Putting our energy where it matters.

2019 Full Year Results Presentation

Twelve months ended 30 June 2019

Disclaimer and important information

This presentation may contain projections or forward-looking statements regarding a variety of items. Such forward-looking statements are based upon current expectations and involve risks and uncertainties.

Actual results may differ materially from those stated in any forward-looking statement based on a number of important factors and risks.

Although management may indicate and believe that the assumptions underlying the forward-looking statements are reasonable, any of the assumptions could prove inaccurate or incorrect and, therefore, there can be no assurance that the results contemplated in the forward-looking statements will be realised.

EBITDAF, underlying profit, free cash flow and operating free cash flow are non-GAAP (generally accepted accounting practice) measures. Information regarding the usefulness, calculation and reconciliation of these measures is provided in the supporting material.

Furthermore, while all reasonable care has been taken in compiling this presentation, Contact accepts no responsibility for any errors or omissions.

This presentation does not constitute investment advice.

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

Agenda

FY19 Highlights and Progress on Strategy

Dennis Barnes
CEO

Strong financial performance and optimisation of the portfolio results in higher dividends

Summary of key financial performance measures

	Twelve months ended 30 June 2019			Continuing operations comparison against FY18
	Continuing operations	Discontinued operation[3]	Total	
EBITDAF[1]	$505m	$13m	$518m	↑ 12% from $449m
Profit	$170m	$175m	$345m	↑ 52% from $112m
Profit per share	23.7 cps	24.5 cps	48.2 cps	↑ 52% from 15.6 cps
Underlying profit[1]	$166m	$10m	$176m	↑ 51% from $110m
Underlying profit per share	23.2 cps	1.4 cps	24.6 cps	↑ 51% from 15.4 cps
Dividend per share			39.0 cps	↑ 22% from 32.0 cps
Operating free cash flow[2]	$334m	$7m	$341m	↑ 23% from $272m
Operating free cash flow per share[2]	46.5 cps	1.0 cps	47.5 cps	↑ 22% from 38.0 cps
SIB capital expenditure (cash)	$58m	$2m	$60m	↓ 19% from $72m

[1] Refer to slides 42-45 for a definition and reconciliation of EBITDAF and underlying profit
[2] Refer to slide 24 for a reconciliation of operating free cash flow
[3] Sale of Rockgas LPG which completed on 30 November 2018

- Completed the sale of Ahuroa Gas Storage (AGS) and the sale of the Rockgas LPG business, receiving net cash proceeds after tax of $390m in the period
- EBITDAF from continuing operations was up by $56m against FY18 having benefited from comparatively stronger hydro generation following record low inflows during 1H18. In addition, our flexible generation portfolio and access to stored gas saw Contact increase wholesale spot market sales at higher prices
- Strong balance sheet, high quality renewable generation assets and lean, low cost operations enable increasing dividends to shareholders with the FY19 ordinary dividend increasing to 39 cents per share, 7 cents per share higher than FY18

Highlights

Continued progress in delivering value for key stakeholders

Comparison against FY18

MAINTAINING FINANCIAL DISCIPLINE

Good cost control, with continuing other operating costs down by $3m (1%). Cash spent on continuing SIB capital expenditure down by $14m (19%). $477m reduction in net debt.

6% Reduction in total ongoing cash operating costs and capital spend

ENHANCED CUSTOMER ADVOCACY

Net promoter score (NPS) for final quarter of FY19 of +26, up from the +20 recorded for the same period in FY18, as the brand was refreshed and smart customer solutions were launched

6 Point improvement in NPS

SAFE AND ENGAGED EMPLOYEES

Three recordable injuries in FY19 after fourteen employees injured in FY18. Targeting improvement on the FY19 engagement score of 75% as we strive to achieve "best-in-class" employer[1] target

75% Reduction in the total recordable injury frequency rate (TRIFR)

REWARDING SHAREHOLDERS

FY19 dividend of 39 cents per share, up 22% on FY18

22% Increase to the declared full year dividend

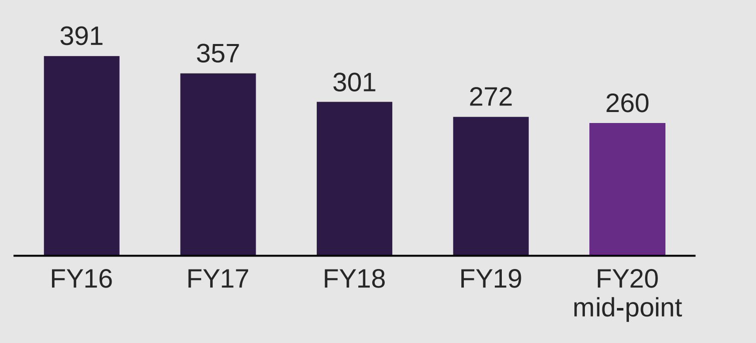
[1] Benchmark for "best-in-class" >82% engagement

Indicates improvement rather than increase

Further operational improvement expected

Maintaining financial discipline

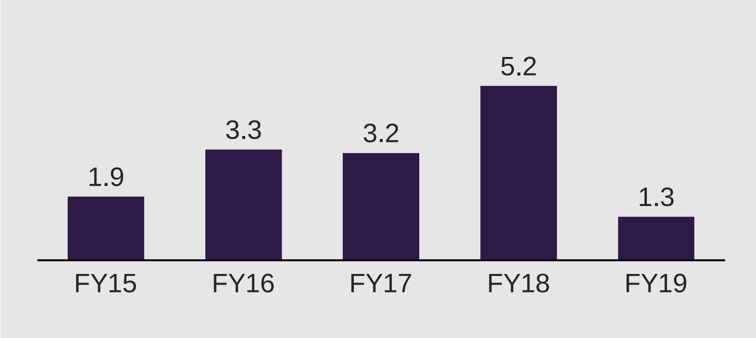
CONTROLLABLE OPEX AND CAPEX ($m)



Safe and engaged employees

TOTAL RECORDABLE INJURY FREQUENCY RATE

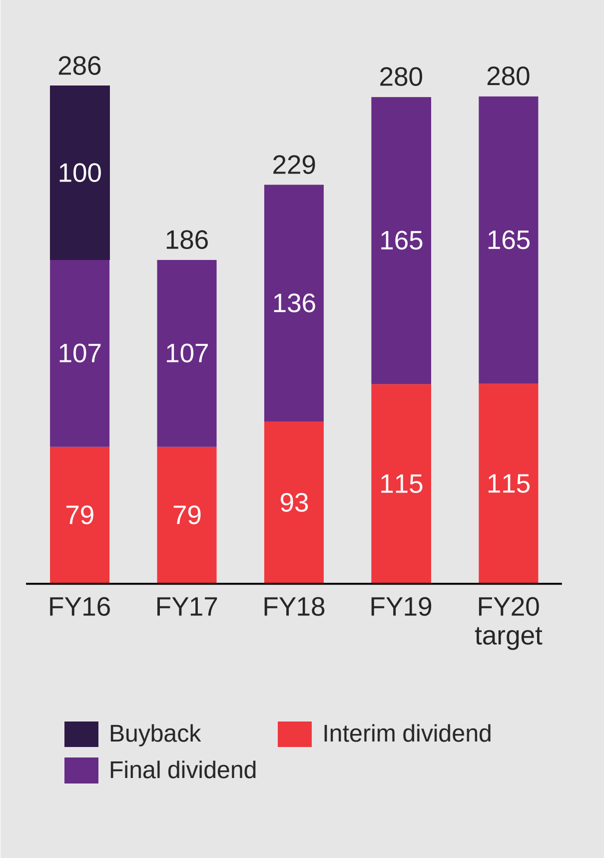
Recordable injuries per million hours worked



Rewarding shareholders

DISTRIBUTIONS ($m)

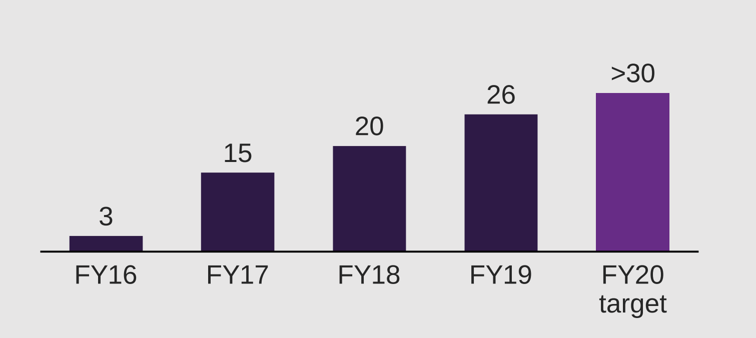
Declared



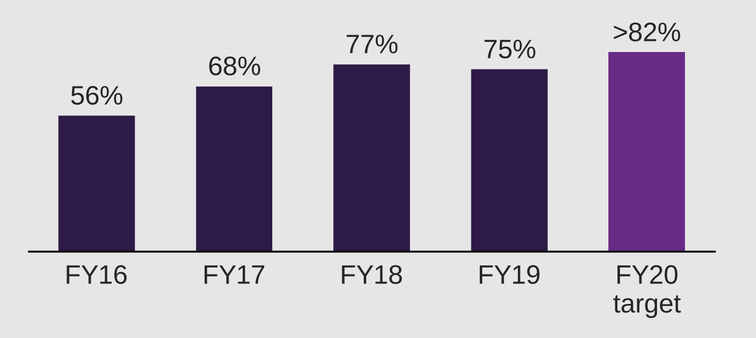
Building customer advocacy

NET PROMOTER SCORE

Promoters less detractors (final quarter)



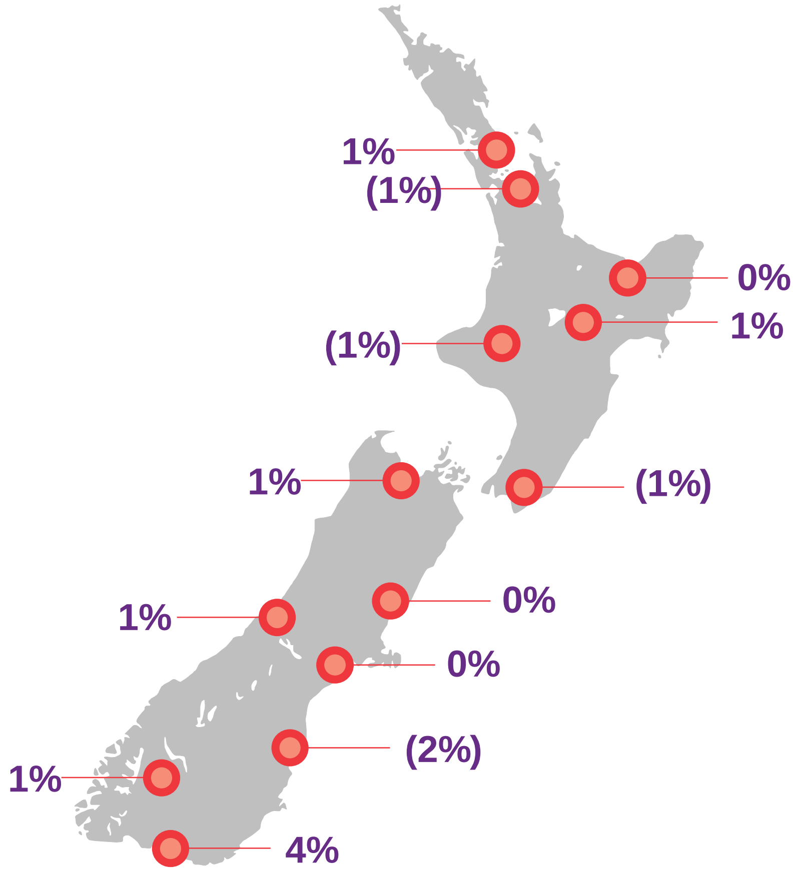
EMPLOYEE ENGAGEMENT (%)



National electricity demand flat

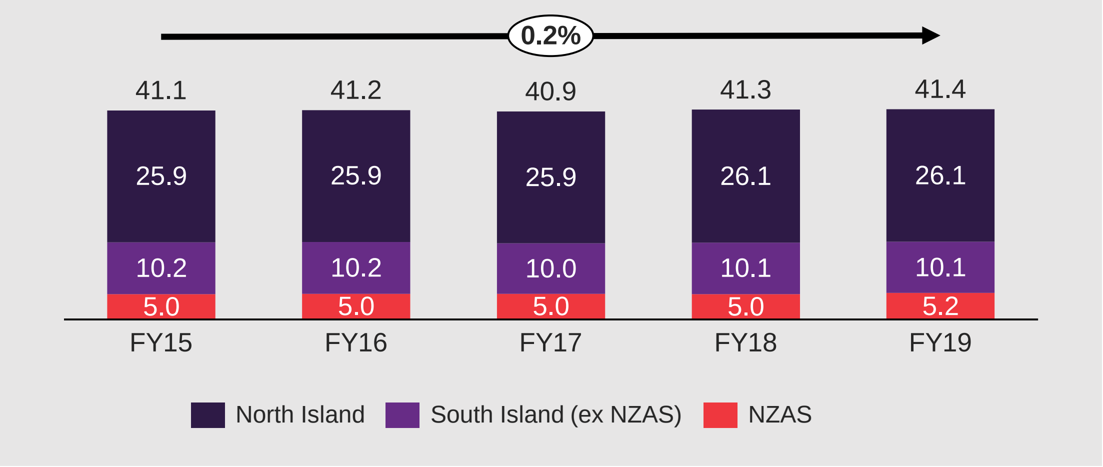
REGIONAL CHANGE (%) FY19 vs FY18

Source: EMI, Contact



NATIONAL ELECTRICITY DEMAND (TWh)

Source: EMI, Contact



- The NZAS gradual re-commissioning of the 4th potline (50MW) from October 2018, contributed to a 4.1% increase in NZAS electricity consumption (12.6%of national demand)
- National electricity demand has remained at about 41TWh since 2008
  - Forestry/agriculture, food processing and commercial have grown since the GFC
  - This growth has been offset by ongoing reductions in demand from the pulp and paper sector as well as residential efficiency

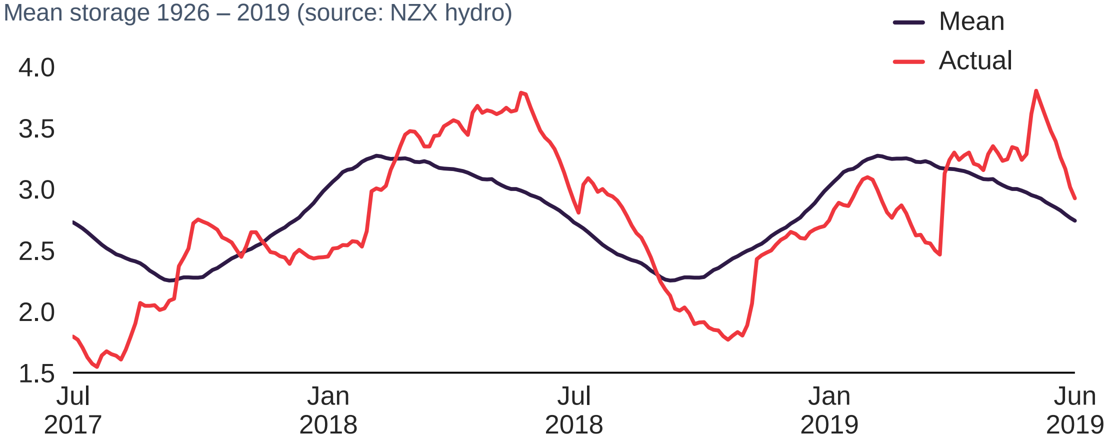
South Island hydrology rebounded

South Island inflows normalised

- Extreme November 2018 rainfall added ~700GWh to national storage over a two week period after the traditional Spring inflows failed to materialise
- A large March event provided an additional ~700GWh, largely in the SI catchments, including Contact's Clutha catchment
- North Island hydro storage was below mean during FY19 after favourable conditions in the two years prior

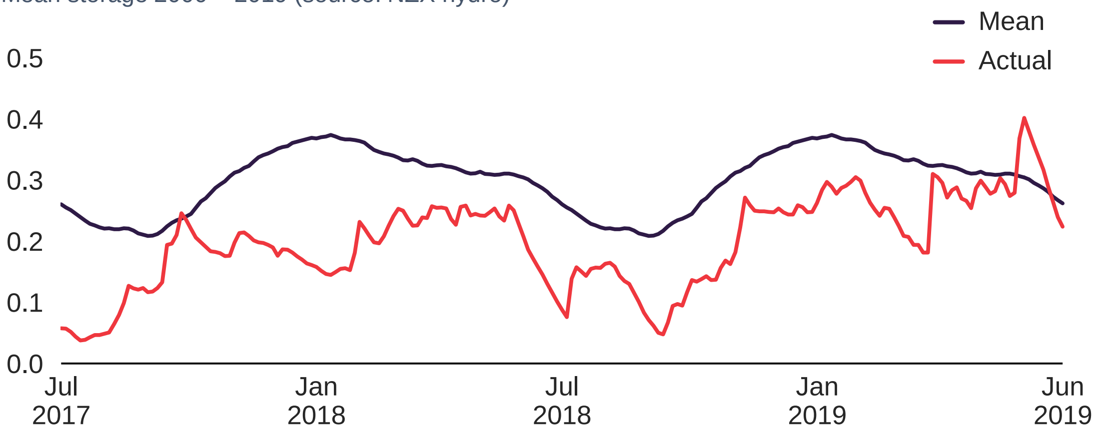
NATIONAL HYDRO STORAGE AGAINST MEAN STORAGE (TWh)

Mean storage 1926 – 2019 (source: NZX hydro)



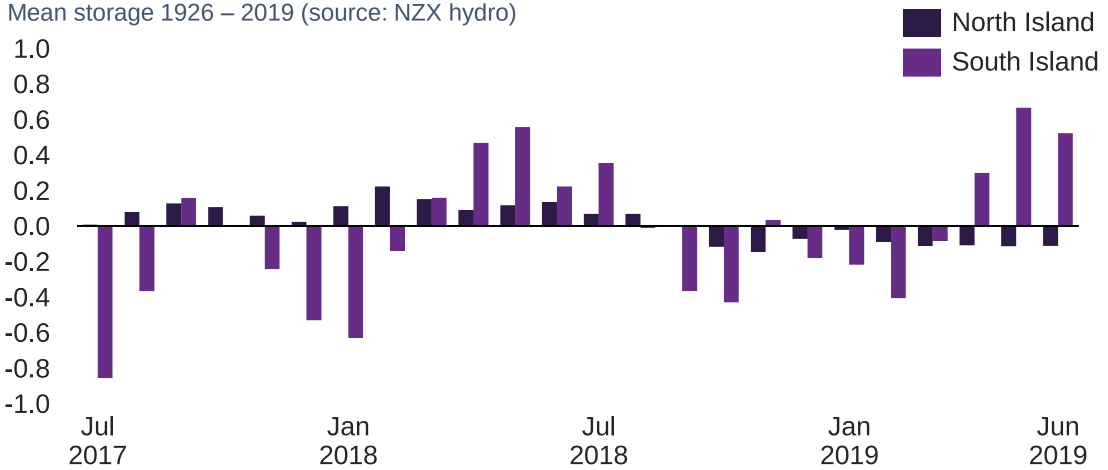
CLUTHA HYDRO STORAGE AGAINST MEAN STORAGE (TWh)

Mean storage 2000 – 2019 (source: NZX hydro)



AVERAGE MONTHLY STORAGE VS MEAN BY ISLAND (TWh)

Mean storage 1926 – 2019 (source: NZX hydro)



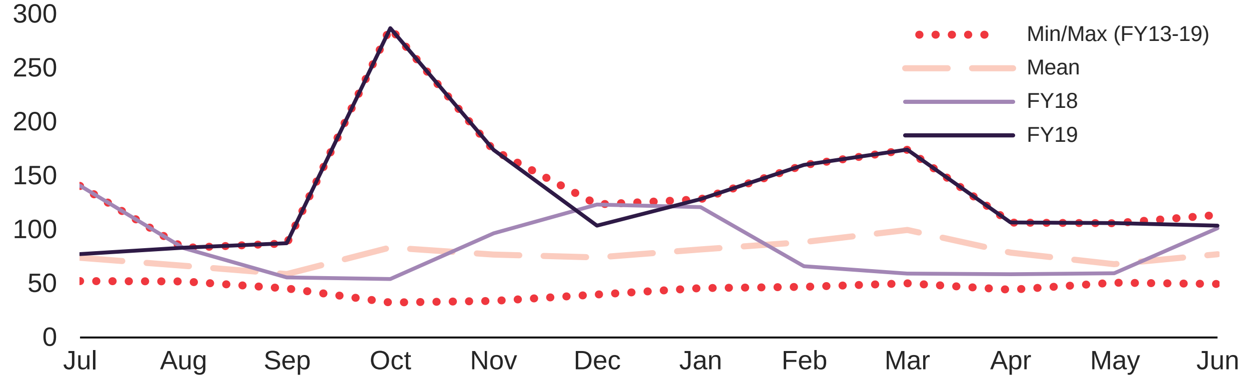
Wholesale spot prices responded to fuel scarcity

Hydro storage volatility and thermal fuel constraints increased spot prices

- While volatile hydrology is a well-known feature of electricity supply in New Zealand, normally reliable gas production significantly constrained generation from thermal assets
- The elevated spot price environment has led to sharp increases in short-dated forwards (i.e. for contracts maturing less than six months ahead)
  - Short dated market movements are usually predominantly impacted by hydrology
- Long-dated forward prices ($97/MWh as at July 19) have increased by over $21/MWh (28%) in the last year
  - While gas availability continues to improve, thermal costs including gas and carbon input costs have risen

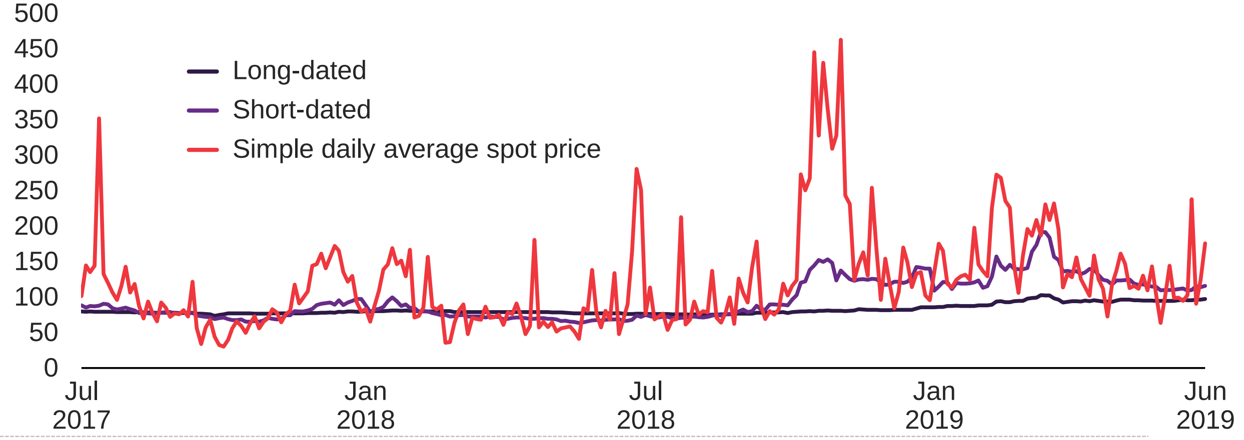
MONTHLY WHOLESALE SPOT ELECTRICITY PRICES ($/MWh)

Generation weighted (source: Electricity Authority – Wholesale electricity prices)



ELECTRICITY FORWARD PRICE CURVES ($/MWh)

Generation weighted (source: Electricity Authority – Wholesale electricity prices)



Creating sustainable value for New Zealanders by putting our energy where it matters

Optimise the Customer and Wholesale businesses to deliver strong cash flows

CUSTOMER BUSINESS STRATEGY

A **service and value focused retailer**, connecting customers and communities to smart solutions that make living easier for them now, and in the future

WHOLESALE BUSINESS STRATEGY

An innovative, safe and efficient generator working with business customers, partners and suppliers to **decarbonise New Zealand's energy sector**

Underpinned by a disciplined and transparent approach to operating and capital expenditure while continuing to investigate ways to optimise our portfolio of assets

Customer business continues to reduce cost to serve while improving customer experience

Near-term description of success

High-performing, efficient retailer with the lowest cost to serve and best customer experience of the tier 1 retailers in New Zealand, with an ability to execute consistently

	FY16	FY17	FY18	FY19
Employee engagement	36%	53%	78%	75%
Net promoter score (final qtr)	+3	+15	+20	+26
Churn variance to market (12 mth avg)	at market	0.7% below	1.3% below	1.7% below
Cost to serve	$113m	$110m	$94m[1]	$94m
Number of calls	1.1m	1.0m	0.9m	0.7m
Debt write-offs	$9.3m	$6.6m	$5.5m	$2.3m
Electricity netback[2]	$100.3/MWh	$100.3/MWh	$102.0/MWh	$102.9/MWh

[1] Includes 50% allocation of the unallocated/corporate segment, in prior years this was fully allocated to the Customer segment

[2] Operating costs allocated by customer connections across electricity, gas and broadband, 50% allocation of the unallocated/corporate segment

Delivering on our strategy

» Move to a simple, lean operating model which is centred on the customer experience reinventing key customer processes

» Capable employees, identifying and driving performance initiatives with ownership and accountability

» Transform technology to drive efficiency and increasingly automated customer experiences

» Reposition the brand and reputation from a strong operational retailer to a smart customer solutions provider

» Accelerate the delivery of products and services to improve access to energy for all

Wholesale business is delivering continuous improvement while enabling decarbonisation

Near-term description of success

Focus on operational excellence and investment in digital with clear payback to accelerate continuous improvement

	FY16	FY17	FY18	FY19
Employee engagement	60%	65%	68%	73%
TRIFR	3.2	3.3	5.2	2.6
Cash costs[1]	$214m	$185m	$165m	$153m
3 year average forward price	$77.00/MWh	$77.80/MWh	$78.60/MWh	$89.90/MWh
Geothermal and hydro volumes	3,297 GWh 4,090 GWh	3,233 GWh 3,562 GWh	3,323 GWh 3,479 GWh	3,256 GWh 4,231 GWh
Plant availability	90%	92%	89%	86%
Unit generation cost	($31.6/MWh)	($32.3/MWh)	($30.9/MWh)	($31.1/MWh)

Delivering on our strategy

» Sustainable cost reduction

» Strengthen geothermal capability to remain as a recognised world leader

» Partner with customers on mutually beneficial decarbonisation opportunities

» Develop options to enable the economic substitution of thermal generation with renewables

» Lower the cost of our geothermal operations to ensure our development options are cost competitive with firmed intermittent renewables

[1] Cash cost includes generation operating costs and SIB Capex, corporate segment costs have been allocated

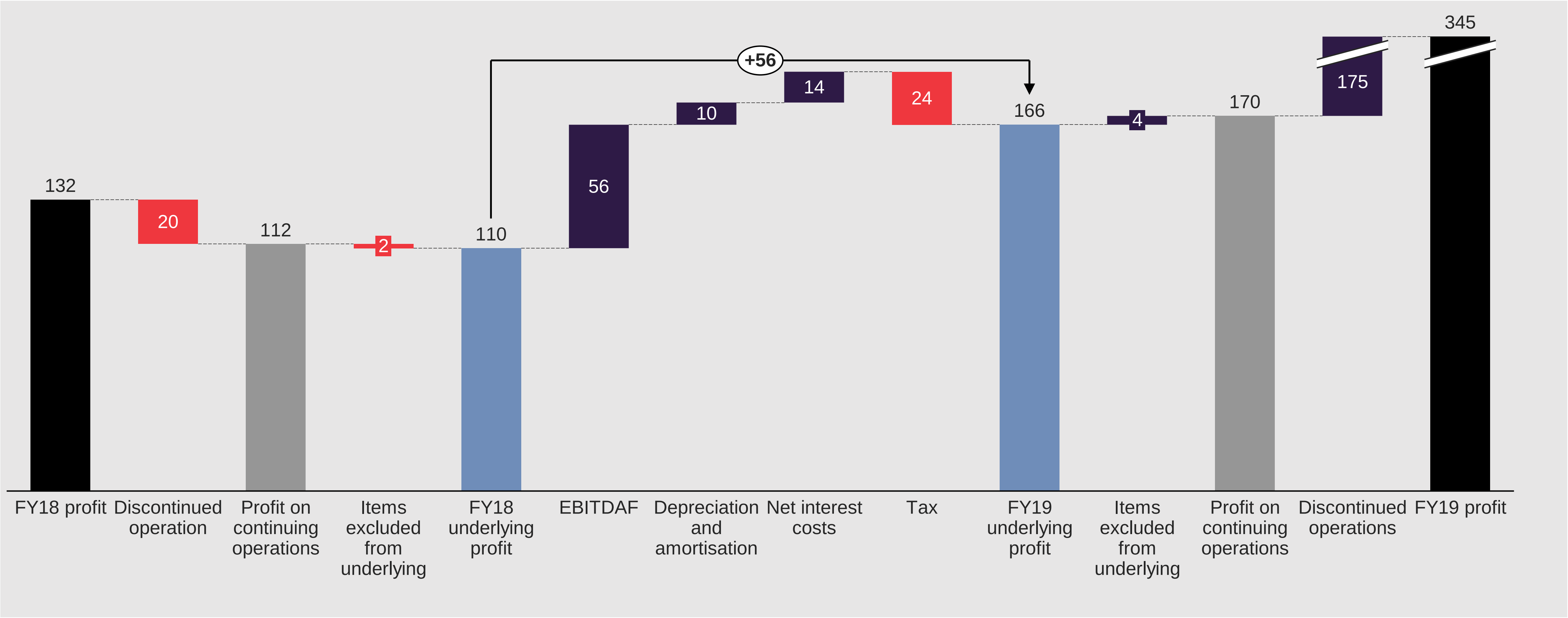
Operational Performance and Financial Results

Dorian Devers
CFO

Profit of $345m, supported by proceeds from divestments

Profit from underlying continuing operations up by 51%; EBITDAF from continuing operations up by $56m

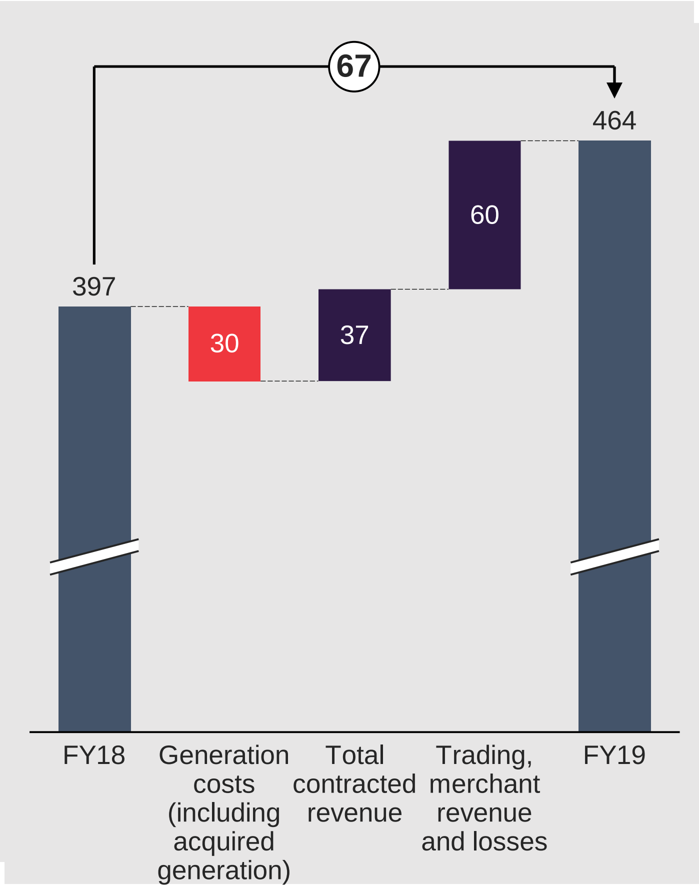
STATUTORY PROFIT ($m)



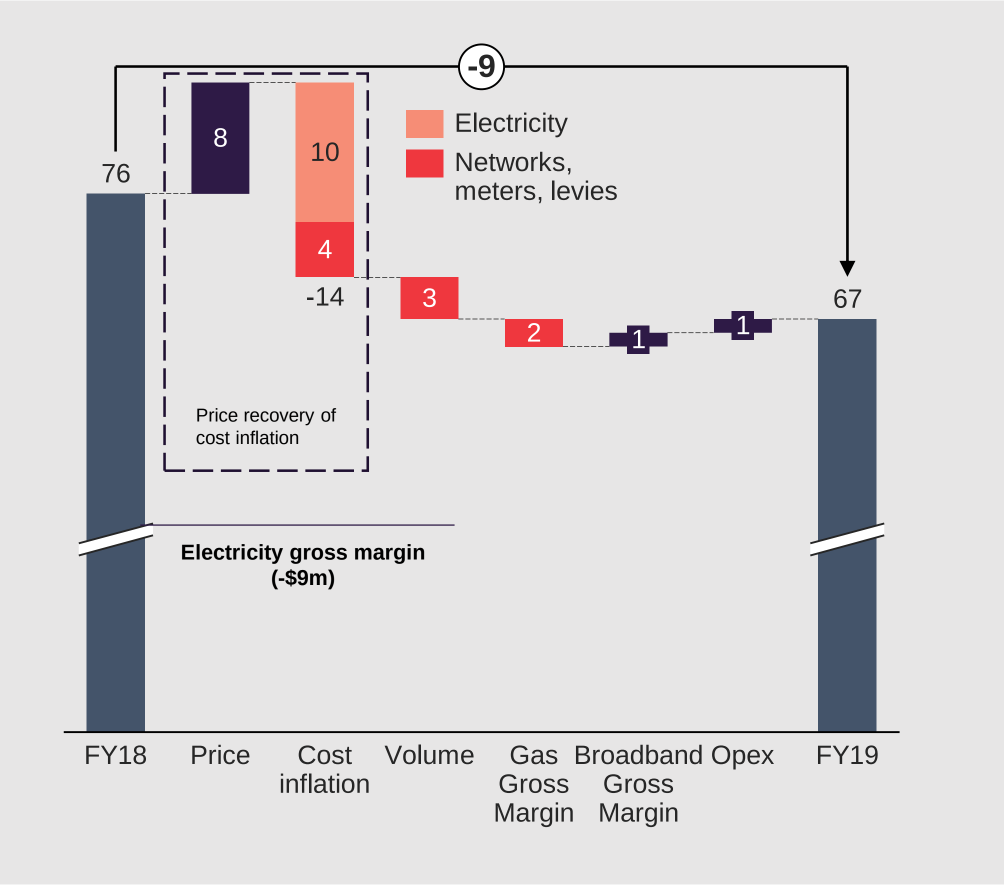
EBITDAF from continuing operations up by $56m

Continuing business performance by segment

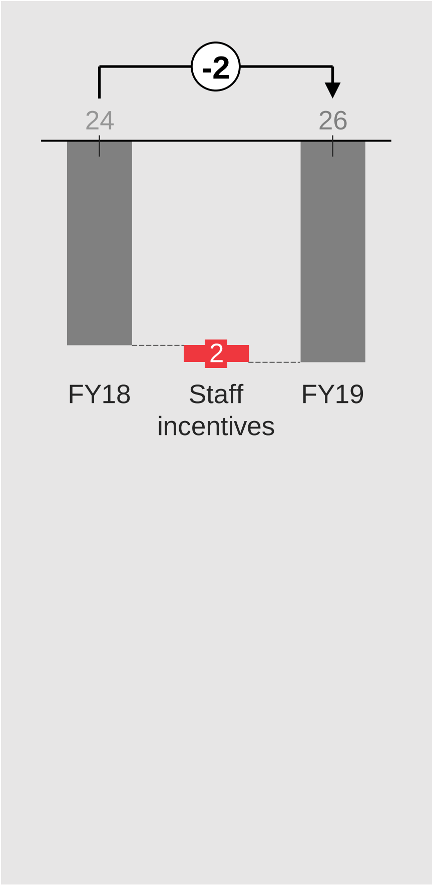
WHOLESALE EBITDAF ($m)



CUSTOMER EBITDAF ($m)



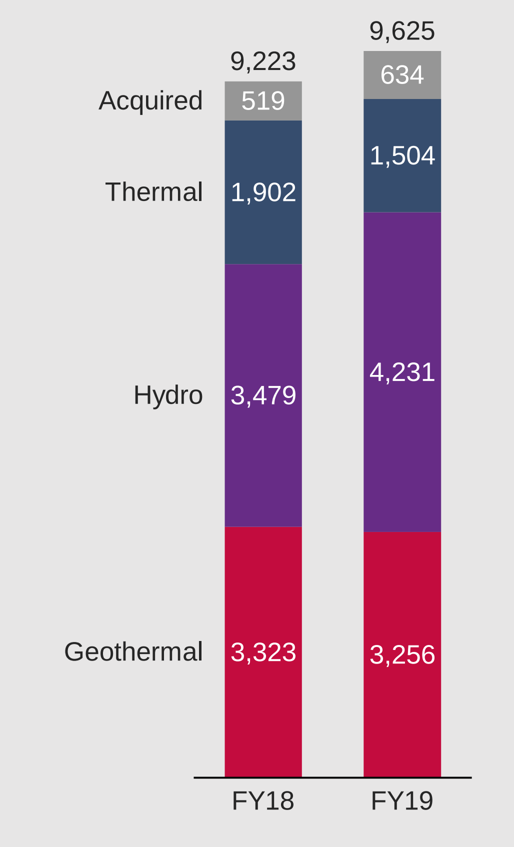
CORPORATE / UNALLOCATED ($m)



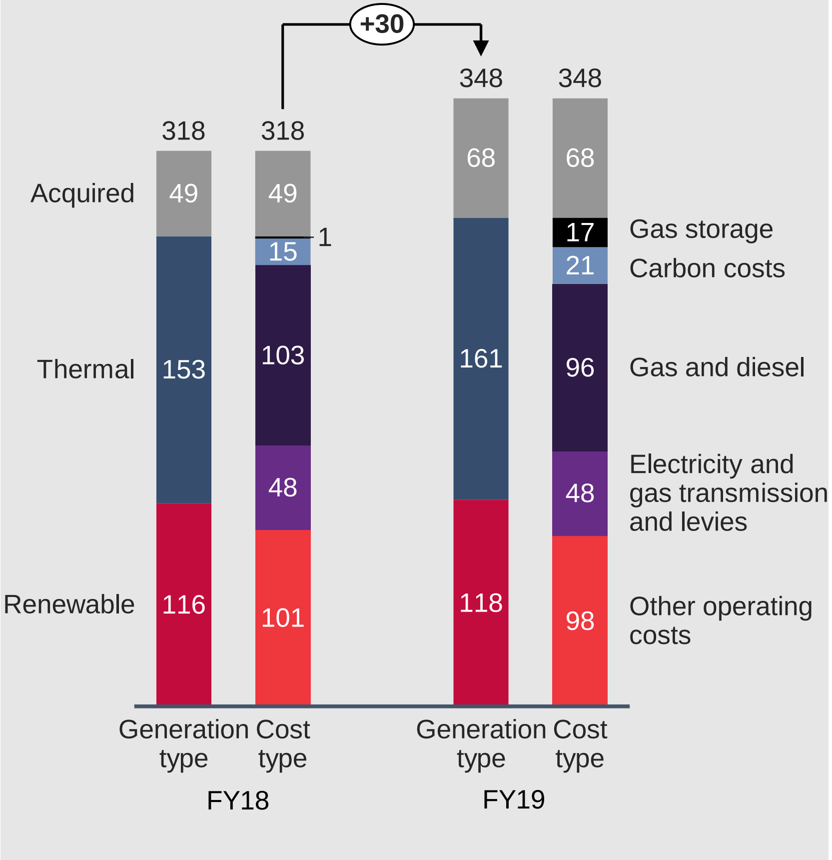
Generation costs

Renewable generation volumes up 10%. Costs up $30m on rising thermal generation and risk management costs

Electricity generated or acquired (GWh)



Electricity generated or acquired costs ($m)

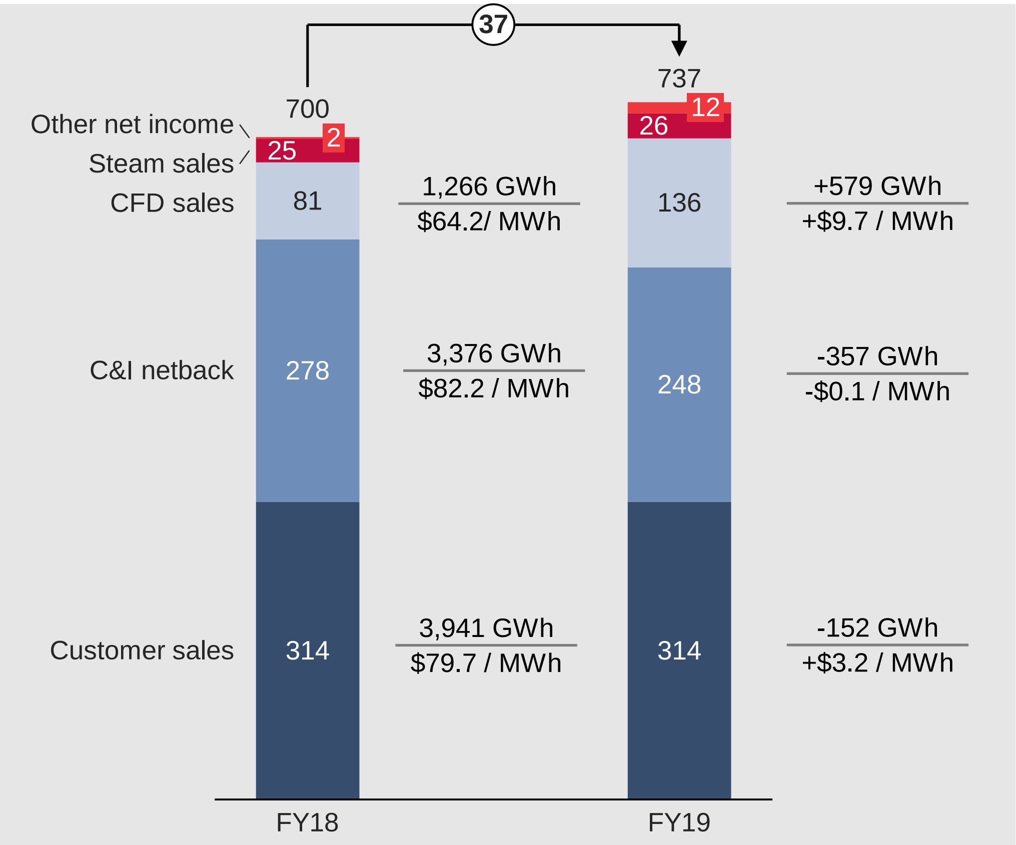


- » Hydro generation was up 752 GWh on FY18 (+21%), which was 8% above what would be expected in a mean year. Geothermal volumes were down 67 GWh (-2%)
  - » Renewable generation costs are predominantly fixed. Geothermal carbon costs were up $1m.
- » Thermal generation costs were up $8m despite lower generation volumes (-21%)
  - » Gas and carbon costs up from $60/MWh in FY18 to $74/MWh (-23%)
  - » Fixed costs, led by the new gas storage contract (since December 18) which was up by $12m (net of other operating costs) on the prior year
- » Gas supply restrictions saw risk management costs up by $19m with acquired generation volume up 22%
  - » Acquired generation costs up from $94/MWh in FY18 to $108/MWh (-23%).

Wholesale contracted revenue

Sales mix adjusted to manage commodity risk; higher pricing and volumes increase revenues

Contracted revenue ($m)

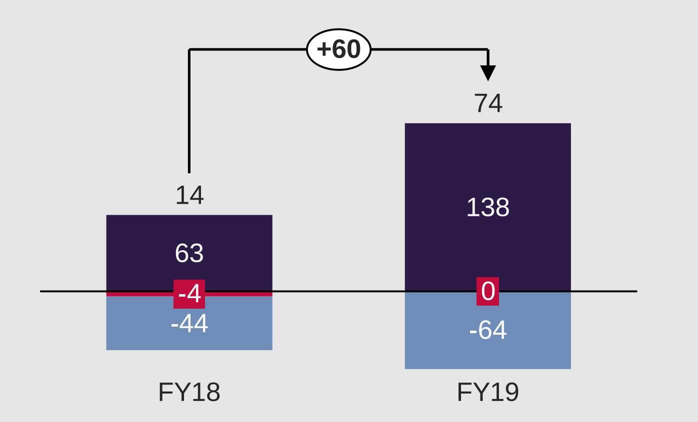


- Fixed price variable volume electricity sales to Customer and C&I customers were 509 GWh lower than FY18 (-$42m), this was partially offset by higher prices (+$12m) to the Customer segment
- Increased CFD sales to support NZAS, which was up by 104 GWh on FY18 contributed to higher long-term CFD electricity sales in FY19 (+$13m). Contact prioritised short term CFD sales (+403 GWh) which were mostly executed to capture favourable short-term pricing (+$35m).
- Higher pricing was achieved on both long-term CFDs (+$2m) and short-term CFD sales to other generators (+$7m)
- Steam revenue was up by $1m on FY18 on a reduction in volumes but increased tariffs on rising carbon costs with customers not taking the minimum volume under their take-or-pay contracts
- Other income was up by $10m, predominantly due to improvements made to market trading processes following FY18 market making losses of $2m

Wholesale trading and merchant revenue

Higher merchant sales at elevated spot prices offered better value than fixed price contracts

TRADING EBITDAF ($m)



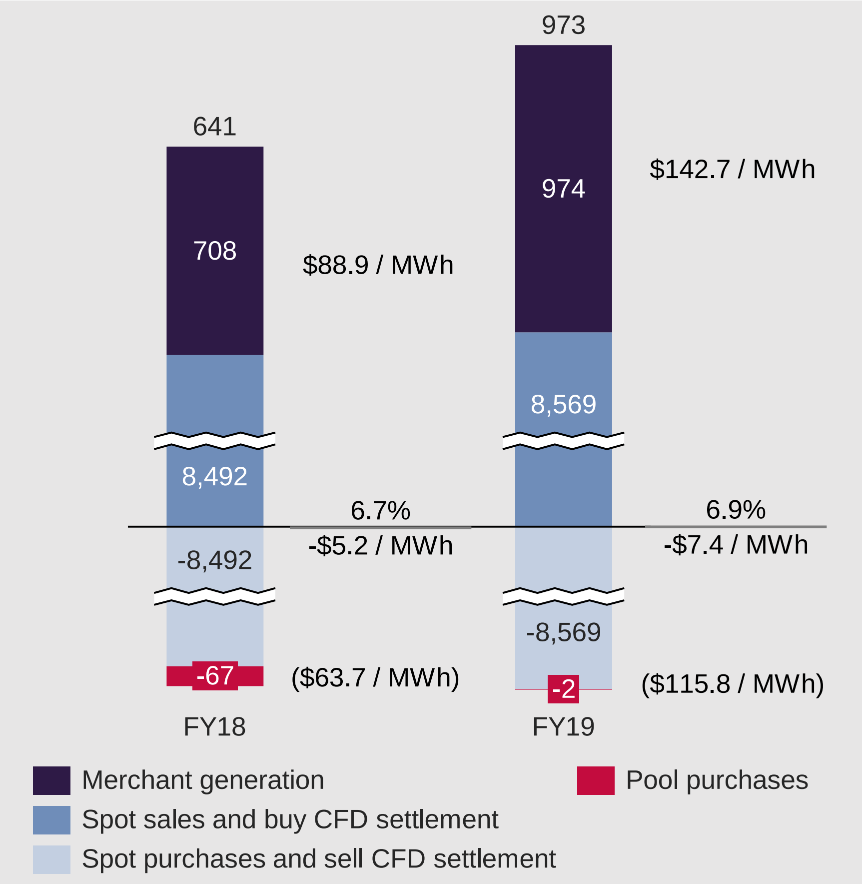
TRADING REVENUE

Merchant sales: short-term sales channel available when the spot prices exceed the opportunity cost on 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)

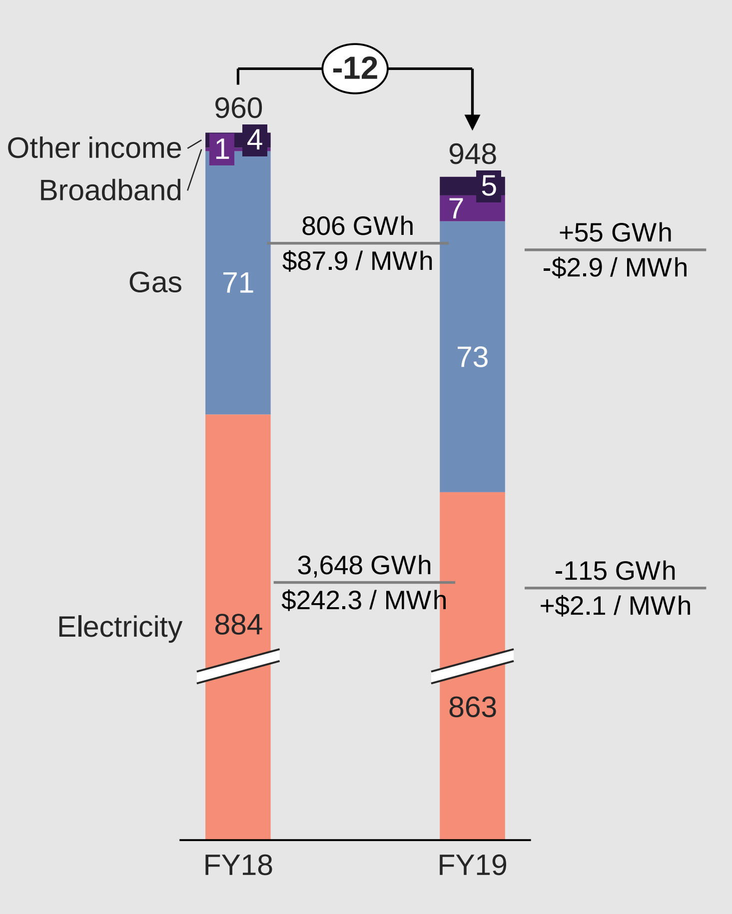


- 266 GWh increase in merchant sales volumes (+$38m). The price received for this “long” generation was up by $53.7/MWh (+$38m)
- Strong generation volumes and risk management saw limited price exposure to unhedged spot market purchases during higher wholesale price periods
- Contact managed price separation well in the period, as a significant increase in South Island generation only increased relative locational losses by 0.2%. However, higher wholesale prices saw absolute LWAP/GWAP up by $20m

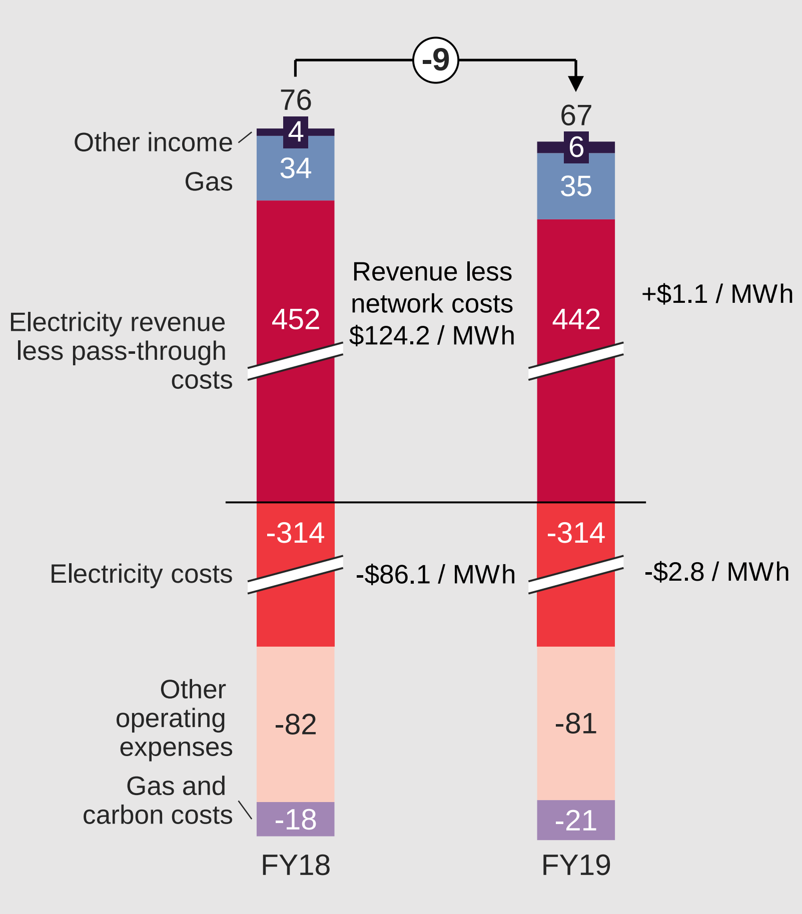
Customer business performance

EBITDAF down by $9m as the 1% increase in tariff was not sufficient to recover rising input costs

Revenue ($m)



EBITDAF ($m)

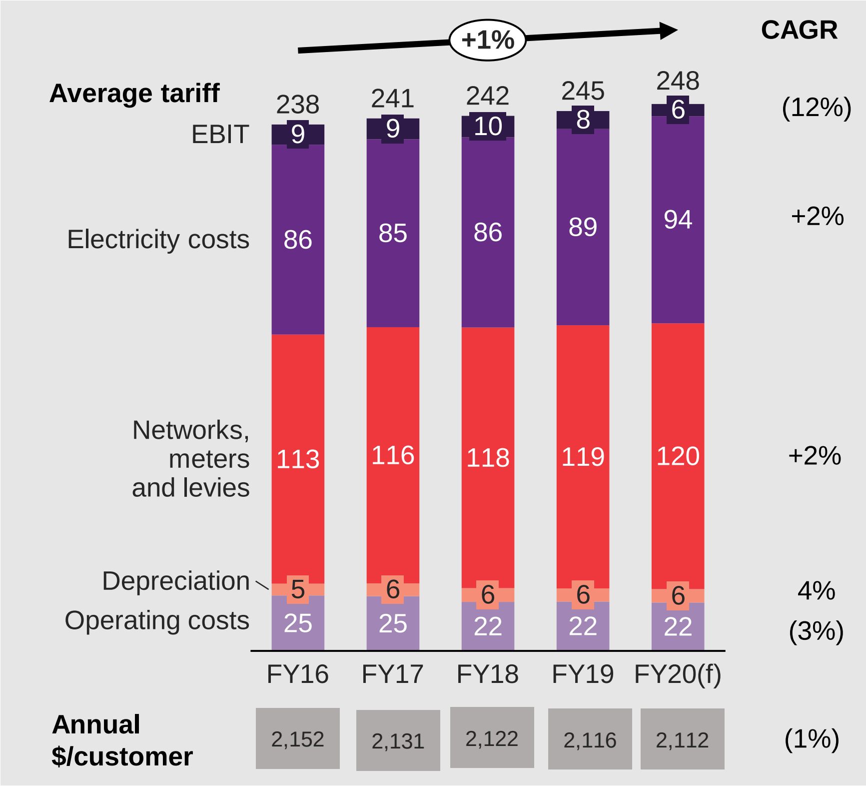


- Electricity gross margin down by $9m, tariff increases (+$8m) only partially recovered pass-through costs
  - Electricity sales volume down 115 GWh (-3%) due to lower customer numbers (-2%) and lower usage per customer, offset by higher gas sales to SME customers
  - Customer numbers up by 4,200 ICPs over 2H19 with new propositions in market. Broadband offer attractive with 10,000 new customers
- Energy costs higher with unit electricity prices up 3% following a sustained period of higher wholesale prices, carbon costs rising
- Other operating expenses down by $1m despite accelerated investment in digital, brand and new products

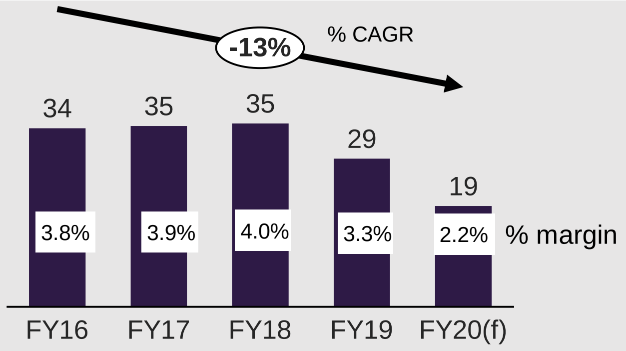
Electricity retailing margins remain under pressure

Intense retail competition has limited tariff increases. When combined with steadily rising input costs, margins from retailing electricity remain under pressure. Contact has focused on reducing its controllable costs and increasing the flexibility of its technology platform leaving it well positioned to capture value from scale

Electricity cost and pricing development ($/MWh)



Contact electricity retailing - industry headwinds (EBIT - $m)



Pricing + 1% p.a.
Intense competition means unable to recover rising costs

- Network costs +2% p.a.
- Energy costs +2% p.a.
- Operating costs -3% p.a.

Positioned to capture value

Contact has developed key strengths with industry leading cost to serve and a flexible IT platform

Leaving us well positioned to capture scale efficiencies

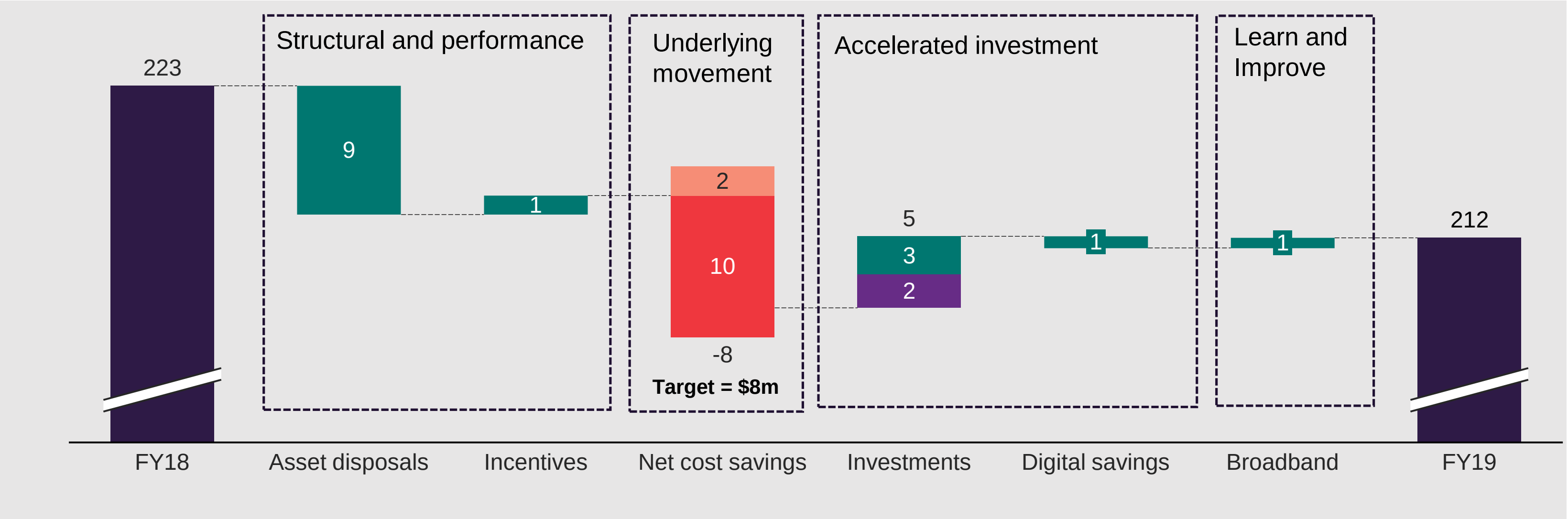
Move to **increased scale** and **cross-industry convergence**

Key assumptions for FY20(f):

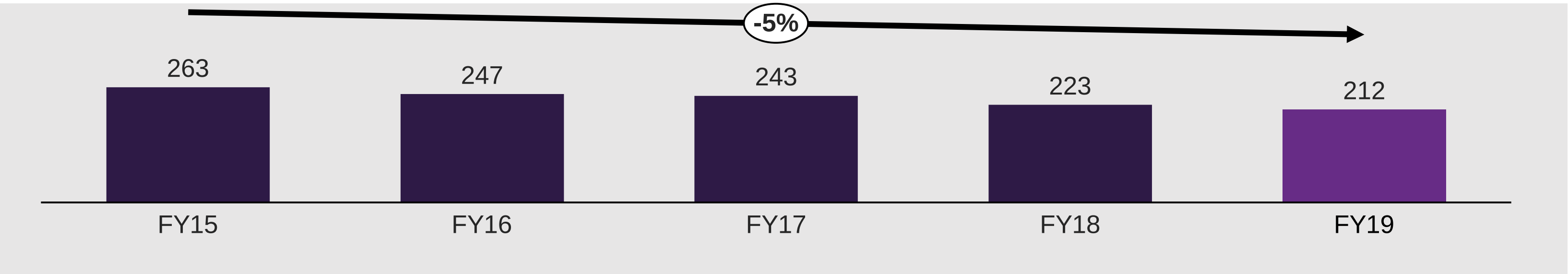
- » Tariff increases, changed in usage per customer in line with history
- » Corporate operating costs and depreciation 50% allocated to Customer
- » Operating costs and depreciation allocated by number of customer connections

Cost efficiency programme continues to deliver controllable cost reduction

OTHER OPERATING COST MOVEMENT ($m)



CONTROLLABLE OPEX ($m)



Underlying movement

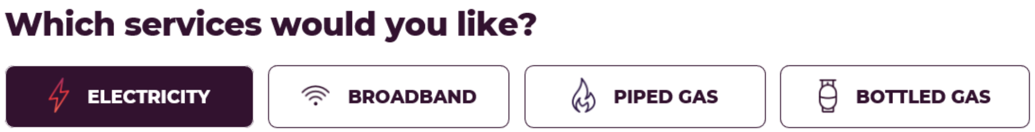
- Delivered $8m of underlying operating cost improvement in line with FY19 target
- $4m from ICT procurement savings
  - Configuration management database optimised applications
  - Rightsizing of application support leveraging internal maturity with systems
- $3m leaner Wholesale operations
- $3m reduction in the cost of bad debt

Purposeful acceleration of operating cost spend

Delivering smart customer solutions

$3m investment in our brand, new product development and promotion. Key journeys digitised.

- Introduced new payment methods with PrePay and weekly/fortnightly billing to help customers manage their bills
  - Fewer customers in arrears, customers who would previously have been declined on credit grounds can now be on-boarded
- New products launched to deliver customer choice and innovative rewards including "free-bill", "promise plan", "broadband bundle" and "basic plan" with no PPD
- Increased digitisation improving NPS and lowering servicing and acquisition costs
  - 11% reduction in call centre volumes
  - 15% increase in web traffic and 7% increase in digital sales

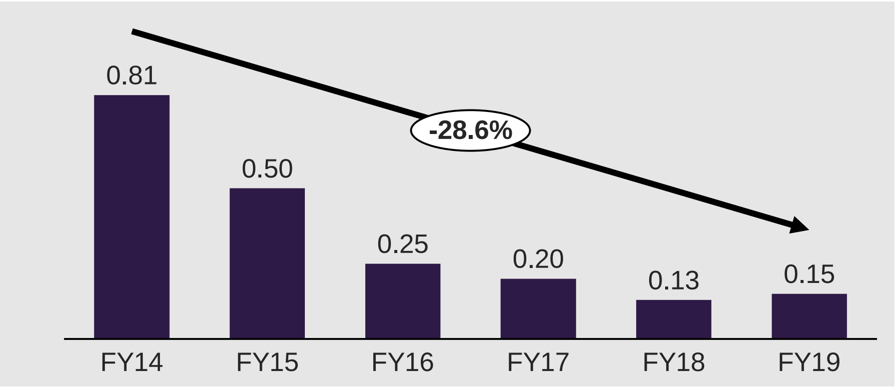


Geothermal fuelling

Additional $2m investment in workovers of geothermal wells. R&D and capability continue to reduce costs

- Delivered 30 GWh p.a. of additional geothermal generation valued at $3m p.a. in FY19
- Our internationally-recognised, subsurface team continues to lower the cost of operations significantly – comfortably New Zealand's lowest cost geothermal operator
  - This improves the economics of geothermal development at Tauhara

Average workover costs per well ($m)



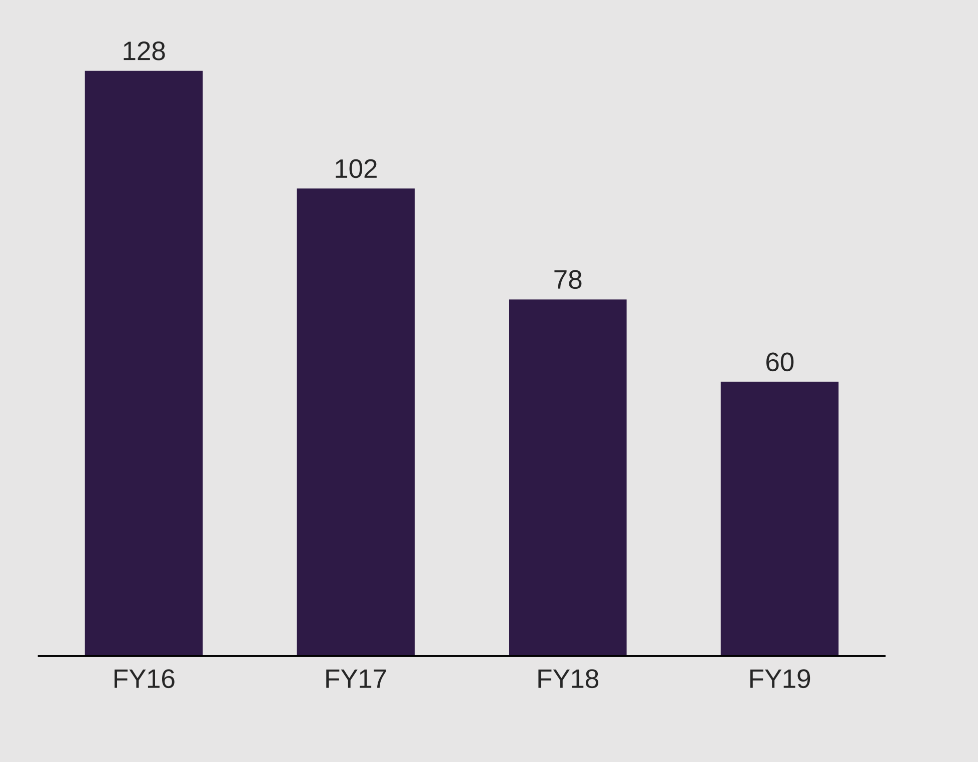
Cash flow and capital expenditure

Operating free cash flow up by $40m on higher EBITDAF and lower interest and SIB capital expenditure

	12 months ended 30 June 2019	12 months ended 30 June 2018	Comparison against FY18	
EBITDAF	**$518m**	$481m	↑	$37m
Working capital changes	**($7m)**	$7m	↓	($14m)
Tax paid	**($47m)**	($33m)	↑	($14m)
Interest paid	**($65m)**	($78m)	↓	$13m
SIB Capital	**($60m)**	($78m)	↑	$18m
Non-cash share based compensation	**$4m**	$3m	↑	$1m
Significant items	**($2m)**	($1m)	↓	($1m)
Operating free cash flow	**$341m**	$301m	↑	$40m
Operating free cash flow per share	**47.5 cps**	42.0 cps	↑	5.5 cps
Proceeds from sale of assets/operations	**$390m**	$6m	↑	$384m
Free cash flow	**$731m**	$307m	↑	$424m

- EBITDAF up on strong Wholesale performance
- Working capital changes $14m lower as NZX receivables were higher on strong June merchant sales position
- Capital expenditure on continuing operations of $58m in FY19

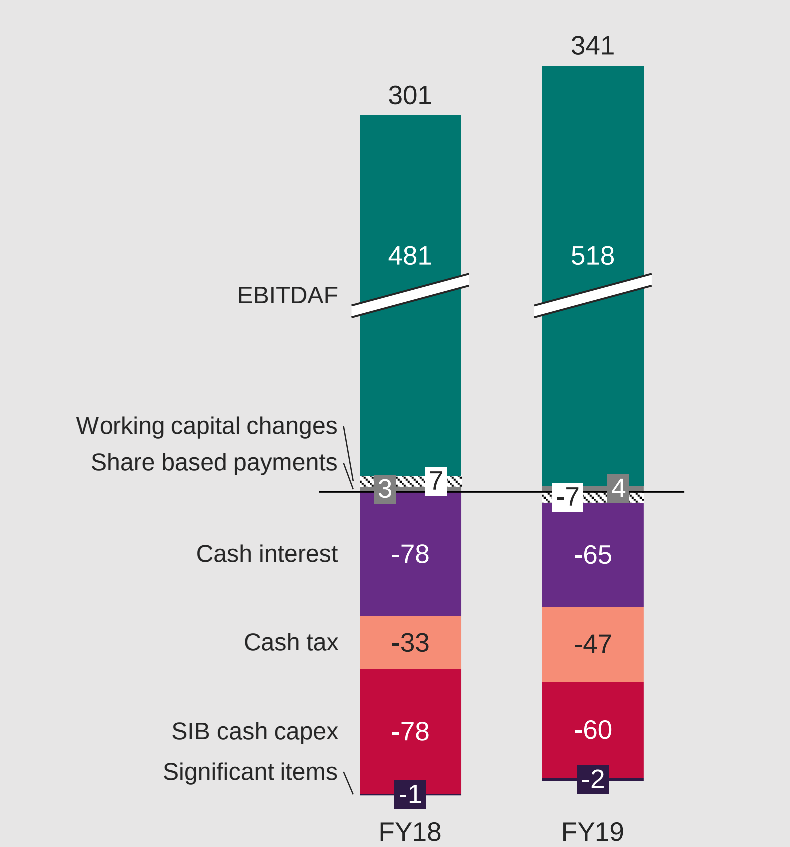
SIB CAPEX ($m)



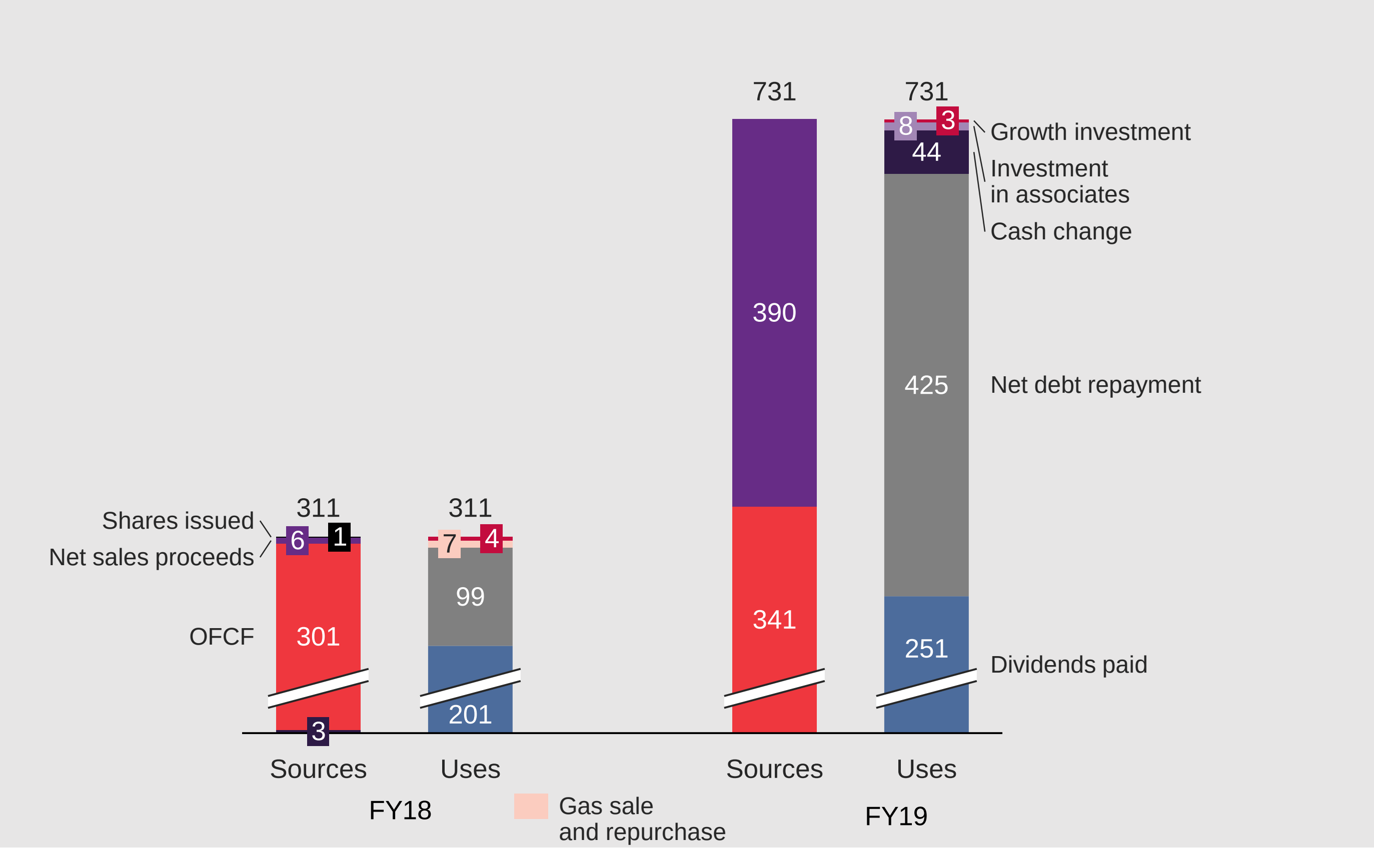
Free cash flow used to strengthen balance sheet

EBITDAF to cash conversion increased to 66% in FY19 from 63% in FY18

OPERATING FREE CASH FLOW – OFCF ($m)



SOURCES AND USES OF CASH ($m)

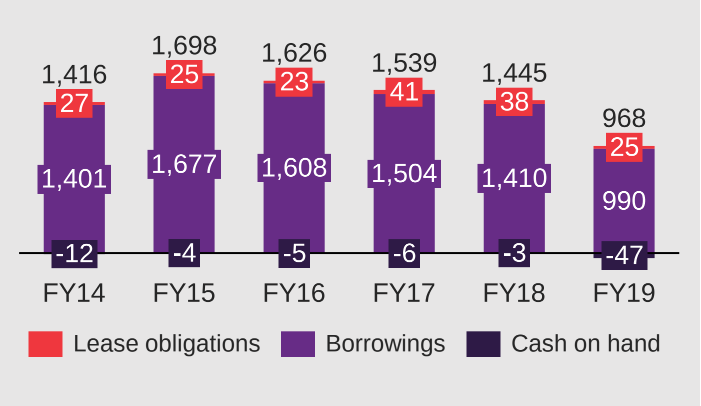


Robust balance sheet

Well managed, diversified portfolio with green certification. Capacity to fund renewable generation

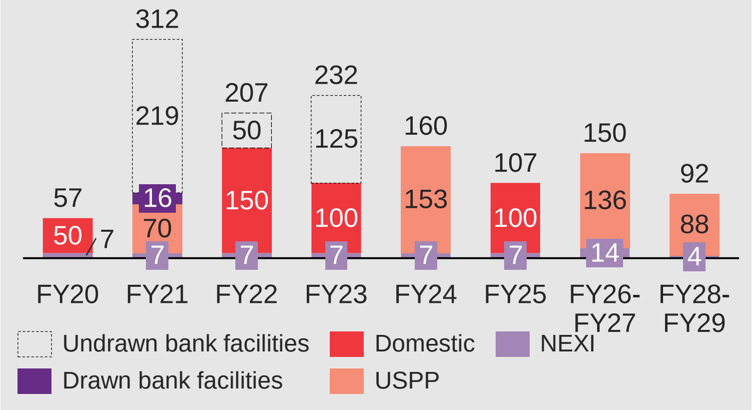
CLOSING NET DEBT ($m)

Face value of borrowings less cash



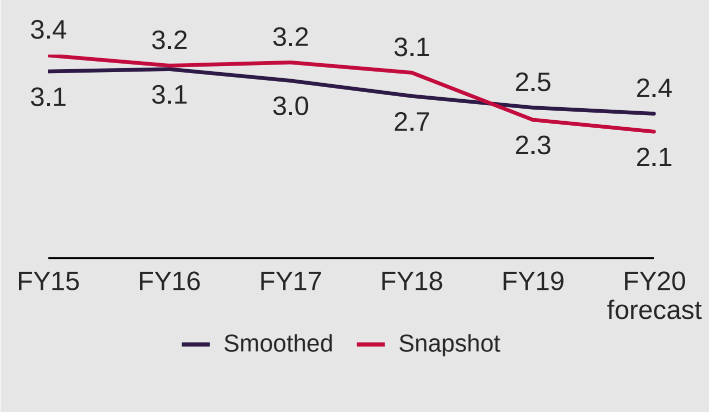
BORROWING MATURITIES ($m)

Average tenor of 3.8 years as at 30 June 2019



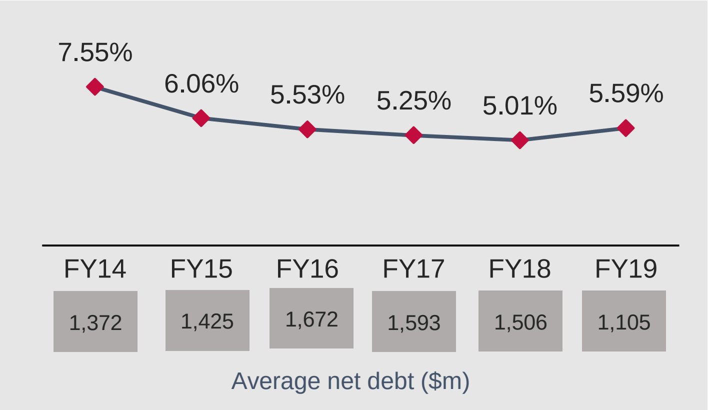
NET DEBT TO EBITDAF (x)

Includes S&P adjustments (in FY19 AGS was treated as a lease)



INTEREST RATE (%)

Weighed average interest rate on average net debt



- Face value of borrowings net of cash reduced by $464m to $943m following the completion of the asset sales and strong operating cash flow which exceeded dividend payments. Net debt has reduced by $730m since the end of FY15. Gearing reduced to 28.3% at 30 June 2019, down from 35.4% at 30 June 2018
- $50m wholesale domestic bond maturity in May 2020, funded through existing facilities
- Weighted average interest rate increased by 58bp on FY18 as more flexible, lower cost floating rate debt was repaid with the asset sales proceeds
- Contact continues to target a credit rating of BBB (net debt / EBITDAF <2.8x)

Distribution policy provides clarity to investors and drives a strong capital discipline

Distribution policy

Ordinary dividend of

100%

=

of expected Operating Free Cash Flow*

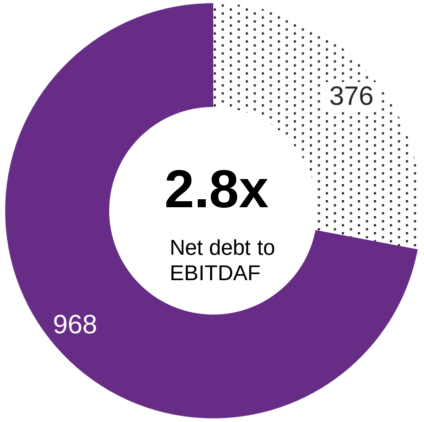
FY19 Ordinary dividend

39 cps

4.7%

At the closing share price on 9 August 2019 of $8.30 per share

Balance sheet capacity



Headroom to BBB ($m)
S&P net debt ($m)

Assuming FY20(f) EBITDAF of $480m

With a new long-term user contracted to access AGS, **S&P will no longer capitalise the storage service payments from FY20**

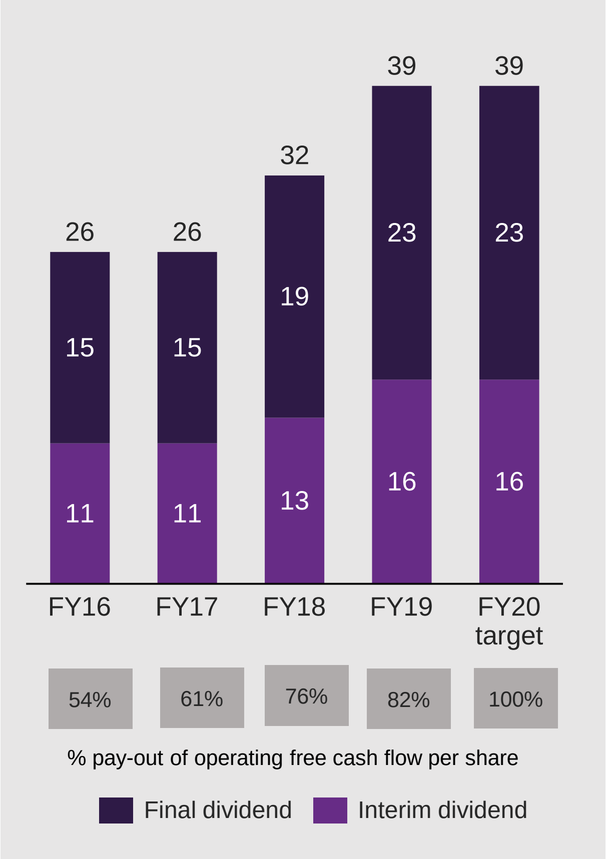
* Operating Cash Flow less stay-in-business capex and net interest costs after adjusting for expected medium-term stay-in-business capital expenditure, mean hydrology and appropriate Board consideration of a sustainable financial structure including targeting the long-term credit rating of BBB from S&P

Distributions

Rewarding shareholders

ORDINARY DIVIDENDS (cps)

Declared or target



FINAL DIVIDEND FOR FY19 OF 23 CENTS PER SHARE UP 21%

- Final dividend of 23 cents per share (Final FY18 19 cents per share) is imputed to 65% or 15 cents per share for qualifying shareholders. This represents a pay-out of 82% of FY19 operating free cash flow per share
- Total FY19 ordinary dividend of 39 cents per share (FY18 32 cents per share)
- Target FY20 ordinary dividend of 39 cents per share (FY19 39 cents per share)
- Record date 29 August 2019; payment date 17 September 2019
- The NZD/AUD exchange rate used for the payment of Australian dollar dividends will be set on 3 September 2019
- **See Appendix (page 34 and 35) for detailed workings explaining the calculation of expected operating free cash flow**

Market update and Outlook

Dennis Barnes
CEO

Progress against near-term priorities

As per 1H19

CONTRACT GAS
- ✓ Engaging with suppliers to contract for gas for 2019 and beyond. Increasingly confident that gas availability will improve as current gas supply constraints are unlocked

MANAGE WHOLESALE MARKET VOLATILITY
- ✓ Contact manages fuel variability through portfolio flexibility and a strong risk management framework
- ✓ In addition to the gas we expect to contract, access to stored gas in AGS and other contractual options which will give us appropriate access to energy

DELIVERING CUSTOMER VALUE
- ✓ Continue to develop customer centred processes, products and propositions that will appeal to all, including the most vulnerable. Next proposition to be released imminently is a “basic plan” i.e. no PPD offer. Ultimately customers will define the value of product features, discounts and rewards
- ✓ Participation in the Electricity Price Review consultation

EXECUTE ON THE COST AND EFFICIENCY PROGRAMME
- ✓ The focus remains on the reduction of controllable costs, simplification of the organisation and asset portfolio
- ✓ Investment in digital and data to build a platform from which we will further reduce costs and develop new, innovative propositions

FULLY COMMERCIALISE GAS STORAGE
- ✓ Work with FlexGas, the new AGS operating entity, to attract long term users into the facility before the expansion is completed (early 2020)

PROGRESS

- ✓ Long-term gas contract signed
- ✓ Reduction in fixed price sales
- ✓ Basic plan launched, Broadband take-up encouraging
- ✓ Targets achieved, cost reduction to continue
- ✓ Long-term user contracted

Progress against medium-term priorities

As per 1H19

DECARBONISATION

- ✓ Develop options to enable the economic substitution of thermal generation with renewables
- ✓ Partner with customers on mutually beneficial decarbonisation opportunities

CAPTURE SCALE EFFICIENCIES

- ✓ Further develop the rich set of brownfield geothermal development opportunities available
- ✓ In time, our large customer base and world class systems will provide an attractive opportunity for partners

PROGRESS

- ✓ Simply Energy acquisition completed in June 2019
- ✓ Tauhara appraisal drilling commencing August 2019

Guidance

Further performance improvements targeted

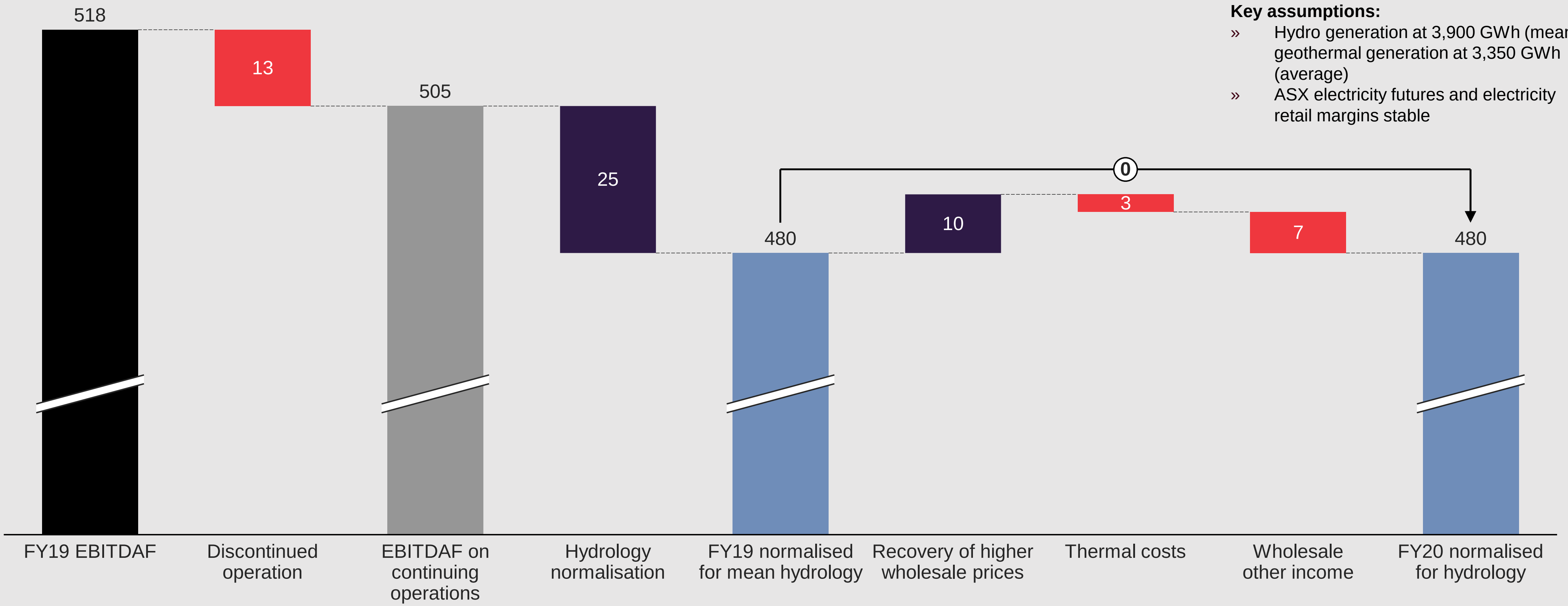
	FY19	Result	FY20 (f)	*Change to prior guidance*	*Comment*
Other operating costs	$200 – 210m	✓	$200 – 205m		Prior range of $245 – 260m. Mid-point now $260m
Stay in business capital expenditure	$60 – 75m	✓	$55 – 60m		
Cash spend ('Totex')	**$260 – 285m**	✓	**$255 – 265m**		
Depreciation and amortisation	$200 – 205m	✓	$195 – 205m	-	Range due to thermal operating hours
Net interest (accounting)	$75 – 80m	✓	$60 – 65m	-	Lower average net debt (full year impact of disposal proceeds received in FY19)
Cash interest	$70 – 75m	✓	$55 – 60m	-	
Cash taxation			$70 – 75m	new	Timing of tax payments in FY20
Target ordinary dividend per share	39 cps	✓	39 cps	-	

Supporting materials

Normalised EBITDAF for FY20

Higher wholesale prices offset by retail margin pressure, a full year of AGS and normalising trading income

EBITDAF ($m)



Key assumptions:

- Hydro generation at 3,900 GWh (mean), geothermal generation at 3,350 GWh (average)
- ASX electricity futures and electricity retail margins stable

» Through time, efficiency improvements will continue to deliver more generation per tonne extracted to offset field decline

Expected operating free cash flow

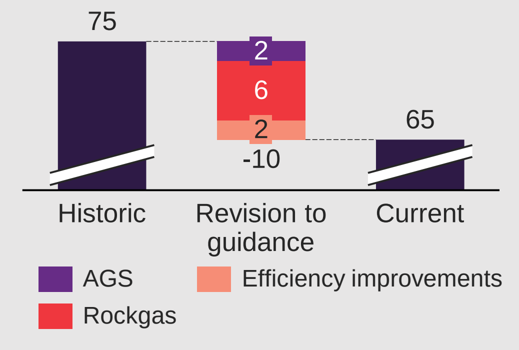
Basis for distributions

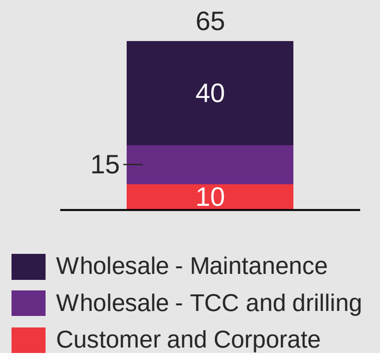
DISTRIBUTION POLICY

- Contact's policy is to distribute ordinary dividends targeting a pay-out ratio of 100% of an Operating Free Cash Flow* which is adjusted for expected medium-term stay-in-business capital expenditure, mean hydrology and the consideration of a sustainable financial structure including the targeting of a long-term credit rating of BBB
- Dividend payments are expected to be split into an interim dividend paid in April, targeting around 40% of the total expected dividend for the financial year, and a final dividend to be paid in September
- It is the intention of the Board to attach imputation credits to dividends to the extent they are available

LONG RUN AVERAGE CAPEX ($m)

Excludes capex associated with Wairakei extension post 2026



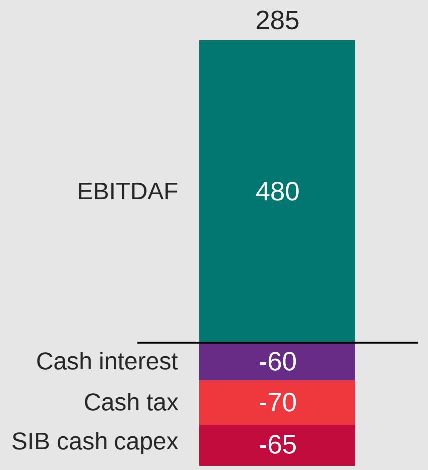


Sustainable capital expenditure is between $60 - $65m per annum and includes:

- Thermal plant refurbishment
- Geothermal well drilling to maintain geothermal generation at 3,350 GWh per annum
- Transformation and continuous improvement initiatives
- Plant and systems maintenance

MEDIUM TERM OFCF ($m)

*Operating Free Cash Flow (OFCF) is operating cash flow less stay-in-business capital expenditure and net cash interest costs

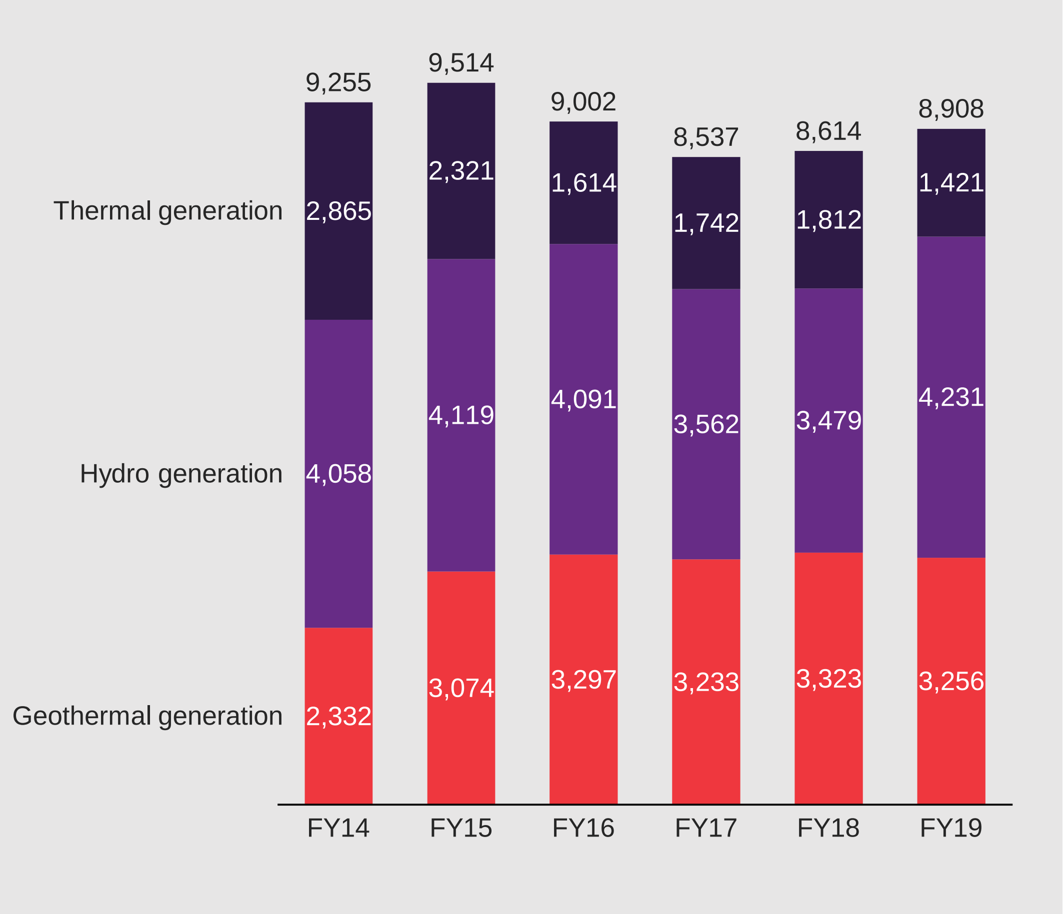


Key assumptions:

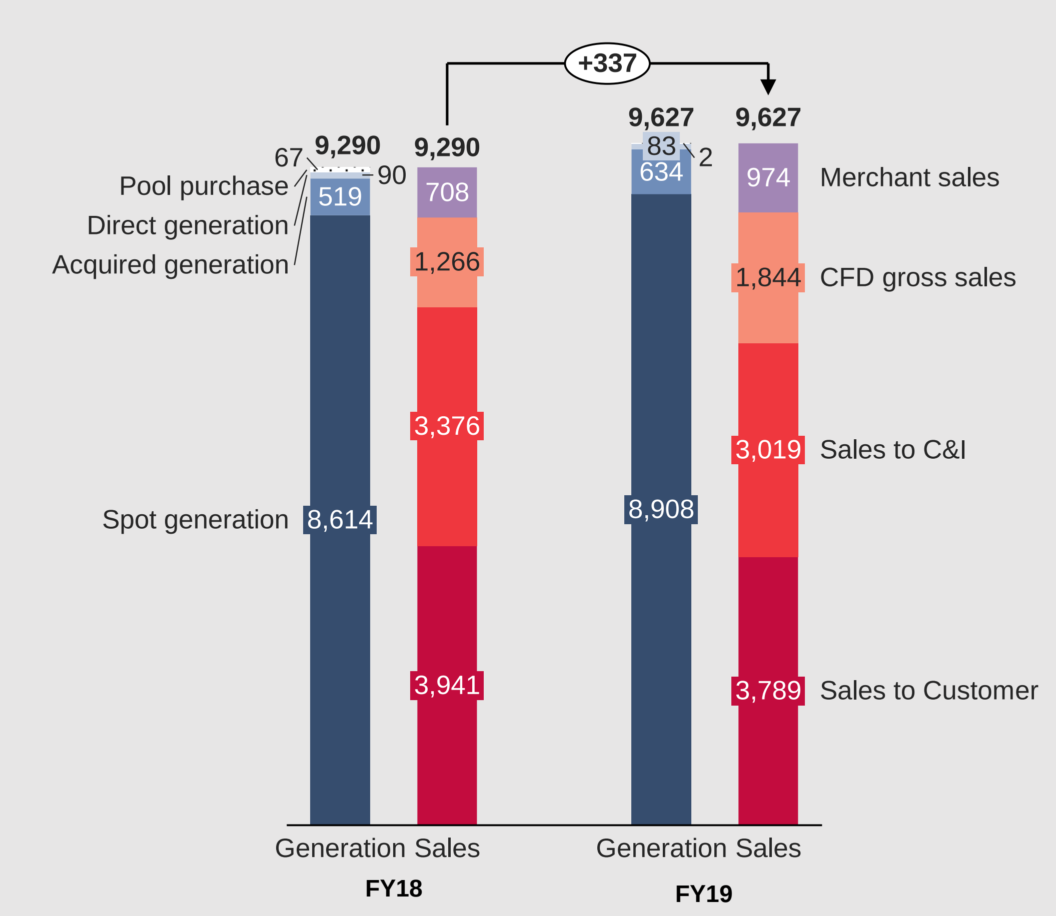
- Hydro generation at 3,900 GWh (mean), geothermal generation at 3,350 GWh (average)
- ASX electricity futures and electricity retail margins stable
- Excludes working capital movements

Generation and sales position

CONTACT GENERATION OUTPUT (GWh)

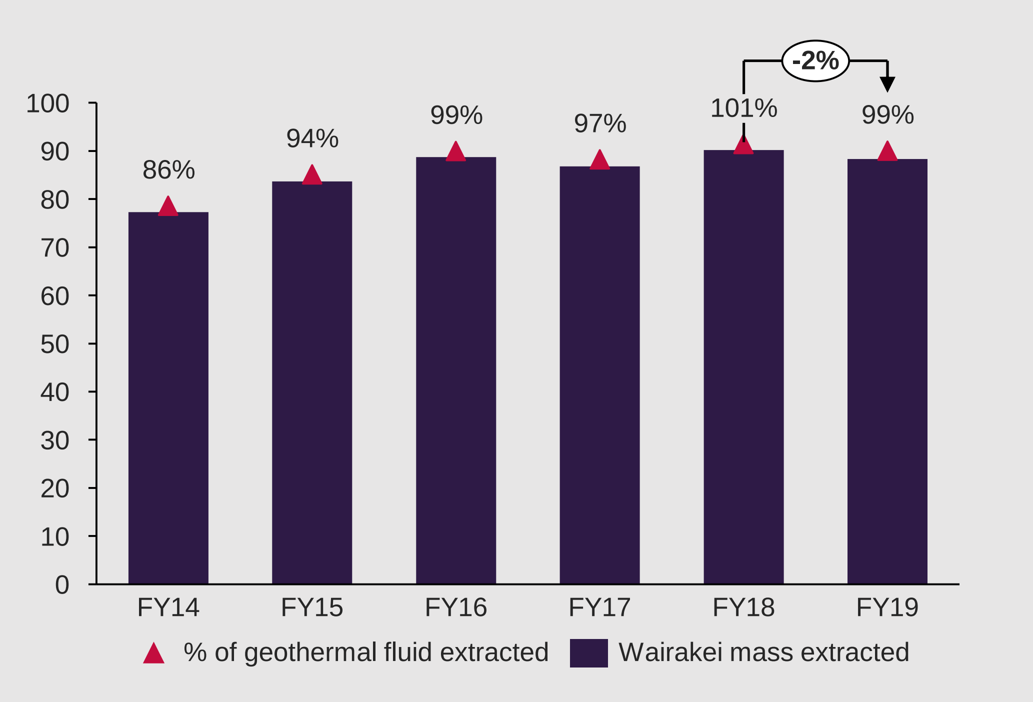


ELECTRICITY GENERATION AND SALES POSITION (GWh)



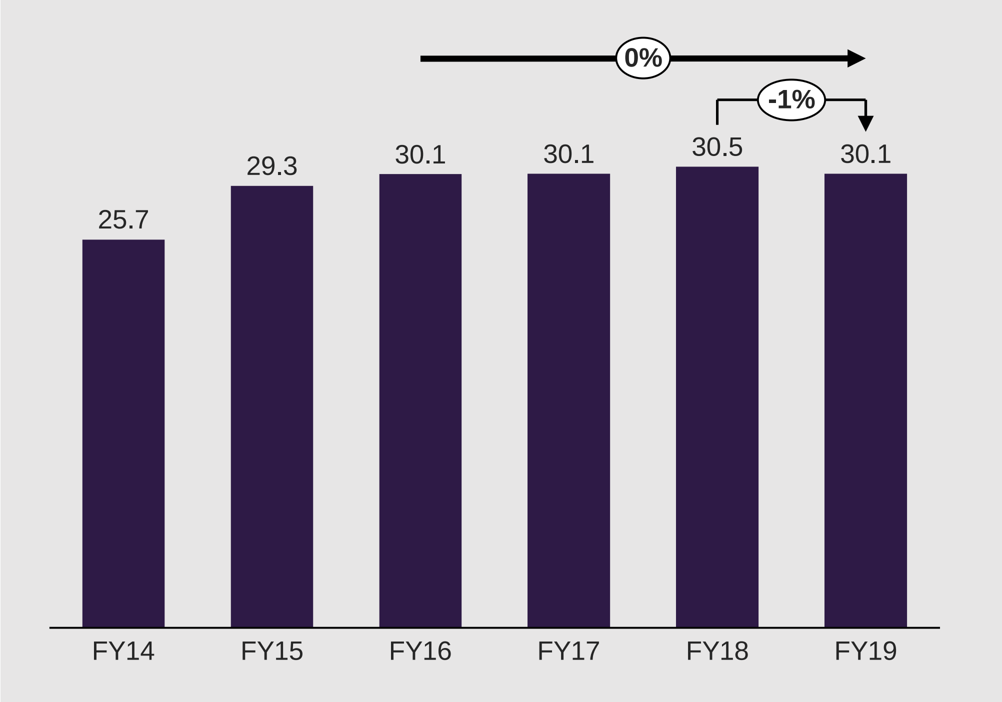
Wairakei geothermal field mass take and efficiency

GEOTHERMAL FUEL EXTRACTED AT WAIRAKEI VS CONSENTED (GWh)



» Obtained a variation to the Wairakei mass take consent in September 2017. This allows for the extraction of 245k tonnes of geothermal fluid per day on average over a year (calculation period ends in February every year).

WAIRAKEI, POIHIPI AND TE MIHI CONVERSION EFFECTIVNESS (MWh per Kt EXTRACTED)

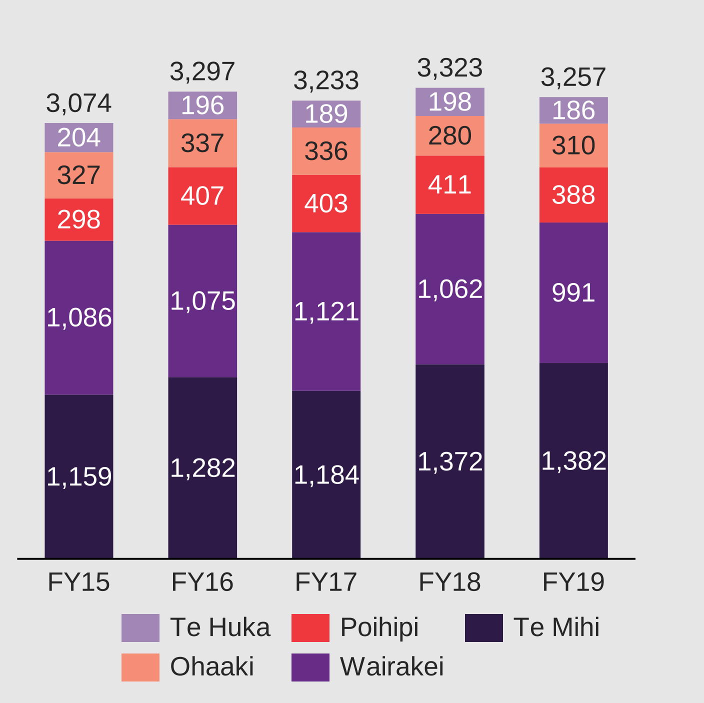


» Through time, efficiency improvements will continue to deliver more generation per tonne extracted to offset field decline

Generation volumes

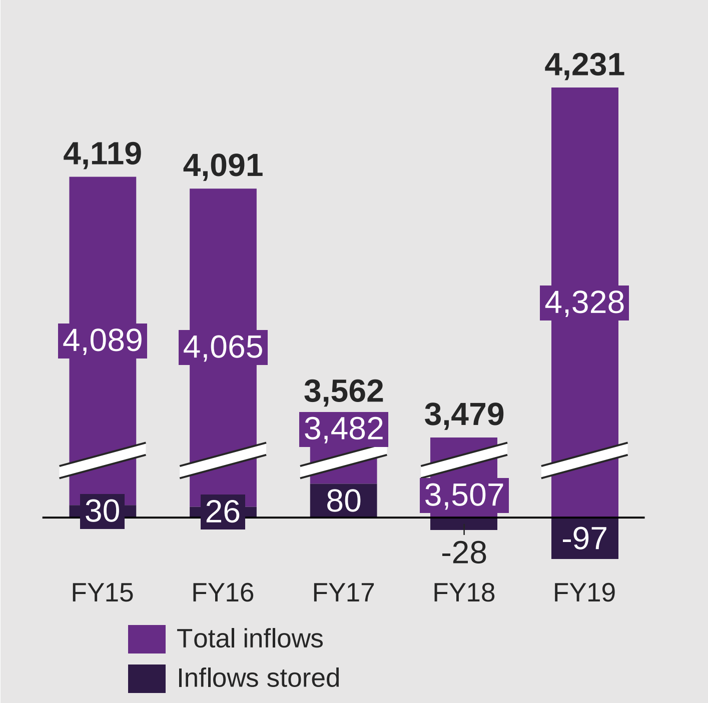
Renewable generation up 10% on FY18

Geothermal generation (GWh)



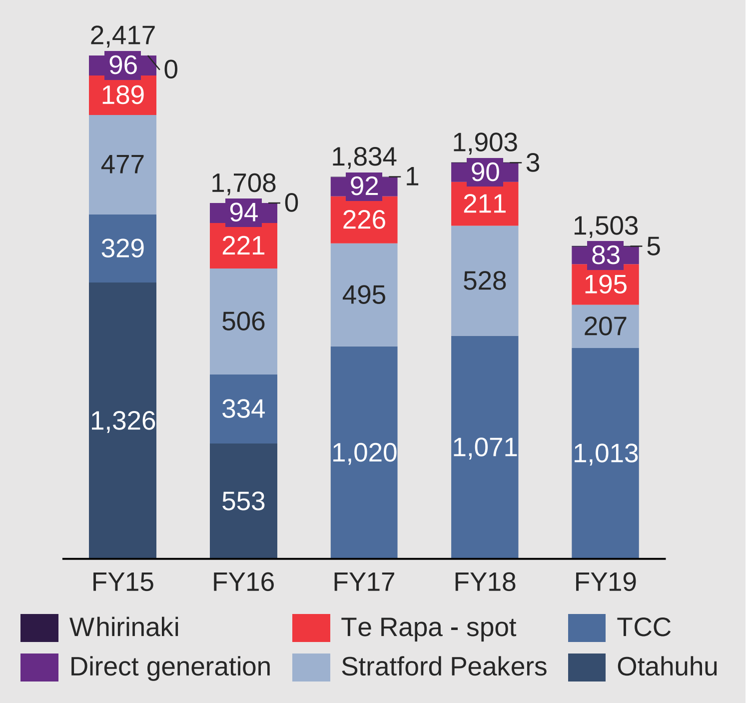
» Geothermal generation was 67GWh lower than FY18 primarily due to the scheduled 4 yearly inspection at Wairakei (53GWh lower) and lower mass extracted in the period

Hydro generation (GWh)



» Hydro generation was 331GWh above mean in FY19 and 752GWh higher than a dry FY18

Thermal generation (GWh)



» Thermal generation volumes were 400GWh lower in FY19 on higher renewable generation, lower sales and restricted availability of gas. Baseload generation at TCC was prioritised over the Stratford peakers

Plant availability

HYDRO

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	($m)
FY16	784	89%	59%	4,091	55	225
FY17	784	92%	52%	3,562	47	169
FY18	784	95%	51%	3,479	78	271
FY19	784	97%	62%	4,231	123	521

TARANAKI COMBINED CYCLE (TCC)

	Net capacity (MW)	Availabilit y (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	($m)
FY16	377	89%	10%	334	59	20
FY17	377	90%	31%	1,021	64	65
FY18	377	68%	32%	1,071	102	110
FY19	377	63%	31%	1,013	115	117

OTAHUHU

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	($m)
FY16	41	89%	154%	553	58	32
FY17						
FY18						
FY19						

GEOTHERMAL

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	($m)
FY16	431	93%	87%	3,297	61	200
FY17	429	91%	86%	3,233	55	177
FY18	425	96%	89%	3,323	80	267
FY19	425	92%	87%	3,256	133	434

PEAKERS (INCLUDING WHIRINAKI)

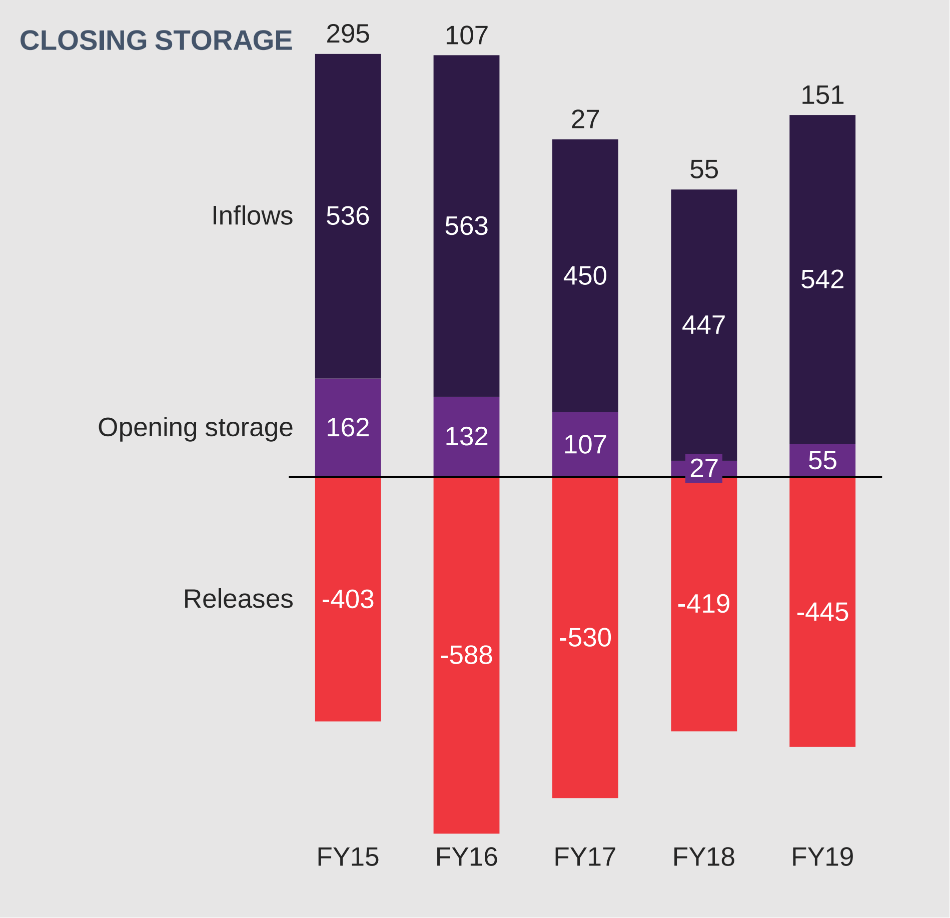
	Net capacity (MW)	Availabilit y (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	($m)
FY16	360	89%	16%	505	69	35
FY17	360	95%	16%	495	73	36
FY18	360	87%	17%	530	116	62
FY19	360	79%	7%	212	192	41

TE RAPA (SPOT GENERATION ONLY)

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	($m)
FY16	41	94%	61%	221	64	14
FY17	41	98%	63%	226	58	13
FY18	41	87%	59%	211	94	20
FY19	41	96%	54%	195	160	31

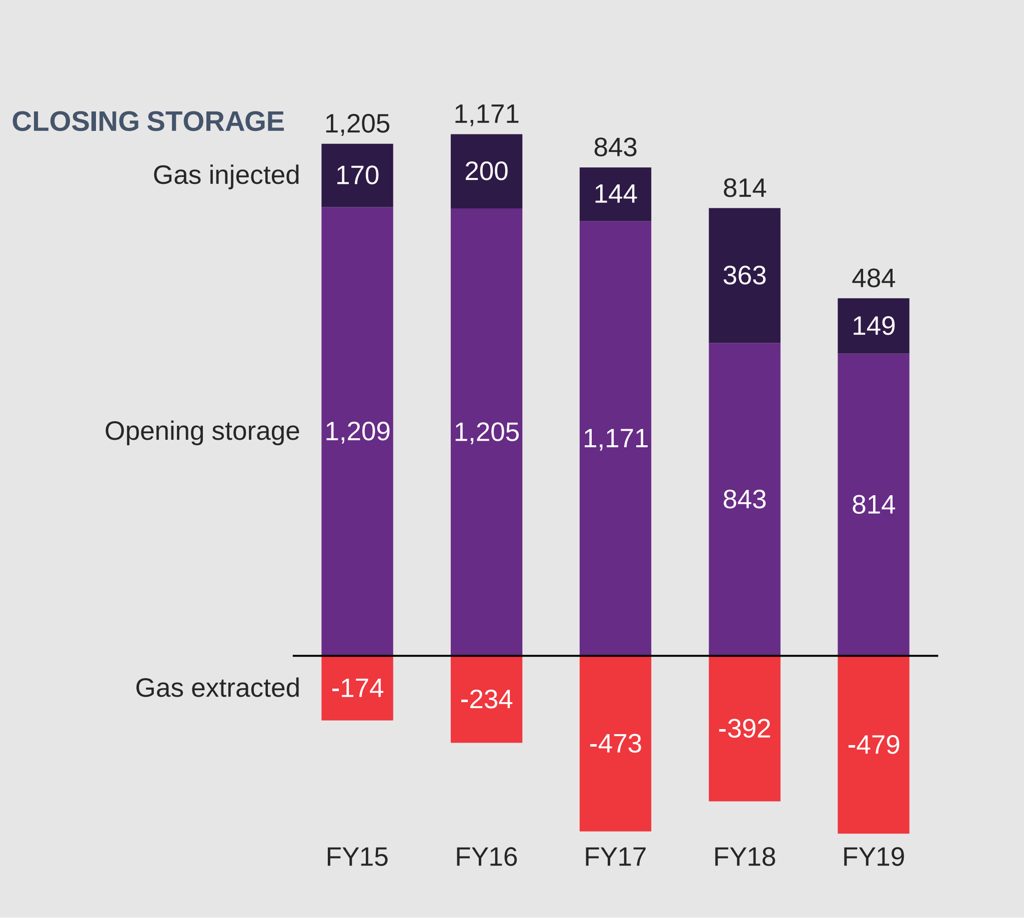
Fuel storage movements

HAWEA STORAGE (GWh)



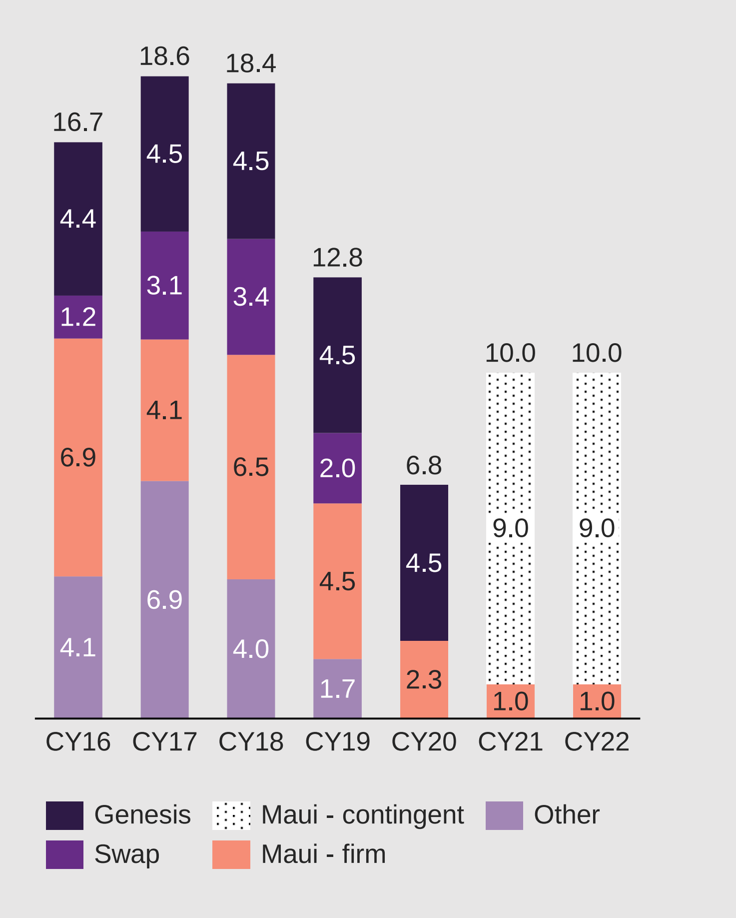
GAS STORAGE (GWh EQUIVALENT)

Using the FY19 thermal efficiency (9.25 TJ/GWh)

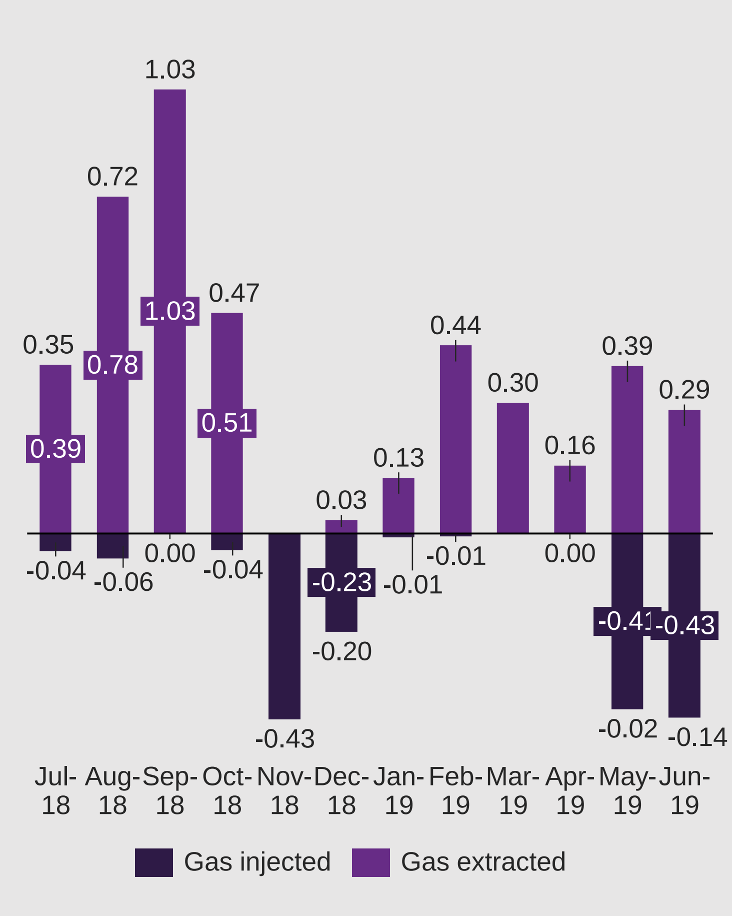


Contracted and stored gas

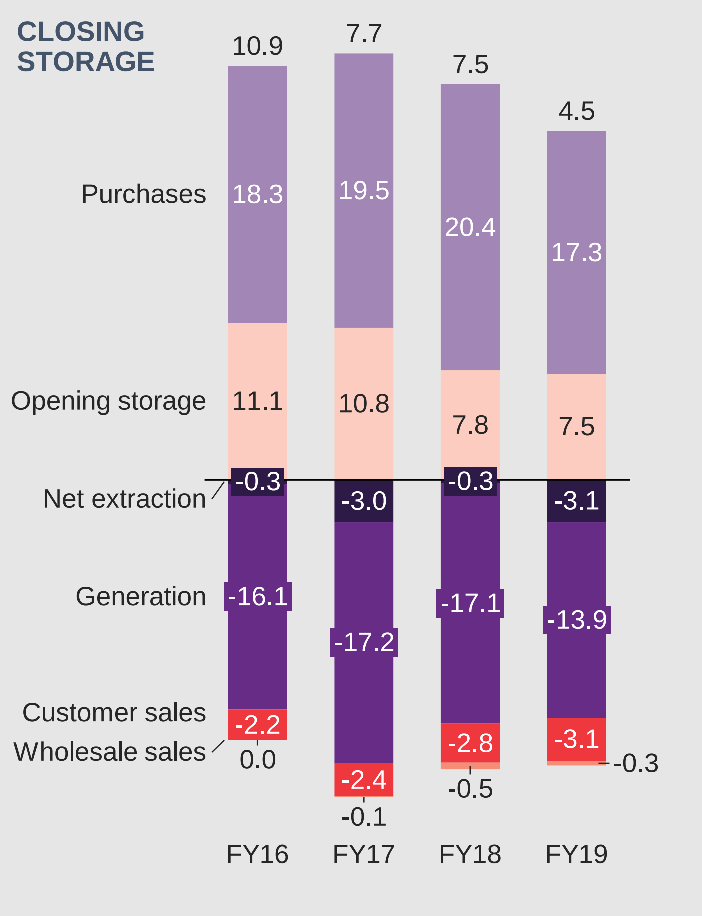
CONTRACTED GAS VOLUMES (PJ)



AHUROA GAS STORAGE MONTHLY INJECTIONS AND EXTRACTIONS (PJ)



SOURCES AND USES OF GAS (PJ)



Non-GAAP profit measure: EBITDAF

- EBITDAF is Contact's earnings before net interest expense, tax, depreciation, amortisation, change in fair value of financial instruments and other significant items
- 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 2019	12 months ended 30 June 2018	Variance on prior year	
			$m	%
Profit	**345**	**132**	**213**	**161%**
Depreciation and amortisation	205	220	(15)	(7%)
Significant items (gross of tax)	(174)	(3)	(171)	5700%
Net interest expense	70	84	(14)	(17%)
Tax expense	72	48	24	50%
EBITDAF	**518**	**481**	**37**	**8%**

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

Reconciliation between Profit and EBITDAF

- The adjustments from EBITDAF to reported profit and movements on FY18 are as follows:
  - **Depreciation and amortisation:** Reduced by $15m (7%) as depreciation on the held for sale asset (AGS) and the discontinued operation (Rockgas) stopped once the criteria for discontinuation was met, this was offset by an increase in thermal depreciation as the TCC plant was utilised more
  - **Change in fair value of financial instruments**: Totalled $2m in FY19 reflecting a favourable movement in electricity price derivatives over the period
  - **Net interest expense:** Reduced by $14m (17%) to $70m in FY19 on reduced average borrowings after the proceeds from asset sales were applied to the reduction of debt. Net interest also includes a $5m unwind in the discount of provisions.
  - **Tax expense** for the year ended 30 June 2019 was $72m up $48m from FY18 on increased operating earnings and tax on significant items. Tax expense represents an effective tax rate of 29% on continuing operations and 17% on total earnings as the gain on the sale of Rockgas were not subject to income tax.
  - **Other significant items** are detailed on the next two slides

Non-GAAP profit measure: Underlying profit

- Underlying profit provides a consistent measure of Contact's ongoing performance
- Underlying profit excludes the effect of significant items from reported profit. Significant items are determined based on principles approved by the Board of Directors
- Other significant items are determined in accordance with the principles of consistency, relevance and clarity. Items considered for classification as other significant items include impairment or reversal of impairment of assets; business integration, restructure, acquisition and disposal costs; and transactions or events outside of Contact's ongoing operations that have a significant impact on reported profit
- Reconciliation of statutory profit for the year to underlying profit:

	12 months ended 30 June 2019	12 months ended 30 June 2018	Variance on prior year	
			$m	%
Profit	**345**	**132**	**213**	**161%**
Change in fair value of financial instruments	(2)	(3)	1	33%
Gain on sale of Rockgas Limited (LPG)	(165)	-	(165)	
Gain on sale of Ahuroa gas storage	(5)	-	(5)	
Remediation for Holidays Act non-compliance	(2)	-	(2)	
Tax on items excluded from underlying profit	5	1	4	400%
Underlying profit	**176**	**130**	**46**	**35%**

Reconciliation between Profit and Underlying profit

- The adjustments from reported profit to underlying profit for FY19 are as follows:
  - Change in the fair value of financial instruments
  - **Rockgas Limited Sale:** Rockgas was sold to Gas Services NZ Midco Limited on 30 November 2018, the net gain on sale was $165m
  - **Ahuroa Gas Storage Facility Sale:** The sale of the AGS Facility to GSNZ SPV1 Limited (GSNZ) was completed on 1 October 2018. Cash proceeds from sale received to date are $190 million resulting in a gain on sale of $5 million before tax. Consideration of up to $10 million remains unrecognised as it is contingent on GSNZ obtaining a favourable binding ruling as to the tax treatment of the main assets it acquired.
  - **Remediation for Holidays Act non-compliance**: During FY19, spend of $1 million has been incurred in order to resolve non-compliance with aspects of the Holidays Act 2003. The provision has also been reduced by $2 million as a result of ongoing reassessment of the expected liability
  - Tax on the items outlined above

Historical financial information

	Unit	2015	2016	2017[2]	2018[3]	2019[3]
Revenue	$m	2,443	2,163	2,079	2,275	2,519
Expenses	$m	1,918	1,640	1,578	1,794	2,001
EBITDAF	$m	525	523	501	481	518
Profit/(loss)	$m	133	(66)	151	132	345
Underlying profit	$m	161	157	142	130	176
Underlying profit per share	cps	21.9	21.7	19.9	18.1	24.6
Operating free cash flow	$m	338	352	305	301	341
Operating free cash flow per share	cps	46.6	48.5	42.6	42.0	47.5
Dividends declared[1]	cps	76	26	26	32	39
Total assets	$m	6,089	5,652	5,455	5,311	4,954
Total liabilities	$m	2,918	2,829	2,677	2,584	2,172
Total equity	$m	3,171	2,823	2,778	2,727	2,782
Gearing ratio	%	36	38	36	35	28

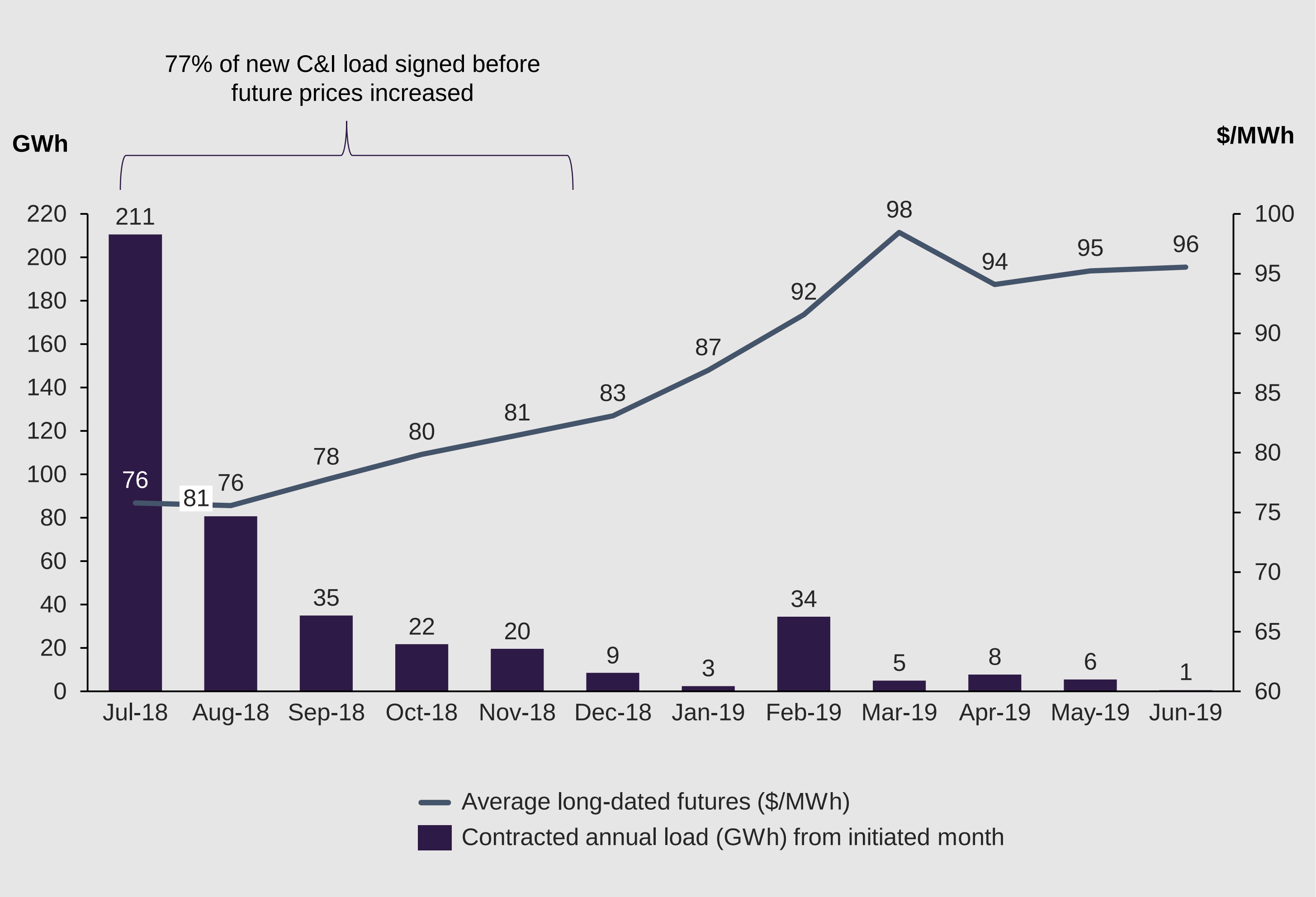
1. FY15 included a special dividend of 50 cents per share
2. Figures have been restated for the adoption of NZ IFRS 15 *Revenue from Contracts with Customers* and NZ IFRS 16 *Leases*
3. Figures above reflect the combined result and position for continuing and discontinued operations and certain 2018 amounts have been reclassified to conform to the current year’s presentation

Wholesale segment

Note: this table has not been rounded and might not add	FY19 Twelve months ended 30 June 2019 Volume GWh	GWAP $/MWh	$m	FY18 Twelve months ended 30 June 2018 Volume GWh	GWAP $/MWh	$m	Reference to Wholesale segment note
Electricity sales to Customer	**3,789**	**83.0**	**314**	**3,941**	**79.7**	**314**	Inter-segment electricity sales
Electricity sales to Fixed C&I (netback)	2,936	81.6	240	3,285	82.0	269	*Data in operating report*
Electricity sales – Direct	83	99.2	8	90	90.9	8	
Electricity sales to C&I	**3,019**	**82.1**	**248**	**3,376**	**82.2**	**278**	C&I electricity revenue (C&I and spot) less Electricity networks, levies and meters (fixed and spot) less Electricity purchases (Spot) *less C&I operating costs*
CfDs – Tiwai support	805			701			
CfDs - Long term sales	569			497			
CfDs - Short term sales	471			67			
Electricity sales - CFDs	**1,844**	**73.9**	**136**	**1,266**	**64.2**	**81**	Wholesale electricity revenue, net of hedging
Total contracted electricity sales	**8,652**	**80.7**	**699**	**8,582**	**78.4**	**673**	
Steam sales	**558**	**47.3**	**26**	**584**	**42.8**	**25**	Steam revenue
Other income			10			(0)	Other Income
Net income on gas sales			1			1	Gas revenue - (cost of gas sold in 'Gas purchases')
Net income on electricity related services			0			1	Electricity related services revenue less cost
Net other income			**12**			**2**	
Total contracted revenue (1)	**9,210**	**80.0**	**737**	**9,166**	**76.4**	**700**	
Generation costs	8,991	(31.1)	(279)	8,704	(30.9)	(269)	Gas purchases, Electricity and gas transmission, Other operating costs, Carbon emissions *[less cost of gas sold and C&I opex]*
Acquired generation cost	634	(107.7)	(68)	519	(94.0)	(49)	Electricity purchases
Generation costs (including acquired generation) (2)	**9,625**	**(36.1)**	**(348)**	**9,223**	**(34.4)**	**(318)**	
Spot electricity revenue	8,908	128.6	1,146	8,614	84.8	730	Wholesale electricity revenue, net of hedging
Settlement on acquired generation	634	146.1	93	519	90.1	47	Electricity purchases, net of hedging
Spot revenue and settlement on acquired generation (GWAP)	**9,542**	**129.8**	**1,238**	**9,132**	**85.1**	**777**	
Spot electricity cost	(6,725)	(137.6)	(925)	(7,226)	(90.7)	(656)	Electricity purchases, net of hedging
Settlement on CFDs sold	(1,844)	(129.2)	(238)	(1,266)	(84.8)	(107)	
Spot purchases and settlement on CFDs sold (LWAP)	**(8,569)**	**(135.8)**	**(1,163)**	**(8,492)**	**(89.8)**	**(763)**	
Trading, merchant revenue and losses (3)			**75**			**14**	
Wholesale EBITDAF (1+2+3)			**464**			**397**	

Commercial and Industrial sales

New C&I load FY19 (GWh) and long-dated futures ($/MWh)



Commercial and Industrial price progression

C&I - FPVV		**FY18**	**FY19**
C&I volumes (GXP)	GWh	3,285	2,936
C&I volumes (ICP)	GWh	3,159	2,821
Netback (GXP)	$/MWh	82.0	81.6
Netback (ICP)	$/MWh	85.2	85.0
C&I – Spot[1]			
C&I volumes (GXP)	GWh	189	196
Netback (GXP)	$/MWh	90.9	140.6
C&I (Spot and FPVV)			
C&I volumes (GXP)	GWh	3,474	3,132
C&I volumes (ICP)	GWh	3,348	3,017
Netback (GXP)	$/MWh	82.5	85.3
Netback (ICP)	$/MWh	88.8	91.8

1. For internal reporting Contact does not include spot sales in reporting of C&I sales. Spot sales are a short-term sales channel and a reflected in trading revenue to avoid the distorting effect of higher wholesale prices on netbacks

Customer segment

Residential electricity		FY16	FY17	FY18	FY19
Average connections	#	362,456	362,570	359,171	353,105
Sales volumes	GWh	2,603	2,628	2,549	2,491
Average usage	per ICP	7.2	7.2	7.1	7.1
Tariff	$/MWh	247.8	248	250.1	251.7
Network, meters and levies	$/MWh	-117.3	-119.8	-122.4	-122.1
Energy costs	$/MWh	-86.4	-85.7	-86.7	-89.5
Gross margin	**$/MWh**	**44.1**	**42.5**	**41**	**40.2**
Gross margin	$ per ICP	316	308	291	283
Gross margin	$m	115	112	104	100

SME electricity		FY16	FY17	FY18	FY19
Average connections	#	57,364	56,292	57,309	55,020
Sales volumes	GWh	1,189	1,074	1,099	1,042
Average usage	per ICP	20.7	19.1	19.2	18.9
Tariff	$/MWh	217.3	224.1	224.1	226.8
Network, meters and levies	$/MWh	-103	-106.6	-108	-111.9
Energy costs	$/MWh	-85.1	-83.8	-84.8	-87.7
Gross margin	**$/MWh**	**29.3**	**33.7**	**31.3**	**27.2**
Gross margin	$ per ICP	606	643	599	516
Gross margin	$m	35	36	34	28

Customer EBITDAF					
Electricity Gross margin	$m	150	148	139	128
Gas Gross Margin	$m	15	15	15	14
Broadband Gross Margin	$m	-	-	0	1
Total Gross Margin	**$m**	**165**	**163**	**154**	**144**
Other income	$m	5	4	4	4
Other operating costs[1]	$m	-109	-105	-82	-81
Customer EBITDAF	**$m**	**61**	**62**	**76**	**67**
Corporate allocation (50%)[1]	$m			-12	-13
EBITDAF from retailing	**$m**	**61**	**62**	**64**	**54**
EBITDAF margins	%	6%	6%	7%	6%

Residential gas		FY16	FY17	FY18	FY19
Average connections	#	58,741	59,809	60,905	61,711
Sales volumes	TJ	1,577	1,581	1,600	1,605
Average usage	per ICP	26.8	26.4	26.3	26
Tariff	$/GJ	32.1	32	31.6	31.5
Network, meters and levies	$/GJ	-19.5	-19.5	-19.6	-18.4
Energy costs	$/GJ	-6.2	-5.8	-5.6	-5.9
Carbon costs	$/GJ	0	-0.3	-0.7	-1
Gross margin	**$/GJ**	**6.3**	**6.4**	**5.8**	**6.3**
Gross margin	$ per ICP	170	168	152	165
Gross margin	$m	10	10	9	10

SME gas		FY16	FY17	FY18	FY19
Average connections	#	2,368	2,981	3,677	3,901
Sales volumes	TJ	649	883	1,300	1,492
Average usage	per ICP	274	296.3	353.5	382.6
Tariff	$/GJ	18.2	17.5	15.5	15.1
Network, meters and levies	$/GJ	-4.2	-5.3	-4.5	-5.5
Energy costs	$/GJ	-6.2	-5.8	-5.6	-5.9
Carbon costs	$/GJ	0	-0.3	-0.7	-1
Gross margin	**$/GJ**	**7.8**	**6.1**	**4.8**	**2.8**
Gross margin	$ per ICP	2,145	1,817	1,689	1,068
Gross margin	$m	5	5	6	4

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