MARKET RELEASE
Date: 25 August 2015

Genesis Energy Limited (GNE): Strong result in challenging conditions

	Year ended 30 June 2015	Change year on year
EBITDAF[1]	$344.8 million	Up 12% from $307.8 million
Net Profit	$104.8 million	Up 113% from $49.2 million
Earnings per share	10.5 cents	Up 113% from 4.9 cents
Dividend per share	16.0 cents	Up 23% from 13.0 cents
Free cash flow[2]	$197.7 million	Up 22% from $161.8 million
Stay in business capital[3] **expenditure**	$43.6 million	Down 20% from $54.5 million

Against the backdrop of variable weather conditions, sustained retail competition, a subdued wholesale market and declining oil prices, Genesis Energy's diverse portfolio allowed it to post a strong financial result for the full year to the end of June 2015.

Earnings before finance expense, income tax, depreciation, depletion, amortisation, impairment, fair value changes and other gains and losses (EBITDAF) were $344.8 million, 12% higher than the $307.8 million attained in Financial Year 2014 (FY2014). Revenue grew to $2.1 billion from $2.0 billion in the previous year.

Genesis Energy's Chair, Dame Jenny Shipley, said that the Board of Directors was satisfied with the overall performance of the Company in what has been a challenging year. The Board of Directors also noted the higher than forecast Net Profit After Tax of $104.8 million, up 113% from $49 million in 2014, and confirmed that a final dividend of 8 cents per share will be paid on 16 October 2015, with a record date of 2 October 2015.

The Company's two retail brands, Genesis Energy and Energy Online, ended the year with customer connections stabilising at 636,676 (647,047 in FY2014) after sustained competition for customers from both traditional and new competitors. Retail gas volume and LPG sales were up 5.8% and 15%, respectively. Despite a 1.7% loss in customer accounts, the Customer Experience segment improved its earnings contribution to the bottom line through improved costs to serve and increased margin per customer.

---

[1] Earnings before finance expense, income tax, depreciation, depletion, amortisation, impairment, fair value changes and other gains and losses
[2] Free Cash Flow is EBITDAF, less finance expense, tax paid and stay in business capital expenditure.
[3] Stay in business capital expenditure is the capital expenditure required to maintain ongoing asset management and life-cycle maintenance of the Company's asset portfolio.

Genesis Energy's Chief Executive, Albert Brantley, said the Company continued to manage risk and maximise value from all of its generation assets.

While at times in the early part of the year the coal/gas fired Rankine Units at the Huntly Power Station ran regularly, they sat largely idle in May and June as the Company took advantage of lower wholesale spot prices, as well as purchasing hedges for less than fuel cost to meet its retail load.

Reflecting this continued decrease in utilisation of the Rankine Units over recent years, the Company recently announced that the Rankine Units would be permanently retired by December 2018, unless market conditions change significantly.

Total net debt (adjusted for foreign currency translation and fair value movements related to USD denominated borrowings) decreased 6% to $905.1 million as at 30 June 2015.

At $197.7 million, Free Cash Flow in FY2015 was 22% higher than a year ago. The key driver of this outcome was lower than expected 'stay in business' capital expenditure of $43.6 million.

Outlook

"We have set a clear objective for the Company as we move into 2016 and beyond. Our strategic direction focuses effort into developing new revenue streams from our core business activities, driving greater value from our operating practices and making energy services simple for our customers," Mr Brantley said.

The Company's recently announced retirement of the Rankine Units, and the early termination of the Solid Energy coal supply contract, continues to be a focus for the Company and will result in a reduction in operating expenditure and cost savings at the Huntly Power Station beginning to materialise well before their final retirement date in 2018.

Kupe continues to produce oil and gas at consistent rates. Currently output is approximately 10% above the base level. Although the low international oil prices are likely to have some impact on Kupe EBITDAF, current hedging in place for FY2016 covers 80% of the projected oil production at US$85.40 per barrel.

Genesis Energy expects to report FY2016 EBITDAF in line with that reported in FY2015, and to increase its total dividend declared in FY2016 in line with the Company's progressive dividend policy.

ENDS

For media enquiries, please contact:
Richard Gordon
Public Affairs Manager
Genesis Energy
P: 09 951 9280
M: 021 681 305

For investor relations enquiries, please contact:
Rodney Deacon
Group Manager Strategy and Investor Relations
Genesis Energy
P: 09 571 4970
M: 021 631 074

About Genesis Energy

Genesis Energy (NZX: GNE) is a diversified New Zealand energy company. It sells electricity, reticulated natural gas and LPG through its retail brands of Genesis Energy and Energy Online. It is New Zealand's largest energy retailer with around 637,000 customer accounts. The Company generates electricity from a diverse portfolio of thermal and renewable generation assets located in different parts of the country. Genesis Energy also has a 31% interest in the Kupe Joint Venture, which owns the Kupe Oil and Gas Field offshore of Taranaki, New Zealand. Genesis Energy had revenue of $NZ2.1 billion during the 12 months ended 30 June 2015. More information can be found at www.genesisenergy.co.nz genesis ENERGY | we're in it for you

Management Discussion of Financial Results for the 12 Months Ended 30 June 2015

Against the backdrop of variable weather conditions, sustained retail competition, a subdued wholesale market and declining oil prices, Genesis Energy's diverse portfolio allowed it to post a strong financial result for the full year to the end of June 2015.

Strategic Highlights:

- Signs of stabilisation in the customer numbers late in the year
- Major planned outage of Huntly Unit 5 in November to December 2014 completed
- Undertook a US Private Placement of debt securities in November 2014
- Responded to a sharp fall in Brent crude oil price by agreeing with Kupe Joint Venture partners to increase production from the Kupe field
- Retired second Huntly 250MW coal/gas Rankine unit in June 2015

Summary financial results

12 months ended 30 June	2015 $m	2014 $m	Change year on year
Revenue	**2,097.6**	**2,005.0**	5%
Total operating expenses[1]	1,752.8	1,697.2	3%
EBITDAF[2]	**344.8**	**307.8**	12%
Depreciation depletion & amortisation	155.7	156.7	-1%
Impairment	14.0	10.1	39%
Fair value change (gains)/losses	(32.1)	(0.4)	7081%
Other (gains)/losses	0.2	1.6	-87%
Earnings before interest and tax	**207.0**	**139.8**	48%
Net finance expense	66.7	68.2	-2%
Tax	35.5	22.4	58%
Net profit after tax	**104.8**	**49.2**	113%
Earnings per share (cents per share)	10.5	4.9	113%
Stay in business capital expenditure[3]	43.6	54.5	-20%
Free cash flow[4] (FCF)	**197.7**	**161.8**	22%
Dividends declared	160.0	130.0	23%
Dividends per share (cents per share)	**16.0**	**13.0**	23%
Dividends declared as a % of FCF	80.9%	80.4%	1%
Net debt[5]	**905.1**	**966.0**	-6%

[1] Includes cost of electricity purchases
[2] Earnings before net interest, tax, depreciation, amortisation, fair value changes and other gains and losses
[3] Stay in business capital expenditure relates to ongoing asset management and life-cycle maintenance and re-investment programme expenditure
[4] Free Cash Flow (FCF) is defined as EBITDAF less finance expense less income tax expense less stay in business capital expenditure
[5] Reported net debt of $937.2 million has been adjusted for $32.1 million of foreign currency translation and fair value movements related to USD denominated borrowings which have been fully hedged with cross currency interest rate swaps.

Genesis Energy's EBITDAF for the 12 months ended 30 June 2015 of $344.8 million was 12% above the EBITDAF reported in the last financial year, but 5% lower than the prospective financial information (PFI) forecast published in the Company's share offer prospectus. Performance compared to FY2014 was due to increased retail electricity and gas revenues, reduced corporate overheads, offset by lower oil and gas earnings.

Other key financial metrics of net profit after tax, capital expenditure, and free cash flow (FCF) in FY2015 were all better than the PFI forecasts.

Net profit of $104.8 million was significantly higher than the net profit of $49.2 million reported in FY2014 and 10% above the PFI forecast. In each case this was due mainly to a much higher than expected gain on fair value changes - which in turn was a result of lower than predicted wholesale electricity prices – and reduced finance expense.

As was the case in FY2014, the conversion of EBITDAF to FCF was particularly strong in FY2015. At $197.7 million, FCF in FY2015 was 22% higher than a year ago. The key driver of this outcome was a 20% reduction in stay in business capital expenditure from FY2014 to $43.6 million.

Cashflow

Cashflow: 12 months to 30 June ($m)	2015	2014	Change year on year
Net operating cashflow	318.5	303.9	5%
Net investing cashflow	-48.6	-82.9	-41%
Net financing cashflow	-272.2	-220.4	24%
Net increase (decrease) in cash	**-2.3**	**0.6**	-457%

Operating cashflow of $318.5 million was 5% ahead of last year, predominantly due to higher operating earnings, while net investing cash outflows of $48.6 million were 41% lower than last year due to the lower capital expenditure. Net financing cash outflows were 24% higher than in FY2014, reflecting the increased dividends paid in FY2015 and increased repayment of borrowings.

Liquidity and balance sheet:

Balance Sheet: As at 30 June ($m)	2015	2014	Change year on year
Cash and cash equivalents	21.0	23.3	-10%
Other current assets	325.5	334.0	-3%
Non-current assets	3,181.5	3,272.1	-3%
Total assets	**3,528.0**	**3,629.4**	-3%
Total borrowings	958.2	989.3	-3%
Other liabilities	744.4	759.3	-2%
Total equity	**1,825.4**	**1,880.7**	-3%
Net debt[6]	**905.1**	**966.0**	-6%
Gearing	34.4%	34.5%	0%
EBITDAF interest cover	6.2	5.3	16%
Net debt: EBITDAF	2.6	3.1	-16%
NTA per share ($ per share)	$1.70	$1.75	-3%

During FY2015 Genesis Energy restructured some of its debt by undertaking a US Private Placement (USPP) of debt securities to a select group of institutions in the United States of America. In total the Company issued US$150 million of securities, and used the proceeds to pay down short term NZ dollar denominated bank debt, increasing the average maturity of funding facilities from 7.1 to 8.8 years. At the same time there was also the opportunity to reduce the Company's current undrawn facilities, which will help to reduce financing costs in the future.

After adjusting for the foreign currency translation and fair value movements associated with the USPP, net debt was $905.1 million compared to $966.0 million at 30 June 2014. Genesis Energy's gearing ratio (debt to debt plus equity) now sits at 34.4% which is lower than the 34.5% reported at the end of FY2014.

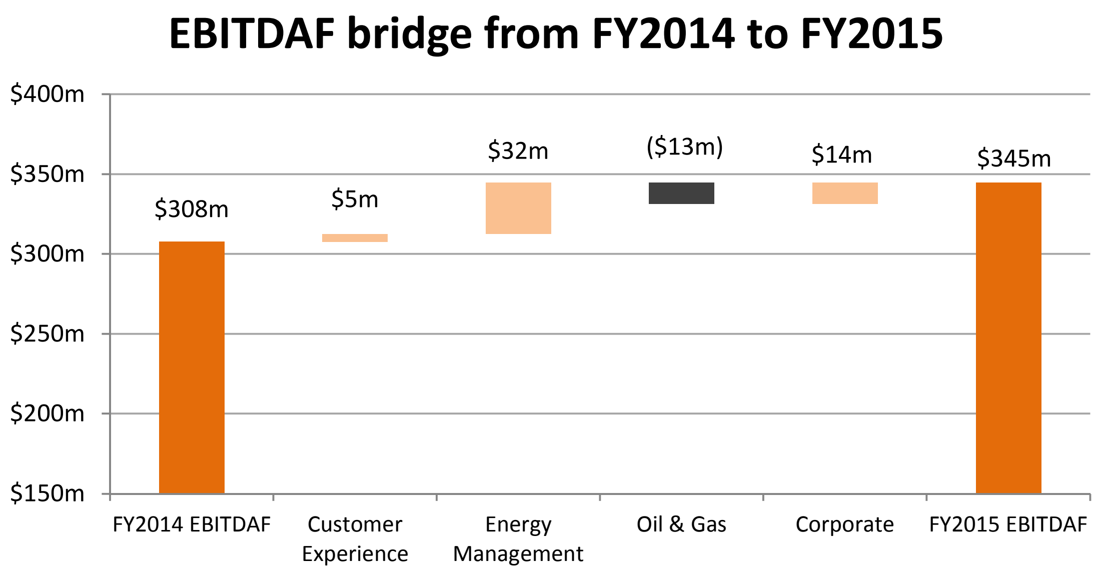
Net borrowing costs for the 12-month period reduced by $1.5 million from $68.2 million in FY2014 to $66.7 million in FY2015, reflecting lower average debt levels throughout the year. and lower interest rates.

Genesis Energy has declared a final dividend of 8.0 cents per share (cps) for FY2015, ahead of the 6.6cps final dividend declared in FY2014. Coupled with the interim dividend of 8.0cps, this brings the total dividend declared in FY2015 to 16.0cps, equating to 80.9% of FCF compared to 80.4% in FY2014. The final dividend will be paid on 16 October 2015 with a record date of 2 October 2015.

The chart below indicates the contribution to total EBITDAF growth in FY2015 by each of the Company's business segments. Customer Experience and Energy Management both experienced growth in EBITDAF versus 2014, contributing $4.7 million and $32.2 million, respectively, while Corporate costs reduced by $13.6 million. Oil and Gas EBITDAF of $93.5

[6] Adjusted net debt as per footnote 5

million was $13.5 million, or 13% lower than in FY2014, mainly due to lower international oil prices and lower production volumes. Oil and Gas EBITDAF from the Kupe field contributed 27% of total EBITDAF in FY2015 versus 35% a year ago.

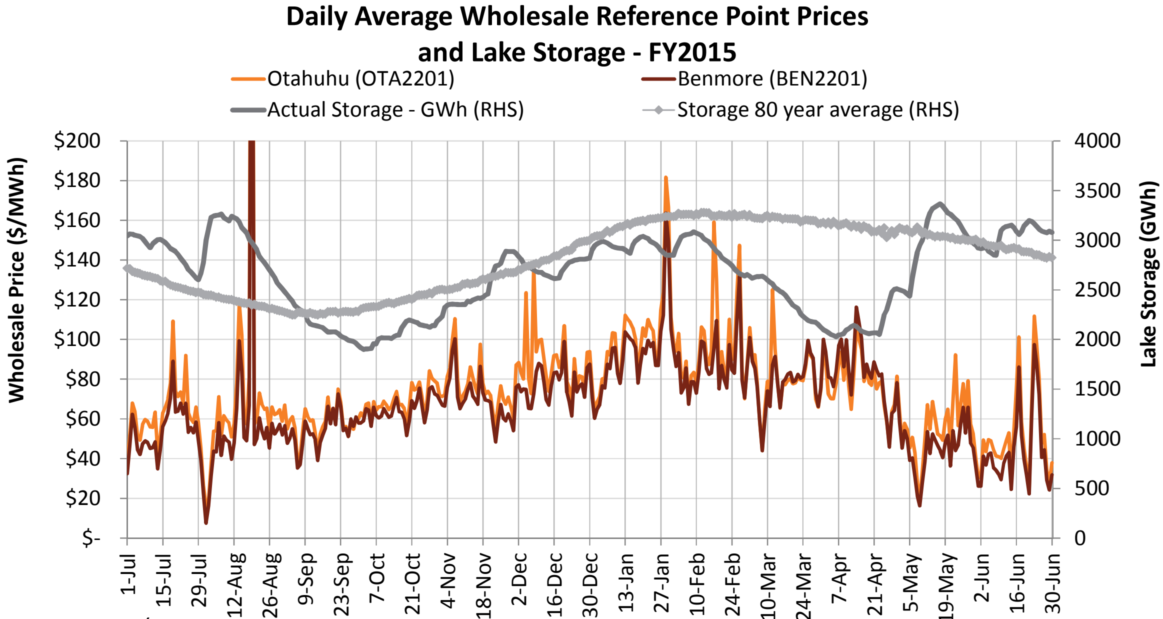


Wholesale Electricity Market Conditions

The wholesale electricity market during FY2015 was split into four distinct periods of hydrological conditions which affected national wholesale electricity prices. In the period from 1 July to late August 2014 there was above average rainfall, and lake storage levels were consistently in excess of the long run average. Except for one notable observation, this led to wholesale prices sitting around the $50/MWh to $60/MWh level for a number of weeks.

From early September 2014 until mid-February 2015 national lake storage levels were in line or slightly below the long run average. However, average wholesale prices steadily increased, due to the impact of generation plant outages throughout summer, with some notable price spikes in December 2014, then again in January 2015.

From mid-February until late April 2015 very low rainfall throughout the country reduced national hydro storage levels to around 64% of the long run average (and 45% of the maximum), to levels last seen in 2008. Despite this the average wholesale electricity price stayed within the $70/MWh to $100/MWh range as a number of structural factors meant that the large renewable generators in the South Island continued to run their hydro stations consistently, seemingly without fear of running out of water. These structural factors include the increase in geothermal baseload generation compared to previous years, improved transfer of electricity through the HVDC link across the Cook Strait, de-facto levels of dry year insurance held by market participants and ultimately the movement in hydro risk curves. These factors resulted in a disconnect between national hydro storage levels and the wholesale electricity price in this period.

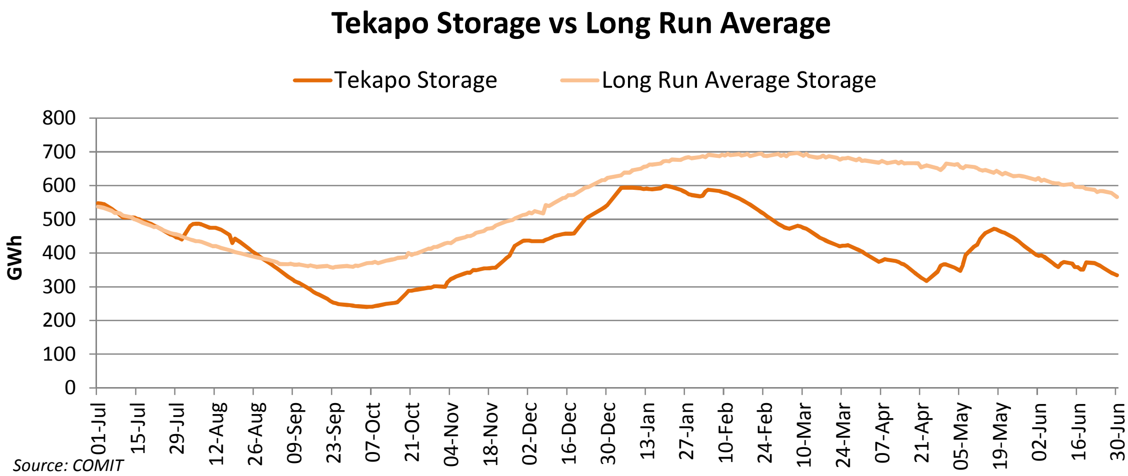


Source: COMIT/Genesis Energy

In late April to early May 2015 there were a number of significant rainfall events across New Zealand that quickly and materially changed national hydro storage levels, returning them to above average for the remainder of FY2015. This led to a large correction in the wholesale electricity price in May and June, which averaged $52/MWh, and was 13% lower than the same period a year ago.

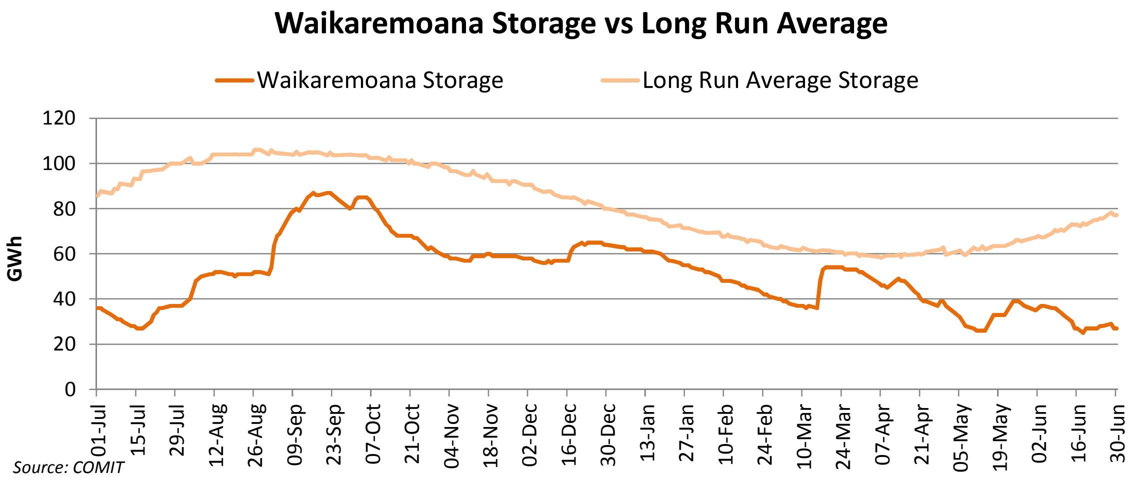
The average price for the whole of FY2015 was $73.22/MWh, which was 5% higher than the average for FY2014 and compared to the $60.50/MWh to $70.50/MWh range forecast in the IPO prospectus.

Genesis Energy's two most significant storage lakes are Lake Tekapo and Lake Waikaremoana. During FY2015 Lake Tekapo's storage levels followed a similar trend to the long run average level up until mid-January 2015 when inflows reduced and lake levels started to fall. From then until late April 2015 Tekapo storage fell to around 55% of the long run average. Although inflows increased significantly a decision was made to run the Tekapo A and B stations in favour of thermal units elsewhere in the portfolio given the lower wholesale price, hence storage levels did not recover in line with other hydro lakes in the South Island.



Source: COMIT

Lake levels at Waikaremoana were significantly below the long run average for the majority of FY2015 given the extremely low inflows, as rainfall in the first half of the year was at approximately the tenth percentile level. This ultimately impacted the amount of electricity generated by the Waikaremoana Power Scheme and was similar to that experienced at the Tongariro Power Scheme, which is largely operated as 'run of the river' (i.e. it has very little storage).



Source: COMIT

These hydrology charts provide some insight to the hydro generation deficit (relative to mean) experienced in FY2015 which has been valued at approximately 360GWh (or $23 million) for Genesis Energy catchments. Traditionally this value would have been offset by long thermal volume at high prices.

Customer Experience

Customer Experience: 12 months to 30 June	2015	2014	Change year on year
Electricity Customers	516,574	523,278	-1%
Gas Customers	106,263	111,966	-5%
Total Customers ex LPG[7]	**622,837**	**635,244**	-2%
LPG Customers	13,839	11,803	17%
Total Customer Accounts	**636,676**	**647,047**	-2%
Total Advanced Meters Installed	364,129	367,882	-1%
Average Customer Switching Rate[8]	19.1%	21.2%	-10%
Retail Electricity Sales (GWh)	5,414	5,391	0%
Retail Electricity Purchases (GWh)	5,769	5,729	1%
Retail Gas Sales (PJ)	7.1	6.1	16%
Retail Gas Purchases (PJ)	7.0	6.1	15%
Retail LPG Sales (tonnes)	3,523	3,018	17%
Average Retail Electricity Purchase Price ($/MWh)[9]	74.67	69.80	7%
LWAP/GWAP ratio[10]	99%	99%	0%
Customer Experience EBITDAF ($m)	**87.2**	**82.5**	6%

The retail electricity market provided significant challenges in FY2015 as the number of retailers increased, new products entered the market and switching rates remained elevated. Genesis Energy's total electricity customers reduced 1% to 516,574 at 30 June 2015 as a result of these pressures, although customer numbers started to stabilise near the end of the year. The bulk of the customer losses have occurred around central to southern North Island regions including Waikato, Taranaki, Kapiti and Wellington. Genesis Energy's national challenger brand Energy Online grew by approximately 7,000 customers in FY2015, while the Genesis Energy brand continues to grow in the South Island and Auckland.

As a result of lower customer numbers and subdued mass market demand, offset by higher Time of Use (TOU) sales, Customer Experience recorded total retail electricity sales of 5,414 GWh which remained in line with FY2014, but 5% behind the PFI estimate.

Total gas customers of 106,263 at 30 June 2015 were 5% lower than a year ago, reflecting strong competition for dual fuel customers and competitors utilising lower wholesale gas pricing to aggressively discount products. Energy Online had 4,259 gas customers at the end of the year, a 91% increase on the same time last year. Total retail gas volumes during FY2015

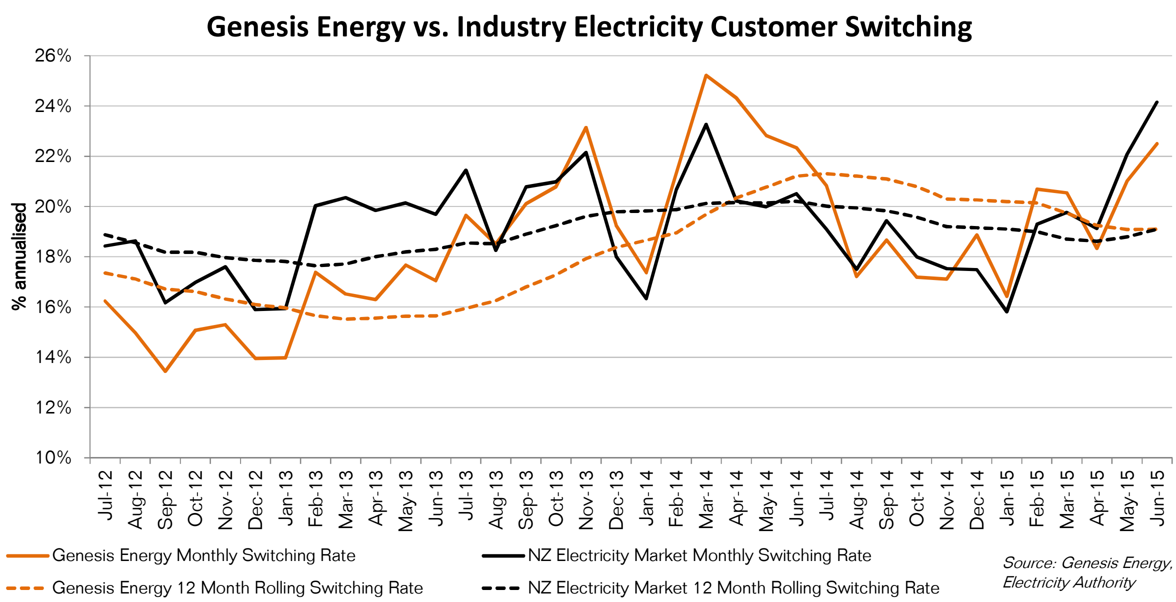
---

[7] Based on Genesis Energy customer records, excluding vacant accounts and defined by number of connections.
[8] Based on the number of ICPs (or points of connection).
[9] Excludes settlements from electricity derivatives.
[10] The ratio of average retail electricity purchase price to average price received for generation

were up 16% to 7.1PJ and benefitted from a 3% increase in mass market volumes on the back of increased usage per customer. TOU volumes increased significantly, up 39% year on year to 3.0 PJ and now represent 44% of all gas sales.

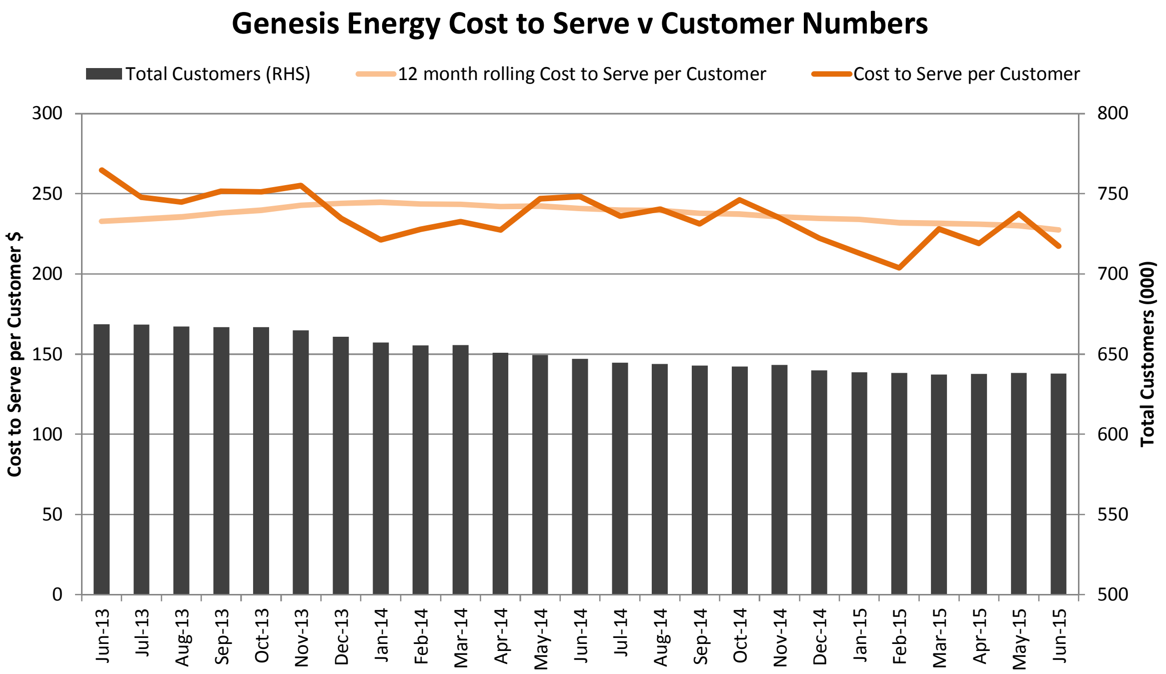
LPG volumes sold were up 17% at 3,523 tonnes compared to 3,018 a year ago and were in line with the increase in customers to 13,839 at 30 June 2015.

Genesis Energy worked hard to reduce its electricity switching rates below that of the wider market. June 2015 was the first time since March 2014 when Genesis Energy's rolling 12 month switching rate of 19.1% matched that of the wider market and was 2% points lower than a year ago.



Despite the reduction in electricity and gas customers the Customer Experience segment EBITDAF increased 6% to $87.2 million from $82.5 million in FY2014. Higher revenues were due to price increases offsetting lower customer numbers, while lines and distributions costs were lower due to lower electricity volumes.

Genesis Energy has continued to focus on reducing both its cost to serve per customer and any costs to acquire either electricity or gas customers. The chart below shows that, even though total customers have declined, a focus on the constituents of cost to serve has still reduced the cost per customer.

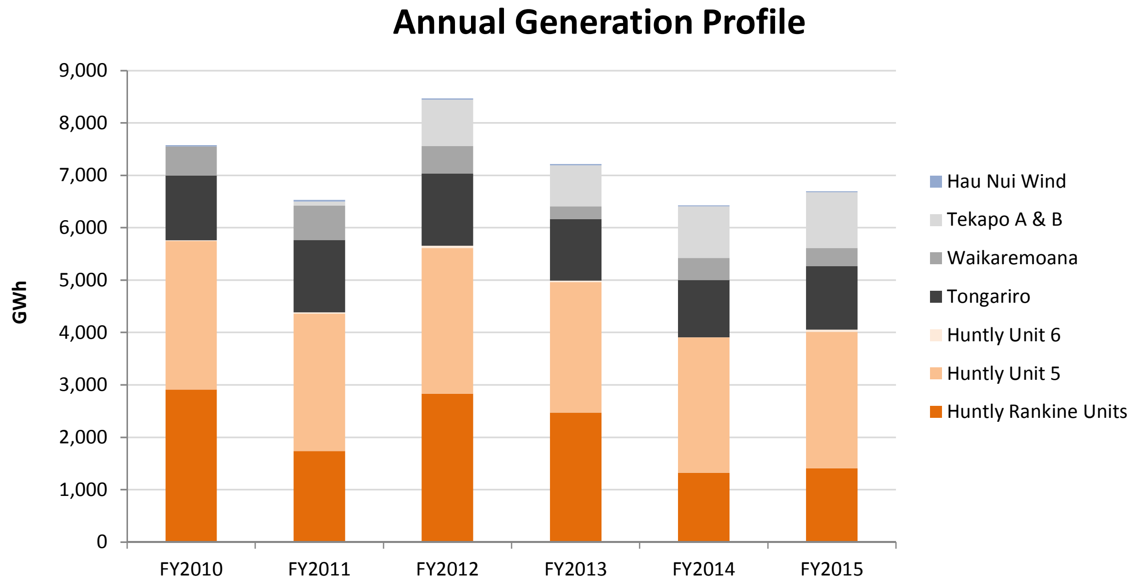


Energy Management

Generation: 12 months to 30 June	2015	2014	Change year on year
Gas (GWh)	2,772	2,930	-5%
Coal (GWh)	1,277	977	31%
Total Thermal (GWh)	**4,049**	**3,907**	4%
Hydro (GWh)	2,627	2,497	5%
Wind (GWh)	22	23	-5%
Total Renewable (GWh)	**2,649**	**2,520**	5%
Total Generation (GWh)	**6,698**	**6,427**	4%
Average Price Received for Generation ($/MWh)[11]	75.41	70.53	7%
Energy Management EBITDAF ($m)	**201.1**	**168.9**	19%

Total thermal generation in FY2015 increased 4% to 4,049 GWh versus 3,907 GWh in FY2014 reflecting increased wholesale electricity prices and cover for hydro generation when inflows into Genesis Energy's North Island hydro schemes were very low. The mix of thermal generation was significantly different to that produced in FY2014. Coal generation increased 31% in FY2015 due to the Huntly Rankine units being used to cover a planned Unit 5 outage and the lack of inflows to hydro schemes in Q3 2015.

[11] Excludes settlements from electricity derivatives

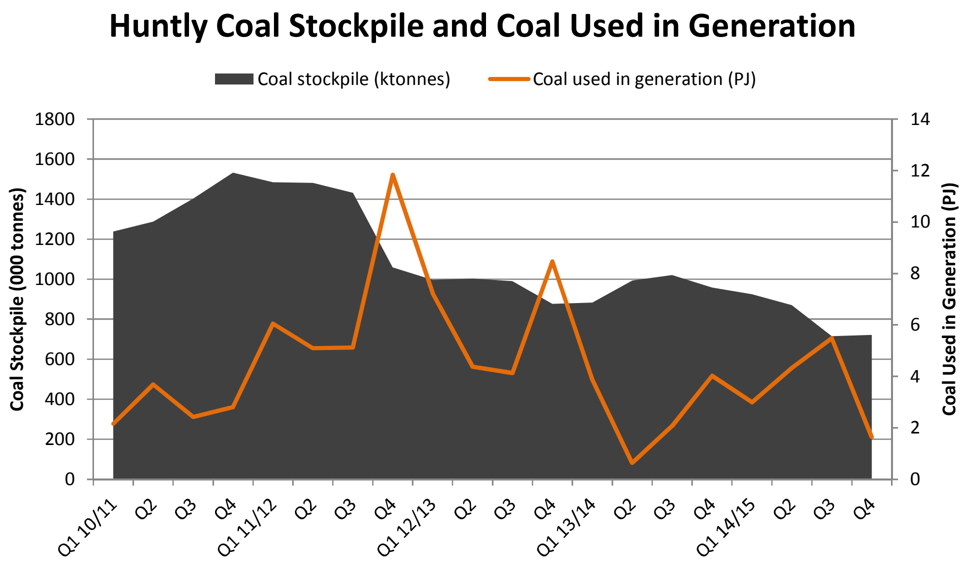


Total generation in FY2015 increased 4% to 6,698 GWh versus 6,427 GWh in FY2014 and even though the mix of generation was different, Energy Management EBITDAF in FY2015 of $201.1 million was 19% higher than last year. This was due to the 7% increase in the average price received for generation, the overall increase in generation volumes and the continued focus on reducing operating and maintaining costs. These efforts were furthered in September 2014 with the award of an integrated services contract for outsourced maintenance services at all Genesis Energy generation sites to Transfield Worley Power Services (TWPS). The TWPS integrated services contract replaced around 80 separate outsourced maintenance contracts.

At the end of June 2015, Genesis Energy permanently retired a second 250MW coal/gas fired Rankine unit at the Huntly Power Station. Market events had proved there was no justification for keeping the additional Rankine unit in storage.

Fuel management: 12 months to 30 June	2015	2014	Change year on year
Wholesale gas sales (PJ)	20.6	15.8	30%
Gas purchases (PJ)	48.5	45.0	8%
Gas used in internal generation. (PJ)	20.8	23.1	-10%
Wholesale coal sales (PJ)	0.7	0.0	N/A
Coal Purchases (PJ)	9.6	12.4	-22%
Coal used in internal generation (PJ)	14.2	10.6	34%
Coal stockpile (kilotonnes)	721	958	-25%

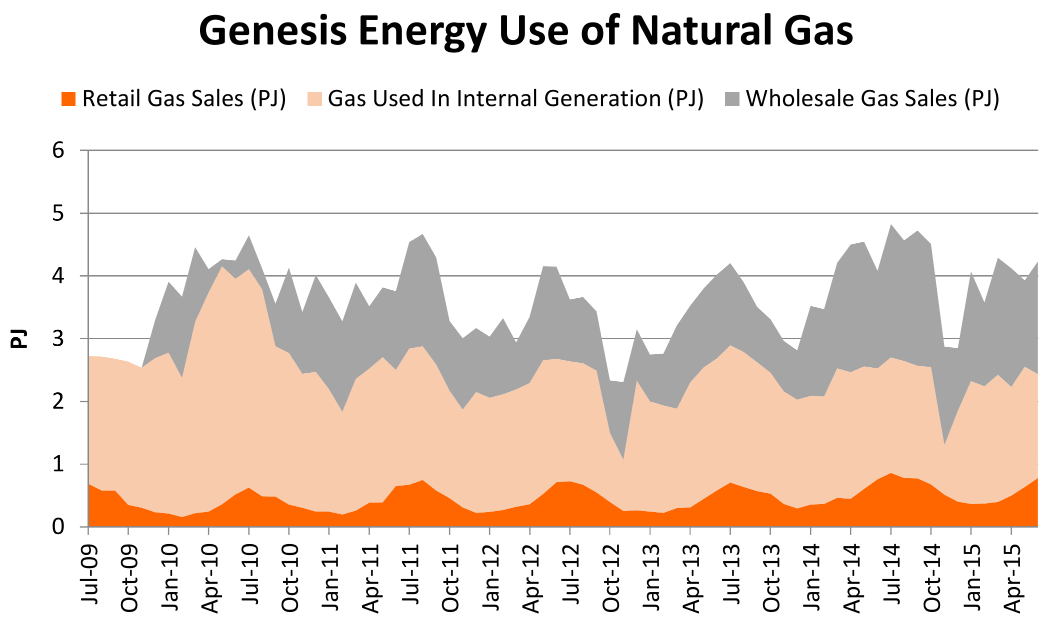
Genesis Energy continues to manage its fuel portfolio to optimise returns from its gas book, with a view to depleting all its coal by the time the Rankine units at Huntly are retired. The time taken to deplete the stockpile will depend on wholesale electricity market conditions, and any coal sales made to third parties. In FY2015 there were 14.2 PJ or 643,000 tonnes of coal burnt in the Rankine units and 0.7 PJ or 30,000 tonnes of wholesale coal sales.



The higher coal usage reflected increased production from the Rankine units in November to December 2014 when they were used to cover a planned outage of Unit 5, and in Q3 2015 when wholesale prices started to increase, and low inflows into Tongariro and Waikaremoana restricted those schemes.

The Unit 5 outage led to reduced gas usage at the Huntly Power Station of 20.8 PJ of gas, which was 10% lower than in 2014. Wholesale gas sales of 20.6 PJ were 30% higher than in FY2014, mainly due to the accelerated gas from Kupe in H2 and the need to sell take or pay gas that was not used in the Huntly Power Station.

The chart below shows the use of gas over the last five years, highlighting the relatively predictable and seasonal retail gas flows, the consistent levels of gas use for generation (mainly reflecting Unit 5's steady operation) and the flexing wholesale gas sales which are dependent on a mix of firm contracts and month to month spot sales.

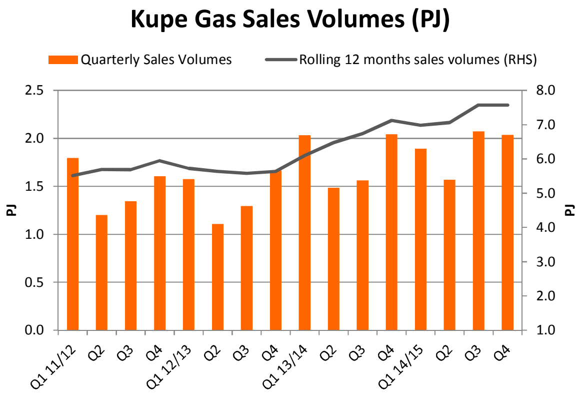


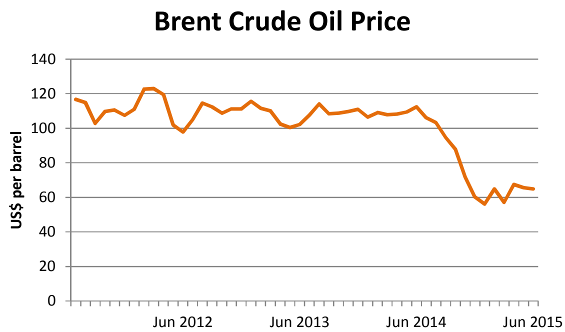
Kupe

Oil and Gas: 12 months to 30 June (Genesis Energy share)	2015	2014	Change year on year
Gas Sales (PJ)	7.6	7.1	7%
Oil Production (kbbl)	502.1	535.3	-6%
Oil Sales (kbbl)	500.8	531.5	-6%
LPG Sales (kilotonnes)	31.6	29.8	6%
Oil and Gas EBITDAF ($m)	**93.5**	**107.0**	-13%

Genesis Energy's 31% share of the Kupe Oil and Gas field delivered EBITDAF of $93.5 million in FY2015, 13% lower than in FY2014 due to reduced H1 production volumes and lower international oil prices in the last seven months of the year.

Gas sales of 7.6PJ were 7% higher than in FY2014 reflecting a decision by the Kupe joint venture partners to increase production volumes in the second half of the financial year to offset the impact of the oil prices which fell from approximately US$110 to US$60 per barrel during the course of the financial year





The impact of the oil price fall was also mitigated by the hedging that was put in place, as 81% of total oil production was hedged at US$91.60/bbl and 87% of NZD/USD cross rate was hedged at 0.77c. Total oil production of 502.1 kbbl was 6% lower than in FY2014 and LPG sales of 31.6 kt were 6% higher than FY2014.

The table below indicates the reserves remaining in the whole Kupe field after adjusting for production over the last three years, based on the last full reserves assessment which was at 30 June 2012. An updated reserves assessment is likely to be completed by the first half of FY2016. The joint venture partners are also reviewing the timing and scope of the second phase of development of the Kupe field committed to by each of the joint venture partners when Kupe was commercialised. This could involve near field drilling and/or compression of the wells.

		Full Field Reserves (2P)	Full Field Production			Full Field Remaining Reserves (2P)		
		30-Jun-12	FY2013	FY2014	FY2015	Developed	Undeveloped	Total
Condensate /Light Oil	barrel (000)	13,629	1,556	1,712	1,608	5,016	3,737	8,753
Gas	PJ	276	18	23	24	123	88	211
LPG	tonne (000)	1,178	77	96	103	532	370	902

Outlook

While Genesis Energy has recently experienced some stabilisation of its electricity customer numbers and reduction in its gas customer losses, the retail electricity and gas markets are expected to remain competitive and switching rates elevated.

The above average hydro storage levels at the beginning of FY2016 are continuing to impact on wholesale electricity and spot generation revenues, although recent cooler temperatures have seen increases in usage of electricity, gas and LPG.

The recent announcement regarding retirement of the Rankine units means that the Company is very focused on reducing its operating expenditure and believes there are cost savings to be made before the final Rankine retirement date by operating the Huntly Power Station more efficiently.

The announcement on 20 August 2015 that the Solid Energy coal supply agreement has been terminated means that Genesis Energy now only has 721,000 tonnes of coal on the stockpile plus four months of coal deliveries to burn through the Rankine units before any alternative fuel would be needed. The announcement also provides increased flexibility of fuel supply for the Rankine units ahead of their retirement, which will have a free cash flow benefit in future periods.

Kupe continues to produce oil and gas at consistent rates. Currently output is at approximately 10% above the base level. Although the low international oil prices are likely to have some impact on Kupe EBITDAF, current hedging in place for FY2016 covers 80% of the projected oil production at US$85.40 per barrel. Recent weakness in the New Zealand dollar will likely benefit Kupe EBITDAF in FY2016.

In summary, Genesis Energy expects to report FY2016 EBITDAF in line with that reported in FY2015, and to increase its total dividend declared in FY2016 in line with the Company's progressive dividend policy.

Ends

About Genesis Energy

Genesis Energy (NZX: GNE) is a diversified New Zealand energy company. It sells electricity, reticulated natural gas and LPG through its retail brands of Genesis Energy and Energy Online. It is New Zealand's largest energy retailer with around 637,000 customer accounts. The Company generates electricity from a diverse portfolio of thermal and renewable generation assets located in different parts of the country. Genesis Energy also has a 31% interest in the Kupe Joint Venture, which owns the Kupe Oil and Gas Field offshore of Taranaki, New Zealand. Genesis Energy had revenue of $NZ2.1bn during the 12 months ended 30 June 2015. More information can be found at www.genesisenergy.co.nz

GENESIS ENERGY

FY2015 Results Presentation

genesis ENERGY

DISCLAIMER

This presentation has been compiled by Genesis Energy Limited for information purposes only. This disclaimer applies to this document and the verbal and written comments of any person presenting it.

Genesis Energy has taken reasonable care in compiling the information in this presentation. However, the information is supplied in summary form only (which is general in nature) and is therefore not necessarily complete nor does it purport to contain all information a prospective investor should consider when evaluating an investment. No representation is made as to the accuracy, completeness or reliability of the information.

Neither Genesis Energy nor any of its directors, employees, shareholders, advisers or any other person ('Other Persons') gives any warranties or representations (expressed or implied) as to the accuracy or completeness of this information. To the maximum extent permitted by law, neither Genesis Energy or any Other Persons shall have any liability whatsoever to any person for any loss (including, without limitation, arising from negligence) arising from this presentation or any information supplied in connection with it.

The statements made in this presentation are made only as at the date of this presentation and there is no obligation to update this presentation at any time after its release.

Forward Looking Statements

The past performance information provided in this presentation may not be a reliable indication of future performance. This presentation may also contain or refer to forward looking statements on a variety of matters and comments about future events, including expectations about the performance of Genesis Energy's business. The words "prospective", "PFI", "forecast", "estimate", "anticipate", "expect", "intend", "should", "could", "may" and "outlook" and similar expressions are intended to identify such forward looking statements.

Forward looking statements involve inherent risks and uncertainties, both general and specific , and there is a risk that such forward looking statements will not be achieved. A number of important factors (including, but not limited to, material adverse events, significant one-off expenses and other unforeseeable circumstances) could cause Genesis Energy's actual results to differ materially from the plans, objectives, expectations, estimates and intentions expressed in such forward looking statements.

Where non-GAAP financial measures are used in this presentation, you should not consider these in isolation from, or as a substitute for, the information provided in the consolidated financial statements.

Genesis Energy gives no warranty or representation as to its future financial performance or any future matter. Except as required by law or the NZX or ASX listing rules, Genesis Energy is not obliged to update this presentation after its release.

This presentation does not constitute financial advice, financial product advice, legal or taxation advice. Further, it is not and should not be construed as an offer to sell or a solicitation of an offer to buy Genesis Energy securities and may not be relied upon in connection with any purchase of Genesis Energy securities.

The information contained in this presentation should be considered in conjunction with the condensed full year financial statements, which are included in Genesis Energy's financial results or statements for the 12 month period ending 30 June 2015 and is available at: https://www.genesisenergy.co.nz/reports-and-presentations

2015 HIGHLIGHTS

Albert Brantley
Chief Executive

FY2015 a strong year

- Focused on delivering a strong performance in second year following listing
- Good result delivered despite a year of continuing challenges including competitive retail market, relatively subdued wholesale prices and a sharp fall in international oil prices
- Key financial metrics in FY2015 showed good growth compared to FY2014
  - EBITDAF of $344.8m was up 12% on previous year
  - NPAT of $104.8m was up 113% on the prior year
  - Adjusted net debt of $905.1m is 6% lower
  - Free cash Flow of $197.7m was up 22%
  - Total dividends declared of 16.0 cps is 23% higher

Strategic Highlights

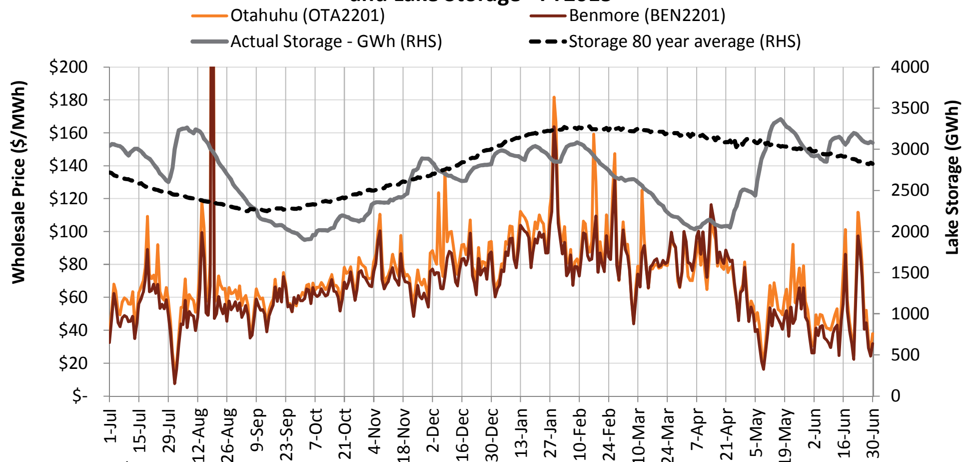
- Signs of stabilisation in the customer numbers late in the year
- Major planned outage of Huntly Unit 5 in November to December 2014, next outage planned for late 2018
- Undertook a US Private Placement of debt securities in November 2014 to further diversify the Company's debt profile
- Genesis Energy responded to a sharp fall in Brent crude oil price by agreeing with Kupe Joint Venture partners to increase production from the Kupe field
- Retired second Huntly 250MW coal/gas Rankine unit in June 2015

Post balance date

- Launch of flat rate gas plans and Energy Online re-branding
- Signed a two year contract with Meridian Energy for 50MW of electricity from 1 January 2017 to 31 December 2018 to support Meridian CFD for Tiwai smelter
- Announced retirement of two remaining Rankine units by December 2018
- Announced termination of coal supply contract with Solid Energy

Wholesale Electricity Market

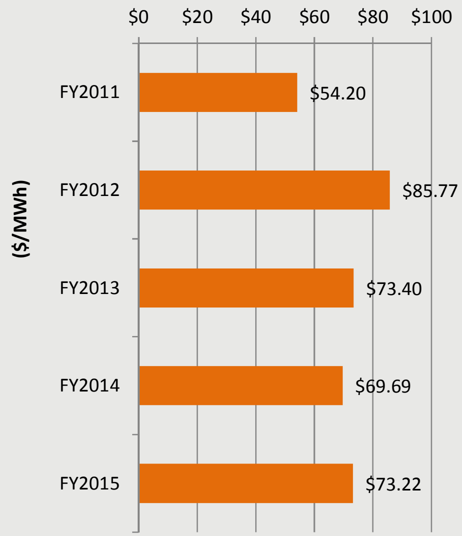
Daily Average Wholesale Reference Point Prices and Lake Storage - FY2015



Source: COMIT/Genesis Energy

- Wholesale electricity prices driven by hydrological conditions but constrained by structural changes to electricity market
  - FY2105 average wholesale price of $73.22/MWh up 5% on FY2014, but lower than FY2013 and FY2012
  - Price spikes through January to March 2015 prompted by summer season of plant outages
  - Dry period from February to April 2015 increased prices, but not to the extent seen in previous years
  - Large rainfall events in late April to early May 2015 rebased national hydro storage levels and collapsed prices
- Waikaremoana and Tongariro had less than 10th percentile inflows, restricting generation through majority of the year

Average Wholesale Electricity Price at Huntly Node



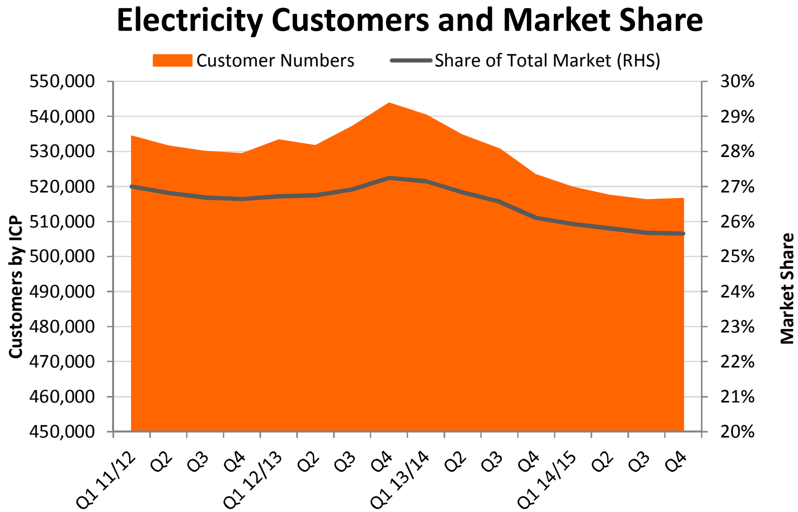
12 months to June 30	2015	2014	% change
Electricity Customers	516,574	523,278	-1%
Gas Customers	106,263	111,966	-5%
Total Customers ex LPG	**622,837**	**635,244**	**-2%**
LPG Customers	13,839	11,803	17%
Total Customer Accounts	**636,676**	**647,047**	**-2%**
Total Advanced Meters Installed	364,129	367,882	-1%
12 months annualised churn rate	19.1%	21.2%	-10%
Retail Electricity Sales (GWh)	5,414	5,391	0%
Retail Electricity Purchases (GWh)	5,769	5,729	1%
Retail Gas Sales (PJ)	7.1	6.1	16%
Retail Gas Purchases (PJ)	7.0	6.1	15%
Retail LPG Sales (tonnes)	3,523	3,018	17%
Average Retail Electricity Purchase Price ($/MWh)	$74.67	$69.80	7%
LWAP/GWAP ratio	99%	99%	0%

Customer Experience Performance

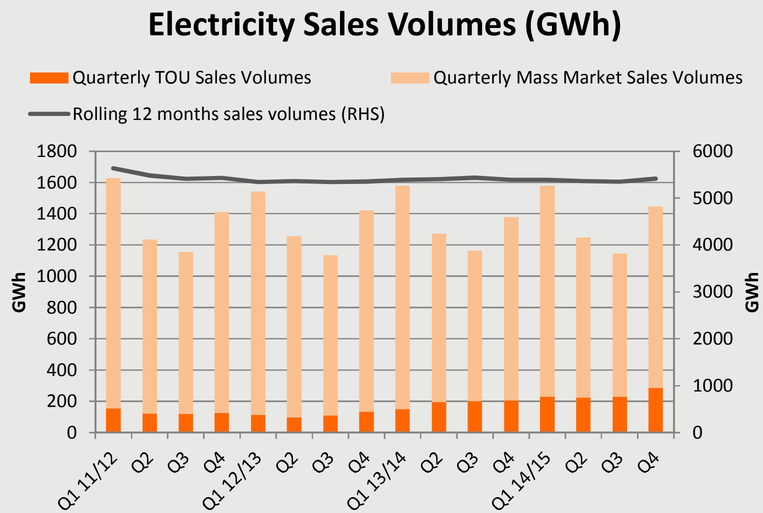
- Customer Experience EBITDAF was up 6% to $87.2m
- Pressure on customer numbers from competition in retail markets - niche offerings, bundled products
  - Total electricity and gas customers down, but starting to stabilise late in the year
  - Both electricity and gas customers at end of FY2015 lower than PFI, but LPG customers in line and growing strongly year on year
- Proportion of electricity customers with advanced meters steady at 71%, but absolute number of advanced meters fallen in line with reduction in customers

Electricity Customers

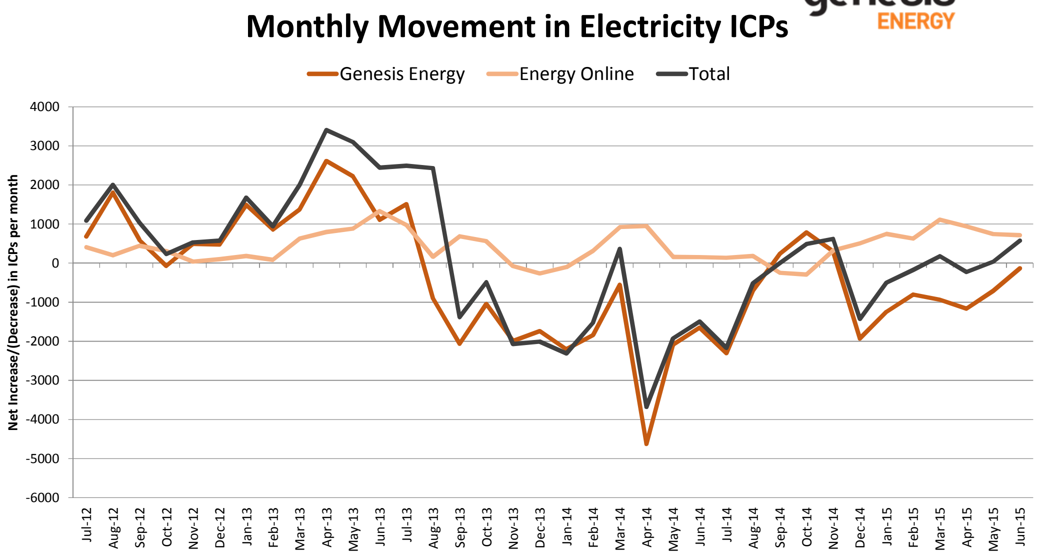
- Electricity customer numbers stabilised by end of FY2015 at 26% market share, maintaining Genesis Energy as the largest retailer
- Total retail electricity sales of 5,414 GWh 0.4% higher in FY2015 reflecting:
  - A 28% increase in TOU sales offsetting a 4% decline in mass market sales volumes
  - Mass market declines reflect lower customer numbers and subdued consumption per household
  - Rolling 12 month total sales volumes show a flat trend over last three years
- Consumption per mass market customer grew modestly in Q4 2015 year on year, but otherwise has been reducing



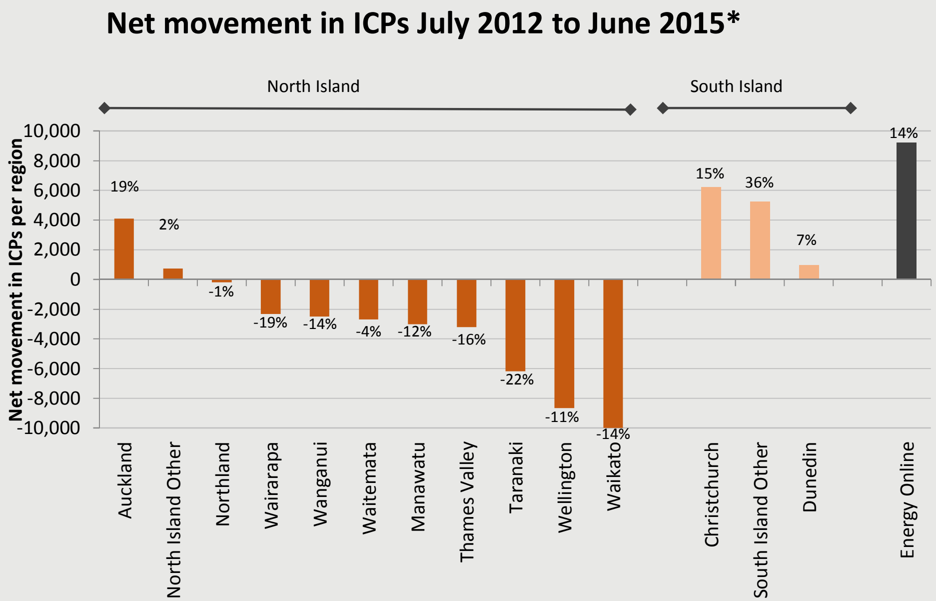
Source: Company data, Electricity Authority



Electricity Customer Trends

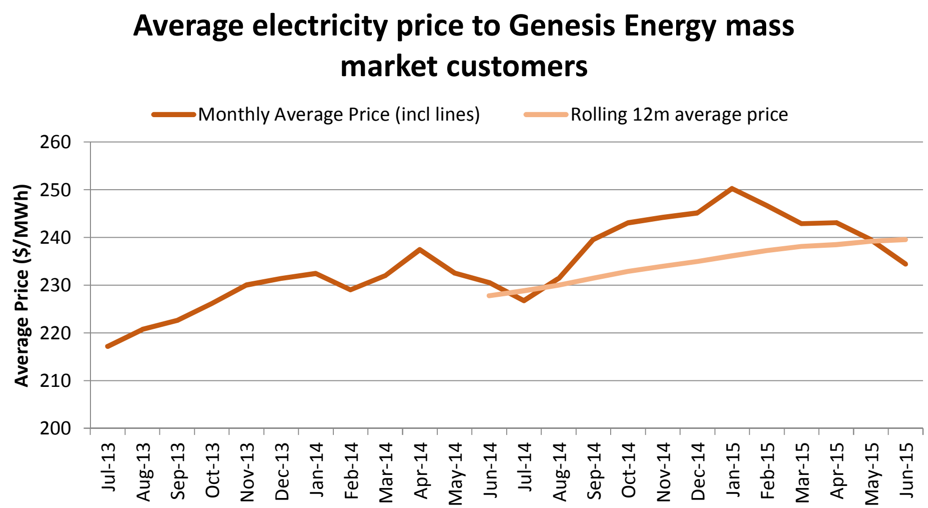


- Analysis of movement in customer numbers shows that Energy Online achieving consistent monthly growth and driving total Company growth
- Genesis Energy brand net losses peaked in April 2014, and have improved since then
- Three regions have suffered the biggest absolute losses in electricity customers – Waikato, Wellington and Taranaki – with the latter losing 22% of the total base since July 2012
- Auckland region has been growing along with all of the South Island plus Energy Online (North Island focussed until recently)
- Highlights that central and lower North Island Genesis Energy branded customers have been key targets of competitors

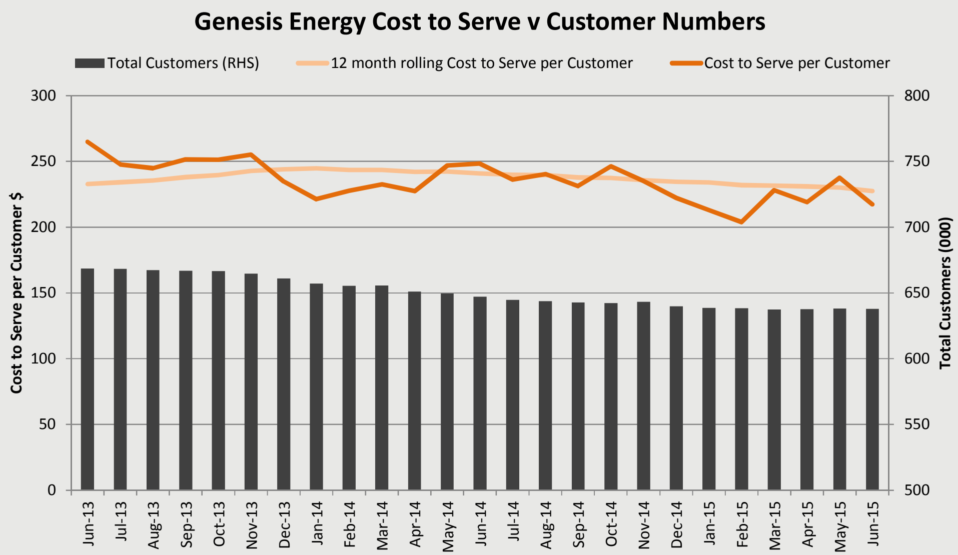


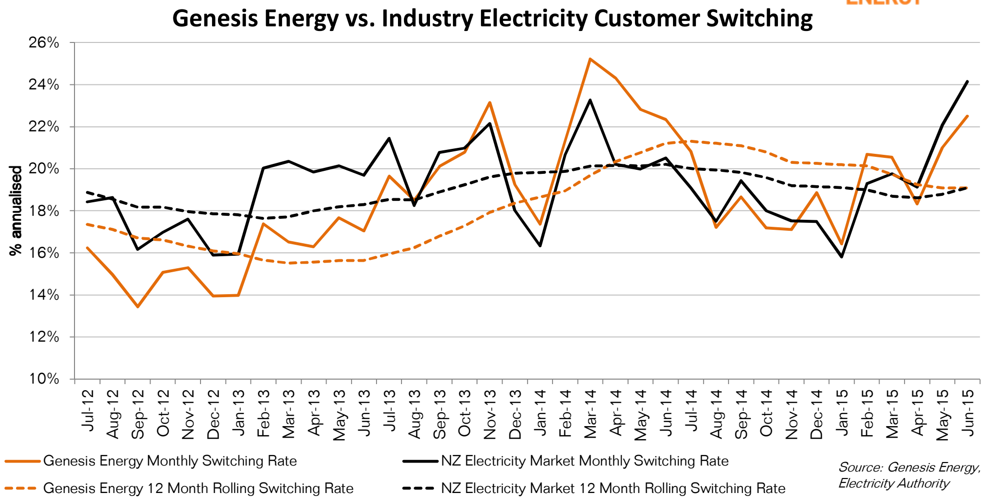
*Percentage change in customer base since July 2012 noted for each region

Financial Drivers of Electricity Earnings



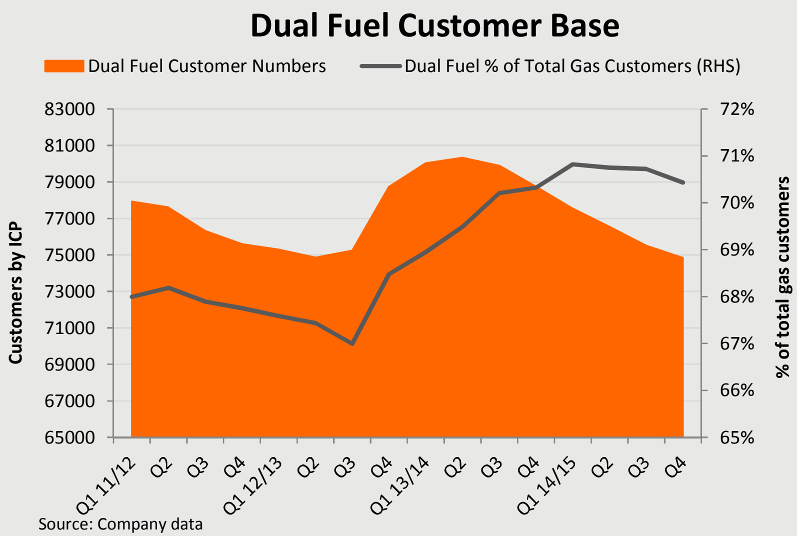
- The 12 month rolling average electricity price to Genesis Energy mass market customers has increased 5% in the last year
  - Due to a combination of energy component of bill increasing in February to April 2014 and changes to line charges
  - Expect 12 month rolling to flatten in next year given no energy price increases in FY2015
- Genesis Energy has worked hard to reduce Cost to Serve per customer, despite customers reducing in FY2015
  - Rolling 12 month cost to serve is 6% lower at 30 June 2015 than a year ago, equating to a $13m reduction in Cost to Serve in FY2015



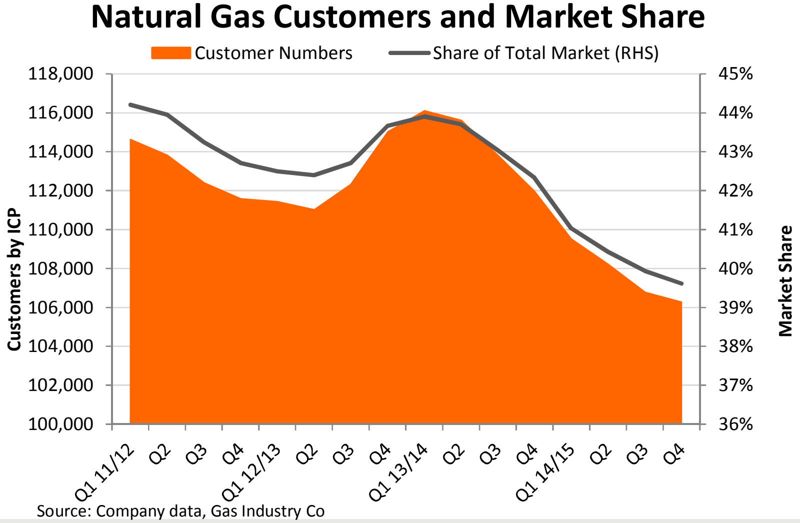


Retaining Customers

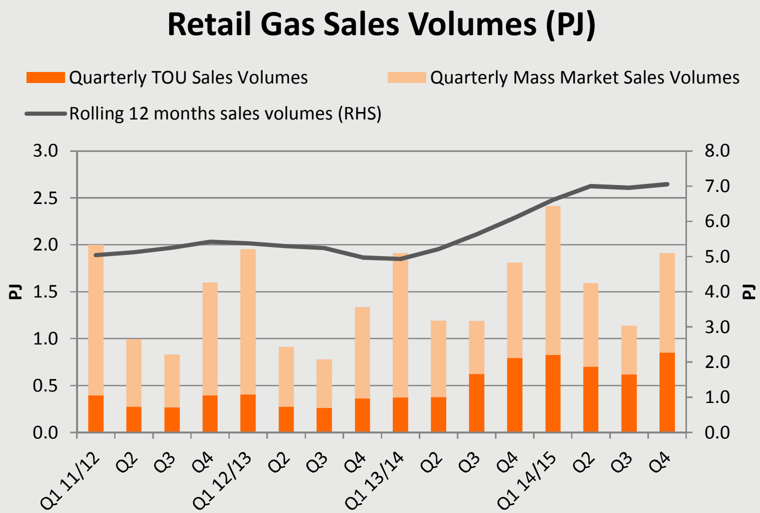
- Industry switching rates subdued for first six months of the year, then increased sharply
- Genesis Energy's switching rates improved relative to the rest of the market so that by the end of FY2015 its 12 month rolling rate of 19.1% was in line with the wider market
  - First time since March 2014 and 2% points lower than a year ago
  - Result of improving customer service, more effective win-backs and enhanced products
- Dual fuel customer base has been further eroded due to these customers being targeted by competitors
  - Recent flat pricing gas offers have been successful in targeting existing customers

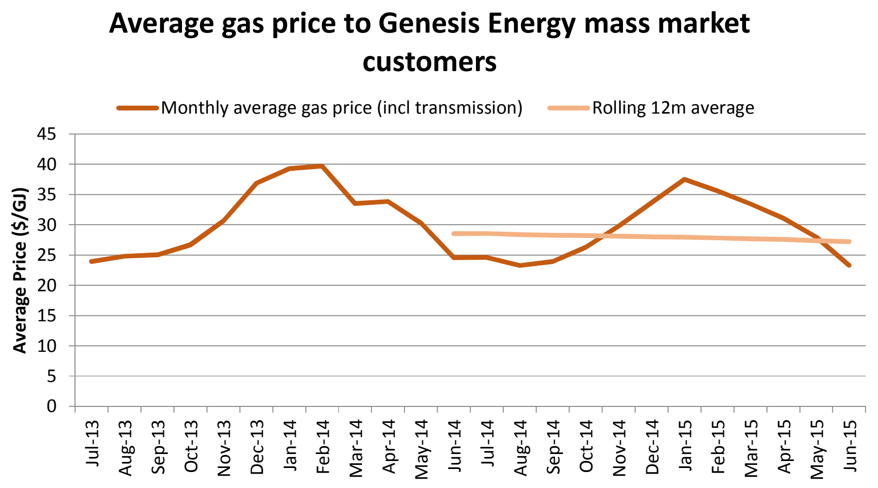


Gas Customers



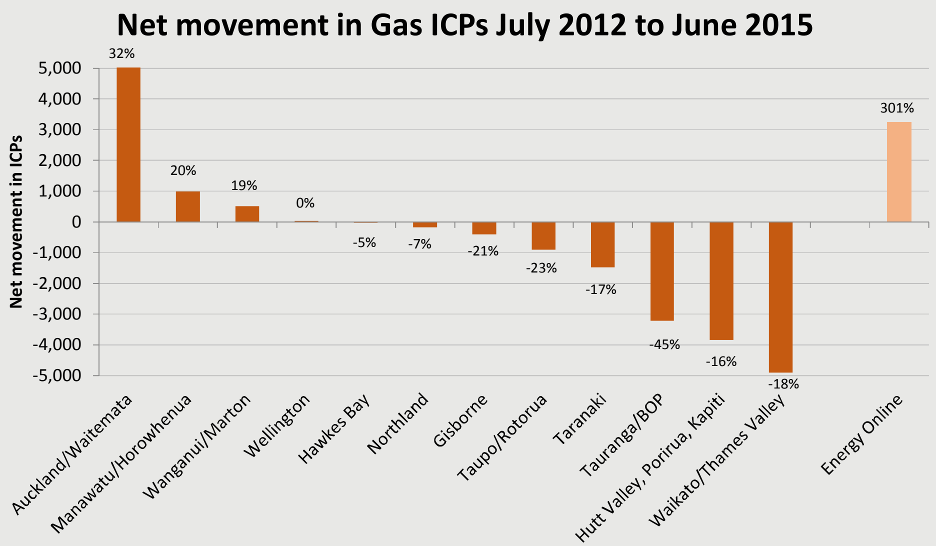
- 106,263 gas customers at 30 June 2015, representing a 40% share of the market by ICPs, but 5,703 fewer customers than a year ago
- Total retail gas sales volumes up 16% in FY2015 to 7.1PJ, compared to 6.1PJ in FY2014
  - Driven by TOU gas sales which are up 39% and mass market up 3% year on year
  - Also increased usage per household reflecting colder weather and increased underlying demand
- 13,839 LPG customers, up 17% on FY2014
  - Growth and customers constrained to 45kg bottled markets in both North and South Islands
  - Kupe offtake volumes provides base to grow LPG activity further





Gas Customer Trends

- As was the case in the electricity market, majority of gas customers lost were from three regions – Bay of Plenty, Wellington/Kapiti, Waikato/Thames Valley
  - Auckland region has shown single biggest movement – up
  - Energy Online increasing, but from a small base
- Lower wholesale gas prices from increased supply has put pressure on average selling price to mass market customers
  - 12 month rolling average selling price down 4.5% year on year
  - Aggressive discounting in gas market has seen switching rates surpass those in the electricity market

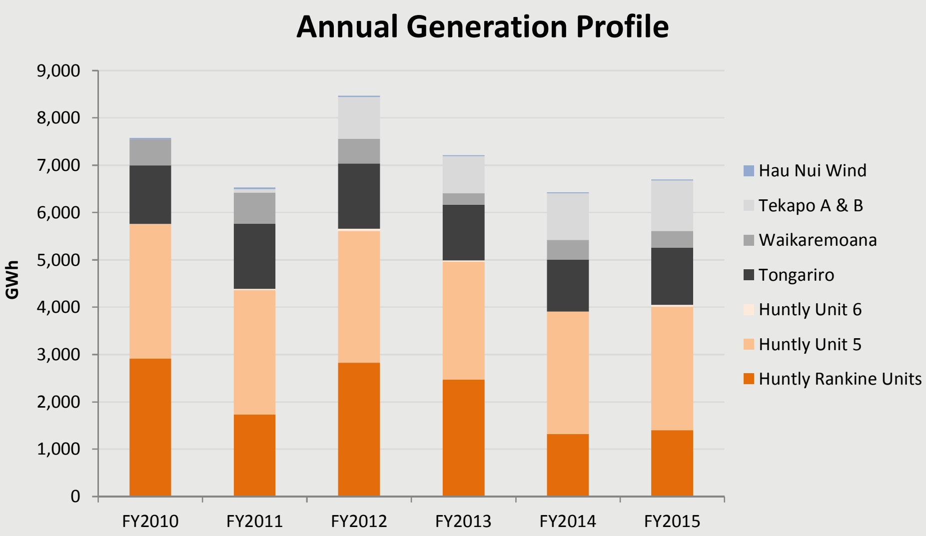


12 Months to 30 June	2015	2014	% change
Gas (GWh)	2,772	2,930	-5%
Coal (GWh)	1,277	977	31%
Total Thermal (GWh)	**4,049**	**3,907**	**4%**
Hydro (GWh)	2,627	2,497	5%
Wind (GWh)	22	23	-5%
Total Renewable (GWh)	**2,649**	**2,520**	**5%**
Total Generation (GWh)	**6,698**	**6,427**	**4%**
Average Price Received for Generation ($/MWh)	$75.41	$70.53	7%

Generation Performance

Total generation up 4% from FY2014 to 6,698 GWh

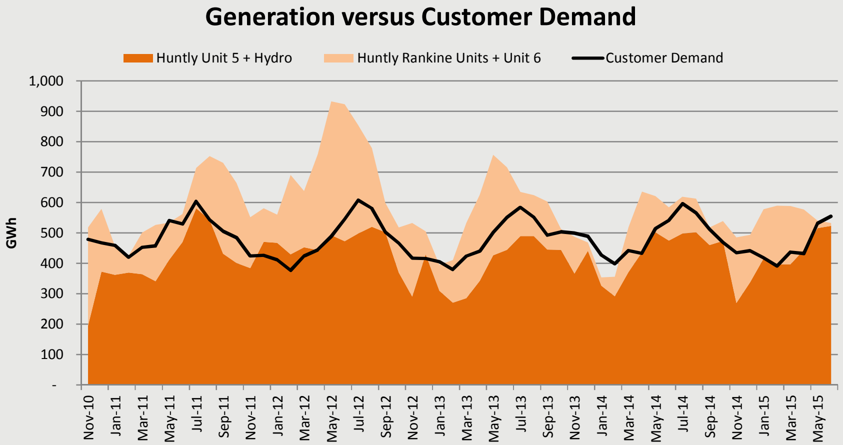
- Reflects a different than expected mix of generation due to hydrological conditions
- Increase in coal generation due to Huntly Rankine units covering planned Unit 5 outage and retail position when North Island hydro constrained
- Hydro generation up 5% versus FY2014 due to full year of Tekapo A and B (post canal repairs), but lower than expectations due to record low inflows into Waikaremoana and Tongariro Power Schemes
- Average price received for generation of $75.41/MWh was 7% higher than in FY2014, but 8% lower than PFI



Generation Versus Customer Demand

Customer demand continues to be matched broadly by generation output from Huntly Unit 5 plus the hydro stations

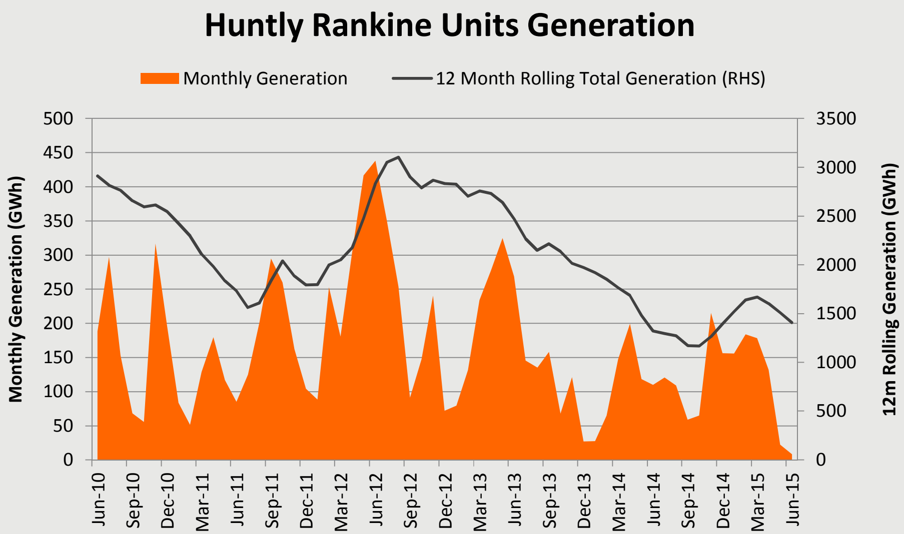
- With only two Rankine units in use, the ability to hit seasonal peak was reduced, but utilisation of individual units was higher
- Some periods throughout the year where demand not matched by generation
    - A Rankine unit only ran on 11 days in May 2015 and 7 days in June 2015 (prices in these months averaged only $54.68/MWh and $50.83/MWh, respectively)
    - Reflects the strategy of going short generation when prices are lower



Rankine Retirement

On 6 August 2015 Genesis Energy announced that, it will retire the two remaining Rankine units at Huntly by December 2018

- Rationale is driven by reduction in significant holding costs which is expected to offset potential option value
- $20m to $25m operating and capital expenditure savings post Rankine retirement are expected
- Current cash costs in FY2015 for the two Rankines are $10m to $15m higher, so additional savings expected to be made between now and retirement
- Remediation costs expected to be offset by proceeds from either selling or scrapping units

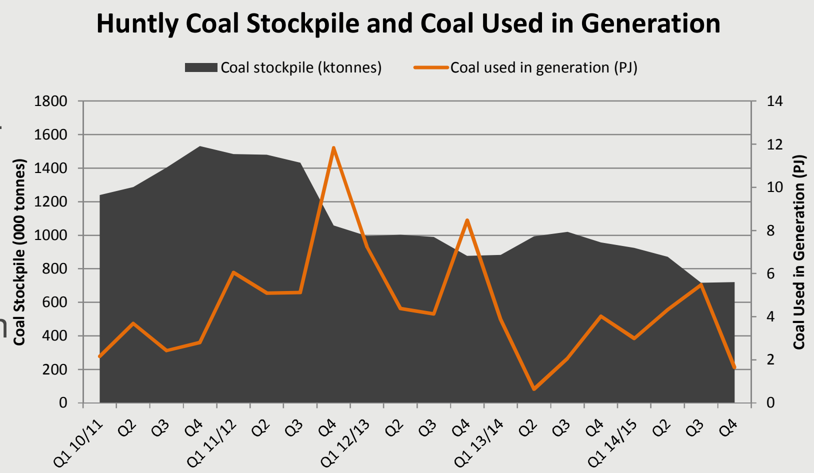


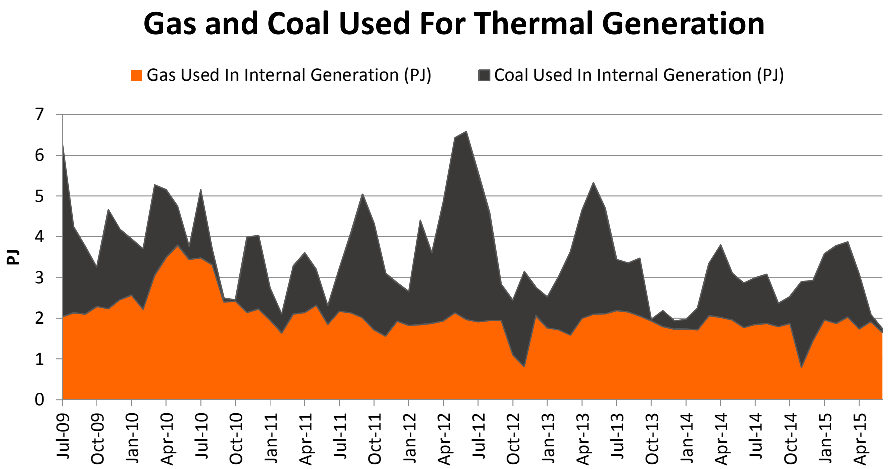
12 Months to 30 June	2015	2014	% change
Wholesale Gas Sales (PJ)	20.6	15.8	30%
Total Gas Purchases (PJ)	48.5	45.0	8%
Gas Used in Internal Generation. (PJ)	20.8	23.1	-10%
Wholesale Coal Sales (PJ)	0.7	0.0	N/A
Coal Purchases (PJ)	9.6	12.4	-22%
Coal Used in Internal Generation (PJ)	14.2	10.6	34%
Coal Stockpile (kilotonnes)	720.9	958	-25%

Fuel Management

Management of gas and coal remains a key feature of Genesis Energy's portfolio

- Wholesale gas sales increased in FY2015 due to Methanex's ramping up production, plus accelerated gas offtake from Kupe
- Gas used in internal generation decreased 10% versus FY2014 due to planned Unit 5 outage
- Coal used in generation up 34% year on year, to cover Unit 5 outage and to reduce coal held in stockpile
- Coal stockpile reduced 25% to 721kt due to increased coal burn plus some wholesale coal sales
- Recent decision to exit Solid Energy coal supply agreement provides more flexibility in future around gas use at Huntly





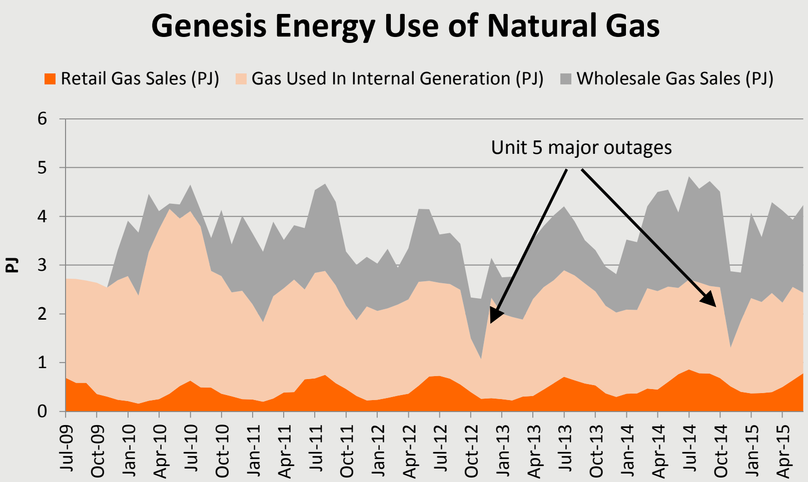
Coal and Gas Use

Traditionally fuel use at Huntly has been dominated by gas used for generation from Unit 5 with coal firing of the Rankine units to hit the market peaks

- Variability in coal usage is managed through storage on the coal stockpile
- In future (post Rankine retirement) gas usage may need to be more flexible

Retail gas sales have increased significantly in last few years with growth in the TOU book, but still are only a fraction of wholesale sales and gas used for generation

Genesis Energy has been 'long' gas in the past, but depleting the coal stockpile and burning gas through the Rankines before retirement could materially change the gas position



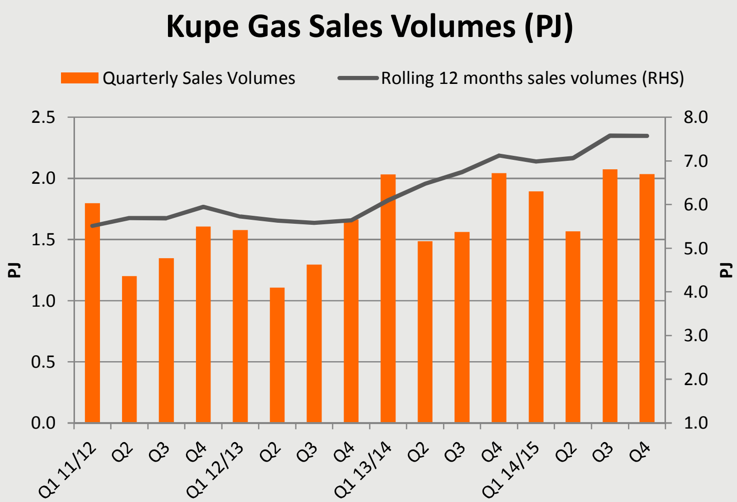
Source: Genesis Energy

Kupe: 12 Months to 30 June	2015	2014	% change
Gas Sales (PJ)	7.6	7.1	7%
Oil Production (kbbl)	502.1	535.3	-6%
Oil Sales (kbbl)	500.8	531.5	-6%
LPG Sales (kilotonnes)	31.6	29.8	6%
Oil and Gas EBITDAF	**93.5**	**107.0**	**-13%**

Kupe

Kupe continues to be a consistent source of earnings

- Natural gas, oil and LPG volumes all up versus expectations as offtake was accelerated in H2 2015
- Genesis Energy's share of gas sales was up 7% year on year to 7.6PJ
- Additional accelerated gas was sold closer to "spot" rates



		Full field reserves (2P)	Full Field Production			Full Field Remaining Reserves (2P)		
		30-Jun-12	FY2013	FY2014	FY2015	Developed	Undeveloped	Total
Condensate / Light Oil	barrel (000)	13,629	1,556	1,712	1,608	5,016	3,737	8,753
Gas	PJ	276	18	23	24	123	88	211
LPG	tonne (000)	1,178	77	96	103	532	370	902

Kupe cont'd

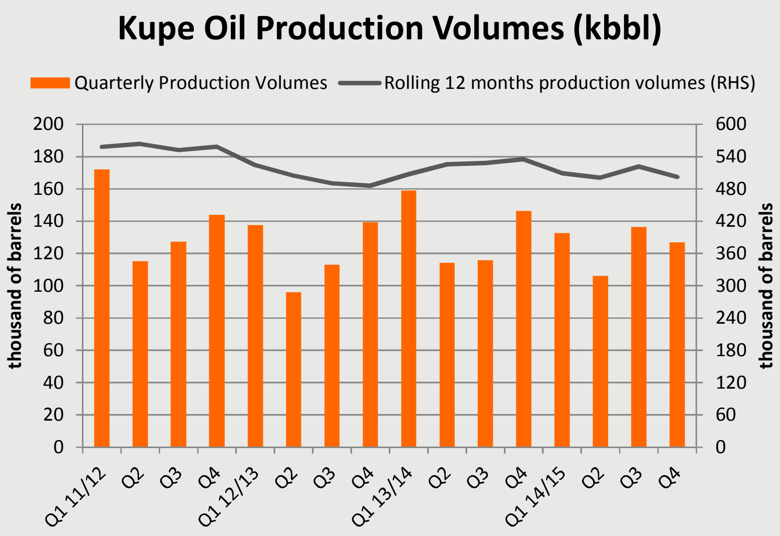
The increased oil production and the hedging put in place helped to offset the impact of the fall in oil prices

- In FY2015 81% of total oil production was hedged at US$91.60/bbl, and 87% of NZD/USD cross rate at 0.77c
- Current hedging for FY2016 of 80% production at US$85.40/bbl, and 74% of NZD/USD exposure at 0.76c

Based on the latest field assessment done in June 2012 and following recent field production there is approximately 8.7m barrels of oil left in field, 211 PJ of gas and 902 kt of LPG

A review of the field's long term potential is likely to be completed by the JV partners in H2 2016 and will include:

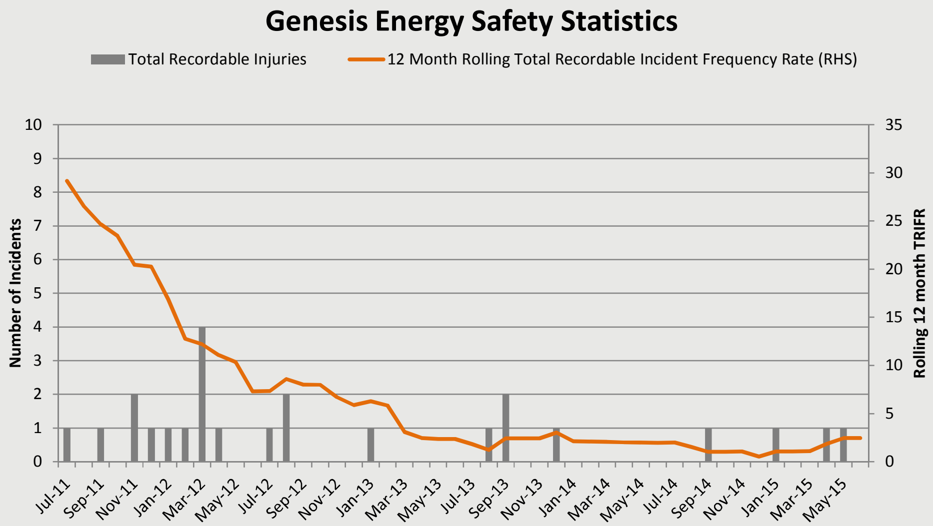
- A reserves re-assessment
- The timing and form of Stage II of the field development plan (ie near field drilling, compression)



People, Health and Safety

The safety of our employees and workplace remains a priority

- Genesis Energy is committed to a zero harm work environment
- Three lost time incidents in FY2015 (2 in FY2014) and no serious incidents
- TRIFR* of 2.43 was slightly higher than at the end of FY2014 but still significantly lower than a few years ago



Source: Genesis Energy, TRIFR is measured by number of incidents per million man hours worked

*Total Recordable Injury Frequency Rate per million man hours

2015 FINANCIAL PERFORMANCE

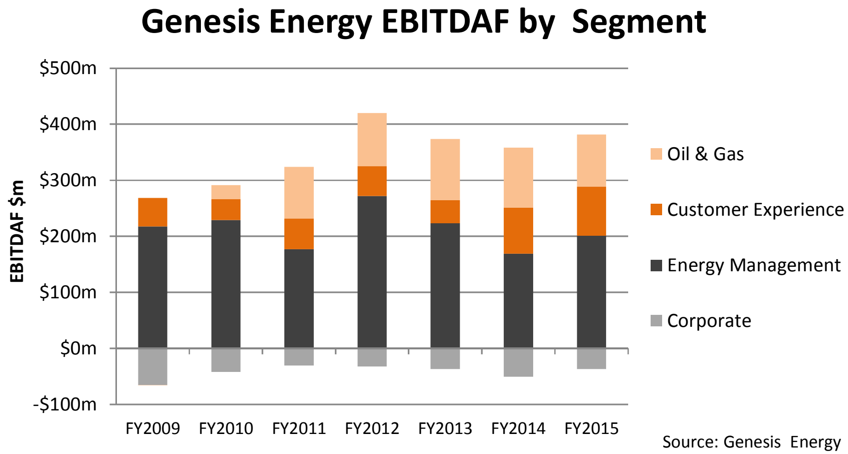
Andrew Donaldson
Chief Financial Officer

Results Summary

- NPAT and Free Cash Flow (FCF) are better than the Prospectus forecasts – dividends are in line
- EBITDAF of $344.8m was up 12% on FY2014 and at the top end of $330m to $345m April 2015 range
  - Low international oil prices
  - The generation mix at the end of FY2015 different to that projected with resulting impact on fuel costs
  - Retail margins impacted by lower customer numbers, offset by reduced costs
- NPAT up 10% versus PFI and 113% ahead of FY2014 due to lower net interest charge, positive fair value changes and lower effective tax rate
- FCF up 22% due to lower stay in business capital expenditure, and total dividends up 23%

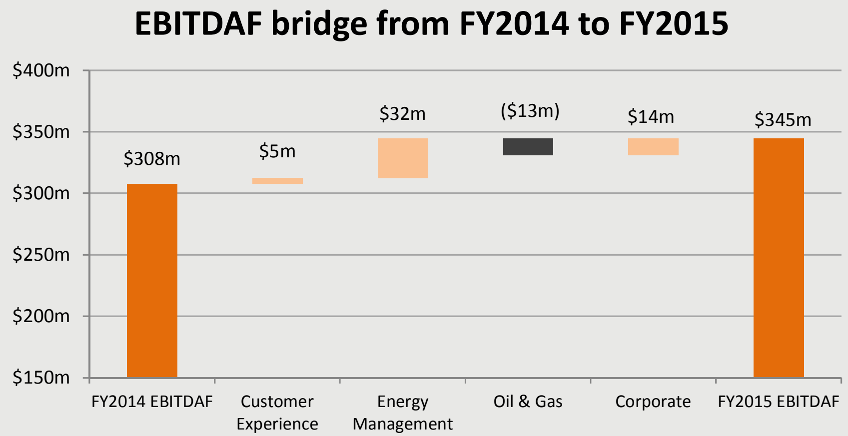
12 months to 30 June ($m)	2015	2014	% change
Revenue	**2097.6**	**2,005.0**	5%
Total operating expenses [1]	1,752.8	1,697.2	3%
EBITDAF [2]	**344.8**	**307.8**	12%
Depreciation depletion & amortisation	155.7	156.7	-1%
Impairment	14.0	10.1	39%
Fair value change (gains)/losses	(32.1)	(0.4)	7081%
Other (gains)/losses	0.2	1.6	-87%
Earnings before interest and tax	**207.0**	**139.8**	48%
Interest	66.7	68.2	-2%
Tax	35.5	22.4	58%
Net profit after tax	**104.8**	**49.2**	113%
Earnings per share (cents per share)	10.5	4.9	113%
Stay in business capital expenditure	43.6	54.5	-20%
Free cash flow	**197.7**	**161.8**	22%
Dividends declared	160.0	130.0	23%
Dividends per share (cents per share)	16.0	13.0	23%
Dividends declared as a % of FCF	80.9%	80.4%	1%
Net debt [3]	**905.1**	**966.0**	-6%

[1] Includes cost of electricity purchases
[2] Earnings before net finance expense, tax, depreciation, amortisation, fair value changes and other gains and
[3] Reported net debt of $937.2m has been adjusted for $32.1m of foreign currency translation and fair value movements related to USD denominated borrowings which have been fully hedged with cross currency interest rate swaps.



Segmental Detail

- Customer Experience, Energy Management and Corporate business segments all contributed to EBITDAF growth
  - Reductions in cost to serve, flow on of price increases made in FY2014 from Customer Experience
  - Increased wholesale prices, more generation, lower costs from Energy Management
  - Reduced head office costs, benefits of employee restructuring undertaken in FY2014 from Corporate
- Oil and Gas EBITDAF reduced by $13m to $93.5m
  - Lower overall production and sales, and lower oil prices
  - Represents 27% of Group EBITDAF (35% in FY2014)



EBITDAF $m	FY2014	FY2015	Change %	Change $m
Energy Management	168.9	201.1	19%	32.2
Customer Experience	82.5	87.2	6%	4.7
Oil & Gas	107.0	93.5	-13%	-13.5
Corporate	-50.6	-37.0	-27%	13.6
Total EBITDAF	**307.8**	**344.8**	**12%**	**37.0**

Balance Sheet

As at 30 June ($m)	2015	2014	% change
Cash and cash equivalents	21.0	23.3	-10%
Other current assets	325.5	334.0	-3%
Non-current assets	3,181.5	3,272.1	-3%
Total assets	**3,528.0**	**3,629.4**	**-3%**
Total borrowings	958.2	989.3	-3%
Other liabilities	744.4	759.3	-2%
Total equity	**1,825.4**	**1,880.7**	**-3%**
Net debt [1]	**905.1**	**966.0**	**-6%**
Gearing	34.4%	34.5%	0%
EBITDAF interest cover	6.2	5.3	16%
Net debt: EBITDAF	2.6	3.1	-16%
Net Assets	1,825.4	1,880.8	-3%

(1) FY2015 net debt of $937.2m has been adjusted for $32.1m of foreign currency translation and fair value movements related to USD denominated borrowings which have been fully hedged with cross currency interest rate swaps.

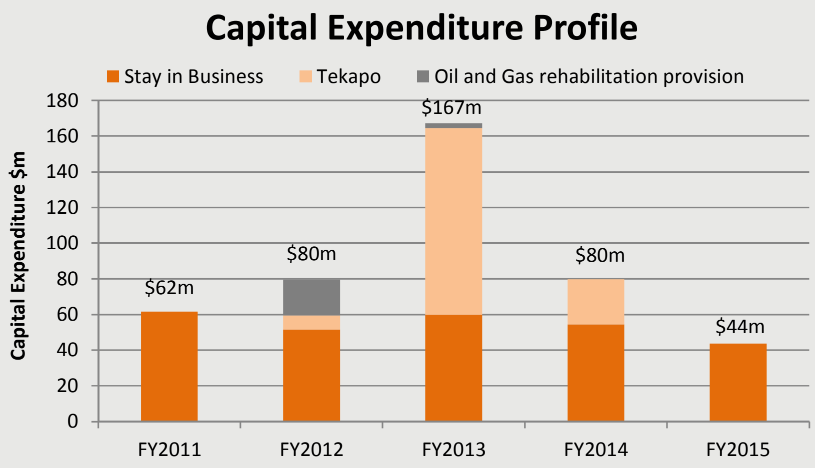
- Despite the increased dividends paid in FY2015, net debt was down 6% to $905m
  - Net debt remains within the target range and maintains the BBB+ rating from S&P with net debt to EBITDAF ratio of 2.6
  - Adjusting gearing of 33.7% has improved versus FY2014
- Adjusting for $32.1m of foreign currency and fair value movements associated with the US Private Placement (USPP) undertaken in Oct/Nov 2014 provides a better comparison with FY2014 levels
- EBITDAF interest cover improved since last year given the reduction in interest costs and the increased EBITDAF
- Currently there is $325m of funding headroom with average debt maturity of 8.5 years

Debt Comparisons $m	FY2015	FY2014	Change
Total Debt	958.2	989.3	-3%
Cash and cash equivalents	21.0	23.3	-10%
Headline Net Debt	**937.2**	**966.0**	**-3%**
USPP FX and FV adjustments	32.1	0.0	-
Adjusted Net Debt	**905.1**	**966.0**	**-6%**
Headline Gearing	34.4%	34.5%	0%
Adjusted Gearing	33.7%	34.5%	-1%

Cashflow and Capital Expenditure Summary

Cashflow: 12 months to 30 June ($m)	2015	2014	% change
Net operating cashflow	318.5	303.9	5%
Net investing cashflow	-48.6	-82.9	-41%
Net financing cashflow	-272.2	-220.4	24%
Net increase (decrease) in cash	**-2.3**	**0.6**	-457%
Stay in business capex	43.6	54.5	-20%
Total capex	**43.6**	**79.8**	-45%
Free cash flow	**197.7**	**161.8**	22%

- Operating cashflows increased 5% vs FY2014 due to increased EBITDAF
- Investing cashflows better than expected due to 20% decrease in stay in business capital expenditure to $43.6m
  - Result of new Asset Management Plans and running assets more efficiently
- Financing cash outflows increased due to increase in dividends paid
- Free cash flow of $197.7m was 22% higher than FY2014

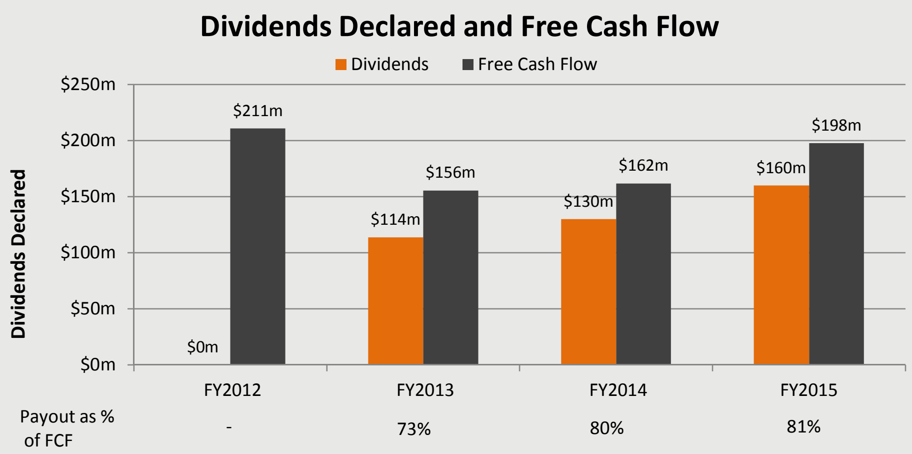


Dividend policy:

- Intention is to pay a dividend that provides shareholders with a consistent, reliable and attractive dividend even in periods of business-cycle downturn
- Imputation expected to be less than 100% in future

Dividends

- Final dividend of 8.0cps takes total dividends declared in FY2015 to 16.0cps
  - 23% ahead of FY2014
  - Record date of final dividend 2 October 2015, payment date 16 October 2105
  - Fully imputed
  - Equates to a net yield of 9.2% based on share price at 30 June 2015
- FY2015 dividends equate to 81% of Free Cash Flow
  - Compares to 80% in FY2014



Summary and Outlook

- In the face of dynamic retail and wholesale electricity and gas markets, Genesis Energy has delivered FY2015 results ahead of those in FY2014
- A number of the announcements post balance date will set the tone for the Company's strategy over the next few years
- The shape of the electricity industry is also likely to change given a tightening of the generation capacity
- There will be opportunities to derive more value from the Company's current portfolio and reduce operating costs and capital expenditure further

Outlook

- Above average national hydro storage levels will continue to impact wholesale electricity prices in the near term, with medium term upward pressure from improving demand and generation capacity reductions
- Genesis Energy can continue to deliver a sustainable dividend underpinned in FY2016 by EBITDAF in line with that reported in FY2015
- In line with the progressive dividend policy, the total dividend declared in FY2016 is expected to increase

APPENDIX

Reconciliation of EBITDAF to NPAT

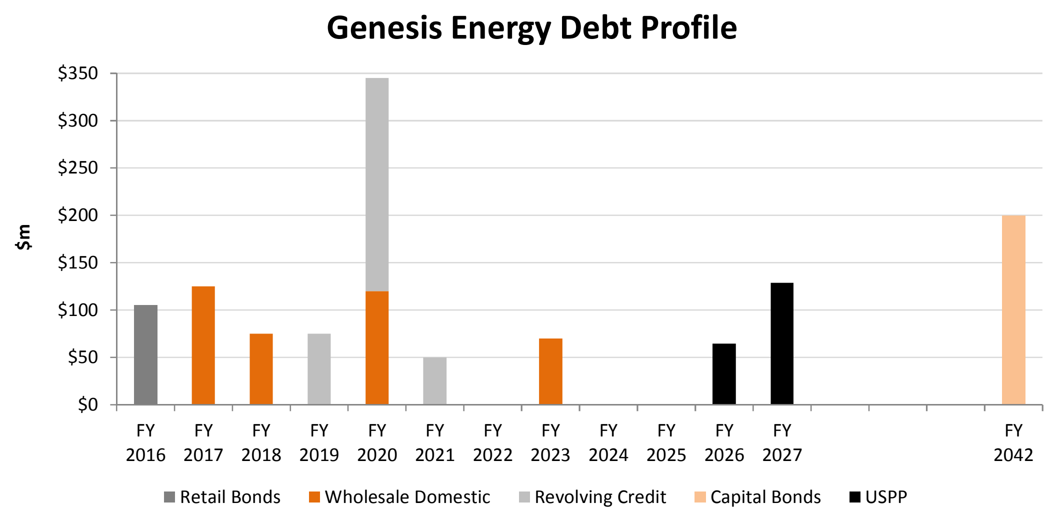
$m 12 Months to 30 June	2015	2014	% change
EBITDAF	344.8	307.8	12%
Depreciation, depletion and amortisation	-155.7	-156.7	-1%
Impairment of non-current assets	-14.0	-10.1	39%
Change in fair value of financial instruments	32.1	0.4	7081%
Other gains (losses)	-0.2	-1.6	-87%
Profit before net finance expense and income tax	**207.0**	**139.8**	48%
Finance revenue	1.3	0.9	44%
Finance expense	-68.0	-69.1	-2%
Profit before income tax	**140.3**	**71.6**	96%
Income tax expense	-35.5	-22.4	58%
Net profit after tax	**104.8**	**49.2**	113%

- EBITDAF is a non-GAAP item but is used as a key metric by management to monitor performance at a business segment and group level
- Genesis Energy believes that reporting EBITDAF assists stakeholders and investors in understanding the Company's operational performance
- In FY2015 EBITDAF of $348.8m was up 12% on FY2014
- FY2015 Net Profit After Tax of $104.8m was 113% higher than in FY2014 and 10% higher than the PFI estimate

$m 12 Months to 30 June	2015	2014	% change
EBITDAF	**344.8**	**307.8**	12%
Less finance expense	68.0	69.1	-2%
Less income tax expense	35.5	22.4	58%
Less stay in business capital expenditure	43.6	54.5	-20%
Free Cash Flow	**197.7**	**161.8**	22%

Free Cash Flow

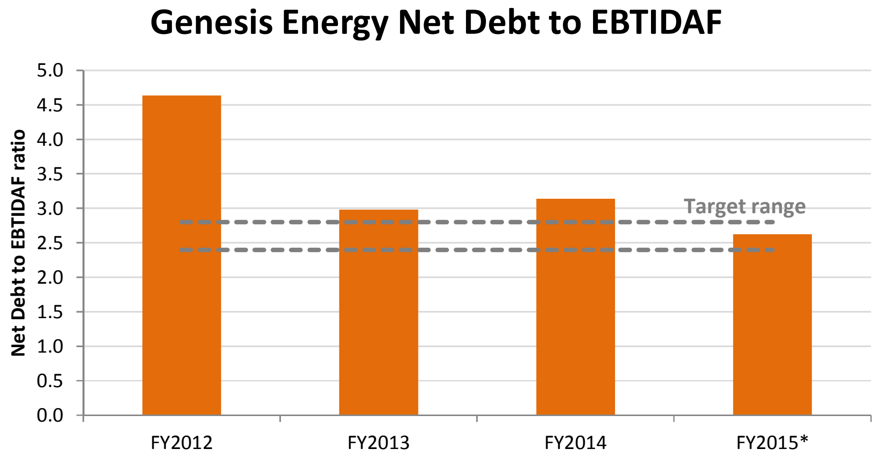
- Free Cash Flow (FCF) is a key metric showing ability to pay cash dividends
- Calculated using EBITDAF, finance expense tax paid, and stay in business capital expenditure
- In FY2015 FCF of $197.7m was up 22% on FY2014 mainly due to decrease in stay in business capital expenditure and lower finance expense



Debt Profile

- Recent restructuring of revolving credit facilities has led to reduced finance expenses
- Capital Bonds were modified in July 2013:
  - Amount reduced from $275 million to $200 million
  - Coupon reduced from 8.50% to 6.19%
- US$150 million (NZ$193 million) raised in first USPP in October 2014 at an average coupon of 3.67%
- $325m of revolving cash facilities were undrawn at 30 June 2015
- Average maturity tenor is 8.5 years

Net Debt to EBITDAF ratio



*FY2015 net debt adjusted for USPP

- Net Debt to EBITDAF ratio is the key metric focused on by credit ratings agencies including Standard and Poors
- In order to maintain a BBB+ rating the target range for the EBITDAF ratio is 2.4 to 2.8
- Note that S&P calculation of Net debt/EBITDAF includes a number of adjustments to reported numbers eg USPP foreign currency translation

THANK YOU

Consolidated Financial Statements

Genesis Energy Limited
Consolidated Financial Statements
for the year ended 30 June 2015

Contents

Notes to the financial statements

Consolidated comprehensive income statement

For the year ended 30 June 2015

	Note	2015 $ million	2014 $ million
Operating revenue			
Electricity revenue		**1,730.4**	1,661.1
Gas revenue		**282.9**	251.3
Petroleum revenue		**64.7**	84.4
Other revenue		**19.6**	8.2
		2,097.6	2,005.0
Operating expenses			
Electricity purchases, transmission and distribution		**(953.7)**	(897.7)
Gas purchases and transmission		**(297.1)**	(249.8)
Petroleum production, marketing and distribution		**(26.1)**	(30.6)
Fuels consumed		**(187.4)**	(191.3)
Employee benefits	4	**(80.6)**	(89.2)
Other operating expenses	4	**(207.9)**	(238.6)
		(1,752.8)	(1,697.2)
Earnings before net finance expense, income tax, depreciation, depletion, amortisation, impairment, fair value changes and other gains and losses		**344.8**	307.8
Depreciation, depletion and amortisation	5	**(155.7)**	(156.7)
Impairment of non-current assets	15	**(14.0)**	(10.1)
Change in fair value of financial instruments	6	**32.1**	0.4
Other gains (losses)		**(0.2)**	(1.6)
		(137.8)	(168.0)
Profit before net finance expense and income tax		**207.0**	139.8
Finance revenue		**1.3**	0.9
Finance expense	7	**(68.0)**	(69.1)
Profit before income tax		**140.3**	71.6
Income tax (expense)	8	**(35.5)**	(22.4)
Net profit for the year		**104.8**	49.2
Other comprehensive income			
Items that may be reclassified subsequently to profit or loss:			
Change in cash flow hedge reserve	25	**(20.1)**	5.0
Income tax credit (expense) relating to items that may be reclassified	25	**5.6**	(1.4)
Total items that may be reclassified subsequently to profit or loss		**(14.5)**	3.6
Total other comprehensive income (expense) for the year		**(14.5)**	3.6
Total comprehensive income for the year		**90.3**	52.8
Earnings per share from operations attributable to shareholders of the Parent			
Basic and diluted earnings per share (cents)	9	**10.49**	4.92

The above statements should be read in conjunction with the accompanying notes.

Consolidated statement of changes in equity

For the year ended 30 June 2015

	Note	Share capital $ million	Share-based payments reserve $ million	Asset revaluation reserve $ million	Cash flow hedge reserve $ million	Retained earnings $ million	Total $ million
Balance as at 1 July 2013		540.6	–	806.4	(8.7)	611.5	1,949.8
Net profit for the year		–	–	–	–	49.2	49.2
Other comprehensive income							
Change in cash flow hedge reserve	25	–	–	–	5.0	–	5.0
Income tax expense relating to other comprehensive income	8	–	–	–	(1.4)	–	(1.4)
Total comprehensive income for the year		–	–	–	3.6	49.2	52.8
Revaluation reserve reclassified to retained earnings on disposal of assets		–	–	(0.6)	–	0.6	–
Acquisition of Treasury shares	11	(0.9)	–	–	–	–	(0.9)
Dividends	10	–	–	–	–	(121.0)	(121.0)
Balance as at 30 June 2014		539.7	–	805.8	(5.1)	540.3	1,880.7
Net profit for the year		–	–	–	–	104.8	104.8
Other comprehensive income							
Change in cash flow hedge reserve	25	–	–	–	(20.1)	–	(20.1)
Income tax credit relating to other comprehensive income	8	–	–	–	5.6	–	5.6
Total comprehensive income (expense) for the year		–	–	–	(14.5)	104.8	90.3
Share-based payments	12	–	0.3	–	–	–	0.3
Dividends	10	–	–	–	–	(145.9)	(145.9)
Balance as at 30 June 2015		**539.7**	**0.3**	**805.8**	**(19.6)**	**499.2**	**1,825.4**

The above statements should be read in conjunction with the accompanying notes.

Consolidated balance sheet

As at 30 June 2015

	Note	2015 $ million	2014 $ million
Current assets			
Cash and cash equivalents		**21.0**	23.3
Receivables and prepayments	13	**187.7**	216.4
Inventories	14	**80.0**	93.8
Assets held for sale	16	**3.1**	–
Intangible assets	18	**4.3**	3.9
Tax receivable		**16.2**	–
Derivatives	25	**34.2**	19.9
Total current assets		**346.5**	357.3
Non-current assets			
Receivables and prepayments	13	**0.9**	0.9
Inventories	14	**24.4**	34.1
Property, plant and equipment	15	**2,682.5**	2,758.8
Oil and gas assets	17	**292.4**	342.1
Intangible assets	18	**127.4**	128.2
Derivatives	25	**53.9**	8.0
Total non-current assets		**3,181.5**	3,272.1
Total assets		**3,528.0**	3,629.4
Current liabilities			
Payables and accruals	22	**158.3**	194.8
Tax payable		**–**	3.4
Borrowings	23	**117.8**	12.3
Provisions	24	**12.3**	13.6
Derivatives	25	**21.5**	22.5
Total current liabilities		**309.9**	246.6
Non-current liabilities			
Payables and accruals	22	**0.7**	0.7
Borrowings	23	**840.4**	977.1
Provisions	24	**123.7**	126.9
Deferred tax liability	8	**397.2**	384.2
Derivatives	25	**30.7**	13.2
Total non-current liabilities		**1,392.7**	1,502.1
Total liabilities		**1,702.6**	1,748.7
Shareholders' equity			
Share capital	11	**539.7**	539.7
Reserves		**1,285.7**	1,341.0
Total equity		**1,825.4**	1,880.7
Total equity and liabilities		**3,528.0**	3,629.4

The Directors of Genesis Energy Limited authorise these financial statements for issue on behalf of the Board.

Rt Hon Dame Jenny Shipley DNZM
Chairman of the Board
Date: 24 August 2015

Joanna Perry MNZM
Chairman of the Audit and Risk Committee
Date: 24 August 2015

The above statements should be read in conjunction with the accompanying notes.

Consolidated cash flow statement

For the year ended 30 June 2015

	2015 $ million	2014 $ million
Cash flows from operating activities		
Cash was provided from:		
Receipts from customers	2,122.0	2,055.1
Interest received	1.3	0.9
	2,123.3	2,056.0
Cash was applied to:		
Payments to suppliers and related parties	1,687.6	1,649.7
Payments to employees	81.0	89.1
Tax paid	36.2	13.3
	1,804.8	1,752.1
Net cash inflows from operating activities	318.5	303.9
Cash flows from investing activities		
Cash was provided from:		
Proceeds from disposal of property, plant and equipment	1.3	0.4
Proceeds from disposal of oil and gas assets	–	0.1
	1.3	0.5
Cash was applied to:		
Purchase of property, plant and equipment	35.5	66.5
Purchase of oil and gas assets	4.1	1.2
Purchase of intangibles (excluding emission units)	10.3	15.7
	49.9	83.4
Net cash (outflows) from investing activities	(48.6)	(82.9)
Cash flows from financing activities		
Cash was provided from:		
Proceeds from borrowings	193.0	167.1
	193.0	167.1
Cash was applied to:		
Repayment of borrowings	256.1	195.0
Interest paid and other finance charges	61.6	66.6
Repayment of principal on finance lease liabilities	1.6	4.0
Dividends	145.9	121.0
Acquisition of Treasury shares	–	0.9
	465.2	387.5
Net cash (outflows) from financing activities	(272.2)	(220.4)
Net increase (decrease) in cash and cash equivalents	(2.3)	0.6
Cash and cash equivalents at 1 July	23.3	22.7
Cash and cash equivalents at 30 June	21.0	23.3

The above statements should be read in conjunction with the accompanying notes.

Consolidated cash flow statement (continued)

For the year ended 30 June 2015

Reconciliation of net profit to net cash inflow from operating activities	Note	2015 $ million	2014 $ million
Net profit for the year		**104.8**	49.2
Items classified as investing/financing activities			
Net (gain) loss on disposal of property, plant and equipment		**2.5**	(0.1)
Interest and other finance charges paid		**61.8**	63.4
		64.3	63.3
Non-cash items			
Depreciation, depletion and amortisation expense	5	**155.7**	156.7
Impairment of non-current assets	15	**14.0**	10.1
Change in fair value of financial instruments	6	**(32.1)**	(0.4)
Deferred tax expense	8	**18.6**	1.2
Change in capital expenditure accruals		**1.9**	4.4
Change in rehabilitation and contractual arrangement provisions		**(0.3)**	1.3
Other non-cash items		**2.0**	(3.1)
		159.8	170.2
Movements in working capital			
Change in receivables and prepayments		**28.7**	51.5
Change in inventories		**23.5**	(13.8)
Change in emission units on hand		**(2.0)**	(5.1)
Change in payables and accruals		**(36.5)**	(30.0)
Change in tax receivable/payable		**(19.6)**	8.1
Change in provisions		**(4.5)**	10.5
		(10.4)	21.2
Net cash inflow from operating activities		**318.5**	303.9

The above statements should be read in conjunction with the accompanying notes.

Notes to the consolidated financial statements

For the year ended 30 June 2015

1. General information

Genesis Energy Limited (the 'Parent') is a company registered under the Companies Act 1993. The Parent is majority owned by Her Majesty the Queen in Right of New Zealand (the 'Crown') and is listed on the NZSX, NZDX and ASX. The Parent, as a mixed ownership model company, is bound by the requirements of the Public Finance Act 1989. The liabilities of the Parent are not guaranteed in any way by the Crown. The Parent is an FMC Reporting Entity under the Financial Markets Conduct Act 2013 and the Financial Reporting Act 2013.

The consolidated financial statements comprise the Parent, its subsidiaries and the Group's interests in joint operations (together, the 'Group'). The Group is designated as a profit-oriented entity for financial reporting purposes.

The Group's core business is located in New Zealand and involves the generation of electricity, retailing and trading of energy, and the development and procurement of fuel sources. To support these functions, the Group's scope of business includes retailing and trading of related complementary products designed to support its key energy business.

2. Basis of accounting

Basis of preparation

The financial statements have been prepared in accordance with and comply with New Zealand Generally Accepted Accounting Practice ('NZ GAAP'), New Zealand Equivalents to International Financial Reporting Standards ('NZ IFRS') and other applicable New Zealand Financial Reporting Standards as appropriate for profit-oriented entities. These financial statements comply with International Financial Reporting Standards ('IFRS').

The financial statements have been prepared in accordance with the Financial Reporting Act 2013 and the Companies Act 1993, and are presented in New Zealand dollars rounded to the nearest million. The accounting policies adopted in the preparation of these financial statements are set out below and in the relevant notes to the financial statements. These policies have been applied consistently to all years presented, unless otherwise stated.

The financial statements have been prepared under the historical-cost convention, modified by the revaluation of derivatives and generation assets.

Goods and Services Tax ('GST')

The financial statements are prepared on a GST exclusive basis with the exception of receivables and payables, which include GST where GST has been invoiced.

Basis of consolidation

Subsidiaries

Subsidiaries are all those entities (including structured entities) controlled by the Group. Control is achieved when the Parent has exposure or rights to variable returns and has the power to affect those returns. Subsidiaries are consolidated from the date control is acquired. They are de-consolidated from the date control ceases. The acquisition method of accounting is used to account for the acquisition of subsidiaries.

Joint operations

Where the Group invests in joint operations, the Group's share of revenue, expenditure, assets and liabilities is included in the appropriate categories within the Group financial statements on a proportionate line-by-line basis.

Transactions and balances eliminated on consolidation

Intercompany transactions, balances, revenue and expenditure between Group companies are eliminated on consolidation.

Critical accounting estimates and judgements

The preparation of financial statements requires management to make estimates and assumptions that affect the application of policies and the reported amounts of assets, liabilities, revenues and expenses.

The estimates and associated assumptions are based on historical experience and various other factors that are reasonable under the circumstances. Actual results may differ from these estimates.

The estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognised in the period in which the estimate is revised if the revision affects only that period, or in the period of the revision and future periods if the revision affects both current and future periods.

Significant areas of estimation in these financial statements are as follows:

Valuation of generation assets

The Group's generation assets are carried at fair value. The fair value is based on the present value of the estimated future cash flows of the assets, excluding any reduction for costs associated with rehabilitation and restoration. The key assumptions used in the valuation and the carrying value of generation assets are disclosed in note 15.

Depletion of oil and gas producing assets

Depletion of oil and gas producing assets is based on the proven reserves to which the assets relate. Proven reserve estimates can change over time. The proven reserve estimates used to deplete oil and gas producing assets and the carrying value of the assets are disclosed in note 17.

Valuation of rehabilitation and restoration provision

The financial statements include an estimate of the liability in relation to the abandonment and restoration of generation and oil and gas production sites. Such estimates are measured at the present value of the cash flows expected to settle the obligation. The key assumptions used in the calculation and the carrying value of the rehabilitation and restoration provision are disclosed in note 24.

Valuation of electricity derivatives

The valuation of electricity derivatives classified as level three financial instruments is based on forecasted internally generated electricity price paths which incorporate a number of assumptions. The key assumptions used in the valuation and the carrying value of electricity derivatives classified as level three financial instruments are disclosed in note 27.

Impairment of assets

Assets that have indefinite useful lives are not subject to amortisation and are tested annually for impairment. Assets that are subject to depletion, depreciation or amortisation are reviewed for impairment annually, or whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If an asset's carrying value exceeds its recoverable amount, the difference is recognised as an impairment loss in profit or loss, except where the asset is carried at a revalued amount then it is treated as a revaluation decrease.

The recoverable amount is the higher of an asset's fair value less costs to sell, and the asset's value in use. In assessing value in use, the estimated future cash flows are discounted to their present value at a rate that reflects current market assessments of the time value of money. This discount rate is adjusted for the risks specific to the asset where the estimated cash flows have not been adjusted.

2. Basis of accounting (continued)

For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash flows (cash-generating units). Non-financial assets other than goodwill that have been impaired are reviewed for possible reversal of the impairment at each reporting date.

Where an impairment loss subsequently reverses, the carrying amount of the asset is increased to the revised estimate of its recoverable amount, but only to the extent the carrying amount of the asset at the date the impairment is reversed does not exceed what the amortised cost would have been had the impairment not been recognised. A reversal of an impairment loss is recognised in profit or loss immediately, unless the relevant asset is carried at fair value, in which case the reversal of the impairment loss is treated as a revaluation increase. Impairment of goodwill is not reversed.

Foreign currency transactions

Transactions denominated in a foreign currency are converted at the exchange rate in effect at the date of the transaction. At balance date monetary assets and liabilities denominated in foreign currencies are translated at the closing rate. Exchange gains and losses arising from these translations and the settlement of these items are recognised in profit or loss, except when deferred in equity where cash flow hedging is applied (refer to the derivatives accounting policy disclosed in note 25).

Statement of cash flows

The following definitions are used in the statement of cash flows:

Operating activities

Operating activities include all transactions and other events that are not investing or financing activities.

Investing activities

Investing activities are those activities relating to the acquisition, holding and disposal of property, plant and equipment, oil and gas assets, intangible assets (excluding emission units) and investments.

Financing activities

Financing activities are those activities that result in changes to the size and composition of the capital structure of the Group. They include both equity and debt not falling within the definition of cash. Dividends and interest paid in relation to the capital structure are included in financing activities.

Payments to suppliers and related parties disclosed in operating activities include the net amount of GST paid/received during the year. GST is disclosed on a net basis as the gross amounts do not provide meaningful information for financial statement purposes.

Capital and reserves

Asset revaluation reserve

The asset revaluation reserve is used to record movements in the fair value of generation assets in accordance with the property, plant and equipment accounting policy disclosed in note 15.

Cash flow hedge reserve

The cash flow hedge reserve comprises the effective portion of the cumulative net change in the fair value of cash flow hedging instruments related to hedge transactions that have not yet occurred.

Share-based payments reserve

The share-based payments reserve is used to recognise the value of equity-settled share-based payments provided to employees, including key management personnel, as part of their remuneration.

Adoption of new and revised accounting standards, interpretations and amendments

There have been no new and revised accounting standards, interpretations or amendments effective during the year which have a material impact on the Group's accounting policies or disclosures.

Accounting standards, interpretations and amendments in issue not yet effective

The International Accounting Standards Board (IASB) has published the final version of IFRS 9 *Financial Instruments*, which is effective for annual reporting periods beginning on or after 1 January 2018. Therefore, the Group is required to adopt this standard for the financial year ending 30 June 2019. The standard comprises three phases: phase one, Classification and Measurement; phase two, Impairment; and phase three, Hedge Accounting. Phases one and two are not expected to have a material impact on the Group's financial statements. The impact of phase three has yet to be assessed.

NZ IFRS 15 *Revenue from Contracts with Customers* is effective for annual reporting periods beginning on or after 1 January 2017. The Group has yet to determine the impact this standard will have on the Group's financial statements.

All other standards, interpretations and amendments approved but not yet effective in the current year are either not applicable to the Group or are not expected to have a material impact on the Group's financial statements and, therefore, have not been discussed.

3. Segment reporting

For management purposes, the Group is currently organised into four segments as follows:

Segment	Activity
Customer experience	Supply of energy (electricity, gas and LPG) to end-user customers as well as related services.
Energy management	Generation and trading of electricity and related products. The segment includes electricity sales to the wholesale electricity market, derivatives entered into to fix the price of electricity, and wholesale gas and coal sales.
Oil and gas	Exploration, development, production and sale of gas, LPG and light oil.
Corporate	Head office functions including new generation investigation and development, fuel management, information systems, human resources, finance, corporate relations, property management, legal and corporate governance. Corporate revenue is made up of property rental and miscellaneous income.

The segments are based on the different products and services offered by the Group. No operating segments have been aggregated.

Year ended 30 June 2015	Customer experience $ million	Energy management $ million	Oil and gas $ million	Corporate $ million	Inter-segment items $ million	Total $ million
Operating revenue						
Electricity revenue	1,180.3	1,037.9	–	–	(487.8)	1,730.4
Gas revenue	149.1	188.3	59.3	–	(113.8)	282.9
Petroleum revenue	–	–	64.7	–	–	64.7
Other revenue	9.0	9.1	0.4	1.1	–	19.6
	1,338.4	1,235.3	124.4	1.1	(601.6)	2,097.6
Operating expenses						
Electricity purchase, transmission and distribution	(978.6)	(462.9)	–	–	487.8	(953.7)
Gas purchase and transmission	(125.0)	(229.0)	–	–	56.9	(297.1)
Petroleum production, marketing and distribution	–	–	(26.1)	–	–	(26.1)
Fuel consumed	–	(244.3)	–	–	56.9	(187.4)
Employee benefits	(25.5)	(28.4)	–	(26.7)	–	(80.6)
Other operating expenses	(122.1)	(69.6)	(4.8)	(11.4)	–	(207.9)
Earnings before net finance expense, income tax, depreciation, depletion, amortisation, impairment, fair value changes and other gains and losses	87.2	201.1	93.5	(37.0)	–	344.8
Depreciation, depletion and amortisation	(3.0)	(85.4)	(55.3)	(12.0)	–	(155.7)
Impairment of non-current assets	–	(13.1)	–	(0.9)	–	(14.0)
Change in fair value of financial instruments	–	29.4	4.7	(2.0)	–	32.1
Other gains (losses)	–	(0.2)	1.1	(1.1)	–	(0.2)
Profit (loss) before net finance expense and income tax	84.2	131.8	44.0	(53.0)	–	207.0
Finance revenue	0.1	–	0.2	1.0	–	1.3
Finance expense	(0.3)	(3.3)	(2.9)	(61.5)	–	(68.0)
Profit (loss) before income tax	84.0	128.5	41.3	(113.5)	–	140.3
Other segment information						
Capital expenditure	4.3	29.2	4.0	6.1	–	43.6

3. Segment reporting (continued)

Year ended 30 June 2014	Customer experience $ million	Energy management $ million	Oil and gas $ million	Corporate $ million	Inter-segment items $ million	Total $ million
Operating revenue						
Electricity revenue	1,141.5	990.0	–	–	(470.4)	1,661.1
Gas revenue	142.3	159.5	58.2	–	(108.7)	251.3
Petroleum revenue	–	–	84.4	–	–	84.4
Other revenue	5.2	2.0	0.1	0.9	–	8.2
	1,289.0	1,151.5	142.7	0.9	(579.1)	2,005.0
Operating expenses						
Electricity purchase, transmission and distribution	(936.7)	(431.4)	–	–	470.4	(897.7)
Gas purchase and transmission	(118.2)	(184.9)	–	–	53.3	(249.8)
Petroleum production, marketing and distribution	–	–	(30.6)	–	–	(30.6)
Fuel consumed	–	(246.7)	–	–	55.4	(191.3)
Employee benefits	(26.5)	(33.2)	–	(29.5)	–	(89.2)
Other operating expenses	(125.1)	(86.4)	(5.1)	(22.0)	–	(238.6)
Earnings before net finance expense, income tax, depreciation, depletion, amortisation, impairment, fair value changes and other gains and losses	82.5	168.9	107.0	(50.6)	–	307.8
Depreciation, depletion and amortisation	(2.9)	(85.9)	(56.4)	(11.5)	–	(156.7)
Impairment of non-current assets	–	(9.9)	–	(0.2)	–	(10.1)
Change in fair value of financial instruments	–	2.0	(1.6)	–	–	0.4
Other gains (losses)	–	(0.9)	(0.5)	(0.2)	–	(1.6)
Profit (loss) before net finance expense and income tax	79.6	74.2	48.5	(62.5)	–	139.8
Finance revenue	0.3	–	0.1	0.5	–	0.9
Finance expense	(0.2)	(3.1)	(2.8)	(63.0)	–	(69.1)
Profit (loss) before income tax	79.7	71.1	45.8	(125.0)	–	71.6
Other segment information						
Capital expenditure	3.3	60.2	1.7	17.2	–	82.4

Inter-segment revenue

Sales between segments is based on transfer prices developed in the context of long-term contracts. Inter-segment gas revenue includes the Group's share of Kupe gas sales to Energy Management and gas on-sold from Energy Management to Customer Experience.

Geographic information

All business segments operate within New Zealand.

Major customer information

The Group has no individual customers that account for 10 per cent or more of the Group's external revenue (2014: none).

4. Operating expenses

	2015 $ million	2014 $ million
Operating expenses include:		
Auditor's remuneration:		
Audit of financial statements		
– Audit fees for interim financial statements (Deloitte)	–	0.3
– Review fees for interim financial statements (Deloitte)	**0.1**	–
– Audit fees for annual financial statements (Deloitte)	**0.4**	0.4
Other services		
– Audit-related services (Deloitte)[1]	–	0.2
– Other services (Deloitte)[2]	–	0.1
Directors' fees	**0.8**	0.7
Bad debts	**7.2**	6.2
Employee benefits expense – defined contributions	**2.8**	2.9
Rental expenses on operating leases	**8.0**	7.8
Contract termination fee and related onerous contracts[3]	**(3.2)**	16.8
Offer costs	**0.2**	9.8

1 Audit–related services in 2014 relates to the examination of certain financial information included in the Prospectus and attendance as observers at each Due Diligence Committee meeting. This fee is excluded from the offer costs amount.

2 Other services provided by Deloitte relates to trustee reporting and review of the Global Reporting Initiative ('GRI') Report.

3 The contract termination fee and related onerous contracts expense relates to the exit of the coal import contract. The credit in the current year relates to changes in assumptions associated with the onerous contracts.

5. Depreciation, depletion and amortisation

	Note	2015 $ million	2014 $ million
Depreciation of property, plant and equipment	15	**88.6**	88.4
Depreciation and depletion of oil and gas assets	17	**55.3**	56.3
Amortisation of intangibles	18	**11.8**	12.0
		155.7	156.7

6. Change in fair value of financial instruments

	Note	2015 $ million	2014 $ million
Change in fair value of derivatives – gain (loss)	25	**33.3**	(0.5)
Fair value interest rate risk adjustment on borrowings – gain (loss)		**(1.2)**	0.9
		32.1	0.4

The change in the fair value of derivatives for the year mainly relates to the movement in the fair value of electricity swaps and options ($29.1 million). The movement in the fair value of electricity swaps and options primarily reflects movements in the electricity price path between the date contracts were entered into and balance date.

7. Finance expense

	Note	2015 $ million	2014 $ million
Interest on borrowings (excluding Capital Bonds)		**49.1**	50.4
Interest on Capital Bonds		**12.4**	12.6
Total interest on borrowings		**61.5**	63.0
Other interest and finance charges		**0.6**	1.0
Time value of money adjustments on provisions	24	**6.2**	5.7
		68.3	69.7
Capitalised finance expenses	15	**(0.3)**	(0.6)
		68.0	69.1
Weighted average capitalisation rate		**6.4%**	6.6%

Interest on borrowings, bank and facility fees and transaction costs are recognised in profit or loss over the period of the borrowings using the effective interest rate method, unless such costs relate to funding capital work in progress. Time value of money adjustments on provisions is recognised in profit or loss up to the point the provision is used or released.

Finance expense on capital work in progress (qualifying assets) is capitalised during the construction period. The capitalisation rate used to determine the amount of finance expense to be capitalised is based on the weighted average finance expenses incurred by the Group.

8. Income tax

	2015 $ million	2014 $ million
Current tax		
– Current year	**37.6**	24.0
– Under (over) provided in prior periods	**(1.1)**	(2.8)
– Hydroelectric powerhouses – depreciation determination	**(1.1)**	–
– Tekapo Canal remediation costs – settlement	**(18.5)**	–
Deferred tax		
– Current year	**2.5**	(0.8)
– Under (over) provided in prior periods	**0.3**	2.0
– Hydroelectric powerhouses – depreciation determination	**(2.7)**	–
– Tekapo Canal remediation costs – settlement	**18.5**	–
Income tax expense	**35.5**	22.4
Current tax	**16.9**	21.2
Deferred tax	**18.6**	1.2
	35.5	22.4

Reconciliation of income tax expense on pre–tax accounting profit to income tax expense

Profit before income tax	**140.3**	71.6
Income tax at 28%	**39.3**	20.0
Tax effect of adjustments:		
– Under (over) provided in prior periods	**(0.8)**	(0.8)
– Recognition of tax depreciation on hydroelectric powerhouses	**(3.8)**	–
– Non-deductible expenditure and other adjustments	**0.8**	3.2
	35.5	22.4

Income tax is recognised in profit or loss except to the extent that it relates to items recognised directly in other comprehensive income, in which case the income tax is recognised in other comprehensive income.

Current tax is the expected tax payable on taxable income for the year, using tax rates enacted or substantively enacted at the end of the reporting period, together with any unpaid tax or adjustment to tax payable in respect of previous years.

8. Income tax (continued)

Deferred tax liability	Property, plant and equipment $ million	Oil and gas assets $ million	Provisions $ million	Finance lease liabilities $ million	Other $ million	Total $ million
Balance as at 1 July 2013	350.5	83.1	(33.3)	(5.0)	(13.7)	381.6
Amount recognised in profit or loss	6.0	(2.6)	(0.7)	0.7	(2.2)	1.2
Amount recognised in other comprehensive income	–	–	–	–	1.4	1.4
Balance as at 30 June 2014	356.5	80.5	(34.0)	(4.3)	(14.5)	384.2
Amount recognised in profit or loss	17.5	(10.1)	(1.8)	0.8	12.2	18.6
Amount recognised in other comprehensive income	–	–	–	–	(5.6)	(5.6)
Balance as at 30 June 2015	**374.0**	**70.4**	**(35.8)**	**(3.5)**	**(7.9)**	**397.2**

Deferred tax is calculated using the balance sheet liability method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. The amount of deferred tax provided is based on the expected manner of realisation or settlement of the carrying amounts of assets and liabilities, using tax rates enacted or substantively enacted at the end of the reporting period.

Tax depreciation deductions on buildings

Tax depreciation deductions were disallowed for buildings with estimated useful lives of 50 years or more from 1 July 2011. As a result, adjustments to deferred tax liabilities totalling $12.4 million were made in the 2010 and 2011 financial years relating to generation powerhouse assets, offices and leasehold improvements.

On 25 March 2015, the Inland Revenue Department issued a Depreciation Determination for Hydroelectric Powerhouses which allows the Group to claim an annual depreciation deduction of two per cent on hydroelectric powerhouses; this applies retrospectively from the 2012 income year. As a result, a $3.8 million adjustment has been made to tax expense in the current year, the majority of which related to reversing the 2010 and 2011 adjustments made when the change in tax depreciation on buildings was substantively enacted.

On 7 July 2015, the Inland Revenue Department released a draft provisional Depreciation Determination for Geothermal and Thermal Powerhouses, including proposed depreciation rates. The Determination is subject to public consultation and, as a result, is not yet finalised. If the draft provisional Depreciation Determination is approved in its current form, the estimated impact on the Income Statement is to decrease income tax expense by between $3.0 million and $5.0 million as at 30 June 2015 which has been disclosed as a contingent asset. Refer to Note 30.

Tekapo Canal Remediation Project

During the year, a resolution was reached with Inland Revenue on the tax treatment of costs associated with the Tekapo Canal Remediation Project. The impact of the resolution resulted in an increase in current tax receivable and deferred tax liability of $18.5 million.

Unrecognised deferred tax assets and liabilities

Taxable temporary differences in relation to investments in subsidiaries for which deferred tax liabilities have not been recognised is $15.6 million (2014: $11.6 million).

9. Earnings per share

	2015	2014
Numerator		
Net profit for the year attributable to shareholders ($ million)	**104.8**	49.2
Denominator		
Weighted average number of ordinary shares (million units)	**1,000.0**	1,000.0
Less weighted average number of Treasury shares (million units)	**(0.5)**	(0.1)
Weighted average number of ordinary shares for basic and diluted earnings per share calculation (million units)	**999.5**	999.9
Basic and diluted earnings per share (cents)	**10.49**	4.92

10. Dividends

		2015 $ million	2014 $ million	2015 Cents per share	2014 Cents per share
Dividends declared and paid during the year					
Previous year's final dividend	Fully imputed	**66.0**	57.0	**6.60**	10.54
Current year's interim dividend	Fully imputed	**79.9**	64.0	**8.00**	11.84
		145.9	121.0	**14.60**	22.38
Dividends declared subsequent to balance date					
Final dividend	Fully imputed	**80.0**	66.0	**8.00**	6.60

Imputation credits

The Group has $0.1 million imputation credits available for use in subsequent reporting periods (2014: $12.4 million).

11. Share capital

	2015 $ million	2014 $ million	2015 No of shares million	2014 No. of shares million
Issued capital				
Balance as at 1 July	**540.6**	540.6	**1,000.0**	540.6
Share capital issued	–	–	–	459.4
Balance as at 30 June	**540.6**	540.6	**1,000.0**	1,000.0
Treasury shares				
Balance as at 1 July	**(0.9)**	–	**(0.5)**	–
Acquisition of Treasury shares	–	(0.9)	–	(0.5)
Balance as at 30 June	**(0.9)**	(0.9)	**(0.5)**	(0.5)
Total share capital	**539.7**	539.7	**999.5**	999.5

On 10 March 2014, the Parent made a taxable bonus issue of 459,434,998 ordinary shares.

All shares are ordinary authorised, issued and fully paid shares. They all have equal voting rights and share equally in dividends and any surplus on winding up. The shares have no par value.

Treasury shares were acquired in the prior year to meet the current and future obligations under the long-term incentive plan. Refer to note 12.

12. Share–based payments

Long–term incentive plan

During the prior year, the Group implemented a long-term incentive (LTI) plan for senior executives and a Trust was established to administer the plan (refer to note 19). The Trust acquired shares in the Parent; these shares were recorded as Treasury shares in the Group (refer to note 11). Under the plan senior executives purchase shares at market value, funded by interest-free loans from the Parent. The shares are held on Trust by the Trustee of the LTI plan until the end of the vesting period. If the shares vest, each executive is entitled to a cash amount which, after deduction for tax, is equal to the outstanding loan balance on day one for the shares which have vested. That cash amount must be applied towards repayment of their loan balance and the corresponding shares are released by the Trustee back to the individual. The initial vesting period is from April 2014 to June 2017.

Vesting of shares is dependent on continued employment through the vesting period and meeting financial targets in the prospective financial information ('PFI') as disclosed in the Investment Statement dated 13 March 2014. It is also dependent on the Group achieving a positive total shareholder return over the period and the Group's performance relative to the benchmark peer group. If the Group's total shareholder return performance over the vesting period exceeds the 50th percentile total shareholder return of the benchmark peer group, 50 per cent of the shares will vest; 100 per cent of an executive's shares will vest upon meeting the performance of the 75th percentile of the benchmark peer group, with vesting on a straight-line basis between these two points. In the event that the total shareholder return is negative over the period or is less than the 50th percentile of the benchmark peer group and the PFI targets are not met, or if the participant ceases to be employed by the Group other than for qualifying reasons, no shares will vest and the shares will be forfeited to the Trustee without compensation, and the relevant executive will receive no benefits under the plan (unless the Board exercises its discretion to allow some or all of the shares to vest). The benchmark peer group comprises a selected number of NZX-listed electricity generators and energy retailers.

The plan represents the grant of in-substance nil-price options to executives. The cost of the LTI is measured by reference to the fair value at grant date. The fair value of the options granted under the plan are estimated as at the date of grant using an option pricing model that takes into account the terms and conditions upon which the options were granted. The estimated fair value of the in-substance nil-price options at grant date was $0.5 million. In accordance with the rules of the plan, the model simulates the Group's total shareholder return and compares it against the peer group over the vesting period. As the Parent is newly listed and, therefore, has insufficient historical information, the historical dividends, share price volatilities and co-variances of similar entities have been used to compare to the peer group to produce a predicted distribution of relative share performance. This is applied to the relevant grant to give an expected value of the total shareholder return element.

The cost of the LTI is recognised, together with a corresponding increase to the share-based payments reserve within equity, over the period in which the performance and/or service conditions are fulfilled. The cumulative expense recognised for the LTI at each reporting date until the vesting date reflects the extent to which the vesting period has expired and the best estimate of the number of equity instruments that will ultimately vest.

During the year, the Company expensed $0.15 million in relation to the scheme (2014: $0.04 million) and granted 30,812 in-substance nil-price options to senior executives (2014: 335,713), of which none (2014: 43,735) was forfeited during the year.

Employee Share Scheme

During the year, the Group implemented a Employee Share Scheme ('ESS'). The ESS allows Genesis Energy employees to purchase Genesis Energy shares and, subject to certain conditions, receive award shares at no additional cost. Each year, each eligible employee can choose an annual amount (of a maximum of $5,000 and a minimum of $250) they wish to invest from their after-tax pay. The annual amount is divided by the number of after-tax payments an employee will receive in the year and is then deducted from their monthly/fortnightly pay. The deduction is used to purchase shares on a monthly basis. If the eligible employee remains employed by Genesis Energy for the applicable qualification period (three years), they will receive one free share (award share) for every two purchased shares acquired in the first scheme year of the qualification period which the eligible employee continues to hold at the end of the qualification period.

If an employee leaves Genesis Energy, they receive all the shares already purchased with their pay deductions; however, in most circumstances, if an employee leaves within the three-year qualification period, they will not be entitled to receive any award shares. The equity-settled, share-based payment expense is recognised over the three-year vesting period and is equivalent to the fair value of the award shares provided to the employee, calculated as at the grant date. The amount recognised as an expense takes into account an expectation of the number of employees who will leave during the three-year vesting period and will therefore forfeit their shares. At each balance date, the Group revises its estimates of the employees who

12. Share-based payments (continued)

have left or are expected to leave during the three-year period; the expense is adjusted to reflect the actual number of employees not completing or expected to complete the service condition. A corresponding entry is recognised in equity as a share-based payment reserve. The estimated fair value of the in-substance nil-price options at grant date was $0.4 million. During the year, the Group expensed $0.08 million in relation to the scheme.

13. Receivables and prepayments

	2015 $ million	2014 $ million
Trade receivables	**99.4**	132.7
Accrued revenue for unread gas and electricity meters	**81.3**	75.4
Allowance for doubtful receivables	**(6.4)**	(6.9)
	174.3	201.2
Emission units receivable	**1.1**	0.9
Other receivables	**1.8**	1.8
Prepayments	**11.4**	13.4
Total	**188.6**	217.3
Current	**187.7**	216.4
Non-current	**0.9**	0.9
Total	**188.6**	217.3

Revenue is measured at the fair value of the consideration received or receivable net of prompt-payment discounts. Revenue is recognised when the significant risks and rewards of ownership have passed or when the service has been rendered to the customer.

Receivables are initially recognised at fair value and are subsequently measured at amortised cost less any allowance for doubtful receivables. Receivables which are known to be uncollectable are written off. An allowance for doubtful receivables is established when there is objective evidence that the Group will not be able to collect amounts due. The allowance for doubtful receivables is the difference between the carrying value and the estimated recoverable amount.

Emission units receivable are accounted for in the period in which they are earned within receivables and prepayments and are transferred to intangibles when the emission units are received.

14. Inventories

	2015 $ million	2014 $ million
Fuel	**81.6**	107.3
Petroleum products	**0.4**	0.4
Consumables and spare parts	**20.1**	20.2
Emission units held for trading	**2.3**	–
Total	**104.4**	127.9
Current	**80.0**	93.8
Non-current	**24.4**	34.1
Total	**104.4**	127.9

Fuel, petroleum, consumables and spare parts are recognised at the lower of cost and net realisable value. Cost is determined using the weighted average cost basis which includes expenditure incurred in bringing the inventories to their present location and condition, including shipping and handling. Net realisable value is the estimated selling price in the ordinary course of business less the estimated costs necessary to make the sale.

Fuel inventories mainly consist of coal used in electricity production. The amount of fuel inventories (excluding natural gas) expensed during the year was $75.0 million (2014: $51.2 million).

Petroleum products consist of LPG and light crude oil held for resale, produced from the Kupe production facility. The amount of petroleum products expensed during the year was $28.5 million (2014: $29.9 million).

Emission units held for trading purposes are initially measured at cost and are subsequently remeasured to their fair value. Changes in the fair value are recognised immediately in profit or loss.

15. Property, plant and equipment

	Note	Generation assets $ million	Buildings and improvements $ million	Other property, plant and equipment $ million	Capital work in progress $ million	Total $ million
Carrying value at 1 July 2013		2,708.5	3.1	28.8	59.7	2,800.1
Additions		2.3	–	–	60.0	62.3
Capitalised finance expenses	7	–	–	–	0.6	0.6
Change in rehabilitation and contractual arrangement assets		–	–	–	2.9	2.9
Transfer to (from) capital work in progress		58.2	–	12.6	(70.8)	–
Transfer between asset categories		3.6	(1.4)	(4.7)	2.5	–
Transfer to oil and gas assets	17	–	–	–	(8.3)	(8.3)
Disposals		(0.3)	–	–	–	(0.3)
Impairment		–	(0.1)	–	(10.0)	(10.1)
Depreciation expense	5	(82.4)	–	(6.0)	–	(88.4)
Carrying value at 30 June 2014		2,689.9	1.6	30.7	36.6	2,758.8
Additions		0.1	–	–	39.7	39.8
Capitalised finance expenses	7	–	–	–	0.3	0.3
Change in rehabilitation and contractual arrangement assets		–	–	–	1.8	1.8
Transfer to (from) capital work in progress		26.5	0.1	7.3	(33.9)	–
Transfer between asset categories		(0.7)	–	0.5	0.2	–
Transfer to intangible assets	18	–	–	–	(9.4)	(9.4)
Transfer to assets held for sale	16	(3.1)	–	–	–	(3.1)
Disposals		(3.0)	–	(0.1)	–	(3.1)
Impairment		–	–	–	(14.0)	(14.0)
Depreciation expense	5	(81.7)	(0.1)	(6.8)	–	(88.6)
Carrying value at 30 June 2015		**2,628.0**	**1.6**	**31.6**	**21.3**	**2,682.5**
Summary of cost and accumulated depreciation and impairment						
Cost		64.1	2.1	99.5	45.0	210.7
Fair value		2,708.5	–	–	–	2,708.5
Accumulated depreciation and impairment		(82.7)	(0.5)	(68.8)	(8.4)	(160.4)
Carrying value at 30 June 2014		2,689.9	1.6	30.7	36.6	2,758.8
Cost		90.0	2.2	107.0	24.9	224.1
Fair value		2,702.0	–	–	–	2,702.0
Accumulated depreciation and impairment		(164.0)	(0.6)	(75.4)	(3.6)	(243.6)
Carrying value at 30 June 2015		**2,628.0**	**1.6**	**31.6**	**21.3**	**2,682.5**

Generation assets

Generation assets include land, buildings, and plant and equipment associated with generation assets. Generation assets are recognised in the balance sheet at their revalued amounts, being the fair value at the date of their revaluation, less any subsequent accumulated depreciation and impairment losses. The underlying assumptions used in the revaluation are reviewed annually and revaluations are performed with sufficient regularity, not exceeding five yearly, to ensure the carrying amount does not differ materially from that which would be determined using fair values at the balance date.

Any increase in the revaluation of individual generation assets is recognised in other comprehensive income, unless it reverses a revaluation decrease for the same asset previously recognised in profit or loss, in which case it is recognised in profit or loss to the extent of the decrease previously recognised in profit or loss. A decrease in carrying amount arising on the revaluation of individual generation assets is recognised in profit or loss to the extent that it exceeds the balance, if any, held in the asset revaluation reserve relating to a previous revaluation of that asset. Any accumulated depreciation at the date of the revaluation is eliminated against the gross carrying value of the asset so that the gross carrying amount after revaluation equals the revalued amount.

Subsequent additions to generation assets are recognised at cost. Cost includes the consideration given to acquire the asset plus any other costs incurred in bringing the asset to the location and condition necessary for its intended use including major inspection costs, resource consent and relationship agreement costs. The cost of assets constructed includes the cost of all materials and direct labour used in construction, resource consent costs, finance expenses and an appropriate proportion of applicable variable and fixed overheads.

15. Property, plant and equipment (continued)

The last revaluation of generation assets was performed at 30 June 2013. A review of the carrying value of generation assets has been undertaken. The results indicate the carrying value is unlikely to be materially different to the fair value. For this reason, the Group has not undertaken a full revaluation of generation assets.

Fair value of generation assets is determined using a discounted cash flow model. The valuation was based on the present value of the estimated future cash flows of the assets. The valuation was prepared by Management and was independently reviewed by PricewaterhouseCoopers ('PwC'), who has the appropriate qualifications and experience in valuing generation assets. The valuation was calculated by generating site except for the Huntly site where it was calculated by type of unit (units 1 to 4, unit 5 and unit 6).

Valuation of generation assets requires significant judgement and, therefore, there is a range of reasonably possible assumptions that could be used in estimating the fair value of these assets. The wholesale electricity price path is the key driver of changes in the valuation of generation assets. Changes in the wholesale electricity price path have a direct impact on generation volumes and operating costs. The forecasted internally generated price path is influenced by changes in demand, hydrology and new generation build. The key unobservable inputs, range of assumptions and third-party inputs combine to determine the wholesale electricity price path. The significant unobservable inputs in the valuation model were:

Assumptions made at the time of the revaluation at 30 June 2013

Significant unobservable inputs	Method of determination	Sensitivity range	Impact on fair value of generation assets	Interrelationships between unobservable inputs
Wholesale electricity price path	In-house market modelling of the wholesale electricity market cross-checked against publicly available price paths. The wholesale electricity price paths used to value generation assets on a time-weighted basis range from $76 per MWh to $137 per MWh over the period from July 2014 to 31 December 2025.	Plus/minus 10%	$527 million to ($440 million)	Hydrological inflows affect generation volumes as well as wholesale electricity prices.
Generation volumes at average weighted price	In-house market modelling of the wholesale electricity market. The generation volumes used in the valuation ranged between 3,320 GWh and 6,112 GWh.	Plus/minus 10%	$527 million to ($440 million)	Wholesale electricity price affects the amount of generation.
Discount rate	Pre-tax equivalent discount rate scenarios ranging between 11.3 per cent and 12.8 per cent.	Plus/minus 1%	$466 million to ($284 million)	Discount rate is independent of wholesale price and volume.

Generation assets carried at historical cost	2015 $ million	2014 $ million
This table presents the carrying value of generation assets as if they were recognised on the historical cost basis:		
Cost	**2,675.0**	2,641.0
Accumulated depreciation and impairment	**(1,035.0)**	(954.8)
Carrying value at 30 June	**1,640.0**	1,686.2

Impairment

Impairment relates to capital expenditure on Huntly units 1 to 4 and 6 and associated structures, and rehabilitation of the Huntly ash ponds associated with the units (2014: capital expenditure on Huntly units 1 to 4 and 6, rehabilitation of the Huntly ash ponds associated with the units and minor building alterations). Refer to note 3 for disclosure of impairment by segment. Expenditure associated with Huntly units 1 to 4 and 6 is immediately impaired when incurred as the fair value of these units is nil.

All other categories of property, plant and equipment

All other categories of property, plant and equipment, with the exception of land and capital work in progress, are recognised at cost less accumulated depreciation and any accumulated impairment losses. Land and capital work in progress are not depreciated.

Depreciation

For generation assets carried at fair value, their fair value, less any estimated residual value, is charged to profit or loss on a straight-line basis over their estimated remaining useful lives. Where a generation asset's remaining useful life changes, the depreciation charge is adjusted prospectively. The estimated remaining useful lives of generation assets used in the depreciation calculation was up to 80 years.

For all other property, plant and equipment carried at cost, their cost, less any estimated residual value, is charged to profit or loss on a straight-line basis over their estimated useful lives. The estimated useful lives of different classes of property plant and equipment are as follows:

	Estimated useful lives
Buildings and improvements	10 to 50 years
Other plant and equipment	3 to 15 years
Leased plant and equipment	20 to 25 years

The estimated useful lives of assets are reviewed annually. An asset's carrying amount is written down immediately to its recoverable amount if the carrying amount is greater than its estimated recoverable amount.

The gain or loss on the disposal or retirement of an item of property, plant and equipment is determined as the difference between the sale proceeds and the carrying amount of the asset. The gain or loss is recognised in profit or loss. Any balance attributable to the disposed asset in the asset revaluation reserve is transferred to retained earnings.

16. Assets held for sale

Non-current assets (and disposal groups) classified as assets held for sale are recorded at the lower of carrying amount and fair value less costs to sell. Non-current assets are classified as held for sale if their carrying amounts will be recovered through sale transactions rather than through continuing use. This condition is regarded as met only when:

- the sale is highly probable;
- the non-current asset (or disposal group) is available for immediate sale in its present condition; and
- the sale of the non-current asset (or disposal group) is expected to be completed within one year from the date of classification.

The Group intends to dispose of four development properties within the Corporate segment which have become surplus to requirements. These properties are being actively marketed and are expected to be sold within 12 months. No impairment loss was recognised on reclassification of the properties as held for sale as the fair value (estimated based on the recent market prices of similar properties in similar locations) less costs to sell is higher than the carrying amount. The carrying value of the properties at 30 June 2015 was $3.1 million.

17. Oil and gas assets

	Note	Exploration and evaluation expenditure $ million	Oil and gas producing assets $ million	Other oil and gas assets $ million	Capital work in progress $ million	Total $ million
Carrying value at 1 July 2013		1.3	375.0	15.6	–	391.9
Additions		0.2	0.8	–	0.7	1.7
Transfer from property, plant and equipment	15	–	–	–	8.3	8.3
Transfer to (from) capital work in progress		–	4.1	–	(4.1)	–
Disposals and reversals		–	–	(0.1)	(3.4)	(3.5)
Depreciation and depletion expense	5	–	(55.4)	(0.9)	–	(56.3)
Carrying value at 30 June 2014		1.5	324.5	14.6	1.5	342.1
Additions		0.7	2.3	–	1.2	4.2
Transfer to (from) capital work in progress		–	–	0.1	(0.1)	–
Change in rehabilitation asset		–	1.4	–	–	1.4
Depreciation and depletion expense	5	–	(54.7)	(0.6)	–	(55.3)
Carrying value at 30 June 2015		**2.2**	**273.5**	**14.1**	**2.6**	**292.4**
Summary of cost and accumulated depreciation, depletion and impairment						
Cost		20.0	550.0	18.4	1.5	589.9
Accumulated depreciation, depletion and impairment		(18.5)	(225.5)	(3.8)	–	(247.8)
Carrying value at 30 June 2014		1.5	324.5	14.6	1.5	342.1
Cost		20.7	553.7	18.5	2.6	595.5
Accumulated depreciation, depletion and impairment		(18.5)	(280.2)	(4.4)	–	(303.1)
Carrying value at 30 June 2015		**2.2**	**273.5**	**14.1**	**2.6**	**292.4**

Exploration and evaluation expenditure

All exploration and evaluation costs, including directly attributable overheads, general permit activity, and geological and geophysical costs are expensed as incurred except for the costs of drilling exploration wells and the costs of acquiring new interests. The costs of drilling exploration wells are initially capitalised pending the determination of the success of the well. Costs are expensed immediately where the well does not result in a successful discovery. Costs incurred before the Group has obtained the legal rights to explore an area are expensed as incurred.

Exploration and evaluation expenditure assets are not amortised; instead, they are assessed annually for indicators of impairment. Any impairment is recognised in profit or loss. Once commercial approval has been obtained for the development of a project, the accumulated expenditure in relation to the project is transferred to oil and gas producing assets.

Oil and gas producing assets

Oil and gas producing assets include costs associated with the production station transferred from development expenditure and mining licences. Depletion of oil and gas producing assets is based on the amount of units produced during the period in comparison to the total expected to be produced from the proven reserves (1P). Proven reserves (1P) are the estimated quantities of oil and gas which geological and engineering data demonstrates with reasonable certainty to be recoverable in future years from known reservoirs, under existing economic and operating conditions. Proven reserves (1P) are defined as those which have a 90 per cent likelihood of being delivered. The proven oil and gas reserves used to deplete the oil and gas producing assets is reviewed annually.

Total proven reserves (1P) of the Kupe oil and gas field are 379.7 petajoule equivalents (total proven and probable reserves (2P) of the Kupe oil and gas field are 489.1 petajoule equivalents). Included in the (1P) 379.7 petajoule equivalents are undeveloped reserves totalling 35.3 petajoule equivalents. No change has been considered necessary to the reserve estimate since 30 June 2012. The Group has a 31 per cent interest in the Kupe Joint Venture's reserves. The Joint Venture is currently undertaking a review of the reserves; the outcome of the review is not yet known. Any change in reserves will be applied prospectively. At 30 June 2015, total remaining proven reserves (1P) were 188.2 petajoule equivalents (total remaining proven and probable reserves (2P) were 302.4 petajoule equivalents).

17. Oil and gas assets (continued)

Because the geology of the Kupe oil and gas field subsurface cannot be examined directly, an indirect technique known as volumetrics has been used to estimate the size and recoverability of the reserve. Reserve estimates contain uncertainty and these are reviewed annually. There are high levels of uncertainty in terms of accessibility of reserves through sealing faults and pressure support. Proven reserve estimates have a 90 per cent likelihood of being delivered. A reduction of 10 per cent in these reserves would impact depletion charges going forward by up to $8.1 million per annum at current production rates.

Other oil and gas assets

Other oil and gas assets include land, buildings, storage facilities, sales pipeline, motor vehicles and the ongoing costs of continuing to develop reserves for production. The cost of other oil and gas assets, less any estimated residual value, is charged to profit or loss on a straight-line basis over their estimated useful lives. The estimated useful lives of other oil and gas assets are as follows:

	Estimated useful lives
Buildings	50 years
Storage facilities	25 years
Sales pipeline	25 years
Motor vehicles	5 years

18. Intangible assets

	Note	Goodwill $ million	Computer software $ million	Emission units $ million	Naming rights $ million	Total $ million
Carrying value at 1 July 2013		102.6	15.8	1.6	4.2	124.2
Additions		–	14.0	11.0	0.9	25.9
Disposed of or surrendered		–	–	(5.9)	(0.1)	(6.0)
Amortisation expense	5	–	(10.2)	–	(1.8)	(12.0)
Carrying value at 30 June 2014		102.6	19.6	6.7	3.2	132.1
Additions		–	–	8.8	0.5	9.3
Transfer from property, plant and equipment	15	–	9.4	–	–	9.4
Disposed of or surrendered		–	(0.5)	(6.8)	–	(7.3)
Amortisation expense	5	–	(10.2)	–	(1.6)	(11.8)
Carrying value at 30 June 2015		**102.6**	**18.3**	**8.7**	**2.1**	**131.7**
Summary of cost and accumulated amortisation and impairment						
Cost		102.6	121.7	6.7	10.6	241.6
Accumulated amortisation and impairment		–	(102.1)	–	(7.4)	(109.5)
Carrying value at 30 June 2014		102.6	19.6	6.7	3.2	132.1
Current		–	–	3.9	–	3.9
Non-current		102.6	19.6	2.8	3.2	128.2
Carrying value at 30 June 2014		102.6	19.6	6.7	3.2	132.1
Cost		102.6	130.9	8.7	11.1	253.3
Accumulated amortisation and impairment		–	(112.6)	–	(9.0)	(121.6)
Carrying value at 30 June 2015		**102.6**	**18.3**	**8.7**	**2.1**	**131.7**
Current		**–**	**–**	**4.3**	**–**	**4.3**
Non-current		**102.6**	**18.3**	**4.4**	**2.1**	**127.4**
Carrying value at 30 June 2015		**102.6**	**18.3**	**8.7**	**2.1**	**131.7**

Goodwill

Goodwill represents the excess of the cost of a business combination over the fair value of the Group's share of the net identifiable assets, liabilities and contingent liabilities of the acquired subsidiary/associate at the date of acquisition. Goodwill on the acquisition of subsidiaries is included in intangible assets. Goodwill on the acquisition of associates is included in the investment in associates. Goodwill is assessed as having an indefinite useful life and is not amortised but is subject to impairment testing annually or whenever there are indications of impairment.

For the purpose of impairment testing, goodwill has been allocated to the Customer Experience cash-generating unit ('CGU').

The impairment test is based on an estimated discounted cash flow analysis (value in use). Estimated future cash flow projections are based on the Group's five-year business plan for the Customer Experience business unit and are extrapolated using a 1.0 per cent year-on-year growth

18. Intangible assets (continued)

rate (2014: 1.0 per cent). The estimated future cash flow projections are discounted using pre-tax equivalent discount rate scenarios ranging between 11.0 per cent and 12.2 per cent (2014: 11.0 per cent and 12.8 per cent). Any reasonably possible further change in key assumptions on which the recoverable amount is based is not expected to cause the carrying value of the Customer Experience goodwill to exceed its recoverable amount.

Key assumptions in the value-in-use calculation were:

Assumptions	Method of determination
Customer numbers and customer churn	Review of actual customer numbers and historical data regarding movements in customer numbers (the historical analysis is considered against expected market trends and competition for customers)
Gross margin	Review of actual gross margins and consideration of expected market movements and impacts
Cost to serve	Review of actual costs to serve and consideration of expected future costs

Computer software

Items of computer software are assets with finite lives. These assets are recognised at cost less accumulated amortisation and impairment losses. Amortisation is charged to profit or loss on a straight-line basis over the estimated useful life of the asset from the date it is available for use. The estimated useful life is between one and four years.

Emission units

Emission units on hand are initially recognised at fair value. Fair value is cost in the case of purchased units or the initial market value in the case of government-granted units. Emission units held to settle the Group's emission obligation are not revalued subsequent to initial recognition. They are assessed as having indefinite useful lives and are not amortised but are subject to annual impairment testing or whenever there are indicators of impairment.

Naming rights

Naming rights are assets with finite lives. These assets are recognised at cost less accumulated amortisation and impairment losses. Amortisation is charged to profit or loss on a straight-line basis over the estimated useful life of the asset from the date it is available for use. The useful life is based on the contract period which ranges between one and 15 years.

19. Investments in subsidiaries

During the prior year, the Group established Genesis Energy Insurance Pte Limited to manage the Group's insurance risk and Genesis Energy Limited Executive Long-term Incentive Plan Trust (the 'Trust') to administer the LTI plan. The Trust has been consolidated into the Group on the basis that the Parent has determined the way in which the Trust is designed and operated, the Parent controls the financing and investing activities of the Trust and the Trust is dependent on funding from the Parent.

On 31 July 2014, Kinleith Cogeneration Limited and GP No. 1 Limited were amalgamated into the Parent.

Name of entity	Principal activity	Place of incorporation and operation	Interest held 2015 %	Interest held 2014 %
Genesis Power Investments Limited	Holding company	New Zealand	**100**	100
Kinleith Cogeneration Limited	Non-trading	New Zealand	–	100
Kupe Holdings Limited	Joint venture holding company	New Zealand	**100**	100
GP No. 1 Limited	Joint venture holding company	New Zealand	–	100
GP No. 2 Limited	Joint venture holding company	New Zealand	**100**	100
GP No. 5 Limited	Joint venture holding company	New Zealand	**100**	100
Genesis Energy Insurance Pte Limited	Captive insurance company	Singapore	**100**	100
Genesis Energy Limited Executive Long–term Incentive Plan Trust	Trust	New Zealand	–	–

All subsidiaries have 30 June balance dates.

20. Joint operations

The Group has a 31.0 per cent interest in the Kupe production facility and Petroleum Mining Permit 38146 held by the Kupe Joint Venture (2014: 31.0 per cent). The principal activity of the Kupe Joint Venture is petroleum production and sales. The Joint Venture is unincorporated and operates in New Zealand. The Group is considered to share joint control based on the contractual arrangements between the Group and other joint operators that state unanimous decision-making is required for relevant activities which most significantly impact the returns of the joint operation.

The Joint Venture is classified as a joint operation under NZ IFRS 11. The operating results of the Kupe Joint Venture are included in the Oil and Gas segment in note 3 and the Group's share of capital expenditure commitments relating to joint operations is disclosed in note 29.

21. Related–party transactions

Majority shareholder and entities controlled by and related to the majority shareholder

The majority shareholder of the Parent is the Crown. The Parent and Group transact with Crown-controlled and related entities independently and on an arm's-length basis for the purchase of coal and use of coal-handling facilities, emission activities including emission unit purchases and sales, royalties, scientific consultancy services, electricity transmission, postal services and energy-related products (including electricity derivatives). All transactions with Crown-controlled and related entities are based on commercial terms and conditions, and relevant market drivers.

During the year, the Group entered into a contract with Meridian Energy, a Crown-controlled entity, to provide dry-year cover for four years from 1 January 2015. The 150MW contract follows on from the existing 200MW contract between Genesis Energy and Meridian Energy, which expired in October 2014.

Dividends paid to the Crown during the year were $106.3 million (2014: $121.0 million). There were no other individually significant transactions with the Crown and Crown-controlled and related entities during the year (2014: nil).

Other transactions with Crown-controlled and related entities, which are collectively but not individually significant, relate to the purchase of coal, the sale of gas and electricity derivatives. All of the coal acquired by the Group during the year was supplied by Crown-controlled and related entities under coal supply agreements which expire in June 2017 (2014: 88.7 per cent). Approximately 29.4 per cent (2014: 12.4 per cent) of the gas sales were made to Crown-controlled and related entities under gas sales agreements which expire in December 2015. Approximately 79.5 per cent of the value of electricity derivative assets and approximately 15.4 per cent of the value of electricity derivative liabilities held by the Group at year-end are held with Crown-controlled and related entities (2014: 57.9 per cent and 35.7 per cent, respectively). The contracts expire at various times; the latest expiry date is December 2025.

Key management personnel compensation

The key management personnel of the Group consists of the Directors and the Executive Management team. Key management personnel compensation is as follows:

	2015 $ million	2014 $ million
Short-term benefits	**6.8**	7.8
Post-employment benefits	**0.2**	0.2
Termination benefits	**0.3**	0.1
Share-based payments	**0.1**	–
Total key management personnel compensation	**7.4**	8.1

Other transactions with key management personnel or entities related to them

Key management personnel and their families may purchase gas and electricity from the Group on an arm's-length basis and may purchase shares in the Company. The total number of shares held by key management personnel as at 30 June 2015 was 784,188 (2014: 504,352). During the year, dividends paid to key management personnel and their families was $99,558 (2014: nil). No other transactions took place between key management personnel and the Group (2014: nil). As at 30 June 2015, the balance payable to key management personnel was nil (2014: nil).

22. Payables and accruals

	2015 $ million	2014 $ million
Trade payables and accruals	**150.2**	186.8
Employee benefits	**5.9**	6.3
Emission obligations	**2.9**	2.4
Total	**159.0**	195.5
Current	**158.3**	194.8
Non-current	**0.7**	0.7
Total	**159.0**	195.5

Trade payables and accruals are recognised when the Group becomes obligated to make future payments resulting from the purchase of goods or services, and are subsequently carried at amortised cost.

A liability for employee benefits (wages and salaries, annual and long-service leave, and employee incentives) is recognised when it is probable that settlement will be required and the amount is capable of being measured reliably. Provisions made in respect of employee benefits are measured using the remuneration rate expected to apply at the time of settlement

Emission obligations are recognised as a liability when the Group incurs the emission obligation. Emission units payable to third parties are recognised at the average cost of emission units on hand up to the amount of emission units on hand at the recognition date. Where the emission obligation exceeds the level of units on hand, the excess obligation over the units on hand is measured at the contract price where forward contracts exist or the market price for any obligation not covered by units on hand or forward contracts.

23. Borrowings

	2015 $ million	2014 $ million
Revolving credit and money market	**101.0**	357.9
Wholesale term notes	**320.1**	320.5
Retail term notes	**107.1**	106.8
Capital Bonds	**202.6**	202.6
USPP	**227.4**	–
Finance lease liabilities	**–**	1.6
Total	**958.2**	989.4
Current	**117.8**	12.3
Non-current	**840.4**	977.1
Total	**958.2**	989.4

Borrowings are initially recognised at fair value, net of transaction costs incurred. Borrowings are subsequently measured at amortised cost. Borrowings designated in a hedge relationship are carried at amortised cost adjusted for the change in the fair value of the hedged risk. Any difference between the proceeds (net of transaction costs) and the redemption amount is recognised in profit or loss over the period of the borrowings using the effective interest method.

Borrowings are classified as current liabilities unless the Group has an unconditional right to defer settlement of the liability for at least 12 months after the balance date.

	2015 $ million	2014 $ million
Revolving credit and money market		
Money market	**–**	6.1
Revolving credit drawn down	**100.0**	350.0
Accrued interest	**1.0**	1.8
Total revolving credit and money market	**101.0**	357.9
Revolving credit		
Expiring 2016	**–**	125.0
Expiring 2017	**–**	75.0
Expiring 2018	**75.0**	75.0
Expiring 2019	**75.0**	350.0
Expiring 2020	**225.0**	–
Expiring 2022	**50.0**	–
Total available revolving credit facility	**425.0**	625.0
Revolving credit drawn down (excluding accrued interest)	**100.0**	350.0
Total undrawn revolving credit facility	**325.0**	275.0

During the year, the Group restructured its revolving credit arrangements, decreasing its revolving credit facilities from $625.0 million to $425.0 million and extending the maturity profile.

23. Borrowings (continued)

	2015 $ million	2014 $ million
Wholesale term notes		
Expiring 2017	**125.0**	125.0
Expiring 2020	**120.0**	120.0
Expiring 2023	**70.0**	70.0
Fair value interest rate risk adjustment	**1.0**	1.4
Accrued interest	**4.5**	4.5
Capitalised issue costs	**(0.4)**	(0.4)
Total wholesale term notes	**320.1**	320.5
Retail term notes		
Expiring 2016	**105.0**	105.0
Accrued interest	**2.4**	2.4
Capitalised issue costs	**(0.3)**	(0.6)
Total retail term notes	**107.1**	106.8
Capital Bonds		
Expiring 2042	**200.0**	200.0
Accrued interest	**2.6**	2.6
Total Capital Bonds	**202.6**	202.6

The Group may redeem all or some of the Capital Bonds on a reset date or on any quarterly interest payment date after the first reset date, which is 16 July 2018. On the first reset date and every five years thereafter, the interest rate will reset to be the sum of the five-year swap rate on the relevant reset date plus a margin of 2.4 per cent. Redemptions on a reset date are at par; redemptions on a quarterly interest payment date must be at the greater of par or market value.

	2015 $ million	2014 $ million
USPP		
Expiring 2026	**73.8**	–
Expiring 2027	**147.5**	–
Fair value interest rate risk adjustment	**4.0**	–
Accrued interest	**3.0**	–
Capitalised issue costs	**(0.9)**	–
Total USPP	**227.4**	–

On 24 October 2014, the Group entered into a firm commitment for the issue of $150.0 million United States dollar-denominated unsecured notes to United States-based institutional investors. A Note Purchase Agreement ('NPA') was signed on 25 November 2014. Cross-currency interest rate swaps ('CCIRS') have been used to manage foreign exchange and interest rate risks on the notes (refer to note 25 for further information on CCIRS). The United States Private Placement ('USPP') is measured at amortised cost adjusted for the change in fair value associated with the hedged risks in accordance with the Group's accounting policy. While the New Zealand dollar amount required to repay the USPP in 2026 and 2027 is fixed as a result of the CCIRS, the USPP is required to be translated to New Zealand dollars at the spot rate at the reporting date, in accordance with NZ IFRS. Any increase/decrease in the carrying value of the USPP as a result of this translation is offset by the movement in the fair value of the CCIRS disclosed in note 25. The proceeds from the USPP were used to reduce revolving credit facilities.

Security

All of the Group's borrowings are unsecured with the exception of finance leases. The Group borrows under a negative pledge arrangement, which does not permit the Group to grant any security interest over its assets, unless it is an exception permitted within the negative pledge.

Finance lease liabilities are effectively secured as the rights to the leased assets recognised in the financial statements revert to the lessor in the event of default.

24. Provisions

Provisions are recognised when the Group has a present obligation (legal or constructive) as a result of a past event, it is probable that the Group will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. The amount recognised as the provision is the best estimate of the consideration required to settle the present obligation at the end of the reporting period taking into account the risks and uncertainties surrounding the obligation. Where a provision is measured using the cash flows estimated to settle the present obligation, its carrying amount is the present value of those cash flows.

24. Provisions (continued)

Rehabilitation and restoration

The rehabilitation and restoration provision relates to the Meremere generation site, the Huntly ash ponds and the Kupe production facility. These sites require remediation as a result of past and present operations. Different methods and techniques can be used to remediate the sites. The provision represents the present value of the Group's best estimate of future expenditure to be incurred based on the Group's assessment of the most appropriate methods to remediate the sites at balance date. Key assumptions include: an estimate of when the rehabilitation and restoration is likely to take place, the possible remediation alternatives available, the expected expenditures attached to each alternative and the foreign currency exchange rate at balance date.

There is an obligation to restore parts of the Huntly site related to the Rankine Units once they are retired. The Rankine Units are currently scheduled to be retired by 31 December 2018 however, there is no intention to exit the Huntly site. There may be costs and recoveries associated with retiring the Rankine Units that cannot be reliably estimated at this time.

The assumptions used to estimate the rehabilitation and restoration provision require balanced judgement as there is a range of possible assumptions that could be used in estimating the carrying value of these obligations. The key assumption that could have a material impact on the Meremere generation site rehabilitation estimate relates to the extent of rehabilitation required at the end of the lease. The extent of rehabilitation depends on the effectiveness of the historical rehabilitation work and the rehabilitation obligations under the lease. The current assumption is that the current remediation work with some further tidy-up at the end of the lease in 2017 will be sufficient. If future monitoring indicates that the clay caps need further remediation work, the provision would need to increase by up to $2.0 million. The site is monitored regularly and the rehabilitation plan amended as necessary.

The key assumption that could have a material impact on the Huntly ash ponds rehabilitation estimate relates to the extent of rehabilitation work required. The current assumption is that all the ash would be removed from the ponds but, if some of the ash were capped in situ, the provision could decrease by $9.9 million. The rehabilitation work on the ash ponds is estimated to be completed within the next six years.

The key assumptions that could have a material impact on the Kupe production facility rehabilitation estimate relates to foreign exchange rates, scrap-steel prices, labour rates, concrete removal costs, offshore supply vessel and jack-up rig rates, and associated mobilisation and demobilisation costs. The majority of costs are based in United States dollars and, therefore, are sensitive to fluctuations in foreign exchange rates. Given the equipment required to complete the rehabilitation comes from overseas, the mobilisation and demobilisation costs can fluctuate significantly depending on the volume of other work the contractor has at the time the rehabilitation is required to be completed. If the foreign exchange rate were to decrease by 10 per cent and if the transportation costs for the mobilisation and demobilisation were unable to be shared with other entities, the provision would increase by $18.1 million. Also affecting the provision are regulations around the removal of the subsea pipeline. Currently, there are no regulations around this and, as such, the provision assumes the subsea pipeline will be flushed and left in situ. The rehabilitation is estimated to be completed in approximately 10 years.

Contractual arrangements

The contractual arrangements provision relates to relationship and sponsorship agreements with various parties. The provision represents the present value of the best estimate of cash flows required to settle the Group's obligations under the agreements. The timing of the outflows is between 10 and 35 years.

Other provisions

Other provisions represent the onerous contract provision associated with changes to contractual arrangements and other minor provisions. In the prior year, a provision was recognised for 60 per cent of the full liability of the Brownie Points programme as this reflected the estimated redemption rate at the time. The Brownie Points programme was closed during the year and, as a result, there was no provision for Brownie Points at 30 June 2015. The onerous contracts provision relates to onerous lease agreements associated with coal importation. The provision is based on the cash flows associated with the contracts. The timing of the outflows is expected to occur over the next five years.

	Note	Rehabilitation and restoration	Contractual arrangements	Other provisions	Total
Balance at 1 July 2013		66.5	55.7	7.9	130.1
Provisions made during the year		6.4	1.4	14.8	22.6
Provisions reversed during the year		(2.7)	(0.5)	(2.7)	(5.9)
Provisions used during the year		(4.0)	(4.3)	(3.7)	(12.0)
Time value of money adjustment	7	3.4	2.1	0.2	5.7
Balance at 30 June 2014		69.6	54.4	16.5	140.5
Provisions made during the year		5.4	0.7	3.9	10.0
Provisions reversed during the year		–	(0.5)	(10.0)	(10.5)
Provisions used during the year		(1.7)	(4.2)	(4.3)	(10.2)
Time value of money adjustment	7	3.4	2.4	0.4	6.2
Balance at 30 June 2015		**76.7**	**52.8**	**6.5**	**136.0**
Current		2.2	8.3	3.1	13.6
Non-current		67.4	46.1	13.4	126.9
As at 30 June 2014		69.6	54.4	16.5	140.5
Current		**2.4**	**8.5**	**1.4**	**12.3**
Non-current		**74.3**	**44.3**	**5.1**	**123.7**
As at 30 June 2015		**76.7**	**52.8**	**6.5**	**136.0**

25. Derivatives

The Group's activities expose it to a variety of financial risks: market risk (including price risk, currency risk and interest rate risk), credit risk and liquidity risk. The Group uses the following derivatives to hedge its financial risk exposures:

- Interest rate swaps
- Foreign exchange swaps and options
- Electricity swaps and options
- Oil swaps
- CCIRS
- Forward sale-and-purchase agreements of emission units held for trading.

The Group also enters into electricity derivatives with wholesale electricity market participants which allows them to hedge wholesale electricity market exposures.

During the year, the Group entered into CCIRS to swap the United States dollar principal and fixed coupon obligation for the USPP disclosed in note 23.

Derivatives are initially recognised at fair value on the date a derivative contract is entered into and are subsequently remeasured to their fair value. The method of recognising the resulting gain or loss depends on whether the derivative is designated as a hedging instrument and, if so, the nature of the item being hedged.

For the purpose of hedge accounting, hedges are classified as:

- cash flow hedges where the Group hedges the exposure to variability in cash flows that is attributable either to a particular risk associated with a recognised asset or liability or to a highly probable forecast transaction; or
- fair value hedges where the Group hedges the exposure to changes in fair value of a recognised asset or liability.

The Group documents, at the inception of the transaction, the relationship between the hedging instruments and hedged items, as well as its risk-management objective and strategy for undertaking various hedge transactions. The Group also documents its assessment, both at hedge inception and on an ongoing basis, of whether the derivatives that are used in hedging transactions have been and will continue to be highly effective in offsetting changes in fair values or cash flows of hedged items.

Forward sale-and-purchase agreements in relation to emission units held for trading do not meet the 'own use' exemption and, therefore, meet the definition of a derivative. These contracts are initially recognised at fair value on the date the contract is entered into and are subsequently remeasured to their fair value. Changes in the fair value are recognised immediately in profit or loss.

Derivatives designated in a cash flow hedge relationship

The effective portion of changes in the fair value of derivatives that are designated and qualify as cash flow hedges are recognised in other comprehensive income and accumulate in the cash flow hedge reserve. The gain or loss relating to the ineffective portion is recognised immediately in profit or loss.

Amounts accumulated in other comprehensive income are reclassified to profit or loss in the period when the hedged item will affect the profit or loss. However, when the forecast transaction that is hedged results in the recognition of a non-financial asset (for example, inventory) or liability, the gains and losses previously deferred in the cash flow hedge reserve are reclassified from the cash flow hedge reserve and included in the initial measurement of the cost of the asset or liability.

When a hedging instrument expires or is sold, terminated or exercised, or when a hedge no longer meets the criteria for hedge accounting, the cumulative gain or loss at that time remains in the cash flow hedge reserve and is reclassified to profit or loss when the transaction occurs. If the forecast transaction is no longer expected to occur, the cumulative gain or loss recognised in the cash flow hedge reserve is reclassified immediately to profit or loss.

The margin and basis component of the CCIRS is designated as a cash flow hedge of the margin and basis component of the USPP notes. The interest rate risk associated with interest on New Zealand dollar borrowings is hedged using interest rate swaps. Foreign currency risk associated with future foreign currency cash flows is hedged using forward exchange derivatives. Electricity and oil derivatives are used to manage price risk associated with spot market exposures.

Derivatives designated in a fair value hedge relationship

Changes in the fair value of derivatives that are designated and qualify as fair value hedges are recorded in profit or loss, together with any changes in the fair value of the hedged asset or liability that are attributable to the hedged risk.

The USPP and $25.0 million of the wholesale term notes are designated in fair value hedge relationships. CCIRS are used to swap the United States-dollar principal and fixed coupon obligations related to the notes to New Zealand dollar floating rate exposure. Interest rate swaps are used to convert the fixed coupons on wholesale term notes to floating rates.

25. Derivatives (continued)

Derivatives that do not qualify for hedge accounting

Changes in the fair value of any derivatives that do not qualify for hedge accounting are recognised immediately in profit or loss.

Net carrying value of derivatives	2015 $ million	2014 $ million
Derivatives designated in a cash flow hedge relationship		
Foreign exchange swaps	**(10.3)**	3.3
Interest rate swaps	**(16.7)**	(3.3)
Electricity swaps	**(2.7)**	(5.5)
Oil swaps	**10.6**	(4.4)
CCIRS	**24.3**	–
Derivatives designated in a fair value hedge relationship		
Interest rate swaps	**1.0**	1.4
CCIRS	**1.4**	–
Derivatives not designated as hedges		
Foreign exchange options	**–**	1.4
Electricity swaps and options	**28.1**	(0.7)
Forward sale-and-purchase agreements of emission units held for trading (Forward 'S&P' agreements)	**0.2**	–
Total	**35.9**	(7.8)
Carrying value of derivatives by balance sheet classification		
Current assets	**34.2**	19.9
Non-current assets	**53.9**	8.0
Current liabilities	**(21.5)**	(22.5)
Non-current liabilities	**(30.7)**	(13.2)
Total	**35.9**	(7.8)

25. Derivatives (continued)

Change in carrying value of derivatives	Note	Forward 'S&P' agreements $ million	CCIRS $ million	Oil swaps $ million	Interest rate swaps $ million	Foreign exchange swaps and options $ million	Electricity swaps and options $ million	Total $ million
Balance as at 1 July 2013		–	–	1.0	(1.7)	(3.0)	(11.0)	(14.7)
Total change recognised in electricity revenue		–	–	–	–	–	32.6	32.6
– Net change in derivatives not designated as hedges		–	–	–	–	0.2	3.8	4.0
– Net change in fair value hedges		–	–	–	(1.0)	–	–	(1.0)
– Ineffective gain (loss) on cash flow hedges		–	–	(1.6)	–	(0.1)	(1.8)	(3.5)
Total change recognised in the change in fair value of financial instruments	6	–	–	(1.6)	(1.0)	0.1	2.0	(0.5)
Gain (loss) recognised in other comprehensive income		–	–	(6.8)	0.7	4.9	14.4	13.2
Settlements		–	–	3.0	0.1	1.5	(12.1)	(7.5)
Sales (option fees)		–	–	–	–	–	(32.1)	(32.1)
Purchases (option fees)		–	–	–	–	1.2	–	1.2
Balance as at 30 June 2014		–	–	(4.4)	(1.9)	4.7	(6.2)	(7.8)
Total change recognised in electricity revenue		–	–	–	–	–	24.9	24.9
– Net change in derivatives not designated as hedges		0.2	–	–	–	(1.6)	27.6	26.2
– Net change in fair value hedges		–	1.4	–	(0.4)	–	–	1.0
– Ineffective gain (loss) on cash flow hedges		–	(0.2)	5.1	(0.4)	0.1	1.5	6.1
Total change recognised in the change in fair value of financial instruments	6	0.2	1.2	5.1	(0.8)	(1.5)	29.1	33.3
Gain (loss) recognised in other comprehensive income		–	24.5	19.2	(15.4)	(15.9)	8.8	21.2
Settlements		–	–	(9.3)	2.4	2.2	(7.4)	(12.1)
Sales (option fees)		–	–	–	–	–	(23.8)	(23.8)
Purchases (option fees)		–	–	–	–	0.2	–	0.2
Balance as at 30 June 2015		**0.2**	**25.7**	**10.6**	**(15.7)**	**(10.3)**	**25.4**	**35.9**

Reconciliation of movements in the cash flow hedge reserve	CCIRS $ million	Oil swaps $ million	Interest rate swaps $ million	Foreign exchange swaps $ million	Electricity swaps $ million	Total $ million
Balance as at 1 July 2013	–	0.9	(3.0)	(2.2)	(4.4)	(8.7)
Total reclassified from the cash flow hedge reserve to profit or loss	–	2.8	0.1	0.3	(12.1)	(8.9)
Total reclassified from the cash flow hedge reserve to the cost of assets	–	–	–	0.7	–	0.7
Effective gain (loss) on cash flow hedges recognised directly in the cash flow hedge reserve	–	(6.8)	0.7	4.9	14.4	13.2
Total change in cash flow hedge reserve	–	(4.0)	0.8	5.9	2.3	5.0
Income tax on change in cash flow hedge reserve	–	1.1	(0.2)	(1.7)	(0.6)	(1.4)
Balance as at 30 June 2014	–	(2.0)	(2.4)	2.0	(2.7)	(5.1)
Total reclassified from the cash flow hedge reserve to profit or loss	(30.6)	(9.2)	2.4	3.4	(7.5)	(41.5)
Total reclassified from the cash flow hedge reserve to the cost of assets	–	–	–	0.2	–	0.2
Effective gain (loss) on cash flow hedges recognised directly in the cash flow hedge reserve	24.5	19.2	(15.4)	(15.9)	8.8	21.2
Total change in cash flow hedge reserve	(6.1)	10.0	(13.0)	(12.3)	1.3	(20.1)
Income tax on change in cash flow hedge reserve	1.7	(2.8)	3.6	3.5	(0.4)	5.6
Balance as at 30 June 2015	**(4.4)**	**5.2**	**(11.8)**	**(6.8)**	**(1.8)**	**(19.6)**

The gain (loss) on interest rate swaps and CCIRS is recognised in finance expenses, the gain (loss) on foreign exchange swaps and options is recognised in other operating expenses, the gain (loss) on electricity swaps and options is recognised in electricity revenue in the profit or loss and the gain (loss) on oil swaps is recognised in petroleum revenue.

26. Financial instruments and financial risk–management

Financial instruments

For financial reporting purposes, the Group designates its financial instruments into the following categories:

Loans and receivables

- Cash and cash equivalents
- Receivables

Financial instruments in a hedge relationship

- Foreign exchange swaps
- Interest rate swaps
- Electricity swaps
- Oil swaps
- CCIRS

Financial instruments held for trading (derivatives not in a hedge relationship)

- Foreign exchange options
- Electricity swaps and options
- Forward sale-and-purchase agreements of emission units held for trading

Financial liabilities measured at amortised cost

- Payables
- Borrowings

Risk–management

The Group's overall risk-management programme focuses on the unpredictability of financial markets and seeks to minimise financial risk to the Group. The Board of Directors (the 'Board') has established policies which provide an overall risk-management framework, as well as policies covering specific areas, such as electricity and oil price risk, foreign exchange risk, interest rate risk, credit risk, use of derivatives and the investment of excess liquidity. Trading in financial instruments, including derivatives, for speculative purposes is not permitted by the Board. Interest rate, foreign exchange and oil price exposures are managed by the central Treasury function ('Treasury') and electricity exposures are managed by the risk-management group ('Risk'). Treasury and Risk identify, evaluate and hedge financial risks in close cooperation with the Group's operating units. Compliance with policies and exposure limits is independently reviewed by the Group's internal auditor.

Price risk

The Group is exposed to movements in the spot price of electricity arising through the sale and purchase of electricity to and from the market. The Group is also exposed to movements in the spot price of light crude oil arising from sales of its share of oil from the Kupe production facility. The Group has limited exposure to changes in the sale price for gas and LPG as most of the volume is forward sold.

Electricity sales and purchases

The Group manages price risk in relation to electricity sales and purchases by entering into electricity swaps and options. Electricity swaps and options are either traded on the ASX or negotiated bilaterally with other energy companies and major customers. Electricity options are entered into as needs are identified and as counterparties seek to hedge their electricity purchase exposure. At balance date, the Group had electricity option contracts giving the counterparty the right to exercise a call option and electricity cap contracts.

The aggregate notional face value of the outstanding electricity swaps and options at balance date was $1,482.5 million (2014: $1,666.2 million).

Light crude oil sales

The Group manages price risk in respect of oil sales by entering into price swap contracts which provide a fixed price for future oil sales. The Group's Treasury policy sets minimum and maximum control limits ranging from between 50 per cent and 90 per cent for the first 12 months to between 25 per cent and 75 per cent for months 13 to 24.

The aggregate notional value of the outstanding oil swaps at balance date was 37.8 million United States dollars (2014: 50.3 million United States dollars).

The value of electricity and oil swaps are sensitive to changes in forward prices, and oil swaps are also sensitive to movements in foreign exchange rates. The table below summarises the impact an increase/decrease in these assumptions would have on the Group's post-tax profit or loss for the year and on the Group's cash flow hedge reserve. The sensitivity analysis is based on the assumption that the relevant market prices (future electricity and oil price paths) had increased/decreased by 10 per cent with all other variables held constant. A positive number represents an increase in profit or the cash flow hedge reserve.

There have been no changes in the methods and assumptions used in the sensitivity calculations from the previous year.

26. Financial instruments and financial risk-management (continued)

	2015 $ million	2014 $ million
Electricity swaps and options		
Post-tax impact on profit or loss		
+10%	**(5.8)**	(3.9)
–10%	**3.8**	2.9
Post-tax impact on cash flow hedge reserve (equity)		
+10%	**(4.9)**	(1.2)
–10%	**4.9**	1.2
Oil swaps		
Post-tax impact on profit or loss		
+10%	**(0.5)**	(1.7)
–10%	**0.5**	1.7
Post-tax impact on cash flow hedge reserve (equity)		
+10%	**(2.7)**	(2.7)
–10%	**2.7**	2.8

Foreign currency risk

The Group is exposed to foreign currency risk as a result of capital and operational transactions and borrowings denominated in a currency other than the Group's functional currency (including the purchase of capital equipment and maintenance, and the sale of gas and petroleum). The currencies giving rise to this risk are primarily the United States dollar, Australian dollar, Euro and Japanese yen.

The Group uses foreign exchange swaps and options to manage foreign exchange risk on capital and operational transactions. All significant capital project commitments and all capital purchase orders where exposure and currency levels are confirmed are hedged. All sales, operational commitments and purchase orders denominated in foreign currency over the equivalent of $500,000 New Zealand dollars are also hedged, in accordance with the Group's Treasury policy. For ongoing operating commitments, the equivalent of at least the next 12 months' exposure must be hedged. For the currency exposure arising from the sale of oil and gas, the policy sets minimum and maximum control limits ranging from between 50 per cent and 90 per cent for the first 12 months to between 25 per cent and 75 per cent for months 13 to 24.

The Group uses CCIRS to manage foreign exchange risk on overseas borrowings. All interest and principal repayments are hedged. The combination of the foreign denominated debt and the CCIRS results in a net exposure to New Zealand floating interest rates and a fixed New Zealand-denominated principal repayment. The New Zealand floating interest rate risk is managed using the process described in the interest rate risk section below.

The following table details the foreign exchange swaps and options outstanding at balance date. A positive number represents a buy contract and a negative number represents a sell contract.

	Foreign amount		Face value		Fair value	
Currency of contract	**2015 $ million**	2014 $ million	**2015 $ million**	2014 $ million	**2015 $ million**	2014 $ million
Foreign exchange swaps						
United States dollar	**(60.0)**	(87.9)	**(80.1)**	(109.2)	**(9.9)**	6.5
Japanese yen	**1,183.5**	1,259.8	**15.3**	16.5	**(0.4)**	(1.5)
Other	–	2.9	–	3.5	–	(0.3)
CCIRS						
United States dollar	**150.0**	–	**193.2**	–	**25.7**	–
Total foreign exchange swaps and options			**128.4**	(89.2)	**15.4**	4.7

The values of foreign exchange swaps and options and CCIRS are sensitive to changes in the forward prices of currencies. Foreign currency borrowings are fully hedged against movements in foreign currencies. Any movements in the value of borrowings, or in the interest payable due to a movement in the exchange rate, are offset by any equal and opposite movements in the value and cash flows applicable to the hedge.

The table below summarises the impact an increase/decrease in foreign exchange rates would have on the Group's post-tax profit or loss for the year and on the Group's cash flow hedge reserve. The sensitivity analysis is based on the assumption that the New Zealand dollar had weakened/strengthened by 10 per cent against the currencies with which the Group has foreign currency risk, with all other variables held constant. A positive number represents an increase in profit or the cash flow hedge reserve.

There have been no changes in the methods and assumptions used in the sensitivity calculations from the previous year.

26. Financial instruments and financial risk-management (continued)

Currency of contract	% change in rate	2015 $ million	2014 $ million
Post–tax impact on profit or loss			
United States dollar	+10%	–	2.6
	–10%	–	(1.0)
Total foreign exchange swaps and options	+10%	–	2.6
Total foreign exchange swaps and options	–10%	–	(1.0)
Post–tax impact on cash flow hedge reserve (equity)			
United States dollar	+10%	**5.8**	3.6
	–10%	**(7.1)**	(4.5)
Japanese yen	+10%	**(0.9)**	(0.9)
	–10%	**1.1**	1.1
Other	+10%	–	(0.2)
	–10%	–	0.3
Total foreign exchange swaps and options	+10%	**4.9**	2.5
Total foreign exchange swaps and options	–10%	**(6.0)**	(3.1)

Interest rate risk

The Group is exposed to interest rate risk as a portion of borrowings have floating interest rates. The Group uses interest rate swaps to manage interest rate risk. The Group's policy sets maximum and minimum control limits for fixed interest rate exposure which range from between 50 per cent and 100 per cent of projected debt with an age profile of less than one year to a maximum of 50 per cent for projected debt with an age profile of greater than five years and a maximum of 20 per cent for projected debt with an age profile of greater than 10 years.

The following table details the notional principal amounts and the remaining terms of interest rate swaps outstanding at balance date:

	Average contracted fixed interest rates		Notional principal amount		Fair value	
Currency of contract	**2015 %**	2014 %	**2015 $ million**	2014 $ million	**2015 $ million**	2014 $ million
Not later than one year	**3.67**	–	**50.0**	–	**(1.2)**	–
Later than one year and not later than two years	**5.08**	3.67	**100.0**	50.0	**(2.9)**	–
Later than two years and not later than five years	**5.23**	5.05	**90.0**	145.0	**(3.7)**	1.3
Later than five years	**5.06**	5.33	**265.0**	185.0	**(7.9)**	(3.2)
	4.96	5.01	**505.0**	380.0	**(15.7)**	(1.9)

The values of interest rate swaps are sensitive to changes in forward interest rates. The table below summarises the impact an increase/decrease in interest rates would have on the Group's post-tax profit or loss for the year and on the Group's cash flow hedge reserve. The sensitivity analysis is based on the assumption that interest rates had been 100 basis points higher/lower with all other variables held constant. A positive number represents an increase in profit or the cash flow hedge reserve.

There have been no changes in the methods and assumptions used in the sensitivity calculations from the previous year.

	2015 $ million	2014 $ million
Post-tax impact on profit		
+1%	**(0.6)**	(0.4)
–1%	**0.8**	0.4
Post-tax impact on cash flow hedge reserve (equity)		
+1%	**11.1**	6.3
–1%	**(12.1)**	(6.8)

Credit risk

Credit risk refers to the risk that a counterparty will default on its contractual obligations, resulting in financial loss to the Group. The Group is exposed to credit risk in the normal course of business arising from trade receivables, finance leases (where the Group is lessor), and with banks and financial institutions where short-term deposits are held. The Group is also exposed to credit risk arising from derivative counterparties defaulting on their contractual obligations.

26. Financial instruments and financial risk-management (continued)

The Group is a producer and retailer of electricity and gas. In terms of wholesale sales to the national grid, credit risk is significantly reduced as the Group purchases from the grid for its retail customer base with credit risk being limited to the net position on settlement. In addition, market security requirements in place ensure that there is no significant credit risk for any one participant. Market participants are required to provide letters of credit to the market clearing agent (NZX Limited), which would be called upon should any market participant default.

Credit risk exposure arising from the supply of electricity and gas to the retail market is mitigated due to the Group's large customer base and, in respect of its larger customers, the diverse range of industries they represent throughout New Zealand. The Group has adopted a policy of only dealing with creditworthy trade counterparties and obtaining collateral, where appropriate, as a means of mitigating the risk of financial loss from defaults. The Group also minimises its exposure to credit risk in this area through the adoption of counterparty credit limits, and active credit-management practices such as monitoring the size and nature of exposures and mitigating the risk deemed to be above acceptable levels.

A bond is held as collateral from any post-paid electricity customer whose credit profile does not meet the standard set by the Group. The bond is managed in accordance with the terms and conditions outlined in the supply agreement with individual customers. The bond is returned to the customer at cessation of supply. The value of collateral held at balance date was $3.6 million (2014: $4.2 million). The carrying value of the bond is considered to approximate its fair value.

Derivative counterparties and cash transactions are limited to high-credit-quality financial institutions and other organisations. The Group's exposure and the credit ratings of its counterparties are continuously monitored, and the aggregate value of transactions concluded is spread amongst approved counterparties. The Group has no significant concentration of credit risk with any one financial institution.

The carrying amounts of financial assets recognised in the balance sheet best represent the Group's maximum exposure to credit risk at the reporting date.

Liquidity risk

The Group's liquidity risk arises from its ability to attract cost-effective funding; this is largely driven by its credit standing (Standard & Poor's = BBB+). Prudent liquidity risk-management implies maintaining sufficient cash and marketable securities, the availability of funding through an adequate amount of committed credit facilities and the spreading of debt maturities.

Liquidity risk is monitored by continuously forecasting cash flows and matching the maturity profiles of financial assets and liabilities.

The table below details the Group's liquidity analysis for its financial liabilities and derivatives. The table has been drawn up based on the undiscounted cash inflows (outflows) for all financial liabilities and derivatives. The amounts in the table are the undiscounted contractual cash flows. Where the amount payable or receivable is not fixed, the amount disclosed has been determined by reference to the internally generated forward price curves existing at balance date. As the amounts included in the tables are contractual undiscounted cash flows, these amounts will not reconcile to the amounts disclosed in the balance sheet.

As at 30 June 2015	Weighted average effective interest rate %	Less than 1 year $ million	1 to 2 years $ million	2 to 5 years $ million	More than 5 years $ million	Total contractual cash flows $ million
Non–derivative financial liabilities						
Trade and other payables	**Non–bearing**	**(156.1)**	**–**	**–**	**–**	**(156.1)**
Revolving credit and money market	**5.6**	**(5.7)**	**(5.6)**	**(105.8)**	**–**	**(117.1)**
Wholesale term notes	**6.8**	**(21.4)**	**(143.3)**	**(156.1)**	**(82.2)**	**(403.0)**
Retail term notes	**8.0**	**(113.0)**	**–**	**–**	**–**	**(113.0)**
Capital Bonds	**6.2**	**(12.4)**	**(12.4)**	**(37.1)**	**(463.1)**	**(525.0)**
USPP	**5.4**	**(8.1)**	**(8.1)**	**(24.4)**	**(274.7)**	**(315.3)**
		(316.7)	**(169.4)**	**(323.4)**	**(820.0)**	**(1,629.5)**
Derivative assets (liabilities)						
Net–settled derivatives						
Interest rate swaps (cash flow hedges)		**(1.5)**	**(4.1)**	**(11.2)**	**(2.1)**	**(18.9)**
Interest rate swaps (fair value hedges)		**0.6**	**1.0**	**–**	**–**	**1.6**
Electricity swaps (cash flow hedges)		**2.5**	**(2.2)**	**(2.3)**	**(1.2)**	**(3.2)**
Electricity swaps and options (not designated as hedges)		**11.5**	**7.5**	**11.6**	**–**	**30.6**
Oil swaps (cash flow hedges)		**10.1**	**0.3**	**–**	**–**	**10.4**
Forward sale-and-purchase agreements of emission units held for trading		**0.2**	**–**	**–**	**–**	**0.2**
Gross–settled derivatives						
Foreign exchange swaps (cash flow hedges)						
– Inflows		**0.1**	**–**	**–**	**–**	**0.1**
– Outflows		**(7.3)**	**(2.1)**	**(0.1)**	**–**	**(9.5)**
CCIRS						
– Inflows		**8.1**	**8.1**	**24.4**	**274.6**	**315.2**
– Outflows		**(9.5)**	**(9.2)**	**(30.8)**	**(269.3)**	**(318.8)**
		14.8	**(0.7)**	**(8.4)**	**2.0**	**7.7**

The foreign exchange swaps cash flows above include no inflow in the less-than-one-year category in relation to capital projects which would not be recognised in profit or loss.

26. Financial instruments and financial risk-management (continued)

As at 30 June 2014	Weighted average effective interest rate %	Less than 1 year $ million	1 to 2 years $ million	2 to 5 years $ million	More than 5 years $ million	Total contractual cash flows $ million
Non–derivative financial liabilities						
Trade and other payables	Non–bearing	(193.1)	–	–	–	(193.1)
Revolving credit and money market	5.2	(24.5)	(18.5)	(386.5)	–	(429.5)
Wholesale term notes	6.6	(19.5)	(20.8)	(167.9)	(213.3)	(421.5)
Retail term notes	8.0	(8.0)	(113.0)	–	–	(121.0)
Capital Bonds	6.2	(12.4)	(12.4)	(37.1)	(478.6)	(540.5)
Finance lease payable	7.1	(1.8)	–	–	–	(1.8)
		(259.3)	(164.7)	(591.5)	(691.9)	(1,707.4)
Derivative assets (liabilities)						
Net–settled derivatives						
Interest rate swaps (cash flow hedges)		(0.8)	0.1	(2.6)	(0.4)	(3.7)
Interest rate swaps (fair value hedges)		0.5	0.3	0.7	–	1.5
Electricity swaps (cash flow hedges)		(0.7)	(1.1)	(3.7)	(0.1)	(5.6)
Electricity swaps and options (not designated as hedges)		(0.3)	1.2	(1.5)	–	(0.6)
Oil swaps (cash flow hedges)		(3.6)	(1.0)	–	–	(4.6)
Gross–settled derivatives						
Foreign exchange swaps (cash flow hedges)						
– Inflows		2.2	3.1	–	–	5.3
– Outflows		(1.4)	(0.4)	–	–	(1.8)
Foreign exchange options (not designated as hedges)						
– Inflows		0.9	–	–	–	0.9
		(3.2)	2.2	(7.1)	(0.5)	(8.6)

The foreign exchange swaps and options cash flows above include $0.6 million outflow in the less-than-one-year category in relation to capital projects which would not be recognised in profit or loss.

Capital risk–management

The Group manages its capital in a prudent manner to ensure that each entity in the Group will be able to continue as a going concern while maximising the return to shareholders through the appropriate balance of debt and equity. This is achieved by ensuring that the level and timing of its capital investment programmes, equity raisings and dividend distributions are consistent with the Group's capital structure strategy. This strategy remains unchanged from previous years. The capital structure of the Group consists of debt, which includes the borrowings disclosed in note 23, cash and cash equivalents and equity attributable to the shareholders of Genesis Energy Limited, comprising issued capital, reserves and retained earnings as disclosed in the balance sheet.

Under the Group's debt funding facilities, the Group has given undertakings that the ratio of debt to equity will not exceed a prescribed level and the interest cover will not be below a prescribed level. For the purpose of these undertakings, the Capital Bonds and related interest costs are treated as 50 per cent equity. The covenants are monitored on a regular basis to ensure they are complied with. There were no breaches in covenants during the year (2014: nil).

27. Fair value

Fair value hierarchy

The Group's assets and liabilities measured at fair value are categorised into one of three levels as follows:

Level one - the fair value is determined using unadjusted quoted prices from an active market for identical assets and liabilities. A market is regarded as active if quoted prices are readily and regularly available from an exchange, a dealer, a broker, an industry group, a pricing service or a regulatory agency, and those prices represent actual and regularly occurring market transactions on an arm's-length basis.

Level two - the fair value is derived from inputs other than quoted prices included within level one that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices). Financial instruments in this level include interest rate swaps, foreign exchange swaps and options, oil swaps and electricity derivatives which are valued using observable electricity price paths.

Level three - the fair value is derived from inputs that are not based on observable market data. Financial instruments included in this level include electricity derivatives which are valued using internally generated electricity price paths.

The Group's policy is to recognise transfers into and transfers out of fair value hierarchy levels as of the date of the event or change in circumstances that caused the transfer. There were no transfers between levels one, two and three during the year (2014: nil).

Level two items carried at fair value

Recurring fair value measurements	2015 $ million	2014 $ million
Level two		
Derivatives		
Interest rate swaps	**(15.7)**	(1.9)
Foreign exchange swaps and options	**(10.3)**	4.7
Oil swaps	**10.6**	(4.4)
Electricity swaps and options (not designated as hedges)	**(2.3)**	0.5
CCIRS	**25.7**	–
Forward sale-and-purchase agreements of emission units held for trading	**0.2**	–
	8.2	(1.1)
Inventory		
Emission units held for trading	**2.3**	–

Valuation of level two items carried at fair value

The fair values of level two derivatives and emission units held for trading carried at fair value are determined using discounted cash flow models. The key inputs in the valuation model were:

Item	Valuation input
Interest rate swaps	Forward interest rate price curve
Foreign exchange swaps and options	Forward foreign exchange rate curves
Oil swaps	Forward oil price and foreign exchange rate curves
Electricity swaps (cash flow hedges)	ASX forward price curve
Electricity swaps (not designated as hedges)	ASX forward price curve
CCIRS	Forward interest rate price curve and foreign exchange rate curves
Forward sale-and-purchase agreements of emission units held for trading	OM Financial forward curve
Emission units held for trading	OM Financial forward curve

Level three items carried at fair value

Recurring fair value measurement	Note	2015 $ million	2014 $ million
Level three			
Derivatives			
Electricity swaps (cash flow hedges)		**(2.7)**	(5.5)
Electricity swaps and options (not designated as hedges)		**30.4**	(1.2)
		27.7	(6.7)
Property, plant and equipment			
Generation assets	15	**2,628.0**	2,689.9

27. Fair value (continued)

Valuation of level three items carried at fair value

Valuation processes of the Group

The Group's finance department includes a team who perform the valuations of level three fair values for generation assets and derivatives. This team reports directly to the Chief Financial Officer. Discussions of valuation processes and results are held between the Chief Financial Officer and the valuation team at least six monthly for generation assets, and monthly for derivatives. As part of these discussions, the team presents analysis to explain the reasons for changes in fair value measurements. The Chief Financial Officer reports key changes to inputs to the Board in the monthly finance report and any changes to the valuation methodology are reported to the Audit Committee through update papers when any changes are anticipated or have been made due to changes in the business.

Valuation method of the Group

"The valuation of electricity swaps in level three is based on a forecast internally generated electricity price path. The selection of variables used within the price path requires significant judgement and, therefore, there is a range of reasonable assumptions that could be used in estimating the fair value of these derivatives. The key unobservable inputs driving potential changes to the forecast internally generated price path are changes in demand, hydrology and new generation build. Any one of these factors could result in a change to the price path and, therefore, the fair value of electricity swaps and options within level three. The electricity price path assumes national demand growth based on the latest available industry information and Genesis Energy's view of growth within various sectors of the economy. Forecast hydrology is based on 79 years of historical hydrological inflow data. New generation build assumptions are based on announcements made to the New Zealand market.

The electricity price path requires several inputs derived from third parties. These inputs include discount rates, demand, new build, planned outages, latest hydrology and several others which are checked and signed off by senior management personnel who are responsible for the price path that is output for use across the Group. These inputs are obtained from reputable institutions and are checked by the business for reasonableness as well as ensuring they align with the requirements of NZ IFRS.

The key unobservable inputs, range of assumptions and third-party inputs combine to determine the wholesale electricity price path. The wholesale electricity price paths used to value level three electricity swaps and options on a time-weighted basis range from $69 per MWh to $115 per MWh over the period from July 2015 to 31 December 2025 (2014: $70 per MWh to $113 per MWh over the period from July 2014 to 31 December 2025).

Valuation of electricity swaps and options

If the price path increased by 10 per cent while holding the discount rate consistent, this would result in the carrying value of the electricity derivatives decreasing to $12.1 million asset (2014: $13.7 million liability). If the price path decreased by 10 per cent while holding the discount rate constant, the carrying value would increase to $40.7 million asset (2014: $1.1 million liability).

The valuation of electricity options is based on a discounted cash flow model over the life of the agreement. The key assumptions in the model are: the callable volumes, strike price and option fees outlined in the agreement, the forecast internally generated electricity price path, 'day one' gains and losses, emission credits and the discount rate. The options are deemed to be called when the internally generated price path is higher than the strike prices after taking into account obligations relating to the specific terms of each contract. The discount rate used in the model ranged from 2.9 per cent to 8.9 per cent (2014: 3.4 per cent to 5.5 per cent) and the emission credit price used ranged between $7.50 and $25.00 (2014: $6.00 and $26.00).

Valuation of generation assets

Refer to note 15 for the valuation and reconciliation of movements in generation assets.

Reconciliation of level three derivatives

	2015 $ million	2014 $ million
Balance as at 1 July	**(6.7)**	(9.1)
Total gain (loss)		
– Electricity revenue	**24.9**	32.7
– Change in fair value of financial instruments	**32.0**	(0.5)
Total gain (loss) in profit or loss	**56.9**	32.2
Total gain (loss) recognised in other comprehensive income	**4.6**	9.2
Settlements (gain) loss	**(3.1)**	(6.9)
Sales	**(24.0)**	(32.1)
Balance as at 30 June	**27.7**	(6.7)

Change in fair value of financial instruments for the year included an unrealised gain of $31.5 million (2014: $0.8 million loss) relating to level three derivatives that are measured at fair value at the end of each reporting period.

27. Fair value (continued)

Deferred 'day one' gains (losses)

There is a presumption that when derivative contracts are entered into on an arm's length basis, and no payment is received or paid on day one, the fair value at inception would be nil. The contract price of non-exchange traded electricity derivative contracts are agreed on a bilateral basis, the pricing for which may differ from the prevailing derived market price for a variety of reasons. In these circumstances, an adjustment is made to bring the initial fair value of the contract to zero at inception. The adjustment is called a 'day one' gain (loss) and is deferred and amortised, based on expected call volumes over the term of the contract. The carrying value of derivatives is disclosed net of the 'day one' adjustments.

The following table details the movements and amounts of deferred 'day one' gains (losses) included in the fair value of electricity derivatives held at balance date:

	2015 $ million	2014 $ million
Balance as at 1 July	**12.9**	26.0
Deferred 'day one' gains (losses) on new derivatives	**15.0**	0.1
Deferred 'day one' gains (losses) realised during the year	**(10.8)**	(13.2)
Balance as at 30 June	**17.1**	12.9

The $17.1 million 'day one' adjustment is included in the level three derivates balance of $27.7 million.

Items disclosed at fair value

	Carrying value		Fair value	
Currency of contract	**2015 $ million**	2014 $ million	**2015 $ million**	2014 $ million
Level one				
Retail term notes	**(107.1)**	(106.8)	**(110.2)**	(111.8)
Capital Bonds	**(202.6)**	(202.6)	**(204.9)**	(198.2)
Level two				
Wholesale term notes	**(320.1)**	(320.5)	**(341.1)**	(327.5)
USPP	**(227.4)**	–	**(224.4)**	–

The carrying value of all other financial assets and liabilities in the balance sheet approximates their fair values.

Valuation of wholesale term notes

The valuation of wholesale term notes is based on estimated discounted cash flow analyses using applicable market yield curves adjusted for the Group's credit rating. Market yield curves at balance date used in the valuation ranged from 3.7 per cent to 5.1 per cent (2014: 4.3 per cent to 6.5 per cent).

Valuation of USPP

The valuation of USPP is based on estimated discounted cash flow analyses using applicable United States market yield curves adjusted for the Group's credit rating. The credit-adjusted market yield curve at balance date used in the valuation was 3.6 per cent.

28. Comparison to prospective financial information ('PFI') as disclosed in the Investment Statement dated 13 March 2014

Consolidated comprehensive income statement

	2015 Actual $ million	2015 PFI $ million
Operating revenue		
Electricity revenue	1,730.4	1,844.1
Gas revenue	282.9	244.0
Petroleum revenue	64.7	68.3
Other revenue	19.6	9.4
	2,097.6	2,165.8
Operating expenses		
Electricity purchases, transmission and distribution	(953.7)	(1,025.3)
Gas purchases and transmission	(297.1)	(235.4)
Petroleum production, marketing and distribution	(26.1)	(28.5)
Fuels consumed	(187.4)	(212.4)
Employee benefits	(80.6)	(85.2)
Other operating expenses	(207.9)	(215.6)
	(1,752.8)	(1,802.4)
Earnings before net finance expense, income tax, depreciation, depletion, amortisation, impairment, fair value changes and other gains and losses	344.8	363.4
Depreciation, depletion and amortisation	(155.7)	(150.2)
Impairment of non-current assets	(14.0)	(13.5)
Change in fair value of financial instruments	32.1	4.1
Other gains (losses)	(0.2)	–
	(137.8)	(159.6)
Profit before net finance expense and income tax	207.0	203.8
Finance revenue	1.3	–
Finance expense	(68.0)	(70.5)
Profit before income tax	140.3	133.3
Income tax (expense)	(35.5)	(37.9)
Net profit for the year	104.8	95.4
Other comprehensive income		
Items that may be reclassified subsequently to profit or loss:		
Change in cash flow hedge reserve	(20.1)	2.6
Income tax credit (expense) relating to items that may be reclassified	5.6	(0.7)
Total items that may be reclassified subsequently to profit or loss	(14.5)	1.9
Total other comprehensive income (expense) for the year	(14.5)	1.9
Total comprehensive income for the year	90.3	97.3
Earnings per share from operations attributable to shareholders of the Parent		
Basic and diluted earnings per share (cents)	10.49	9.54

Electricity revenue was lower than PFI due to reduced electricity generation as a result of significant hydro inflows combined with unseasonably warm conditions, resulting in lower-than-expected energy consumption. Gas revenue was higher than PFI due to increased Time of Use load from new commercial and industrial customers being greater than reduced mass market gas usage. Depressed wholesale electricity prices led to lower electricity purchase, transmission and distribution costs and a preference for hydro over thermal generation resulted in lower fuel costs than PFI, while other operating expenses benefited from lower maintenance and costs associated with running the thermal fleet. Net Profit after Tax (NPAT) was above PFI, due to the positive impact of changes in fair value of financial instruments, and the write-back of tax expenses associated with previous period earnings.

28. Comparison to prospective financial information ('PFI') as disclosed in the Investment Statement dated 13 March 2014 (continued)

Consolidated statement of changes in equity

	2015 Actual $ million	2015 PFI $ million
Balance as at 1 July 2014	1,880.7	1,871.2
Net profit for the year	104.8	95.4
Other comprehensive income		
Change in cash flow hedge reserve	(20.1)	2.6
Income tax credit relating to other comprehensive income	5.6	(0.7)
Total comprehensive income (expense) for the year	90.3	97.3
Share-based payments	0.3	–
Dividends	(145.9)	(144.0)
Balance as at 30 June 2015	1,825.4	1,824.5

Total equity was in line with PFI as the additional NPAT was offset by a reduction in the cash flow hedge reserve and the adjustment to income tax.

28. Comparison to prospective financial information ('PFI') as disclosed in the Investment Statement dated 13 March 2014 (continued)

Consolidated balance sheet

	2015 Actual $ million	2015 PFI $ million
Current assets		
Cash and cash equivalents	21.0	24.5
Receivables and prepayments	187.7	259.3
Inventories	80.0	63.5
Assets held for sale	3.1	–
Intangible assets	4.3	2.3
Tax receivable	16.2	–
Derivatives	34.2	4.0
Total current assets	346.5	353.6
Non-current assets		
Receivables and prepayments	0.9	1.0
Inventories	24.4	52.3
Property, plant and equipment	2,682.5	2,733.8
Oil and gas assets	292.4	295.4
Intangible assets	127.4	109.6
Derivatives	53.9	1.5
Total non-current assets	3,181.5	3,193.6
Total assets	3,528.0	3,547.2
Current liabilities		
Payables and accruals	158.3	228.5
Tax payable	–	8.0
Borrowings	117.8	114.7
Provisions	12.3	11.6
Derivatives	21.5	4.6
Total current liabilities	309.9	367.4
Non-current liabilities		
Payables and accruals	0.7	0.6
Borrowings	840.4	834.2
Provisions	123.7	129.0
Deferred tax liability	397.2	381.5
Derivatives	30.7	10.0
Total non-current liabilities	1,392.7	1,355.3
Total liabilities	1,702.6	1,722.7
Shareholders' equity		
Share capital	539.7	540.6
Reserves	1,285.7	1,283.9
Total equity	1,825.4	1,824.5
Total equity and liabilities	3,528.0	3,547.2

Current assets were lower than PFI primarily due to a reduction in receivables and prepayments as a result of a change in settlement procedures for electricity sales and purchases, offset to some degree by the higher current portion of inventories and financial derivatives. Note the increase in tax receivable was due to the resolution reached with the Inland Revenue Department in relation to the Tekapo Canal Remediation Project claim and the Hydroelectric Powerhouse claim. Non-current assets were lower than PFI due to the decrease in the non-current portion of the coal stockpile as a result of the change in the coal burn forecast and higher coal burn in the current year, and reduced capital expenditure.

Current liabilities were lower than PFI mainly due to a decrease in payables and accruals as a result of a decrease in electricity purchases and the change in settlement procedures for electricity sales and purchases discussed above. Non-current liabilities were higher than PFI mainly due to an increase in the deferred tax liability and derivatives. Electricity and interest rate derivatives were higher than PFI due to changes in the wholesale electricity and interest rate price paths.

28. Comparison to prospective financial information ('PFI') as disclosed in the Investment Statement dated 13 March 2014 (continued)

Consolidated cash flow statement

	2015 Actual $ million	2015 PFI $ million
Cash flows from operating activities		
Cash was provided from:		
Receipts from customers	2,122.0	2,188.3
Interest received	1.3	–
	2,123.3	2,188.3
Cash was applied to:		
Payments to suppliers and related parties	1,687.6	1,726.6
Payments to employees	81.0	85.2
Tax paid	36.2	31.6
	1,804.8	1,843.4
Net cash inflows from operating activities	318.5	344.9
Cash flows from investing activities		
Cash was provided from:		
Proceeds from disposal of property, plant and equipment	1.3	–
	1.3	–
Cash was applied to:		
Purchase of property, plant and equipment	35.5	61.1
Purchase of oil and gas assets	4.1	1.6
Purchase of intangibles (excluding emission units)	10.3	1.4
	49.9	64.1
Net cash (outflows) from investing activities	(48.6)	(64.1)
Cash flows from financing activities		
Cash was provided from:		
Proceeds from borrowings	193.0	–
	193.0	–
Cash was applied to:		
Repayment of borrowings	256.1	68.1
Interest paid and other finance charges	61.6	67.1
Repayment of principal on finance lease liabilities	1.6	1.6
Dividends	145.9	144.0
	465.2	280.8
Net cash (outflows) from financing activities	(272.2)	(280.8)
Net increase (decrease) in cash and cash equivalents	(2.3)	–
Cash and cash equivalents at 1 July	23.3	24.5
Cash and cash equivalents at 30 June	21.0	24.5

Net cash flows for the year were similar to PFI and only varied due to the operating net outflows being offset by the reduced capital expenditure and lower cash outflows associated with financing activities. Lower capital expenditure reflects reduced spend on retail and corporate head office projects compared to forecast and lower renewable generation expenditure.

29. Commitments

Capital commitments

	2015 $ million	2014 $ million
Not later than one year	1.2	8.3
Later than one year but not later than five years	4.3	4.1
Total capital commitments	5.5	12.4

The capital commitments disclosed above include $1.1 million in relation to Kupe Joint Venture (2014: $1.0 million).

29. Commitments (continued)

Leases

Leases are classified as finance leases whenever the terms of the lease transfer substantially all the risks and rewards of ownership to the lessee. All other leases are classified as operating leases. When assets are leased under a finance lease, the present value of the minimum lease payments is recognised as either a payable or a receivable in the balance sheet. Repayments are allocated between the capital and interest over the term of the lease in order to reflect a constant periodic rate of return on the net investment outstanding in respect of the lease. Payments made under operating leases (net of any incentives received from the lessor) are charged to profit or loss on a straight-line basis over the lease term. Receipts from operating leases are recognised in profit or loss on a straight-line basis over the lease term.

Operating lease commitments

Where the Group is lessee

The Group leases building accommodation for its offices and land for its generation sites under operating lease arrangements. The Group also leases vehicles and certain office equipment. These leases are of a rental nature and are on normal commercial terms and conditions. These leases have varying lease periods of up to 20 years. In some cases, renewal rights exist with market review clauses. The Group does not have any options to purchase the leased assets at the expiry of the lease period.

	2015 $ million	2014 $ million
Not later than one year	**8.4**	11.7
Later than one year but not later than five years	**17.0**	26.0
Later than five years	**13.6**	16.5
Total operating lease commitments	**39.0**	54.2

Lease commitments are disclosed exclusive of GST.

30. Contingent assets and liabilities

The Group had contingent assets and liabilities at 30 June 2015 in respect of:

Land claims, law suits and other claims

The Parent acquired interests in land and leases from Electricity Corporation of New Zealand Limited ('ECNZ') on 1 April 1999. These interests in land and leases may be subject to claims to the Waitangi Tribunal and may be resumed by the Crown. The Parent would expect to negotiate with the new Maori owners for occupancy and usage rights of any sites resumed by the Crown. Certain claims have been brought to or are pending against the Parent, ECNZ and the Crown under the Treaty of Waitangi Act 1975. Some of these claims may affect land and leases purchased by the Parent or its subsidiaries from ECNZ. In the event that land is resumed by the Crown, the resumption would be affected by the Crown under the Public Works Act 1981 and compensation would be payable to the Parent.

The Board of Directors cannot reasonably estimate the adverse effect (if any) on the Parent if any of the foregoing claims are ultimately resolved against it, or any contingent or currently unknown costs or liabilities crystallise. There can be no assurances that these claims will not have a material adverse effect on the Group's business, financial condition or results of operations.

Inland Revenue Department draft provisional Depreciation Determination for Geothermal and Thermal Powerhouses – contingent asset

On 7 July 2015, the Inland Revenue Department released a draft provisional Depreciation Determination for Geothermal and Thermal Powerhouses, including proposed depreciation rates. The Determination is subject to public consultation and, as a result, is not yet finalised. If the draft provisional Depreciation Determination is approved in its current form, the estimated impact of the draft provisional Depreciation Determination on the Income Statement is to decrease income tax expense by between $3.0 million and $5.0 million as at 30 June 2015.

There are no other known material contingent assets or liabilities (2014: nil).

31. Events occurring after balance date

Subsequent to balance date, the Parent declared a final fully imputed dividend of $80.0 million (8 cents per share).

The following other events occurred subsequent to balance date:

- New Zealand Aluminium Smelters (NZAS) confirmed on 3 August 2015 that it had varied its contract with Meridian Energy Limited to purchase electricity at its Tiwai Point smelter near Bluff, Southland. Genesis Energy entered into a back-to-back agreement with Meridian Energy to supply 50MW of electricity to the Huntly node from 1 January 2017 to 31 December 2018;
- On 6 August 2015 the Board of Directors announced plans to retire the Huntly Rankine units by 31 December 2018;
- On 13 August 2015 Solid Energy was placed into voluntary administration and on 20 August 2015 Genesis Energy subsequently exercised a right to exit its coal supply agreement with Solid Energy for the supply of coal to the Huntly Power Station; and
- On 17 August 2015 Contact Energy announced plans to close its Otahuhu B Power Station at the end of September 2015.

There is no impact on the financial statements at 30 June 2015 arising from these events.

There have been no other significant events subsequent to balance date.

Independent Auditor's Report

To the Shareholders of Genesis Energy Limited Group
Report on the audit of the financial statements for the year ended 30 June 2015

The Auditor-General is the auditor of Genesis Energy Limited and its New Zealand domiciled subsidiaries. The Auditor-General has appointed me, Andrew Dick, using the staff and resources of Deloitte, to carry out the audit of the financial statements of the Group, consisting of Genesis Energy Limited and its subsidiaries and other controlled entities (collectively referred to as 'the Group'), on her behalf.

Opinion

We have audited the financial statements of the Group on pages 70 to 108 that comprise the balance sheet as at 30 June 2015, the comprehensive income statement, statement of changes in equity and cash flow statement for the year ended on that date and the notes to the financial statements that include accounting policies and other explanatory information.

In our opinion the financial statements of the Group comply with generally accepted accounting practice in New Zealand and present fairly, in all material respects, its financial position as at 30 June 2015 and its financial performance and cash flows for the year then ended in accordance with New Zealand Equivalents to International Financial Reporting Standards and International Financial Reporting Standards.

Our audit was completed on 24 August 2015. This is the date at which our opinion is expressed.

The basis for our opinion is explained below. In addition, we outline the responsibilities of the Board of Directors and our responsibilities, and explain our independence.

Basis of opinion

We carried out our audit in accordance with the Auditor-General's Auditing Standards, which incorporate the International Standards on Auditing (New Zealand). Those standards require that we comply with ethical requirements and plan and carry out our audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

Material misstatements are differences or omissions of amounts and disclosures that, in our judgement, are likely to influence shareholders' overall understanding of the financial statements. If we had found material misstatements that were not corrected, we would have referred to them in our opinion.

An audit involves carrying out procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgement, including our assessment of risks of material misstatement of the financial statements whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the preparation of the Group's financial statements in order to design audit procedures that are appropriate in the circumstances but not for the purpose of expressing an opinion on the effectiveness of the Group's internal control.

An audit also involves evaluating:

- the appropriateness of accounting policies used and whether they have been consistently applied;
- the reasonableness of the significant accounting estimates and judgements made by the Board of Directors;
- the adequacy of the disclosures in the financial statements; and
- the overall presentation of the financial statements.

We did not examine every transaction, nor do we guarantee complete accuracy of the financial statements.

Also we did not evaluate the security and controls over the electronic publication of the financial statements.

We believe we have obtained sufficient and appropriate audit evidence to provide a basis for our audit opinion.

Responsibilities of the Board of Directors

The Board of Directors is responsible for the preparation and fair presentation of financial statements for the Group that comply with generally accepted accounting practice in New Zealand (being in accordance with New Zealand Equivalents to International Financial Reporting Standards and International Financial Reporting Standards).

The Board of Directors is also responsible for such internal control as it determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error. The Board of Directors is also responsible for the publication of the financial statements, whether in printed or electronic form.

The Board of Directors' responsibilities arise from the Financial Markets Conduct Act 2013.

Responsibilities of the Auditor

We are responsible for expressing an independent opinion on the financial statements and reporting that opinion to you based on our audit. Our responsibility arises from section 15 of the Public Audit Act 2001.

Independence

When carrying out the audit we followed the independence requirements of the Auditor-General, which incorporate the independence requirements of the External Reporting Board.

In addition to the audit we have carried out assignments in the areas of trustee reporting, review of the Integrated report, scrutineers notice and review of the interim report, which are compatible with those independence requirements. In addition to these assignments, principals and employees of our firm deal with the Group on arm's length terms within the ordinary course of trading activities of the Group. Other than the audit and these assignments, we have no relationship with or interests in the Group.

Andrew Dick
Deloitte
On behalf of the Auditor-General
Auckland, New Zealand

Appendix 4E
GENESIS ENERGY LIMITED
(ARBN 149 509 599)
INCORPORATED IN NEW ZEALAND

FULL YEAR REPORT

Reporting period twelve months to 30 June 2015
Previous reporting period twelve months to 30 June 2014

RESULTS FOR ANNOUNCEMENT TO THE MARKET – 25 AUGUST 2015

Revenue and Net Profit	30 June 2015 Amount ($NZ million)	30 June 2014 Amount ($NZ million)	Percentage change
Revenues from ordinary activities	2,097.6	2,005.0	5%
Profit (loss) from ordinary activities after tax attributable to security holder.	104.8	49.2	113%
Net profit (loss) attributable to security holders	104.8	49.2	113%

Dividends – Ordinary Shares	30 June 2015 Amount per security (NZ cents)	30 June 2014 Amount per security (NZ cents)	Percentage change
Final dividend	8.0	6.6	21%
Final dividend - imputed amount	8.0	6.6	21%

Record date: 2 October 2015
Payment date: 16 October 2015

COMMENTARY ON RESULTS FOR THE PERIOD
For commentary on the results please refer to the Management Discussion and Analysis attached.

FINANCIAL INFORMATION
The Appendix 4E should be read in conjunction with the consolidated financial statement for the year ended 30 June 2014 as attached.

Net Tangible Assets – Ordinary Shares	30 June 2015 Amount per security (NZ cents)	30 June 2014 Amount per security (NZ cents)	Percentage change
Net Tangible Asset	170	175	-3%

APPENDIX 7 – NZSX Listing Rules

EMAIL: announce@nzx.com

Notice of event affecting securities

NZSX Listing Rule 7.12.2. For rights, NZSX Listing Rules 7.10.9 and 7.10.10.
For change to allotment, NZSX Listing Rule 7.12.1, a separate advice is required.

Number of pages including this one (Please provide any other relevant details on additional pages): ☐

Full name of Issuer	Genesis Energy Limited
Name of officer authorised to make this notice	Maureen Shaddick, General Counsel and Company Secretary
Authority for event, e.g. Directors' resolution	Directors' resolutions
Contact phone number	09 951 9304
Contact fax number	
Date	25 / 08 / 2015

Nature of event
Tick as appropriate

Bonus Issue	☐
If ticked, state whether: Taxable	☐
/ Non Taxable	☐
Conversion	☐
Interest	☐
Rights Issue Renouncable	☐
Rights Issue non-renouncable	☐
Capital change	☐
Call	☐
Dividend	☒
If ticked, state whether: Interim	☐
Full Year	☒
Special	☐
DRP Applies	☐

EXISTING securities affected by this

If more than one security is affected by the event, use a separate form.

Description of the class of securities	Ordinary Shares
ISIN	NZGNEE0001S7

If unknown, contact NZX

Details of securities issued pursuant to this event

If more than one class of security is to be issued, use a separate form for each class.

Description of the class of securities	
ISIN (*If unknown, contact NZX*)	
Number of Securities to be issued following event	
Minimum Entitlement	
Ratio, e.g ① for ②	for
Conversion, Maturity, Call Payable or Exercise Date (*Enter N/A if not applicable*)	
Treatment of Fractions	
Tick if pari passu	☐
OR provide an explanation of the ranking	
Strike price per security for any issue in lieu or date Strike Price available.	

Monies Associated with Event

Dividend payable, Call payable, Exercise price, Conversion price, Redemption price, Application money.

In dollars and cents

Amount per security (does not include any excluded income)	$0.08 per share
Source of Payment	Retained Earnings
Excluded income per security (only applicable to listed PIEs)	
Currency	NZ Dollars
Total monies	$80,000,000

Supplementary dividend details - NZSX Listing Rule 7.12.7

Amount per security in dollars and cents	$0.014 per share
Date Payable	16 October, 2015

Taxation

Amount per Security in Dollars and cents to six decimal places

In the case of a taxable bonus issue state strike price	$
Resident Withholding Tax	$0.006 per share
Imputation Credits (Give details)	$0.031 per share
Foreign Withholding Tax	$
FDP Credits (Give details)	

Timing (Refer Appendix 8 in the NZSX Listing Rules)

Record Date 5pm *For calculation of entitlements -*	2 October 2015
Application Date *Also, Call Payable, Dividend / Interest Payable, Exercise Date, Conversion Date. In the case of applications this must be the last business day of the week.*	16 October 2015
Notice Date *Entitlement letters, call notices, conversion notices mailed*	
Allotment Date *For the issue of new securities. Must be within 5 business days of application closing date.*	

OFFICE USE ONLY
Ex Date:
Commence Quoting Rights:
Cease Quoting Rights 5pm:
Commence Quoting New Securities:
Cease Quoting Old Security 5pm:

Security Code:

Security Code:

NZX