2023 interim results presentation

Six months ended 31 December 2022

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Agenda

Performance reflects short-term wholesale market conditions, investing in decarbonisation strategy

	Six months ended 31 December 2022 (1H23)		Six months ended 31 December 2021 (1H22)	
	Underlying[1]	Reported	Against underlying	
EBITDAF[2]	$246m	*$126m*	↓	24% from $322m
Profit	$79m	*($7m)*	↓	41% from $134m
Profit per share	10.1c	*(0.9 c)*	↓	41% from 17.2c
Operating free cash flow[3]	$60m		↓	54% from $131m
Operating free cash flow per share[3]	7.7 c		↓	54% from 16.8 c
Dividend declared	$110m		↑	$109m
Dividend declared per share	14.0 c		→	14.0 c
Stay-in-business (SIB) capital expenditure (cash)	$55m		↑	57% from $35m
Growth capital expenditure (cash)	$217m		↑	87% from $116m

1H23 market

The operating conditions in 1H23 were characterised by:

- Nationwide hydro inflows at the 96th percentile of historic. With hydro inflows especially extreme in North Island catchments. This led to:
    - Lower wholesale spot prices.
    - Lower thermal generation.
    - Higher price separation between North and South Islands.
- Thermal generation costs remain high:
    - High coal and rising carbon costs.
    - Continued reductions in forecast gas deliveries from ageing fields.
    - Rising fixed costs will need to be recovered over less generation as renewable penetration increases.
- Medium term electricity prices impacted by lower expected gas availability, high coal and carbon costs, the end of 'swaption' contracts and the notified reduction in gas storage capacity.

Contact has responded to the short-term conditions by:

- Reducing thermal generation to reflect market conditions.
- Preparing to mitigate the impacts of the modelled reduced storage at AGS for winter 2023 by entering flexible gas contracting arrangements and if necessary, acquiring additional gas.

Medium term:

- Continuing investment programme to deliver on its decarbonisation strategy to displace thermal generation.
- Recognising a $120 million ($86 million after tax) onerous contract provision for Ahuroa Gas Storage facility (AGS).

Operating earnings (EBITDAF) was down by $76m when compared to 1H22 on an underlying basis[1].

[1] Underlying EBITDAF and profit are shown excluding a $120 million onerous contract provision ($86 million after tax) for AGS. All variances and commentary reflect movements in underlying performance.
[2] Refer to slide 36 for a definition and reconciliation of EBITDAF.
[3] Refer to slide 24 for a reconciliation of operating free cash flow.

Contact26 Our strategy to lead NZ's decarbonisation

Strategic theme	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

Enablers

ESG: create long-term value through our strong performance across a broad set of environmental, social and governance factors

Operational excellence: continuously improving our operations through innovation and digitisation

Transformative ways of working: create a flexible and high-performing environment for New Zealand's top talent

Outcomes

Growth
Pivot our business to a new growth era that captures the value unlocked by decarbonisation

Resilience
Deliver sustainable shareholder returns, aligned with our ESG commitment

Performance
Realise a step-change in performance, materially growing EBITDAF through strategic investments

Improving demand outlook for electricity

Decarbonisation ambitions and thermal economics will support growth

Focus area	Large scale data centres	Industrial process heat	Major industrial energy users	Road transport	Green chemicals
What we've learned	• Attractive baseload characteristics • Low emission customers • Pipeline of hyperscale data centres announced e.g. CDC, DCI, Microsoft, Amazon	• Some barriers remain e.g. high transmission costs • Higher carbon pricing needed to drive increased rate of boiler conversions • $69m in confirmed GIDI funding allocated since 2020	• Increasing commitment to decarbonisation targets by major energy users • Significant appetite for flexible, renewables-backed electricity contracts	• Technology advancement enabling options for heavy transport • Increasing uptake of EVs – 21% of all registrations in December 2022[1] • Expansion of charging infrastructure required	• Hydrogen export economics challenging vs alternatives • Domestic opportunity for green chemicals in a range of hard to abate sectors
Examples of our progress	• Data centres under construction or highly likely totalling 200MW • >100MW capacity due to be added by 2024	• Supported around 50MW of new-to-market lower South Island electricity demand	• Long term Tauhara backed PPAs: Genesis, Oji Fibre and Pan Pac • NZAS negotiations underway • Working with NZ Steel on options around interruptibility	• Working with the HW Richardson Group to assess a trial use of hydrogen for heavy transport • Extended time of use retail offering to EV plan, introducing *Dream Charge*	• Carbon capture trials complete at Te Huka. Have option to reinject or harvest • Working with BOC, a Linde company, to assess highest value commercial options for $C0_2$ captured at geothermal facilities

Demand response

- ✓ **Demand response is introduced wherever possible when entering into new supply contracts – this is high value to Contact, industrial customers and NZ**
- ✓ **Will contribute to decarbonisation of New Zealand whilst improving the security of supply at peak periods**
- ✓ **High degree of customer appetite for demand response mechanisms to be packaged into new contracts**

[1] "EVs" includes the number of electric vehicle registrations for December 2022 as reported by the Motor Industry Association. This is inclusive of 100% electric (2,295), plug-in petrol hybrid (389) and petrol hybrid vehicles (1,286).

Wairākei geothermal consents granted

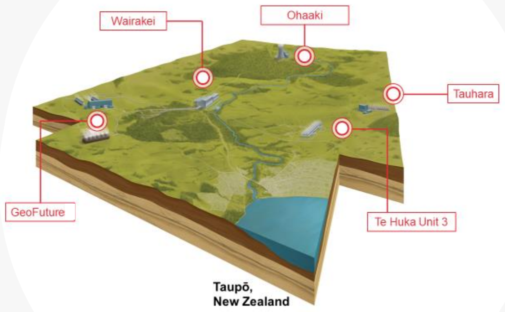
Consent received to operate for the next 35 years on the Wairākei field, enabling Contact to proceed with its plans for the replacement of Wairākei A and B legacy geothermal power stations at Te Mihi (GeoFuture)

Wairākei re-consent highlights

- ✓ Consent to continue operations for next 35 years on Wairākei geothermal steamfield.
- ✓ Consent for large new plant at Te Mihi – up to 180 MW additional to the existing Te Mihi units 1 and 2 – providing investment optionality / flexibility.
- ✓ Will result in significant local investment for Waikato during construction.
- ✓ Immediate benefits from higher geothermal mass take – 2% higher than current.
- ✓ Reinvigorated partnership with local iwi and hapu.
- ✓ All Contact's operational steamfield discharges into Waikato River cease from 30 June 2026.

GeoFuture planned development key features

(capacity / output shown as previously indicated)



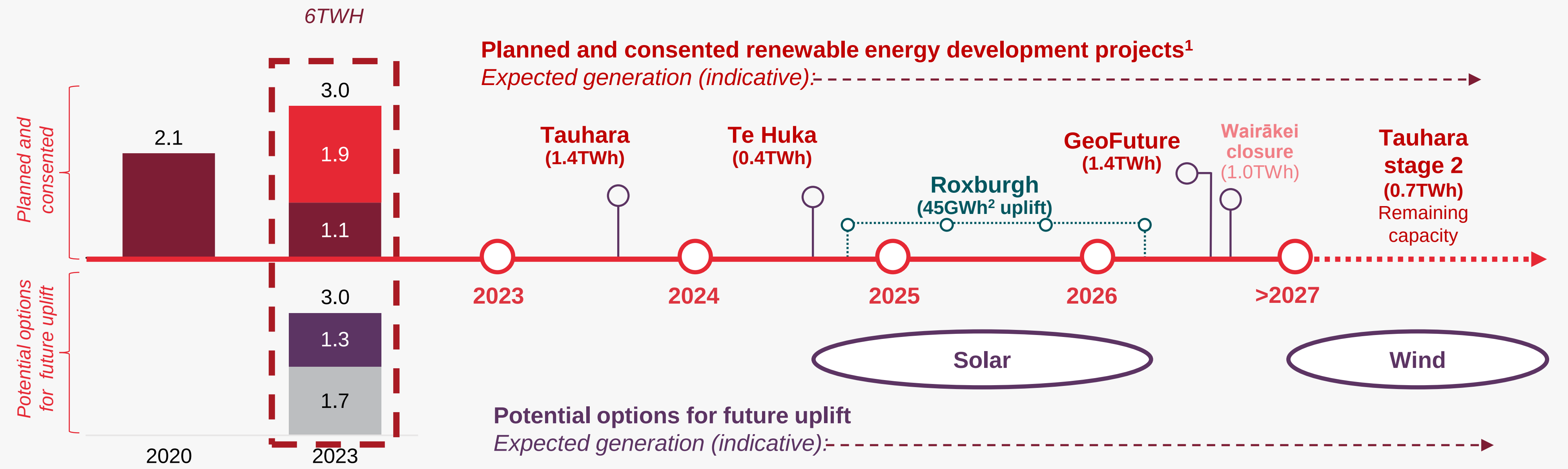
Indicative MW (net export to grid)	~168MW
Estimated plant capacity factor/ annual generation	95% / ~1.4TWh p.a.
Net generation uplift from field resource after closure of Wairākei A and B	~0.4TWh p.a.
Targeted final investment decision / Indicative timing for on-line date	End of 2023 / 2H 2026[1]

Balance sheet prepared, enabling investment option to proceed fully funded

[1] References are to calendar years.

Market leading renewable development pipeline

Contact has built a renewable electricity development pipeline of 6TWh, with capability to deliver



- Consented post-FID (under construction)
- Consented pre-FID (development option)
- Consenting in progress
- Land access secured / exclusivity

Solar and wind development pipeline advancing, with projects entering consenting stage:

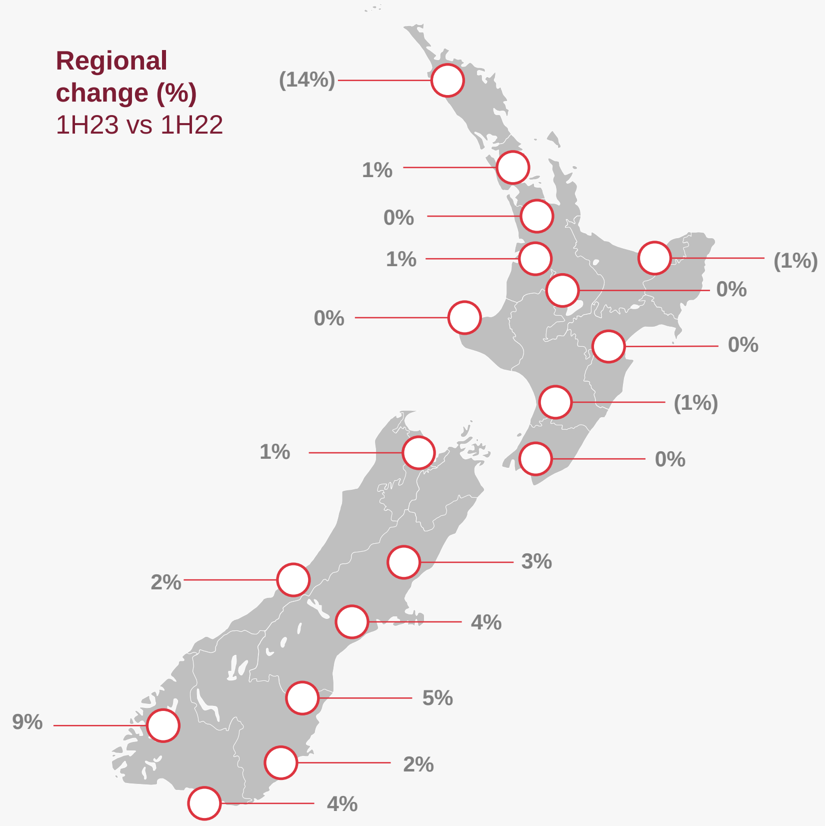
- Contact/Lightsource bp JV selected by Christchurch Airport to deliver 170MWp (150MW) solar farm at Kōwhai Park. Subject to a final investment decision, construction targeted to begin in 2024.
- Consenting underway for priority North Island solar farm site (170MWp/150MW) and South Island wind site (220MW).
- Land access secured for a further development potential of 60MWp (50MW) solar and 450MW wind.

[1] All uncommitted investment / closures are subject to Board investment decisions. The Tauhara, Te Huka and Roxburgh investments have been committed to.
[2] 45GWh p.a. uplift is based on mean hydrology conditions.

National electricity demand

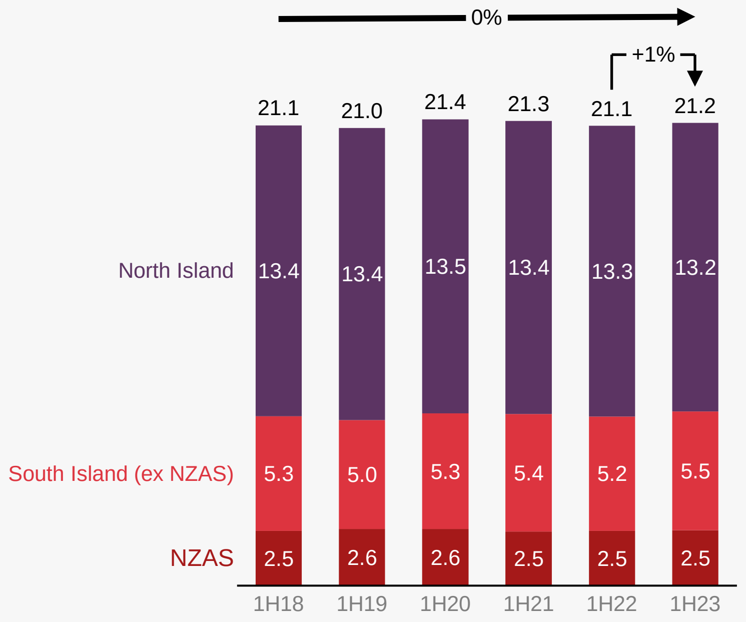
New Zealand electricity demand shows marginal increase on 1H22, despite industrial closures and weather impacts, indicating underlying demand growth

Regional change (%)
1H23 vs 1H22



Source: EMI, Contact.
Does not include NZAS

National electricity demand (TWh)



Source: EMI, Contact

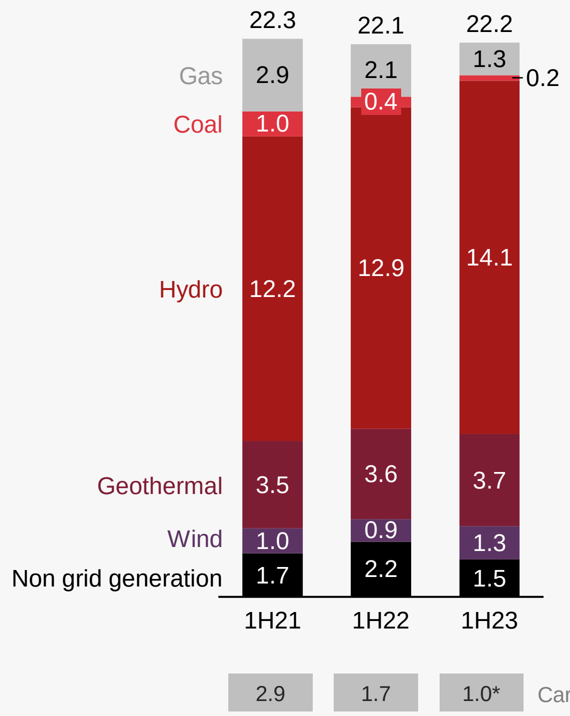
Total national electricity demand increased by 0.141 TWh (0.67% from 1H22):

- The decrease in Northland regional demand (14%) was a result of Marsden Point refinery converting to an import-only terminal – a reduction of 260GWh on the prior half.
- A dry November and December for the South Island in 2022 saw higher irrigation demand at major South Island irrigation demand nodes.
- The 29 GWh decrease in NZ steel demand was offset by a 24 GWh increase in Tiwai demand. Tiwai usage for the period was 580 MW, 8 MW above contracted usage of 572 MW.
- Our assessment, removing the impact from major industrial variations, unusual weather and other known impacts, is that underlying demand is up ~2-3%.

Hydrology and impact on generation mix

High hydro inflows limited the need for thermal generation

Generation by type (TWh)
Generation from generator retailers
- excludes embedded generation



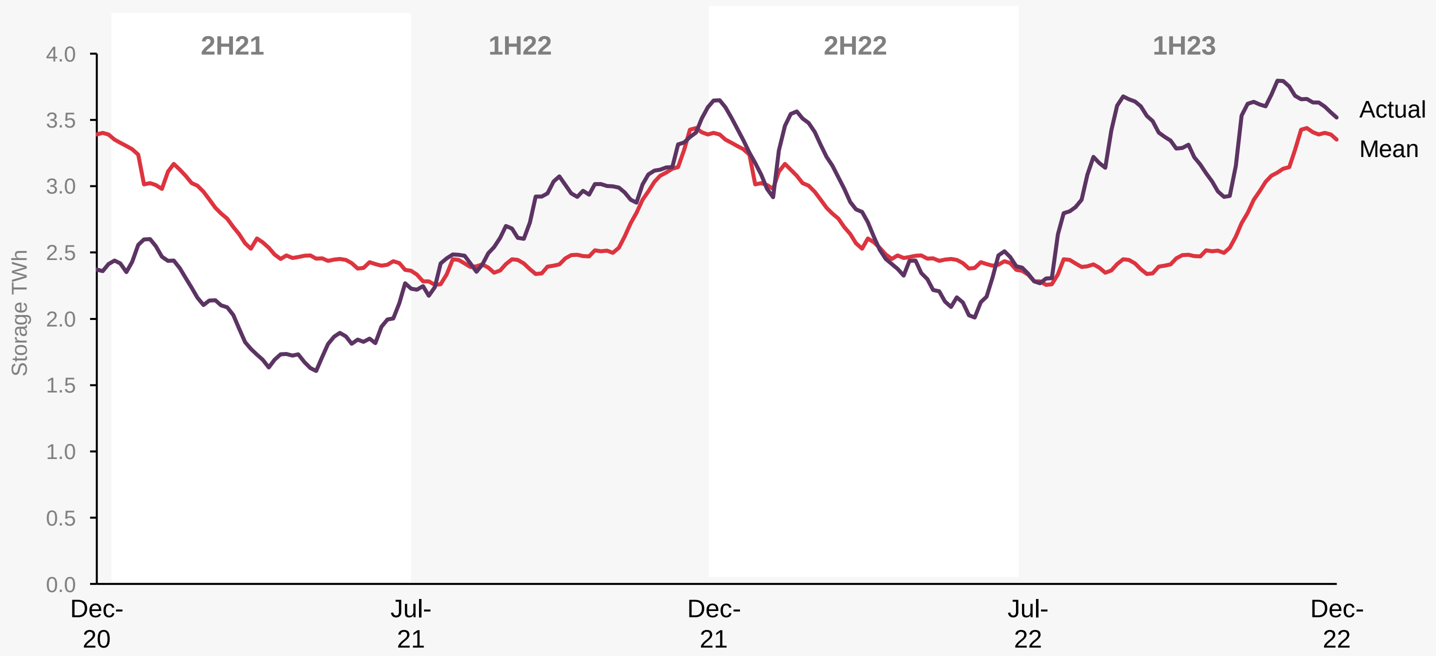
Source: EMI & MBIE

Hydro generation was up 9% when compared to 1H22, driven by a >40% uplift in the North Island (South Island down 2%).

Impacts included:

- Lower spot wholesale prices.
- Higher price separation between North and South Islands.
- Limited need for thermal generation and lower industry carbon emissions.

National hydro storage



Strong hydro inflows in 1H23 saw actual storage levels higher than mean, reducing reliance on gas and coal.

Source: NZX

*Carbon emissions for 1H23 Oct-Dec quarter has been estimated using historic conversion rates with actual generation data. The reduction in carbon emissions of 0.7mT CO_2-e was due to the decrease in coal and gas generation as a result of significantly higher hydro generation in 1H23. Some generation has been estimated based on prior period operation

Wholesale risks remain elevated

Forward wholesale pricing reflects current market conditions, including fuel cost and availability risks

Short-term external factors that can influence the market
Changes as at 31 December 2022 in comparison to 31 December 2021

Aluminium prices lower (-$411/t, down 10%)

Methanol pricing at US$345/t (down 8%)

Extreme weather events led to above mean hydro storage in last 6 months. Controlled storage at ~125% of mean (700GWh above mean) in December

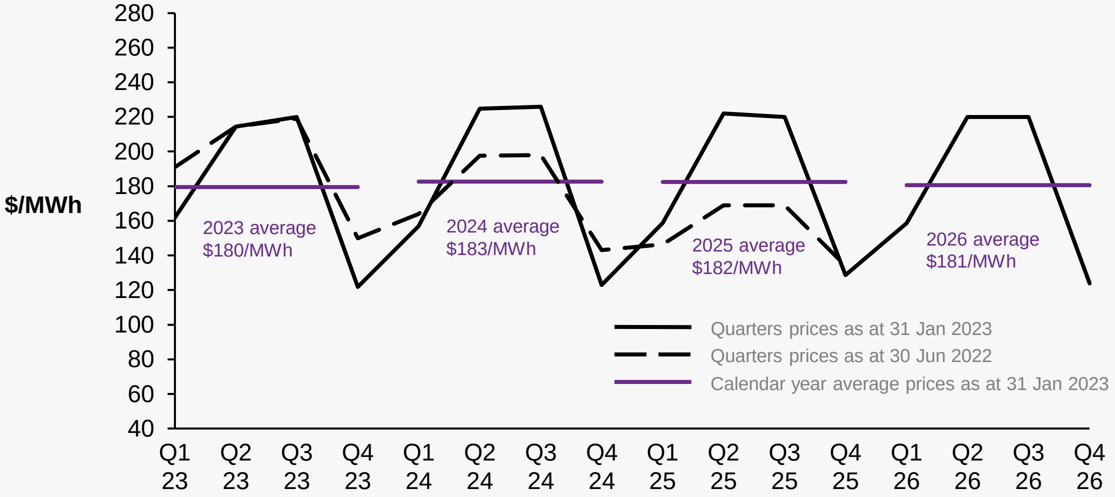
Technical Working Group concluded that 4PJ of stored gas at AGS is unavailable for immediate use

Increase in coal prices +US$300/t (375%)

Carbon prices up 13% to $77/New Zealand Unit

Demand was flat year on year

Elevated wholesale pricing out to 2026
ASX Futures (Quarterly, base period, Otahuhu)



Source: ASX

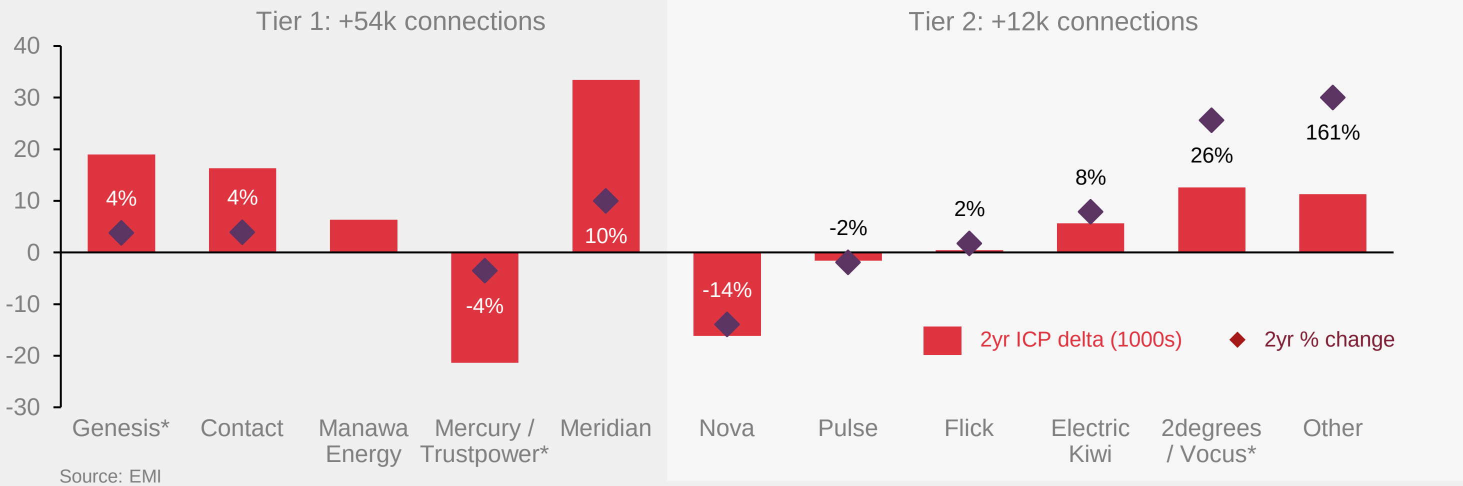
Wholesale market conditions are volatile:

» Near term ASX Futures impacted by lower expected gas availability, high coal and carbon costs and the end of the ‘swaption’ contracts.
» Impact of renewable generation coming online is being offset by higher expected firming costs in the medium term.
» Expect market to rebalance from 2027 with further additions of renewable generation and normalisation of coal costs.

Retail competition remains intense

Retailer’s long-term view of pricing rides through short-term wholesale input cost volatility

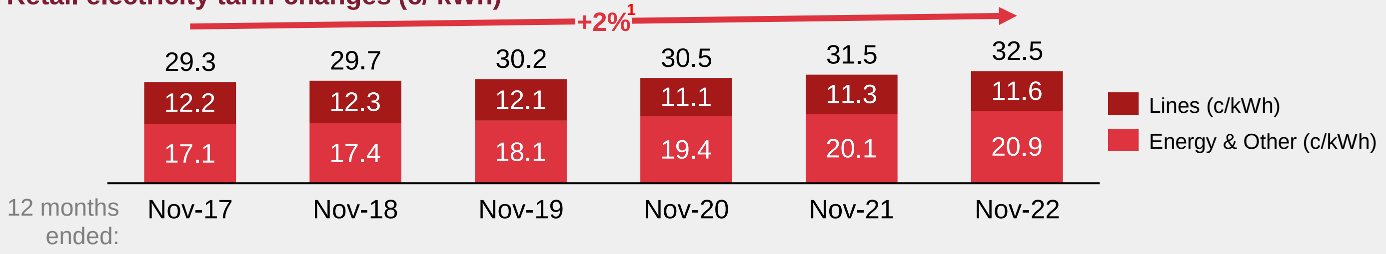
Change in customer electricity connections (000s)
31 December 2020 – 31 December 2022



Source: EMI

- Competition remains intense despite sustained high wholesale futures prices. Market churn continues to reflect this with switching at 19%.
- Tier 1 market share has stabilised (85% Dec-20 & 84% Dec-22) after a number of years of decline. Tier 2 connections were also relatively flat YoY (15% Dec-20 & 14% Dec-22). Tier 1’s (primarily Genesis, Contact and Meridian) added connections as household formation contributed to a continued ~1% p.a. growth in ICPs.
- Mercury purchased the Trustpower retail business in FY22 and is the largest retailer by ICP (26% market share).
- 2degrees and Vocus merged on 1 June 2022 becoming the third largest telco, alongside providing energy and insurance products, and are now the leading Tier 2 in electricity connections growth (+13k).
- Contact electricity connections +1k YoY maintaining 19% market share.

Retail electricity tariff changes (c/ kWh)



Source: MBIE

- Despite sharply higher wholesale prices over the last four years, tariffs were up by a compound annual growth rate of only 2%. Average tariff increases for the last year of 3% remain materially below consumer price inflation (>7%).
- Households have been largely insulated from higher wholesale prices to date because of fixed price residential contracts and retailers’ longer-term view of pricing that rides through short-term volatility.
- Continued firming future wholesale prices and wider industry costs will need to be recovered by retailers. The real residential unit cost per unit of electricity has fallen in every year since 2018.

*Genesis customer electricity connections consolidates Ecotricity (held 70% of Ecotricity as at 28 February 2022). Mercury completed the purchase of the Trustpower retail business on 1 June 2022. 2degrees completed the purchase of Vocus on 1 June 2022. Companies have been grouped together as relevant for the period under review despite being in different ownership.
[1] Compound annual growth rate.

Climate change and regulation

The New Zealand regulatory framework is being adapted to deliver on this societal imperative. There is political consensus to deliver net zero by 2050 and on the emissions reductions budgets needed to get there

Potential electricity demand impact

- Net zero New Zealand carbon emissions by 2050
- Transport policies
- Emissions Reduction Plan[1]
- Current Tiwai contract ends 2024
- Government Procurement
- Significant increase in GIDI subsidies

Potential renewable generation impact

- Government Energy Strategy[2]
- Resource consenting reform
- Gas Transition Plan

Potential wider electricity sector impact

- Market reviews to support highly renewable market[3]
- New Zealand Battery Project feasibility
- Transmission pricing and grid upgrades

Announced

In progress

Society is demanding action on climate change, with clear progress expected.

[1] While the Government's first Emissions Reduction Plan has now been released, there is ongoing work on implementation and further planning. Work on the next Emissions Reduction Plan will also start in 2023.
[2] Covering electricity, hydrogen, and industry decarbonisation. Terms of Reference have been released.
[3] Including BCG's "The Future is Electric"; EA/Transpower's "Future Security and Resilience Project"; EA's Market Development Advisory Group; Wholesale Market Review (EA currently consulting on proposals).

Topical regulatory matters

Key themes

Wholesale market security

Medium term spot and hedge market prices continue to be higher than long term averages due to coal prices, gas availability and the cost of carbon. This is increasing pressure on unhedged energy intensive industries.

The industry, Transpower and the EA are paying close attention to capacity in winter 2023. The industry CEO forum is working closely with the EA to minimise the risk of any shortage in 2023.

NZ Battery Project

The Government is assessing options to address New Zealand's dry year risk with 100% renewable generation. This includes assessing its initially preferred solution of pumped hydro at Lake Onslow.

In October 2022, Boston Consulting Group released a report "The Future Is Electric" which showed that a range of industry-led solutions were available to address the dry-year risk without the need for the proposed Lake Onslow project.

What Contact is doing

Wholesale market security

Contact is exploring further renewable generation opportunities across geothermal, wind and solar to reduce future impacts from thermal fuel volatility.

Contact is working with customers to smooth out pricing volatility through long-term contracts.

Contact is leading the development of the demand response market for C&I customers, and has introduced time-of-use offerings for retail customers, helping to reduce load during peak periods.

Contact is continuing to engage with the EA on the longer-term impacts of market volatility. The sector is now entering a period of intense investment to both decarbonise existing generation and build new generation to meet future demand.

NZ Battery Project

Contact supports further analysis to address dry year risk. Multiple options exist that will require careful evaluation, including interruptible green hydrogen, interruptible load for other major customers and grid-scale batteries.

Contact continues to assess low cost, low capital options to support decarbonisation through market-led thermal solutions.

Financials

Key themes from the financial results

$120m non-cash onerous contract provision recognised on gas storage contract

Extreme hydrology impacts 1H EBITDAF, well positioned for 2H

New renewable electricity from projects under development to be sold into high priced futures market

Sales channels repricing, further opportunity exists

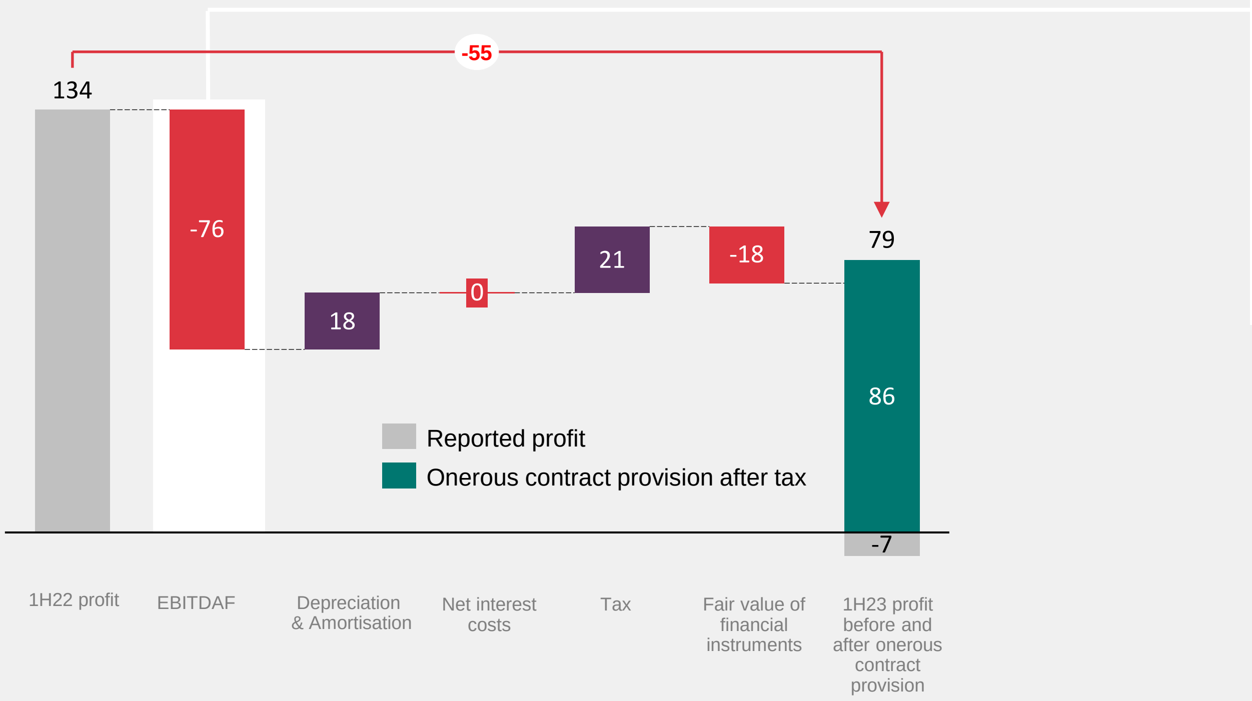
Higher operating costs to support growth and sustainability strategy

Capital Markets Day to be held in late May 2023

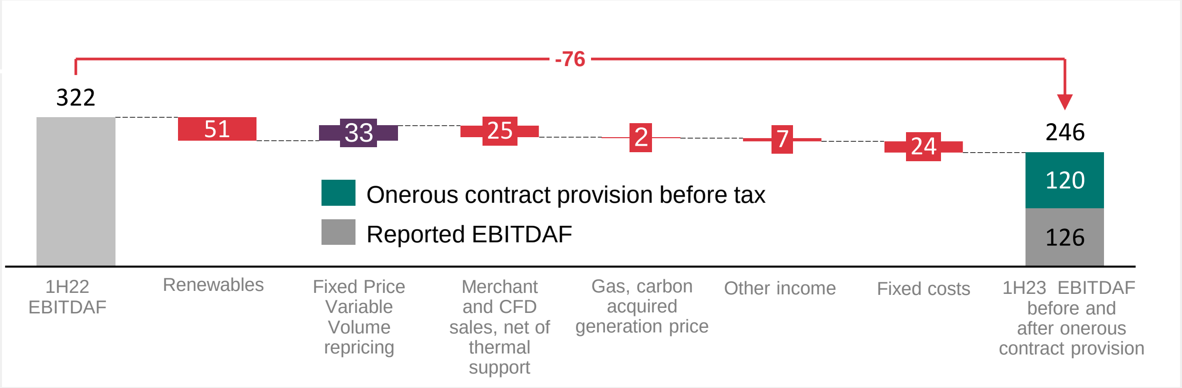
Loss of $7m for 1H23

Excluding the onerous contract provision, EBITDAF down $76m (underlying) reflecting results from a record prior period and lower renewable generation

Profit ($m)



EBITDAF ($m)

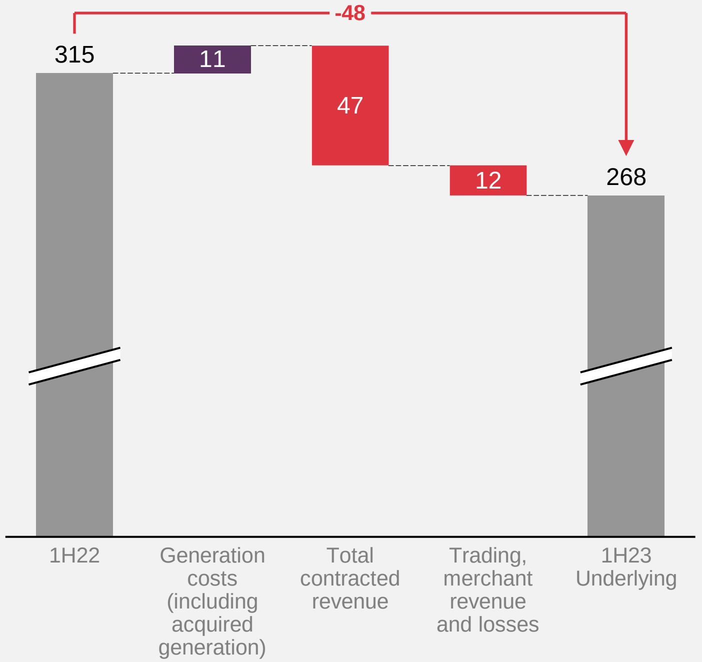


1. Renewables down 391GWh as hydro generation reverted to mean
2. 9% increase in yield from C&I, retail and long-term channels
3. Lower wholesale prices saw lower realised CFD and merchant sales and limited ability to generate marginal thermal generation
4. Higher carbon unit costs on geothermal generation
5. Other income lower as improvement to gas gross margin offset by market making losses (-$10m yoy)
6. Fixed costs higher with increase in other operating costs (-$20m) and higher electricity transmission costs (-$4m) from the removal of ACOT

EBITDAF down by $76m

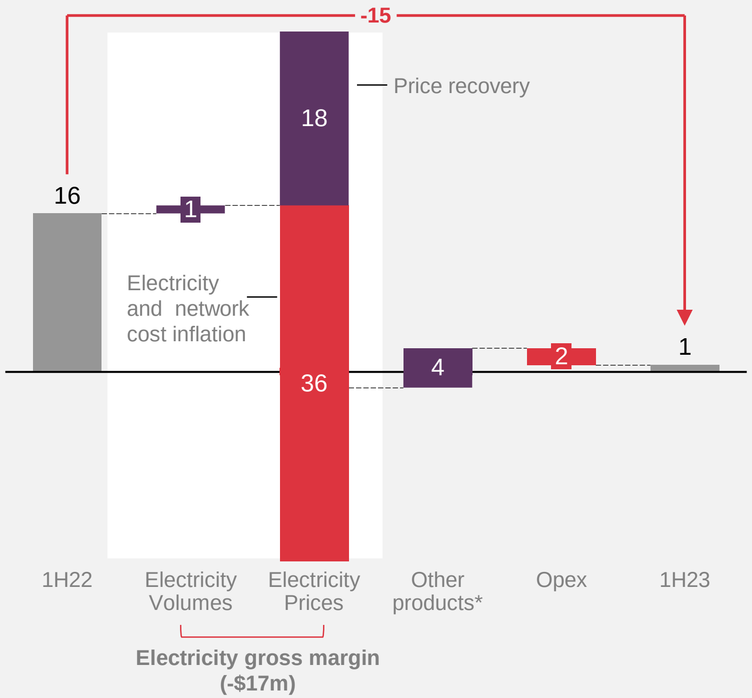
Business performance by segment

Wholesale EBITDAF ($m)



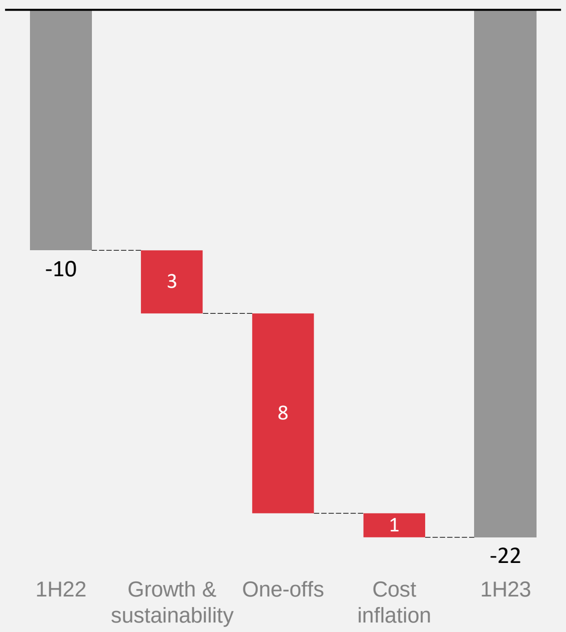
Refer to slides 19 - 21

Retail EBITDAF ($m)



Refer to slide 22

Corporate / unallocated costs ($m)



Simply and Western included within Wholesale EBITDAF

Underlying EBITDAF is shown excluding a $120 million onerous contract provision for AGS

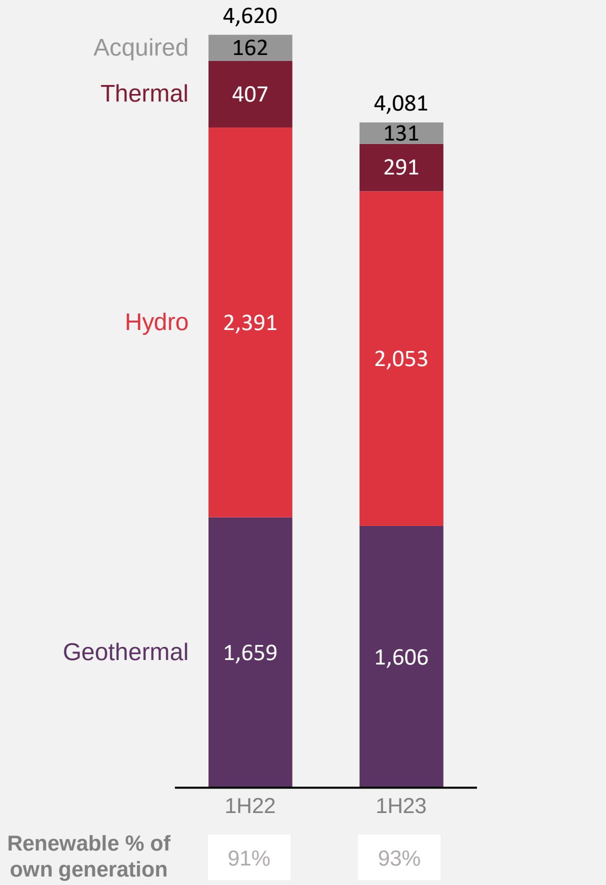
*Other products includes retail gas and broadband gross margins

One-off movements from 1H22 include the Holidays Act provision reversal and SaaS asset write off (together totalling $6m). 1H23 included execution programme setup costs and industry report ($2m).

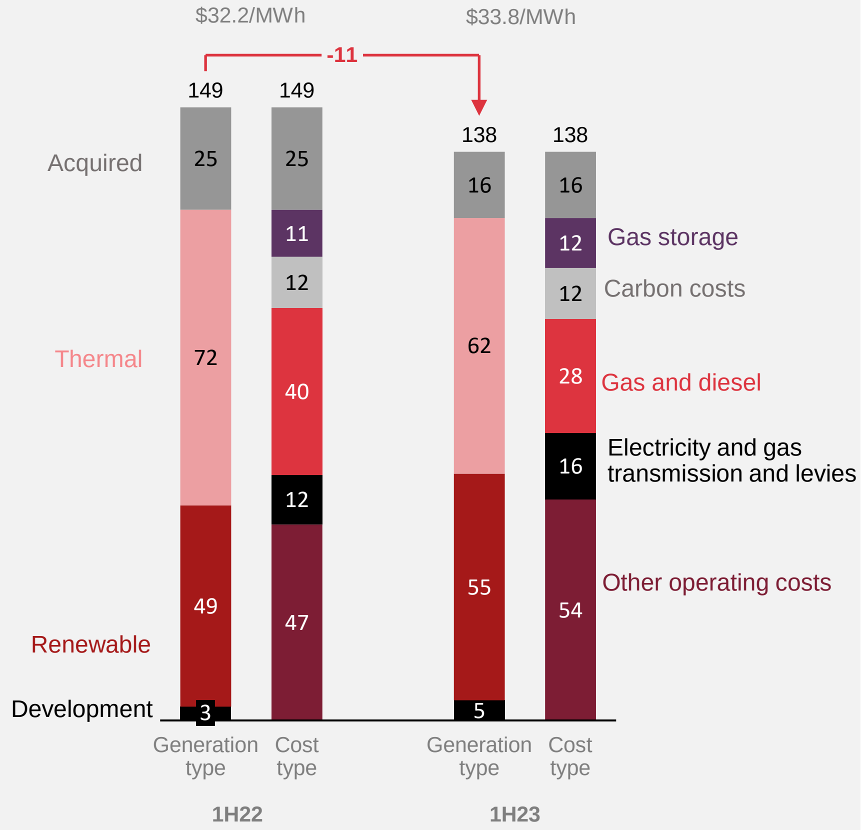
Generation costs

Costs down $11m on reduced thermal generation volumes, up $1.6/MWh on a higher proportion of fixed costs

Electricity generated or acquired (GWh)



Electricity generated or acquired costs ($m)



Generation volumes

- Hydro generation down 338GWh on 1H22 (-14%), 64GWh (+3%) above mean year expectations.
- Geothermal volumes were 53GWh down on prior period (-3%), 19GWh (-1%) below mean year expectations as a result of the 5 yearly Wairākei plant outage and geothermal volumes being conserved for 2H23.
- Thermal volumes were 116 GWh (-29%) lower than 1H22 as a result of the hydrological conditions and low spot wholesale prices.

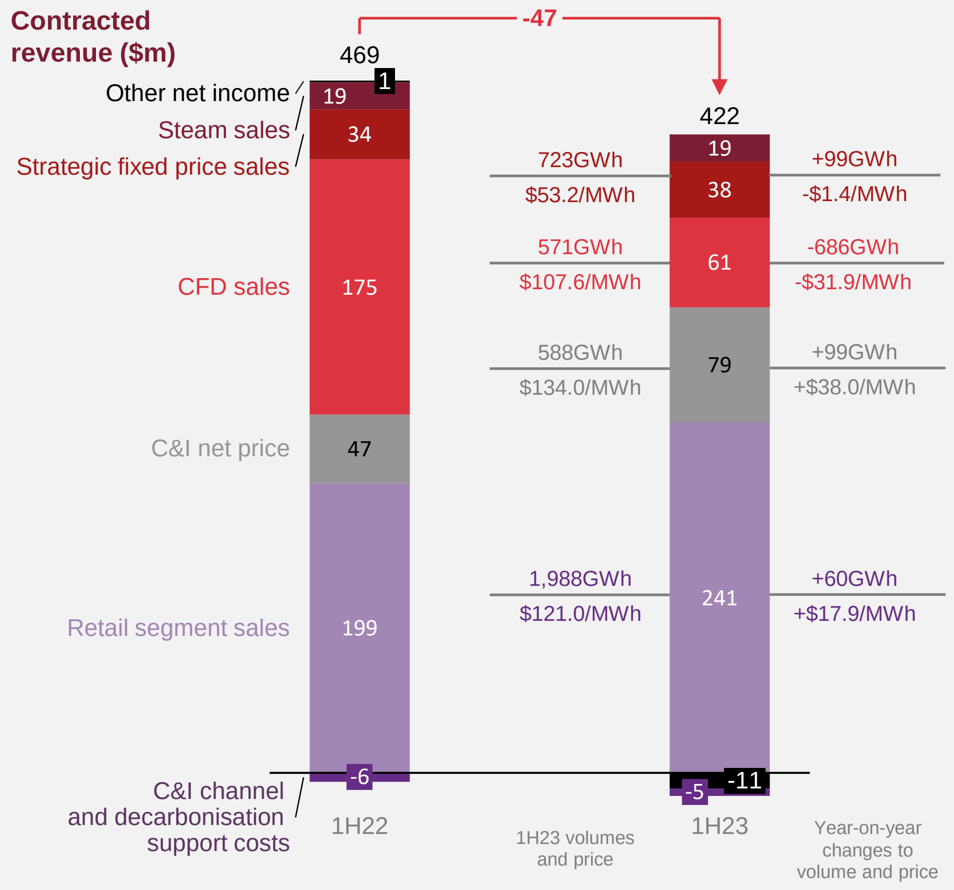
Costs

- Renewable generation costs were up $6m on 1H22 (13%) on removal of ACOT payment for Te Huka and higher unit carbon costs on geothermal and operating cost inflation.
- Thermal generation costs were down by $10m (-14%) on lower thermal volumes.
    - Thermal fuel costs of $120.1/MWh (1H22: $121.4/MWh). With gas costs marginally lower (1H22: $9.2/GJ, 1H23: $7.9/GJ) and carbon prices (1H22 $34/unit, 1H23 $43/unit) higher.

*Gas storage costs exclude $120m onerous contract provision for AGS.

Wholesale contracted revenue

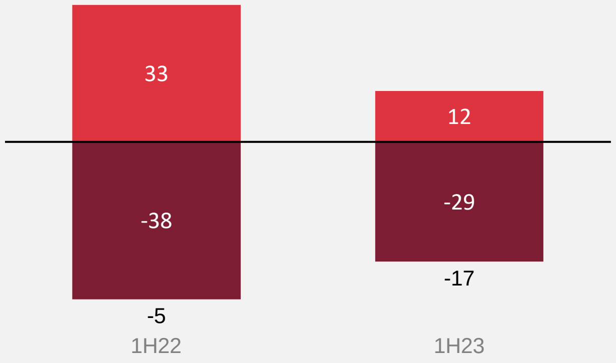
Diversified mix of long-term and ASX linked sales channels



- Fixed price variable volume electricity sales to the Retail segment and C&I customers ended 159GWh higher than 1H22 (+$16m). Prices were up $22/MWh to $124/MWh (+$58m), reflecting higher wholesale prices over the three preceding years.
- Strategic fixed price sales were 99GWh higher than 1H22 (+$5m) reflecting more volume under the NZAS support contract. Prices were down by $1.4/MWh as inflationary adjustments to long-term sales where not enough to offset the mix change from lower NZAS price (-$1m).
- CFD sales volumes were down by 686GWh (-$96m) on lower renewable generation and prices that did not support the sale of thermal generation. Prices were down by $32/MWh reflecting hydro inflows (-$18m).
- Operating costs to support commercial and industrial customers lower as Simply acquisition synergies captured.
- Other income was $12m lower predominantly due to market making losses in 1H23 (1H22: -$2m, 1H23: -$12m)

Wholesale trading and merchant revenue

Trading EBITDAF ($m)

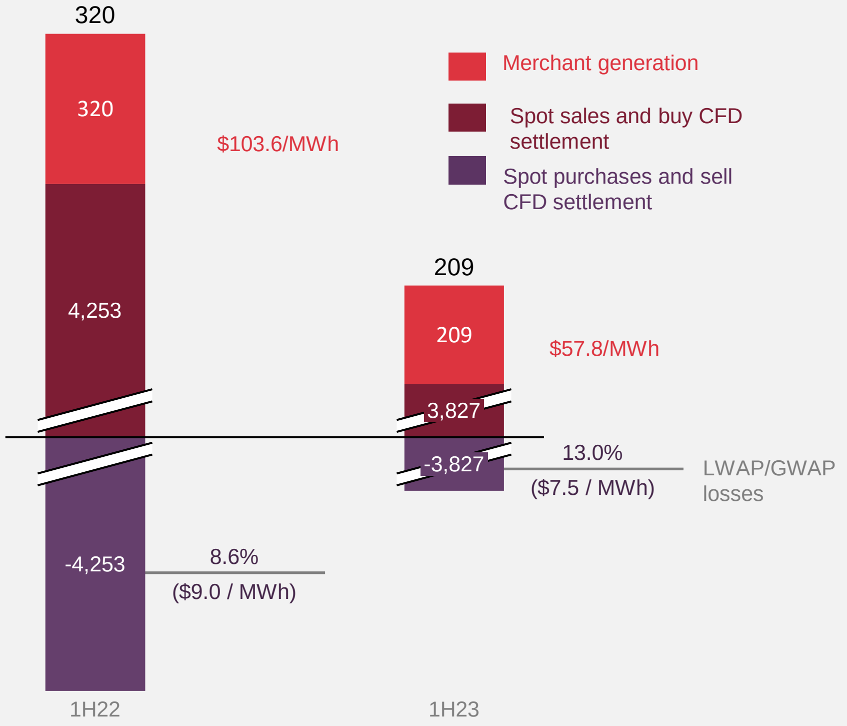


Trading revenue

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)



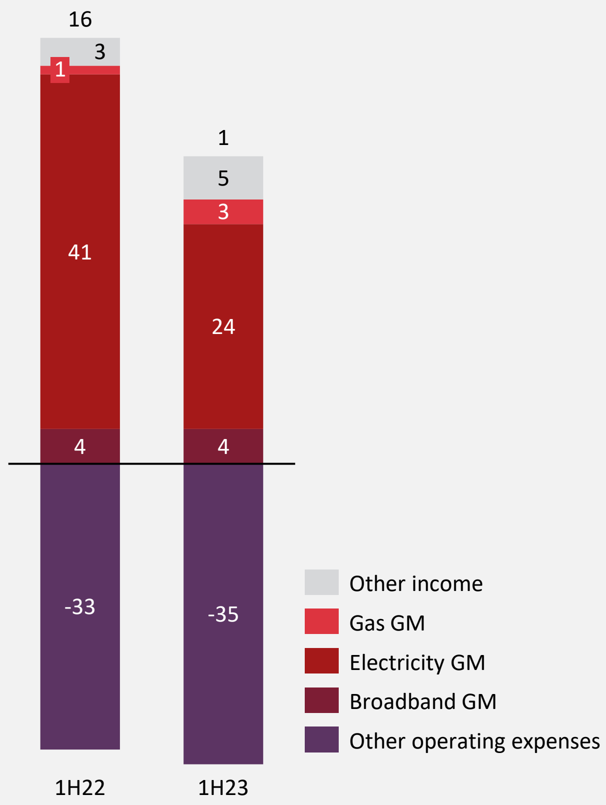
- Rainfall events throughout the half significantly reduced market price vs. 1H22 with average spot price down 46%. Critically, events were nationwide vs 1H22 which was biased to Clutha catchment.
- This lead to significant retraction in hydro and thermal volumes generated (-452 GWh) and corresponding reduction in merchant generation volumes (-110 GWh) and short order CFD channels (-426 GWh).
- Softer market prices reduced LWAP / GWAP cost in absolute terms.

Retail business performance

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

Revenue & Tariff[1] ($m)	1H22	1H23		Variance	
	$m	$m	*Tariff[1]*	$m	*Tariff*
Electricity gross revenue	450	486	*260*	36	*11*
PPD[2] not taken	2	1		(1)	
Incentives paid	(3)	(3)		(0)	
Net revenue (cash)	**449**	**484**	***259***	**35**	***10***
Capitalised incentives	3	1			
Amortised incentives	(4)	(2)			
Net revenue (P&L)	**448**	**483**	***259***	**35**	***10***
Gas revenue	43	48	*32*	5	*5*
Broadband revenue	25	32	*70*	7	*(1)*
Other income	3	5		2	
Total revenue	**519**	**568**		**49**	
Contract Asset (closing)	6	6		(0)	
# of connections (closing)	552k	571k		20k	
Cost to serve/connection (6mths)	$62	$61		($1)	

EBITDAF ($m)



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

- Retail EBITDAF decreased by $15m on 1H22 as a $36m increase in electricity costs was not fully passed through to customers.

Continued to smooth the impact of higher electricity costs for customers and target average increases below general inflation:

- Electricity net price at ICP improved by 6% from 1H22 with targeted retail price rises partially offset by increased network and meter costs.
- Around 79% of customers received a price increase in the last 12 months.
- Retail energy tariffs will need to rise to reflect higher wholesale electricity, gas & carbon costs since 2018.

Connection growth slowed in the half given increased focus on multiproduct connections and value.

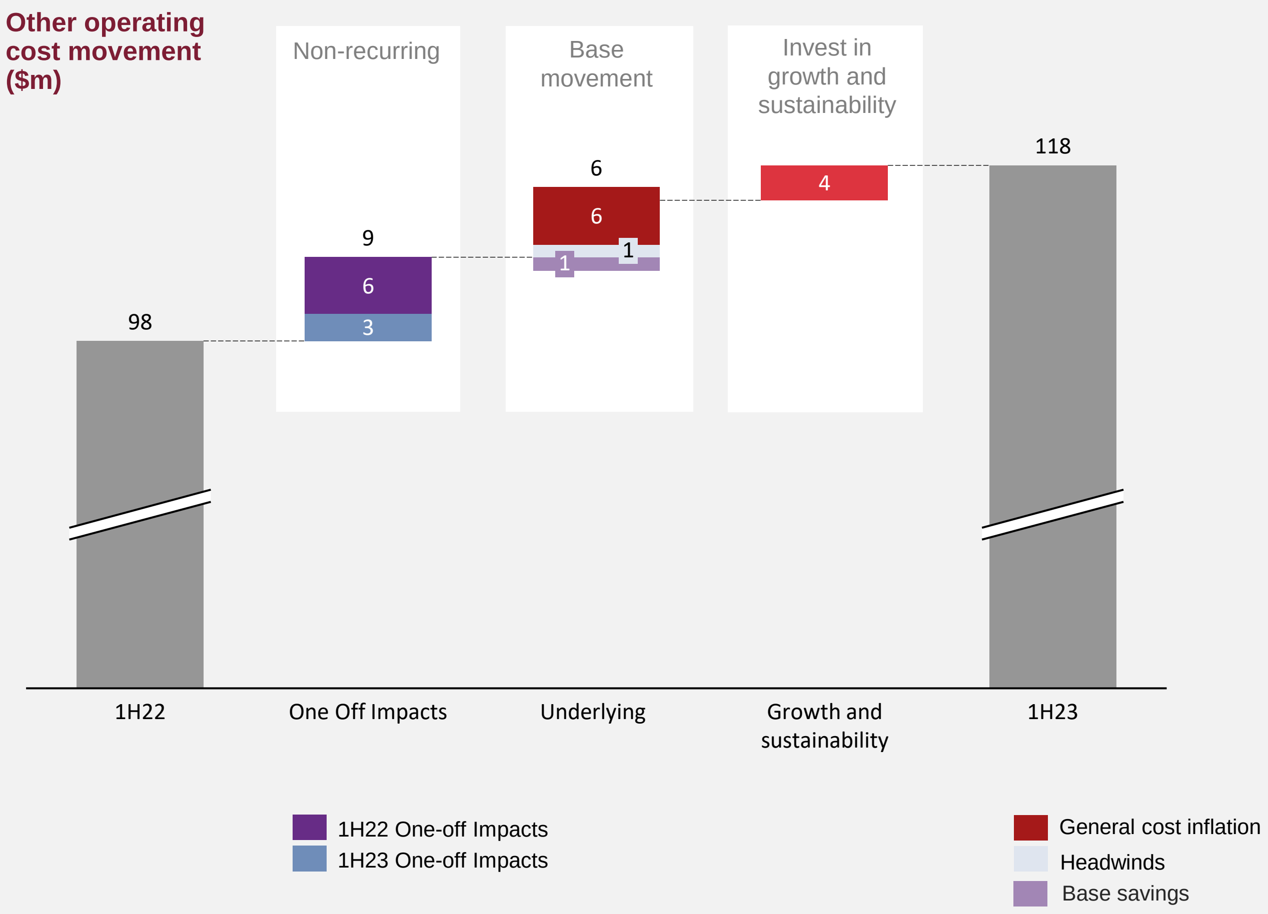
- Total connections still +20k on 1H22 primarily through continued growth in broadband.
- Multiproduct customers up 13% on 1H22, including through new products with launch of fixed wireless.

Cost to serve – digitised interactions continue to grow driving improvements in cost to serve per connection (down $1/connection on 1H22) and customer experience (NPS +6 points on 1H22).

[1]Tariff is $/MWh for electricity, $/GJ for gas and $ per month per customer connection for broadband
[2] Prompt Payment Discount

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

Operating costs up on investments in growth strategy and cost pressures



Non-recurring

- Holidays Act provision released in 1H22 post successful Metro Glass appeal, partially offset by accounting adjustments related to software as a service (SaaS), write down of thermal development costs.
- 1H23 one-off impacts represent strategic execution programme set up costs, Contact's share of BCG industry report, cost of retaining Te Rapa employees until plant closure and one-off back pay of new parental leave policy (Grow Your Whanau).

Base movement

- General inflation of 5-7% impacting operating costs. These have been seen across the business, including labour cost.
- Headwinds include increase in travel expenditure in a post-Covid environment.
- Base savings include productivity savings and shift in focus from prior BAU activity to growth initiatives.

Growth and sustainability

- $1m incremental investment related to retail connection growth.
- Operating costs to deliver on strategic growth priorities including;
  - Ongoing costs of transformation.
  - Increase in renewable development (decarbonisation demand growth, wind and solar) which flows through operating expenditure in early stages.
  - ESG and compliance opex investments to increase capability, furthering ESG outcomes.
- Targeted leadership development training and costs associated with "Grow your Whanau" policy implementation.

Cash flow and capital expenditure

Cash conversion for 1H23 impacted by higher tax paid, SIB capex and an increase in gas and carbon inventory

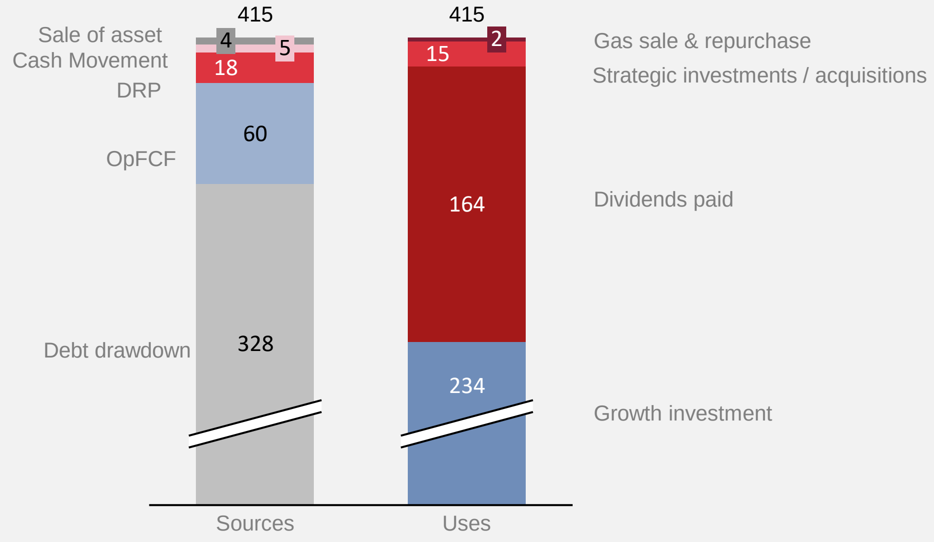
	6 months ended 31 Dec 2022	6 months ended 31 Dec 2021	Comparison against 1H22	
EBITDAF (underlying[1])	**$246m**	$322m	↓	($76m)
Working capital changes	**($43m)**	($69m)	↑	$26m
Tax paid	**($76m)**	($65m)	↓	($11m)
Interest paid, net of interest capitalised	**($12m)**	($15m)	↑	$3m
SIB capital expenditure	**($55m)**	($35m)	↓	($20m)
Non-cash items included in EBITDAF	**-**	($7m)	↓	$7m
Operating free cash flow (OpFCF)	**$60m**	$131m	↓	($71m)
Operating free cash flow per share	**7.7 c**	16.8 c	↓	(9.1c)
Cash conversion (OpFCF / EBITDAF)	**24%**	41%	↓	(17%)

[1] Underlying EBITDAF is shown excluding a $120 million onerous contract provision for AGS.

Commentary

- Lower EBITDAF on soft short-term wholesale market conditions.
- Working capital increase of $43m in 1H23. This relates to higher levels of gas and carbon inventory following lower thermal generation in 1H23. This is expected to reverse as more thermal generation is required over winter.
- Tax paid is up $11m on higher provisional tax payments based on strong FY21 earnings.
- Stay-in-business capital expenditure (cash) increase of $20m is linked to accelerated spending identified to support higher asset availability and output as well as an SAP systems upgrade project.

Sources and uses of cash ($m)

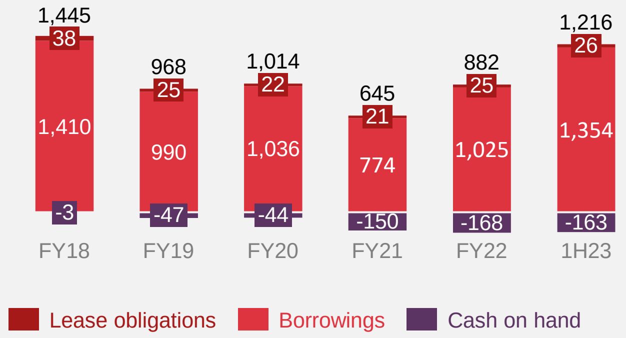


Strong balance sheet

A green and sustainably-linked debt portfolio aligned to our Contact26 strategy

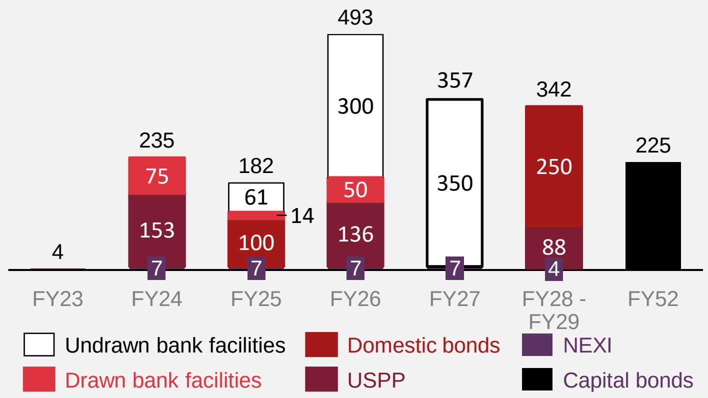
Closing net debt ($m)

Face value of borrowings less cash



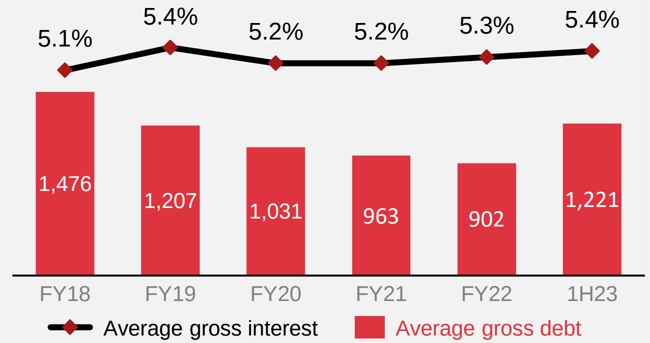
Borrowing maturities ($m)

Average tenor of 6.4 years as at 31 December 2023



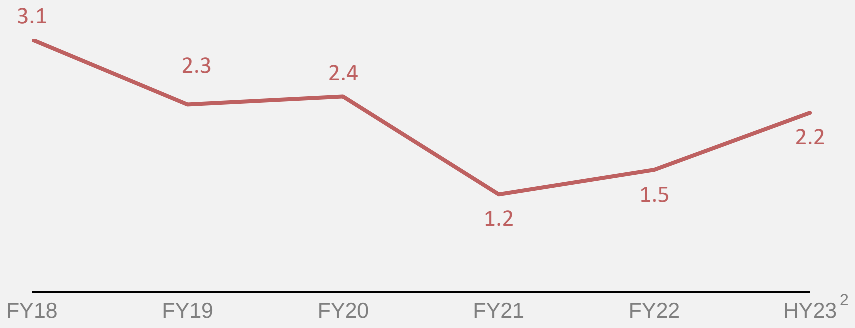
Interest rate (%)

Weighted average gross interest[1] on average borrowings



Net debt to EBITDAF (x)

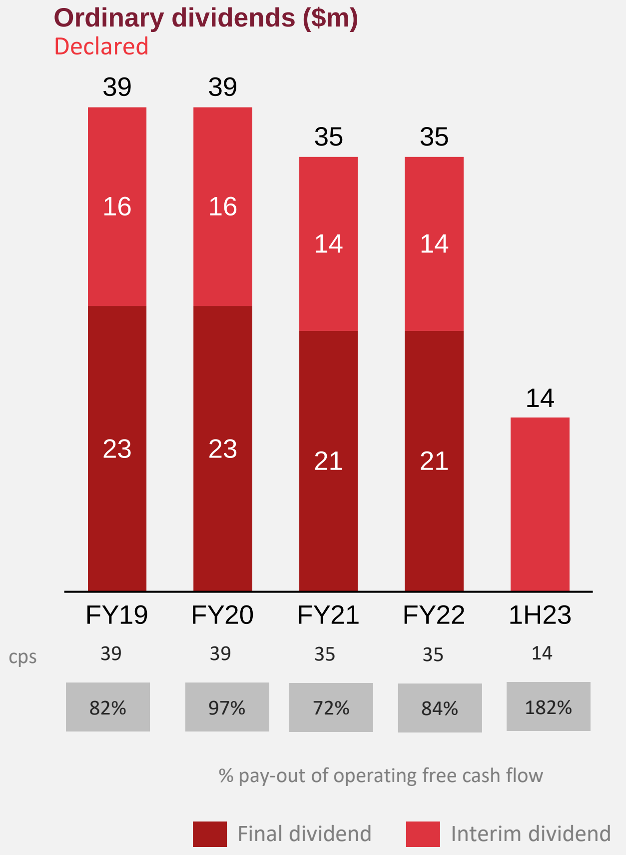
Includes S&P adjustments (prior to FY20, AGS was treated as a lease)



- Face value of borrowings (excl. leases) increased by $329m to $1,354m from 30 June 2022. This increase in debt levels is due to the construction of the Te Huka and Tauhara geothermal power stations.
- Additional funding activity will be undertaken in 2H23 to finance these ongoing construction projects.
- Bank facilities have been increased to allow greater use of the low-cost CP program without introducing any refinancing risk and provides additional capacity to cover prudential requirements for ASX trades.
- The bank facilities are all sustainably linked and have been updated to align with the Contact26 strategy to lead the decarbonisation of New Zealand.
- Gearing increased to 30% at 31 December 2022, up from 23.5% at 30 June 2022.
- The increased debt levels combined with higher floating interest rates have resulted in a slightly higher average interest rate on gross debt.

1. Gross interest includes all interest on borrowings, bank commitment fees and deferred financing costs. Unwind of leases, provisions and capitalised interest not included.
2. Based on a normalised and expected EBITDAF of $550m.

Dividend for 1H23



Interim dividend for 1H23 of 14 cents per share

- Interim dividend of 14 cents per share is imputed to 86% or 12 cents per share for qualifying shareholders.
- Record date of 10 March 2023; payment date of 30 March 2023.
- The NZD/AUD exchange rate used for the payment of Australian dollar dividends will be set on 21 March 2023.

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.
- For this dividend, there will be no discount offered and Contact will have the right to terminate or suspend the plan at any time.
- Dividend reinvestment plan application forms must be in by 13 March 2023 to confirm participation in the plan.
- Trading period for setting price for DRP is 9 March 2023 to 15 March 2023. DRP strike price will be announced: 16 March 2023

Channel yields suggest an increase in normalised EBITDAF

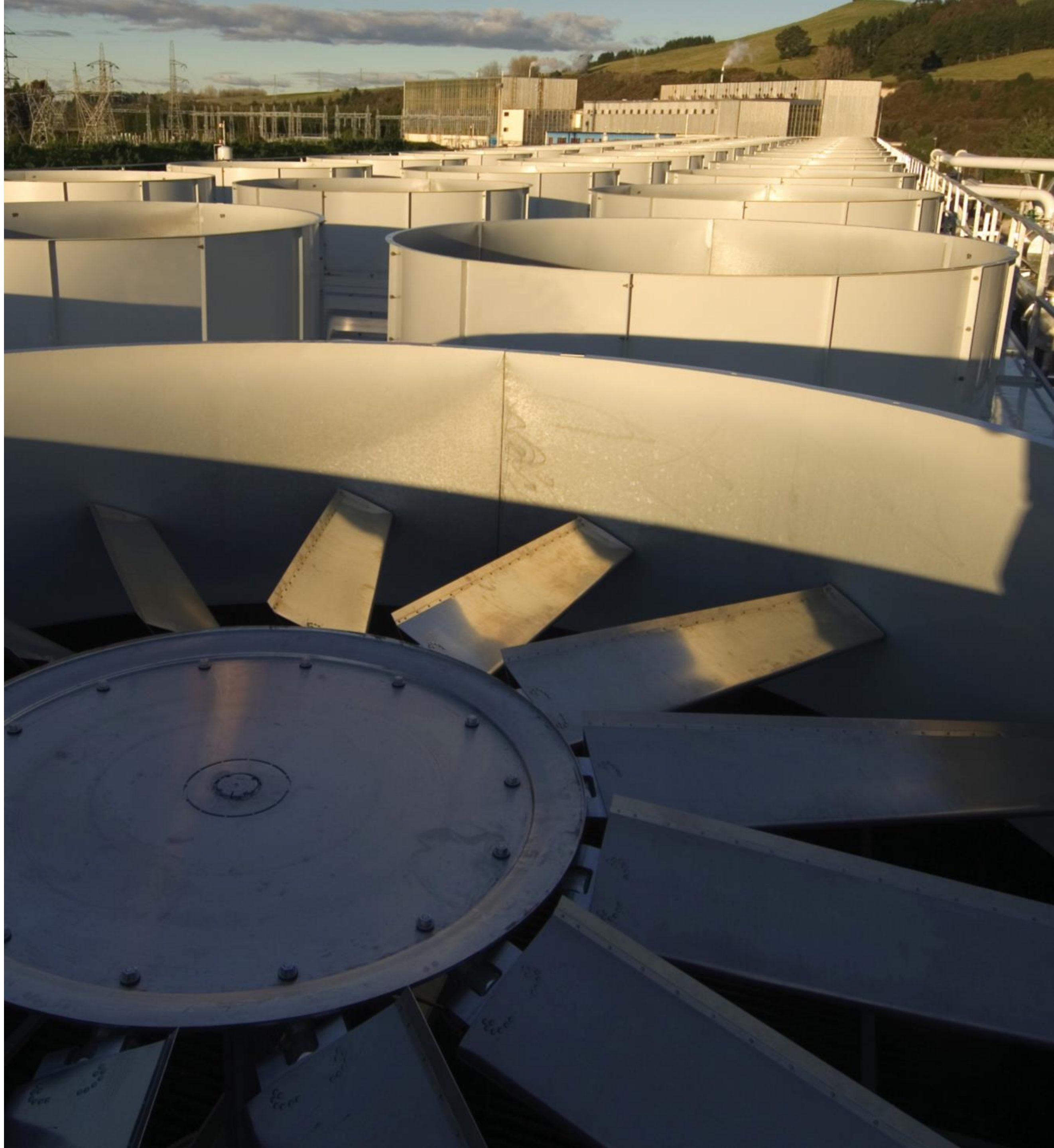
Expect partial recovery of 1H impacts with sustainable pricing changes

¹ See slide 40 for assumptions underpinning FY23 normalised and expected earnings

Guidance confirmation

	Updated FY23 guidance	1H23 result	Change to prior guidance	
Stay in business capital expenditure (cash)	$110 - 120m	$55m	+$22m	Sustainable SIB capex remains $65m p.a. An additional $100m SIB capex above this level is expected between FY22-27 to support higher asset availability and output as well as the SAP system upgrade. The increase in guidance reflects pull-forward elements of this programme and $6m capital costs for the Wairkei reconsenting mitigation agreements in the FY.
Growth capital expenditure (cash)	$465 – 565m	$217m	-	
Depreciation and amortisation	$220 – 230m	$111m	($10m)	
Net interest (accounting)	$35 – 45m	$19m	+$5m	Adjusted for unwind of onerous contract provision and higher floating interest rates.
Cash interest (in operating cash flow)	$20 – 30m	$12m	+$10m	Timing of interest payments with updated debt facilities and higher floating interest rates.
Cash taxation	$110 – 120m	$76m (2/3rd of payments in 1H23)	-	
Corporate costs	$42m	$22m	-	
Target ordinary dividend per share	35 cps (40%/60%)	14 cps (interim)	-	

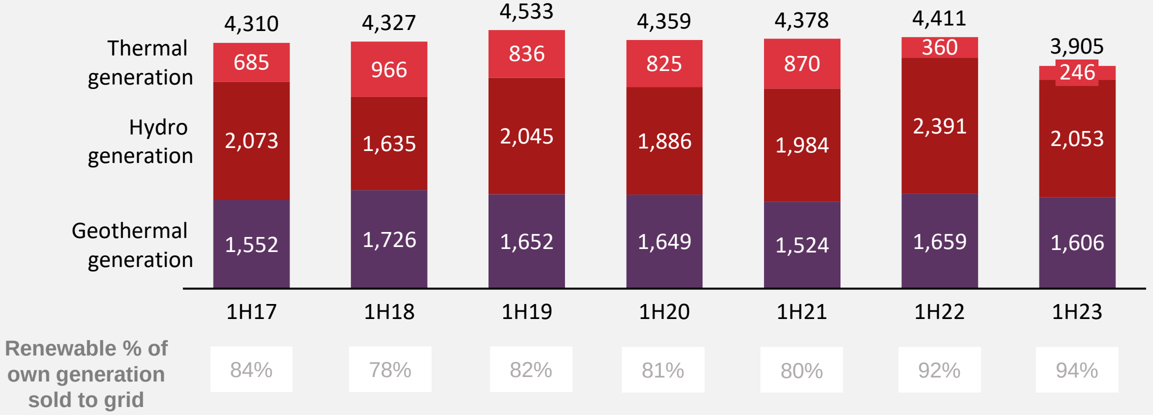
Questions



Supporting materials

Generation and sales position

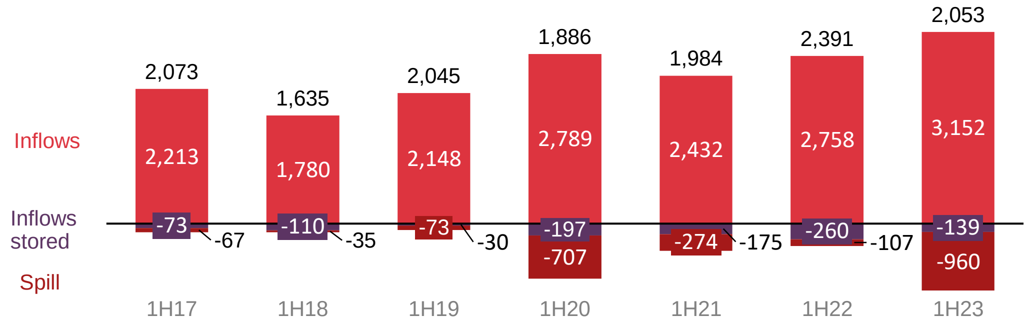
Contact generation output sold to the national grid (GWh)



Thermal generation volumes were 114GWh lower than 1H22 as a result of the strong renewable generation and low wholesale prices

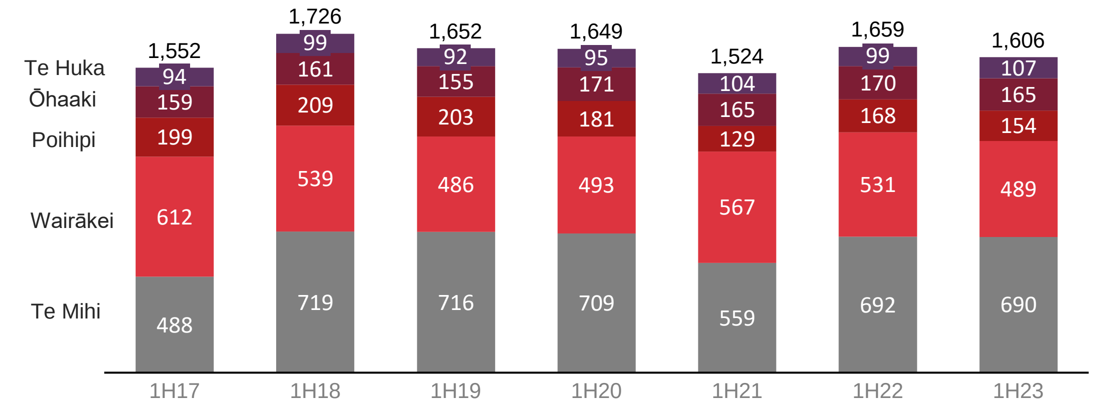
Hydro generation (GWh)

Inflows stored include uncontrolled storage lakes



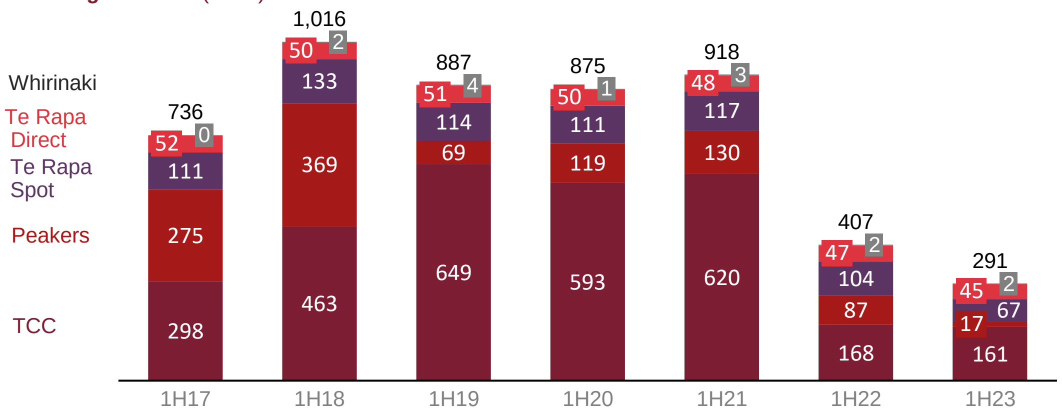
The large spill in 1H23 was a result of strong hydrology inflows coming in three main rain events coupled with some longer outages which effected our ability to generate

Geothermal generation (GWh)



Geothermal generation was 53GWh lower than 1H22 primarily as result of a Wairākei station statutory inspection (once every 5 years)

Thermal generation (GWh)

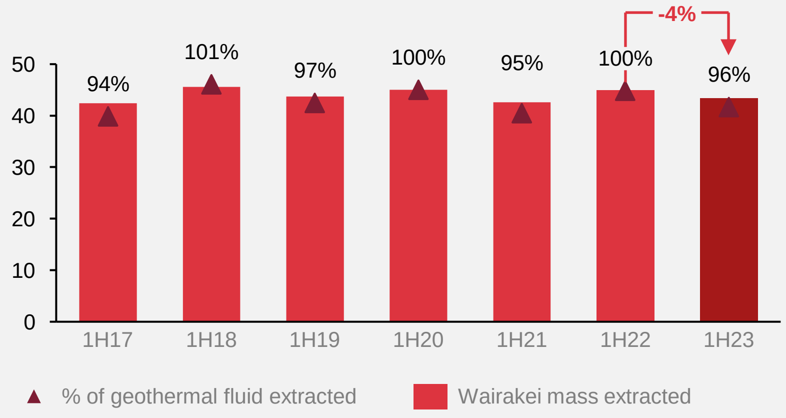


Thermal generation volumes were 115GWh lower than 1H22 as a result of the strong renewable generation and low wholesale prices

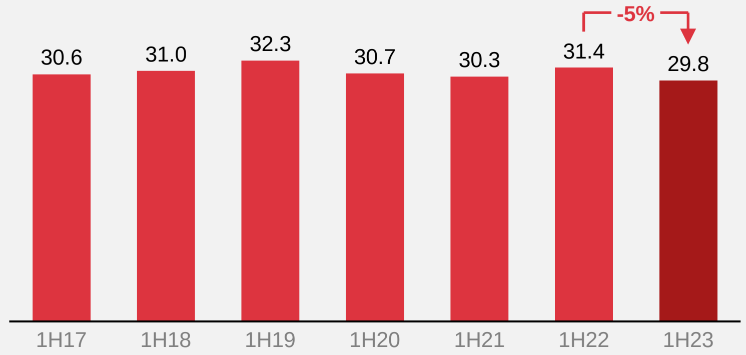
Plant and fuel performance

Geothermal fuel performance

Geothermal fuel extracted at Wairākei vs consented (GWh)



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)
1H19	784	95%	59%	2,045	129	265
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

Taranaki combined cycle (TCC)

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
1H19	377	63%	39%	649	119	78
1H20	377	78%	36%	593	113	67
1H21	377	96%	37%	620	127	79
1H22	377	100%	10%	167	183	31
1H23	377	89%	10%	161	107	17

Te Rapa (spot generation only)

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
1H19	41	98%	63%	114	161	18
1H20	41	100%	61%	111	116	13
1H21	41	99%	65%	117	122	14
1H22	41	100%	57%	104	108	11
1H23	41	95%	34%	67	55	4

Geothermal

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
1H19	425	91%	88%	1,652	137	226
1H20	425	94%	88%	1,649	106	175
1H21	425	86%	81%	1,524	118	180
1H22	410	96%	92%	1,660	105	175
1H23	410	94%	89%	1,606	56	89

Stratford Peakers

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
1H19	202	65%	8%	69	214	15
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

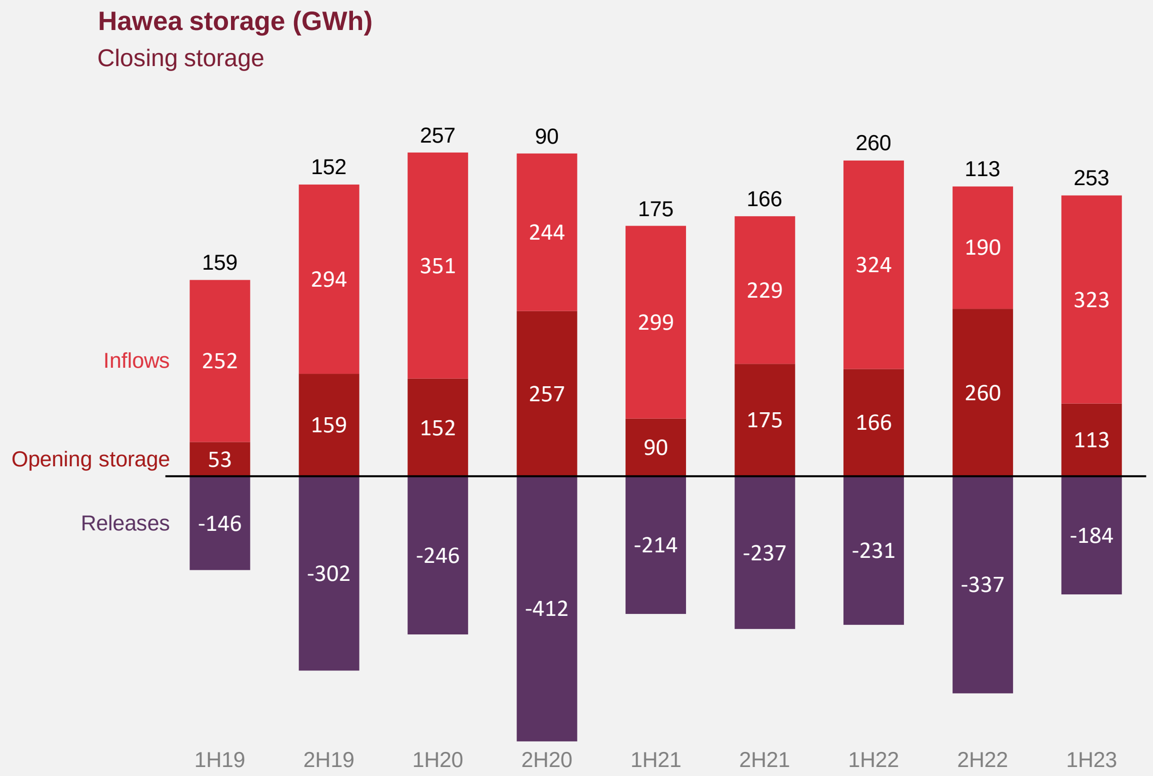
Whirinaki

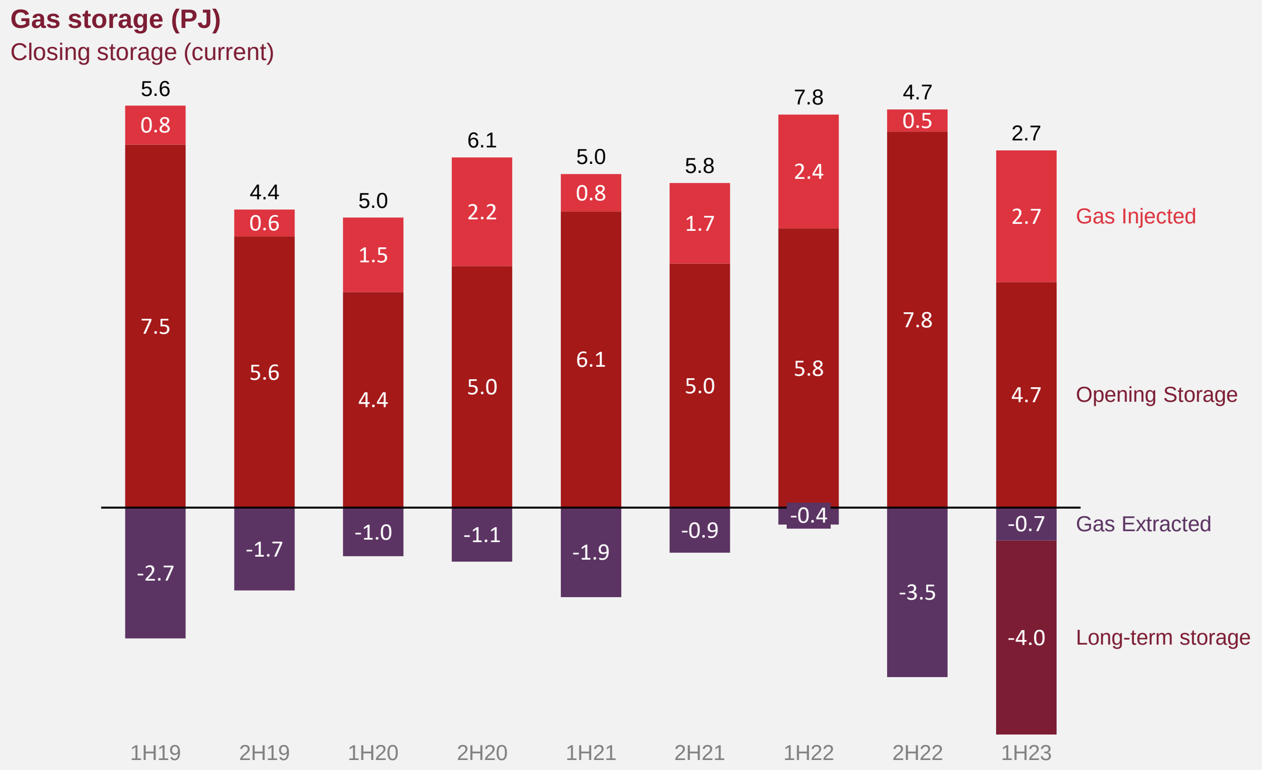
	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
1H19	158	98%	1%	4	519	2.1
1H20	158	97%	0%	1	269	0.4
1H21	158	91%	0%	3	305	0.8
1H22	158	98%	0%	2	783	1.8
1H23	158	97%	0%	2	274	0.4

Availability Factor calculation includes all station outages (Planned, Maintenance, Forced) but does not consider plant deratings.

Operational data

Fuel storage movements





Transferred to long-term storage (PJ)	1H19	2H19	1H20	2H20	1H21	2H21	1H22	2H22	1H23
	0	0	0	0	0	0	0	0	4

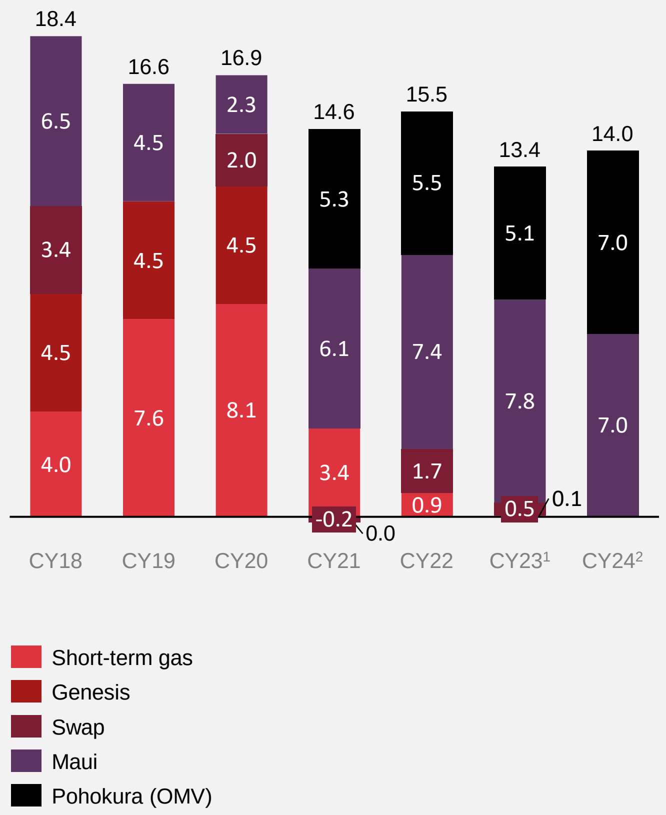
Following the completion of a joint technical working group, set up by Contact and the Ahuroa Gas Storage Facility (AGS) owner FlexGas in 2022, Contact advised the market in December 2022 that approximately 4PJs of gas owned by Contact and currently stored in AGS may only be available for extraction at the end of the contract in 2033. Excluding this volume, the estimated storage capacity of the facility is ~6-8PJ (P-50). Contact has several mitigations available to limit the impact for winter 2023, including entering flexible gas contracting arrangements and if necessary, acquiring additional gas.

Source: NZX hydro

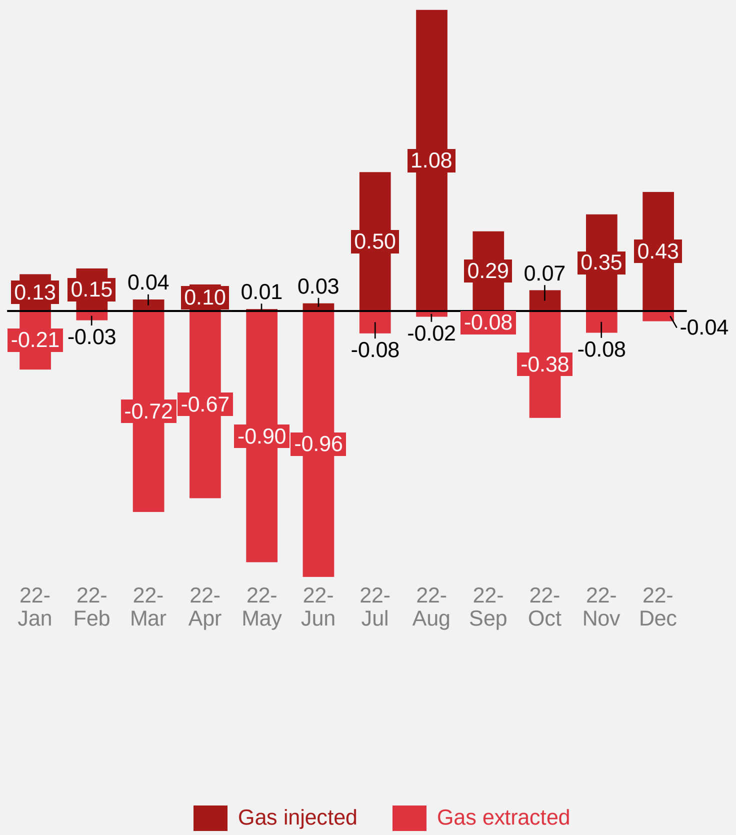
Operational data

Contracted and stored gas

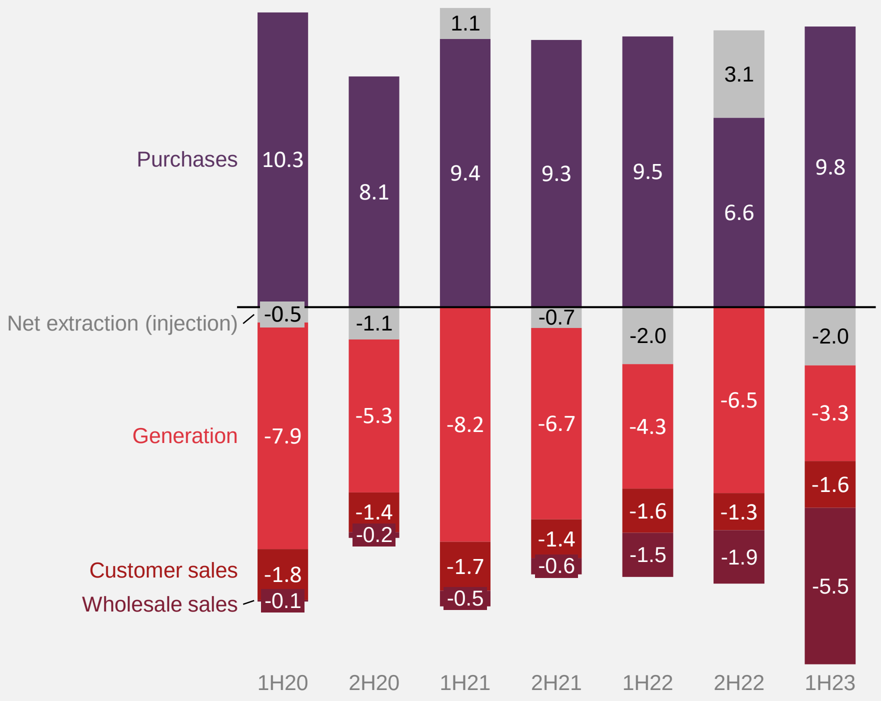
Contracted gas volumes (PJ)



Gas storage monthly injections and extractions (PJ)



Uses of gas (PJ)

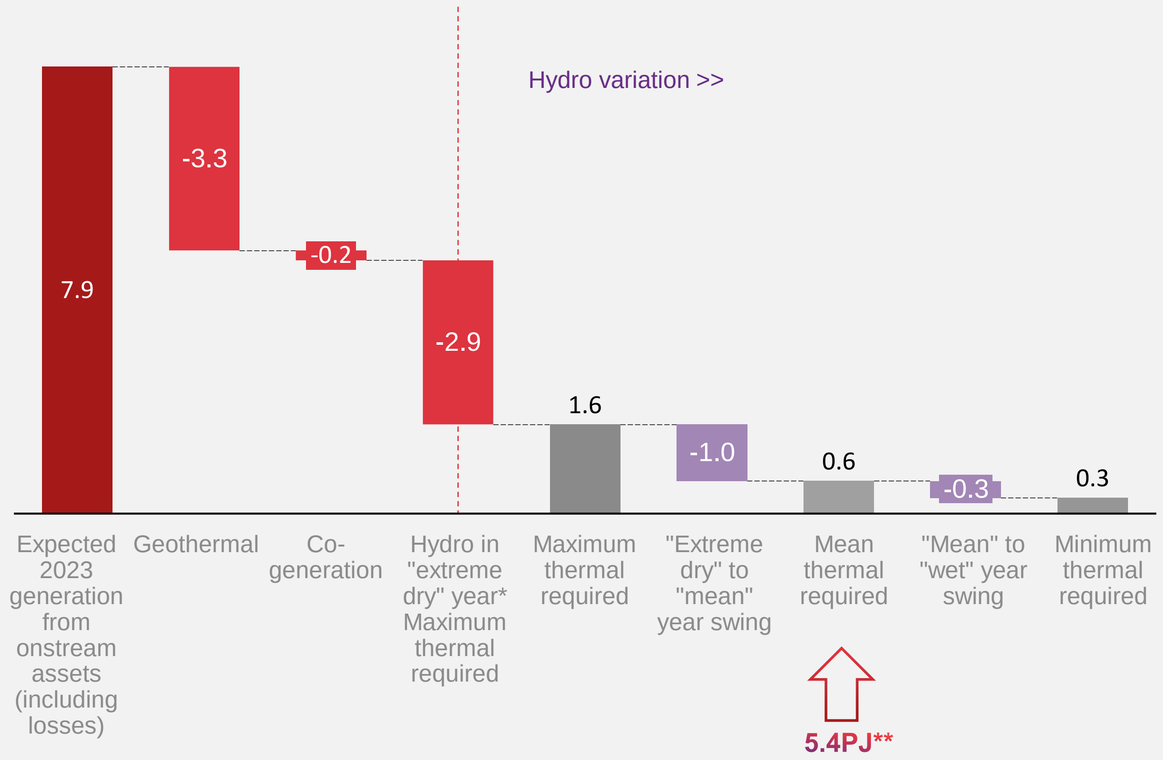


[1] Maui and Pohokura volumes for CY23 reflect forecast volumes. Contracted volumes in the period are: Maui 10PJ and Pohokura 7PJ.
[2] No forecast available at this time for CY24. Contracted amounts shown.

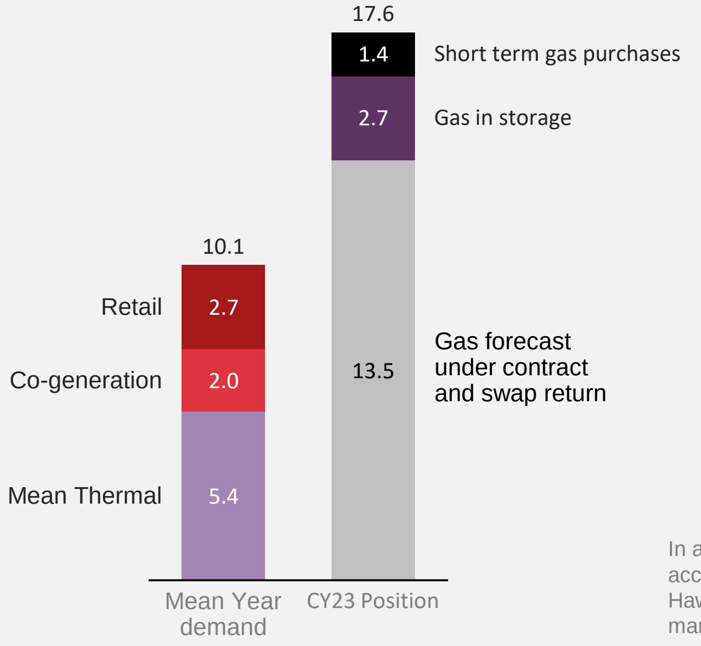
Storage balance at 31 December 2022 was 6.7PJs, of which 2.7PG is immediately accessible

Contractual fuel position sufficient to support expected sales position

Portfolio requirements for thermal generation (TWh)



Gas supply and demand 2023 (PJ)



In addition, Contact has access to stored water in Hawea to support risk management

- Hydro generation in FY12

** Assumes mix of TCC and peaker generation (portfolio heat rate (9GJ/MWh))

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 2022		6 months ended 31 December 2021	Variance on prior year	
				$m	%
	Underlying	Reported	Reported	Against underlying	
Profit	**79**	**(7)**	**134**	**(55)**	**(41%)**
Depreciation and amortisation	111		129	18	14%
Change in fair value of financial instruments	6		(13)	(19)	(146%)
Net interest expense	19		19	0	0%
Tax expense	32	(2)	53	21	40%
EBITDAF	**246**	**126**	**322**	**(76)**	**(24%)**

Depreciation and amortisation, change in fair value of financial instruments, net interest and tax expense are explained on the right.

The adjustments from EBITDAF to reported profit and movements on 1H22 are as follows:

- **Depreciation and amortisation:** decreased by $18m (14%) on 1H22 primarily resulting from acceleration of depreciation for aspects of SAP due to SAP upgrade project in 1H22.
- **Net interest expense:** In line with 1H22 with higher average borrowings being offset by higher capitalisation of interest relating to the Tauhara and Te Huka projects.
- **Tax expense** for the period decreasing by $21m following lower operating earnings.

Underlying EBITDAF and profit are shown excluding a $120 million onerous contract provision ($86 million after tax) for AGS. All variances and commentary reflect movements in underlying performance.

Historical financial information

	Unit	1H18	1H19	1H20	1H21	1H22	1H23	
							Underlying[1]	Reported
Revenue	$m	1,190	1,363	1,110	1,141	1,141	994	
Expenses	$m	954	1,072	889	895	819	748	868
EBITDAF	$m	236	291	221	246	322	246	126
Profit	$m	58	276	59	78	134	79	(7)
Operating free cash flow	$m	141	203	120	157	131	60	
Operating free cash flow per share	cps	19.7	28.3	16.8	21.9	16.8	7.7	
Dividends declared	cps	13.0	16.0	16.0	14.0	14.0	14.0	
Total assets	$m	5,390	5,140	4,850	4,738	4,978	5,408	
Total liabilities	$m	2,663	2,297	2,170	2,212	2,027	2,748	
Total equity	$m	2,727	2,843	2,680	2,526	2,951	2,660	
Gearing ratio[2]	%	35.4	29.7	29.9	31.1	19.3	30.6	

[1] Underlying expenses, EBITDAF and profit are shown excluding a $120 million onerous contract provision ($86 million after tax) for AGS.
[2] Gearing ratio is calculated as: Senior debt - including finance lease liabilities/(Senior debt - including finance lease liabilities + Equity).

Wholesale segment

Note: this table has not been rounded and might not add	1H23 Six months ended 31 December 2022 Volume GWh	GWAP $/MWh	$m	1H22 Six months ended 31 December 2021 Volume GWh	GWAP $/MWh	$m
Electricity sales to Retail segment	**1,988**	**121.0**	**240.6**	**1,928**	**103.1**	**198.7**
Electricity sales to C&I (netback)	781	112.3	87.8	671	81.7	54.8
Electricity sales – Direct	45	165.4	7.5	47	132.7	6.2
Electricity sales to C&I	**826**	**115.2**	**95.2**	**718**	**85.0**	**61.0**
CfDs – Tiwai support	486	35.0	17.0	397	35.0	13.9
CfDs - Long term sales	210	116.4	24.4	264	102.1	26.9
CfDs - Short term sales	361	102.4	37.0	993	149.4	148.4
Electricity sales – CFDs	**1,057**	**74.2**	**78.4**	**1,654**	**114.4**	**189.2**
Total contracted electricity sales	**3,872**	**107.0**	**414.2**	**4,300**	**104.4**	**448.9**
Steam sales	**336**	**55.4**	**18.6**	**361**	**51.8**	**18.7**
Other income			(15.2)			0.9
Net income on gas sales			1.2			1.2
Net income on electricity related services			3.3			(0.9)
Net other income			**(10.7)**			**1.2**
Total contracted revenue	**4,208**	**100.3**	**422.2**	**4,661**	**100.6**	**468.9**
Generation costs[1]	3,950	(30.8)	(121.8)	4,458	(27.8)	(123.8)
Acquired generation cost	131	(122.5)	(16.1)	162	(153.7)	(24.9)
Generation costs (including acquired generation)	**4,081**	**(33.8)**	**(137.9)**	**4,620**	**(32.2)**	**(148.7)**
Spot electricity revenue	3,905	57.6	225.1	4,411	102.7	453.1
Settlement on acquired generation	131	62.7	8.2	162	128.4	20.8
Spot revenue and settlement on acquired generation (GWAP)	**4,036**	**57.8**	**233.3**	**4,573**	**103.6**	**473.9**
Spot electricity cost	(2,770)	(69.8)	(193.4)	(2,599)	(117.3)	(305.0)
Settlement on CFDs sold	(1,057)	(53.6)	(56.7)	(1,654)	(105.2)	(173.9)
Spot purchases and settlement on CFDs sold (LWAP)	**(3,827)**	**(65.3)**	**(250.0)**	**(4,253)**	**(112.6)**	**(478.9)**
Trading, merchant revenue and losses			**(16.7)**			**(4.9)**
Wholesale EBITDAF underlying[1]			**267.6**			**315.2**
Onerous contract provision			(120.0)			
Wholesale EBITDAF reported			**147.6**			**315.2**

[1] Generation costs and wholesale EBITDAF underlying are shown excluding a $120 million onerous contract provision ($86 million after tax) for AGS.

Retail segment

Residential electricity	unit	1H20	1H21	1H22	1H23
Average connections	#	355,216	357,756	367,199	381,222
Sales volumes	GWh	1,328	1,349	1,408	1,445
Average usage	MWh per ICP	3.7	3.8	3.8	3.8
Tariff	$/MWh	248.2	251.1	251.5	261.4
Network, meters and levies	$/MWh	-122.5	-116.2	-115.9	-118.2
Energy costs	$/MWh	-91.6	-101.1	-110.8	-128.7
Gross margin	**$/MWh**	**34.1**	**33.8**	**24.8**	**14.5**
Gross margin	$ per ICP	141	127	95	55
Gross margin	$m	50	45	35	21

Residential gas	unit	1H20	1H21	1H22	1H23
Average connections	#	61,959	60,563	63,182	66,796
Sales volumes	TJ	911	954	970	881
Average usage	GJ per ICP	14.7	15.7	15.4	13.2
Tariff	$/GJ	30.6	31.3	32.6	38.1
Network, meters and levies	$/GJ	-17.3	-15.3	-16.2	-20.7
Energy costs	$/GJ	-7.6	-8.3	-11.3	-10.2
Carbon costs	$/GJ	-1.4	-1.4	-2	-4.2
Gross margin	**$/GJ**	**4.3**	**6.3**	**3.2**	**3.0**
Gross margin	$ per ICP	70	99	50	39
Gross margin	$m	4	6	3	3

SME electricity	unit	1H20	1H21	1H22	1H23
Average connections	#	55,295	51,407	48,323	47,702
Sales volumes	GWh	533	465	392	421
Average usage	MWh per ICP	9.6	9.0	8.1	8.8
Tariff	$/MWh	226.7	230.7	239.0	249.2
Network, meters and levies	$/MWh	-113.5	-104.4	-113.0	-113.0
Energy costs	$/MWh	-89.3	-99.7	-109.0	-129.8
Gross margin	**$/MWh**	**23.9**	**26.5**	**17.0**	**6.4**
Gross margin	$ per ICP	242	240	138	56
Gross margin	$m	13	12	7	3

SME gas	unit	1H20	1H21	1H22	1H23
Average connections	#	3,991	3,858	3,918	3,656
Sales volumes	TJ	845	720	628	635
Average usage	GJ per ICP	211.8	186.7	160.4	173.6
Tariff	$/GJ	14.9	15.8	18.6	23.1
Network, meters and levies	$/GJ	-5.4	-7.9	-8.7	-8.4
Energy costs	$/GJ	-7.6	-8.3	-11.3	-10.2
Carbon costs	$/GJ	-1.4	-1.4	-2.0	-4.2
Gross margin	**$/GJ**	**0.5**	**-1.8**	**-3.3**	0.3
Gross margin	$ per ICP	97	-474	-532	54
Gross margin	$m	0	-2	-3	0.2

Broadband	unit	1H20	1H21	1H22	1H23
Average connections	#	17,038	33,197	57,498	74,974
Tariff	$/cust/mth	70.7	65.2	71.8	70.4
Network, provisioning, modems	$/cust/mth	-68.9	-74.0	-61.6	-62.8
Gross margin	$/cust/mth	**1.8**	**-8.8**	**10.2**	**7.6**
Gross margin	$m	0	-2	4	4

Retail segment EBITDAF		1H20	1H21	1H22	1H23
Electricity Gross margin	$m	58	58	41	24
Gas Gross Margin	$m	4	5	1	3
Broadband Gross Margin	$m	0	-2	4	4
Total Gross Margin	**$m**	**62**	**61**	**46**	**31**
Other income	$m	2	3	3	5
Other operating costs	$m	-35	-33	-33	-35
Retail segment EBITDAF	**$m**	**30**	**30**	**16**	**1**
Corporate allocation (50%)	$m	-7	-7	-5	-11
Retail EBITDAF	**$m**	**23**	**23**	**11**	**-10**
EBITDAF margins (% of revenue)	%	4.70%	4.60%	2.10%	-1.80%

During 1H23 metering costs of $6m, which were previously in operating costs to serve were reclassified into networks meters and levies (COGS) to better reflect the nature of the costs. Comparisons have been restated.
From FY22 onwards, ICT costs previously included within operating costs for the retail business have been moved to corporate (prior years have not been restated).

Normalised and expected EBITDAF assumptions

With reconciliation to actual performance

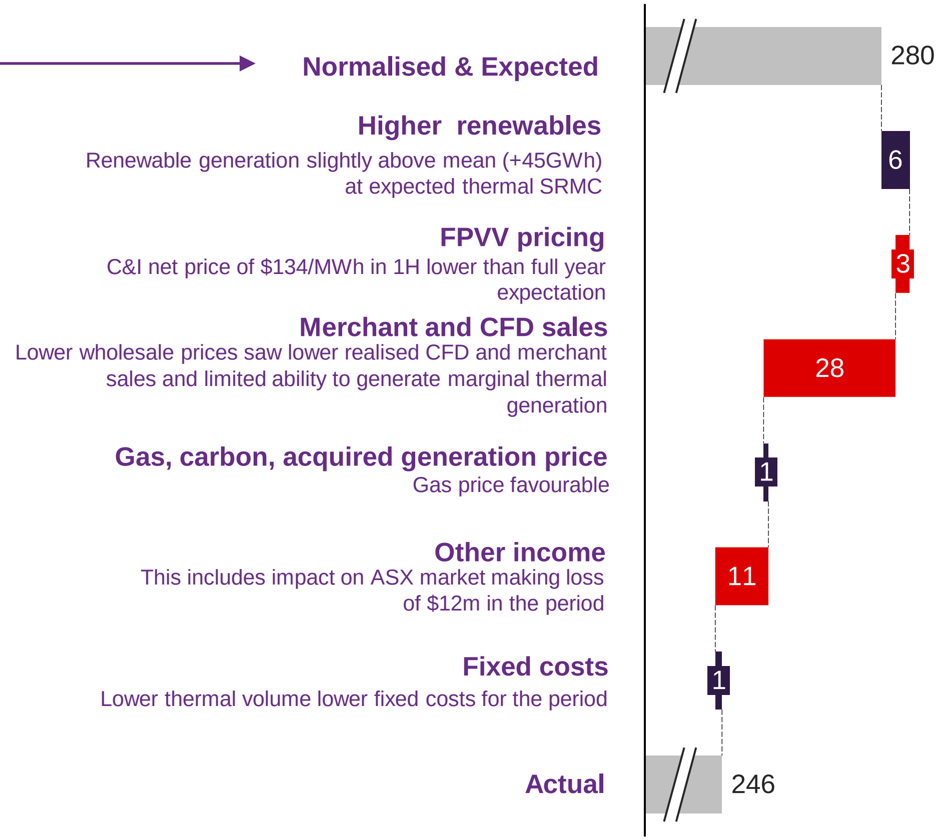
1H23 assumptions that deliver expected & normalised EBITDAF of $550m over a financial year

1 Channel choices maximise long term value[1]		X	2 Net price[2] driven by best commercial practices	=	Total
Strategic fixed price	725GWh	x	$54/MWh	=	$39m
CFDs	640GWh	x	$135/MWh	=	$86m
C&I	600GWh	x	$140/MWh	=	$84m
Retail	2,000GWh	x	$132/MWh		$264m
Other income[3]					$34m
					$507m

3 Hydrology & Asset availability optimise generation		X	4 Access to and price of fuel* drives financials & risk position	=	Total
Hydro	1,989GWh	x	$0/MWh	=	-$0m
Geothermal	1,625GWh	x	$3/MWh	=	-$5m
Thermal[4]	525GWh	x	$122/MWh	=	-$64m
Acquired	67GWh	x	$150/MWh	=	-$10m
					-$79m

5 Trading delivers value to more than offset locational losses		6 Digitalisation & continuous improvement optimise fixed costs	
Length[5]	$40m	Transmission/Storage	-$30m
Location losses[6]	-$40m	Operating expenses	-$118m
Total	**$0m**	**Total**	**-$148m**

EBITDAF reconciliation to 1H23



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 $7.9/GJ, carbon price of $50/unit and thermal portfolio heat rate (11.2GJ/MWh)
5. Length of 241GWh for 1H23 assumed
6. Locational losses of 6.7% on spot purchases and settlement of CFDs sold at a wholesale price of $150/MWh

* Fuel is natural gas and carbon costs

Onerous contract provision for AGS

Contact has recognised an onerous contract provision of $120m ($86m after tax) in 1H23, reflecting the modelled reduction in gas storage capacity at AGS

Onerous contract treatment for AGS:

- A non-cash accounting adjustment that recognises the difference between the expected benefits received and the contracted schedule of payments. The difference is discounted at the risk-free rate to determine the size of the provision.
- These schedules (RHS) show the current modelled impacts to EBITDAF and profit and loss before tax over the life of the contract.
- Accounting standards require that the provision is tested for potential restatement in each reporting period.
- This detail is being provided as a one-time illustration i.e. will not be published every reporting period.

Key assumptions:

- *Storage cost:* Current annual cost (net of rebate from 3rd party usage) escalated at PPI until the end of the contract in September 2033.
- *Discount rate*: Risk free rate of 4.48% (10-year NZ government bond) has been used as the pre-tax discount rate, in line with the accounting standard.

Provision release schedule ($m)

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34
Provision open	**-120**	**-121**	**-124**	**-118**	**-115**	**-103**	**-91**	**-77**	**-61**	**-44**	**-26**	**-5**
Provision release	1	3	11	9	16	17	18	19	19	20	21	5
Interest on unwind of discount	-3	-5	-5	-5	-5	-4	-4	-3	-2	-2	-1	0
Provision close	**-121**	**-124**	**-118**	**-115**	**-103**	**-91**	**-77**	**-61**	**-44**	**-26**	**-5**	**0**

Profit and loss before tax ($m)

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34
Storage cost	-26	-28	-29	-30	-31	-32	-33	-34	-35	-36	-37	-9
Provision release	1	3	11	9	16	17	18	19	19	20	21	5
EBITDAF impact	**-25**	**-25**	**-19**	**-21**	**-15**	**-15**	**-15**	**-15**	**-15**	**-15**	**-15**	**-4**
Interest on unwind of discount	3	5	5	5	5	4	4	3	2	2	1	0
Profit and loss before tax	**-22**	**-20**	**-13**	**-16**	**-10**	**-11**	**-12**	**-12**	**-13**	**-14**	**-15**	**-4**