contact

2022 full year results presentation

Twelve months ended 30 June 2022

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Agenda

Strong performance despite volatile market conditions, investment ramps up

	Twelve months ended 30 June 2022 (FY22)	Twelve months ended 30 June 2021 (FY21)	
EBITDAF[1]	$537m	↓	3% from $553m
Profit	$182m	↓	3% from $187m
Profit per share	23.4 c	↓	8% from 25.3 c
Operating free cash flow[2]	$325m	↓	12% from $371m
Operating free cash flow per share[2]	41.8 c	↓	17% from 50.2 c
Dividend declared	$273m	↑	$272m
Dividend declared per share	35.0 c	→	35.0 c
Stay-in-business (SIB) capital expenditure (cash)	$75m	↑	23% from $61m
Growth capital expenditure (cash)	$291m	↑	283% from $76m

FY22 market

The operating conditions in FY22 were characterised by:

- Strong Clutha hydro flows in the first six months of the year, followed by dry South Island conditions in Q4 FY22.
- Lower wholesale spot prices.
- Continued increases to gas and carbon costs.
- Extreme volatility across commodity markets, driven by a combination of global energy supply and security concerns, exacerbated by the impact of the Russian invasion of Ukraine, with subsequent unprecedented increases in international energy prices including coal, gas and oil.
- Domestically, gas field declines and high coal and gas prices have contributed to a steep escalation in medium-term wholesale electricity prices.

Contact has responded to the conditions by:

- Increasing renewable generation and using the flexibility of our thermal fuel supply to manage volatile hydrology.
- Long-term offtake agreements signed.
- Investment programme to deliver on decarbonisation strategy ramping up.

Operating earnings (EBITDAF) was down by $16m when compared to FY22.

[1] Refer to slides 45 for a definition and reconciliation of EBITDAF
[2] Refer to slides 25 for a reconciliation of operating free cash flow

Contact26 Our strategy to lead NZ's decarbonisation

	Grow demand	Grow renewable development	Decarbonise our portfolio	Create outstanding customer experiences
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

18 months into strategy execution, we have seen solid progress

Complete / On-track   Minor delay   Major delay

Strategic theme	FY22 Achievements / progress		Contact26 strategy targets[3]
Grow demand	Southern Green Hydrogen RFP completed, down to the final two participants Engaging with several parties about industrial electrification opportunities Lake Parime data centre construction underway, interest from other data centre operators	Lock in major industrial user electrification NZAS negotiations underway Supported around 50MW of new-to-market lower South Island electricity demand	• Senior in-house capability to support industry electrification partnerships by 2021 • 100 MW of new commercial and industrial demand by 2025 • Identified 300+ MW of market-backed demand opportunities, replacing NZAS in the lower SI by end of 2024 (e.g. hydrogen).
Grow renewable development	Build Tauhara Te Huka 3 investment decision Secure solar partnership or add capability	Wind monitoring mask erected Completed the economic assessment of a grid scale battery Current battery commodity costs have deferred investment decision	• Tauhara online by 2023 • Final investment decision on next renewable build (e.g. Wairākei geothermal, new wind, new solar) by 2024 • Decision on North Island battery by end of 2023, for delivery in 2024 • 100 MW demand response capacity by 2025.
Decarbonise our portfolio	Outline lowest cost / least carbon solutions for thermal assets in transition to 100% renewable Announced the closure of Te Rapa in 2023, 12-month extension to TCC to 2024. On target to meet carbon reduction commitments	Thermal review ongoing Electricity 'swaption' with Meridian agreed for 2023 and 2024	• Complete thermal review in 2022, and executed by 2024 • TCC decommissioned by end of 2023 • Reduce Scope 1 and 2 GHG emissions 45% compared to 2018 baseline by 2026.
Create outstanding customer experiences	Launch time of use offer, with extension into EVs Targeted growth in broadband and energy connections SAP finance and generation on track, CRM implementation experiencing delays	Pilot launch of wireless broadband Investigate data driven energy monitoring commercial models Launch new Brand position	• Top 10 'most trusted brand' by 2025[2] • +650,000 customer connections by 2025 • CTS < $90 per connection[3] • 75% of customer interactions through digital channels.

1. After 2025 (As per Colmar Bunton Rep Track report)
2. Set in May 2021
3. Rebased for operating cost reclassifications in FY22

Tauhara progress

As expected in the current construction environment there continues to be cost pressures, but there are trade-off opportunities to further enhance capacity

Tauhara development key metrics

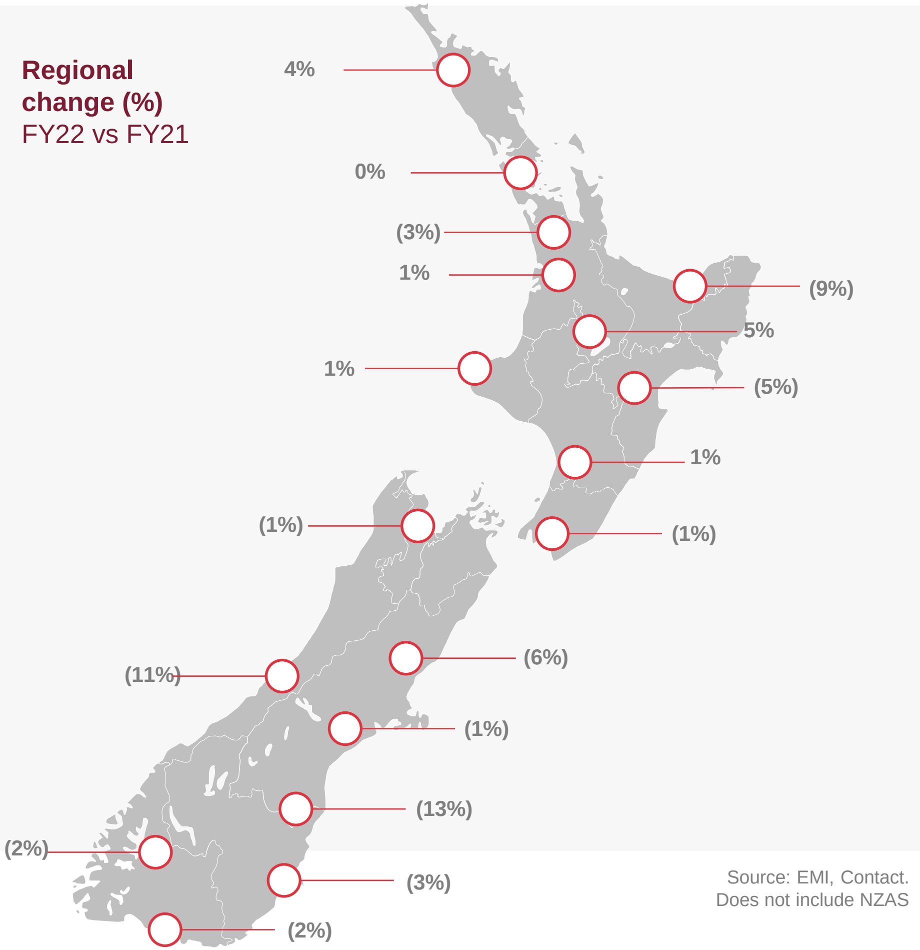
- Estimated MW (net export to grid) | **168MW**
- Estimated forward capital expenditure (cash)[1] | **~$390m**
- Estimated plant capacity factor/ annual generation | **95% / ~1,400GWh**
- Low carbon resource* | **0.05T of C02e/MWh**
- Total estimated construction costs related to this phase of development (2008 – 2024)[3] | **$818m ($4.9m/MW)**
- Estimated cash costs of generation[2] | **~$15/MWh**
- % of production/injection capacity secured | **~100% / ~100%**

* (Gas CCGT ~9x more, Gas Peaker ~11x more)

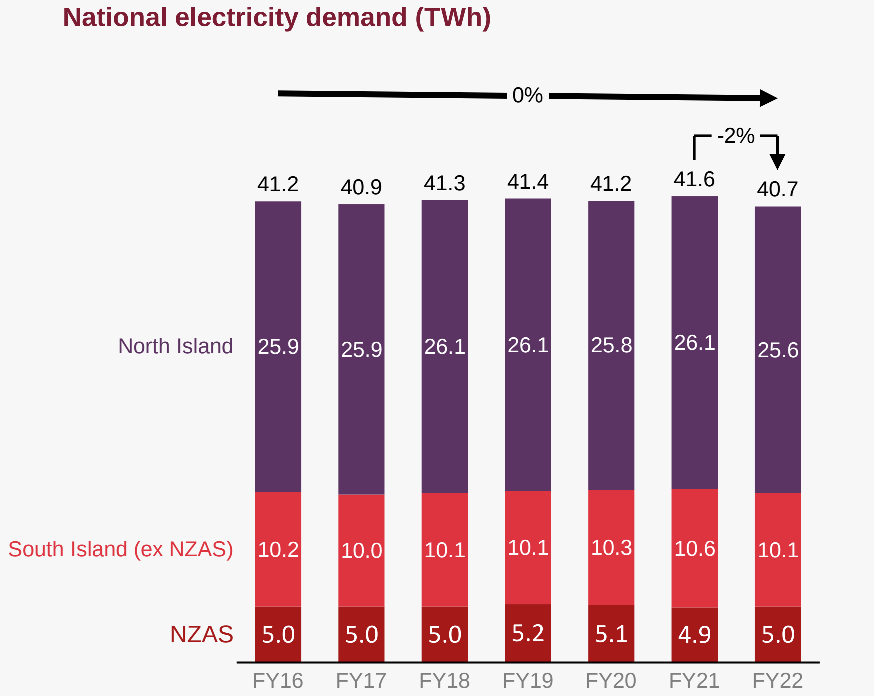
[1] Excluding capitalised interest as at 30 June 2022.
[2] Includes operating costs, carbon costs and stay-in-business capex (excluding make-up drilling and major mid-life capex replacement)
[3] The total addition to PPE on Tauhara commissioning will include ~$18m capitalised transmission asset, ~$80m of capitalised interest ($27m sunk) and $24m of residual sunk capex related to the next phase of development of the field expected total of $940m ($818m + $18m + $80m + $24m)

National electricity demand

Electricity demand lower than FY21



Source: EMI, Contact.
Does not include NZAS



Source: EMI, Contact

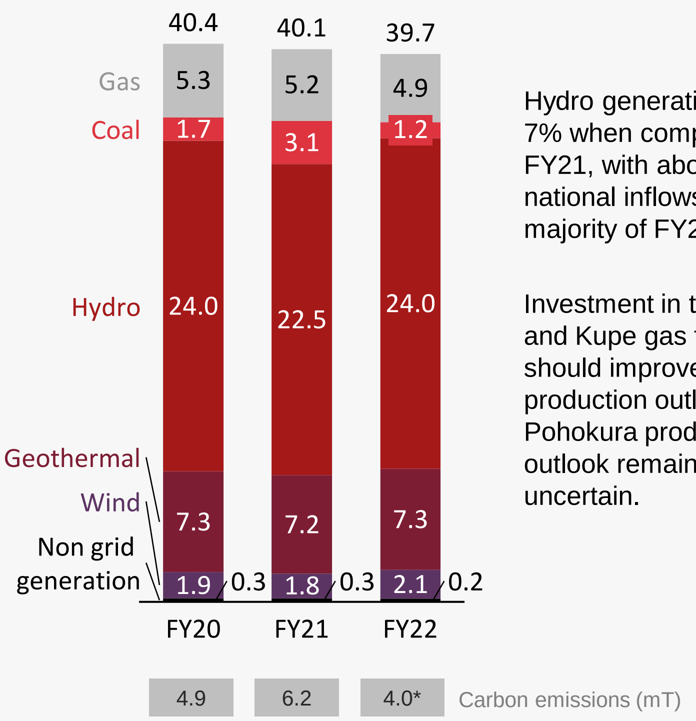
Total national electricity demand decreased by 0.9TWh (-2% from FY21):

- Demand from large industrial users was down by 0.3TWh, largely as a result of the closure of Norske Skog in June 2021.
- A wetter year than FY21 saw lower irrigation demand at major South Island irrigation demand nodes (-0.3TWh).

Hydrology and impact on generation mix

Improved hydro inflows and generation in FY22 saw a reduced reliance on gas and coal

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

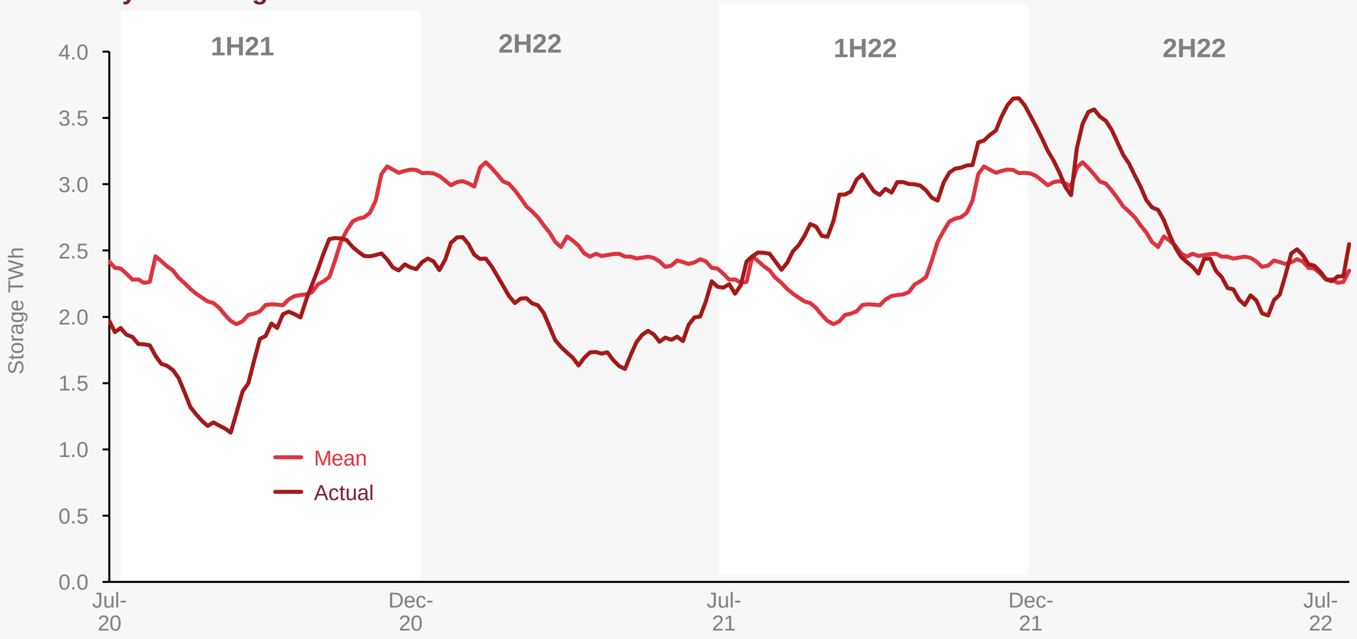


Hydro generation was up 7% when compared to FY21, with above mean national inflows for the majority of FY22.

Investment in the Maui and Kupe gas fields should improve the gas production outlook. Pohokura production outlook remains uncertain.

Source: EMI & MBIE

National hydro storage



Lake levels were appropriately managed through the period to manage the risk around gas availability and expected La Nina conditions in 2022.

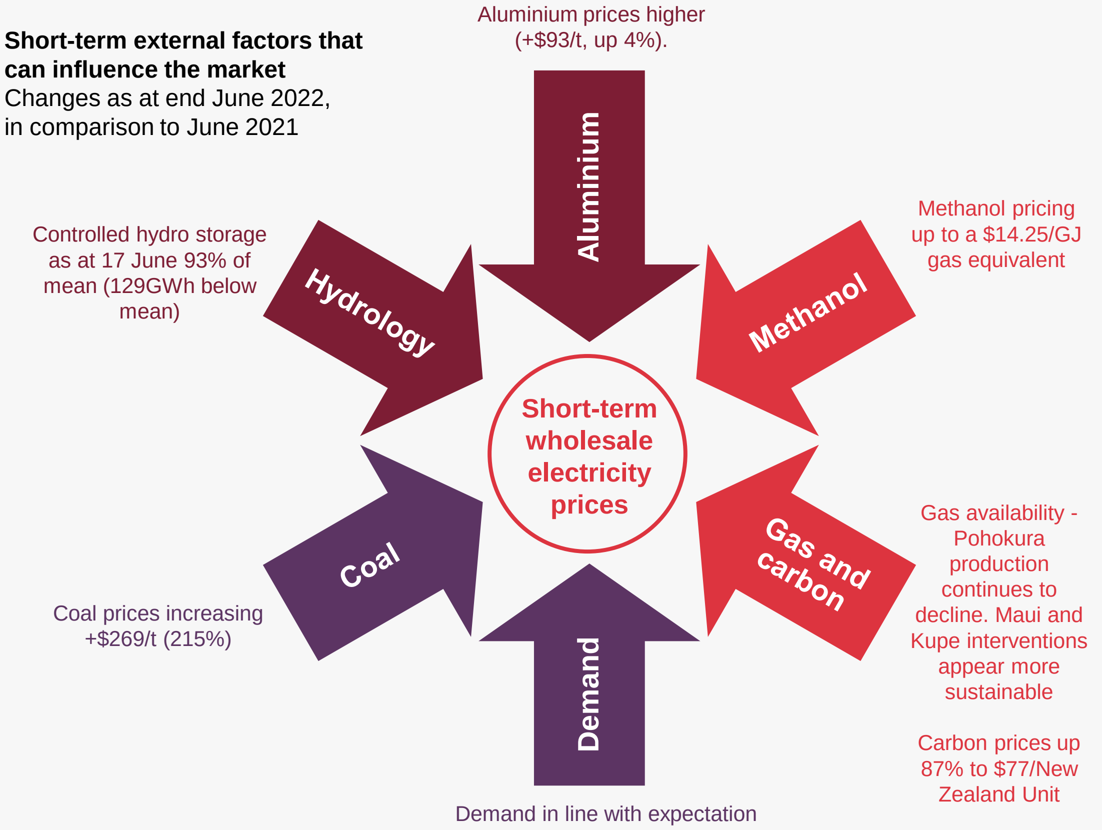
Source: NZX

*Carbon emissions for FY22 Apr-Jun quarter has been estimated using historic conversion rates with actual generation data. The reduction in carbon emissions of 2.2mT CO_2-e was due to the decrease in coal and gas generation
Some generation has been estimated based on prior period operation,

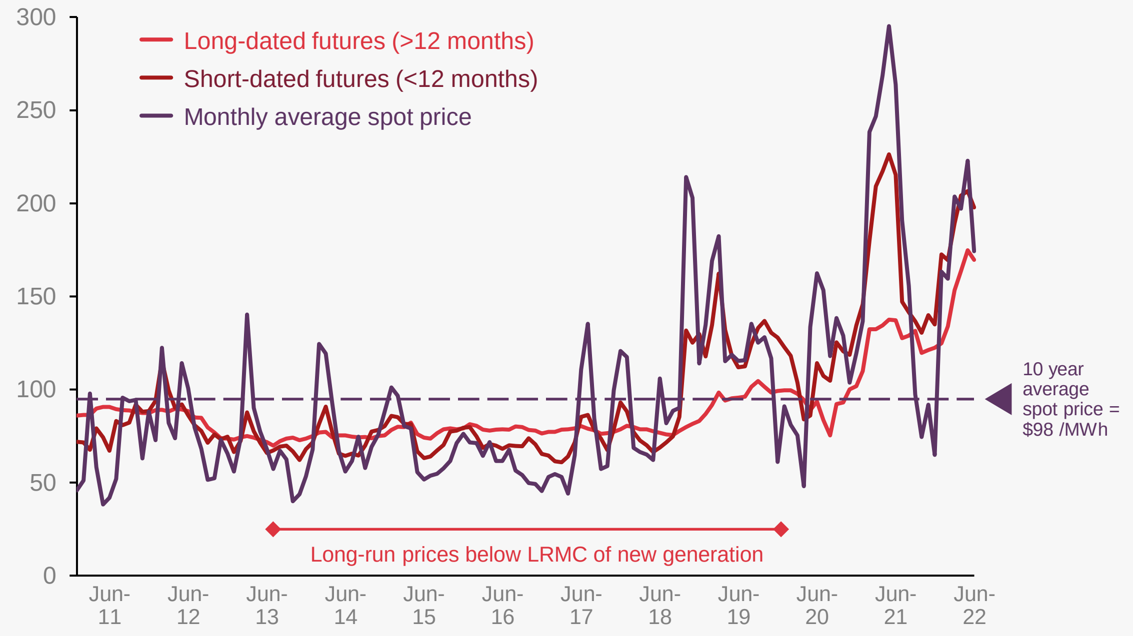
Factors that influence short-term prices, beyond hydrology, sharply higher over last 12 months

Longer-term the market is reacting to these price signals and adding new capacity

Short-term external factors that can influence the market
Changes as at end June 2022, in comparison to June 2021



Wholesale and futures electricity pricing ($/MWh)



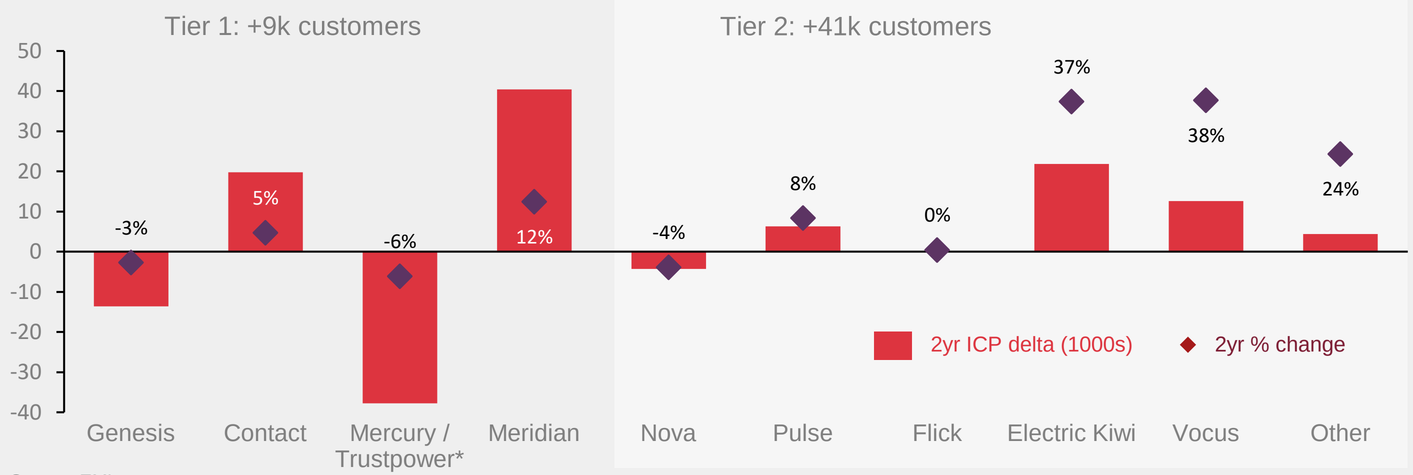
Source: EMI wholesale pricing

There is currently extreme volatility across commodity markets, driven by a combination of global energy supply and security concerns, exacerbated by the impact of the Russian invasion of Ukraine, with subsequent unprecedented increases in international energy prices including coal, gas and oil. Domestically, gas field outages and high coal and gas prices have contributed to a steep escalation in wholesale electricity prices.

Retail competition remains intense

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

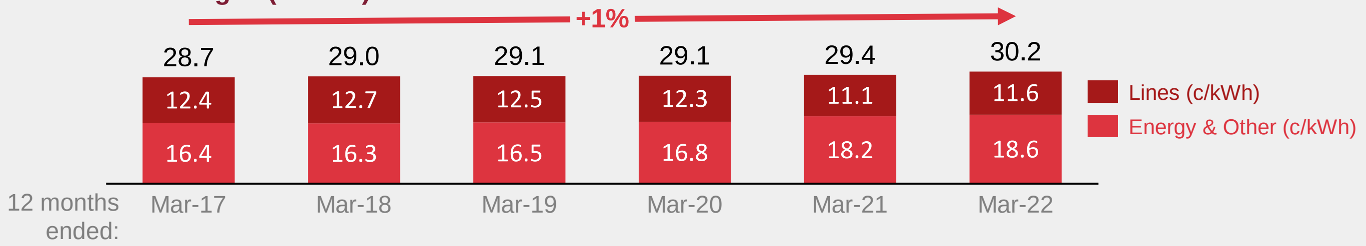
Change in customer connections (000s)



Source: EMI

- Competition remains intense, not only from new and disruptive competitors, but reinvigorated incumbents
- While Tier 1 market share continues to decline (84% of connections vs 86% 24 months ago). Both tier 1 and 2 players continue to add connections as household formation has contributed to a ~1% p.a. growth in ICPs
- Mercury purchased the Trustpower retail business in FY22 and are the largest retailer by ICP (26% market share)
- Meridian added another 40k connections over the last two years (16% market share) and Contact (20% market share) followed with an addition of 20k connections overall.
- Electric Kiwi has continued with an additional 21k connections (80k total), followed by Vocus (now 2degrees) 13k connections.

Retail tariff changes (c/ kWh)



Source: MBIE

- Despite sharply higher wholesale prices over the last four years, tariffs up by a compound annual growth rate of only 1%.
- Average tariff increases for the last year of 2.7% remain materially below consumer price inflation (>7%)
- Households have been largely insulated from higher wholesale prices because of fixed price residential contracts and retailers' longer-term view of pricing that rides through short-term volatility.
- The real residential cost per unit of electricity has fallen in every year since 2018.

*Mercury completed the purchase of the Trustpower retail business on 1 June 2022. Mercury and Trustpower have been grouped together for the period under review despite being in different ownership.

Climate change and regulation

Bi-partisan support for the New Zealand regulatory framework is being adapted to deliver on this societal imperative.

Potential electricity demand impact

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

Potential renewable generation impact

- Government Energy Strategy[1]
- Resource consenting reform
- Ban on offshore oil and gas exploration
- Emission Trading Scheme review

Potential wider electricity sector impact

- Wholesale market review[2]
- New Zealand Battery Project
- Transmission Pricing Methodology

Announced

In progress

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

[1] Covering electricity, hydrogen, gas transition, and industry decarbonisation.
[2] Preliminary findings release, under consultation.

Topical regulatory matters

Key themes		What Contact is doing
Wholesale market volatility	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 Electricity Authority (EA) continues to review wholesale electricity market competition for the period 2019-21. Its draft analysis finds that prices have generally reflected underlying supply and demand conditions, however NZAS may be paying below the opportunity cost for energy.	**Contact** is exploring further renewable generation opportunities across geothermal, wind, 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 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 building new generation to meet future demand.
Climate Change	In May 2022 the Government released its first emissions budgets and Emissions Reduction Plan (ERP). The ERP set a target to achieve 50% of total final energy consumption to come from renewable sources by 2035. It also included a substantial boost to funds to support reducing industrial emissions (GIDI fund) and to increase uptake of Evs (~$650m) In July 2022, the Climate Change Commission made recommendations to government on the emissions trading scheme. If accepted these recommendations would likely substantially increase the costs of carbon, and may incentivise greater electrification	**Contact** strongly supports the target of reaching 50% of total final energy consumption coming from renewable sources by 2035. We will continue to assess opportunities for renewable energy developments, demand growth, and decarbonisation of process heat, for example by leveraging the expanded GIDI fund. **Contact** continues to closely engage in the government's work and assess the strategic opportunities and impacts for Contact. **Contact,** along with others in the industry, is funding Boston Consulting Group to independently develop a roadmap for a low carbon energy system in Aotearoa New Zealand. **Contact's** risk mitigation tools ensure our carbon purchases will enable a sustainable transition away from thermal generation. In line with our decarbonisation strategy, this should reduce reliance on thermal fuel costs.

Topical regulatory matters

Key themes		What Contact is doing
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.	**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** released a proposal to develop a ThermalCo which would be a low capital, low cost and low risk solution to accelerate decarbonisation.
Energy hardship	Covid-19 and the broader economic environment continue to place pressure on New Zealand households and businesses. Contact is actively working to minimise energy hardship. The Government has established two specialist energy hardship panels to support work to alleviate energy hardship in New Zealand.	**Contact** has established a dedicated group within our retail business focusing on consumer energy wellbeing. **Contact's** tikanga, pricing principles and proactive work with its customers who are struggling to pay their bills has resulted in reduced disconnections and bad debt. **Contact** offers a range of payment options including weekly and fortnightly billing, pre-pay and price smoothing products. **Contact** is working with industry through ERANZ on the EnergyMate programme and PowerCredits scheme in association with budget advisors and FinCap.

Financials

Putting our energy where it matters.

Key themes from the financial results

Mean year EBITDAF continues to rise

Visible leadership in decarbonising our industry

Long-run electricity prices adjusting to reflect inflation

Demand outlook continues to firm

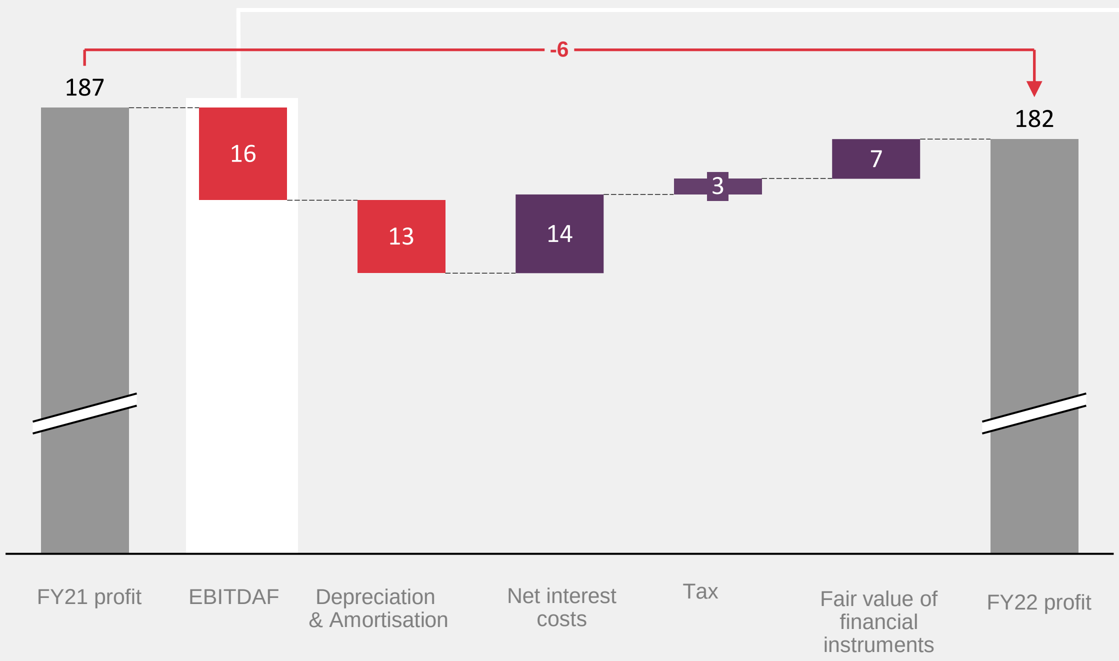
Around 50% of Tauhara output signed as long-term inflation linked PPAs

Strong focus on delivering returns on invested capital

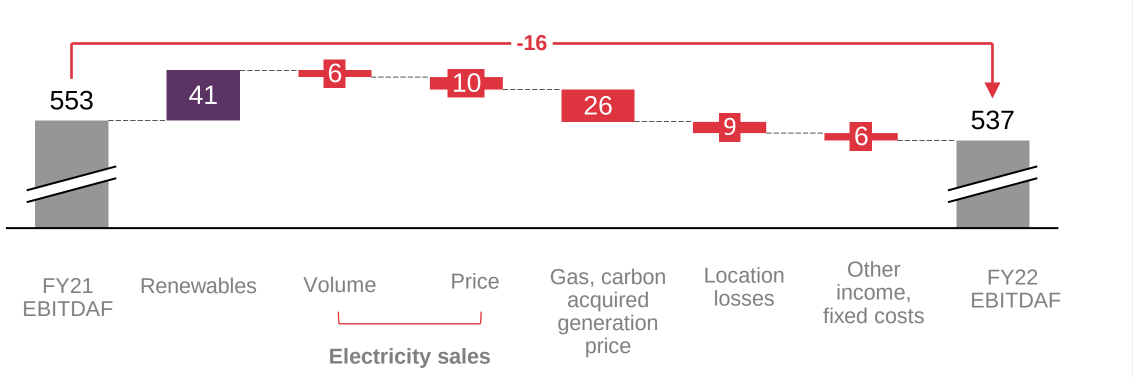
Profit of $182m, down $5m

EBITDAF down $16m, as higher renewable generation offset by rising unit thermal fuel costs and lower wholesale prices than the prior year

Profit ($m)



EBITDAF ($m)

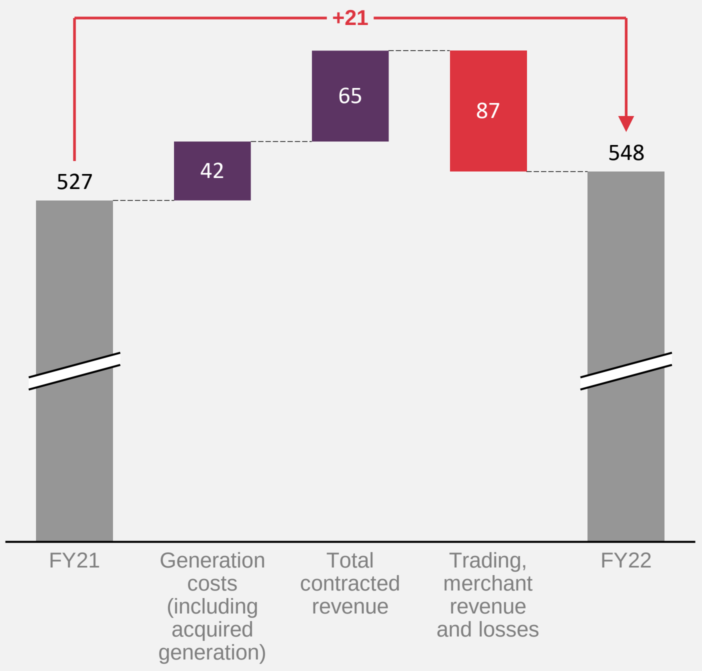


1. Renewables up 411GWh as hydro generation reverted to mean
2. Sales volumes lower on reduced thermal generation
3. Electricity net sale price 1% lower on full year of NZAS support, partially offset by strong market channel performance
4. Higher gas and carbon costs to run thermal generation
5. Location losses higher on proportionately lower North Island generation volumes
6. Fixed costs higher as increase in other operating costs (-$13m) partially offset by lower transmission costs ($+6m)

EBITDAF down by $16m

Business performance by segment

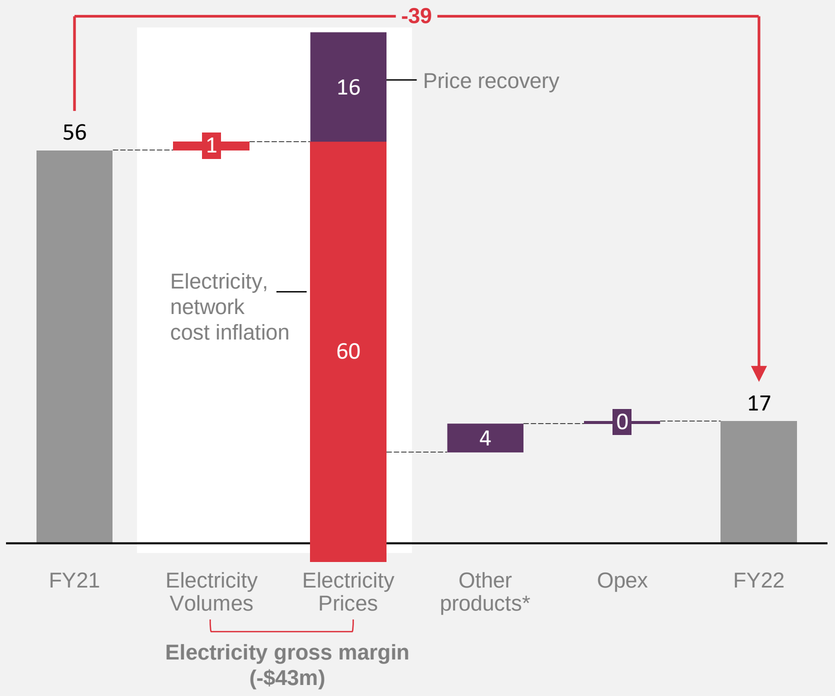
Wholesale EBITDAF ($m)



Refer to slides 19 - 21

Simply and Western included within Wholesale EBITDAF

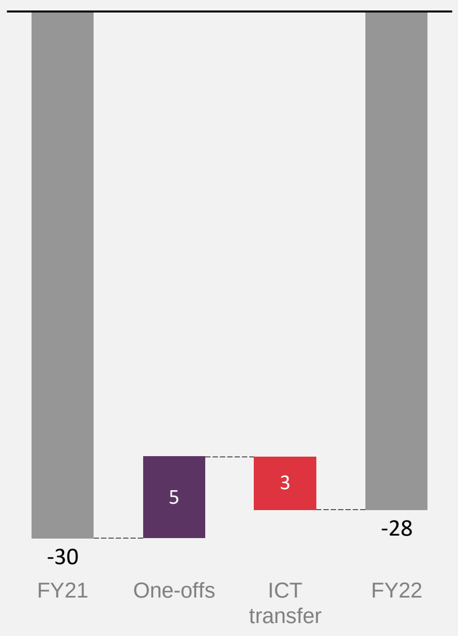
Retail EBITDAF ($m)



Refer to slide 22

*Other products includes retail gas and broadband gross margins

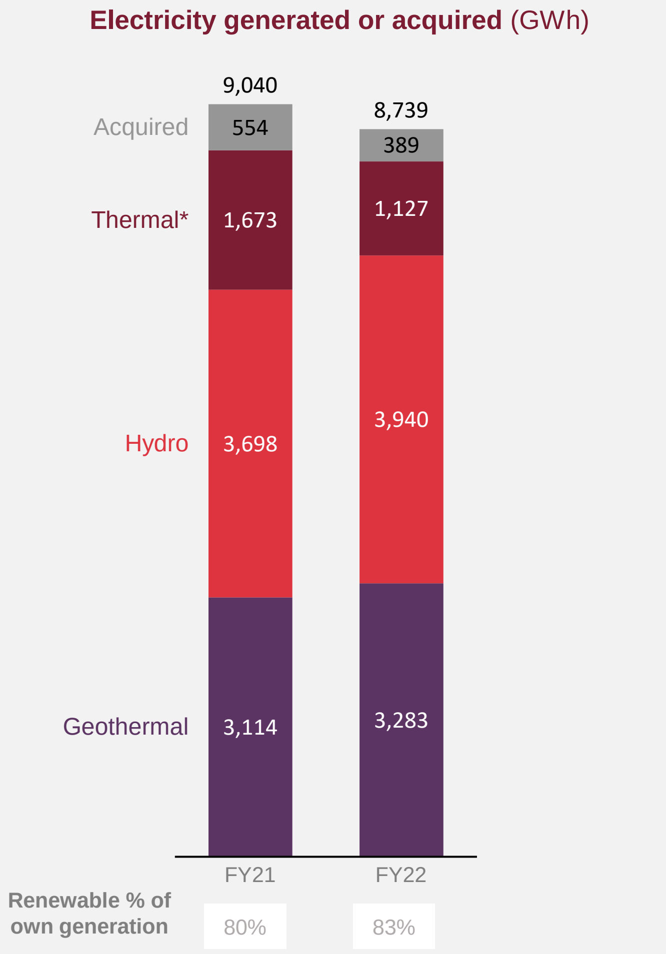
Corporate / unallocated costs ($m)

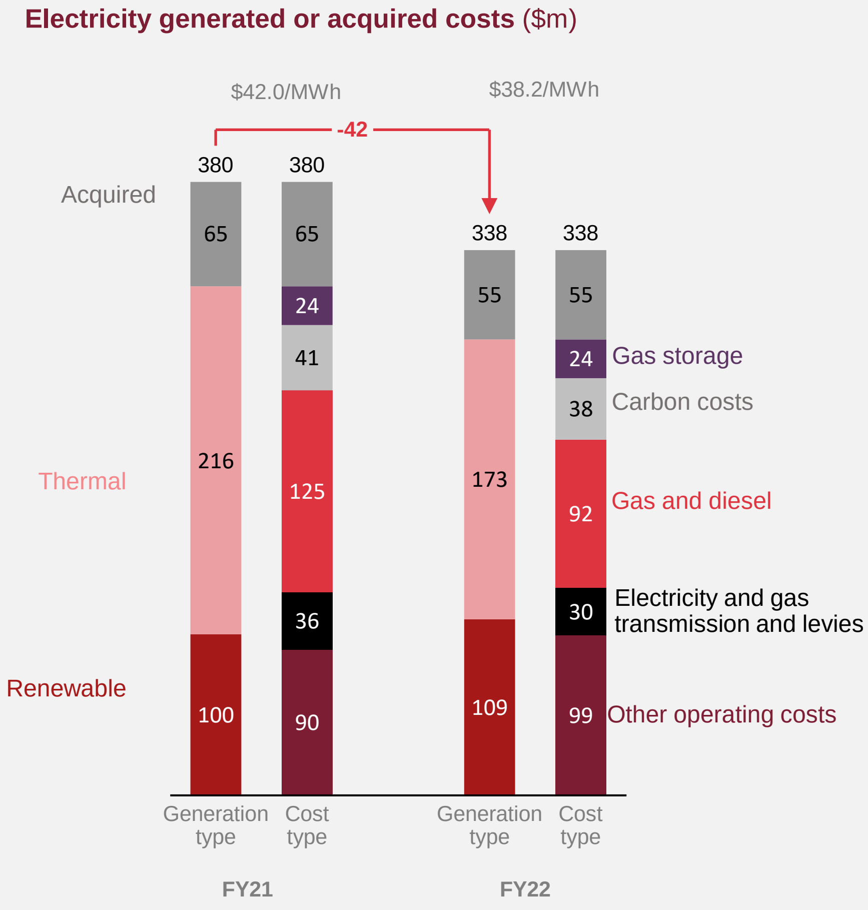


ICT costs previously included within the Retail business operating costs. Prior year not restated. One-offs include the Holidays Act provision reversal ($6.8m) and Contact SaaS and write down of thermal asset development costs

Generation costs

Costs down $42m ($3.8/MWh) on higher renewable generation reducing thermal and acquired generation





Hydro generation up 242GWh on FY21 (+7%), 40GWh (+1%) above mean year expectations. Geothermal volumes were 169GWh up on prior year which had the 4-yearly Te Mihi outage (+5%).

- Renewable generation costs were up $9m on FY21 as a $10m reduction in operating costs was recognised on the acquisition of Western Energy in FY21.

Thermal generation costs were down by $43m (-20%) on lower thermal volumes (-33%).

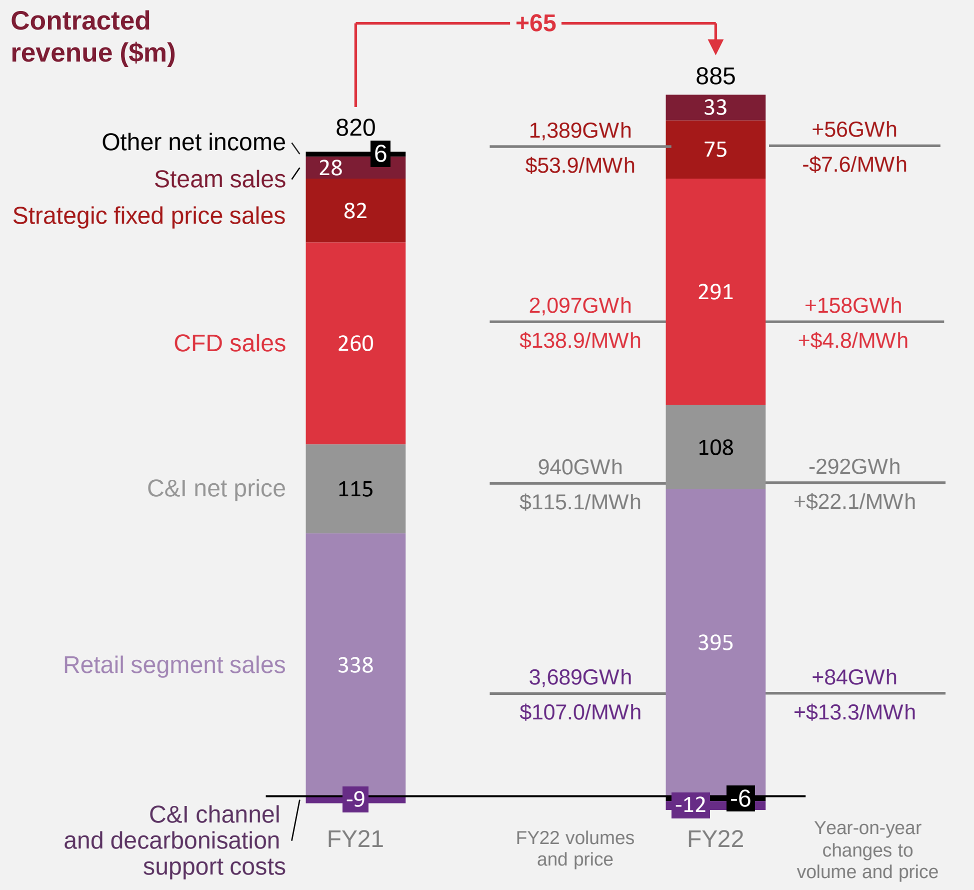
- Thermal fuel costs up from $95/MWh in FY21 to $109/MWh (+15%). With gas (FY21 $8.0/GJ, FY22 $8.3/GJ) and carbon prices (FY21 $31/unit, FY22 $40/unit) higher.
- Electricity and gas transmission costs were down by $6m on the prior comparative period on higher ACOT revenue, changes to the TCC gas transmission contract and higher HVDC loss rebates.

Acquired generation costs where down by $10m as wholesale prices were lower in the period offering less ability to sell acquired generation into a higher wholesale spot market (volumes down 165 GWh).

*Thermal includes tolling of ~312GWh in FY21 and ~245GWh FY22

Wholesale contracted revenue

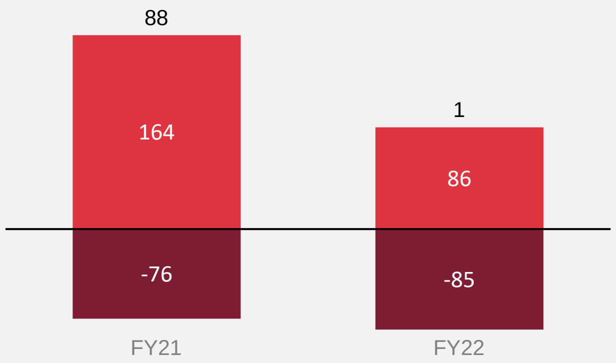
Diversified mix of long-term and ASX linked sales channels



- Fixed price variable volume electricity sales to the Retail segment and C&I customers ended 208GWh lower than FY21 (-$19m), this was offset by higher prices (+$70m), reflecting higher wholesale prices over the three preceding years.
- Strategic fixed price sales were 56GWh higher than FY21 (+$3m), lower NZAS pricing was offset by an increase in sales to customers under long-term PPAs (-$11m).
- CFD sales volumes were up by 158GWh (+$21m) as nearer term higher priced channels were prioritised at higher average prices (+$10m).
- Steam revenue was up $5m on FY21 with steam tariffs on Te Rapa generation rising with carbon costs changes.
- Operating costs to support commercial and industrial customers higher as capability added to support decarbonisation and a closer customer relationship and a full year of acquired Simply Energy operating costs.
- Other income was $12m lower predominantly due market making losses in FY22 (FY22: -$10m, FY21- nil)

Wholesale trading and merchant revenue

Trading EBITDAF ($m)

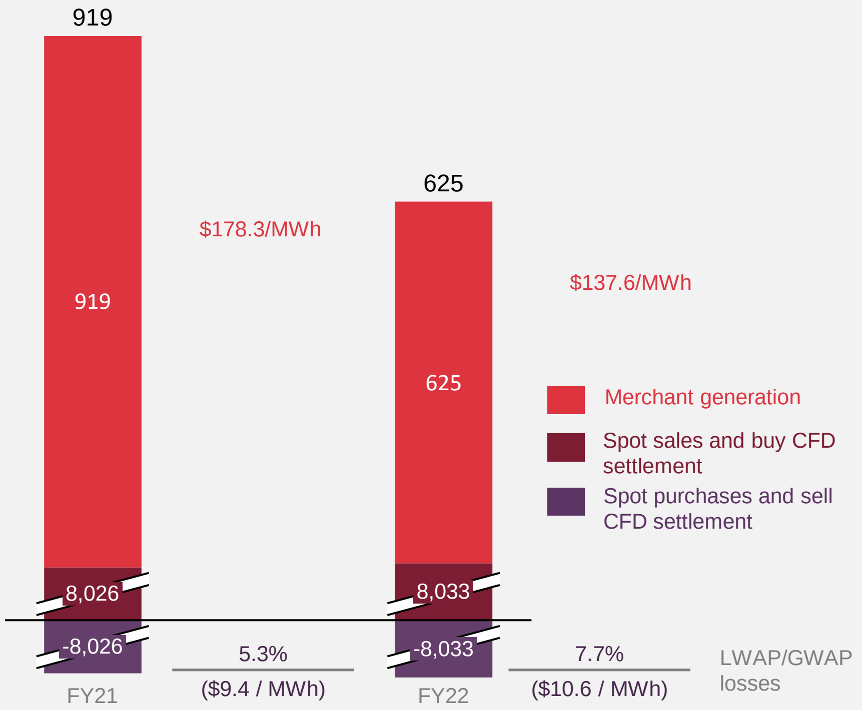


Trading revenue

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)



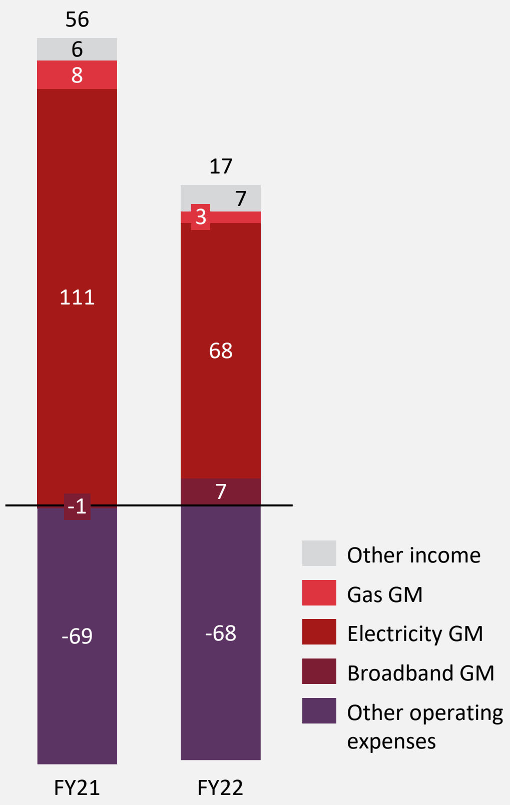
- 294GWh decrease in merchant sales volumes. The price received for this “long” generation was down by $40.7/MWh on FY21.
- Inter-island separation increased from 5% to 8%, this was partially offset by lower absolute prices. The cost of generation losses increased by $9m.

Retail business performance

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

Revenue & Tariff[1] ($m)	FY21	FY22		Variance	
	$m	$m	*Tariff[1]*	$m	*Tariff*
Electricity gross revenue	841	872	253	32	5
PPD not taken	5	3		(2)	
Incentives paid	(5)	(5)		0	
Net revenue (cash)	**841**	**871**	**253**	**30**	**4**
Capitalised incentives	7	5		(2)	
Amortised incentives	(9)	(6)		3	
Net revenue (P&L)	**838**	**869**	**252**	**31**	**5**
Gas revenue	74	82	29	8	3
Broadband revenue	32	53	70	20	2
Other income	6	7		1	
Total revenue	**951**	**1,011**		**60**	
Contract Asset (closing)	9	7		(2)	
# of connections (closing)	523k	574k		51k	
Cost to serve/connection[2]	($134)	($123)		+$11	

EBITDAF ($m)



Continue to smooth the impact of higher electricity costs for customers:

- Electricity net price at ICP improved by 1% from FY21 with targeted retail price rises partially offset by increased network and meter costs.
- Total electricity gross margins decreased by 39% driven by elevated wholesale electricity costs over the past 3 years.
- Retail energy tariffs will need to rise to reflect elevated wholesale electricity, gas & carbon costs.

The electricity tariff changes balance the recovery of rising input costs, the competitive environment and regulatory pressures:

- Around 60% of customers received a price increase in the last 12 months.
- Electricity connection growth of 25k, and multi-product customers up 21k on prior year.

Strong growth in Broadband connections (+20k up on FY21, now at 71k). Average revenue per connection has increased by 3%, and standalone gross margin contribution of $7m (FY21: -$1m).

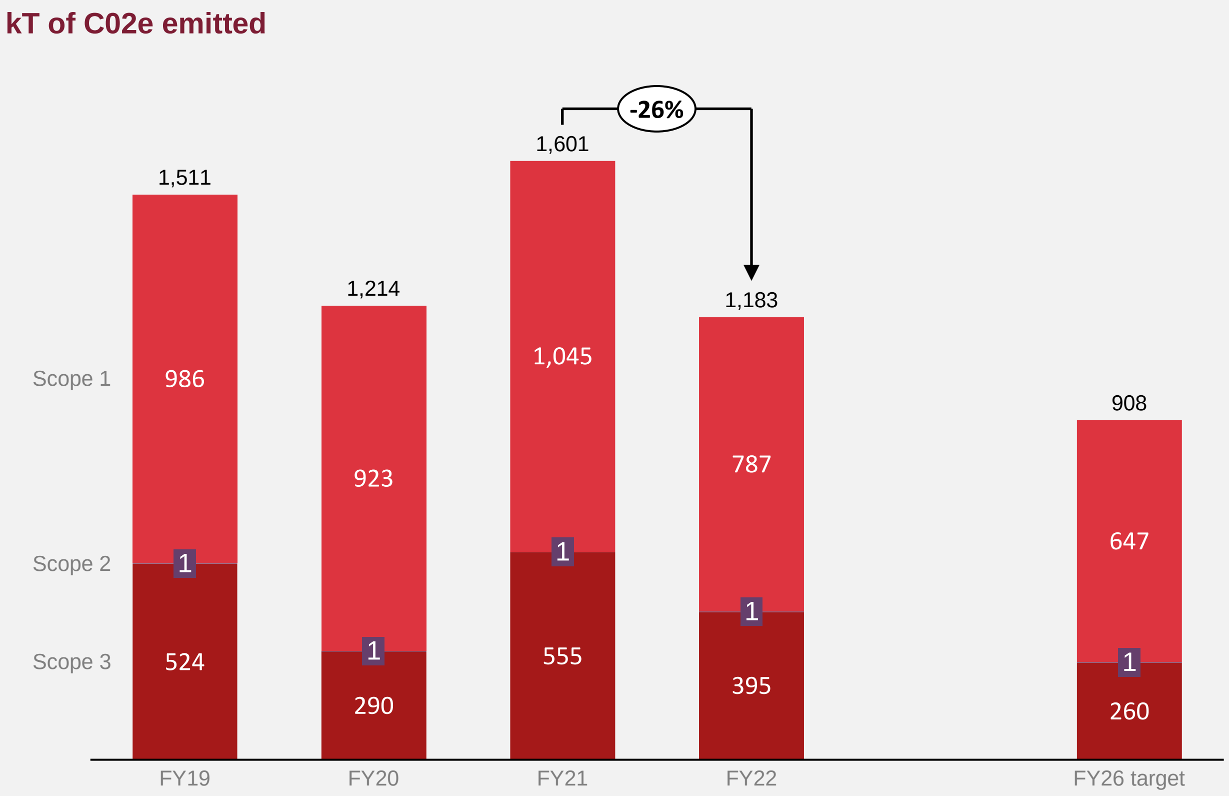
Cost to serve – continued focus on operational efficiency through leveraging data and digital investments driving further reductions in cost to serve per connection.

1. Tariff is $/MWh for electricity, $/GJ for gas and $ per month per customer connection for broadband
2. During FY22 metering costs of $13m, 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

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

Greenhouse gas reporting

Lower carbon emissions reflects higher renewable generation and lower thermal and acquired generation, on target to achieve 2026 SBTi commitments



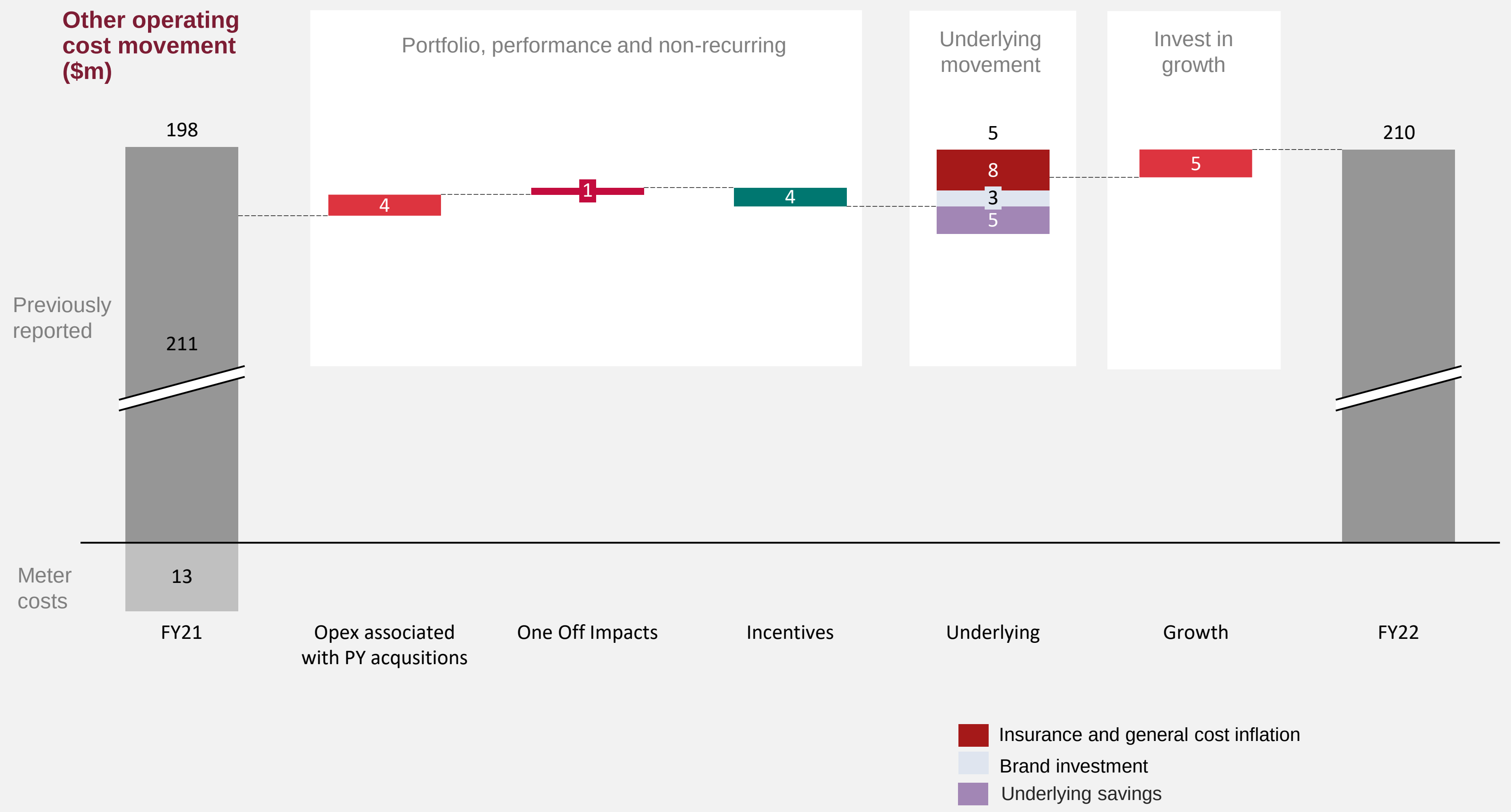
Performance

Total scope 1,2 and 3 emissions were 418 kT lower in FY22.

- Emissions from generation (Scope 1) were lower in FY22 as a result of higher renewable generation volumes and lower sales.
- Scope 3 emissions 160 kT lower.
  - Higher capital goods emissions due to Tauhara construction build has been offset by significantly less swaption emissions due to less swaption exercised in the year compared to FY21.

See slide 40 for detailed greenhouse gas emissions reporting

Operating costs flat despite acquisitions, strong performance and cost pressures



Other operating costs

- All costs associated with meters are now reflected in Cost of Goods (Network, Meters and Levies) to align with industry reporting. Previously a portion of smart meter costs were included in other operating costs to provide comparability to prior periods where there were higher manual meter reading costs.

Portfolio performance and non-recurring

- Holidays Act provision released in FY22 post successful Metro Glass appeal, partially offset by accounting adjustments related to software as a service (SaaS), write down of thermal development costs and prior year one off provision reduction for well restoration.
- Full 12 months of operating costs acquired as part of the strategic transactions of Western Energy (April 21) and Simply Energy (September 20).
- Incentive costs are lower with assessment of a broad range of KPIs beyond financial performance.

Underlying movement

- General inflation of over 6% impacts general operating costs, cost efficiency achieved through digital investments in customer servicing efficiency and broadband provisioning

Growth

- $2m incremental investment in retail connection growth
- Operating costs to deliver on strategic growth priorities.

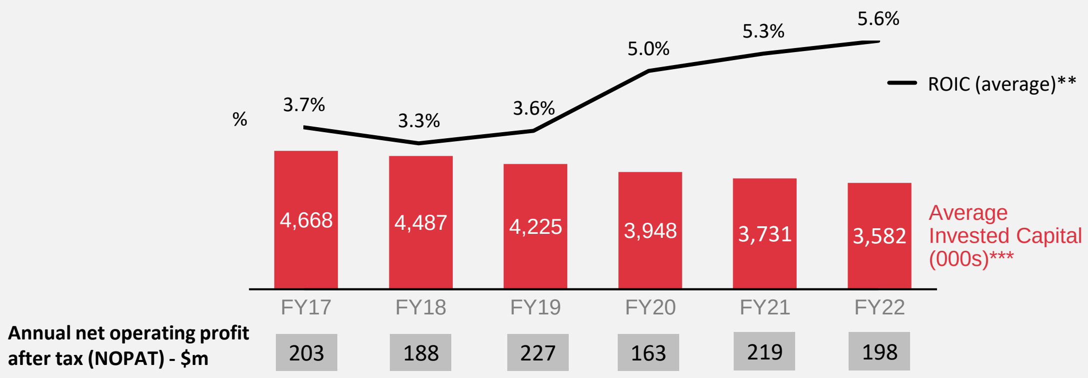
Cash flow and capital expenditure

Underlying cash conversion for FY22 impacted by lower EBITDAF, higher tax paid and higher SIB capex

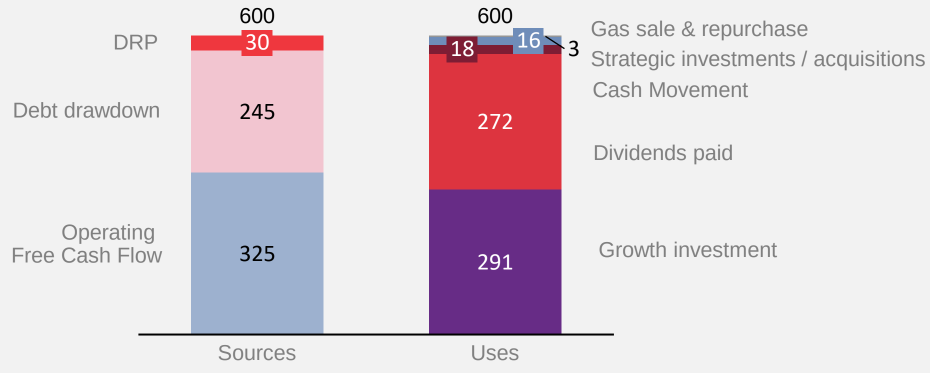
	12 months ended 30 June 2022	12 months ended 30 June 2021	Comparison against FY21	
EBITDAF	**$537m**	$553m	↓	($16m)
Working capital changes	**($17m)**	$3m	↓	($20m)
Tax paid	**($89m)**	($79m)	↓	($10m)
Interest paid, net of interest capitalised	**($28m)**	($43m)	↑	$15m
SIB capital expenditure	**($75m)**	($61m)	↓	($14m)
Non-cash items included in EBITDAF	**($3m)**	($2m)	↓	$1m
Operating free cash flow	**$325m**	$371m	↓	$46m
Operating free cash flow per share	**41.8cps**	50.2cps	↓	8.4cps
Cash conversion (OpFCF / EBITDAF)	**60%**	67%	↓	6%

- EBITDAF down $16m on lower wholesale electricity prices and the rising gas and carbon unit costs, which were partially offset by more renewable generation
- Working capital changes $20m unfavourable to FY21 tied to decrease in payables on FY21 payment of short term incentives and subsequent changes to scheme and timing of carbon purchases
- Stay-in-business capital expenditure (cash) of $75m with higher spending expected the next 5 years to support higher asset availability and output as well as an SAP systems upgrade

Return on invested capital (ROIC*)



Sources and uses of cash ($m)



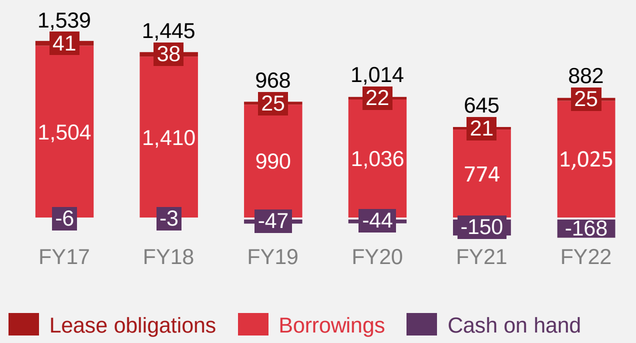
* For details underpinning the calculation of ROIC see slide 38
** NOPAT (4-year average) /Average IC (average of the 4-year average)
*** Average invested capital (opening + closing balance)/2

Strong balance sheet

Green debt portfolio with capacity to support the Contact26 strategy

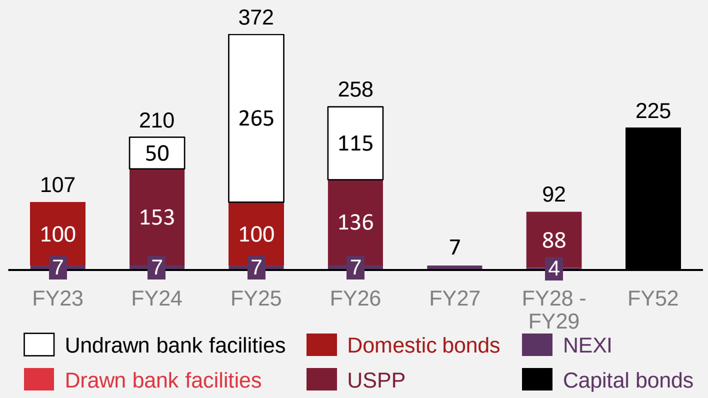
Closing net debt ($m)

Face value of borrowings less cash



Borrowing maturities ($m)

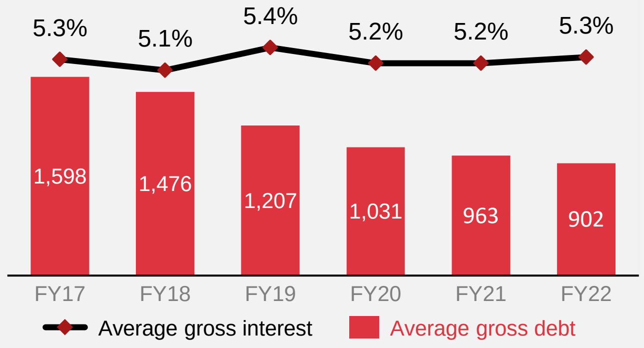
Average tenor of 7.4 years as at 30 June 2022



- Face value of borrowings (excl. leases) increased by $251m to $1,025m from 30 June 2021. This is due to the issuance of $225m of capital bonds replacing $150m of maturing retail bonds in November 21, and increased use of the CP program. The Tauhara geothermal power station construction has driven the increase in debt levels.
- Net debt has reduced by $657m since the end of FY17. Gearing increased to 23.5% at 30 June 2022, up from 22.6% at 30 June 2021.
- The average interest rate on gross debt has increased slightly from FY21 due to the increase in the interest rates for the floating rate portion of the debt portfolio.
- A credit rating of BBB (net debt / EBITDAF <2.8x) continues to be targeted.
- All bank facilities are sustainability linked loans, and all debt instruments are certified green.

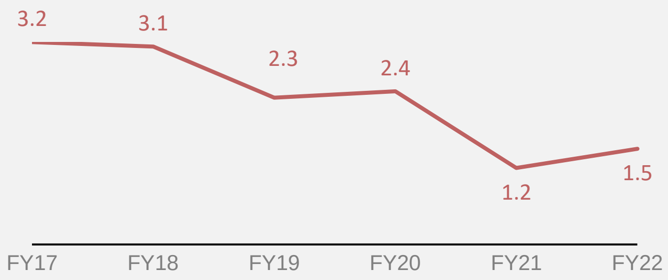
Interest rate (%)

Weighted average gross interest[1] on average borrowings



Net debt to EBITDAF (x)

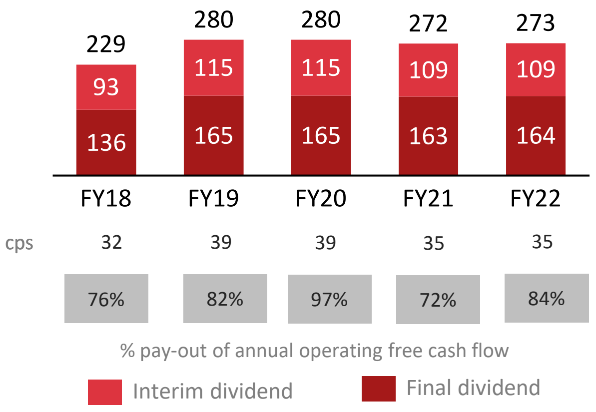
Includes S&P adjustments (prior to FY20 AGS was treated as a lease)



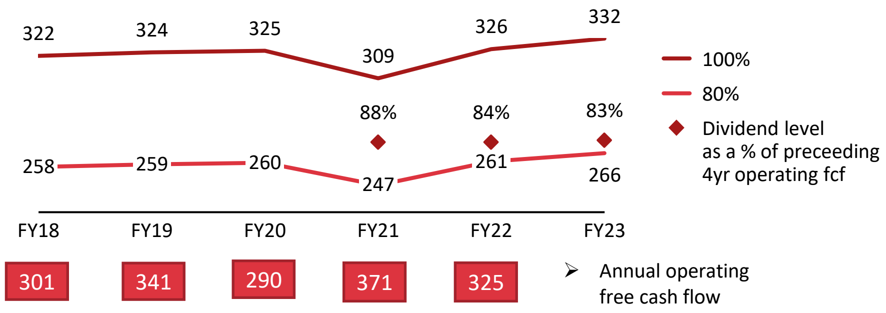
1. Gross interest includes all interest on borrowings, bank commitment fees and deferred financing costs. Unwind of leases, provisions and capitalised interest not included.

Dividend for FY22 in line with performance

Ordinary dividends ($m)
Declared



Operating free cash flow
Average operating cash flow for the preceding four financial years



Dividend policy range: 80-100% of average operating free cash flow for the preceding four years

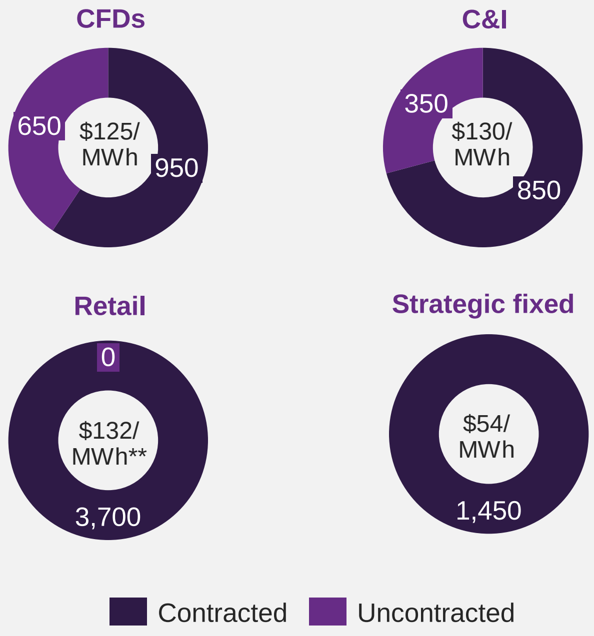
Dividend for FY22 of 35 cents per share

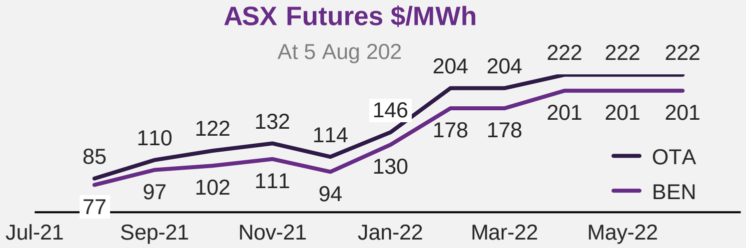
- Final dividend of 21 cents per share is imputed to 90% or 19 cents per share for qualifying shareholders. This represents a pay-out of 84% of FY22 operating free cash flow per share and 84% of the operating free cash flow over the preceding 4 financial years (FY18-FY21)
- The dividend policy is to pay-out between 80-100% of average operating free cash flow of the preceding four years.
- Record date of 9 September 2022; payment date of 27 September 2022.
- The NZD/AUD exchange rate used for the payment of Australian dollar dividends will be set on 16 September 2022.

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 for the FY22 final dividend and Contact will have the right to terminate or suspend the plan at any time.
- Dividend reinvestment plan application forms must be in by 12 September 2022 to confirm participation in the plan.
- Trading period for setting price for DRP is 8 September 2022 to 14 September 2022. DRP strike price will be announced: 16 September 2022

Normalised and expected FY23 EBITDAF assumptions



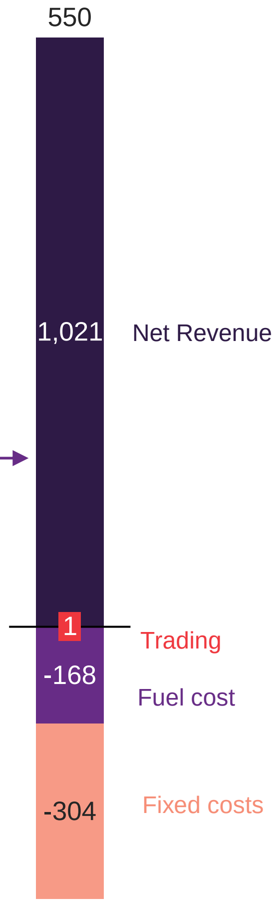


FY assumptions that deliver expected & normalised EBITDAF for FY23

1 Channel choices maximise long term value[1]		X	2 Net price[2] driven by best commercial practices	=	Total
Strategic fixed price	1,450GWh	x	$54/MWh	=	$78m
CFDs	1,600GWh	x	$135/MWh	=	$216m
C&I	1,200GWh	x	$140/MWh	=	$168m
Retail	3,700GWh	x	$132/MWh		$488m
Other income[3]					$70m
					$1,021m

3 Hydrology & Asset availability optimise generation		X	4 Access to and price of fuel* drives financials & risk position	=	Total
				=	
Hydro mean	3,900GWh	x	$0/MWh	=	-$0m
Geothermal average	3,250GWh	x	$3/MWh	=	-$10m
Thermal	1,050GWh	x	$115/MWh[4]	=	-$121m
Acquired	250GWh	x	$150/MWh		-$38m
					-$168m

5 Trading delivers value to more than offset locational losses		6 Digitalisation & continuous improvement optimise fixed costs	
Length[5]	$81m	Transmission/Storage	-$68m
Location losses[6]	-$80m	Operating expenses	-$235m
Total	**$1m**	**Total**	**-$304m**

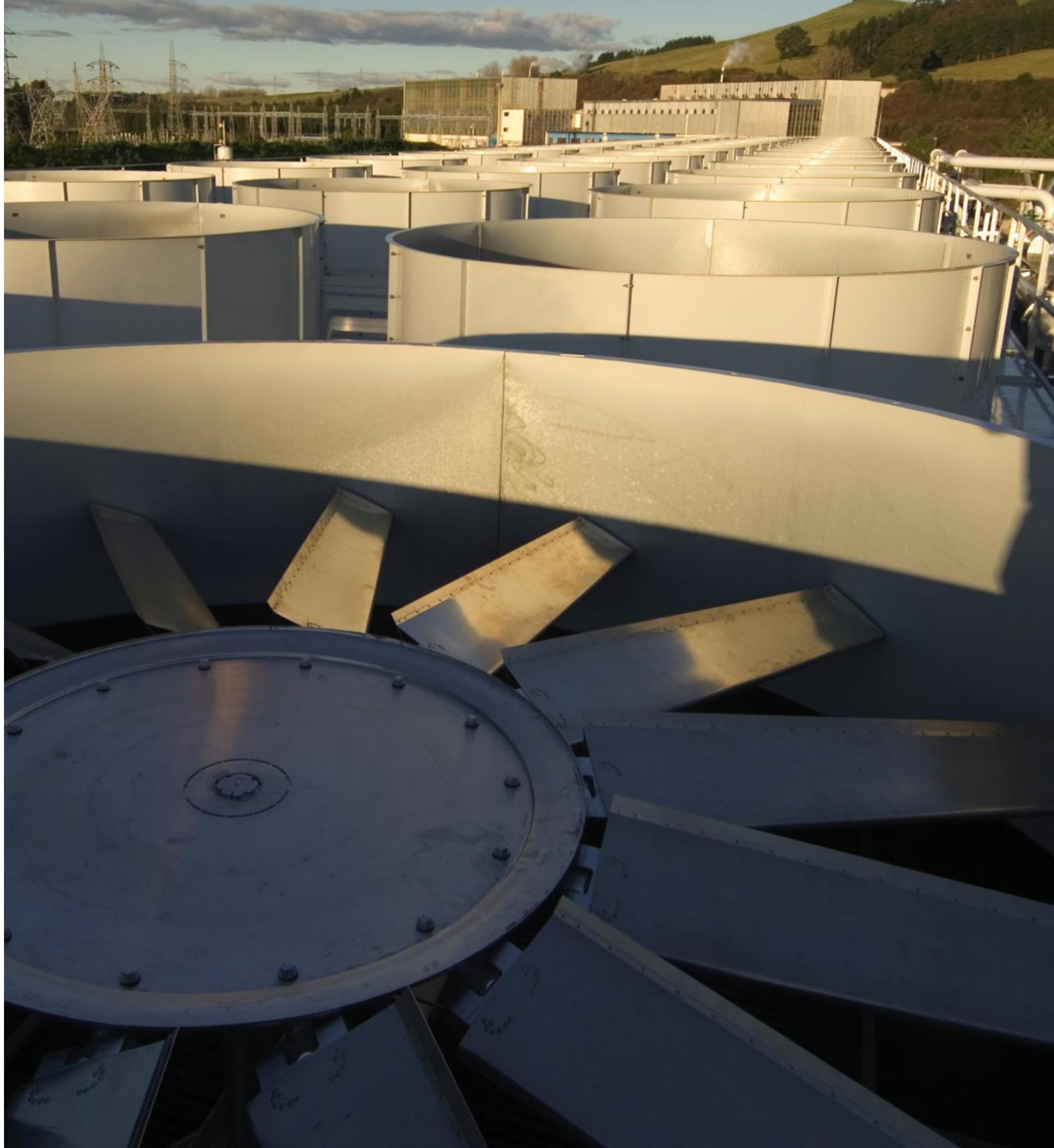


1. All volumes are at the Grid Exit Point (GXP)
2. Net price is equal to tariff less pass-through costs (network, meters and levies) /MWh
3. Steam sales, retail gas gross margin, other income
4. Gas price of $7.9/GJ, carbon price of $50/unit and thermal portfolio heat rate (11.2GJ/MWh)
5. Length of 500GWh p.a. 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

** Retail volume contracted, competitive risk remains on pricing achieved (FY22 $125.5/MWh)

Progress on Strategy



Te Huka investment

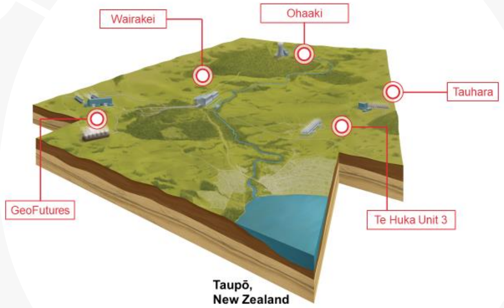
Contact is investing to deliver renewable energy

Te Huka development key metrics

Estimated forward capital expenditure (cash)[1] | ~$272m

Low carbon resource* | 0.03T of C02e/MWh

Estimated cash costs of generation[2] | ~$20/MWh



Estimated MW (net export to grid) | 51.4MW

Estimated plant capacity factor/ annual generation | 95% / ~430GWh p.a.

Total estimated construction costs[3] | $300m ($5.8m/MW)

% of production/injection capacity secured | ~100% / ~100%

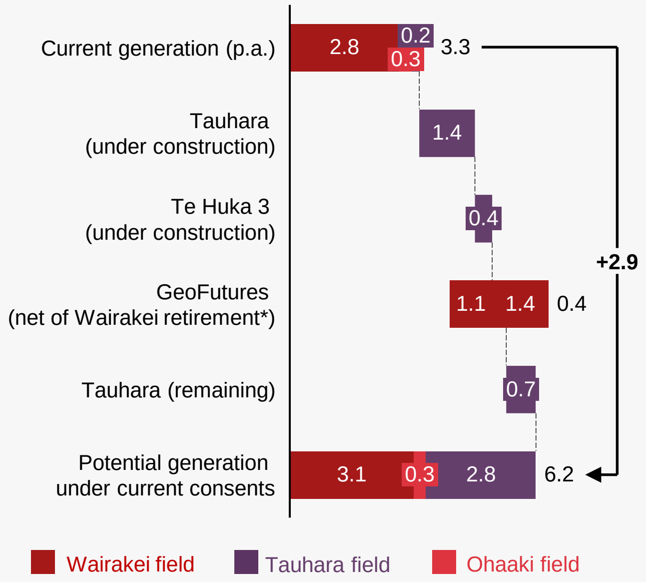
* (Gas CCGT ~15x more, Gas Peaker ~18x more)

[1] Excluding capitalised interest as at 30 June 2022.
[2] Includes operating costs, carbon costs and stay-in-business capex (excluding make-up drilling and major mid-life capex replacement)
[3] Excludes finance leases and capitalized interest (estimated ~$13m). $28m of project costs spent by 30 June 2022.

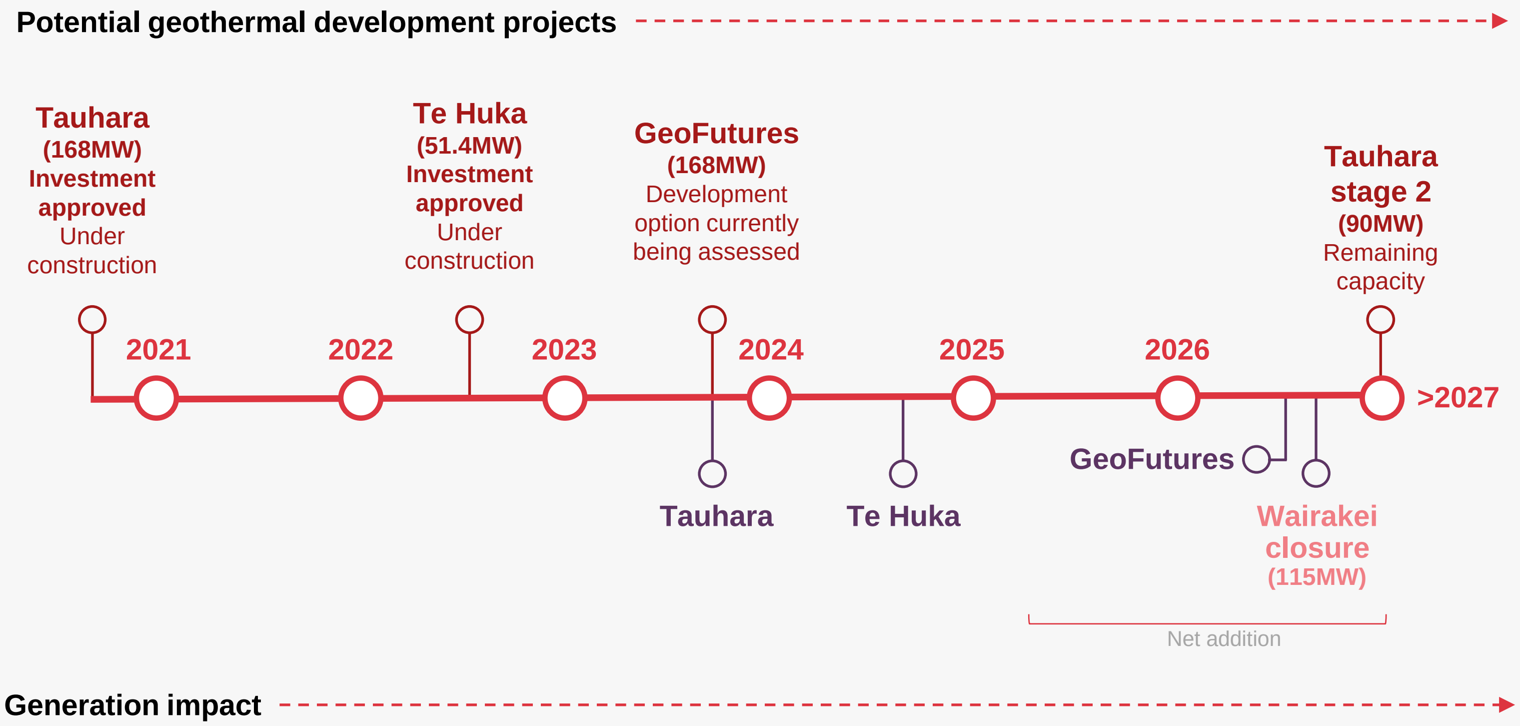
Market leading development pipeline

In line with core markets and capability

Geothermal generation potential (TWh p.a.)



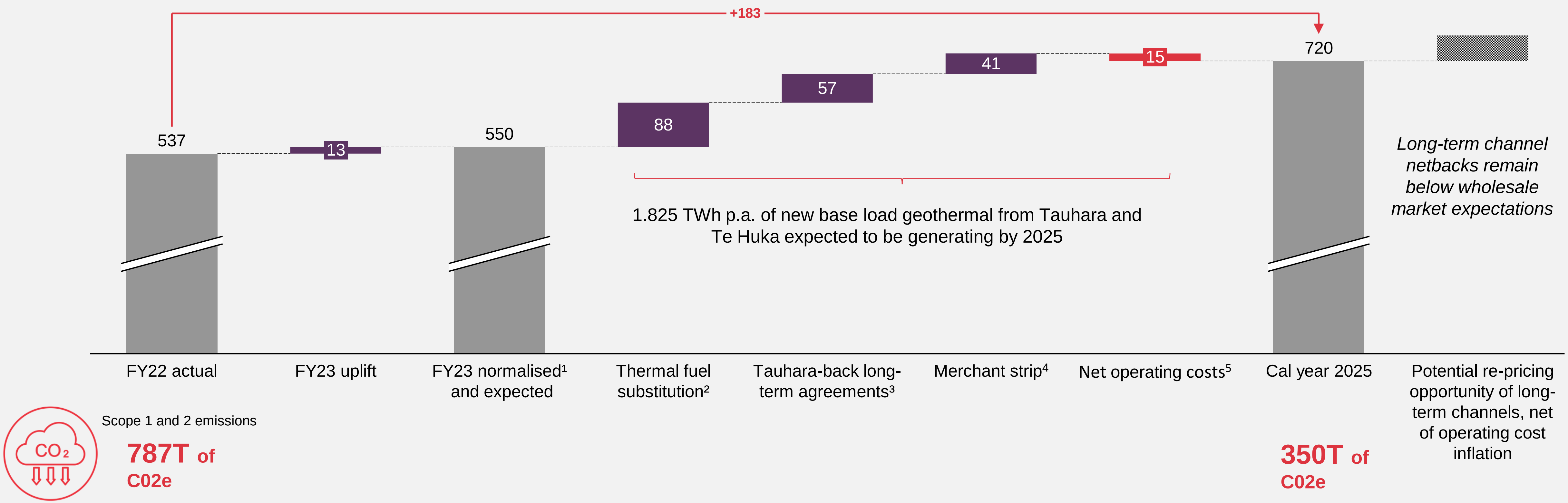
Geothermal field responses to extraction and injection will determine the ultimate geothermal generation potential beyond current consents.



*Expected enthalpy decline at Wairakei is expected to be offset through continuous improvement projects

Subject to Board investment decisions

Contact indicative EBITDAF after completion of announced investment programme

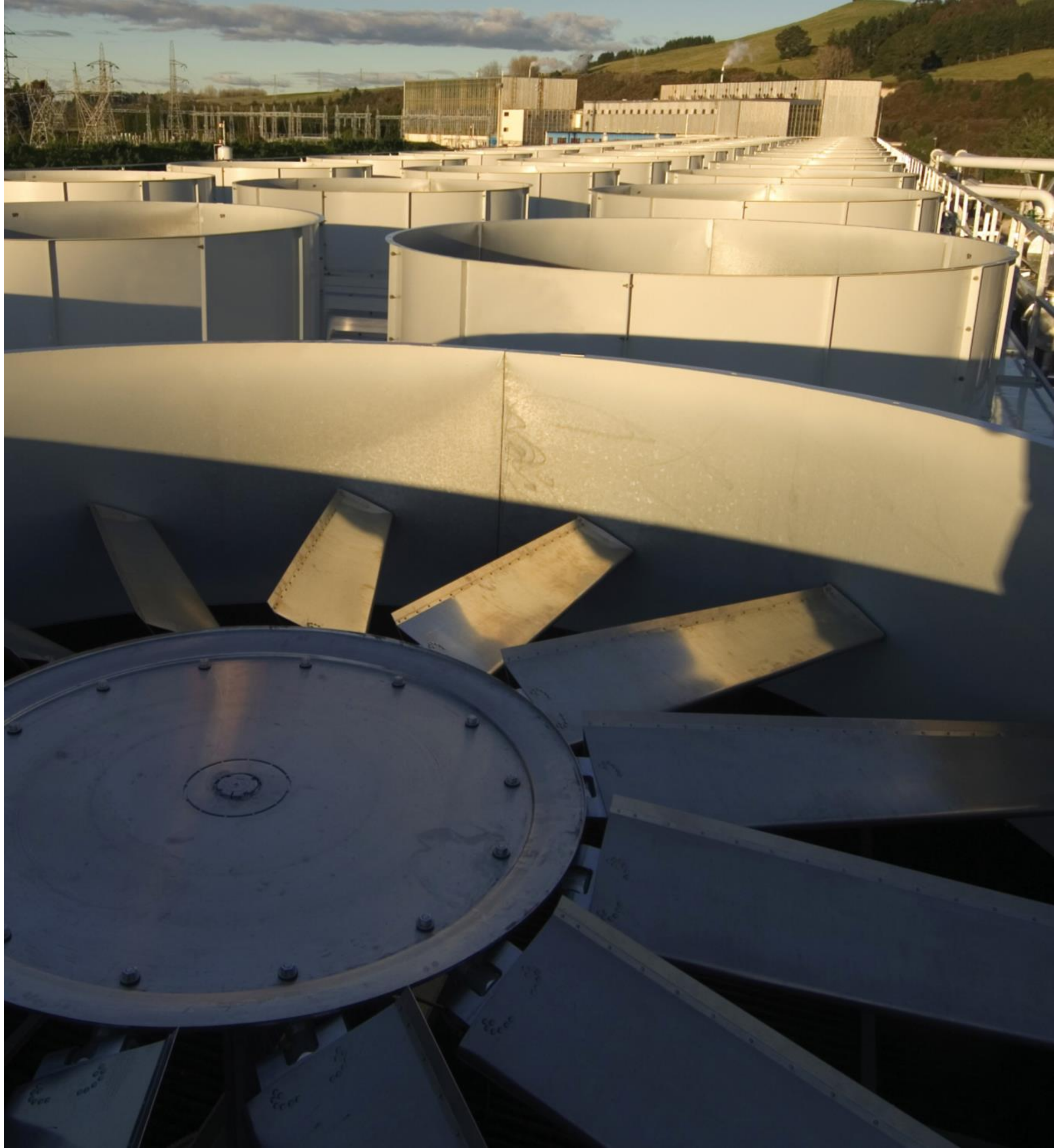


[1] See slide 28 for assumptions underpinning assumptions for FY23 normalised and expected earnings
[2] Substitution of around 875GWh of thermal generation from TCC and Te Rapa at the expected FY23 fuel cost of $115/MWh less net revenue from Fonterra linked to Te Rapa (steam and electricity sales)
[3] Expected revenue from long-term PPA electricity sales already signed
[4] Additional sales above the FY23 contracted position (250GWh) at the 2025 ASX average price of $162/MWh (as at 11 August 2022)
[5] Geothermal operating costs for new stations net of reduction in operating costs following the closure of thermal assets

Our operational plan: What you can expect in the next 12 months

Strategic theme	FY23	
Grow Demand	Decision of hydrogen export Enable the build of data centres Commence boiler electrification	Western Energy – invest in new coil tubing drilling
Grow renewable development	Tauhara build (cont.) Te Huka 3 build commences Secure consents for Wairakei post 2026 Commence solar and wind consenting	Progress GeoFutures development to FID Roxburgh turbine replacement Hydro transformers installed
Decarbonise our portfolio	Complete thermal review Prepare for end of TCC scheduled hours Te Rapa closure	
Create outstanding customer experiences	Customer technology upgrade (cont.) Launch of Electric Vehicle product Roll out of an additional adjacency product	

Questions



Supporting materials

Normalised and expected EBITDAF assumptions

With reconciliation to actual performance

FY22 assumptions that deliver expected & normalised EBITDAF of $520m over a financial year

1 Channel choices maximise long term value[1]		X	2 Net price[2] driven by best commercial practices	=	Total
Strategic fixed price	1,000GWh		$38/MWh		$38m
CFDs	1,660GWh		$139/MWh		$231m
C&I	1,600GWh		$104/MWh		$166m
Retail	3,550GWh		$126/MWh		$446m**
Other income[3]					$50m
					$931m

3 Hydrology & Asset availability optimise generation		X	4 Access to and price of fuel* drives financials & risk position	=	Total
Hydro mean	3,900GWh		$0/MWh		-$0m
Geothermal average	3,250GWh		$2/MWh		-$7m
Thermal	800GWh		$123/MWh[4]		-$98m
Acquired	300GWh		$131/MWh		-$39m
					-$144m

5 Trading delivers value to more than offset locational losses		6 Digitalisation & continuous improvement optimise fixed costs	
Length[5]	$58m	Transmission/Storage	-$60m
Location losses[6]	-$57m	Operating expenses	-$208m**
Total	**$1m**	**Total**	**-$268m**

EBITDAF reconciliation to FY22

Normalised & Expected

Higher renewables
Renewable generation above mean (+73GWh) saw less thermal generation at expected thermal SRMC

Gas, carbon and acquired generation costs
Achieved a better heat rate by prioritising TCC over the peakers

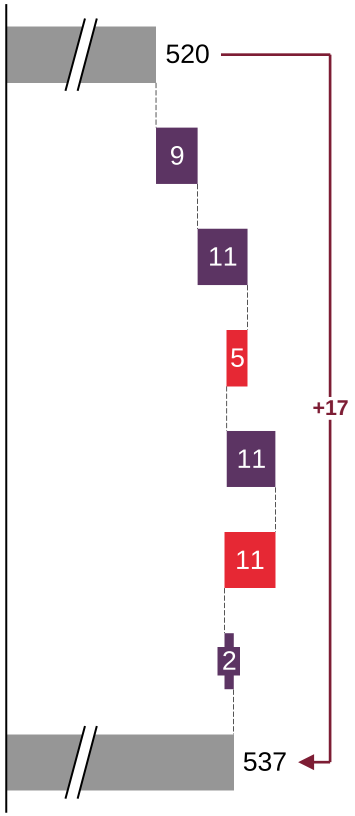
Electricity sales volume (net of thermal)
While sales volumes were higher than guidance the thermal costs to support this position were higher than the average sales price achieved

Electricity sales price
Achieved sales price up by $1.2/MWh vs guidance with a higher proportion of sales to market channels

Location losses
Volatile hydrology saw a wet South Island in 1H vs mean increasing losses and a higher generation volumes

Fixed costs and other income
Strong steam sales and lower transmission costs partially offset by larger market making losses

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 $8.4/GJ, carbon price of $37/unit and thermal portfolio heat rate (11.4GJ/MWh)
5. Length of 220GWh p.a. assumed
6. Locational losses of 5.6% on spot purchases and settlement of CFDs sold at a wholesale price of $125/MWh

*Fuel is natural gas and carbon costs
** Metering costs have been restated: Previously included in other operating costs now in Networks, Meters and Levies. Impact: Other operating costs $12m favourable, retail net price $12m unfavourable

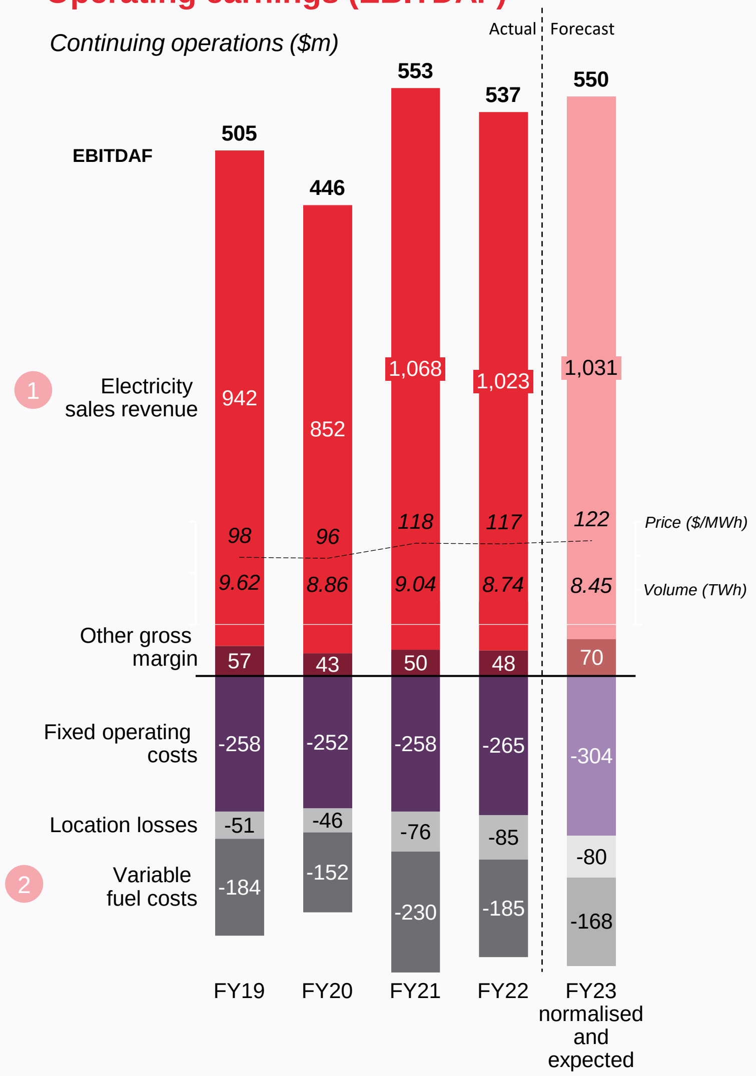
Guidance below EBITDAF

	FY22 guidance	FY22 result	FY23 guidance	Commentary
Stay in business capital expenditure (cash)	$88-98m	$75m	$88-$98m	**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.
Growth capital expenditure (cash)	n/a	$291m	$465m - $565m	Growth capital for Tauhara and Te Huka.
Depreciation and amortisation	$265 – 275m	$262m	$230 - 240m	Lower thermal asset depreciation to reflect the Te Rapa asset that is held for sale and an additional year of TCC operation into 2024.
Net interest (accounting)	$30 – 40m	$36m	$30 – 40m	Capitalisation of interest to growth capital projects (Tauhara and Te Huka).
Cash interest (in operating cash flow)	$20 – 30m	$28m	$10 – 20m	
Cash taxation	$85 – 95m	$89m	$110 – 120m	FY23 provisional payments based on higher FY21 results (FY22 provisional tax payments based on FY20).
Corporate costs	$28m	$28m	$42m	FY22 one-time benefits, inflation, and additional capacity and capability added to accelerate the delivery of the strategy.
Target ordinary dividend per share	35 cps	35 cps	35 cps	Pay-out in line with dividend policy (40% interim / 60% final)

Integrated portfolio performance

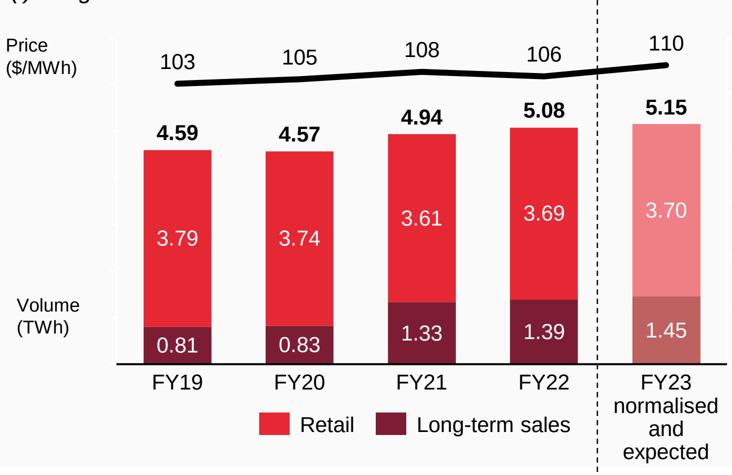
Operating earnings (EBITDAF)

Continuing operations ($m)

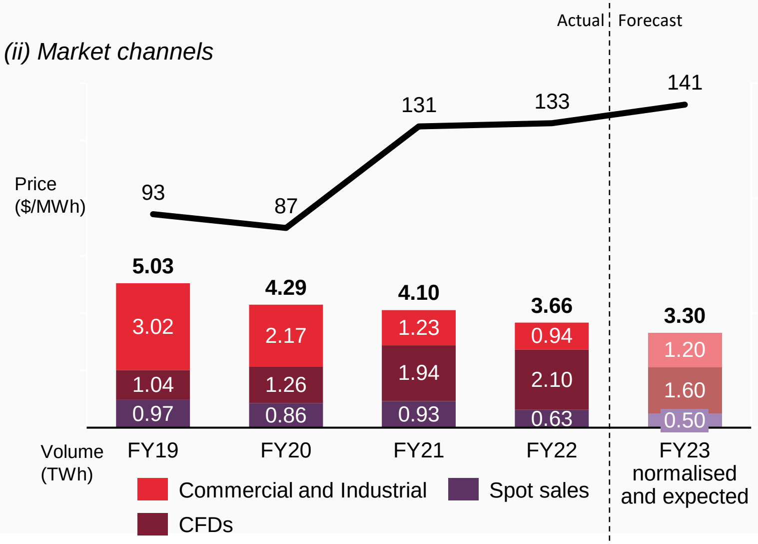


1 Electricity sales

(i) Long-term channels

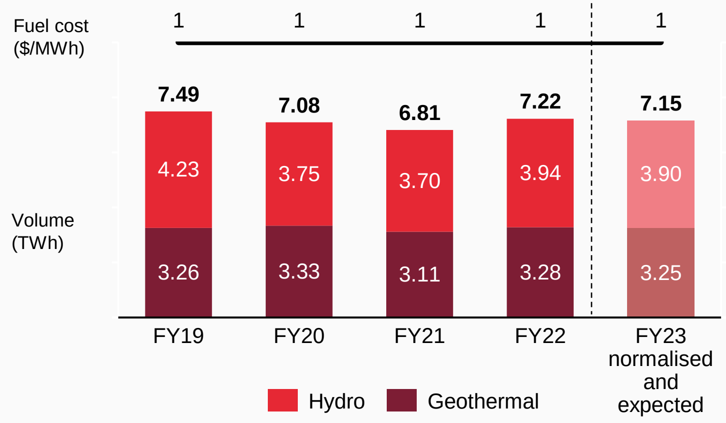


(ii) Market channels

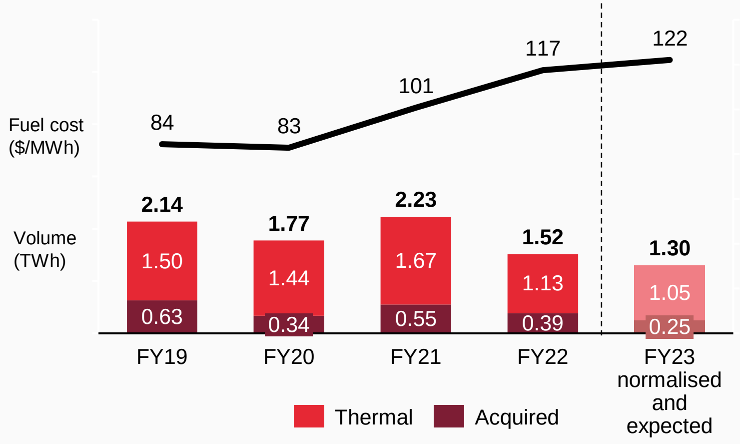


2 Variable fuel costs

(i) Renewables



(ii) Thermal and acquired

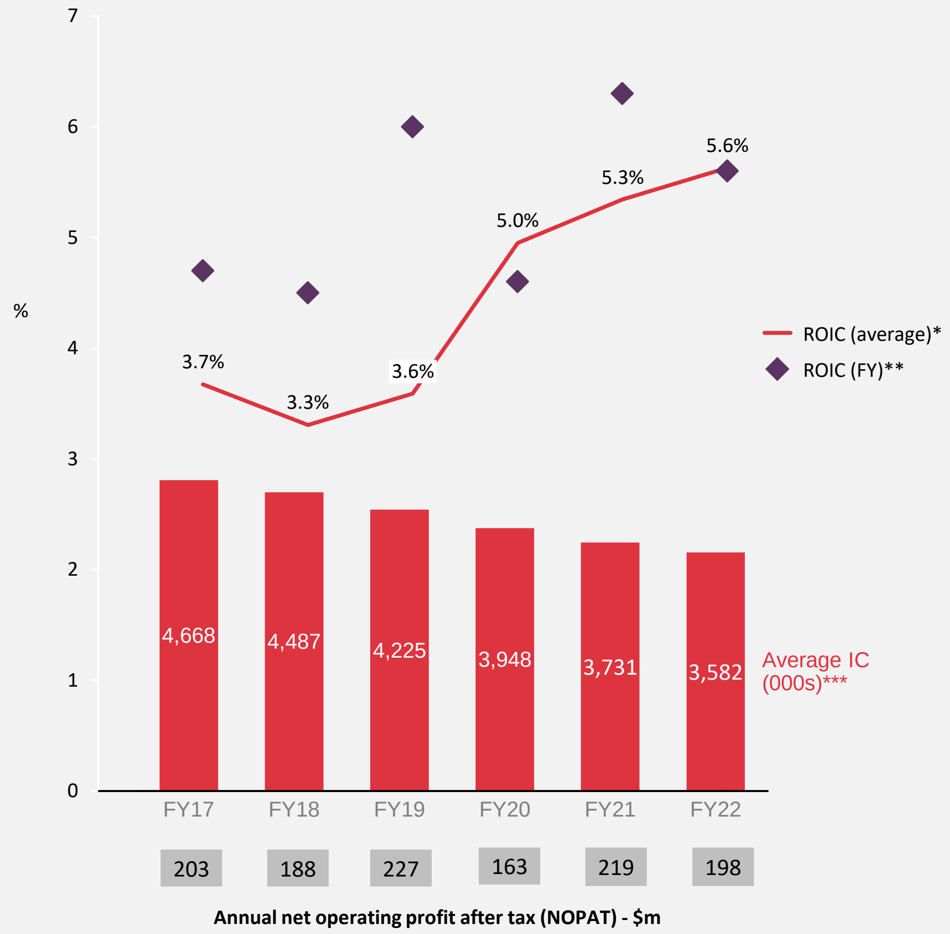


FY23 normalised and expected provides an indication of the expected FY23 performance from Contact in a mean hydrological year. If hydro inflows are below mean, then more thermal generation will be required to support the fixed sales position increasing costs and reducing operating earnings in line with the thermal and acquired fuel cost. There remans price risk in forward projections. See slide 28 for details around the contractual sales position

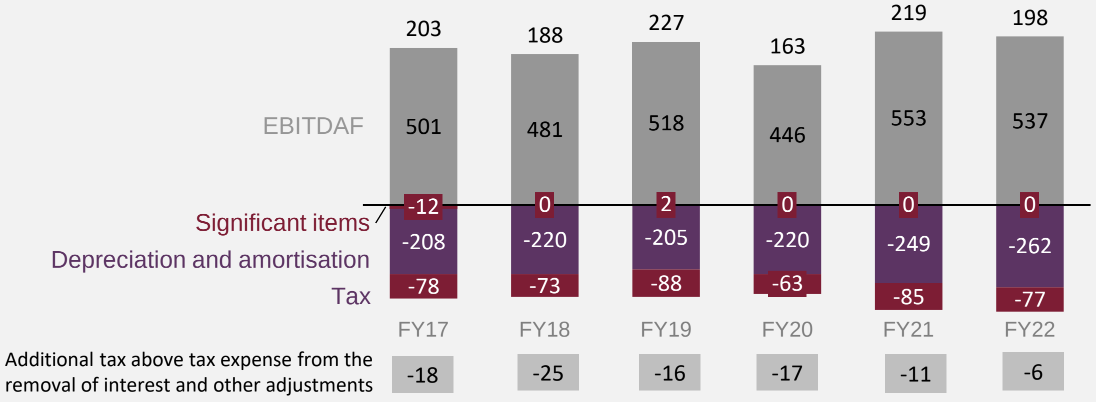
Return on invested capital

Focus on improving returns on invested capital through the medium term capex programme

Return on invested capital

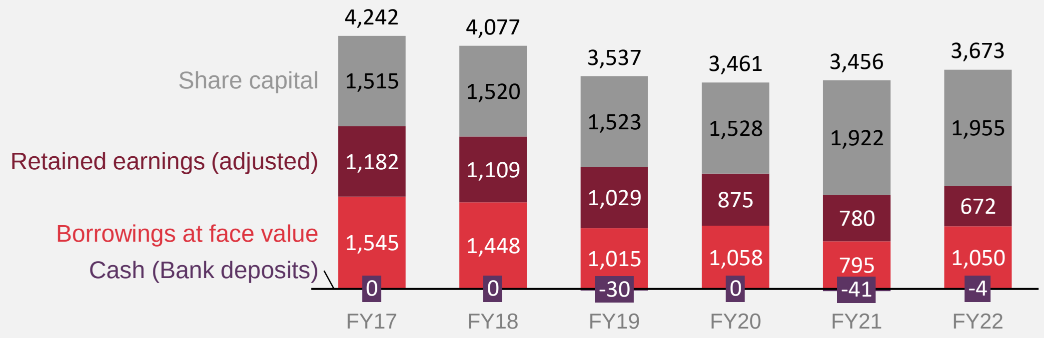


Net operating profit after tax (NOPAT)



	FY17	FY18	FY19	FY20	FY21	FY22
NOPAT	203	188	227	163	219	198
EBITDAF	501	481	518	446	553	537
Significant items	-12	0	2	0	0	0
Depreciation and amortisation	-208	-220	-205	-220	-249	-262
Tax	-78	-73	-88	-63	-85	-77
Additional tax above tax expense from the removal of interest and other adjustments	-18	-25	-16	-17	-11	-6

Invested capital (year-end balance)



	FY17	FY18	FY19	FY20	FY21	FY22
Total	4,242	4,077	3,537	3,461	3,456	3,673
Share capital	1,515	1,520	1,523	1,528	1,922	1,955
Retained earnings (adjusted)	1,182	1,109	1,029	875	780	672
Borrowings at face value	1,545	1,448	1,015	1,058	795	1,050
Cash (Bank deposits)	0	0	-30	0	-41	-4
Cumulative adjustment to retained earnings*****	52	85	259	259	268	286

* NOPAT (4-year average) /Average IC (4-year average)
** NOPAT (FY)/Average IC (FY)
*** Invested capital (opening + closing balance)/2

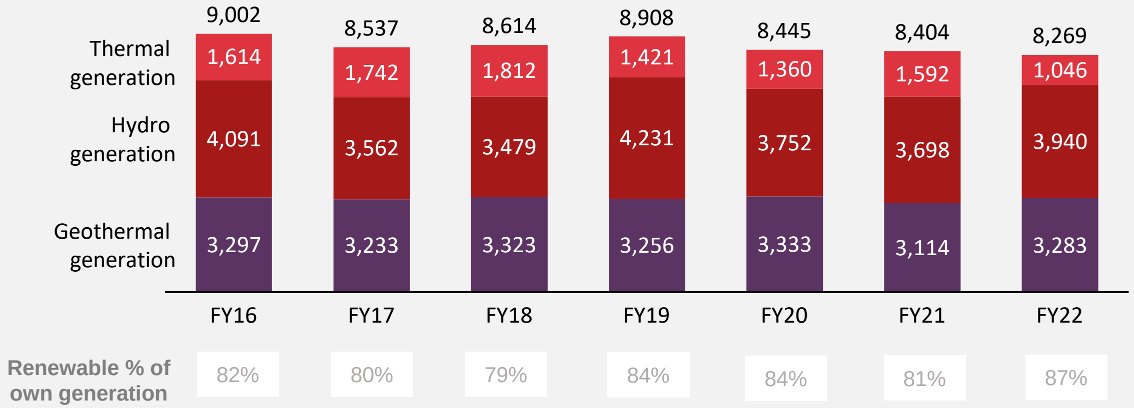
**** Tax for NOPAT does not include the benefit of interest deductibility in the reported current tax payment
***** Adjustments to retained earnings for profit on sale of assets and businesses, FV movement of financial instruments, these adjustments cumulatively cover the period FY13 to FY22.

Greenhouse gas emissions

Indicator	Unit	Target	FY19	FY20	FY21	FY22
Direct GHG emissions (Scope 1)	**tC02e**	45% reduction of 2018 Scope 1 and 2 emissions by 2026 (Absolute emissions reduction target)	**985,905**	**920,403**	**1,044,744**	**786,842**
- Stationary combustion	tC02e		984,903	920,403	1,044,537	786,544
- Mobile combustion	tC02e		880	270	178	297
- Fugitive emissions	tC02e		122	4	29	1
Indirect GHG emissions (Scope 2)	tC02e		**1,374**	**1,258**	**1,303**	**1,399**
Sub-total Scope 1 and 2	**tC02e**	**647,443**	**987,279**	**921,935**	**1,046,047**	**788,241**
Indirect GHG emissions (Scope 3)	**tC02e**	**259,118**	**524,314**	**317,384**	**555,035**	**394,784**
- Category 1 – Purchased goods and services	tC02e	30% reduction of 2018 Scope 3 GHG emissions from use of sold products by 2026.	35,267	39,397	16,699	6,371
- Category 2 – Capital goods	tC02e		6,536	18,052	41,726	57,876
- Category 3 – Fuel and energy	tC02e		175,811	91,857	330,207	149,743
- Category 4 - Upstream distribution and transportation	tC02e		628	14	27	444
- Category 5 – Waste	tC02e		148	123	149	108
- Category 6 – Business travel	tC02e		1,256	719	263	567
- Category 7 – Employee commuting	tC02e		514	606	306	832
- Category 11 – Use of sold products	tC02e		301,640	166,310	165,259	178,554
- Category 13 – Downstream leased assets	tC02e		445	306	399	289
- Category 14 – Franchise	tC02e		2,069			
Total Scope 1,2 and 3 emissions	**tC02e**	**906,561**	**1,511,081**	**1,239,319**	**1,601,082**	**1,183,025**

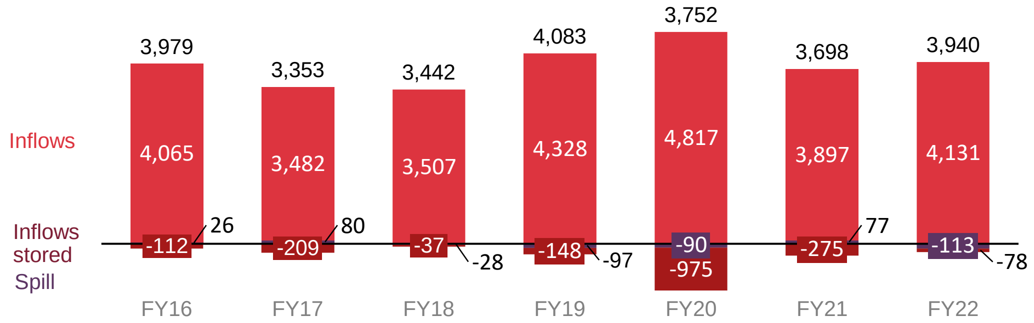
Generation and sales position

Contact generation output sold to the national grid (GWh)



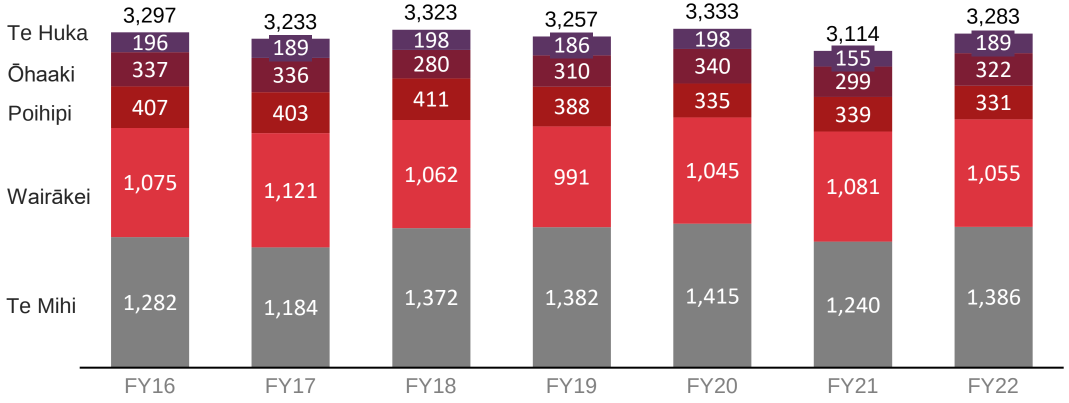
Hydro generation (GWh)

Inflows stored include uncontrolled storage lakes



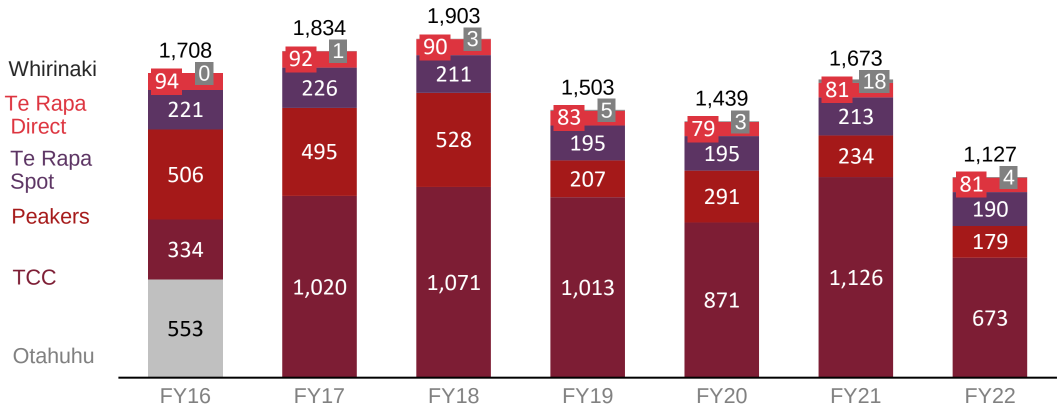
Hydro generation was 40GWh above mean (3,900GWh) in FY22, 242GWh higher than FY21. Inflows were consistent throughout the period which limited spill.

Geothermal generation (GWh)



Geothermal generation was 169GWh higher than FY21. FY21 had the 4-yearly statutory Te Mihi outage and an extended outage required on process safety improvements required at the Te Huka binary plant.

Thermal generation (GWh)

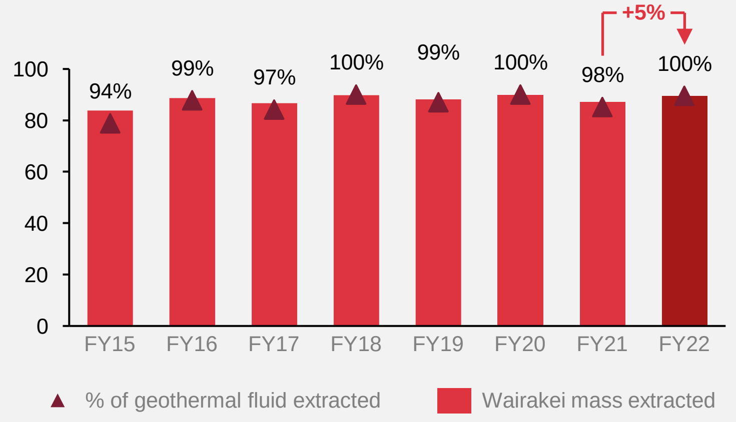


Thermal generation volumes were 546GWh lower than FY21 as a result of the strong renewable generation and low wholesale prices.

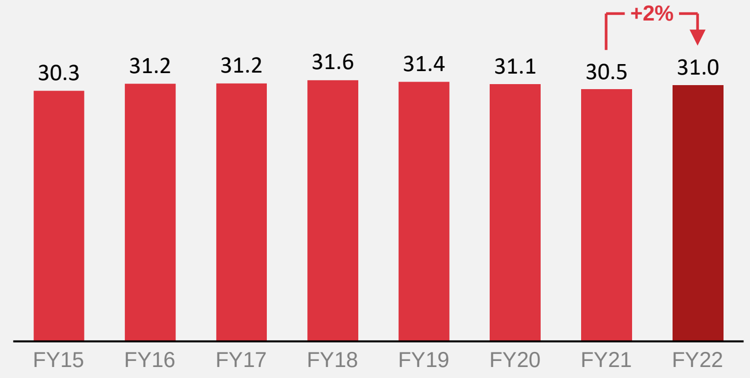
Plant and fuel performance

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)
FY18	784	95%	51%	3,479	78	271
FY19	784	97%	62%	4,231	123	521
FY20	784	92%	54%	3,752	90	338
FY21	784	84%	54%	3,698	167	617
FY22	784	83%	57%	3939	121	478

Taranaki combined cycle (TCC)

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
FY18	377	6	32%	1,071	102	110
FY19	377	63%	31%	1,031	115	117
FY20	377	88%	26%	870	120	104
FY21	377	89%	34%	1,126	193	217
FY22	377	84%	20%	672	180	121

Te Rapa (spot generation only)

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
FY18	41	87%	59%	211	94	20
FY19	41	96%	54%	195	160	31
FY20	41	98%	51%	184	106	21
FY21	41	93%	58%	208	174	37
FY22	41	95%	54%	195	145	28

Geothermal

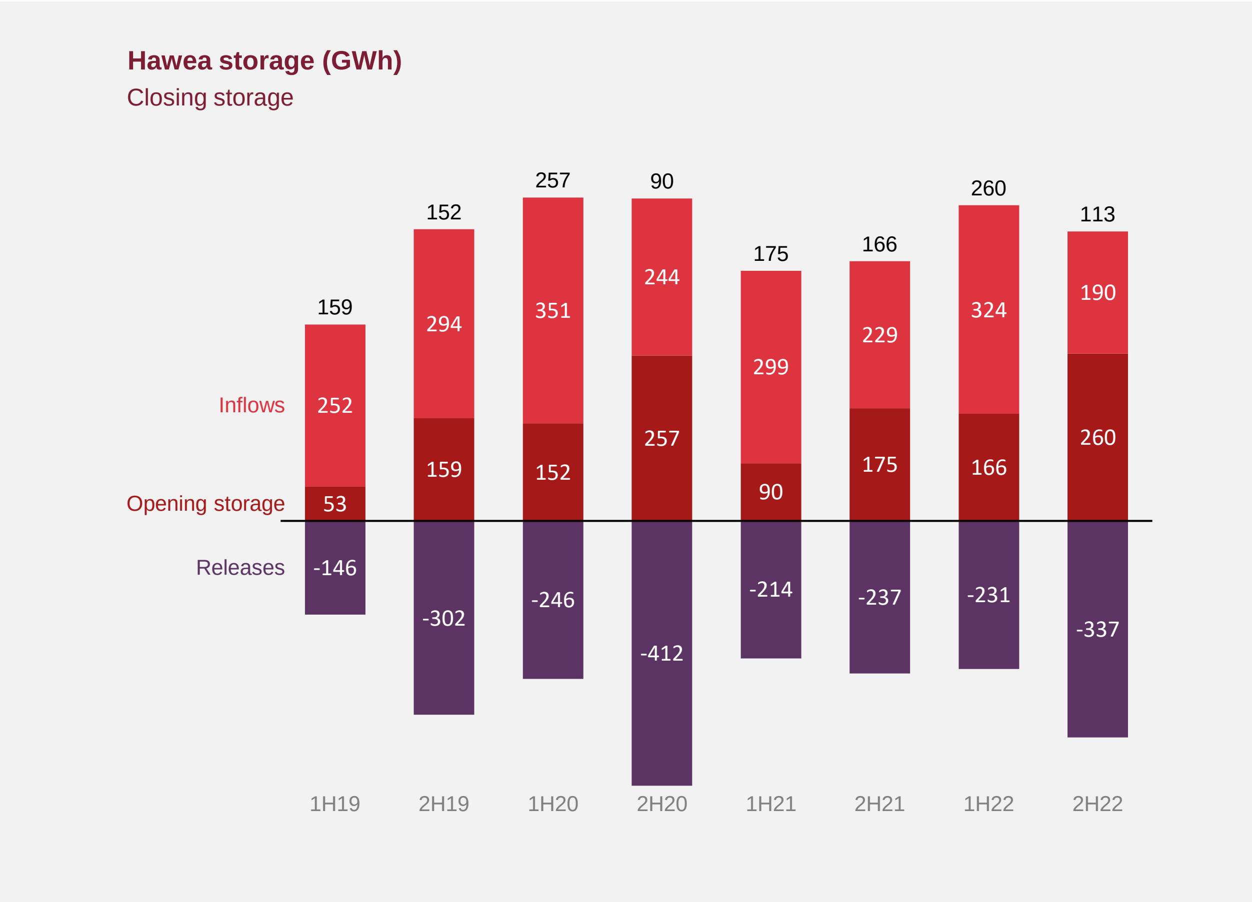
	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
FY18	425	96%	89%	3,323	80	267
FY19	425	92%	87%	3,256	133	434
FY20	425	95%	89%	3,333	99	330
FY21	425	89%	84%	3,114	175	546
FY22	425	97%	91%	3,284	140	458

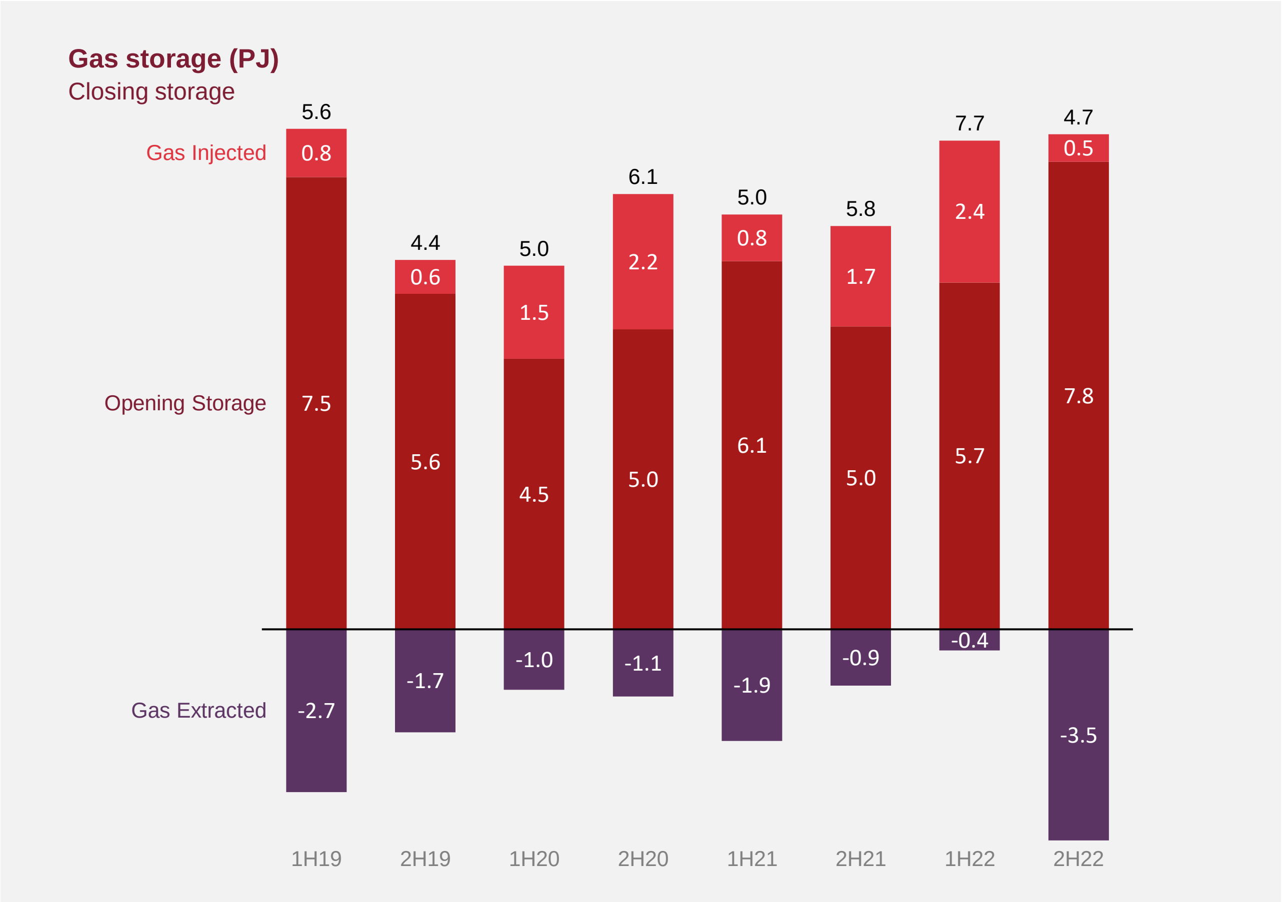
Peakers (including Whirinaki)

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
FY18	360	87%	17%	530	116	62
FY19	360	79%	7%	212	192	41
FY20	360	88%	9%	295	162	48
FY21	360	92%	8%	249	230	54
FY22	360	71%	6%	179	220	40

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

Fuel storage movements



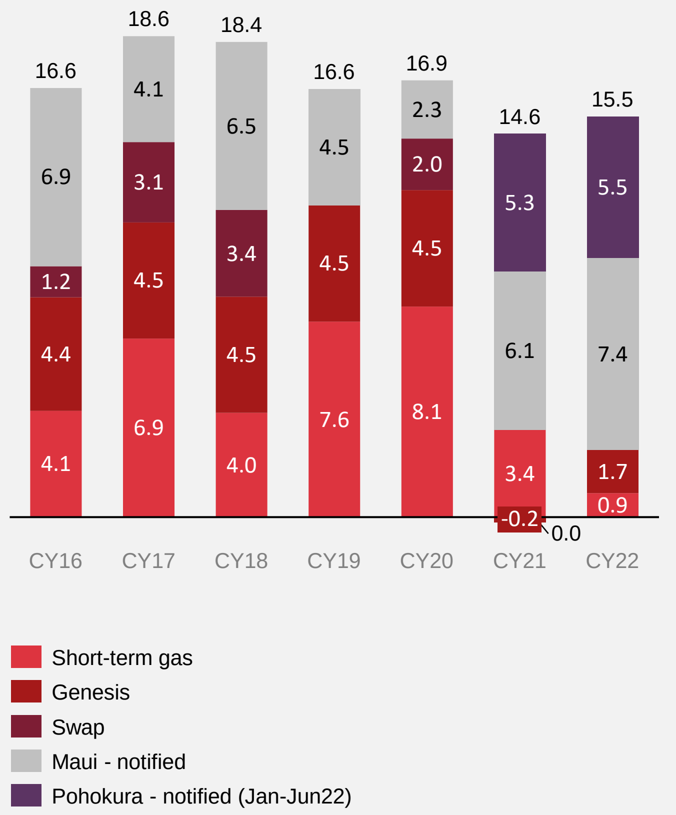


In late 2021 we were notified of an unexpected and unexplained increase in pressure recorded in the Ahuroa Gas Storage Facility (AGS) by the owner and operator of the facility, FlexGas. In conjunction with FlexGas, we will be assessing the potential implications of this on our contractual rights over the next several months. We will support a prudent operating regime and will adapt our injection into the facility to maintain appropriate facility pressures. In a fuel short market, this is not expected to have any financial impact.

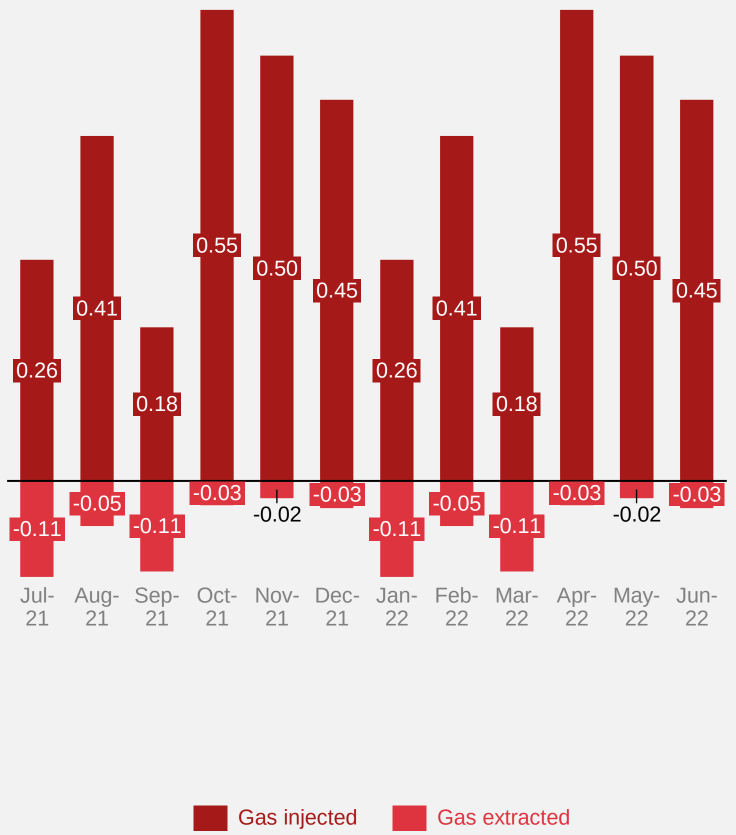
Source: NZX hydro

Contracted and stored gas

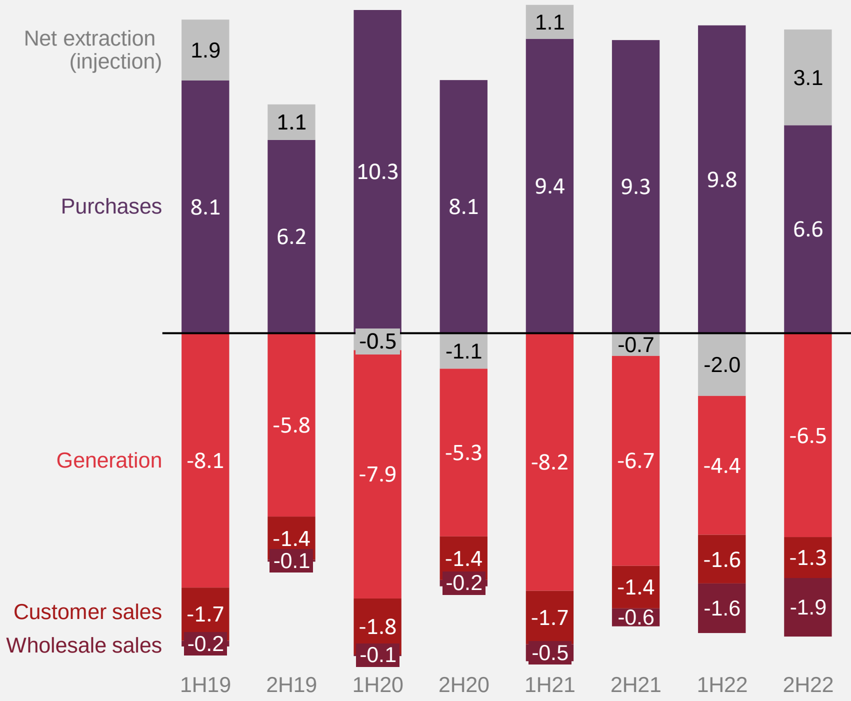
Contracted gas volumes (PJ)



Gas storage monthly injections and extractions (PJ)



Uses of gas (PJ)



Storage balance at 30 June 2022 was 4.7PJs

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:

	12 months ended 30 June 2022	12 months ended 30 June 2021	Variance on prior year	
			$m	%
Profit	**182**	**187**	**(5)**	**(1%)**
Depreciation and amortisation	262	249	13	5%
Change in fair value of financial instruments	(14)	(7)	(7)	(100%)
Net interest expense	36	50	(14)	(28%)
Tax expense	71	74	(3)	(4%)
EBITDAF	**537**	**553**	**(16)**	**(3%)**

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 FY21 are as follows:

- **Depreciation and amortisation:** Increased by $13m (5%) on FY21 primarily resulting from acceleration of depreciation for aspects of SAP due to SAP upgrade project.
- **Net interest expense:** Reduced by $14m (28%) with lower average borrowings post 2021 equity raise as well as the capitalisation of interest relating to the Tauhara geothermal project.
- **Tax expense** for the period decreasing by $3m following lower operating earnings. Higher depreciation offset by lower net interest expense. Tax expense for FY22 represents an effective tax rate of 28%. The effective tax rate for FY21 was 28%.

Historical financial information

	Unit	FY18	FY19	FY20	FY21	FY22
Revenue	$m	2,275	2,519	2,073	2,573	2,387
Expenses	$m	1,794	2,001	1,622	2,020	1,850
EBITDAF	$m	481	518	446	553	537
Profit	$m	132	345	125	187	182
Operating free cash flow	$m	305	301	341	290	325
Operating free cash flow per share	cps	42.6	42	47.5	40.4	41.8
Dividends declared	cps	26	32	39	39	35
Total assets	$m	5,311	4,954	4,896	5,028	5,166
Total liabilities	$m	2,584	2,172	2,275	2,101	2,326
Total equity	$m	2,727	2,782	2,621	2,927	2,840
Gearing ratio[1]	%	35	28	31	23	23

[1] 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	FY22 Twelve months ended 30 June 2022 Volume GWh	GWAP $/MWh	$m	FY21 Twelve months ended 30 June 2021 Volume GWh	GWAP $/MWh	$m	Reference number for Wholesale segment note (see following page)
Electricity sales to Retail segment	**3,689**	**107.0**	**395**	**3,605**	**93.7**	**338**	1
Electricity sales to C&I (netback)	1,373	94.8	130	1,762	82.3	145	
Electricity sales – Direct	81	134.3	11	81	111.1	9	2
Electricity sales to C&I	**1,454**	**97.0**	**141**	**1,844**	**83.6**	**154**	
CfDs – Tiwai support	875			734			
CfDs - Long term sales	470			531			3
CfDs - Short term sales	1,627			1,408			
Electricity sales - CFDs	**2,972**	**108.7**	**323**	**2,673**	**109.7**	**293**	
Total contracted electricity sales	**8,114**	**105.9**	**859**	**8,121**	**96.7**	**785**	
Steam sales	**595**	**55.7**	**33**	**645**	**43.7**	**28**	4
Other income			(10)			5	5
Net income on gas sales			3			2	6
Net income on electricity related services			(1)			1	7
Net other income			**(7)**			**16**	
Total contracted revenue (1)	**8,709**	**101.6**	**885**	**8,766**	**93.4**	**821**	
Generation costs	8,350	(33.8)	(283)	8,486	(38.3)	(316)	8
Acquired generation cost	389	(142)	(55)	554	(116.8)	(65)	9
Generation costs (including acquired generation) (2)	**8,739**	**(38.6)**	**(338)**	**9,040**	**(43.1)**	**(381)**	
Spot electricity revenue	8,269	136.6	1,129	8,404	176.4	1,482	10
Settlement on acquired generation	389	160.1	62	554	207.6	115	11
Spot revenue and settlement on acquired generation (GWAP)	**8,658**	**137.6**	**1,192**	**8,959**	**178.3**	**1,597**	
Spot electricity cost	(5,062)	(153.1)	(775)	(5,367)	(185.9)	(998)	12
Settlement on CFDs sold	(2,972)	(139.8)	(415)	(2,673)	(191.3)	(511)	13
Spot purchases and settlement on CFDs sold (LWAP)	**(8,033)**	**(148.2)**	**(1,190)**	**(8,040)**	**(187.7)**	**(1,509)**	
Trading, merchant revenue and losses (3)			**1**			**88**	
Wholesale EBITDAF (1+2+3)			**548**			**527**	

Wholesale segment key

	Wholesale segment	Reference to detailed operating segment performance	Comment
Revenue	C&I electricity – fixed price	2	
	C&I electricity – pass through	2-pass through	Spot sales are regarded as a pass-through and not reflected in performance reporting, any margin included in C&I netback
	Wholesale electricity, net of hedging	3 + 10 + 13	
	Electricity related services revenue	7	
	Inter-segment electricity sales	1	
	Gas	6	Revenue from wholesale gas sales, purchase cost of gas and diesel purchases
	Steam	4	
	Other income / other market costs	5	Note: In FY22 a $15m loss was recognised on the close out of CFDs in the financial statements. For management reporting these were netted off against CFD gross revenue as the mark-to-market of the close out was reflected there
Costs	Electricity purchases, net of hedging	9 + 11 + 12	
	Electricity purchases – pass through	2-pass through	Spot sales are regarded as a pass-through
	Electricity related services cost	7	
	Gas and diesel purchases	8 (less costs identified relating to 6)	Includes wholesale gas sales purchases (if any)
	Gas storage costs	8	
	Carbon emissions	8	
	Generation transmission and reserve costs	8	
	Electricity networks, transmission and meter costs – fixed price	2	
	Electricity networks, transmission and meter costs – pass through	2-pass through	Spot sales are regarded as a pass-through
	Gas networks, transmission and meter costs	8	
	Other operating expenses	8 (less costs identified relating to 2)	C&I operating costs are included in the calculation of netback (2) and are excluded from generation operating costs

Retail segment

Residential electricity	unit	FY19	FY20	FY21	FY22
Average connections	#	353,105	355,073	357,117	373,347
Sales volumes	GWh	2,491	2,532	2,520	2,644
Average usage	MWh per ICP	7.1	7.1	7.1	7.1
Tariff	$/MWh	251.7	250.4	253.4	256.4
Network, meters and levies	$/MWh	-126.0	-122.1	-118.0	-119.5
Energy costs	$/MWh	-89.5	-94.8	-100.2	-115.0
Gross margin	**$/MWh**	**36.2**	**33.5**	**35.2**	**21.9**
Gross margin	$ per ICP	256	239	249	155
Gross margin	$m	90	85	89	58

Residential gas	unit	FY19	FY20	FY21	FY22
Average connections	#	61,711	61,591	60,701	64,649
Sales volumes	TJ	1,605	1,577	1,495	1,583
Average usage	GJ per ICP	26.0	25.6	24.6	24.5
Tariff	$/GJ	31.5	33.1	35.3	36.6
Network, meters and levies	$/GJ	-18.9	-18.5	-18.6	-18.7
Energy costs	$/GJ	-5.8	-7.9	-8.6	-11.8
Carbon costs	$/GJ	-1.0	-1.4	-1.5	-2.1
Gross margin	**$/GJ**	**5.8**	**5.3**	**6.5**	**4.1**
Gross margin	$ per ICP	153	136	107	101
Gross margin	$m	9	8	10	7

SME electricity	unit	FY19	FY20	FY21	FY22
Average connections	#	55,020	55,033	49,679	48,459
Sales volumes	GWh	1,042	991	860	798
Average usage	MWh per ICP	18.9	18.0	17.3	16.5
Tariff	$/MWh	226.8	229.3	231.7	239.7
Network, meters and levies	$/MWh	-113.4	-115.8	-106.4	-112.9
Energy costs	$/MWh	-87.7	-93	-99.3	-113.7
Gross margin	**$/MWh**	**25.7**	**20.5**	**26.1**	**13.0**
Gross margin	$ per ICP	488	369	451	215
Gross margin	$m	27	20	22	10

SME gas	unit	FY19	FY20	FY21	FY22
Average connections	#	3,901	3,949	3,876	3,889
Sales volumes	TJ	1,492	1,441	1,313	1,224
Average usage	GJ per ICP	382	365	339	315
Tariff	$/GJ	15.1	15.4	16.3	19.8
Network, meters and levies	$/GJ	-5.5	-6.0	-7.9	-8.7
Energy costs	$/GJ	-5.8	-7.9	-8.6	-11.8
Carbon costs	$/GJ	-0.9	-1.4	-1.5	-2.1
Gross margin	**$/GJ**	**2.9**	**0.2**	**-1.6**	**-2.7**
Gross margin	$ per ICP	1093	63	-552	-858
Gross margin	$m	4	0	-2	-3

Broadband	unit	FY19	FY20	FY21	FY22
Average connections	#	5.692	19,979	39,245	62,388
Tariff	$/cust/mth	97.7	70.1	68.2	70.1
Network, provisioning, modems	$/cust/mth	-89.7	-69.6	-69.9	-60.5
Gross margin	$/cust/mth	**8.0**	**0.5**	**-1.6**	**9.6**
Gross margin	$m	0.4	0.1	-1	7

Retail segment EBITDAF		FY19	FY20	FY21	FY22
Electricity Gross margin	$m	117	105	111	68
Gas Gross Margin	$m	14	9	8	3
Broadband Gross Margin	$m	0	0	-1	7
Total Gross Margin	**$m**	**131**	**114**	**118**	**79**
Other income	$m	4	5	6	7
Other operating costs	$m	-69	-69	-68	-68
Retail segment EBITDAF	**$m**	**67**	**50**	**55**	**17**
Corporate allocation (50%)	$m	-13	-15	-15	-14
Retail EBITDAF	**$m**	**54**	**35**	**40**	**3**
EBITDAF margins (% of revenue)	%	5.7%	3.6%	4.3%	0.3%

During FY22 metering costs of $13m, 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.