Results Presentation

Six month period ended 31 December 2010

22 February 2011

Disclaimer

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

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

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

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

This presentation does not constitute investment advice.

Outline

EBITDAF $225m, and Underlying Earnings $79m
Consistent with 1H10

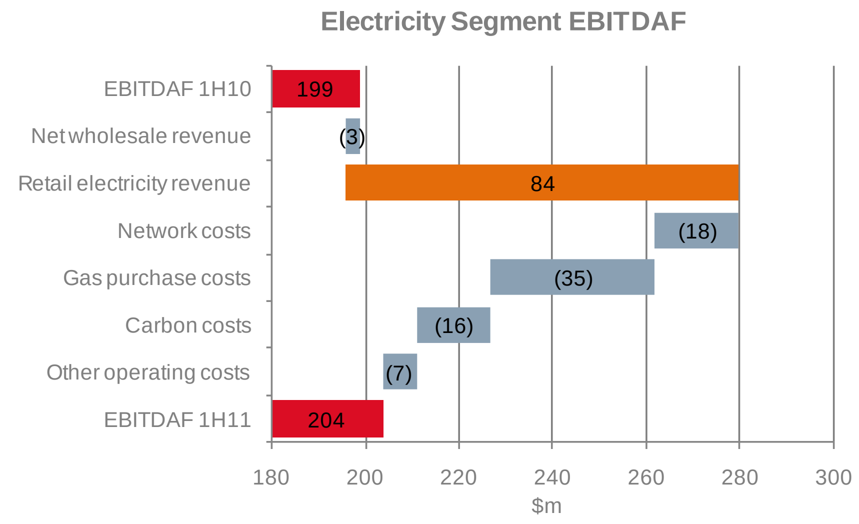
- **Good result given challenging operating environment**
  - Wet conditions
  - Gas, network, carbon cost increases
  - Portfolio inflexibility
- **First stage of Ahuroa Gas Storage commissioned**
  - Operational performance better than expected
  - Excellent safety performance during construction
- **Stratford Peaker Project commissioning well advanced**
  - Commissioning delays not materially impacting financial performance
  - Good unit performance
  - Commissioning complete in April

Key financial information	1H11	1H10	Variance $	Variance %
EBITDAF ($m)	225.5	225.0	0.5	0%
Profit for the Period ($m)	83.7	87.1	(3.4)	(4%)
Underlying Earnings After Tax ($m)	78.8	79.0	(0.2)	0%
Capital expenditure ($m)	202.4	214.6	12.2	6%
Operating cash flow after tax ($m)	167.7	165.1	2.6	2%
Net debt ($m)	1,416.3	1,229.7	(186.6)	(15%)
Net debt / net debt + equity (%)	33%	31%	(2%)	(6%)

EBITDAF: $225m, consistent with 1H10
Price increases absorbed by increasing costs

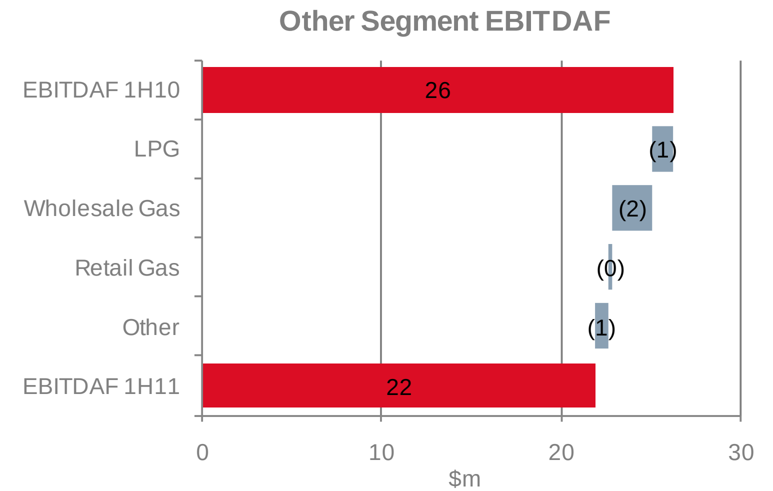
Electricity segment EBITDAF up $5m (2%) to $204m

- Retail electricity revenue up $84m (13%) due to higher sales volumes (+9%) and tariff increases (+4%)
- Operating costs (excl retail purchases) up $76m (15%)
  - Network costs up $18m
  - Carbon costs up $16m
  - Gas costs up $35m
  - Other operating costs up $7m



Other segment EBITDAF down $4m (16%) at $22m

- Retail gas sales volumes down 0.3 PJ (14%) and LPG volumes down 2,005 tonnes (5%)
- Carbon costs of $3.5m



Underlying earnings: $79m, consistent with 1H10
Distribution of 11 cents per share, consistent with 1H10

contact

	1H11 $m	1H10 $m	Variance $m	Variance %
EBITDAF	**225.5**	**225.0**	**0.5**	**0%**
Depreciation and amortisation	(85.5)	(86.7)	1.2	1%
Equity accounted earnings of associates	1.8	1.5	0.3	20%
Net interest expense	(30.1)	(29.0)	(1.1)	(4%)
Income tax expense	(32.9)	(31.8)	(1.1)	(3%)
Underlying earnings after tax	**78.8**	**79.0**	**(0.2)**	**0%**
Underlying earnings per Share (cents)	**12.89**	**13.36**	**(0.5)**	**(4%)**
Distribution per Share (cents)	**11.0**	**11.0**	**-**	**0%**

- Depreciation and amortisation down $1.2m (1%) as a result of a minor extension in asset lives as part of a normal periodic review undertaken prior to the FY10 financial results
- Net interest expense increased by $1.1m (4%) due to lower interest income resulting from lower levels of cash held during the period, partly offset by a lower average interest rate on borrowings
- Underlying earnings are flat
  - Underlying earnings per share declines slightly because of increased number of shares on issue as a result of the operation of the profit distribution plan
- Distribution per share of 11 cents per share
  - Represents a pay-out of 86% of underlying earnings for the period
  - Consistent with 1H10 distribution

Statutory profit: $84m, down 4% relative to 1H10
lower benefit from the movement in value of interest rate swaps

	1H11 $m	1H10 $m	Variance $m	Variance %
Underlying earnings after tax	**78.8**	**79.0**	**(0.2)**	**(0%)**
Change in fair value of financial instruments (after tax)	1.3	8.1	(6.8)	(84%)
Impact of change in corporate income tax rate	3.6	-	3.6	
Profit for the Period	**83.7**	**87.1**	**(3.4)**	**(4%)**

- **Key adjustments to move from Underlying Earnings to Statutory Profit for the Period:**
  - **Benefit in the change in fair value of financial instruments net of tax reduced $6.8m (84%) due to a lower favourable movement in the value of interest rate swaps that do not qualify for hedge accounting**
  - **Income tax expense reduced $3.6m driven by a reassessment of the impact of the change in corporate income tax rate on deferred tax liability**
- **Contact expects the effective tax rate on profit for FY11 will be approximately 28%**

Strategy – (i) – Increase portfolio flexibility

- **Ahuroa Gas Storage**
  - 3.3 PJ injected during the half (mitigating $25m of additional gas costs)
  - At 31 December 2010, total gas and LPG in the reservoir: 14.6 PJ (8.3 PJ of which is inventory gas)
  - Extraction facilities commissioned
  - Operational at 32 TJ/d in, 45 TJ/day out
  - Working volume now around 17PJ

- **Stratford Peaker Project**
  - Commissioning delays with balance of plant
  - Plant output and efficiency above expectations
  - Commissioning complete in April

- **Lower take-or-pay gas volumes from 1/1/11**
  - Expiry of GSA2 gas contract lowers take-or-pay gas from 31 PJ in 1H11 to 20 PJ in 2H11

Ahuroa gas storage project

Stratford peaker and TCC power stations

Strategy – (ii) – Lower average cost of generation

- **23 MW Te Huka geothermal power plant**
  - Completed in May 2010
  - Operating performance above expectations

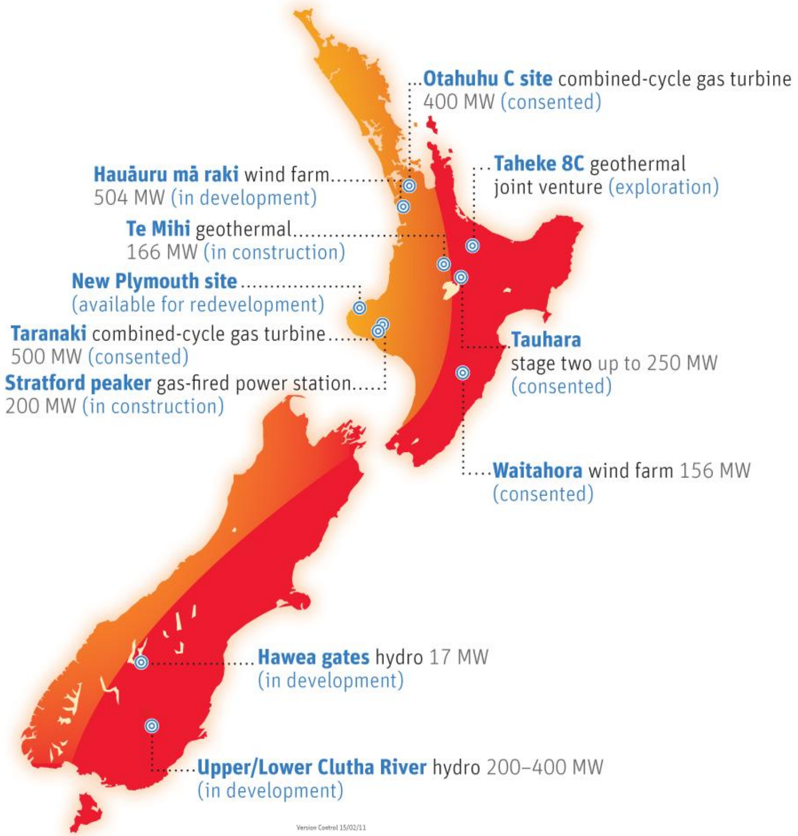
- **166 MW Te Mihi geothermal power project (net 159 MW)**
  - Engineering, procurement and construction (EPC) contract executed today
  - Project cost: $623m
  - Replaces 45 MW of existing Wairakei capacity and adds about 114 MW of new capacity to the national grid
  - Increases operational efficiency
  - Lowers unit operation and maintenance costs
  - Lowers discharges of geothermal fluids into the Waikato River
  - Assuming no demand growth or Huntly retirement, Te Mihi will reduce Contact's base-load gas-fired (CCGT) generation capacity factor from 65% to 50%
  - Funded with a combination of debt and equity
  - Pro-rata renounceable rights issue expected to be launched in the near term
  - Contact's majority shareholder, Origin Energy has confirmed that it will subscribe for its share of the issue

Te Huka power station

Rendition of the Te Mihi power station

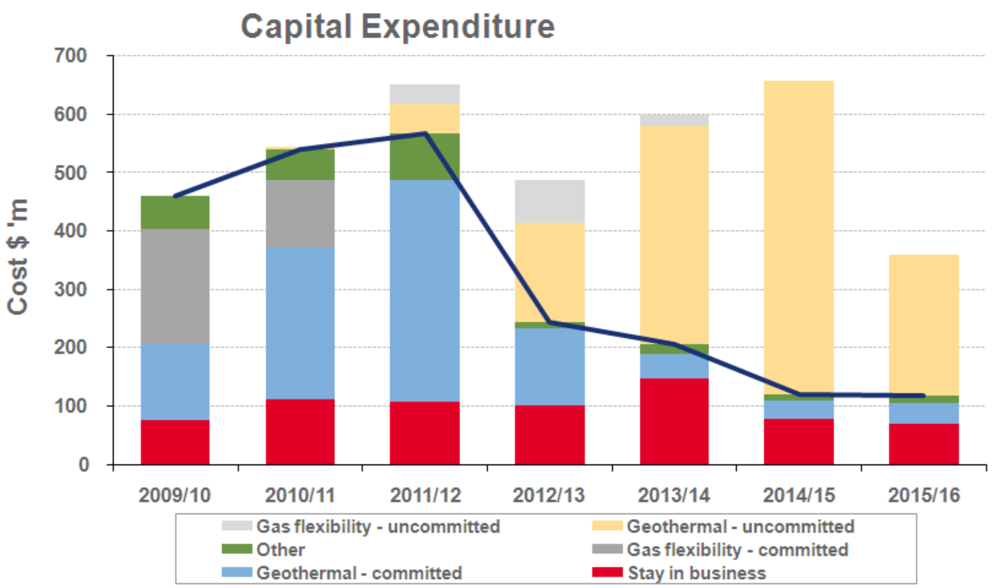
Strategy – (iii) – Generation market share growth

- **Geothermal**
  - 250 MW Tauhara 2 project: Consented
  - Likely to follow Te Mihi
  - Taheke – three exploration wells drilled; positive preliminary results
- **Wind**
  - 156 MW Waitahora project: Consented
  - 504 MW Hauāuru mā raki project: Consent decision pending
- **Hydro**
  - Progressing selection of favoured Clutha hydro option
- **Gas**
  - Progressing future peaker options
  - Next stage of gas storage under consideration



Capital expenditure – reflects Contact's strategy

- **Stay in business capital expenditure increased marginally to $34m in 1H11, up from $30m in 1H10**
- **Growth capital expenditure was $168m, (including capitalised interest) compared with $185m in 1H10**
- **Committed capex includes:**
  - Ahuroa gas storage – first stage
  - Te Mihi geothermal project
  - Enterprise transformation (SAP) programme
  - Other geothermal investment in existing field (wells, steamfield investment etc.)
- **Tauhara 2 and the possible expansion of Ahuroa are not committed**
- **Balance sheet gearing level supports growth. As at 31 December 2010:**
  - Net debt $1.42bn
  - Gearing ratio 33%
  - $520m in available credit facilities (of which $175m was drawn)



Enterprise Transformation Programme
Successfully accomplished two major milestones on schedule and on budget

- **Phased replacement of Contact's business and procurement, generation and retail systems**
- **New finance and procurement systems completed on schedule and on budget in October 2010**
- **New generation asset management completed at the first two generation sites**
  - Completion at all sites expected in 2011
- **Retail transformation (customer care and billing) blueprint phase nearing completion**
  - Completion expected in 2012
- **The majority of the design and implementation work is being carried out by Wipro Technologies**
- **Contact is also in the process of transferring some back office retail functions, such as billing and payments processing, to Wipro Technologies**
  - Contact's call centres will continue to be NZ based

Health, safety and environmental performance

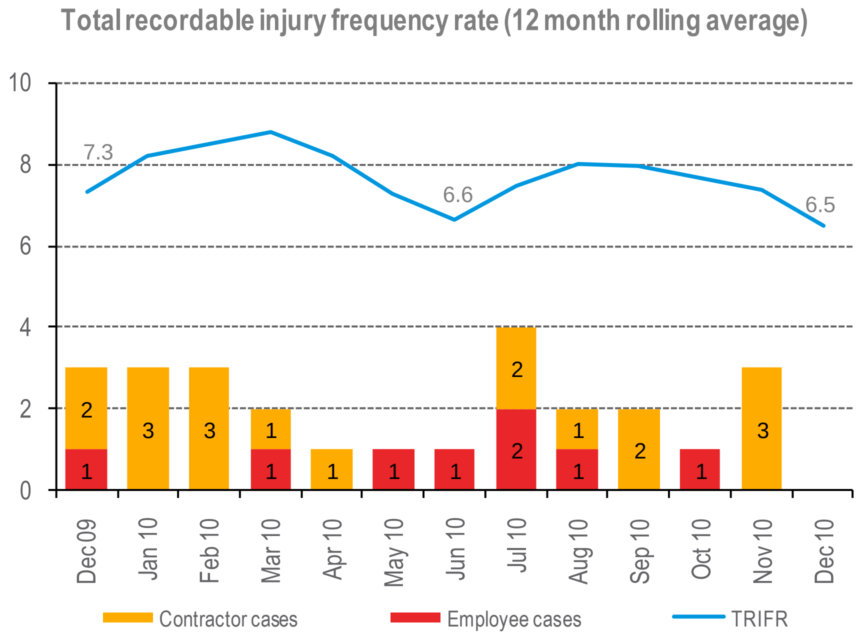
Modest improvement in safety performance in the six months to 31 December 2010. Continues to be a priority focus

- **The safety of our employees, contractors and visitors to any Contact site is the company's highest priority**
- **Safety performance is measured in various ways**

  Total recordable injury frequency rate (TRIFR)

  TRIFR: $\dfrac{\text{total number of recordable injuries}}{\text{million person-hours worked}}$

- **Contact's TRIFR improved from 6.8 in 2H10 to 6.5 in 1H11**
- **Contact's aspiration is zero harm**
  - **FY11 safety goal: < 5.2**



Outline

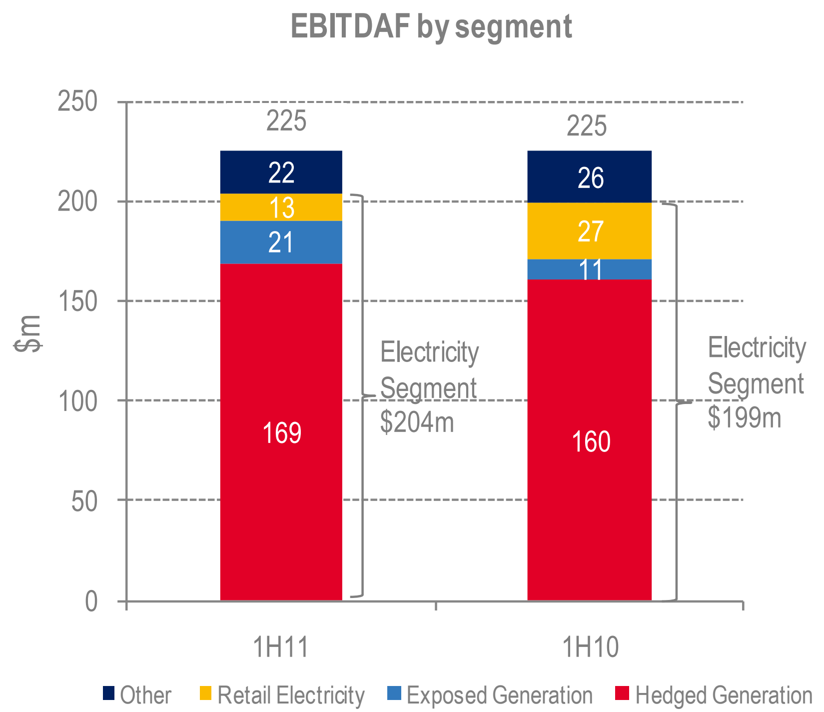
Segment overview

Electricity segment EBITDAF: up $5m (2%) at $204m:

- **Hedged generation:** Up $9m (5%) due to higher volumes and transfer price offset by carbon costs and higher gas costs
- **Exposed generation:** Up $10m (92%) due to higher sales volumes and wholesale prices
- **Retail:** Down $14m (52%) due to increasing unit energy and mass market network costs more than offsetting the benefits of tariff increases and growth in Time of Use sales

Other segment EBITDAF: down $4m (16%) at $22m:

- **LPG:** Down $1m (9%) due to lower demand and carbon costs
- **Wholesale and retail gas:** Down $2m (53%) due to the onset of carbon costs



Electricity segment operational performance data (1H10 in parentheses)

contact

Generation: 5,482 GWh (5,207)

Thermal
2,423 GWh (2,162)
(including swaption)

Hydro
1,905 GWh (1,887)

Geothermal
1,154 GWh (1,158)

Exposed generation
EBITDAF: $21m (11)
Unhedged volume: 725 GWh (547)
Unit generation operating cost: $36.5/MWh (34.1)
Average wholesale price: $65.9/MWh (54.4)

CfD volume: 284 GWh (518)

Hedged generation
EBITDAF: $169m (160)
Retail volume: 4,473 GWh (4,142)
Energy transfer price: $88/MWh (81)
Expected line losses: 223 GWh (231)
GWAP – Haywards differential $2/MWh (4)
Unit generation operating cost: $54.7/MWh (46.9)
(including LTMA costs: $57.7/MWh (49.6))

TOU volume: 1,891 GWh (1,400)

Retail
EBITDAF: $13m (27)
Residential/SME volume: 2,359 GWh (2,511)
Energy purchase price: $88/MWh (81)
Actual line losses: 3.7% (1.8)
LWAP – Haywards differential $5/MWh (1)
Location factor (LWAP/GWAP): 113% (112)
Network costs: $60/MWh (60)
TOU network costs: $28/MWh (29)
Mass market network costs $81/MWh (73)
Cost to serve: $13/MWh (14)
Average sales price: $169/MWh (162)
Retail margin: 2% (4)
Total sales volume: 4,250 GWh (3,911)

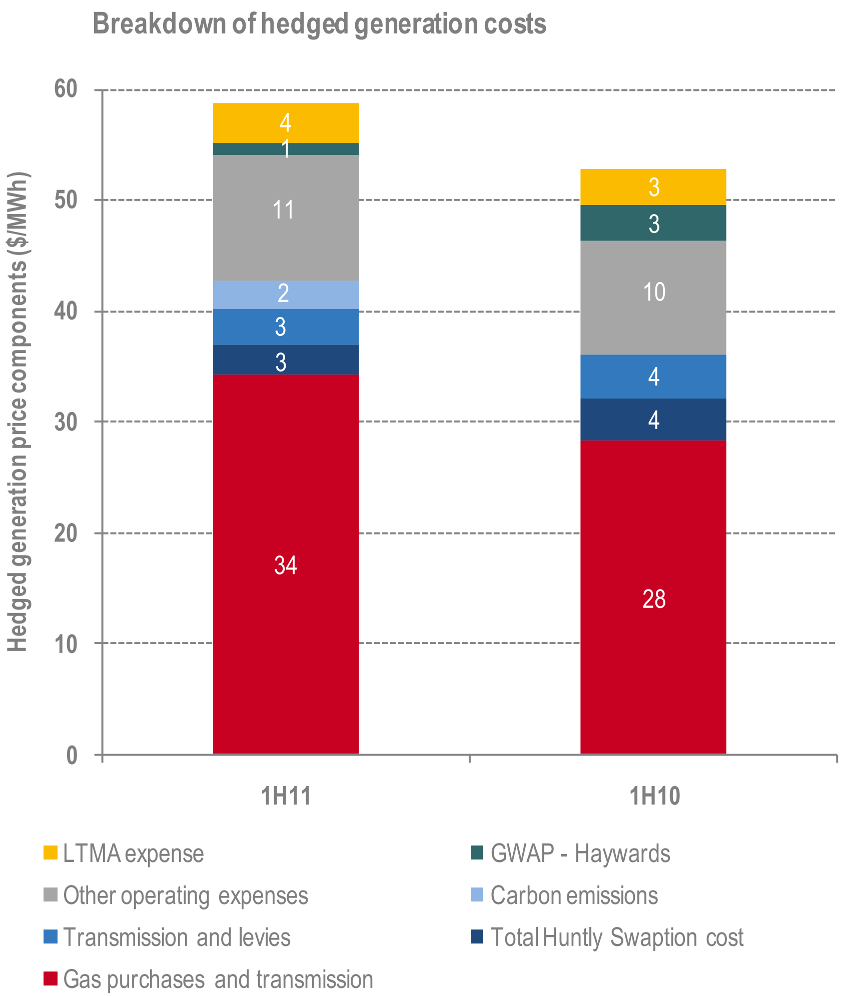
Energy sold into the wholesale market

Energy sold to customers

Note: line losses in hedged generation are based on an expected annual level of line losses; actual line losses are reflected in retail

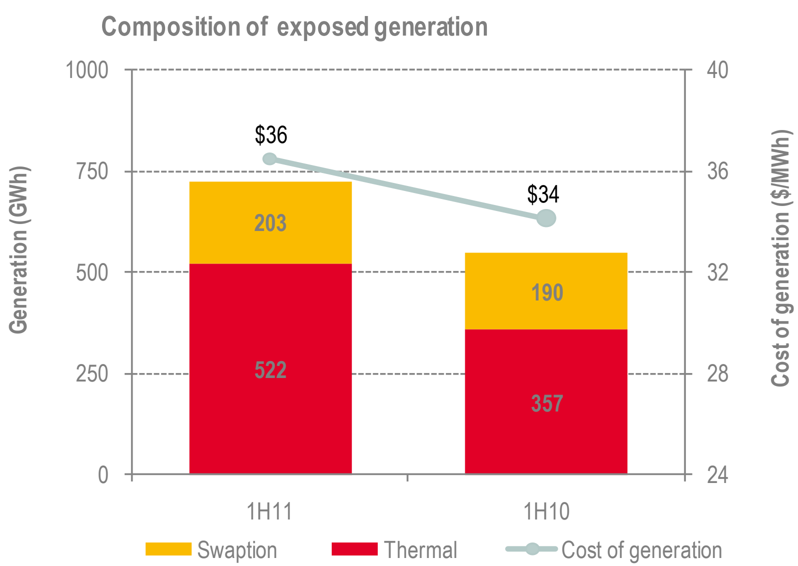
Hedged Generation - Up $9m (5%)
Due to higher transfer price and volumes offset by higher costs

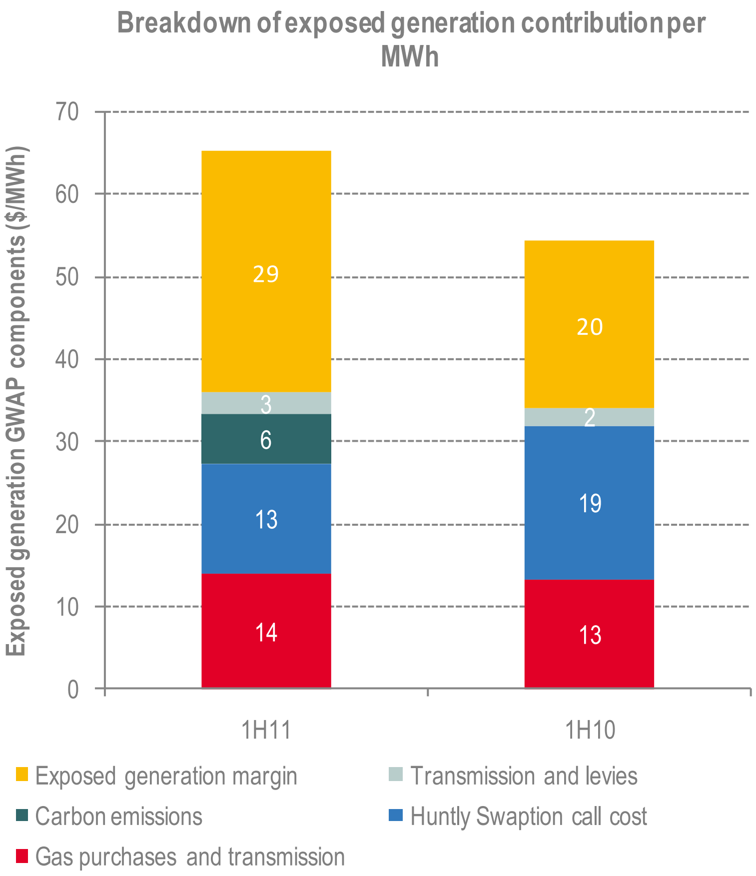
- **Hedged generation volume increased 98 GWh**
  - Renewable and thermal mix was similar to the prior period at 65% renewable (66% in the prior period)
- **Unit sales price to retail increased by $7/MWh to $88/MWh**
  - Reflecting generation cost increases
    - gas purchase costs (+$6/MWh) due to higher underlying gas costs and the costs of gas length
    - carbon (+$2/MWh) incurred on gas used in generation and geothermal steam extraction



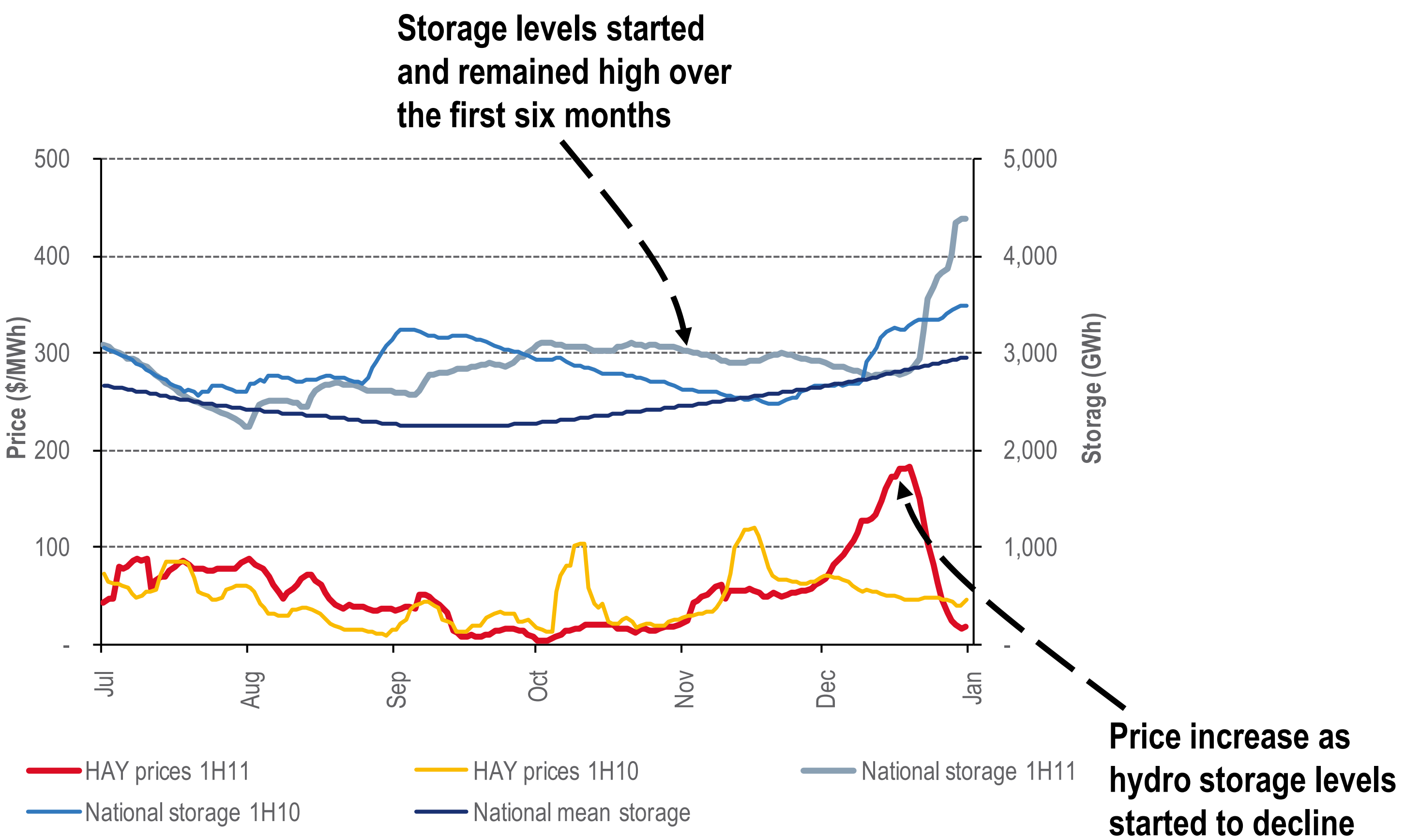
Exposed Generation - Up $10m (92%)
Due to higher average wholesale prices and increased volumes

- **Exposed volume up 178 GWh (33%) to 725 GWh**
- **Average price earned by exposed generation up $12/MWh (21%) to $66/MWh**
  - **23% premium to average Haywards price**
- **Average cost of generation increased $2/MWh (7%) due to the introduction of carbon and increased gas costs**





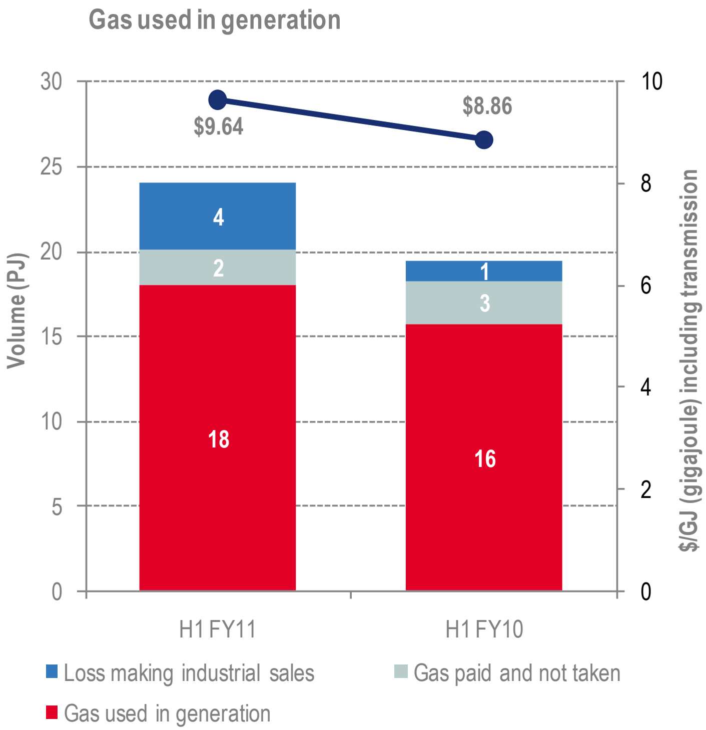
Predominantly wet conditions through the period
Wholesale prices averaged $54/MWh, up $11/MWh from 1H10



Effective gas costs for generation increased from $8.86/GJ in 1H10 to $9.64/GJ

- **Underlying gas costs increased $0.75/GJ**
- **Gas length during 1H11 was 9.3 PJ (6.3 PJ in 1H10)**
- **Injections into storage mitigated 3.3 PJ (avoiding $25m in additional costs)**
- **The remaining gas was either sold at a net loss or not taken**
- **Gas length resulted in a total of $23m ($1.27/GJ) of additional gas costs for the half relative to contracted gas costs**

Total Gas Usage	Volume (PJ)		Cost to generation ($m)		Average unit cost ($/GJ)	
	1H11	1H10	1H11	1H10	1H11	1H10
Take-or-pay obligations	31.3	29.1				
Gas used in generation	18.0	15.7	139.8	109.9	7.75	7.00
Retail sales	1.6	1.8				
Wholesale (excl distressed sales)	2.4	5.2				
Gas length	9.3	6.3				
Injected into storage	3.3	2.5				
Loss on distressed sales	3.9	1.2	10.4	3.6	0.58	0.23
Gas paid and not taken	2.0	2.5	12.5	15.5	0.69	0.99
Total generation gas cost			162.7	129.0	8.33	7.23
Generation transmission costs			11.2	10.1	0.62	0.64
Generation gas cost (incl transmission)			173.9	139.1	9.64	8.86



If Stratford, Ahuroa and the 2H11 gas take-or-pay volumes were in place for 1H11 - EBITDAF would have been up to $35-45m higher

- Gas length costs of ~$25m would have been avoided
- The Stratford peakers would have covered for CCGT outages and operated during peak periods
  - CCGTs would have been shut down during periods where prices were below short run costs
  - The thermal volume reduction would result in a reduction in gas volumes of 3-5 PJ, with associated generation revenues also reduced
  - Resulting in an EBITDAF improvement of up to $10-20m for the half

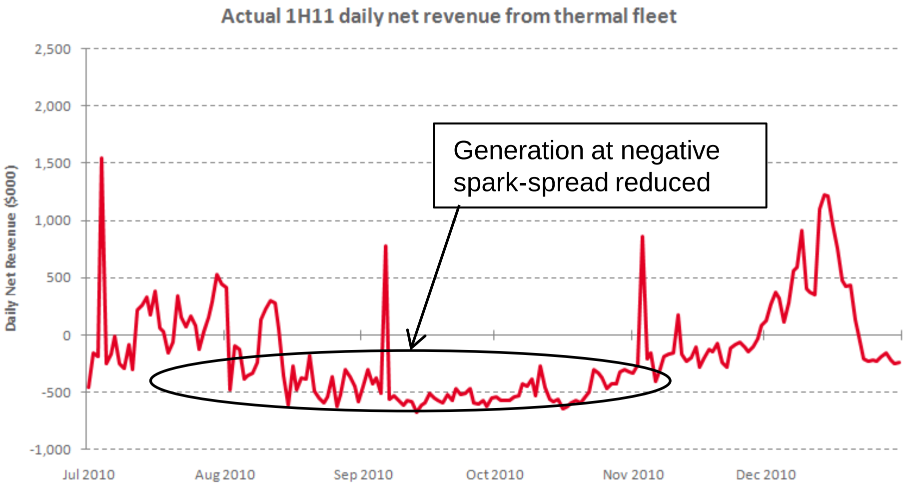
- The tables below show how the reduced gas commitments from CY11 would enable the reduction of 5 PJ of gas use in thermal generation and therefore improve earnings

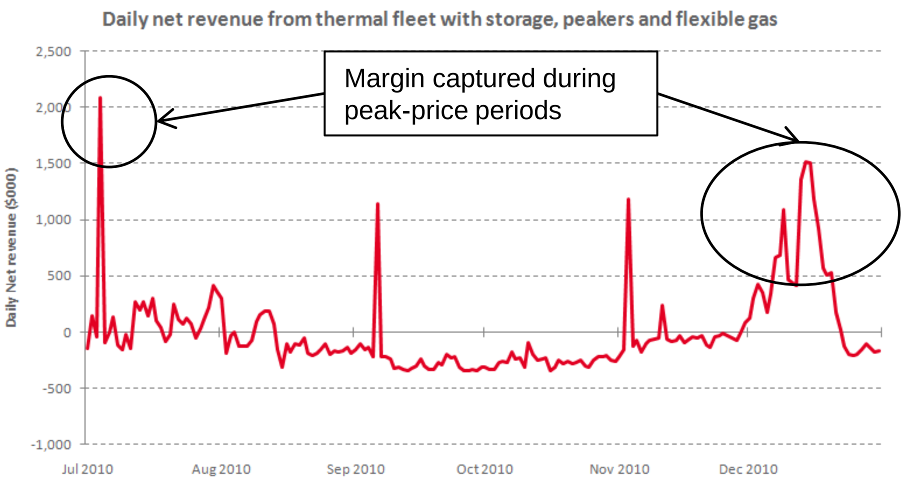
Optimal generation position from 1H11	PJ
Generation volume 1H11	18.0
Reduction for more optimal running	(4.9)
Total optimal use for 1H11	**13.1**

Calendar 2011 minimum gas for generation	PJ
ToP for the year	39.7
Less wholesale and retail demand	(4.4)
Total gas for generation/storage	**35.2**
Max net Storage injections for CY11	(9.0)
Minimum Generation volume from thermals	**26.2**
Minimum generation volume from thermals per half	**13.1**

Net revenue improvements would have resulted from lower CCGT operation and use of peakers

- **The addition of peakers and storage allow Contact to minimise gas use in periods where gas and other costs exceed the spot price**

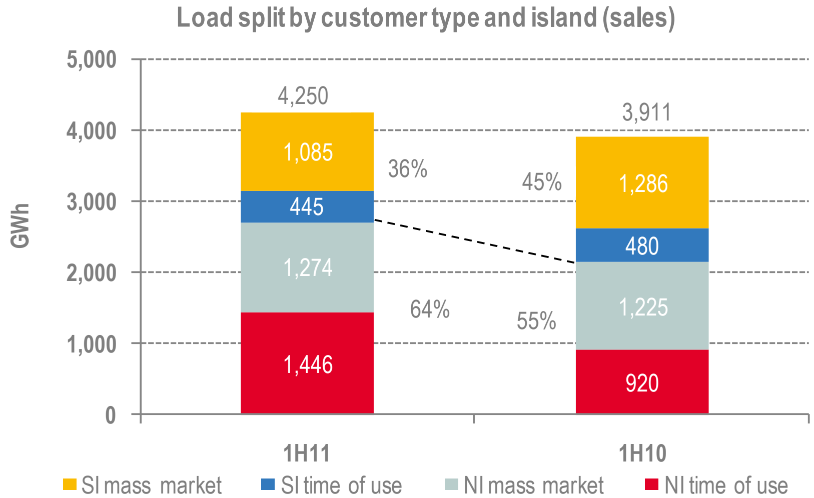


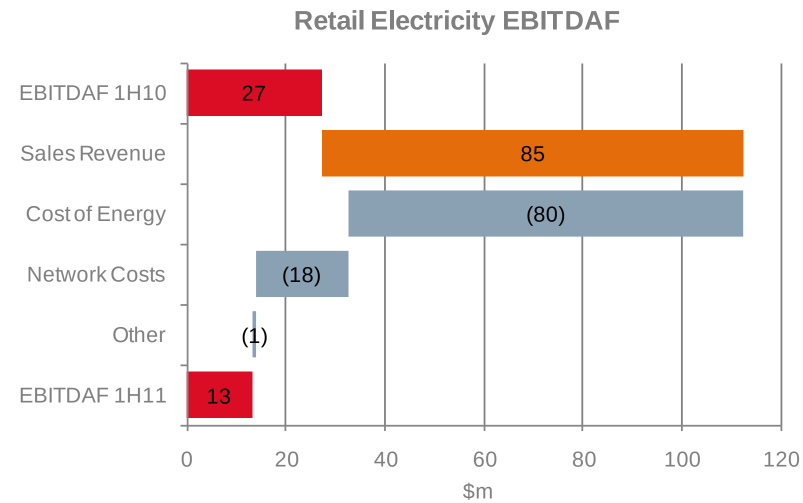


Retail Electricity - Down $14m (52%)

Due to higher energy and mass market network costs more than offsetting the impact of tariff increases and growth in Time of Use sales

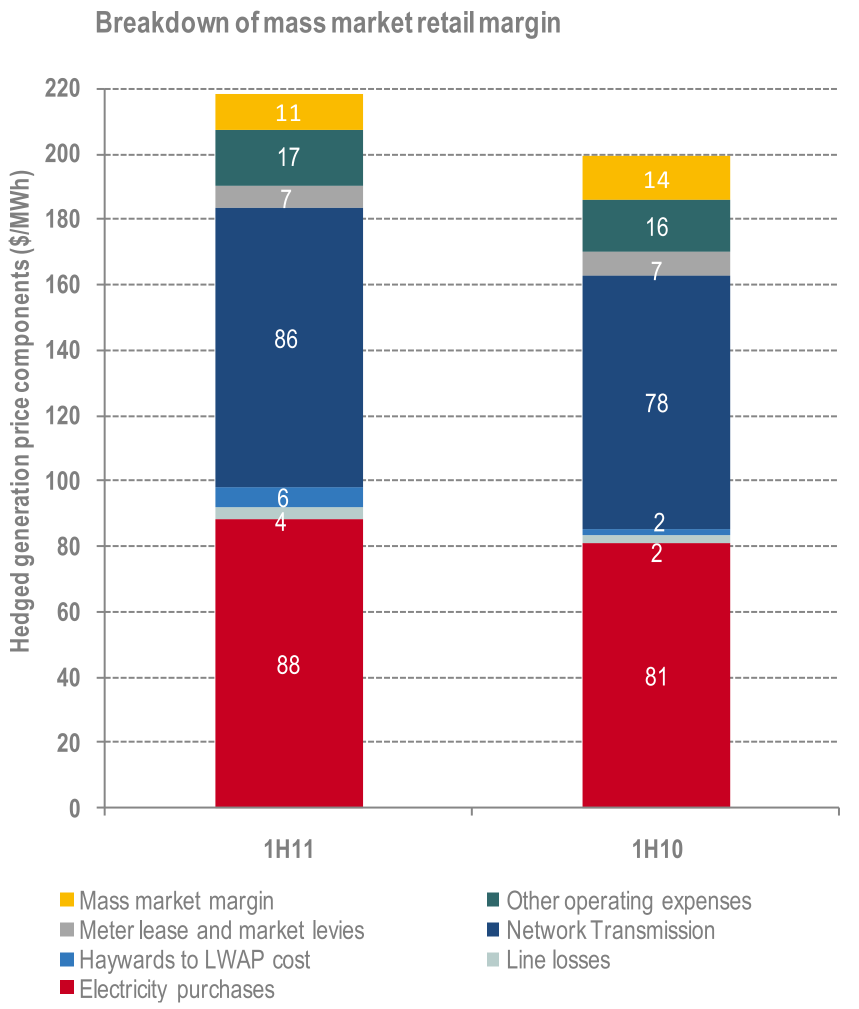
- Sales volume up 9% to 4,250 GWh
  - Time of Use sales up 35% to 1,891 GWh
  - Mass market sales down 6% to 2,359 GWh
  - North Island sales increased from 55% to 64% of total sales
- Average electricity sales price up 4% or $6.80/MWh
- Increase in energy cost from $81/MWh to $88/MWh
- Network costs up $18m due to mass market network unit costs up $8/MWh and Time of Use volume increases
- Retail cost to serve down $1/MWh (7%) to $13/MWh with bad-debt write-offs down by 36%





Mass Market Electricity
External costs (wholesale electricity, networks) continue to rise

- Wholesale electricity up $7/MWh to $88/MWh
- Mass market network costs up $8/MWh
- Other operating expenses up $1/MWh to $17/MWh
  - High churn levels increasing costs to acquire and serve
  - Write-offs down $2m (36%)
- Margins decreased from 7% to 5%



Wholesale and retail prices will continue to adjust to reflect the costs of supply security

- **Wholesale prices will continue to adjust to reflect the costs of thermal generation ($98-$107/MWh)**
  - **Thermal generation is critical for security of supply**
- **Low wholesale prices during 2010 have resulted in discounted pricing to customers by some participants**
  - **Giving the appearance of attractive margins**
  - **But are loss making at wholesale prices which reflect the costs of security**
- **Retailers also continue to carry significant risks in supplying retail customers – current offers would not cover these risks. Examples of these include:**
  - **Location and risk around transmission constraints**
  - **Management of peaks and troughs in customer demand; and**
  - **Significant network company and other third party cost increases**

Example of competitor margins on current residential tariffs as at 31 December 2010

All figures $/MWh unless stated	Hamilton		Christchurch	
Energy cost at Haywards	**$54/MWh**	**$88/MWh**	**$54/MWh**	**$88/MWh**
Revenue after PPD	201.0	201.0	167.5	167.5
Energy cost	(54.0)	(88.2)	(54.0)	(88.2)
Network costs	(90.4)	(90.4)	(65.5)	(65.5)
Meter and EC Levy costs	(8.9)	(8.9)	(7.2)	(7.2)
Location and line losses	(7.9)	(12.0)	(8.8)	(13.4)
Cost to serve	(25.6)	(25.6)	(19.6)	(19.6)
Net margin	**14.3**	**(24.1)**	**12.5**	**(26.3)**
Margin %	**7%**	**-12%**	**7%**	**-16%**

Revenue estimates from supplier websites

Cost estimates from internal Contact Energy sources

Short term margins are positive based on current low wholesale prices ($54/MWh), but unsustainable at prices which reflect the costs of supply security

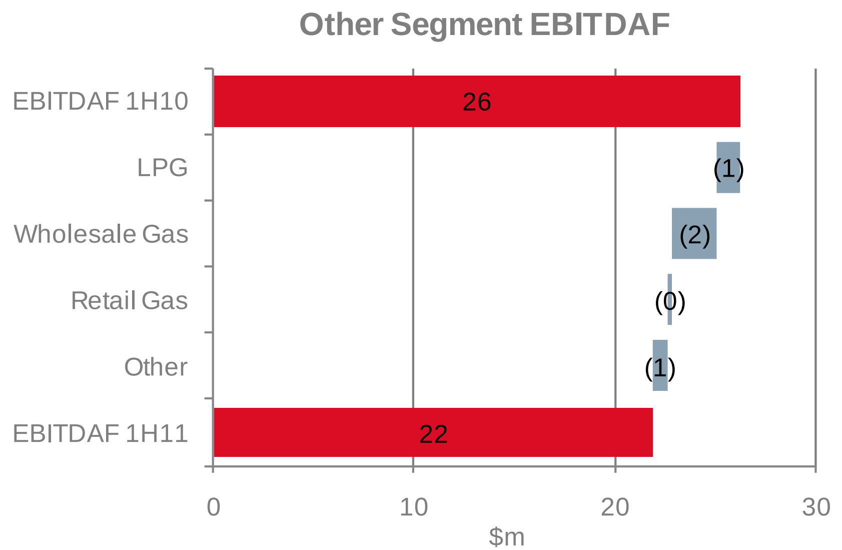
Total electricity segment operating expenses are up $7m
Primarily due to investment in capability

- **Operational excellence and risk focus to create competitive advantage**
  - Centralised risk management group, supported by a newly appointed Chief Risk Officer, to align and bolster risk management capability across the group
    - Health, safety and environment
    - Enterprise risk management
- **Addition of new staff to manage and operate new assets – peakers, storage, geothermal additions**
- **Additional capability to support developments in the portfolio**
    - Generation Operations is transitioning from operating as a group of self-contained, individual assets to a portfolio of assets, managed as a fleet
    - The new organisational structure groups the existing plants into four units focused on production, operations and maintenance (North, Taranaki, Geothermal and Hydro), and introduces new functional units providing specialist services across the portfolio, namely:
      - specialist engineering
      - overhaul and project management
      - operational excellence including HSE, shared services and training

"Other" segment contribution down $4m (16%) to $22m
Due to decreasing volumes and carbon costs

- **LPG EBITDAF down $1m to $6.3m**
  - Volumes down 2,005 tonnes to 36,127
  - Purchase and sales price down $68/T and $69/T respectively due to favourable CP and fx rates
  - Carbon costs $1m
- **Wholesale gas EBITDAF down $2m to $0.4m**
  - Volume stable at 6.3 PJ (1H10 6.4PJ) with increased wholesale distressed sales and the expiry of a long term contract
  - Carbon costs $2m
- **Retail gas EBITDAF down $0.2m to $1.7m**
  - Volume down 0.3 PJ (14%) to 1.6 PJ driven by a 5% reduction in customer numbers (down 3,000 to 62,000)
  - Carbon cost $0.5m

– **Other revenue down $1m**



Summary

- **Good financial performance in challenging conditions**
  - Higher revenues
  - Offset by increasing external costs
- **Significant achievements**
  - Ahuroa Gas Storage commissioned
  - Stratford peakers close to completion
  - Te Mihi committed
  - Tauhara 2 consented
  - Wind projects consented
- **Focus on next stage of growth**
  - Execution of Te Mihi
  - Preparing Tauhara 2 for commitment
  - Developing Taheke and finding future options

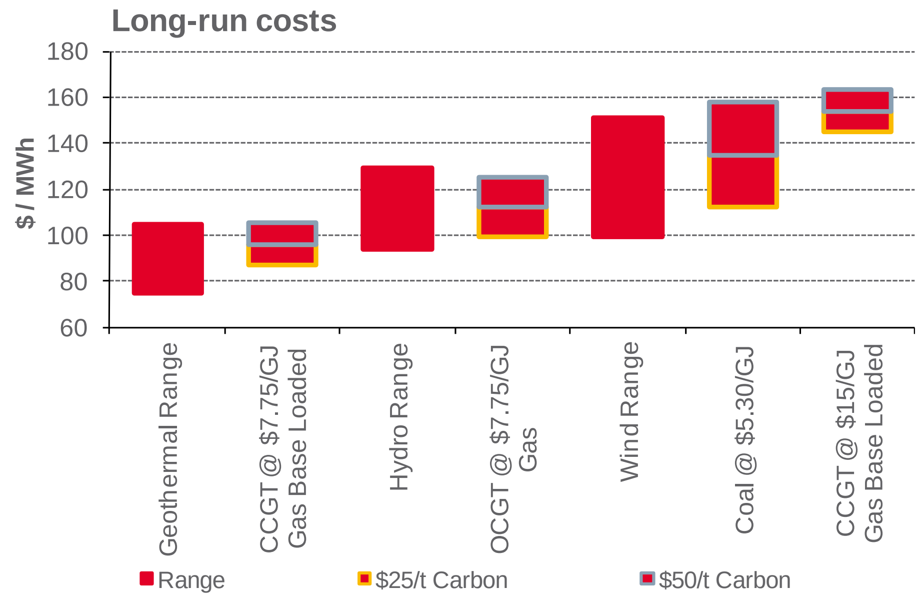
Ahuroa Gas Storage Stage 1

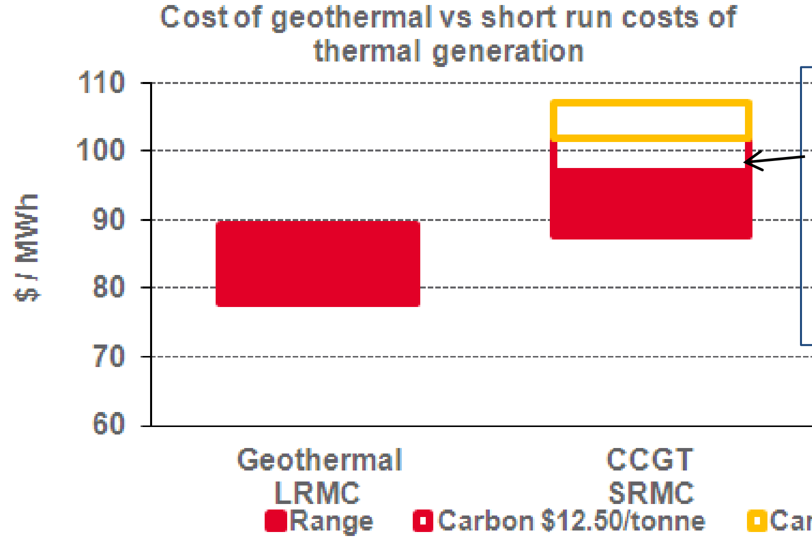
Outline

Te Mihi and Tauhara 2 are low-cost geothermal projects

To meet demand growth, or replace higher-cost thermal generation

- Assuming no demand growth, Te Mihi will substitute for higher-cost thermal generation
  - With maintenance costs, the price of flexible gas and carbon, the short run cost of gas fired thermal generation is above the all in cost of geothermal
  - Also facilitated by gas storage and a lower gas contracting position
  - If Te Mihi substituted for CCGTs, capacity factors would reduce by about 15% (~65% to ~50%)

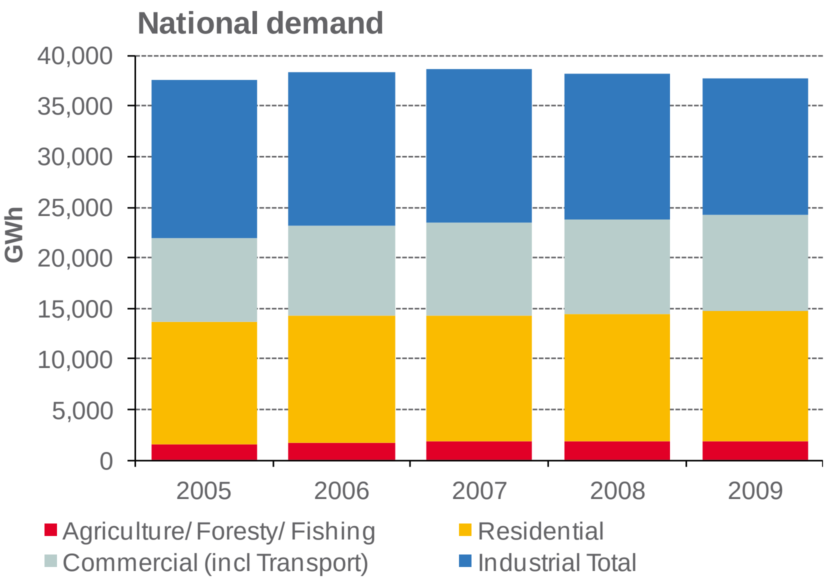




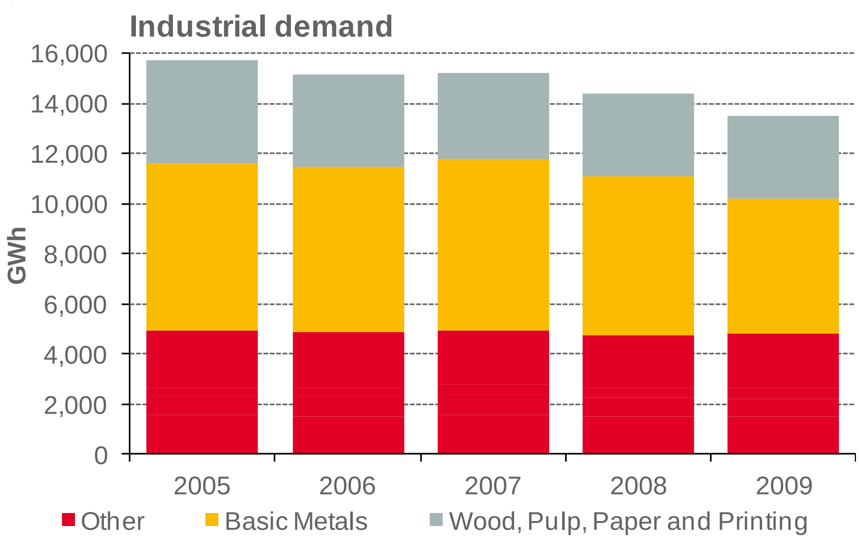
Short run costs of coal are expected to be well above gas short run costs (particularly as carbon costs rise)

Total demand from 2005 to 2009 is flat but the composition has changed

- **National demand in 2009 was within 0.3% of that in 2005 (Energy data file); however the composition has changed**
  - Annual average industrial demand growth rate from 2005 to 2009 was -3.7% while commercial and residential demand have increased at 3.4% and 1.6% per annum respectively.
- **Reduced industrial demand has primarily been driven by falling demand in basic metals (08, 09) and wood, pulp, paper and printing (06, 07)**
- **Total year on year demand growth for first three quarters of 2010 is +3.4% (0.1% excluding Tiwai) (Electricity Authority, final quarter demand not yet available)**



Source: Energy data file



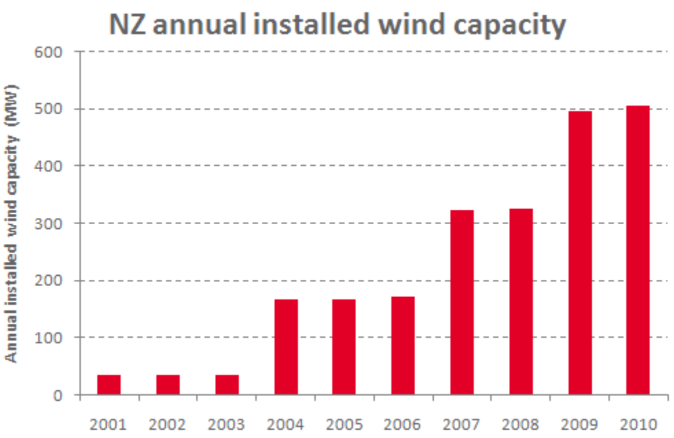
Source: Energy data file

Demand growth - year on year (excluding Tiwai)	2006		2007		2008		2009		Annual
	GWh	%	GWh	%	GWh	%	GWh	%	average
National (excl Tiwai)	+787	2%	+79	0%	-0	0%	+149	0%	1%
Industrial (excl Tiwai)	-571	-5%	-158	-2%	-309	-3%	-276	-3%	-3%
Commercial	+642	8%	+284	3%	+109	1%	+147	2%	3%
Residential	+521	4%	-209	-2%	+222	2%	+271	2%	2%
Ag/forest/fish	+196	13%	+161	10%	-22	-1%	+7	0%	5%

Source: Energy data file

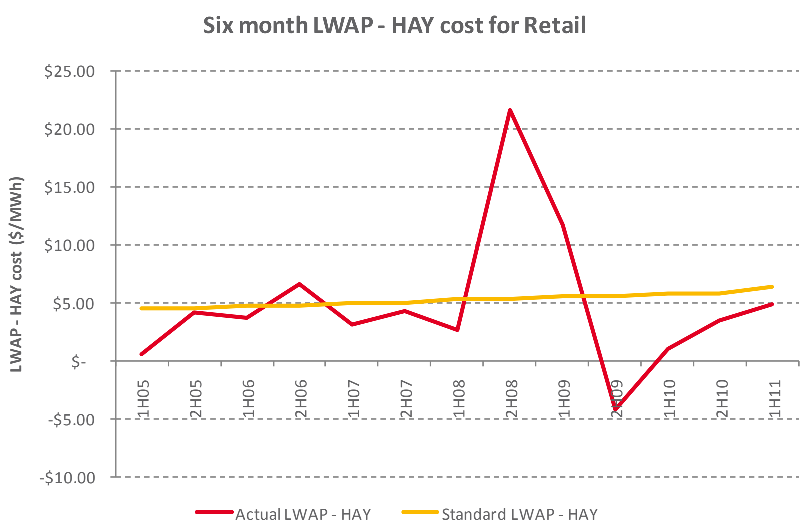
Wholesale electricity market conditions are expected to become increasingly volatile with higher peak demand, transmission constraints and the changing nature of New Zealand's generation base

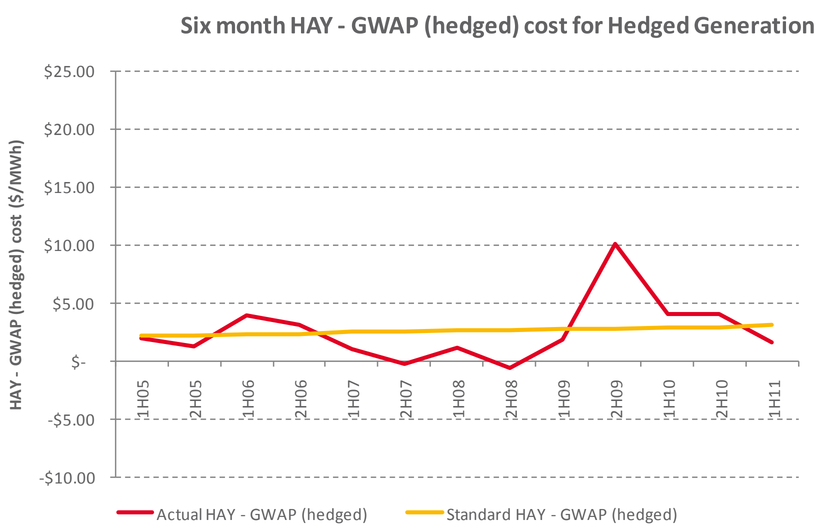
- **Four key drivers of increased wholesale market volatility:**
  - More volatile and higher peak demand levels with growing electricity use
  - Continuation of transmission constraints prior to necessary transmission grid updates
  - Increased levels of wind generation, providing unpredictable changes in base generation levels
  - Lower levels of "must run" thermal generation
- **Both Contact and Genesis moving thermal plant out from base load operation, increasing the variable operation of New Zealand's thermal generation plant**
  - Genesis is working to allow "greater flexibility to either store [Huntly] units so as to return if market conditions change or retire at some future date"
  - Contact is shifting its plant to more mid-merit operation, with Ahuroa gas storage providing greater gas and operational flexibility



Location costs have increased by $17m for Retail and decreased by $8.3m for Hedged Generation – Net $8.7m increase for the company

- LWAP-HAY costs for Retail have increased from $1.01/MWh to $4.90/MWh. With purchase volumes increasing by 413 GWh this has resulted in a total LWAP-HAY cost increase of $17m for retail
- HAY-GWAP (hedged) costs for Hedged generation have fallen from $4.02/MWh to $1.64/MWh. This fall has been partially offset by purchase volumes increasing 413 GWh and has resulted in a total HAY-GWAP (hedged) cost reduction of $8.3m for Hedged Generation
- At a total company level the impact on Retail and Hedged Generation netted to $8.7m, reflecting the normal impact on the LWAP/GWAP differential of the increase in average spot prices during the period from $45/MWH to $53/MWh, and purchase volumes rising by 413 GWh
- The graph below shows how LWAP-HAY and HAY-GWAP costs have tracked historically and the expected costs at transfer price levels
  - This shows both LWAP-HAY and GWAP-HAY costs below expected levels for H1 FY11
  - The large movement from H1 FY10 positions is largely due to inter-island price separation in H1 FY10





Financial Results Summary

	6 Months Ended 31 December 2010 $m	6 Months Ended 31 December 2009* $m	Variance $m	Variance %
Revenue and Other Income	1,198.6	1,070.2	128.4	12%
Operating Expenses [(1)]	(973.1)	(845.2)	(127.9)	(15%)
EBITDAF [(2)]	**225.5**	**225.0**	**0.5**	**0%**
Depreciation and Amortisation	(85.5)	(86.7)	1.2	1%
Equity Accounted Earnings of Associates	1.8	1.5	0.3	20%
Change in Fair Value of Financial Instruments	1.8	11.5	(9.7)	(84%)
Earnings Before Net Interest Expense and Income Tax (EBIT)	**143.6**	**151.3**	**(7.7)**	**(5%)**
Net Interest Expense	(30.1)	(29.0)	(1.1)	(4%)
Income Tax Expense	(29.8)	(35.2)	5.4	15%
Profit for the Period	**83.7**	**87.1**	**(3.4)**	**(4%)**
Underlying Earnings After Tax [(3)]	**78.8**	**79.0**	**(0.2)**	**(0%)**
Underlying Earnings Per Share [(3)]	**12.89**	**13.36**	**(0.47)**	**(4%)**
Shareholders' Equity	**2,859.4**	**2,727.4**	**132.0**	**5%**

(1) Includes electricity purchases.

(2) Earnings before net interest expense, income tax, depreciation, amortisation, change in fair value of financial instruments and other significant items.

(3) Underlying earnings after tax removes significant one-off items and the non-cash change in fair value of financial instruments.

* Comparatives have been restated due to a voluntary change in accounting policy for generation plant and equipment at 30 June 2010.

Electricity segment result

Electricity Segment	6 Months Ended 31 December 2010 $m	6 Months Ended 31 December 2009 $m	Variance $m	Variance %
Wholesale Electricity Revenue	288.2	232.6	55.6	24%
Retail Electricity Revenue	740.9	657.0	83.9	13%
Steam revenue	11.1	11.5	(0.4)	(3%)
Total Electricity Revenue	**1,040.2**	**901.1**	**139.1**	**15%**
Electricity Purchases	(253.5)	(195.1)	(58.4)	(30%)
Electricity Transmission, Distribution and Levies	(279.7)	(261.8)	(17.9)	(7%)
Gas Purchases and Transmission	(173.9)	(139.1)	(34.8)	(25%)
Carbon Emissions	(16.0)	-	(16.0)	
Meter lease internal charge (1)	(14.7)	(14.4)	(0.3)	(2%)
Labour Costs and Other Operating Expenses	(98.8)	(91.9)	(6.9)	(8%)
Total Operating Expenses	**(836.6)**	**(702.3)**	**(134.3)**	**(19%)**
EBITDAF	**203.6**	**198.8**	**4.8**	**2%**
Depreciation and Amortisation	(80.8)	(82.5)	1.7	2%
Segment Result	**122.8**	**116.3**	**6.5**	**6%**
Average Wholesale Electricity Price ($ per MWh) (2)	$53.68	$42.49	$11.19	26%
Cost of exposed generation ($ per MWh)	($36.49)	($34.14)	($2.35)	(7%)
Cost of hedged generation ($ per MWh)	($54.67)	($46.92)	($7.75)	(17%)
Hedged generation margin ($ per MWh)	$35.54	$34.43	$1.11	3%
Gas Used in Internal Generation (PJ)	18.0	15.7	2.3	15%
Swaption Generation - Hedged (GWh)	-	2	(2)	(100%)
Swaption Generation - Exposed (GWh)	203	190	13	7%
Thermal Generation - Hedged (GWh)	1,678	1,599	79	5%
Thermal Generation - Exposed (GWh)	522	357	165	46%
Geothermal Generation (GWh)	1,154	1,158	(4)	(0%)
Hydro Generation (GWh)	1,905	1,887	19	1%
Embedded Generation (GWh)	20	14	6	43%
Total Generation including Swaption (GWh)	**5,482**	**5,207**	**276**	**5%**
Average Electricity Purchase Price ($ per MWh) (2)	($58.70)	($46.12)	($12.58)	(27%)
Retail Electricity Purchases (GWh)	4,413	3,974	(439)	(11%)
Generation - Exposed (GWh)	725	547	178	33%
CfD Sales (GWh)	284	518	(234)	(45%)
Retail Electricity Sales (GWh)	4,250	3,911	339	9%
Electricity Customer Numbers	464,000	478,000	(14,000)	(3%)

(1) Intersegment meter lease internal charge of $14.7m is eliminated upon consolidation of the two segments.

(2) This price excludes contracts for differences.

Other segment result

Other Segment	6 Months Ended 31 December 2010 $m	6 Months Ended 31 December 2009 $m	Variance $m	Variance %
Wholesale Gas Revenue	43.4	43.3	0.1	0%
Retail Gas Revenue	39.6	43.8	(4.2)	(10%)
LPG Revenue	65.0	71.3	(6.3)	(9%)
Meter Leases Revenue	6.3	5.8	0.5	9%
Meter Leases Revenue - Internal (1)	14.7	14.4	0.3	2%
Other Revenue	4.1	5.0	(0.9)	(18%)
Total Other Segment Revenue	**173.1**	**183.6**	**(10.5)**	**(6%)**
Gas Purchases and Transmission	(69.9)	(72.8)	2.9	4%
LPG Purchases	(45.0)	(50.2)	5.2	10%
Meter Lease costs	(10.7)	(10.4)	(0.3)	(3%)
Carbon Emissions	(3.5)	-	(3.5)	
Market Levies	(0.4)	(1.1)	0.7	64%
Labour Costs and Other Operating Expenses	(21.7)	(22.9)	1.2	5%
Total Operating Expenses	**(151.2)**	**(157.4)**	**6.2**	**4%**
EBITDAF	**21.9**	**26.2**	**(4.3)**	**(16%)**
Depreciation	(4.7)	(4.2)	(0.5)	(12%)
Segment Result	**17.2**	**22.0**	**(4.8)**	**(22%)**
Gas Sales Wholesale Customers (PJ)	6.3	6.4	(0.1)	(2%)
Gas Sales Retail Customers (PJ)	1.6	1.9	(0.3)	(14%)
Gas Sales LPG Customers (Tonnes)	36,127	38,132	(2,005)	(5%)
Gas Customer Numbers	62,000	65,000	(3,000)	(5%)
LPG Customer Numbers (including franchisees)	58,700	55,900	2,800	5%

(1) Intersegment internal meter leases revenue of $14.7m is eliminated upon consolidation of the two segments.

Hedged - Up $9m (5%) due to higher transfer price and hedged volumes offset by carbon costs and higher gas costs

Hedged segment contribution	Units	1H11	1H10	Var	Var (%)
Hedged generation	**GWh**	**4,757**	**4,659**	**98**	**2%**
Transfer price	**$ / MWh**	**88.21**	**81.11**	**7.10**	**9%**
Hedged generation at GWAP transfer	**$ 'm**	**419.6**	**377.9**	**41.7**	**11%**
Expenses					
Gas Purchases and Transmission	$ 'm	(163.3)	(131.8)	(31.5)	(24%)
Huntly Swaption call cost	$ 'm	(12.6)	(18.1)	5.5	30%
Electricity Transmission	$ 'm	(13.6)	(16.0)	2.4	15%
Market Levies	$ 'm	(3.7)	(2.5)	(1.2)	(48%)
Carbon Emissions	$ 'm	(11.7)	-	(11.7)	-
Other Operating Expenses	$ 'm	(56.9)	(50.5)	(6.4)	(13%)
Total expenses	**$ 'm**	**(261.8)**	**(218.9)**	**(42.9)**	**(20%)**
Other generation (steam, CFD, ancillary, location costs adj, etc.)	**$ 'm**	**11.3**	**1.4**	**9.9**	**707%**
Hedged segment contribution	**$ 'm**	**169.1**	**160.4**	**8.7**	**5%**

Exposed Generation - Up $10m (92%) due to a 21% increase in average price earned by exposed generation and 33% increase in volumes

Exposed segment contribution	Units	1H11	1H10	Var	Var (%)
Exposed generation volume	**GWh**	**725**	**547**	**178**	**33%**
Exposed GWAP	**$ / MWh**	**65.90**	**54.40**	**11.5**	**21%**
Revenue	**$ 'm**	**47.8**	**29.8**	**18.0**	**60%**
Expenses					
Gas Purchases and Transmission	$ 'm	(10.6)	(7.3)	(3.3)	(45%)
Huntly Swaption call cost	$ 'm	(9.7)	(10.1)	0.4	4%
Electricity Transmission	$ 'm	(1.5)	(1.1)	(0.4)	(36%)
Carbon Costs	$ 'm	(4.3)	-	(4.3)	-
Market Levies	$ 'm	(0.4)	(0.2)	(0.2)	(100%)
Other Operating Expenses	$ 'm	-	-	-	-
Total expenses	**$ 'm**	**(26.5)**	**(18.7)**	**(7.8)**	**(42%)**
Exposed segment contribution	**$ 'm**	**21.3**	**11.1**	**10.2**	**92%**

Retail - Down $14m (52%) due to increasing unit energy and mass market network costs more than offsetting the impact of tariff increases and growth in Time of Use sales

contact

Retail electricity contribution	Units	1H11	1H10	Var	Var (%)
Sales	**GWh (ICP)**	**4,250**	**3,911**	**339**	**9%**
Revenue	**$'m**	**745.8**	**660.6**	**85.2**	**13%**
Cost of electricity - internal transfer price	$/MWh	(88.21)	(81.11)	(7.10)	(9%)
Cost of electricity - LWAP - Haywards	$/MWh	(5)	(1)	(4)	(400%)
Planned line losses	%	5%	6%	1%	17%
Cost of electricity delivered	$/MWh	(98)	(86)	(12)	(14%)
Energy costs	$'m	(415.5)	(335.5)	(80.0)	(24%)
Transmission and market costs	$'m	(260.5)	(242.0)	(18.5)	(8%)
Meter lease costs	$'m	(14.7)	(14.4)	(0.3)	(2%)
Retail costs (other OPEX)	$'m	(41.9)	(41.4)	(0.5)	(1%)
Total expenses	**$'m**	**(732.6)**	**(633.3)**	**(99.3)**	**(16%)**
Retail electricity contribution	**$'m**	**13.2**	**27.3**	**(14.1)**	**(52%)**
Retail electricity margin	**%**	**2%**	**4%**	**(2%)**	**(50%)**

Carbon costs

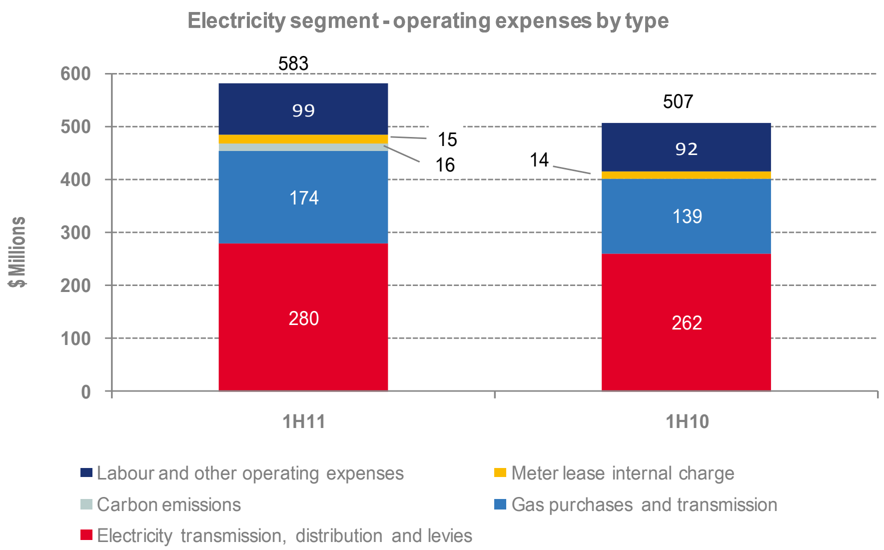
Carbon costs	Volume	Average factor	Tonnes	Unit cost	Carbon expense
Gas purchases	26.0 PJ	53,500 T/PJ	1,390,230	$21.07	$14.6m
Geothermal generation	11m T*	0.0132	145,200	$21.07	$1.5m
LPG	36,127T	3.0	107,470	$23.72	$1.3m
Swaption	202 GWh	970 T/GWh	196,060	$21.07	$2.1m

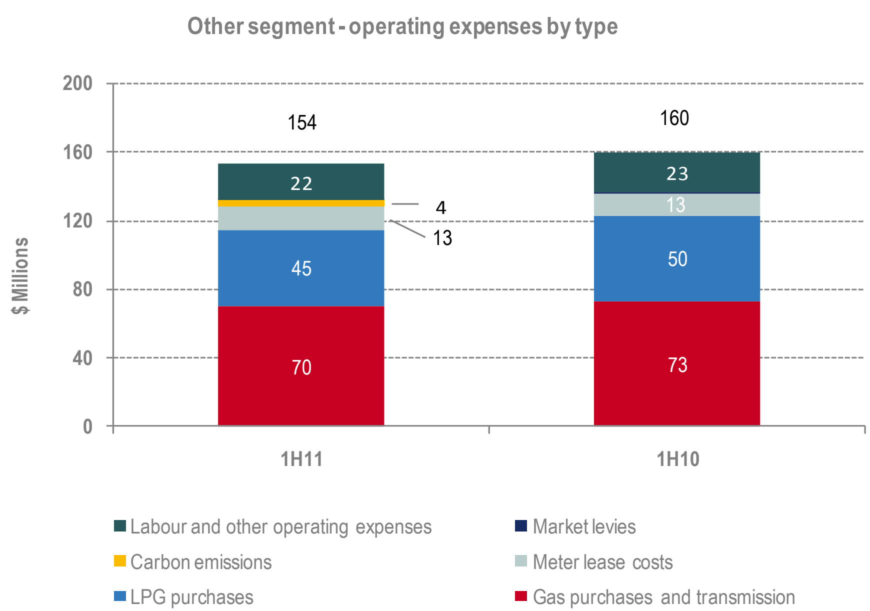
* Geothermal volume measured in geo-fluid tonnes

- Contact pays carbon based on the source of carbon generating fuels i.e. Gas carbon costs are based on the field from which the gas was supplied
- The average carbon factors are:
  - 53,500 tonnes per PJ purchased for gas
  - 0.0132 tonnes per geo-fluid tonne for geothermal
  - 3.0 tonnes per tonne of LPG
- Swaption carbon costs are shown on a generation T/GWh basis

– Note: Carbon obligation is currently 50% under the Emissions Trading Scheme

Operating expenses by segment (excluding electricity purchases)





Electricity segment expenses up $76m (15%)

- Electricity transmission costs increased by $18m
- Gas purchases increased by $35m – higher volume and increased loss making gas sales
- Carbon emissions additional $16m
- Labour and other operating costs – up $7m
  - Labour costs up $4.8m
    - New generation plant employees
    - Generation development projects
    - Establishment of enterprise and commodity risk functions
    - Additional capability for trading and new markets
  - Repairs and maintenance costs up $3.2m due to statutory shutdown at Wairakei
  - Write-offs down $2.3m

Other segment: expenses decreased by $6m (down 4%)

- Gas costs down by $3m due to lower retail sales and purchase price
- LPG purchases reduced by $5m due to lower average cost and volume reduction
- Carbon emissions additional $4m