2021 Interim Results Presentation

Six months ended 31 December 2020

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1H21 performance highlights

Mike Fuge, CEO

Financial performance strong; as portfolio positioning and active channel management offset rising thermal generation costs

	Six months ended 31 December 2020 (1H21)	Six months ended 31 December 2019 (1H20)	
EBITDAF[1]	$246m	↑	11% from $221m
Profit	$78m	↑	32% from $59m
Operating free cash flow[2]	$157m	↑	31% from $120m
Operating free cash flow per share[2]	21.9 cps	↑	30% from 16.8 cps
Stay-in-business (SIB) capital expenditure (cash)	$31m	↑	15% from $27m

1 Refer to slides 36 for a definition and reconciliation of EBITDAF and underlying profit

2 Refer to note A3 of the 2021 interim financial statements for a definition and reconciliation between cash flow from operating activities and the non-GAAP measure operating free cash flow. Operating free cash flow represents cash available to repay debt, to fund distributions to shareholders and growth capital expenditure.

Operating earnings (EBITDAF[1]) were up by $25m when compared to 1H20.

The operating conditions in 1H21 were characterised by significant uncertainty around:

- The near-term future of major energy users, including NZAS.
- The future deliverability of gas from declining gas fields.

Despite the uncertainty in operating conditions, active channel management, combined with strong asset availability, saw Contact capture higher wholesale prices and disciplined commodity risk management to control fuel risks delivered an improved financial performance over 1H20.

Contact completed a suite of major statutory geothermal outages in the period on time and under budget.

Key organisational highlights from 1H21

A resilient business with strong systems and capability

- Enterprise-wide programme management office set up identifying opportunities to improve performance
  - Transforming Ways of Working (TWOW) programme to redesign all aspects of our work at Contact
  - Consolidated physical office space
  - Converted a second bilateral bank facility into a Sustainability Linked Loan.

- Digital self service interactions up 45%
- Launch of fully integrated chat service channel
- NPS growth from +17 for FY20 to +30 in 1H21
- Over 500k energy and broadband connections, year on year increase of 2.2%

- Major outages were managed well with net uplifts in generation when geothermal plant returned.
- Managed fuel appropriately in line with changes in the market.
- Safety issues at a minimum with a high level of outages in 1H21

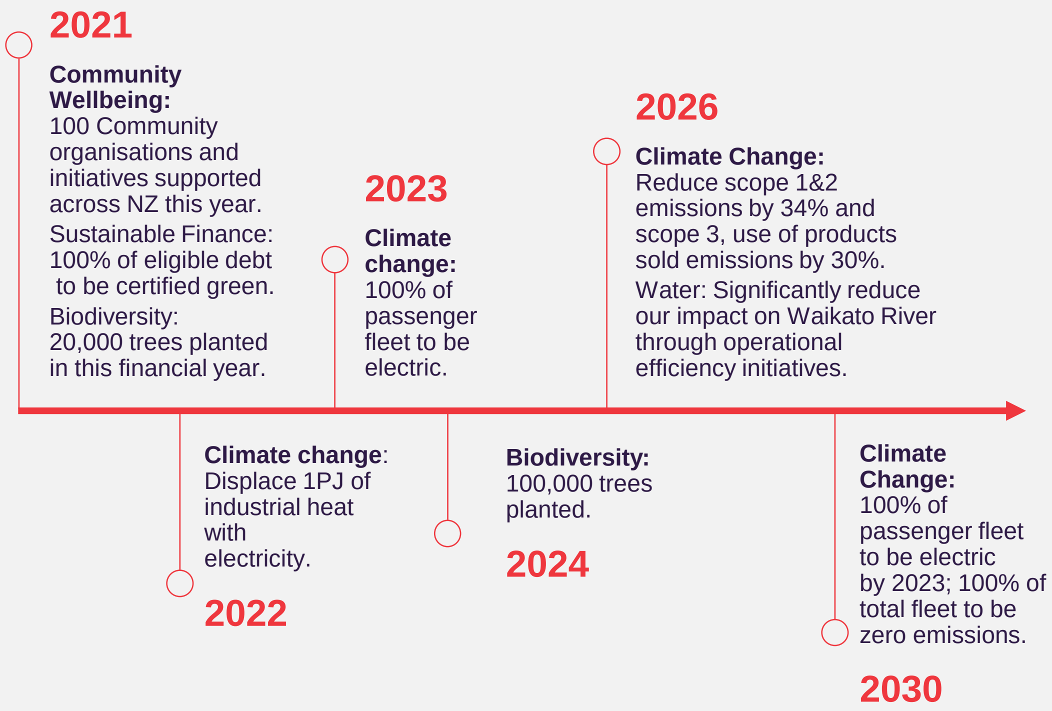
ESG targets

Contact has set ESG targets aimed at creating value by driving positive outcomes for our communities and environment

ESG performance dashboard

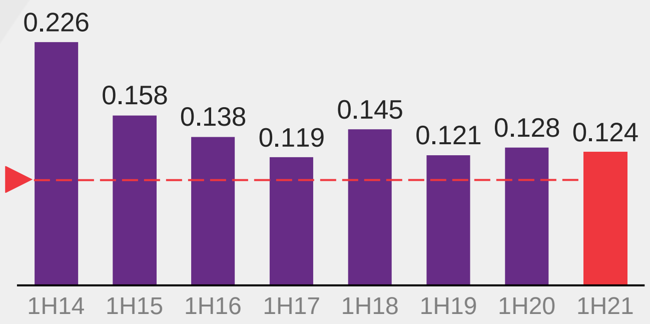
Theme	Current position	Target
Climate Change	- 22% reduction on scope 1&2 emissions achieved - 53% electric passenger fleet	- 1PJ of gas equivalent industrial heat displaced - Reduce scope 1 and 2 emissions by 34%, Scope 3 by 30% - 100% electric passenger fleet - 100% total fleet to be zero emissions
Water	Project to reconsent Wairakei operations and baseline environmental studies conducted on Waikato River.	Reduce impact on Waikato River by reducing operational discharges.
Biodiversity	25k trees expected to be planted 2021	100k trees planted by 2024
Community Wellbeing	37 community orgs supported across NZ	100 community orgs supported across NZ
Energy Hardship	$97k spent (1,005 families / households)	$250k dedicated
Diversity	46% / 54%	Between 40-60% gender balance
Sustainable Finance	- 87% of eligible debt certified green - 2 bi-lateral bank facilities converted to sustainability linked loans - 62 percentile in the Dow Jones Sustainability Initiative (DJSI)	- 100% of eligible debt certified green - All bi-lateral bank facilities converted to sustainability linked loans. - Inclusion in the Asia Pacific Index of DJSI (currently 67 percentile)

Timeline

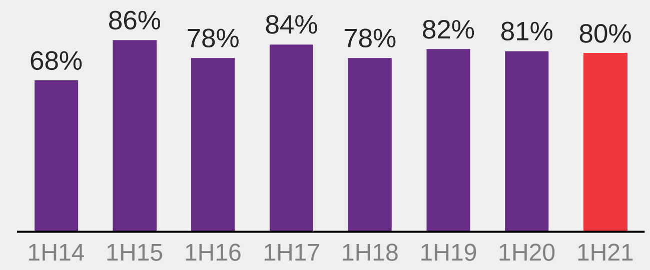


We take a holistic view on our operations to benefit all stakeholders

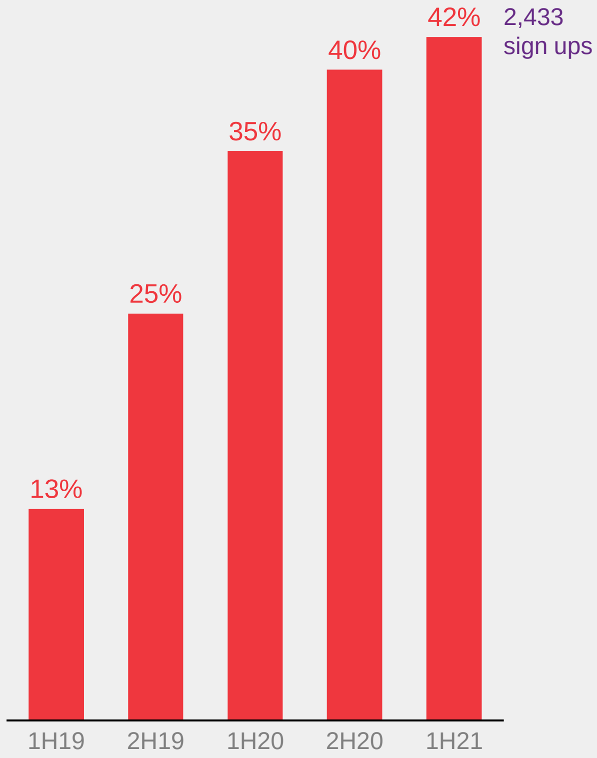
Total generation emissions intensity
tCO2-e / MWh



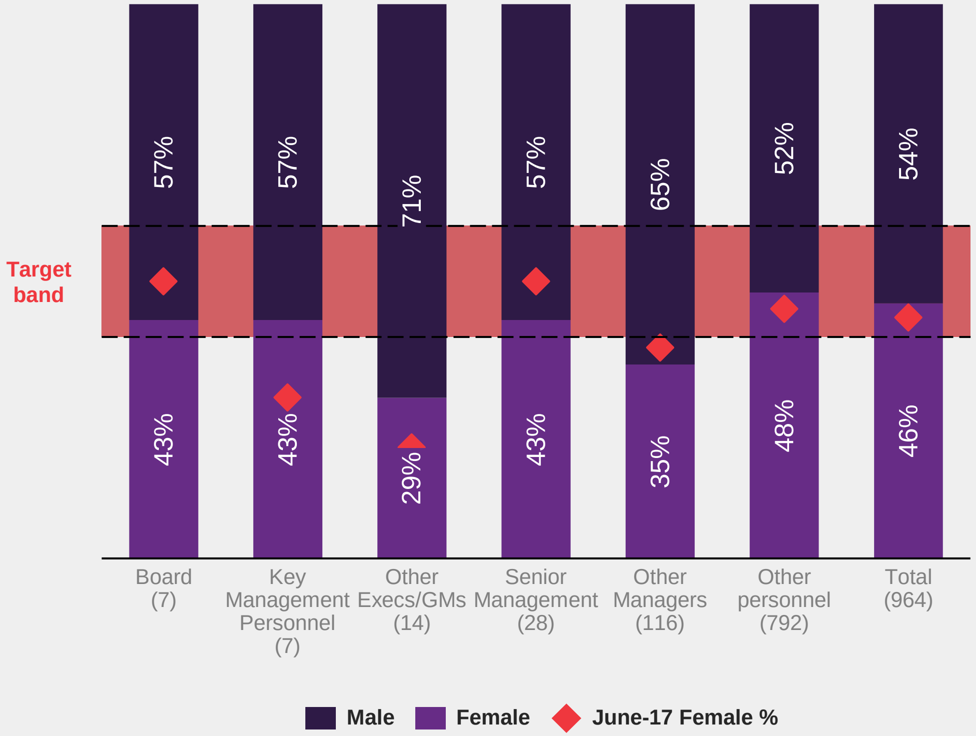
Renewable generation
% of total generation



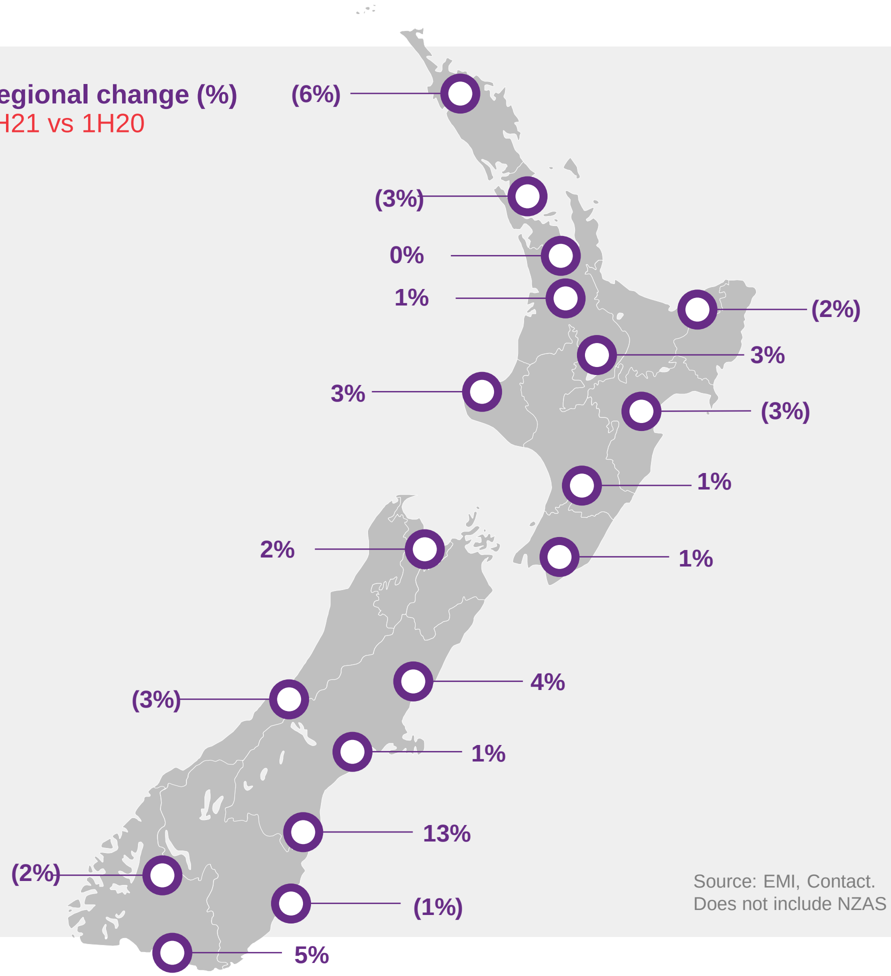
Customers with impaired credit now accepted
% of impaired credit customers accepted



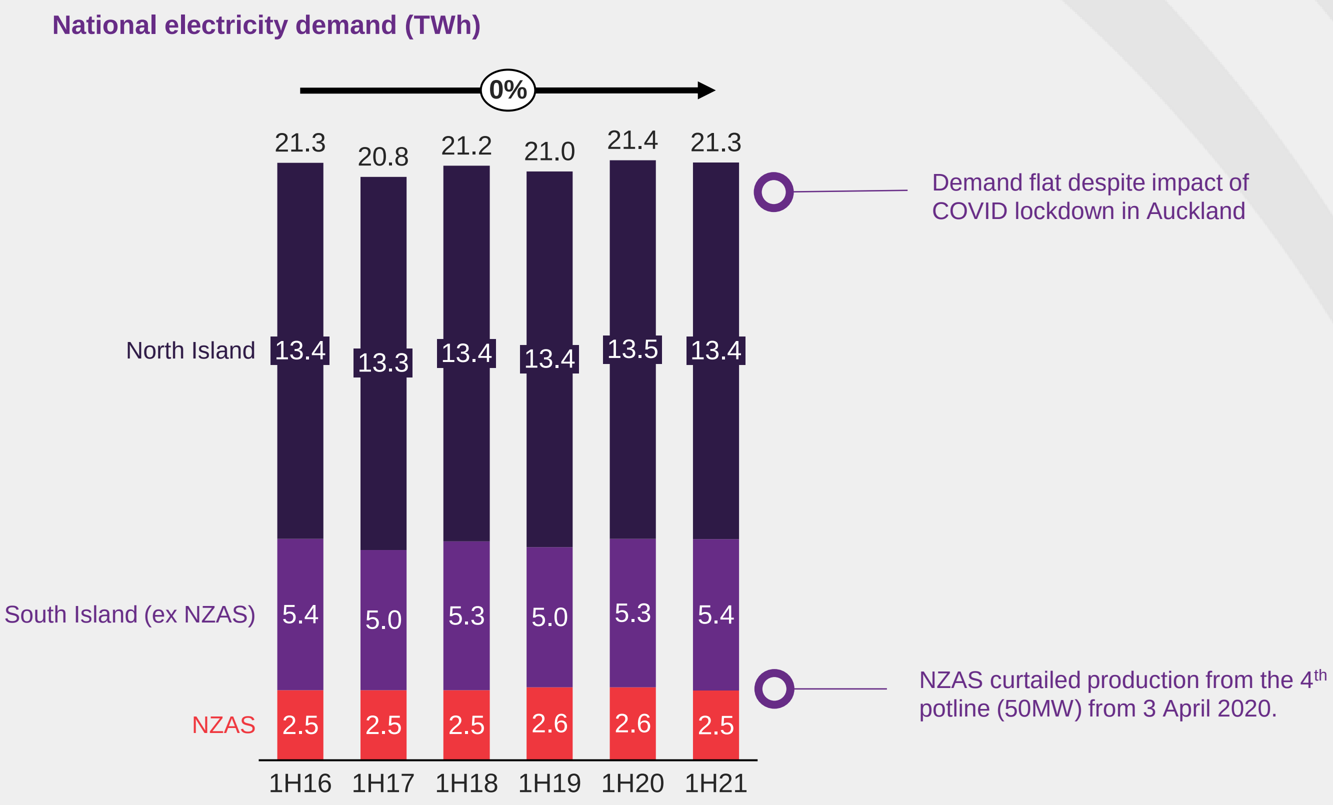
Gender diverse workforce
% of total workforce



National electricity demand



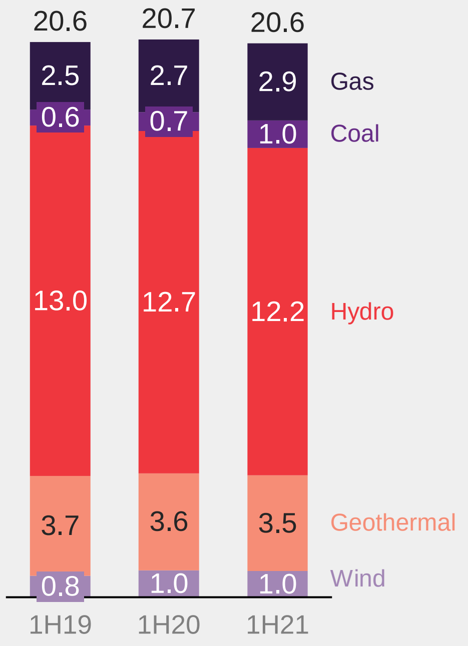
Source: EMI, Contact.
Does not include NZAS



Source: EMI, Contact

Hydrology and impact on generation mix

Generation by type (TWh)
Generation from generator retailers

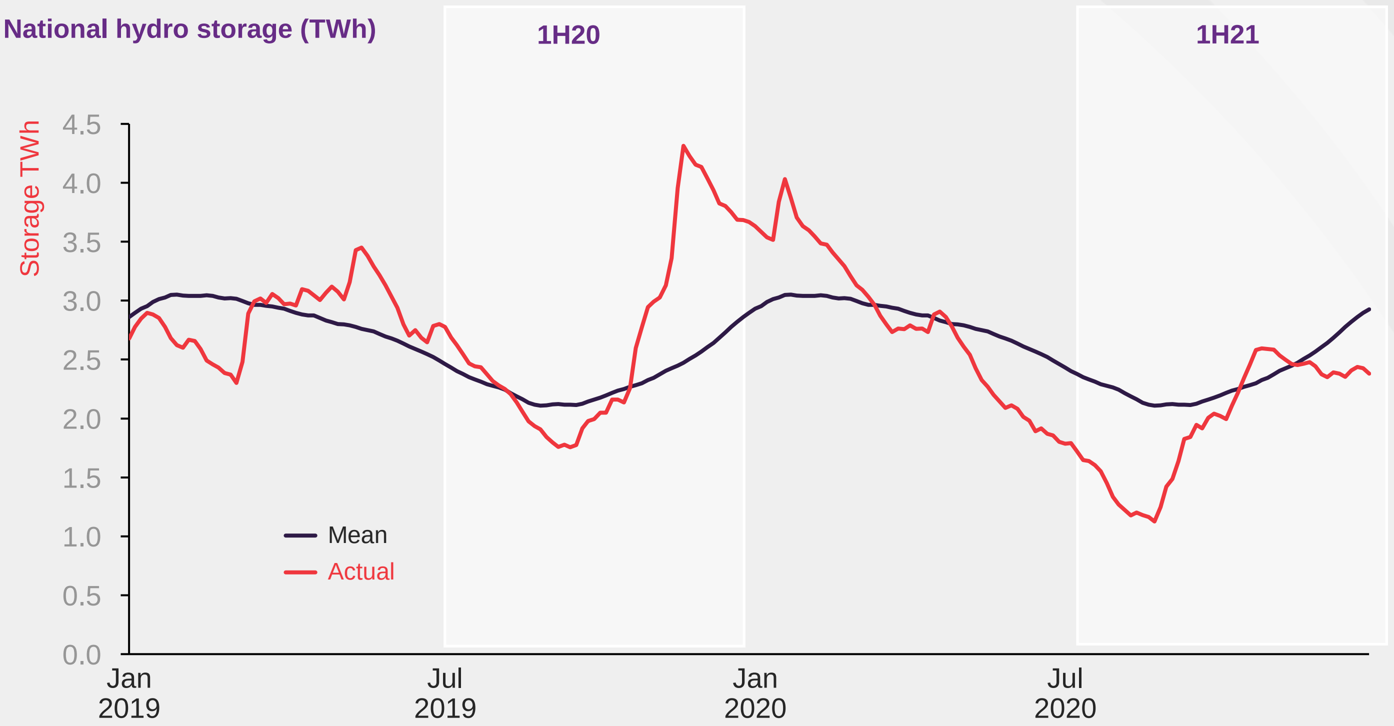


Hydro generation was down by 4% when compared with 1H20. This was driven by lower North Island inflows in the first quarter of 1H21 and restricted South Island generation resulting from the transmission outages from the Transpower Clutha Upper Waitaki (CULWP) Lines project.

With limited gas availability, generation from coal increased by 43% on 1H20.

Source: EMI

National hydro storage (TWh)



Despite below average Southern hydro inflows between October and December 2020, storage has been held relatively steady – this most likely indicates generators are holding storage in anticipation of the effects of dryer La Nina conditions and reduced gas supply from Pohokura.

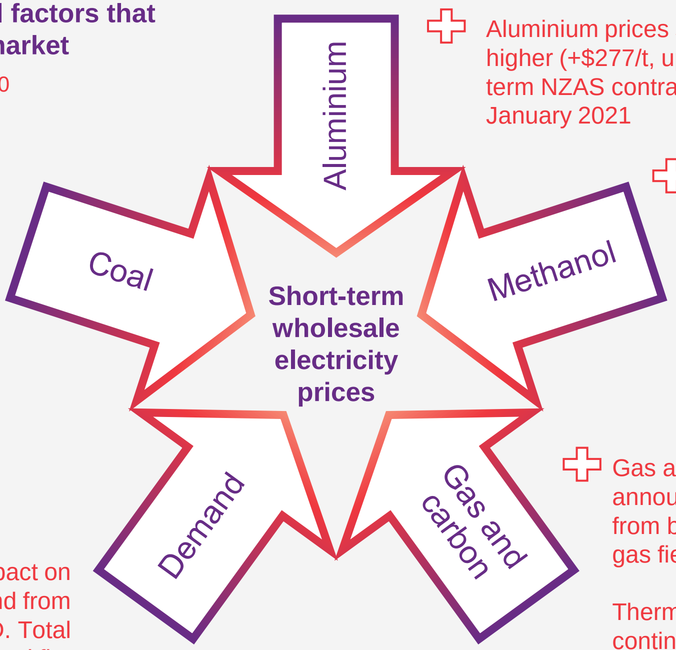
Source: NZX

In addition to hydrology, wholesale electricity prices are influenced by multiple factors

The market quickly responds to key market inputs by sending price signals.

Short-term external factors that can influence the market

Changes since June 2020



Aluminium prices sharply higher (+$277/t, up 16%). New term NZAS contract signed in January 2021

Coal prices increasing +$31/t (39%)

Methanol pricing up by over >$4/GJ gas equivalent (100% increase)

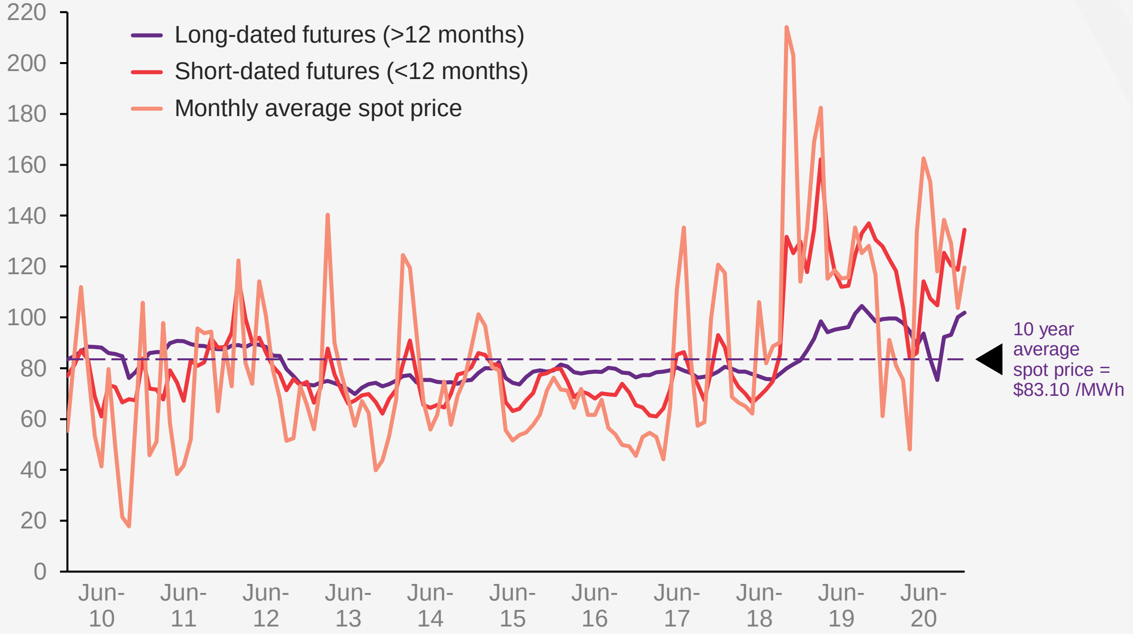
Gas availability - OMV announced reduced volumes from both Pohokura and Maui gas fields over calendar 2021

Thermal fuel cost will continue to remain elevated.

Limited impact on demand from COVID. Total demand flat

Long-term pricing is linked to the **long-run marginal costs of new renewable projects** plus costs associated with **firming renewable intermittency** to meet growing demand

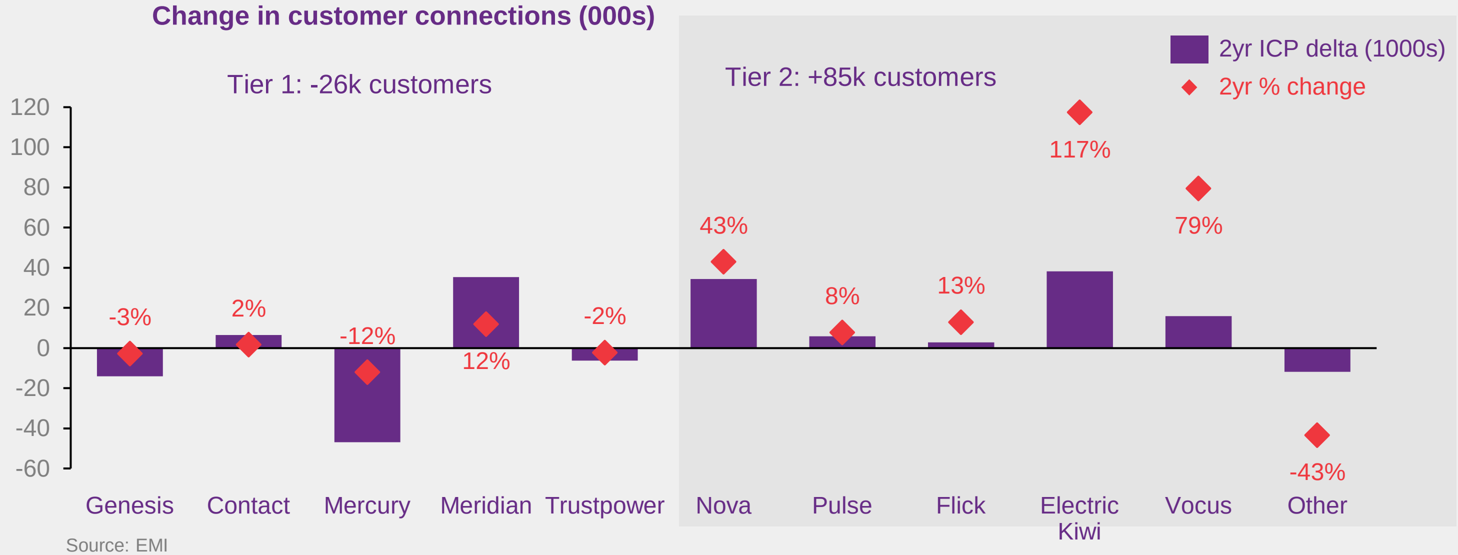
Wholesale and futures electricity pricing ($/MWh)



Both long-dated and short-dated prices remain well above long-term averages, reflecting higher thermal fuel costs and fuel risk

Source: EMI wholesale pricing

Retail competition remains intense



Source: EMI

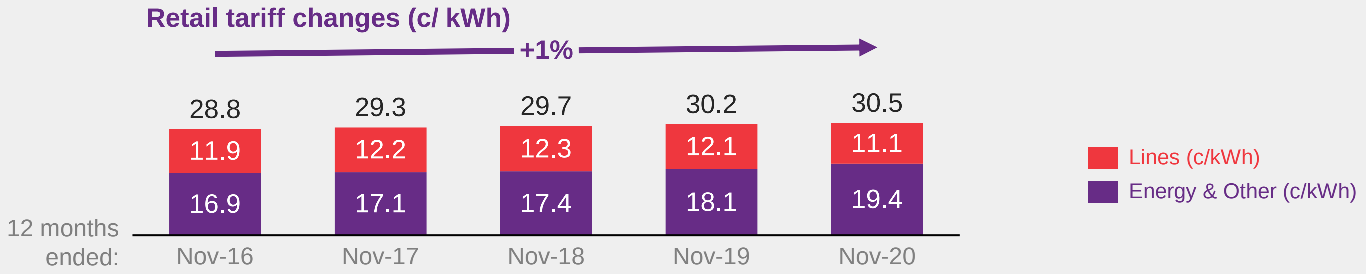
Retail competition remains intense.

Divergent views on the value of a customer:

- Tier 1: Mercury reducing customers, Meridian growing market share
- Nova and Electric Kiwi continuing growth trajectory
- Reducing market share of main players continues, Tier 2 market share now at 16% (from 12% November 2018).
- New connections were up slightly compared to prior year (~1.5% p.a. increase)

Competitive landscape could change post announced strategic reviews

- Contact is always open to considering value accretive transactions aligned to its core business and is therefore monitoring the recent strategic reviews that have been announced, including Trustpower Retail, and will consider a range of options and their potential implications.



Source: MBIE

Despite sharply higher wholesale prices over the last three years, tariffs up by a compound annual growth rate of 1% p.a. reflecting intense competition and diverging views of long-term wholesale prices.

Regulatory reset of Electricity Distributors WACC, has led to network cost reductions since 1 April 2020 partially offsetting rising energy costs over the period.

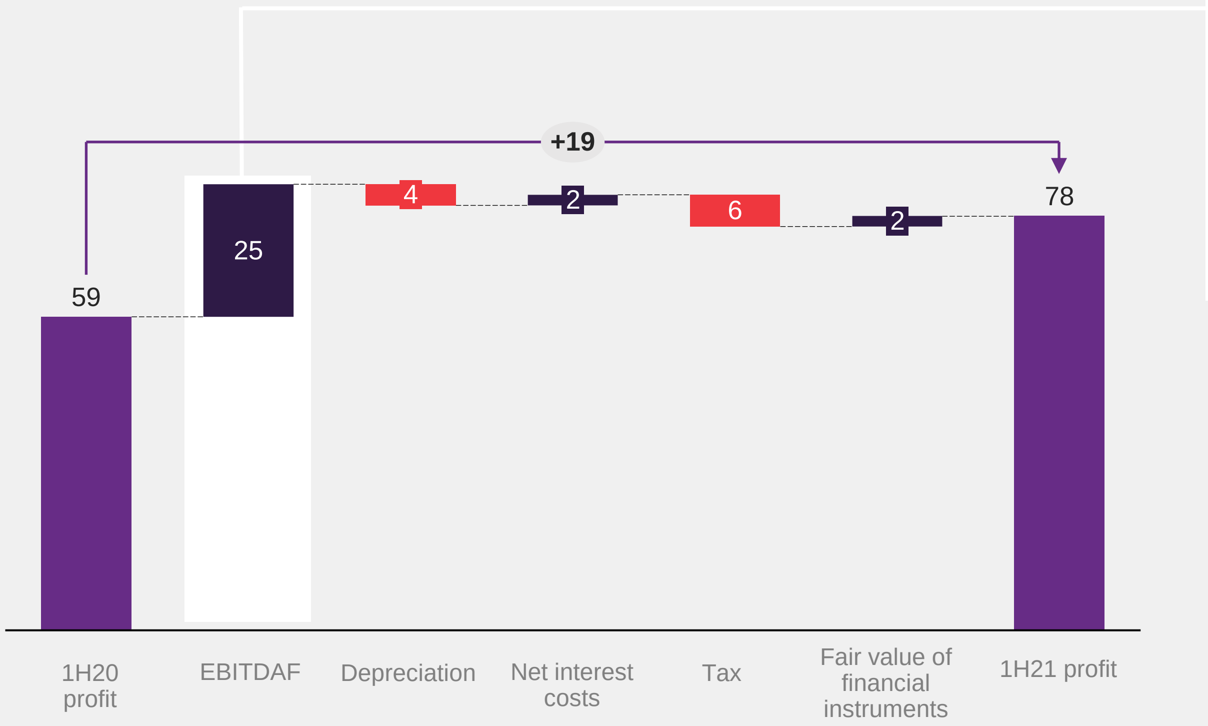
Operational performance and financial results

Dorian Devers, CFO

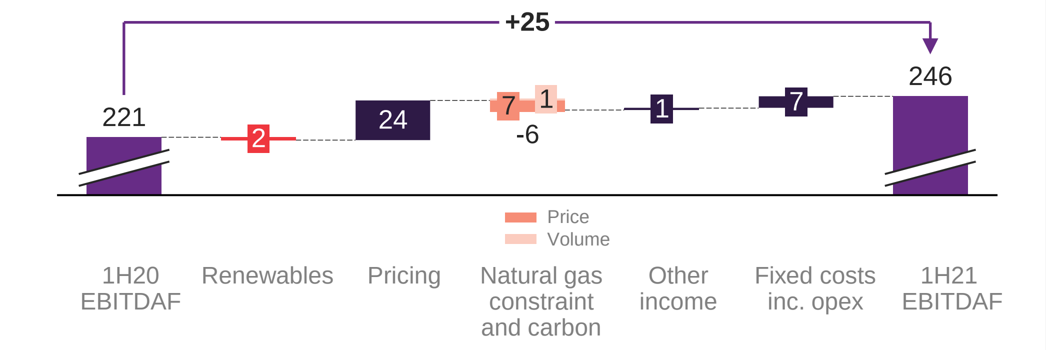
Profit of $78m, up $19m

EBITDAF up by $25m, reflecting strong channel management to capture rising wholesale prices

Profit ($m)



EBITDAF ($m)

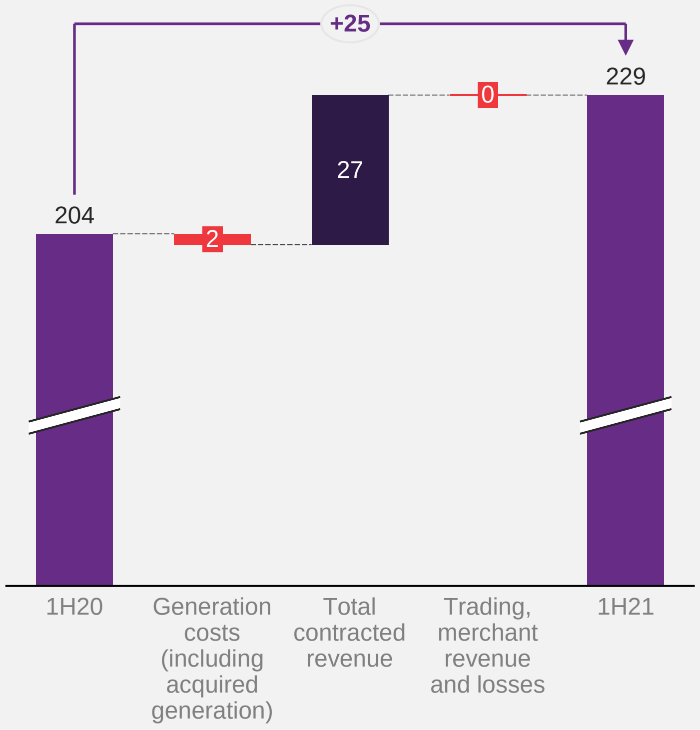


1. Lower geothermal generation year on year impacted by 4-yearly Te Mihi outage partially offset by increased hydro generation
2. Strong channel management with gradual re-pricing of channels
3. Price impact of lower gas availability continuing
4. Market making marginally improved on 1H20 despite more onerous obligations
5. Lower electricity transmission costs as some HVDC costs fully recovered. Transpower regulated WACC also lower.

EBITDAF from continuing operations up by $25m

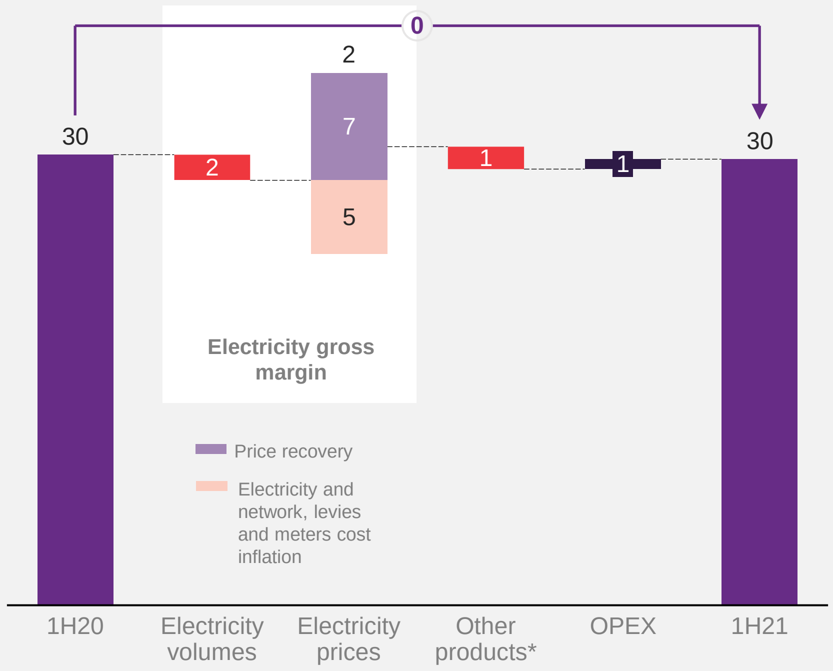
Business performance by segment.

Wholesale EBITDAF ($m)



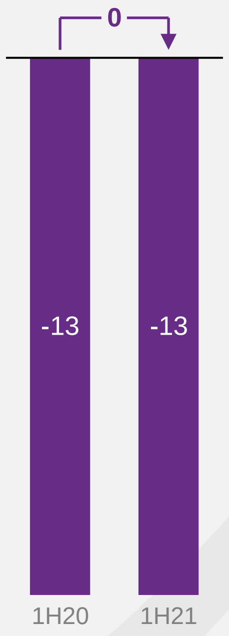
Refer to slides 16 - 18

Customer EBITDAF ($m)



Refer to slide 19

Corporate / unallocated costs ($m)



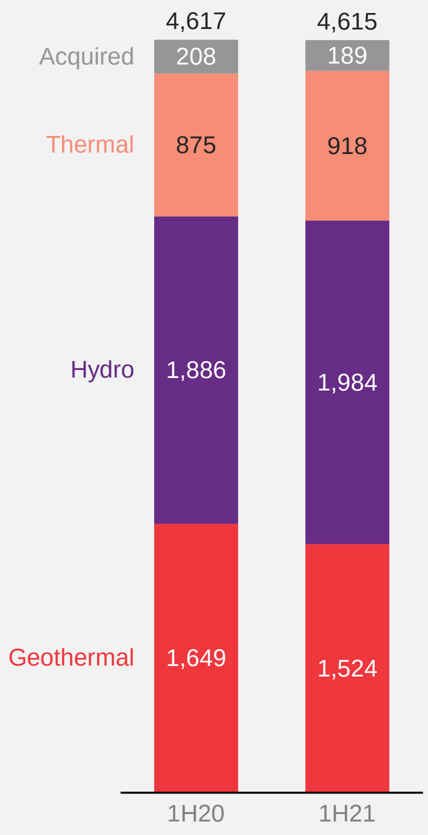
*Simply included within Wholesale EBITDAF

*Other products includes retail gas and broadband gross margins

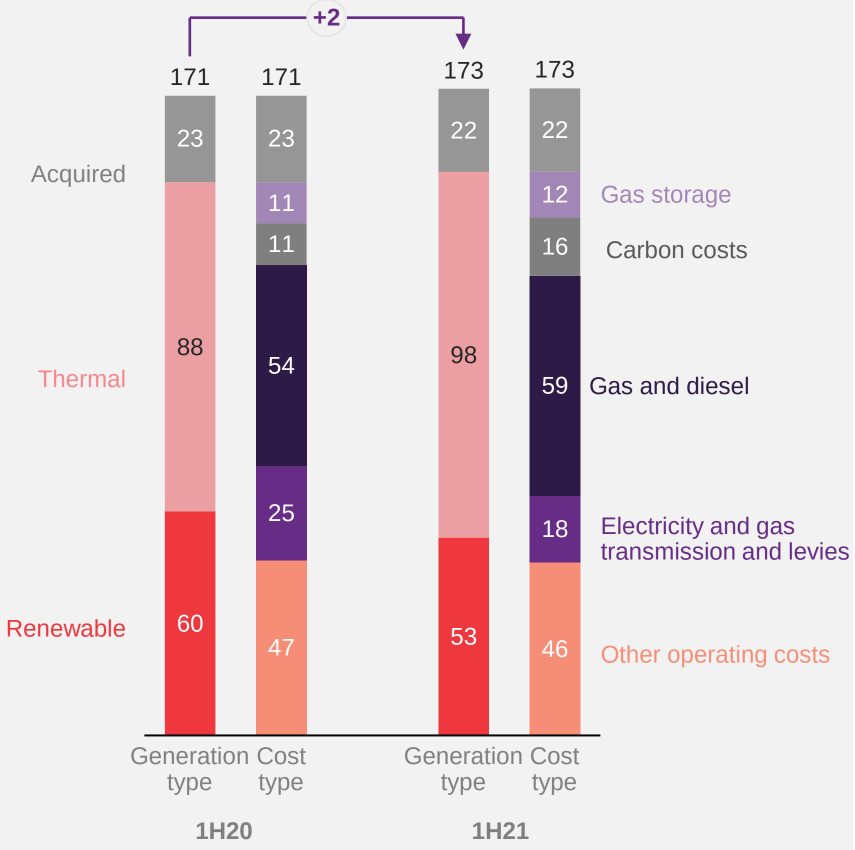
Generation costs

Costs up $2m ($0.4/MWh) as higher thermal fuel costs were partially offset by lower transmission costs

Electricity generated or acquired (GWh)



Electricity generated or acquired costs ($m)



Hydro generation up 98GWh on 1H20 (+5%), in line with that expected in a mean year. Geothermal volumes were 124GWh down on prior year (down on an average 1H generation by 126GWh) following a significant 4-yearly outage programme in the period.

- Renewable generation costs were down by $7m. Transmission costs for renewable assets down by $6m as HVDC pole 1 costs ended, other operating costs down $1m.

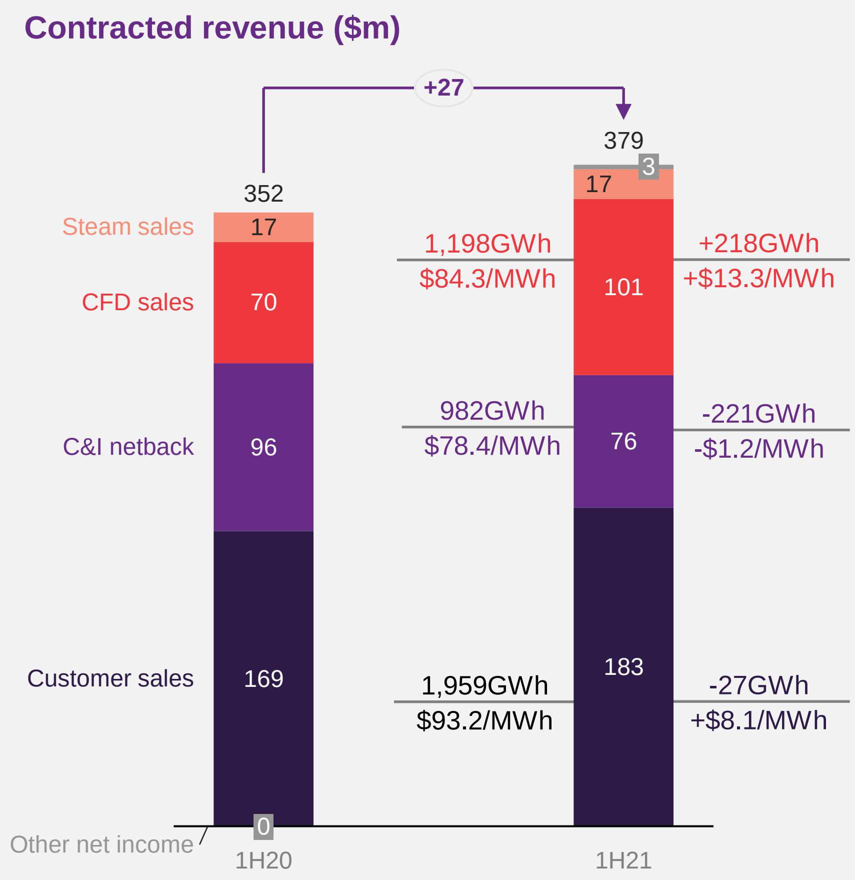
Thermal generation costs were up by $10m due to higher gas (1H20 $6.75/GJ, 1H21 $7.20/GJ) and carbon prices (1H20 $17.6/unit, 1H21 $24/unit) and marginally higher thermal generation in the six months.

- Gas and carbon unit costs up from $71/MWh in 1H20 to $79/MWh (+11%)
- Fixed costs relating to AGS and other operating costs were up by $1m on the prior comparative period as the AGS facility expansion was commissioned on 30 September 2020

Acquired generation was in line with the prior period as Contact's improved gas position was offset by the cover for the planned geothermal outages.

Wholesale contracted revenue

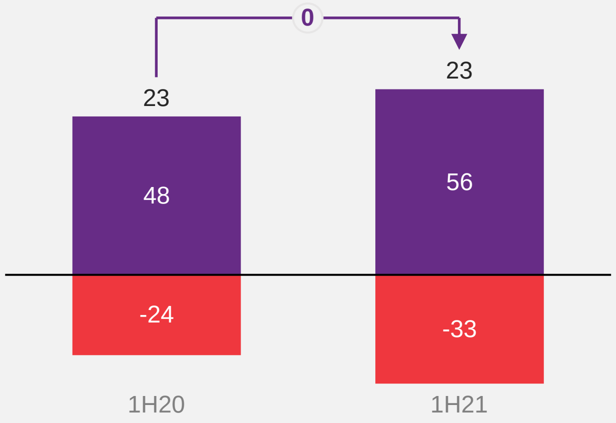
Sales mix adjusted to target higher value, shorter term channels



- Fixed price variable volume electricity sales to the Customer segment and C&I customers ended 248GWh lower than 1H20 (-$20m), this was partially offset by higher prices (+$15m) predominantly to the Customer business, reflecting higher wholesale prices over the three preceding years.
- CFD sales were up by 218GW, despite lower sales to NZAS (down by 83GWh), as nearer term higher priced channels were prioritised (+$31m)
- Steam revenue was in line with 1H20 with a reduction in volume but increased tariffs on rising carbon costs.
- Other income was up by $2m predominantly on profit from market making.

Wholesale trading and merchant revenue

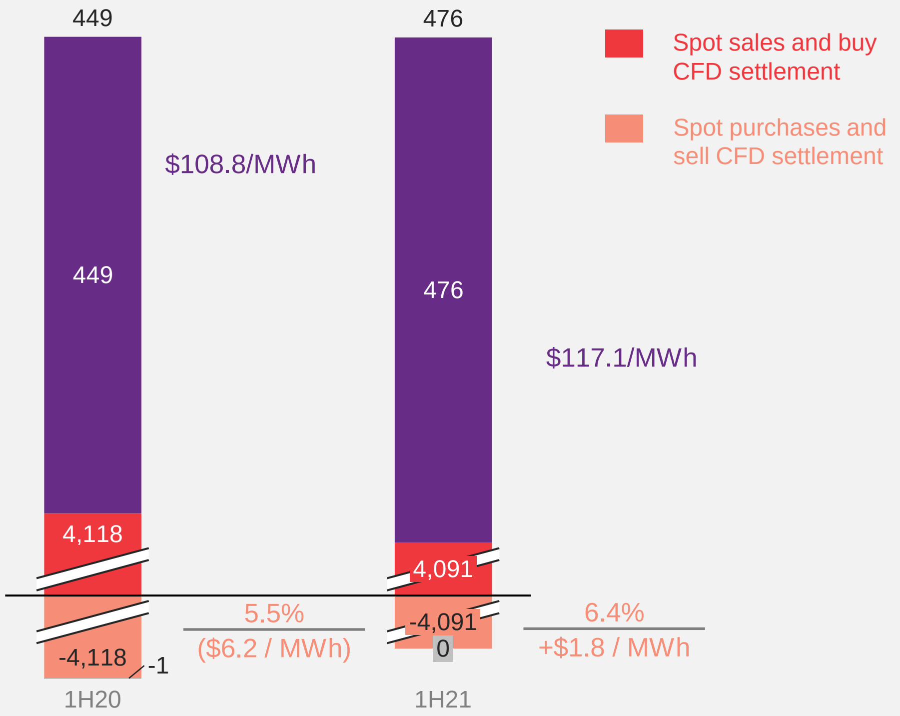
Trading EBITDAF ($m)



Trading revenue

- **Merchant sales:** short-term sales channel available when the spot prices exceed the opportunity cost of Contact generation.
- **Pool purchase:** short-term opportunistic purchases from the spot electricity market when better value than alternatives (adjusted for volatility and volume).
- **LWAP / GWAP losses:** locational price differences between where electricity is generated and purchased.

Long / short position (GWh)



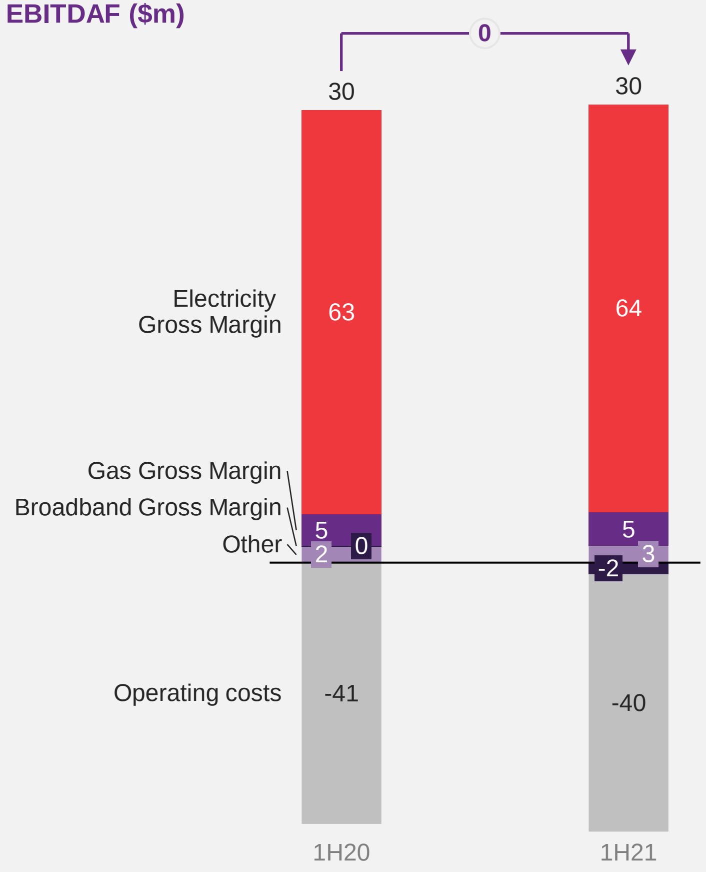
- 27GWh increase in merchant sales volumes. The price received for this “long” generation was up by $9.5/MWh.
- Larger price separation during periods of transmission outages saw LWAP/GWAP increase by $9m.

Customer business performance

Government's regulatory review completed.

Revenue & Tariff[1] ($m)	1H20	1H21		Variance	
	$m	$m	*Tariff*	$m	*Tariff*
Electricity gross revenue	448.8	445.7	*245.8*	(3.1)	4.6
PPD not taken	6.1	3.1		(2.9)	
Incentives paid	-4.1	-2.3		1.8	
Net revenue (cash)	**450.8**	**446.5**	***246.3***	**(4.3)**	**4.0**
Capitalised incentives	4.1	3.3			
Amortised incentives	-4.6	-4.0			
Net revenue (P&L)	**450.4**	**445.8**	***245.8***	**(4.6)**	**3.8**
Gas revenue	40.5	41.3	*24.7*	0.8	1.6
Broadband revenue	7.2	13.0	*65.1*	5.7	(5.6)
Other income	2.5	2.6		0.1	
Total revenue	**500.5**	**502.6**		**2.1**	
Contract Asset (closing)	10.9	8.5		(2.4)	

1. Tariff is $/MWh for electricity, Gas $/GJ and $ per month per customer connection for broadband



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

Electricity tariff changes balance the regulatory pressures, the competitive environment and rising input costs:

- End to further Prompt Payment Discounts - 48% reduction in PPD not taken
- Around ~40% of customers received a price increase in FY20

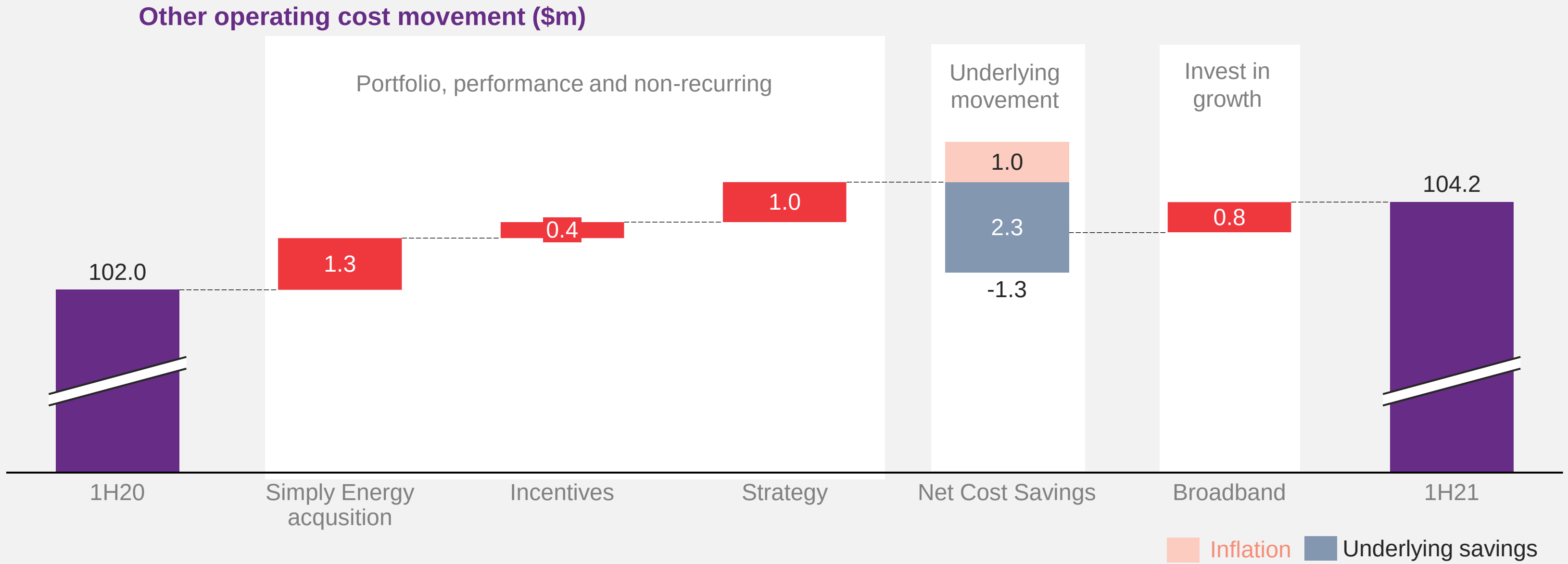
Continue to smooth the impact of higher electricity costs for customers, which are up by 11% on 1H20.

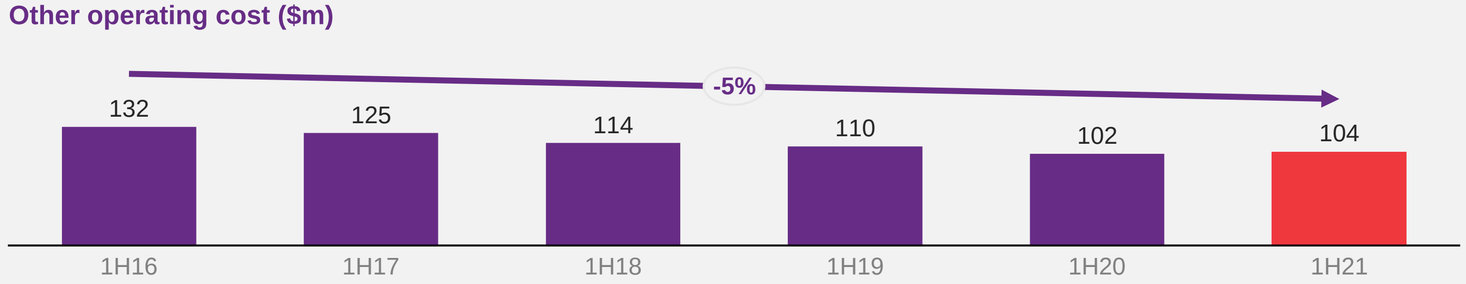
- Combination of targeted retail price rises and a reduction in network costs from 1 April 2020 has seen gross margins stable.

Retail gas tariffs to SMEs will need to rise to reflect rising gas and carbon costs.

Strong growth in Broadband connections (>90% on 1H20).

Underlying operating costs flat. Productivity gains offset inflation





Underlying movement

$2.3m from transformative ways of working (TWOW) and lower advertising spend.

- Travel has reduced by $1.1m from TWOW and changing COVID levels.
- Change in sales channels resulting in $0.9m saving from a reduction in door-to-door marketing.
- Bad debts down by $0.7m on prior year due to focused credit management.

Broadband

Further investment in FTEs to support broadband growth.

Benefits of change in provider and further digitisation resulting in 52% productivity increase as measured by broadband connections per FTE.

Other operating cost trajectory

Reduction of 5% CAGR since FY16.

Normalised and expected EBITDAF assumptions

With reconciliation to actual performance.

1H assumptions that deliver expected & normalised EBITDAF of $480m over a financial year

1 Channel choices maximise long term value[1]		X	2 Net price[2] driven by best commercial practices	=	Total
CFDs	725GWh	x	$64/MWh	=	$46m
C&I	1,675GWh	x	$81/MWh	=	$136m
Retail	2,014GWh	x	$117/MWh	=	$236m
Other income[3]					$29m
					$447m

3 Hydrology & Asset availability optimise generation		X	4 Access to and price of fuel* drives financials & risk position	=	Total
Hydro	1,990GWh	x	$0/MWh	=	-$0m
Geo	1,650GWh	x	$1/MWh	=	-$2m
Thermal[4]	974GWh	x	$66/MWh	=	-$64m
Acquired	50GWh	x	$100/MWh	=	-$5m
					-$71m

5 Trading delivers value to more than offset locational losses		6 Digitalisation & continuous improvement optimise fixed costs	
Length[5]	$27m	Transmission/Storage	-$35m
Location losses[6]	-$18m	Operating expenses	-$104m
Total	**$9m**	**Total**	**-$139m**

EBITDAF reconciliation to 1H21

Normalised & Expected

Lower renewables

Higher thermal generation required to offset below mean renewable generation (132GWh) at expected thermal SRMC

Pricing

Preserved retail margin despite rising wholesale electricity costs; shorter term wholesale channels prioritised

Natural gas constraint and carbon

Natural gas availability has led to increased cost of gas; carbon costs continue to rise

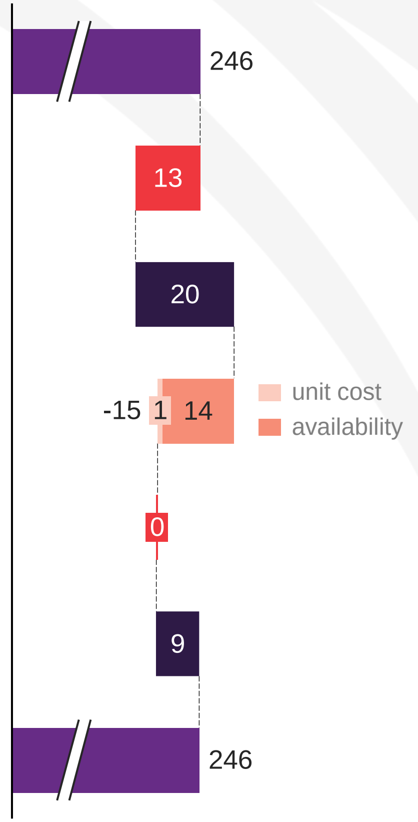
Other income

In line with expectations

Fixed costs

Other operating cost control (-$4m), transmission costs lower (-$6m)

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, other income
4. Gas price of $6/GJ, carbon price of $20/unit and thermal portfolio heat rate (9.25GJ/MWh)
5. Length of 500GWh p.a. assumed
6. Locational losses of 5.6% on spot purchases and settlement of CFDs sold at a wholesale price of $75/MWh

* Fuel is natural gas and carbon costs

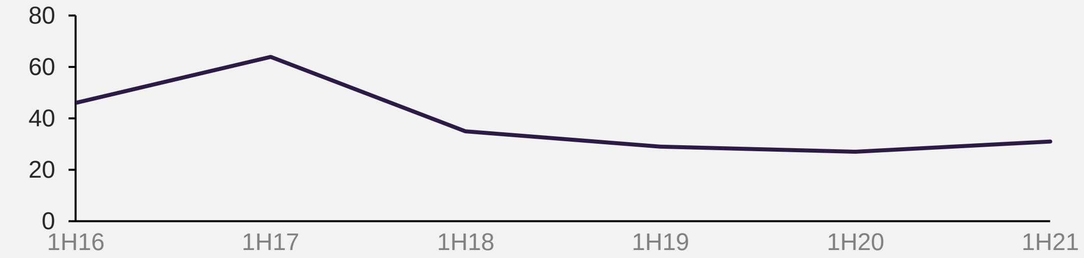
Cash flow and capital expenditure

Underlying cash conversion remains strong.

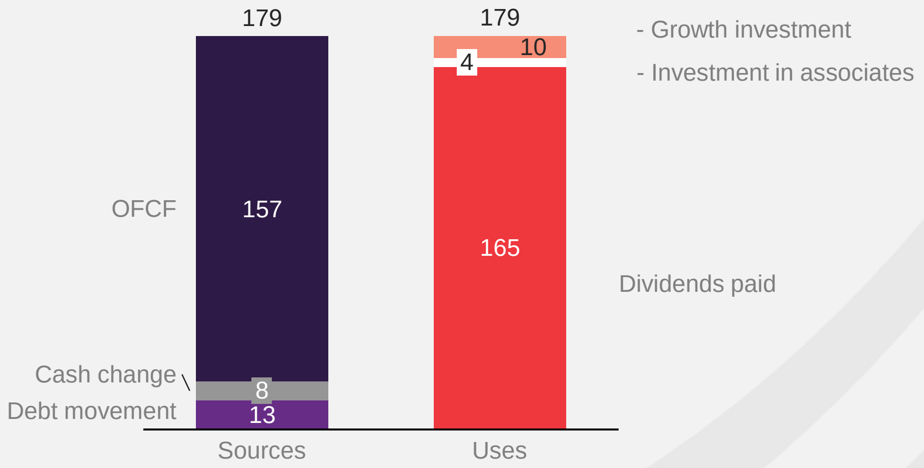
	6 months ended 31 December 2020	6 months ended 31 December 2019	Comparison against 1H20	
EBITDAF	**$246m**	$221m	↑	$25m
Working capital changes	**$22m**	$5m	↑	$17m
Tax paid	**($58m)**	($56m)	↓	($2m)
Interest paid, net of interest capitalised	**($23m)**	($25m)	↑	$2m
SIB capital expenditure	**($31m)**	($27m)	↓	($4m)
Non-cash items included in EBITDAF	**$1m**	$2m	↑	$1m
Operating free cash flow	**$157m**	$120m	↑	$37m
Operating free cash flow per share	**21.9**	16.8	↑	5.1
Free cash flow	**$157m**	$120m	↑	$37m
Cash conversion (OpFCF / EBITDAF)	**64%**	54%	↑	10%

- EBITDAF up $25m on improved pricing across key channels
- Working capital changes $17m favourable due to net gas extraction from storage and gas swap arrangements
- Capital expenditure (cash) $31m in 1H21, $4m more than 1H20 due to statutory geothermal outage programme

SIB capital expenditure – accounting ($m)



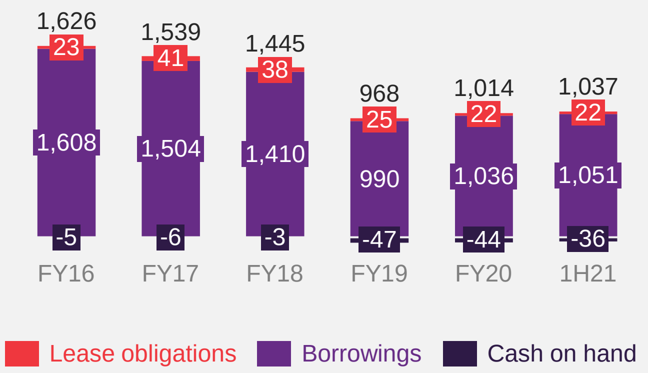
Sources and uses of cash ($m) 1H21



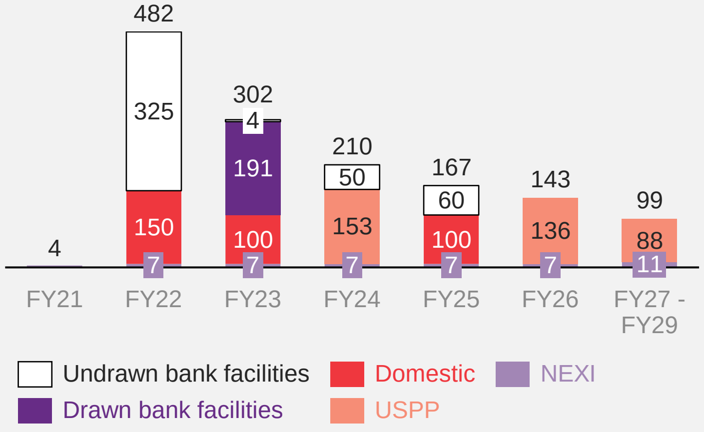
Robust balance sheet.

Well-managed, diversified portfolio with green certification.

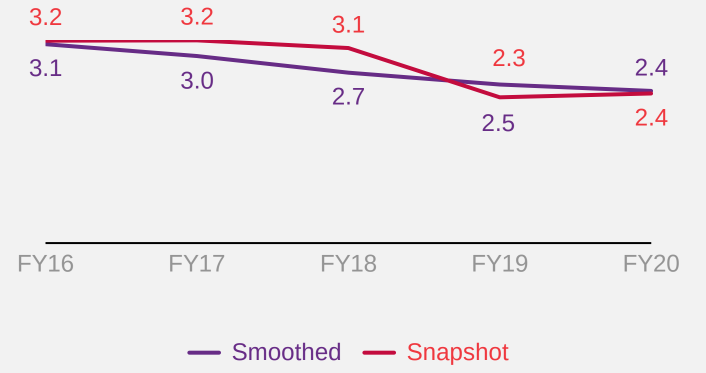
Closing net debt ($m)
Face value of borrowings less cash



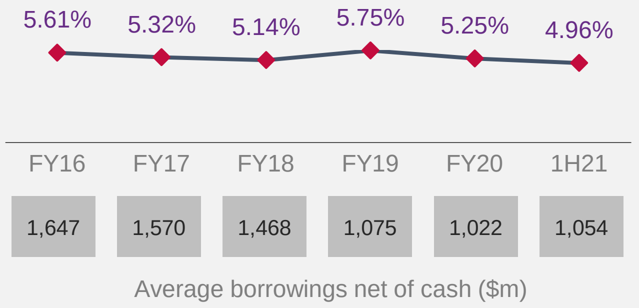
Borrowing maturities ($m)
Average tenor of 2.7 years as at 31 December 2020



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



Interest rate (%)
Weighted average net interest[1] on average borrowings net of cash



- Face value borrowings net of cash (excl. leases) increased by $15m to $1,051m from 30 June 2020. This was primarily due to growth investments exceeding operating free cash flow.
- Weighted average interest rate reduced by 29bp compared to FY20. This was due to an increased proportion of floating rate debt and historically low interest rates during 1H21.
- An investment grade credit rating (net debt / EBITDAF <2.8x) continues to be targeted.
- Contact is in the process of converting further bank facilities to sustainability linked loans.

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

FY21 guidance unchanged

	FY21	1H21 result	Guidance commentary
Other operating costs	$200 – 210m*	$104m	No change
Stay in business capital expenditure	$55 – 60m	$31m	No change
Cash spend ('Totex')	**$255 – 270m**	**$135m**	No change
Depreciation and amortisation	$215 – 225m	$114m	No change
Net interest (accounting)	$45 – 50m	$26m	No change
Cash interest (in operating cash flow)	$40 – 45m	$23m	
Cash taxation	$75 – 85m	$58m (2/3 payments in 1H)	No change
Geothermal volumes	3,100GWh	1,524GWh	Significant outages completed in 1H21 – plant back in service ahead of schedule

* Excludes any additional abnormal impacts due to COVID-19

The New Zealand regulatory framework is being adapted to deliver on this societal imperative.

Potential electricity demand impact

- Net zero NZ carbon emissions by 2050
- Transport policies
- Climate Change Commission (CCC)
- Current Tiwai contract ends 2024
- Ban on new gas connections from 2025
- CC Response (Zero Carbon) Amendment Act

Potential renewable generation impact

- Govt 100% renewable generation target by 2030
- Coal phase out for electricity generation by 2030[1]
- Freshwater reform
- Ban on offshore oil and gas exploration
- NZ Battery Project

Potential wider electricity sector impact

- Electricity Pricing Review[2]
- Emissions Trading Scheme
- Transmission Pricing Methodology
- Carbon Emissions budgets

Announced

In progress

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

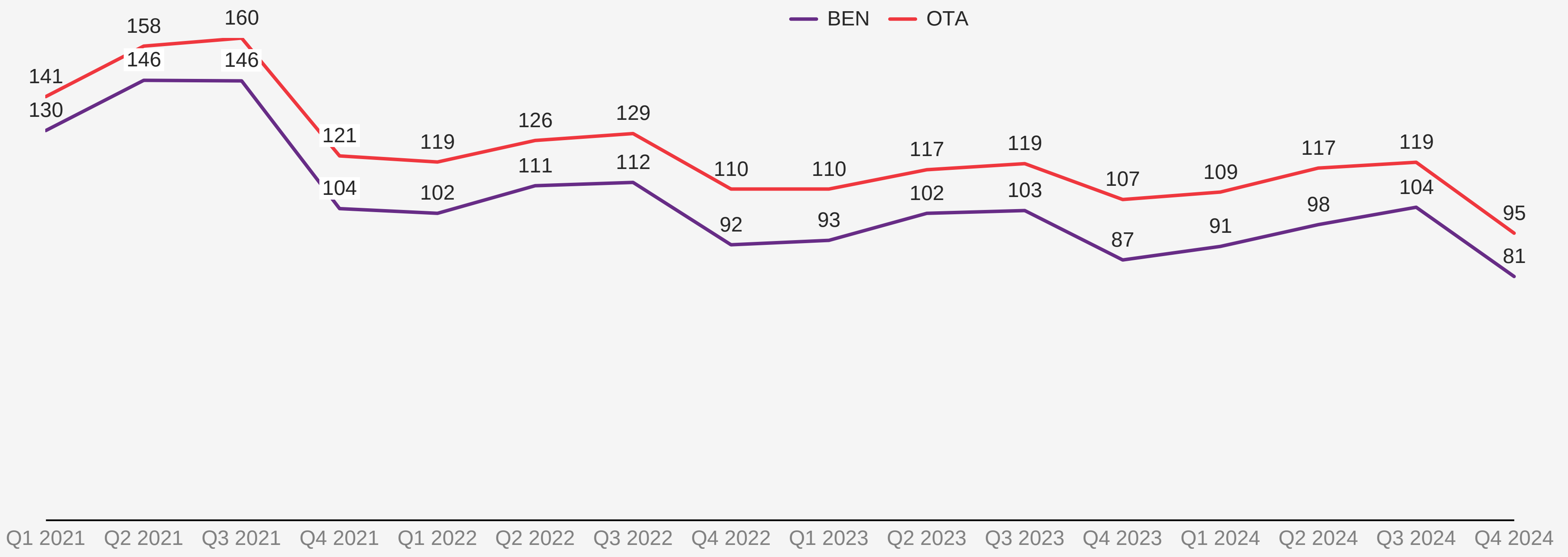
[1] A commitment made by the Government when New Zealand joined the Powering Past Coal Alliance.
[2] Review complete, findings announced and into implementation.

Questions

Supporting materials

Futures ASX pricing in fuel risk

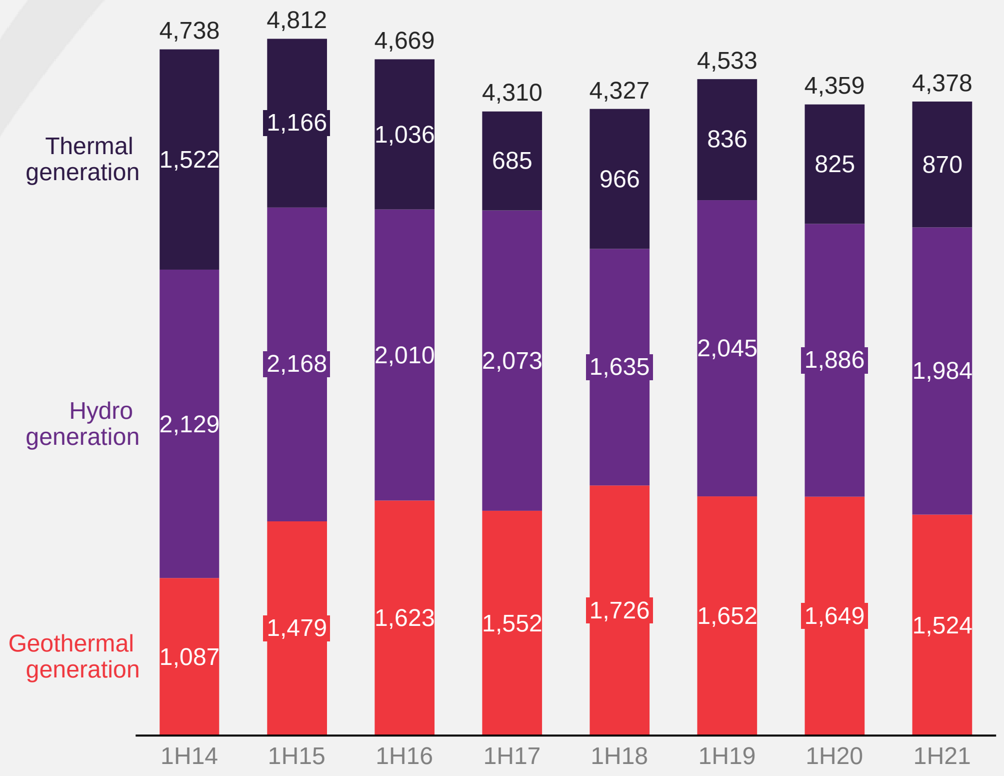
ASX electricity forward pricing ($/MWh)



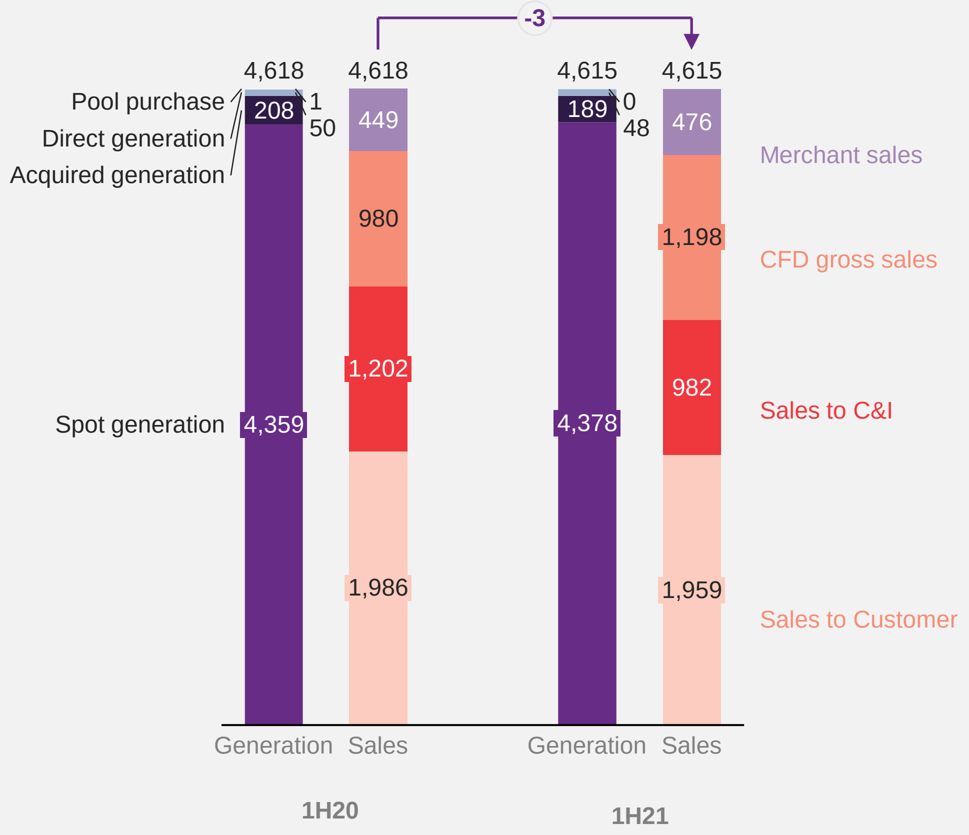
Source: ASX Energy 21 Jan 2021

Generation and sales position

Contact generation output sold to the national grid (GWh)

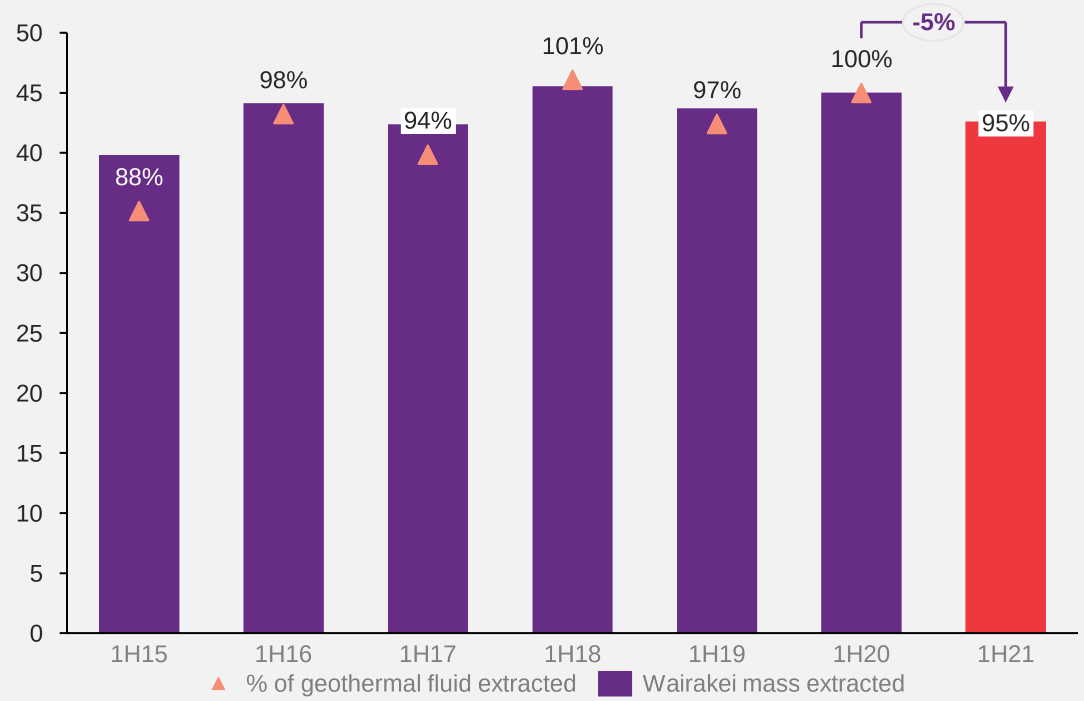


Electricity and generation sales position (GWh)

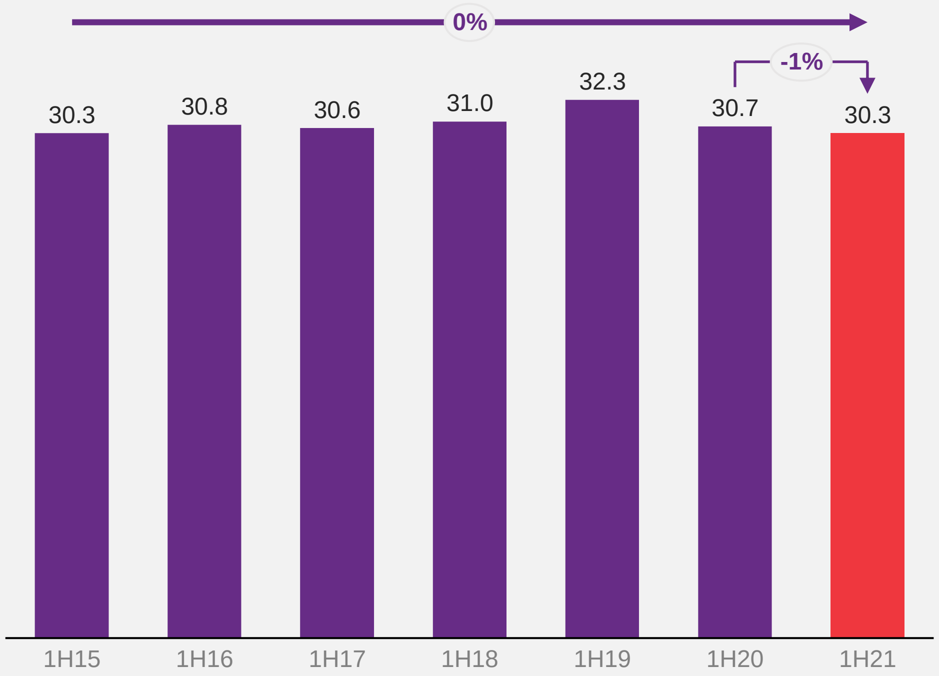


Wairakei geothermal field mass take and efficiency

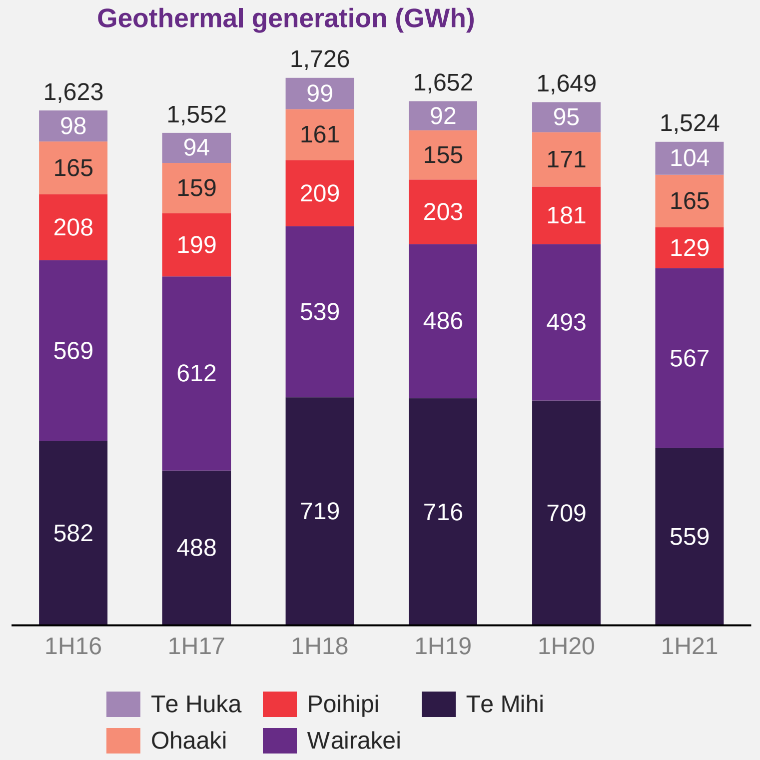
Geothermal fuel extracted at Wairakei vs consented (GWh)



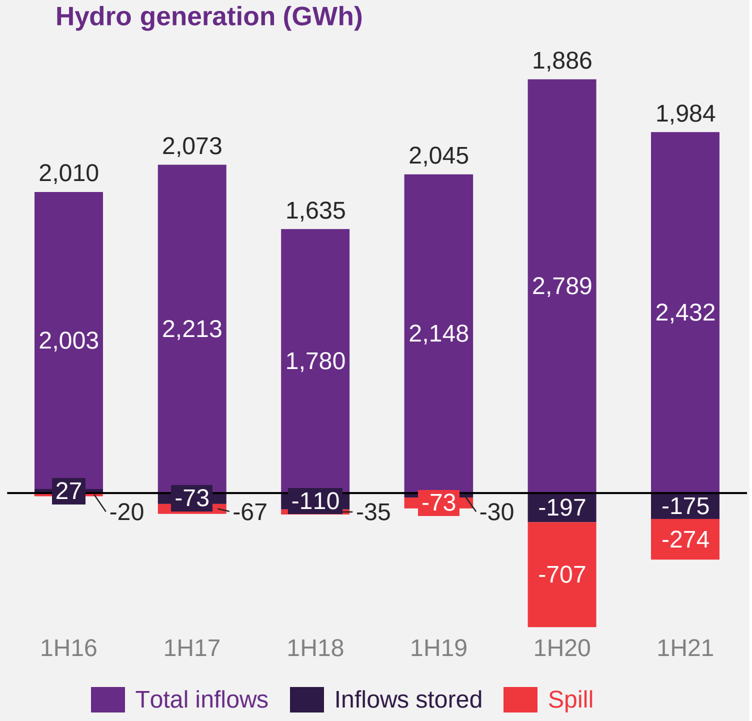
Wairakei, Poihipi and Te Mihi conversion effectiveness (MWh per kT extracted)



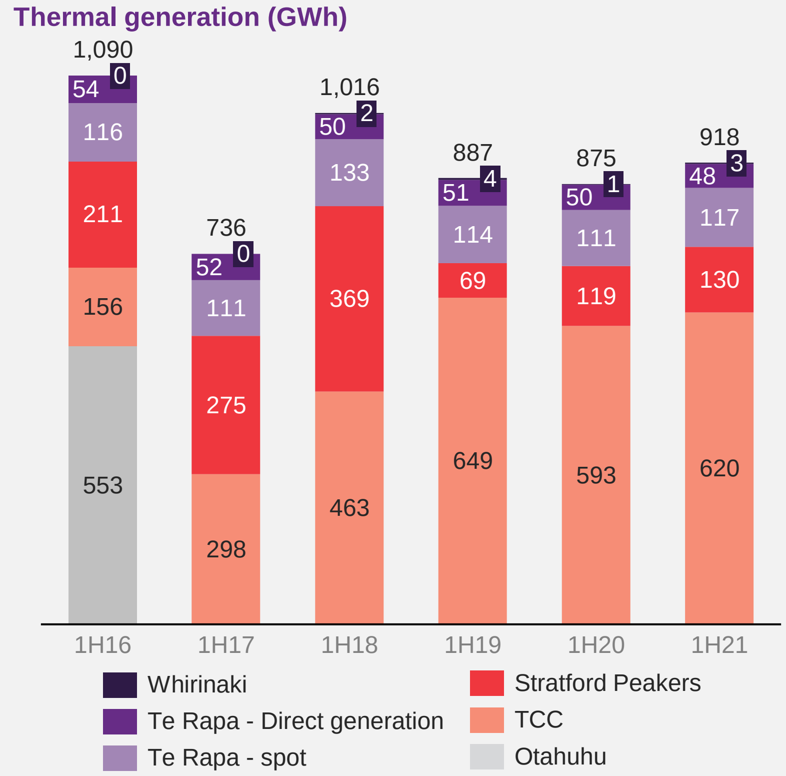
Generation volumes: renewable generation down by 1% on 1H20



Geothermal generation was 125GWh lower than 1H20 following the 4-yearly statutory Te Mihi outage in the period



Hydro generation was 6GWh below mean (HY 1,990GWh, FY 3,900GWh) in 1H21, 98GWh above 1H20. During the period Transpower had a number of outages to progress the Clutha Upper Waitaki Lines project this meant that we could not process all of the water through our hydro stations and had to spill it.



Thermal generation volumes were 43GWh higher than 1H20 on lower sales, stronger renewables and contracted gas.

Plant availability

Hydro

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
1H17	784	91%	60%	2,073	42	87
1H18	784	95%	47%	1,635	88	144
1H19	784	95%	59%	2,045	129	265
1H20	784	94%	54%	1,886	98	184
1H21	784	85%	57%	1,984	110	218

Geothermal

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
1H17	429	89%	82%	1,552	50	78
1H18	429	97%	91%	1,726	86	148
1H19	425	91%	88%	1,652	137	226
1H20	425	94%	88%	1,649	106	175
1H21	425	86%	81%	1,524	118	180

Taranaki combined cycle (TCC)

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
1H17	377	95%	18%	298	52	15
1H18	377	51%	28%	463	110	51
1H19	377	63%	39%	649	119	78
1H20	377	78%	36%	593	113	67
1H21	377	96%	37%	620	127	79

Peakers (including Whirinaki)

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
1H17	360	96%	16%	276	60	17
1H18	360	98%	21%	370	120	44
1H19	360	79%	4%	73	231	17
1H20	360	78%	7%	120	153	18
1H21	360	88%	8%	133	150	20

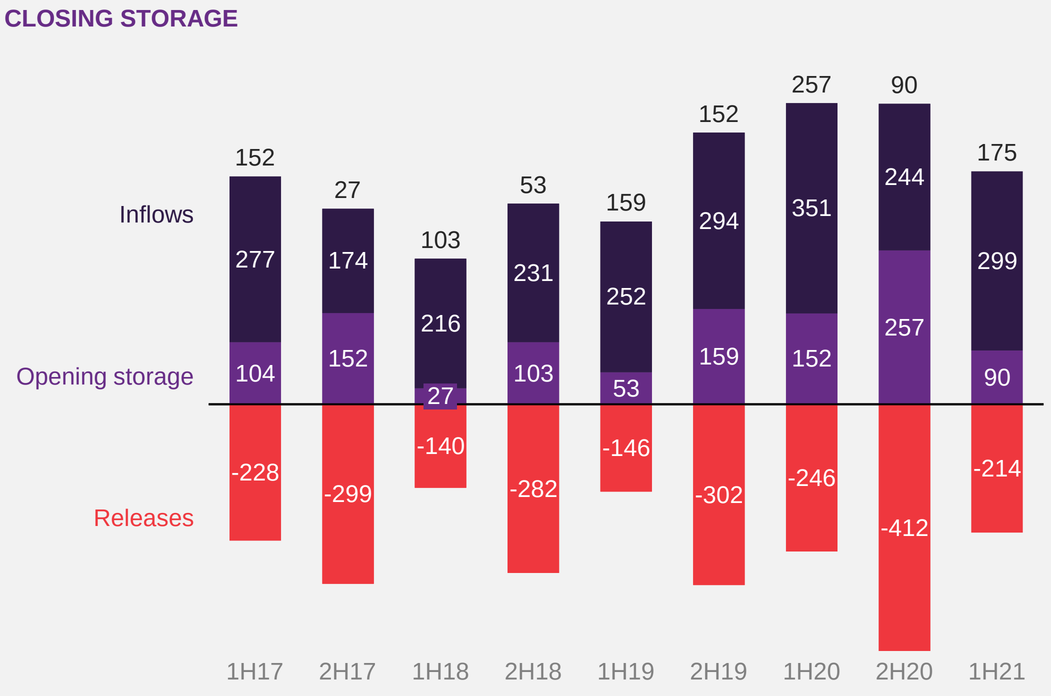
Te Rapa (spot generation only)

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
1H17	41	100%	31%	111	53	6
1H18	41	99%	37%	133	93	12
1H19	41	98%	32%	114	161	18
1H20	41	100%	31%	111	116	13
1H21	41	99%	33%	117	122	14

*TCC is currently derated by 3MW due to vibration. This is not reflected in the availability figure.

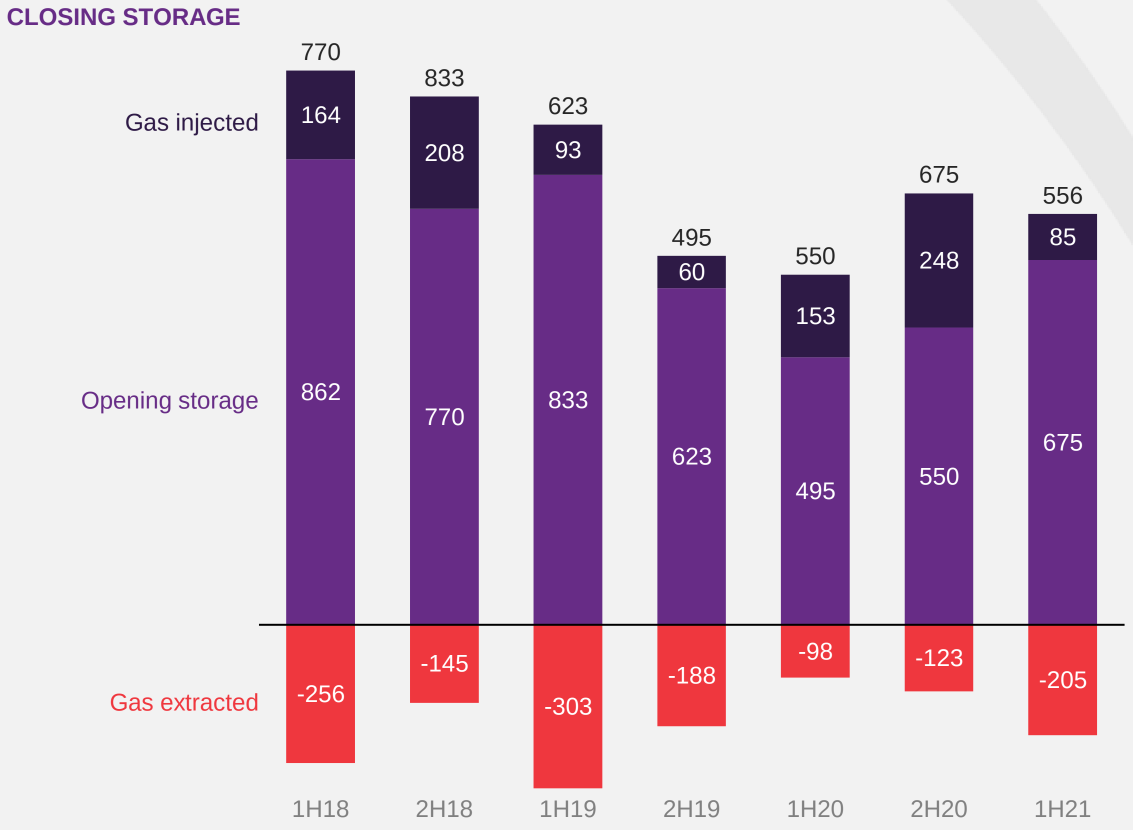
Fuel storage movements

Hawea strorage (GWh)



Gas storage (GWh equivalent)

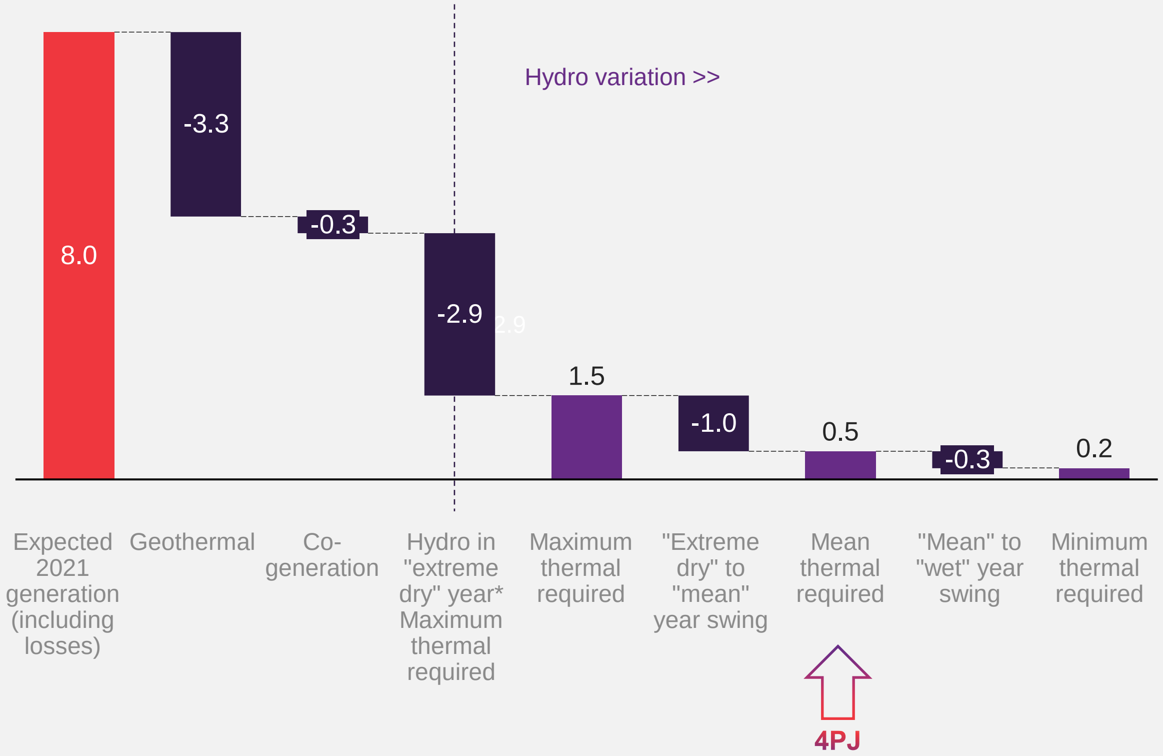
Using the FY20 thermal efficiency (9.04 TJ/GWh)



Source: NZX hydro

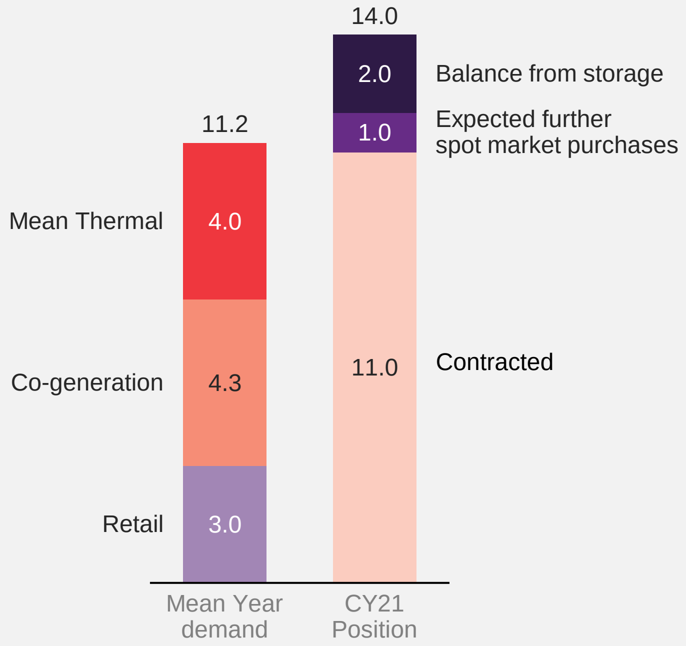
Contractual fuel position impacted by gas availability issues

Portfolio requirements for thermal generation (TWh)



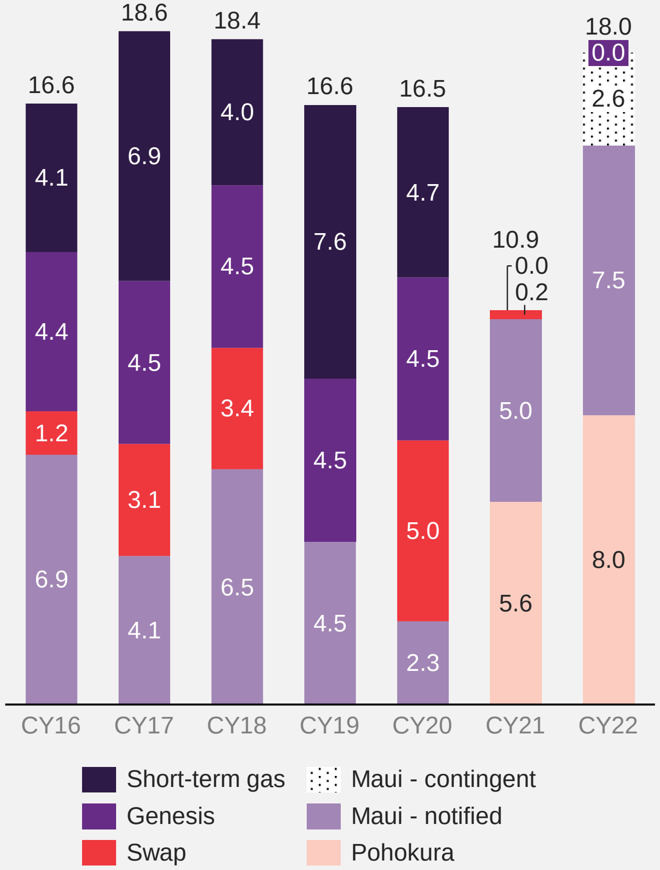
* Hydro generation in FY12

Gas supply and demand CAL21 (PJ)

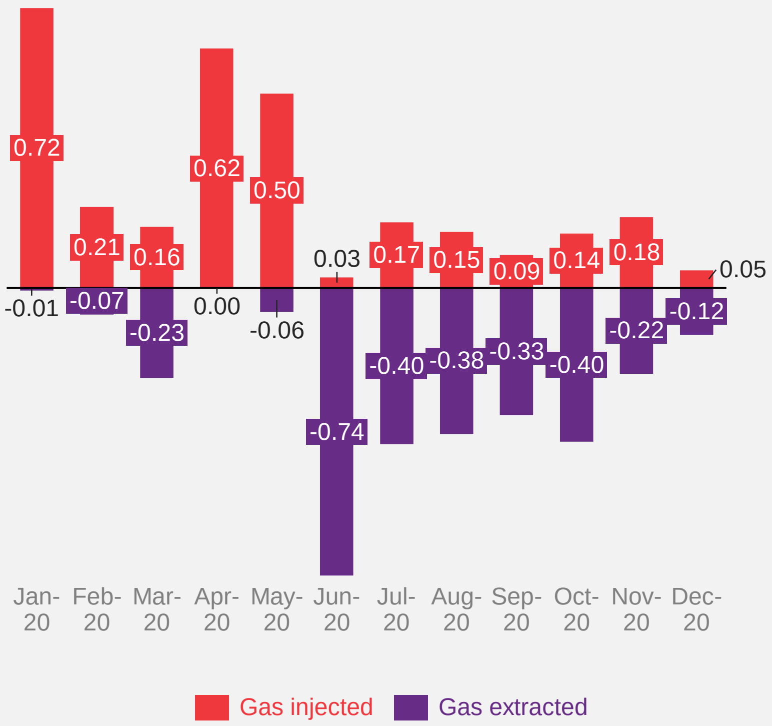


Contracted and stored gas

Contracted gas volumes (PJ)

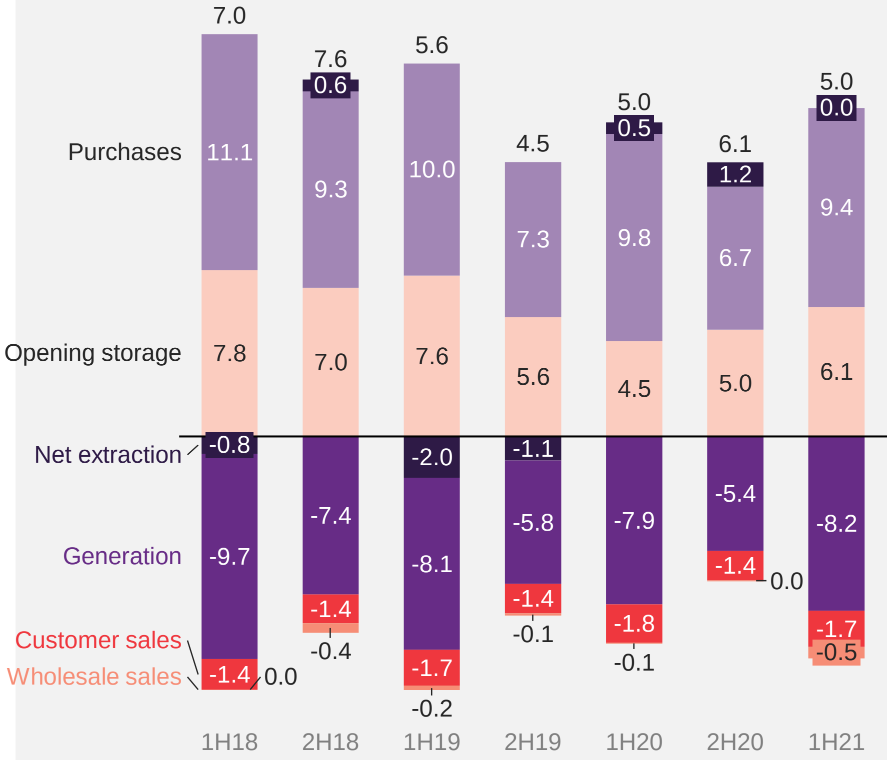


Ahuroa gas storage monthly injections and extractions (PJ)



Sources and uses of gas (PJ)

Closing storage



Storage balance at 31 December 2020 was 5.0PJ

Reconciliation between Profit and EBITDAF

- EBITDAF is Contact's earnings before net interest expense, tax, depreciation, amortisation, and change 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 2020	6 months ended 31 December 2019	Variance on prior year	
			$m	%
Profit	**78**	**59**	**19**	**32%**
Depreciation and amortisation	114	110	(4)	(4%)
Change in fair value of financial instruments	(4)	(2)	2	100%
Net interest expense	26	28	2	7%
Tax expense	32	26	6	23%
EBITDAF	**246**	**221**	**25**	**11%**

- Depreciation and amortisation, change in fair value of financial instruments, net interest and tax expense are explained in the following slide

The adjustments from EBITDAF to reported profit and movements on 1H20 are as follows:

- **Depreciation and amortisation:** Increased by $4m (4%) on 1H20 primarily resulting from the review of Ohaaki plant assets which has resulted in accelerated depreciation impacting 1H21 only.
- **Net interest expense:** Reduced by $2m (7%) over 1H20 with higher average borrowings offset by lower interest rate as well as the capitalisation of interest relating to the Tauhara geothermal project (1H21 $4m), a $1m increase against 1H20.
- **Tax expense** for the period was $6m up following higher operating earnings and higher depreciation partially offset by lower net interest expense. Tax expense for 1H21 represents an effective tax rate of 29%. The effective tax rate for 1H20 was 30%.

Historical financial information

	Unit	1H17	1H18	1H19	1H20	1H21
Revenue	$m	1,037	1,190	1,363	1,110	1,141
Expenses	$m	773	954	1,072	889	895
EBITDAF	$m	264	236	291	221	246
Profit/(loss)	$m	96	58	276	59	78
Operating free cash flow	$m	134	141	203	120	157
Operating free cash flow per share	cps	18.7	19.7	28.3	16.8	21.9
Dividends declared[1]	cps	11.0	13.0	16.0	16.0	14.0
Total assets	$m	5,587	5,390	5,140	4,850	4,738
Total liabilities	$m	2,766	2,663	2,297	2,170	2,212
Total equity	$m	2,821	2,727	2,843	2,680	2,526
Gearing ratio	%	36.4	35.4	29.7	29.9	31.1

Wholesale segment

Note: this table has not been rounded and might not add	1H21 Six months ended 31 December 2020 Volume GWh	GWAP $/MWh	$m	1H20 Six months ended 31 December 2019 Volume GWh	GWAP $/MWh	$m	Reference number for Wholesale segment note (see following page)
Electricity sales to Customer	**1,959**	**93.2**	**183**	**1,986**	**85.2**	**169**	1
Electricity sales to C&I (netback)	934	76.7	72	1,152	79.1	91	
Electricity sales – Direct	48	110.4	5	50	105.1	5	2
Electricity sales to C&I	**982**	**79.0**	**78**	**1,202**	**80.2**	**96**	
CfDs – Tiwai support	353			436			
CfDs - Long term sales	301			301			3
CfDs - Short term sales	544			243			
Electricity sales - CFDs	**1,198**	**84.3**	**101**	**980**	**71.0**	**70**	
Total contracted electricity sales	**4,138**	**87.1**	**361**	**4,168**	**80.4**	**335**	
Steam sales	**390**	**44.1**	**17**	**343**	**49.4**	**17**	4
Other income			1			(1)	5
Net income on gas sales			1			1	6
Net income on electricity related services			1			0	7
Net other income			**2**			**(0)**	
Total contracted revenue (1)	**4,528**	**84.0**	**380**	**4,512**	**77.9**	**352**	
Generation costs	4,426	(34.3)	(152)	4,409	(33.6)	(148)	8
Acquired generation cost	189	(117.4)	(22)	208	(111.3)	(23)	9
Generation costs (including acquired generation) (2)	**4,615**	**(37.7)**	**(174)**	**4,617**	**(37.1)**	**(171)**	
Spot electricity revenue	4,378	117.1	513	4,359	105.2	459	10
Settlement on acquired generation	189	116.8	22	208	124.7	26	11
Spot revenue and settlement on acquired generation (GWAP)	**4,567**	**117.1**	**535**	**4,567**	**106.1**	**485**	
Spot electricity cost	(2,893)	(127.6)	(369)	(3,138)	(114.1)	(358)	12
Settlement on CFDs sold	(1,198)	(119.0)	(142)	(980)	(105.2)	(103)	13
Spot purchases and settlement on CFDs sold (LWAP)	**(4,091)**	**(125.1)**	**(512)**	**(4,118)**	**(112.0)**	**(461)**	
Trading, merchant revenue and losses (3)			**23**			**23**	
Wholesale EBITDAF (1+2+3)			**229**			**204**	

Wholesale segment key

	Wholesale segment	Reference to detailed operating segment performance	Comment
Revenue	C&I electricity – Fixed Price	2	
	C&I electricity – Spot	2-spot	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 in gas and diesel purchases
	Steam	4	
	Other income	5	
Costs	Electricity purchases, net of hedging	9 + 11 + 12	
	Electricity purchases – Spot	2-spot	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 – Spot	2-spot	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

Customer segment

Residential electricity	unit	1H18	1H19	1H20	1H21
Average connections	#	361,412	352,159	355,216	357,756
Sales volumes	GWh	1,343	1,335	1,328	1,349
Average usage	per ICP	3.7	3.8	3.7	3.8
Tariff	$/MWh	247.8	249.9	248.2	251.1
Network, meters and levies	$/MWh	-123.3	-120.3	-119.0	-111.7
Energy costs	$/MWh	-84.2	-85.4	-91.6	-101.1
Gross margin	**$/MWh**	**40.3**	**44.2**	**37.6**	**38.3**
Gross margin	$ per ICP	150	168	141	144
Gross margin	$m	54	59	50	52

SME electricity	unit	1H18	1H19	1H20	1H21
Average connections	#	57,302	55,156	55,295	51,407
Sales volumes	GWh	564	539	533	465
Average usage	per ICP	9.8	9.8	9.6	9.0
Tariff	$/MWh	222.9	224.4	226.7	230.7
Network, meters and levies	$/MWh	-105.2	-106.5	-112.2	-104.4
Energy costs	$/MWh	-81.9	-83.6	-89.3	-99.7
Gross margin	**$/MWh**	**35.7**	**34.2**	**25.1**	**26.5**
Gross margin	$ per ICP	352	335	242	240
Gross margin	$m	20	18	13	12

Customer EBITDAF					
Electricity Gross margin	$m	74	77	63	64
Gas Gross Margin	$m	9	8	5	5
Broadband Gross Margin	$m	0	0	0	-2
Total Gross Margin	**$m**	**83**	**86**	**68**	**67**
Other income	$m	3	2	2	3
Other operating costs	$m	-41	-40	-41	-40
Customer EBITDAF	**$m**	**45**	**48**	**30**	**30**
Corporate allocation (50%)[1]	$m	-7	-7	-7	-7
Retailing EBITDAF	**$m**	**39**	**41**	**23**	**23**
EBITDAF margins (% of revenue)	%	7.8%	8.2%	4.7%	4.6%

1. Prior to FY18, corporate costs were fully allocated to the reporting segments.

Residential gas	unit	1H18	1H19	1H20	1H21
Average connections	#	60,870	61,332	61,959	60,563
Sales volumes	TJ	946	936	911	954
Average usage	per ICP	15.5	15.3	14.7	15.7
Tariff	$/GJ	29.6	29.1	30.6	31.3
Network, meters and levies	$/GJ	-18.2	-16.7	-16.7	-14.6
Energy costs	$/GJ	-5.1	-5.6	-7.6	-8.3
Carbon costs	$/GJ	-0.5	-0.9	-1.4	-1.4
Gross margin	**$/GJ**	**5.8**	**5.9**	**4.9**	**7.0**
Gross margin	$ per ICP	90	90	73	88
Gross margin	$m	5	6	4	5

SME gas	unit	1H18	1H19	1H20	1H21
Average connections	#	3,582	3,865	3,991	3,858
Sales volumes	TJ	679	809	845	720
Average usage	per ICP	189.7	209.4	211.8	186.7
Tariff	$/GJ	15.5	14.8	14.9	15.8
Network, meters and levies	$/GJ	-4.4	-5.3	-5.4	-7.9
Energy costs	$/GJ	-5.1	-5.6	-7.6	-8.3
Carbon costs	$/GJ	-0.5	-0.9	-1.4	-1.4
Gross margin	**$/GJ**	**5.5**	**3.0**	**0.5**	**-1.9**
Gross margin	$ per ICP	1,049	625	107	-352
Gross margin	$m	4	2	0	-1