System Operator Annual Review and Assessment 2009/10

1 September 2009 to 31 August 2010

SYSTEM OPERATOR

Keeping the energy flowing

TRANSPOWER

Transpower New Zealand Ltd The National Grid

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1. EXECUTIVE SUMMARY

It has been a busy year for the System Operator in terms of both its operations and development initiatives. During the year in review, the System Operator focused its efforts on the industry and its needs by leveraging the benefits delivered through the new market system.

To this end, the System Operator implemented a number of industry initiatives during the 2009/2010 year. Variable reserves capability and frequency keeping selection were reinstated after the new market system was implemented. The Electricity Commission's winter initiatives package was implemented in mid 2010 and the System Operator has assisted the Commission in the development of the Interim Pricing period which will come into effect in October 2010.

Several significant security projects were started and completed during the reporting period. These projects included:

- a review of credible events, which has resulted in some significant changes to the way in which we plan for and manage power system events;
- a technical review of Automatic Under Frequency Load Shedding requirements and the adequacy of such arrangements; the economic and policy aspects of the review will now be progressed;
- studies into fault ride through to inform discussions into the requirements for generation to remain connected to the system following voltage and frequency disturbances.

From an operational perspective, the System Operator:

- managed 37 grid emergencies, 45 system events and 26 connection point events;
- coordinated 6104 grid asset outages;
- assisted with the planning and coordination of the commissioning of 2 new generators as well as a number of other grid asset commissioning projects;
- significantly contributed to the tool development work as part of the Pole 3 commissioning;
- managed dry North Island issues and continued working with the National Winter Group.

The period 1 September 2009 to 31 August 2010 included a high level of outage planning activity compared with the previous reporting period. Of the 6,104 asset outages planned, 5,850 required re-planning. In the forthcoming year, the System Operator will focus considerable effort on working with asset owners to reduce the amount of rework on outages.

There was one major over-frequency event during the reporting period. This occurred on 30 October 2009 when a forklift carrying a container hit the line near Otahuhu causing a loss of supply to North Auckland and Northland. This highlighted a major security concern with placing significantly loaded regions on reduced security during outages, leading to the System Operator identifying the need to procure over frequency reserves in the North Island. The tendering process commenced in August 2010.

The System Operator and the Electricity Commission entered into the Technical Advisory Services Contract (TASC) in September 2009. Since then, the System Operator through TASC, has provided advice to the Electricity Commission on AGC, Interruptible Load, and proposed changes to the 2 hour rule. A number of these work streams are ongoing and continue into the 2010/11 year.

The 2010/11 year will be another challenging one for the System Operator. The System Operator intends to build on the security studies it has performed during the year. Work continues on the AUFLS economic and policy review and the implementation of major projects such as Pole 3 commissioning and NIGUP. The System Operator will also implement the automatic constraint builder module of the Simultaneous Feasibility Test (SFT) software that was developed as part of the new market system. These initiatives, combined with another busy outage season, will see the System Operator planning and operational resources fully committed.

The planned industry development initiatives for this upcoming period include:

- implementing the Interim Pricing Period
- implementing the SFT software
- implementing Pole 3 control systems
- continued work on scoping an AGC industry solution
- progressing demand side bidding and forecasting initiatives
- working with the Electricity Authority to scope a solution for Scarcity Pricing
- progressing other aspects of the Market Development Programme as required by the Electricity Authority

The System Operator will continue to work closely with the Electricity Authority on resource planning during the 2010/2011 year.

One outcome of the review of electricity market performance, in support of improving electricity market governance, is the transfer of responsibilities for emergency management and security of supply to the System Operator. Work will continue over the next 12 months to update and implement policies in respect of those new responsibilities. In addition, there are a number of changes to the System Operator's operational and compliance tools and databases to implement the recoding of rules to the new codes.

2. PRINCIPAL PERFORMANCE OBLIGATIONS

2.1 TIME ERROR

There were three instances of time error exceeding the +/- 5 second limit during the review period. The first occurred at approximately 11:54 on 18 February 2010 in the North Island. Unplanned outages of HVDC Poles 1 and 2 during South to North transfer resulted in a drop in the North Island frequency and a considerable increase in the South Island. Dedicated efforts to return the frequencies back to the normal band resulted in North Island time error excursion drifting to -7.5 seconds. The time error was returned to the normal band approximately 49 minutes later.

The second event occurred at approximately 12:55 on 18 February 2010, an hour after the previous event. Continued efforts to return the frequency to the normal band after the unplanned outages of HVDC Poles 1 and 2 resulted in the North Island time error drifting to -7.1 seconds. The time error was returned to the normal band approximately 25 minutes later.

The third event occurred at approximately 00:30 on 17 April 2010, also in the North Island. We have reported a breach in respect of this incident.

2.2 VOLTAGE VIOLATIONS 220 KV & 110 KV

There were no instances of 220 kV and 110 kV grid voltage exceeding the +/-10% limits between September 2009 and August 2010.

2.3 FREQUENCY

Frequency excursions for the reporting period remained within the annual frequency performance targets. There was one excursion above 51 Hz reported for the period (this event is discussed in more detail in section 3.2.1).

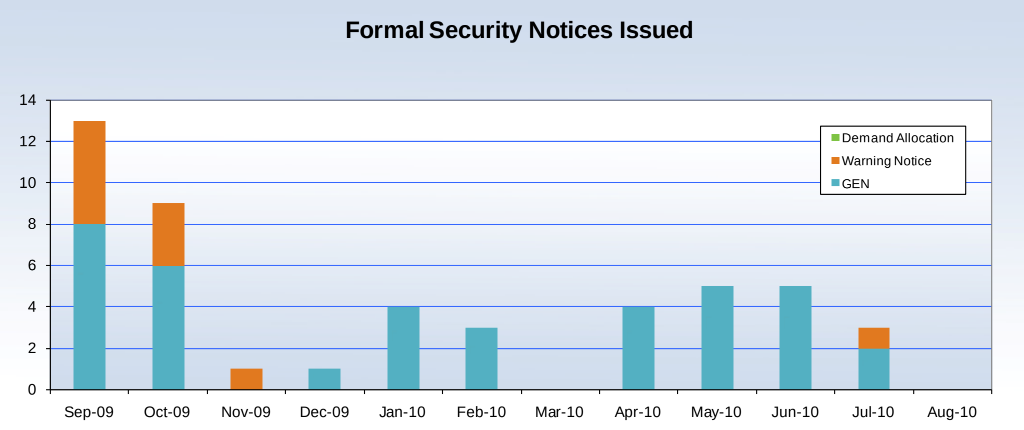
Frequency Band (Hz)	2009				2010								Annual rate	PPO target
	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug		
55.00 > Freq >= 52.00													0	
52.00 > Freq >= 51.25		1			1						1		3	7
51.25 > Freq >= 50.50	6	4	1	1		2	1	2	1	1	1		20	50
50.50 > Freq >= 50.20	292	228	85	148	140	279	348	351	286	376	382	337	3252	
50.20 > Freq > 49.80	Normal													
49.80 >= Freq > 49.50	154	152	98	134	109	278	268	367	253	281	368	291	2753	
49.50 >= Freq > 48.75	3	2		2	2	5	5	3	1	6	4	1	34	60
48.75 >= Freq > 48.00													0	6
48.00 >= Freq > 47.00													0	0.2
47.00 >= Freq > 45.00													0	0.2

Note 1. The PPO target is 1 in any 60 month period.

2.4 SECURITY NOTICES

A total of 47 formal security notices were issued between 1 September 2009 and 31 August 2010.

Notice Type	Number of Notices Issued*
GEN	37
WRN - Warning Notice	10



*Note: numbers given include notices issued declaring an emergency situation and the notices issued advising the emergency situation has ended.

Of the grid emergencies declared during this period, the majority were issued during September and October 2009 with all but one related to managing insufficient generation offers as well as insufficient transmission capacity to meet demand.

2.5 PARTICIPANT ADVICE NOTICES

A total of 210 Customer Advice Notices (CANs) were issued during the review period.

2.6 STABILITY LIMITS

There were no instances of stability limits being exceeded on the grid during the review period. However, there were four stability constraints that bound for a total of 90 hours. Approximately 55 hours related to managing voltage stability limits on the West Coast during outages of certain transmission circuits in that region. Approximately 20 hours related to managing voltage stability limits at the top of the South Island during outages of one of the Islington-Kikiwa circuits. Others included managing voltage stability limits in the Upper South Island (March 2010) and Taranaki (June 2010) during planned outages.

2.7 STANDBY RESIDUAL CHECK NOTICES

Standby residual check notices are published by the System Operator to indicate there is insufficient generation and interruptible load offered for dispatch to maintain system security and meet forecast demand if the largest single credible event were to occur. Notices were issued by the System Operator for approximately 2399 affected trading periods in the year to 31 August 2010.

3. SECURITY ISSUES

3.1 OPERATIONAL REVIEW

A major event at Haywards occurred at the start of the year. On 22 September 2009, a fire arising from a failed synchronous condenser at Haywards resulted in an unplanned outage of three Haywards interconnecting transformers T1, T2 and T5. While load was not constrained (Pole 1 was used to manage load) T2 remained out of service for some time. Pole 1 was subsequently on several occasions (while Haywards equipment was out of service) to avoid North Island load management. All four synchronous condensers were unavailable for some time, and then progressively returned to service as repairs were completed (C3 and C4 were not returned to service until 2010).

Cold weather in October, the unavailability of equipment at Haywards and unavailability of some key North Island generating equipment again meant Pole 1 transfers were required to avoid North Island load shedding on a number of occasions. Voltage management in the lower North Island was also a major management issue during the month.

October ended with a major outage on 30 October when a forklift carrying a container hit the Henderson-Otahuhu 1 circuit which, at the time, was supplying all load north of Auckland (due to a planned outage of Otahuhu-Southdown 1 circuit and Hepburn Rd-Mt Roskill circuits 1 and 2 were on planned outage). Approximately 600MW of load was lost. While the restoration of customers was well executed, some customers were without service for up to four hours.

On 25 January 2010, a material outage occurred north of Hamilton due to trippings on Hamilton-Whakamaru 1 and Ohinewai-Whakamaru 1 circuits (and subsequent trippings on Arapuni-Hamilton 1 and 2 and Arapuni-Bombay 1 circuits). The trippings were caused by a fire under the circuits south of Hamilton; the duration of which was extended when fire services had problems accessing the seat of the fire. Load management was required in the Vector, Northpower, and Top Energy distribution networks.

The summer was characterised by fires in a number of regions. These were notable in the Dunedin, Christchurch, and Marlborough/Nelson areas, causing management issues (including circuit trippings) on many occasions. A significant outage was on 18 February 2010, when fire resulted in Poles 1 and 2 being taken out of service. Load management was required in the North Island as a consequence.

The dry North Island summer caused concern for the System Operator-led 2010 winter review. Lake Taupo levels reached the lowest levels for many years from late summer through to early winter. The developing low water situation was under active review by the System Operator and generators during the autumn with contingency planning having been commenced. Lake Taupo storage levels fell below 12% in late May before levels began to increase to less concerning levels in early June. Industry planning meetings were held in April to review winter prospects; no issues required management, apart from the developing North Island water storage issue.

In April 2010, an excess of water storage in the southern lakes became a problem, with spill occurring on a number of occasions. Significant northward transfers were accomplished using the HVDC, including use of Pole 1. A major 110kVbus fault at Wilton on 22 April 22 resulted in loss of load in the Wellington area.

June was an active month on the system. There were a number of events resulting in interruptible load activations. Several generator plant issues resulted in bona fide claims and resultant usage of discretion to manage system security. There were also a number of load management and loss of supply situations, including losses of supply at Oamaru, Mount Maunganui, and load management in Taranaki-Wanganui.

An unplanned outage of both HVDC poles occurred in July. Three interruptible load events occurred (including the loss of Pole 2 on the 4th and generator trippings on 12 July and 14 July).

In summary, the System Operator faced a challenging year from an operational perspective. Its dispatch and market systems, introduced at the end of the previous year, provided high levels of availability. Co-ordination, market support, and planning staff made good progress in familiarisation of the systems. Work on refining the management of the market systems occurred throughout the year, including reducing the time during which the systems are unavailable during planned and unplanned site failovers (the times for which have reduced from up to 1.5 hours to less than 1 hour).

3.2 Summary of Grid Emergency Notices

The following table shows the number of Grid Emergency Notices issued during the reporting period. Multiple notices were issued for some grid emergencies.

Month	Issued GEN
September 09	8
October 09	6
November 09	0
December 09	1
January 10	3
February 10	3
March 10	0
April 10	4
May 10	5
June 10	5
July 10	2
August 10	0

3.3 EVENTS LEADING TO DECLARATION OF GRID EMERGENCIES

The following table lists the grid emergencies during the reporting period.

Grid Emergencies Date	Time	Summary Details	Island
21-Sep-09	07:30	A Grid Emergency was declared for insufficient generation offers in North Island which required the starting up of HVDC Pole 1.	North
22-Sep-09	12:44	A Grid Emergency was declared following the unplanned outages of Haywards interconnecting transformers T1, T2 and T5. HVDC Pole 1 was started up to alleviate the need for load management in the North Island.	North
23-Sep-09	09:24	A Grid Emergency was declared for insufficient generation offers in North Island following unplanned outages of multiple Huntly units. A 5% load management in the North Island was required.	North
23-Sep-09	08:35	A Grid Emergency was declared for insufficient transmission capacity in Grid Zone 8 (Wellington-Wairarapa) which required the starting up of HVDC Pole 1.	North
23-Sep-09	17:00	A Grid Emergency was declared for insufficient generation offers in North Island which required the starting up of HVDC Pole 1.	North
24-Sep-09	17:00	A Grid Emergency was declared for insufficient transmission capacity in Grid Zone 8 (Wellington-Wairarapa) which required the starting up of HVDC Pole 1.	North
25-Sep-09	08:30	A Grid Emergency was declared for insufficient transmission capacity in Grid Zone 8 (Wellington-Wairarapa) which required the starting up of HVDC Pole 1.	North
28-Sep-09	17:30	A Grid Emergency was declared for insufficient transmission capacity in Grid Zone 8 (Wellington-Wairarapa) which required the starting up of HVDC Pole 1.	North
5-Oct-09	09:25	A Grid Emergency was declared for insufficient generation offers in the North Island which required the starting up of HVDC Pole 1. Reserves requirements in the North Island were also zeroed to alleviate the need for load management.	North
6-Oct-09	08:00	A Grid Emergency was declared for insufficient generation offers in the North Island. Reserves requirements in the North Island were zeroed to alleviate the need for load management.	North
9-Oct-09	09:20	A Grid Emergency was declared for insufficient generation offers in the North Island. Increased generation offers alleviated the need for load management.	North
14-Oct-09	17:49	A Grid Emergency was declared for insufficient generation offers in the North Island which required the starting up of HVDC Pole 1. Reserves requirements in the North Island were also zeroed to alleviate the need for load management.	North
23-Oct-09	08:46	A tripping of Hamilton Whakamaru circuit 1 would overload Kinleith Tarukenga circuits 1 and 2. A system split was made at Kinleith to alleviate the issue.	North
30-Oct-09	07:59	Unplanned outage on Henderson - Otahuhu circuit 1 while Otahuhu - Southdown circuit 1 and Hepburn Road - Mount Roskill circuits 1 and 2 were removed from service for planned outages.	North
30-Dec-09	23:48	A Grid Emergency was declared due to EGR N-1 voltage limit being exceeded at Te Kowhai. A grid reconfiguration removing Taumarunui-Te Kowhai 1 circuit and Taumarunui T8 supply transformer alleviated the problem.	North
21-Jan-10	11:20	A Grid Emergency was declared for load management and a grid reconfiguration at Bombay to manage a contingency of either Ohinewai-Otahuhu 1 or 2 circuits which would cause offload time	North

Grid Emergencies Date	Time	Summary Details	Island
		violations on Bombay-Hamilton 1 and 2 circuits.	
25-Jan-10	15:12	A Grid Emergency was declared for load management in Zone 1. Trippings of Hamilton-Whakamaru 1 and Ohinewai-Whakamaru 1 circuits as a result of fire under the circuits caused overloading and subsequent trippings of Arapuni-Hamilton 1 and 2 as well as Arapuni-Bombay 1 circuits.	North
28-Jan-10	15:46	A Grid Emergency was declared at Penrose and Pakuranga for transfer of load from Penrose to Mount Roskill due to an unplanned outage of Otahuhu T4 interconnecting transformer. For the loss of either Bombay-Hamilton 1 or 2, or Otahuhu-Penrose 5 or 6 circuits, Otahuhu T2 interconnecting transformer would exceed its advised rating.	North
1-Feb-10	12:17	A Grid Emergency was declared for load restoration in West Coast following unplanned outages of Dobson T12 interconnecting transformer as well as T1 and T2 supply transformers. Lake Coleridge-Otira 2 and Arthurs Pass-Otira 1 circuits were removed from service for planned outages at the time, causing loss of load at Dobson, Greymouth, Kumara, Hokitika and Otira.	South
16-Feb-10	08:49	A Grid Emergency was declared for grid reconfiguration and load management at Bombay following an unplanned outage of Arapuni-Bombay 1 circuit.	North
18-Feb-10	11:49	A Grid Emergency was declared requesting for increase in energy and transmission offers in the North Island following unplanned outages of HVDC Poles 1 and 2. In addition to increased generation, North Island load had to be reduced by 5%. No reserves were dispatched in North Island during this period.	North
20-Apr-10	16:00	A Grid Emergency was declared for insufficient generation offers in the North Island. HVDC Pole 1 was started to alleviate the issue.	North
21-Apr-10	08:19	A Grid Emergency was declared for load management at Balclutha following a unplanned outage of Balclutha-Halfway Bush 1 circuit. A tripping of Gore-Roxburgh 1 circuit would overload Edendale-Invercargill 1 circuit.	South
22-Apr-10	15:21	A Grid Emergency was declared for the restoration of Wilton 110 kV bus and associated circuits connected to it following an earlier bus fault. The fault resulted in loss of connections to Central Park, Kaiwharawhara and West Wind.	North
24-Apr-10	12:51	A Grid Emergency was declared for grid reconfiguration at Brydone-Gore 1 circuit following a unplanned outage of Balclutha-Halfway Bush 1 circuit. A tripping of Gore-Roxburgh 1 circuit would overload Edendale-Invercargill 1 circuit.	South
3-May-10	18:12	A Grid Emergency was declared for insufficient reserve offers in the South Island following the unplanned loss of some South Island generation. An increase in reserve offers from participants alleviated the situation.	South
6-May-10	00:39	A Grid Emergency was declared as grid voltages in the lower North Island exceeded or were at risk of exceeding EGR limits as a result of the switching of HVDC Pole 1. To reduce the high voltage, Brunswick-Stratford 1 and Bunnythorpe-Haywards 1 circuits were removed from service.	North
7-May-10	14:42	A Grid Emergency was declared for independent action taken by the asset owner to remove Bream Bay T2 supply transformer from service due to multiple operations of the low voltage circuit breaker.	North
7-May-10	15:51	A Grid Emergency was declared for independent action taken by the asset owner to remove Bream Bay T2 supply transformer from	North

Grid Emergencies Date	Time	Summary Details	Island
		service due to multiple operations of the low voltage circuit breaker.	
30-May-10	17:30	A Grid Emergency was declared due to insufficient generation offers in the North Island. HVDC Pole 1 was started to alleviate the problem.	North
9-Jun-10	17:50	A Grid Emergency was declared due to insufficient generation offers in the North Island. North Island Contingent event risk adjustment factors were reduced to 0.6 until 18:52.	North
14-Jun-10	13:45	A Grid Emergency was declared due to an unplanned outage of Atiamuri-Whakamaru 1 circuit, where a system split was required at Kinleith-Tarukenga 1 and 2 circuits for system security.	North
16-Jun-10	12:18	A Grid Emergency was declared for switching instructions to restore supply at Mount Maunganui following an unplanned outage of Kaitimako-Mount Maunganui 1 circuit while Kaitimako-Mount-Maunganui-Tauranga 1 circuit was out of service.	North
18-Jun-10	14:48	A Grid Emergency was declared due to voltage limit at Hawera exceeding the EGR limit, which required the local network company reducing load to alleviate the issue.	North
26-Jun-10	10:33	A Grid Emergency was declared due to insufficient generation offers in Zone 1. The grid was reconfigured by creating an operational split on Kinleith-Tarukenga 1 and 2 circuits to avoid circuit overloading for a Hamilton-Whakamaru 1 circuit tripping.	North
4-Jul-10	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-Jul-10	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

Fifty percent of grid emergency declarations called for the management of insufficient transmission capacity, insufficient generation, or reserves offers to meet demand. The remainder of the grid emergencies were split between reconfiguring grids to avoid post-contingency violation on circuits; restoration of load or security following forced outages; and managing loading on grid assets to avoid exceeding stated capability under normal power system conditions.

3.3.1 Major System Frequency Events

During the review period there was one major system frequency event. On 30 October 2009, Henderson-Otahuhu 1 circuit tripped while Otahuhu-Southdown 1 circuit and Hepburn Road-Mount Roskill circuits 1 and 2 were out of service for planned outages. The tripping caused loss of supply for North Auckland and Northland of approximately 600 MW. A forklift carrying a container hit the line near Otahuhu causing the tripping. Restoration of load took just over two hours. Frequencies in both islands rose above 51 Hz before recovering.

The event raised some concerns around placing a region with considerable load on N security during planned outages; particularly its affect on system frequency if the remaining circuit trips. Analysis carried out by the System Operator indicates that if the remaining circuit was to trip, the frequency in the North Island could rise over 52 Hz, thereby resulting in an over frequency event in the North Island.

The Grid Owner has requested future outages on the circuits supplying the top part of North Island. Such outages would leave a single circuit as the only remaining supply to North Auckland and Northland. As a result, the System Operator has commenced tendering for the provision of over frequency reserve ancillary service in the North Island.

3.4 SUMMARY OF SYSTEM EVENTS

System Events Date	Time	Summary Details	Island	Freq (Hz)
1-Sep-09	19:33	Tiwai potline tripped causing a momentary rise in frequency in the South Island.	South	50.51
9-Sep-09	23:13	Tiwai potline tripped causing a momentary rise in frequency in both North and South Islands.	North South	50.47 50.53
22-Sep-09	11:36	Haywards T2 interconnecting transformer tripped causing momentary fluctuations in frequency in both the North and South Islands.	North South	49.03 51.06
23-Sep-09	06:43	Manapouri unit 7 tripped causing a momentary drop in frequency in the South Island.	South	49.42
23-Sep-09	09:08	Huntly units 2 and 3 tripped causing a momentary drop in frequency in the North Island.	North	49.23
24-Sep-09	13.27	Tiwai potline tripped causing a momentary rise in frequency in the South Island.	South	50.53
27-Sep-09	13:30	Tiwai potline tripped causing a momentary rise in frequency in the South Island.	South	50.56
29-Sep-09	20:57	Tiwai potline tripped causing a momentary rise in frequency in the South Island.	South	50.57
5-Oct-09	22:50	Huntly unit 2 tripped causing a momentary drop in frequency in both North and South Islands.	North South	49.25 49.43
10-Oct-09	16:16	Tiwai potline tripped causing a momentary rise in frequency in the South Island.	South	50.61
12-Oct-09	13:21	Tiwai potline tripped causing a momentary rise in frequency in the South Island.	South	50.46
15-Oct-09	13:27	Tiwai potline tripped causing a momentary rise in frequency in the South Island.	South	50.55
30-Oct-09	07:59	Henderson Otahuhu 1 circuit tripped during a planned outage of Otahuhu-Southdown 1 circuit resulting in the loss of connection to North Auckland and Northland and a momentary rise in the frequency in both North and South Island.	North South	51.21 51.45
10-Nov-09	11:50	Huntly unit 2 tripped causing a momentary fluctuation in frequency in the both North and South Islands	North South	49.25 49.57
11-Nov-09	09:01	A ripple control fault in Orion’s network caused momentary rise in frequency in the South Island.	South	50.59
25-Nov-09	13:18	An unplanned line reduction at Tiwai caused a momentary rise in frequency in the South Island.	South	50.64
29-Nov-09	09:54	Huntly Unit 5 tripped.	National	N 49.16 S 49.42
30-Nov-09	21:37	Tiwai Line 1 emergency line reduction.	South	50.58
17-Jan-10	10:16	HVDC runback operation causing momentary frequency fluctuations in both North and South Islands.	North South	49.18 50.41 51.94

System Events Date	Time	Summary Details	Island	Freq (Hz)
21-Jan-10	17:13	Maraetai-Waipapa, Maraetai-Whakamaru 1 and 2 circuits tripped causing momentary drop in frequency in the North Islands.	North	49.3
25-Jan-10	14:45	Hamilton-Whakamaru 1 circuit tripped (preceded by the tripping of Ohinewai-Whakamaru 1 circuit earlier at 14:17) causing a momentary drop in frequency in the North Island.	North	49.5
16-Feb-10	00:46	Nga Awa Purua generation tripped causing a momentary drop in frequency in the North Island.	North	49.5
18-Feb-10	11:40	HVDC Pole 2 had an emergency shut down causing momentary fluctuations in frequency in both the North and South Islands.	North South	49.26 50.74
18-Feb-10	12:53	Excessive load restoration following an earlier emergency shutdown of HVDC Pole 2 caused a momentary drop in frequency in the North Island.	North	49.44
22-Feb-10	11:49	Tiwai potline tripped causing a momentary rise in frequency in the South Island.	South	50.64
25-Feb-10	21:42	Nga Awa Purua generation tripped causing a momentary drop in frequency in the North Island.	North	49.47
9-Mar-10	15:45	Huntly unit tripped causing a momentary drop in frequency in the North Island.	North South	49.2 49.47
12-Mar-10	07:31	An HVDC Pole 2 operation caused a momentary drop in frequency in the South Island.	South	49.45
12-Mar-10	19:43	A planned shutdown of Otahuhu station resulted in a momentary drop in frequency in the North Island.	North	49.48
14-Mar-10	10:43	A Manapouri unit tripped caused a momentary drop in frequency in the South Island.	South	49.42
22-Mar-10	15:17	An emergency Tiwai potline reduction resulted in a momentary rise in frequency in the South Island.	South	50.7
3-Apr-10	19:27	An HVDC Pole 2 operation caused momentary fluctuations in frequency in the South Island.	South	49.3 50.7
6-Apr-10	00:36	An HVDC Pole 2 operation caused a momentary rise in frequency in the South Island.	South	50.6
12-Apr-10	13:15	Benmore generation tripped causing a momentary drop in frequency in the South Island.	South	49.25
13-Apr-10	17:34	Huntly unit 5 tripped causing a momentary drop in frequency in both the North and South Islands.	North South	49.17 49.38
11-May-10	14:44	Huntly unit 2 tripped causing a momentary drop in frequency in the North Island.	North	49.43
18-May-10	14:29	An emergency Tiwai potline reduction resulted in a momentary rise in frequency in the South Island.	South	50.69
24-Jun-10	15:41	Tiwai potline trip resulted in a momentary rise in frequency in the South Island.	South	50.52
26-Jun-10	08:41	Huntly unit 5 trip resulted in a momentary drop in frequency in the North Island.	North South	49.08 49.32
26-Jun-10	16:41	Huntly unit 5 trip resulted in a momentary drop in frequency in the North Island.	North South	49.2 49.47
4-Jul-10	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-Jul-10	04:08	Stratford power station tripped resulting in a momentary drop in frequency in the North Island.	North	49.14

Security Issues

System Events Date	Time	Summary Details	Island	Freq (Hz)
14-Jul-10	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-Jul-10	12:44	Tiwai potline tripped resulting in a momentary rise in frequency in the South Island.	South	51.43
3-Aug-10	03:56	Stratford generation ran back resulted in a momentary drop in frequency in the North Island.	North	49.43

3.5 SUMMARY OF CONNECTION POINT EVENTS

Connection Point Events Date	Time	Summary Details	Generation/ Load interrupted (MW)	Restoration time (minutes)
19-Oct-09	20:21	A fault in the Stoke 33 kV network caused trippings of Stoke supply transformers T8, T9 and T10, resulting in loss of load at Stoke.	86	91
30-Oct-09	07:59	A tripping of Henderson-Otahuhu 1 circuit while Otahuhu-Southdown 1 circuit and Hepburn Road - Mount Roskill circuits 1 and 2 were removed from service for planned outages resulted in loss load in North Auckland and Northland regions.	Approx 600	152
21-Nov-09	21:22	Karapiro-Te Awamutu 1 tripped causing loss of supply to Te Awamutu.	25	215
24-Nov-09	08:55	A fault in Timaru 11 kV network caused trippings of all three supply transformers T2, T3 and T4 and loss of supply to Timaru.	28	247
14-Dec-09	02:16	West Wind T1 generating transformer tripped causing a partial loss of connection to West Wind generation.	52	885
21-Jan-10	04:47	Balclutha-Halfway Bush 1 tripped resulting in loss of connection at Berwick.	5	116
21-Jan-10	17:13	Maraetai-Waipapa 1, Maraetai-Whakamaru 1 and 2 circuits tripped causing loss of connection at Waipapa and Maraetai.	WPA 43.7 MTI 151	157 154
1-Feb-10	12:06	Unplanned outages of Dobson T12 interconnecting transformer as well as T1 and T2 supply transformers while Lake Coleridge-Otira 2 and Arthurs Pass-Otira 1 circuits were removed from service for planned outages caused loss of load at Dobson, Greymouth, Kumara, Hokitika and Otira.	Approx 34 MW total	Between 16-51
4-Feb-10	09:33	A fault in the Ohau B 220 kV bus caused loss of connection at Ohau B.	30	70
23-Feb-10	12:51	Kaikohe-Kaitaia 1 tripped resulting in loss of connection at Kaitaia.	15	300
6-Mar-10	11:54	Central Park-Westwind-Wilton 3 circuit and Central Park T3 supply transformer tripped resulting in a loss of connection at Westwind.	56	140
16-Mar-10	08:39	Cromwell-Frankton 2 circuit tripped while Cromwell-Frankton 1 was out of service for a planned outage, resulting in a loss of connection at Frankton.	21	70

Connection Point Events

Date	Time	Summary Details	Generation/ Load interrupted (MW)	Restoration time (minutes)
20-Mar-10	21:36	Benmore T2 interconnecting transformer tripped resulting in a partial loss of connection at Benmore.	80	1304
31-Mar-10	05:53	Whirinaki T1 supply transformer tripped resulting in a partial loss of connection at Whirinaki.	43	37
21-Apr-10	07:59	Balclutha-Berwick-Halfway Bush 1 circuit tripped resulting in a partial loss of connection at Berwick.	32	42
22-Apr-10	15:21	A fault on the Wilton 110 kV bus caused all 110 kV circuits connected to the bus to trip, resulting in partial loss of connections at Central Park, Kaiwharawhara and West Wind.	CPK – 109 KWA – 26 WWD - 93	66 71 239
25-May-10	09:30	Karapiro-Te Awamutu 1 circuit tripped causing loss of connection to Te Awamutu.	21.7	106
11-Jun-10	14:21	Balclutha-Berwick-Halfway Bush 1 circuit tripped causing loss of connection to Berwick.	44	16
11-Jun-10	17:53	Oamaru T1 supply transformer tripped six times during recommissioning. Oamaru T2 supply transformer was out of service, loss of connection at Oamaru resulted.	19.5	Total of 60
16-Jun-10	12:18	Kaitimako-Mount Maunganui 1 circuit tripped while Kaitimako-Mount-Maunganui-Tauranga 1 circuit was out of service, causing loss of connection at Mount Maunganui.	43.9	28
17-Jun-10	13:02	Whakamaru-Poihipi Road-Wairakei 1 circuit tripped causing loss of connection at Poihipi Rd.	40	41
24-Jul-10	13:01	Balclutha-Berwick-Halfway Bush 1 circuit tripped causing loss of connection to Berwick.	36	170
13-Aug-10	07:10	Blenheim-Kikiwa 1 circuit tripped causing loss of connection to Argyle.	10	201
20-Aug-10	08:50	Karapiro-Te Awamutu 1 circuit tripped causing loss of connection to Te Awamutu.	29	42
20-Aug-10	23:15	Hawera T1 and T2 supply transformers tripped causing loss of connection to Hawera.	17	82
30-Aug-10	16:09	ASB T8 tripped.	20	68

4. SECURITY OF SUPPLY

4.1 SHORT TERM SECURITY ISSUES

4.1.1 UPPER SOUTH ISLAND SECURITY

As in previous years the System Operator convened and led an Upper South Island stakeholder group to ensure a co-ordinated response to managing the region within power system capability limits over the 09/10 summer period and the 2010 winter period. No issues were identified and the group maintained a watching brief.

4.1.2 UPPER NORTH ISLAND SECURITY

The System Operator also convened and led an Upper North Island stakeholder group to manage the region within power system capability limits over the 09/10 summer period, as well as an industry group to monitor and plan for supply issues in the Upper North Island over winter 2010. No issues were identified and the groups maintained a watching brief.

4.2 Specific Security Projects

4.2.1 AUFLS

Following the credible event review, the System Operator initiated a review of the current New Zealand AUFLS scheme from a technical, economic and policy perspective. The purpose of the review is to:

1. Inform the industry and stakeholders of the effectiveness of the current AUFLS arrangements
2. Enable a wider discussion to be held to determine the benefits, risk and opportunities for New Zealand with regard to AUFLS and other methods of under-frequency management
3. Inform the AUFLS exemption process
4. List the options available for moving forward.

The first part of the review, the technical review, was completed by the System Operator in the first half of 2010. The results from this review concluded that the System Operator's tools will ensure that there is sufficient reserve generation and demand available to be disconnected to prevent system collapse from large defined risks, such as the sudden disconnection of HVDC bi-pole, at all times. This is likely to require limiting the transfer on the HVDC link to below its maximum capability under certain system conditions to ensure power system security.

However, the technical review also concluded that the overall design of the AUFLS scheme provides the System Operator with insufficient confidence that the current AUFLS scheme will be effective to prevent the system from collapsing from large risks that are not currently identified. The studies have also shown that significant over-voltage issues are likely to occur following AUFLS operation which have the potential to collapse the system.

The System Operator has identified a number of options to address these issues and these were presented and discussed with industry at System Operator workshops in August 2010:

- Improve the performance of the existing AUFLS scheme

  Significant improvements can be made to the existing AUFLS scheme by modifying the number and size of the AUFLS blocks and their activation mechanisms and settings. When reviewing the design of the AUFLS scheme, the total size, speed of the response and the make up of the blocks are key considerations that need to be viewed as a total package to produce the best outcomes.

- Review the products provided in the instantaneous reserves market

  The technical studies revealed that system collapse can occur in less than 4 seconds following a very large event. This highlights the need for investigation of new products and markets, such as a 3 second instantaneous reserves market, to ensure that there are sufficient fast-acting measures (reserves) available on the system to ensure power system security.

- Move toward a coordinated over-voltage protection scheme

  The System Operator will address the over-voltage issues in the North Island as a matter of priority. The potential options and appropriate course of actions to address this issue will be discussed and coordinated with the Grid Owner and the industry.

The System Operator recognises that the options will need to be subjected to further economic assessment as it is important to achieve the right balance between the instantaneous reserves market (a $33.8 million[1] market) and the mandated AUFLS scheme. The System Operator will lead the next stage of the review, being the consideration of economic and policy aspects of AUFLS arrangements, during 2010/2011.

4.2.2 Credible Event Review

During 2009, the System Operator reviewed the credible event policy as described in the System Operator's Policy Statement. This review focussed on the identification, classification, and management of credible events.

An assessment of historical data, and the international planning and operational standards, resulted in a set of credible events, and determined additional investigation was required to assess how the System Operator should manage the loss of a busbar section or interconnecting transformer. The analysis used steady state studies to determine potential consequences of such losses and identify measures that could minimise those consequences and associated costs.

The studies found the loss of an interconnecting transformer or busbar section, with the subsequent overload and tripping of additional assets, would result in unplanned load shedding in a significant number of cases. The introduction of planned load shedding, where reasonable and possible, would allow post event parallel transformer overloads to be managed and thus avoid unplanned load shedding associated with subsequent asset trippings. Re-classification of the event as an Extended Contingent Event, along with other key wording changes in the policy, would oblige the System Operator to plan for these events and employ planned post event load shedding, as appropriate, to manage the risk of unplanned load shedding. Analysis shows that there are cost benefits associated with managing the loss of a 220 kV, 110 kV and 66 kV busbar sections (connected to the core grid), and 220 kV interconnecting transformers, as Extended Contingent Events.

The credible event review concluded the following:

- specifically include planned post event load shedding as a key mitigation measure for Extended Contingent Events;
- classify the loss of a 220 kV interconnecting transformer and the loss of a 220 kV or 110 kV or 66 kV (connected to a core grid asset) busbar section as an Extended Contingent Event;
- classify the loss of Reactive Support/SVC fault as a Contingent Event;
- classify the following as 'other events' (being events for which there are no planned mitigation measures)
  - the loss of multiple power system components in close succession is classified as an Other Event;
  - the loss of a 110 kV interconnecting transformer;
  - the loss of a 66 kV busbar section not connected to core grid assets
- classify the loss of two transmission circuits on the same tower as a Contingent Event (in line with international practice) when a change to environmental or operating conditions indicates there is a high likelihood of occurrence.

Importantly, the review concluded that the portfolio of management measures available to the System Operator is in line with international practice. However, for single feeder circuits, line spurs and/or single transformers, there is an inherent lack of security. This review was unable to recommend changes that would improve the security of supply. The System Operator assumes that distribution companies and direct connect customers are aware of potential security risks and will discuss investment options to improve security with the Grid Owner.

[1] $33.8 million was spent on instantaneous reserves from July 2009 to June 2010.

The next credible event management review is scheduled for delivery on or before December 2014.

4.2.3 Generator Fault Ride Through

The island nature of the New Zealand power system means that it frequently experiences voltage and frequency disturbances, and therefore it is critical that generation remains connected to the system to avoid cascade failure. To manage these conditions, the system may require a specific fault ride through criteria that may differ to those specified in large well-interconnected continental power systems.

The Electricity Commission initiated an investigation by the System Operator to determine a suitable Fault Ride Through as part of the EGRs.

The investigation established that an island based FRT envelope is required to account for the differences in North and South Island system performance. The envelopes recommended are a combination of the existing Transpower requirements and actual system performance, where the Transpower requirements cannot be met with the present system. A margin was applied to allow for actual system conditions. The investigation also concluded that the FRT envelope should be reviewed once additional reactive plant has been committed, as it is expected that a common FRT envelope for both islands can be implemented once this has been achieved.

The report and recommendations are with the Electricity Commission.

5. Commissioning

5.1 Commissioning Projects

The System Operator assessed approximately 300 commissioning plans in the 2009_10 year. These commissioning projects included:

- 2 new connection points (Nga Awa Purua and Bells Pond)
- 1 new switching station (Drury)
- 3 station reconfigurations (Otahuhu GIS, Marsden, and Mount Maunganui)
- 2 new generating stations (Nga Awa Purua and Tauhara)
- 9 Transformers commissioned (3 inter-connectors, 5 supply, 1 SVC)
- 2 FACTS (Flexible AC Transmission System) Devices (ISL SVC 9, KIK STC2A/B)
- 2 Capacitor Bank Installations (Otahuhu and Hokitika)
- 77 Protection system upgrades
- More than 150 Switchgear, Measuring Transformer Upgrades, and new installations (CB's / CT's / DS / VT's)
- 27 Communications systems and RTU Upgrades / modifications

5.2 Supporting the Development of Transpower's Pole 3 project

Since the contract for the Pole 3 project was awarded to Siemens in November 2009, the System Operator has been actively supporting project delivery in a number of areas; including:

- Providing advice on project timing and delivery to minimise the industry impact of outages and commissioning activities
- Supporting engagement with the EC and wider industry on commissioning requirements through the Commissioning Industry Advisory Group
- Working with the project on design of P3 controls and protection to support current and future market operation
- Developing change requirements for updating the operational tools during the detailed design phase

- Reviewing and contributing to detailed commissioning test requirements.

6. RULE CHANGES

6.1 PROPOSED BY SYSTEM OPERATOR

The System Operator made the following recommendations for changes to the Electricity Governance Rules and Regulations ("the Rules") during the review period:

6.1.1 UNDER FREQUENCY EVENT CHARGES

The System Operator requested that the Electricity Commission initiate a review of the Rules relating to under frequency event charges given its concern regarding the lack of rule clarity about when an event charge should apply and to whom it should apply. These changes occurred during the year in review and apply from August 2010.

6.1.2 POLICY STATEMENT

The System Operator submitted a draft policy statement to the Electricity Commission on 31 March 2010 in accordance with its obligations under the Rules. This came into effect on 1 September 2010. The key changes to the policy statement related to those recommended as part of the System Operator's credible event review in 2009.

6.1.3 PROCUREMENT PLAN

The System Operator submitted a draft procurement plan to the Electricity Commission on 7 May 2010, in accordance with its obligations under the Rules, which proposed minor amendments. This is expected to come into effect on 1 December 2010.

6.2 CONTRIBUTIONS BY THE SYSTEM OPERATOR

The System Operator assisted the Electricity Commission with a number of actual or proposed industry initiatives. These included the following:

6.2.1 TECHNICAL ADVISORY SERVICES CONTRACT (TASC)

The System Operator and the Electricity Commission entered into the TASC in September 2009. The TASC is a consultancy arrangement for the provision of advice that relates directly to the System Operator's role and expertise. During the year 1 September to 31 August, the System Operator provided advice to the Electricity Commission on the following[2]:

6.2.1.1 *Automatic Generation Control (AGC)*

This project related to the Multiple Frequency Keepers work-stream which has the objective of developing a system to coordinate multiple frequency keepers in a national market rather than an island based market. This project was an initial investigation to scope the technical requirements for the implementation of a basic AGC system to coordinate a frequency keeper in each island with the HVDC link.

6.2.1.2 *Extended Control – development of post event compliance*

This project related to the Event Management work-stream – Extended Load Control, which has the objective of extending the use of low cost interruptible load (IL) using frequency sensitive relays. This particular project related to assessing and

[2] Some of these projects were started in the reporting period and continue into the next.

introducing a different post compliance assessment methodology to encourage more competition into the IL market.

6.2.1.3 *Review of Gate Closure*

This TASC project was to investigate, from a System Operator perspective, any security and operational implications of reducing Gate closure from its present two hours. This study focused on the individual and cumulative effects of a reduction in Gate closure for Energy Offers, Energy Bids, Reserve Offers, Grid Availability, and Frequency Keeping Offers, as well as the potential implications of implementing any changes to Gate closure in conjunction with several significant projects currently underway.

6.2.1.4 *Normal Frequency Review*

This TASC project is to review the normal frequency band; analyse and review the probability standard; and review the frequency keeping MW band. The project brief will be finalised during September 2010. Work is ongoing.

6.2.1.5 *AGC – Investigation of a project scope*

This objective of this TASC project is to investigate an alternative approach to AGC (based on block dispatch and alternative offer arrangements) and comment on its technical feasibility. Work is ongoing.

6.2.2 Managing Locational Price Risk

The System Operator has contributed to the development of tools to mitigate locational price risk (LPR) through active participation in the Electricity Commission's LPR technical group and through the provision of detailed papers on application of financial transmission rights (FTRs) in the New Zealand context. The System Operator has taken a constructive approach to the resolution of LPR by investigating and proposing alternative strategies to managing this risk while retaining the integrity of the locational price signals. Relatively simple FTRs that can evolve with experience remain the System Operator's preference for achieving this.

6.2.3 Scarcity Pricing

The System Operator, as a member of the Electricity Commission's Scarcity Price Technical Group, has been contributing to the Commission's and industry's discussions on scarcity pricing.

6.2.4 Load Forecasting

The System Operator has embarked on a process to determine whether its existing load forecasting tools are adequate to meet future requirements. Such requirements may include demand side bidding and forecasting, demand and side participation through Grid Security Contracts, and other market development initiatives.

6.2.5 Multiple Frequency Keepers

The System Operator took an active role in this initiative to open up the frequency keeping market, with a view to reducing costs and potentially improving performance. The System Operator consulted with the key industry participants and produced a report detailing the work that would be required to implement an AGC-based system capable of coordinating frequency control in both islands (refer to paragraph 6.2.1.1). The System Operator is presently engaged with the project's Technical Stakeholder Group and responding to questions regarding details of the design as part of ongoing TASC work.

6.2.6 Demand Side Bidding and Forecasting Project

The System Operator is undertaking the investigation stage of this project to meet the requirements set out in the Electricity Commission's draft proposal. A business case, which will include a project timeline and costing, will be delivered to the Electricity Commission in the second week of December.

6.2.7 INTERIM PRICING PERIOD

As part of the Pricing Improvement Project, a consultation on an Interim Pricing Period was published in September/October 2009. The concept was received well by industry participants and, as a result, the System Operator will be rolling out the functionality in the market system release prior to 1 October 2010.

6.2.8 SFT IMPLEMENTATION

The System Operator initiated a project in September 2009 to enable the Simultaneous Feasibility Test (SFT) automated constraint generation. The enabling of this software will require a period of testing and consultation with the industry. The introduction of SFT is expected to produce up to a 2% gain in Grid efficiency.

The Market Systems Project developed SFT and enabled SFT Check in the Market Systems. The SFT Constraint Builder module of the SFT Software creates security constraints automatically and was not enabled as part of the original project. The use of the automatic constraint creation module in the existing market to create constraints requires operator interface modification and tailoring to the existing market environment to enable participants and the System Operator to fully realise its benefits.

The project to enable SFT has incorporated a number of necessary modifications to the software, and functional, integration, user and regression testing to the combined code prior to releasing the software to production. It is also involving a significant period of parallel running to enable industry testing and to allow participants to ensure their own tools and processes can accommodate the outputs from the software. The expected go-live date for the SFT software implementation is 28 March 2010.

6.2.9 WINTER INITIATIVES

Following its expression of concern about the market incentives for adequate generation offers for thermal plant to meet peak demand, the System Operator worked with the Commission and industry to develop and implement a package of measures to incentivise the availability of thermal generation. The package included:

- reviewing the offer for Whirinaki;
- reintroducing variable reserves;
- improving the information provided by the SO to market participants;
- urgent rule changes to improve instantaneous reserve dispatch and pricing; and
- changing the rules and market model to facilitate partial dispatch of instantaneous reserves during grid emergencies.

6.2.10 MINISTERIAL REVIEW

The System Operator worked with the Electricity Commission to prepare for the handover of the security of supply forecasting and emergency management functions, including advice on drafts of the Code, Security of Supply Forecasting and Information Policy, Emergency Management Plan, and System Operator Rolling Outage Plan.

6.2.11 HVDC POLE 3 PREPARATION

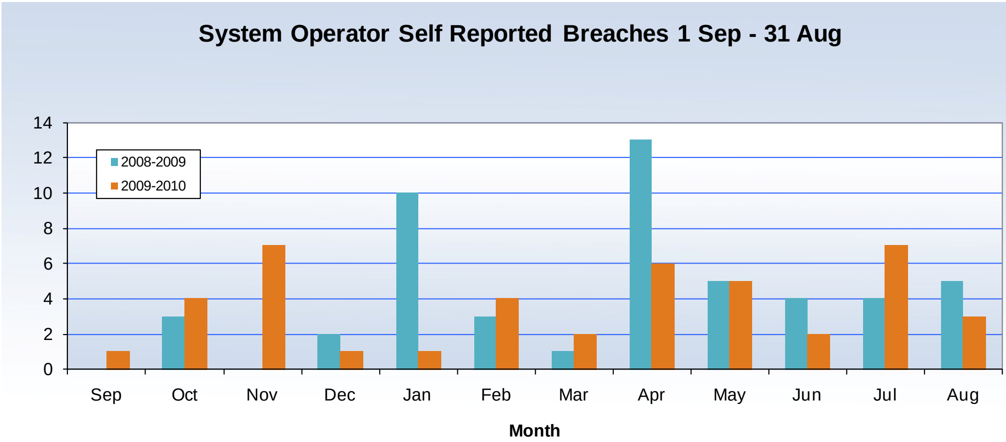
The System Operator is involved in the definition of the tools impacted by the commissioning of HVDC. Detailed design of the various SCADA/EMS components is currently in progress.

7. Compliance Matters

7.1 System Operator Self-Notified Breaches

The following graph and table represent breaches of the Rules by the System Operator which it self-notified to the Electricity Commission during the period. The data is based on the reporting date of the breaches rather than the date on which the breaches occurred. The period concerned is 01 September – 31 August.

7.1.1 By number of breaches



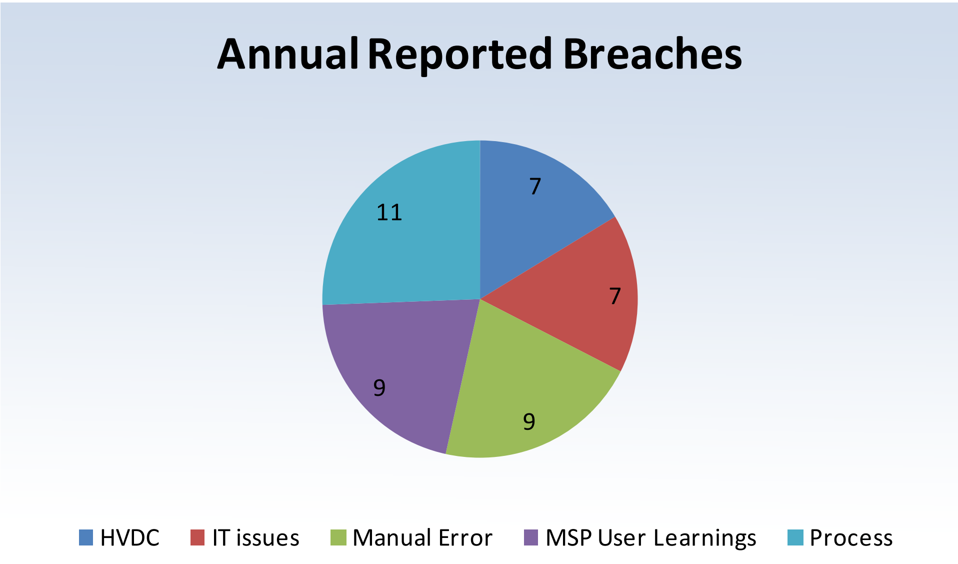
7.1.2 By rule

Comparisons are made between the previous and current years.

Rule	2008-2009	2009-2010
Part C Schedule C4 13.1	1	
Part C Schedule C4 20	3	
Part C Schedule C4 22.3	1	
Part C Schedule C4 22.5	2	2
Part C Schedule C4 32.2		1
Part C Schedule C4 61	1	
Part C Schedule C4 89.4		1
Part C Schedule C4 90.1	1	
Part C Schedule C4.11.9		1
Part C Schedule C5 Appendix A, Clause 116	1	
Part C Section II 2.2.5		1
Part C Section IV 11.7.2	1	
Part C Section IV 11.9		2
Part G Schedule G6 1.3.1.3	8	1
Part G Schedule G6 1.3.2.1		1
Part G Schedule G6 1.3.2.4	1	4
Part G Schedule G6 1.3.3.3		2
Part G Schedule G6 1.3.4.3		1
Part G Schedule G6 1.3.4.6	3	
Part G Schedule G6 1.3.4.7	13	14
Part G Section III 1.3.4.1		1

Rule	2008-2009	2009-2010
Part G Section III 10.2	2	1
Part G Section III 10.3 and 10.4.8		1
Part G Section III 10.4		2
Part G Section III 3.5.13	1	
Part G Section III 3.7.2	1	1
Part G Section III 3.7.4	2	
Part G Section III 3.8	1	2
Part G Section III 4.1	1	
Part G Section III 4.3	3	
Part G Section III 4.4.1	1	1
Part G Section III 4.5		2
Part G Section III 4.9.1 and 4.9.2		1
Part G Section III 9	1	
Regulations – 63	1	
Total	50	43

7.1.3 BY ERROR SOURCE



7.2 OBSERVATIONS ON COMPLIANCE STATISTICS

The System Operator anticipated that there would be an increase in the number of breaches following the implementation of the new market system as teething problems with the IT tool were identified and resolved and users became familiar with the tool functionality. We are therefore encouraged that there was in fact a small decrease in the number of self-notified System Operator breaches in the 2009/10 year compared with the previous year (43 in 2009/2010 compared to 50 in 2008/2009).

As set out in the graphs above, the System Operator has monitored its breach statistics throughout the year in relation to the rules breached but also in relation to the source of the error.

Specific observations based on this monitoring are as follows:

- 11 breaches related to HVDC modelling errors. These were primarily related to Pole 1 tool issues. A number of tool changes have been made which will reduce the likelihood of these reoccurring.
- 9 breaches have been categorised as "MSP User Learnings" being errors that arose as users became familiar with the new market system. We fully expect this category to be significantly reduced, if not completely eliminated, during the 2010/2011 year.
- The amount of breaches relating to updating grid information (rules 1.3.1.3, 1.3.2.4, and 1.3.4.7 of Schedule G6) has decreased to 14 from last year's total of 22. The expectation was that the new market system would reduce the amount of manual requirements in real time associated with grid changes and therefore these types of breaches should decrease. This has proved to be correct. Whilst there still remain a number of errors in updating grid information, the cause of these errors is not manual.

7.2.1 PRINCIPLE PERFORMANCE OBLIGATIONS (PPOs)

There was one breach of the PPOs notified by the System Operator during the period concerned being a breach of the obligation to act as a reasonable prudent operator with the objective of ensuring frequency time error is not greater than 5 seconds. This event occurred on 17 April 2010, when the time error was exceeded by over 5 seconds between 00:31 and 00:51. The System Operator has recently been advised that an investigator has been appointed in relation to this breach.

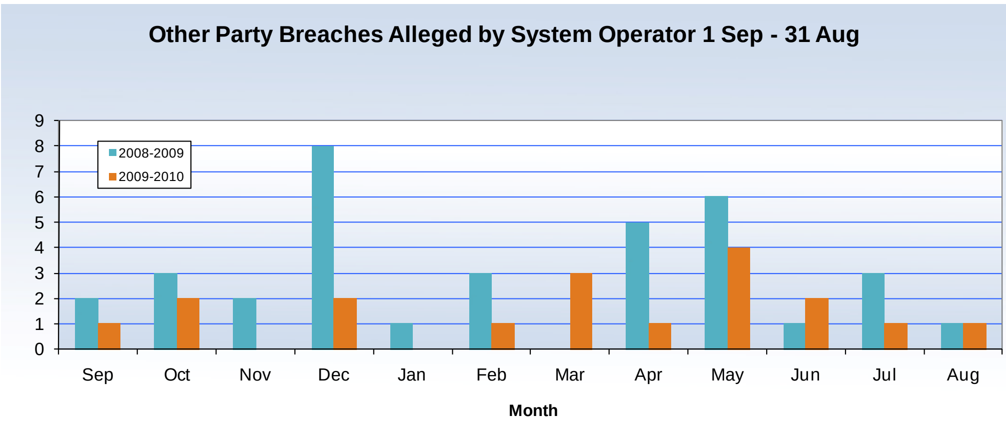
7.3 ALLEGED SYSTEM OPERATOR BREACHES REPORTED BY OTHER PARTIES (INCLUDING THE ELECTRICITY COMMISSION)

There were no System Operator breaches notified by other participants during the period.

7.4 BREACHES ALLEGED BY SYSTEM OPERATOR AGAINST OTHER PARTICIPANTS

The following graphs represent Rule breaches by third parties as notified by the System Operator, 18 for 2009/10, compared with 35 for 2008/09. The graph represents the breaches by number reported and the table shows a comparison in the type of rule breaches between the previous and current years

Comparisons are made between the current (1 September 2009 to 31 August 2010) and previous (1 September 2008 to 31 August 2009) years.



Rule	2008-2009	2009-2010
Part C Schedule C3 Technical Code A 2.5.5		1
Part C Schedule C3 Technical Code A 2.7		1
Part C Schedule C3 Technical Code A 4.4.1	3	
Part C Schedule C3 Technical Code A Appendix A, Rule 3	1	
Part C Schedule C3 Technical Code C 5.2	6	1
Part C Schedule C3 Technical Code C 8.2	4	1
Part C Schedule C3 Technical Code C 8.3	1	
Part C Section III 2.3		1
Part G Section II 3.4		2
Part G Section II 3.6.2		1
Part G Section II 6.11	1	
Part G Section III 4.11	15	10
Part G Section III 4.9.3	4	
Total	35	18

The data shows a significant decrease in identified generators non-compliances, which may in part, be due to difficulties in identifying such breaches in the new market system during real time. The System Operator is currently working on other means to identify these non-compliances post real time.

7.5 Settlements

7.5.1 Settlement of System Operator breach allegations

There were no investigations taken against the System Operator in the period in question. Accordingly, no settlements were required.

7.5.2 Settlement of other participant breach allegations

The System Operator participated in five settlements during the year.

7.6 Assurance

The System Operator's assurance programme has been on hold since 2007 due to the workload from the new market systems project implementation. The System Operator has been working on strengthening its event investigation process over the last three years. This process, together with the rest of its compliance and quality measures, means it is unlikely the System Operator will resume this aspect of its compliance programme in the near future.

7.7 Rulings Panel

There were no System Operator breaches referred by the Electricity Commission to the Rulings Panel during the reporting period.

7.8 Near Misses

There were no near misses reported during this period.

8. Specific Compliance Requirements under the Rules

8.1 Monthly Reports

The System Operator has complied with its obligations under regulations 44 and 45 to undertake a monthly self review and report the results of each such review. All reports have been published by both the System Operator and the Electricity Commission.

8.2 System Security Forecast

The Rules require the System Operator to publish a System Security Forecast (SSF) every two years and review the need to revise the latest SSF every six months. In December 2008 the System Operator published a new SSF and this is available on the System Operator website[3]. A new SSF is due to be published in December 2010.

8.3 Procurement Plan – Ancillary Services

Due to the pending introduction of the Electricity Industry Act, the Commission requested that the System Operator bring forward the timeframes for reviewing the draft plan this year. The System Operator submitted the 2010/11 draft Procurement Plan on 7 May 2010. In developing the 2009/10 plan, the System Operator met with selected participants and, separately, invited comment from all industry participants. The key changes proposed for the 2010/11 plan were:

- changes to provide the System Operator with more flexibility in procuring ancillary services;
- recording the System Operator's intention to explore options regarding changes to data monitoring resolution requirements;
- providing for flexibility in the testing requirements for over frequency reserve.

Procurement Plan 2009/2010

The 2009/10 Procurement Plan came into effect on 1 December 2009. Tendering for ancillary services commenced on 9 October 2009 and was completed prior to the plan operative date. The major changes[4] introduced in the plan were:

- Special testing requirements for interruptible load providers - this change introduced a new testing regime for IL providers whereby they are required to carry out an annual "end-to-end" test of their equipment, unless they have shown operational performance during the previous 12 months (by successfully responding to an under-frequency event).
- Frequency keeping standard deviation obligations - this change clarified that failure to comply with the standard deviation obligations for frequency keeping would be a material breach of the ancillary service procurement contracts, allowing for termination.

[3] SSF – December 2008 - http://www.systemoperator.co.nz/publications

[4] This commentary is not a comprehensive list of changes introduced. Full details of the changes introduced in the 2008/2009 Procurement Plan have been published on the Electricity Commission website (http://www.electricitycommission.govt.nz/opdev/comqual/procurement/index.htmll) in comprehensive schedules.

8.3.1 CONTRACTED ANCILLARY SERVICES

The following table summarises the contracted services as at 31 August 2010:

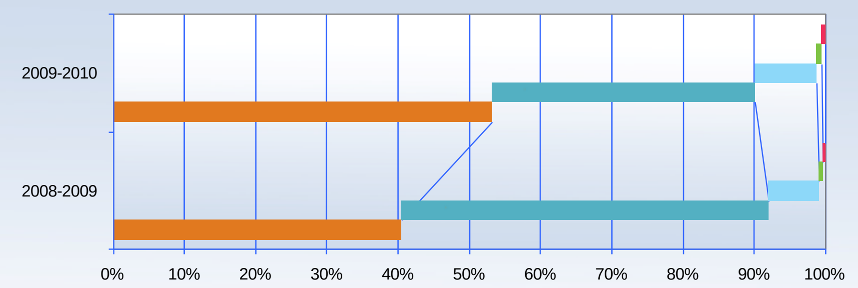
Ancillary Service Agent	(1)FK	(2)IR	(3)OFR	(4)BS	(5)VS
Meridian Energy	√*	√	√	√	
Contact Energy	√	√	√*	√	√
Mighty River Power	√	√		√*	√*
Genesis Power	√	√		√	
TrustPower		√			
Vector		√*			
Wellington Electricity Networks		√			
Northpower		√			
Powerco		√			
Unison		√			
WELNetworks		√			
CountiesPower		√			
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 (over two years)

8.3.2 ANCILLARY SERVICE PROCUREMENT COSTS

8.3.2.1 *Procurement 1 September 2009 – 31 August 2010*

The total ancillary service costs for the period were.



	2008-2009	2009-2010
Frequency Keeping Costs	$47,000,381	$48,204,732
Instantaneous Reserve	$60,049,629	$33,480,685
Voltage Support (incl Events)	$8,213,289	$7,956,499
Over Frequency Reserve	$635,495	$672,855
Black Start	$395,420	$475,629

8.4 POLICY STATEMENT

The System Operator provided a draft Policy Statement for 2010/11, which came into force on 1 September 2010. The changes included:

- Changes to the credible event policy to reflect the conclusions of the credible event review which was undertaken by the System Operator during 2009. This review focussed on the identification, classification and management of credible events. The key changes to the policy statement arising from this review is to treat the loss of 220 kV interconnecting transformers, 220 kV or 110 kV busbars, or 66 kV busbars which are directly connected to the core grid as extended contingent events.
- Minor changes to the notice requirements for temporary security constraints, removal of requirement to publish the input data for the standby residual check notices.
- Minor wording changes.

8.4.1 Departures from Policy Statement

There were no departures from the Policy Statement during the review period.

8.5 Software Auditing

The System Operator arranged the following audits of software to meet the requirements of regulation 51 (1). All necessary audit certificates were provided to the Board.

8.5.1 Annual RMT and SPD Certification

The System Operator procured an audit of the Scheduling, Pricing and Dispatch (SPD) Software and the Reserve Management Tool (RMT) by PA Consulting on 08 March 2010.

This audit opinion (noting that it was satisfactory) was the annual certification of RMT/SPD for the period of the review, as required in the System Operator Service Provider Agreement (“SOSPA”) and in regulation 51 (1).

8.5.2 RMT

The System Operator sought an opinion (noting it was satisfactory) from the auditor (PA Consulting) in respect of RMT

- on 2 October 2009, regarding:
  - replacement of the governors at the Whaeo power station
  - changes to the values of generation unit inertia
  - performance of RMT following a low frequency event in the South island on 1 August
  - increase in the level of North Island demand which is not available for automatic under-frequency load shedding.
- on 22 October 2009, regarding:
  - parameter value changes to Aviemore and Benmore (no opinion required).
- on 22 December 2009, regarding:
  - inclusion of the Nga Awa Purau geothermal power station
  - inclusion of new gas turbine units at Stratford
  - values of generation unit inertia at the Mokai geothermal power station
  - value of the South Island risk
  - values for generation governor model parameters resulting from generation unit performance testing.
- on 26 January 2010, regarding:
  - inclusion of the Tauhara geothermal power station.
- on 13 May 2010, regarding:

- parameter changes to allow commissioning unit to be flagged as CE or ECE secondary risk (no opinion required).

8.5.3 SPD

The System Operator sought the following opinion (noting it was satisfactory) from the auditor (PA Consulting) in respect of SPD:

- **SPD TP38_1_2**. Opinion provided by PA Consulting on 8 December 2009. The changes related to SPD post processing which is not specified within the Formulation and is not used for the purposes specified in the Service Provider Agreement. The post-processing is for Transpower's internal use only.
- **SPD TP38_1_7**. Opinion provided by PA Consulting on 22 June 2010. The change is to introduce additions to the factors which can set the "island risks" to be covered by reserves and to increase the penalty prices associated with the constraint violation variables. The change to the software is also reflected in a change to the software specification.

9. Specific Compliance Requirements under SOSPA

9.1 Disaster Recovery Plan

The System Operator is currently in the process of updating its Disaster Recovery Plan (last provided and approved by the Electricity Commission in 2005). This new Disaster Recovery Plan will include IT changes required following the introduction of the new Market System.

The Business Continuity Plan for the System Operator was reviewed in conjunction with the IT Business Continuity Plan. This has been updated to include new information relating to the Market System and to ensure the accuracy of all personnel and industry contact details. The Control Room and non-operational response kits were also checked and updated.

As part of the review, the availability and functionality of the Business Continuity 'fall back' venue was checked. The current venue is the Pole 2 Building at the Haywards Substation, and as work continues on the new HVDC Pole 3, this will eventually be unavailable. A new venue has been identified and transitioning between venues is currently progressing.

The System Operator participated in the IT Business Continuity simulation exercise in May 2010. A System Operator Business Continuity simulation is planned for December 2010.

9.2 Warranties

At the date the SOSPA was entered into, the System Operator provided the Electricity Commission with certain warranties. As at 31 August 2010 the System Operator:

- is not aware of anything within its reasonable control which might or would adversely affect its ability to provide the contracted services under the SOSPA
- does have sufficient skills and supervision to carry out the said services.

10. Specific Compliance Activities

10.1 Dispensation and Equivalence Applications

Month	Applications Received	Granted in Draft	Granted	Withdrawn	Not Granted	Revoked
Sep 2009	4	0	0	0	0	0
Oct	4	0	6	0	0	0
Nov	2	0	0	0	0	0
Dec	1	0	6	2	0	0
Jan 2010	0	1	0	0	0	0
Feb	0	0	1	0	0	0
Mar	0	0	0	4	0	0
Apr	0	0	0	0	0	0
May	0	2	0	0	0	0
Jun	0	2	0	0	0	0
Jul	0	0	2	1	0	0
Aug 2010	0	0	0	0	0	0
TOTALS	11	5	15	7	0	0

10.2 Exemption Applications

The System Operator sought the following exemptions during the reporting period:

- Clause 59.1 of schedule C4 to limit the publication of Standby Residual Notices in accordance with the Winter Initiatives rules that came into effect in May 2010. The exemption was granted from 4 May until 31 August when the new Policy Statement came into effect.
- Rule 33.3 of section V and Schedule G2 in Part G for not using the additional model parameters required by the Winter Initiatives rule change. The exemption granted applied from May 2010 to 31 August 2010, when the Rule changes were implemented by the System Operator.
- Rule 6.1.2 of Part J from the new rule requirement to provide the Reconciliation Manager with additional information about load shifting between points of connection. The System Operator is awaiting notification that this exemption is to be granted.

11. Ancillary Service Provider Performance

11.1 Instantaneous Reserves

The table below summarises the Instantaneous Reserve (including IL) performance assessments carried out by the System Operator for the period 1 September 2009 to 31 August 2010.

Under Frequency Event Summary - Instantaneous Reserve Event Assessments							
Date	Time	Event Causer/ Site initiated at	Lowest Frequency (Hz)		MW Lost	Number of Dispatched IR Ancillary Service Agents (ASA)	Performers (and Non-Performers)
			North Island	South Island			
22/09/09	11:36	Grid Owner (HVDC)	49.21	49.65	88	4	
23/09/09	09:08	Genesis (HLY U2&3)	49.23	49.58	384	4	
29/11/09	09:54	Genesis (HLY U5)	49.16	49.43	322	15	Vector breached
17/01/10	10:16	Grid Owner (HVDC)	49.18	49.92	257	15	Vector breached
09/03/10	15:45	Genesis (HLY U5)	49.20	49.47	243.2	12	
13/04/10	17:33	Grid Owner (HLY U5)	49.17	49.38	356	17	PowerCo & Vector breached
26/06/10	08:41	Genesis (HLY U5)	49.08	49.32	299.3	15	
26/06/10	16:41	Genesis (HLY U5)	49.20	49.47	230.2	14	
04/07/10	13:11	Grid Owner (HVDC)	49.06	52.46	325.8	16	
12/07/10	04:08	Contact (SPL)	49.14	49.53	139.6	10	Counties Power breached
14/07/10	06:17	Genesis (HLY U5)	49.16	49.33	259.9	16	

11.2 Frequency Keeping Reserves

The System Operator assesses the performance of frequency keeping ancillary services on a monthly basis on an outcome-based performance criteria. Performance issues are identified and addressed directly with the ancillary service agent. In the period of this review no major issues relating to performance were taken up with frequency keeping service providers.

11.3 Black Start

Mighty River Power and the System Operator successfully performed a black start test at Maraetai on 6 March 2010. Black start tests are required to demonstrate the capability of a generator to start up from a position of not being connected and not taking supply from the grid, and involve:

- starting one unit without supply from the grid
- synchronising a second unit at the same station
- energising a section of the transmission grid system.

11.4 Voltage Support

During the period 1 September 2009 to 31 August 2010 the System Operator dispatched contracted zone 1 voltage support on 29 occasions.

12. INDUSTRY CONSULTATION PAPERS

12.1 CONTRIBUTIONS AND SUBMISSIONS

The System Operator actively contributed to a number of Electricity Commission consultation activities. These contributions were made to industry discussion papers or rule change proposals. The contributions were in respect of the following matters and were generally made in conjunction with the Grid Owner, as Transpower New Zealand Ltd responses or papers:

- Property Rights for Load Management
- Payment in Same Day Cleared Funds
- Interim Pricing Period
- Proposed amendments to parts E and J of the Rules (and consequential amendments to parts A and H of the Rules)
- Consultation on Part D: Issues and proposed options
- AUFLS Exemptions – Issues and Options
- Consultation on dispatchable demand – options
- Consultation on draft guidelines for reporting breaches of the Electricity Governance Rules
- Minor Editorial Rule Changes
- Proposed appropriations and work priorities for the 2010/11 Financial Year
- Reducing the delay for publishing bids and offers
- Discussion paper: Security, Web Services, and EIEP Data Exchange
- Further consultation: proposed amendments to parts E and J of the Rules and consequential amendments to parts A and H of the Rules
- Wind forecasting and market integration: options
- Amendments to the advanced metering infrastructure guidelines
- Settlement of Islanded Embedded Generation
- Under-frequency Event Causer Determination
- Review of urgent rule amendments relating to instantaneous reserve dispatch improvements
- Review of the UTS Provisions
- Dispatchable Demand Regime
- Frequency Keeping Cost Allocation
- Normal Frequency - Generator Asset Owner Performance Obligations
- Draft 2010 Statement of Opportunities
- Managing Locational Price Risk: Options

13. People and Resources

13.1 People

The System Operator FTE's during the reporting period were:

	31/08/2009	31/08/2010	Change
General Manager	2.0	2.0	0.0
Risk & Performance	4.2	5.8	+1.6
Development	7.0	7.0	0.0
System Operations	37.4	40.4	+3.0
Investigations	14.0	18.0	+4.0
Operations Planning	17.4	18.4	+1.0
Market Services	12.0	9.4	-2.6
Total	94.0	101.0	+7.0

13.2 Customer Service

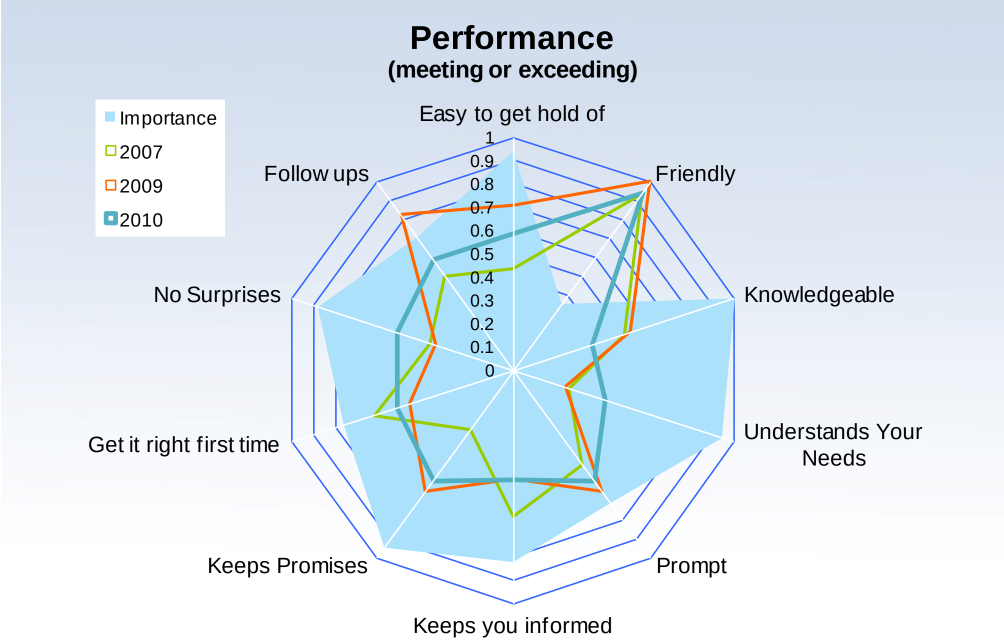
13.2.1 Customer satisfaction survey

The System Operator undertook a further customer survey in August 2010. The survey (carried out by an independent professional) sought to provide an updated perspective on how participants saw the System Operator with regard to ten internationally recognised service factors. A similar survey approach was used in 2003, 2004, 2006, 2007 and 2009.

The service factors asked about were:

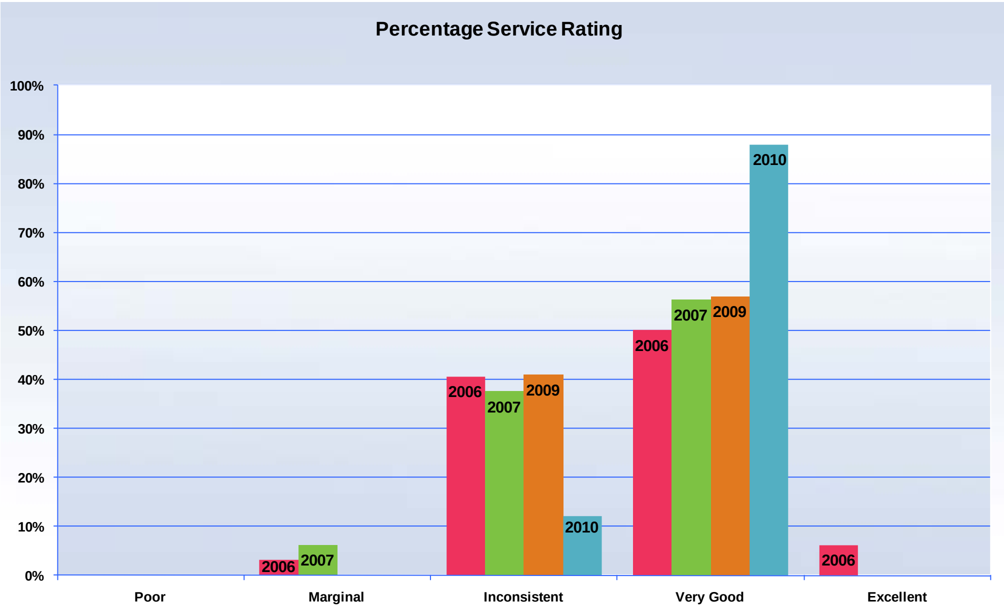
- is the System Operator **easy** to get hold of?
- are staff **friendly**?
- are staff **knowledgeable**?
- do staff **understand** your needs?
- are staff are **prompt**?
- do staff keep you **informed**?
- do staff keep their **promises**?
- do staff get things **right** first time?
- are there no **surprises**?
- do staff **follow** up?

Each survey participant was first asked how important each service factor was to them and then how the System Operator was performing. The summarised results (comparing 2007, 2009 and 2010) are set out below. The importance of each service factor is based on those respondents who rated the factor of 'high importance'.



13.2.1.1 *Overall performance*

The following graph shows the consolidated ranking of the System Operator's performance.



The System Operator views the results as disclosing areas where participants believed better service efforts were required or desirable. As part of the survey the System Operator provides an opportunity for customers to suggest areas where service delivery can be improved. The System Operator actively continued to devote effort towards improving its level of service.

A further survey is expected to be commissioned in 2011.

13.3 SYSTEMS DEVELOPMENT

13.3.1 MARKET SYSTEMS CHANGE RELEASES

The System Operator's new market systems went live last year on Tuesday 21 July 2009. Since then there have been a number of managed change releases.

Release number	Implemented	Release content
16	29/10/2009	Changes to the MOI (Market Operating Interface)
17	17/12/2010	Changes to Frequency Keeper selection and introduction of shoulder ratings
18	02/03/2010	Re-introduction of Variable Reserves functionality and Special Winter Schedule
19	24/06/2010	Introduction of Winter Initiatives and some SFT functionality

The next planned releases are:

Release number	Implemented	Release content
19.1	October 2010	Introduces the Interim Pricing Period functionality
20	December 2010	SFT go-live code

14. INFORMATION TO PARTICIPANTS

14.1 WORKSHOPS AND NEWSLETTERS

Four System Operator newsletters were issued during the review period, the focus of these have now moved back to our core business activities. We have also moved back to publishing a newsletter every two months to ensure participants are kept informed on what is happening in the System Operator.

There were two industry workshops held during the review period. Both were held in Auckland, Christchurch and Wellington and related to:

1. A review of the under-frequency event of 1 August and the issues / lessons arising from it.
2. The findings of the Auto Under Frequency Load Shedding technical review carried out by the System Operator.

14.2 SYSTEM OPERATOR WEBSITE

The System Operator maintains a website through which it distributes information to registered participants (password protected areas may apply) and the public at large. The System Operator increasingly provides information through the website, including, for example, copies of relevant parts of its operational procedures, newsletters, operational reports, industry data, and required reporting. The site is now a primary means of distributing information.

14.2.1 USAGE

Traffic Analysis	1 Sep 2008 to 31 Aug 2009	1 Sep 2009 to 31 Aug 2010
Total visits:	53,319	25,029
Total pages viewed:	8,100,905	124,485
Total hits:	11,102,585	Not available
Average visits per day:	162	69

Traffic Analysis	1 Sep 2008 to 31 Aug 2009	1 Sep 2009 to 31 Aug 2010
Average visits per week:	1,135	250
Average visits per month:	4,912	2078
Average pages viewed per visit:	165	5
Average pages viewed per day:	26,678	169

Note: We have changed our analytical tool so the numbers in the last year are not comparable to the previous year.

The most requested page continues to be the Upper and Top SI Security which received 25% of all hits to the System Operator website.

The top 5 most popular web site pages were:

Page Name	Upper and Top SI Security	Home Page	Zone Loading	Power System Overview	Upper and Top NI Security
Hits	30,767	15,187	8,765	8,511	3,598
Page Image					
% age of overall Views	24.8	12.3	7.1	6.9	2.9

14.2.2 Content

Over the last 12 months the System Operator has continued to add additional website information intended to give participants greater knowledge about the status of the power system and enhance participants' ability to manage local networks.

Whilst the basic site structure has been maintained over the last 12 months, the site has had some subtle rebranding.

15. Financial Review (SOSPA)

The following information is based on the SOSPA signed on 12 August 2009.

15.1 Base Contract

Fees charged under the base SOSPA were as follows:

Financial review: SOSPA	1 September 2009 – 31 August 2010
System Operator Service Provider Contract Base Fee for the period 1 September 2009 – 30 June 2010	$20,903,333
System Operator Service Provider Contract Base Fee for the period 1 July 2010 – 31 August 2010	$4,909,715
Total fees paid under the SOSPA	$25,813,048

15.2 ADDITIONAL FEES

The following is a summary of the fees charged to the Electricity Commission for services in addition to those provided under the SOSPA.

Variable Revenue	1 September 2009 – 31 August 2010
TASC Advice	$65,426
Technical Investigations	$76,035
Total variable revenue	$141,461