System Operator Reports

May 2009

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System Operator
Monthly Operational Performance Report
to the Electricity Commission

For the month ended 30 May 2009

This report summarises the results of the System Operator self review of its performance for the above month, as required under Regulation 45 of the EGR's. An additional Operational Update is also provided for the information of the Commission.

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1 Compliance with Rule Book, Part C and Regulations:

1.1 Principal Performance Obligations (PPOs)

The Principal Performance Obligations (PPOs) of the System Operator are to act as a reasonable and prudent operator with the objective of meeting certain PPO outcomes. The System Operator's performance against the PPO outcomes, during the month was as follows:

PPO No	Description	PPO Outcome
2.1	Avoid cascade failure	Met
2.2.1	Maintain frequency in the normal band	Met
2.2.2	Manage frequency during momentary fluctuation	Met
2.2.3	Limit rate of occurrences of momentary fluctuations	Met
2.2.4	Recover quickly from a fluctuation	Met
2.2.5	Manage time error	Met
2.2.6	Eliminate time error once a day	Met
2.3	Maintain other standards	Met
5.0	Restoration objective	Met

Grid Emergencies

There were four (4) grid emergencies reported in the period.

Date	Time	Summary Details	Island
4 May 2009	17:54	A Grid Emergency was declared due to insufficient standby reserve offers in the North Island. North Island Contingent event risk adjustment factors were reduced to 0.6 until 19:00.	North
5 May 2009	17:00	A Grid Emergency was declared due to insufficient standby reserve offers in the North Island. HVDC Pole 1 was operated until 21:00.	North
21 May 2009	07:41	A Grid Emergency was declared due to insufficient standby reserve offers in the North Island. North Island Contingent event risk adjustment factors were reduced to 0.8 until 08:34.	North
23 May 2009	17:47	A Grid Emergency was declared due to insufficient standby reserve offers in the North Island. North Island Contingent event risk adjustment factors were reduced to 0.8 until 18:30.	North

1.2 System Events

There were three (3) system events (frequency excursions) during the reporting period:

Significant Frequency excursions				
Date	**Time**	**Summary Details**	**Island**	**Freq (Hz)**
3 May 2009	04:23	A Tiwai potline tripped causing a momentary rise in frequency in both North and South Islands.	North South	50.36 50.69
5 May 2009	14:05	Huntly Unit 1 tripped causing a momentary drop in frequency in both North and South Islands.	North South	49.46 49.71
20 May 2009	11:07	Huntly Unit 1 tripped causing a momentary drop in frequency in the North Island.	North	49.53

1.3 Connection Point Events

There was one (1) connection point incident during the reporting period.

Connection Point Events				
Date	**Time**	**Summary Details**	**Generation/Load interrupted (MW)**	**Restoration time (minutes)**
7 May 2009	13:31	A fault in the Twizel 220kV network caused multiple trippings of Benmore-Twizel 1, Islington-Tekapo B 1 and Tekapo B-Twizel 1 circuits, resulting in loss of generation at Tekapo B.	60	117

1.4 System Operator Compliance with Rule Book: Part C

The System Operator self-notified two Part C breaches in May 2009 for failing to apply a temporary security constraint regarding COB_STK2.2 and for failing to correctly apply a temporary security constraint regarding CML_T8 when CML_FKN_1 is out of service.

1.5 Participant Compliance

The System Operator notified two alleged Part C breaches against participants in May 2009. One alleged breach related to the failure to have protection systems which were selective whilst operating. The second related to the failure by a participant to ensure they were providing accurate measurements to the System Operator.

1.6 Applications for Dispensations

Nil

1.7 Ancillary Services

The System Operator submitted the draft 2009/10 Procurement Plan to the Electricity Commission, as required under the Rules. During preparation of the draft the System Operator invited comment and held a number of consultation discussions with individual participants regarding the terms of the plan. Comments received were considered by and assisted the System Operator in preparing the draft plan. In many cases participant's suggestions were adopted in the draft plan.

The major changes proposed in the draft plan are:

1. *Special Testing Requirements for Interruptible Load.* This change introduces a requirement on providers of Interruptible Load reserve to carry out an annual end-to-end test of the functionality of the equipment used to provide the services, unless they have shown operational performance during that year, through offering into the market and successfully responding during an under-frequency event.

2. *No offering of AUFLS (Paragraph 129A).* This clause was inserted in response to the concern that demand aggregators are able to contract for Interruptible Load reserve with end-use customers while avoiding the regulatory obligations facing distributors and purchasers. The new clause codifies the obligation already contained in the ancillary service procurement contracts.

3. *Frequency keeping performance standard (Clause 53A).* The change is to clarify the wording used for the standard deviation provisions. The changes are intended to encourage participation by frequency keeping providers with plant unable to achieve strict performance requirements. When this provision was originally drafted, the inter-relationship between it and the material breach/ termination provisions (which are intended to cover one-off events) were not considered. The consequence is that there is the potential for a significant period of frequency keeping non-compliance to take place before action can be taken against a provider.

2 Compliance with Rule Book: Part G

2.1 System Operator Compliance

The System Operator notified three Part G breaches during May 2009.

3 Recommendations for Change to EGRs and Related Matters:

3.1. Rule change proposals

There were no new rule changes proposed by the System Operator during May 2009.

3.2. Policy Statement Review

During May, the System Operator responded to the submissions received by the Electricity Commission on the draft Policy Statement.

3.3 Exemption applications

There were no exemption applications submitted by the System Operator in May 2009.

4 Operational Update:

4.1 Commissioning of generation assets

The following table is a summary of active, publicly disclosed commissioning projects where the System Operator is involved:

Summary of generator commissioning			
Generator name	**Asset Owner**	**Description**	**Status**
Nga Awa Purua	Mighty River Power	A second geothermal power station at Rotokawa	Commissioning planning.
Te Rere Hau	NZ Windfarms	A new wind farm development located in the Tararua Ranges	Commissioning activities commenced and will continue in 2009 as new turbines are connected.
West Wind	Meridian Energy	A new wind farm development located close to Wellington	First turbines were connected in early March 09. Commissioning is ongoing.
Stratford peaking plant	Contact Energy	Two 100MW gas fired peaking units to be located close to the existing Stratford power plant.	Commissioning planning.

5 Conflict of Interest

Nil

6 Development and Resources:

6.1 Resources

During May, in addition to routine operations, System Operator resources were applied to:

- Procurement Plan review
- Policy Statement - provided additional comment on draft statement
- Security policy review - scope and methodology presented to the industry
- Continued work on market system project including shadow operations
- AUFLS
- HVDC Pole 1

We expect these tasks to use all available resources until the end of July.

6.2 Market Systems Project (MSP)

The System Operator's expectation is now for the new systems to go-live in late-July.

The System Operator has continued parallel running the new and old systems with good progress being made in revolving performance issues.

Major MSP achievements in May included:

- improved performance of the new system
- delivery and successful deployment of new releases from AREVA
- continued data and interface setup
- testing the code release

Planned work for June includes:

- continue shadow operations
- continue testing in final go live configuration
- gain confidence in the new system running as a shadow of the existing system

7 Regulation 50 (4) Statement:

In performing its role as System Operator, Transpower New Zealand Limited (Transpower) has not been materially affected by any other role or capacity Transpower has under the Electricity Governance Regulations 2003 or the Rules or under any agreement.

System Performance Report

May 2009

Purpose
This System Performance Report summarises power system performance each month. The detailed reporting of system events is intended to provide an understanding of the nature of system events that occur in the normal course of the real time co-ordination of security and to identify emerging issues in system operation.

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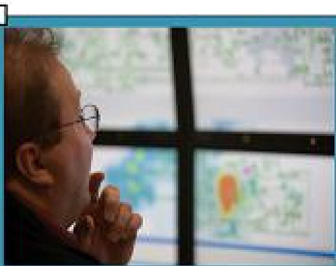


SYSTEM OPERATOR

Keeping the energy flowing

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Summary of System Performance

This system performance report covers the month of May 2009.

Principal Performance Obligations

The System Operator met the Principal Performance Obligations during the reporting period.

Operational Management

It has been a challenging month operationally. The unavailability of a couple of key thermal generating plants in the North Island due to planned outages has resulted in tight system security situations in the first half of the month. The high numbers of Standby Residual Check (SRC) notices issued reflect these.

Four Grid Emergency Notices were issued advising of insufficient standby reserve offers in the North Island. As a result, North Island instantaneous reserve requirements were partially met by reducing Contingent event risk adjustment factors to less than unity. On one occasion, HVDC Pole 1 was operated to allow additional energy flowing from the South Island and free up North Island generation to meet reserve requirements.

HVDC Pole 1 was operated in extended capability mode on 12 and 13 May due to unavailability of major thermal plants in the North Island resulting in a potential grid emergency with an expected inability to provide reserves within 30 minutes of an event (loss of generation) occurring. Pole 1 was also operated on 14 May when the grid owner advised of an urgent live line work on HVDC Pole 2 conductor.

HVDC Pole 2 was removed from service on 17 May for urgent repairs to an overhead conductor joint. On 19 May numerous joints on the electrode line between Oteranga Bay and Haywards were also found to have become overheated, resulting in an unplanned outage of HVDC Bi-pole. A further planned outage of HVDC Bi-pole on 24 May for repairs on the overhead conductor joints was cancelled due to adverse weather conditions. The outage is now planned for 6 June.

The 2009 report from the National Winter Group (NWG) has been published. The report outlines that there is a high confidence that the power system will meet peak winter demand if all available generation are committed to run.[1]

Subsequent industry meetings for the Upper South Island and Upper North Island were held on 21 and 22 May respectively to update stakeholders on information and studies completed to date for winter 2009. Studies have shown that peak winter demand in both Upper North and Upper South Islands could be met with all available plants in service. There will be no requirements for contingency plans. System conditions will continue to be monitored for unexpected plant outages.

System Events

A fault in the Twizel 220 kV network on 7 May caused multiple trippings of Benmore-Twizel 1, Islington-Tekapo B 1 and Tekapo B-Twizel 1 circuits, resulting in loss of generation at Tekapo B.

Other noteworthy events occurring during the reporting period include:

[1] The report is available from http://www.systemoperator.co.nz/n2128.

- the tripping of Tiwai potline on 3 May;
- the trippings of Huntly Unit 1 on 5 May, 20 May and 30 May;
- trippings of Central Park-West Wind-Wilton 2 and 3 circuits on 6 May and 23 May, resulting in loss of connection to West Wind windfarm;
- the tripping of Kaiwharawhara T1 supply transformer on 7 May, resulting in loss of connection to Kaiwharawhara;
- the tripping of Otahuhu B station on 8 May;
- the tripping of Ohau A G4 unit on 8 May and 10 May;
- the tripping of Balclutha-Berwick-Halfway Bush 1 circuit on 14 May and 25 May, resulting in loss of connection to Waipori power station;
- the tripping of Mangahao G1 unit on 15 May;
- the tripping of Coleridge-Otira 1 circuit twice on 15 May, resulting in loss of connection to Castle Hill and Arthurs Pass;
- the tripping of Wairakei G15 unit on 15 May;
- the tripping of Waipori generation unit on 15 May and 18 May;
- the tripping of Benmore G5 unit on 18 May;
- the tripping of Central Park-West Wind-Wilton 3 circuit on 18 May, 22 May (6 times) and 23 May (2 times), resulting in partial loss of connection to West Wind windfarm;
- the trippings of Huntly Unit 3 on 21 May;
- the tripping of Benmore G6 unit on 26 May; and
- the tripping of Manapouri G3 unit on 29 May.

1 Principal Performance Obligations

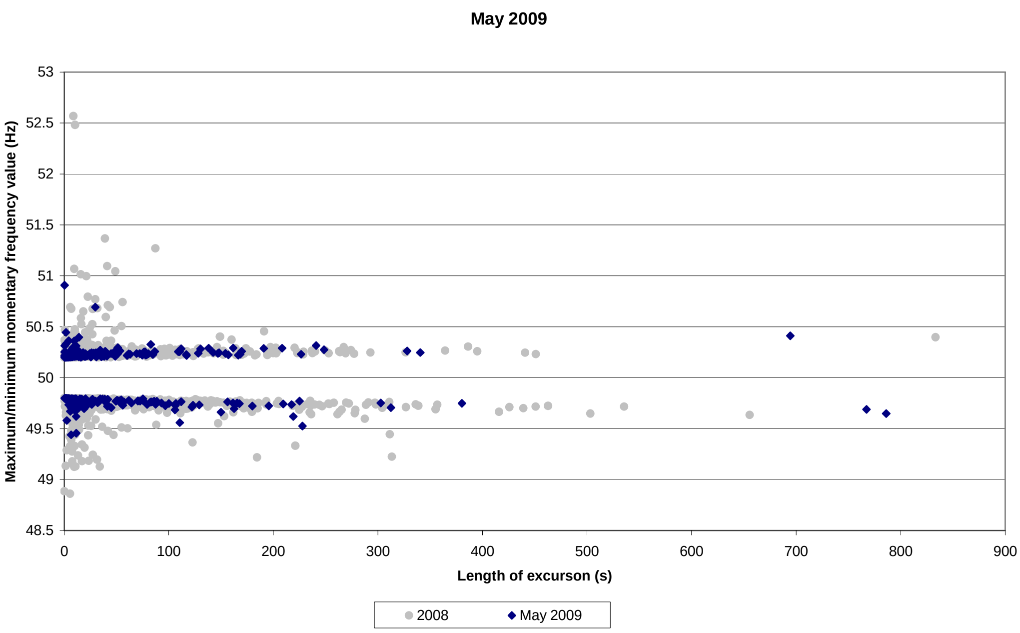
1.1 Avoid Cascade Failure

No instances of cascade failure resulting in loss of demand arising from frequency or voltage balances or supply and demand imbalances occurred during the reporting period.

1.2 Frequency

1.2.1 Maintain frequency in normal band and recover quickly from a fluctuation

The chart below shows the number, maximum or minimum frequency reached and length of frequency excursions outside the normal band (49.8 to 50.2 Hz) during the reporting period. The majority of excursions are with 0.4 Hz of the normal band and frequency typically returns to within the normal band within 2 minutes.



1.2.2 Manage Frequency and limit rate of occurrences during momentary fluctuations

The table below shows the total number of momentary fluctuations outside the frequency normal band, recorded in both Islands, over the last 12 months. The 12 month cumulative totals, grouped by frequency band, are compared to the frequency performance objective (PPO).

Frequency Band	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Annual rate	PPO target
55.00 >= Freq > 52.00											1		**1**	
52.00 >= Freq > 51.25					1	1					1		**3**	**7**
51.25 >= Freq > 50.50	3			7	1	3	1	1	1		2	2	**21**	**50**
50.50 >= Freq > 50.20	147	104	82	128	210	182	132	167	152	241	380	231	**2156**	
50.20 >= Freq > 49.80														
49.80 >= Freq > 49.50	136	122	91	138	153	170	100	144	129	114	221	181	**1699**	
49.50 >= Freq > 48.75			2	1	3	7	2	4	5	4	9	2	**39**	**60**
48.75 >= Freq > 48.00											1		**1**	**6**
48.00 >= Freq > 47.00													**0**	**0.2**
47.00 >= Freq > 45.00													**0**	**0.2**

Summary of number of momentary fluctuations outside the frequency normal band

1.2.3 Manage time error and eliminate time error once per day

The time error performance criteria are:

- Time error must be managed within +/- 5 seconds.
- Time error must be eliminated at least once every day.

Time Error Compliance Table		Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09
Time Error Management	NI	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
	SI	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Time Error Elimination	NI	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
	SI	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

Summary of compliance against time error criteria over the last 12 months

2 Operational Management

2.1 Security Notices

The following table shows the number of Warning Notices, Grid Emergency Notices, Customer Advice Notices and Demand Allocation Notices issued over the last 12 months.

Notices issued	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09
Demand Allocation Notice												
Grid Emergency Notice	2	1						1	1	4	8	4
Warning Notice				1	2						4	3
Customer Advice Notice		8	9	11	11	3	4	2		3	19	23

2.2 Grid Emergencies

The following table shows grid emergencies declared by the System Operator in the reporting period.

Date	Time	Summary Details	Island
4 May 2009	17:54	A Grid Emergency was declared due to insufficient standby reserve offers in the North Island. North Island Contingent event risk adjustment factors were reduced to 0.6 until 19:00.	North
5 May 2009	17:00	A Grid Emergency was declared due to insufficient standby reserve offers in the North Island. HVDC Pole 1 was operated until 21:00.	North
21 May 2009	07:41	A Grid Emergency was declared due to insufficient standby reserve offers in the North Island. North Island Contingent event risk adjustment factors were reduced to 0.8 until 08:34.	North
23 May 2009	17:47	A Grid Emergency was declared due to insufficient standby reserve offers in the North Island. North Island Contingent event risk adjustment factors were reduced to 0.8 until 18:30.	North

A summary of grid emergencies that have occurred in the last 12 months is shown in the following table.

Island	Region	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Total
North Island	Northland													**0**
	Auckland	1								1				**2**
	Zone 1													**0**
	Waikato													**0**
	Bay of Plenty										1			**1**
	Hawkes Bay													**0**
	Taranaki													**0**
	Bunnythorpe										1	1		**2**
	Wellington								1			1		**2**
	North Island (all)												4	**4**
South Island & HVDC	Nelson Marlborough	1									1	3		**5**
	West Coast											1		**1**
	Christchurch													**0**
	Canterbury		1								1			**2**
	Zone 3													**0**
	Otago													**0**
	Southland											2		**2**
	South Island (all)													**0**
	HVDC													**0**

2.3 Customer Advice Notices (CANs)

Twenty three CANs (Customer Advice Notices) were issued in the reporting period:

- one advising of a change to winter ratings from 07:00 on 10 May;
- one advising of a change to the modelling of HVDC reserve sharing in RMT;
- one advising of a change of risk subtractor for HVDC Pole 1 in bipole operation;
- five advising of planned operation of HVDC Pole 1 in extended capability mode;
- six advising of a outage of HVDC Pole 2 on 17 May;
- two advising of an unplanned outage of HVDC Bi-pole on 19 May;
- three advising of revision to permanent constraints as a result of the re-rating of Bunnythorpe-Tokaanu 1 and 2 circuits;
- two advising of a planned outage of Te Apiti Runback Scheme; and
- two advising of a planned outage of HVDC Bi-pole on 24 May.

2.4 Standby Residual Check (SRC) notices

One hundred and sixteen SRC notices were issued during the reporting period. SRC notices reported here are those issued based on the SDS (System Operator's own load forecasting tool). Other SRC notices were issued based on the PDS (based on participants demand bids), these notices are not summarised below.

The SRC notices applied to trading periods throughout the month except 15, 23 and 29 May. The SRC notices identified energy and capacity shortfalls in the North Island. A Capacity Shortfall indicates that there would be insufficient generation and reserve offers remaining after the tripping of the largest risk (Generator or HVDC Pole) to restore reserves for a subsequent event within 30 minutes. An Energy Shortfall indicates that there would be insufficient generation remaining after the tripping of the largest risk (Generator or HVDC Pole) to release reserves after the event and that the unplanned disconnection of demand would likely be required following the loss of the largest risk.

2.5 Voltage Management

Grid voltages did not exceed the EGR voltage ranges during the reporting period. There were some occasions when post contingency voltages could have exceeded the grid voltage range (had the contingency occurred) but these were managed through re-dispatch of generation and reactive devices.

Generation at Cobb was constrained on to meet voltage quality targets this month.

No contracted voltage support ancillary services were called upon during the reporting period. This is expected for this time of year.

2.6 Outage Management

The following table shows the number of outages over the last 12 months where operational measures (generation agreements, load management agreements or grid re-configurations) were required to allow the outage to proceed. Load agreements generally require the distributor to manage load at one or more grid exit points. Generation agreements are required to ensure that sufficient regional generation is available to provide energy or reactive support during the outage to maintain security standards. Grid re-configurations typically involve splitting the network during the outage to manage post contingency power flows. Security of supply is sometimes reduced by grid re-configuration.

Island	Region	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Total
North Island	Northland	4	7	6	8	11	10	**46**
	Auckland	4	6	7	10	3	5	**35**
	Waikato	2	0	5	3	3	5	**18**
	Bay of Plenty	3	2	1	1	5	3	**15**
	Hawkes Bay	0	6	3	1	5	2	**17**
	Taranaki	0	5	1	1	2	2	**11**
	Bunnythorpe	8	1	5	4	10	6	**34**
	Wellington	6	6	9	3	2	12	**38**
Total		27	33	37	31	41	45	**214**
South Island	Nelson Marlborough	3	4	6	6	4	1	**24**
	West Coast	3	5	2	6	2	7	**25**
	Christchurch	2	0	4	1	5	3	**15**
	Canterbury	1	0	0	1	4	2	**8**
	Otago	2	9	7	3	2	3	**26**
	Southland	3	7	5	7	5	4	**31**
Total		14	25	24	24	22	20	**129**

Outages where operational measures were required to allow the outage to proceed – data will be filled in over time

2.7 Constraints

2.7.1 Summary: Security Constraints Binding During the Month

The following table shows the constraints binding during the reporting period.

Island	Region	Constraint Name	Description
North Island	Waikato	ARI_67_77_117	The effect of this constraint is to manage flows through Arapuni - Hamilton 1 for a contingency of Arapuni - Pakuranga when Arapuni bus section 67 77 117 is out of service.
		ARI_PAK_1_S_O_1of2	The effect of this constraint is to manage flows through an Arapuni -Hamilton circuit for a contingency of an Arapuni -Hamilton circuit when Arapuni - Pakuranga 1 is out of service.
	Hawkes Bay	FHL_RDF_1&2_S_P	The effect of this constraint is to manage flows through Fernhill-Redclyffe 1 for a contingency of Fernhill-Redclyffe 2 during low Tuai generation and high Hawkes Bay load.
		FHL_RDF_1&2_W_P_1_z	The effect of this constraint is to manage flows through Fernhill-Redclyffe 1 for a contingency of Fernhill-Redclyffe 2 during low Tuai generation and high Hawkes Bay load.
		FHL_RDF_2&RDF_TUI_1_W_O_2	The effect of this constraint is to manage flows through Redclyffe-Tuai-2 for a contingency of Fernhill-Tuai-1 during high Tuai generation when Redclyffe-Tuai-1 and Fernhill-Redclyffe-2 are out of service.
		RDF_TUI_2_W_O_1A_z	The effect of this constraint is to manage flows through Redclyffe-Tuai 1 for a contingency of Fernhill-Tuai 1 during high Tuai generation and low Hawkes Bay load when Redclyffe - Tuai 2 is out of service.
	Bunnythorpe	BPE_TKU_1_W_O_4of5_z	The effect of this constraint is to manage flows through Bunnythorpe-Tokaanu 2 for a contingency of Rangipo-Tangiwai 1 during high south transfer, high HLY, high RPO when Bunnythorpe-Tokaanu 1 is out of service and TKU CB128 intertrip is disabled.
South Island	Nelson Marlborough	STK_UTK_1_S_P	The effect of this constraint is to manage flows through STK_UTK_1 for a contingency of COB_STK_2 during

Island	Region	Constraint Name	Description
			low COB generation.
		STK_UTK_1_W_P	The effect of this constraint is to manage flows through STK_UTK_1 for a contingency of COB_STK_2 during low COB generation.
	West Coast	WEST_COAST_SPLIT_O_1	The effect of this constraint is to manage voltage stability on the West Coast during low West Coast generation and high West Coast load when one of the following is out of service: Greymouth-Kumara, Dobson-Greymouth, Atarau-Dobson or Atarau-Reefton-Inangahua.
	Christchurch	ISL_KIK_1_TOP_SOUTH_ISLAND_STABILITY_O_1A	The effect of this constraint is to manage flows through the Islington-Kikiwa-2 and 3 circuits for a contingency of either of the two circuits. This is to ensure that voltage stability limits are not exceeded during periods when the load at the Top of the South Island is high and Islington-Kikiwa-1 is out of service.
	Otago	ASB_TIM_TWZ_1	The effect of this constraint is to manage flows through Livingstone-Waitaki for a contingency of Islington-Tekapo B when Ashburton-Timaru-Twizel is out of service.
& HVDC	Southland	CYD_TWZ_2_W_O_1_z	The effect of this constraint is to manage flows through Naseby-Roxburgh-1 for a contingency of Clyde-Twizel-1 during northwards power flow when Clyde-Twizel-2 is out of service.
		NSY_ROX_1_W_P_1_z	The effect of this constraint is to manage flows through Naseby-Roxburgh-1 for a contingency of Clyde-Twizel-1 or 2 during high Southland generation and with all circuits in service
		NSY_ROX_1_S_P_z	The effect of this constraint is to manage flows through Naseby-Roxburgh-1 for a contingency of Clyde-Twizel-1 during high Southland generation when all circuits are in service
		NMA_TWI_1_W_O_1	The effect of this constraint is to manage flows through the Invercargill - North Makarewa circuit for a contingency of North Makarewa - Tiwai 2 during high generation at Manapouri when North Makarewa - Tiwai 1 is out of service.
	HVDC	BEN_HAY1.1	The purpose of this constraint is to limit the flow on HVDC Pole 1 to the Asset Owner’s offered capability.
		DCNPole1Max	The purpose of this constraint is to limit the flow on HVDC Pole 1 to the Asset Owner’s offered capability.
		DCNPole1Min	The purpose of this constraint is to limit the flow on HVDC Pole 1 to the Asset Owner’s offered capability.
		BEN_HAY2.1	The purpose of this constraint is to limit the flow on HVDC Pole 2 to the Asset Owner’s offered capability.
		BENtoHAY_Transfer_Limit	The purpose of this constraint is to limit the flow on HVDC from Benmore to Haywards to the Asset Owner offered capability.

Additional information on security constraints can be found on the following website address: http://www.transpower.co.nz/?id=5979. This information includes constraint equations and a brief summary of their purpose.

2.7.2 *Constraints binding during last 12 months*

The following table shows the constraints binding during the reporting period for more than 4 trading periods and during the previous 12 months for more the 48 trading periods.

			Reporting period		Previous 12 months	
Island	Region	Constraint	Number of trading periods that constraint bound	Percentage of trading periods	Number of trading periods that constraint bound	Percentage of Trading periods
North Island	Waikato	ARI_PAK_1_S_O_1of2	4	0.27%	6	0.03%
	Hawkes Bay	FHL_RDF_1&2_S_P_1_z	0	0.00%	74	0.42%
	Bunnythorpe	BPE_TKU_1&2_W_P_2of2	0	0.00%	549	3.13%
	Wellington	MGM_MST_1_or_MGM_WDV_1_WELLINGTON_STABILITY_O_1_z	0	0.00%	359	2.05%
South Island & HVDC	Nelson Marlborough	ISL_KIK_1_TOP_SOUTH_ISLAND_STABILITY_O_1A	11	0.74%	0	0.00%
		STK_UTK_1_S_P	10	0.67%	163	0.93%
		STK_UTK_1_W_P	11	0.74%	4	0.02%
	West Coast	WEST_COAST_SPLIT_O_1	5	0.34%	139	0.79%
	Otago	LIV_WTK_1_W_P_2A	0	0.00%	126	0.72%
	Southland	BWK_HWB_S_O_z	0	0.00%	125	0.71%
		CYD_TWZ_2_W_O_1_z	12	0.81%	0	0.00%
		NSY_ROX_1_S_P_z	4	0.27%	456	2.60%
		NSY_ROX_1_W_P_1_z	32	2.15%	52	0.30%
	HVDC	BEN_HAY1.1	5	0.34%	42	0.24%
		DCNPole1Max	7	0.47%	46	0.26%
		DCNPole1Min	5	0.34%	14	0.08%
		BEN_HAY2.1	14	0.94%	9	0.05%
		BENtoHAY_Transfer_Limit	15	1.01%	5	0.03%

3 System Events

3.1 Significant System Events

The following table shows significant events (frequency excursions and connection point events) which occurred during the reporting period.

Significant Frequency excursions				
Date	**Time**	**Summary Details**	**Island**	**Freq (Hz)**
3 May 2009	04:23	A Tiwai potline tripped causing a momentary rise in frequency in both North and South Islands.	North South	50.36 50.69
5 May 2009	14:05	Huntly Unit 1 tripped causing a momentary drop in frequency in both North and South Islands.	North South	49.46 49.71
20 May 2009	11:07	Huntly Unit 1 tripped causing a momentary drop in frequency in the North Island.	North	49.53
Connection Point Events				
Date	**Time**	**Summary Details**	**Generation /Load interrupted (MW)**	**Restoration time (minutes)**
7 May 2009	13:31	A fault in the Twizel 220kV network caused multiple trippings of Benmore-Twizel 1, Islington-Tekapo B 1 and Tekapo B-Twizel 1 circuits, resulting in loss of generation at Tekapo B.	60	117

3.2 System Events during reporting period

System events that occurred during the reporting period are summarised below.

Contingent Events		
Event	*Number*	*Summary*
Loss of single AC transmission circuit	42	These related to loss of • Halfway Bush-Palmerston 1; • Islington-Kikiwa 2; • Central Park-West Wind-Wilton 3 (x10 with 9 Auto Recloses); • Studholme-Timaru 1; • Islington-Tekapo B 1; • Kaitimako-Te Matai 1 (Auto Reclose); • Carrington Street-Huirangi 1 (x2); • Bunnythorpe-Haywards 2 (Auto Reclose); • Edgecumbe-Waiotahi 2 (Auto Reclose) (x2); • Gore-Roxburgh 1; • Islington-Livingstone 1 (Auto Reclose) (x2); • Balclutha-Berwick-Halfway Bush 1 (x2); • Inangahua-Kikiwa 1 (x4); • Inangahua-Kikiwa 2; • Coleridge-Otira 1; • Coleridge-Otira 2; • Otahuhu-Whakamaru 2 (Auto Reclose);

Contingent Events		
		• Motupipi-Upper Takaka 1; • Halfway Bush-Roxburgh 1 (x2); • Ohakune-Ongarue 1; • Edgecumbe-Kawerau 2; • Arapuni-Hangatiki-Ongarue 1; • Bunnythorpe-Mangahao 2; • Bunnythorpe-Haywards 1 (Auto Reclose); and • Gisborne-Tuai 1 (Auto Reclose).
Loss of HVDC pole	0	
Loss of single generation units	15	These related to loss of • Huntly U1 (x3); • Huntly U3; • Otahuhu B (x2); • Ohau A G4 (x2); • Mangahao G1; • Waipori (x2); • Wairakei (x2); • Benmore G5; • Benmore G6; and • Manapouri G3.
Total during reporting period	57	

Extended Contingent Events		
Event	*Number*	*Summary*
Loss of both HVDC poles	0	

Other Events		
Event	*Number*	*Summary*
Loss of multiple AC transmission circuits	5	These related to trippings of • Coleridge-Otira 1 and 2; • Inangahua-Robertson Street-Westport 1, Inangahua-Kikiwa 1 & 2; • Inangahua-Kikiwa 2 and Atarau-Inangahua 1; and • Central Park-West Wind-Wilton 2 and 3 (x2).
Loss of bus bar section	2	These events related to bus trippings of • Tekapo B 220 kV (x2).
Loss of interconnecting transformer	0	
Loss of grid reactive plant	3	These events related to trippings of • Haywards SC7; • Haywards F1; and • Ongarue C1.
Loss of supply transformer	3	These events related to trippings of • Maungatapere T1; • Kaiwharawhara T1; and • Tangiwai T2.

Other Events		
Demand change	1	This event related to a tripping of • Tiwai potline.
Loss of multiple generation units	0	
HVDC Start/ Stop	0	
Total during reporting period	14	

Other disturbances		
Event	*Number*	*Summary*
Feeder trippings	41	Various locations
Misc.	3	Arthurs Pass CB 622 (x2) and Huntly CB 242
Total during reporting period	44	

3.3 System Events – Trend

	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Total	Average Events per month
Contingent Event – transmission	36	38	6	13	25	26	17	22	19	24	23	42	291	24.3
Contingent Event – generation	4	5	1	8	16	13	5	10	7	7	8	15	99	8.3
Contingent Event - HVDC	0	3	0	1	0	1	6	0	0	0	1	0	12	1.0
Extended Contingent Event	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Other Event – AC transmission	4	2	6	2	1	2	1	3	0	1	2	5	29	2.4
Other Event – Busbar	0	1	0	1	0	3	0	1	0	3	2	2	13	1.1
Other Event – Demand	4	0	0	3	1	3	0	0	0	0	4	1	16	1.3
Other Event – Generation	0	0	1	0	0	0	0	0	1	4	0	0	6	0.5
Other Event – Interconnecting transformer	1	0	1	2	1	1	0	0	0	0	0	0	6	0.5
Other Event – Reactive plant	2	4	10	4	0	4	4	3	6	2	9	3	51	4.3
Other Event – Supply transformer	4	5	11	3	3	4	1	8	8	7	3	3	60	5.0

System Operator

Ancillary Services Procurement Report

May 2009

Purpose

This Ancillary Service Procurement Report is required to be provided to the Board in accordance with the Procurement Plan – Part C Schedule C5. The report is designed to summarise the procurement of ancillary services as follows:

1. Settlement volumes, prices, costs, and administrative costs where appropriate.
2. Any issues arising with respect to cost allocation, liability and disputes.
3. Other general procurement issues to be contained within the System Operator Monthly Report provided in accordance with Regulation 45.

The System Operator expects the ancillary service procurement reporting to evolve and develop to reflect feedback from the Commission and Participants.

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1 Summary of Procurement Costs 1
2 Summary of Contracted Ancillary Services 8
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4 Events Requiring Further Consideration for Regulation and or Rule Change 9

1.1 Frequency Keeping (FK)

Frequency Keeping	Cost
Constrained Off	$450,904.52
Constrained On	$557,428.78
Market offer	$2,792,489.33
Total monthly frequency keeping cost	**$3,800,822.63**

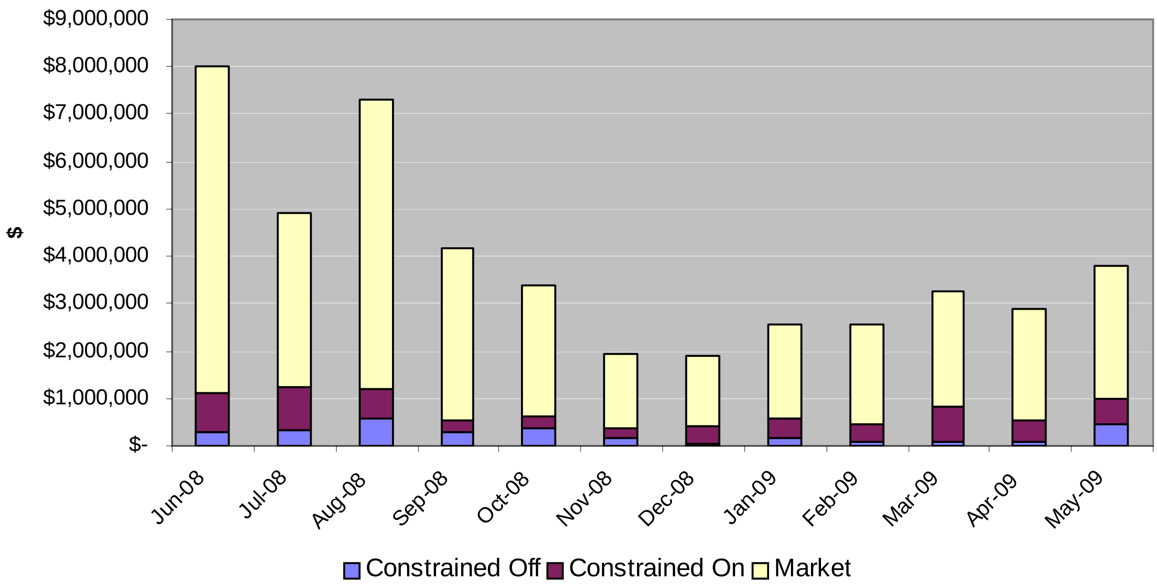

Chart 1.1(a): FK costs – 12 months

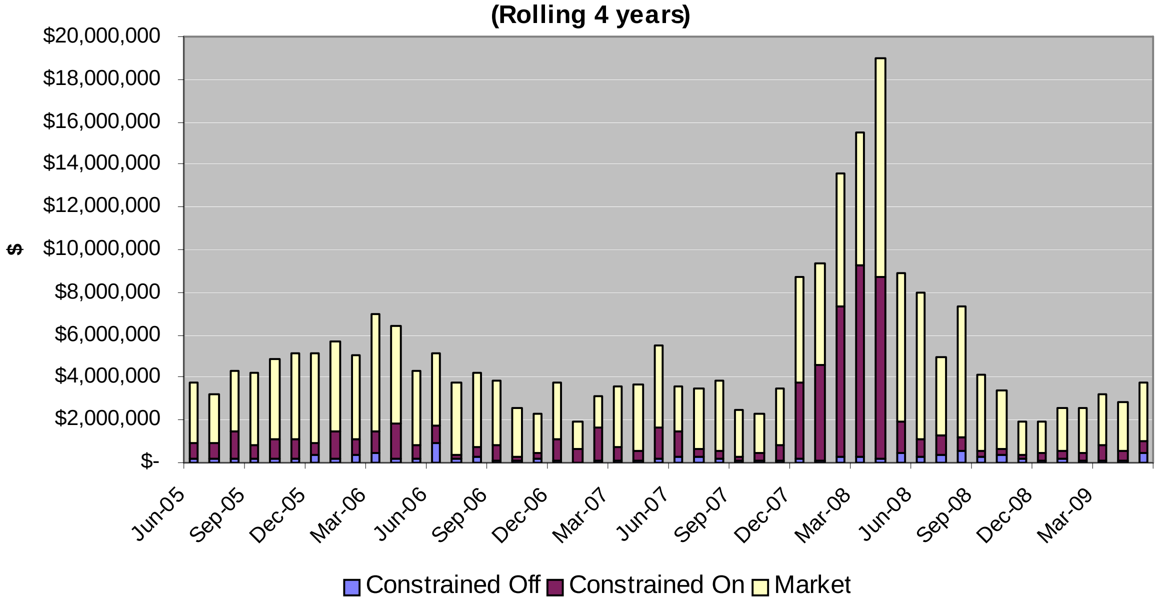

Chart 1.1(b): Historical cost of FK

1.2 Instantaneous Reserve (IR)

Instantaneous Reserve	Cost
Spinning reserve	$10,023,994.29
Interruptible Load	$6,326,140.40
Total monthly Instantaneous Reserve cost	**$16,350,134.69**

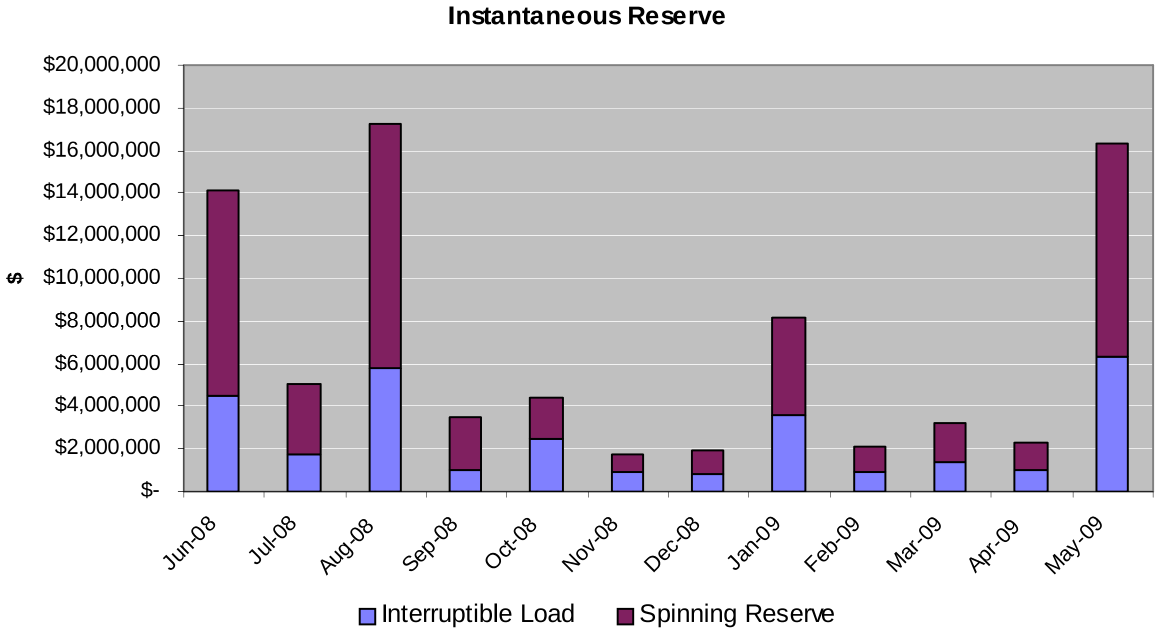

Chart 1.2(a): IR cost – 12 months

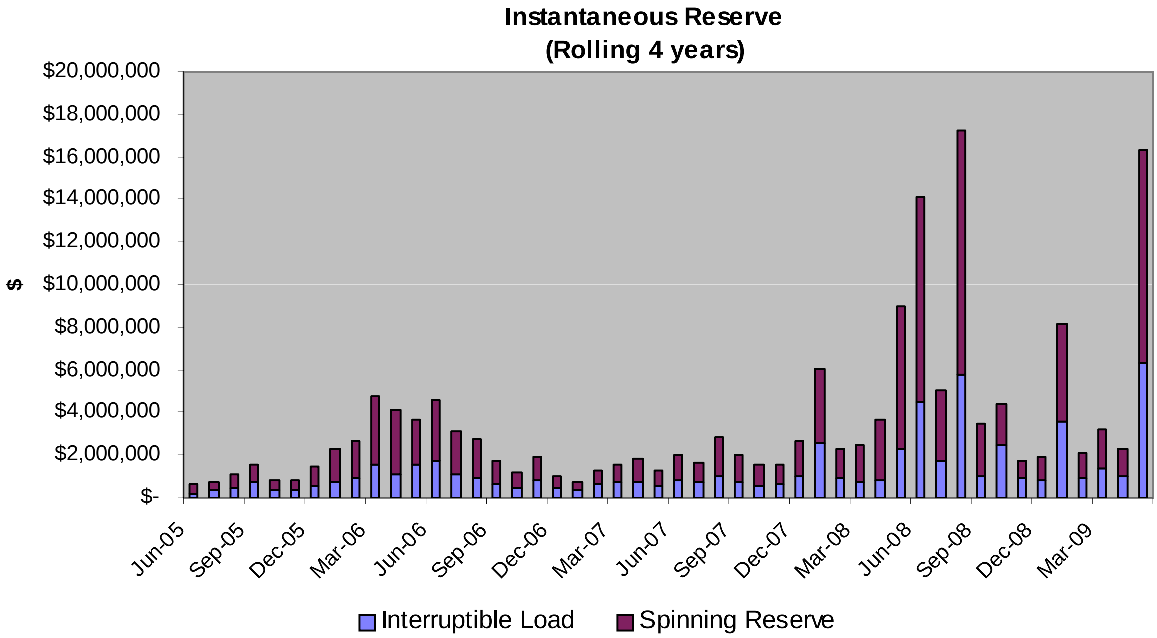

Chart 1.2(b): Historical cost of instantaneous reserves

1.3 Over Frequency Reserve (OFR)

Over Frequency Reserve	Cost
Total monthly Over Frequency Reserve cost	**$53,284.86**

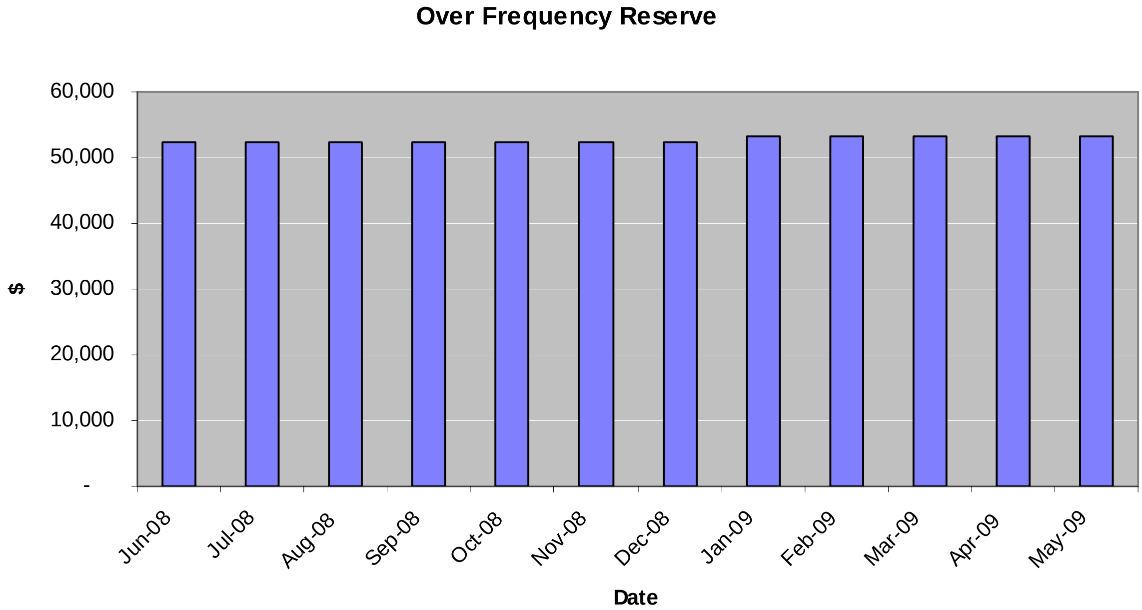

Chart 1.3(a): Monthly OFR cost – 12 months

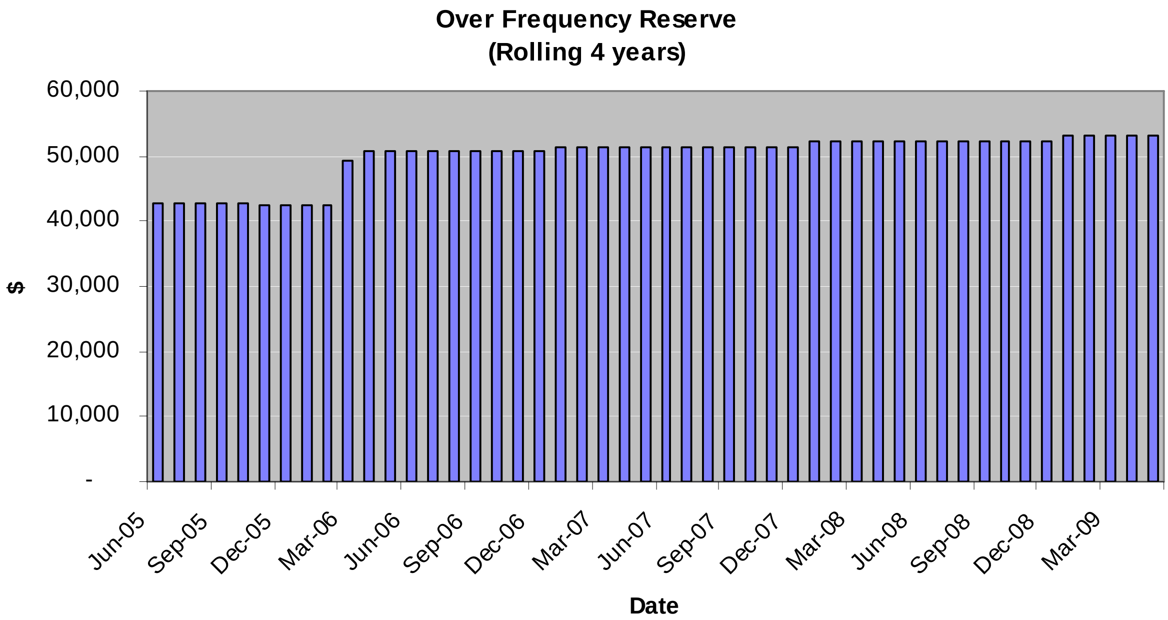

Chart 1.3(b): Historical cost of OFR

1.4 Black Start (BS)

Black Start	Cost
Total monthly Black Start cost	**$25,142.59**

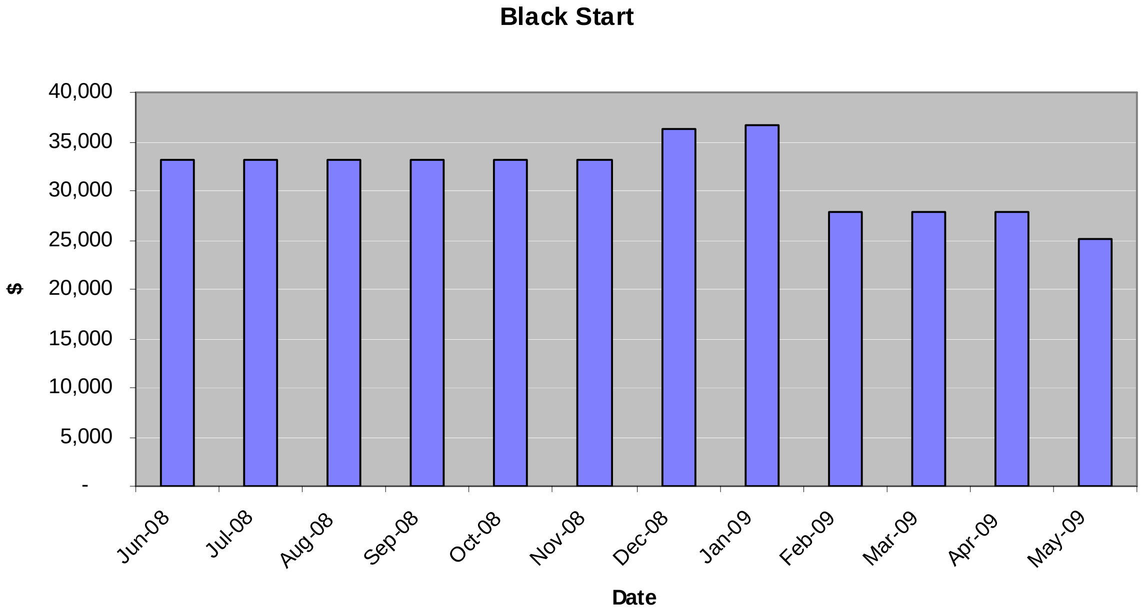

Chart 1.4(a): Monthly BS cost – 12 months

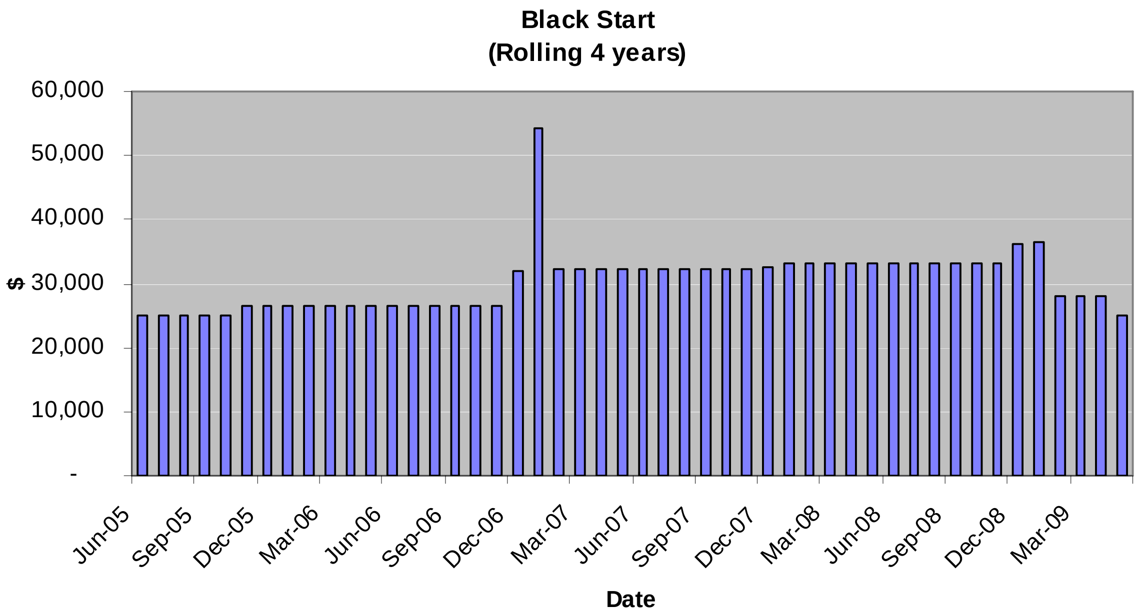

Chart 1.4(b): Historical cost of BS

1.5 Voltage Support (VS)

Voltage Support	Cost
Total monthly Voltage Support cost	**$655,146.57**

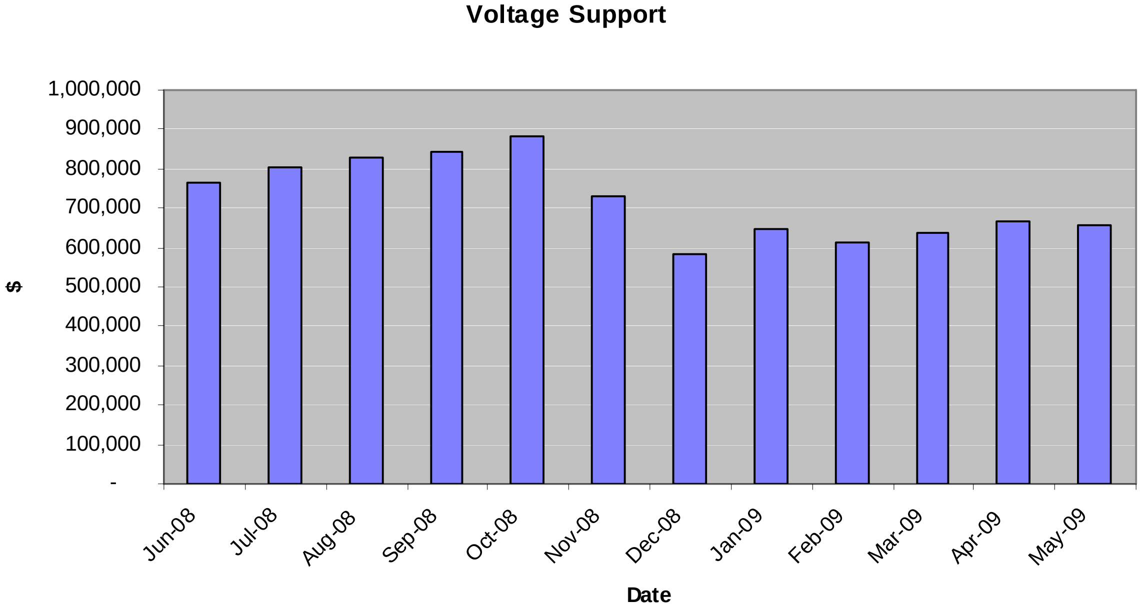

Chart 1.5(a): Monthly VS cost – 12 months

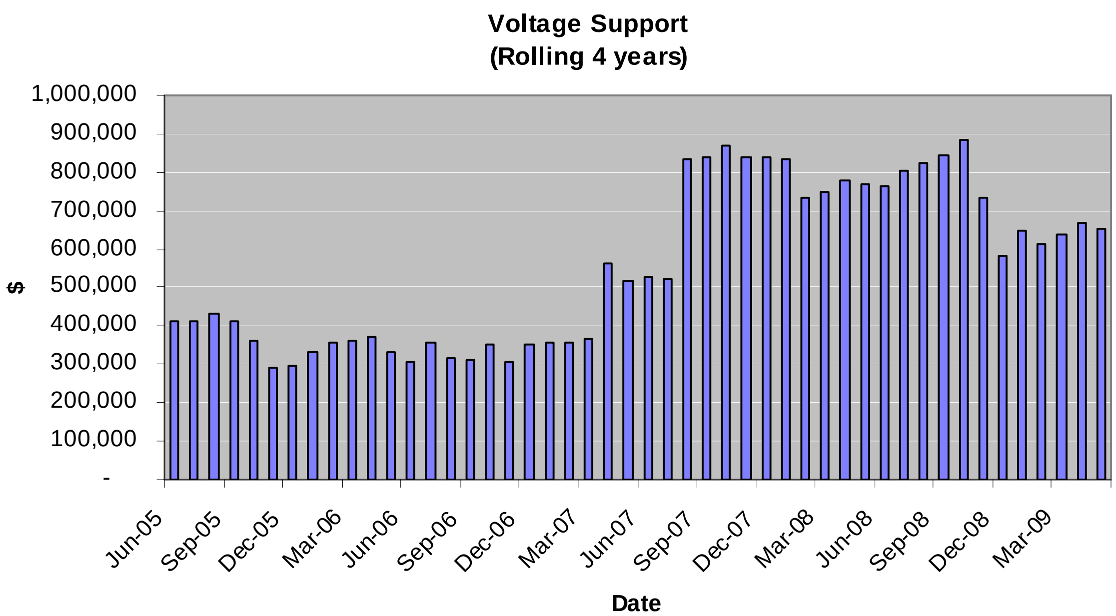

Chart 1.5(b): Historical cost of VS

1.6 Administrative Costs

Nil

2 Summary of Contracted Ancillary Services

The table 2.1 below provides a summary of contracted ancillary services as at 31 May 2009.

Table 2.1 Summary of contracted ancillary services

Ancillary Service Agent	(1)FK	(2)IR	(3)OFR	(4)BS	(5)VS
Meridian Energy	√	√	√*	√*	
Contact Energy	√*	√*	√*		√*
Mighty River Power	√	√		√*	√*
Genesis Power	√	√		√	
TrustPower		√*			
Vector		√			
Northpower		√			
Powerco		√*			
Unison		√			
WELNetworks		√			
CountiesPower		√			
NZ Steel		√*			
Pan Pac		√			
Winstone Pulp International		√*			
KCE Mangahao and Todd Mangahao		√*			
Norske Skog		√*			
Energy Response		√			
NZ Aluminium Smelters		√*			

(1) FK - Frequency Keeping
(2) IR - Instantaneous Reserves
(3) OFR - Over Frequency Reserve
(4) BS - Black Start
(5) VS - Voltage Support
***Longer term contract**

3 System Operator Compliance to Procurement Plan 08/09

The System Operator submitted the draft 2009/10 Procurement Plan to the Electricity Commission by 1 June, as required under the Rules. In preparing the draft plan the System Operator invited comment and held a number of consultation discussions with individual participants regarding the terms of the Plan. Comments received were considered by and assisted the System Operator in preparing the draft plan. In several cases participant's suggestions were adopted in the draft plan.

3.1 Changes to Ancillary Service Procurement Contracts

Nil

4 Events Requiring Further Consideration for Regulation and or Rule Change

Nil

Report Ends