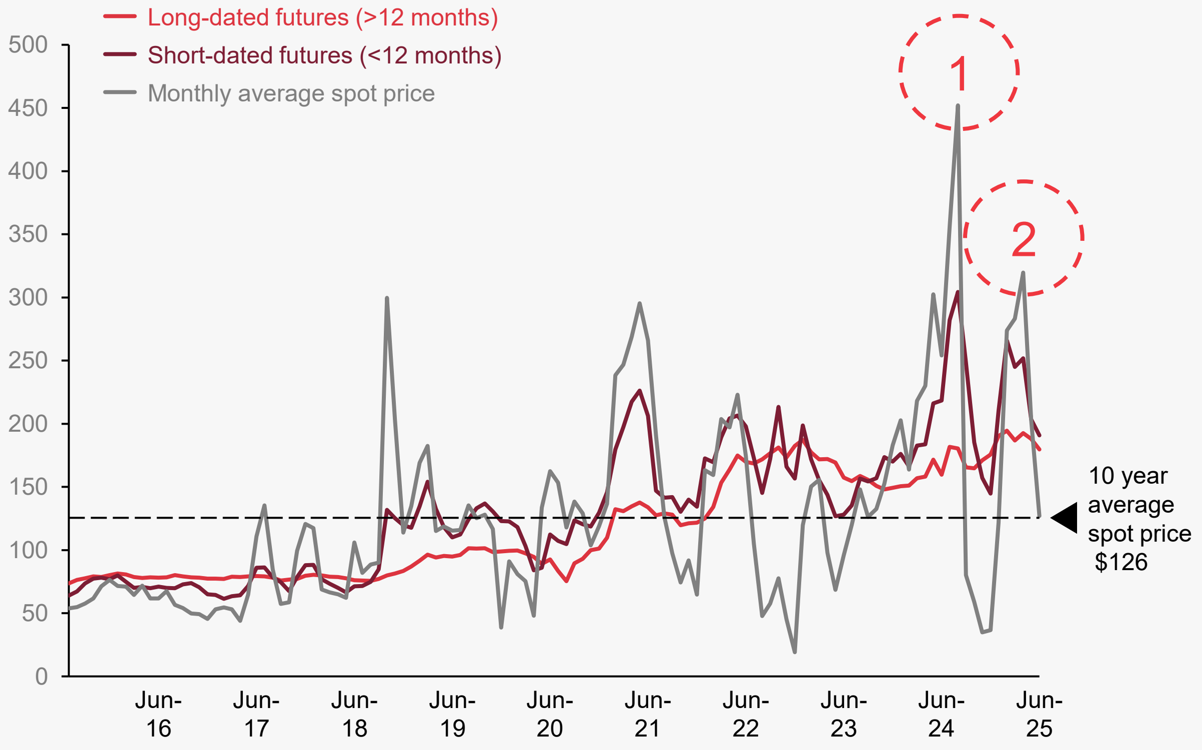


Average annual forecast production (2025 – 2030)



Source: MBIE gas statistics; 2P reserves data.

Wholesale and futures electricity pricing ($/MWh)



Source: EMI wholesale pricing

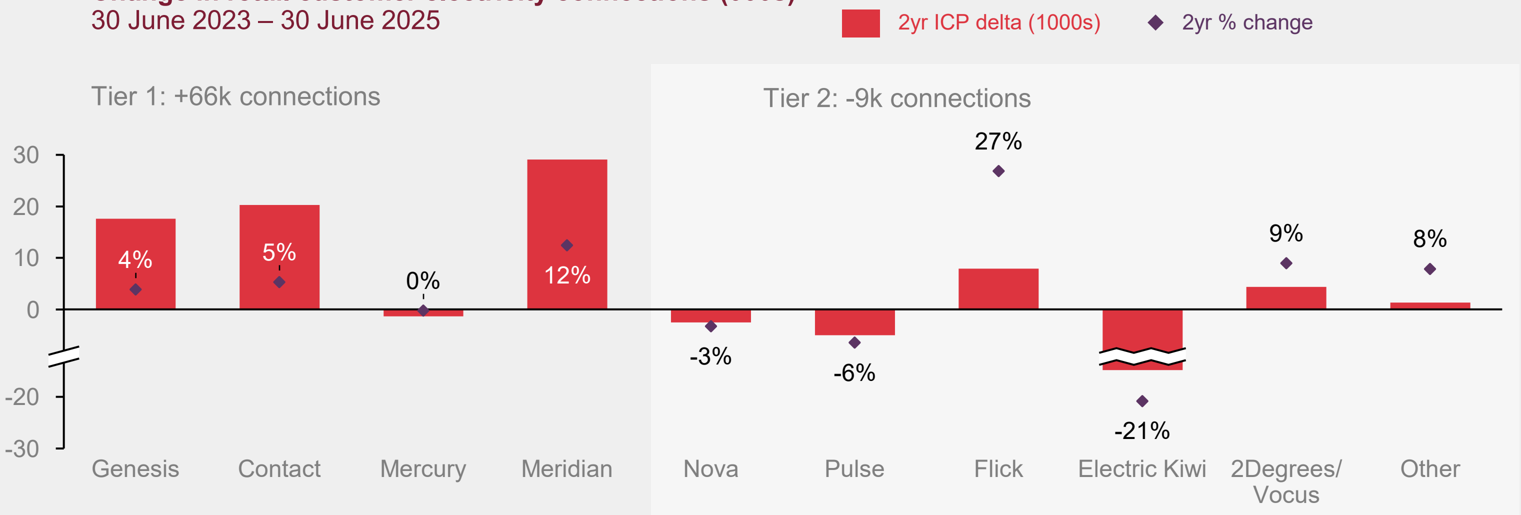
Pricing Commentary – FY25

- Spot and short-term futures prices spiked during two dry periods—Winter 2024 and Summer 2025—driven by low hydro inflows, limited wind, and a 20% year on year reduction in gas supply. Prices eased as hydro inflows recovered and Methanex gas was made available for generation.
- Long-dated futures rose in response to declining domestic gas forecasts (down by 20% on average) and the rising cost of firming intermittent renewables. While the HFO agreement (including a strategic reserve at Huntly) helps reduce scarcity risk, prices continue to reflect the cost of dispatchable fuel—whether gas, coal, or demand response—needed to meet winter demand.

Retail strategic value outweighs margin headwinds

Medium-term cost pressures not deterring long-term positioning or competition

Change in retail customer electricity connections (000s)
30 June 2023 – 30 June 2025

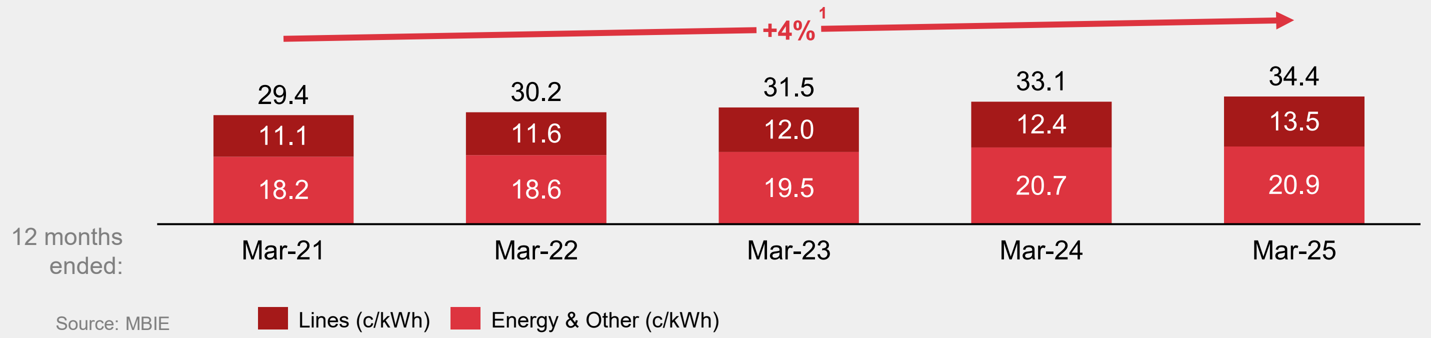


Source: EMI – residential ICPs only

Retail Electricity Market Connection Trends

- Competition remains strong, with churn steady at ~19% despite elevated wholesale prices.
- Tier 1 retailers now hold ~85% market share. Growth over the last 2 years was led by Meridian (+12% over two years, excluding Flick), followed by Genesis (+4%) and Contact (+5%). Mercury remained stable.
- Meridian's acquisition of Flick Energy (announced May 2025) adds ~41k connections, though these are not yet reflected in reported market share.
- Tier 2 retailers are losing ground, with most stepping back from customer acquisition. Flick (+27%) and 2Degrees (+9%) were exceptions.
- Contact added 20k residential connections over the past two years, reaching 20% market share.

Retail electricity tariff changes (c/ kWh)



Source: MBIE

Retail Pricing Trends

- Residential electricity prices have risen steadily, with a compound annual growth rate of ~4% over the past five years to March 2025. The average increase in the year to March 2025 was ~4%.
- Cost pressures are expected to continue. Key drivers include:
  - Higher wholesale electricity prices, particularly in winter when usage is highest.
  - Increased cost of transmission and distribution infrastructure.[2]

These factors are expected to keep upward pressure on retail prices over the near term. Continued investment in new renewable generation is expected to bring down electricity costs over time.

[1] Compound annual growth rate.

[2] 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).

Responding to the energy challenges that matter

Contact is investing in renewables, flexible storage, and demand response - guided by clear market signals and long-term national priorities; These actions reflect strong alignment with government objectives and reinforce the value of stable, predictable policy settings

Leading sustainable decarbonisation in the transition to Net Zero 2050

	Energy wellbeing	Investing at pace	Making the most of favourable consenting environment	Fuel security and dry year risk	Regional growth
Market	▪ Industry-wide focus on energy wellbeing and reducing punitive practices. ▪ Disconnections now viewed as last resort.	▪ Generation totalling 6.7TWh built or committed by industry between 2020 and 2027. ▪ 335MW of grid-scale batteries now online or under construction in New Zealand.	▪ Fast Track Approvals Act passed into law. ▪ Changes to national policy statements proposed. ▪ Replacement Resource Management legislation to be introduced before end of year.	▪ NZAS demand response activated, releasing ~0.8TWh to the market in FY25.[1] ▪ Signed 10 year, 150MW HFO agreement keeping rankines available for dry year risk.[2] ▪ Methanex short-term gas interruptibility achieved.	▪ Major renewable developments underway creating jobs in the regions. Including Southland, Central North Island, Hawkes Bay, Northland and wider.
Contact	▪ Removed all disconnection and reconnection fees and financial barriers for reconnection. ▪ Free power and broadband to all Women's Refuge safehouses and refuges nationwide along with other targeted social agencies.	▪ 225MW of baseload renewables brought online at Tauhara and Te Huka 3 geothermal stations in CY 2024. ▪ Investments in battery and solar to come online in CY 2026. Te Mihi Stage 2 to come online CY 2027.	▪ Contact and Manawa together can move at pace on a robust pipeline of consentable developments and reconsents. ▪ Engaging on RMA reforms, including seeking automatic reconsent for schemes <50MW.	▪ Entered 50MW HFO agreement.[2] ▪ Secured up to 10PJ p.a. gas supply to CY 2032 with option to extend. ▪ Improved performance of AGS gas storage enhances flexibility.	• Contact's geothermal development programme has led to job creation in Taupo region. • Tauhara alone involved 2.65 million work hours with over 4,000 people helping to build it.

We are anticipating the government's response to the review of electricity market performance in September
We expect this to propose sensible market enhancements to improve outcomes for consumers

[1] Based on observed volume at the Tiwai node.
[2] HFO agreement is subject to Commerce Commission review.

Financial results and outlook

Key themes from the financial results

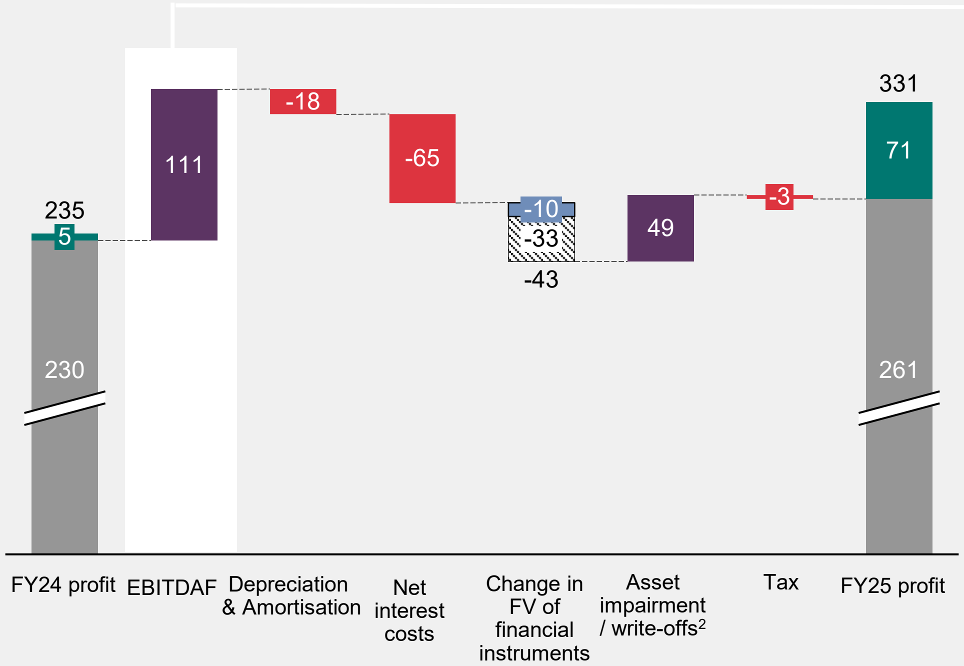
Delivering value from fuel flexibility	TCC and AGS storage enabled Contact to secure ~6PJ of short-term gas from Methanex, supporting renewable generators during dry conditions.	New NZAS contract delivered improved pricing, enabled demand response during dry conditions, and provided long-term certainty to support renewable investment.[1]	Improved confidence in the ability to access AGS storage capacity, and the rising value of thermal flexibility, increased the value of the AGS contract and led to the removal of the non-cash provision.
Delivering value from renewable generation growth	Delivered 1.5TWh of new baseload geothermal from Tauhara and Te Huka 3; Contact's hydro generation was 15% below mean.	Underlying EBITDAF $774m[2] ($792m before Manawa-related costs); ahead of normalised and expected EBITDAF.	FY26 normalised and expected[3] EBITDAF of $980m (or $945m after transaction and integration costs), up from the initial $770m in FY25.

[1] Net cost of NZAS demand response to Contact in FY25 was $22m. Includes fixed and variable payments to NZAS and the NZAS CFD revenue foregone, net of assumed spot sales.
[2] Reported EBITDAF, including AGS onerous contract provision release of $98m, was $872m.
[3] 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).

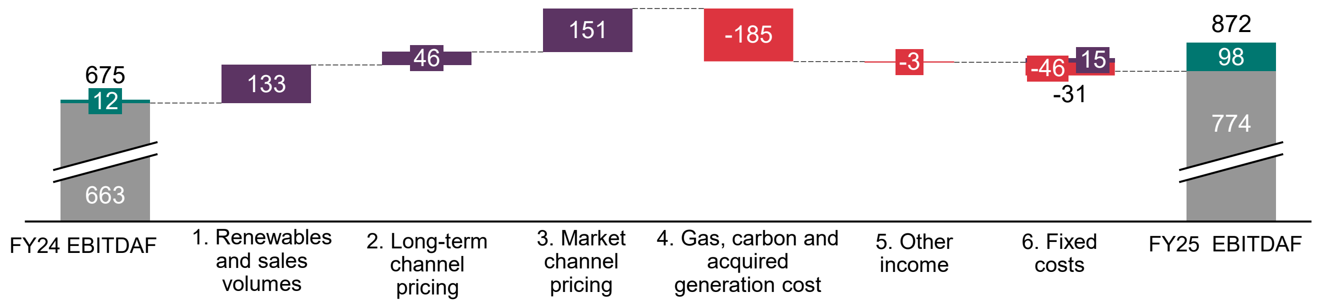
Strong earnings growth reflects investment

Performance underpinned by renewable growth, fuel flexibility, and pricing discipline

Profit ($m)[1]



Underlying EBITDAF ($m)[1]



1

Renewables up 0.8TWh, with 1.2TWh more geothermal from Tauhara and Te Huka 3 offsetting 0.3TWh lower hydro—reducing reliance on thermal and acquired generation ($200/MWh). Partly offset by a volume mix shift to longer-term sales channels.

2

Long-term channel pricing rose $9/MWh to $136/MWh (+7%), reflecting improved NZAS contract terms from 1 July and retail pricing moving closer to long-run expectations.

3

Market channel pricing up $36/MWh to $186/MWh (+24%), driven by higher realised C&I, CFD and merchant prices in a fuel-constrained market.

4

Gas and acquired generation costs rose $85/MWh to $200/MWh (+72%), driven by short-term Methanex purchases and NZAS demand response.

5

Other income was lower in the period reflecting loss on sale of gas.

6

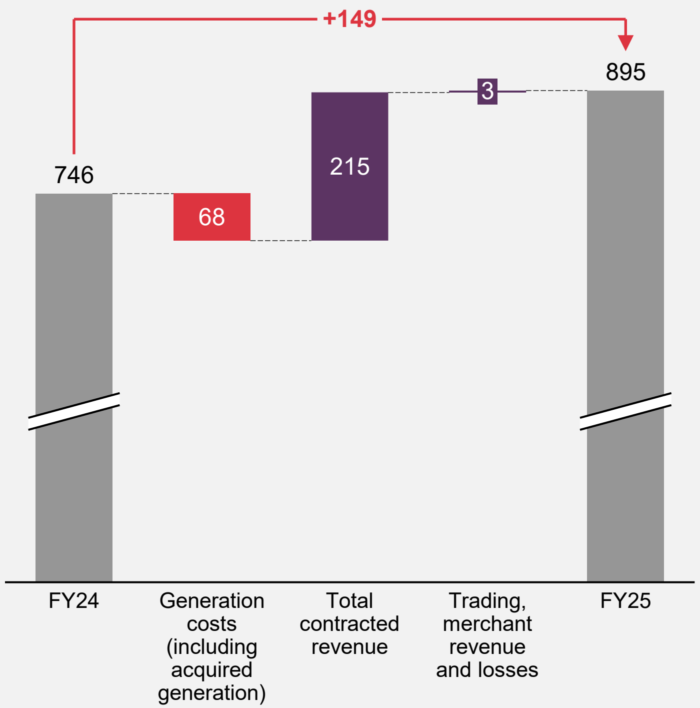
Opex higher, including transaction and integration costs ($18m) and for new plants online; partly offset by non-cash AGS unwind ($15m).

[1] Movements in profit and EBITDAF are shown on an underlying basis. For FY24, this excludes all impacts of the AGS onerous contract provision—EBITDAF increased by $12m, interest decreased by $5m, tax decreased by $2m, and NPAT increased by $5m. For FY25, underlying figures include the cumulative impact of monthly provision unwinds—EBITDAF increased by $15m, tax decreased by $4m, and NPAT increased by $8m—but exclude $98m from the release of the provision.
[2] In FY24, Contact recognised $50m of write-offs, primarily relating to peaker engine damage, Tauhara assets impacted by the 2023 steam hammer event and valve failures, and software assets from discontinued HRIS and CRM projects. In FY25, a further $1 million was written off, relating to capital work in progress and inventory.

Wholesale business performance offsets retail losses and integration-related costs

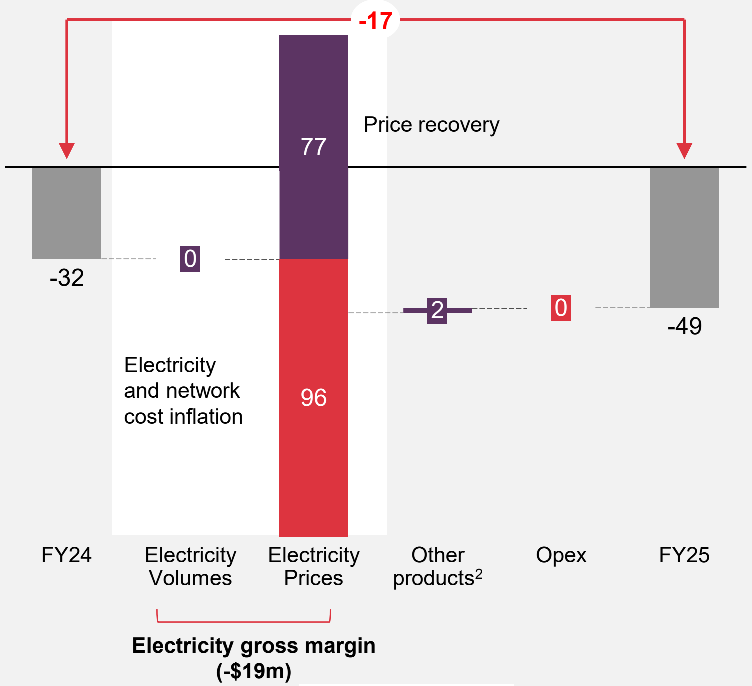
Operating performance by segment

Wholesale EBITDAF[1] (underlying, $m)



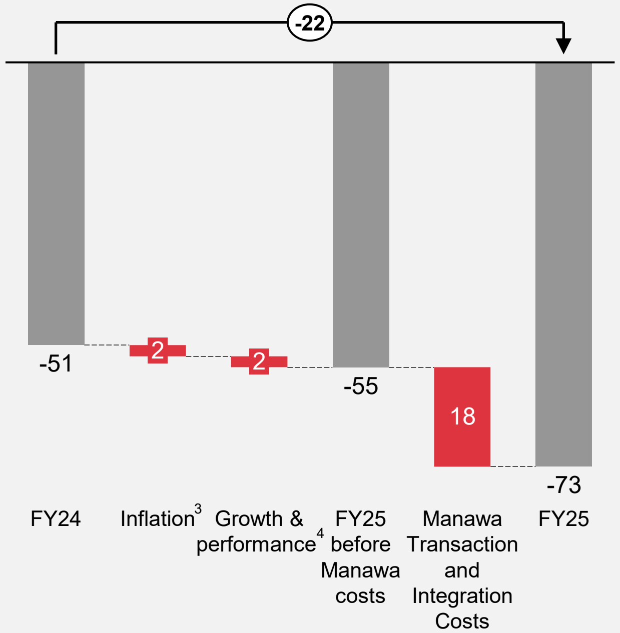
Refer to slides 20 - 22

Retail EBITDAF ($m)



Refer to slide 23

Corporate / unallocated costs ($m)



[1]Simply and Western included within Wholesale EBITDAF.
Underlying EBITDAF is shown excluding a net $12 million AGS onerous contract provision movement in FY24 and a $98m provision release in FY25.

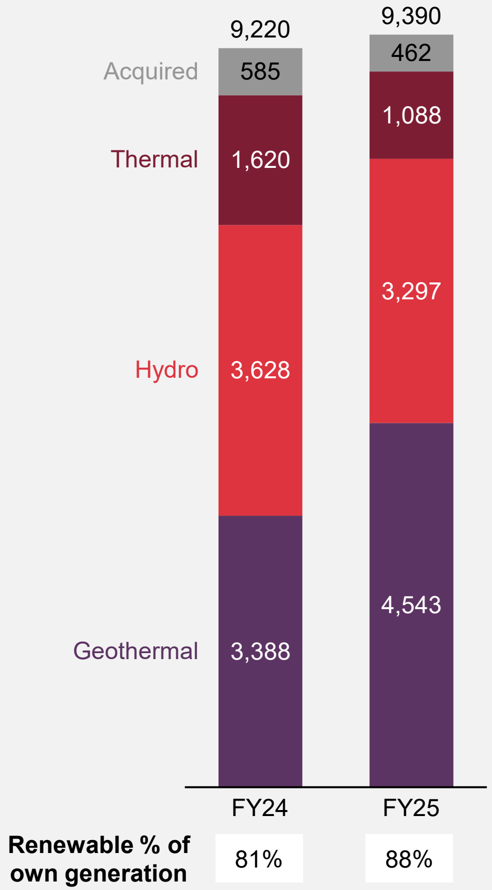
[2] Other products includes retail gas and telco gross margins.

[3] Stats NZ CPI increase over the 12 months to June 2025 plus wage inflation.
[4] Net of $4.3m of Manawa transaction costs incurred in FY24.

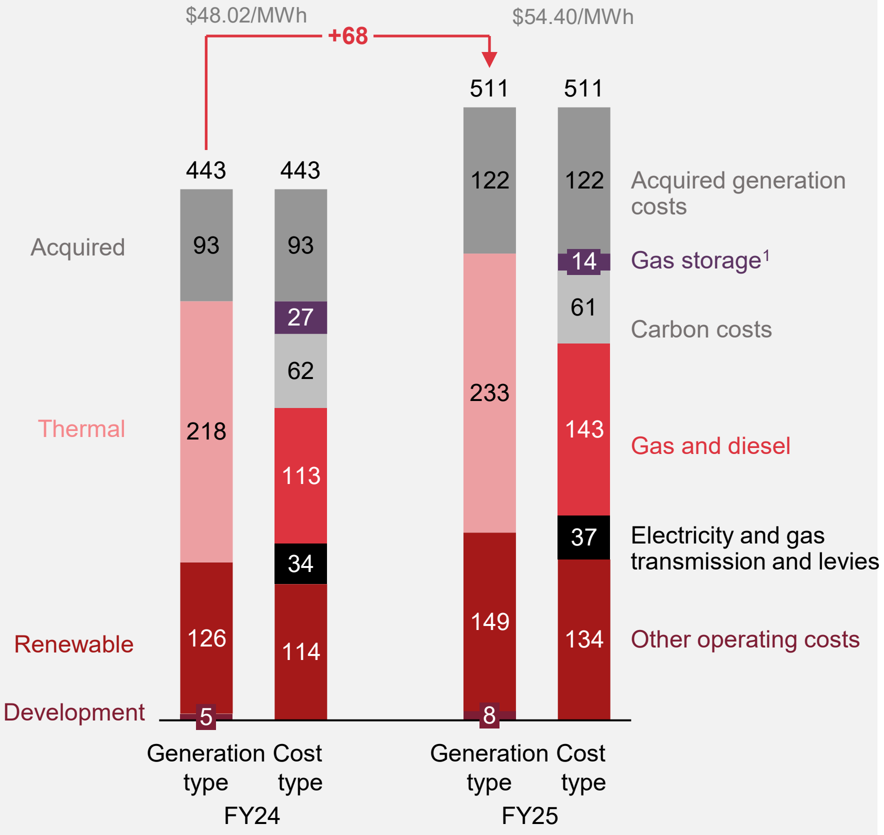
Generation costs

Generation costs rose despite strong geothermal growth, reflecting elevated gas and demand response costs

Electricity generated or acquired (GWh)



Electricity generated or acquired costs ($m)



Generation volumes

- FY25 saw two distinct periods of historically low hydro inflows. The result was a reduction in hydro generation of 331GWh (9%) when compared to FY24 and 603GWh below mean (~15% vs 3,900GWh).
- Geothermal volumes were up 1,156GWh on FY24 (34%). This increase was a result of Tauhara being operational for the entire period and Te Huka 3 being operational for 2H25. Their 1.5TWh contribution was partly offset by statutory outages at other stations.
- While thermal generation was required to support periods of low hydro inflows, particularly in Winter 2024 and Q1 2025, it was down on FY24 by 532GWh as the geothermal stations were online.
- While acquired generation was used to help cover supply risk from reduced hydro inflows in FY25, total volume was down 123GWh on FY24. Costs, but not volume associated with the call on NZAS demand response FY25 are captured in acquired generation.

Costs

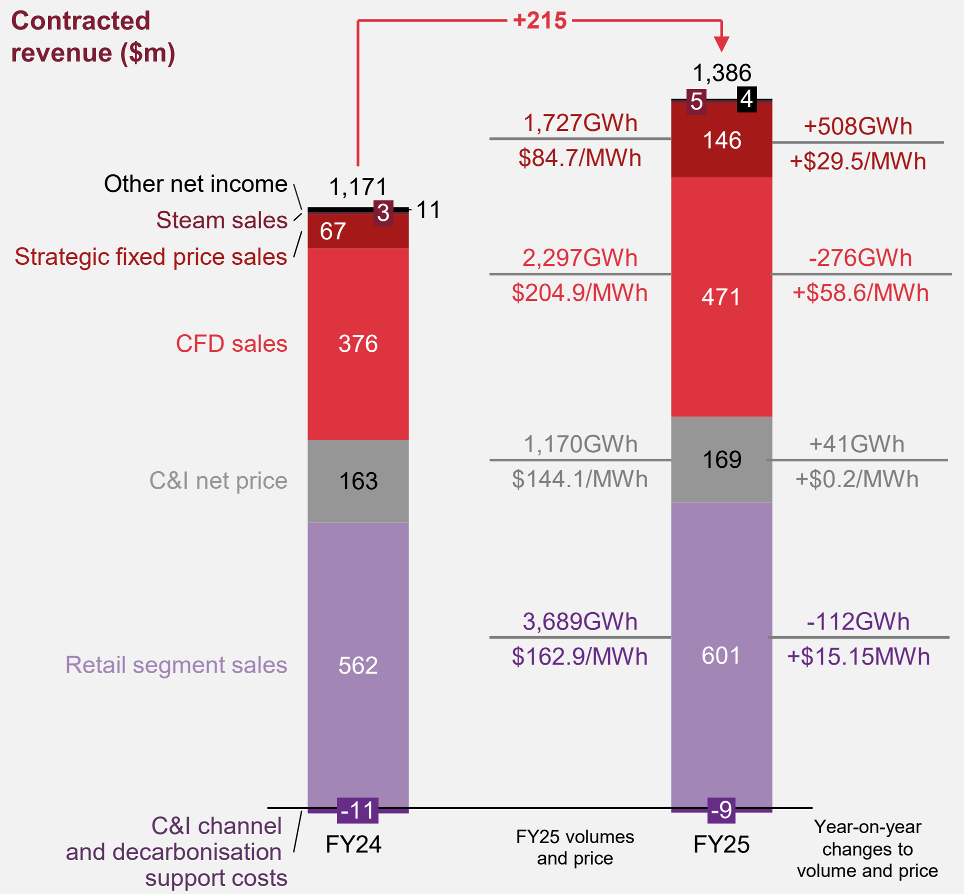
- Renewable generation costs were up $23m (18%) on FY24 due to the costs of operating new stations ($7m within opex), geothermal outage acceleration, higher transmission costs and rates.
- Thermal generation costs, were up $15m (7%) on increased average cost of gas as a result of short-term purchases in a constrained market (FY24: $8.5/GJ, FY25: $15.4/GJ).
- Acquired generation costs were up $29m (31%) despite lower volume. Reflects NZAS demand response payments of $35m[2] and no associated volume recognised (FY24: $159/MWh, FY25: $264/MWh).

[1] Gas storage costs exclude the $12 million net movement in the AGS provision in FY24 and the $98 million provision release recognised in FY25. In FY25, gas storage costs include a $14.6 million provision unwind released throughout the year.

[2] Total payments to NZAS. Does not account for foregone revenue from NZAS on the demand response volume nor any associated sales opportunity.

Wholesale contracted revenue

Diversified mix of long-term and ASX linked sales channels

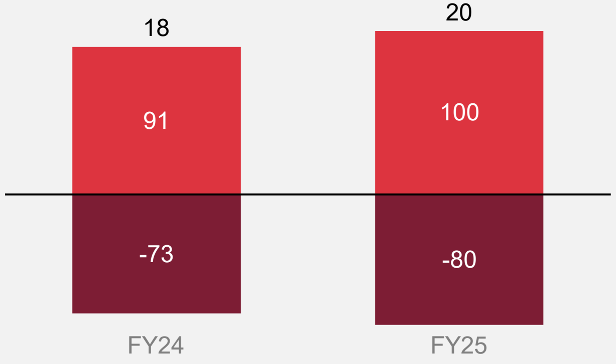


Contracted wholesale revenue increased across most channels, supported by higher prices and strategic volume shifts.

- Sales to the retail segment were 112GWh lower than FY24, with warmer conditions reducing usage per connection. The electricity transfer price rose by $15/MWh to $163/MWh—reflecting higher wholesale prices over the past three years—resulting in a $39 million increase in revenue.
- C&I channel sales were marginally higher in FY25 (+41GWh) with fueling limitations in Winter 2024 and early 2025 reducing the ability to sell additional volume in the period. Net price improved slightly (+$0.2MWh) reflecting customer contracts repricing closer to the prevailing ASX price during the period.
- CFD volumes fell by 276GWh as more sales volume was allocated to long-term strategic channels. This was partly offset by a large risk management contract sold to Meridian in 1H25. CFD pricing rose by $58.6/MWh to $205/MWh, reflecting the market conditions.
- Strategic fixed price volumes rose by 508GWh, driven by new PPAs linked to Tauhara and higher contracted volumes to NZAS. This was partly offset by NZAS demand response during the period. Pricing for these sales increased by $29.5/MWh, reflecting both the Tauhara-backed PPAs and a full year of sales under the new NZAS agreement effective 1 July 2024.
- Other income was lower due to a loss on gas sales, driven by a materially higher weighted average cost of gas following purchases from Methanex in early FY25.

Wholesale trading and merchant revenue

Trading EBITDAF ($m)

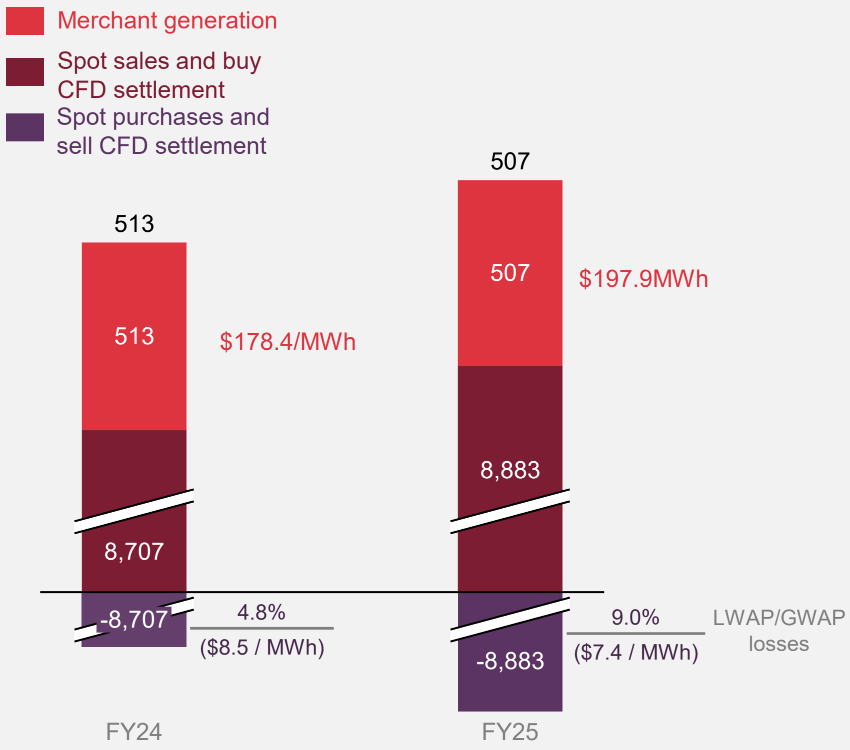


Trading revenue

Merchant sales: short-term sales channel available when the spot prices exceed the opportunity cost of Contact generation.

LWAP / GWAP losses: locational price differences between where electricity is generated and purchased.

Long / short position (GWh)



In FY24, hydro volatility and elevated spot prices led to reduced hydro generation and increased reliance on higher-cost thermal, resulting in lower merchant generation compared to FY23. This trend continued in FY25, with merchant generation remaining broadly flat year-on-year.

FY25 conditions were shaped by:

- Historically low hydro inflows, significantly reducing hydro output.
- Lower wind generation, compounding the supply gap.
- Elevated wholesale spot prices throughout the year.
- Significant demand response from NZAS, helping reduce system demand during tight periods.
- A shift away from merchant exposure, as short-dated electricity sales contracts were used to de-risk material gas arrangements.

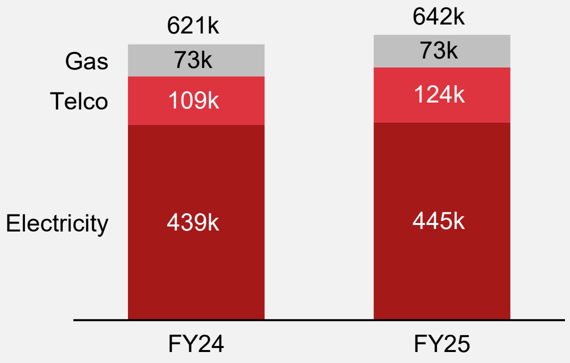
The LWAP/GWAP spread widened to 9%, reflecting volatile market conditions, including periods of higher South Island prices and periods where generation at thermal nodes was concentrated (suppressing pricing).

Retail business performance

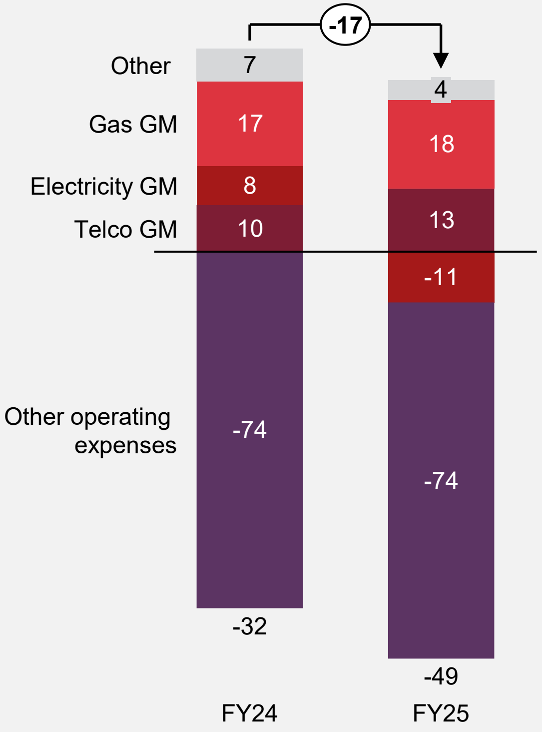
Managing through rising wholesale input costs while growing market share through a multi-product strategy

Revenue & Tariff[1] ($m)	FY25		FY24	Variance	
	$m	*Tariff*	$m	$m	*Tariff*
Electricity revenue	**1,079**	**$312/MWh**	**1,018**	**61**	**+$25/MWh**
Gas revenue	103	$49/GJ	96	7	+$8/GJ
Telco revenue	101	$72/Mth	82	19	-
Other income	7		10	-3	
Total revenue	**1,290**		**1,206**	84	
Contract Asset (closing)	3		3	0	
# of connections (closing) [1]	642k		621k		
Cost to serve/connection[2]	$116		$123		

Closing connections (k)



EBITDAF ($m)



	FY24	FY25
Electricity transfer price[3]	$148/MWh	$164/MWh
Networks, meters and levies[3]	$118/MWh	$132/MWh

Retail margins have contracted, driven by sustained high wholesale prices and rising distribution costs.

- Retail EBITDAF decreased by $17m on FY24 largely driven by the $96m increase in electricity input costs that were not fully passed through to customers.

The average retail electricity tariff increased by 8.8% reflecting targeted retail price rises to partially offset rising wholesale costs and full recovery of lines cost increases.

- Around 91% of customers received a price increase in the last 12 months.

As the energy industry decarbonises, cost pressure for retailers is expected to remain, including:

- Significant investment in lines and distribution infrastructure.[4]
- Continued elevated wholesale futures prices.

This will result in an increase in the cost that consumers will pay over the coming years.

Connections grew strongly since 2H24 particularly through telco and Time of Use (ToU) electricity Good plans, with a focus on multi-product customers.

- Total connections +21k on FY24 with telco up 15k and energy up 6k.
- Multi-product customers up 7% on FY24, driven by strong telco product attachment alongside ToU Good plans growth.

Cost to serve – reduced by $7/connection, largely driven by increased connections, lower marketing spend and productivity improvements through continued growth in digitised interactions, partially offset by wage inflation.

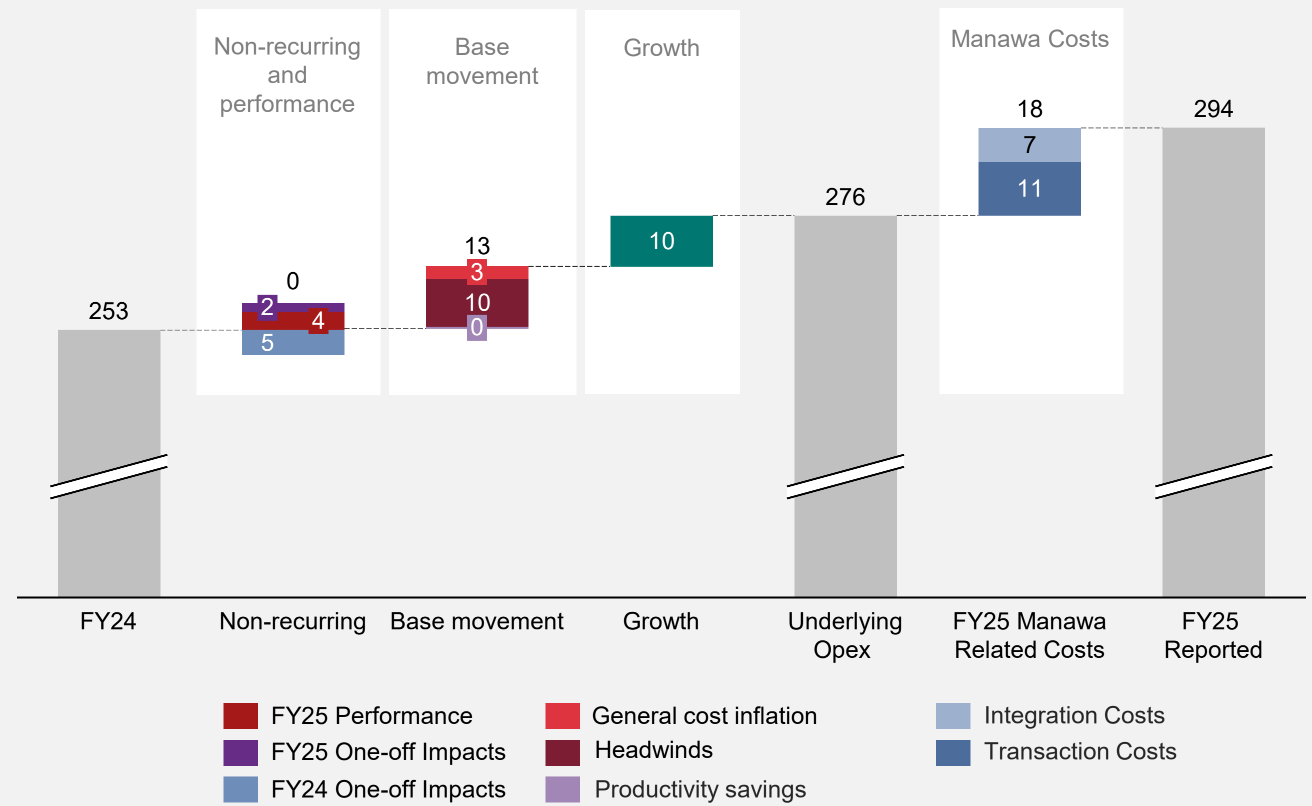
[1] Retail connections only, excludes Simply Energy.
[2] Reflects total operating costs (direct and indirect) / average connections. Includes customer acquisition costs.

Gross Margin (GM) is Revenue less Cost of Goods (Networks, meters, levies, energy, carbon and telco)
[3] Input costs shown per MWh at the GXP.

[4] 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).

Operating costs reflect inflation, growth, and one-off items related to the Manawa acquisition

Other operating cost movement ($m)



Non-recurring and performance items

- FY24 included $4 million of one-off costs related to assessing the Manawa acquisition (in addition to costs for cyclone repair and restructuring).
- In FY25, non-recurring spend outside of Manawa included feasibility costs for the Wairakei extension, SAP Ariba implementation and restructuring. FY25 saw an increase in employee incentives, reflecting strong performance outcomes.

Base movement

- General inflation contributed approximately $3 million (2.7%). However, several key cost categories rose faster than inflation:
  - Labour costs increased by 3.5%, including $5 million for staff development under the Grow Your Whānau parental support programme.
  - Rates rose by 36% ($1 million).
  - Staff benefit costs higher—including medical insurance, electricity subsidy support, and increased retirement contributions— to support capability retention.
  - Insurance costs increased by 20%, although this was partly offset by changes to the insurance programme structure.
  - Productivity improvements in the Retail and C&I businesses helped mitigate some of these cost pressures.

Growth

- Retail connection growth added $1 million in operating costs.
- Tauhara and Te Huka 3 contributed $7 million in additional operating expenditure.
- A further $2 million was invested in feasibility work for future geothermal, wind, and solar development.

Cash flow and capital expenditure

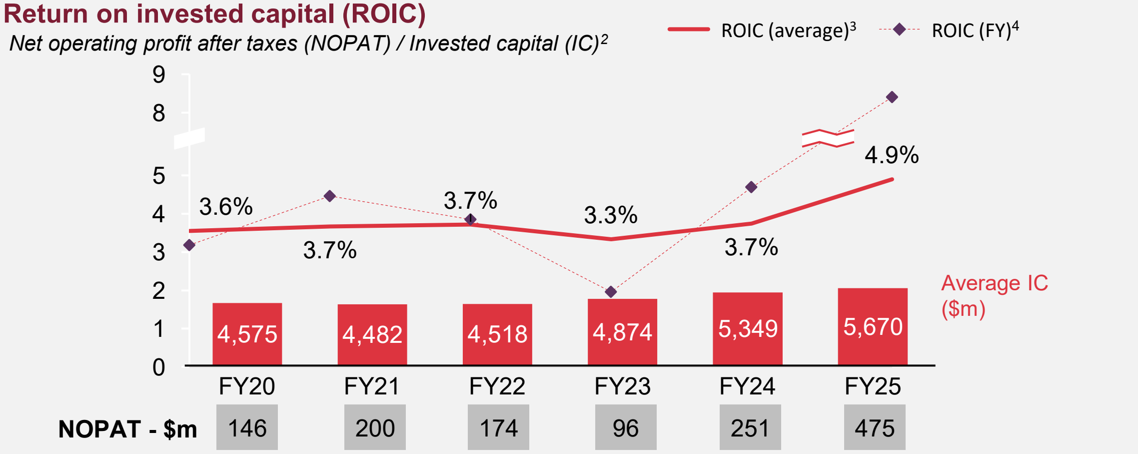
Cash conversion lower with strong EBITDAF growth offset by negative working capital changes and interest

	12 months ended 30 June 2025	12 months ended 30 June 2024	Comparison against FY24	
EBITDAF (underlying)	$774m	$663m	↑	$111m
Working capital changes	($35m)	$31m	↓	($66m)
Tax paid	($106m)	($97m)	↓	($9m)
Interest paid, net of interest capitalised	($77m)	($21m)	↓	($56m)
SIB capital expenditure[1]	($110m)	($156m)	↓	$46m
Non-cash items included in EBITDAF	($12m)	$4m	↓	$16m
Operating free cash flow[1]	$434m	$424m	↑	$10m
Operating free cash flow per share	54.4 c	53.9 c	↑	0.5 c
Cash conversion (OpFCF / underlying EBITDAF)	55%	64%	↓	down 9%

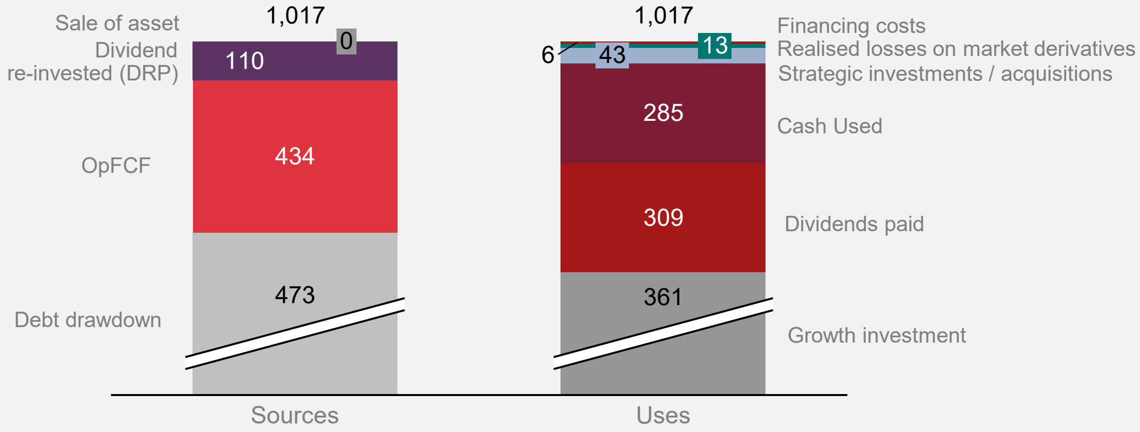
- Higher underlying EBITDAF, as detailed on slide 18.
- Working capital change was a negative $35m impact to OpFCF (vs. positive $31m in FY24), mainly due to increased gas inventory purchases—both in volume and cost per GJ.
- Tax paid was $9m higher, reflecting stronger operating profit and the July 2024 final wash-up payment for FY24.
- Interest paid, net of capitalised interest, rose by $56m. This was driven by the commissioning of Tauhara, which reduced the amount of interest eligible for capitalisation compared to FY24.

Return on invested capital (ROIC)

Net operating profit after taxes (NOPAT) / Invested capital (IC)[2]



Sources and uses of cash ($m)



[1] Pre-FID costs associated with Te Mihi Stage 2 have been reclassified as SIB capex in FY24 ($46m). These were previously allocated to growth capex. FY24 operating cash flow has been adjusted accordingly.
[2] NOPAT is calculated as annual EBIT less tax (tax includes annual tax expense and movements in deferred tax over the year as a proxy for cash tax paid). Invested capital is calculated as the average of the opening and closing balance of: net working capital (adjusted to remove current borrowings, current net derivatives and excess cash above $50m) + non-current assets (adjusted to remove non-current derivatives). The ROIC calculation includes the after-tax movement in the AGS provision over time. In FY25 this amounted to a $71m benefit in the NOPAT figure.
[3] ROIC average is calculated as NOPAT (4-year average) / Average IC (4-year average).
[4] ROIC (FY) is calculated as Annual NOPAT (FY) / Average IC (FY).

Growth capital expenditure

Contact’s FY25 growth investment demonstrates progress in the strategic execution of its renewable development pipeline

Growth capital expenditure – cash basis ($m)[1]

	Up to 30 June 2024	12 months ended 30 June 2025	Remaining under current approvals	Total[2]
Tauhara	$852m	$53m	$26m	$931m
Te Huka 3	$246m	$47m	$12m	$305m
Te Mihi Stage 2	$57m	$144m	$511m	$712m[3]
Wind	$13m	$8m	$5m	$26m
Glenbrook-Ohurua BESS	$5m	$87m	$71m	$163m
Other[4]	$17m	$2m	$3m	$23m
Capitalised interest	$173m	$23m	$70m[5]	$266m
Total	**$1,363m**	**$363m**	**$697m**	**$2,425m**

Investment in joint ventures and associates ($m)

	Up to 30 June 2024	12 months ended 30 June 2025	Remaining under current approvals	Total[2]
Solar[6]	-	-	$37m	$37m
$C0_2$	$2m	$5m	$1m	$7m
Forestry	$44m	$39m	$1m	$84m
Total	**$45m**	**$43m**	**$39m**	**$128m**

- Construction commenced in FY25 on three major renewable projects: the Glenbrook-Ohurua Battery Energy Storage System (BESS), 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 $66 million for Te Mihi Stage 2 geothermal and $5 million for the Glenbrook-Ohurua BESS.
- Construction of the Tauhara and Te Huka 3 geothermal plants is now complete. Remaining spend on Tauhara relates to planned works during its first statutory outage in November 2025. For Te Huka 3, the 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 and associates, and is therefore excluded from growth capital expenditure.

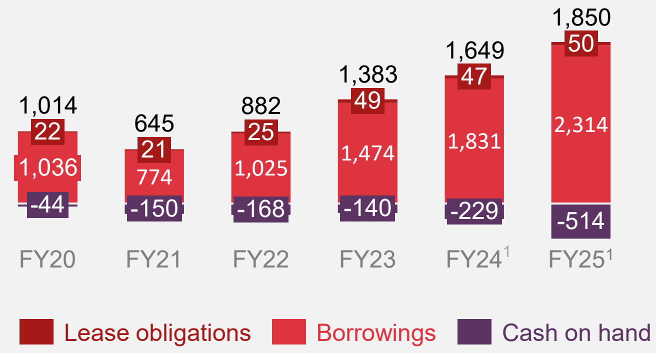
[1] Excludes ~$1m of development capex that has been approved to advance Manawa projects in FY26.
[2] Total under current board approvals.
[3] For Te Mihi Stage 2, the board approved an additional $49m contingency (over and above the contingency amount already included in the expected and approved total construction cost of $712m) to account for a scenario where a broader range of risks materialise and to ensure prudent balance sheet management. If called on, this would take the total cost to $761m.
[4] Relates primarily to Western coil tube drilling and deployment of demand flex technology.
[5] Relates to Te Mihi Stage 2 and Glenbrook-Ohurua BESS development.
[6] Excludes pre-FID development expenses for solar which are captured within receivables.

Supportive balance sheet

Contact's diverse funding sources enable continued renewable build

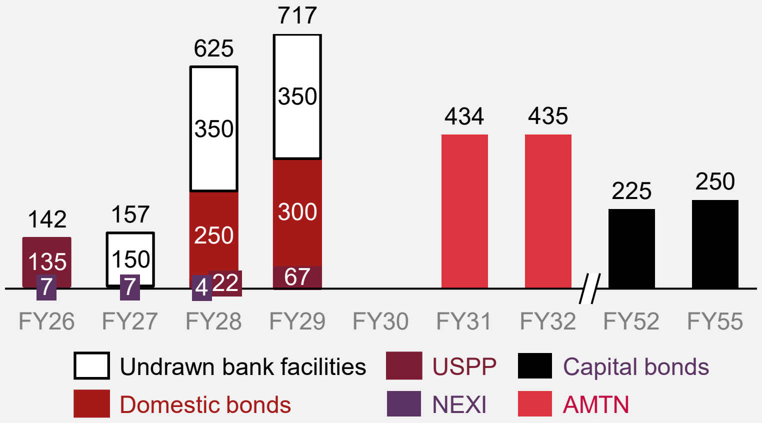
Closing net debt ($m)

Face value of borrowings less cash



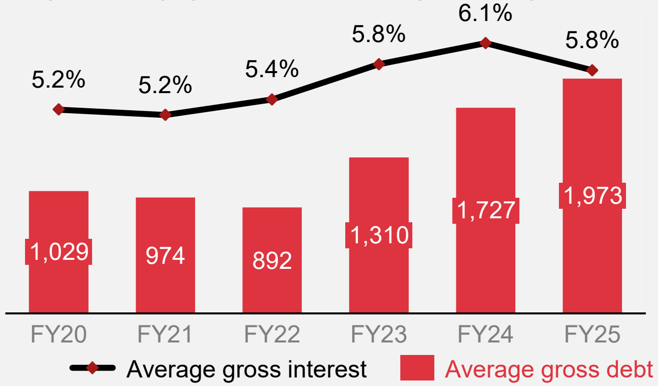
Borrowing maturities ($m)

Average tenor of 7.7 years as at 30 June 2025



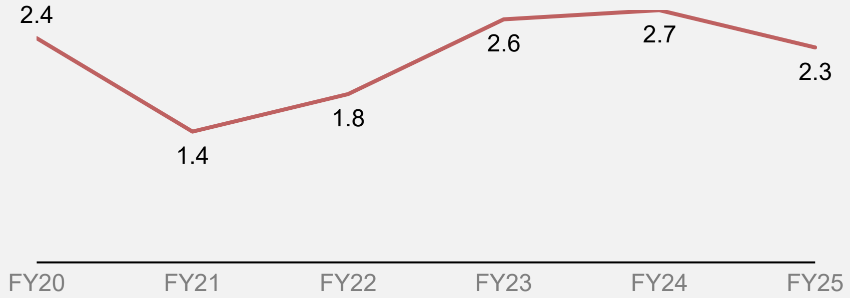
Interest rate (%)

Weighted average gross interest[2] on average borrowings



Net debt to EBITDAF (x)

Includes S&P adjustments[3]



Approach and FY25 highlights

- Contact's capital management strategy is anchored to maintaining an investment grade credit rating, which is supported by a net debt to EBITDAF sustainably below 3.0x. At FY25 year-end, the point estimate of net debt to EBITDAF was 2.3x.
- During FY25, Contact issued a NZ$250 million Capital Bond and a A$400 million Australian Medium Term Note (AMTN). Both instruments were certified Green under the Climate Bonds Initiative framework and support the funding of Contact's renewable development pipeline.

Looking ahead

- Following the completion of the Manawa acquisition on 11 July 2025, Contact raised NZ$900 million in new bank debt. This was used to repay Manawa's existing bonds (NZ$388 million), settle bank facilities, and fund the cash consideration paid to Manawa shareholders.
- It is expected that the Manawa acquisition will increase net debt to EBITDAF in the near term and it may temporarily lift above 3.0x. However, it is expected to return below the threshold as the benefits of the acquisition are realised.

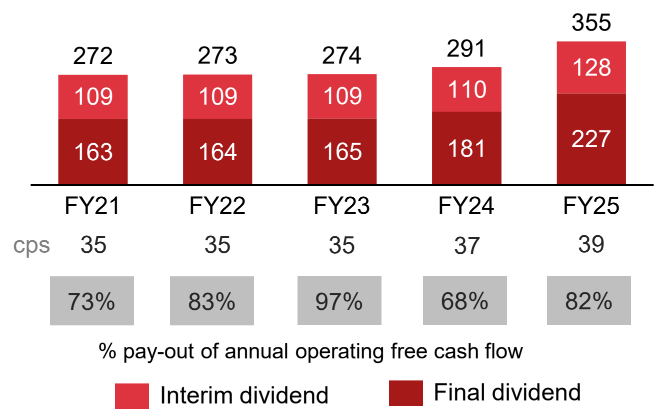
[1] Includes $87m (FY24) and $0m (FY25) of collateral held on deposit for margin calls associated with the trading of electricity price derivatives on the ASX. Includes $180m of commercial paper (FY25) not shown in borrowings breakdown (right).
[2] Gross interest includes all interest on borrowings, bank commitment fees and deferred financing costs. Unwind of leases, provisions and capitalised interest not included.
[3] Illustrated here on a point basis based on expected S&P adjustments. See breakdown of S&P approach on slide 51.

Dividend per share for FY25 39cps, up 5%

Reflects 101% of the average operating free cash flow for the preceding four years

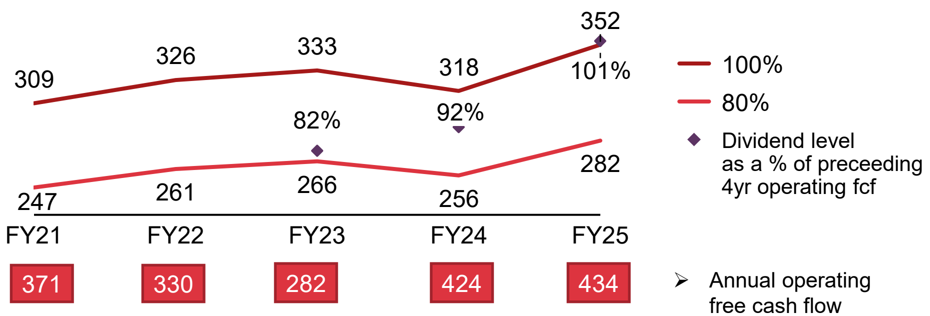
Ordinary dividends ($m)

Declared



Operating free cash flow

Average operating free cash flow for the preceding four financial years



Contact's dividend policy is to pay dividends of 80-100% of average operating free cash flow of the preceding four years. As the historic measure will not capture the operating free cash flow contribution from Manawa within the history, the Board will apply discretion in the first few years post-acquisition, if the measure is temporarily above 100%, so that it is not constrained in delivering the expected DPS uplift. This has been the approach taken in FY25. If the shares issued as consideration for Manawa are excluded, the FY25 dividend declared would represent a pay-out of 72% of FY25 operating free cash flow and 89% of the preceding 4-year average.

Dividend for FY25 of 39 cents per share

- The final dividend of 23 cents per share is imputed up to 57% or 13 cents per share for qualifying shareholders.
- This takes the total FY25 dividend declared to 39 cents per share, representing a pay-out of 82% of FY25 operating free cash flow and 101% of the average operating free cash flow over the preceding 4 financial years (FY21-FY24).
- The record date is 26 August 2025; payment date is 24 September 2025.
- The NZD / AUD exchange rate used for the payment of Australian dollar dividends will be set on 3 September 2025.

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 FY25 final dividend and Contact will have the right to terminate or suspend the plan at any time.
- Dividend reinvestment plan application forms must be in by 27 August 2025 to confirm participation in the plan.
- The trading period for setting the price for the DRP is 25 August 2025 to 29 August 2025. The DRP strike price will be announced: 1 September 2025.

Dividend expectations

- Contact indicated that it expects to lift the total dividend in FY26 to 40cps and between 41 and 42cps in FY27.[1]
  - On this basis, dividends in FY26-FY27 are expected to be imputed up to ~80%.
- Reliable ordinary dividends are expected to increase over time with growth in operating free cash flow.

[1] All dividend decisions are a matter for the Board at the conclusion of each reporting period. These align to the dividend policy and are dependent on business and market conditions when each payment decision is made.

ASSUMPTIONS FOR NORMALISED EARNINGS

Normalised and expected FY26 EBITDAF $980m[1]

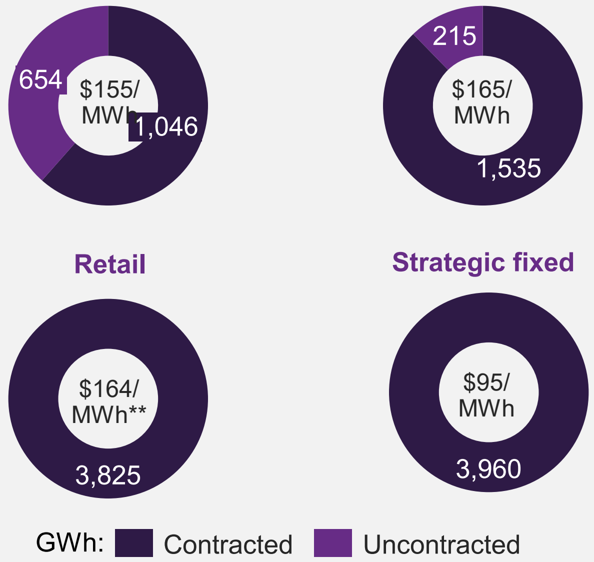
Before Manawa transaction and integration costs and assuming mean hydrology and wind conditions

CFDs

C&I

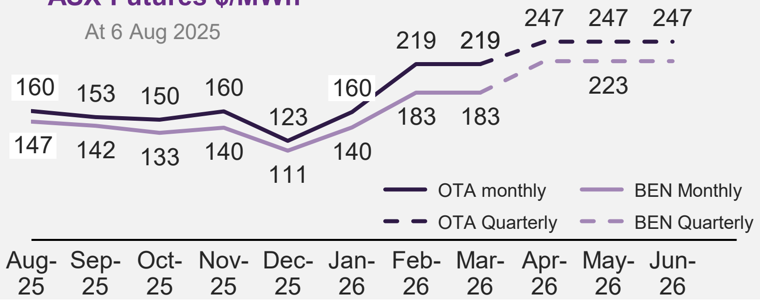
Retail

Strategic fixed



ASX Futures $/MWh

At 6 Aug 2025



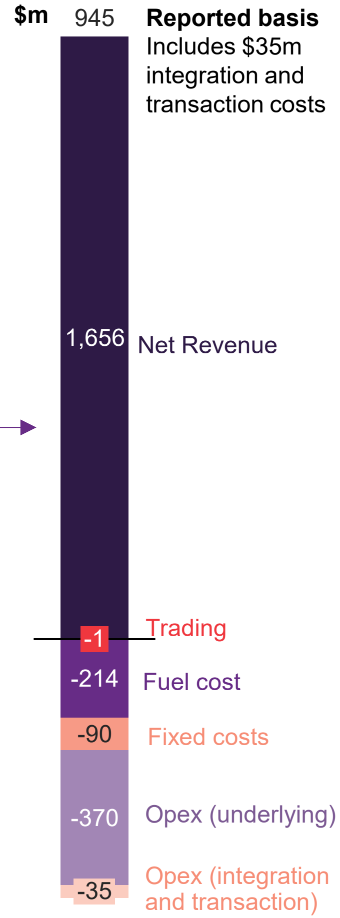
FY assumptions that deliver expected & normalised EBITDAF for FY26

1 Channel choices maximise long term value[2]		X	2 Net price[3] driven by best commercial practices	=	Total
Strategic fixed price	3,960GWh	x	$95/MWh	=	$376m
CFDs	1,700GWh	x	$155/MWh	=	$264m
C&I	1,750GWh	x	$165/MWh	=	$289m
Retail	3,825GWh	x	$164/MWh	=	$627m
Other income[4]					$100m
					$1,656m

3 Hydrology & Asset availability optimise generation		X	4 Access to and price of fuel* drives financials & risk position	=	Total
Hydro mean	5,750GWh	x	$0/MWh	=	-$0m
Geothermal average	4,950GWh	x	$4/MWh	=	-$20m
Thermal	275GWh	x	$215/MWh[5]	=	-$59m
Renewable PPAs	830GWh	x	$100/MWh	=	-$83m
Acquired	200GWh	x	$260/MWh[6]	=	-$52m
					-$214m

5 Trading delivers value to largely offset locational losses	
Length[7]	$139m
Location losses[8]	-$140m
Total	**$-1m**

6 Digitalisation & continuous improvement optimise fixed costs	
Transmission/Storage	**-$90m**
Opex underlying (including in-year synergies)	-$370m
Opex - Integration & transaction costs	-$35m
Total Opex	**-$405m**
Total	**-$495m**



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, telco 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 770GWh p.a. 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.

** Retail volume contracted. Competitive risk remains on pricing achieved.

Note: All figures are subject to rounding.

Update on Manawa and strategic delivery

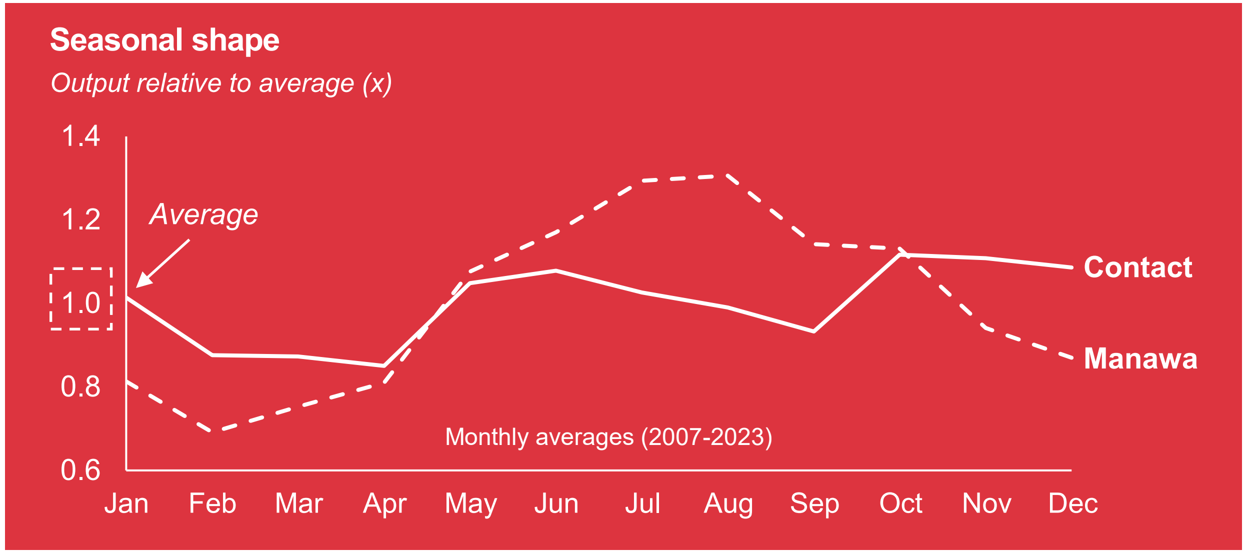
Recap: A strategically compelling acquisition

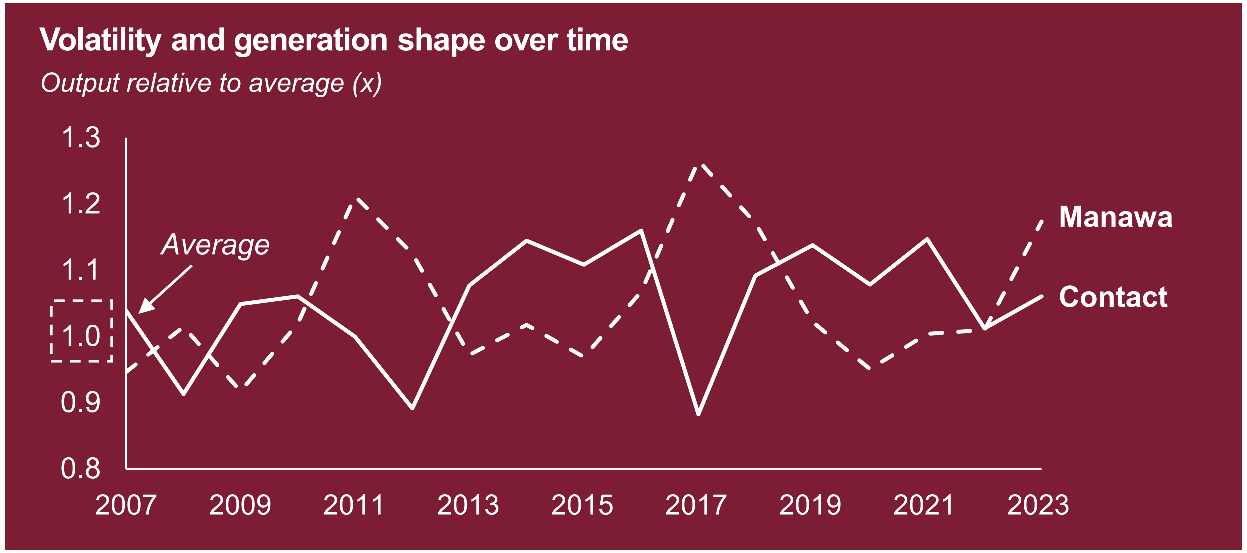
1. **Geographically diversified hydro schemes** are complementary, **enhancing portfolio resilience** and the volume of fixed price supply agreements able to be placed into the market.[1]

2. Hydro flexibility is expected to provide firming to **expedite intermittent renewable development.**

3. Combined portfolio will see mean **renewable generation of more than 11TWh[2] with ~98% renewable output[2]**, accelerating Contact's strategy to grow renewable **generation while decarbonising its portfolio.**

4. Highest value options can be advanced from an **attractive and diversified combined development pipeline**, supported by **Contact & Manawa's renewable development execution capabilities.**





[1] When compared to the volume that can be supported by Contact's and Manawa's standalone hydro portfolios.
[2] Based on long term average hydrological conditions and an expectation of 200GWh to 300GWh of gas generation through the Stratford peakers following the planned closure of the Taranaki Combined Cycle gas plant in late 2025. Excludes any short-term acquired generation purchases e.g. fuel replacement via ASX which will reflect the renewable mix of the market.

Delivering on the promise of the Manawa acquisition

Contact is well-positioned to deliver the benefits of the Manawa acquisition, backed by market tailwinds and a proven integration approach

Re-cap: Expected benefits on transaction announcement (EBITDAF)[1]

Embedded value – Future Manawa standalone earnings potential

Generation normalisation	MCY, PPA & C&I contract rollover	Cost synergies	Expected portfolio benefits
~$11m	~$21m	$23m – $28m *100% within 18-24 months*	$10m - 20m

Status

Generation normalisation	MCY, PPA & C&I contract rollover	Cost synergies	Expected portfolio benefits
✓ On track	✓ On track	✓ On track	✓ On track

Key changes

Key milestones met in Manawa asset refurbishment programme

- Matahina upgrade completed in FY25 (17GWh mean annual uplift)
- On track to achieve mean annual hydro generation of 1,991GWh from FY28

Contact's view of long-term wholesale prices remains $115 to $125/MWh[2]

- Benefit of ~$21m is a long-term estimate i.e. no change
- Near-term upside from ASX electricity futures uplift since announcement

Continued integration plan refinement has underpinned confidence in cost synergies

- Targeting $25m - $28m operating cost reduction
- Targeting $26m - $29m cash opex and financing cost synergies
- 100% within 12-18 months (exit run-rate)

Emerging market trends support future quantified and non-quantified portfolio benefits

Widening of winter / summer ASX electricity futures pricing gap since announcement (up >20%)

- Value shift to flexibility

[1] Expected EBITDAF benefits as presented at announcement on 11th September 2024 – Shown with reference to Manawa's FY24 EBITDAF (March year end).
[2] Real 2025. This is a through-the-cycle measure in a balanced market. Prices achieved are a function of the market at a point in time.

Asset upgrades and market tailwinds building confidence

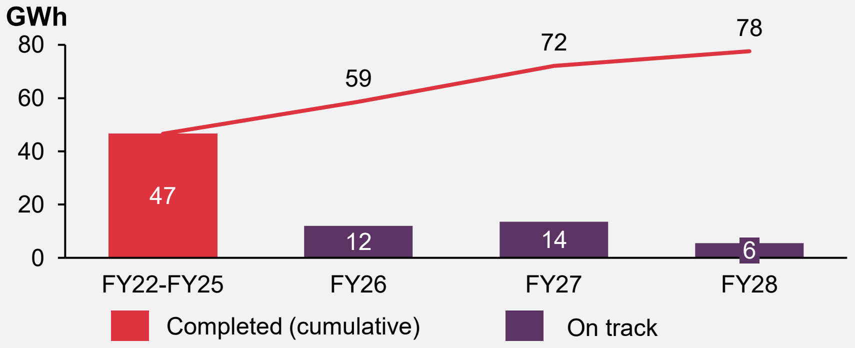
Key milestones met in Manawa's asset refurbishment programme: On track for 1,991GWh p.a. mean output from FY28

Increase in electricity futures prices expected to provide higher near-term hedge repricing benefits

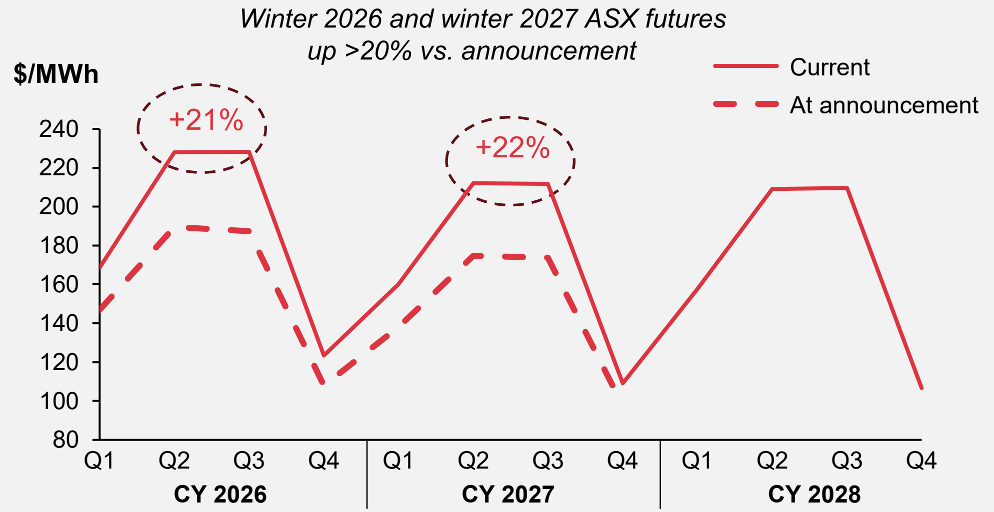
Hydro improvement project status

Project	Status	Uplift (GWh)[1]
Branch	Completed	10
Matahina	Completed	17
Waipori	Completed	-
Cobb	Completed	-
Arnold	Completed	-
Various	Completed	20
Highbank	On track – FY27	8
Coleridge	On track – FY28[2]	23
Total		**78**

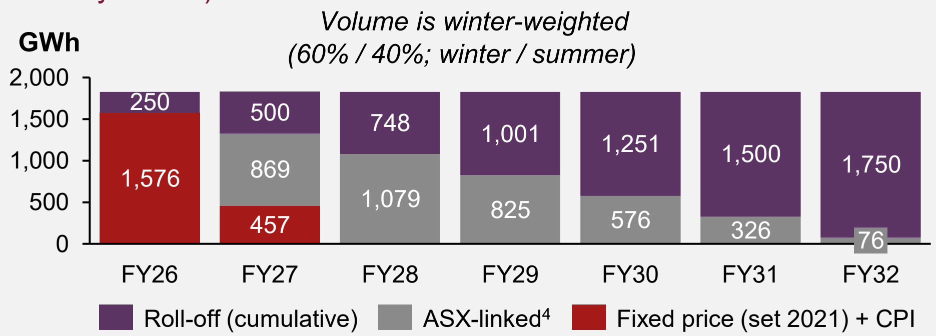
Hydro uplift over time – approved projects[1]
(30 June year end)



ASX Futures (Quarterly, base period, OTA)[3]



Mercury hedge volume
(30 June year end)



[1] Represents incremental annual output delivered by the programme. Assumes mean hydro and a 2021 baseline.
[2] Phased uplift to occur from FY26.

[3] ASX NZ Electricity Otahuhu base quarter futures pricing as at 30 July 2025.
[4] Pricing linked to historic rolling ASX prices from 1 October 2026.

Cost synergies on track

Integration Management Office (IMO) established…..

A well resourced integration management programme is in place

6 Integration management workstreams	**9** Functional workstreams	**~70** Initiatives

Executive sponsorship for each workstream and initiative

IMO accountabilities:

- Ensure a smooth transition for teams, systems, and operations.
- Achieve ~70% of targeted cost reductions within the first six months *(exit run-rate basis).*
- Deliver the full value of the acquisition, including cost synergies.
- Guide the organisation through its transition to the future operating model.

…..with granular plans firming up targets for cost synergies

Cost reduction targets confirmed (all shown pre-tax)

Opex reduction target at announcement:

$23m - $28m

100% within 18-24 months post completion (exit run-rate)

Opex reduction target now:

$25m - $28m

100% within 12-18 months post completion (exit run-rate)

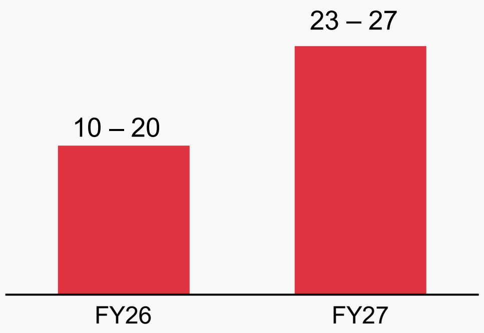
Cash opex and financing cost synergy target:

$26m - $29m

100% within 12-18 months post-completion (exit run-rate)

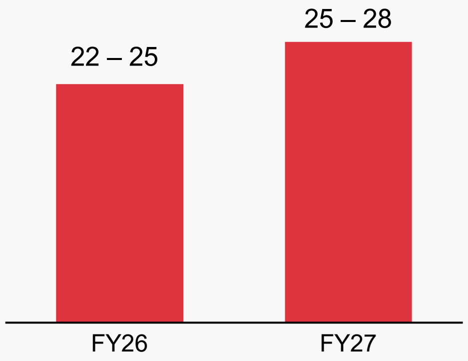
Opex reduction target: In-year benefit

$m



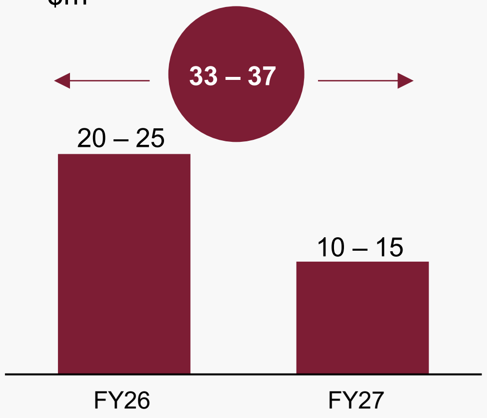
Opex reduction target: Exit run-rate

$m



Integration costs (opex)[1]

$m



Expected combined operating costs FY26

$m

	$m
Opex reduction (in-year benefit)	10 – 20
Less: Integration costs within opex[1]	(20 – 25)
Less: Transaction costs within opex	(13)
Total operating costs	**(400 – 410)**

[1] Approved integration costs (both opex and capex) total $45m over FY25 to FY27 ($7m has been incurred in FY25) with an additional $9m contingency. The ultimate allocation between opex and capex is dependent on accounting treatment and is yet to be confirmed.

Upside from portfolio combination benefits to come

Focus on capturing the benefits of increased generation flexibility, increased access to renewable winter energy and reducing hydrology risk

Supported by market trends…

Material downgrade to gas field reserves

Since the acquisition announcement, updated New Zealand gas reserve data shows a decline of more than 20% in forecast production for each year through to 2030, relative to 2024 estimates.[1] Limited gas availability and rising costs have pushed the marginal cost of thermal generation above $200/MWh.

Winter Summer Price Separation Widening

While average prices continue to reflect long-run economics, ASX Futures show winter prices rising significantly faster than summer prices. This trend is driven by the need to recover higher thermal fuel costs and the growing share of must-run renewables in the market. Futures for winter 2026 and 2027 are now up >20% compared to levels at the time of the acquisition announcement.

Value shift to flexibility

We expect market value to increasingly favour operators of flexible, intra-day assets and those with fuel storage—rather than intermittent renewable generators.

… which are expected to grow the portfolio combination benefits

	1 Combined inflow characteristics / 2 More efficient participation in spot market	3 Increasing importance of flexibility
How is it captured?	• Portfolio diversification reduces risk. • Increased fixed-price sales enhance revenue certainty. • Greater flexibility in managing stored fuel (eg AGS and Hydro). • Reduced generation costs through avoided gas use. • Lower spend on risk management products (e.g. HFO). • Improved arbitrage margins from battery storage (BESS). • Higher generation-weighted average price (GWAP).	• Increasing GWAP:TWAP ratio for key flexible assets over time.
Steps to achieve	• Initial coordination in place from Day 1 through existing communications and processes. • Gradual integration of dispatch operations across both portfolios. • Enhanced real-time decision-making to optimise dispatch across all assets.	• Unlock further flexibility and improve monetisation with improved trading of assets.
Quantification (2025, Real, $m)	• $10m - $20m, mid-point $15m targeted FY27[2] • $5m targeted FY26[2]	• n/a
	Benefits quantified and included in acquisition evaluation	***Not included in acquisition evaluation. Benefits present future upside potential***

[1] Source: MBIE 2P reserves data published 5 June 2025; Contact analysis.

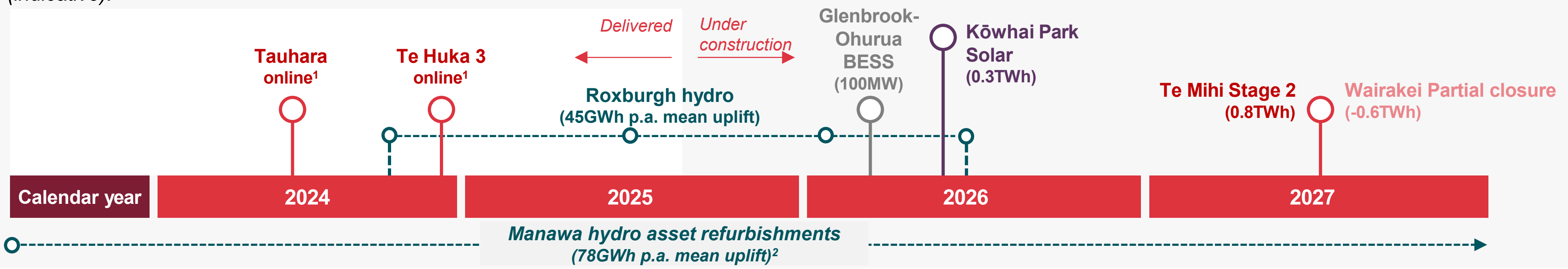
[2] This is a through-the-cycle measure. Actual result will be impacted by hydrology, fuel and other market conditions.

Combined portfolio 98% renewable from FY26 (mean wind and hydro)

Annual mean renewables to support electricity sales to be above 12TWh per annum from FY28

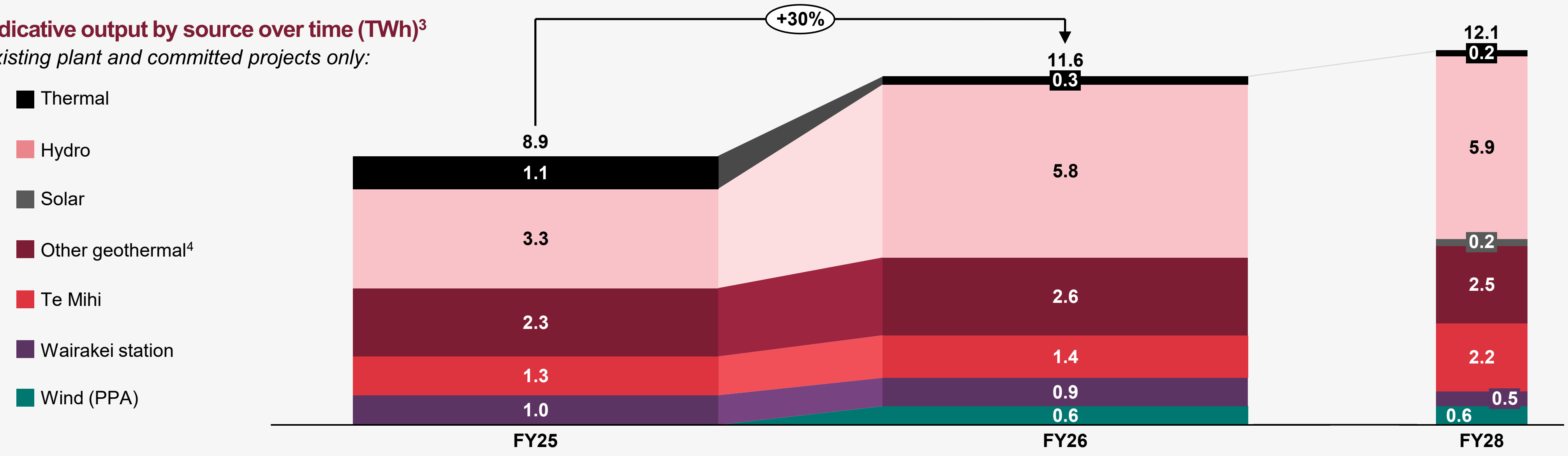
Summary of renewable projects delivered and under construction

Expected generation (indicative):



Indicative output by source over time (TWh)[3]

Existing plant and committed projects only:



Other renewable electricity assets available by FY28

100MW/200MWh Glenbrook-Ohurua BESS

Chart excludes short-term acquired generation purchases e.g. fuel replacement via ASX which will reflect the renewable mix of the market

Renewable output:	FY25	FY26	FY28
	88%	~98%	~98%

[1] Final commissioning activities were ongoing at the illustrated online dates for each of Tauhara and Te Huka 3. Those commissioning activities were completed in FY25.
[2] The uplift of 78GWh p.a. is on a 2021 base and assumes mean hydrology. As at 30 June 2025, asset refurbishments have been completed delivering 47GWh p.a. of this uplift, with work continuing on the 31GWh p.a. remaining. See slide 33.
[3] FY25 generation figures reflect actual volumes in FY25. FY26 and FY28 volumes assume mean hydro and wind generation and account for planned hydro outages (refurbishments) and the geothermal statutory outage schedule. See slide 47.
[4] Other geothermal volume excludes geothermal PPA purchases due to the near-term completion of the contract (December 2026).

Development prioritised as the market requires

Development options across Contact and Manawa's integrated pipeline will be prioritised and advanced based on key strategic evaluation criteria and guiding capital allocation principles

Key strategic evaluation criteria for renewable projects

- Quality of resource; Capacity factors
- Ease of consent; Ease of construction
- Grid connection and transmission
- Location and shape vs. demand
- Portfolio diversification and fit
- Relative cost; Funding model

Strategic evaluation criteria are used to prioritise development options that will offer the most attractive returns on investment; prioritised projects compete under our capital allocation framework

Recap: Contact's guiding capital allocation principles

Continue to attract capital

- Deliver competitive shareholder returns including dividend commitment.
  - Reliable ordinary dividends that increase in line with growth in cash flow.
  - Pay-out ratio of 80-100% of average operating free cash-flow over the preceding 4 years.
- Balance sheet strength with investment grade credit metrics through the cycle.
  - Target BBB <3x net debt to EBITDAF.
  - If temporarily above, always have clear plan to restore metrics.

Optimise existing operations and manage risk

- Reduce carbon exposure and manage market volatility during the thermal transition.
- Disciplined approach to sustaining capital spend.
  - Efficient deployment of stay-in-business capital expenditure.
- Strong operating cash flow.

Invest to deliver value accretive growth

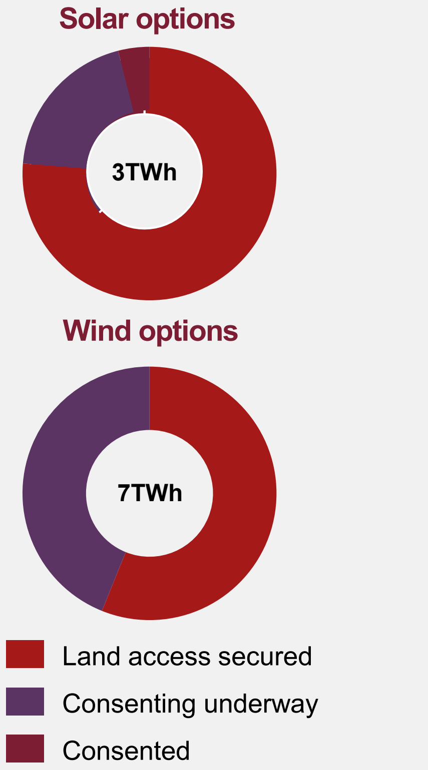
- Returns improved through prioritisation of non-equity funding.
- Projects ranked considering returns available and overall portfolio implications.
- Allocate capital to strategic priorities, with an ability to scale down in downside scenarios.

Considering supportive market conditions and a broad range of attractive projects post Manawa acquisition, we will prioritise investments to grow shareholder value and distributions

An attractive and diversified development pipeline

Development options across a diverse combined pipeline of >10TWh

Combined solar and wind pipeline options of >10TWh



		Project	Capacity (MW)[1]	Estimated output (GWh)	Expected online date	Earliest available investment timing / decision[2]	Project status: Land secured	Project status: Consent lodged	Project status: Consented	Project status: Under construction
Contact	Committed	Kōwhai Park Solar	168	275	Q2 CY2026					
Contact	Committed	Glenbrook-Ohurua BESS	100	n/a	Q1 CY2026					
Contact	Committed	Te Mihi Stage 2	101	840	Q3 CY2027					
Contact	Assessing	Glorit Solar	170	280		FY26				
Contact	Assessing	Glenbrook BESS 200[3]	200[3]	n/a		FY26				
Contact	Assessing	Southland Wind[4]	326	1,210		FY27				
Contact	Assessing	Strafford BESS[5]	100	n/a		FY27				
Contact	Assessing	Stratford Solar	180	300		FY27				
Contact	Assessing	Other solar	700	1,155		Various				
Contact	Assessing	Other wind	685	2,470		Various				
Contact	Assessing	Other geothermal[6]	TBC	~1TWh		>FY28				
Manawa	Assessing	Argyle 1 & 2	90	177		FY26				
Manawa	Assessing	Kaipara	113	190		FY27				
Manawa	Assessing	Huriwaka	300	890		FY27				
Manawa	Assessing	Hawke's Bay Airport	45	80		FY27				
Manawa	Assessing	Kaihiku (JV)[7]	300	1,060		FY27				
Manawa	Assessing	Hapuakohe	230	710		FY28				
Manawa	Assessing	Mackenzie Basin	283	540		FY28				
Manawa	Assessing	Ototoka	150	530		FY29				
Manawa	Assessing	Marlborough Wind	100	330		FY29				

1. Capacity for solar projects is shown as MWp.
2. All available FID timings are to be confirmed.
3. Indicative sizing at FID. Consent application filed for 400MW new capacity, providing future optionality.
4. Based on 6MW turbines. Turbine size is to be confirmed.
5. Capacity of 100MW consented. Preparing to seek consent for additional capacity.
6. Reflects uplift in output available from Tauhara Stage 2 and Te Mihi Stage 3 from consented fluid take.
7. Kaihiku is a 50:50 JV with 300MW total capacity.

Our operational plan for the next 12 months

Next update on strategy will be provided at Contact's November 2025 Capital Markets Day

Strategic theme	FY26		
Grow Demand	New demand facilitated since FY21 to reach >250MW[1] At least 50% of new demand contracted in-year structured with favourable shape (considering load and generation)	Achieve FID for CO_2	
Grow renewable development	Glenbrook-Ohurua BESS online Q1 CY2026 Kōwhai Park solar online Q2 CY2026 Te Mihi Stage 2 geothermal on track for online Q3 CY2027	Subject to market conditions and obtaining consents, achieve FID on: ▪ Solar (e.g. Glorit, Argyle); and/or ▪ Glenbrook 200 BESS	Consents lodged on at least 2 renewable development projects
Decarbonise our portfolio	Close TCC gas generation plant late CY 2025 Scope 1 & 2 emissions <650ktCO_2e[2]	Sustained New Zealand leadership position in the Asia Pacific DJSI	
Create outstanding customer experiences	Multi-product customers >156k (up from 149k) Cost to serve <$116/connection[3]	Targeting net price up by ~2%	
Manawa integration	In-year benefits target: ▪ Opex reduction $10m to $20m ▪ Portfolio benefits $5m[4]	Exit run-rate benefits target: ▪ Opex reduction $22m to $25m ▪ Portfolio benefits $10m to $20m[4]	

[1] Cumulative measure (~230MW as at 30 June 2025). Shown on a total contracted basis.
[2] Assumes mean hydrological conditions.
[3] Excludes customer acquisition costs.
[4] This is a through-the-cycle measure. Actual result will be impacted by hydrology, fuel and other market conditions.


Questions

Supporting materials

Guidance topics

	FY25 guidance	FY25 result	FY26 guidance	FY26 Guidance Commentary
Stay in business (SIB) capex (cash)	**$120-130m**	**$110m**	**$175m - $190m**	
SIB capital expenditure BAU	$77m - $87m	$71m	$115m - $125m	At the mid-point ~$5m higher than long-run expectations due to consenting.
SIB accelerated programme	~$40m	$36m	$12m - $13m	Close-out of Contact's $150m accelerated capex programme announced 2021.
SIB capital expenditure Wairakei	$2m - $3m	$3m	$20m - $25m	Wairakei extension costs.
SIB capital expenditure enhancements and integration	na	na	$23m - $27m	Geothermal wells (~$8m), Manawa hydro refurbishment (~$12m) and integration.
Growth capital expenditure (cash)[1]	$450m - $550m	$363m	$390m - $400m	Growth capital for Tauhara, Te Huka 3, Te Mihi Stage 2, Wind and BESS projects.
Depreciation and amortisation	$275m - $285m	$273m	$280m - $290m	Reflects useful life changes on thermal assets, introduction of Tauhara and Te Huka 3 as well as Manawa expected depreciation.
Net interest (accounting)	$105m - $115m	$100m	$145m - $165m	Reduction in capitalisation of interest with Tauhara commissioning. Higher interest rate environment and increased borrowings with Manawa acquisition.
Cash interest (in operating cash flow)	$85m - $95m	$80m	$135m - $155m	
Cash taxation	$105m - $115m	$106m	$130m - $140m	FY26 provisional payments based on FY24 results and higher final tax payment relating to FY25. Includes estimated Manawa tax payments.
Realised (gains) / losses on market derivates not in a hedge relationship	$15m - $20m	$13m	$10m - $15m	Including (gains) / losses on ASX market making.
Corporate costs - ex Manawa	$54m	$55m	$55m	Reflects Contact corporate costs only. Manawa corporate costs are all allocated to wholesale. As integration progresses, allocations may be updated.
Corporate costs - Manawa integration and transaction	$20m	$18m	$30m - $40m	Non-recurring costs relating to the Manawa acquisition.
Target ordinary dividend per share	39 cps	39 cps	40 cps	Increase in the ordinary dividend to reflect benefits of the Manawa acquisition
Operating cash flow conversion	50%	55%[2]	~50%	Higher interest costs as investments come online (meaning lower capitalised interest) and reflecting Manawa debt. Working capital to support HFO.

[1] Growth capital expenditure includes capitalised interest.
[2] Based on $774m underlying EBITDAF.

Normalised and expected EBITDAF assumptions

With reconciliation to actual performance

FY25 assumptions that deliver expected & normalised EBITDAF of $770m over a financial year

1 Channel choices maximise long term value[1]		X	2 Net price[2] driven by best commercial practices	=	Total
Strategic fixed price	1,900GWh	x	$80/MWh	=	$152m
CFDs	1,770GWh	x	$154/MWh	=	$273m
C&I	1,300GWh	x	$150/MWh	=	$195m
Retail	3,800GWh	x	$154/MWh		$585m
Other income[3]					$47m
					$1,252m

3 Hydrology & Asset availability optimise generation		X	4 Access to and price of fuel* drives financials & risk position	=	Total
Hydro	3,900GWh	x	$0/MWh	=	-$0m
Geothermal	4,620GWh	x	$4/MWh	=	-$19m
Thermal[4]	350GWh	x	$130/MWh[4]	=	-$46m
Acquired	350GWh	x	$215/MWh	=	-$75m
					-$139m

5 Trading delivers value to more than offset locational losses		6 Digitalisation & continuous improvement optimise fixed costs	
Length[5]	$86m	Transmission/Storage	-$71m
Location losses[6]	-$85m	Operating expenses	-$272m
Total	**$1m**	**Total**	**-$343m**

EBITDAF guidance reconciliation to actual FY25

Normalised & Expected

Lower renewables
Hydro generation below mean (-603GWh). Impact calculated at thermal SRMC

Increased long–term channel price
Retail ($160/MWh) & Strategic fixed price sales ($85/MWh) prices higher than expectation (the latter due to NZAS demand response)

Increased market channel price
Higher CFD price ($205/MWh) with tight market conditions and thermal-backed CFD sales

Gas, carbon, acquired generation price
Gas prices were materially higher in the period ($15/GJ)
Demand response payments to NZAS included

Net volume impact
Volumes above expected; lower than expected location loses

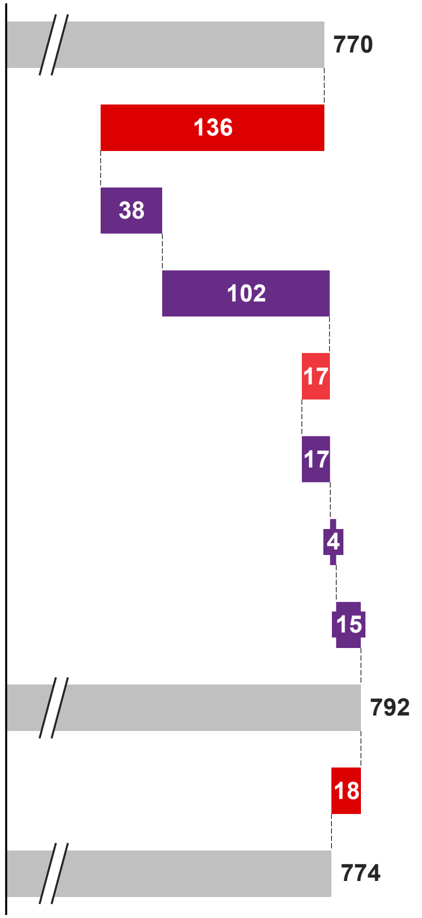
Other income
Risk management sales premiums and expected losses from distressed gas sales not realised

Fixed costs
LCE rebates ($11.5m) and AGS provision unwind partly offset by opex increase

EBITDAF pre Manawa-related costs

Manawa transaction and integration costs

Actual FY25 EBITDAF (underlying)



1. All volumes are at the Grid Exit Point (GXP).
2. Net price is equal to tariff less pass-through costs (network, meters and levies) /MWh.
3. Steam sales, retail gas gross margin, telco gross margin and other income.
4. Gas price of $8.2/GJ, carbon price of $80/unit and thermal portfolio heat rate (10GJ/MWh).
5. Length of 450GWh assumed.
6. Locational losses of 5.1% on spot purchases and settlement of CFDs. sold at a wholesale price of $190/MWh.

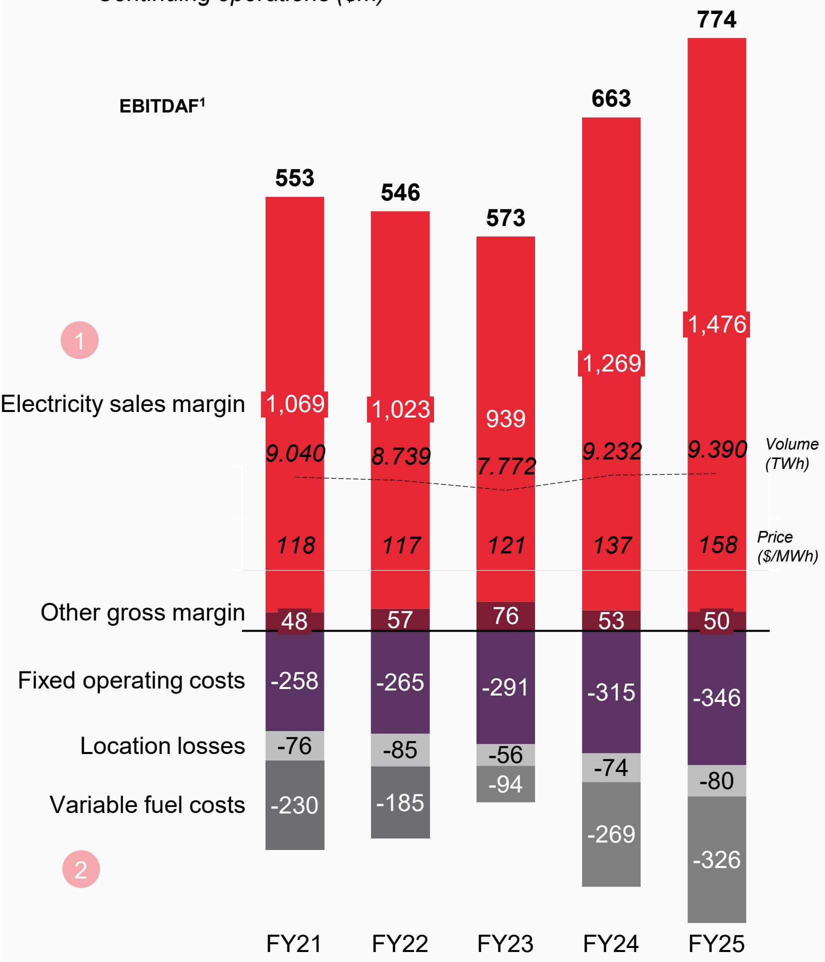
* Fuel is natural gas and carbon costs.

Historic performance

Integrated portfolio performance

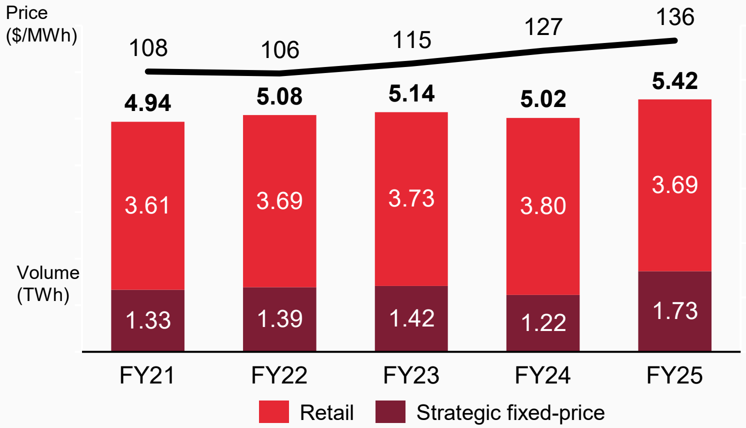
Operating earnings (EBITDAF)

Continuing operations ($m)

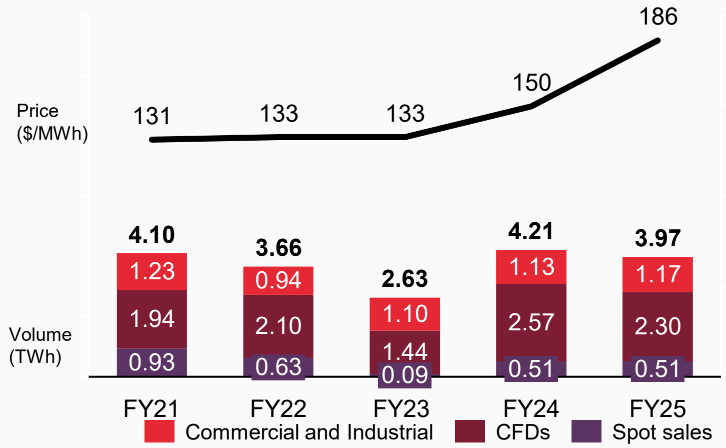


1 Electricity sales

(i) Long-term channels

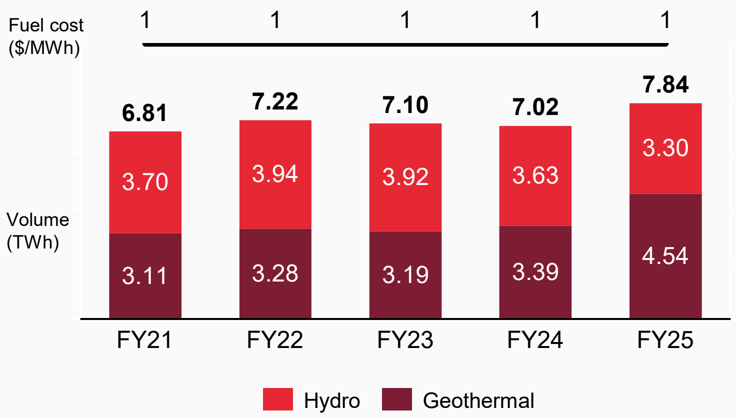


(ii) Market channels

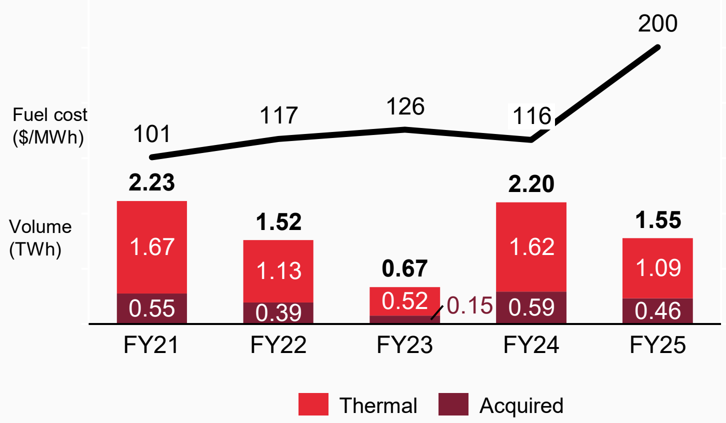


2 Variable fuel costs

(i) Renewables



(ii) Thermal and acquired



[1] Refer to slide 50 for a definition and reconciliation of EBITDAF. All EBITDAF figures are underlying i.e. excluding the impacts of the ($113m) AGS onerous contract provision expense in FY23, a $12m net movement in the AGS provision in FY24, and a release of the AGS provision of $98m in FY25.

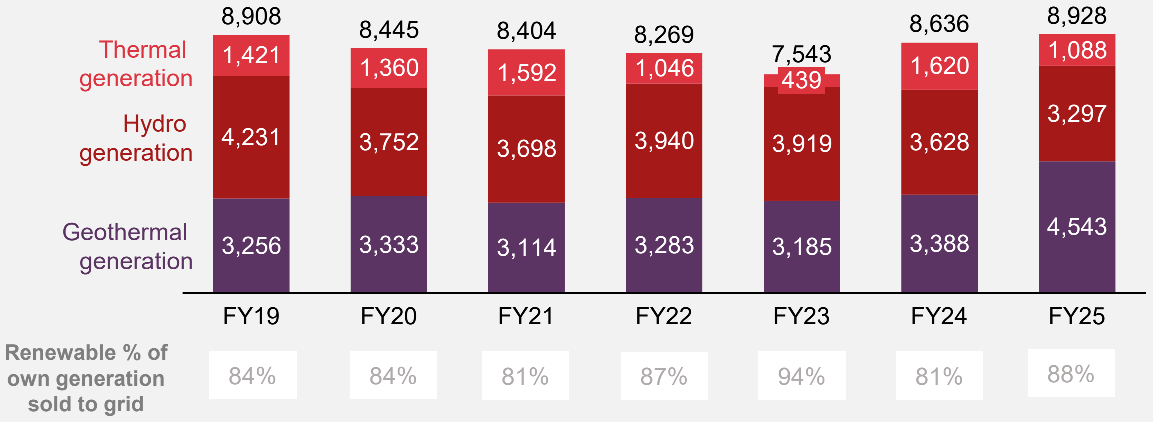
Greenhouse gas emissions

Indicator	Unit	Target	FY21	FY22	FY23	FY24	FY25
Direct GHG emissions (Scope 1)	**tC02e**	45% reduction of 2018 Scope 1 and 2 emissions by 2026 (Absolute emissions reduction target)[2]	**1,044,744**	**786,842**	**526,621**	**947,491**	**740,468**
- Stationary combustion	tC02e		1,044,537	786,544	526,282	947,131	739,945
- Mobile combustion	tC02e		178	297	307	332	409
- Fugitive emissions	tC02e		29	1	32	28	114
Indirect GHG emissions (Scope 2)	tC02e		**1,303**	**1,399**	**1,957**	**975**	**1,183**
Sub-total Scope 1 and 2	**tC02e**	**647,443**	**1,046,047**	**788,241**	**528,579**	**948,466**	**741,651**
Indirect GHG emissions (Scope 3)	**tC02e**	**259,118**	**555,035**	**394,784**	**273,673**	**265,034**	**369,583**
- Category 1 – Purchased goods and services	tC02e		16,699	6,371	6,197	6,522	8,799
- Category 2 – Capital goods	tC02e		41,726	57,876	88,266	79,185	87,203
- Category 3 – Fuel and energy[1]	tC02e		330,207	149,743	1,050	5,130	8,006
- Category 4 – Upstream distribution and transportation	tC02e	30% reduction of 2018 Scope 3 GHG emissions from use of sold products by 2026[2]	27	444	108	254	205
- Category 5 – Waste	tC02e		149	108	47	58	69
- Category 6 – Business travel	tC02e		263	567	1,274	1,601	1,081
- Category 7 – Employee commuting	tC02e		306	832	965	927	956
- Category 11 – Use of sold products	tC02e		165,259	178,554	175,603	170,929	250,612
- Category 13 – Downstream leased assets	tC02e		399	289	164	429	339
- Category 14 – Investments	tC02e		-	-	-	-	12,313
Total Scope 1, 2 and 3 emissions	**tC02e**	**906,561**	**1,601,082**	**1,183,025**	**802,252**	**1,213,500**	**1,111,235**

[1] Contact's swaption with Genesis Energy ended 31 December 2022 and was not called during FY23.
[2] All Science-based targets are on a calendar year basis.

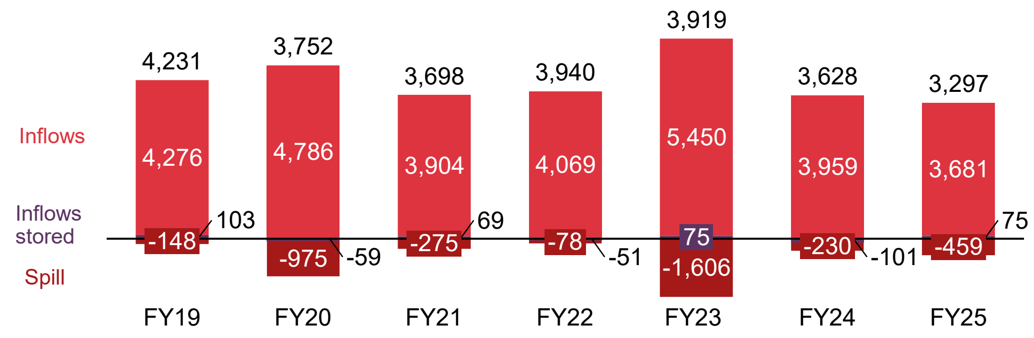
Generation and sales position

Contact generation output sold to the national grid (GWh)



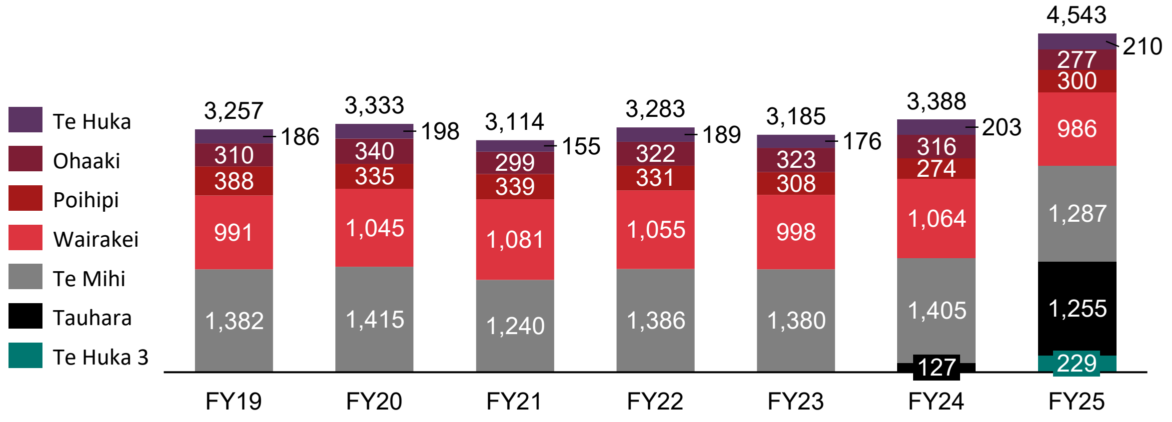
Hydro generation (GWh)

Inflows stored include uncontrolled storage lakes



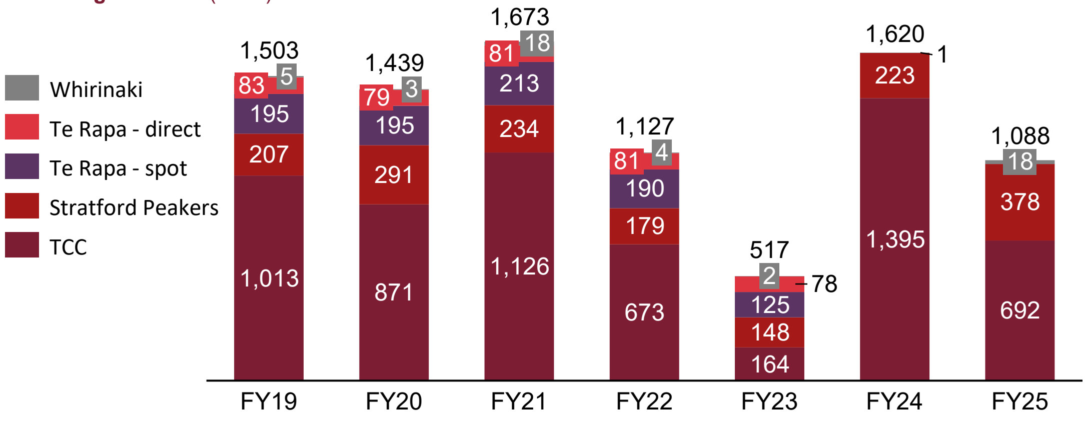
FY25 was marked by two periods of historically low inflows (July – August 2024 and January – April 2025). The result of these conditions meant total inflows for the year were 701GWh below FY24 volumes.

Geothermal generation (GWh)



FY25 geothermal generation was ~1.2TWh higher than FY24. Generation from the new Tauhara and Te Huka 3 plants (1.5TWh) was partially offset by statutory outages at Te Mihi, Wairakei and Ohaaki.

Thermal generation (GWh)



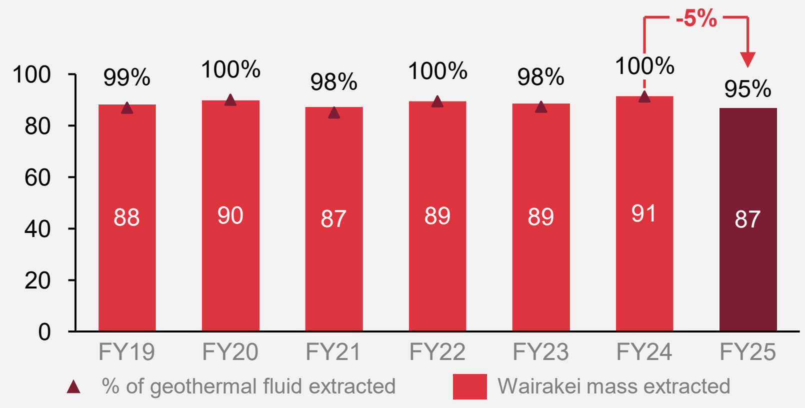
Although down significantly on FY24, thermal generation volumes were materially higher than mean expected volumes due to dry conditions in winter 2024 and Jan to April 2025.

Operational data

Plant and fuel performance

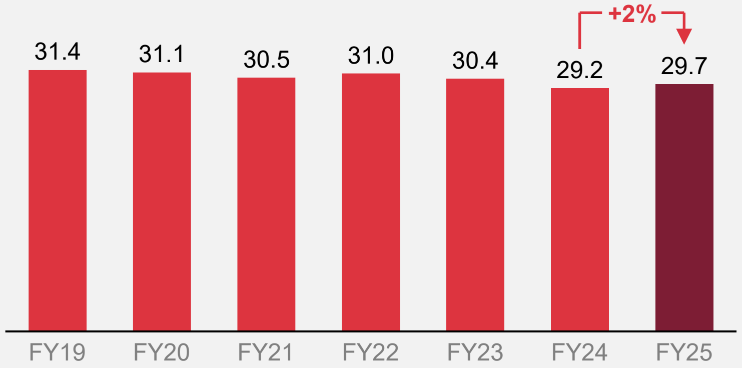
Geothermal fuel performance

Geothermal fuel extracted at Wairakei vs consented (mT)



Wairakei total mass extracted, and extracted volumes as a % of consented mass take, were significantly down on FY24 as a result of a planned outage (25 days) at Te Mihi and an electrical outage at Wairakei A&B station.

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



Plant availability

Hydro

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
FY21	784	84%	54%	3,698	167	617
FY22	784	83%	57%	3,940	121	478
FY23	784	84%	57%	3,919	74	290
FY24	784	90%	53%	3,628	164	594
FY25	784	87%	48%	3,297	163	538

Taranaki combined cycle (TCC)

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
FY21	377	89%	34%	1,126	193	217
FY22	377	84%	20%	673	180	121
FY23	377	85%	5%	164	107	18
FY24	377	82%	42%	1,395	184	257
FY25	377	89%	21%	692	330	229

Whirinaki

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
FY21	158	94%	0%	18	410	7.5
FY22	158	95%	0%	4	597	2
FY23	158	82%	0%	2	491	1.2
FY24	158	97%	0%	1	687	1.1
FY25	158	92%	1%	18	661	12

Geothermal[1]

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
FY21	425	89%	84%	3,114	175	546
FY22	425	97%	91%	3,283	140	458
FY23	410	94%	89%	3,185	80	254
FY24	586	94%	89%	3,388	177	601
FY25	635	90%	84%	4,543	186	845

Stratford Peakers

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
FY21	202	90%	13%	234	230	54
FY22	202	53%	10%	179	212	38
FY23	202	77%	8%	148	207	31
FY24	202	50%	12%	223	175	39
FY25	202	70%	22%	378	217	82

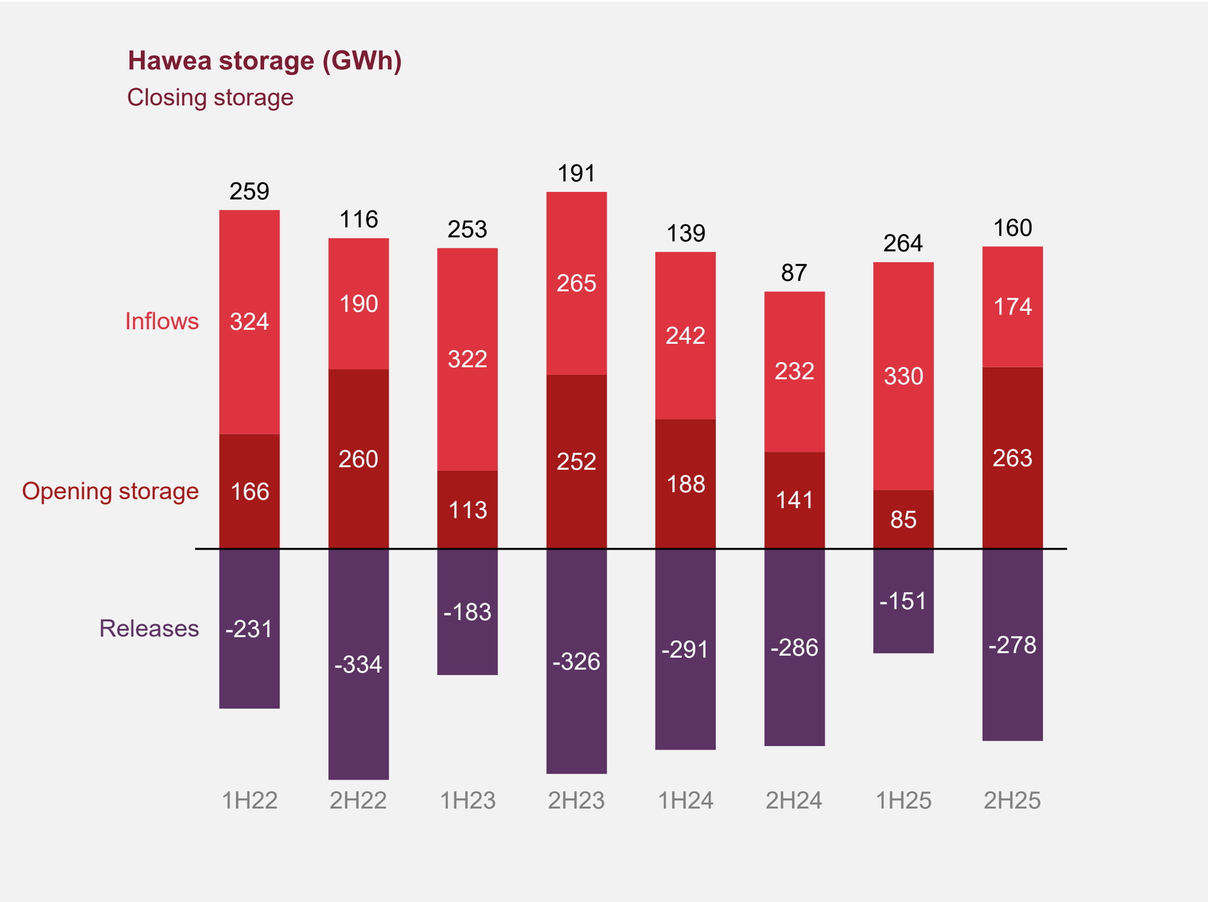
Upcoming geothermal statutory turnarounds (outages)[2]

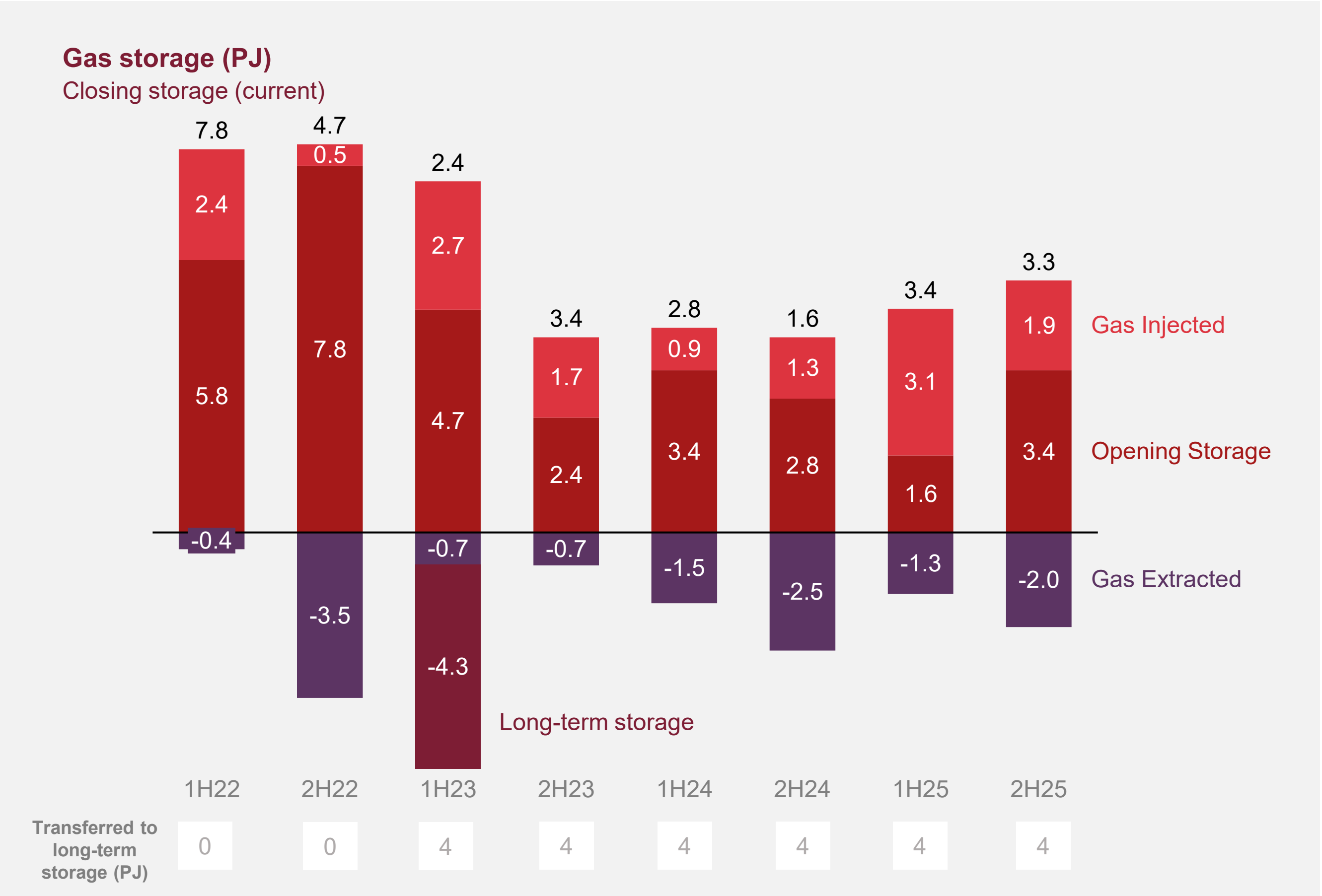
Plant	Impact (GWh)	FY	Frequency & type
Tauhara	113	26	Y1 Stat Turnaround
Te Huka 3	37	26	Y1 Stat Turnaround
Wairakei	25	26	4y Stat turnaround
Te Huka 1&2	25	27	4Y Stat Turnaround
Wairakei	300	27	4y Stat turnaround + ext works
Poihipi	31	28	4y Stat turnaround
Te Mihi Stage 2	73	28	Y1 Stat Turnaround
Tauhara	169	28	Y3 Stat Turnaround
Te Huka 3	37	28	Y3 Stat Turnaround

Availability Factor calculation includes all station outages (Planned, Maintenance, Forced) but does not consider plant deratings.
[1] Reduction in geothermal net capacity in FY23 was a result of decommissioning wells on the Wairakei steam field. Increases in FY24 and FY25 related to Tauhara and Te Huka 3 respectively.

[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.

Fuel storage movements

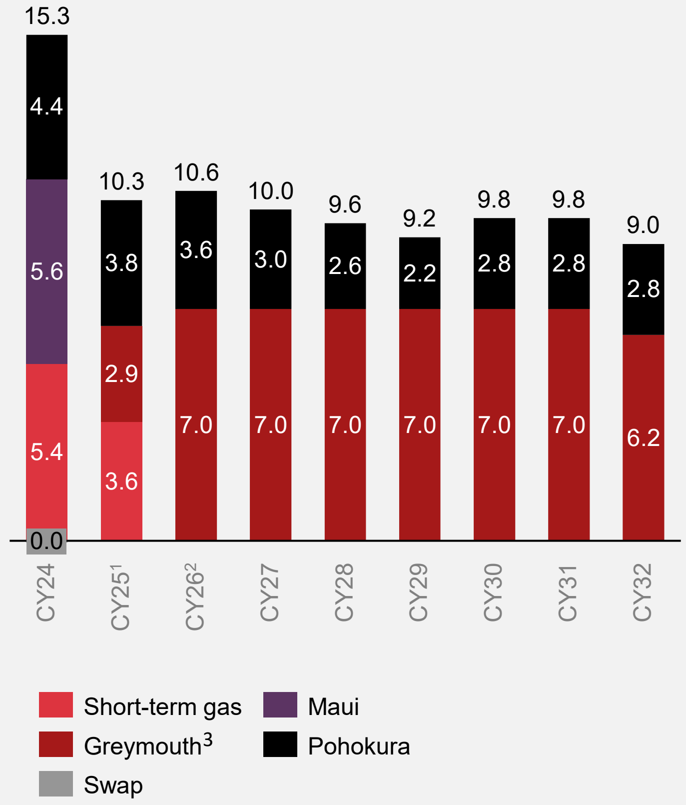




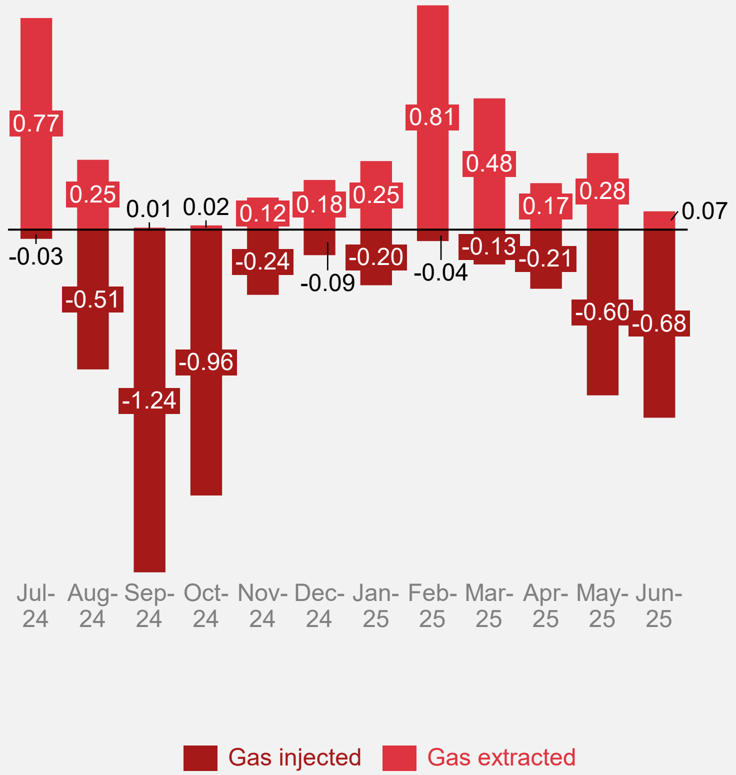
Source: NZX Hydro data

Contracted and stored gas

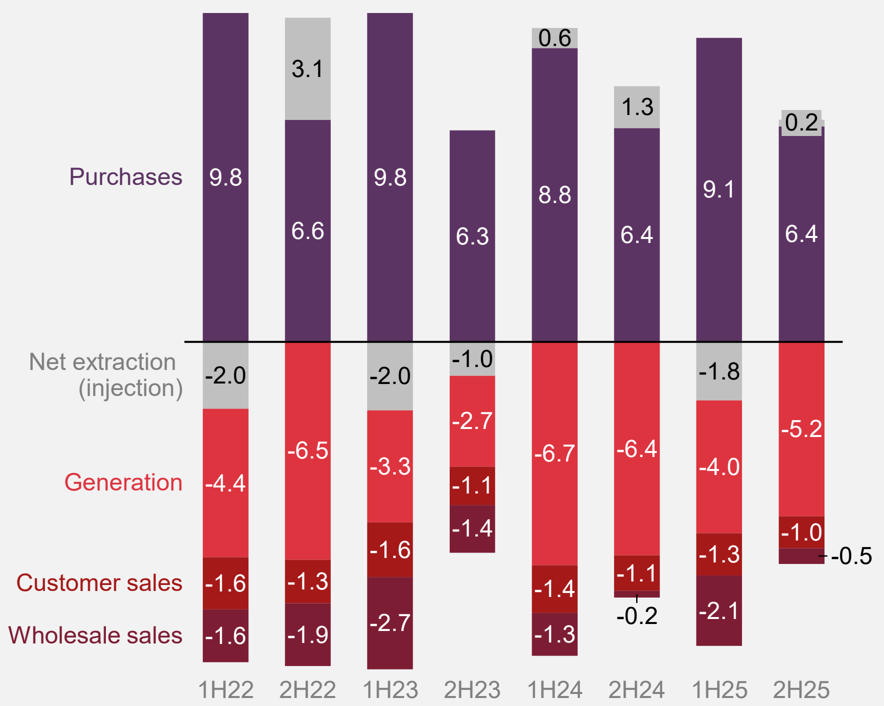
Contracted gas volumes (PJ)



Gas storage monthly injections and extractions (PJ)



Uses of gas (PJ)



[1] CY25 reflects actual volumes and forecasts for the second half of the year.
[2] CY26-CY32 reflects the maximum volume of gas available under contracts. Forecasted volumes for these periods are not yet available.
[3] Greymouth Gas volumes illustrated based on maximum gas available at Contact's option up to October 2032. The contract also includes an option to extend for a further 3 years from October 2032.

Reconciliation between Profit and EBITDAF

EBITDAF is Contact's earnings before interest, tax, depreciation and amortisation, asset impairment and write-offs, 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:

	12 months ended 30 June 2025		12 months ended 30 June 2024	Variance on prior year	
				$m	%
	Underlying[1]	Reported	Underlying[1]	Against underlying	
Profit	**261**	**331**	**230**	**31**	**13%**
Depreciation and amortisation	273		255	18	7%
Change in fair value of financial instruments	35		(8)	43	na
Net interest expense	100		35	65	186%
Tax expense	104	132	101	3	3%
Asset impairment / write-offs	1		50	(49)	(98%)
EBITDAF	**774**	**872**	**663**	**111**	**17%**

Movements in depreciation and amortisation, net interest, tax expense and asset impairment / write-offs are explained on the right.

The movements between FY25 and FY24 underlying profit are as follows:

- **Depreciation and amortisation:** Increased by $18m. Increase driven by Tauhara and Te Huka 3 (representing operational assets of ~$1.2b), partially offset by extension of the useful life of Wairakei assets and thermal assets now fully depreciated in FY24.
- **Net interest expense:** Interest was up $65m on FY24 reflecting that debt related to Tauhara is no longer being capitalised.
- **Tax expense** for the period increased by $3m due to the tax impact of higher operating earnings. Of note, FY24 tax expense was elevated by $6m relating to the removal of tax depreciation on buildings.
- **Asset impairment / write offs:** Decreased 98%. In FY24, Contact recognised $50m write-offs relating to peaker engine damage, Tauhara assets (relating to the 2023 steam hammer event and failure of valves) and software assets (due to HRIS and CRM projects not proceeding as planned).

[1] All variances and commentary reflect movements in underlying performance. In FY24 Contact recognised a net movement in the AGS onerous contract provision of $12m within EBITDAF and $5m within profit – underlying excludes these impacts. In FY25, reported results include a release of the AGS onerous contract provision of $98m pre-tax ($71m after tax). Underlying performance excludes the impact of the provision release.

S&P Net Debt / EBITDAF ratio

	FY21	FY22	FY23	FY24	FY25
	Actuals from S&P ratings report				Estimated
Net Debt					
Carrying value of borrowings	856	1,099	1,556	1,913	2,449
Fair value adjustments	(64)	(55)	(43)	(41)	(93)
Restoration and environmental provisions net of tax	53	53	120	142	163
Hybrid bond credits[1]	-	(113)	(113)	(113)	(237)
Accessible cash[2]	(41)	(4)	(89)	(146)	(514)
S&P Adjusted Net Debt	**804**	**980**	**1,431**	**1,763**	**1,768**
EBITDAF					
Reported EBITDAF (underlying)	553	546	573	663	774
Realised gains/losses on market derivatives	(1)	(9)	(27)	(6)	(13)
Share based compensation	3	4	4	4	5
Transaction costs related to the Manawa acquisition					11
S&P Adjusted EBITDAF	**555**	**541**	**551**	**661**	**777**
Net debt/EBITDAF (x)	**1.4**	**1.8**	**2.6**	**2.7**	**2.3**

- These calculations have been provided as an illustration of the adjustments made by Contact's ratings agency, S&P Global, when assessing Contact's Net Debt/EBITDAF ratio.
- Net Debt has been adjusted from the financial statements to include certain long-term liabilities where S&P considers these to have debt-like characteristics.
- Adjusted EBITDAF reflects S&P's view of core operating items (unrelated to investing and financing).

[1] 50% equity credit for capital bonds.
[2] Cash less restricted cash held by Macquarie for ASX prudential.

Reconciliation of change in fair value of financial instruments

Change in fair value of financial instruments	Realised / unrealised	FY25	FY24	Variance	Description
(A) Net market making	**Realised**	**(13)**	**(3)**	**(10)**	Realised gains or losses on the settlement of electricity derivatives entered into to meet Contact's market making obligations
- Market making	Unrealised	2	4	(2)	Mark-to-market of open electricity derivatives in future periods
- NZAS long-term sale CFD		(7)	-	(7)	NPV of the changes to the forecast forward wholesale price path vs the wholesale path when the contracts were agreed
- Kōwhai Park acquired PPA		(13)	-	(13)	
- Other non-hedged movements		(4)	7	(11)	Mark-to-market of open electricity/interest rate derivatives in future periods
(B) Unrealised movements in non-hedge effective electricity derivatives	Unrealised	(22)	11	(33)	
Total change in fair value of financial instruments as per segment note (A+B)	**Realised and unrealised**	**(35)**	**8**	**(43)**	
Commercial hedges recognised in EBITDAF that do not qualify for hedge accounting					
– Financial Transmission Rights (FTR) settlements and Exchange for Physical (ASX)	Realised	(5)	-	(5)	Financial contracts that hedge portfolio sales that are settled in the period
– Net settlement of NZAS contract in the period		(134)	-	(134)	Realised settlement (difference between the fixed contract and spot settlement)
Change in fair value of financial instruments as per Income Statement		(174)	8	(167)	

In the period, Contact entered into two long-term contracts for difference (CFD) that were not eligible for hedge accounting. These contracts relate to the sales of electricity to NZAS and the purchase of electricity from the under-development Kōwhai Park solar farm (expected online in Q2 CY2026).

As a result, movements in expected wholesale prices when compared to forward wholesale prices when the contracts were entered into are recognised in change in fair value of financial instruments, increasing volatility of Net Profit After Tax. These non-cash movements, which relate to future periods, are recognised in the current period.

The primary change to wholesale price expectations in the period was the listing of the 2028 ASX contract from October 2024, which was higher than Contact's internally generated price path for the same period.

Historical financial information

	Unit	FY21	FY22	FY23		FY24		FY25	
				Underlying[2]	Reported	Underlying[2]	Reported	Underlying[2]	Reported
Revenue[1]	$m	2,573	2,387	2,118		2,867		3,306	
Expenses[1]	$m	2,020	1,820	1,500	1,613	2,204	2,192	2,532	2,434
EBITDAF	$m	553	546	573	460	663	675	774	872
Profit	$m	187	182	211	127	230	235	261	331
Operating free cash flow	$m	371	330	282		424		434	
Operating free cash flow per share	cps	50.2	42.4	36.0		53.9		54.4	
Dividends declared	cps	35	35	35		37		39	
Total assets	$m	5,028	5,166	5,808		6,208		6,813	
Total liabilities	$m	2,101	2,326	3,004		3,589		4,053	
Total equity	$m	2,927	2,840	2,804		2,619		2,760	
Gearing ratio[3]	%	23	28	36		42		47	

[1] Revenue and expense figures align with the treatment of realised movements in financial instruments within the segment note of the financial statements.

[2] In FY23 Contact recognised a net onerous contract provision expense for AGS of ($113m) within EBITDAF and ($84m) within profit. In FY24 Contact recognised a net movement in the AGS onerous contract provision of $12m within EBITDAF and $5m within profit. In FY25, the release of the AGS onerous contract provision increased reported EBITDAF by $98m and profit by $71m. Underlying performance excludes these impacts.

[3] Gearing ratio is calculated as: Senior debt - including finance lease liabilities / (Senior debt - including finance lease liabilities + Equity).

Note: From FY24 Contact no longer reports impairments and write-offs within EBITDAF. These are now reported separately to better reflect underlying performance. FY24 EBITDAF is stated excluding $50m of write-offs and impairments. Previous years have not been restated (FY22 includes a $1.5m peaker write-off).

Wholesale segment

Note: this table has not been rounded and might not add	FY25 Year ended 30 June 2025 Volume GWh	GWAP $/MWh	$m	FY24 Year ended 30 June 2024 Volume GWh	GWAP $/MWh	$m
Electricity sales to Retail segment	**3,689**	**163**	**601**	**3,801**	**148**	**562**
Electricity sales to C&I (netback)	**1,566**	**133**	**208**	**1,456**	**129**	**188**
CfDs – Tiwai support sales	920			892		
PPAs	411			-		
CfDs - Long term sales	394			752		
CfDs and ASX - Short term sales	1,903			1,820		
Electricity sales – CFDs	**3,629**	**157**	**569**	**3,465**	**118**	**407**
Total contracted electricity sales	**8,883**	**155**	**1,377**	**8,707**	**133**	**1,157**
Steam sales	**229**	**21**	**5**	**194**	**18**	**3**
Other income			14			8
Net income on gas sales			(12)			3
Net income on electricity related services			1			(0)
Net other income			**4**			**11**
Total contracted revenue	**9,112**	**152**	**1,386**	**8,901**	**132**	**1,171**
Generation costs[1]	8,928	(44)	(389)	8,635	(40)	(349)
Acquired generation cost	462	(264)	(122)	585	(160)	(93)
Generation costs (including acquired generation)	**9,390**	**(54)**	**(511)**	**9,220**	**(48)**	**(443)**
Spot electricity revenue	8,928	195	1,742	8,635	177	1,529
Settlement on acquired generation	462	252	116	585	195	114
Spot revenue and settlement on acquired generation (GWAP)	**9,390**	**198**	**1,858**	**9,220**	**178**	**1,643**
Spot electricity cost	(5,255)	(218)	(1,143)	(5,243)	(193)	(1,009)
Settlement on CFDs sold	(3,629)	(191)	(695)	(3,465)	(178)	(616)
Spot purchases and settlement on CFDs sold (LWAP)	**(8,883)**	**(207)**	**(1,838)**	**(8,707)**	**(187)**	**(1,626)**
Trading, merchant revenue and losses	**507**		**20**	**513**		**18**
Wholesale EBITDAF underlying[1]			**895**			**746**
Onerous contract provision			98			12
Wholesale EBITDAF reported			**994**			**758**

[1] In FY24 a net movement in the AGS onerous contract provision equated to $12m within generation costs and EBITDAF. In FY25, the release of the AGS onerous contract provision equated to $98m within generation costs and EBITDAF. Underlying performance excludes these impacts.

Retail segment

Residential electricity	unit	FY22	FY23	FY24	FY25
Average connections	#	373,347	380,482	388,459	401,332
Sales volumes	GWh	2,644	2,688	2,798	2,809
Average usage	MWh per ICP	7.1	7.1	7.2	7.0
Tariff	$/MWh	256.4	272.1	287.9	311.5
Network, meters and levies	$/MWh	-119.5	-122.7	-128.0	-142.2
Energy costs[1]	$/MWh	-115.0	-138.6	-158.8	-174.5
Gross margin	**$/MWh**	**21.9**	**10.8**	**1.1**	**-5.1**
Gross margin	$ per ICP	155	77	8	-36
Gross margin	$m	58	29	3	-14

Residential gas	unit	FY22	FY23	FY24	FY25
Average connections	#	64,649	66,605	68,092	70,369
Sales volumes	TJ	1,583	1,504	1,584	1,509
Average usage	GJ per ICP	24.5	22.6	23.3	21.4
Tariff	$/GJ	36.6	42.1	45.1	52.9
Network, meters and levies	$/GJ	-18.9	-22.9	-24.5	-29.0
Energy costs	$/GJ	-11.8	-10.1	-9.8	-11.0
Carbon costs	$/GJ	-2.1	-4.2	-3.1	-4.4
Gross margin	**$/GJ**	**3.8**	**4.9**	**7.7**	**8.5**
Gross margin	$ per ICP	92	112	181	182
Gross margin	$m	6	7	12	13

SME electricity	unit	FY22	FY23	FY24	FY25
Average connections	#	48,459	46,962	44,113	41,654
Sales volumes	GWh	798	794	754	651
Average usage	MWh per ICP	16.5	16.9	17.1	15.6
Tariff	$/MWh	239.7	259.3	282.2	313.4
Network, meters and levies	$/MWh	-112.9	-117.0	-118.3	-132.9
Energy costs[1]	$/MWh	-113.7	-138.6	-157.3	-174.5
Gross margin	**$/MWh**	**13.0**	**3.6**	**6.6**	**5.9**
Gross margin	$ per ICP	215	62	112	93
Gross margin	$m	10	3	5	4

SME gas	unit	FY22	FY23	FY24	FY25
Average connections	#	3,889	3,519	2,972	2,662
Sales volumes	TJ	1,224	1,063	794	607
Average usage	GJ per ICP	315	302	267	228
Tariff	$/GJ	19.8	25.2	31.0	38.5
Network, meters and levies	$/GJ	-8.3	-9.5	-11.6	-13.9
Energy costs	$/GJ	-11.8	-10.1	-9.8	-11.0
Carbon costs	$/GJ	-2.1	-4.2	-3.1	-4.4
Gross margin	**$/GJ**	**-2.4**	**1.4**	**6.5**	**9.2**
Gross margin	$ per ICP	-769	412	1,750	2,103
Gross margin	$m	-3	1	5	6

Telco	unit	FY22	FY23	FY24	FY25
Average connections	#	62,388	79,057	95,168	116,709
Tariff	$/cust/mth	70.1	69.6	71.8	72.1
Network, provisioning, modems	$/cust/mth	-60.5	-63.5	-63.4	-62.8
Gross margin	$/cust/mth	**9.6**	**6.2**	**8.4**	**9.3**
Gross margin	$m	7	6	10	13

Retail segment EBITDAF		FY22	FY23	FY24	FY25
Electricity Gross margin	$m	68	32	8	-11
Gas Gross Margin	$m	3	9	17	18
Telco Margin	$m	7	6	10	13
Total Gross Margin	**$m**	**79**	**47**	**35**	**21**
Other income	$m	7	9	7	4
Other operating costs	$m	-68	-69	-74	-74
Retail segment EBITDAF	**$m**	**17**	**-14**	**-32**	**-49**
Corporate allocation (50%)	$m	-14	-22	-25	-36
Retail EBITDAF	**$m**	**3**	**-36**	**-57**	**-85**
EBITDAF margins (% of revenue)	%	0.3%	-3.3%	-4.8%	-6.6%

[1] Energy costs reflect electricity purchased from solar customers: $1.2m in FY24 and $2.7m in FY25.