

System Performance Report

To the Electricity Commission

July 2010

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.



SYSTEM OPERATOR

Keeping the energy flowing

TRANSPower



Table of Contents

1.	SUMMARY OF SYSTEM PERFORMANCE.....	2
2	PRINCIPAL PERFORMANCE OBLIGATIONS	3
2.1	Avoid Cascade Failure	3
2.2	Frequency.....	3
3	OPERATIONAL MANAGEMENT	4
3.1	Security Notices.....	4
3.2	Grid Emergencies	5
3.3	Customer Advice Notices (CANs)	6
3.4	Standby Residual Check (SRC) notices.....	6
3.5	Voltage Management.....	6
3.6	Outage Management	6
3.7	Constraints.....	7
4	SYSTEM EVENTS	9
4.1	Significant System Events.....	9
4.2	System Events during reporting period	9
4.3	System Events – Trend.....	11



1. SUMMARY OF SYSTEM PERFORMANCE

This system performance report covers the month of July 2010.

Principal Performance Obligations

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

Operational Management

While the number of planned outages was down from the levels of a few months ago, July was still a very busy month. A number of material events occurred on the system that resulted in interruptible load (IL) tripping and the use of discretion by co-ordination staff.

On the 4th there was an unplanned outage of both HVDC Pole 1 and 2. Initially Pole 2 tripped resulting in an IL event, then Pole 1 failed to start when dispatched. A Warning Notice was issued to advise North Island participants that there were insufficient offers of generation to meet the evening load peak. This was subsequently upgraded to a Grid Emergency and the grid was reconfigured at Kinleith by putting splits in place on the Kinleith-Tarukenga circuits so that the generation from Arapuni could be maximized.

On the 13th the System Operator was advised of a Potential (Gas) Critical Contingency by the Critical Contingency Operator due to an unplanned outage of the Pohokura production station. This was subsequently upgraded to a Critical Contingency. In response to this the System Operator issued two CA's to advise participants of the situation however no additional action was required and the situation was ended at 22:40.

Due to voltage stability issues following the tripping of the Kumara-Otira 1 circuit on the 30th, a Grid Emergency was declared to allow a split to be placed in the West Coast. This was done by removing the Dobson-Greymouth 1 circuit.

In addition to the IL event on the 4th, there were IL events on the 12th and 14th associated with the tripping of large thermal generators.

Please refer to section 3.2 for further details on Grid Emergencies declared during the month.

System Events

Balclutha-Berwick-Halfway Bush 1 circuit tripped on 24 July resulting in a loss of connection at Berwick of approximately 36 MW.

Other noteworthy events occurring during the reporting period include:

- tripping of Tauhara G1 and G2 units on 2 July;
- tripping of Highbank G1 unit on 4 July;
- tripping of Tuai G1 unit on 4 July;
- tripping of Wairakei G9 and G14 units on 5 July;
- trippings of Stratford station on 7 and 12 July;
- tripping of Rangipo G5 unit on 8 July;
- tripping of Southdown G102 unit on 8 July;
- tripping of Aniwhenua G2 unit on 13 July;
- tripping of Huntly unit 5 on 14 July;
- tripping of Benmore G6 unit on 21 July;



- trippings of Tuai G1, G2 and G3 units on 26 July;
- tripping of Southdown ST1 unit on 26 July;
- trippings of multiple units of Mokai on 31 July; and
- tripping of Southdown G105 unit on 31 July.

2. PRINCIPAL PERFORMANCE OBLIGATIONS

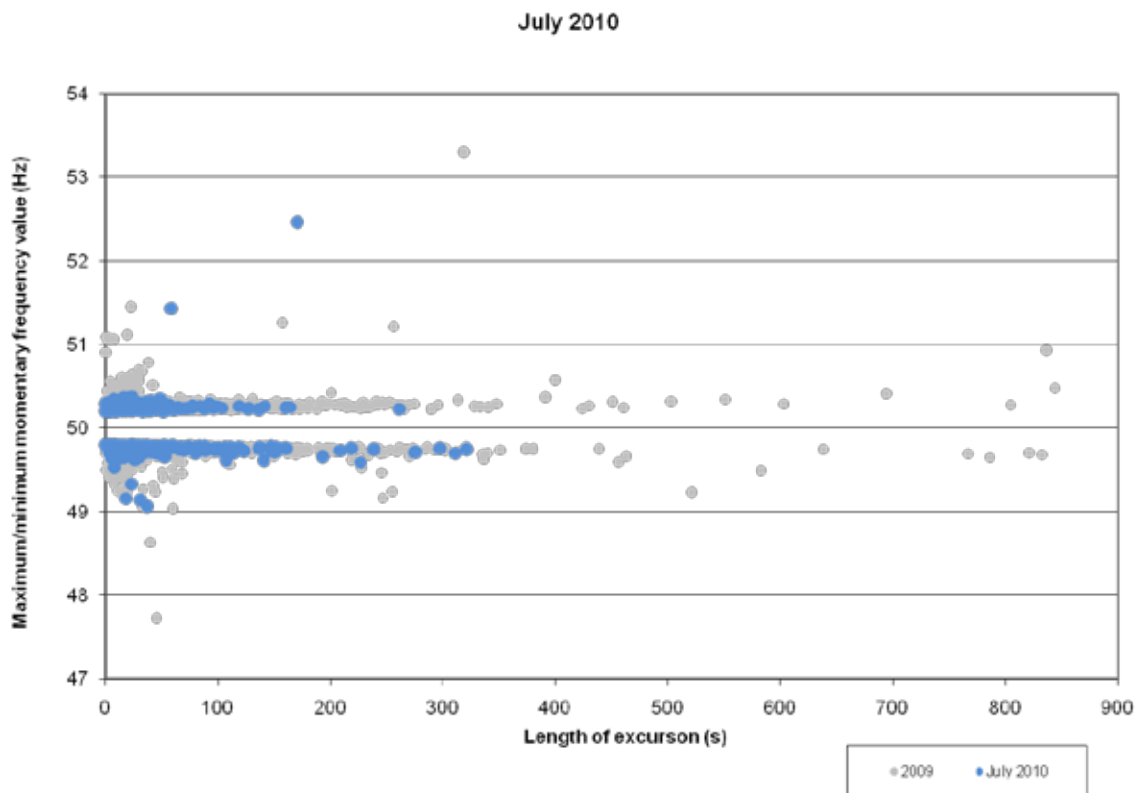
2.1 AVOID CASCADE FAILURE

No instances of cascade failure occurred during the reporting period.

2.2 FREQUENCY

Maintain frequency in normal band and recover quickly from a fluctuation

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



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	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Annual rate	PPO target
55.00 >= Freq > 52.00													0	
52.00 >= Freq > 51.25				1			1						2	7
51.25 >= Freq > 50.50	2	2	6	4	1	1		2	1	2	1	1	23	50
50.50 >= Freq > 50.20	416	359	292	228	85	148	140	279	348	351	286	376	3308	
50.20 >= Freq > 49.80														
49.80 >= Freq > 49.50	336	257	154	152	98	134	109	278	268	367	253	281	2687	
49.50 >= Freq > 48.75	3	1	3	2		2	2	5	5	3	1	6	33	60
48.75 >= Freq > 48.00													0	6
48.00 >= Freq > 47.00		1					1						2	0.2
47.00 >= Freq > 45.00													0	0.2

Manage time error and eliminate time error once per day

The time error performance criteria are:

Time error must be managed within +/- 5 seconds.

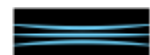
Time error must be eliminated at least once every day.

Time Error Compliance Table		Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10
Time Error Management	NI	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	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

3. OPERATIONAL MANAGEMENT

3.1 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	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10
Demand Allocation Notice												
Grid Emergency Notice		8	6		1	4	3		4	5	5	2
Warning Notice		5	3	1								1
Customer Advice Notice	6	7	41	16	11	18	31	16	12	20	10	17

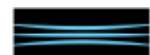
3.2 GRID EMERGENCIES

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

Grid Emergencies			
Date	Time	Summary Details	Island
4 July 2010	16:30	A Grid Emergency was declared due to insufficient generation offers in the North Island as a result of an unplanned outage of HVDC Bipole. Additional generation offers, load control, increase in intermittent generation, and later on the availability of HVDC Pole 1 alleviated the need to reduce reserve requirements or involuntary load control. In addition, a grid reconfiguration was required at Kinleith to optimise available North Island generation	North
30 July 2010	10:55	A Grid Emergency was declared due to an unplanned outage of Kumara-Otira 1 circuit. The outage caused voltage stability issues at Otira, Hokitika, Kumara, Greymouth and Dobson which required a split at Dobson-Greymouth 1 circuit.	South

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

Island	Region	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Total
North Island	Northland										2			2
	Auckland			1			2	1						4
	Zone 1						1					1		2
	Waikato			1		1								2
	Bay of Plenty											2		2
	Hawkes Bay													0
	Taranaki												1	1
	Bunnythorpe													0
	Wellington		5							1				6
	North Island (all)		3	4				1			2	1	1	12
South Island & HVDC	Nelson Marlborough													0
	West Coast							1		1			1	3
	Christchurch													0
	Canterbury													0
	Zone 3													0
	Otago													0
	Southland									1				1
	South Island (all)										1			1
	HVDC									1				1



3.3 CUSTOMER ADVICE NOTICES (CANs)

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

- four related to a change in HVDC capability due to an unplanned outage of HVDC Bipole;
- six related to a change in HVDC Pole 1 capability;
- one advised of a revision to the Arapuni runback scheme winter permanent constraint.
- one advised of a revision to the permanent constraints involving the Hawera auto-bus splitting scheme (ABSS);
- two advised of a critical gas contingency;
- one advised of a revision to Roxburgh T10 permanent constraint;
- two related to a planned outage of HVDC Bipole; and
- one advised of an issue with the publication of the Special Winter Schedule (SWS).

3.4 STANDBY RESIDUAL CHECK (SRC) NOTICES

A total of one hundred and one SRC notices were issued during the reporting period based on the SDS (System Operator's own load forecasting tool). These SRC notices were in respect of trading periods on 2nd-7th, 10th, 12th-16th, 21st-22nd, 26th-27th and 29th-30th.

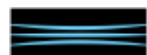
3.5 VOLTAGE MANAGEMENT

Grid voltages did not exceed the EGR voltage ranges during the reporting period.

No contracted voltage support ancillary services were called upon during the reporting period.

3.6 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	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Total
North Island	Northland	4	4	8	24	4	1	21	16	19	7	7	2	117
	Auckland	3	15	7	13	8	1	2	9	4	4	1	5	72
	Waikato	2	3	6	7	5	2	10	12	5	19	9	3	83
	Bay of Plenty	3	10	4	5	2	2	11	12	8	12	6	1	76
	Hawkes Bay		1	2	3	1	3	6	2	1	6	7		32
	Taranaki			1	3	1	1	5	1		8	4	1	25
	Bunnythorpe			5	3	1	3	5	9	16	5	5	2	54
	Wellington	1	7	4	7	6	2	7	11	6	4	9	5	69
Total		13	40	37	65	28	15	67	72	59	65	48	19	528
South Island	Nelson Marlborough	3	10	5	6	2	1	5	6	6	4	4		52
	West Coast	4	2	2	4			2	3	3	3	3	7	33
	Christchurch	1	4	4	3	4	2	1	2		3			24
	Canterbury	1		3	3			2	6	4		5	3	27
	Otago	3	1	5	2		3		2	4		4	6	30
	Southland	3		10	4	2	2	6	4	2	3		3	39
Total		15	17	29	22	8	8	16	23	19	13	16	19	205

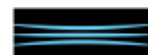
3.7 CONSTRAINTS

SUMMARY: Security constraints binding during the month

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

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.

Island	Region	Constraint Name	Description
North Island	Hamilton	ARI_HAM_1_and_2_ARI_RUNBACK_ENABLED_W_P_1	The effect of this constraint is to manage flows through Arapuni-Hamilton 1 and 2 for a contingency of Arapuni-Hamilton 2 or 1 during high ARI generation. Arapuni Runback Scheme enabled.
		ARI_HAM_1_and_2_ARI_RUNBACK_ENABLED_W_P_1A	The effect of this constraint is to manage flows through Arapuni-Hamilton 1 and 2 for a contingency of Arapuni-Hamilton 2 or 1 during high ARI generation. Arapuni Runback Scheme enabled.
South Island & HVDC	Canterbury	ASB_TIM_TWZ_2_W_O_1A	The effect of this constraint is to manage flows through Livingstone-Waitaki for a contingency of Ashburton-Timaru-Twizel 1 when Ashburton-Timaru-Twizel 2 is out of service.
	Otago	LIV_WTK_1_W_P_2A	The effect of this constraint is to manage flows through Livingstone Waitaki-1 for a contingency of a Clyde Cromwell Twizel-2 circuit during low Southland generation when all circuits are in service and HVDCS
	HVDC	DCNPole1Max	The purpose of this constraint is to limit the flow on HVDC Pole 1 to the Asset Owner's offered capability.



Constraints binding during last 12 months

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

Island	Region	Constraint	Reporting period		Previous 12 months	
			Number of trading periods that constraint bound	Percentage of trading periods	Number of trading periods that constraint bound	Percentage of Trading periods
North Island	Hamilton	ARI_HAM_1_and_2_ARI_RUN BACK_DISABLED_S_P_1	0	0.00%	56	0.32%
		ARI_HAM_1_and_2_ARI_RUN BACK_ENABLED_S_P_1	0	0.00%	54	0.31%
		ARI_HAM_1_and_2_ARI_RUN BACK_ENABLED_W_P_1	5	0.34%	16	0.09%
		ARI_HAM_1_and_2_ARI_RUN BACK_ENABLED_W_P_1A	6	0.40%	0	0.00%
South Island & HVDC	Canterbury	ASB_TIM_TWZ_2_W_O_1A	9	0.60%	0	0.00%
	West Coast	WEST_COAST_SPLIT_O_1	0	0.00%	114	0.65%
	Otago	LIV_WTK_1_W_P_2A	14	0.94%	0	0.00%
		NSY_ROX_1_S_P_z	0	0.00%	337	1.92%
	HVDC	DCNPole1Max	31	2.08%	3414	19.49%
		DCNPole1Min	0	0.00%	2549	14.55%
		BEN_HAYP1max	0	0.00%	542	3.09%



4. SYSTEM EVENTS

4.1 SIGNIFICANT SYSTEM EVENTS

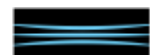
The following table shows significant events (frequency excursions and connection point events) which occurred during the reporting period.

Significant frequency excursions

Date	Time	Summary Details	Island	Freq (Hz)
4 July 2010	13:11	HVDC Pole 2 tripped resulting in a momentary change in frequency in both the North and South Islands.	North South	49.06 52.47
12 July 2010	04:08	Stratford power station tripped resulting in a momentary drop in frequency in the North Island.	North	49.14
14 July 2010	06:17	Huntly unit 5 tripped resulting in a momentary drop in frequency in both the North and South Islands.	North South	49.16 49.33
23 July 2010	12:44	Tiwai potline tripped resulting in a momentary rise in frequency in the South Island.	South	51.43

Connection point events

Date	Time	Summary Details	Generation/Load interrupted (MW)	Restoration time (minutes)
24/07/2010	13:01	Balclutha-Berwick-Halfway Bush 1 circuit tripped causing loss of connection to Berwick.	36	170



4.2 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	11	These related to trippings of <ul style="list-style-type: none"> § Clyde-Twizel 2 § Blenheim-Stoke 2 (Auto Reclose) § Henderson-Maungatapere 2 (Auto Reclose) § Mangamaire-Woodville 1 (Auto Reclose) § Taumarunui-Te Kowhai 1 § Otahuhu-Whakamaru 2 (Auto Reclose) § Balclutha-Berwick-Halfway Bush 1 § Islington-Kikiwa 1 (Auto Reclose) § Huirangi-Motunui 1 (Auto Reclose) § Kumara-Otira 1 § Arapuni-Bombay 1
Loss of HVDC pole	2	This related to trippings of <ul style="list-style-type: none"> § Arcback on HVDC Valve Group VG1 § HVDC Pole 2
Loss of single generation units	13	These related to trippings of <ul style="list-style-type: none"> § Tauhara G1 & 2 § High Bank G1 § Tuai G1 § Wairakei G9 & G14 § Stratford (x2) § Rangipo G5 § Southdown GE102 & 105, & ST1 § Aniwhenua G2 § Huntly U5 § Benmore G6
Total during reporting period	26	

Extended contingent events

Event	Number	Summary
Loss of both HVDC poles	0	

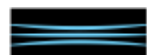


Other events

Event	Number	Summary
Loss of multiple AC transmission circuits	0	
Loss of bus bar section	0	
Loss of interconnecting transformer	0	
Loss of grid reactive plant	3	These events related to trippings of § Kikiwa Station STC2B § Hokitika C7, C8, C9 (x2)
Loss of supply transformer	3	These events related to trippings of § Tangiwai T2 § Melling T1 § Kinleith T3
Demand change	1	This event related to a tripping of § Tiwai Potline
Loss of multiple generation units	2	This event related to trippings of § Tuai G1, 2 & G3 § Mokai G1, G2, G10, G11, G12, G21 & G22
HVDC Start/ Stop	1	This event related to a tripping of § Benmore T2 shortly after HVDC Pole 1 started
Total during reporting period	10	

Other disturbances

Event	Number	Summary
Feeder trippings	34	Various locations
Total during reporting period	34	



4.3 SYSTEM EVENTS – TREND

	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Total	Average Events per month
Contingent Event – transmission	24	16	22	4	12	51	20	10	15	23	17	11	225	19.2
Contingent Event – generation	9	11	14	13	15	8	10	13	13	8	14	13	141	11.6
Contingent Event - HVDC	1	0	15	2	1	4	7	0	0	1	1	2	34	2.7
Extended Contingent Event	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Other Event – AC transmission	0	1	1	0	1	5	0	1	0	0	2	0	11	1.1
Other Event – Busbar	1	1	0	2	1	2	1	2	1	1	1	0	13	1.1
Other Event – Demand	2	5	4	4	1	0	0	1	0	1	1	1	20	2.0
Other Event – Generation	0	2	0	1		1	0	0	2	0	2	2	10	0.8
Other Event – Interconnecting transformer	0	1	0	0	1	1	1	1	0	1	2	0	8	0.7
Other Event – Reactive plant	1	6	10	2	8	5	6	5	3	4	2	3	55	4.3
Other Event – Supply transformer	4	3	3	4	4	3	2	11	1	3	7	3	48	4.3

