2021 Full Year Results Presentation

Twelve months ended 30 June 2021

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FY21 performance highlights

Mike Fuge, CEO

Solid financial performance supports continued investment to decarbonise New Zealand

	Twelve months ended 30 June 2021 (FY21)	Twelve months ended 30 June 2020 (FY20)	
EBITDAF[1]	$553m	↑	24% from $446m[3]
Profit	$187m	↑	50% from $125m
Profit per share	25.3 cps	↑	45% from 17.5 cps
Operating free cash flow[2]	$371m	↑	28% from $290m
Operating free cash flow per share[2]	50.2 cps	↑	24% from 40.4 cps
Dividend declared	$272m	↓	3% from $280m
Dividend declared per share	35.0 cps	↓	10% from 39.0 cps
Stay-in-business (SIB) capital expenditure (cash)	$61m	↑	20% from $51m
Growth capital expenditure (cash)	$76m	↑	55% from $49m
Strategic investments (cash)	$40m	↑	471% from $7m

[1] Refer to slides 48 for a definition and reconciliation of EBITDAF
[2] Refer to slides 24 for a reconciliation of operating free cash flow
[3] Restated to account for the removal of the Significant items classification previously excluded from EBITDAF

Operating earnings (EBITDAF) were up by $107m when compared to FY20.

The operating conditions in FY21 were characterised by significant uncertainty around:

- The near-term future of major energy users, including NZAS.
- La Niña weather patterns and dry national hydrology.
- The deliverability of gas from declining gas fields.
- Rising carbon costs.

Despite the uncertainty in operating conditions, Contact supported wholesale customers with strong asset availability while managing our fuel risks.

During the year, Contact committed to the construction of the new 152MW Tauhara geothermal development, with the total capital investment totalling $177m for the financial year.

Key strategic highlights from FY21

	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
FY21 highlights	Supported the extension of NZAS, facilitating an orderly 2024 exit Undertook hydrogen study and opened registration of interest process First 10MW flexible electricity agreement signed with a data centre Simply Energy 100% acquisition Agreed PPA terms with Genesis for 62.5MW backed by Tauhara	New renewable investment committed: 152MW geothermal power station New capability added to accelerate decarbonisation: Roaring 40s wind partnership and Western Energy acquisition Balance sheet strengthened to support renewable pipeline: $400m equity raise	Launched ThermalCo concept, started stakeholder engagement Battery RFP concluded; engaged with EA to unlock regulatory barriers within the Transmission Pricing Methodology Secured an additional 17MW of green flexibility Currently no intention of renewing the Swaption post 2022	Protected mass market customers from high wholesale prices – tariff up 1.4% on FY20 Connections up 4%, with broadband connections up 25k (now 51k broadband connections) End-to-end digital customer journeys programme delivered online refunds, new bill emails, asynchronous messaging and new CSR Tools to significantly increase use of digital self-serve channels .

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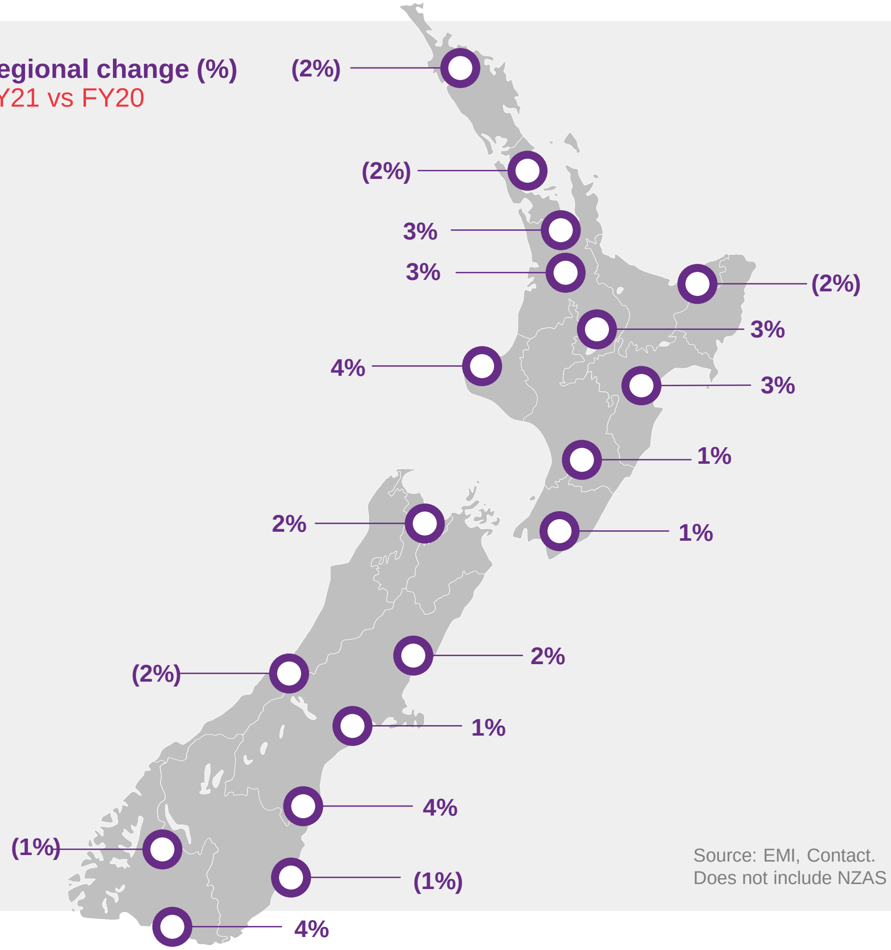
Key strategic highlights from FY21

	Our ESG commitment	Operational excellence	Transformative ways of working
Objective	Create long-term value through our strong performance across a broad set of environmental, social and governance factors	Continuously improving our operations through innovation and digitisation	Create a flexible and high-performing environment for NZ's top talent
FY21 highlights	Converted all bi-lateral bank facilities to sustainability-linked loans and eligible debt certified as 'green'; 1st New Zealand company to join the Nasdaq Sustainable Bond Network. Over half of our passenger fleet is electric. Sustainable Procurement strategy established including board approval of our Supplier Code of Conduct and Modern Slavery Statement. We planted more than 29,000 trees across our sites this year Improved on DJSI ranking to 62 percentile (from FY19: 55 percentile) Supported 123 community initiatives through sponsorship, donations, grants and volunteer time.	Thermal generation availability highest since FY17, due to engineering and maintenance undertaken to meet market demand Safety performance was outstanding Fueling innovation by acquiring Western Energy to deliver lower cost geothermal fuel	57% reduction in travel emissions, 348 tonnes of CO2-e saved through reduction in commuting and 413 tonnes saved with a reduction in business travel A new engagement tool Peakon launched with employee engagement 7.8/10 and +30 eNPS Several initiatives launched to grow our capability including a new leadership and learning framework Reduction in office footprint

National electricity demand

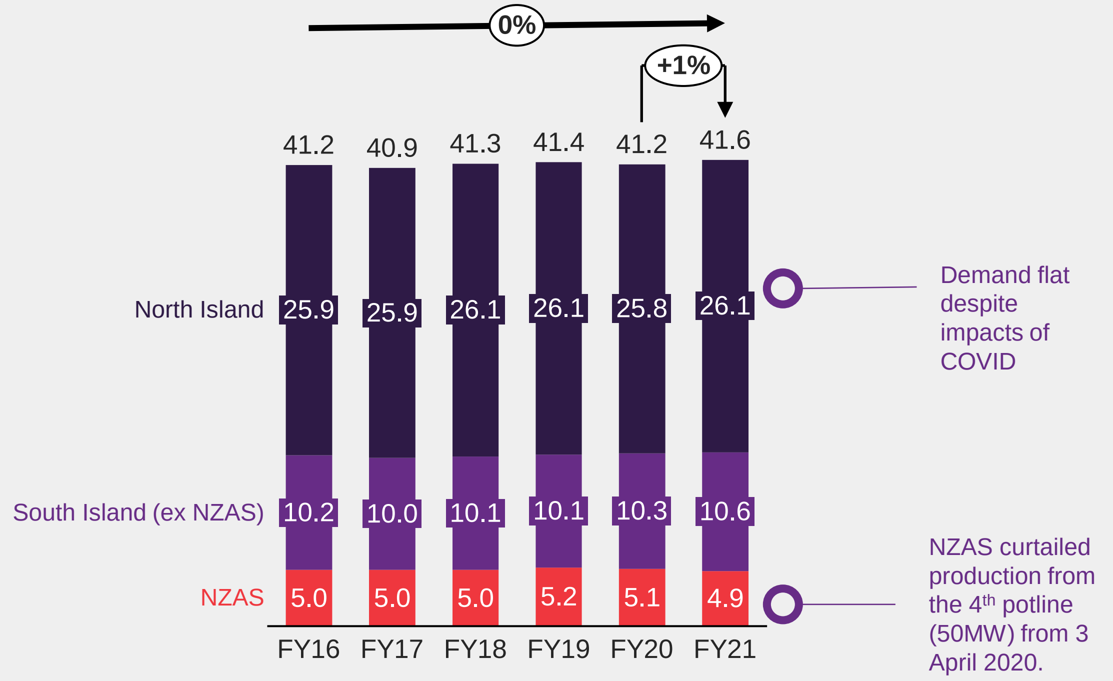
Encouraging demand growth despite limited net migration and economic uncertainty.

Regional change (%)
FY21 vs FY20



Source: EMI, Contact.
Does not include NZAS

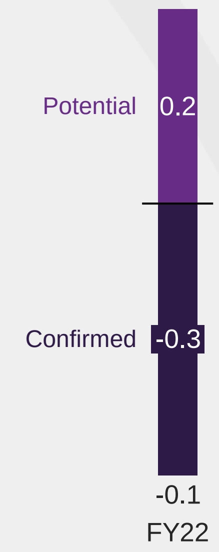
National electricity demand (TWh)



Source: EMI, Contact

FY22 potential demand changes (TWh)

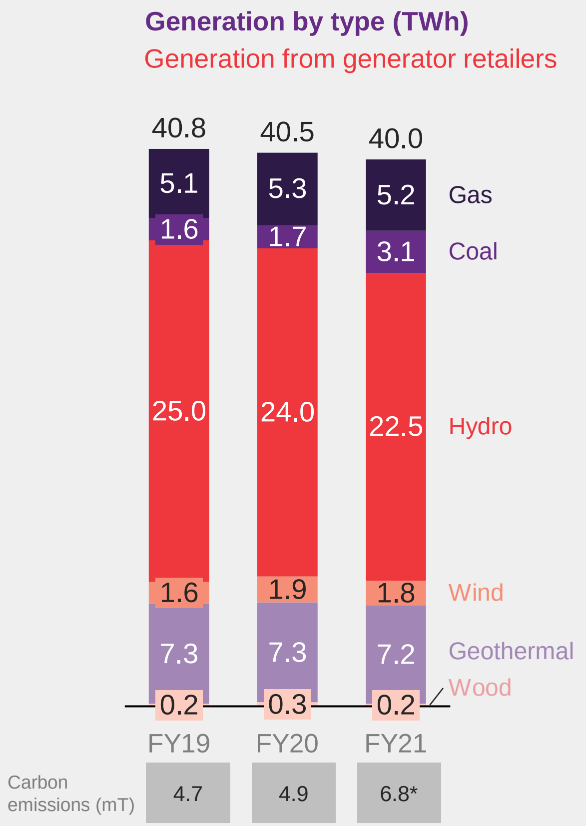
Major industrials



Source: Company announcements, Contact

Hydrology and impact on generation mix

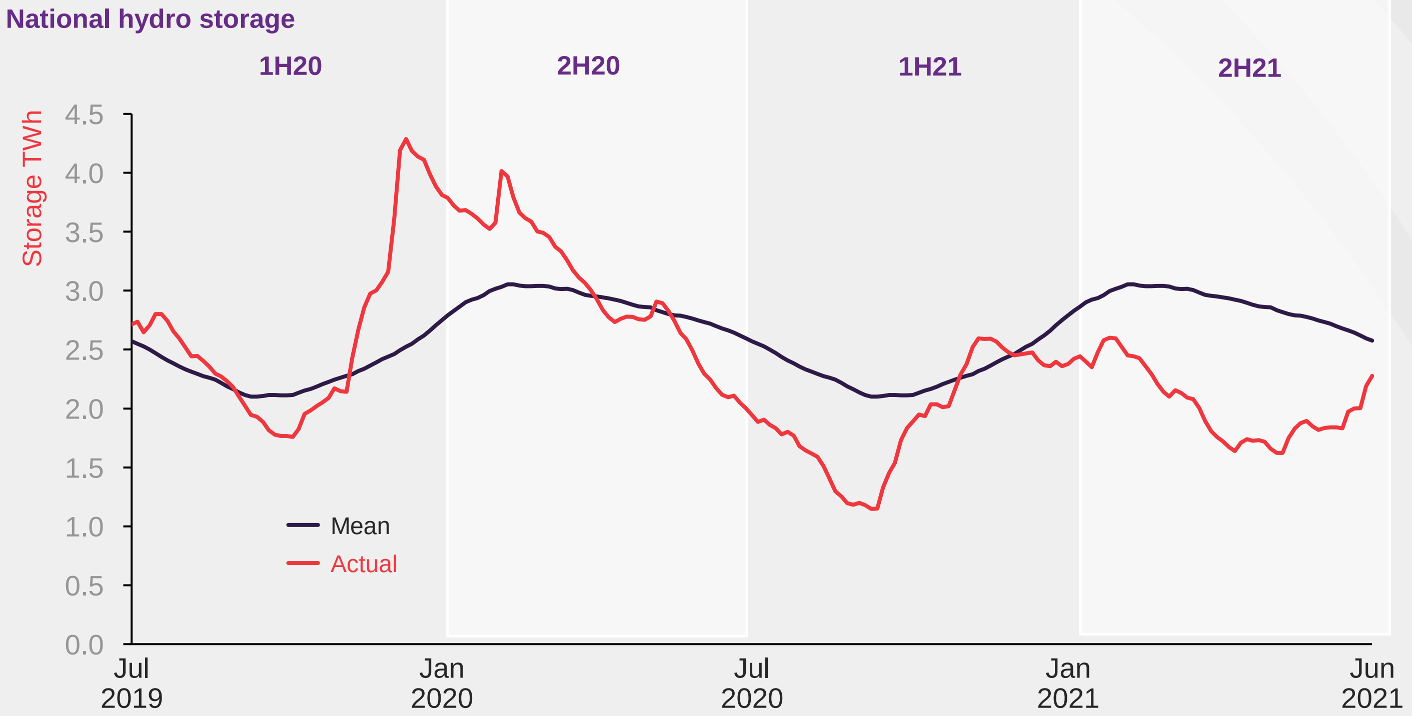
A reduction in natural gas production saw higher coal generation.



Hydro generation was down by 5% when compared to FY20 with below mean national inflows for the majority of the financial year.

With limited gas availability, due to the production declines at Pohokura and Kupe, generation from coal increased by 82% on FY20.

Source: EMI & MBIE



Lake levels were appropriately managed through the financial year to manage the risk around gas availability and delivery. Unseasonably strong inflows in June and July 2021 has seen national storage recover above mean.

Source: NZX

*Carbon emissions for FY21 Apr-Jun quarter has been estimated using historic conversion rates with actual generation data. The uplift in carbon emissions of 1.9mT CO2-e was due to the increase in coal generation from FY20 to FY21.

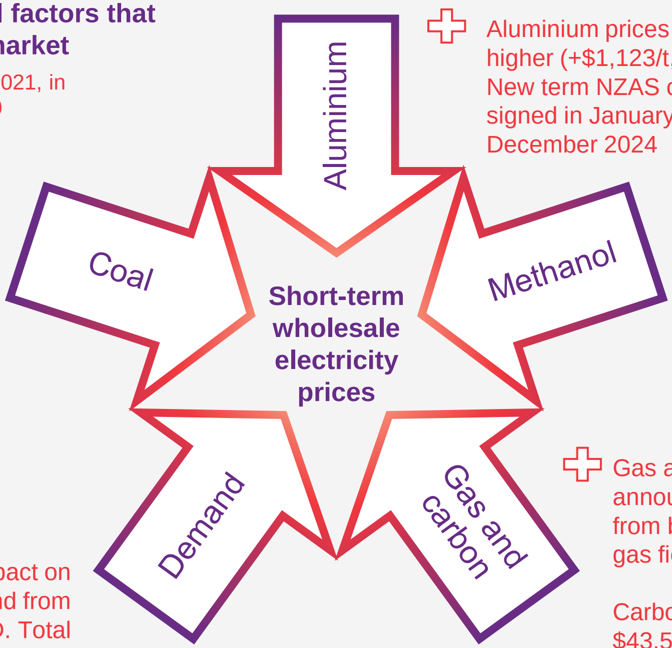
Not all generation stations are captured in the chart above.

Short-term factors influencing price all sharply higher over the last 12 months

The market is reacting to these price signals and adding new capacity.

Short-term external factors that can influence the market

Changes as at 30 June 2021, in comparison to June 2020



Aluminium prices sharply higher (+$1,123/t, up 45%). New term NZAS contract signed in January 2021 to December 2024

Coal prices increasing +$113/t (248%)

Methanol pricing up by $2.88/GJ gas equivalent (86% increase)

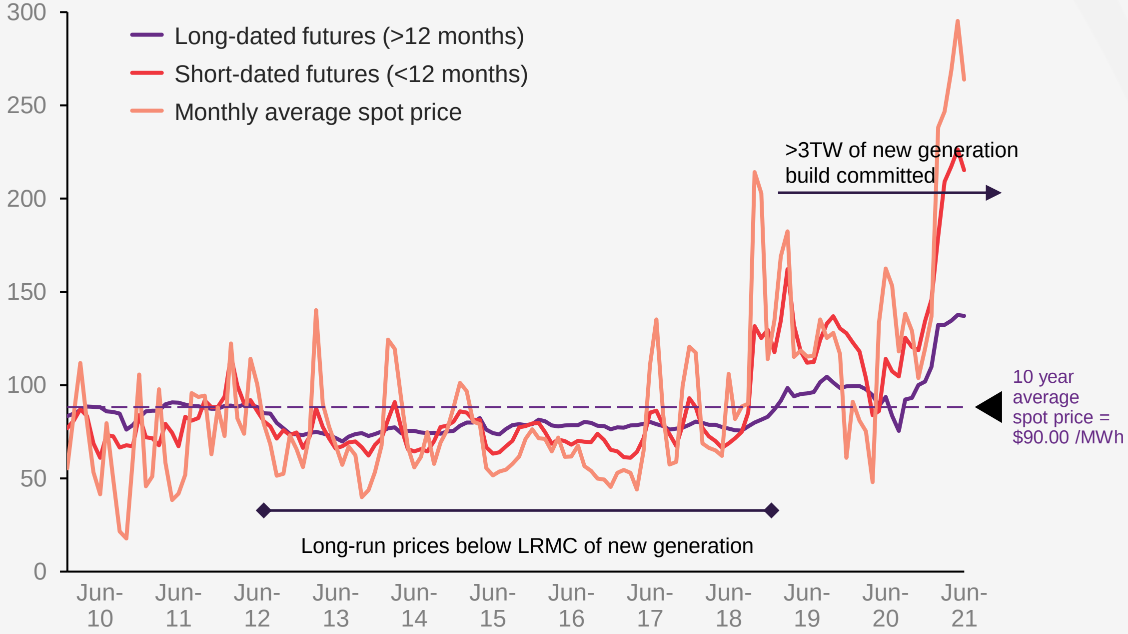
Gas availability - OMV announced reduced volumes from both Pohokura and Maui gas fields

Carbon prices up 35% to $43.5/NZU

Limited impact on demand from COVID. Total demand up 1%

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)

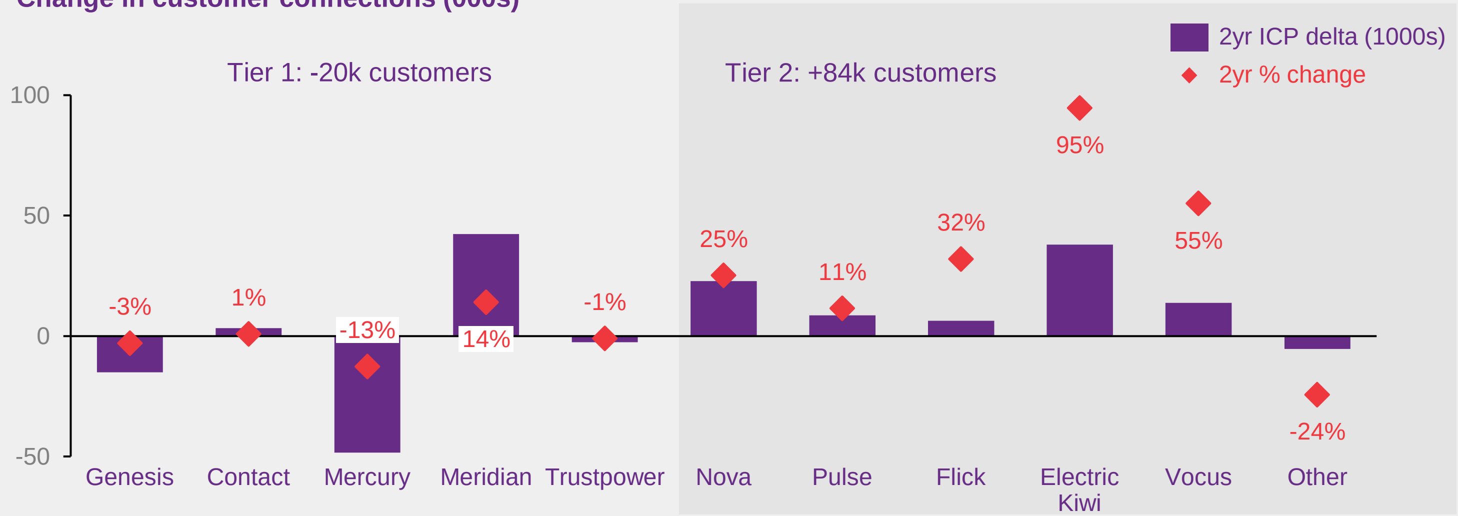


Both long-dated and short-dated prices remain well above long-term averages, reflecting higher thermal fuel costs and availability fuel risk

Source: EMI wholesale pricing

Retail competition remains intense

Change in customer connections (000s)

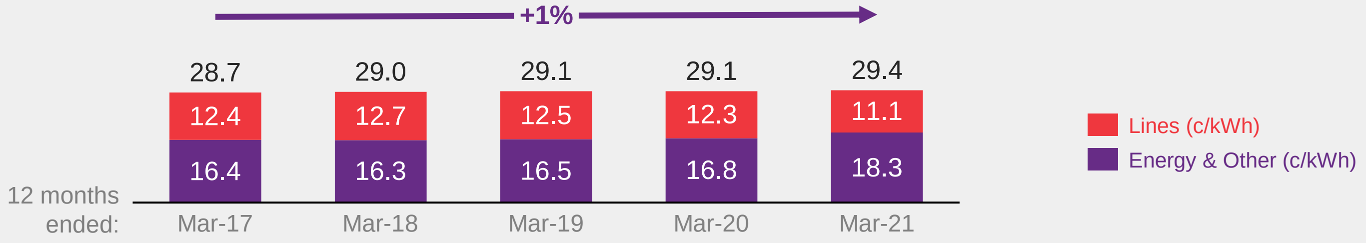


Source: EMI

Divergent views on the value of a customer:

- Tier 1: Mercury 50k connections down over 2 years, Meridian growing market share (+42k connections) now 3rd largest mass market retailer.
- Nova and Electric Kiwi continuing incredibly strong growth trajectory.
- Reducing market share of main players continues, Tier 2 market share now at 16% (from 12% November 2018) despite volatile and higher wholesale prices.
- New connections were up slightly compared to prior year (~1.5%. increase).

Retail tariff changes (c/ kWh)



Source: MBIE

Despite sharply higher wholesale prices over the last three years, tariffs up by a compound annual growth rate of 1% 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 FY21. Network costs expected to rise above inflation over the medium term.

Topical regulatory matters

Key themes		What Contact is doing
Wholesale market volatility	Gas availability and lower mean water levels through 2021 have resulted in higher spot and hedge market prices, increasing pressure on unhedged energy intensive industries, and retail pricing. The Electricity Authority, GIC and Minister continue to closely monitor security of supply, fuel availability and its impact on the wholesale market.	**Contact** is investing $580m in Tauhara, rolling out virtual Peaker product and working with industry to efficiently increase thermal generation in a fuel constrained market **Contact** is working with customers to smooth out pricing volatility through long-term contracts **Contact** continues to brief officials on its approach to managing current volatility. **Contact** cooperates with various market enquiries by providing relevant data where required.
Climate Change Commission	In June 2021, the Commission delivered its final report on carbon budgets and policy recommendations. The government must publish an Emissions Reduction Plan by the end of 2021.	**Contact** strongly supports the recommended direction of the Commission report, and the role that the energy sector will play in decarbonisation. **Contact** continues to closely engage in the government's work and assess the strategic opportunities and impacts for Contact.

Topical regulatory matters

Key themes		What Contact is doing
New Zealand 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. **Contact** is advancing the thinking on ThermalCo which appears to be a low capital, low cost and low risk solution **Contact** is engaging with government in assessing potential options
Energy hardship	Covid-19 has placed additional pressure on New Zealand households and businesses. Contact is actively working to minimise energy hardship.	**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.

Operational performance and financial results

Dorian Devers, CFO

Key themes from the financial results

Asset portfolio and trading capability ensure support for the market at time of increased fuel risk

Gas availability expected to remain an issue for the market but Contact is relatively well positioned

Recent Mergers & Acquisitions aligned to strategy

Changes in depreciation reflect the expected decarbonisation of our asset portfolio

Equity raise was well received and positions the business well for growth

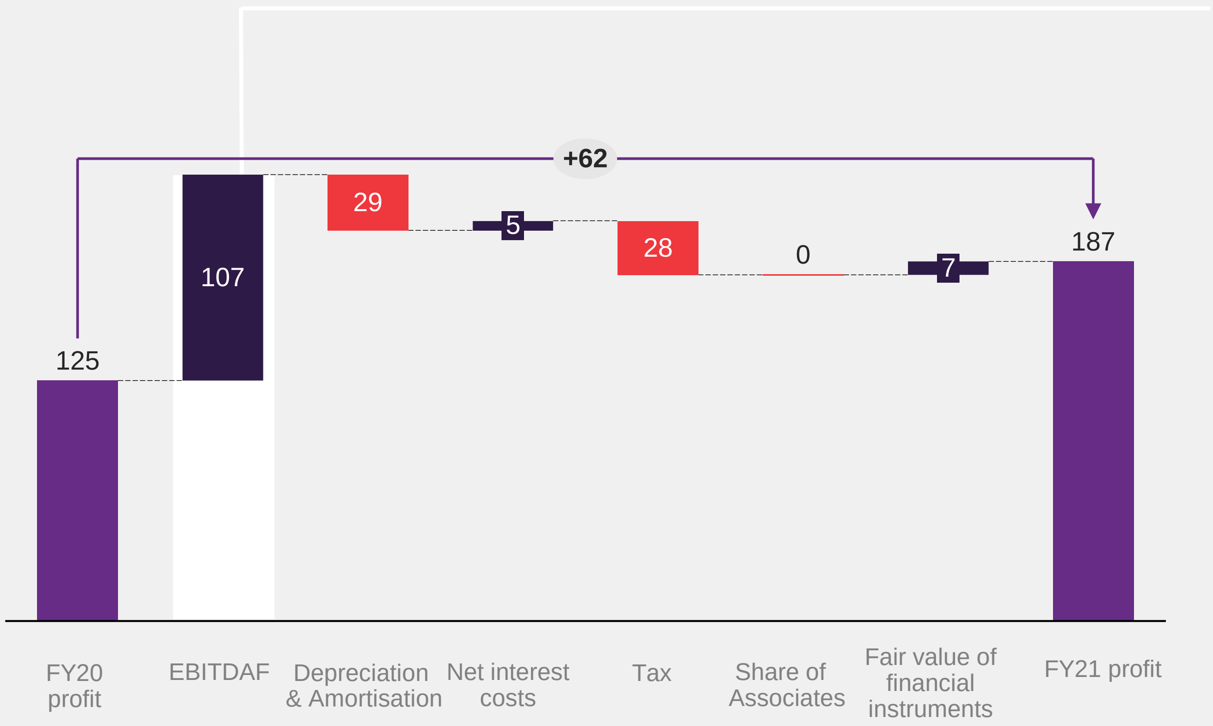
Significant items no longer reported separately

Key ESG KPI's now included with operational performance and getting same prominence as financial performance

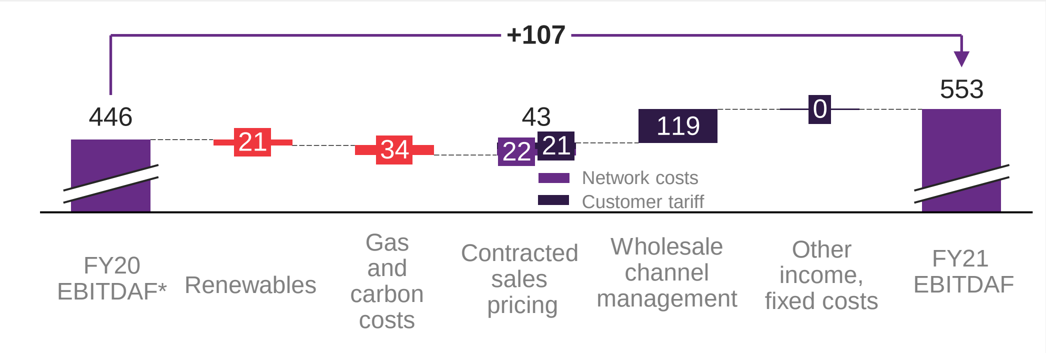
Profit of $187m, up $62m

EBITDAF up by $107m, as Contact supported the wholesale market in a period of fuel uncertainty.

Profit ($m)



EBITDAF ($m)

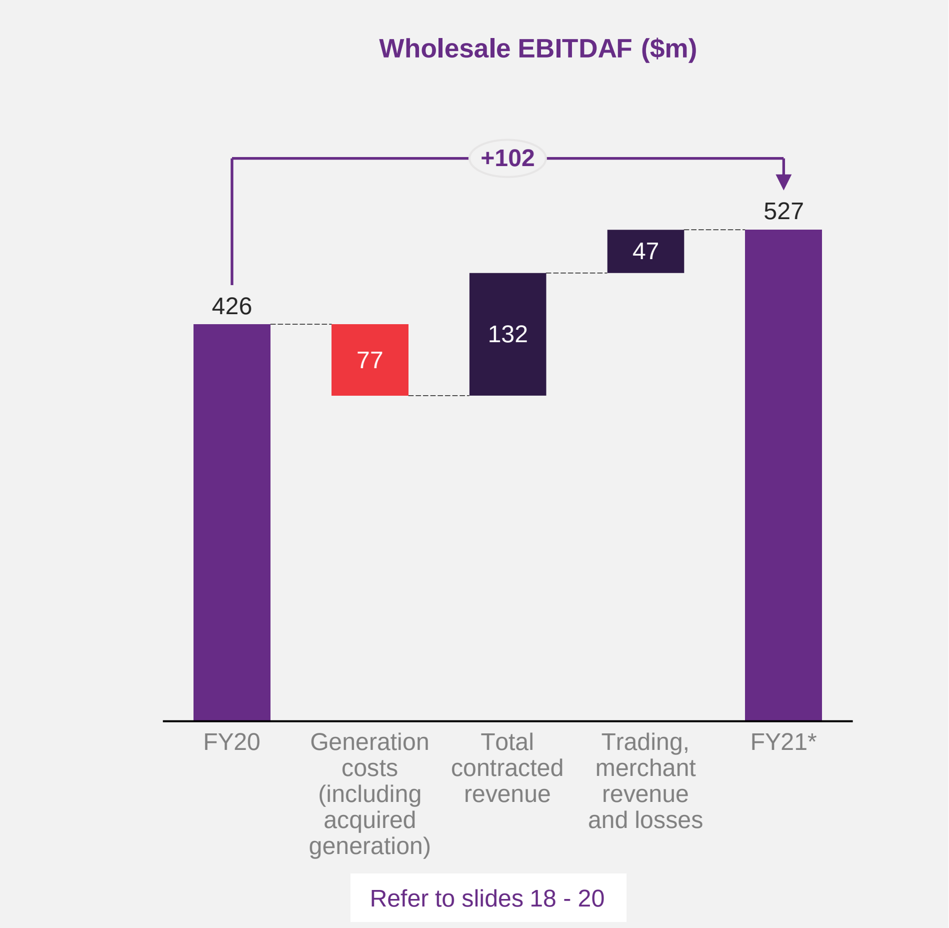


1. Lower geothermal generation year on year impacted by 4-yearly Te Mihi outage with lower hydro generation
2. Higher gas and carbon costs to run thermal generation
3. Improved net pricing from contracted customers as network costs reduced
4. Active channel management with increased sales to support fuel constrained market participants at a higher price
5. Higher other income and lower electricity transmission costs offset by higher operating costs

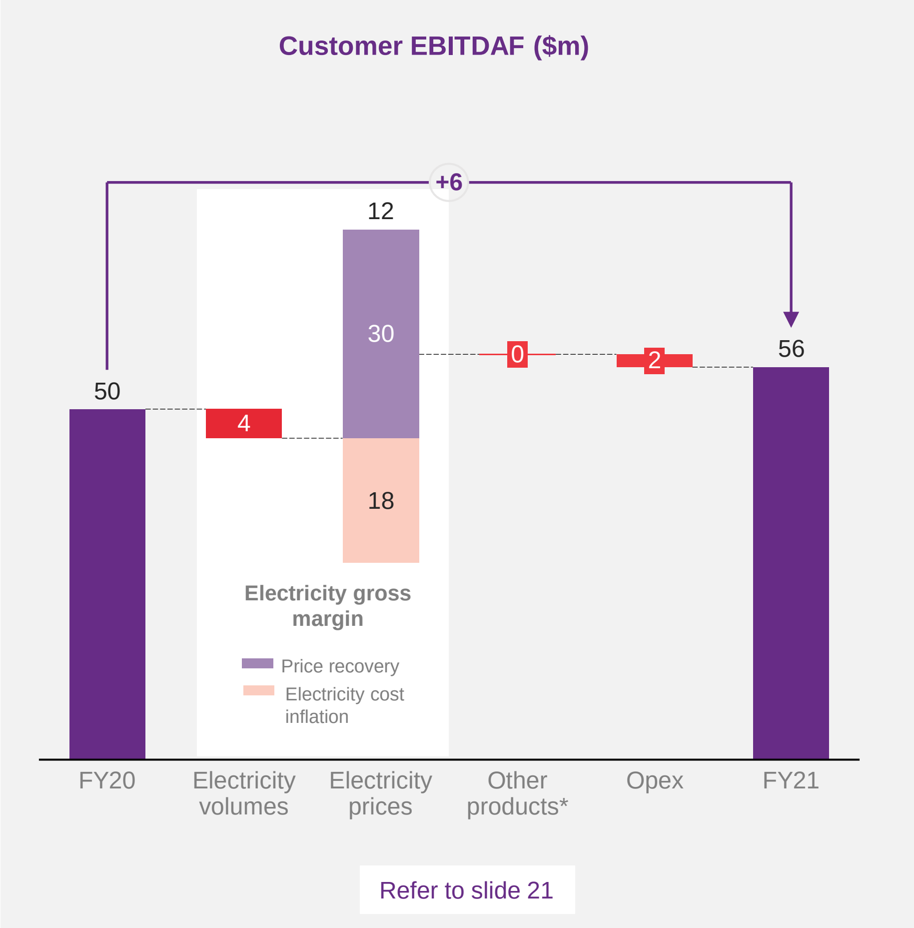
*EBITDAF restated to reflect the removal of significant items

EBITDAF up by $107m

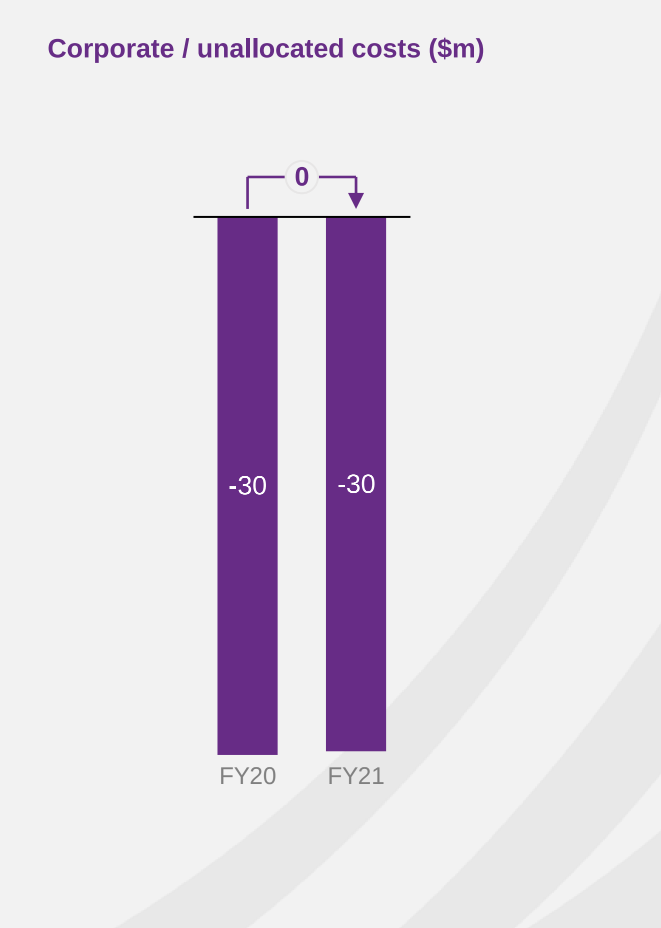
Business performance by segment.



*Simply and Western included within Wholesale EBITDAF



*Other products includes retail gas and broadband gross margins

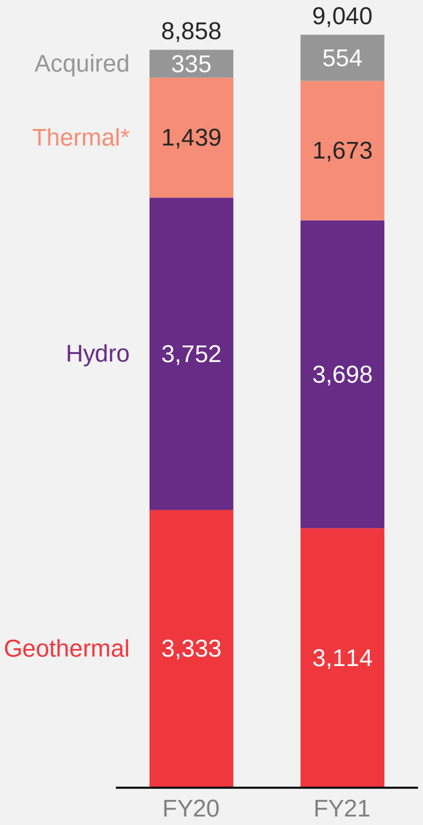


FY20 restated to include Holiday Act expense ($5m) after the removal of Significant items

Generation costs

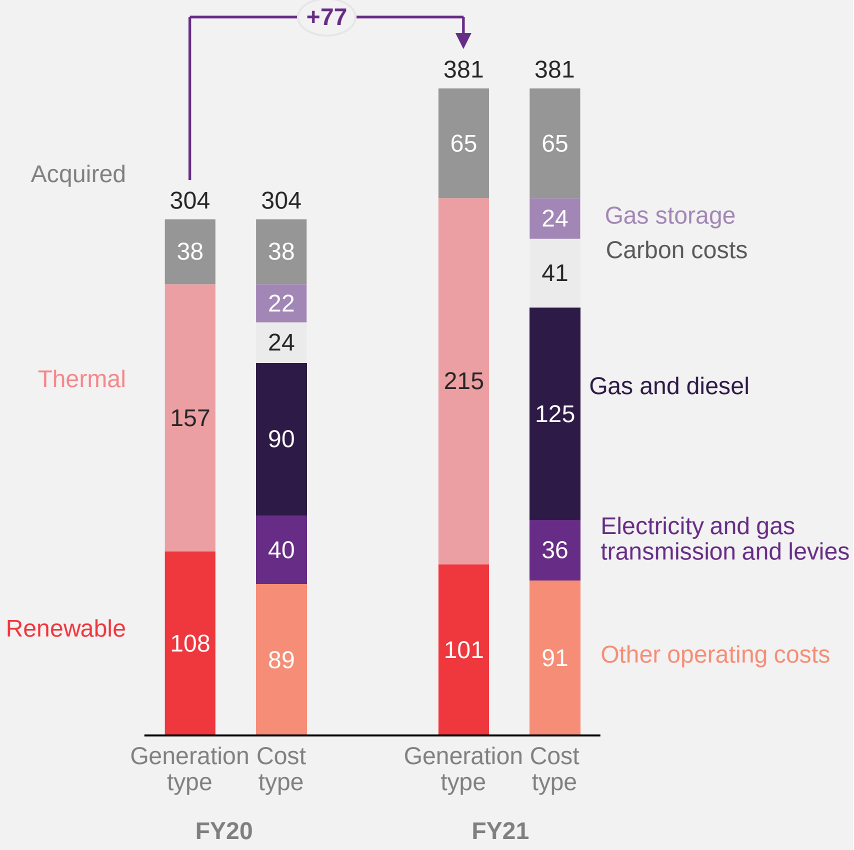
Costs up $77m ($8.5/MWh) as gas and carbon costs rose. Acquired generation sharply higher.

Electricity generated or acquired (GWh)



*Thermal includes tolling of ~261GWh FY20 and ~312GWh FY21

Electricity generated or acquired costs ($m)



Hydro generation down 53GWh on FY20 (-1%), 202GWh (-5%) below mean year expectations. Geothermal volumes were 219GWh down on prior year following a significant 4-yearly outage programme in the period.

- Renewable generation costs were down $7m on FY20. Transmission costs for renewable assets were down by $7m on FY20 as HVDC pole 1 costs ended.

Thermal generation costs were up by $58m due to higher gas (FY20 $6.7/GJ, FY21 $8.0/GJ) and carbon prices (FY20 $24/unit, FY21 $31/unit) and higher thermal generation in FY21.

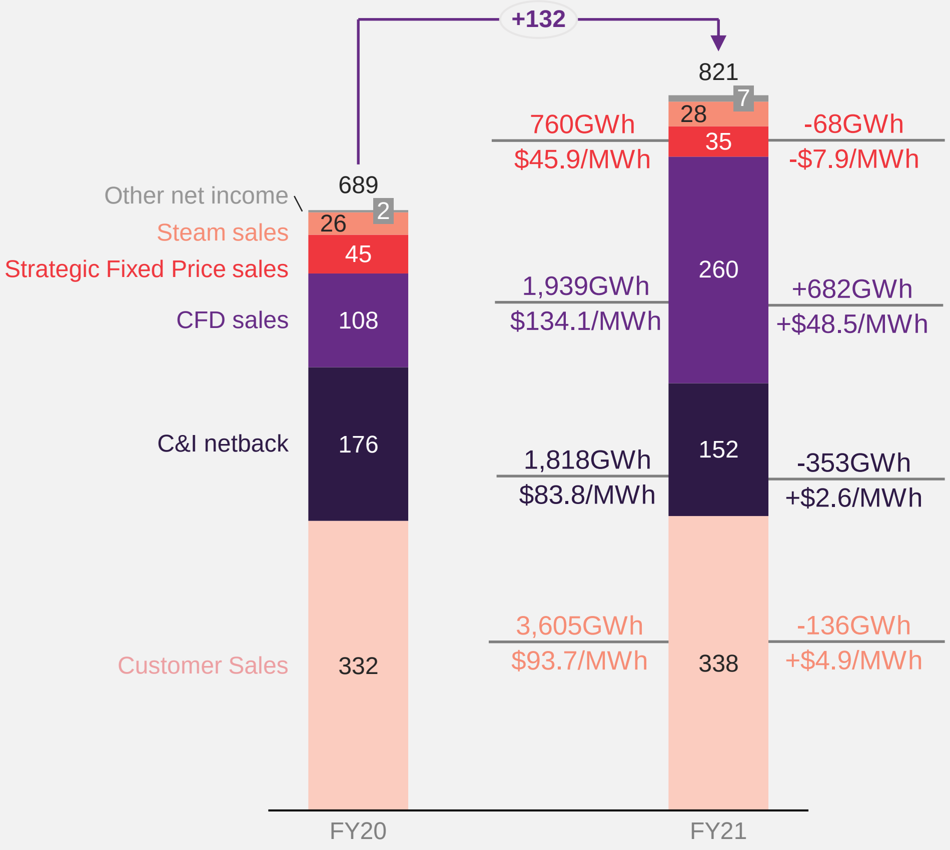
- Gas and carbon fuel costs up from $76/MWh in FY20 to $96/MWh (+26%)
- Fixed costs relating to AGS and other operating costs were up by $2m each on the prior comparative period as the AGS facility expansion was commissioned on 30 September 2020

Increased acquired generation on the prior period as wholesale spot prices encouraged swaption calls.

Wholesale contracted revenue

Sales mix adjusted to reflect the uncertainty of fuel availability.

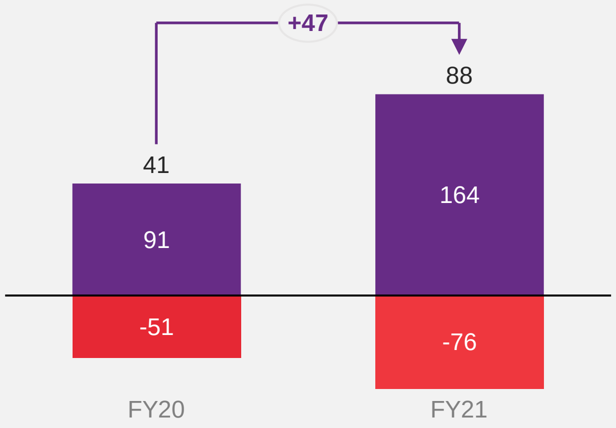
Contracted revenue ($m)



- Fixed price variable volume electricity sales to the Customer segment and C&I customers ended 489GWh lower than FY20 (-$42m), this was partially offset by higher prices (+$24m), reflecting higher wholesale prices over the three preceding years.
- Strategic fixed price sales were down with lower sales to support NZAS due to the suspension of the 4th potline, partially offset by an increase in volume supplied to industry under a long-term PPA. Lower pricing reflects updated NZAS support contract from January 2021 (-$10m)
- CFD sales volumes were up by 682GW as nearer term higher priced channels were prioritised (+$152m)
- Steam revenue was up $2m on FY20 with an increase in geothermal steam sales secured (+77GWh) with steam tariffs on Te Rapa generation rising with carbon costs changes.
- Other income was up by $5m as the $2m loss on market making in FY20 was not repeated and income from the Western Energy acquisition (1 April 2021) was realised ($2m)

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)

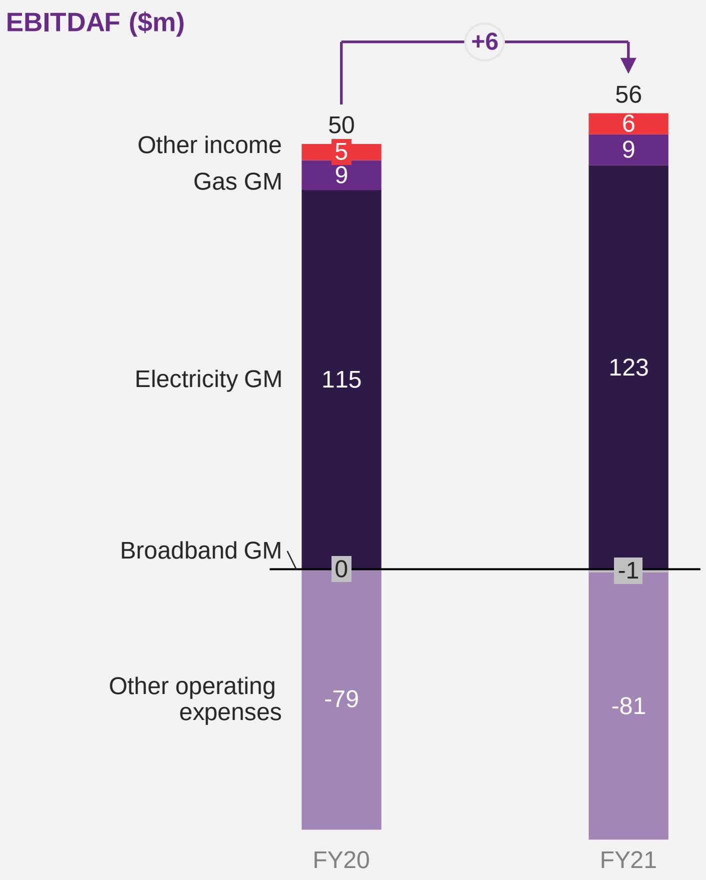
- 43GWh increase in merchant sales volumes. The price received for this “long” generation was up by $74.20/MWh on FY20.
- Inter-island separation reduced from 6% to 5% on dry South Island conditions, this was offset by higher absolute prices to increase generation losses by $25m.

Customer business performance

Managing through elevated wholesale input costs.

Revenue & Tariff[1] ($m)	FY20	FY21		Variance	
	$m	$m	*Tariff*	$m	*Tariff*
Electricity gross revenue	859	841	249	(18)	7
PPD not taken	10	5		(5)	
Incentives paid	(6)	(5)		1	
Net revenue (cash)	**862**	**841**	**249**	**(22)**	**4**
Capitalised incentives	7	7			
Amortised incentives	(8)	(9)			
Net revenue (P&L)	**861**	**838**	**248**	**(23)**	**3**
Gas revenue	74	74	94	(0)	5
Broadband revenue	17	32	68	15	(2)
Other income	5	6		1	
Total revenue	**957**	**951**		**(7)**	
Contract Asset (closing)	13	9		(3)	

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



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

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

- 67% of our residential customers are on non-PPD products from 1 July.
- Around 50% of customers received a price increase in FY21.
- Ending Prompt Payment Discounts, - 50% reduction in PPD not taken.

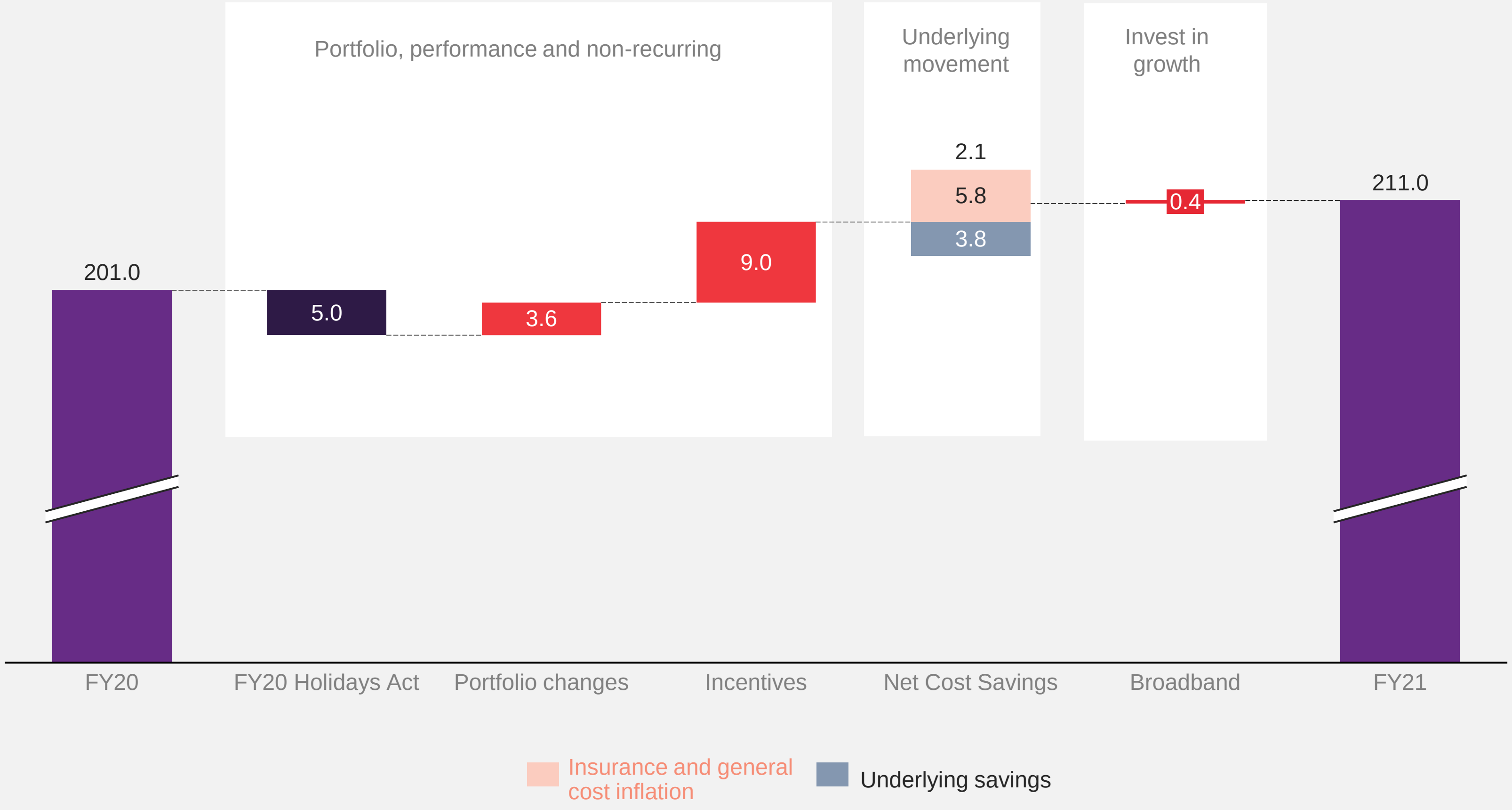
Continue to smooth the impact of higher electricity costs for customers:

- Combination of targeted retail price rises and a reduction in network costs from 1 April 2020 has seen electricity gross margins improve by 7% from FY20.
- Retail energy tariffs - will need to rise to reflect elevated wholesale electricity, gas and carbon costs.

Strong growth in Broadband connections (+25k up on FY20).

Operating costs up on acquisitions and improved financial performance

Other operating cost movement ($m)



Portfolio performance and non-recurring

- Holidays Act provision (-$5m) recognised in FY20 not repeated.
- Operating costs acquired as part of the strategic transactions of Western Energy and Simply Energy ($3.6m).
- Strong FY21 performance leading to higher incentive costs, FY20 incentives were reduced after consideration of COVID potential ($9m).
- Benefits of the strategic acquisition of Western Energy on the well restoration provision offset by costs incurred to execute the refreshed strategy (nil).

Underlying movement

- Strong credit collection and payment products saw a reduction in bad debt ($3.0m).
- Digital journeys programme improved customer service efficiency

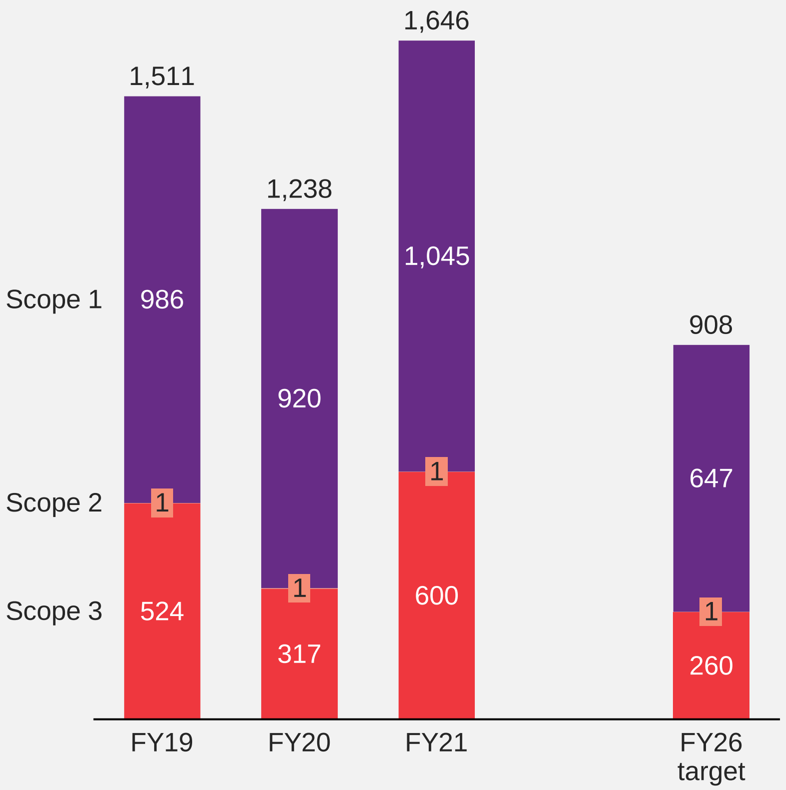
Broadband

- Further incremental investment in broadband growth. Benefits of change in provider and further digitisation resulting in 87% productivity increase as measured by broadband connections per full time equivalent.

Greenhouse gas reporting

Carbon emissions up as low hydro inflows led to increased thermal generation and coal based swaption calls.

kT of C02e emitted



Performance

- Scope 1 emissions up 125kT, predominantly from carbon emitted from thermal generation with high volumes in FY21 to support lower renewable generation
- Carbon from swaption up over 300% as Contact made more calls under the swaption and a higher emissions intensity factor from the fuel mix (FY21: 300kT, FY20: 90kT)
- Emissions from business travel and employee commenting down by 57%, enabled by our transformative ways of working programme

Targets

- Our targets have been approved by the Science-based targets initiative (1.5 degree warming)
- Reduce Scope 1 and 2 GHG emissions 45% compared to 2018 baseline by 2026
- 30% reduction of 2018 Scope 3 GHG emissions by 2026.

See slide 40 for detailed greenhouse gas emissions reporting

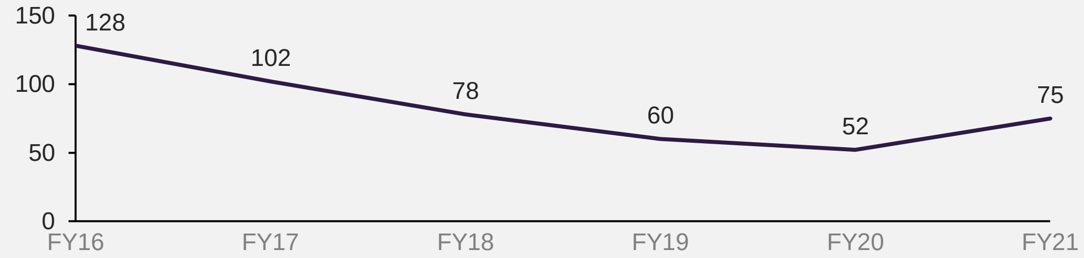
Cash flow and capital expenditure

Underlying cash conversion remains strong.

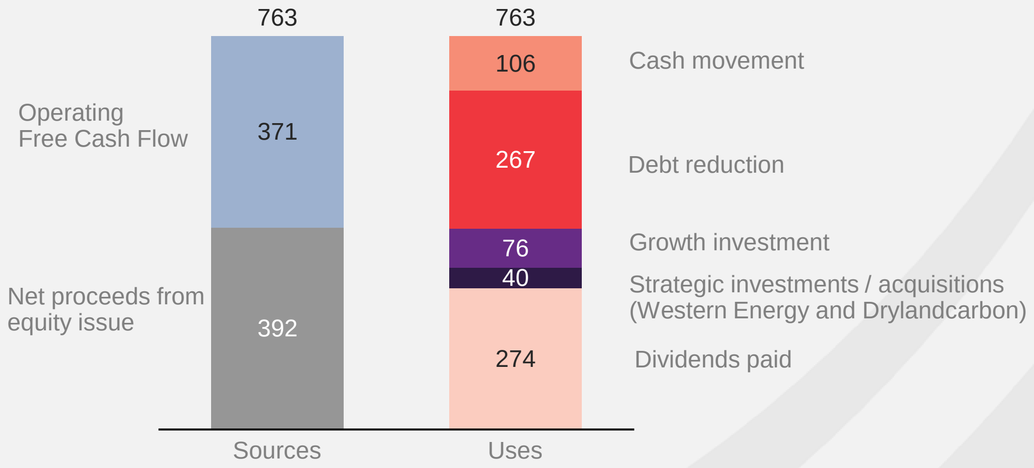
	12 months ended 30 June 2021	12 months ended 30 June 2020	Comparison against FY20	
EBITDAF	**$553m**	$446m	↑	$107m
Working capital changes	**$3m**	$7m	↓	($5m)
Tax paid	**($79m)**	($70m)	↓	($9m)
Interest paid, net of interest capitalised	**($43m)**	($49m)	↑	$6m
SIB capital expenditure	**($61m)**	($51m)	↓	($10m)
Non-cash items included in EBITDAF	**($2m)**	$7m	↓	$9m
Operating free cash flow	**$371m**	$290m	↑	$81m
Operating free cash flow per share	**50.2cps**	40.4cps	↑	9.8cps
Cash conversion (OpFCF / EBITDAF)	**67%**	65%	↑	2%

- EBITDAF up $107m on improved pricing across key channels
- Working capital changes $5m unfavourable to FY20 due to the increased value of gas inventory and additional purchase of carbon in the period, including exercising the final fixed price option for carbon surrender in May 2021
- Capital expenditure (cash) $61m in FY21, $10m more than FY20 due to statutory geothermal outage programme and initial payments for SAP upgrade programme

SIB capital expenditure – accounting ($m)



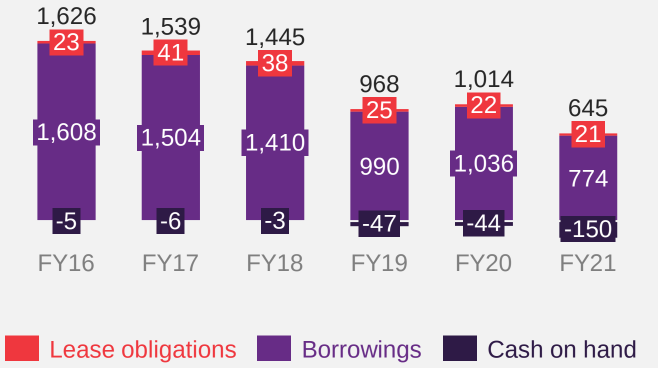
Sources and uses of cash ($m) FY21



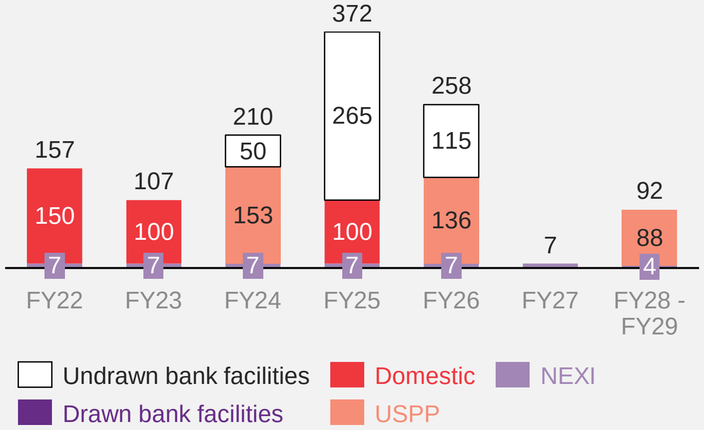
Robust balance sheet.

Diverse debt portfolio with green certification. Capacity to fund renewable generation projects.

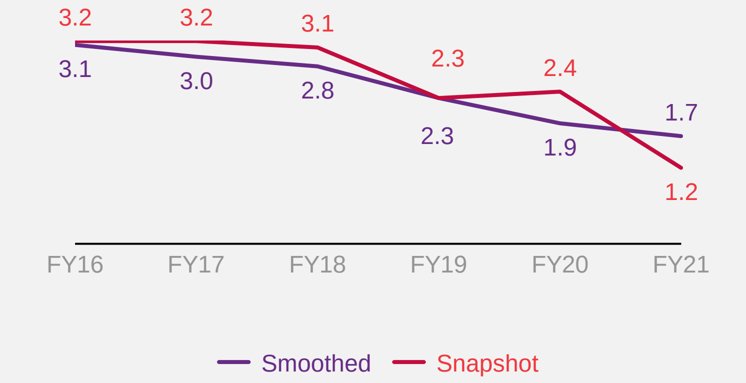
Closing net debt ($m)
Face value of borrowings less cash



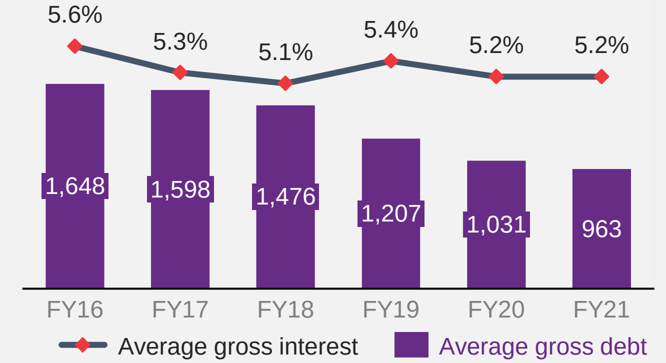
Borrowing maturities ($m)
Average tenor of 3.3 years as at 30 June 2021



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



Interest rate (%)
Weighted average gross interest[1] on average borrowings

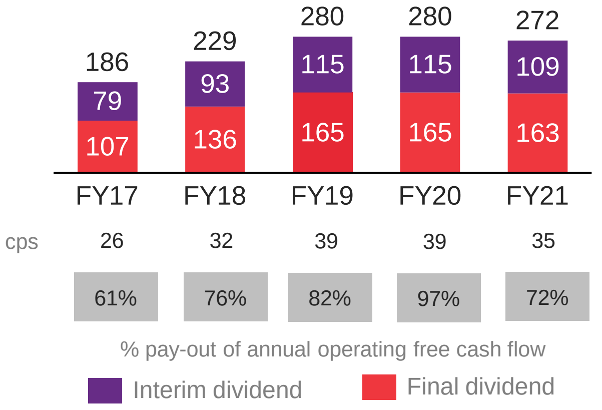


- Face value borrowings (excl. leases) decreased by $262m to $774m from 30 June 2020. The decrease is due to the inflow from the $400m equity raise in February 2020 less surplus held as cash.
- Net debt has reduced by $981m since the end of FY16. Gearing decreased to 22.6% at 30 June 2021, down from 31.4% at 30 June 2020.
- Average interest rate on gross debt has remained flat due to the repayment of more flexible, lower cost floating rate debt with the proceeds from the equity raise offsetting the lower rate environment.
- A credit rating of BBB (net debt / EBITDAF <2.8x) continues to be targeted.
- All bank facilities have now been converted to sustainability linked loans, and all our debt instruments are certified green.

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

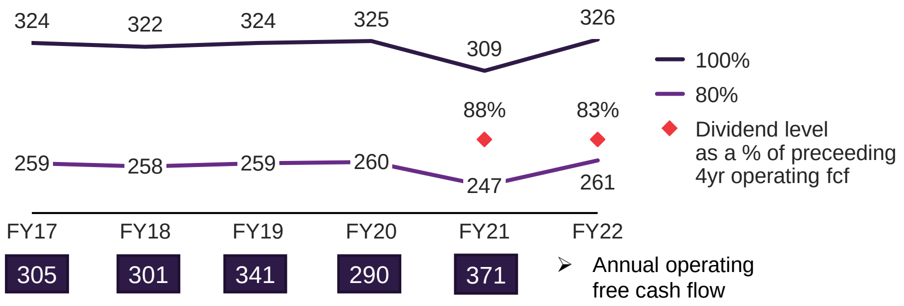
Dividend for FY21 in line with performance

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

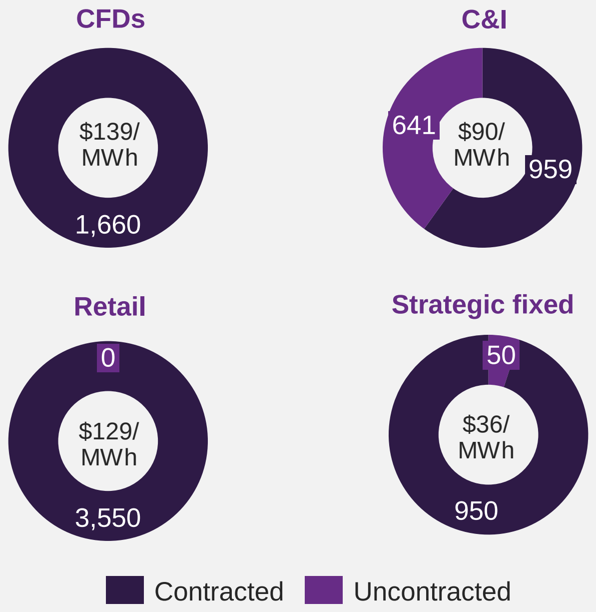
Dividend for FY21 of 35 cents per share

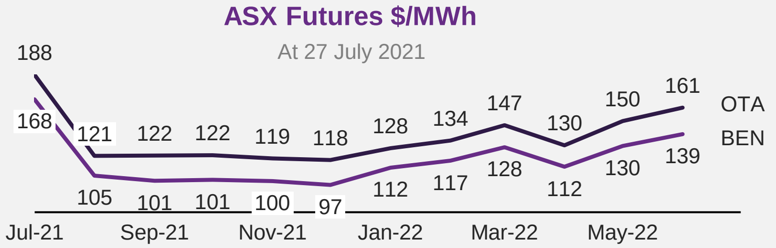
- Final dividend of 21 cents per share is imputed to 67% or 14 cents per share for qualifying shareholders. This represents a pay-out of 72% of FY21 operating free cash flow and 88% of the operating free cash flow over the preceding 4 financial years (FY17-FY20)
- Record date of 27 August 2021; payment date of 15 September 2021.
- The NZD/AUD exchange rate used for the payment of Australian dollar dividends will be set on 02 September 2021.

Dividend reinvestment plan

- Shareholders will have the option of full, partial or no participation. If a shareholder elects to participate they will remain in the plan at the same participation level until they elect to terminate or amend their participation level.
- There will be no discount offered for the FY21 final dividend and Contact will have the right to terminate or suspend the plan at any time.
- Dividend reinvestment plan (DRP) forms must be in by 30 August 2021 to confirm participation in the plan.
- Trading period for setting price for DRP is 26 August 2021 to 01 September 2021. DRP strike price will be announced: 02 September 2021

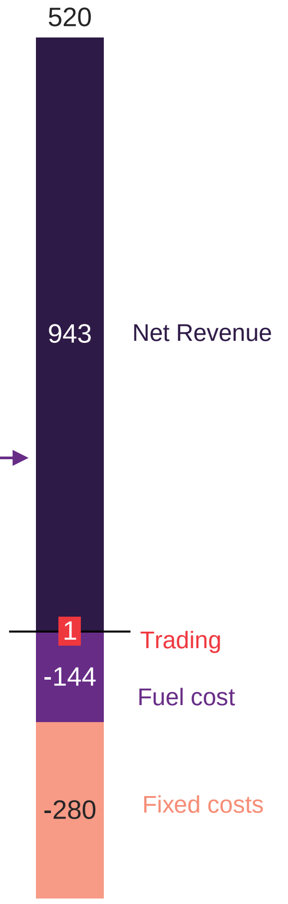
Normalised and expected FY22 EBITDAF assumptions





FY assumptions that deliver expected & normalised EBITDAF for FY22

1 Channel choices maximise long term value[1]		X	2 Net price[2] driven by best commercial practices	=	Total
Strategic fixed price	1,000GWh	x	$38/MWh	=	$38m
CFDs	1,660GWh	x	$139/MWh	=	$231m
C&I	1,600GWh	x	$104/MWh	=	$166m
Retail	3,550GWh	x	$129/MWh		$458m
Other income[3]					$50m
					$943m
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	$2/MWh	=	-$7m
Thermal	800GWh	x	$123/MWh[4]	=	-$98m
Acquired	300GWh	x	$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		-$220m
Total	**$1m**		**Total**		**-$280m**



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 $8.4/GJ, carbon price of $37/unit and thermal portfolio heat rate (11.4GJ/MWh)
5. Length of 440GWh 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

Strong delivery in FY21.
Capability and capacity to be added in FY22.

	FY21 Guidance	Result	FY22 Guidance	Guidance commentary
Other operating costs	$200 – 210m	$211m	$215-225m	Additional capacity and capability added to accelerate the delivery of the strategy. SIB capex will support higher asset availability and output as well as a SAP systems upgrade
Stay in business capital expenditure (cash)	$55 – 60m	$61m	$95-105m	
Cash spend (‘Totex’)	**$255 – 270m**	**$272m**	**$310 – 330m**	
Depreciation and amortisation	$215 – 225m	$249m	$265 – 275m	Accelerated depreciation on thermal assets in line with expected useful lives and decarbonisation goals
Net interest (accounting)	$45 – 50m	$50m	$30 – 40m	
Cash interest (in operating cash flow)	$40 – 45m	$43m	$20 – 30m	
Cash taxation	$75 – 85m	$79m	$85 – 95m	Taxation paid up to reflect strong FY21 financial performance
Corporate costs	-	$30m	$33m	ICT costs previously included in Customer now in Corporate
Target ordinary dividend per share	35 cps	35 cps	35 cps	Pay-out in line with dividend policy
Geothermal volumes	3,100GWh	3,114GWh	3,250 GWh	Minor geothermal safety programme outage

Progress on Strategy

Mike Fuge, CEO & Dorian Devers, CFO

Contact26 Our strategy to lead NZ's decarbonisation

Strategic theme	Grow demand	Grow renewable development	Decarbonise our portfolio	Create outstanding customer experiences
Objective	Attract new industrial demand with globally competitive renewables	Build renewable generation and flexibility on the back of new demand	Lead an orderly transition to renewables	Create NZ's leading energy and services brand to meet more of our customers' needs

Enablers

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

Operational excellence: continuously improving our operations through innovation and digitisation

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

Outcomes

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

Resilience
Deliver sustainable shareholder returns, aligned with our ESG commitment

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

We have set ambitious measures of success across our strategic themes

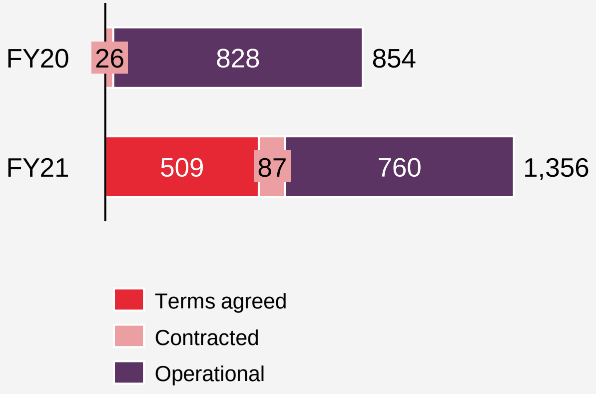
	Grow demand	Grow renewable development	Decarbonise our portfolio	Create outstanding customer experiences
Metrics & measures	Senior in-house capability to support industry electrification partnerships by 2021 100 MW of new commercial and industrial demand by 2025 Identified 300+ MW of market-backed demand opportunities in the lower SI by end of 2024 (e.g., hydrogen)	Tauhara online by mid 2023 Final investment decision on next renewable build (Wairākei, wind, and/or solar) by 2024 Decision on North Island battery by end of 2023, for delivery in 2024 100 MW demand response capacity by 2025	Complete thermal review in 2021, and executed by the end of 2022 TCC decommissioned by end of 2023 Reduce Scope 1 and 2 GHG emissions 45% compared to 2018 baseline by 2026[2]	Top 10 'most trusted retailer' by 2025[1] 650,000 customer connections by 2025 Cost to serve (CTS) < $120 per connection 75% of customer interactions through digital channels

1. As per Colmar Brunton Rep Track report, 2021 ranked 44th
2. Science Based Targets Initiative (Sbti) target at 1.5 degrees.

Contact26 Tracking to targets

Grow demand

Demand backed by strategic fixed price PPA (GWh)

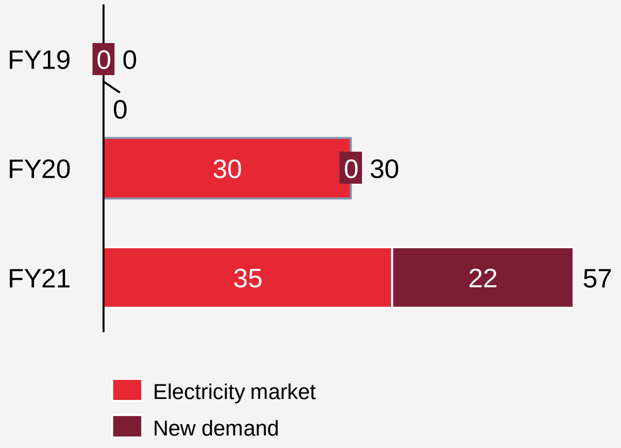


New load contracted, expected online in FY23

Terms agreed with Genesis Energy

Additional long-term agreements under negotiation

Avoided carbon emissions (kTC02e)



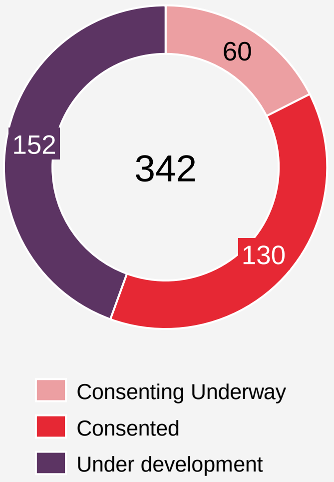
New industrial heat electricity boilers rather than coal

Tolling arrangement with Nova saw the most efficient plants used

Contact26 Tracking to targets

Grow renewable development

New geothermal development (MW)

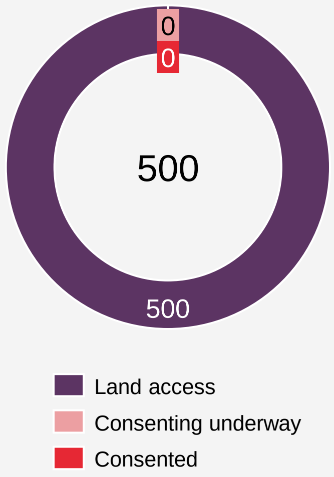


Consenting for increased generation on the Wairakei field (incremental to current position)

Tauhara stage 1 under development. Field is more productive than envisaged.

Look to secure additional geothermal consents on operational fields

New wind and solar development (MW)



Land access agreements signed for up to 500MW of wind generation potential

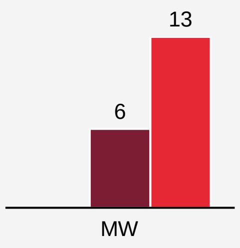
Assessment phase to follow

Consenting underway in FY22

Contact26 Tracking to targets

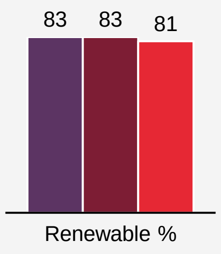
Decarbonise our portfolio

Demand flex



Strong growth in our demand flex proposition – lowered the install cost and increased the sales network

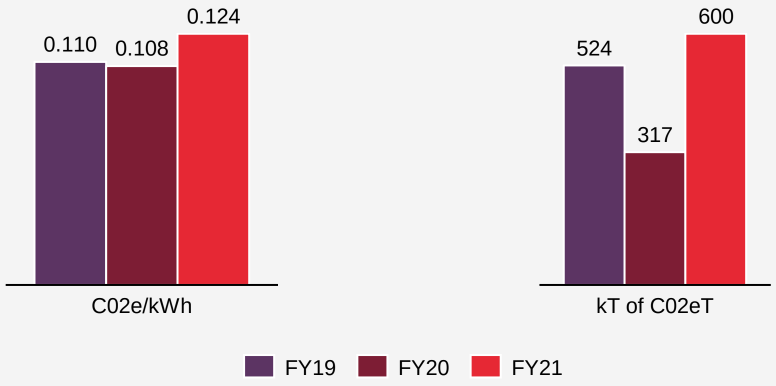
Renewable generation



Expect renewable generation % to grow with investment and higher thermal fuel costs

Scope 1 and 2 greenhouse gas (GHG) intensity

Scope 3 emissions

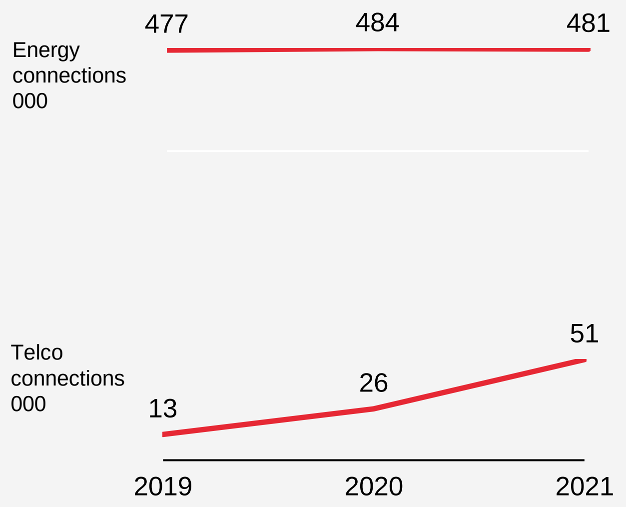


Scope 3 emission higher as Contact called generation under the swaption arrangement with Genesis which was run higher

Contact26 Tracking to targets

Create outstanding customer experiences

Growth

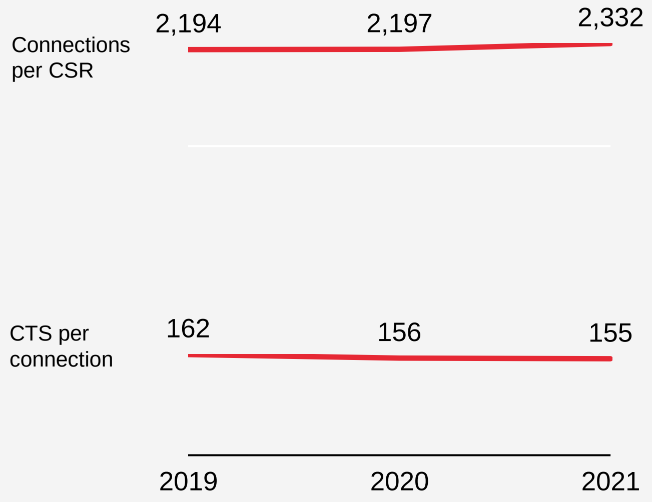


Continue to grow telco customer connections

Protecting the core energy base in a rising energy cost environment

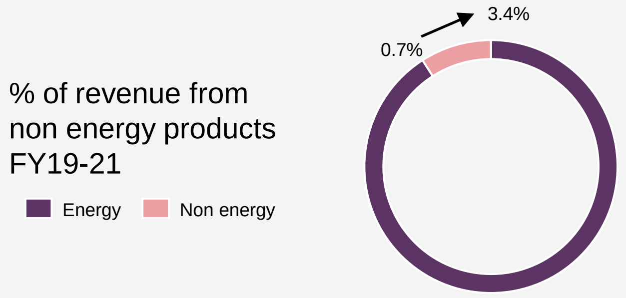
Prepare to launch new complementary products

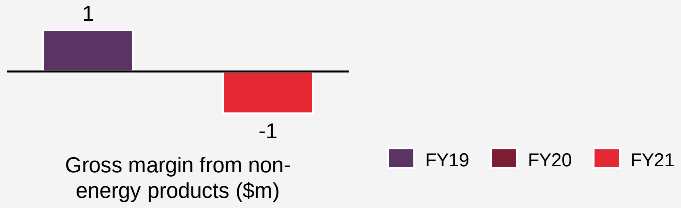
Efficiency



Continue to invest in data and digital journeys for our customers and people to improve experience and efficiency

Value





Broadband gross margin positive from FY22

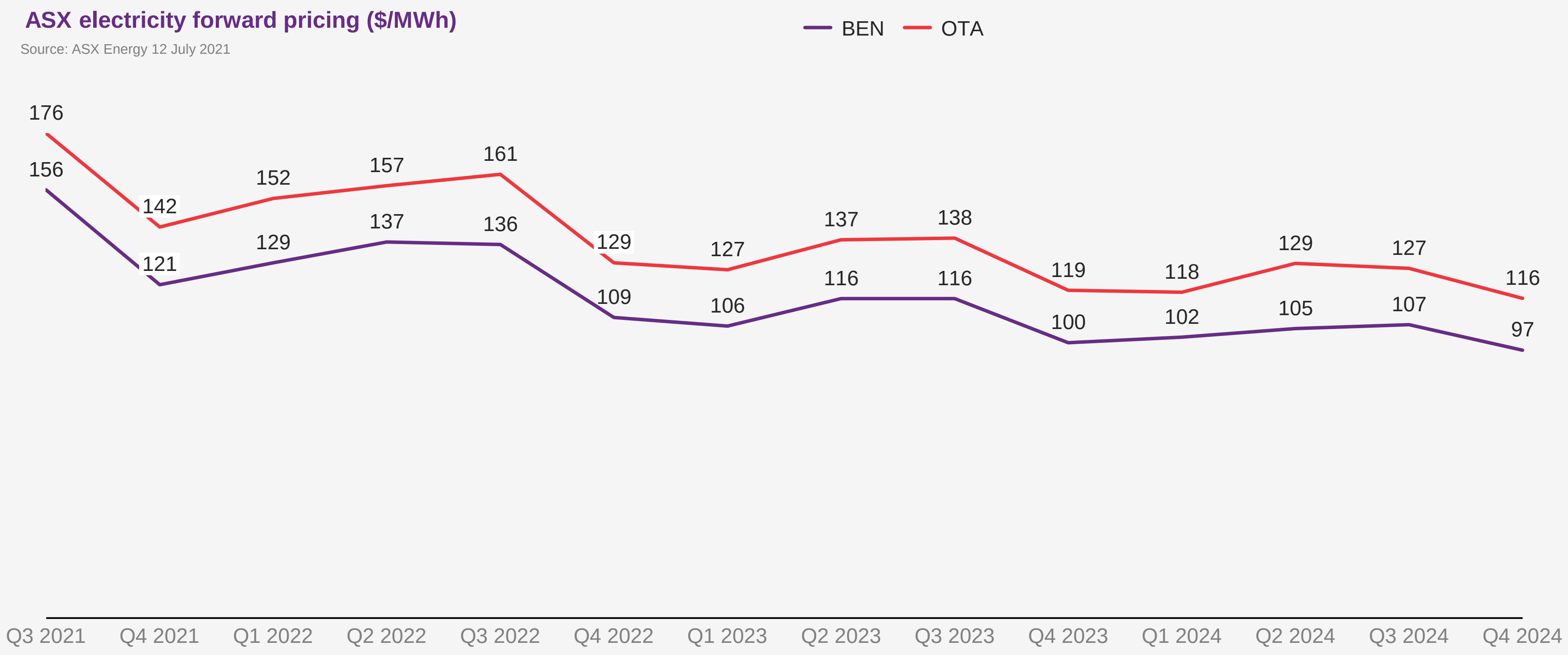
Our operational plan: What you can expect in the next 18 months

Strategic theme	H1-FY22	H2-FY22	H1-FY23
Grow Demand	Hydrogen registration of interest followed by request for proposals Advance data centre partnerships Engage on industrial electrification	Assess hydrogen position Build data centres Lock in major industrial user electrification	Develop hydrogen option Data centres online Commence boiler electrification
Grow renewable development	Build Tauhara Prepare further geothermal consents Secure solar partnership or add capability	Build Tauhara Further geothermal consenting Secure and consent wind sites	Complete Tauhara Tauhara phase II consent Secure solar consents Complete battery feasibility
Decarbonise our portfolio	Complete thermal review and design principles for structure Engage 3rd party to structure 'ThermalCo'	Align future-state thermal structure Agree structure with owners and regulators Execute 'ThermalCo' and buy back PPAs	Prepare for end of TCC scheduled hours
Create outstanding customer experiences	Launch time of use offer, with extension into EVs Implications of sale of Trustpower retail to Mercury Customer technology upgrade	Pilot launch of wireless broadband Investigate data driven energy monitoring commercial models Customer technology upgrade (cont.)	Pilot complementary products Customer technology upgrade (cont.)

Questions

Supporting materials

ASX futures pricing in fuel risk over the next 12 months

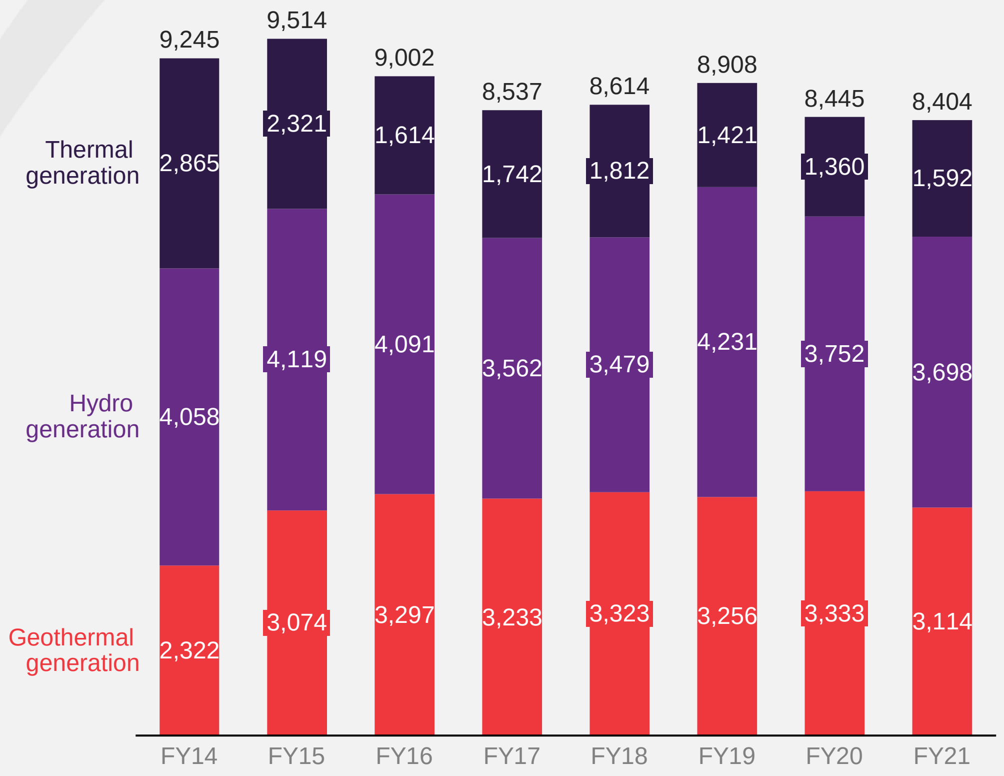


Greenhouse gas emissions

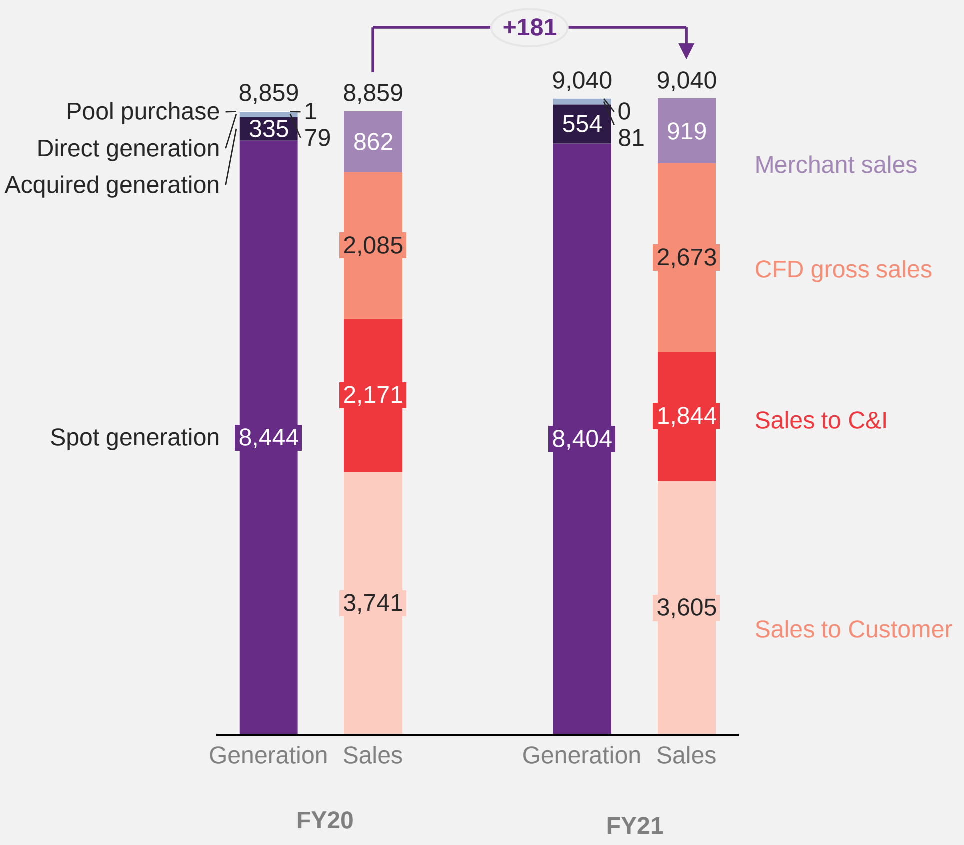
Indicator	Unit	Target	FY19	FY20	FY21
Direct GHG emissions (Scope 1)	**tC02e**	45% reduction of 2018 Scope 1 and 2 emissions by 2026 (Absolute emissions reduction target)	**985,905**	**920,403**	**1,044,893**
- Stationary combustion	tC02e		984,903	920,403	1,044,536
- Mobile combustion	tC02e		880	270	270
- Mobile combustion – Simply Energy	tC02e				20
- Mobile combustion – Western Energy	tC02e				38
- Fugitive emissions	tC02e		122	4	29
Indirect GHG emissions (Scope 2)	tC02e		**1,374**	**1,258**	**1,230**
Sub-total Scope 1 and 2	**tC02e**	**647,443**	**987,279**	**921,935**	**1,046,122**
Indirect GHG emissions (Scope 3)	**tC02e**	**259,118**	**524,314**	**317,384**	**600,389**
- 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	63,296
- Category 2 – Capital goods	tC02e		6,536	18,052	40,521
- Category 3 – Fuel and energy	tC02e		175,811	91,857	330,202
- Category 4 - Upstream distribution and transportation	tC02e		628	14	26
- Category 5 – Waste	tC02e		148	123	121
- Category 6 – Business travel	tC02e		1,256	719	258
- Category 7 – Employee commuting	tC02e		514	606	306
- Category 11 – Use of sold products	tC02e		301,640	166,310	165,259
- Category 13 – Downstream leased assets	tC02e		445	306	399
- Category 14 – Franchise	tC02e		2,069		
Total Scope 1,2 and 3 emissions	**tC02e**	**906,561**	**1,511,081**	**1,239,319**	**1,646,511**

Generation and sales position

Contact generation output sold to the national grid (GWh)



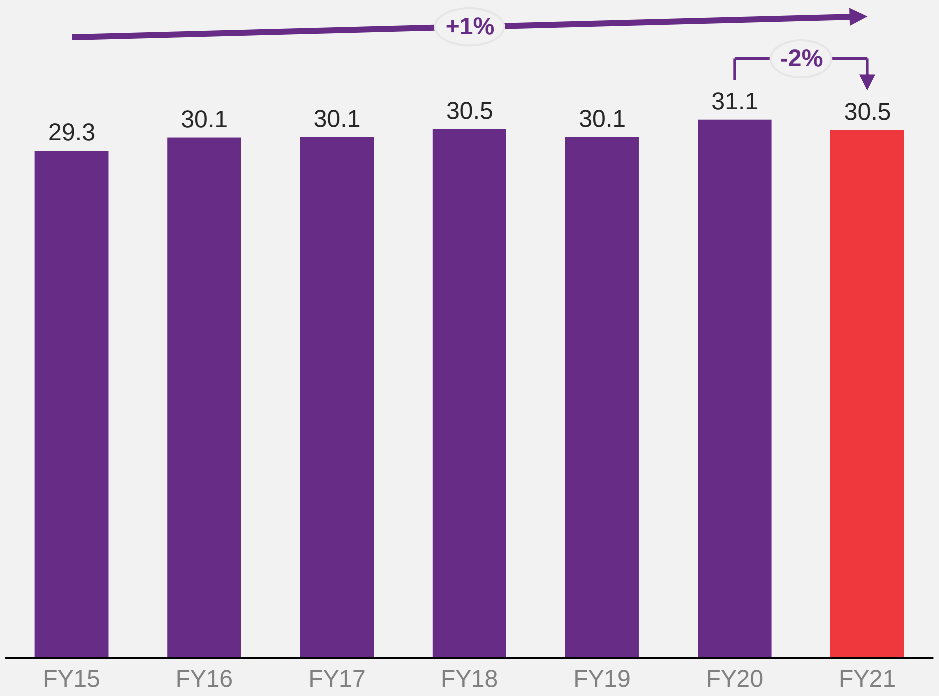
Electricity and generation sales position (GWh)



Wairākei geothermal field mass take and efficiency

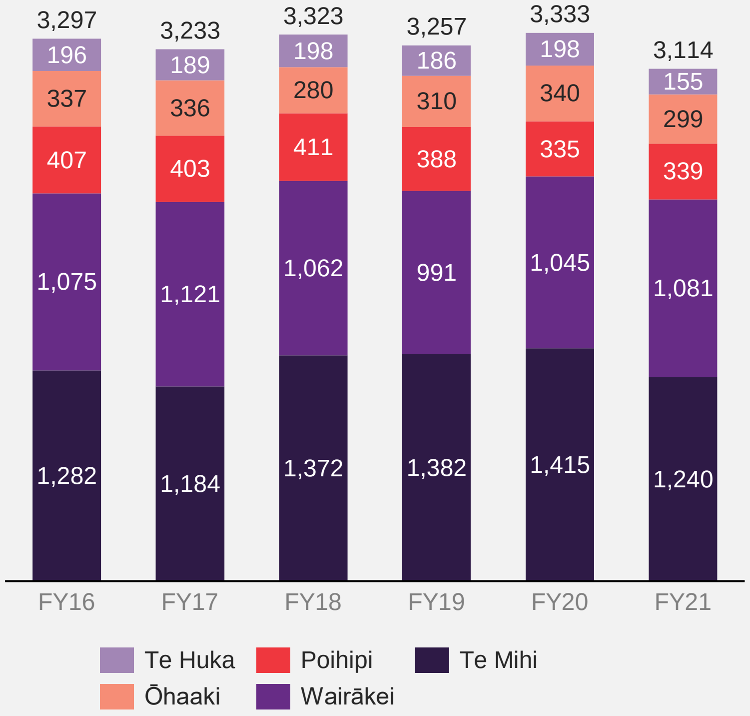
Geothermal fuel extracted at Wairākei vs consented
(GWh)

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



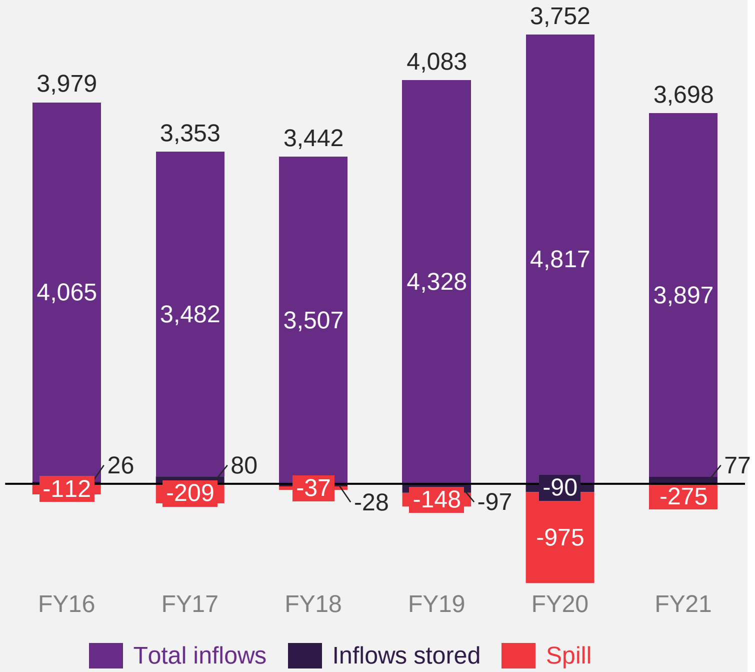
Generation volumes: renewable generation down by 4% on FY20

Geothermal generation (GWh)



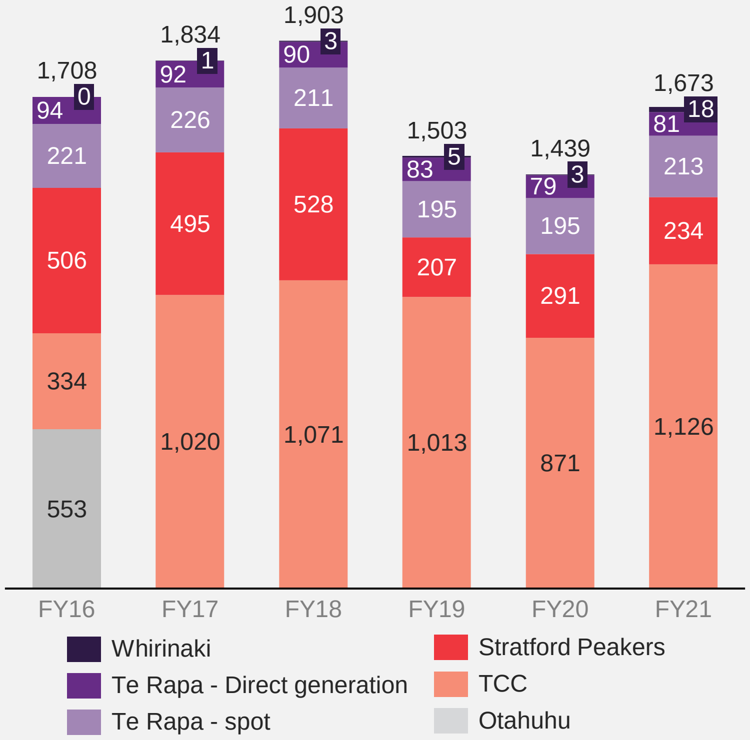
Geothermal generation was 219GWh lower than FY20 following the 4-yearly statutory Te Mihi outage in the period and an extended outage required on process safety improvements required at the Te Huka binary plant.

Hydro generation (GWh)



Hydro generation was 202GWh below mean (3,900GWh) in FY21, 53GWh lower than FY20.

Thermal generation (GWh)



Thermal generation volumes were 235GWh higher than FY20 as a result of the arrangement to toll gas from Nova Energy (FY20: 239GWh, FY21: 278GWh)

Plant availability

Hydro

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	($m)
FY17	784	92%	52%	3,562	47	169
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

Geothermal

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	($m)
FY17	429	91%	86%	3,233	55	177
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

Taranaki combined cycle (TCC)

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	($m)
FY17	377	90%	31%	1,021	64	65
FY18	377	68%	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

Peakers (including Whirinaki)

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	($m)
FY17	360	95%	16%	495	73	36
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

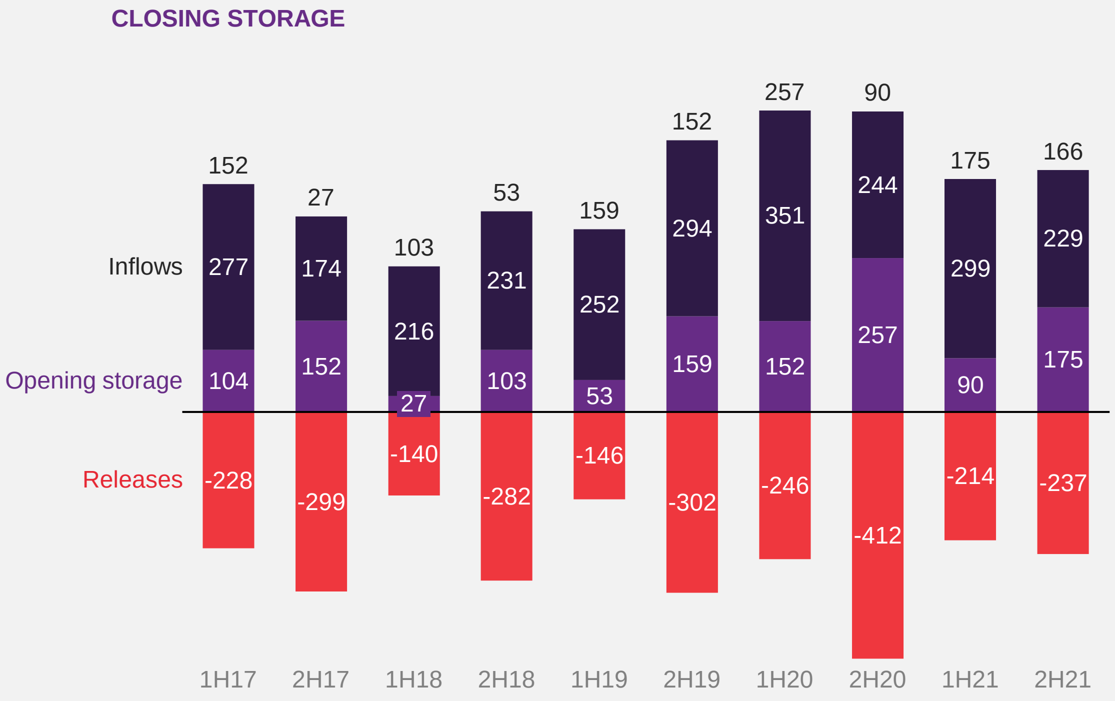
Te Rapa (spot generation only)

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	($m)
FY17	41	98%	63%	226	58	13
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

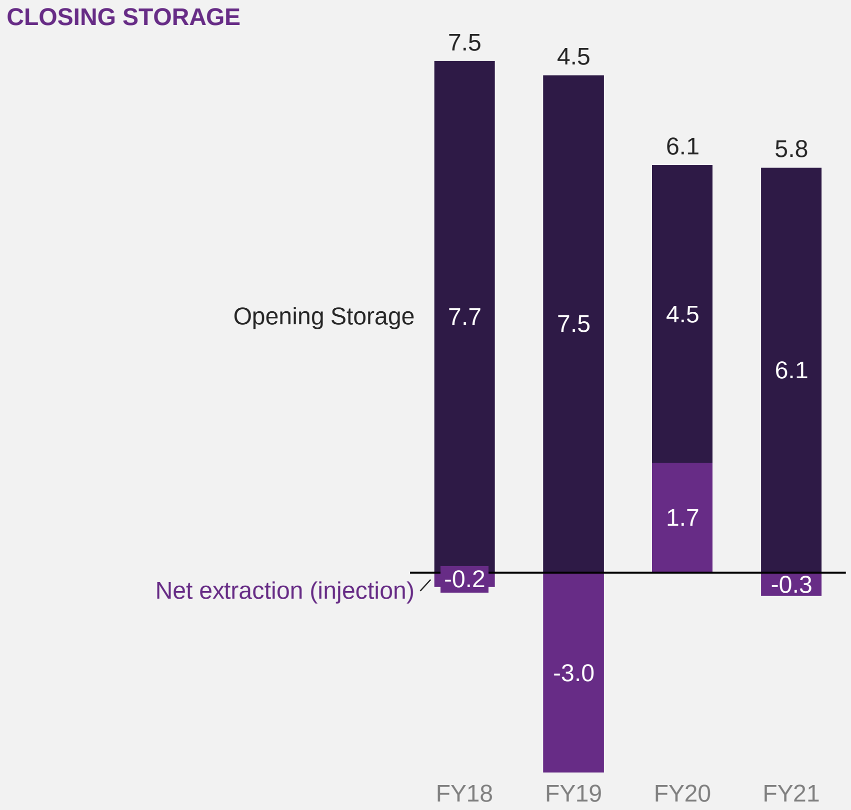
Availability Factor calculation includes all station outages (Planned, Maintenance, Forced) but does not consider deratings.

Fuel storage movements

Hawea storage (GWh)



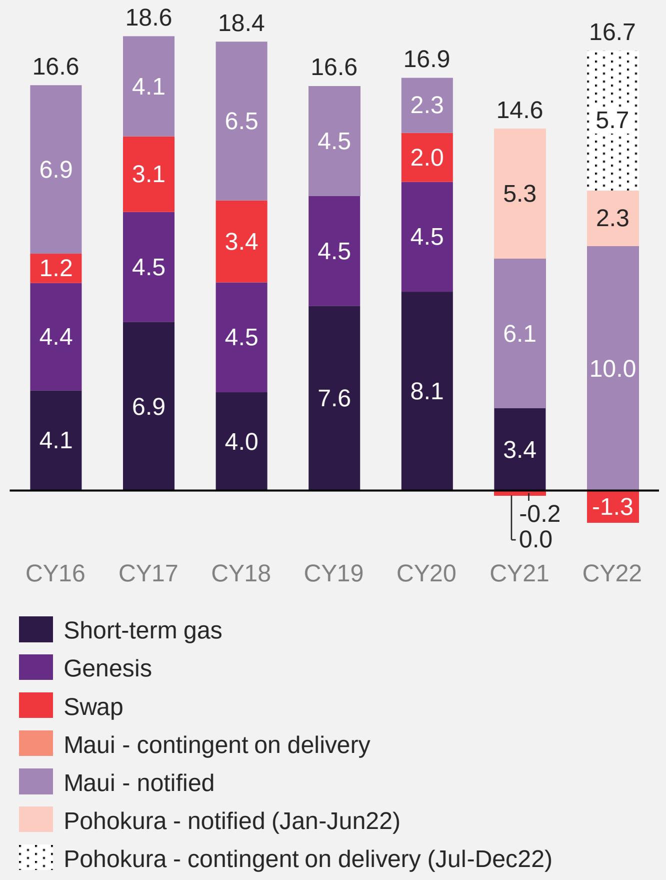
Gas storage (PJ)



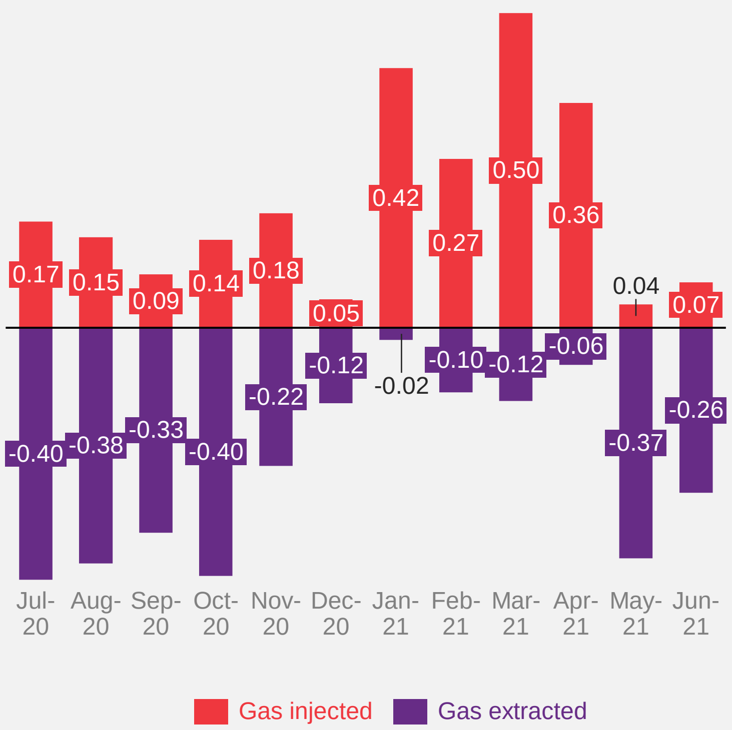
Source: NZX hydro

Contracted and stored gas

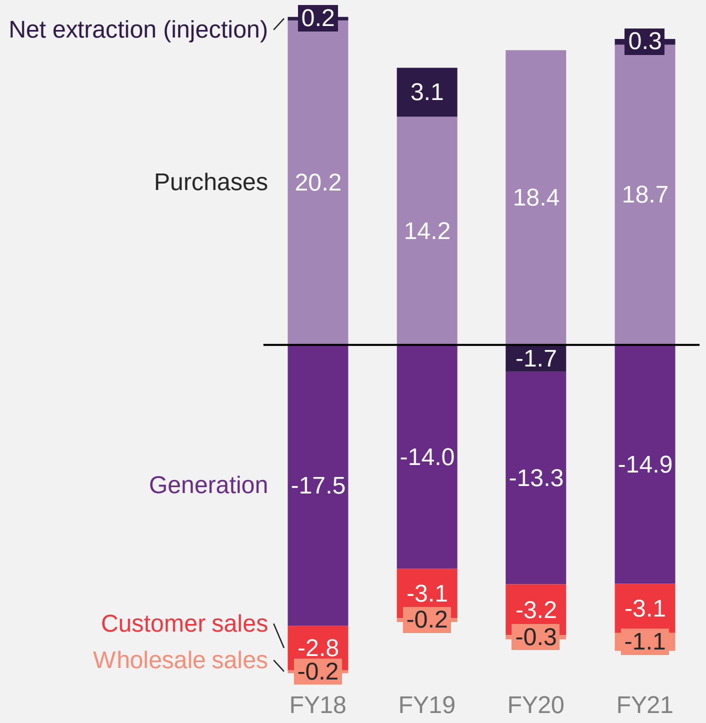
Contracted gas volumes (PJ)



Gas storage monthly injections and extractions (PJ)

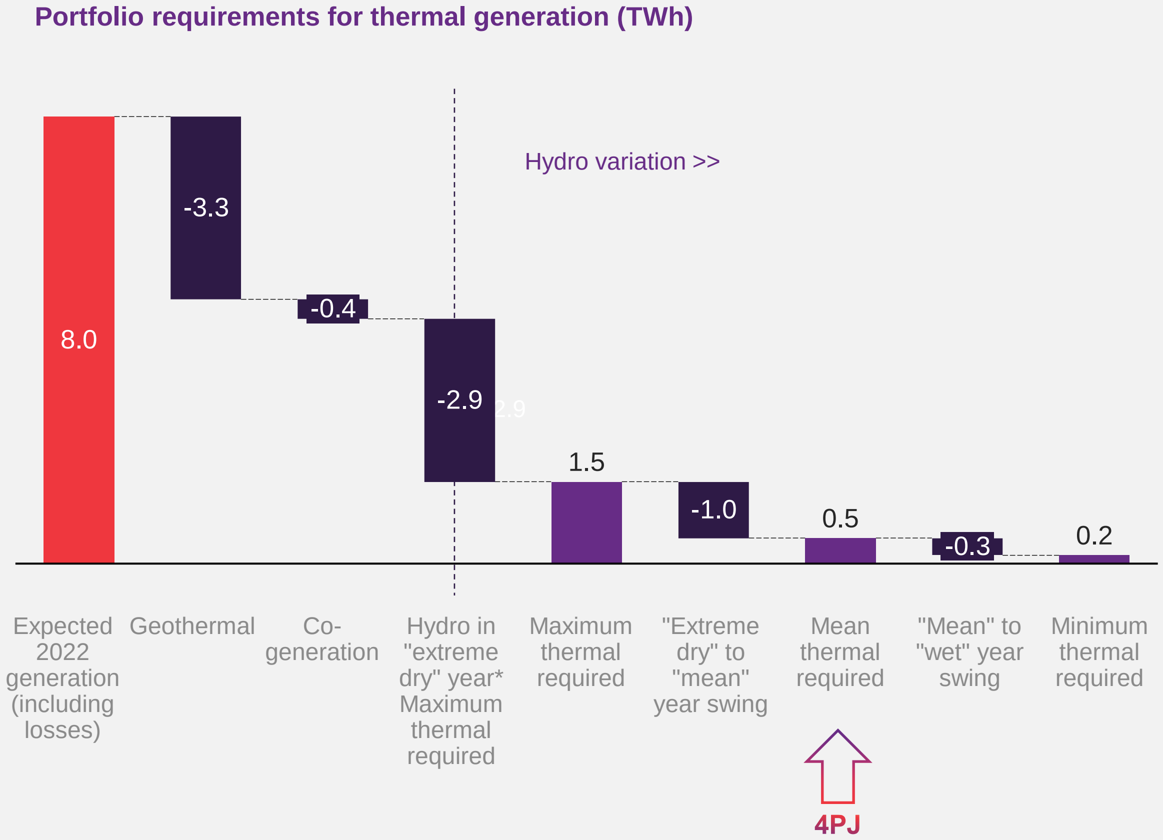


Uses of gas (PJ)

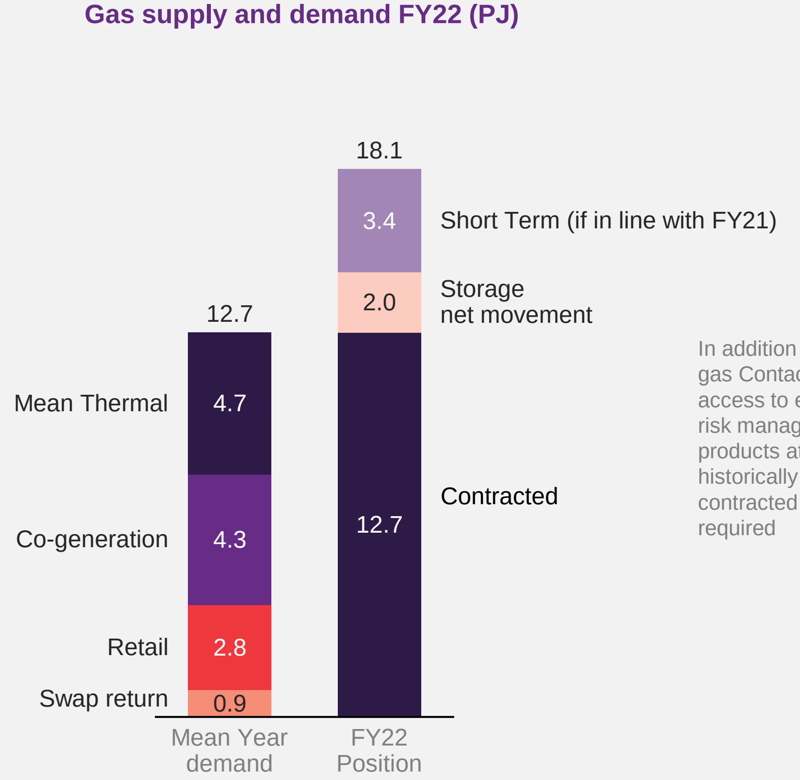


Storage balance at 31 December 2020 was 5.0PJ

Contractual fuel position impacted by gas availability issues



* Hydro generation in FY12



In addition to market gas Contact has access to effective risk management products at historically contracted rates if required

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 2021	12 months ended 30 June 2020	Variance on prior year	
			$m	%
Profit	**187**	**125**	**62**	**50%**
Depreciation and amortisation	249	220	(29)	(13%)
Change in fair value of financial instruments	(7)	-	(7)	700%
Net interest expense	50	55	5	8%
Tax expense	74	46	(28)	(61%)
EBITDAF	**553**	**446**	**107**	**24%**

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

The adjustments from EBITDAF to reported profit and movements on FY20 are as follows:

- **Depreciation and amortisation:** Increased by $29m (13%) on FY20 primarily resulting from the review of Ōhaaki plant, Wairākei and TCC opening hours.
- **Net interest expense:** Reduced by $5m (8%) over FY20 lower average borrowings post equity raise and coupled with lower interest rate as well as the capitalisation of interest relating to the Tauhara geothermal project (FY21 $8m), a $2m increase against FY20.
- **Tax expense** for the period was $28m up following higher operating earnings with higher depreciation partially offset by lower net interest expense. Tax expense for FY21 represents an effective tax rate of 28%. The effective tax rate for FY20 was 27%.

Historical financial information

	Unit	FY17	FY18	FY19	FY20	FY21
Revenue	$m	2,079	2,275	2,519	2,073	2,573
Expenses	$m	1,578	1,794	2,001	1,622	2,020
EBITDAF	$m	501	481	518	446	553
Profit/(loss)	$m	151	132	345	125	187
Profit per share - basic	cps	21.0	18.4	48.2	17.5	25.3
Operating free cash flow	$m	305	301	341	290	371
Operating free cash flow per share	cps	42.6	42	47.5	40.4	50.2
Dividends declared[1]	cps	26	32	39	39	35
Dividends paid	$m	186	201	251	280	274
Total assets	$m	5,455	5,311	4,954	4,896	5,028
Total liabilities	$m	2,677	2,584	2,172	2,275	2,101
Total equity	$m	2,778	2,727	2,782	2,621	2,927
Gearing ratio	%	36	35	28	31	23

Wholesale segment

Note: this table has not been rounded and might not add	FY21 Twelve months ended 30 June 2021 Volume GWh	GWAP $/MWh	$m	FY20 Twelve months ended 30 June 2020 Volume GWh	GWAP $/MWh	$m	Reference number for Wholesale segment note (see following page)
Electricity sales to Customer	**3,605**	**93.7**	**338**	**3,741**	**88.8**	**332**	1
Electricity sales to C&I (netback)	1,762	82.3	145	2,092	80.3	168	
Electricity sales – Direct	81	111.1	9	79	105.1	8	2
Electricity sales to C&I	**1,844**	**83.6**	**154**	**2,171**	**81.2**	**176**	
CfDs – Tiwai support	734			828			
CfDs - Long term sales	531			581			3
CfDs - Short term sales	1,408			676			
Electricity sales - CFDs	**2,673**	**109.7**	**293**	**2,085**	**72.9**	**152**	
Total contracted electricity sales	**8,121**	**96.7**	**785**	**7,997**	**82.6**	**661**	
Steam sales	**645**	**43.7**	**28**	**544**	**47.6**	**26**	4
Other income			5			0	5
Net income on gas sales			2			1	6
Net income on electricity related services			1			2	7
Net other income			**16**			**2**	
Total contracted revenue (1)	**8,766**	**93.4**	**821**	**8,540**	**80.6**	**689**	
Generation costs	8,486	(38.3)	(316)	8,523	(31.2)	(266)	8
Acquired generation cost	554	(116.8)	(65)	335	(113.9)	(38)	9
Generation costs (including acquired generation) (2)	**9,040**	**(43.1)**	**(381)**	**8,858**	**(34.3)**	**(304)**	
Spot electricity revenue	8,404	176.4	1,482	8,444	99.7	842	10
Settlement on acquired generation	554	207.6	115	335	115.4	39	11
Spot revenue and settlement on acquired generation (GWAP)	**8,959**	**178.3**	**1,597**	**8,779**	**100.3**	**880**	
Spot electricity cost	(5,367)	(185.9)	(998)	(5,833)	(109.0)	(636)	12
Settlement on CFDs sold	(2,673)	(191.3)	(511)	(2,085)	(97.8)	(204)	13
Spot purchases and settlement on CFDs sold (LWAP)	**(8,040)**	**(187.7)**	**(1,509)**	**(7,918)**	**(106.0)**	**(840)**	
Trading, merchant revenue and losses (3)			**88**			**41**	
Wholesale EBITDAF (1+2+3)			**527**			**426**	

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	FY18	FY19	FY20	FY21
Average connections	#	359,171	353,105	355,073	357,117
Sales volumes	GWh	2,549	2,491	2,532	2,520
Average usage	per ICP	7.1	7.1	7.1	7.1
Tariff	$/MWh	250.1	251.7	250.4	253.4
Network, meters and levies	$/MWh	-122.4	-122.1	-118.8	-113.5
Energy costs	$/MWh	-86.7	-89.5	-94.8	-100.2
Gross margin	**$/MWh**	**41.0**	**40.2**	**36.8**	**39.7**
Gross margin	$ per ICP	291	283	262	280
Gross margin	$m	104	100	93	100

SME electricity	unit	FY18	FY19	FY20	FY21
Average connections	#	57,309	55,020	55,033	49,679
Sales volumes	GWh	1,099	1,042	991	860
Average usage	per ICP	19.2	18.9	18.0	17.3
Tariff	$/MWh	224.1	226.8	229.3	231.7
Network, meters and levies	$/MWh	-108.0	-111.9	-114.5	-106.4
Energy costs	$/MWh	-84.8	-87.7	-93.0	-99.3
Gross margin	**$/MWh**	**31.3**	**27.2**	**21.8**	**26.1**
Gross margin	$ per ICP	599	516	393	451
Gross margin	$m	34	28	22	22

Customer EBITDAF		FY18	FY19	FY20	FY21
Electricity Gross margin	$m	139	128	115	123
Gas Gross Margin	$m	15	14	9	9
Broadband Gross Margin	$m	0	1	0	-0.8
Total Gross Margin	**$m**	**154**	**144**	**125**	**131**
Other income	$m	4	4	5	6
Other operating costs	$m	-82	-81	-79	-81
Customer EBITDAF	**$m**	**76**	**67**	**50**	**56**
Corporate allocation (50%)[1]	$m	-12	-13	-15	-15
Retailing EBITDAF	**$m**	**64**	**54**	**35**	**40**
EBITDAF margins (% of revenue)	%	6.7%	5.7%	3.7%	4.3%

Residential gas	unit	FY18	FY19	FY20	FY21
Average connections	#	60,905	61,711	61,591	60,701
Sales volumes	TJ	1,600	1,605	1,577	1,495
Average usage	per ICP	26.3	26.0	25.6	24.6
Tariff	$/GJ	31.6	31.5	33.1	35.3
Network, meters and levies	$/GJ	-19.6	-18.4	-17.9	-17.7
Energy costs	$/GJ	-5.6	-5.9	-7.9	-8.6
Carbon costs	$/GJ	-0.7	-1.0	-1.4	-1.5
Gross margin	**$/GJ**	**5.8**	**6.3**	**5.9**	**7.5**
Gross margin	$ per ICP	152	165	151	185
Gross margin	$m	9	10	9	11

SME gas	unit	FY18	FY19	FY20	FY21
Average connections	#	3,677	3,901	3,947	3,876
Sales volumes	TJ	1,300	1,492	1,425	1,313
Average usage	per ICP	353.5	382.6	361.0	338.8
Tariff	$/GJ	15.5	15.1	15.5	16.3
Network, meters and levies	$/GJ	-4.5	-5.5	-6.0	-7.9
Energy costs	$/GJ	-5.6	-5.9	-7.9	-8.6
Carbon costs	$/GJ	-0.7	-1.0	-1.4	-1.5
Gross margin	**$/GJ**	**4.8**	**2.8**	**0.2**	**-1.6**
Gross margin	$ per ICP	1,689	1,068	72	-552
Gross margin	$m	6	4	0	-2