# 2024 interim results presentation

**Six months ended 31 December 2023**

19 February 2024

contact

# Disclaimer and important information

While all reasonable care has been taken in compiling this presentation, neither Contact nor any of its directors, employees, shareholders nor any other person gives any representation as to the accuracy or completeness of this information or accepts any liability for any errors or omissions.

This presentation may contain certain forward-looking statements with respect to a variety of matters. All such forward-looking statements involve known and unknown risks, significant uncertainties, assumptions, contingencies, and other factors, many of which are outside the control of Contact, which may cause the actual results or performance of Contact to be materially different from any future results or performance expressed or implied by such forward-looking statements. Such forward-looking statements speak only as of the date of this presentation. Except as required by law or regulation (including the NZX Listing Rules and the ASX Listing Rules), Contact undertakes no obligation to update these forward-looking statements for events or circumstances that occur subsequent to the date of this presentation or to update or keep current any of the information contained herein. Any estimates or projections as to events that may occur in the future (including projections of revenue, expense, net income and performance) are based upon the best judgement of Contact from the information available as of the date of this presentation.

EBITDAF, free cash flow and operating free cash flow are financial measures that are "non-GAAP (generally accepted accounting practice) financial information" under Guidance Note 2017: 'Disclosing non-GAAP financial information' published by the New Zealand Financial Markets Authority, "non-IFRS financial information" under ASIC Regulatory Guide 230: 'Disclosing non-IFRS financial information' and "non-GAAP financial measures" within the meaning of Regulation G under the U.S. Exchange Act of 1934.

Such financial information and financial measures (including EBITDAF, free cash flow and operating free cash flow) do not have standardised meanings prescribed under New Zealand equivalents to International Financial Reporting Standards ("NZ IFRS"), Australian Accounting Standards ("AAS") or International Financial Reporting Standards ("IFRS") and therefore, may not be comparable to similarly titled measures presented by other entities, and should not be construed as an alternative to other financial measures determined in accordance with NZ IFRS, AAS or IFRS accounting practice) measures. Information regarding the usefulness, calculation and reconciliation of these measures is provided in the supporting material.

This presentation does not constitute financial or investment advice. This presentation does not constitute an offer to sell, or a solicitation of an offer to buy, Contact securities and may not be relied on in connection with any purchase of a Contact security.

Numbers in the presentation have not all been rounded and might not appear to add.

All references to $ are New Zealand dollar unless stated otherwise.

All trademarks, service marks and company names are the property of their respective owners. All company, product and service names used in this presentation are for identification purposes only. Use of these names, trademarks and brands does not imply endorsement or that they are or will be customers of Contact and reflects public announcements of intention only.

# Agenda


1 **1H24 highlights and market update** / Mike Fuge, CEO 4 - 13

2 **Financial results and outlook** / Dorian Devers, CFO 14 - 28

3 **Supporting materials** 30 - 41

# Underlying performance strength

## Focus on delivering geothermal developments and supporting security of supply

| | Six months ended 31 December 2023 (1H24) | | Six months ended 31 December 2022 (1H23) | |
|---|---|---|---|---|
| | Underlying[1] | *Reported* | Against underlying | |
| EBITDAF[2] | $325m | *$354m* | ↑ | 26% from $257m |
| Profit | $134m | *$153m* | ↑ | 70% from $79m |
| Profit per share | 17.2 c | *19.5 c* | ↑ | 70% from 10.1c |
| Operating free cash flow[3] | $187m | | ↑ | 163% from $71m |
| Operating free cash flow per share[3] | 23.7 c | | ↑ | 162% from 9.1c |
| Dividend declared | $110m | | → | $110m |
| Dividend declared per share | 14 c | | → | 14.0 c |
| Stay-in-business (SIB) capital expenditure (cash) | $64m | | ↑ | 16% from $55m |
| Growth capital expenditure (cash)[4] | $233m | | ↑ | 7% from $217m |

| | Market | contact |
|---|---|---|
| 1H24 | A return to hydro volatility categorised the operating conditions in 1H24. The market observed:<br>• High inflows and soft wholesale spot prices through July and August.<br>• Higher spot wholesale pricing as inflows reduced, particularly in the second quarter.<br>• Higher thermal generation compared to 1H23, which had highest inflows in post-market history. | • High contracted sales volumes in anticipation of Tauhara coming online and a strong starting fuel position.<br>• Thermal generation and some acquired generation required to meet sales position.<br>• Mitigations in place for the impacts of Tauhara delay.<br>• Channel pricing aligned closer to the wholesale market. |
| Medium term | • Lines cost increases from 1 April 2024.<br>• Disappointing results from Maui drilling campaign factoring into expected future gas availability.<br>• Pricing volatility increasing, particularly in peak periods, as intermittent generation comes online.<br>• Rising thermal fixed costs at ageing thermal plants will need to be recovered over less generation and will factor into risk management pricing.<br>• Increases to wind costs appear to be structural.<br>• Conditions support a view of long-term wholesale prices of at least **$110-120/MWh (2024 real).[5]** | • TCC outage brought forward and completed in December 2023. Expect to decommission TCC at end of 2024.<br>• Expect Peaker GT22 to return to service before winter 2024.<br>• Commissioning of Tauhara and Te Huka geothermal plants in Q3 and Q4 of 2024 will add 1.9TWh of new renewable output to the portfolio annually once at full capacity.<br>• Recognising a net $29 million provision release within EBITDAF for Ahuroa Gas Storage facility (AGS) onerous contract.[1] |

[1] The onerous contract provision for AGS is assessed every 6 months in line with NZ IAS 37. In 1H24 there has been a net provision release resulting in impacts of $29m EBITDAF and $19m profit after tax and interest. Underlying performance excludes these impacts. All variances and commentary reflect movements in underlying performance.

[2] Refer to slide 38 for a definition and reconciliation of EBITDAF. Contact has made reclassifications to better align with IFRIC guidance on IFRS 9 resulting in realised gains/losses from market derivatives not in a hedge relationship (includes market making activity) no longer being reported in operating income (EBITDAF). 1H23 figures restated accordingly.

[3] Refer to slide 23 for a reconciliation of operating free cash flow.

[4] Includes capitalised interest.

[5] As indicated in November 2022, updated for inflation.

# Contact26 Key strategic highlights from 1H24

| | Grow demand | Grow renewable development | Decarbonise our portfolio | Create outstanding customer experiences |
|---|---|---|---|---|
| **Objective** | Attract new industrial demand with globally competitive renewables | Build renewable generation and flexibility on the back of new demand | Lead an orderly transition to renewables | Create NZ's leading energy and services brand to meet more of our customers' needs |
| **1H24 highlights** | Constructive negotiations with Rio Tinto have re-enforced Contact's long-held view that a new long-term agreement for the supply of electricity to NZAS appears likely.<br><br>Released a request for proposals seeking strategic partnership to commercialise food-grade quality geothermal $CO_2$. | At Tauhara, re-construction of the steam separation plant is near complete. Te Huka 3 construction proceeding in line with expectations.<br><br>Drilling, advanced steamfield design and tendering progressed to prepare for GeoFuture final investment decision (FID) in 2024.[1]<br><br>Advanced stages of preparation for a JV FID on Kōwhai Park in 2024.[1]<br><br>Consent lodged for a potential ~300 MW Southland wind project under fast-track process. | Emissions intensity from thermal generation down ~30% on 1H23 driven largely by the closure of Te Rapa on 30 June 2023.<br><br>Assessment of 100MW battery at Glenbrook[2] has been advanced ahead of FID in 2024.[1]<br><br>TCC decommissioning expected at end of 2024.[1] | Expansion of telecommunications offering with introduction of Contact Mobile.<br><br>Total closing connections up by 20,000 on 1H23, driven primarily by broadband and prioritising residential connection growth within a target channel sales volume.<br><br>Expansion of time of use offerings with the launch of Good Weekends.<br><br>Energy Retailer of the Year finalist (for the second consecutive year). |

[1] Calendar year references.
[2] Remains subject to consent.

# A new long-term deal for NZAS would support the decarbonisation of New Zealand

## De-risking investment in new renewable generation, contributing to energy security and supporting growth and decarbonisation of the New Zealand economy

### Negotiations progressing

- ✓ Constructive negotiations with Rio Tinto have re-enforced Contact's long-held view that NZAS appears likely to stay.
- ✓ Contact expects a new agreement to:
  - Be long-term;
  - At a fair price, materially above the current pricing; and
  - Include demand response (dry-year risk mitigation).

### Anticipated sector outcomes

- ✓ Would create market certainty, de-risking investment in new renewable generation.
- ✓ Having a large-scale demand response participant would contribute to dry-year risk mitigation in a decarbonising market.

### Complexities

- Bilateral electricity supply negotiations.
- Multiple stakeholders with a range of interests.
- Any agreement can be expected to be conditional on third-parties.

**Contact has been expecting NZAS to continue operations at Tiwai Point and has been managing its portfolio with that outcome in sight. The smelter is valuable to New Zealand as a major exporter and its continued operation would contribute to economic growth. It is highly carbon efficient in its production of premium aluminium, and a major employer and contributor to the Southland economy.**

# Geothermal investment programme update

## Supporting the decarbonisation of New Zealand by building world class geothermal power stations

| | Tauhara | Te Huka 3 | GeoFuture[3] |
|---|---|---|---|
| Size (TWh p.a) | 1.4[2] | 0.4 | 1.4[4] |
| FID date | Feb 2021 | Aug 2022 | 1H 2024 |
| Online date | Q3 2024 | Q4 2024 | 2H 2026 |
| Project progress (at 31 Dec) | 98% | 75% | Pre-FID development |
| Spend to date (to 31 Dec)[1] | $804m | $213m | $31m |
| Committed spend[1] | $920m | $300m | $114m[5] |
| Total expected project cost | $920m | $300m | $5.3 – 5.7m/MW[6] |

Note: Calendar year references

[1] Includes sunk costs. Excludes capitalised interest.

[2] Output at full 174MW capacity after additional steam plant remediation to be undertaken during first planned outage. Initial planned capacity of around 152MW expected at online date.

[3] Subject to final investment decision (FID).

[4] Based on mid-point of 160-180MW indicative capacity range. Represents a net uplift of 0.4TWh per annum following the closure of Wairākei plants.

[5] Approved pre-FID development costs. Contact has been undertaking drilling from September 2023 and advancing steam-field design.

[6] Range as indicated in May 2023. Currently in an active tender process for GeoFuture.

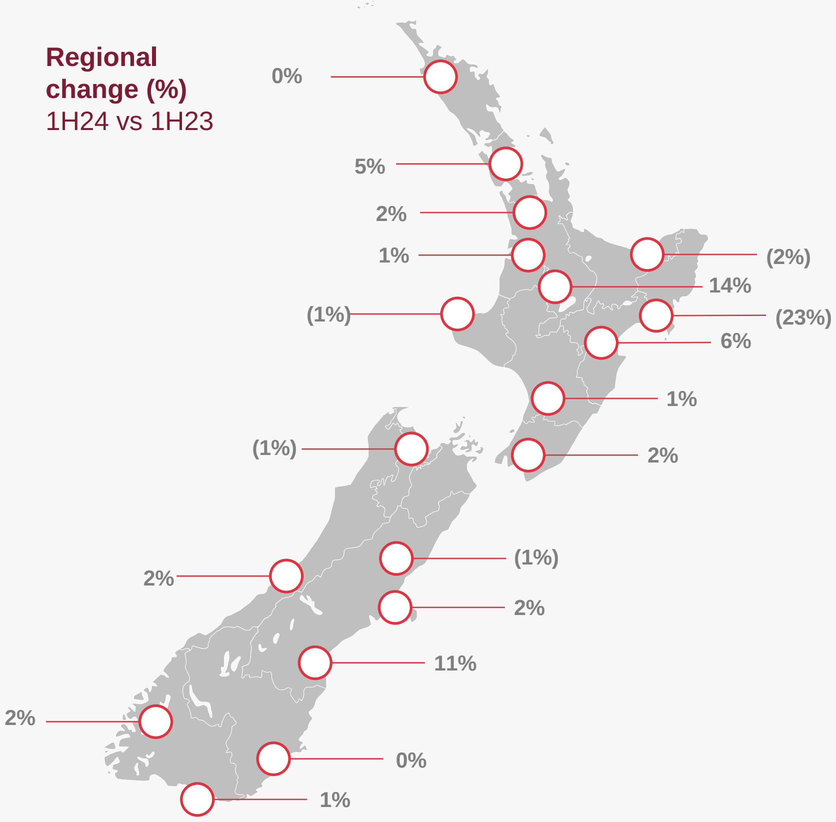
Contact26

# 1H24 delivery supported by enablers

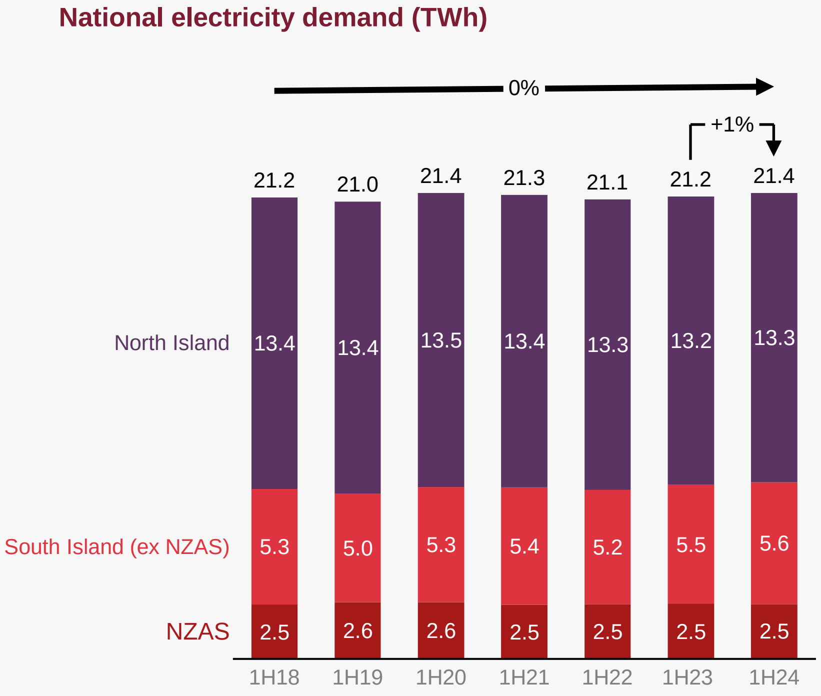
| | Our ESG commitment | Operational excellence | Transformative ways of working |
|---|---|---|---|
| **Objective** | Create long-term value through our strong performance across a broad set of environmental, social and governance factors | Continuously improving our operations through innovation and digitisation | Create a flexible and high-performing environment for NZ's top talent |
| **1H24 highlights** | Included in DJSI Asia Pacific for the second consecutive year, moving into the number one ranking of participating NZ companies.<br><br>Sustainability Leadership winner in the Deloitte Top 200 Awards. | Operationalised the higher consented fluid take at Wairākei field (5kt per day) translating to a **50GWh p.a. uplift in average geothermal generation** (before new developments online).<br><br>TCC planned outage brought forward and completed in December 2023 with additional operating hours approved.<br><br>Contact has worked to accelerate the return of its spare peaker engine. Now expecting GT22 to be back in service for winter 2024 (expected return May 2024). | Wellbeing Award winner, NZ Energy Excellence Awards, for Contact's Grow Your Whanau Policy.<br><br>Enhanced our Health & Safety toolkit with the launch of the Roam App and Protect@Contact website. |

# National electricity demand

## New Zealand electricity demand was up ~1% on 1H23




Source: EMI, Contact. Does not include NZAS




Source: EMI, Contact

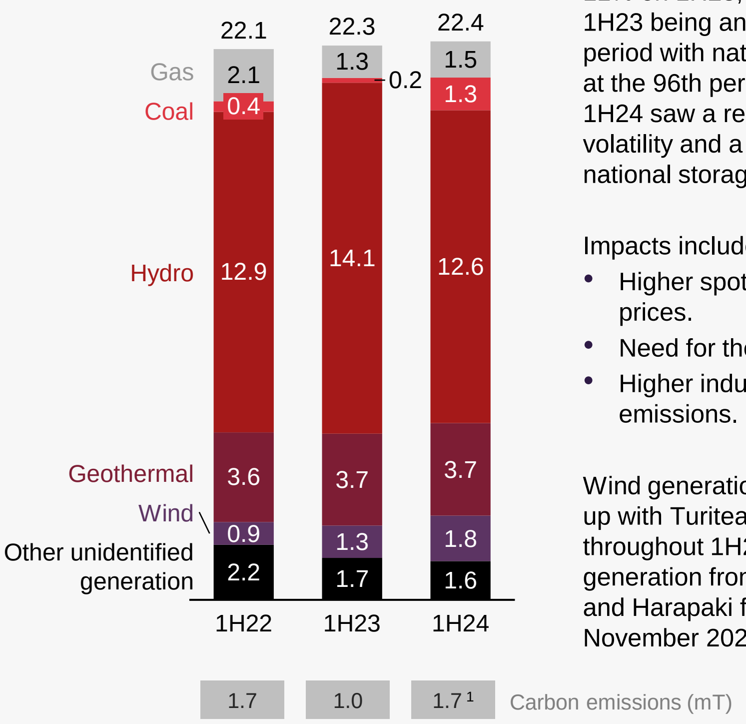
Total national electricity demand increased by 0.15 TWh (1% from 1H23).

- Dry conditions increased demand at major irrigation nodes in Huntly and South Canterbury, particularly on the Lower Waitaki plains.
- Temperature did not have a significant impact on demand as a cold August was partly offset by warmer surrounding months.
- East Coast regional demand was down 23% with Pan Pac’s Whirinaki site closed until further notice due to impacts from Cyclone Gabrielle.
- Normalising for weather and Pan Pac, which largely offset eachother, demand growth came in at just over ~1%.

# Hydrology significantly impacted generation mix

## El Niño sequence saw low hydro inflows increasing the need for thermal generation; wind farms power up

### Generation by type (TWh)




Hydro generation was down 11% on 1H23, largely due to 1H23 being an unusually wet period with nationwide inflows at the 96th percentile of historic. 1H24 saw a return to hydro volatility and a reduction in national storage levels.

Impacts included:

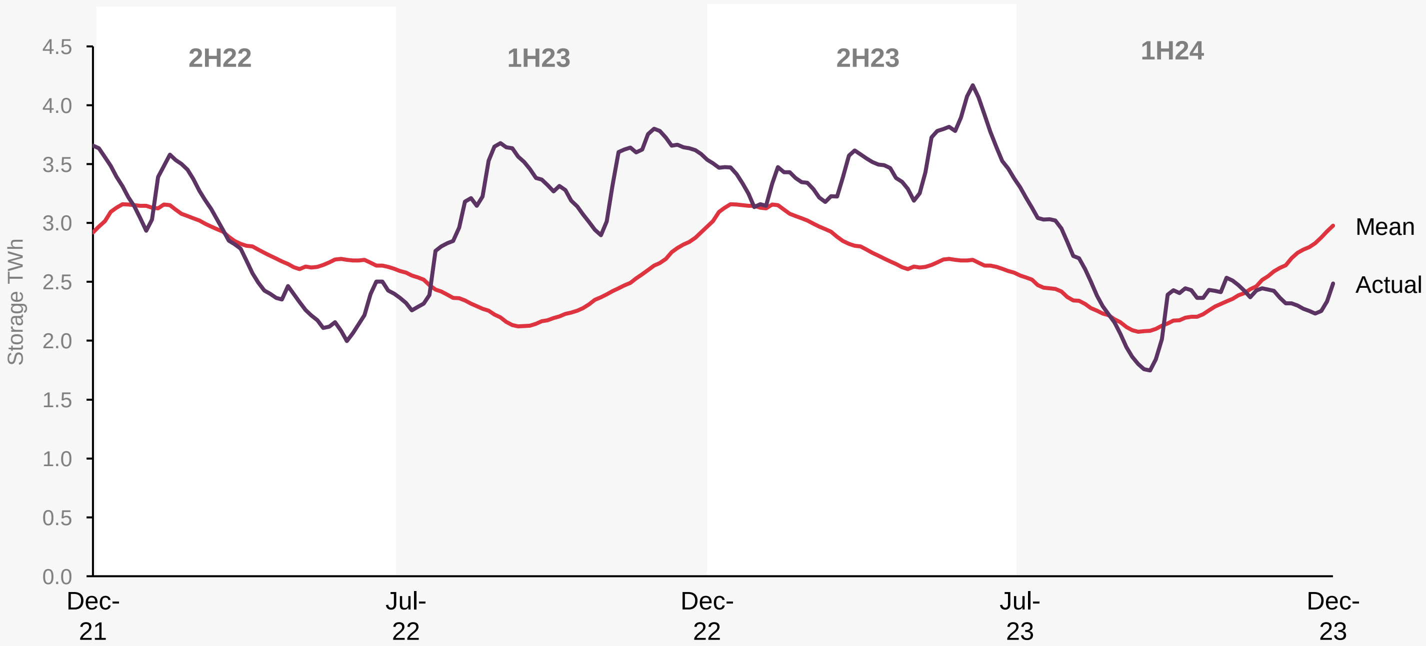
- Higher spot wholesale prices.
- Need for thermal generation.
- Higher industry carbon emissions.

Wind generation has stepped up with Turitea online throughout 1H24 and initial generation from Kaiwera Downs and Harapaki from October and November 2023 respectively.

The increase in carbon emissions of 0.7mT (70%) $CO_2$-e was due to the increase in coal and gas generation year on year.

Source: EMI & MBIE

### National hydro storage



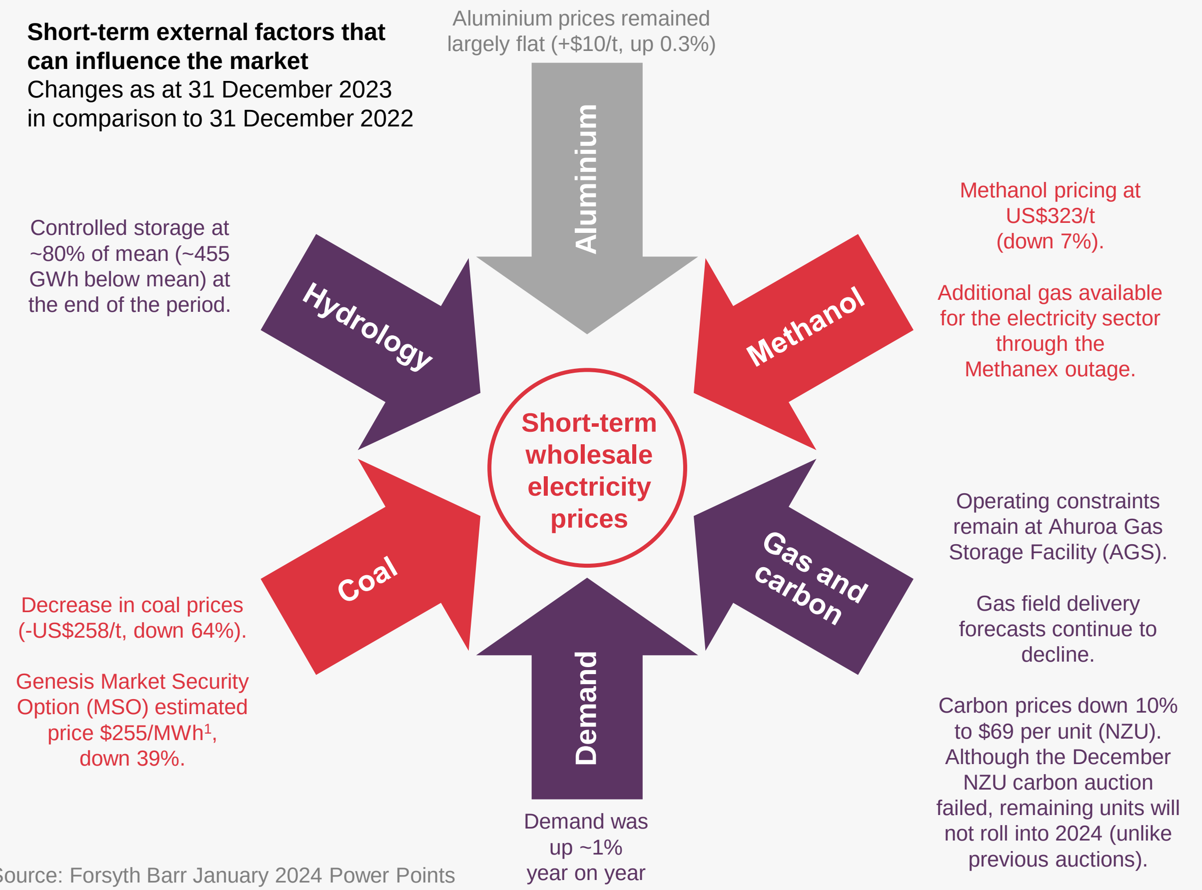

At the onset of 1H24, hydro storage levels started notably higher than the historical mean but dropped significantly due to low inflows into both North and South Island catchments. National hydro storage levels were lower on average, compared to 1H23, increasing the market's reliance on thermal generation.

Source: NZX

[1] Carbon emissions for 1H24 Oct-Dec quarter has been estimated using historic conversion rates with actual generation data.

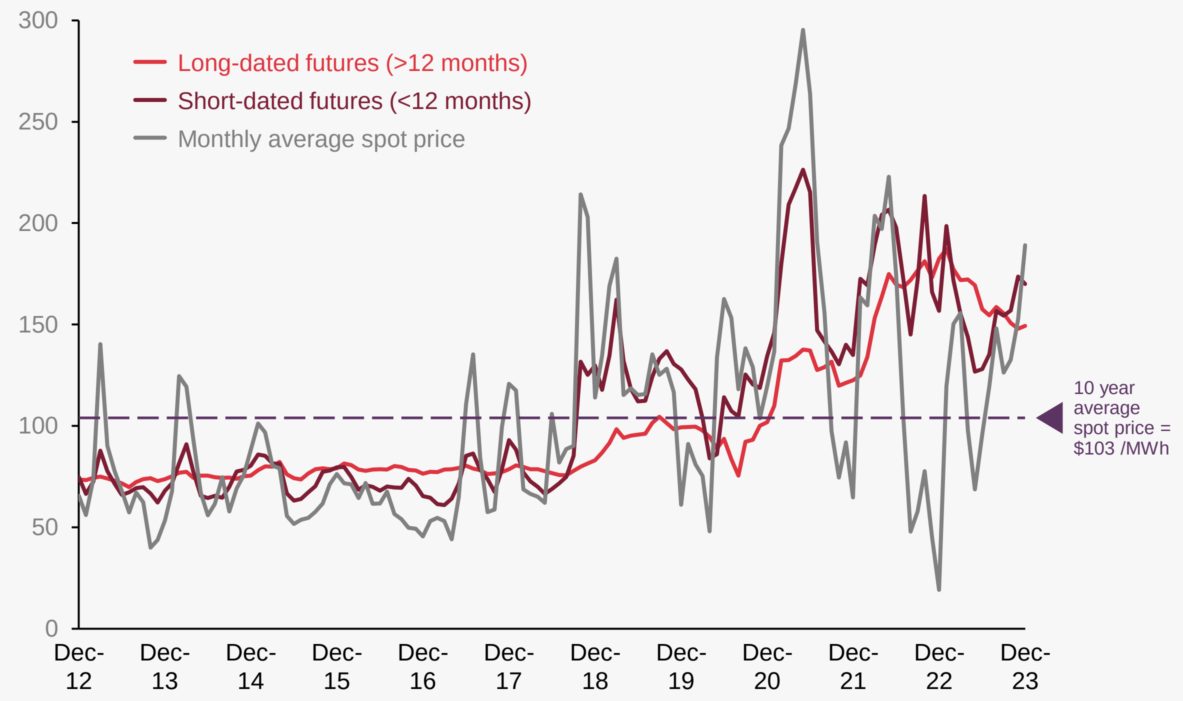
# Forward wholesale pricing continues to reflect high fuel cost and availability risk

**Short-term external factors that can influence the market**
Changes as at 31 December 2023 in comparison to 31 December 2022




¹ Source: Forsyth Barr January 2024 Power Points

**Wholesale and futures electricity pricing ($/MWh)**



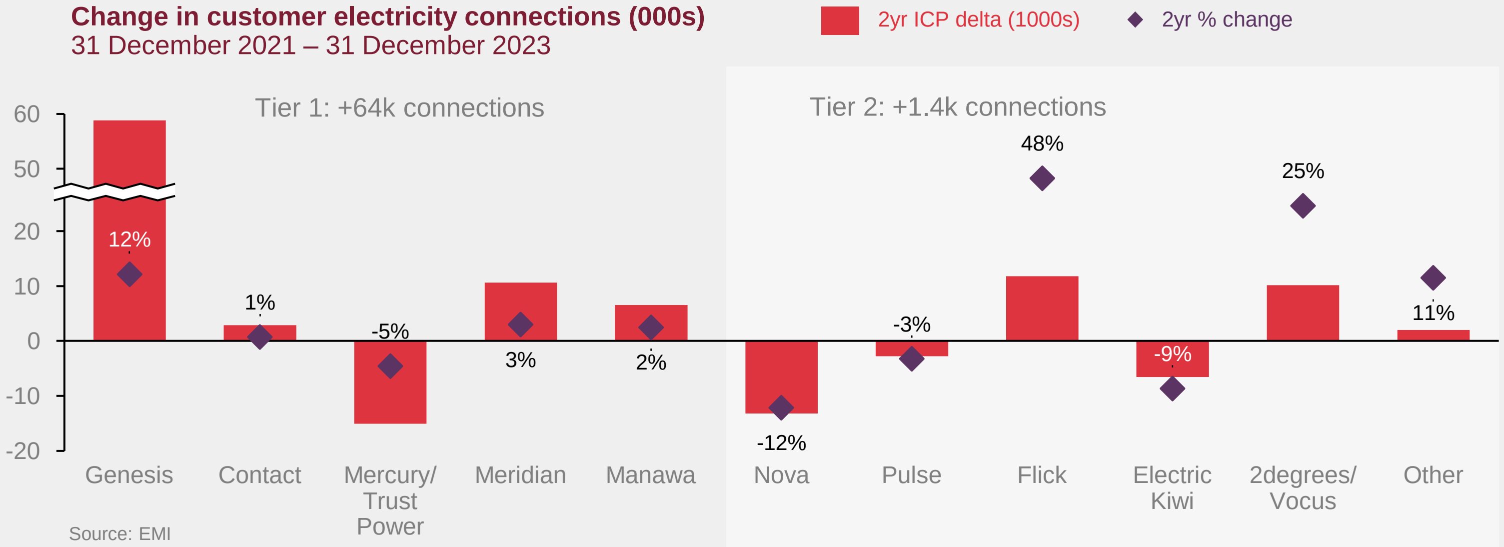

Source: EMI wholesale pricing

**Fundamental requirement for thermal generation to support a hydro dominated system. Expected future marginal thermal costs and higher renewable development costs supporting the forward electricity price path.**

# Differences in retail strategies apparent

## Reflects range of views on the value of retail as a channel; Rising pass-through costs on the horizon

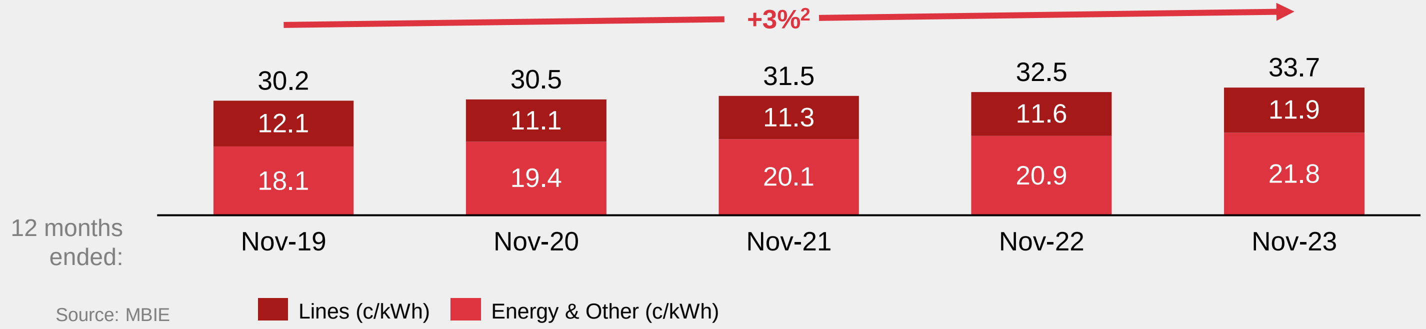
**Change in customer electricity connections (000s)**
31 December 2021 – 31 December 2023




Source: EMI

- Competition remains intense despite sustained high wholesale futures prices. Market churn continues to reflect this with switching at 19%.
- New buildings contributed to a continued ~1% p.a. growth in ICPs.
- Tier 1 retailers have a seen a 0.5% increase in market share to ~85% in December 2023 (84% December 2021). Genesis's growth is partially driven by the acquisition of Ecotricity in Feb 2022.
- Tier 2 retailer growth rates have slowed as they have repriced to rising input costs (energy and networks), resulting in a 1% decline in market share to ~15% (16% December-21) but some (Flick, 2degrees) are growing strongly.
- 2degrees and Vocus merged on 1 June 2022 becoming the third largest telco, while also providing energy products. Since 31 December 2021, 2degrees has grown connections by 10k (25%). Flick Electric returned to strong growth in 2023, +11k connections (44%) on the prior year.
- Contact electricity connections +3k from December 2021 to December 2023 resulting in a 19% market share. Contact had the third lowest churn over the two year period.

**Retail electricity tariff changes [1] (c/ kWh)**




Source: MBIE

- Increasing wholesale energy and, more recently, network costs have resulted in a lift in Residential electricity tariffs with the compound annual growth rate of 3% across the last five years to November 2023.
- Average tariff increases for the year to November 2023 of 3.7% were materially below consumer price inflation (~4.7%)[3], with households largely insulated from increasing input costs due to retailers' longer-term view of pricing that rides through short-term volatility.
- Input cost pressure for retailers is expected to remain with ongoing elevated wholesale prices and significant network cost increases pending:
  - 1 April 2024 inflation adjustments.
  - 1 April 2025 price regulation reset.

Retailers' pricing will need to increase to recover these rising costs.

[1] Inclusive of GST
[2] Compound annual growth rate
[3] Stats NZ CPI index increase in the 12 months to December 2023.

# Topical regulatory matters

## Contact's focus on building new renewable generation, flexible storage and customer-focused demand response solutions is well aligned with the political focus on electrifying NZ's economy while maintaining security of supply

| | Security of supply | Electricity Price pressures | Reconsideration of energy policy priorities | Lines assets regulation / investment | Resource management reform |
|---|---|---|---|---|---|
| **Theme** | Maintaining security of supply is the top priority of the new government.<br><br>Industry, Transpower and the EA paying close attention to capacity this year and beyond. | Retail energy prices are facing cost pressures from increasing government levies, wholesale energy costs and lines charges, driven by the 1 April 2025 regulatory reset.<br><br>Increased wholesale price volatility is placing pressure on unhedged energy intensive industries. | Work on Lake Onslow has ceased, and there is a wider reconsideration of energy policy priorities. We expect increased focus on market-driven solutions.<br><br>Work on an energy strategy likely to continue in some form, but with an increased focus on energy security. | Government price regulation of EDBs and Transpower for 2025-30.<br><br>BCG report found a need for $22bn[2] of expenditure on distribution infrastructure before 2030.<br><br>BCG noted a 30% increase in spend required in 2026-30 relative to 2021-25. | Government has reinstated the RMA[3] and will begin work on a new replacement Act.<br><br>Government refreshing the national policy statement for renewable electricity generation (NPS-REG).<br><br>New Fast Track legislation to be introduced in Q1 2024. |
| **Contact Approach** | Investment in new baseload renewables, storage and demand response.<br><br>Operate our assets in a way to avoid contributing to any supply shortage. | Working with industry groups and communicating with customers on the drivers of price increases.<br><br>Focus on demand flex and TOU[1] plans to help customers better manage their energy use and resulting costs.<br><br>Continuing our focus on energy wellbeing for those in most need. | Working with electricity industry to establish near-term actions to implement the plan set out in BCG's report "the Future is Electric".<br><br>Orderly decarbonisation of own portfolio. Focus on energy security and affordability. | Sufficient line capacity is critical to decarbonisation, however, must be balanced against the impact on consumers.<br><br>Recommends regulatory changes to reduce connection costs aiding electrification projects. | Contact has advocated for a balance between environmental effects and the need to decarbonise our economy.<br>Reinstatement of RMA reduces disruption and we will engage in the design of the replacement Act.<br><br>Draft NPS-REG looks promising. |
| **Timing** | Engagement ongoing.<br><br>Contact targeting 10.3TWh of renewables and 100MW battery by FY27. | ERANZ/ENA joint work on communicating price increase pressures in 1H 2024. | NZ Energy Strategy due for completion by end of 2024. | Draft decision on 2025-30 revenue caps due in May 2024, and a final decision in November 2024. | NPS-REG is part of new government's 100-day plan.<br><br>RMA replacement Bill will be proposed as part of 2026 election campaign. |

[1] Time of Use

[2] Note $22bn refers to opex and capex spend required from 2022 to 2030. Expenditure required on distribution infrastructure out to 2050 is $71bn.

[3] Resource Management Act

# Financial results and outlook

# Key themes from the financial results

Key indicators re-enforce our view on long-term wholesale electricity pricing of $110-120/MWh (2024 real)[1]

Uplift in expected and normalised performance; Expecting $620m EBITDAF in FY24

Sales channels repricing to better align with wholesale market; Retail facing headwinds from network cost increases

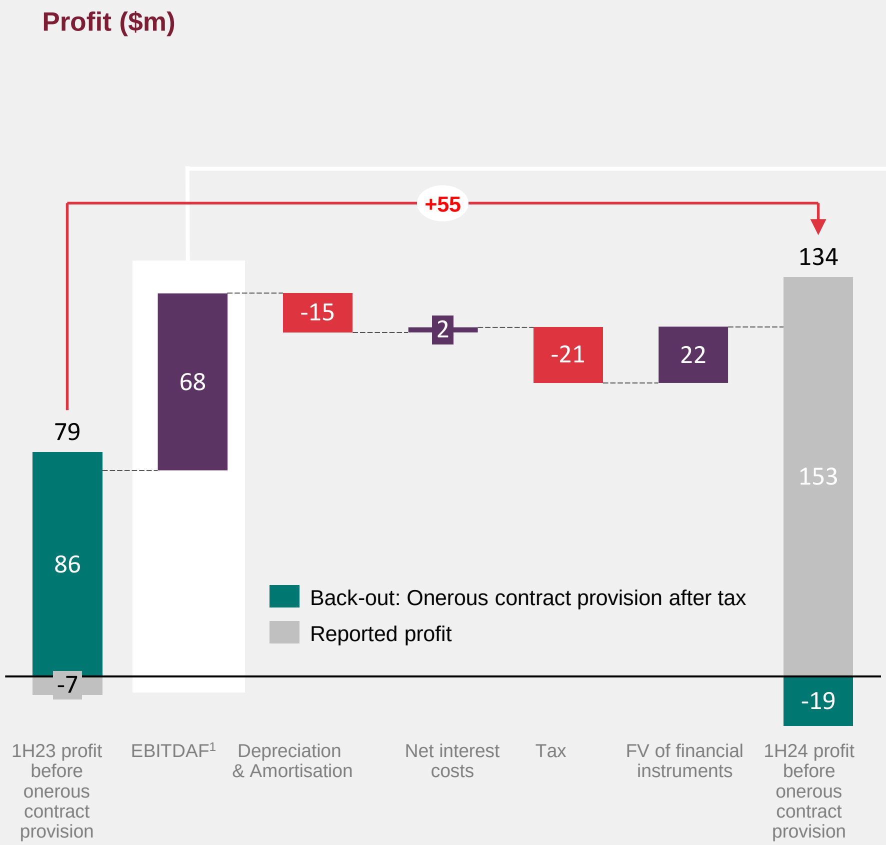
Thermal assets keep market in balance; Increasing costs from ageing assets need to be recovered

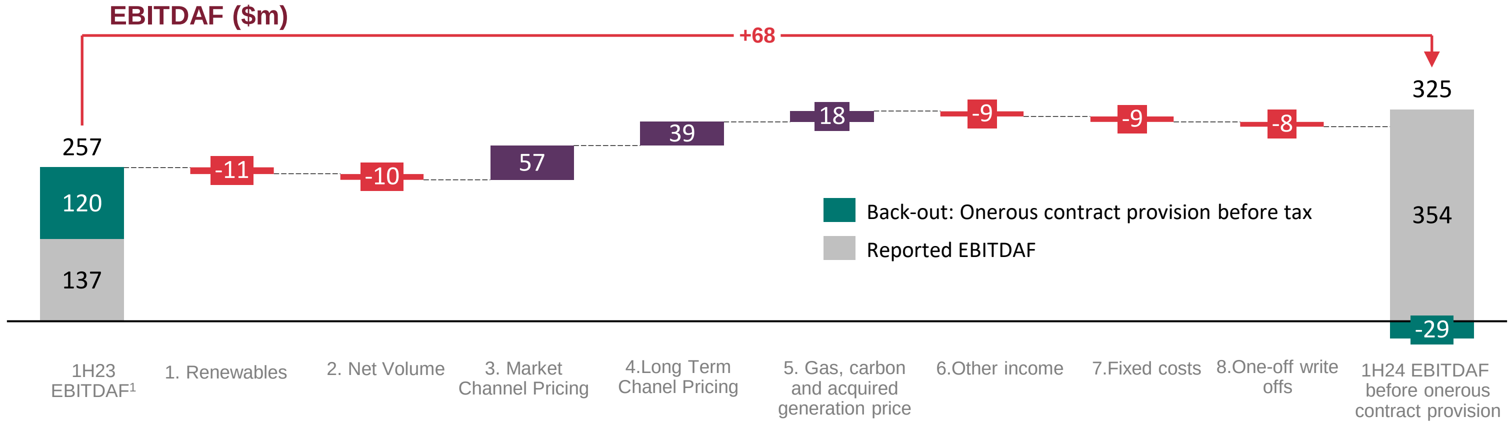
Net release of AGS onerous contract provision $29m within EBITDAF

[1] As indicated in November 2022, updated for inflation.

# Profit of $134m for 1H24 (underlying)

## Excluding the AGS onerous contract provision, underlying EBITDAF up $68m (26%) reflecting continued improvement in the alignment of channel pricing to the wholesale market



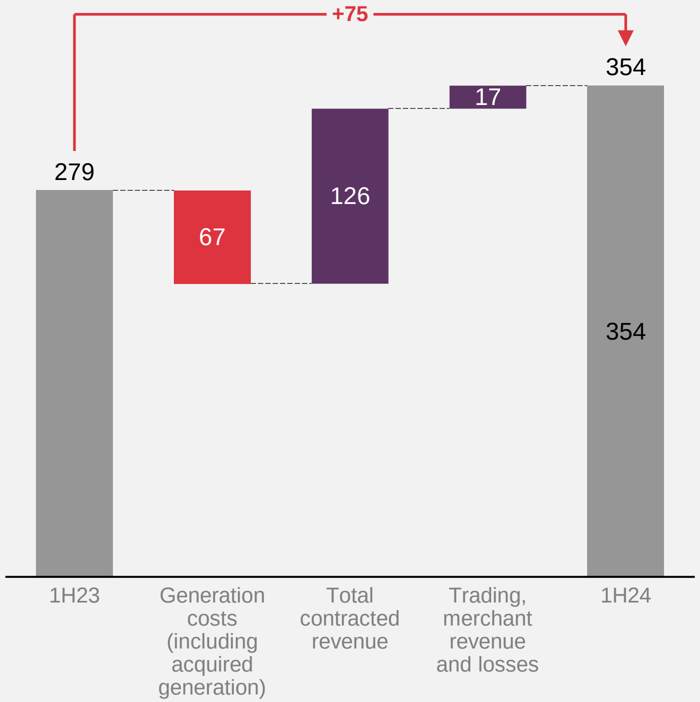

1. Renewables down 91GWh with 137GWh decrease in hydro generation partly offset by 47GWh geothermal uplift
2. Increased contracted sales volumes were largely backed by thermal generation due to Tauhara delay
3. Wholesale prices saw higher realised CFD and merchant sales
4. Retail pricing aligning to recoup energy and pass-through costs
5. Increase in thermal efficiency due to the closure of Te Rapa and a high proportion of TCC generation
6. Reduced steam revenue post Te Rapa closure, partly offset by an increase in gas gross margin
7. Fixed costs higher due to inflation impacts and growth
8. One-off write offs relate to Peaker damage (-$4.0m) & CRM system project not continuing as originally planned (-$3.9m)

[1] Contact has made reclassifications to better align with IFRIC guidance on IFRS 9 resulting in realised gains/losses from market derivatives not in a hedge relationship (includes market making activity) no longer being reported in operating income (EBITDAF). 1H23 figures restated accordingly.
Note: All figures are exclusive of the impacts of the onerous contract provision for AGS. Impacts of the onerous contract are as follows, EBITDAF (+$29m), interest (-$3m), tax (-$7m), NOPAT (+$19m).

# EBITDAF up by $68m (underlying)

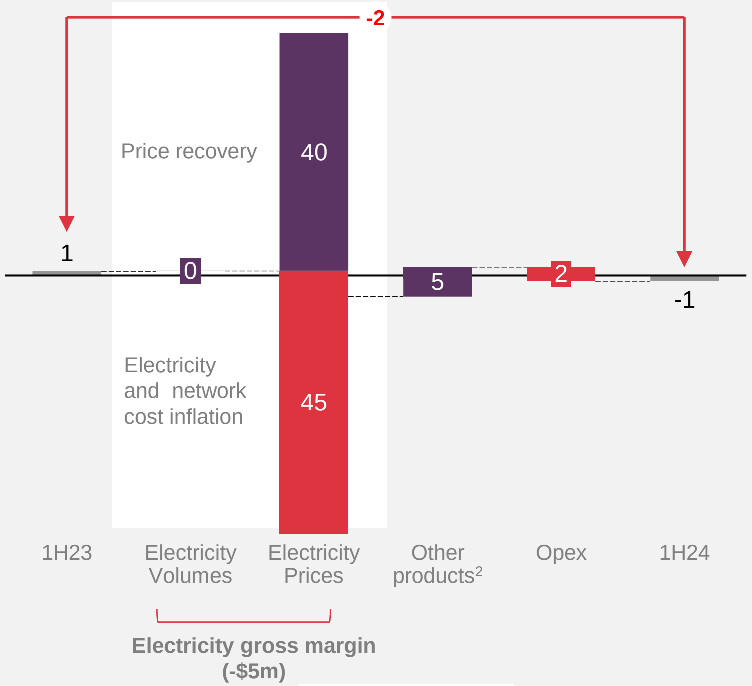
## Business performance by segment

### Wholesale EBITDAF[1] (underlying, $m)



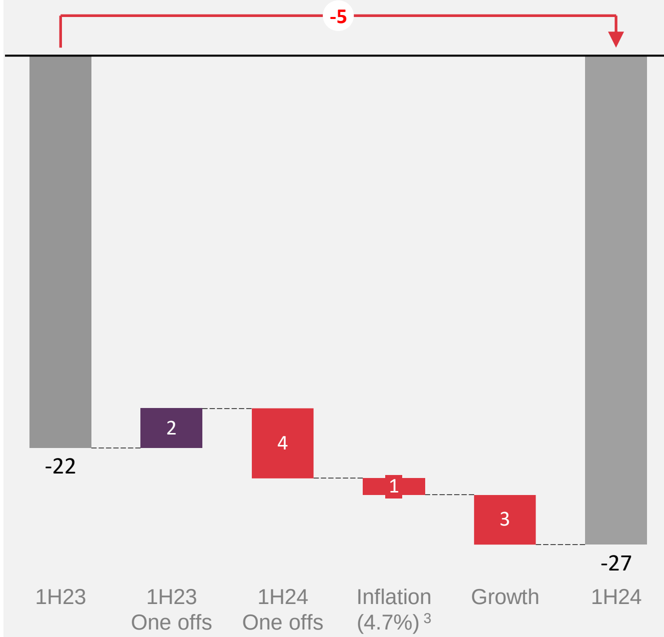

Refer to slides 18 - 20

### Retail EBITDAF ($m)




Refer to slide 21

### Corporate / unallocated costs ($m)




[1] Simply and Western included within Wholesale EBITDAF.
Underlying EBITDAF is shown excluding $29m net release of the onerous contract provision for AGS. Contact has made reclassifications to better align with IFRIC guidance on IFRS 9 resulting in realised gains/losses from market derivatives not in a hedge relationship (includes market making activity) no longer being reported in operating income (EBITDAF). 1H23 figures restated accordingly.

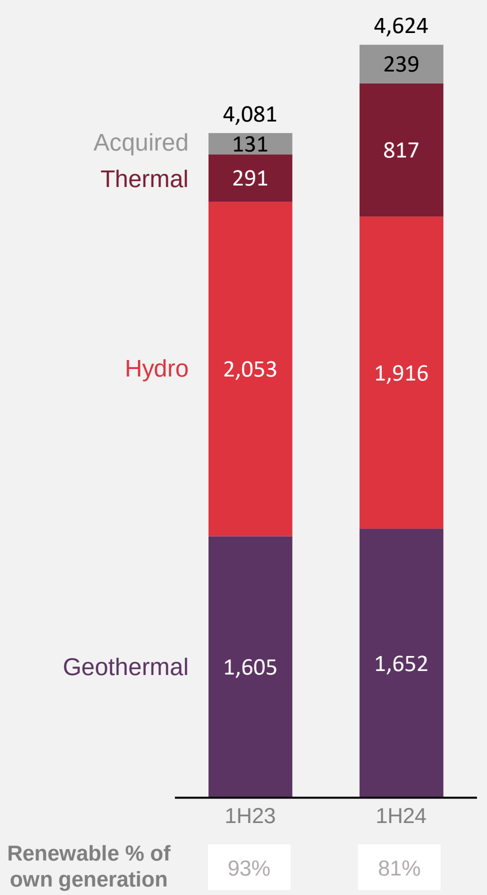
[2] Other products includes retail gas and broadband gross margins and gains on sale of legacy meter assets.

One-off movements from 1H23 included execution programme setup costs and BCG industry report ($2m). 1H24 one-off movement is a write-off relating to the CRM system project not continuing as originally planned.
[3] Stats NZ CPI increase in the 12 months to December 2023.

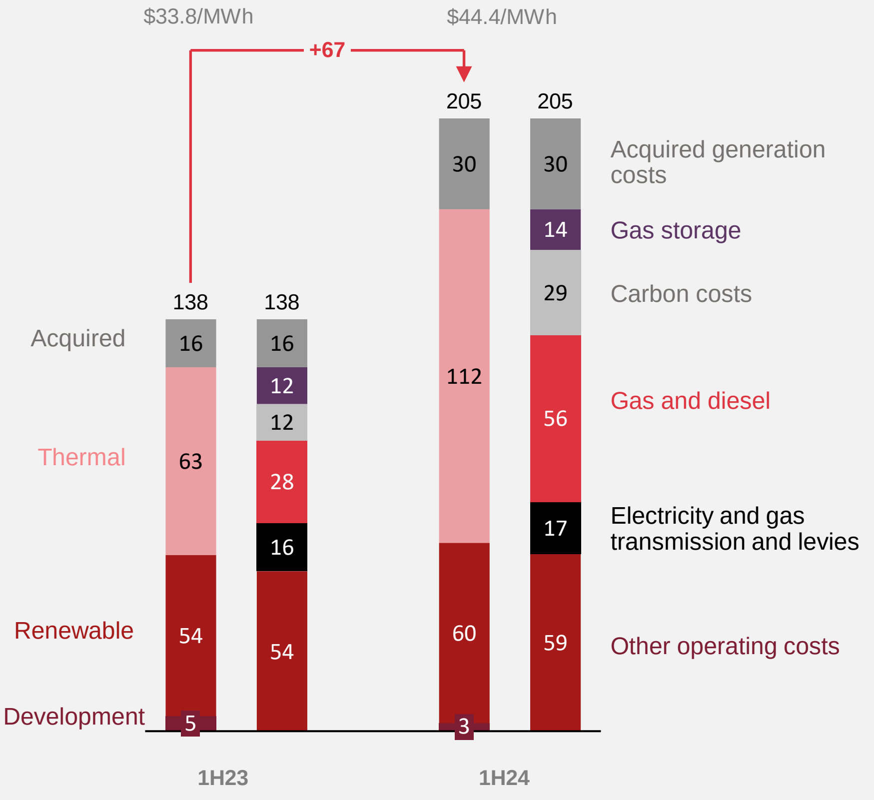
# Generation costs

## Costs up $67m on increased thermal and acquired generation volumes to back higher sales position

**Electricity generated or acquired** (GWh)




**Electricity generated or acquired costs** ($m)




**Generation volumes**

- Hydro generation of 1,916GWh was down 137GWh (7%) on 1H23 following low inflows.
- Geothermal generation was up 47GWh (3%) on 1H23, ~34GWh (73%) of the uplift is attributable to the increased consented mass take from the Wairākei steam field (from 245,000 to 250,000 t/d).
- 1H24 thermal generation volumes were 526GWh (181%) higher than 1H23 as depleting hydro storage and the delay to Tauhara's online date meant Contact's increased sales position was partly backed by thermal generation.

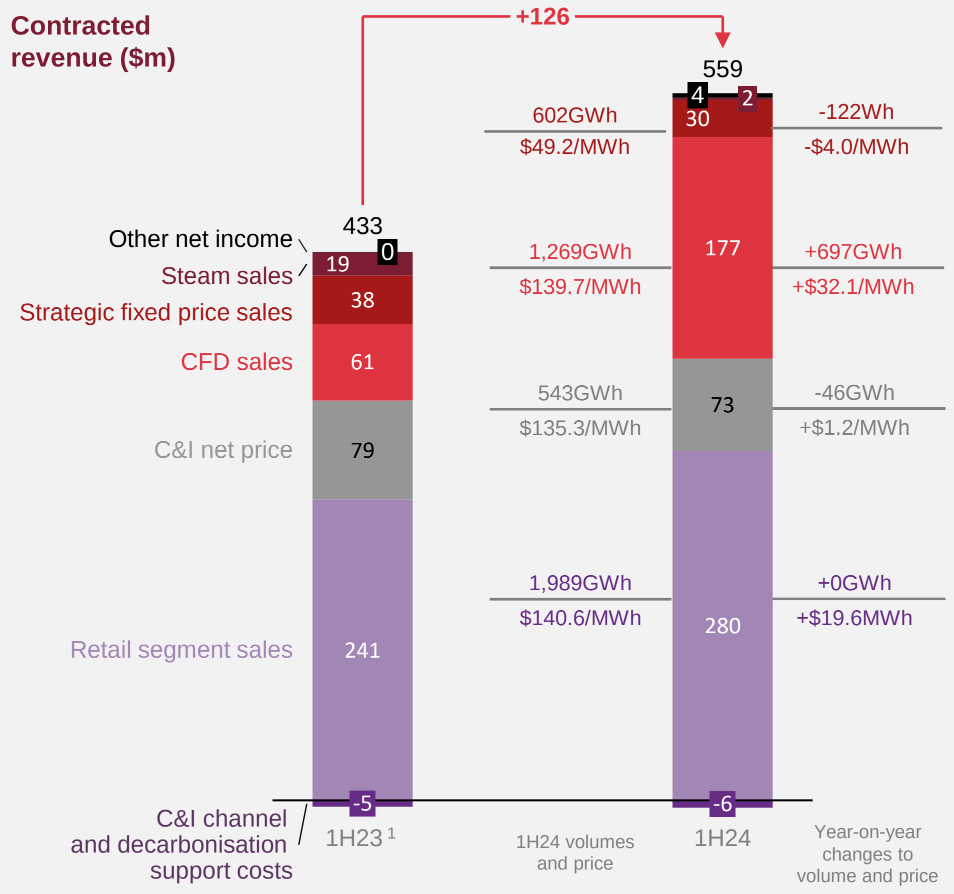
**Costs**

- Renewable generation costs were up $6m (11%) through a combination of higher insurance, rates, higher geothermal carbon costs and general inflationary pressures.
- Thermal generation costs, excluding the net release of the onerous contract provision AGS ($29m), were up $49m (78%) on increased thermal volumes.
- Thermal fuel costs dropped to $96.40/MWh (1H23: $120.10/MWh) largely due to improved thermal efficiency following the closure of Te Rapa and a high proportion of TCC generation (1H23: 11.8 TJ/MWh, 1H24: 8.2 TJ/MWh). This was slightly offset by increased gas costs (1H23: $7.9/GJ, 1H24: $8.3/GJ) and higher unit price of carbon (1H23 $43/unit, 1H24 $59/unit).

*Gas storage costs exclude the 1H24 $29m net release within EBITDAF of the onerous contract provision for AGS.

# Wholesale contracted revenue

## High stored fuel balances at the beginning of 1H24 paired with the anticipation of Tauhara coming online drove an increase in contracted sales volumes

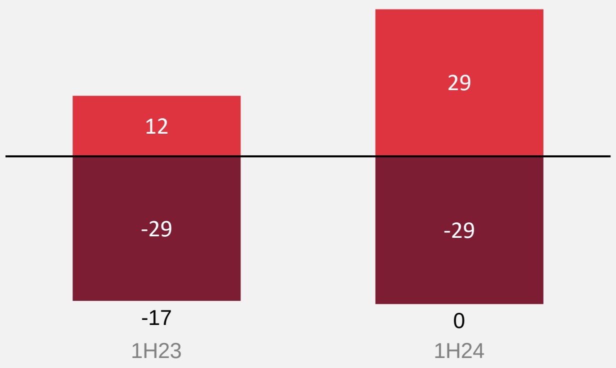



- Fixed price variable volume electricity sales to the Retail segment and C&I customers ended 46 GWh lower than 1H23 (-$6m). The volume shift is attributed to C&I, with the CFD channel prioritised over C&I in 1H24 and Retail volumes held steady.
  - Pricing to C&I was up $1.2/MWh, broadly in line with last year, with preference given to CFDs in calendar 2023.
  - Pricing to the Retail channel up $19.6/MWh to $140.6/MWh reflecting higher wholesale prices over the three preceding years.
- Strategic fixed price sales were 122GWh lower than 1H23 (-$8m), reflecting the roll off of the Fonterra contract following the closure of Te Rapa. Pricing of strategic fixed priced sales is down $4/MWh as inflationary adjustments to long-term sales were not enough to offset the mix change from proportionally higher NZAS volume.
- CFD sales volumes were up by 697GWh (+$75m) due to the anticipation of Tauhara coming online. Prices were up by $32.1/MWh reflecting low hydro inflows over the period (+$41m).
- Steam sales down on the closure of Te Rapa (-$16.8m).
- Other income was higher (+$4m) mainly due to premiums received from the CfD swaption deal with Meridian over the period.

[1] Contact has made reclassifications to better align with IFRIC guidance on IFRS 9 resulting in realised gains/losses from market derivatives not in a hedge relationship (includes market making activity) no longer being reported in operating income (EBITDAF). 1H23 figures restated accordingly.

# Wholesale trading and merchant revenue

## Trading EBITDAF ($m)

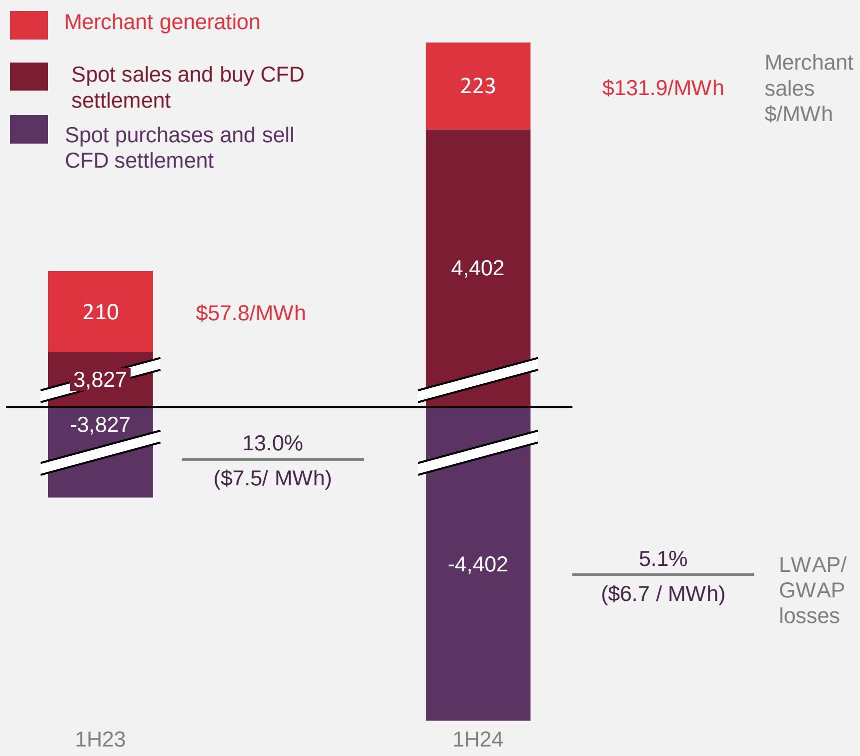



## Trading revenue

**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 1H24, merchant length offset location losses. This is in line with guidance which assumed mean hydro conditions and that any merchant length and location losses would offset.
- Compares to 1H23 where exceptionally high national inflows led to soft wholesale prices and higher location losses relative to merchant length.

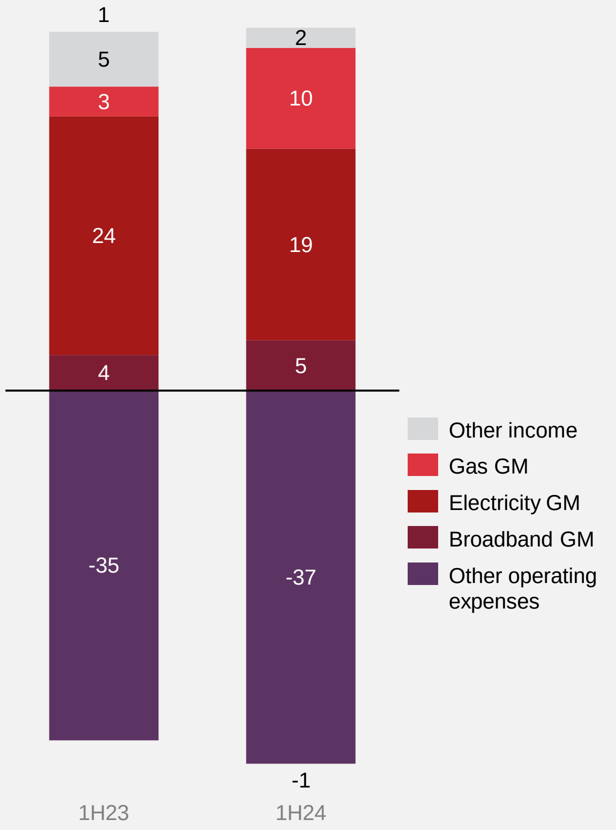
[1] Source: EMI

# Retail business performance

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

| Revenue & Tariff[1] ($m) | 1H24 | | 1H23 | Variance | |
|---|---|---|---|---|---|
| | $m | *Tariff[1]* | $m | $m | *Tariff* |
| Electricity revenue | 524 | 280 | 483 | 42 | 22 |
| Gas revenue | 51 | 37 | 48 | 3 | 6 |
| Broadband revenue | 39 | 73 | 32 | 7 | 3 |
| Other income | 4 | | 6 | (2) | |
| **Total revenue** | **618** | | **568** | **50** | |
| Contract Asset (closing) | 4 | | 6 | (2) | |
| # of connections (closing)[2] | 591k | | 571k | 20k | |
| *Electricity* | *428k* | | *423k* | *5k* | |
| *Gas* | *70k* | | *70k* | *0k* | |
| *Telecommunications[3]* | *93k* | | *78k* | *15k* | |
| Cost to serve/connection | $63 | | $61 | ($2) | |

### EBITDAF ($m)




Gross Margin (GM) is Revenue less Cost of Goods (Networks, meters, levies, energy, carbon and broadband).

Retail margins have contracted, driven by sustained high wholesale prices.

- Retail EBITDAF decreased by $2m on 1H23 largely driven by the $45m increase in electricity costs that were not fully passed through to customers.

The Retail business has continued to insulate customers from significant input cost rises with the forecast annual tariff increase largely in line with consumer price inflation.

- The average Retail tariff increased on 1H23 reflecting significant customers rolling off fixed term contracts and targeted retail price rises to partially offset rising wholesale and network cost increases.
- Around 84% of customers received a price increase in the last 12 months.
- Retail energy tariffs will need to continue to rise to recover the ongoing elevated wholesale prices and significant network cost increases due to the 1 April 2025 price regulation reset.
- Contact remains focused on supporting our customers in energy hardship through ERANZ, with offerings like ConnectMe and EnergyMate, and directly with community groups.

Connection growth slowed in 1H24 with an increased focus on input cost recovery.

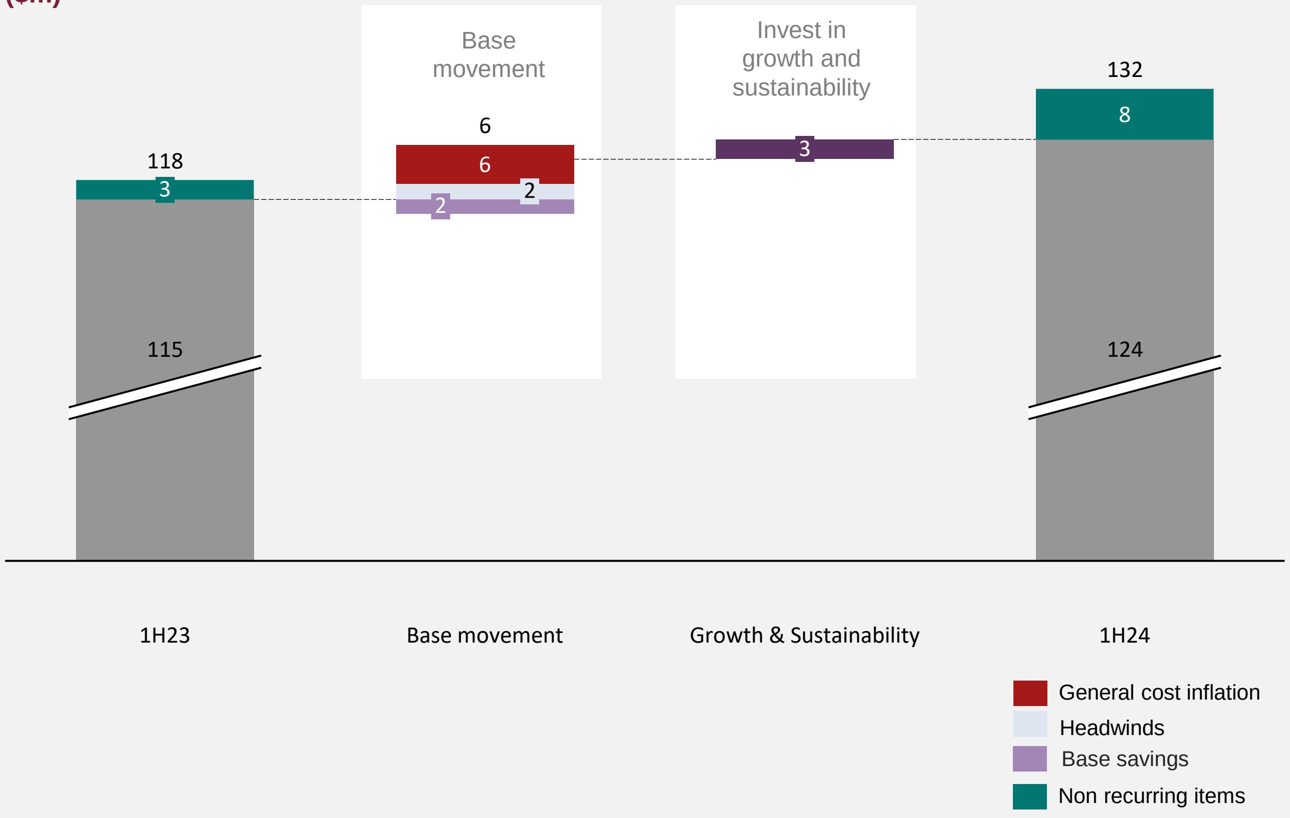
- Total connections still +20k on 1H23 primarily through continued growth in broadband.
- Multiproduct customers up 9% on 1H23, driven by Time of Use Good plans growth with high broadband attachment.

Cost to serve – increased by $2/connection largely driven by timing of marketing spend and higher bad debt. This was partially offset by productivity improvements through continued growth in digitised interactions.

[1] Tariff is $/MWh for electricity, $/GJ for gas and $ per month per customer connection for broadband.
[2] Retail connections only, excludes Simply Energy.
[3] Includes broadband and mobile connections.

# Operating costs up on investments in growth strategy and cost pressures

**Other operating cost movement ($m)**




## Non-recurring

- 1H23 one-off impacts related to strategic execution set up costs, Contact's share of BCG Industry report and cost of retaining Te Rapa employees until plant closure.
- 1H24 one-off impacts represent a write-off from damaged Peaker assets and a write-off relating to the CRM system upgrade project no longer continuing as originally planned.

## Base movement

- General inflation of 5-6% impacting operating costs. These have been seen across the business, including labour cost and insurance inflation.
- Headwinds include remaining repair costs relating to Cyclone Gabrielle and increased level of bad debts from our Retail business.

## Growth and sustainability

- $1m incremental investment related to retail connection growth.
- $1m investment in advertising in launching Contact Mobile.
- Operating costs to deliver on strategic growth priorities including;
    - Sustainability and furthering ESG outcomes;
    - Procurement; and
    - Full 6 months of costs from increase in Corporate functions to support growth activity.

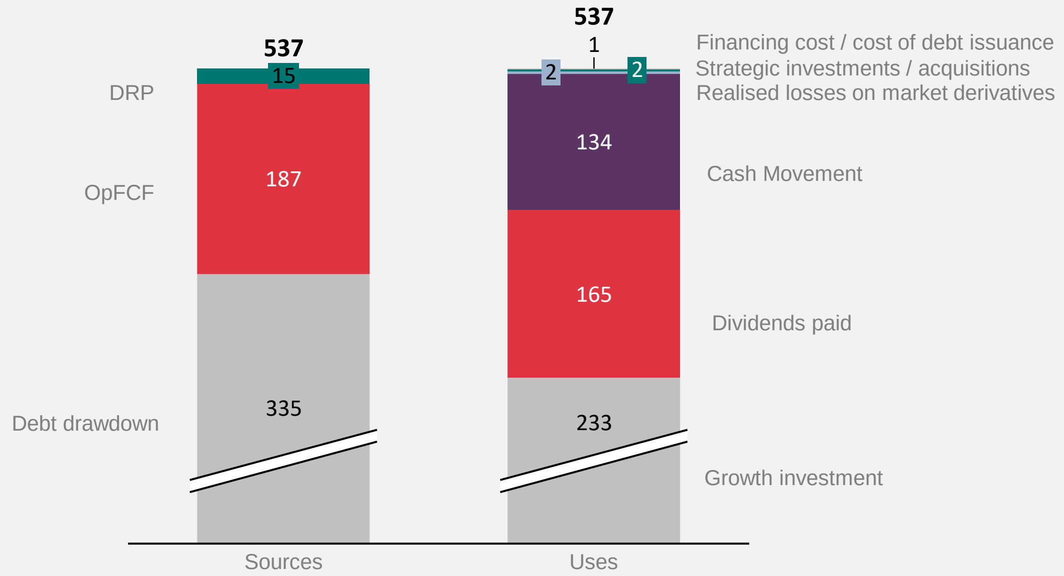
# Cash flow and capital expenditure

## Cash conversion for 1H24 impacted by higher EBITDAF, lower fuel inventory and lower tax payments

| | 6 months ended 31 December 2023 (1H24) | 6 months ended 31 December 2022 (1H23) | Comparison against 1H23 | |
|---|---|---|---|---|
| EBITDAF (underlying[1]) | **$325m** | $257m[1] | ↑ | $68m |
| Working capital changes | **($10m)** | ($43m) | ↑ | $33m |
| Tax paid | **($66m)** | ($76m) | ↑ | $10m |
| Interest paid, net of interest capitalised | **($9m)** | ($12m) | ↑ | $3m |
| SIB capital expenditure | **($64m)** | ($55m) | ↓ | ($9m) |
| Non-cash items included in EBITDAF | **$11m** | ($0m) | ↑ | $11m |
| Operating free cash flow | **$187m** | $71m[1] | ↑ | $116m |
| Operating free cash flow per share | **23.7 c** | 9.1 c[1] | ↑ | 14.6 c |
| Cash conversion (OpFCF / EBITDAF) | **58%** | 28% | ↑ | 30% |

- Higher underlying EBITDAF on execution of long-term channel price increases.
- Working capital increase was $33m less than in the prior year due to lower levels of gas storage following higher thermal generation in 1H24 and seasonal movements in net receivable balances.
- Tax paid is down $10m with final FY23 payment being lower than final FY22 payment.
- Stay-in-business capital expenditure (cash) increase of $9m is linked to accelerated spending identified to support higher asset availability and output as well as an SAP systems upgrade project. Accelerated SIB capex programme spend in the period totaled $24m.

### Sources and uses of cash ($m)



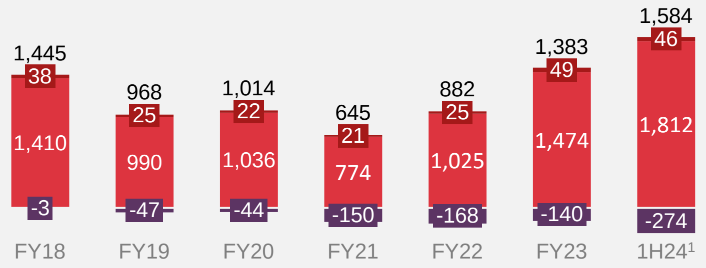

[1] Contact has made reclassifications to better align with IFRIC guidance on IFRS 9 resulting in realised gains/losses from market derivatives not in a hedge relationship (includes market making activity) no longer being reported in operating income (EBITDAF). 1H23 figures restated accordingly.

# Strong balance sheet

## With market leading sustainable finance principles built on diversified sources of funding

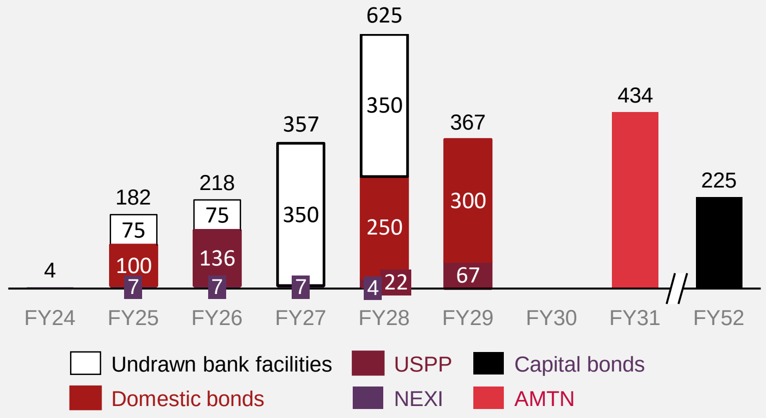
### Closing net debt ($m)

Face value of borrowings less cash



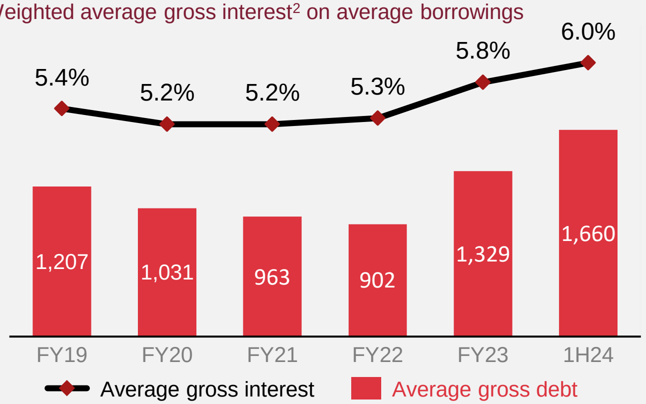

### Borrowing maturities ($m)

Average tenor of 6.4 years as at 31 December 2023



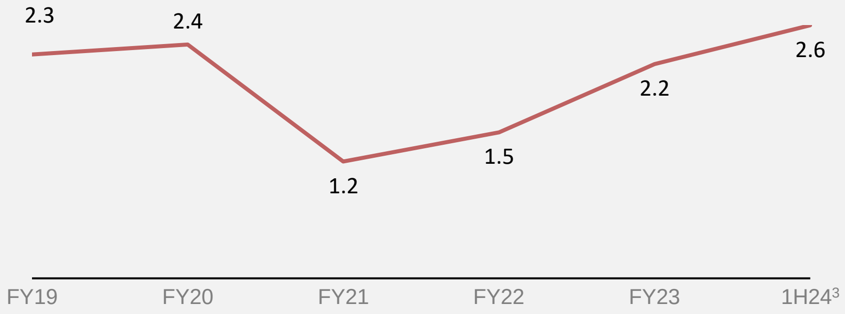

### Interest rate (%)

Weighted average gross interest[2] on average borrowings




### Net debt to EBITDAF (x)

Includes S&P adjustments (prior to FY20, AGS was treated as a lease)




- Face value of borrowings (excl. leases) increased by $338m to $1,812m from 30 June 2023.
- A Green Australian Medium Term Note (AMTN) was issued during the half year, this was partly to refinance a maturing tranche of USPP in December 2023, but also to provide additional funding for the ongoing capital investment programme.
- All facilities are classified green under Contact's sustainable finance framework, and the bank facilities are sustainably linked with alignment to the Contact26 strategy to lead the decarbonisation of New Zealand.
- The KPIs on Contact's sustainably linked loan for emissions reductions and DJSI performance were met for FY23 providing a discount on the borrowing rate for Contact.
- Contact's planning aligns with maintaining its investment grade credit rating. This requires net debt to EBITDAF to remain below 3.0x over a sustained period. Point estimate net debt to EBITDAF is currently 2.6x and Contact's EBITDAF outlook, DRP and capacity for additional hybrid bonds provide the ability to mange this metric effectively.

[1] Includes $112m of collateral held on deposit for margin calls associated with the trading of electricity price derivatives on the ASX.
[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 a normalised and expected EBITDAF of $600m.

# Growth investment funding strategy

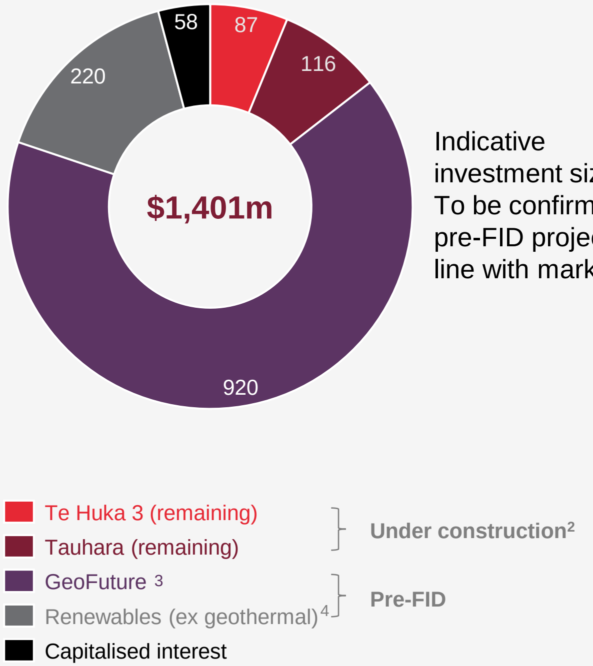
## Complementing conventional debt funding and hybrid debt instruments, Contact has a Dividend Reinvestment Programme that can provide additional equity support

### Growth capital expenditure ($m)

| | Up to 31 December 2023 | Remaining under current approvals | Total |
|---|---|---|---|
| Tauhara | $804m | $116m | $920m |
| Te Huka 3 | $213m | $87m | $300m |
| GeoFuture | $31m | $83m | $114m |
| Wind | $10m | $5m | $15m |
| Capitalised interest | $134m | $58m | $192m |
| **Total** | **$1,192m** | **$349m** | **$1,541m** |

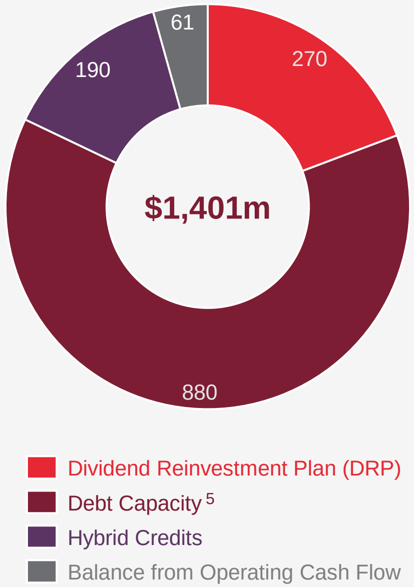
### Medium-term capital investment programme[1]

Active developments and projects coming to FID in 2024




Indicative investment sizing – To be confirmed on pre-FID projects in line with market

### Potential sources of funding to FY28

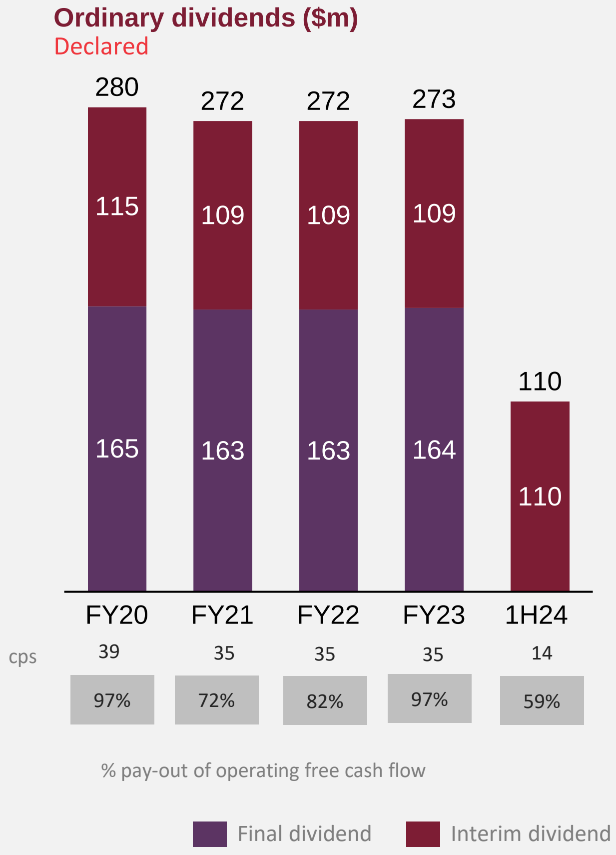



The DRP draws from expected available capacity from the programme where a discount is offered. Any operating cash flow in excess of gross dividends provides another source of funding.

**Commitment to maintaining S&P investment grade credit rating continued.**

Note: All figures in pie charts exclude capitalised interest.
[1] Assumes capital calls for associate investments, Dryland Carbon and Forest Partners, as well as realised losses on market derivatives not in a hedge relationship are funded through retained operating cash flow above gross dividends.
[2] Remaining under current approvals as at 31 December 2023.
[3] Based on ~$950m total project capital ($5.3-5.7m/MW for a 160-180MW capacity plant) less ~$30m pre-FID development costs incurred as at 31 December 2023.
[4] Includes one battery and one solar project going to FID in 2024 and ~$5m of pre-FID wind development costs remaining under current approvals.
[5] Debt capacity is assessed based on end of FY27 run rate EBITDAF of $815m indicated in May 2023.

# Dividend for 1H24



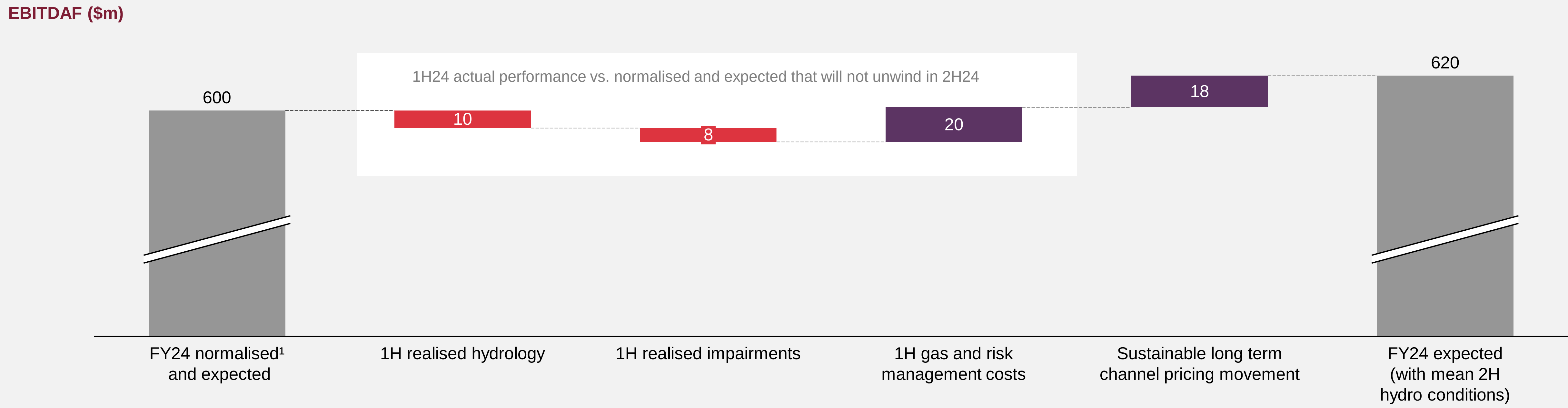

### Interim dividend for 1H24 of 14 cents per share

- Interim dividend of 14 cents per share is imputed to 86% or 12 cents per share for qualifying shareholders.
- Dividend timeline brought forward. Record date of 27 February 2024; payment date of 18 March 2024.
- The NZD/AUD exchange rate used for the payment of Australian dollar dividends will be set on 7 March 2024.

### 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.
- There will be no discount offered for the 1H24 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 28 February 2024 to confirm participation in the plan.
- Trading period for setting price for DRP is 26 February 2024 to 1 March 2024. DRP strike price will be announced: 7 March 2024.

# Sustainable pricing changes drive an uplift in FY24 expected EBITDAF




**Given the requirement for design and construction remediation of the Tauhara steam separation system, Contact is assessing the economic benefits of all costs capitalised to the project and will complete this assessment prior to the finalisation of the FY24 results.**
**Any impact would be immaterial in the context of the Tauhara project. The expected FY24 EBITDAF of $620m does not include this potential impact.**

[1] See slide 32 for assumptions underpinning FY24 normalised and expected earnings as assessed in August 2023.

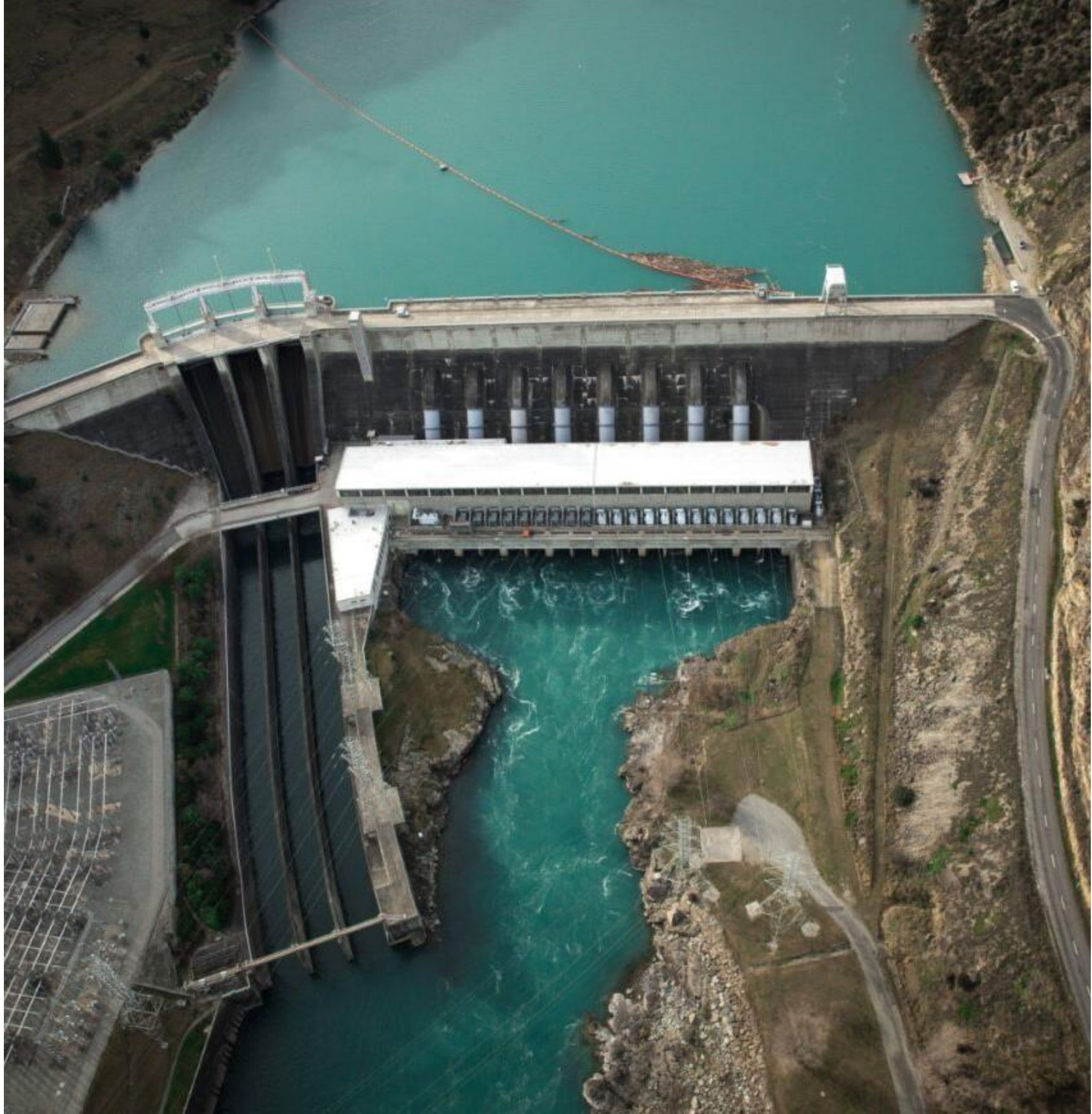
# Our operational plan

## What you can expect in the next 12 months

| Strategic theme | Calendar 2024 | |
|---|---|---|
| Grow Demand | Enter new long-term supply agreement with NZAS. | Final Investment Decision (FID) for $CO_2$ commercialisation. |
| Grow renewable development | Tauhara operational Q3 2024[1].<br>Te Huka 3 operational Q4 2024[1]. | Achieve FID for GeoFuture.<br>Achieve FID for Kōwhai Park solar. |
| Decarbonise our portfolio | Final Investment Decision on BESS (battery). | Expect to decommission TCC at end of 2024.[1] |
| Create outstanding customer experiences | Expansion of demand flex to retail customers. | Further expansion of “It’s good to be home” brand position. |

[1] Calendar year references.

# Questions



# Supporting materials

# Guidance confirmation

| | Updated FY24 guidance | 1H24 result | Change to prior guidance | |
|---|---|---|---|---|
| **Stay in Business Capex** | **$120m - $130m[1]** | **$64m** | +$5m | |
| Stay in business accelerated programme (cash) | $55m - $60m | $24m | - | |
| Stay in business capital expenditure (cash) BAU | $65m - $70m | $40m | +$5m | Non-sustained increase relates to emergency repairs at Wairākei following Cyclone Gabrielle and Peaker GT22 repairs. |
| Growth capital expenditure (cash)[2] | $400m - $500m | $233m | - | Increase in capitalised interest is offset by reductions in projects due to timing of spend. |
| Depreciation and amortisation | $250m - $260m | $126m | +$20m | Acceleration in Peaker assets and change in useful life for geothermal plant partially offset by extension of SAP assets. |
| Net interest (accounting) | $45m - $55m | $17m | -$20m | Higher mix of capitalised interest due to the Tauhara delay. Interest rates reducing and increased interest earned on cash. |
| Cash interest (in operating cash flow) | $27m - $37m | $9m | | |
| Cash taxation | $95m - $105m | $66m | - | |
| Realised (gains) / losses on market derivatives not in a hedge relationship[3] | $10m - $15m | $2m | - | |
| Corporate costs | $52m | $27m | +$4m | Increase is due to one-off write-off of $3.9m relating to the CRM system project not continuing as originally planned. |
| Target ordinary dividend per share | Minimum 35 cps | 14 cps | - | Conditions precedent for increase in guidance not yet met. |

[1] FY24 guidance range is gross i.e. before the netting off insurance proceeds of $15m.
[2] Growth capital expenditure includes capitalised interest and is based on current Board-approved capital spend.
[3] Previously included within EBITDAF (cash).

# Normalised and expected EBITDAF assumptions

## With reconciliation to actual performance

### 1H24 assumptions that deliver expected & normalised EBITDAF of $600m 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 | 600GWh | x | $50/MWh | = | $30m |
| CFDs | 1250GWh | x | $140/MWh | = | $175m |
| C&I | 650GWh | x | $145/MWh | = | $94m |
| Retail | 2,000GWh | x | $144/MWh | = | $288m |
| Other income[3] | | | | | $20m |
| | | | | | **$608m** |

| 3 Hydrology & Asset availability optimise generation | | X | 4 Access to and price of fuel* drives financials & risk position | = | Total |
|---|---|---|---|---|---|
| Hydro | 2,030GWh | x | $0/MWh | = | -$0m |
| Geothermal | 1,625GWh | x | $5/MWh | = | -$8m |
| Thermal[4] | 1,035GWh | x | $120/MWh | = | -$124m |
| Acquired | 0GWh | x | $0/MWh | = | -$0m |
| | | | | | **-$132m** |

| 5 Trading delivers value to more than offset locational losses | | 6 Digitalisation & continuous improvement optimise fixed costs | |
|---|---|---|---|
| Length[5] | $27m | Transmission/Storage | -$35m |
| Location losses[6] | -$26m | Operating expenses | -$129m |
| **Total** | **$1m** | **Total** | **-$164m** |

### EBITDAF reconciliation to 1H24 ($m)

**Normalised & Expected**

**Lower renewables**
Renewable generation below mean (-86GWh) at expected thermal SRMC

**Increased long–term channel price**
Retail net price of $150/MWh in 1H higher than full year expectation

**Lower market channel price**
C&I net price of $135/MWh in 1H lower than full year expectation

**Gas, carbon, acquired generation price**
Gas & carbon price as well as thermal efficiency were favourable

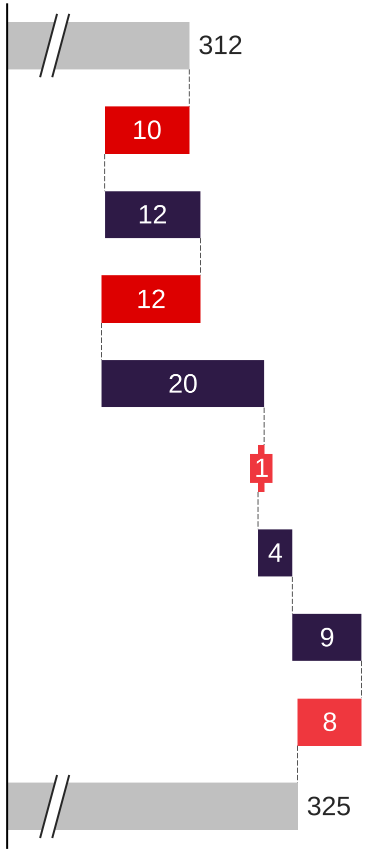
**Net volume impact**
Lower than expected sales volumes, largely offset by reduced SRMC of thermal generation

**Other income**
Expected losses from distressed gas sales not realised

**Fixed costs**
Received 'loss and constraint excess' (LCE) rebates. Prioritisation of geothermal activity and resource

**One-off write-offs**
Impact of one-off write offs for Peaker damage (-$4.0m) & CRM system project not continuing as originally planned (-$3.9m)

**Actual**

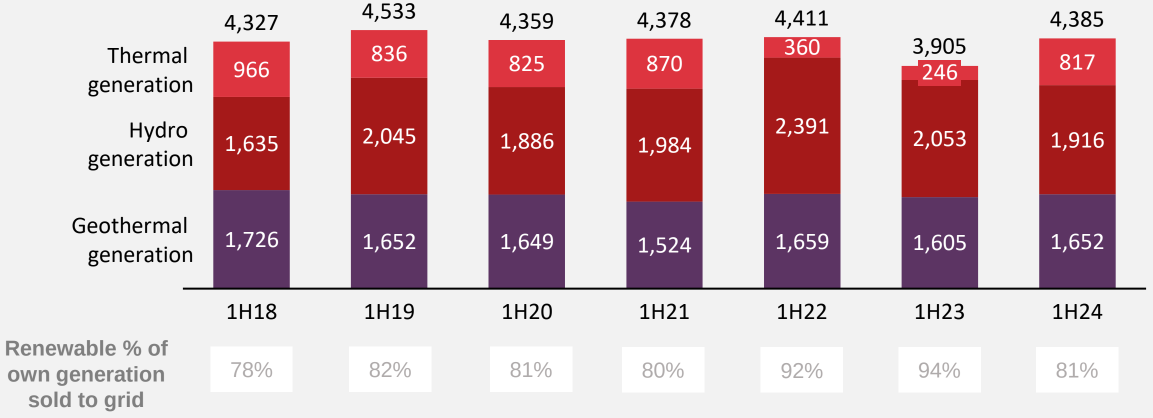



1. All volumes are at the Grid Exit Point (GXP)
2. Net price is equal to tariff less pass-through costs (network, meters and levies) /MWh
3. Steam sales, retail gas gross margin, broadband gross margin and other income
4. Gas price of $9.5GJ, carbon price of $70/unit and thermal portfolio heat rate (9.5GJ/MWh)
5. Length of 194GWh for 1H24 assumed
6. Locational losses of 4.3% on spot purchases and settlement of CFDs sold at a wholesale price of $139/MWh

* Fuel is natural gas and carbon costs

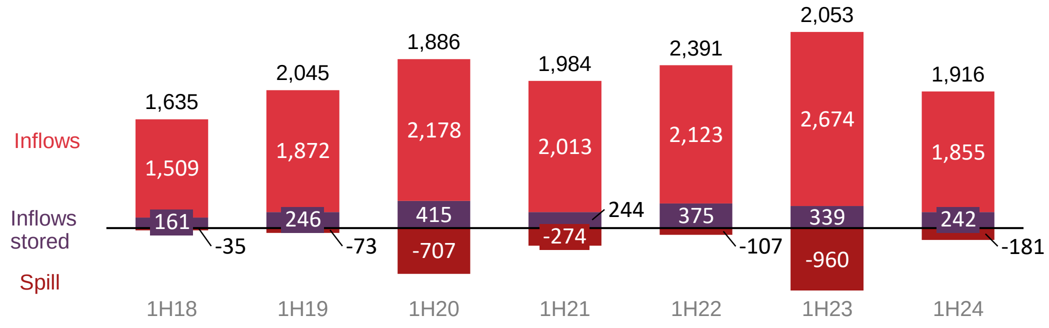
# Generation and sales position

## Contact generation output sold to the national grid (GWh)



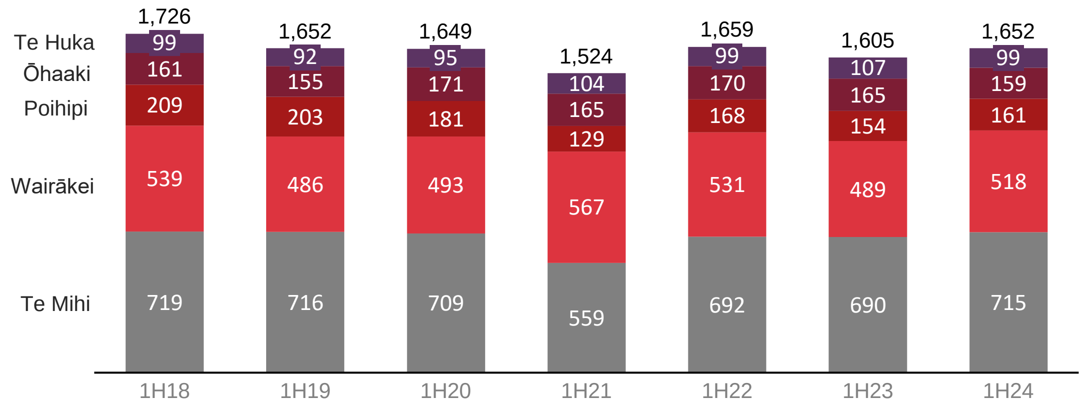

## Hydro generation (GWh)

Inflows stored include uncontrolled storage lakes



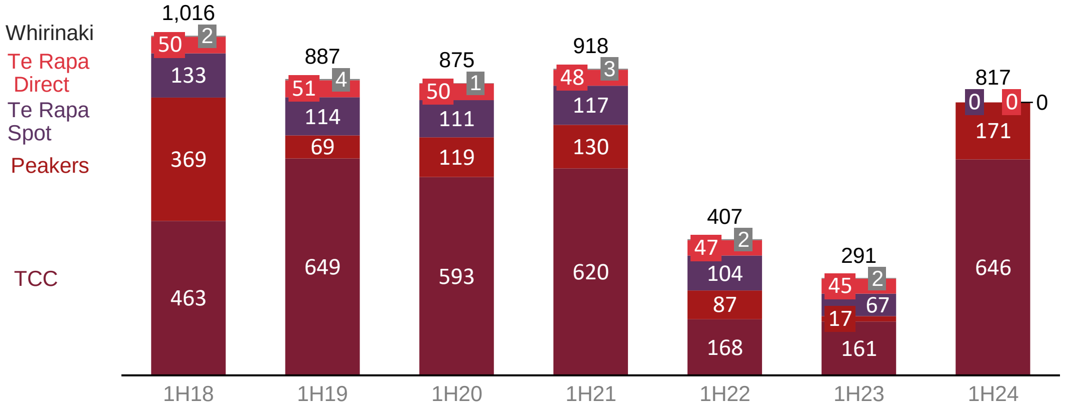

An uncharacteristic El Niño weather pattern resulted in 1H24 hydro volumes being down 137GWh (-7%) on 1H23 as inflows for the period were the lowest seen in five years.

## Geothermal generation (GWh)




Geothermal generation was up 47GWh (3%) on 1H23, ~34GWh (73%) of the uplift is attributable to the increased consented mass take from the Wairākei steam field (from 245,000 to 250,000 t/d).

## Thermal generation (GWh)

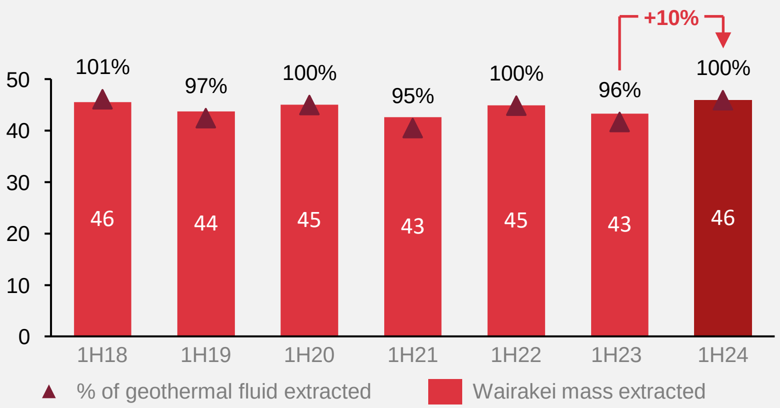



1H24 thermal generation volumes were 526GWh (181%) higher than 1H23 due to three factors: additional thermal generation was required to meet the increased sales position in response to the Tauhara delay; additional gas was available due to the Methanex outage; and closure of Te Rapa increased thermal efficiency as more gas was able to be run through TCC.

# Plant and fuel performance

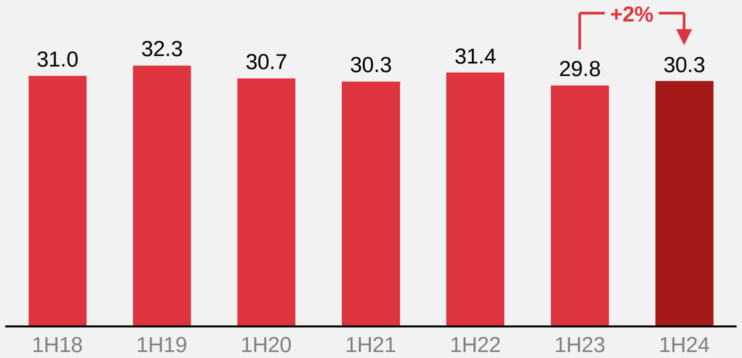
## Geothermal fuel performance

### Geothermal fuel extracted at Wairākei vs consented (mT)




In October 2022 new consents were granted increasing the total allowed geothermal mass take by 2% (from 245,000 to 250,000 t/d), providing an additional ~50GWh of geothermal generation per annum.

### Wairākei, 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) |
|---|---|---|---|---|---|---|
| 1H20 | 784 | 94% | 54% | 1,886 | 98 | 184 |
| 1H21 | 784 | 85% | 57% | 1,984 | 110 | 218 |
| 1H22 | 784 | 83% | 69% | 2,391 | 90 | 215 |
| 1H23 | 784 | 87% | 59% | 2,053 | 52 | 107 |
| 1H24 | 784 | 93% | 55% | 1,916 | 123 | 235 |

### Taranaki combined cycle (TCC)

| | Net capacity (MW) | Availability (%) | Capacity factor (%) | Electricity output (GWh) | Pool revenue ($/MWh) | Pool revenue ($m) |
|---|---|---|---|---|---|---|
| 1H20 | 377 | 78% | 36% | 593 | 113 | 67 |
| 1H21 | 377 | 96% | 37% | 620 | 127 | 79 |
| 1H22 | 377 | 100% | 10% | 168 | 183 | 31 |
| 1H23 | 377 | 89% | 10% | 161 | 107 | 17 |
| 1H24 | 377 | 69% | 39% | 646 | 127 | 82 |

### Whirinaki

| | Net capacity (MW) | Availability (%) | Capacity factor (%) | Electricity output (GWh) | Pool revenue ($/MWh) | Pool revenue ($m) |
|---|---|---|---|---|---|---|
| 1H20 | 158 | 97% | 0% | 1 | 269 | 0.4 |
| 1H21 | 158 | 91% | 0% | 3 | 305 | 0.8 |
| 1H22 | 158 | 98% | 0% | 2 | 783 | 1.8 |
| 1H23 | 158 | 97% | 0% | 2 | 274 | 0.4 |
| 1H24 | 158 | 100% | 0% | 0 | 0 | 0.0 |

### Geothermal

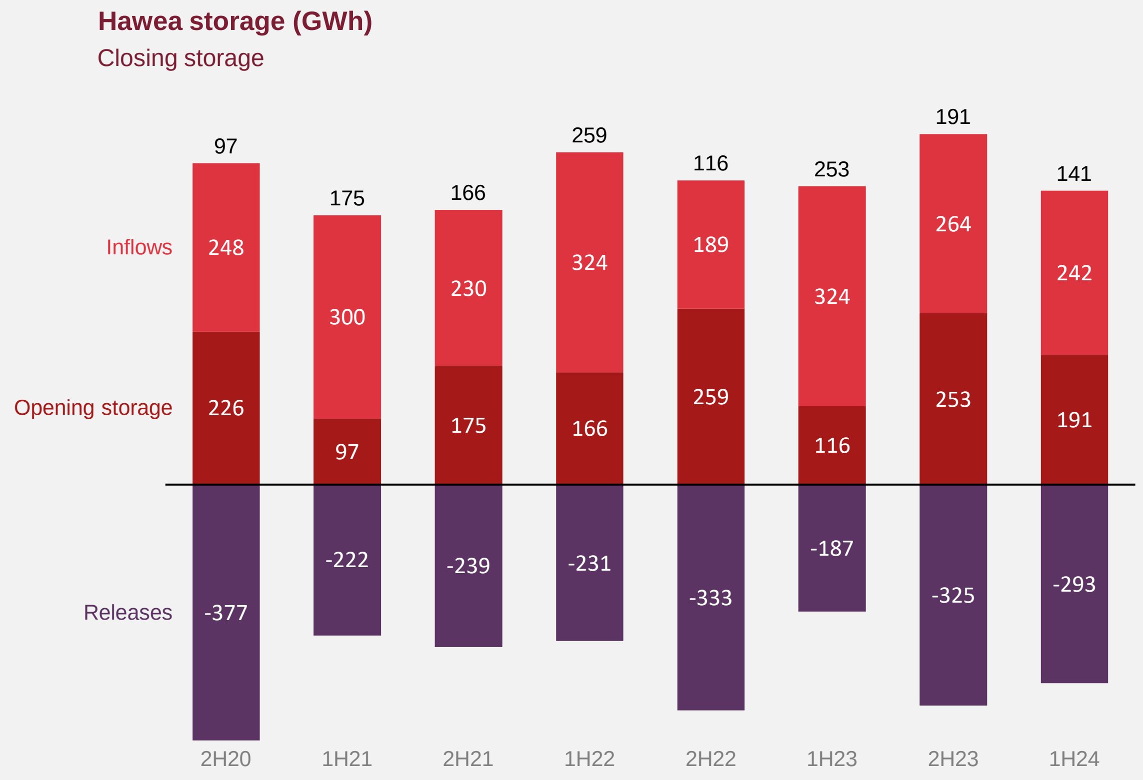
| | Net capacity (MW) | Availability (%) | Capacity factor (%) | Electricity output (GWh) | Pool revenue ($/MWh) | Pool revenue ($m) |
|---|---|---|---|---|---|---|
| 1H20 | 425 | 94% | 88% | 1,649 | 106 | 175 |
| 1H21 | 425 | 86% | 81% | 1,524 | 118 | 180 |
| 1H22 | 410[1] | 96% | 92% | 1,659 | 105 | 175 |
| 1H23 | 410 | 94% | 89% | 1,605 | 56 | 89 |
| 1H24 | 410 | 95% | 91% | 1,652 | 134 | 221 |

### Stratford Peakers

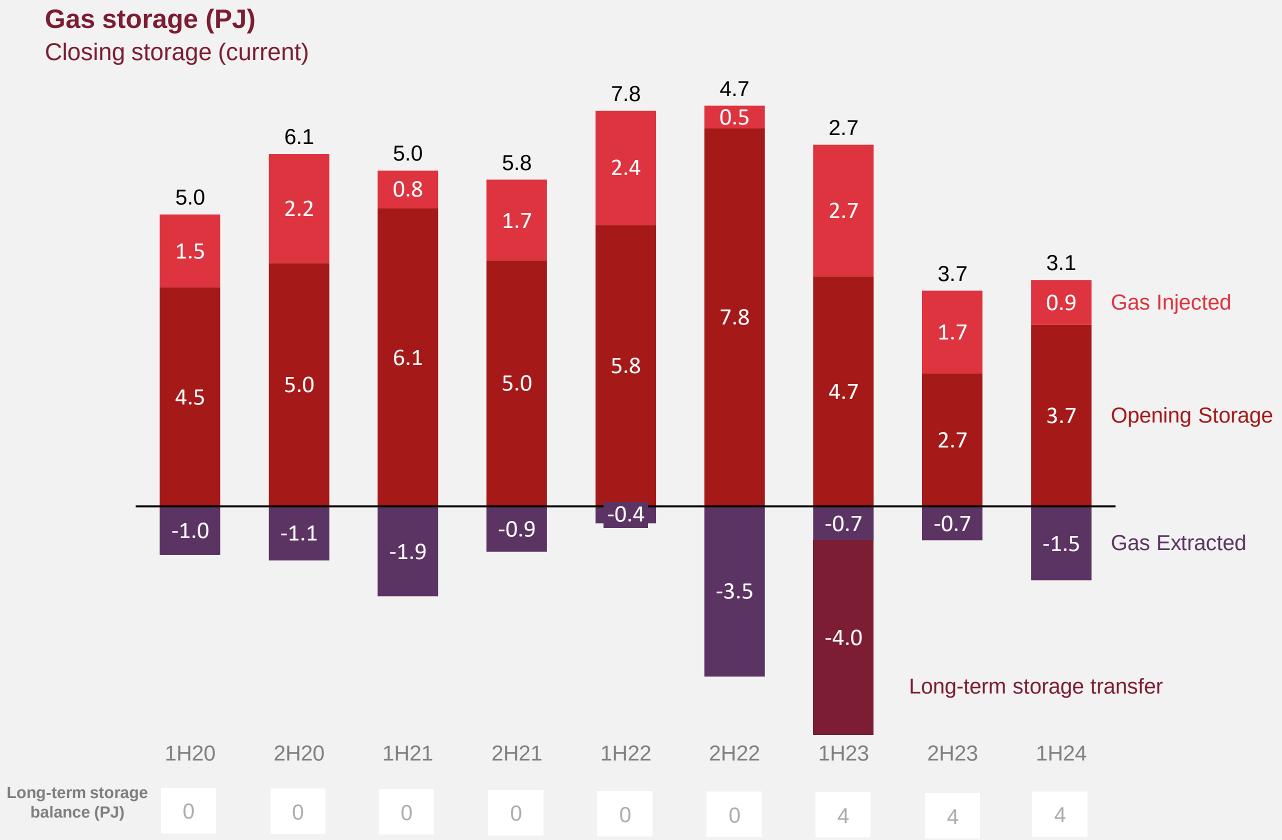
| | Net capacity (MW) | Availability (%) | Capacity factor (%) | Electricity output (GWh) | Pool revenue ($/MWh) | Pool revenue ($m) |
|---|---|---|---|---|---|---|
| 1H20 | 202 | 63% | 13% | 119 | 152 | 18 |
| 1H21 | 202 | 86% | 14% | 130 | 151 | 20 |
| 1H22 | 202 | 74% | 10% | 87 | 216 | 19 |
| 1H23 | 202 | 57% | 2% | 17 | 190 | 3 |
| 1H24 | 202 | 56% | 19% | 171 | 152 | 26 |

Availability Factor calculation includes all station outages (Planned, Maintenance, Forced) but does not consider plant deratings.
[1] Reduction in geothermal net capacity is a result of decommissioning of wells on the Wairākei steam field.

# Fuel storage movements




Source: NZX hydro

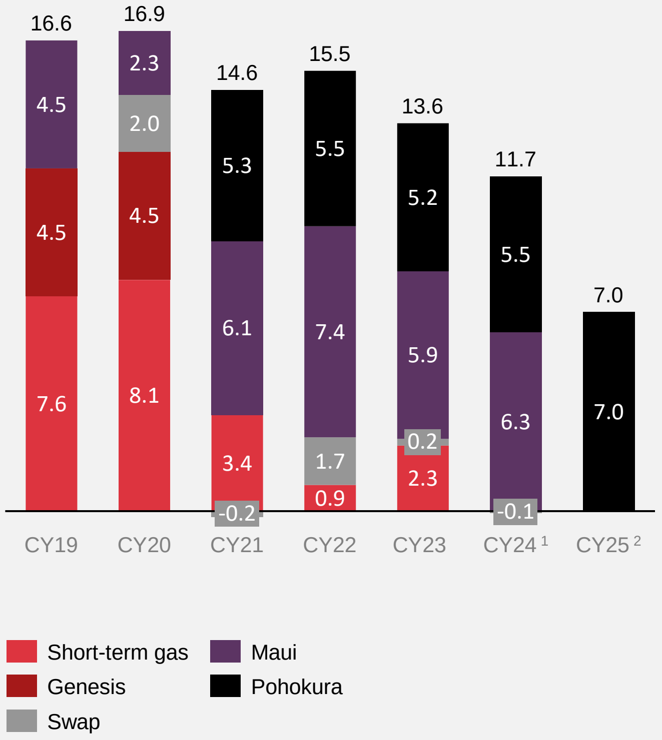



Following the completion of a joint technical working group, set up by Contact and the Ahuroa Gas Storage Facility (AGS) owner FlexGas in 2022, Contact advised the market in December 2022 that approximately 4PJs of gas owned by Contact and currently stored in AGS may only be available for extraction at the end of the contract in 2033. Excluding this volume, the estimated storage capacity of the facility is ~6-8PJ (P-50). Information about the total volume of gas in the facility can be found at https://www.gasindustry.co.nz/data/gas-storage/

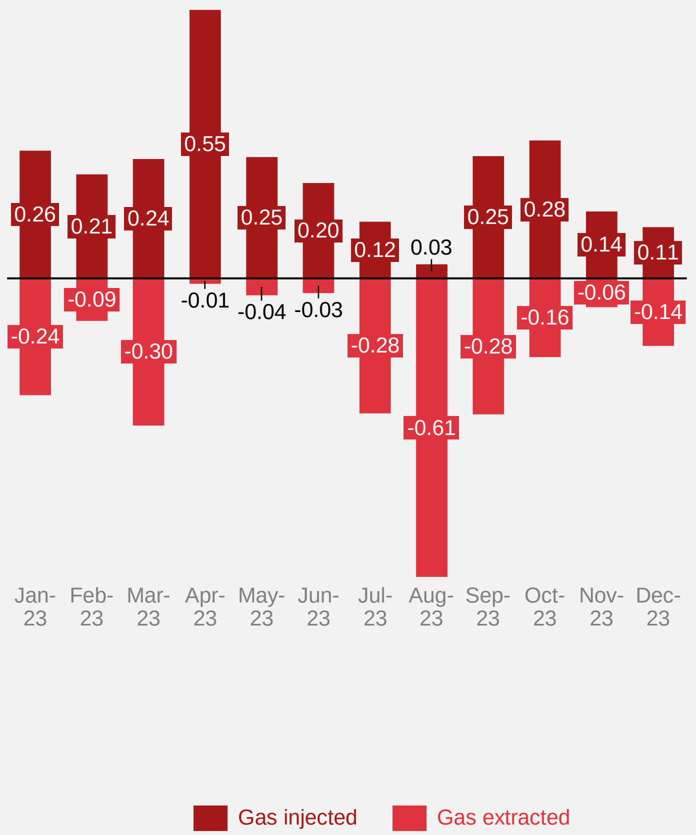
Operational data

# Contracted and stored gas

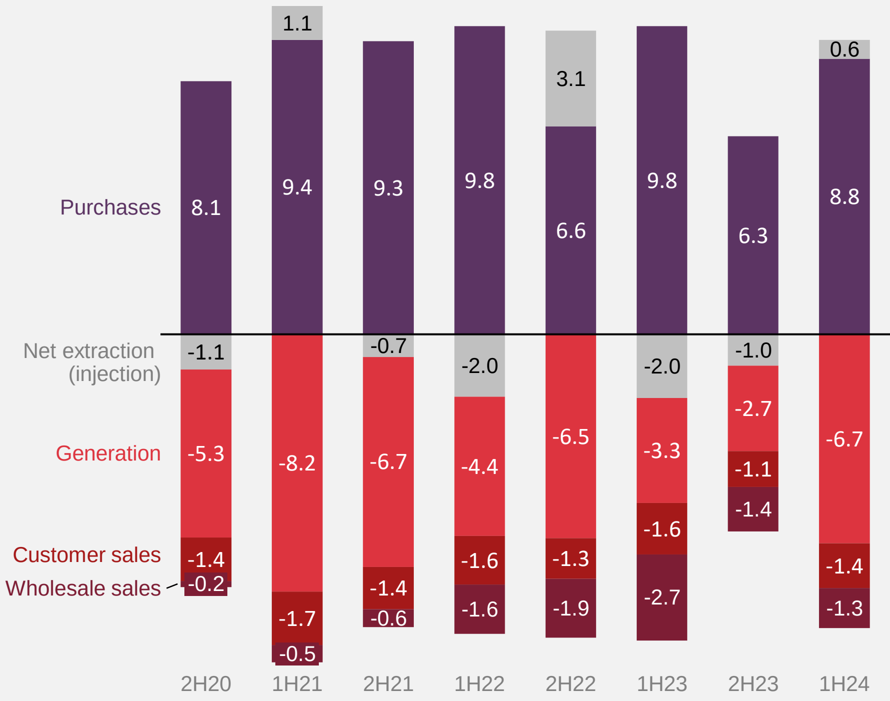
### Contracted gas volumes (PJ)




### Gas storage monthly injections and extractions (PJ)



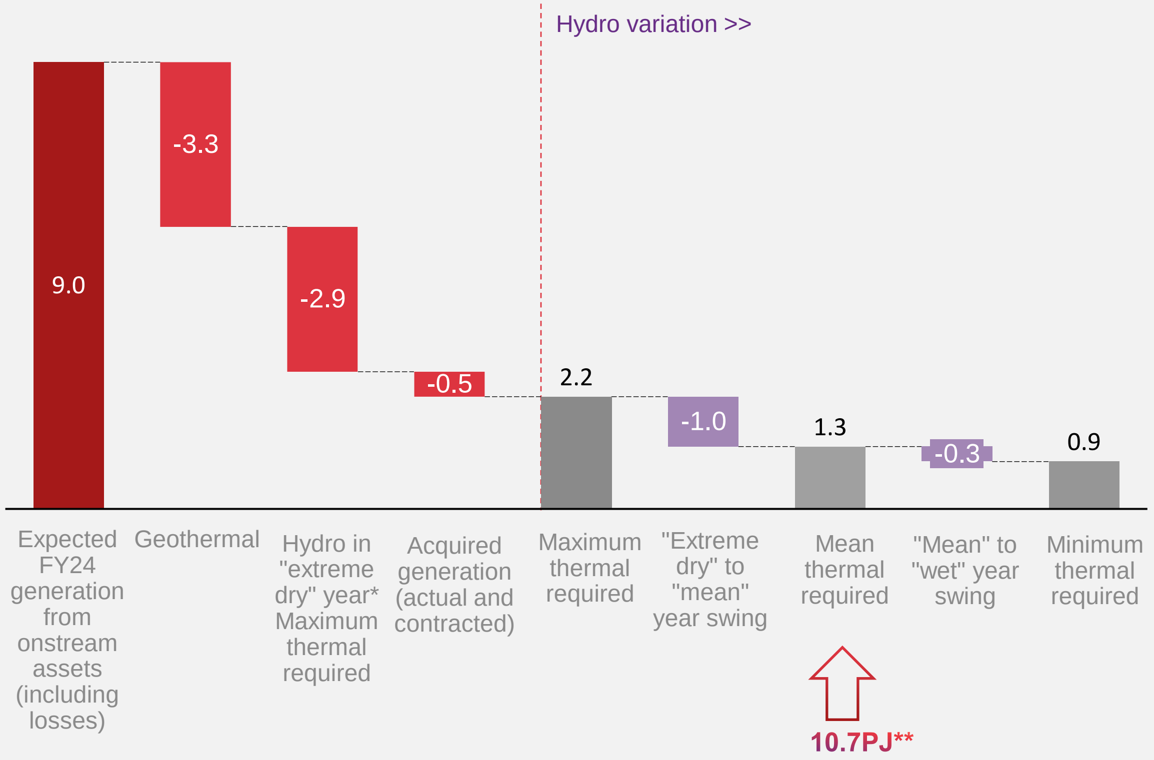

### Uses of gas (PJ)



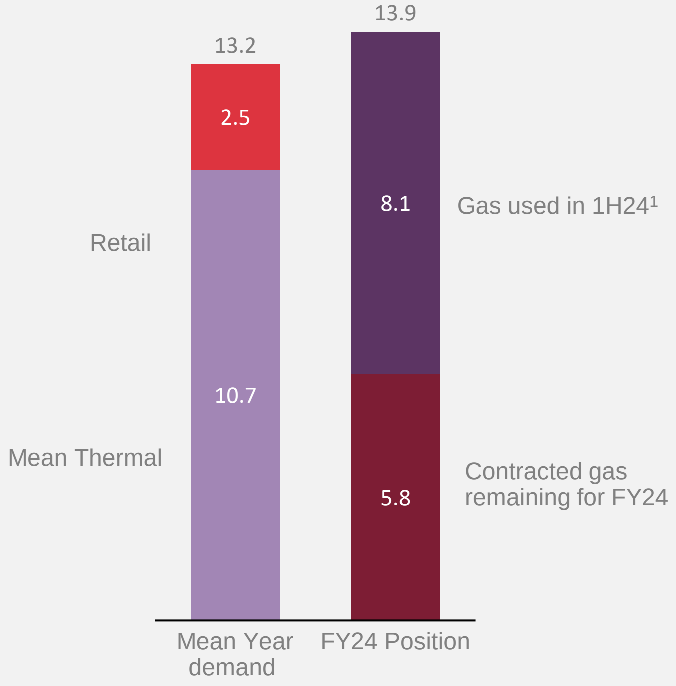

[1] Maui and Pohokura volumes for CY24 reflect forecast volumes.
[2] No forecast currently available for CY25. Contracted amounts shown.

# Contractual fuel position sufficient to support expected sales position

**Portfolio requirements for thermal generation FY24 (TWh)**




**Gas supply and demand FY24 (PJ)**
Excludes stored gas




Options in a dry year:
- Access to stored water in Hawea
- Stored gas
- Purchase spot gas
- Acquire generation from ASX
- Contracted gas above expected mean position

Options in a wet year:
- Gas swaps
- Gas sales
- Hawea storage
- Sell short term ASX

- Hydro generation in FY12.

** Assumes mix of TCC and peaker generation (portfolio heat rate (8.2GJ/MWh)).

[1] Gas used in generation and retail gas sales.

# Reconciliation between Profit and EBITDAF

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

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

Reconciliation of statutory profit back to EBITDAF:

| | 6 months ended 31 December 2023 (1H24) | | 6 months ended 31 December 2022 (1H23) | | Variance on prior year | |
|---|---|---|---|---|---|---|
| | | | | | $m | % |
| | Underlying[1] | Reported | Underlying | Reported[2] | Against underlying | |
| **Profit** | 134 | 153 | **79** | **(7)** | **55** | **70%** |
| Depreciation and amortisation | 126 | | 111 | | (15) | (14%) |
| Change in fair value of financial instruments | -5 | | 17 | | (22) | (129%) |
| Net interest expense | 17 | 20 | 19 | | 2 | 11% |
| Tax expense | 53 | 60 | 32 | (2) | (21) | (66%) |
| **EBITDAF** | **325** | **354** | **257** | **137** | **68** | **26%** |

Depreciation and amortisation, net interest and tax expense are explained on the right.

The adjustments from EBITDAF to reported profit and movements on 1H23 are as follows:

- **Depreciation and amortisation:** increased by $15m and is linked to re assessments in useful life of thermal plant and Wairākei in light of expected final investment decision on replacement. This was partially offset by extending the useful life of SAP assets upgraded as part of recent S/4 Hana upgrade.
- **Net interest expense:** Lower than 1H23 with higher capitalised interest on Tauhara and Te Huka projects partially offset by higher interest on average borrowings.
- **Tax expense** for the period increasing by $21m following higher operating earnings.

[1] Contact has recognised a net onerous contract provision release for AGS of $29m within EBITDAF and $19m within profit after tax and interest. Underlying performance excludes these impacts. All variances and commentary reflect movements in underlying performance.

[2] Contact has made reclassifications to better align with IFRIC guidance on IFRS 9 resulting in realised gains/losses from market derivatives not in a hedge relationship (includes market making activity) no longer being reported in operating income (EBITDAF). 1H23 figures restated accordingly.

# Historical financial information

| | Unit | 1H20 | 1H21 | 1H22 | 1H23[1] | | 1H24 | |
|---|---|---|---|---|---|---|---|---|
| | | | | | Underlying[2] | Reported | Underlying[2] | Reported |
| Revenue | $m | 1,110 | 1,141 | 1,141 | 994 | | 1,306 | |
| Expenses[3] | $m | 889 | 895 | 819 | 737 | 857 | 981 | 952 |
| EBITDAF | $m | 221 | 246 | 322 | 257 | 137 | 325 | 354 |
| Profit | $m | 59 | 78 | 134 | 79 | (7) | 134 | 153 |
| Operating free cash flow | $m | 120 | 157 | 131 | 71 | | 187 | |
| Operating free cash flow per share | cps | 16.8 | 21.9 | 16.8 | 9.1 | | 23.7 | |
| Dividends declared | cps | 16.0 | 14.0 | 14.0 | 14.0 | | 14.0 | |
| Total assets | $m | 4,850 | 4,738 | 4,978 | 5,408 | | 6,059 | |
| Total liabilities | $m | 2,170 | 2,212 | 2,027 | 2,748 | | 3,375 | |
| Total equity | $m | 2,680 | 2,526 | 2,951 | 2,660 | | 2,684 | |
| Gearing ratio[4] | % | 29.9 | 31.1 | 19.3 | 30.6 | | 38.4 | |

[1] Contact has made reclassifications to better align with IFRIC guidance on IFRS 9 resulting in realised gains/losses from market derivatives not in a hedge relationship (includes market making activity) no longer being reported in operating income (EBITDAF). 1H23 Expenses, EBITDAF and operating free cash flow are restated accordingly.
[2] Contact has recognised a net onerous contract provision release for AGS of $29m within EBITDAF and $19m within profit after tax and interest. Underlying performance excludes these impacts.
[3] Includes realised gains/(losses) on risk management derivatives not in a hedge relationship.
[4] Gearing ratio is calculated as: (Senior debt - including finance lease liabilities) / (Senior debt - including finance lease liabilities + Equity).

# Wholesale segment

| | 1H24 Six months ended 31 December 2023 | | | 1H23 Six months ended 31 December 2022 | | |
|---|---|---|---|---|---|---|
| Note: this table has not been rounded and might not add | Volume GWh | GWAP $/MWh | $m | Volume GWh | GWAP $/MWh | $m[2] |
| **Electricity sales to Retail segment** | **1,989** | **141** | **280** | **1,988** | **121** | **241** |
| Electricity sales to C&I (netback) | 686 | 118 | 81 | 781 | 112 | 88 |
| Electricity sales – Direct to Customer | - | - | (0) | 45 | 165 | 7 |
| **Electricity sales to C&I** | **686** | **118** | **81** | **826** | **115** | **95** |
| CfDs – Tiwai support sales | 458 | | | 486 | | |
| CfDs - Long term sales | 390 | | | 210 | | |
| CfDs and ASX - Short term sales | 879 | | | 361 | | |
| **Electricity sales – CFDs** | **1,727** | **112** | **193** | **1,057** | **74** | **78** |
| **Total contracted electricity sales** | **4,402** | **126** | **554** | **3,872** | **107** | **414** |
| **Steam sales** | **118** | **16** | **2** | **336** | **55** | **19** |
| Other income | | | 2 | | | (4) |
| Net income on gas sales | | | 2 | | | 1 |
| Net income on electricity related services | | | 0 | | | 3 |
| **Net other income** | | | **4** | | | **0** |
| **Total contracted revenue** | **4,520** | **124** | **559** | **4,208** | **103** | **433** |
| Generation costs[1] | 4,386 | (40) | (175) | 3,950 | (31) | (122) |
| Acquired generation cost | 239 | (127) | (30) | 131 | (123) | (16) |
| **Generation costs (including acquired generation)** | **4,624** | **(44)** | **(205)** | **4,081** | **(34)** | **(138)** |
| Spot electricity revenue | 4,386 | 132 | 579 | 3,905 | 58 | 225 |
| Settlement on acquired generation | 239 | 130 | 31 | 131 | 63 | 8 |
| **Spot revenue and settlement on acquired generation (GWAP)** | **4,624** | **132** | **610** | **4,036** | **58** | **233** |
| Spot electricity cost | (2,675) | (142) | (380) | (2,770) | (70) | (193) |
| Settlement on CFDs sold | (1,727) | (133) | (230) | (1,057) | (54) | (57) |
| **Spot purchases and settlement on CFDs sold (LWAP)** | **(4,402)** | **(139)** | **(610)** | **(3,827)** | **(65)** | **(250)** |
| *Trading, merchant revenue and losses* | *223* | | *(0)* | *210* | | *(17)* |
| | | | | | | |
| **Wholesale EBITDAF underlying[1]** | | | **354** | | | **279** |
| Onerous contract provision | | | **29[1]** | | | **(120)** |
| **Wholesale EBITDAF reported** | | | **383** | | | **159** |

[1] Contact has recognised a net onerous contract provision release for AGS of $29m within EBITDAF and $19m within profit after tax and interest. Underlying performance excludes these impacts.

[2] Contact has made reclassifications to better align with IFRIC guidance on IFRS 9 resulting in realised gains/losses from market derivatives not in a hedge relationship (includes market making activity) no longer being reported in operating income (EBITDAF). 1H23 figures restated accordingly.

# Retail segment

| Residential electricity | unit | 1H21 | 1H22 | 1H23 | 1H24 |
|---|---|---|---|---|---|
| Average connections | # | 357,756 | 367,199 | 381,222 | 386,540 |
| Sales volumes | GWh | 1,349 | 1,408 | 1,445 | 1,478 |
| Average usage | MWh per ICP | 3.8 | 3.8 | 3.8 | 3.8 |
| Tariff | $/MWh | 251.1 | 251.5 | 261.4 | 281.2 |
| Network, meters and levies | $/MWh | -116.2 | -115.9 | -118.2 | -122.1 |
| Energy costs | $/MWh | -101.1 | -110.8 | -128.7 | -149.9 |
| **Gross margin** | **$/MWh** | **33.8** | **24.8** | **14.5** | **9.2** |
| Gross margin | $ per ICP | 127 | 95 | 55 | 35 |
| Gross margin | $m | 45 | 35 | 21 | 14 |

| Residential gas | unit | 1H21 | 1H22 | 1H23 | 1H24 |
|---|---|---|---|---|---|
| Average connections | # | 60,563 | 63,182 | 66,796 | 67,658 |
| Sales volumes | TJ | 954 | 970 | 881 | 916 |
| Average usage | GJ per ICP | 15.7 | 15.4 | 13.2 | 13.5 |
| Tariff | $/GJ | 31.3 | 32.6 | 38.1 | 41.3 |
| Network, meters and levies | $/GJ | -15.3 | -16.2 | -20.7 | -20.8 |
| Energy costs | $/GJ | -8.3 | -11.3 | -10.2 | -9.7 |
| Carbon costs | $/GJ | -1.4 | -1.9 | -4.2 | -3.0 |
| **Gross margin** | **$/GJ** | **6.3** | **3.2** | **3.0** | **7.8** |
| Gross margin | $ per ICP | 99 | 50 | 39 | 106 |
| Gross margin | $m | 6 | 3 | 3 | 7 |

| SME electricity | unit | 1H21 | 1H22 | 1H23 | 1H24 |
|---|---|---|---|---|---|
| Average connections | # | 51,407 | 48,323 | 47,702 | 44,746 |
| Sales volumes | GWh | 465 | 392 | 421 | 392 |
| Average usage | MWh per ICP | 9.0 | 8.1 | 8.8 | 8.8 |
| Tariff | $/MWh | 230.7 | 239.0 | 249.2 | 276.6 |
| Network, meters and levies | $/MWh | -104.4 | -113.0 | -113.0 | -114 |
| Energy costs | $/MWh | -99.7 | -109.0 | -129.8 | -148.0 |
| **Gross margin** | **$/MWh** | **26.5** | **17.0** | **6.4** | **14.6** |
| Gross margin | $ per ICP | 240 | 138 | 56 | 128 |
| Gross margin | $m | 12 | 7 | 3 | 5 |

| SME gas | unit | 1H21 | 1H22 | 1H23 | 1H24 |
|---|---|---|---|---|---|
| Average connections | # | 3,858 | 3,918 | 3,656 | 3,100 |
| Sales volumes | TJ | 720 | 628 | 635 | 465 |
| Average usage | GJ per ICP | 186.7 | 160.4 | 173.6 | 149.9 |
| Tariff | $/GJ | 15.8 | 18.6 | 23.1 | 29.5 |
| Network, meters and levies | $/GJ | -7.9 | -8.7 | -8.4 | -11.4 |
| Energy costs | $/GJ | -8.3 | -11.3 | -10.2 | -9.7 |
| Carbon costs | $/GJ | -1.4 | -2.0 | -4.2 | -3.0 |
| **Gross margin** | **$/GJ** | **-1.8** | **-3.3** | **0.3** | **5.5** |
| Gross margin | $ per ICP | -474 | -532 | 54 | 828 |
| Gross margin | $m | -2 | -3 | 0.2 | 3 |

| Broadband | unit | 1H21 | 1H22 | 1H23 | 1H24 |
|---|---|---|---|---|---|
| Average connections | # | 33,197 | 57,498 | 74,974 | 88,594 |
| Tariff | $/cust/mth | 65.2 | 71.8 | 70.4 | 73.2 |
| Network, provisioning, modems | $/cust/mth | -74.0 | -61.6 | -62.8 | -64.4 |
| **Gross margin** | $/cust/mth | **-8.8** | **10.2** | **7.6** | **8.8** |
| Gross margin | $m | -2 | 4 | 4 | 5 |

| Retail segment EBITDAF | | 1H21 | 1H22 | 1H23 | 1H24 |
|---|---|---|---|---|---|
| Electricity Gross margin | $m | 58 | 41 | 24 | 19 |
| Gas Gross Margin | $m | 5 | 1 | 3 | 10 |
| Broadband Gross Margin | $m | -2 | 4 | 4 | 5 |
| **Total Gross Margin** | **$m** | **61** | **46** | **31** | **34** |
| Other income | $m | 3 | 3 | 5 | 3 |
| Other direct costs | $m | | | | -1 |
| Other operating costs | $m | -33 | -33 | -35 | -37 |
| **Retail segment EBITDAF** | **$m** | **30** | **16** | **1** | **-1** |
| Corporate allocation (50%) | $m | -7 | -5 | -11 | -14 |
| **Retail EBITDAF** | **$m** | **23** | **11** | **-10** | **-15** |
| EBITDAF margins (% of revenue) | % | 4.60% | 2.10% | -1.80% | -2.43% |