

System Operator Annual Review and Assessment 2006/07

1 March 2006 to 31 August 2007

TRANSPOWER



SYSTEM OPERATOR

Keeping the energy flowing

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1 Principal Performance Obligations

1.1 Time Error

There was one instance of time error exceeding the +/- 5 second limits during the review period. This was on 8th August 2007 when time error in the North Island exceeded the five second threshold for approximately 15 minutes.

1.2 Voltage Disturbance

For the review period, there was an average of 139 voltage disturbances per month. These disturbances can be broken down to localised disturbances, where a fault occurs within a distribution company network (an average 98 per month) and regional disturbances due to faults on grid equipment (an average 41 per month). Typically, voltage disturbances are more frequent during times of strong winds and/or electrical storms.

Voltage Disturbance	2006												2007						Monthly Average this reporting period	Monthly Average last reporting period
	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug		
<i>Regional</i>																				
North Island	12	32	25	45	18	15	12	33	25	18	8	18	14	19	18	19	32	26	21.6	17.7
South Island	10	12	19	117	25	11	14	5	22	6	16	9	11	9	19	19	14	9	19.3	11.9
Total	22	44	44	162	43	26	26	38	47	24	24	27	25	28	37	38	46	35	40.9	29.6
<i>Local</i>																				
North Island	67	45	74	118	52	46	35	89	71	57	62	60	97	59	56	60	101	57	67.0	59.7
South Island	30	23	23	133	19	22	33	52	35	26	25	18	32	14	26	21	13	19	31.3	24.3
Total	97	68	97	251	71	68	68	141	106	83	87	78	129	73	82	81	114	76	98.3	83.9

1.3 Voltage Violations 220kV & 110kV

There were no instance of the 220 kV and 110 kV grid voltage exceeding the allowed +/- 10% limits between March 2006 and August 2007.

1.4 Frequency

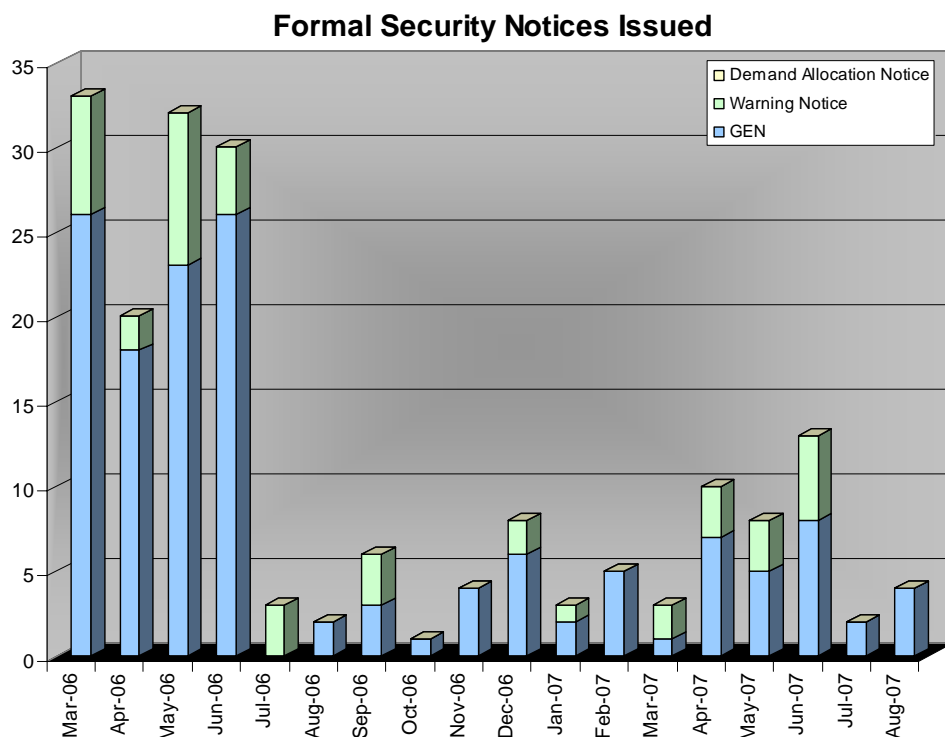
Frequency excursions for reporting period remained within the annual frequency performance targets. There were no excursions below 48 Hz reported for the period.

Frequency Band (Hz)	2006												2007						Cumulative Total this reporting period (18 months)	Frequency PPO Target (18 months)
	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug		
55.00 > Freq >= 53.75	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.3
53.75 > Freq >= 52.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
52.00 > Freq >= 51.25	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	10.5
51.25 > Freq >= 50.50	0	0	2	2	1	0	3	0	1	0	1	0	0	0	0	0	1	1	12	75
50.50 > Freq >= 50.20	156	174	110	85	127	134	120	82	96	124	60	77	142	181	158	153	128	91	2198	
50.20 > Freq > 49.80																				
49.80 >= Freq > 49.50	243	189	173	150	194	197	224	113	107	139	67	109	147	164	187	182	218	219	3022	
49.50 >= Freq > 48.75	3	6	6	3	3	0	3	2	3	4	0	4	4	9	8	8	9	2	77	90
48.75 >= Freq > 48.00	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0	0	0	0	2	9
48.00 >= Freq > 47.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.3
47.00 >= Freq > 45.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.3

1.5 Security Notices

A total of 187 formal security notices were issued between 1st March 2006 and 31st August 2007.

Notice Type	Number of Notices Issued*
GEN	143
WRN - Warning Notice	44
DAN – Demand Allocation Notice	0



*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 in June 2006 for the North Island. These were for a range of issues, from regional security of supply issues in Wellington and the Bay of Plenty, through to national shortfalls of standby generation and under frequency reserves.

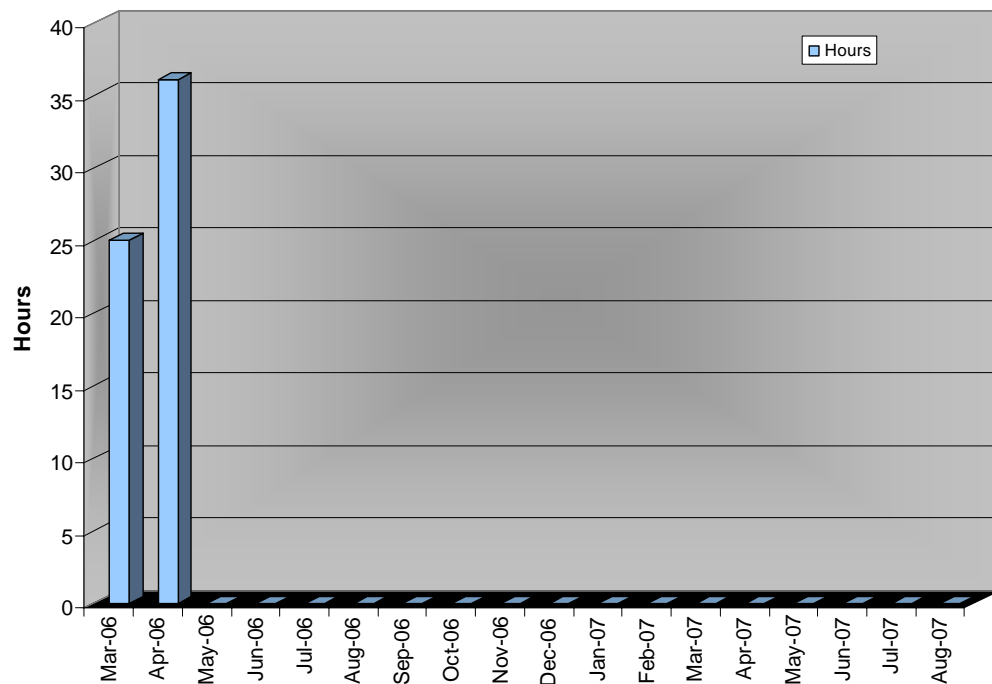
1.6 Participant Advice Notices

The participant advice notices (CANs) process is now automated where participants receive an automatic email notification for changes and alterations to constraints, or changes to configuration. Since its introduction records are no longer kept on participant advice notice numbers.

1.7 Stability Limits

There were no instances of stability limits being exceeded on the grid during the review period. During this time however there were 2 stability constraints that bound for a total duration of 61 hours. This occurred in the upper South Island in March and April 2006, where stability limits were being actively managed prior to the commissioning of the Islington-Kikiwa 2 circuit, and the Blenheim-Stoke 2 circuit.

Stability Constraint Activity



2 Security Issues

2.1 Summary of Grid Emergencies

Month	2006	2007
January		1
February		3
March	10	1
April	12	4
May	18	6
June	15	5
July	0	1
August	1	2
September	3	
October	1	
November	2	
December	2	

2.2 Security Issues and Events of Interest

The following events and issues are a selection of those which occurred during the reporting period. While all events are of concern and interest, some are of greater significance than others, because of their national importance (see the events below for June 2006 and in relation to Huntly Unit 5) or their regional importance (see the events related to supply into the Bay of Plenty).

2.2.1 Grid emergencies due to regional capacity issues

Top of the South Island

A number of grid emergency events in the top of the South Island during 2006 reflected the need for completion of the reinforcement of supply into the region, work which the Grid Owner had underway and which was completed during 2006. Since completion there has been a marked improvement in security of supply. Further work now underway to replace interconnecting transformers at Kikiwa and Stoke should ensure grid emergencies in this region are restricted to truly unforeseen events.

March 2006

19th March 2006; 17:26 – 18:09 hours and 19:29 – 21:00 hours. South Island

A grid emergency was declared due to insufficient dispatch proposals. The short-term post contingent rating of Kikiwa T1 was at risk of being exceeded for a contingency of Blenheim-Stoke 1. Load control was required by Network Tasman and Marlborough Lines.

25th March 2006; 10:50 – 01:05 hours. South Island

26th March 2006; 10:15 – 17:24 hours. South Island

A grid emergency was declared arising from insufficient dispatch proposals. The short-term post contingent rating of Kikiwa T1 was at risk of being exceeded for a contingency on Kikiwa-Stoke 1. Load control was required by Network Tasman, Marlborough Lines, Buller Networks and Electronet. TrustPower also re-offered extra generation at Cobb.

26th March 2006; 19:00 – 19:30 hours. South Island

A grid emergency was declared arising from insufficient dispatch proposals. The voltage stability limit for Grid Zone 9 was at risk of violation. An early return of Islington-Kikiwa 3 and Dobson-Greymouth 1 alleviated the situation.

Bay of Plenty: April - May 2006 and April - June 2007

Due to a combination of high demand and low local generation during the evening of 19 June, demand was shed in the Mount Maunganui - Tauranga area so as to keep assets within ratings. This action was a further reminder of the need for local supply reinforcement in this fast growing region, as evident from the number of grid emergency notices noted below. At the end of June 2007 an inter-trip was commissioned in the region as an interim measure to facilitate greater power transfer into the region (at times of peak demand) until a new switching station and additional capacitor bank is commissioned. This work is planned for early 2008.

19th April 2006; 18:10 – 20:19 hours. North Island

20th April 2006; 18:20 – 21:03 hours. North Island

24th April 2006; 18:14 – 20:00 hours. North Island

A grid emergency was declared because of insufficient dispatch proposals in the Mount Maunganui - Tauranga area. Post contingent off load times were at risk of being exceeded for a tripping of the 110 kV Mount Maunganui-Tarukenga circuit. Load control was provided by Powerco.

26th April 2006; 17:54 – 21:00 hours. North Island

A grid emergency was declared because of insufficient dispatch proposals at Mount Maunganui, Tauranga and Te Matai. The short-term post contingent rating of 110 kV Tauranga-Tarukenga 1 was at risk of being exceeded for a contingency of 110 kV Mount Maunganui-Tarukenga 1 circuit.

27th April 2006; 13:00 – 14:38 hours. North Island

27th April 2006; 18:00 – 21:04 hours. North Island

A grid emergency was declared because of insufficient transmission capacity at Tauranga and Te Matai. The steady state rating of the 110 kV Tauranga-Tarukenga 1 circuit was at risk of being exceeded in real time. Load control was provided by Powerco.

01st May 2006; 17:48 – 21:00 hours. North Island

02nd May 2006; 17:33 – 21:00 hours. North Island

03rd May 2006; 17:40 – 21:00 hours. North Island

04th May 2006; 17:58 – 21:00 hours. North Island

A grid emergency was declared because of insufficient transmission capacity at Tauranga and Te Matai. The rating of Tauranga-Tarukenga 1 circuit was at risk of being exceeded in real time. Powerco responded to a request to control load.

05th May 2006; 17:59 – 21:00 hours. North Island

A grid emergency was declared because of insufficient transmission capacity at Mount Maunganui, Tauranga and Te Matai. The ratings of the Tauranga-Tarukenga 1 and Mount Maunganui-Tarukenga 1 were at risk of being exceeded in real time. Powerco responded to a request to control load.

07th May 2006; 17:58 – 21:00 hours. North Island

08th May 2006; 17:41 – 21:00 hours. North Island

09th May 2006; 07:54 – 10:00 hours. North Island

A grid emergency was declared because of insufficient dispatch proposals at Mount Maunganui, Tauranga and Te Matai. N-1 contingent off load times for a tripping of the Mount Maunganui-Tarukenga circuit were at risk of being exceeded. Load control by Powerco was required and TrustPower reoffered generation at Kaimai.

09th May 2006; 13:22 – 21:00 hours. North Island

A grid emergency was declared because of insufficient dispatch proposals at Mount Maunganui, Tauranga and Te Matai. The offered capability of Tauranga-Tarukenga 1 circuit was at risk of being exceeded for a contingency of Mount Maunganui-Tarukenga 1 circuit. Load control by Powerco was requested.

11th May 2006; 12:24 – 14:30 hours. North Island

A grid emergency was declared due to an interconnecting transformer bank (T1) tripping at Tarukenga while the T2 bank was out of service for maintenance. Load at Mount Maunganui, Te Matai and Tauranga was reduced to bring circuit loading to within thermal rating on the Arapuni-Kinleith 1 and 2 circuits and the Edgecumbe-Owhata circuits. Load control by Powerco was requested; TrustPower also re-offered generation at Kaimai.

19th June 2006; 13:30 – 21:00 hours. North Island

A grid emergency was declared due to insufficient dispatch proposals and insufficient transmission offers at Mount Maunganui, Tauranga and Te Matai. Load management was required by Powerco to maintain system security.

12th April 2007; 18:26 – 20:00 hours. North Island

A grid emergency was declared to prevent the asset capability of the 110 kV Mount Maunganui-Tauranga-Te Matai circuit from being exceeded in case of a 110 kV Tauranga-Tarukenga circuit contingency. The situation was resolved with use load control and local generation.

23rd April 2007; 17:48 – 20:17 hours. North Island

26th April 2007; 18:11 – 19:20 hours. North Island

30th April 2007; 17:37 – 19:30 hours. North Island

Three grid emergencies were declared to prevent the asset capability of the 110 kV Mount Maunganui-Tauranga-Te Matai circuit from being exceeded in case of a 110 kV Tauranga - Tarukenga circuit contingency. The situation was resolved by applying system splits on the Mount Maunganui-Tauranga-Te Matai circuit at Mount Maunganui and Te Matai.

01st May 2007; 17:52 – 19:30 hours. North Island

07th May 2007; 17:58 – 19:30 hours. North Island

08th May 2007; 19:40 – 20:30 hours. North Island

09th May 2007; 17:49 – 20:30 hours. North Island

In each instance a grid emergency was declared to prevent offered capability of the 110 kV Mount Maunganui-Tauranga-Te Matai circuit from being exceeded in the event of a 110 kV Tauranga-Tarukenga circuit contingency. In each instance the situation was resolved using a grid reconfiguration that resulted in application of system splits on the Mount Maunganui-Tauranga-Te Matai circuit at Mount Maunganui and Te Matai for the duration of the emergency.

This action resulted in demand at Mount Maunganui, Tauranga and Te Matai being at risk of loss of supply for any event while the grid remained reconfigured.

20th June 2007; 12:50 – 21:37 hours. North Island

A grid emergency was declared to prevent offered capability of the 110 kV Mount Maunganui-Tauranga-Te Matai circuit from being exceeded in the event of a 110 kV Tauranga-Tarukenga circuit contingency. The situation was resolved by applying system splits on the Mount Maunganui-Tauranga-Te Matai circuit at Mount Maunganui and Te Matai for the duration of the emergency. This action resulted in demand at Mount Maunganui, Tauranga and Te Matai being on N security while the grid was reconfigured.

28th June 2007; 20:59 – 21:42 hours. North Island

A grid emergency was declared to prevent offered capability of the 110 kV Mount Maunganui-Tauranga-Te Matai circuit from being exceeded in the event of a 110 kV Tauranga-Tarukenga circuit contingency. The situation was resolved by managing demand at Tauranga for the duration of the emergency.

Wellington Regional 110 kV: May - June 2006

Several grid emergencies were declared during evening peaks in winter 2006 due to insufficient transmission capacity in the Wellington 110 kV network; this network supplies the Wellington CBD and northern suburbs via Takapu Rd substation from Haywards. This situation was resolved ahead of winter 2007 following the re-stringing of the Haywards-Takapu Rd and Takapu Rd-Wilton circuits together with associated equipment replacements at Haywards substation.

02nd May 2006; 18:49 – 21:00 hours. North Island

03rd May 2006; 18:17 – 21:00 hours. North Island

A grid emergency was declared because of insufficient transmission capacity in the Wellington area. The ratings of Wilton T8, Haywards T2 and T5 were at risk of being exceeded in real time. Powerco, Vector and Electra responded to a request to control load.

22nd June 2006; 11:24 – 23:00 hour. North Island

A grid emergency was declared due to insufficient transmission capacity at Central Park, Kaiwharawhara, Paraparaumu, Pauatahanui and Takapu Road. Participants were requested to decrease demand. The grid was reconfigured with Wilton T8 supplying Central Park, T5 and Haywards-Takapu Rd 1 and 2 supplying Kaiwharawhara, Central Park T3 and T4, Paraparaumu and Pauatahanui. This reconfiguration alleviated the need for demand management.

2.2.2 Major system frequency events

During the review period there were two major system underfrequency events when, in both the cases, loss of injection into the power system was beyond that normally planned for by the System Operator through the dispatch of reserves.

Benmore: March 2007

On 30th March all in service generation at Benmore power station tripped, with the loss of 326 MW. This resulted in the automatic tripping of HVDC Pole 1 with the loss of 240 MW north transfer. The North and South Island frequencies dropped to 49.43 Hz and 48.60 Hz respectively. In accordance with the policy statement the System Operator had scheduled reserves for the loss of 120 MW in the South Island. However the combination of lost HVDC transfer, HVDC reserve sharing and additional reserve response from South Island generators resulted in the minimum frequency being well above the point at which automatic load shedding would have occurred.

An investigation by the generation asset owner established the sequence of events that lead to the tripping but no one single, clear trigger for the event.

Loss of Huntly Unit 5 and Stratford CCGT's on 29 April 2007

29th April; 05:10 hours. Large frequency disturbance in North and South Islands

Huntly Unit 5 (e3p) tripped at full load during commissioning. During the resultant under-frequency excursion Stratford CCGT also tripped. North and South Island frequencies dropped to 48.26 Hz and 49.44 Hz respectively, with the loss of approximately 387 MW and 230 MW of generation from Huntly Unit 5 and Stratford CCGT respectively.

The System Operator had scheduled reserves to cover a 400 MW generation risk (Huntly U5). Interruptible load and generator reserves responded to arrest the frequency fall from the unplanned loss of generation. System response included additional un-dispatched governor and interruptible load provider response and the ramp back of the HVDC south transfer by approximately 30 MW. This combined system response ensured North Island frequency did not reach 47.8 Hz, the point at which Automatic Under-frequency Load Shedding (AUFLS) occurs.

The behaviour of the Stratford CCGT was similar to that seen on 11 December 2005. A collaborative effort between the generator asset owner and the System Operator identified the cause of the Stratford CCGT tripping and the mitigations that were applied to ensure the plant remained stable in similar future events. A summary of the event was published by the System Operator on its website at <http://www.transpower.co.nz/?id=5963>.

Commissioning of Huntly unit 5: April – May 2007

The new Huntly Unit 5 (e3p) commenced commissioning and synchronisation onto the power system in early 2007. This work continued through into July. During the commissioning period the plant was operated under a commissioning plan agreed with the System Operator. This plan required certain activities, including certain tests, to be agreed and co-ordinated to allow the System Operator to plan to manage and to actually manage the power system to meet the principle performance obligations.

During the reporting period a number of planned and unplanned events occurred in which the new plant was involved:

10th April. 11:28 hours. Frequency disturbance in North and South Islands

Huntly Unit 5 tripped causing North and South Island frequency to drop to 49.27 Hz and 49.38 Hz respectively with a loss of approximately 270 MW of generation from Huntly. Reserve response in the North and South Islands, together with HVDC frequency modulation, acted as expected to return the frequency to the normal band.

11th April; 19:40 hours. Frequency disturbance in the North Island

A Huntly Unit 5 planned drop load test resulted in North Island frequency dropping to 49.50 Hz with a loss of approximately 180 MW of Huntly generation. Reserve response in the North and South Islands, together with HVDC frequency modulation, acted as expected to return the frequency to the normal band.

12th April; 14:10 hours. Frequency disturbance in the North Island

This event was caused by a planned Huntly Unit 5 drop load test. North Island frequency dropped to 49.37 Hz with a loss of approximately 270 MW of Huntly

generation. Reserve response in the North and South Islands, together with HVDC frequency modulation, acted as expected to return the frequency to the normal band.

29th April; 05:10 hours. Large frequency disturbance in North and South Islands

Huntly Unit 5 tripped at full load during commissioning. This is noted above, under Taranaki combined cycle commentary.

03rd May; 15:10 hours. Frequency disturbance in North Island and South Islands

This event was caused by a planned Huntly Unit 5 drop load test. The North and South Island frequency dropped to 49.18 Hz and 49.45 Hz respectively with a loss of approximately 390 MW of generation from Huntly. Reserve response in the North and South Islands, together with HVDC frequency modulation, assisted return of the frequency to the normal band.

21st May; 11:11 hours. Frequency disturbance in North Island and South Islands

This event was caused by a planned Huntly Unit 5 drop load test. North and South Island frequencies dropped to 49.21 Hz and 49.28 Hz respectively with a loss of approximately 400 MW of generation from Huntly. Reserve response in the North and South Islands, together with HVDC frequency modulation, assisted the frequency return to the normal band.

3 Security of Supply

3.1 Real Time Security Issues

There were two significant situations during the period of the review when the System Operator invoked the controls described in the emergency section of the Policy Statement.

3.1.1 The events of June 2006

There were two very significant system events in June 2006. The events of the two days, the 12th and 19th of June were significant for the System Operator, the industry and the public. The events of these days were extensively reported and reviewed, including by external parties whose reports were published by the System Operator in its June 2006 month report (which are available on the System Operator's website). Headline details of the events are as follows:

Monday 12th June

loss of supply

Over 50 circuit trippings and circuit outages occurred in the South Island due to snow. The trippings included three of the four circuits to Christchurch and one circuit to Nelson. Despite these trippings the losses of supply from this snow event were restricted to Temuka (~4 hours total), Studholme (~1½ hours), Oamaru (~½ hour) and Arthurs Pass (~30 hours). There were also weather-related losses of supply to Ohaaki and Kapuni in the North Island.

Grid emergency; 02:21 – 07:00 hours. North Island

A grid emergency was declared on Monday from 02:21 until 07:00 following an unplanned outage on Bunnythorpe-Brunswick 2 220 kV circuit. The grid was

reconfigured removing the Wanganui-Waverley 110 kV circuit at Waverley to ensure the 110 kV route was not overloaded.

Grid emergency; 08:51 - 16:30 hours. North Island

A grid emergency was declared Monday morning from 8:51 to 16:30 after the loss of the Penrose-Otahuhu 220 kV line, most of the Otahuhu 110 kV bus and generation at Otahuhu CCGT. Supply was initially lost to Otahuhu, Penrose, Mount Roskill, Mangere and Pakuranga. Load control at Wiri and Bombay was also required to aid restoration. The grid emergency notice was revised several times during the day. Supply was progressively restored by Vector as GXP's were reconnected. Tripped generation was reconnected when the Otahuhu-Penrose line was restored.

Monday 19th June

loss of supply

There was a loss of supply to Rotorua for 53 minutes following the tripping of Rotorua-Taurakenga 1 while Rotorua-Taurakenga 2 was out of service just prior to restoration of the outage circuit.

grid emergency; 13:30 - 20:00 hours. North Island

A grid emergency was declared in the afternoon at Te Matai, Tauranga and Mount Maunganui, from 13:30 until 20:00, as load in the region exceeded the contingency limit. Local generation was fully dispatched. Up to 14 MW of load supplied at Te Matai was disconnected by Powerco from 17:00 as it was unable to fully control load in the region using controlled domestic water heating.

grid emergency; 19th June 17:34 - 20:00 hours. North and South Islands
(also covered under the regional capacity issues above)

A grid emergency was declared in the evening. With unexpectedly high load arising from cold conditions across New Zealand a nation wide grid emergency was declared from 17:34 to 20:00 as there was insufficient generation offered.

Reserves were not dispatched during this period, to avoid the need to shed load. Without reserves dispatch any routine power system event such as a tripping off of a large generator, will result in automatic load shedding of up to 32% of consumers to ensure the power system does not collapse.

Planned maintenance work on transmission lines reduced the combined maximum generation from two of the Waikato River power stations by 170 MW. The lines could not be brought back to service at short notice. Generation at Tokaanu station was severely constrained by a weed problem, removing up to a further 200 MW.

New Plymouth power station (up to 330 MW capacity) was not offered at the time. The Whirinaki reserve energy station was started at 17:00 and again just prior to 20:00, when normal dispatch of reserves was resumed.

The events of 19th June resulted in the Commission and the industry embarking on a review of why a shortage of generation seemed to arise suddenly on the day and about the efficacy of the process by which demand is forecast and made known to the industry in time for suitable response to meet predicted shortfalls. This review was carried out by an industry group, of which the System Operator was a participant, called the National Winter Group (see comments below).

3.2 Short Term Security Issues

3.2.1 *Upper North Island security*

Winter

For winter 2006 and 2007 the stakeholder group again collaborated to establish appropriate contingency plans. In 2006 the addition of additional upper North Island capacitors aided the ability of the power system to meet demand.

For the 2007 winter the addition of additional dynamic reactive support and generation availability, including Huntly Unit 5, meant power system capability was more than 5% above peak demand.

Peak demand with in winter 2006 was 2087 MW, an increase of 4.7%. Peak demand in 2007 was 2118 MW, an increase of 1.5% from 2006.

Summer

The System Operator again led the upper North Island stakeholder group to ensure a co-ordinated response to manage the region within power system capability limits over summer 2006/7. This group has been called together each summer since 1998/9. The summer conditions actually experienced in 2006/7 and the generation availability, including the benefits of an additional cooling tower at Huntly, meant demand was well within power system limits.

As in the upper South Island, the role of the North Island group was extended to informing stakeholders of power system limits during significant outages of the Otahuhu-Whakamaru 1 and 2 circuits occurring at the same time as outages for major generation plant. This meant there was a co-ordinated response by participants to ensure power system capability is not unduly compromised during the outages.

3.2.2 *Upper South Island security*

Winter

The System Operator again led the upper South Island winter stakeholder group to ensure a co-ordinated response to manage the region within power system capability limits over both the 2006 and 2007 winters. Improvements to transmission capability in the top South Island and partial completion of the duplexing of the Islington-Livingstone line have increased the operational limits for the wider upper South Island region.

Peak demand with in winter 2006 was 1066 MW, an increase of 3.3% and which reflected the quite extreme winter conditions experienced in 2006. Peak demand in 2007 was 1091 MW, an increase of 2.3% on 2006, and within 5.5% of maximum power system capability with all assets in services, including reliance on limited under voltage shedding (AUVLS).

Summer

The South Island stakeholder group was also convened by the System Operator to help ensure the regional response within power system limits for outages of the Islington-Livingstone line during the 2006/7 summer.

3.2.3 Top of the South Island security

The top South Island matters are referred to section 3.2 above. Recent upgrades to transmission capability during 2006 together with those currently underway mean no special planning and management measures should be warranted in the near future.

3.2.4 Dry year planning 2006

In March through May of 2006 the System Operator participated in a CEO forum sponsored initiative to plan for the possibility that low 2005/2006 lake inflows, especially in the South Island, would result in reduced generation availability for winter 2006 and the possible security implications arising from that situation. The group investigated and assessed likely demand, available storage and likely generation availability and contingencies together with a range of possible planning arrangements.

In addition to participation in the group planning work System Operator provided information to the industry regarding actions taken in the previous dry year planning (for 2001 and 2003), south transfer system capability and issues, including in relation to flows on BPE-HAY and the impact of Wellington demand on flows across the HVDC. An industry briefing session was provided on relevant transmission, power system and planning issues.

3.2.5 National winter group

The events of June the 19th caused both the Commission and industry to express concern regarding the ability and willingness of the industry to recognise and respond to signals regarding security of supply. This resulted in the establishment of an industry working group to consider the security of supply issues arising from the June event and to propose means of reducing the chance of similar circumstances reoccurring.

From the work of the group three actions were agreed to be immediately undertaken by the System Operator:

- the System Operator would produce a more regular and automated standby reserve report (including known spur line generation constraints) and arrange for publication through Comit. The work resulted in Standby Residual Check data from the SDS, SDPQ and PDS being published (via COMIT) from 17th May 2007. A spreadsheet model to analyse the data was also made available to participants on the System Operator's website. The System Operator also provided a training session for use of the model. SRC notices have been regularly issued since that time and are reported in the System Operator's monthly Performance Report
- increase the allowance for HVDC national reserve sharing in RMT to up to 100MW. Following discussions with the Grid Owner it was agreed the change would be to increase the reserve sharing to 50MW and a change to that effect was implemented in RMT on 10th May 2007
- undertake an education programme with participants regarding the System Operator's actions and participants' obligations in respect of grid emergencies, especially in regard to energy shortages. This obligation was satisfied by meetings the System Operator held with individual distributors and major directly connected customers during April – July of 2007.

Other actions identified by the Group will be reviewed in 2008 for possible future implementation.

3.3 Other Security and Quality Issues

3.3.1 *South Island system performance investigation project*

Following a system event on 4th December 2005, the System Operator identified a need to better understand the dynamic performance of South Island generators and the performance of the South island system as a whole. This need is being accentuated by the increasing congestion of the South Island system and the likely introduction of increasing amounts of wind generation in the lower part of the island.

A formal project to review generator performance was initiated in 2007 involving the System Operator, Meridian Energy and Contact Energy. The project will extend into mid-2008, and will provide the parties with confirmed and updated data on plant capabilities, enabling the System Operator thereafter to better understand and plan for operation of the South Island power system.

3.3.2 *Wind integration*

Throughout the reporting period the System Operator provided significant contributions to the Commission's ongoing Wind Generation Investigation Project (WGIP). During the period, this work was of an investigatory nature and a number of reports were produced by the System Operator and contributions made to others. These reports, published in May 2007 by the Commission, are major inputs to the next phase of the project, namely the identification and assessment of options. The System Operator has offered to contribute to this project work.

In September 2005 the System Operator published an assessment (based on a small amount of data) of the correlation of generation from adjacent Manawatu wind farms. The System Operator expects this information to be updated in 2008, to take account of the recently completed commissioning of the Tararua III wind farm in the same region.

3.3.3 *AGC*

The System Operator recently provided assistance to the Commission's newly commenced AGC project. System Operator personnel have met with the KEMA consultants engaged by the Commission and expect to have ongoing input to this project as it develops during the next reporting period.

4 Commissioning - Generation

4.1 Huntly Unit 5 (e3p)

Genesis Power (Genesis) and the System Operator have been jointly involved in commissioning Genesis' new Huntly Unit 5, combined cycle gas turbine power plant. Huntly Unit 5 is the largest single shaft generating plant (385 MW) ever commissioned in New Zealand at one time.

Initial synchronisation of the unit to the grid occurred 2nd February 2007. Following initial synchronisation Genesis carried out commissioning activities as outlined in the commissioning plan. Some of these activities were of interest to the System Operator given the potential for impact on the power system.

The System Operator and Genesis agreed specific operational processes to manage the commissioning of the unit. Minor changes to the Reserve Management Tool (RMT) were completed prior to first synchronisation to enable it to:

- use a CE secondary trip model and an ECE secondary trip model for the same unit
- consider an AC unit as part of the ECE risk equation; prior to commissioning Huntly Unit 5 only the HVDC bipole was considered to be an extended contingent event.

Communicating to participants at key points of the commissioning was regarded as essential for both forward planning and real-time operations. During the commissioning the following key points were notified to participants:

- the date when the unit was to initially synchronise to the system
- the dates each system ride through test was to take place
- the dates each drop load test was to take place
- the date when Huntly Unit 5 was to be treated as a normal risk.

Genesis successfully completed commissioning the generator in July of 2007. Final assessment of the model and test results will continue over the following few months.

4.2 Huntly Unit 1

Genesis commissioned Huntly Unit 1 following a control and instrument upgrade. The commissioning followed a similar plan previously used in the commissioning of Huntly Unit 3.

Synchronisation of the upgraded Huntly Unit 1 generator occurred on 6th of April 2007. Commissioning tests per an agreed commissioning plan were carried out over a 2 month period. Additional runback and reserve tests are planned for completion in September - October 2007.

4.3 Tararua III Wind Farm

Commissioning of the Tararua stage III 93 MW wind farm (which comprises 31 wind turbine generators) commenced in February 2007 with the enlivening of the first 'string' of generators. Commissioning required installation of a new 220 kV grid connection. Following the connection to the grid a programme for testing wind turbines was co-ordinated between TrustPower and the System Operator.

Commissioning of the wind turbines required testing of each generation 'string' and concluded in July 2007. Grid - wind farm integration testing continued in August and will conclude in September.

4.4 Southdown E105

From December 2005 Mighty River Power and the System Operator were involved in the commissioning a new gas turbine generator (E105, 45 MW) at the existing Southdown site.

This unit is fitted with a clutch to allow it to operate as a synchronous condenser when not running as a generator. Commissioning involved testing of both the turbine generator and the clutch/synchronous condenser. All testing was completed as per the agreed commissioning plan.

The commissioning of E105 concluded 5th of April 2007 with the plant available for both generation of megawatts and synchronous condenser operation.

4.5 White Hill

The System Operator and Meridian Energy coordinated both the technical and market issues related to commissioning the White Hill wind farm. The wind farm (approximately 58 MW) is connected into the local electricity network.

5 Rule Changes

5.1 Proposed by System Operator

The System Operator made no recommendations for changes to the Electricity Governance Rules and Regulations ('the Rules') during the review period, apart from the annual Policy Statement and Procurement Plan changes which are changes in the Rules (to respectively Schedule C4 and Schedule C5 of Part C).

5.1.1 *Policy statement and procurement plan changes*

Because of the 18 month review period, the draft Policy Statement and Procurement Plan for each of 2006/7 and 2007/8 were recommended during the review period for adoption by the Minister. In the case of each of the Policy Statement reviews, the drafts recommended by the System Operator were in each case:

- passed through a consultation process by the Electricity Commission (the 'Commission')
- amended to take into account certain changes suggested by participants
- recommended (in whole) to the Minister of Energy as suitable changes to the Rules
- adopted by the Minister as changes to the EGRs.

The same process was followed in respect of the review of the 2006/7 Procurement Plan and that plan was adopted (in whole) into the EGRs, with certain changes made from the consultation process. As at 31st August 2007 the draft 2007/8 Procurement Plan was in the course of recommendation to the Minister. The System Operator's draft was amended following the consultation process.

5.2 Contributions by the System Operator

The System Operator assisted the Commission with certain actual or proposed rule development initiatives. These included the following:

5.2.1 *High spring washer rules*

This work commenced in the previous reporting period was completed. The rule changes initiated (from that work) were brought into force just after the reporting period. The System Operator undertook the necessary systems development work to enable the rules to be given effect.

5.2.2 Variable reserves

The System Operator contributed to this rule change work which had been initiated by the Commission prior to the reporting period. It became apparent that the rule change required certain market system modifications that would be better completed after the 2008 implementation of the System Operator's new market systems (see section 14.3.1 below). Considerable efforts were made to establish a workable alternative that would allow the introduction of the rule change ahead of the 2008 new systems implementation. However, it became apparent the alternative would be expensive in comparison to the benefit likely to be gained. A decision was taken to delay the rule implementation to as soon as practicable after the new market systems are in place.

5.2.3 Asset owner test plan

The System Operator applied significant resources to assist the Commission develop the revised asset owner test plan rules, currently nearing completion. The Commission determined the test plan would be best delivered partly as rules, defining the high level test obligations, and partly as a separate guide, describing the nature of tests that would (or could) assist participants meet the rule requirements. It was agreed the System Operator would develop and publish, as well as keep up to date, a companion test guide. This guide would describe appropriate tests to support the new rules.

The System Operator's test guide was developed, consulted on and finalised in the review period. It was published on the System Operator website in late August 2008.

5.2.4 Reserve costs allocations

The commissioning of the Huntly Unit 5 in 2006/7 and the view taken by the System Operator with regard to the plant's risk profile during commissioning raised industry concerns regarding the allocation of reserves costs to owners of dispensated plant (rules 7.3.1 and 76.3.3 Section III, Part C). The System Operator and the Commission (as well as certain participants) held different views on the effect of the rules and, despite significant efforts, were unable to agree a common understanding of what the rules meant. That situation prevailed as at 31st August 2007.

The System Operator and a number of participants believe the rules should be reviewed, their meaning clarified and suitable changes made.

5.2.5 Co-generation rules

The System Operator assisted the drafting of the rules relating to co-generation that came into effect in June 2007.

Three applications for co-generation were received in the reporting period for which System Operator input was required.

5.2.6 Automation of customer advice notices

The rule change proposed by the System Operator in November 2005 was implemented in late 2006. As a result of the rule change and subsequent systems changes required to implement the rule change, the System Operator

now electronically notifies participants every 10 minutes when a permanent constraint changes or a temporary constraint is applied in SPD.

5.2.7 \$100k prices

The System Operator was requested to implement changes to its SPD software to prevent a reoccurrence of an event in June 2005. This incident occurred when the SPD model assigned \$100,000 model parameter values to OTA 1101 and OTA 1102, which were published as final prices. In doing so SPD operated in accordance with the current SPD model formulation.

The Commission and industry believed this to be an undesirable outcome. As a result, the Commission asked the System Operator to recommend changes to the SPD specification to prevent a recurrence of the above event.

The System Operator recommended certain changes, which were adopted as a change to the Software Specification contained in the System Operator Service Provider Agreement (SOSPA). The changes to the SPD software were implemented in July 2006.

5.2.8 Operational communications and indications and measurements

The System Operator provided significant input to the indications and measurements section of the Technical Code C rule changes that came into force in November 2006.

Since the revised rules came into effect the System Operator has concerns about the wording and implementation of the new code, particularly as asset owner compliance with Code C has direct consequences for the System Operator in planning to comply and complying with the PPOs.

The reservations include the asset owners' joint ability to consistently meet the rules in relation to data communications, which require 'reasonable endeavours' to be used to ensure availability of data communications and to provide the requisite data communications to a certain accuracy. As the System Operator predicted, asset owners have disparate interpretations of the meaning of 'reasonable endeavours' as they apply to these rules, leading to a number of data communications failures in the reporting period which, in the System Operator's view, are unable to be practicably dealt with through the compliance process.

The obligation on asset owners to agree back up arrangements for data communications with the System Operator is also absorbing significant time and resources. Because of the way the rules are now worded and interpreted, asset owners are proposing the use of manual means to provide indications where normal means have failed (noting failure may be intermittent or affect multiple sites). Whilst the Electricity Commission may not have intended asset owners to continue with the status quo indefinitely (i.e. with no alternative electronic communications pathways), the practical effect of the rules is that asset owners are reluctant to make any technology upgrades to provide back up systems. This makes agreeing back up mechanisms extremely cumbersome, time consuming, and to some extent, ineffective. The use of manual processes to update 8 second data is clearly not practical and imposes additional 'manual' work load increases on the System Operator, which may occur at critical times and impact on the System Operator's ability to comply with the rules, including meeting the PPOs.

In May 2007, the System Operator wrote to the Electricity Commission expressing its concerns and requesting guidance on interpretation of the relevant rules.

5.2.9 Pricing improvement project

Although the Rules provide for some situations when problems occur in the pricing process, participants have raised a number of concerns regarding the pricing process since the Rules came into force in March 2004. Specific events over the past two and a half years have exposed particular issues of confusion about the meaning of some Rules as well as conflicts.

As a result of such concerns, the Commission set up a Pricing Process Improvement Project (PIIP) work stream to address participant and Commission concerns about the certainty, accuracy and level of wholesale electricity prices. The System Operator has committed significant resources to this project.

Rule changes arising from the PIIP work are planned for consultation in June 2008.

5.2.10 Duplicate protection

The System Operator provided significant input into the drafting of Rule changes to clarify the meaning of 'duplicate protection' for asset owners.

These changes came into force on 31st May 2007. The System Operator and asset owners are still working through the implications of the rule change through the dispensations process.

5.2.11 'Tactical' rule changes to facilitate connection of wind generation

In the previous reporting period, the System Operator suggested changes to the rules relating to intermittent generation. These were designed to facilitate the increasing amount of wind generation being introduced onto the power system ahead of completion of the Commission-sponsored Wind Generation Investigation Project (WGIP). That project, current at the 31st of August 2007, is expected to result in recommendations for further and more significant changes to the rules for intermittent generation.

The 'tactical' changes suggested by the System Operator were further worked on during 2006 and advice provided to the Commission.

5.2.12 Frequency keeper selection

The System Operator provided advice to the Commission on the effect of an industry group's proposal to change the method by which the System Operator selects the frequency keeper. The System Operator advised the changes could be implemented and how the changes would impact its new market systems development. It noted the changes could be introduced before the new market systems were implemented but would also require changes to after the new systems are implemented in 2008.

The Commission elected to not proceed with the proposed changes.

5.2.13 Definition of 'reasonable estimate' in relation to interruptible load

The Commission requested advice from the System Operator regarding how the term 'reasonable estimate' should be interpreted and applied in respect of rule 6.3.3 of section II of part G. The request followed concerns arising from several 2004 system events where interruptible load had been triggered and where the interpretation of the rules relating to the provision of reasonable estimates by ancillary services providers was in issue. In respect of these events a composite settlement agreement involving a number of parties was reached in 2005.

The System Operator provided a report to the Commission and published this report on its web site in March 2007 <http://www.transpower.co.nz/?id=5963>.

6 Compliance Matters

During the later part of 2006 the System Operator developed a discussion paper on its experiences since early 2004 of the operation of the compliance regime. The paper also commented on possible changes which the System Operator thought worthy of consideration by the Commission and the industry.

The paper was published in February 2007 on the System Operator website (<http://www.transpower.co.nz/?id=5963>). Since publication the Commission has prepared and issued a paper raising many similar issues and inviting the industry to make submissions on possible changes to the current compliance arrangements (submissions close in October 2007). The System Operator is preparing a submission that will incorporate a number of matters raised in its own discussion paper.

Among the matters raised in the System Operator's paper were:

- a view that access to the Rulings Panel should be available to participants to gain opinions (rulings) on relevant matters related to the rules
- the current rules could be changed to reduce the reporting and management burden in respect of minor breaches and duplicated reporting
- the settlement process could be improved with the right to reach non-unanimous arrangements.

6.1 System Operator Self- Notified Breaches

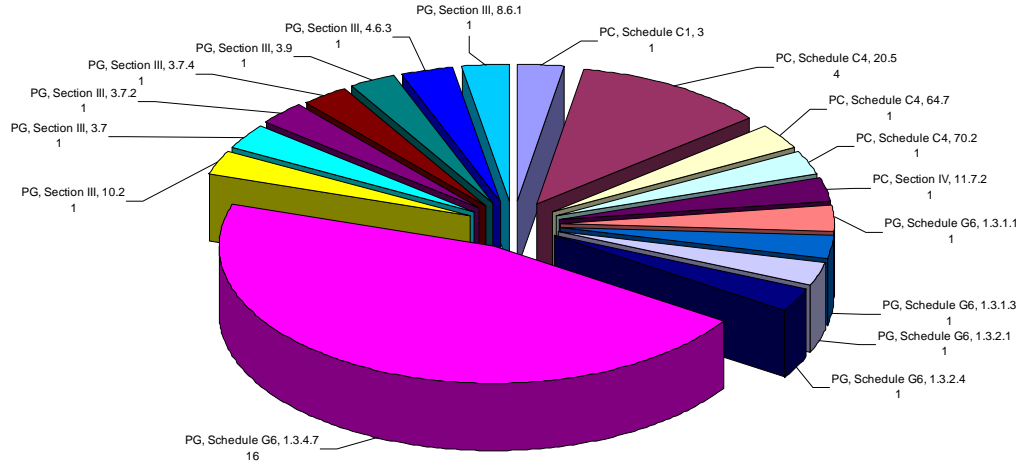
The following graphs represent breaches of the Rules by the System Operator which it self-notified to the Commission. As the review period has changed from previous years, the graphs below represent:

- previous year: 1 September 2005 – 31 August 2006 (35 breaches)
- 'additional' reporting period: 28 February 2006 – 31 August 2006 (19 breaches)
- current year: 1 September 2006 – 31 August 2007 (10 breaches).

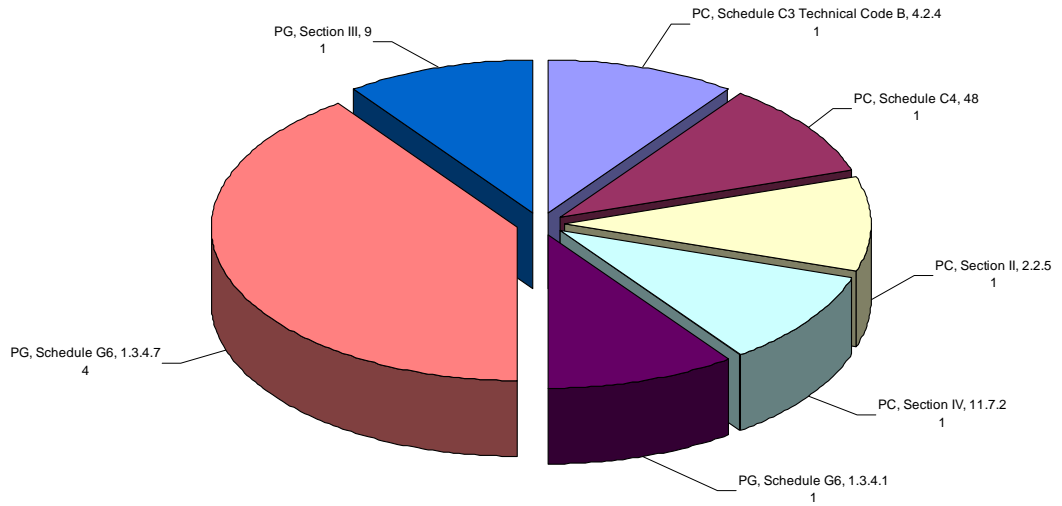
Comparisons are made between the previous and current years. The data for the additional period is represented for completeness and is a subset of that reported for the previous year.

One breach (from April 2006) has been referred to the Rulings Panel.

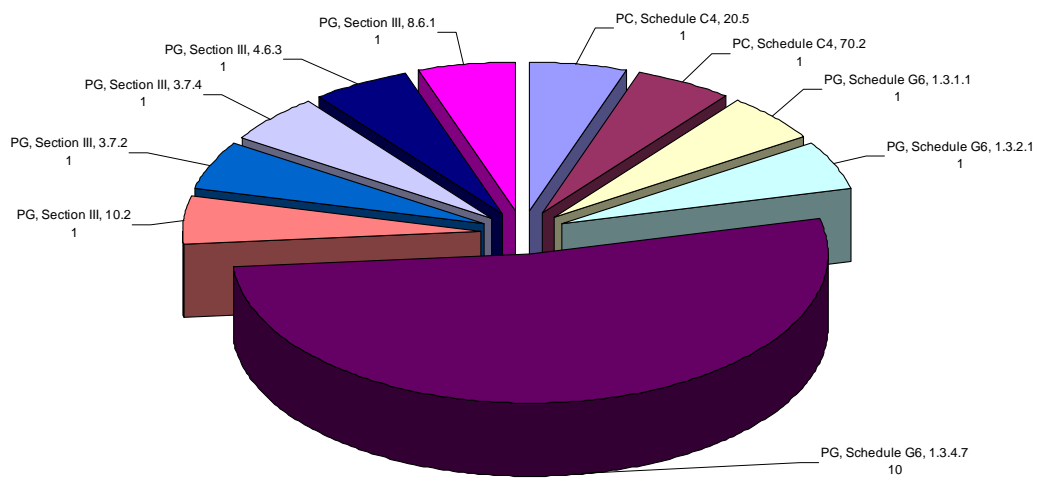
Graph of SO Self-Reported Breaches 1 September 2005 - 31 August 2006



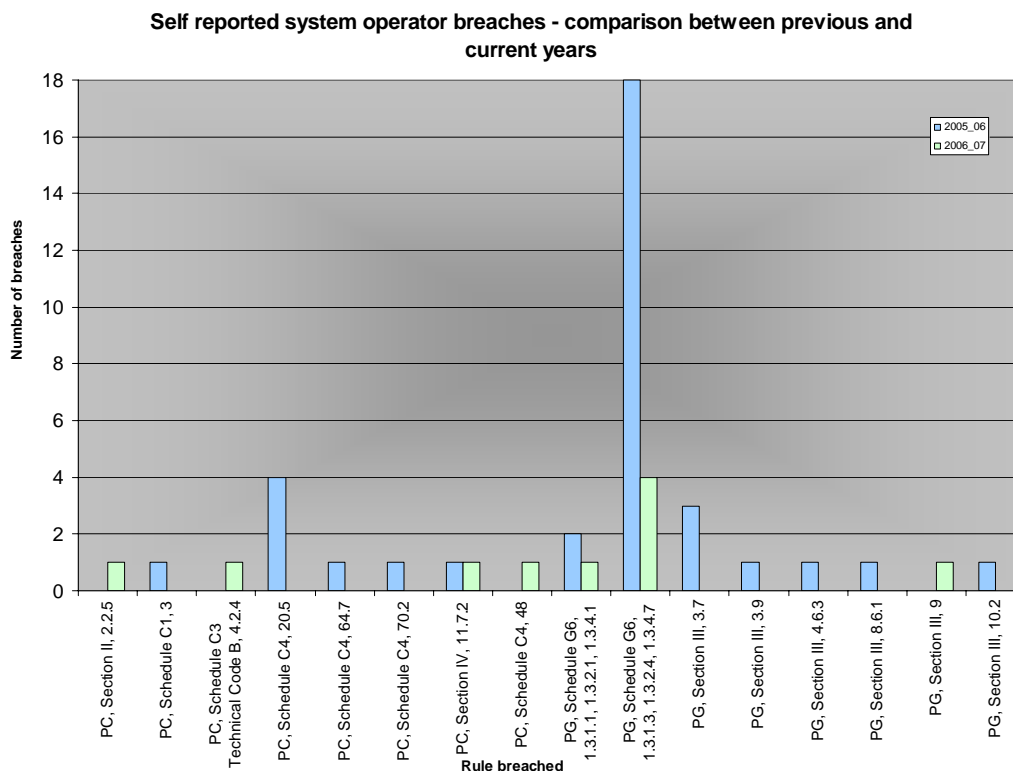
Graph of SO Self-Reported Breaches 1 September 2006 - 31 August 2007



Graph of SO Self-Reported Breaches 28 February 2006 - 31 August 2006



The bar graph below shows a comparison between the previous year and the current year self-notified breaches (35 and 10 respectively).



Overall, there was:

- a significant decrease in the number of self-notified System Operator breaches in the 2006/07 year compared with the previous year
- minimal correlation between the rules breached in the current year compared with last year.

In the System Operator's view this reduction, combined with the lack of further similar breaches, demonstrates it has taken effective quality assurance measures in response to previous rule breaches.

Further specific observations and comparisons with the 2006/07 year can be made:

6.1.1 **Updating grid information in schedules**

(rules 1.3.1.3, 1.3.2.4, and 1.3.4.7 of Schedule G6)

Breaches have decreased from last year's total of 18 to 4. All the reported breaches in this category had negligible market impact.

6.1.2 **Information provision**

Breaches relating to providing market information include three rule categories.

- those relating to the content and sending of information in formal notices issued by the System Operator (Rule 4.2.4 of Technical code B and clause 48 of the Policy Statement). There were two notifications in this reporting period compared with none in the previous year. The System Operator has initiated a project to review the content and sending of formal notices targeting improvements to the quality and timeliness of information about grid

emergencies. Changes arising from this review will be reflected in the 2008/09 Policy Statement

- those relating to System Operator provision of information to the Clearing Manager about allocable costs. There was one breach of rule 11.7.2 of section IV of Part C in the period. Whilst the rules provide for such inaccuracies to be washed up, the System Operator continues to pay particular attention to the accuracy of the ancillary services cost information being provided to the Clearing Manager to minimise the risk of such errors occurring
- those relating to the sending of the System Operator daily report by 0900 every day. There was one breach of this rule, caused by a communications failure. There was no market impact arising from this breach.

6.1.3 **Constraint accuracy**

(Rule 20.5 of Schedule C4)

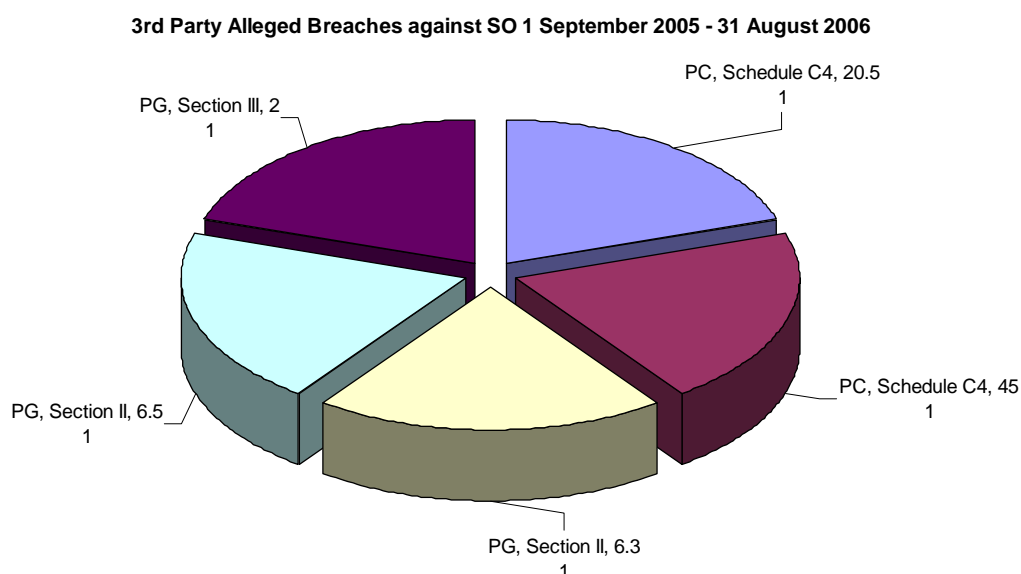
There was one self-notified breach relating to constraint accuracy in the reporting period. This breach, in April 2006 relating to the incorrect modelling in service of the Wilton T8 transformer, was referred to the Rulings Panel. The Panel's hearing is scheduled for October 2007.

6.1.4 **Principle performance obligations (PPOs)**

The System Operator notified one breach of the PPOs in the reporting period. This was a breach of rule 2.2.5 of section II of Part C, in relation to time error. Whilst the breach did not have any security or market impact, the System Operator is treating the breach extremely seriously and is undertaking a thorough investigation into the cause and the corrective actions required.

6.2 **Alleged System Operator Breaches Reported by Other Parties (including the Electricity Commission)**

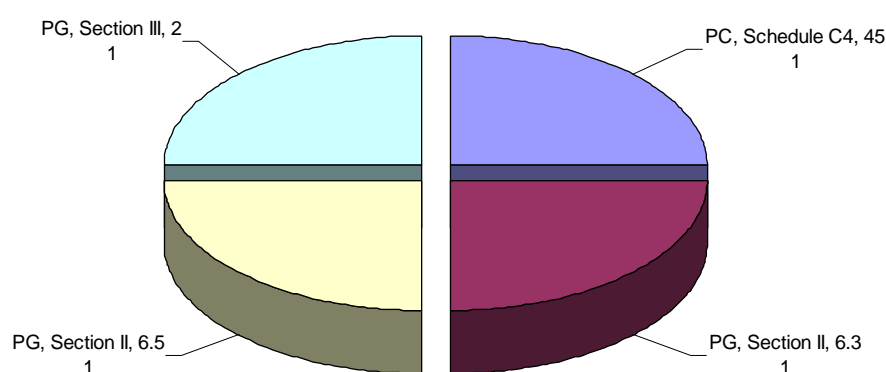
The following graph categorises 5 alleged breaches by the System Operator notified by other participants or the Commission during the reporting period.



There were:

- no breaches were alleged against the System Operator for the period (1 September 2006 – 31 August 2007)
- 4 breaches were alleged against the System Operator during the period 28 February 2006 – 31 August 2006. These are detailed in the graph below. One allegation, by the Commission, and admitted by the System Operator, related to a failure to issue a grid emergency notice in writing on 19 June 2006. The failure was due to issues with the System Operator's faxination system. At the reporting date this breach is subject to settlement discussions. The three remaining breaches, alleged by a participant, were not upheld and were dismissed.

3rd Party Alleged Breaches against SO 28 February 2006 - 31 August 2006



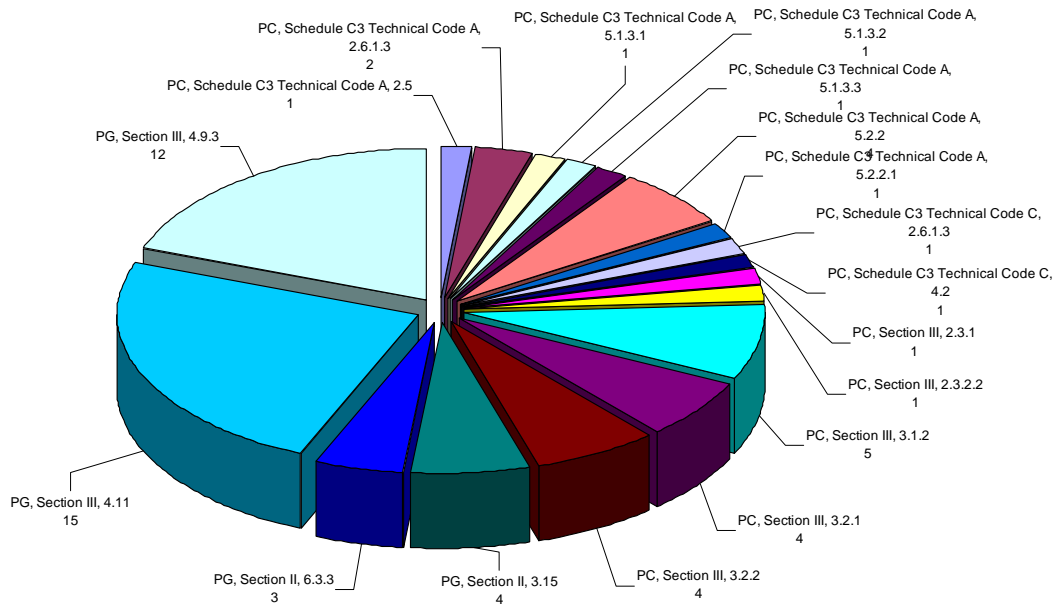
6.3 Breaches Alleged by System Operator Against Other Participants

The following graphs represent Rule breaches by third parties notified by the System Operator. As the review period has changed from previous years, the graphs below represent:

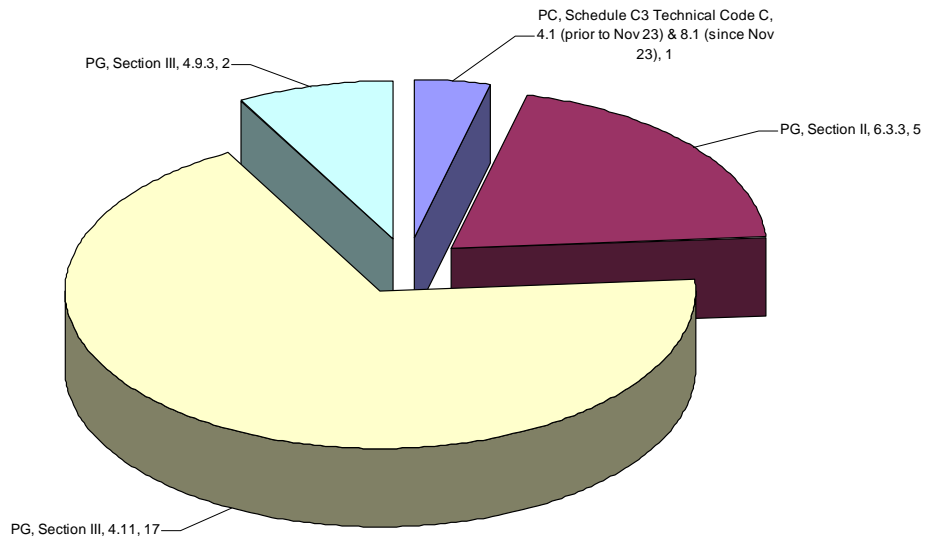
- previous year: 1 September 2005 – 31 August 2006 (62 breaches)
- 'additional' reporting period: 28 February 2006 – 31 August 2006 (36 breaches)
- current year: 1 September 2006 – 31 August 2007 (25 breaches)

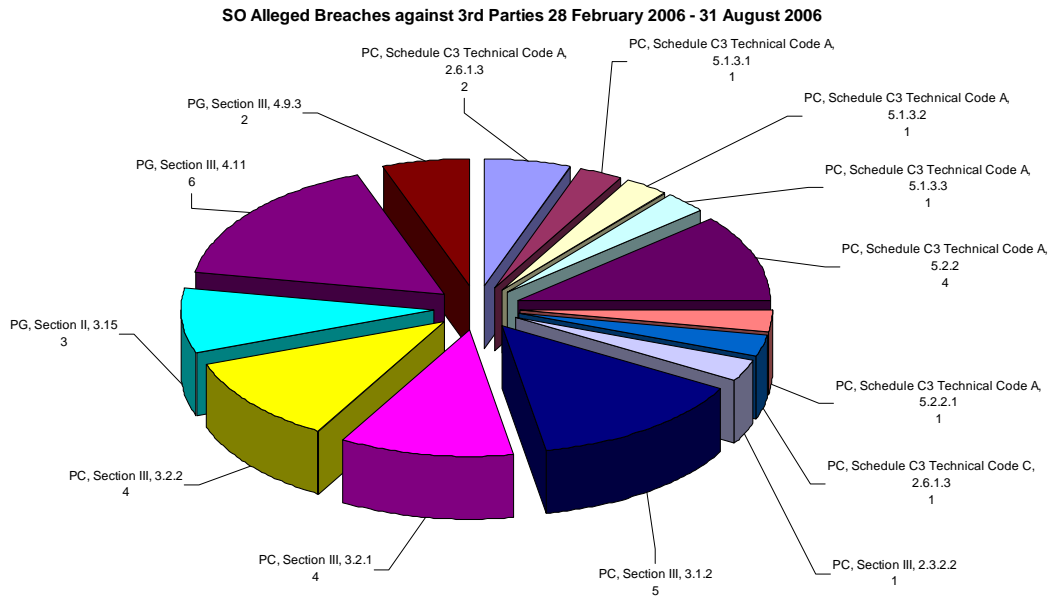
Comparisons are made between the previous (1 September 2005 to 31 August 2006) and current (1 September 2006 to 31 August 2007) years. The data for the additional period is represented for completeness and is a subset of that reported for the previous year.

SO Breaches alleged against 3rd Parties 1 September 2005- 31 August 2006

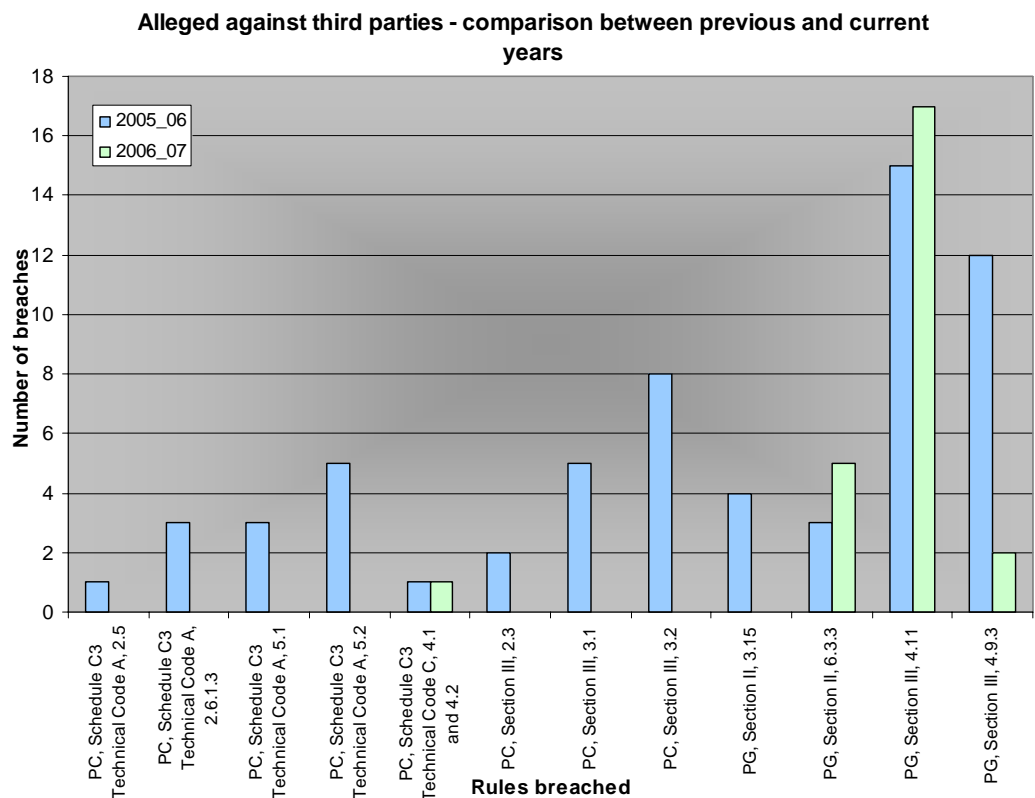


SO Alleged Breaches against 3rd Parties 1 September 2006 - 31 August 2007





The graph below shows a comparison between the previous and current years:



There has been a reduction of 37 breach allegations by third parties since last year (from 62 breaches to 25). This reduction appears to be due primarily to the reduction in Part C breaches relating to asset capability. Potential breach situations are being resolved through the application for and granting of dispensations.

The System Operator makes the following additional observations:

Compliance with dispatch instructions

The number of breaches notified for non-compliance with dispatch instructions increased in the reporting period. However, unlike the previous period, a number relate to non-compliance with reserve dispatch instructions. A significant portion of such reported breaches have been investigated by the Commission and have been settled. Some remain in the Commission's fact finding process.

Failing to acknowledge dispatch instructions

Compliance with dispatch instructions remains a critical outcome of Rules implementation for the System Operator and the industry as a whole. The System Operator must be able to rely on such compliance to plan to comply and comply with the PPOs. The industry also must have confidence in participant compliance, as a moderate level of non-compliance will affect economic dispatch and the dispatch objective.

The System Operator is pleased to note a large reduction in notified breaches for failing to acknowledge dispatch instructions. In our view, this reduction reflects significant work undertaken by participants, the System Operator, and the Electricity Commission on implementing processes and mechanisms to reduce the risk of breaching this rule. Such mechanisms have included working together to achieve a greater understanding by all parties of the compliance requirements in the rules.

6.4 Settlements

6.4.1 Settlement of System Operator breach allegations

One settlement agreement was entered into during the reporting period. This was in respect of an incorrect permanent constraint that was entered for PPI-WRK. All actions agreed to be undertaken in the settlement agreement were completed prior to 31st August 2007.

One matter under investigation at the start of the reporting period, being certain breach allegations made by the Commission in respect of a 10th March 2004 event, was not settled. The breach allegations were that the System Operator provided the Pricing Manager with incorrect risk adjustment factors (RAFs) for use in final pricing for two trading periods. The allegations were strongly resisted by the System Operator which maintained they were without foundation. The matters raised were not capable of settlement.

After significant debate regarding the facts and the meaning of the applicable rules, the Commission granted the Pricing Manager an exemption from rules 4.2, 5.4, and 5.5 of Schedule G6 in respect of reserve inputs. This was followed by the EGR Committee dismissing the breach allegations by the Commission.

6.4.2 Settlement of other participant breach allegations

The System Operator participated in six settlement agreements in respect of notified breaches by other participants.

Three settlement agreements related to the non-provision of reserves by reserve providers (and includes the settlement referred to in paragraph 4.2.13 above). The other three were for non-compliance with MW dispatch instructions.

6.5 Assurance

The System Operator's Assurance Framework is an important element of the System Operator's compliance programme, itself an important element of its business improvement activities. The framework includes an internal audit regime, comprising pre-defined and planned Rules assurance reviews ('reviews') designed to monitor the System Operator Group's ongoing compliance with the Rules. It ensures appropriate processes, procedures, and controls are in place and are observed to support Rule compliance and continued to operational effectiveness.

Each review is designed to verify:

- the System Operator is compliant with Rules that relate to specific processes
- procedural documentation is fit for purpose
- the documentation reflects actual practice.

Each year, an Annual Assurance Plan is developed that identifies individual reviews to be completed, and also allows for reviews to be identified during the year (for arising needs). This approach also ensures appropriate coverage on a rotating basis across all Rule compliance areas. The Annual Assurance Plan runs from 1st July through to 30th June each year. Two plans were in place for the reporting period.

In developing the Annual Assurance Plan the specific reviews to be included are determined by identifying the System Operator's core processes, corresponding EGR compliance requirements, and associated business processes relating to those requirements. The business processes and compliance requirements are assessed to determine a logical split into specific reviews. Deciding which process and compliance requirements to review is based on the risk the process presents to the System Operator's ability to comply with the Rules, the complexity and size of the business process or processes being reviewed, previous breaches (if any) of the Rules associated with the process and the time and resources able to be allocated to complete the review.

During the period March 2006 to August 2006, 3 reviews were undertaken:

- external review of the System Operator's constraint management process
- outage co-ordination process
- conflict of interest procedures.

During the period 1st September 06 to 31st August 2007, 4 reviews were undertaken. These were:

- formulation of the grid plan
- security assessment process
- event investigation process
- dispensations and equivalence process.

In addition, certain elements of the System Operator's business activities are included within the Transpower New Zealand Ltd internal audit plan. Some of these reviews are directly relevant to the capability of the System Operator to function as a reasonable and prudent system operator, such as a review (by PricewaterhouseCoopers) of business continuity planning scheduled to be undertaken just after the reporting period.

7 Rulings Panel

As noted above (see section 6.4) the Commission has referred one breach to the Rulings Panel for determination as to penalty. This matter, which is admitted by the System Operator and involves a situation where a material market impact was caused by the breach, will be heard by the Panel in October 2007.

8 Near Misses

There were no near misses reported during this period.

9 Specific Compliance Requirements under the Rules

9.1 Monthly Reports

The System Operator has complied with its obligation 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 Commission.

9.2 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.

The first SSF issued under the EGR's (the SSF issued in Dec 04) was assessed to determine whether a June 2006 revision was required. The notification that no revision was required to the SSF was advised to the Board in May 2006.

In December 2006, the System Operator published a new SSF (the 2006 SSF). In June 2007 it notified the Board the 2006 SSF would be updated; that update was published in August 2007.

The December 2006 SSF was published in CD-ROM format and contained more information (accessed by incorporation of links to separate reports, also contained on the disk) delivered in a more useable and helpful format.

9.3 Procurement Plan – Ancillary Services

The System Operator submitted the 2006/7 and 2007/8 draft Procurement Plans to the Board by the 1st of June 2006 and 1st of June 2007 respectively. In each case, while developing the draft plans the System Operator met with selected participants and, separately, invited comment from all industry participants. Suggested changes as well as feedback on matters specifically raised by the System Operator were considered in preparing the final drafts submitted to the Board.

Procurement 2005/ 2006

The 2006/7 Procurement Plan came into effect on 1st December 2006, the expected and due date. Tendering for ancillary service had been completed prior to the plan operative date. The major changes¹ introduced in the plan were:

- cost of baseline tests for Black Start ancillary service
- inclusion of CPI-X formula for limiting price path on long term contracts
- description of performance requirement of frequency keepers
- inclusion of assessment of performance requirements for interruptible load (IL)

Procurement 2007/2008

As at 31st August 2007, the 2007/8 plan was in the process of being recommended for adoption by the Minister of Energy. It is expected to come into effect on 1st December 2007. The major changes² introduced in the draft plan are:

- description of frequency keeping performance requirements for ancillary service agents notifying the system operator of outside of limit frequency or time error and the System Operator's action to review dispatch
- procurement of frequency keeping services in an islanded section of the grid
- description of frequency keeping offer requirements
- inclusion of assessment of performance requirement for FIR other than IL
- inclusion of a verified error range in data provided by ancillary service agents (ASA). The System Operator will have regard to the range when assessing ASA compliance with performance requirements.

¹ This commentary is not a comprehensive list of changes introduced. Full details of the changes introduced in each of the 2006/7 and 2007/8 Procurement Plans have been published on the Electricity Commission website (<http://www.electricitycommission.govt.nz/submissions/comqual>) in comprehensive schedules.

² The changes listed for the 2007/8 plan are subject to final approval by the Minister of Energy.

9.3.1 Contracted ancillary services

The following table summarises the contracted services as at 31 August 2007:

Ancillary Service Agent	FK ⁽¹⁾	IR ⁽²⁾	OFR ⁽³⁾	BS ⁽⁴⁾	VS ⁽⁵⁾
Meridian Energy	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/> *	<input checked="" type="checkbox"/> *	
Contact Energy	<input checked="" type="checkbox"/> *	<input checked="" type="checkbox"/> *	<input checked="" type="checkbox"/> *		<input checked="" type="checkbox"/> *
Mighty River Power	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>		<input checked="" type="checkbox"/> *	<input checked="" type="checkbox"/> *
Genesis Power	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>		<input checked="" type="checkbox"/>	
TrustPower		<input checked="" type="checkbox"/>			
Vector		<input checked="" type="checkbox"/>			
Powerco		<input checked="" type="checkbox"/> *			
Unison		<input checked="" type="checkbox"/>			
WELNetworks		<input checked="" type="checkbox"/>			
CountiesPower		<input checked="" type="checkbox"/>			
NZ Steel		<input checked="" type="checkbox"/>			
Pan Pac		<input checked="" type="checkbox"/>			
Winstone Pulp International		<input checked="" type="checkbox"/> *			
Norske Skog		<input checked="" type="checkbox"/> *			
KCE Mangahao and Todd Mangahao		<input checked="" type="checkbox"/>			
Northpower		<input checked="" type="checkbox"/>			

⁽¹⁾ FK - Frequency Keeping

⁽²⁾ IR - Instantaneous Reserves

⁽³⁾ OFR - Over Frequency Reserve

⁽⁴⁾ BS - Black Start

⁽⁵⁾ VS - Voltage Support

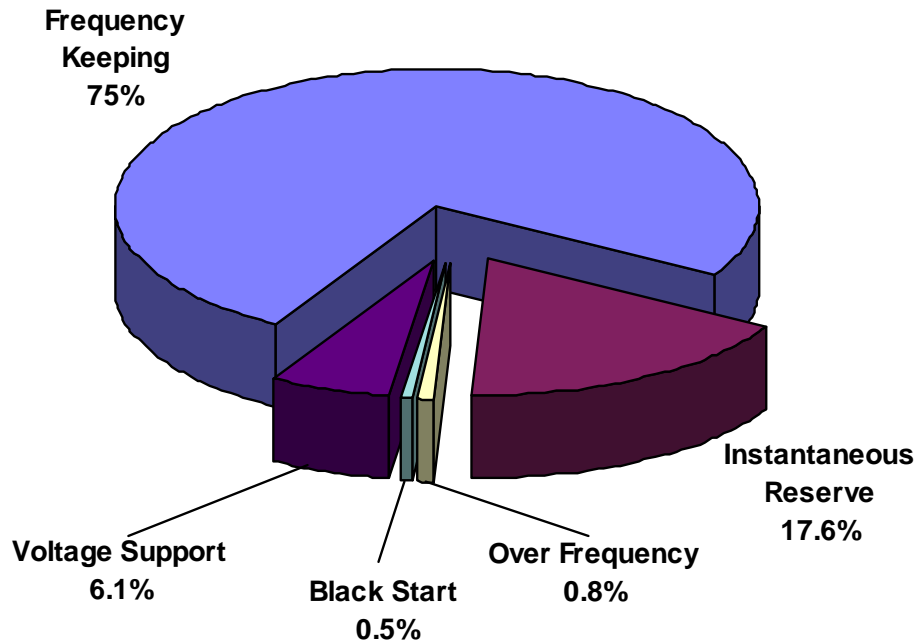
*Longer term contract

9.3.2 Ancillary service procurement costs

Procurement 2004 – 2005

Total ancillary service cost for period = \$61,062,616

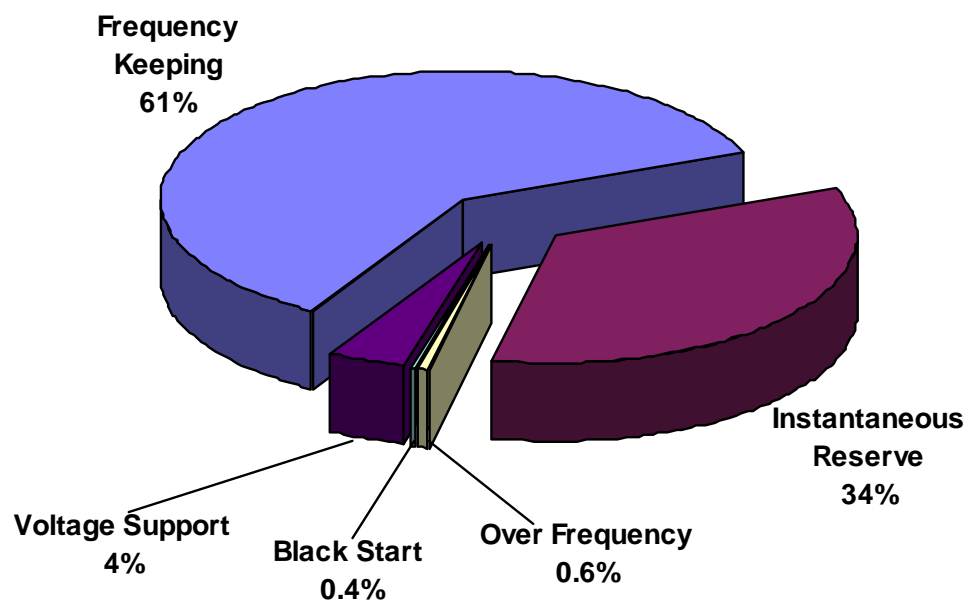
(1 Nov 2004 to 31 Oct 2005)



Procurement 2005 – 2006

Total ancillary service cost for period = \$96,547,876

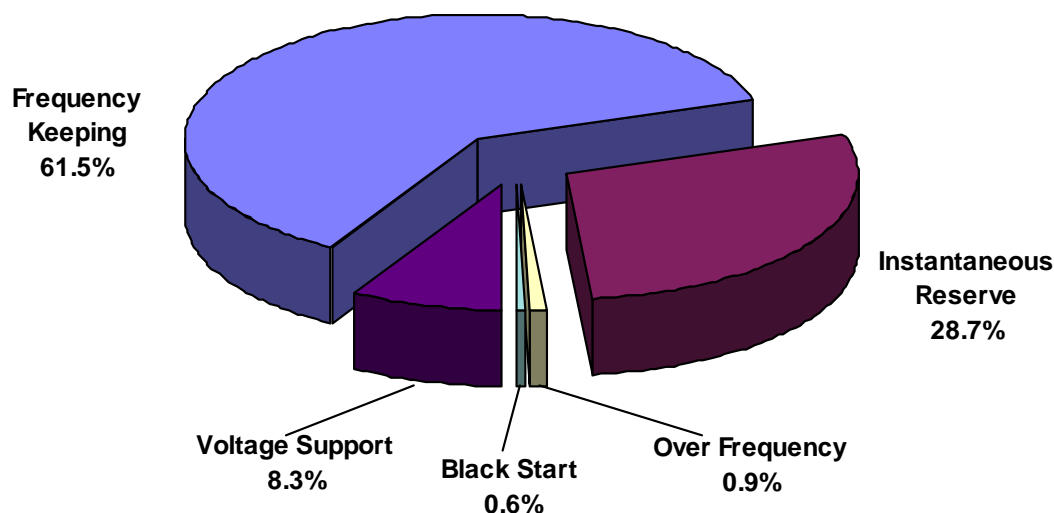
(1 Nov 2005 to 31 Oct 2006)



Procurement 2006 – August 2007 (year to date)

Total ancillary service cost for period = \$56,540,259 (10 months –year to date)

(1 Nov 2006 to 31 Aug 2007)



Note: Schedule C5 of Part C of the Rules (the Procurement Plan) was replaced with a new Schedule C5. This became effective on 1 December 2006.

All ancillary services procured under the 2005/06 Procurement Plan expired 30th November 2006. The contracts for ancillary services procured for the 2006/07 period came into effect on 1st December 2006.

9.4 Policy Statement

The annual Policy Statement review was completed twice during the review period. In each case, when developing the draft statements the System Operator met with selected participants and, separately, invited comment from all industry participants. Suggested changes as well as feedback on matters specifically raised by the System Operator were considered in preparing the final drafts submitted to the Board. The draft policy statements for 2006/7 and 2007/8 were respectively delivered to the Commission by 31st March 2006 and 2007. After consultation by the Commission and adoption by the Minister of Energy the respective drafts became the operative Policy Statements on 1st September 2006 and 1st September 2007.

Major changes introduced with each review³ were:

³ This commentary is not a comprehensive list of changes introduced. Full details of the changes introduced in each of the 2006/7 and 2007/8 Policy Statements have been published on the Electricity Commission website (<http://www.electricitycommission.govt.nz/submissions/comqual>) in comprehensive schedules.

2006/7 Policy Statement:

- commissioning noted as possibly being a “credible event” (for planning purposes)
- clarity of the System Operator’s intention to only choose one ancillary service agent in each island each trading period, to provide frequency keeping ancillary service
- new provisions in the ‘allocation of demand reduction’ section to clarify the demand shedding process and the status of and process for issuing demand allocation notices
- a new process added for asset owners to notify unexpected changes to asset capability via an urgent change notice.

2007/8 Policy Statement:

- requirement added to undertake a full review of defined events on a 5 yearly rotation
- added provision for automatic development of security constraints and simultaneous feasibility testing
- changes to grid emergency declarations to reflect most notices are verbal
- obligations created in respect of regional and other planning forums
- standby residual check obligations added to support National Winter Group work
- obligation added to develop a test plan guide.

9.4.1 Departures from policy statement

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

9.5 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.

9.5.1 Annual RMT and SPD certification

RMT/SPD opinion provided by PA Consulting on 14th March 2007. This opinion was the annual certification of the Scheduling, Pricing and Dispatch (SPD) Software and the Reserve Management Tool (RMT) for the period of the review, as required in the System Operator Service Agreement and in regulation 51 (1).

9.5.2 RMT

- RMT opinion provided by PA Consulting on 8th May 2007. Changes were to: accommodate the White Hill wind farm and allow the HVDC reserve sharing limit to be operator configurable instead of being hard-coded
- RMT opinion provided by PA Consulting on 18th January 2007. Changes were to: model a new Rangipo governor scheme which achieves a higher FIR and SIR response
- RMT opinion provided by PA Consulting on 1st December 2006. Changes were to: add Southdown E105 as an ungoverned generator; add Huntly Unit 5 as an ungoverned generator; add Te Apiti generator under-frequency trip settings corrected to the ACS values and various amendments to RMT.exe (Visual Basic front end) to allow modelling of Huntly Unit 5 as a secondary risk during the commissioning phase.

9.5.3 SPD

SPD TP37.33. Opinion provided by PA Consulting on 30th August 2006. Change was to introduce a new version to refine the application of the SOS1 constraints to address the issue of intermittent \$100,000 bus prices at the Otahuhu buses in the pricing solution.

9.5.4 Test plan

The Commission proposes to amend the rule obligations (Technical Code A of Part C) that require the System Operator to agree a routine test plan. The test plan obligations are likely to be changed to define certain requirements on asset owners to undertake tests and thereby provide ongoing assurance of asset capability. The Rules will also require the System Operator to prepare and maintain a guide to the tests that asset owners can carry out and which are likely to provide the capability assurance required by the rules.

In anticipation of the rule change, and in any event because of the value represented by the guide, the System Operator has completed a guide and published that on its website in August 2008. This guide will be updated from time to time as experience and circumstances dictate.

9.6 Undesirable Trading Situations

One undesirable trading situation was claimed during the reporting period. This was a claim by Genesis Energy which considered there may have been an error in the SPD model used for the calculation of final price for 28th April 2006 which would have resulted in the improper settlement of trades. In particular, the final prices for trading period 35 at Wilton, Haywards, and Greytown and surrounding areas were called into question.

The System Operator assisted the Commission with its inquiry into the relevant events. The Commission determined the circumstances did not constitute an undesirable trading situation.

10 Specific Compliance Requirements under the SOSPA

10.1 Disaster Recovery Plan

No changes were made to the System Operator's disaster recovery plan provided to the Commission and approved by it in 2005.

However, the System Operator has made changes to its Business Continuity Plan. These were identified during a 'table top' exercise held on 7th August 2007. The main objectives of the exercise were to:

- review the content of the business continuity plan
- identify any needed improvements
- raise the visibility and the value of business continuity planning within System Operator
- expose the contributing staff in the exercise to a significant event
- gauge the System Operator's continuing capability to manage continuity events.

Some additions to the business continuity plan were identified. The event reaffirmed the value of regularly exercising business continuity capability to provide assurance of major event recovery capability. The next event, a larger simulation exercise, is planned for 2009.

10.2 Warranties

At the date the SOSPA was entered into the System Operator provided the Commission with certain warranties. These are not able to be reiterated in full. As at 31st August 2007 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 not have sufficient financial resources to carry out the said services and will require additional financial resources from the Commission to ensure it can continue to act as a reasonable and prudent system operator
- does have sufficient skills and supervision to carry out the said services.

The System Operator has commenced negotiations with the Commission regarding the requirement for additional resources (see section 16.1 below).

11 Specific Compliance Activities

11.1 Dispensation and Equivalence Applications

A total of 132 dispensation applications were received in the review period. No equivalence applications were received.

11 dispensations were granted, 14 were the subject of draft decisions (expected to be granted after the review period), 9 applications were withdrawn, 79 applications are awaiting information from the asset owner and 18 applications remained under consideration as at 31st August 2007.

11.2 Exemption Applications

The System Operator assisted the Commission with a number of exemption applications made by participants during the period:

- an application by the Grid Owner in respect of Rule 11.5.2, Section IV of Part C (event charges). The exemption application was withdrawn before being granted
- an application by Genesis Energy in respect of in respect of Rule 11.5.2, Section IV of Part C (event charges, in relation to the Huntly Unit 5 commissioning). The exemption application was granted
- three applications by Mighty River Power in respect of Rule 4.11, Section III of Part G (tolerance related to compliance with dispatch instructions for Southdown, Rotokawa and Mokai). The exemption applications were granted.

The System Operator sought and was granted an exemption in respect of its obligation to provide a review of its performance under Rule 14, Section II of Part C. Following a change in the Rules affecting the reporting period the System Operator would have been obliged to prepare a review for a six month period (March 2006 – August 2006). The System Operator believed a review for

such a short period would have been unworthwhile and sought exemption from doing so. The application was granted.

12 Ancillary Service Provider Performance 2006/7

12.1 Instantaneous Reserves

The table below summarises the Instantaneous Reserve (including Interruptible Load) performance assessments carried out by the System Operator for the period of 1st March 2006 to 31st August 2007.

Under Frequency Event Summary - Instantaneous Reserve event assessments								
Date	Time	Event initiated at	MW	Lowest Frequency (Hz)		MW Lost	Number of Dispatched IR Ancillary Service Agents (ASA)	Performers and (non-Performers)
				North Island	South Island			
09-Mar-06	22:12	MAN U4	67.4		49.15	67	13	12 (1)
29-Mar-06	19:29	HLY U3	222.2	49.21	49.75	222	Not an IL event	*
10-Apr-06	19:18	HLY U4	202.7	49.21	49.91	203	Not an IL event	*
16-Jun-06	16:28	SPL	338	49.21	49.45	338	Not an IL event	*
06-Sep-06	14:25	HLY U3	210	49.24	49.80	210	Not an IL event	*
10-Oct-06	08:23	HLY	243	49.23	49.49	243	Not an IL event	*
8-Nov-06	11:20	OTC	366.0	49.07	49.28	366	14	11 (3)
1-Dec-06	11:03	OTC	297.0	49.20	49.39	297	13	12 (1)
19-Mar-07	18:03	HLY	238.0	49.22	49.36	238	Not an IL event	*
30-Mar-07	09:26	BEN / HVDC	326.0	49.43	48.60	326	No SI IL	*
17-Apr-07	22:15	HLY	230.0	49.21	49.53	230	Not an IL event	*
21-Apr-07	16:07	SPL	306.0	49.17	49.34	306	12	10 (2)
29-Apr-07	05:10	HLY / SPL	610.0	48.26	49.44	610	13	6 (7)
3-May-07	15:10	HLY	386.0	49.18	49.45	386	10	8 (2)
21-May-07	11:11	HLY	390.0	49.21	49.28	390	Not an IL event	*
11-Jun-07	21:20	HLY U5	249.0	49.22	49.43	249	Not an IL event	*
13-Jun-07	11:11	HLY U5	395.0	49.19	49.43	395	13	12 (1)
6-Jul-07	14:25	HLY U5	383.0	49.18	49.43	383	14	12 (2)
16-Jul-07	23:04	HLY U5	385.0	49.17	49.37	385	14	11 (3)
18-Jul-07	12:41	HLY U5	384.0	49.08	49.86	384	14	14 (0)
20-Aug-07	14:25	HLY U5	353.0	49.16	49.42	353	14	13 (1)

Notes:

- Several of event assessments require further analysis and discussion between the System Operator and the Ancillary Service Agent.
- The under frequency events marked with an asterisk (*) did not reach the event trip frequency (49.2Hz) for interruptible load (IL). Assessments were carried out on other IR providers dispatched during these events.

12.2 Frequency Keeping Reserves

The System Operator assesses the performance of frequency keeping ancillary services on a monthly basis.

The analysis considers the performance of each frequency keeper and compares individual performance to other providers. Any identified issues regarding performance are addressed directly with the ancillary service agent.

12.3 Black Start

On the 18th November 2006 Meridian and the System Operator successfully completed a South Island station black start test.

The test involved demonstrating station capability to:

- start up the main generation of the power station from shutdown in agreed timescales without the use of external power supplies
- energise part of the transmission grid system within a pre-agreed time following instruction from Transpower
- synchronise multiple units onto the islanded section of the grid.

The key objectives of the test were:

- demonstrate the processes, systems and plant used for restoring supply are fit for purpose in delivering the service
- increase awareness and understanding in black start processes
- to enhance Transpower and Meridian's capability to manage a black start event
- to enhance Transpower and Meridian's capability to recover from a black start event

A similar black start test is currently being planned for the North Island in November 2007.

12.4 Voltage Support

During the period 1st March 2006 to 31st August 2007 the System Operator has dispatched the contracted zone 1 and zone 3 voltage support for a total of 66 occasions.

Zone 1 voltage support is provided Otahuhu Units 1, 2, 4, 5 and 6, Marsden SC2, and Southdown 105.

Zone 3 voltage support was provided from Cobb power station for the period January 2006 to May 2006

13 Industry Consultation Papers

13.1 Contributions and Submissions

The System Operator actively contributed to a number of 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 concert with the Grid Owner as Transpower New Zealand Ltd responses or papers:

- Instantaneous reserves
- Changes to Part D Schedule 2
- Minor pricing and settlement rule changes
- High spring washer
- Centralised data set
- Notification of constraints
- Co-generation offer and dispatch rules
- Reconciliation rule change- transition rules
- Duplicate protection
- Intermittent Generation rule change
- hedge market - issues and options
- Amended information systems - definition
- Rolling outage regulations and planning
- Publication of reserve offers
- Duplicate protection
- Security of Supply (Castalia discussion paper)
- peak demand information
- COMIT backup arrangements
- Routine testing plan
- Benchmark agreements
- Electricity Commission principal objectives
- Demand forecasting for security of supply
- Two traders at a point of connection
- Allocation of under-frequency charges
- Market design issues
- Demand side bidding and forecasting
- Assorted regulation changes
- Compliance review.

14 System Operator People and Resources

14.1 People

The System Operator personnel numbers during the reporting period were:

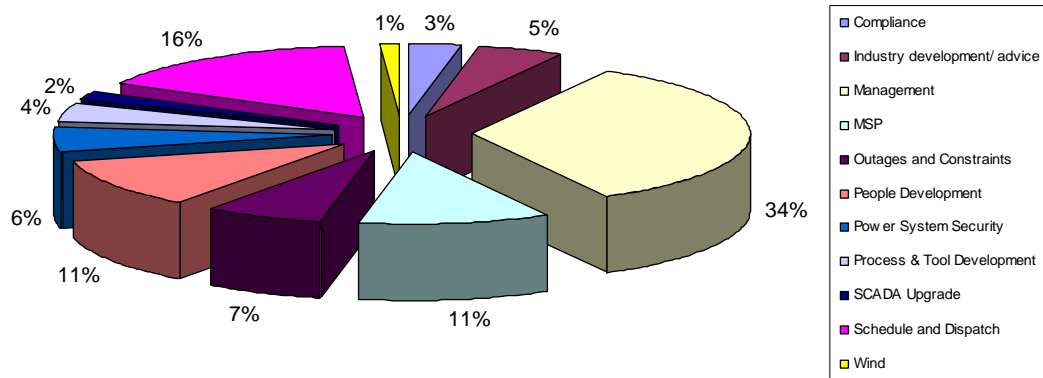
	19/09/2005	Change	17/05/2006	Change	31/08/2007	Change
General Manager	01		01		01	
Executive Assistant	01		01		01	
Risk & Performance	06		06		06	
Development	06		06		06	
System Operations	38	2	36	-2	38	2
Investigations	09	2	12**	3	14**	2
Operations Planning	15	1	17*	2	17*	0
Market Services	08	-2	12**	4	12**	0
General Administrators	03	2	03	0	03	0
Total	87	5	94	7	98	4

* includes one contractor

** includes two contractors

The following chart shows the allocation of personnel time to the System Operator's service areas during the reporting period. Support resources are allocated across each service area in the same proportion as the service represents to total services delivered.

SO Application of Resources: March 2006 - August 2007



14.2 Customer Service

14.2.1 Customer satisfaction survey

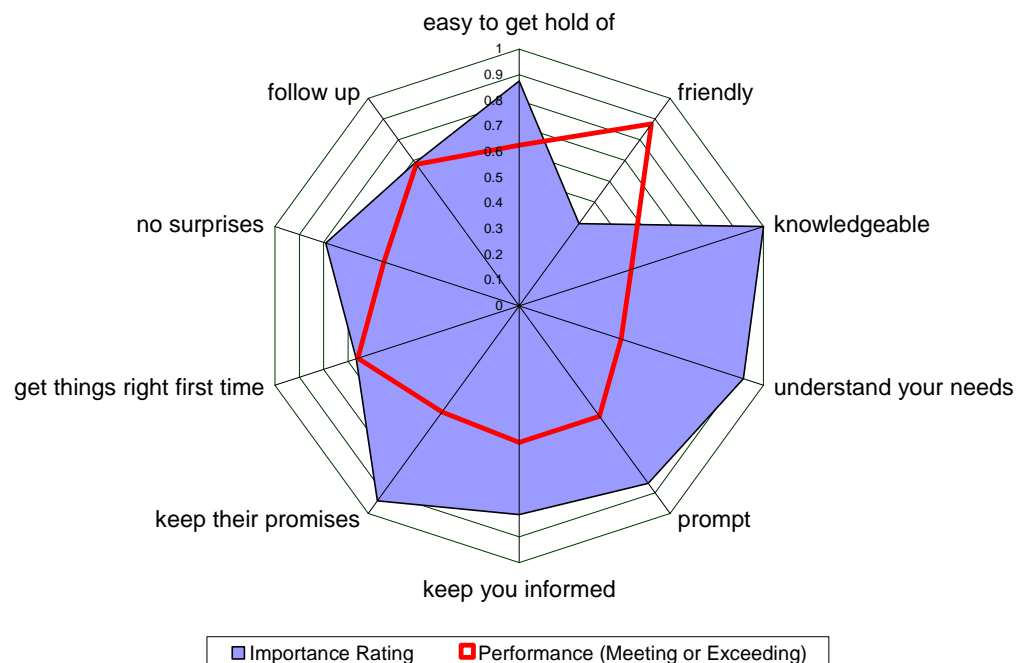
The System Operator undertook a further customer survey in April 2006. The survey (carried out by an independent professional) sought to provide a perspective on how participants and the Commission saw the System Operator with regard to ten internationally recognised service factors. A similar survey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

The service factors asked about were:

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

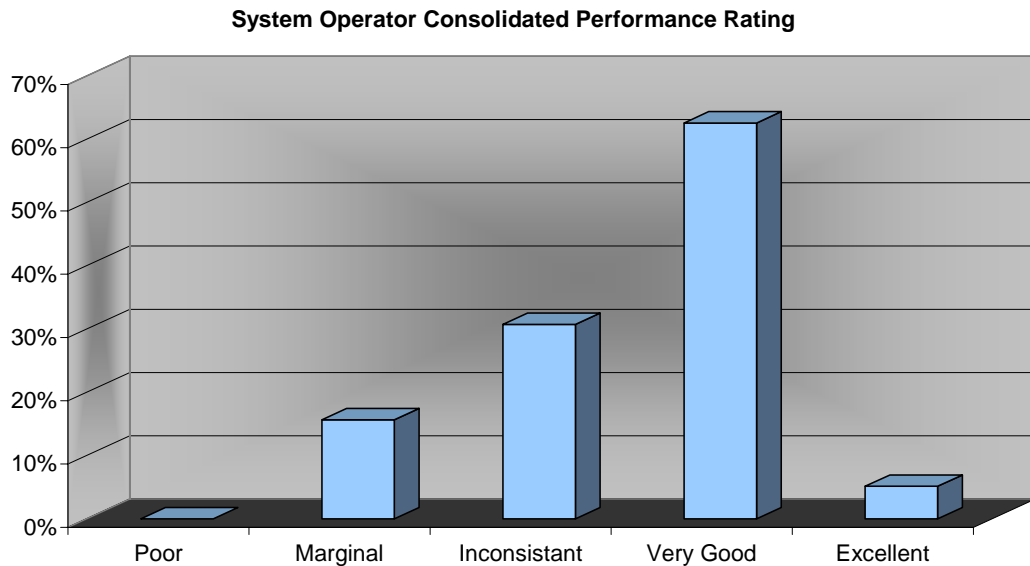
Each survey participant was first asked how important each service factor was to them and then how the System Operator was performing. The summarised results (by industry groups) are set out below. The importance of each service factor is based on those respondents who rated the factor of 'high importance'.

Composite Ratings Across System Operator: All Customer Groups



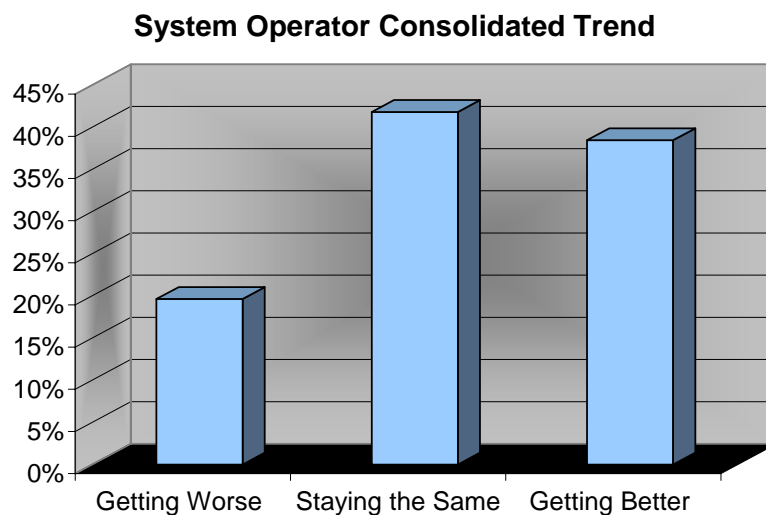
Overall performance

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



Trend of findings

The following graph shows how the survey respondents rated any change in the service levels from the System Operator over the six months prior to the survey.



The System Operator viewed the results as disclosing areas where participants and the Commission believed better service efforts were required or desirable. The System Operator has devoted some effort towards improving its level of service, consistent however with a realistic view of its resources and the requirements of its other projects, particularly its market systems project (see section 14.3).

Planning for the next survey (scheduled for November 2007) was commenced in the reporting period.

14.2.2 Advisory services to the Commission

The Commission indicated on a number of occasions during the reporting period (as well in its report on the previous 2005/6 System Operator annual review) it would like the System Operator to provide it with technical and, in some case, independent advice on engineering and market issues that arise from time to time. The services contemplated are ones that are in addition to the service obligations arising under the Rules but are within the expected competence of the System Operator.

The System Operator is aware the non-Rule services provided to the Commission during the reporting period were not provided at the level of quantity and timeliness the Commission would like. The System Operator is discussing with the Commission how it can increase its capacity to provide such services and on what terms.

14.3 Systems Development

14.3.1 Market systems project (MSP)

Background

The systems in use today for delivering the system operator services to the wholesale electricity market date from Transpower's appointment as System Operator to the NZEM in October 1996. These systems were largely bespoke designs; the core programs, including SPD, are actually prototypes (though refined over the intervening years). It was anticipated that as the market systems entered their second decade they would need to be upgraded.

After the appointment of the Commission in 2004 and the re-appointment of Transpower as the System Operator Transpower initiated investigations that determined that the market systems while stable (in 2004), were not sustainable and hence were 'not fit for purpose'. This meant the continued provision of a reasonable and prudent system operator services, as required under the SOSPA, was not as assured as it should be. The increasing operational risks attendant on continued use of the market systems were confirmed in late 2004 by independent advisors.

The project

Following Transpower Board approval, Transpower tested the market systems upgrade requirements in an RFI issued to an international industry group in mid 2005. A selection of viable vendors for an RFP process (timetabled for late 2005) followed. The market systems that were specified in detail through this process are designed to provide the following direct benefits to the system operator services:

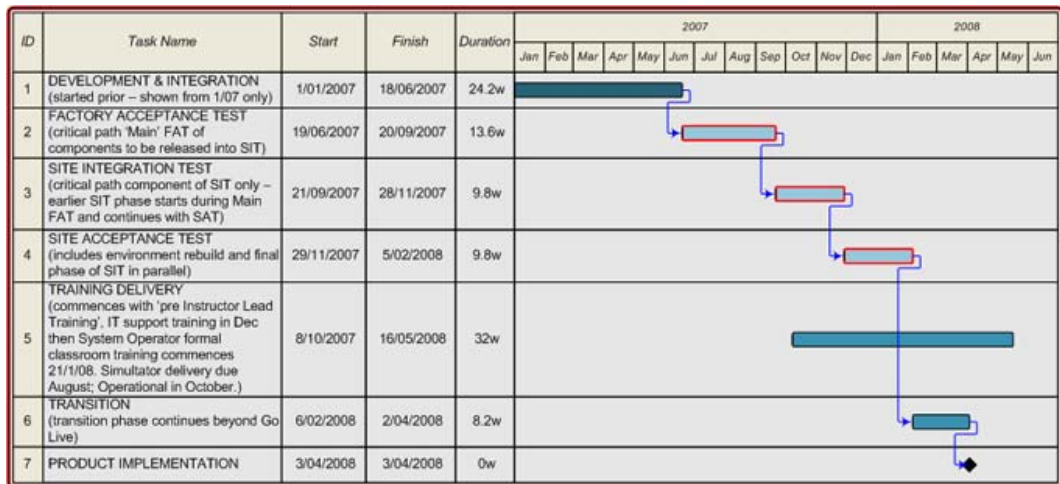
- reduced operational risk, achieved by bringing the market systems up to date with modern industry standards of technology, security, reliability and resilience
- a prudent package that delivers maintainability and flexibility for future development and enhancement of market capability and SO services
- re-engineered business processes, automated where appropriate to reduce reliance on manual (and hence risky) processes
- updated capabilities to enable the changes in the power supply environment to be managed

Transpower signed a contract for delivery of the new systems with AREVA TLD (based in Seattle, USA) in March 2006, with a targeted delivery of the middle of 2007.

The first six months of the programme were given over to project initiation, high level system design, detailed business design and initial development work. These tasks were accomplished while establishing the necessary working relationships between the Transpower Project team established in Wellington, the AREVA development team established in Redmond, Seattle and local subcontractors to AREVA in Wellington. Local subcontractors were engaged by AREVA to undertake system integration, site testing and some training.

Areva transformed the initial business requirements into the High Level System Design, completed in May 2006 and the project then progressively developed these into detailed design documents. The development project was split into 25 components for management reasons. Transpower identified owners for each of the individual component so that the large workload in reviewing and agreeing each of the design documents could be managed. As 2006 progressed, sufficient detailed design notes had been approved for AREVA to commence development work.

By October 2006 it was clear that the completion target of mid- 2007 was overly ambitious. To reduce project risk Transpower reluctantly agreed to reset the base timeline of the project schedule to a go live date of 31st March 2008. This is the timetable shown in the following diagram.



The project has subsequently tracked the rescheduled program, completing the development and integration phase on target. This permitted factory acceptance testing (FAT) to commence on 18th June 2007 thereby achieving a significant milestone on plan. Progress with FAT testing has been good and is on schedule to be completed in late September 2007.

Testing, transition and go-live

Transpower and its contractors have completed the majority of FAT which is the first phase of the comprehensive, three phase testing approach. Testing continues with system integration and site acceptance testing through to early 2008 and which leads onto the final project transition phase.

The project is on schedule to transition from the current to the new market systems on 2nd April 2008.

In parallel with the technical development and delivery of the new systems, a major work effort has been undertaken since mid 2006 to produce updated processes and documentation as well as training materials to support the new systems. This work covers both the core System Operator business areas and the supporting information and system technology areas within Transpower.

Transpower's training team has been working with the market system project team members to identify and capture the changes in knowledge and skills required to operate the new market system. As at the reporting date a large part of a comprehensive learning package has been developed for System Operator personnel. This will be progressively introduced over the balance of 2007 as training gets into full swing by the end of 2007.

All System Operator personnel will receive training, though to varying levels depending on the extent to which roles are affected by the new systems and changes to procedures. Implementation of the training programme has been planned to, wherever possible, minimise impact on the day to day business of System Operator while ensuring all personnel have the opportunity to complete specific programmes of learning.

While the new systems will be complete at the expected introduction date one element of the systems, namely simultaneous feasibility testing (SFT)⁴, will not be introduced until later in 2008. The intention is that the new capability represented by the SFT will be subjected to additional operational testing to provide the System Operator and participants with comfort regarding its capabilities and use in real time.

14.4 Wind Generation Projects

Certain intermittent generation rule changes proposed by the System Operator in January 2006 came into effect in March 2007.

The System Operator assisted the Commission with the Wind Generation Investigation Project to identify the impact of increased amounts of wind generation being connected to the power system. The Commission's Wind Generation Investigation Project (described on the Commission's website) is developing a view of the means by which large amounts of wind generation will be accommodated on the power system. The System Operator is currently providing full time personnel and technical resources to this project.

15 Stakeholder Relations - Website

15.1 Workshops and Newsletters

Eight System Operator newsletters were issued during the review period, three in 2006 and five in 2007.

Two participant workshop series were held in Christchurch, Wellington and Auckland during June 2006 and April 2007. One workshop was held in Wellington in November 2006.

⁴ SFT is a process whereby the current manual means by which security constraints are developed in planning time and in the schedules can be developed automatically and electronically.

Topics covered were:

June 2006

- DC Future Years
- frequency keeping selection
- POCP industry forum review
- System Security Forecast
- Market System Program Update
- Genco – current state and future vision
- Reserves Management Tool.

November 2006

- Huntly Unit 5(e3p) briefing.

April 2007

- implementation of National Winter Group actions
- Standby Residual Check and publication
- emergency management
- constraints development process
- Market System Project update and SFT description
- commissioning generation: a System Operator perspective (Part C)
- commissioning assets: a System Operator perspective (Part G)
- Policy Statement review 2007/08
- energy balance calculation.

15.2 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.

The website was revamped in the reporting period, with all the information being reorganised into categories more friendly to the market participants needs. Additional live data has been added to the site and these live data pages have become the most requested pages from the site. The site offers a subscription service that allows subscribers to be emailed when a registered area of interest has been changed.

15.2.1 Usage






Usage of the System Operator web has increased substantially in the last 12 months.

Traffic Analysis	1 Sep 2005 to 31 Aug 2006	1 Sep 2006 to 31 Aug 2007
Total visits:	<u>30,234</u>	<u>38,392</u>
Total pages viewed:	<u>160,425</u>	<u>904,435</u>
Total hits:	<u>189,087</u>	<u>989,725</u>
Total megabytes transferred:	<u>2</u>	<u>191</u>
Average visits per day:	<u>83</u>	<u>105</u>
Average visits per week:	<u>580</u>	<u>737</u>
Average visits per month:	<u>2,520</u>	<u>3,199</u>
Average pages viewed per visit:	<u>5</u>	<u>24</u>
Average pages viewed per day:	<u>440</u>	<u>2,479</u>
Highest volume time of day	<u>10 a.m. - 11 a.m.</u>	<u>9 a.m. - 10 a.m.</u>
Highest volume day of the week:	<u>Thursday</u>	<u>Thursday</u>
Highest volume month:	<u>May 2006</u>	<u>June 2007</u>

The most requested:

- Information - the published live data (most registered by a large margin)
- page - [Zone Loading page](#) (451,448 hits).

The top 5 most popular web site pages:

Page Name	Zone Loading	Upper South Island Security	Home Page	Upper North Island Security	Power System Overview
Hits	451,448	270,416	84,455	25,544	7,929
Image					

15.2.2 Content

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

- to support the work of the Upper North Island security working group (see section 3.2.1) additional 5 minute load data is now being published for the Henderson-Otahuhu line
- from the National Winter Group work (see section 3.2.5) Standby Residual Check (SRC) information is available, as also is a 'self use' model now available to participants through the website.

A number of System Operator publications were made available via the website during the period, including:

- procedures used for the System Operator's constraints development process. These included procedures for:
 - Security Constraint Development Overview (PR-SH-040)
 - Identify Constraints (PR-SH-042)
 - Conduct Peer Review of Constraint (PR-SH-044)
 - Email Notification, CANs and Updating Website (PR-SH-046)
- revised Conflict of Interest procedure
- an abridged version of Transpower's commissioning process
- documentation for connecting and dispatching new generation in New Zealand
- the Companion Guide for Asset Testing (a Policy Statement requirement)
- forms for Test Plan and Urgent Change Notice arrangements
- reports in respect of the June 2006 events (see section 3.1)
- all formal notices issued by the System Operator (these are published to the site at the same time as they are email to market participants)
- the June 2006 revision to the December 2004 SSF
- the new interactive version of the System Security Forecast (the 2006 SSF), and the June 2007 update
- other significant event reports, such as for the March 2007 Benmore generator tripping
- a number of policy and technical papers and presentations, including:

Title	Date	Description
North Island Frequency Excursion	May 2007	A summary report on the North Island frequency excursion that occurred on 29 th April 2007.
Benmore Tripping Event 30 Mar 2007	Apr 2007	Initial investigation report for the 30 th March 2007 tripping at Benmore Power Station and the HVDC Pole 1 that resulted in the loss of 326 MW from the South Island power system.
Otahuhu and Huntly Tripping Event	Dec 2006	Summary of events on 1 st December 2006 when restoring the power system after the tripping of the Otahuhu CCGT and which coincided with a further loss of generation at Huntly, resulting in a Grid Emergency.
Huntly Unit 5 Commissioning Information Overview Document	Nov 2006	An overview of the changes required to the System Operator's scheduling and dispatch process to enable the commissioning of the new unit 5 generating unit at Huntly.
Wellington Voltage Stability Study During HVDC South Transfer	Sep 2006	Report to determine the system limits for power flow from Bunnythorpe to Haywards while HVDC is in south transfer for the Wellington.
Summary of South Transfer Limits post May 2006	Sep 2006	Explains the transmission limits for future dry year events and comment on South Island reserves interaction with HVDC dispatch.
Review of 19 th June 2006 Generation Shortfall	Jul 2006	Report to determine what factors contributed to the shortfall and the changes in availability of generation on the 19 th June 2006 and the previous day.
Initial Report on 19 th June 2006 Generation Shortfall	Jun 2006	Report for the Minister of Energy into the Operation of the New Zealand Electricity Power System on Monday 19 th June 2006.
System Operator Constraint Audit	Apr 2006	Review of the Process for Design, Development, Testing, Application, Real-Time Use, and Removal of Security Constraints.
System Operator Constraint Audit Recommendations & Actions	Apr 2006	Recommendations and Actions from the Review of the Process for Design, Development, Testing, Application, Real-Time Use, and Removal of Security Constraints.

Title	Date	Description
System Operator Commentary on "Reasonable Estimate"	Feb 2007	The Electricity Commission has sought the System Operator's advice on how the term "reasonable estimate" should be interpreted and applied in Rule 6.3.3 of Section II of Part G. This paper provides comments on the issue of ensuring that sufficient quantity and appropriate quality of reserves are available to the System Operator and the continued downward pressure is applied to the cost of reserves.
Proposal for Changes to the EGR Compliance Regime	Jan 2007	What the objectives of an appropriate industry compliance regime should be, implementation issues with the existing compliance regime and achievement of industry objectives, suggested changes to both processes and regulations and rules that could better achieve industry compliance objectives.
SFT Constraint Publication Specification	Jul 2006	Summarises the proposal for publishing security constraint information from late 2007 when the System Operator introduces a new application to automatically generate n-1 thermal security constraints.

16 Service Provider Agreements

16.1 System Operator Service Provider Agreement (SOSPA)

In late 2006 the System Operator notified the Commission it wished to vary certain terms of the SOSPA, in particular in relation to the fees payable. It was appropriate during the discussion of such variations to also consider the Commission's request (mentioned in its July 2006 Annual Review and Assessment of System Operator's Performance, at pages 11 and 12) for the System Operator to provide additional technical advisory services to support the Commission's requirements. The System Operator is not proposing the current evergreen nature of the contract be changed.

The parties commenced discussions early in 2007, agreeing a general approach for the discussions and a timetable objective. Subsequently the parties have exchanged significant amounts of information and are progressing the discussions including when the proposed changes might be introduced, but recognising the Commission's need to satisfy certain consultation obligations in relation to funding that are requirements under the Electricity Act 1992.

16.2 Pricing Services Agreement

The System Operator's agreement to provide the Pricing Manager with access to the SPD software expired in February 2007. The expiry came at a time when the Pricing Manager services were in the course of being tendered by the Commission. It was not known if the then incumbent, The Marketplace Company Ltd would be re-appointed.

A temporary extension of the Pricing Services Agreement was entered into with The Marketplace Company Ltd to cover the period until a new Pricing Manager service agreement was put in place.

Subsequently, The Marketplace Company Ltd was re-appointed as the Pricing Manager and negotiations have been commenced for a new Pricing Services Agreement to take effect as soon as practicable.

16.3 COMIT System Agreement

At the same time as the Pricing Services Agreement came to an end so also did the COMIT System Agreement. From this agreement the System Operator gained assured access to the COMIT system for receipt of bids and offers and delivery of market information and, in some case, dispatch instructions.

A temporary extension of the agreement was agreed pending the appointment of a new provider (the service was also in the course of being tendered by the Commission). A new Wholesale Information and Trading System (WITS) service provider agreement (with The Marketplace Company Ltd) was established by the Commission as from 1st July 2007. Although the WITS is intended to provide access for all participants (including other service providers) the System Operator and the Commission are discussing the arrangements needed by the System Operator to gain assurance of access on the terms needed by it to fulfil its obligations under the SOSPA.

17 Financial Review (SOSPA)

17.1 Base Contract

Fees charged under the base System Operator Service Provider Contract were as follows:

Financial review: SOSPA	1 March 2006 – 31 August 2007
System Operator Service Provider Contract Base Fee	32,027,999.94
Information System Access Fee*	1,985,984.00
RMT and SPD Audit Fees*	10,762.50
Total fees paid under the SOSPA	34,024,746.44

*The information System Access fee is a reimbursement of cost charged to the System Operator by the Pricing Manager.

*The audit fees are a reimbursement of costs incurred by the System Operator in arranging audits mandated by the rules.

17.2 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 March 2006 – 31 August 2007
EC Advice ⁵	290,078.50
Breach investigations	33,534.50
System upgrades for rule changes	32,999.00
Disbursements and legal expenses refunded ⁶	35,495.33
Exemption applications	4,560.00
Total variable revenue	396,667.33

⁵ Includes some systems costs for rule change implementations.

⁶ Refers to costs incurred in relation to breach allegations against Third Parties and the System Operator.