2016 Interim Results Presentation

Six months ended 31 December 2015

Dennis Barnes, Chief Executive Officer
Graham Cockroft, Chief Financial Officer

15 February 2016

Contact

Disclaimer

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 and 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.

Agenda

Strategy	» Leverage integrated customer and generation business to deliver strong cash flows for distribution to shareholders
	• Deliver value to our customers by providing choice, control and certainty
	  • Build customer centric offers in-house and with partners to improve customer life time value
	  • Target lowest cost to serve in the industry by extracting greater efficiency and customer experience from our investment in customer service and billing systems
	• A low cost, long life and flexible generation portfolio with focus on safety, reliability and resource utilisation
	• Disciplined approach to capital expenditure

Performance	» Free cash flow improved 24% to $203m; impairments at Otahuhu and Taheke resulted in loss for the period of $116m » Continued competition in retail business largely offset by lower purchase volume and improved gas costs • Mass market volume reasonably stable and progress made on initiatives to improve capability and performance • Improved geothermal availability and resource flexibility offset reduced hydro generation
Capital management	» Share buyback purchased $62m shares in 1H16 and expect to complete $100m in FY16 » Interim dividend stable at 11 cents per share; 7 cents per share imputed
Focus on structural efficiency	» Closure of Otahuhu, contract supporting ongoing Tiwai operation and planned refurbishment of TCC has improved New Zealand's energy and capacity balance • Confident industry will resolve any capacity requirements from 2019 in a rational manner » Regulatory changes around transmission pricing, network charging and carbon critical to ensure the right incentives are in place for customers and industry participants » Retail competition expected to continue, despite high costs of churn
Outlook	» Strong cash flow expected to continue » FY16 EBITDAF and underlying profit not to be materially different to FY15 subject to hydrology variability

Statutory loss $116m due to Otahuhu and Taheke impairments

Underlying profit per share down 4%; Free cash flow per share up 24%

	Six months ended 31 December 2015	
EBITDAF[1]	$254m	down 1% from $257m
Profit/(loss)	($116m)	down 327% from $51m
Earnings per share (cents)	(15.9) cps	down 330% from 6.9 cps
Underlying profit[1]	$73m	down 4% from $76m
Underlying profit per share (cents)	10.0 cps	down 4% from 10.4 cps
Interim dividend (cents)	11.0 cps	no change from 11.0 cps
Free cash flow[2]	$203m	up 24% from $164m
Free cash flow per share (cents)	27.7 cps	up 24% from $22.4 cps
Capital expenditure	$71m	up 48% from $48m

[1] Refer to slides 34-37 for a definition and reconciliation of EBITDAF and underlying profit

[2] Refer to slide 24 for a definition and reconciliation of free cash flow

Progress continues across the business

FY16 outlook statement at FY15 results presentation	Progress
Continued strong free cash flow	Up 24% with distributions to shareholders via share buyback and stable dividends
Lower cost to serve offset continued intense retail competition	Retail competition higher than expected and 'cost out' slower but gaining momentum
C&I load reduced following the non-renewal of the Fonterra electricity contract	Additional contracts lost at start of year, however recent improvement in re-sign rates and CfD/ASX sales in place for 2H16
Customer business begins to move beyond system stabilisation to optimisation	New 'fixed term' and 'Home and Bach' products in market. Customer service metrics continue to improve. New Customer management structure in place
No repeat of 1H15 one-off network costs or retail stabilisation costs	Network costs reduced by $3/MWh with the non-recurrence of one-off costs in FY15 more than offsetting notified network price increases
LPG costs reflective of lower oil prices	Cost of sales per tonne reduced 7%
Increased geothermal production offsets return to mean hydrology	Geothermal generation up 10% despite unplanned outage at Te Mihi
New gas contracts and Te Rapa agreement commence	Increased steam revenue and lower contracted gas price
Reduced operating expenses following the closure of Otahuhu	Gas transmission and operating cost reductions achieved post closure

Market dynamics and strategy

Dennis Barnes

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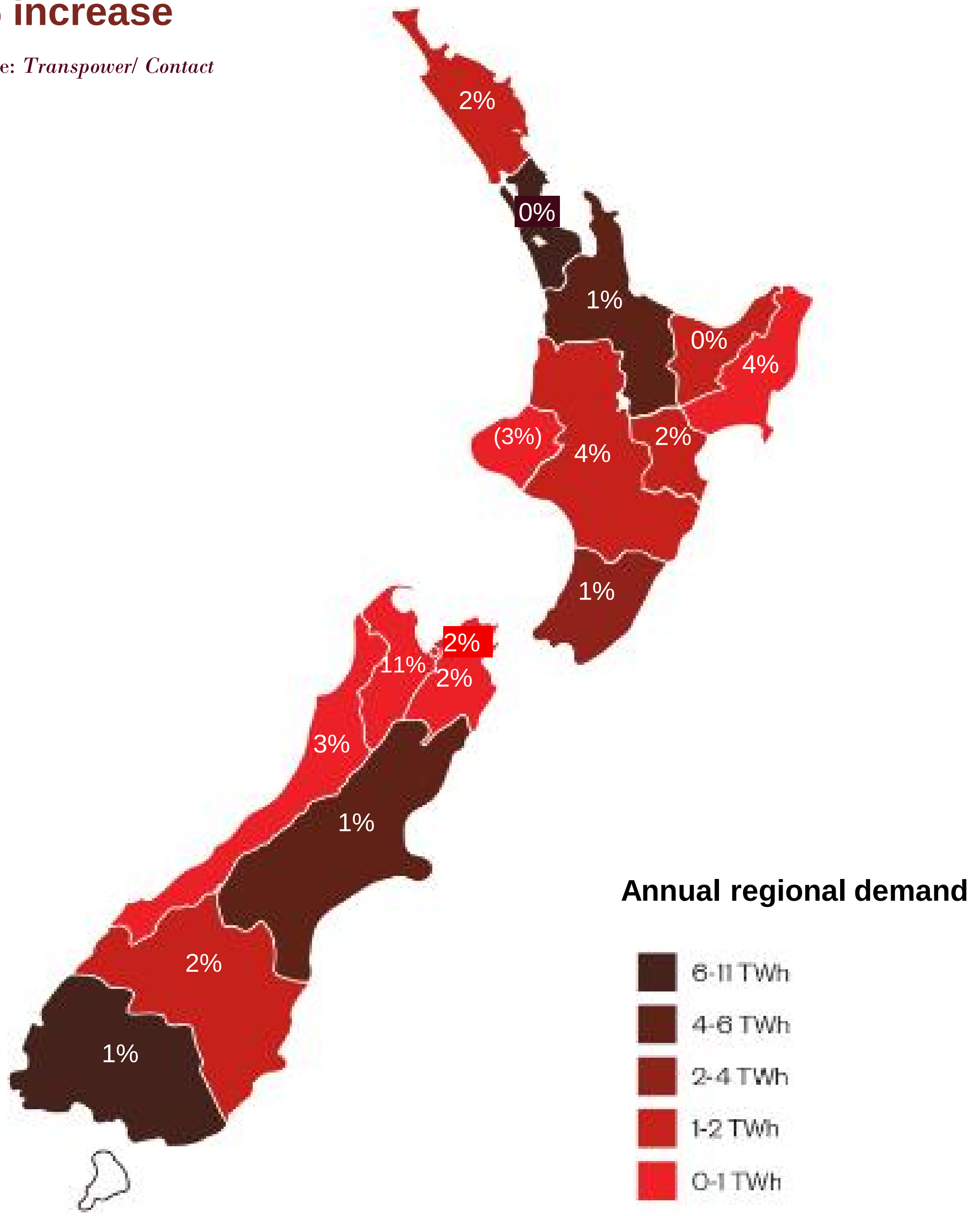
Demand growth, particularly in agriculture, has continued

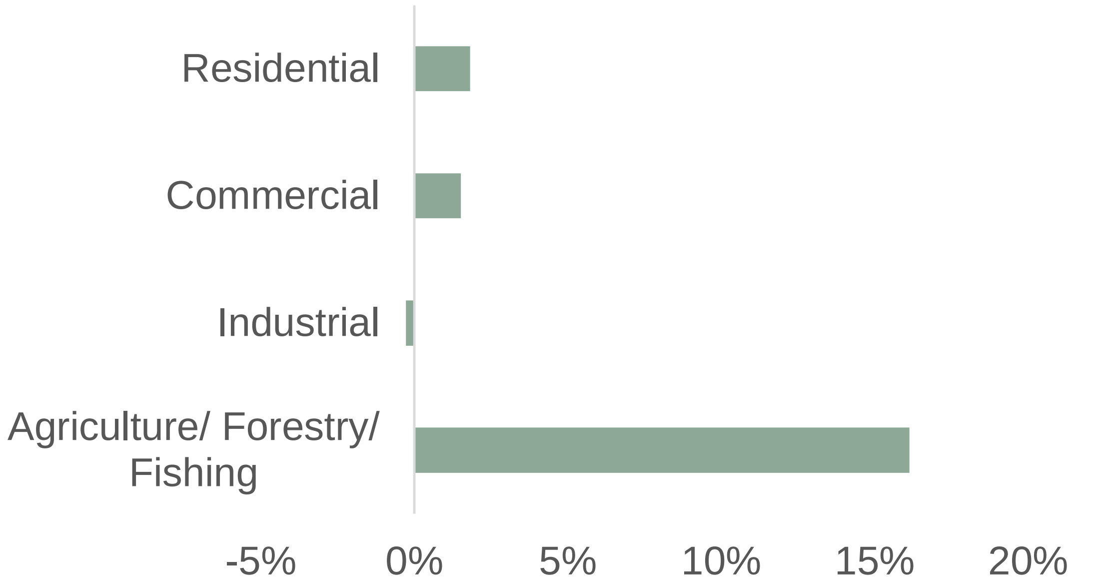
Year on year demand growth continued in 1H16 with a 1% increase

Source: *Transpower/ Contact*



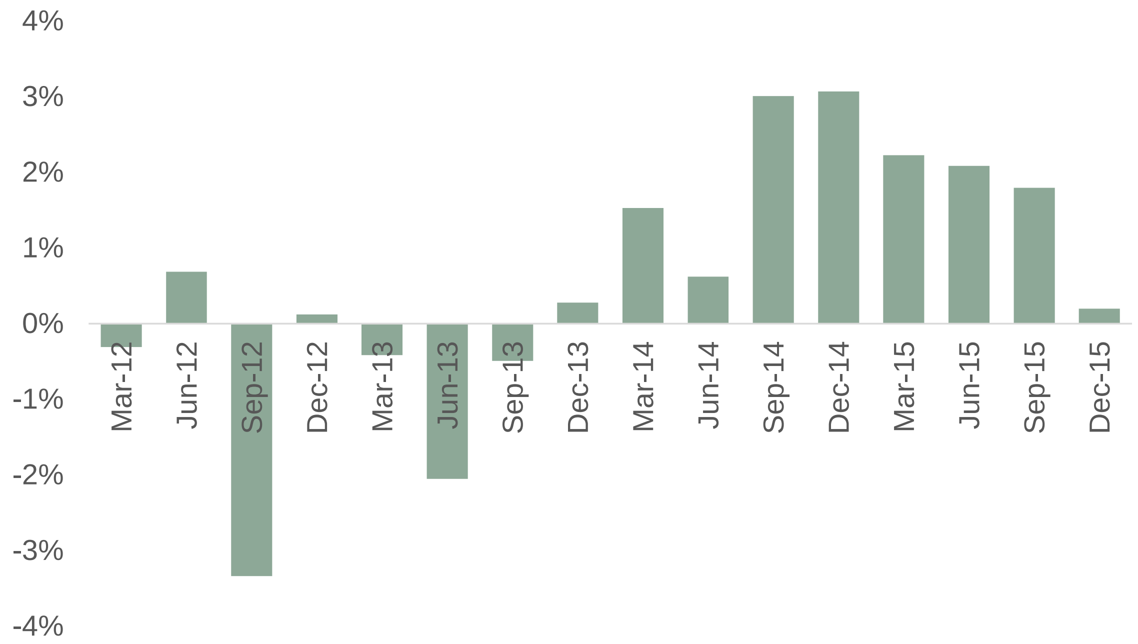
12 month change in electricity consumption

Source: *MBIE; 12 months ended 30 September*



Year on year quarterly change in electricity consumption

Source: *Transpower*



Recent market trends

Mass market

» Retail competition remains intense with new retailers and service offerings entering the market
  - 27 retail brands today, 9 new retail brands over the last 2 years
  - 1H16 churn increased to 21% with discounting remaining the universal currency
  - Residential prices fell in the September quarter by 2.8% (0.7% line costs, 4.2% energy costs)
  - Industry focus on improving customer experience and engagement
  - Initial signs of retail consolidation

» Recent regulatory drive to improve access to consumption and tariff information needs balance to avoid impacts on innovation

» Solar and EVs growing but remain small. Batteries uneconomic for mass market customers

Commercial and industrial

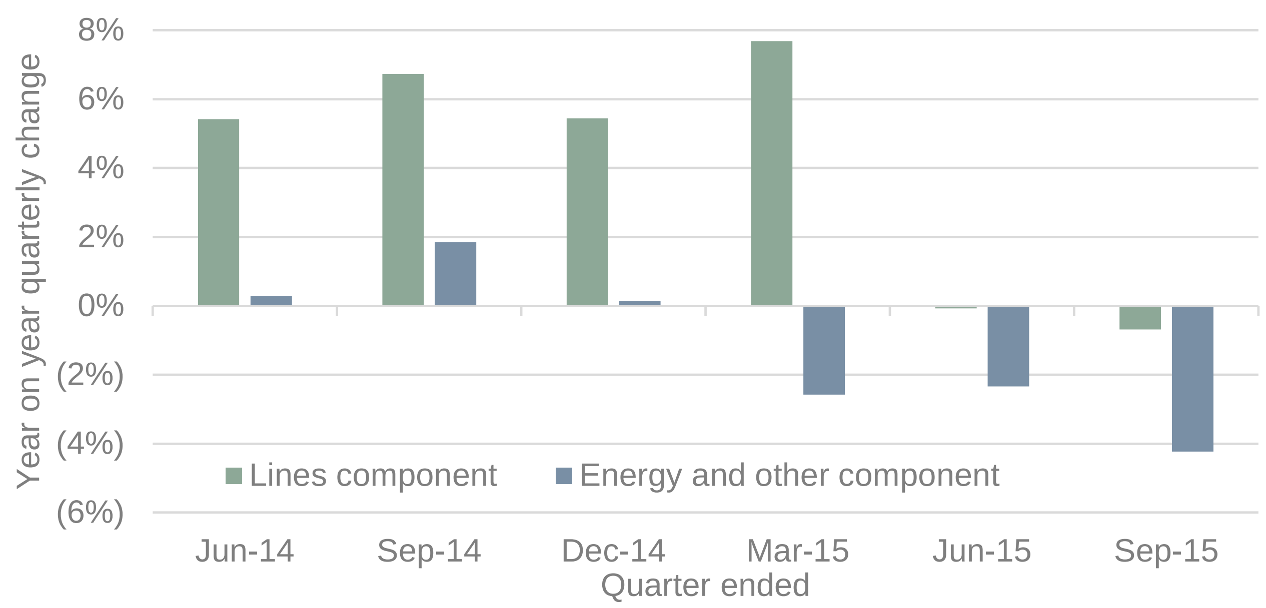
» ASX forward curve has risen

» Increased competition for C&I as netback similar to marginally competed mass market customers

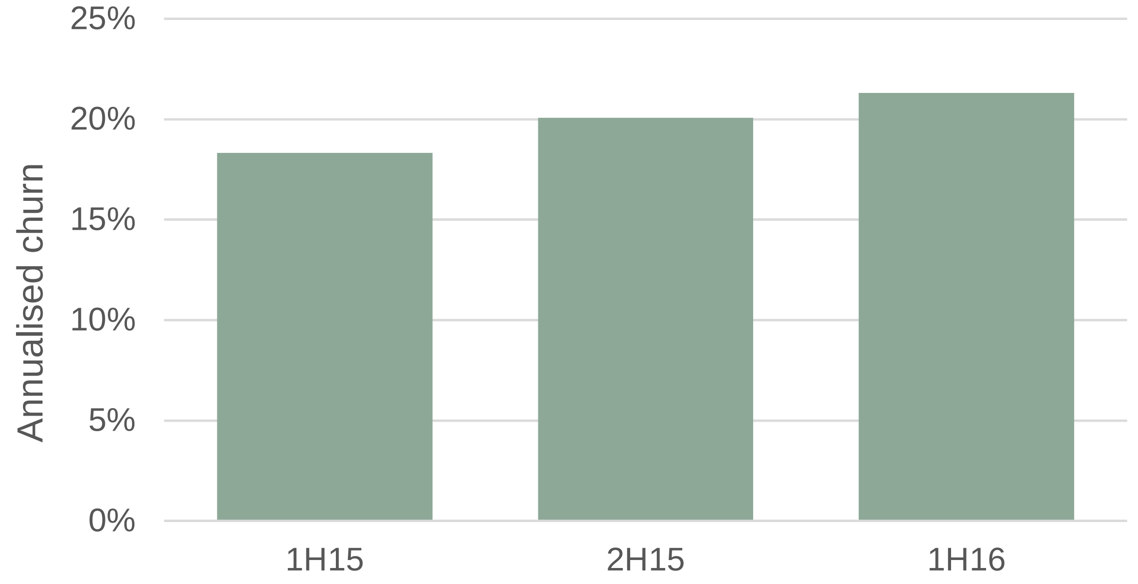
» Initial signs of spot customers returning to contract as ASX and spot prices converge

Year on year quarterly change in electricity prices

Source: MBIE Quarterly Survey of Domestic Electricity Prices



Customer switching activity continues to increase



Contact's response – becoming truly customer inspired

Deliver value to our customers by providing choice, control and certainty

» Contact's historical pricing construct is changing, improving competitiveness and customer life time value
  - Fixed 16/17 product means no price increases when you sign up for a 1 or 2 year term
  - 'Home and Bach' product means you don't pay fixed charges at your bach when you aren't using it
  - Progressing development of a product pipeline that will allow customers to have more choice
  - 76% of customers on non-standard discounts

» Increasing digital presence supported by mobile app launch

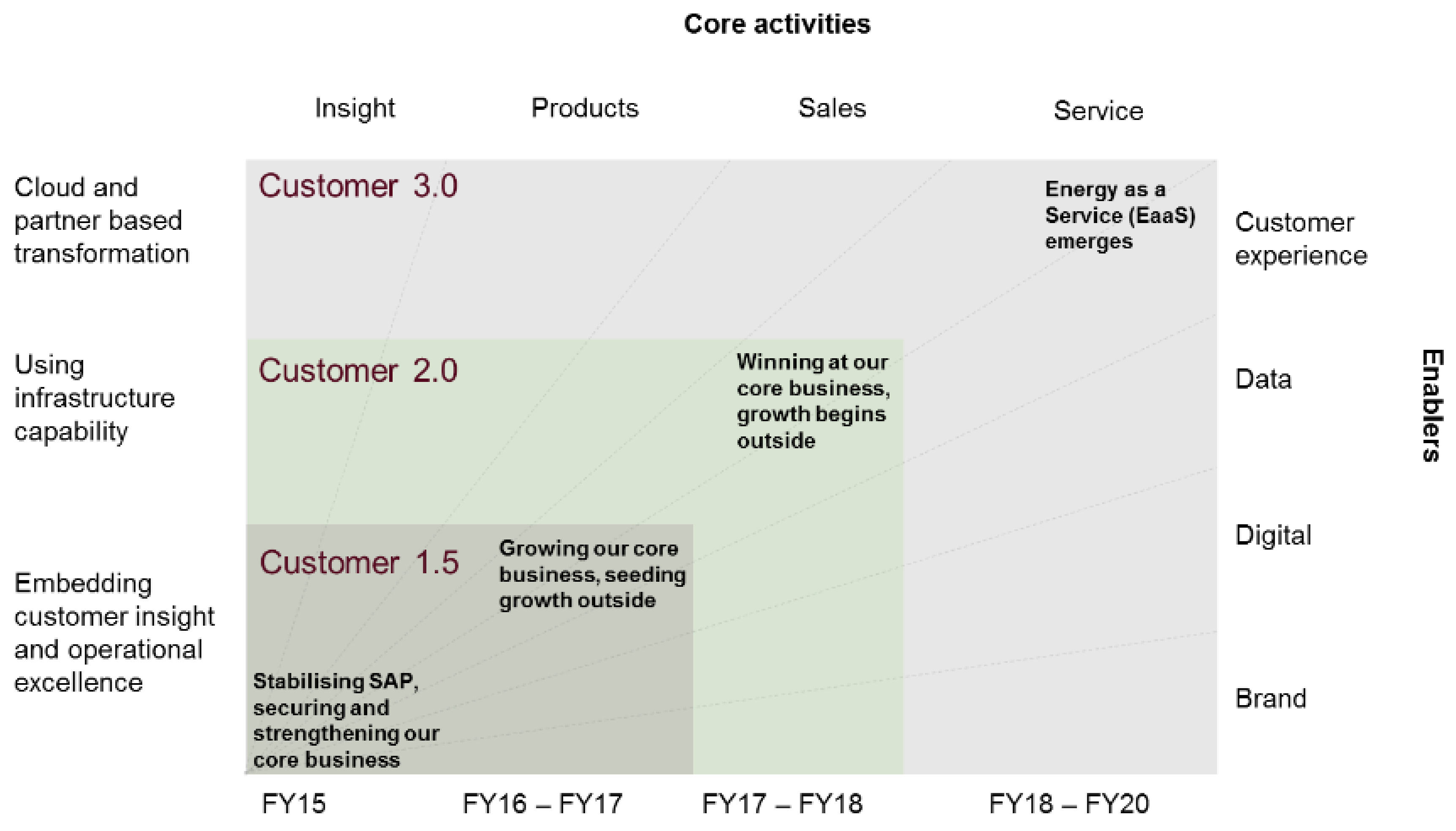
» On-shore of back office functions completed

» Advocating regulation keeps pace with technology change and captures the voice of the customer

Channel selection for commercial and industrial volumes

» 2H16 sales of C&I expected to be similar to 2H15
  - Improving re-sign rates on existing customers
  - Increasing associated benefits to C&I customers beyond price

Customer strategy continues to develop across three horizons



Contact is leveraging its SAP benefits and simplifying its IT systems to reduce cost and improve customer capability

Current systems simplification programme on track to deliver $9m reduction in FY17 operating expenses from the peak in FY15

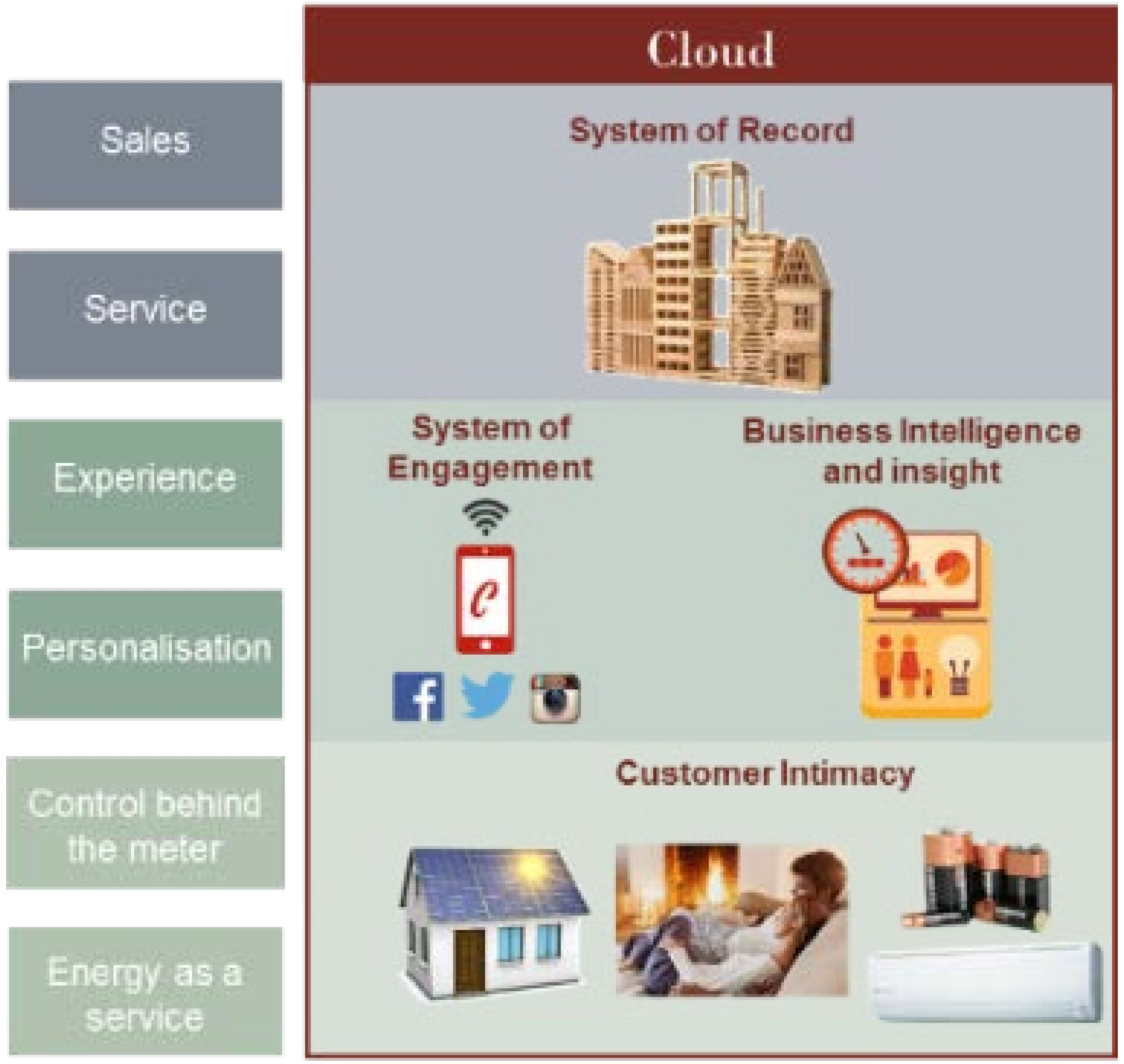
» Decisions made in past 6 months to reduce cost and enhance customer, product, digital and data capability accelerated by Origin exit

- Exit shared agreements with Origin in 2016
- Move from four vendors in FY15 to two vendors in FY17 saving $5m
- Move infrastructure to cloud services
- Insource application management (non-SAP) to increase business flexibility and add digital capability

» Rapid development of systems of engagement such as mobile apps and digital

Milestones

March	May	September	October
» Hybrid mobile app in Apple & Google stores early March	» Foundation digital and data capability May 2016 » Extended product, billing and pricing capability	» Infrastructure to cloud services	» Complete Origin exit



Contact has switched to lower cost fuel and has improved New Zealand's energy and capacity balance

Contact's actions have contributed to a competitive, reliable and sustainable electricity supply

» Energy balance achieved with a reduction in gas contracting volumes by Contact

» Capacity balanced with the closure of Otahuhu

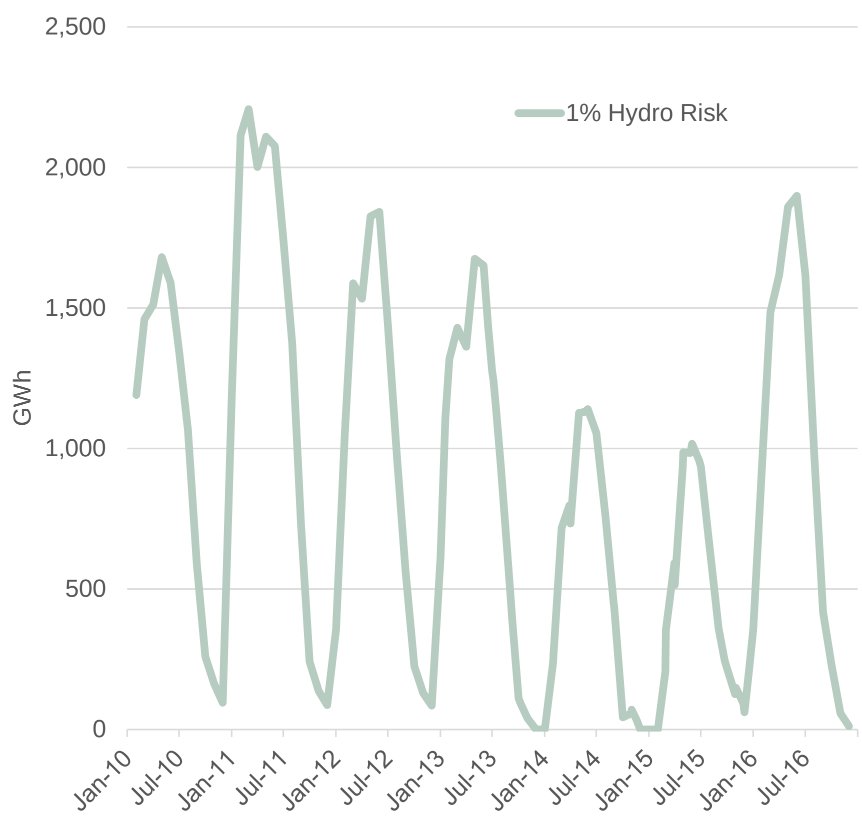
» Increased geothermal output

» System support provided through Ahuroa gas storage, Stratford peakers and the Whirinaki peaking plant

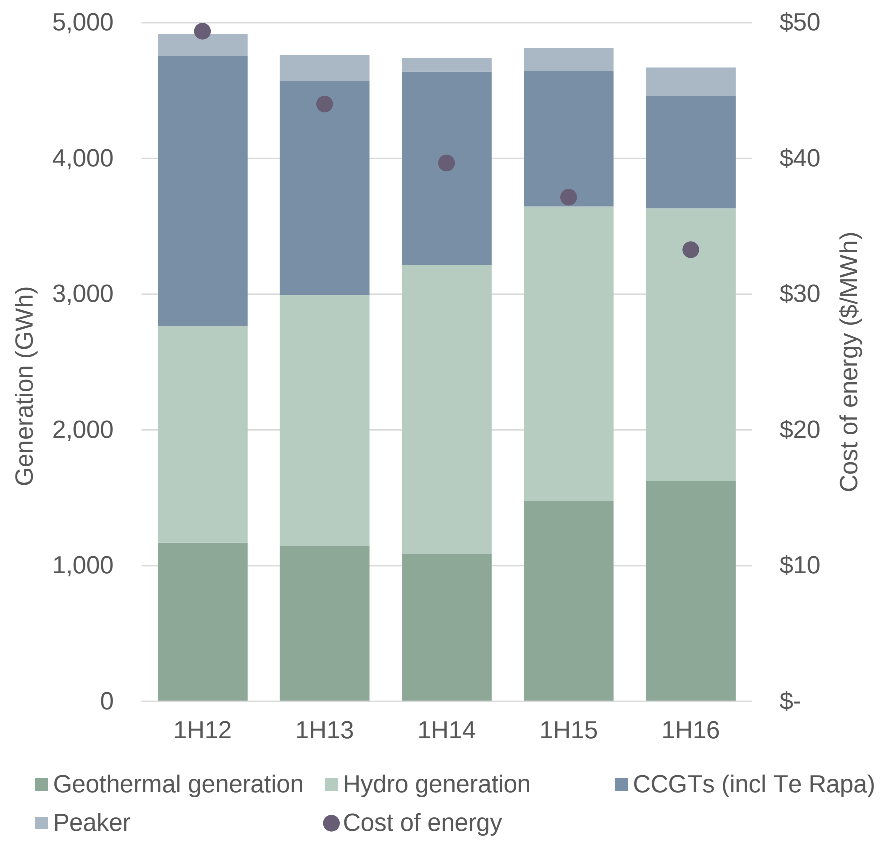
» Contact's 14 year contract with Meridian supports the continued operation of Tiwai

Thermal plant closures have restored balance following a period of reduced risk as new renewable generation was added

Hydro risk curve 2010 - 2016[1]



Generation by source



[1] Source: Transpower. The chart shows the required level of hydro storage to avoid an energy shortage in a dry year. The 1% curve represents the level required for there to be a less than 1% chance of shortage

Contact is confident that the industry will resolve North Island capacity uncertainty

If Huntly closes, North Island capacity is required irrespective of Tiwai plans

- » North Island capacity assessments show a shortfall from 2019 if Huntly closes. These assessments assume the HVDC is flowing North at maximum capacity and so Tiwai's ongoing operation is irrelevant
- » North Island capacity can be delivered through the retention of Huntly, the construction of new capacity, and/or the expansion of transmission capacity
- » Flexible generation is required long term in all scenarios
  - Ahuroa is important in a market where gas supply is getting less flexible
  - Contact has consented thermal options should these prove the best solution

North Island supply and demand currently balanced with additional capacity required

Source: Transpower

Regulatory momentum continues to focus on ensuring the correct incentives are in place

» **Transmission pricing** appears to be approaching a sensible "beneficiary" pays outcome

» **Distribution charging** consultation commenced

- Current pricing principles approach to distribution pricing is not working
- Support a pricing structure that better reflects the cost of utilising the network
- The large number of distributors with differing pricing structures adds significant cost and complexity for retailers and customers

» Commerce Commission **input methodologies review** underway

- Amendments required due to the emergence of new technologies such as batteries and solar blurring the boundaries between distribution and retail

» **COP21** agreement on carbon reduction a positive outcome

- The ETS needs to motivate change which will be difficult to achieve through stationary energy alone given the high level of renewable generation
- The price of carbon needs to reflect the least cost abatement options on a global level, not just domestically

The voice of the customer is often absent in the regulatory process

» We have been active in helping establish the Electricity Retailers Association of New Zealand

» We will continue to promote transparency, simplicity and fairness with regulators and politicians

Safety, agility and efficiency will define Contact's culture and competitive advantage

Increasing our capacity to fail safely

» We continue to advance our cultural journey towards "generative", through an integrated safety improvement programme and on going visible and active leadership

» TRIFR improvement continues down 0.2 to 3.1

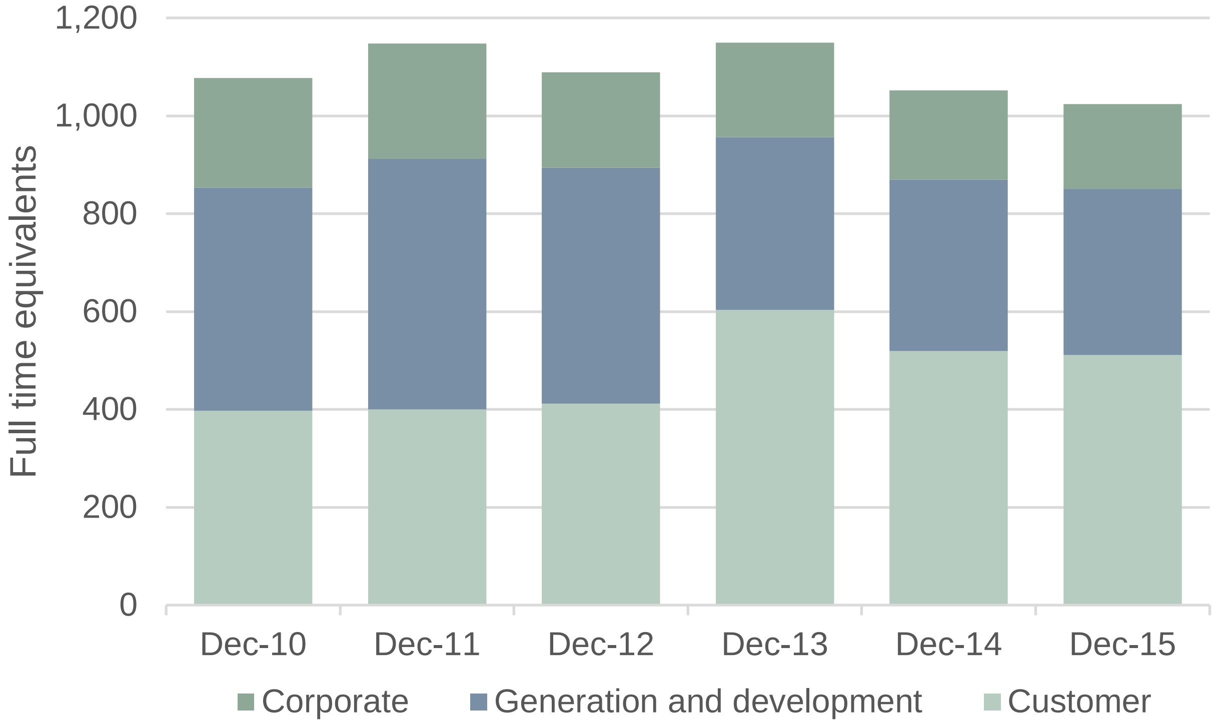
- over 1.6 million hours worked and 5 people hurt during our first half of the year, with 4 injuries being of low severity

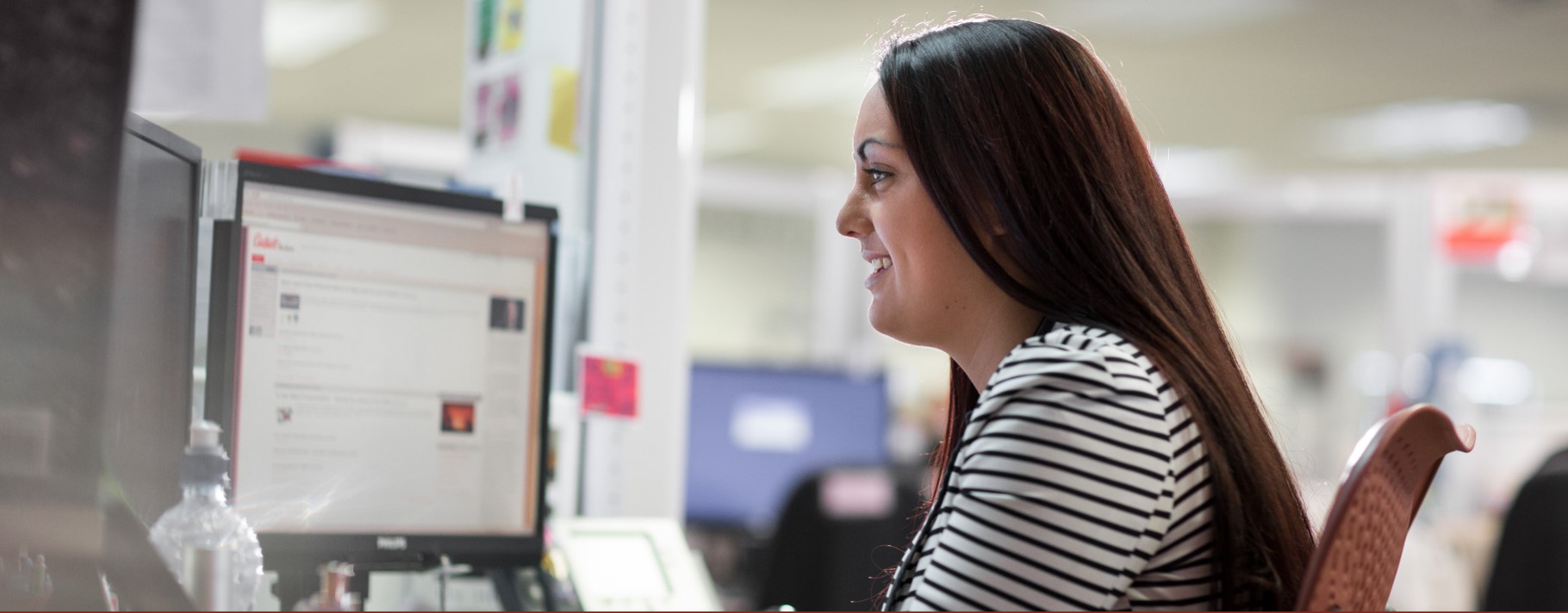
Building capability for a changing market

» New Customer structure reflecting our customer value chain complete

» Geothermal skills being maintained by providing consultancy services

Total permanent and fixed term employees





1H16 performance

Graham Cockroft

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1H16 performance highlights

($116m)
Loss for the period down from $51m profit predominantly due to impairments at Otahuhu and Taheke

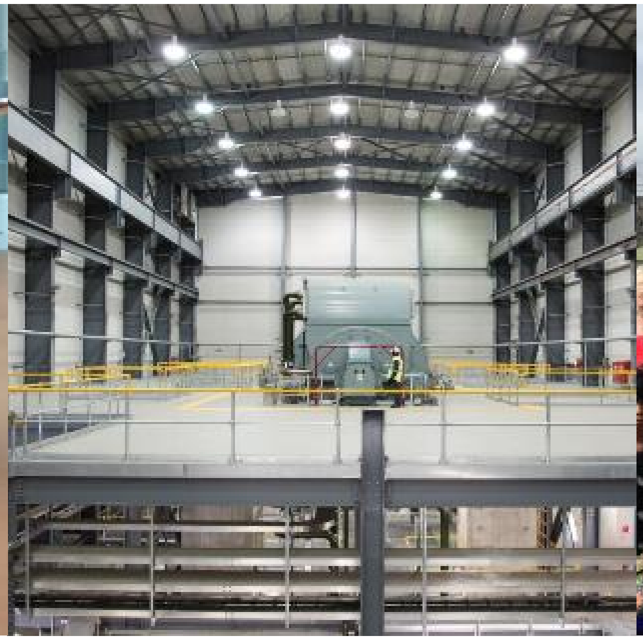
24%
Improvement in free cash flow

$62m
Share buyback completed

$254m
EBITDAF, down 1% from $257m

$82/MWh
Netback down $2/MWh with lower C&I sales and continued discounting in mass market

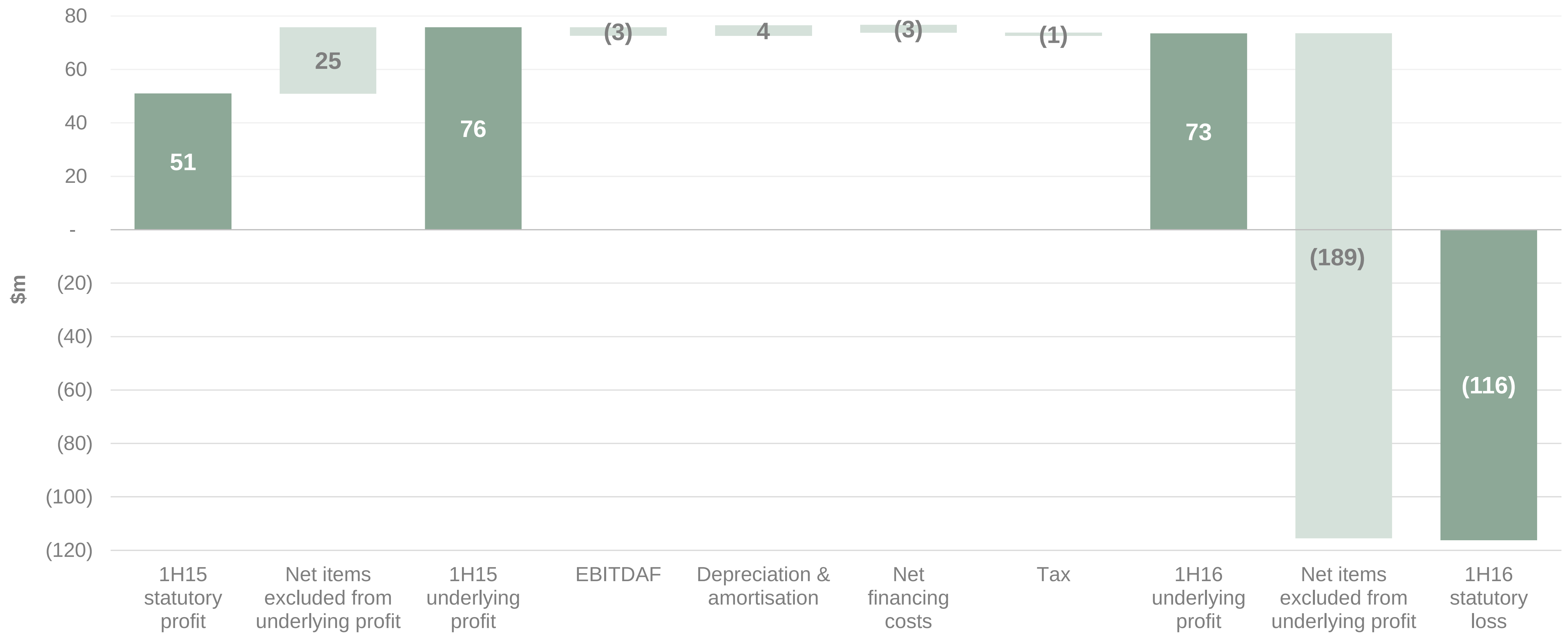
$33/MWh
Cost of energy improved $4/MWh with lower purchase volumes and improved gas costs



Statutory loss $116m due to Otahuhu and Taheke impairments

Underlying profit down 4% from $76m to $73m

Contact's statutory profit



- Depreciation and amortisation down $4m primarily driven by the Otahuhu closure. Total depreciation and amortisation for FY16 is expected to be between $195m and $200m
- Net financing costs up $3m due to increased debt following the special dividend in June 15
- Net items excluded from underlying profit primarily relate to Otahuhu closure ($223m), Taheke asset impairment ($35m), change in fair value of financial instruments ($9m) and transition costs of $5m, with a tax expense credit of $83m

1H16 profit is negatively impacted by $257m of impairments

Otahuhu thermal power station closure

» At the end of September 2015, the Otahuhu thermal power station was closed

» On 15 February 2016 Contact announced the unconditional sale of land and buildings for $30m
  - Payment spread over 2 years ($28m present value)
  - Proceeds from the Otahuhu plant and equipment sales in the 12 months after the sale will be shared equally between the purchaser and Contact

» At 31 December 2015, the carrying value of the land and buildings was impaired to its fair value and classified as an asset held for sale
  - » Impairment recognised was $222m plus $1m of closure costs
  - » The net impact on profit/(loss) for the period was $151m
  - » No value was attributed to the potential sale of plant and equipment in the next 12 months
  - » Excluded from underlying profit

Taheke geothermal resource impaired

» Between 2010 and 2014 Contact spent $35 million assessing the Taheke geothermal resource as a potential site for additional geothermal generation
  - Expenditure primarily related to the drilling and testing of four exploration wells

» A recent review concluded the asset should be impaired to nil as current market conditions mean the resource is unlikely to be developed in the foreseeable future
  - Impairment recognised was $35m
  - The net impact on profit/(loss) for the period was $25m
  - Excluded from underlying profit

» Contact continues to discuss options for developing the resource with joint venture partner Taheke 8C when market conditions warrant it
  - Future spend on maintaining the Taheke development option will be recognised as an operating expense

Margin pressure in mass market and lower C&I sales reduce EBITDAF

Integrated energy segment EBITDAF down $4m (2%) to $234m

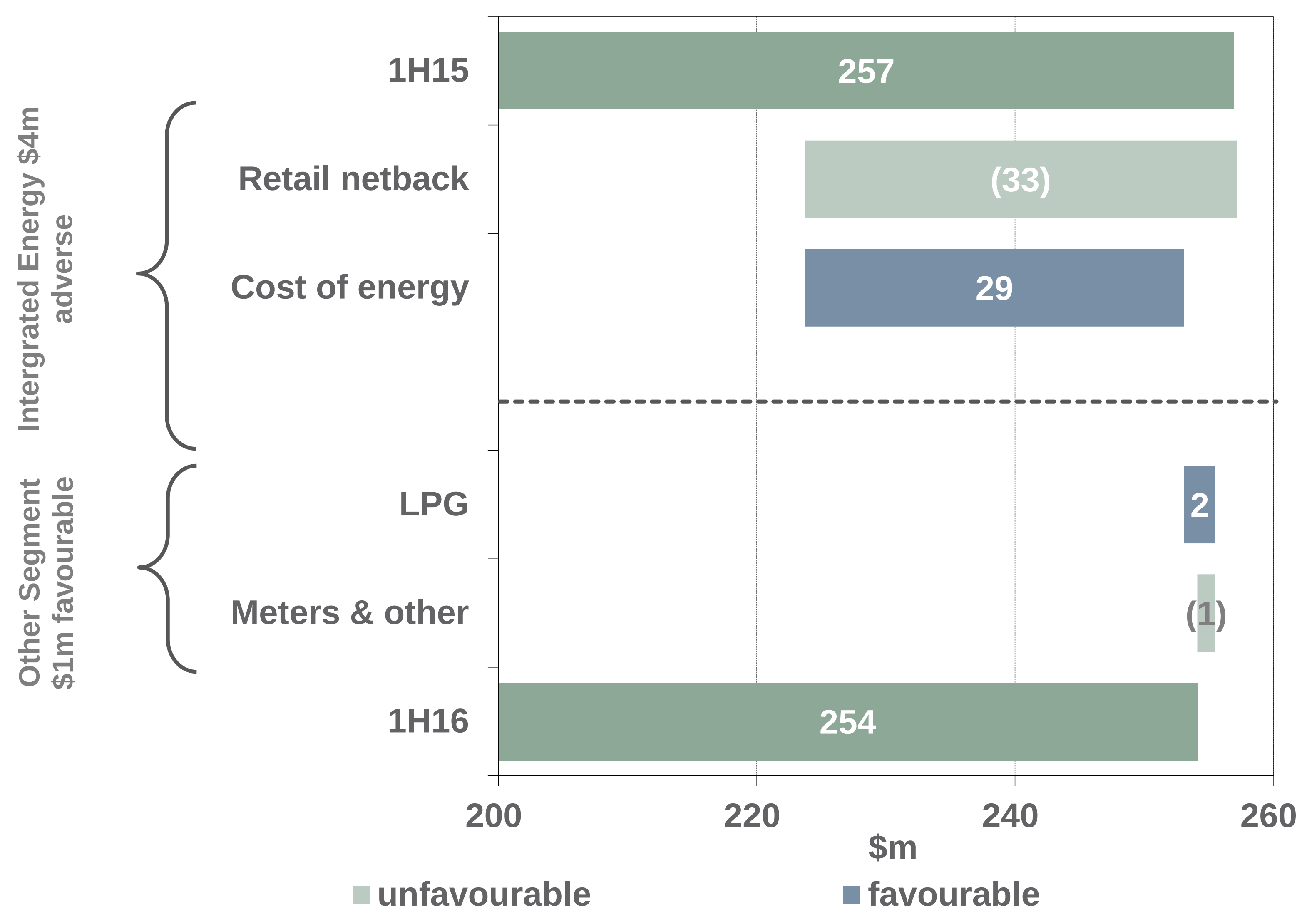
» **Netback** unfavourable $33m (8%) to $392m
- Volumes lower due primarily to reduced C&I sales (-$27m)
- Netback down driven by increased discounting and operating costs (-$15m)
- Improved steam sales

» **Cost of energy** favourable $29m (16%) to -$158m
- Lower retail purchases reducing thermal generation
- Lower gas and transmission unit costs
- Improved plant availability

Other segment EBITDAF increased $1m (5%) to $20m

- **LPG** favourable $2m due to lower product costs
- **Meters & Other** unfavourable $1m reflecting the continued transition to smart meters

EBITDAF Movement



Netback down $33m (8%) to $392m

Lower C&I sales and continued discounting in mass market

» 1H16 sales volume down 291GWh to 4,026 GWh
- MM volumes reasonably stable, although average customer numbers down 10,000. Average usage per customer increased 2%
- C&I sales down 276 GWh driven by decision not to re-sign some lower priced customers

» Mass market electricity netback $8/MWh unfavourable
- Tariff down $9/MWh due to continued discounting in response to competition. The number of customers on non-standard tariff discounts increased from 65% at 31 December 2014 to 76% at 31 December 2015
- Network costs reduced by $3/MWh with one-off costs in 1H15 not recurring to offset notified increases in 1H16
- Operating costs increased due to bad debts and ICT costs

» C&I electricity netback up $1/MWh reflecting expiry of lower priced contracts

» Retail gas volumes and netback largely stable

» Steam revenue up $4m due to commencement of Te Rapa supply agreement

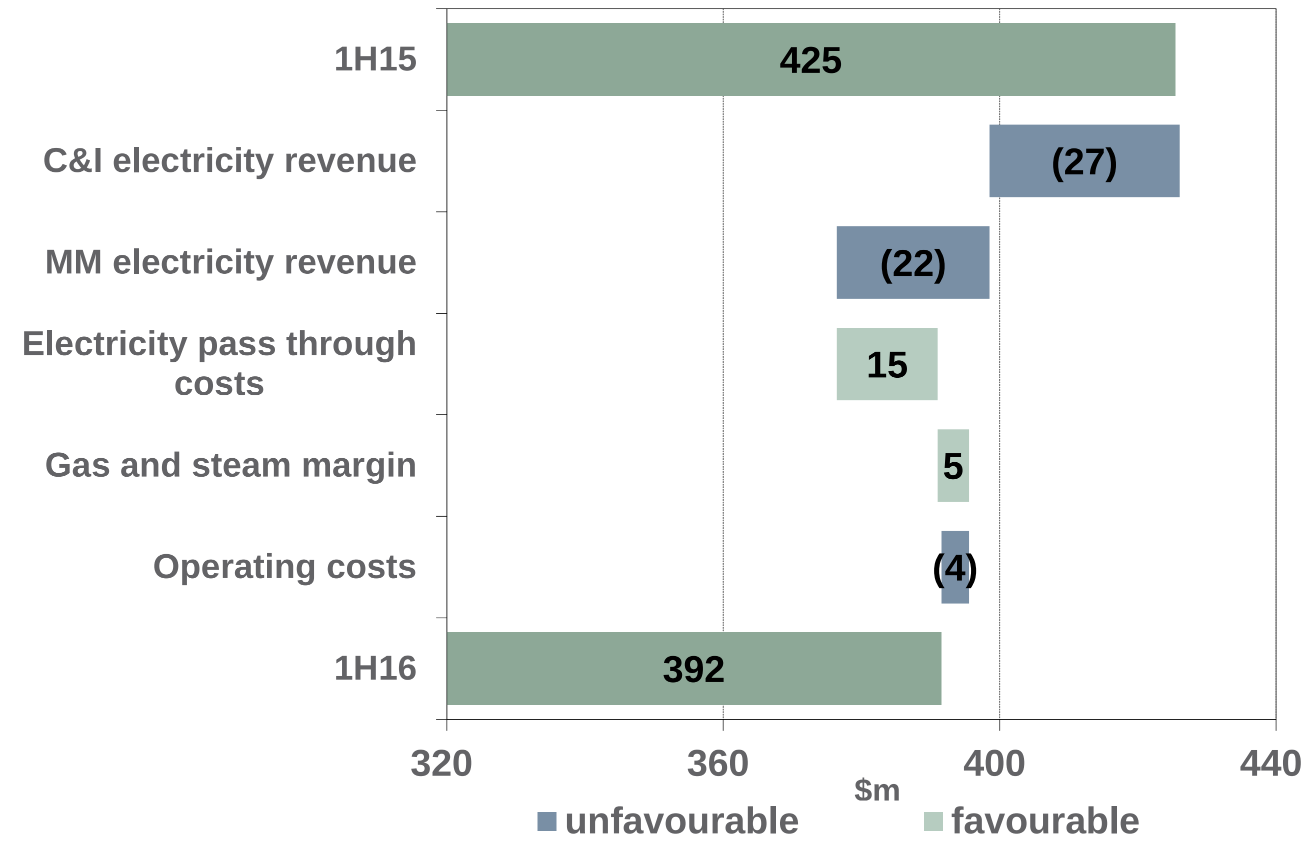
4,026 GWh

Electricity sales volume, down 7% due to lower C&I sales

$82/MWh

Netback down $2/MWh due to continued price pressure in mass market

Netback movement



Improvements are being sought across all retail metrics

Improving acquisitions and service but churn remains above market

	1H15	2H15	1H16
Net promoter score	n/a	-2%	-4%
Average time to answer (seconds)	220	268	222
Churn (variance to market)	+2.9%	-0.2%	+1.4%
% of residential customers on non-10% PPD discount	63%	70%	76%
Saves/ win backs	2,273	2,257	3,362
Cost to serve per customer	$113	$124	$128
Average late bills >30 days	12,000	5,000	2,000
Bad and doubtful debt as a % of revenue	0.55%	0.70%	0.67%

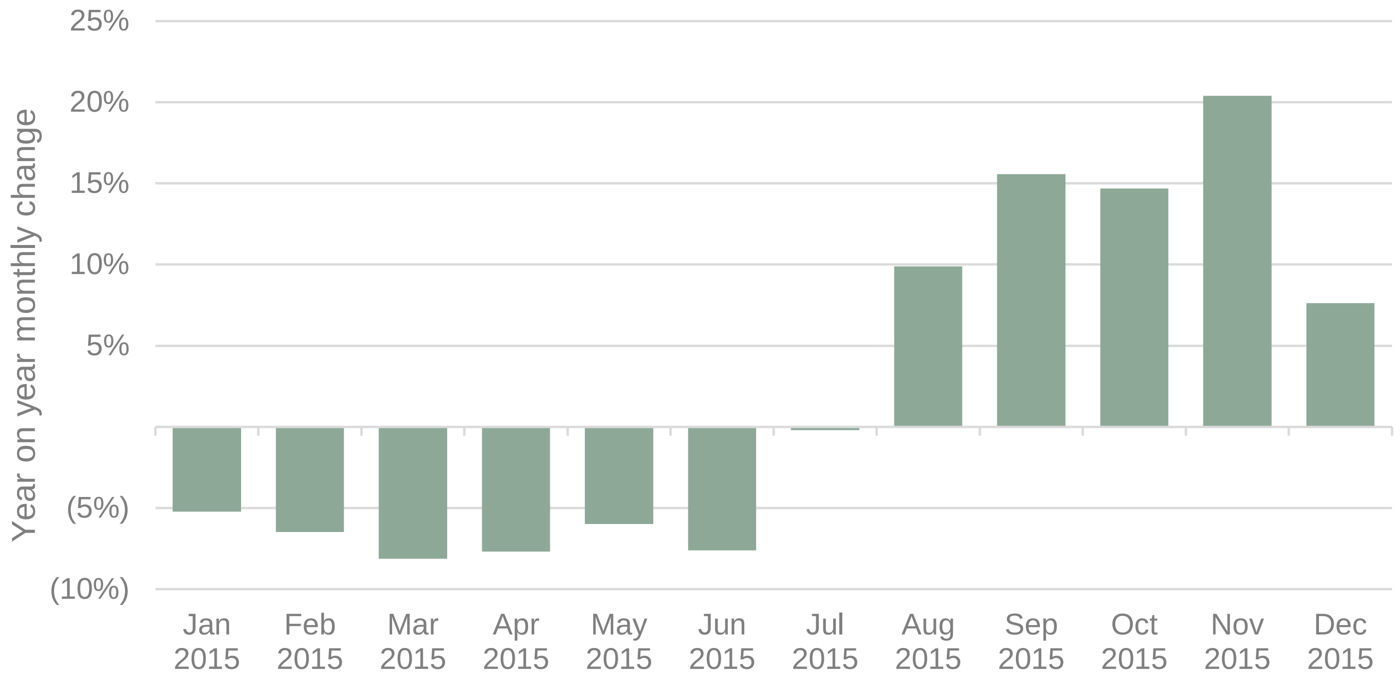
49%

Increase in saves and win backs

76%

Of residential electricity customers on non-standard prompt payment discounts

Year on year change in electricity and gas acquisitions



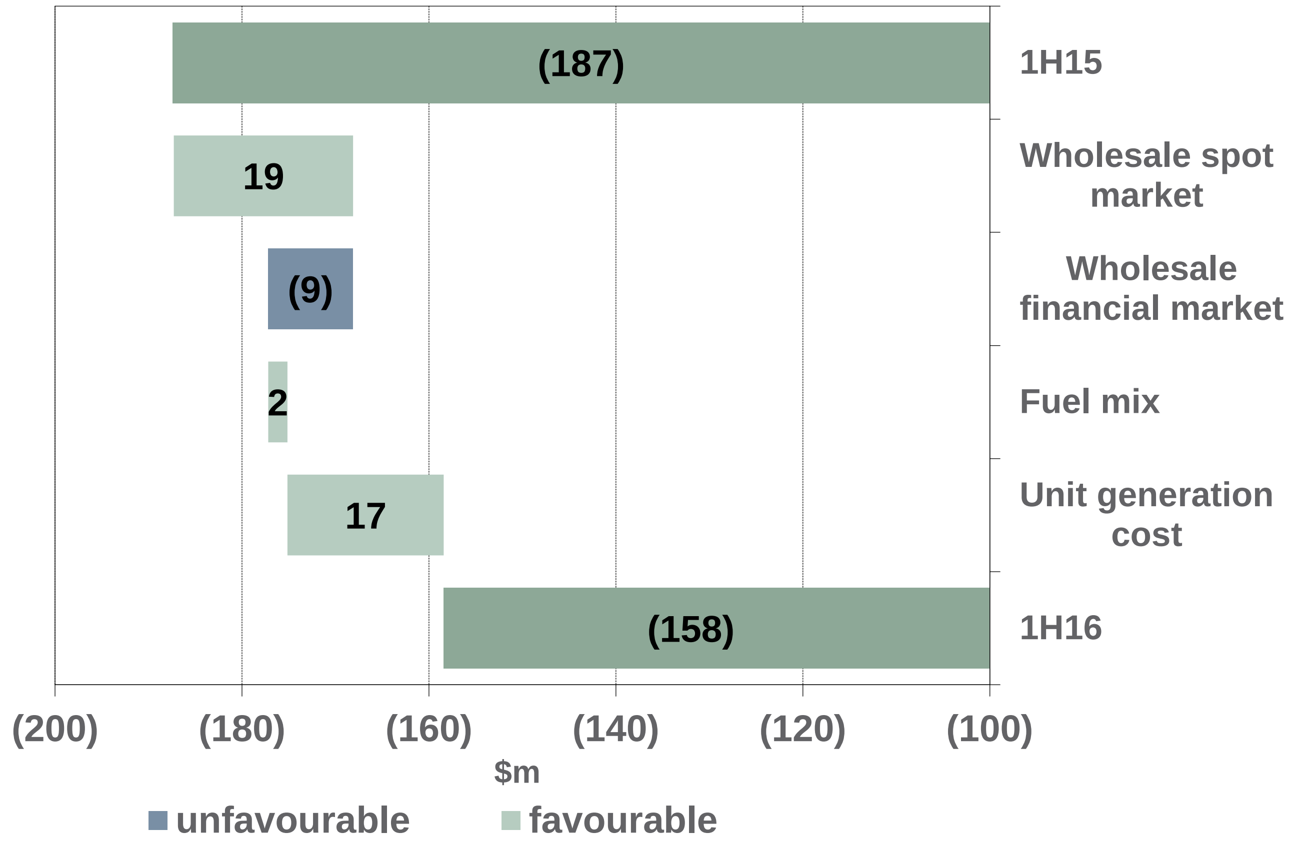
» Net electricity and gas customer losses in 1H16 were 10,000

Cost of energy improved $29m (16%) to -$158m

Lower purchase volumes and improved gas costs reduced cost of energy by $4/MWh

- Wholesale spot market up $19m
  - Retail purchases down 324 GWh on the back of lower retail volumes, resulting in an additional 186 GWh merchant sales
- Wholesale financial market unfavourable $9m due to lower frequency keeping revenue as a result of increased supply being offered and lower CfD returns
- Fuel mix favourable $2m with renewable generation increasing from 76% to 78%
  - Thermal generation down 130 GWh reducing gas purchases by 2 PJ
  - Geothermal generation increased 144 GWh to offset reduced hydro volume despite unplanned Te Mihi outage
  - Plant availability improved from 82% in 1H15 to 91% in 1H16
- Unit generation cost favourable $17m with lower unit gas costs and lower gas transmission and operating costs due to the closure of Otahuhu more than offsetting increased carbon costs and plant maintenance expenses
  - 2 PJ net gas storage extractions support contracted volume and reduced stored volume to 9.3 PJ

Cost of energy movement



78%

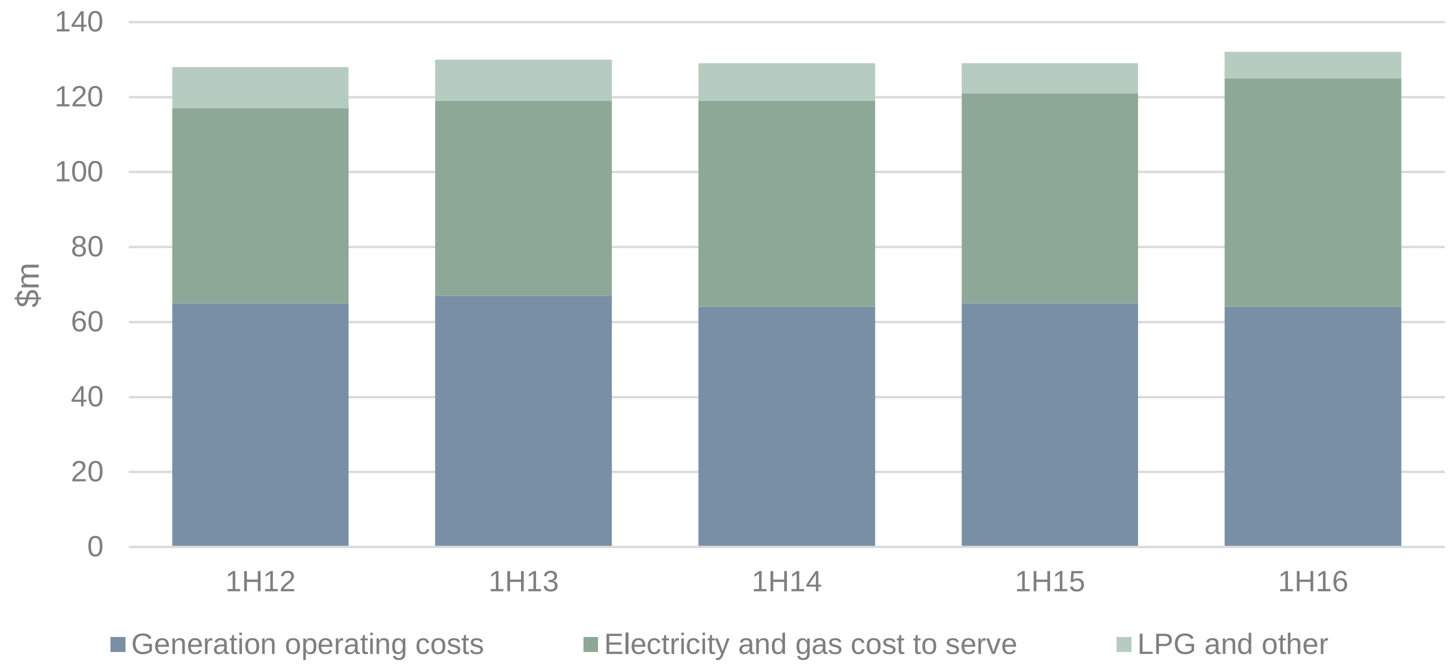
Renewable generation up from 76% in 1H15

4,189 GWh

324 GWh decrease in electricity purchase volumes

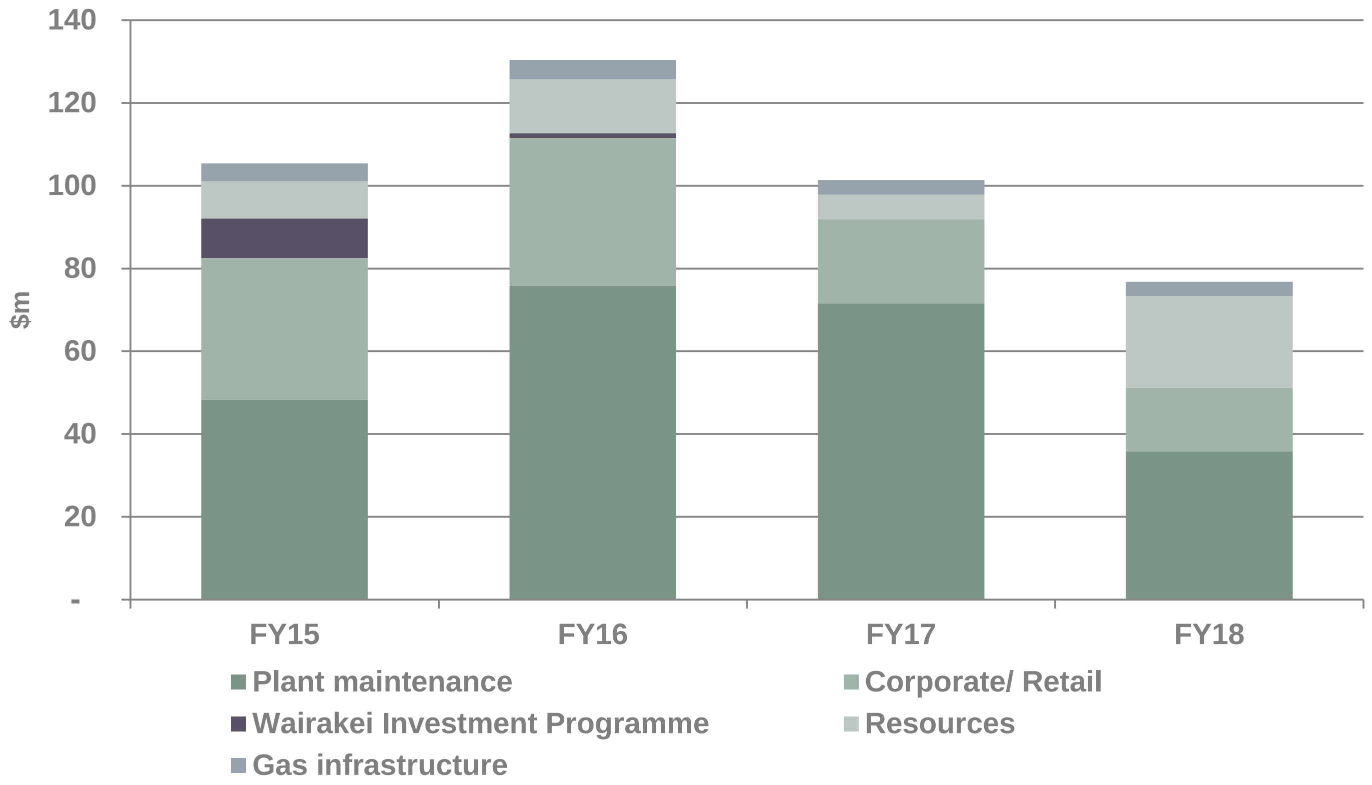
Focus continues across the business on allocation of both operating and capital expenditure

Other operating expenses



- » 1H16 other operating expenses $3m higher than 1H15
  - Labour costs up primarily due to recognising a full year of LTI cost in August following Origin sale
- » 1H16 other operating expenses $2m lower than 2H15
  - Initial signs of bad debt improvement
  - Corporate costs relating to international geothermal review not repeated
  - Savings from Otahuhu closure offset by increased repairs and maintenance costs

Capital expenditure



- » 1H16 capex $71m, up $23m from 1H15 due to the recognition of the Stratford super core as a capital expense and initial payments relating to the TCC inspection outage planned for February 2017
- » ICT capex increases in FY16/17 as data centre move and full Origin separation completed
- » Improved geothermal performance following 1H16 outages supports reduced resources capex forecast from FY18 with no new wells expected pre-2020

Free cash flow up 24%

Lower tax paid is partially offset by higher stay in business capex

» Free cash flow measures the cash generating performance of the business and represents cash available to fund distributions to shareholders and growth capital expenditure

$m	6 months ended 31 December 2015	6 months ended 31 December 2014	Variance $m	Variance %
EBITDAF	**254**	**257**	**(3)**	**(1%)**
Change in working capital	26	23	3	13%
Tax paid	8	(35)	43	(123%)
Significant items	9	8	1	13%
Other	(5)	(17)	12	(71%)
Operating cash flows	**292**	**236**	**56**	**24%**
Stay in business capital expenditure	(46)	(26)	(20)	77%
Proceeds from asset sales	3	1	2	200%
Net interest paid	(46)	(47)	1	(2%)
Free cash flow	**203**	**164**	**39**	**24%**

» The positive cash flow from the increased use of stored gas rather than contract gas in 1H16 was offset by unfavourable retail debtor movements due to one-off collection of late bills in 1H15

» Tax paid reduced due to a tax refund relating to FY15 tax payments and tax benefits from Otahuhu closure

» Partially offset by higher stay in business capital expenditure driven by payments relating to the planned refurbishment of the Taranaki combined-cycle power station

The efficient return of free cash flow to shareholders remains a priority

$62m share buyback completed in 1H16

» 15 cps dividend paid in September 2015

» Share buyback programme announced 15 October to acquire up to $100m of shares
  - 12.5m shares purchased to date at a cost of $62m
  - Expect to complete remainder of the programme in FY16

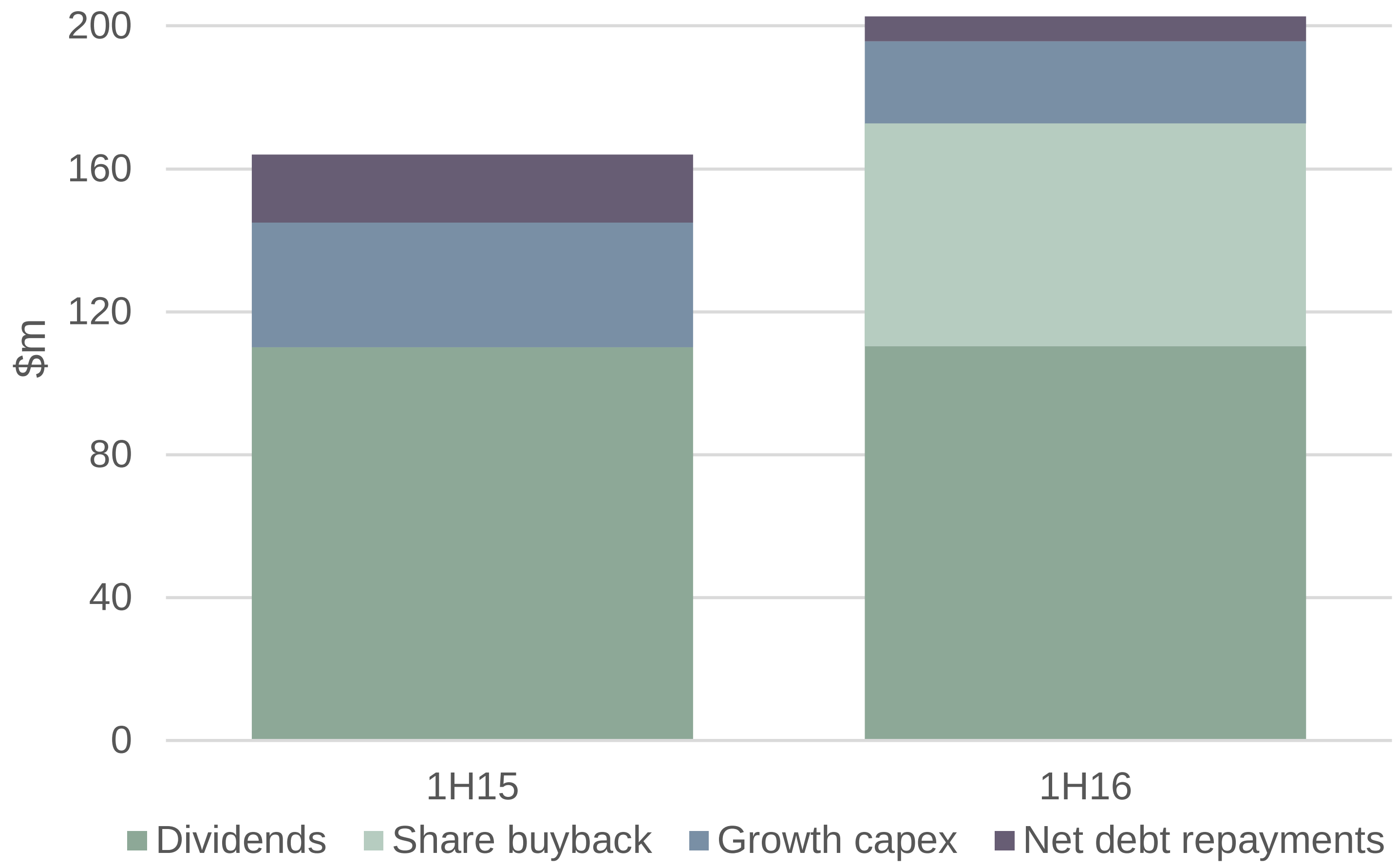
» Face value of net borrowings unchanged from 30 June 2015 as surplus cash was applied to the buyback programme. Gearing increased by 2% to 36.6%
  - Continued commitment to investment grade credit rating with buyback preferred distribution method for additional free cash flow

Interim dividend for 1H16 held stable at 11 cents per share

» 7 cents per share imputed reflecting continued low imputation credit balance following payment of fully imputed special dividend in June 2015

» Record date 2 March 2016; payment date 23 March 2016
  - The NZD/AUD exchange rate used for the payment of Australian dollar dividends will be set in early March

Uses of free cash flow



Summary

Dennis Barnes

Outlook

» Strong cash flow expected to continue

» Second half earnings expected to be similar to prior year

» Expect to complete remainder of current $100m share buyback programme in FY16

» No change in distribution policy with dividends to be imputed dependent on the availability of imputation credits

» Continued sales, service and operational improvement in our customer business

Summary

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Supporting material

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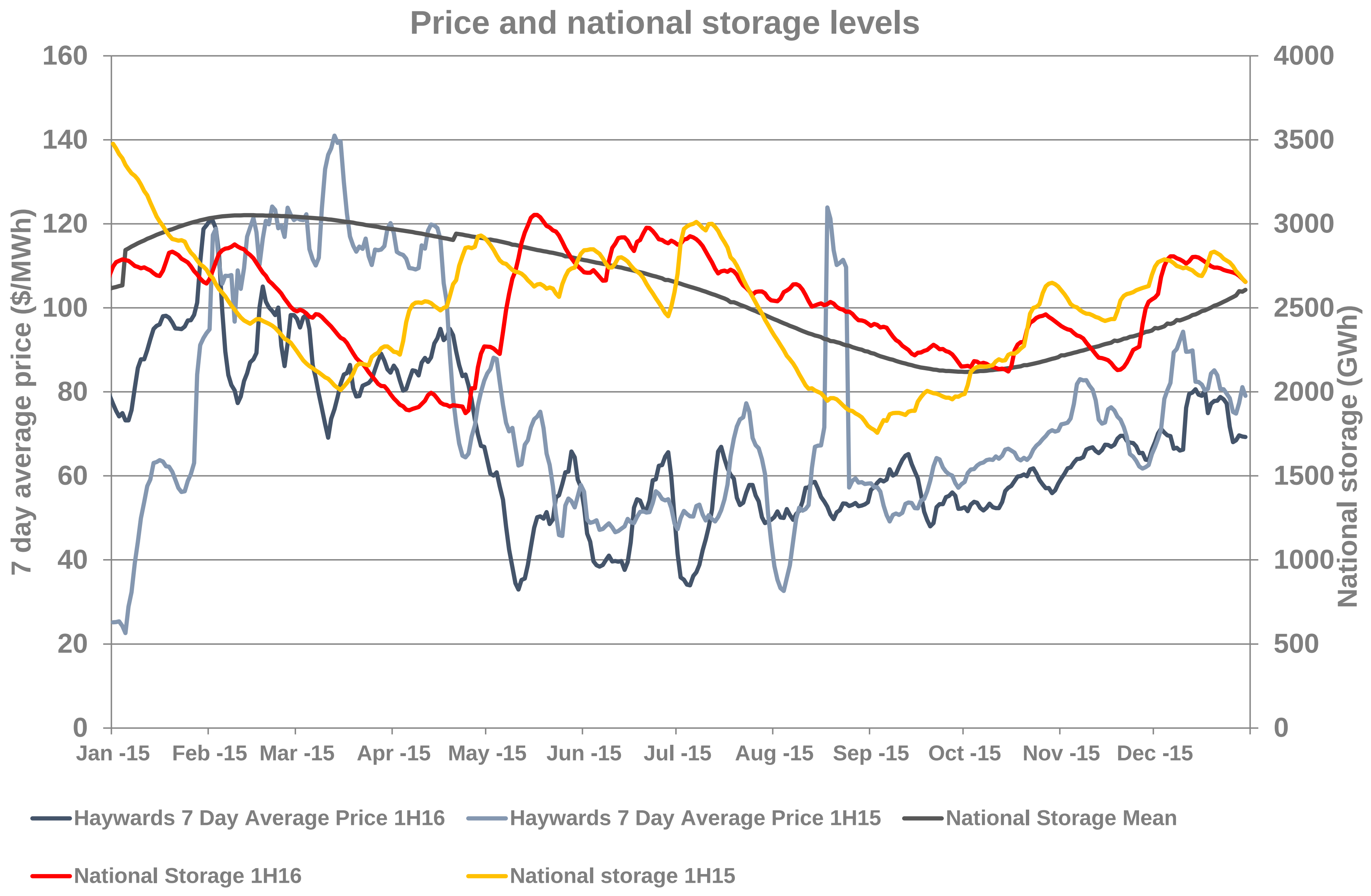
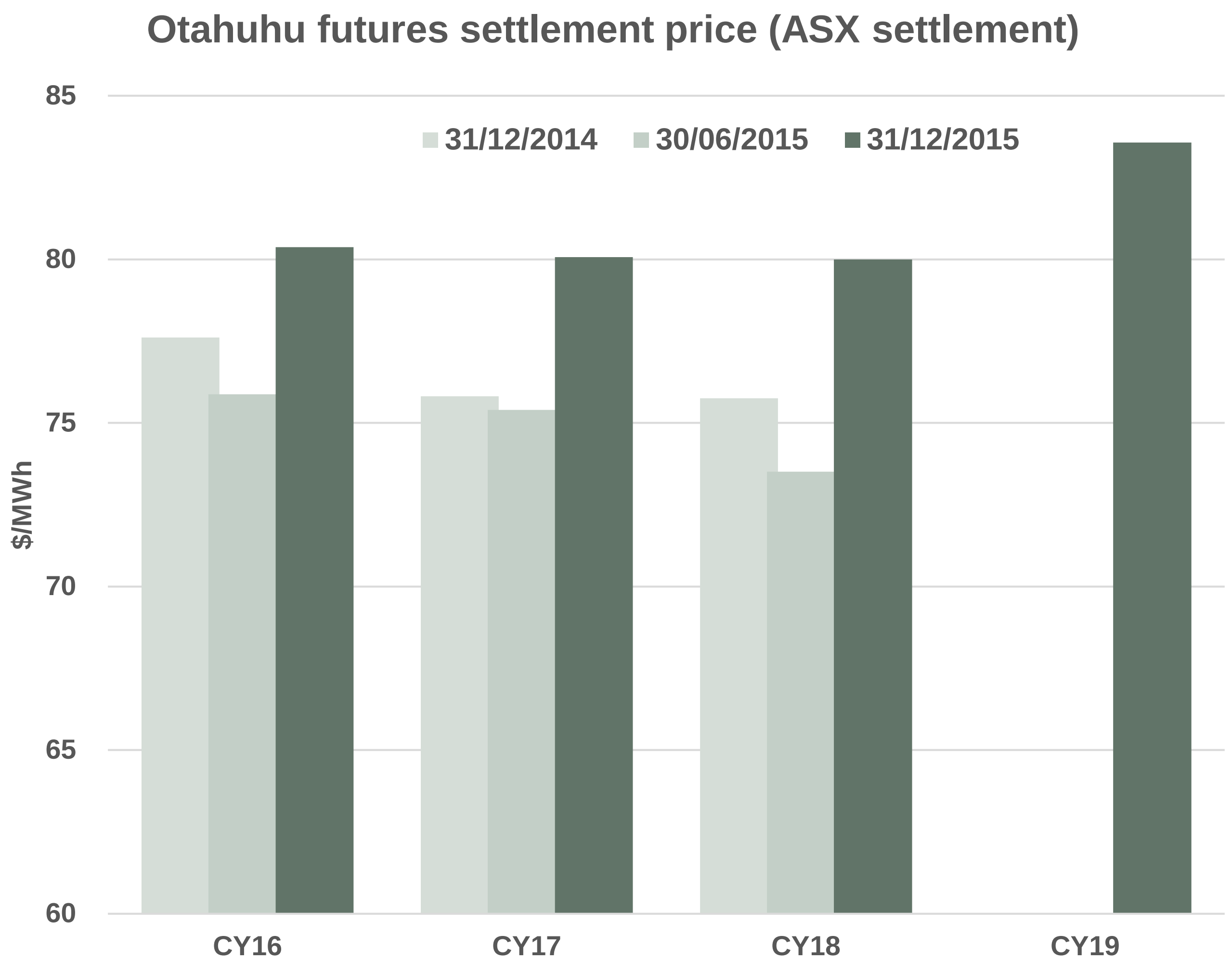
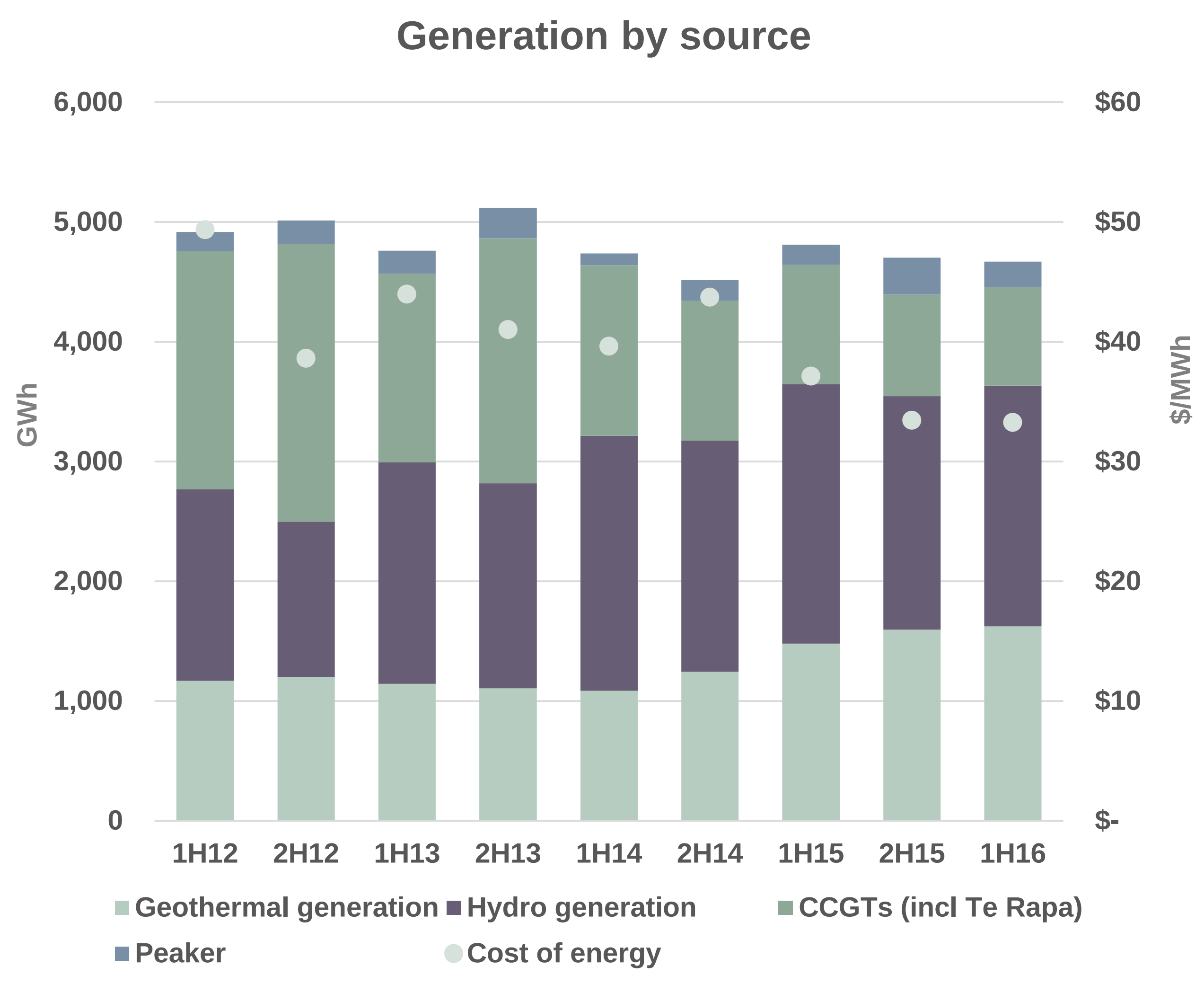
Electricity market conditions





Thermal generation continues to decline supported by improved geothermal availability in 1H16



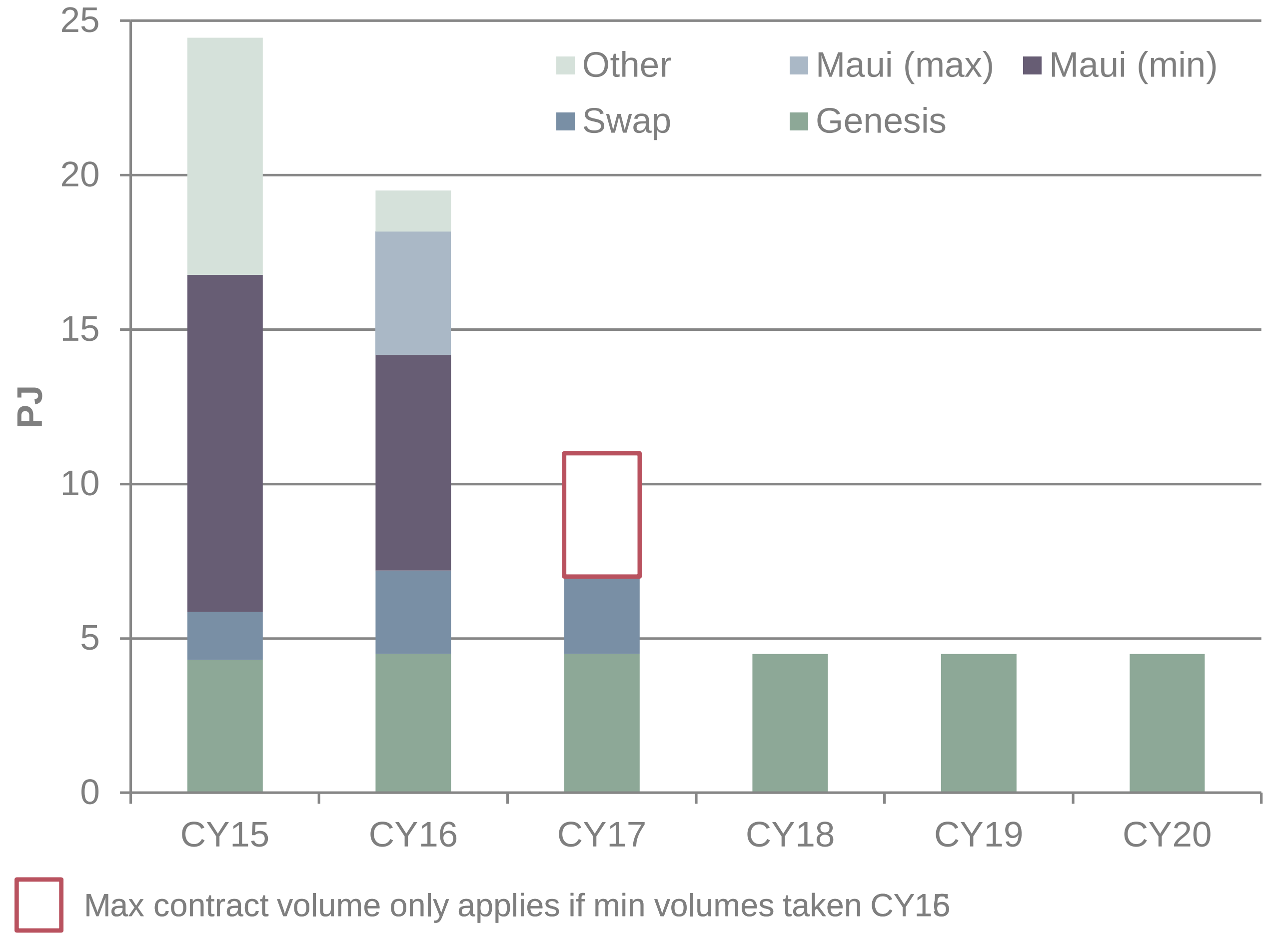
	Gross output (MW)	Plant availability[1] 1H16 (%)	Plant availability[1] 1H15 (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
Hydro	752	84%	89%	61%	2,010	56	112
Geothermal	431	91%	75%	85%	1,623	59	95
CCGTs (incl Te Rapa)*	601	97%	75%	31%	826	54	44
Peakers (incl Whirinaki)	355	93%	90%	13%	210	89	19
Total	**2,139**	**91%**	**82%**	**49%**	**4,669**	**58**	**270**

[1] Measures reliability of our generation plants

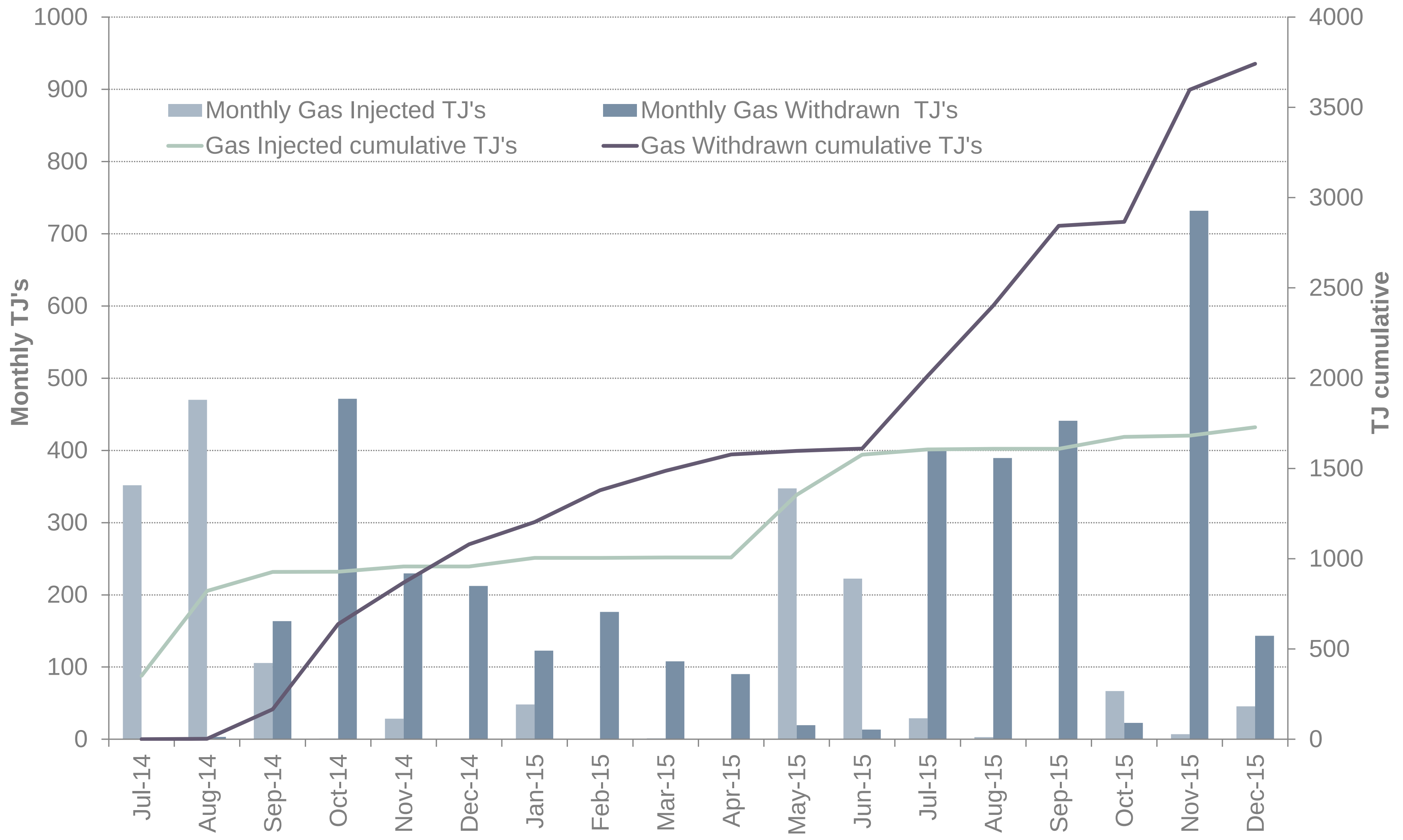
* Otahuhu last day of operation 21 September

No change in contracted gas volumes with support provided by gas storage

Contracted gas volumes

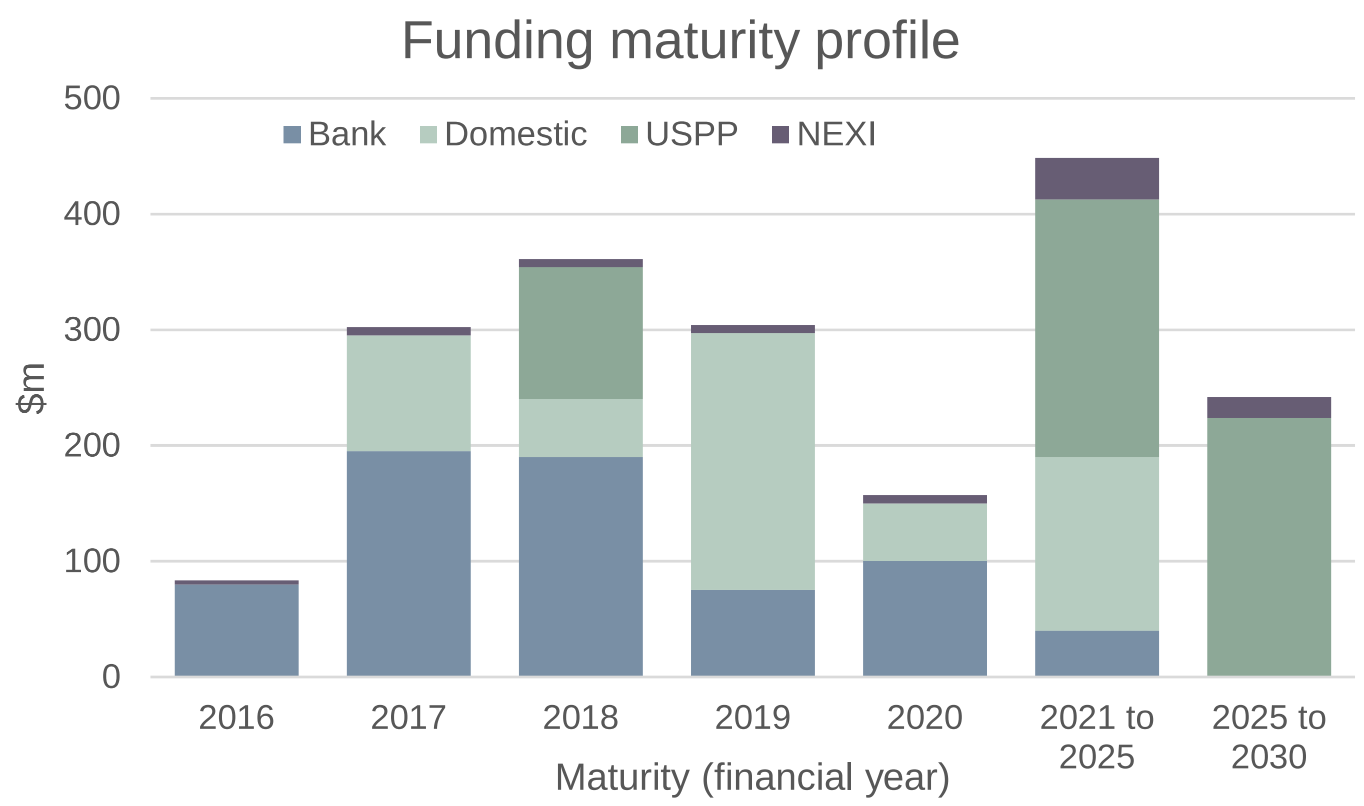


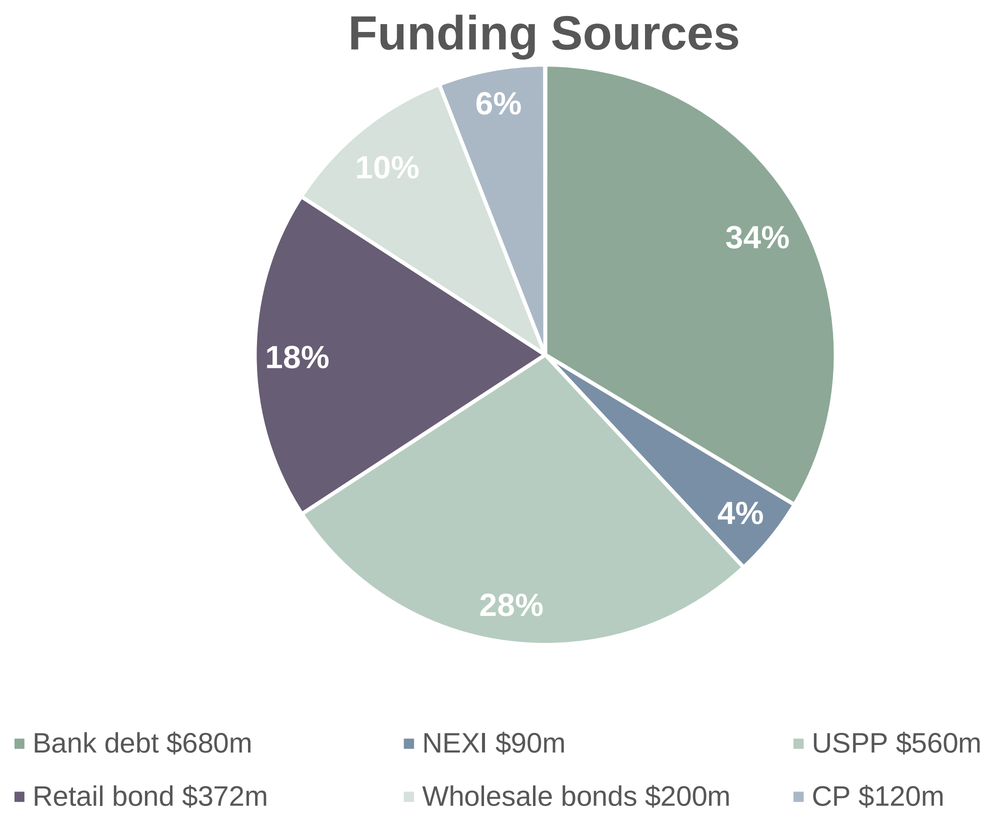
Ahuroa gas storage monthly injections and extractions



» Working volume in Ahuroa gas storage at 31 December 2015 was 9.3PJ

Contact's balance sheet is supported by a robust funding portfolio





» Contact benefits from a funding portfolio that is flexible, efficient, diverse and has a manageable maturity profile:
- Face value of net debt remained unchanged from 30 June 2015
- $680m total committed bank facilities ($342m drawn and $120m commercial paper)
- Weighted average tenor of funding facilities 4.3 years
- Since FY15 balance date, $375m of refinancing has been secured via additional bank facilities ($80m), long term USPP note issuance (US$100m / NZ$145m) and a six year retail bond ($150m)

» Average weighted cost of borrowings down 0.5% from 1H15 to 5.6%

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
- The CEO monitors EBITDAF as a key indicator of Contact's performance at segment and group levels, and believes it assists investors to understand the performance of the core operations of the business
- Reconciliation of EBITDAF to statutory profit/(loss):

$m	6 months ended 31 December 2015	6 months ended 31 December 2014	Variance $m	Variance %
EBITDAF	**254**	**257**	**(3)**	**(1%)**
Depreciation and amortisation	(97)	(101)	4	(4%)
Change in fair value of financial instruments	(9)	(18)	9	(49%)
Other significant items	(263)	(17)	(246)	1445%
Net interest expense	(52)	(49)	(3)	7%
Tax expense	51	(21)	72	(343%)
Profit/(Loss)	**(116)**	**51**	**(167)**	**328%**

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

Explanation of reconciliation between EBITDAF and profit

» The adjustments from EBITDAF to reported profit/(loss) are as follows:

- Depreciation and amortisation: Costs decreased by $4m (4%) reflecting the closure of Otahuhu power station
- Change in fair value of financial instruments: the balance of ($9m) reflecting an unfavourable movement in interest rate derivatives over the period
- Other significant items: these are detailed on the next two slides
- Net interest expense increased $3m (6%) to $52 million in 1H16 due to funding related to the special dividend distributed at the end of FY15. This is partially offset by lower average interest rates reflecting the success of the 2015 refinancing programme
- Tax expense for 1H16 is a $51m credit compared to $21m expense for 1H15 due to lower profit and impairment of Otahuhu and Taheke. Tax expense represents an effective tax rate of 31% compared to 30% in 1H16. The variance from the statutory rate of 28% is a result of tax expense credits relating to Otahuhu gain on sale of land not being taxable.

Non-GAAP profit measure – underlying profit

» The CEO monitors underlying profit and believes it assists investors to understand the ongoing performance of the business

» Underlying profit is calculated by adjusting reported profit/(loss) for the year for significant items that do not reflect Contact's ongoing performance

» 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:

	6 months ended	6 months ended	Variance	
$m	**31 December 2015**	**31 December 2014**	**$m**	**%**
Profit/(Loss)	**(116)**	**51**	**(167)**	**(328%)**
Change in fair value of financial instruments	9	18	(9)	(49%)
Transition costs	5	17	(12)	(70%)
Asset impairments	35	-	35	100%
Otahuhu closure	223	-	223	100%
Tax on items excluded from underlying profit	(83)	(10)	(73)	733%
Underlying profit	**73**	**76**	**(3)**	**(3%)**

Explanation of reconciliation from reported profit to underlying profit

» The adjustments from reported profit to underlying profit are as follows:

- Change in fair value of financial instruments: Movements in the valuation of interest rate derivatives and electricity price derivatives that are not hedge accounted, and the effect of credit risk on hedged debt
- Otahuhu thermal power station closure: At the end of September 2015, the Otahuhu thermal power station was closed. At 31 December 2015, the carrying value of the land and buildings was impaired to its fair value and classified as an asset held for sale in the Statement of Financial Position. Subsequent to the end of the reporting period, the thermal power station site was sold
- Asset impairments: The expenditure on Contact's development of the Taheke geothermal resource was impaired to nil as current market conditions mean the resource is unlikely to be developed in the foreseeable future
- Transition costs:
  - Origin's sale of their majority shareholding in August 2015 ($2 million) comprising ASX listing, incremental share-based compensation expense and other transaction costs
  - The Retail Transformation project and associated activities in the Retail business ($3m) comprising mainly temporary staffing and infrastructure costs

Integrated Energy segment

Integrated energy segment $m	6 months ended 31 December 2015	6 months ended 31 December 2014	Variance $m	 %
Mass market electricity	481	503	(22)	(4%)
Commercial and industrial electricity	249	276	(27)	(10%)
Retail gas	35	34	1	3%
Steam	16	12	4	33%
Total revenue	**781**	**825**	**(44)**	**(5%)**
Cost of energy	(158)	(187)	29	(16%)
Electricity networks, levies & meter costs	(310)	(326)	16	(5%)
Gas networks, levies & meter costs	(18)	(18)	-	0%
Total cost of goods sold	**(486)**	**(531)**	**45**	**(8%)**
Electricity and gas cost to serve	(61)	(56)	(5)	9%
EBITDAF	**234**	**238**	**(4)**	**(2%)**
Mass market electricity sales (GWh)	2,052	2,067	(15)	(1%)
Commercial & industrial electricity sales (GWh)	1,974	2,250	(276)	(12%)
Retail gas sales (GWh)	377	367	10	3%
Steam sales (GWh)	377	376	1	0%
Total retail sales (GWh)	**4,780**	**5,060**	**(280)**	**(6%)**
Average electricity sales price ($/MWH)	181.29	180.56	0.73	0%
Electricity direct pass through costs ($/MWh)	(77.02)	(75.21)	(1.81)	2%
Electricity and gas cost to serve ($/MWh)	(13.75)	(12.07)	(1.68)	14%
Netback ($/MWh)	81.92	84.19	(2.27)	(3%)
Actual electricity line losses (%)	5%	6%	(1%)	(17%)
Retail gas sales (PJ)	1.3	1.3	-	0%
Electricity customer numbers (closing)	421,000	432,000	(11,000)	(3%)
Retail gas customer numbers (closing)	60,500	61,500	(1,000)	(2%)

Cost of Energy

Cost of energy $m	6 months ended 31 December 2015	6 months ended 31 December 2014	Variance $m	 %
Wholesale electricity revenue	276	335	(59)	(18%)
Wholesale gas revenue	1	12	(11)	(92%)
Te Mihi compensation	2	1	1	100%
Total wholesale revenue	**279**	**348**	**(69)**	**(20%)**
Electricity purchases	(262)	(324)	62	(19%)
Other purchase costs	(1)	(3)	2	(67%)
Electricity transmission & levies	(20)	(22)	2	(9%)
Gas purchases	(78)	(107)	29	(27%)
Gas transmission & levies	(8)	(13)	5	(38%)
Emission costs	(4)	(1)	(3)	300%
Total direct costs	**(373)**	**(470)**	**97**	**(21%)**
Generation operating costs	(64)	(65)	1	(2%)
Cost of energy	**(158)**	**(187)**	**29**	**(16%)**
Thermal generation (GWh)	1,036	1,165	(129)	(11%)
Geothermal generation(GWh)	1,623	1,479	144	10%
Hydro generation (GWh)	2,010	2,168	(158)	(7%)
Spot market generation (GWh)	**4,669**	**4,812**	**(143)**	**(3%)**
Spot electricity purchases (GWh)	4,186	4,519	(333)	(7%)
CfD sales/(purchases) (GWh)	39	25	14	56%
GWAP ($/MWh)	57.80	66.32	(8.52)	(13%)
LWAP ($/MWh)	(62.29)	(71.71)	9.42	(13%)
LWAP/GWAP (%)	108%	108%	-	0%
Gas used in internal generation (PJ)	9.8	10.9	(1.1)	(10%)
Wholesale gas sales (PJ)	0.1	1.3	(1.2)	(92%)
Gas storage net movement (PJ)	(2.0)	(0.1)	(1.9)	1900%
Unit generation costs ($MWh)	(35.24)	(38.67)	3.43	(9%)
Cost of energy ($MWh)	(33.27)	(37.13)	3.86	(10%)

Other segment

Other segment $m	6 months ended 31 December 2015	6 months ended 31 December 2014	Variance $m	Variance %
LPG revenue	63	63	-	0%
Meter leases revenue	2	2	-	0%
Other revenue	-	2	(2)	(100%)
Total other segment revenue	**65**	**67**	**(2)**	**(3%)**
LPG purchases	(38)	(40)	2	(5%)
Total direct costs	**(38)**	**(40)**	**2**	**(5%)**
Other operating costs	(7)	(8)	1	(13%)
EBITDAF	**20**	**19**	**1**	**5%**
LPG sales (tonnes)	37,379	37,440	(61)	(0%)
Customer number	72,500	68,000	4,500	7%