SYSTEM OPERATOR

ANNUAL REVIEW 2005/06

TRANSPOWER NEW ZEALAND LIMITED

Period: 1 March 2005 to 28 February 2006

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1 PRINCIPAL PERFORMANCE OBLIGATIONS

Time Error

There were no instances of time error exceeding the +/- 5 second limits during the review period. There were no instances where daily time error elimination was not achieved during the review period.

Voltage Disturbance

For the review period, there was an average of 114 voltage disturbances per month. These disturbances can be broken down to localised disturbances, where a fault occurs within a distribution company network (an average 84 per month) and regional disturbances due to faults on grid equipment (an average 30 per month). Typically, voltage disturbances are more frequent during times of strong winds and/or electrical storms.

Voltage Disturbance	2005										2006		Monthly Average	12 month cumulative
	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb		
Regional														
North Island	26	7	17	17	7	12	21	25	15	38	13	14	17.7	212
South Island	7	18	13	8	10	10	14	14	13	16	13	7	11.9	143
Total	**33**	**25**	**30**	**25**	**17**	**22**	**35**	**39**	**28**	**54**	**26**	**21**	**29.6**	**355**
Local														
North Island	88	44	52	57	50	39	43	64	53	84	95	47	59.7	716
South Island	20	19	22	23	27	28	14	23	26	29	37	23	24.3	291
Total	**108**	**63**	**74**	**80**	**77**	**67**	**57**	**87**	**79**	**113**	**132**	**70**	**83.9**	**1007**

Voltage violations 220kV & 110kV

There was one instance of the 220kV and 110kV grid voltage exceeding the allowed +/- 10% limits between March 05 and February 06. This related to a planned outage of Taumarunui-Te Kowhai circuit from the 13th to 15th October 2005 where the TMN 220 kV bus voltage exceed it's 242 kV upper limit for 9 minutes with the greatest violation being 242.8 kV.

Frequency

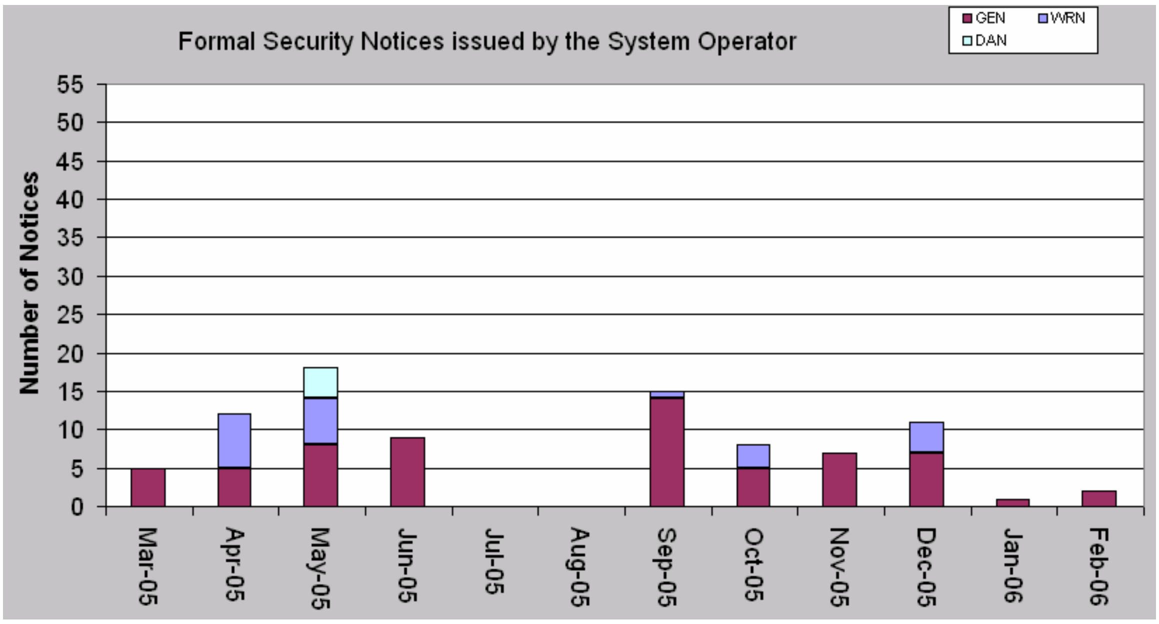
Frequency excursions for the twelve month period remained within the annual frequency performance targets except for one excursion below 48 Hz. This occurred on 4 Dec 2005 07:43 when a tripping of HVDC Pole 2 resulted in a loss of approximately 170 MW HVDC south transfer. This caused the South Island frequency to drop to 47.98 Hz.

New Zealand System Frequency Performance	Year 2005										Year 2006		Cumulative total last 12 months	Rolling Annual Freq. Perf. Obj. (PPO)
Frequency Band (Hz)	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb		
55.00 > Freq >= 53.75	0	0	0	0	0	0	0	0	0	0	0	0	0	0.2
53.75 > Freq >= 52.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2
52.00 > Freq >= 51.25	0	0	0	0	0	0	0	0	0	0	1	0	1	7
51.25 > Freq >= 50.50	3	2	0	0	0	0	1	0	0	0	0	0	6	50
50.50 > Freq >= 50.20	133	111	183	239	288	227	214	139	115	124	96	82	1951	-
50.20 > Freq > 49.80	Normal Frequency Band													
49.80 >= Freq > 49.50	106	173	212	250	294	221	201	173	137	157	121	124	2169	-
49.50 >= Freq > 48.75	5	0	1	1	4	4	6	3	1	9	1	2	37	60
48.75 >= Freq > 48.00	0	0	0	0	0	0	0	0	0	1	0	0	1	6
48.00 >= Freq > 47.00	0	0	0	0	0	0	0	0	0	1	0	0	1	0.2
47.00 >= Freq > 45.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0.2

Security Notices

88 formal security notices were issued between 1 March 2005 and 28 February 2006.

Notice Type	Number of Notices Issued*
GEN	63
WRN - Warning Notice	21
DAN – Demand Allocation Notice	4

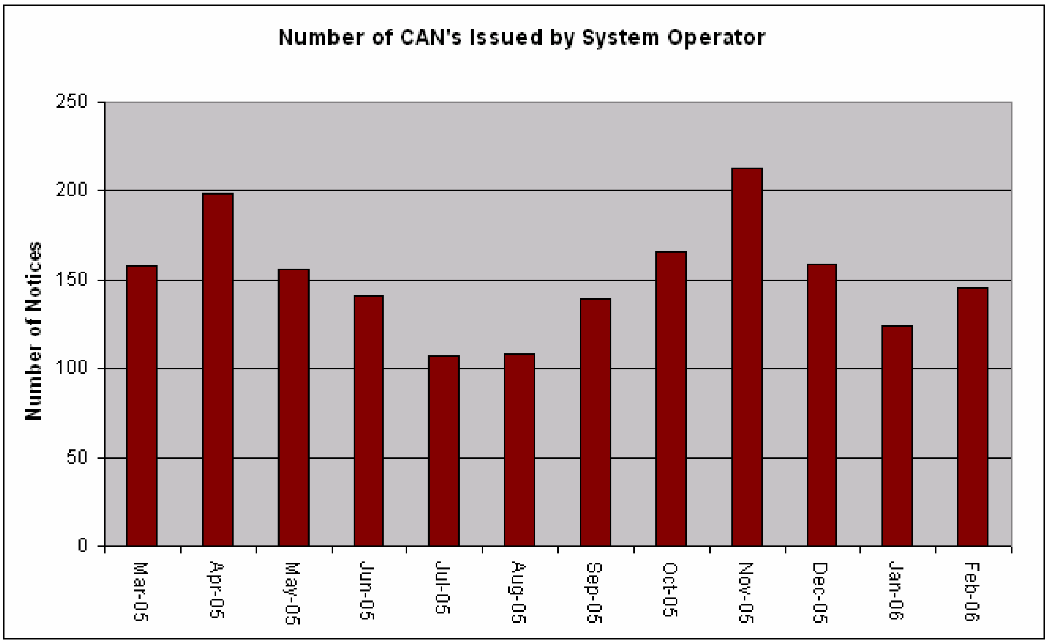


*Note: numbers given include notices issued declaring an emergency situation and the notices issued advising the emergency situation has ended.

Of the grid emergencies declared during this period the majority were issued in September 2005. Of these nine were for the West Coast region where additional local generation offers were required to maintain equipment post contingent loading during the DOB 110 KV upgrade work.

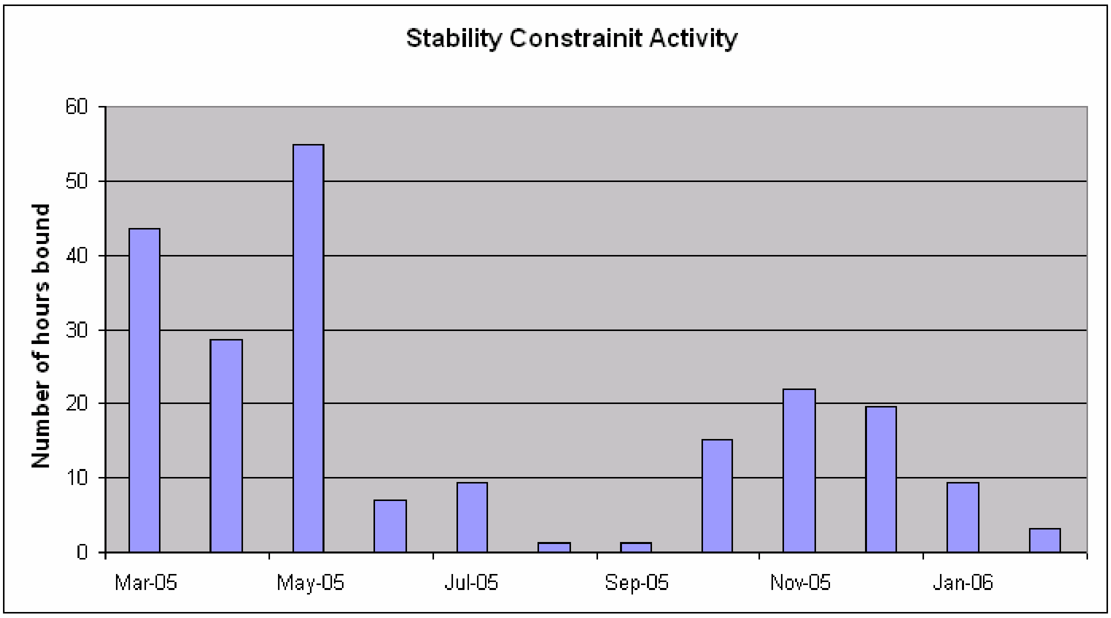
Participant Advice Notices

1815 participant advice notices (CANs) were issued in the review period. The majority were issued to advise participants of the application of constraints, changes to grid configuration or reductions in security for regions of the grid during planned transmission outages. Over 200 notices were issued in November 2005.



Stability Limits

There were no instances of stability limits being exceeded on the grid during the review period. During this time there were 37 stability constraints that bound for a total duration of 216 hours. The majority of these occurred in the upper South Island, where stability limits were being actively managed prior to the commissioning of the Stoke and Islington capacitors, and again during the Grid Owner's South Island transmission tactical upgrade program.



2 SECURITY ISSUES

Summary of real time security issues and events of interest

10th March 2005

A tornado caused a tripping of the Dobson_Greymouth circuit.

16th March 2005 15:46 – 16:23 hours – North Island

A Grid Emergency was declared to affect restoration of lost demand after two 220/110 kV supply transformers at the Grid Owner's Hamilton substation tripped. This resulted in a loss of supply of 135 MW to the wider Hamilton area and a loss of connection to the Te Rapa co-generation plant (40MW). The affected distributor reported all shed demand was restored by 16:54.

25th March 2005 10:29 – 14:30 hours – North Island

A Grid Emergency was declared to affect demand management and restoration of lost demand following multiple transmission trippings on the 220 kV and 110 kV circuits in the Bay of Plenty. In addition to numerous lightning strikes, a tornado had collapsed two towers on the 220kV Edgecumbe_Tarukenga circuits, each of which fell into the adjacent 110kV Edgecumbe_Owhata circuit. The resulting voltage disturbances are estimated to have caused the loss of approximately 190 MW of industrial load at Kawerau and Kinleith (170 MW and 20 MW respectively).

No sustained demand shedding was required as supply into the Bay of Plenty was maintained via the remaining Kawerau-Ohakuri circuit. To reinstate the lost circuits, the Grid Owner erected temporary structures restoring the Edgecumbe_Tarukenge circuit 1 on the 29 March, and circuit 2 on the 31 March. The Edgecumbe_Owhata 110kV circuit was returned to service on the 3 April.

21st June 2005 11:35 to 11:50 hours – North Island

Mangahao transformers T3 and T4 tripped during planned maintenance of a communications circuit. This left Mangahao generation running in an islanded condition supplying demand in the Shannon and Levin areas. Demand prior to the event was 29 MW; post event load was 20 MW. AUFLS had operated within the island, shedding some demand. Neither frequency nor voltage of the islanded demand could be monitored by the System Operator. Without the ability to synchronise the island back to the grid at Mangahao the System Operator instructed the Grid Owner to trip the islanded demand. Transformers T3 and T4 were then returned to service and all demand restored.

04th December 2005 05:41 – 06:20 hours – HVDC

A Grid Emergency was declared due to a fire near the HVDC circuits east of Makara causing a high likelihood of an extended contingent event occurring i.e. HVDC bipole tripping. The HVDC maximum North to South transfer limit was lowered to 180MW.

15th December 2005 18:07 – 18:24 hours – South Island

A Grid Emergency was declared in the West Coast due to an unplanned outage on Hororata_Islington circuits 1 and 2 during a planned outage on the Dobson_Greymouth circuit. This resulted in demand at grid exit points between Hororata and Greymouth being supplied islanded from the remainder of power system with generation at Kumara and Coleridge. Island voltage and frequency was maintained and successfully resynchronised with the grid at 18:24.

15th February, 09:34
An urgent forced outage was required on the Otahuhu_Whakamaru 3 circuit due to arcing at OTA disconnector 506. The circuit tripped before it could be removed from service. This caused a consequential tripping of Glenbrook and Southdown generation. While system voltages remained stable, the voltage disturbance caused the disconnection of approx 200 MW of load across the upper North Island.

3 SECURITY OF SUPPLY

3.1 Real Time Security Issues

There were no significant situations (those affecting a whole island or major load region) during the year when the System Operator invoked the controls described in the emergency section of the Policy Statement. Lesser events of significance were:

- the secondary tripping of Taranaki Combined Cycle (TCC) generating unit on 11 December 2005 during a frequency excursion initiated by the tripping of a Huntly generating unit. North Island frequency fell to 48.03 Hz with the loss of 576 MW from the North Island. Dispatched reserves were only for the loss of a single generating unit. Operation of AUFLS and automatic demand shedding was avoided by additional un-dispatched generator and HVDC response
- a frequency excursion to 47.96 Hz in the South Island on 4 December 2005 following the loss of 170 MW of transfer into the South Island on HVDC Pole 2. Reserves had been dispatched to cover this risk. It appears reserve provider response may not have been adequate
- the secondary tripping of generation at both Glenbrook and Southdown following a fault on the Otahuhu_Whakamau 3 circuit on 15 February. The event presented no risk to demand in the upper North Island given the remaining generation in service at the time.

The System Operator has advised the Electricity Commission that events such as the above highlight the need to progress the establishment and coming into operation of an Asset Owner Test Plan (AOTP) as intended by Part C. The System Operator believes an AOTP is a prudent way of ensuring asset owners can and do verify the capability of assets during major, but infrequent system events.

3.2 Short Term Security Issues

3.2.1 Upper South Island Security

Winter

In March 2005 the System Operator again brought together a stakeholder group to:

- evaluate the upper South Island supply situation in an operational context

- co-ordinate an operational response to any security of supply issues identified for winter 2005.

In the year from the 2004 initial meeting of this group, three power system enhancements had been implemented by the Grid Owner to increase power system limits into the upper South Island. These were the installation of capacitor banks at Islington and Stoke and a thermal upgrade of one transmission line.

For winter 2005 the role of the stakeholder group role was to identify expected and prudent demand, monitor demand trends and agree a contingency plan for managing unplanned situations. As a consequence of a milder winter actual demand peaks during winter 2005 were within the prudent forecast. No additional response by participants to manage controllable load was required.

Further enhancements to the power system over the 2005/6 summer are expected to ensure 2006 winter limits for 2006 are at least 5% above projected demand.

Summer

To facilitate a number of tactical transmission line upgrades over the 2005/6 summer months the winter stakeholder group was used as a forum to plan any desirable response during these outages.

Planned Grid Owner outages were completed successfully, without unplanned demand shedding. On two occasions outages were recalled due to system conditions. The System Operator records the co-operation of stakeholders involved in forecasting demand, managing controllable load, making generation available and contributing to contingency planned.

3.2.2 Top of the South Island Security

The security situation in Nelson, Marlborough and Bullet (top of the South Island) during the year was successfully managed through a co-ordinated approach with affected participants using a similar process to that used for the wider upper South Island.

Grid owner commissioning of additional capacitors at Stoke provided sufficient margin for the supply position in the top of the South Island to remain manageable over the year. At times this needed careful co-ordination by participants because of the dependence on local generation within the area.

Major grid upgrades due to be commissioned in June 2006 will reduce dependence on local hydro generation and raise power system limits by approximately 50%.

3.2.3 Upper North Island Security

For the second year an Industry Response Group was established to manage winter supply issues in the region. The group's objective was to plan to avoid any unplanned pre-event shedding, assuming the largest generating unit to be out of service. The group was able to rely on the procurement of additional voltage support from Marsden and Otahuhu to mitigate situations where generation in the region was constrained or unavailable.

The upper North Island winter situation was successfully managed to within the expected demand forecast, assisted by high availability of generation in the region.

In the review period the System Operator, in conjunction with the industry response group, began reviewing power system limits into the upper North Island for winter 2006. Initial indications are that with additional new capacitors there will be a 4-6% margin over the peak demand in 2006.

For the seventh successive year, the System Operator organised a participant group to plan a response to summer power system issues that could arise in the upper North Island. A mild summer and the addition of a cooling tower at Huntly power station resulted in high availability of generation during the critical risk period. At no time was demand at risk over the 2005/6 summer.

4 RULE CHANGES

4.1 Proposed by System Operator

The System Operator promoted a number of rule changes, some of which were administrative or intended to correct administrative errors in the rules. Other changes were of wider interest or effect and are commented on as follows:

4.1.1 Power Factor for local networks

The System Operator is facing increased operational difficulties managing areas of the grid with low power factor (i.e. below 0.95pf lagging).

Consequently, in March 2005, it recommended the Electricity Commission change Part C of the EGRs to require distributors to ensure that either the power factor at a grid exit point is above a specified minimum (0.95 leading or lagging at all times when demand is above 50% of the annual maximum half hourly peak at the grid exit point) or the aggregate power factor across grid exit points in a region is above a specified minimum (not less than 0.95 leading or lagging at all times when demand is above 50% of the annual aggregate maximum half hourly peak).

4.1.2 Policy statement, procurement plan and SO self-review timeline rule amendments

In September 2005, the System Operator recommended changes be made to the EGRs to provide for:

- the System Operator's Review and Assessment of its performance (currently required in March) to be delivered in April each year
- the System Operator to have 10 working days (rather than the current 5) to make its submissions on the draft policy statement.

4.1.3 Procurement Plan

In November 2005, the System Operator recommended changes be made to Rule 5.3.2 of Section IV of Part C regarding the period within which the System Operator could make submissions to the Commission on participant submissions to the draft procurement plan, proposing an increase from five to ten working days.

4.1.4 Electronic notification of constraints

In November 2005, the System Operator proposed a rule change for it to use electronic means to notify participants of the implementation of and changes to security constraints and outage constraints. This rule change was proposed as the result of a settlement agreement between the System Operator and participants as the result of a breach allegation relating to an incident in 2004. The incident related to a participant alleging the System Operator failed to notify a change to an outage on the Bromely_Islington circuit.

4.1.5 Frequency keeping

In December 2005, the System Operator proposed a rule change to mandate, the selection of the frequency keeping service provider. The change was proposed primarily to initiate discussion with participants on the methodology for frequency keeper selection.

4.1.6 Tactical wind rule changes

In January 2006 the System Operator completed and presented to the Electricity Commission a commentary on certain issues arising from its observations of the impact of wind generation on operation of the New Zealand power system. This report (see section 11 below) was accompanied by a companion paper proposing certain rule changes. The rule changes proposed were as follows:

- require wind generators to provide the most accurate forecasts possible
- revised wind generation indications and measurements
- definition of “synchronised” changed to include wind generating units connected to the power system
- wind generation to be required participate in must run dispatch auction, if wind generators wish to offer at zero price
- define the loss of multiple generating units connected through a single circuit breaker as a contingent event in the policy statement.

4.2 Other

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

4.2.1 High spring washer rules

The Electricity Commission considers it is important participants have confidence in the accuracy of any high spring washer prices appearing in final prices. Together with the Pricing Manager, the System Operator assisted the Electricity Commission with a rule change proposal that, if implemented, would test spring washer effects (that appear in pricing) for accuracy before prices became final. The System Operator and Pricing Manager are developing a methodology for implementation of the possible rule changes.

4.2.2 Instantaneous reserves pricing and dispatch

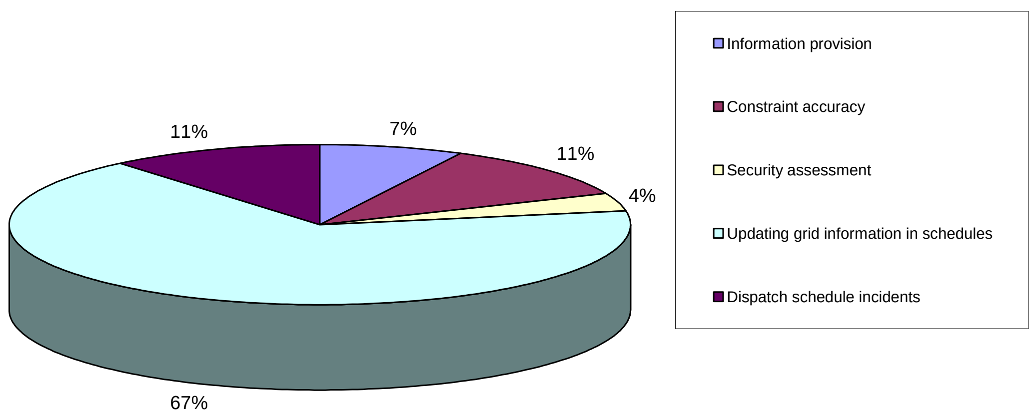
The System Operator worked with the Electricity Commission and the Pricing Manager to develop rule changes relating to dispatch and pricing of instantaneous reserves. The desirability of such changes was originally proposed by the System Operator as part of the settlement process arising from a breach allegation about a 10 March 2004 event (see also section 4.2 below).

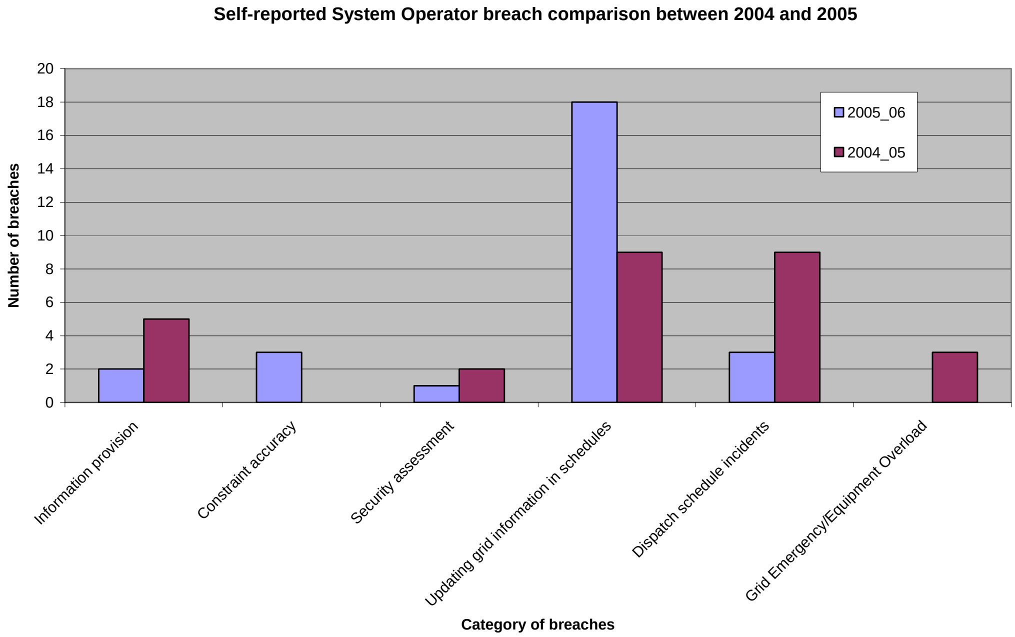
5 BREACHES

5.1 System operator self reported breaches

The following graph categorises twenty seven breaches of the Electricity Governance Regulations and Rules (EGRs) reported by the System Operator to the Electricity Commission during the review period. None of the breaches has (in the reporting period) been referred to the Rulings Panel. The bar graph compares the 2004 and 2005 review periods.

System operator self reported breaches (27)





The System Operator makes the following observations and comparisons with the 04/05 year:

5.1.1 Updating grid information in schedules

This section was reported last year as “outage constraints”. Breaches have increased from last year’s total of nine to eighteen. The majority of breaches relate to outage changes notified to the System Operator at short notice.

The System Operator presented to the April 05 meeting of the EGR Committee to describe the manual process by which outage information is incorporated into the dispatch schedule, the error risks this process creates and the mitigation measures it had put in place to manage the risk. It stressed the level of risk could not be reduced to near zero using existing processes.

The System Operator believes it has minimised the risk of breach to the lowest practicable level with its current tools and processes. However, whilst there has been an actual increase in errors, the average time for which the information has remained incorrect in the dispatch schedule has reduced. The majority of incidents have occurred in real time for periods less than 20 minutes. In contrast, in the 04/05 year the inaccuracy period was often greater than 25 minutes. Our view is the market impact of each breach was negligible.

The System Operator is renewing its market systems, as noted below in section 11. An objective of the renewed systems is to reduce manual work levels in a number of areas, including the development and implementation of constraints. An expected outcome of this work will ultimately be to materially improve the incident rate arising from outage scheduling.

5.1.2 Information Provision

Breaches in this category have reduced from five to two this year. However, the incidents are of a different nature from those experienced last year. One was a failure to notify the Board of a dispensation application and record it on the register. Another was a failure to notify a station dispatch group to the Clearing Manager. Neither breach is expected to reoccur given corrective actions put in place. Both had no market impact; neither was formally investigated.

5.1.3 Dispatch Schedule

Total category breaches were three. Compared to last year's four breaches, only one incident related to dispatch instructions. In this case, the System Operator accepted verbal advice of a bona fide to increase generation when there was no offer in respect of that generation. This resulted in the System Operator being obliged to dispatch un-offered generation for a few minutes.

The two other breaches related to incorporation of reserve information into the dispatch schedule. One breach was due to incorrect set up of a reserve provider; the other was due to incorrect operation of the Reserve Management Tool (RMT). System Operator process changes have been made as a result of the first breach. The RMT software, processes and operation are currently undergoing a thorough review with the objective of defining any desirable or necessary software and process changes.

5.1.4 Constraint accuracy

Three breaches for security constraint inaccuracy were notified during the period and relate to clause 20.5 of the Policy Statement. Two related to grid owner outage changes, where security constraints and branch constraints were bundled together. The System Operator is now reviewing the manner in which it creates constraint bundles.

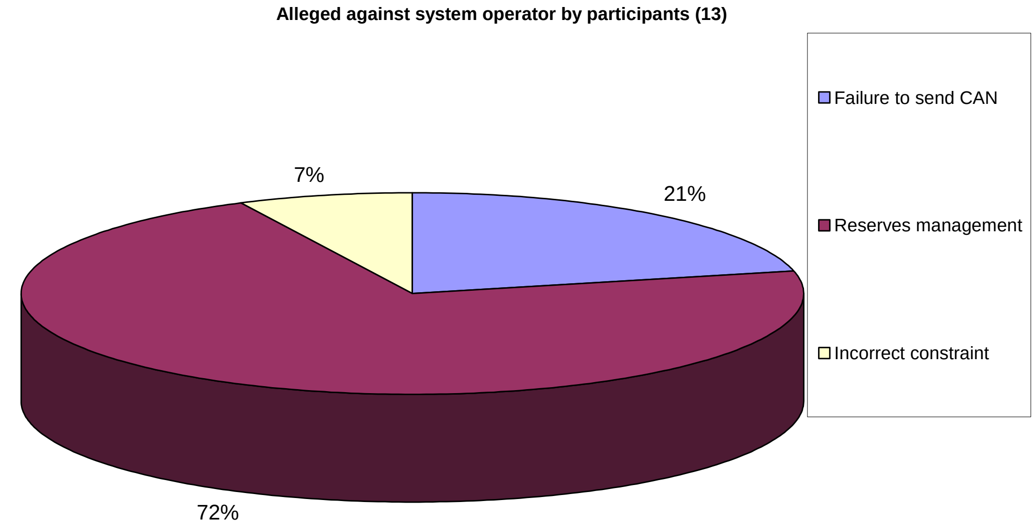
The third breach was of a security constraint inadvertently re-introduced into the schedules after having been previously removed. The System Operator has undertaken an external audit of its security constraint process and initiated an internal review of its processes to address process shortcomings and prevent a reoccurrence. The audit report will be published on the System Operator's website in April 2006.

5.1.5 Security assessment

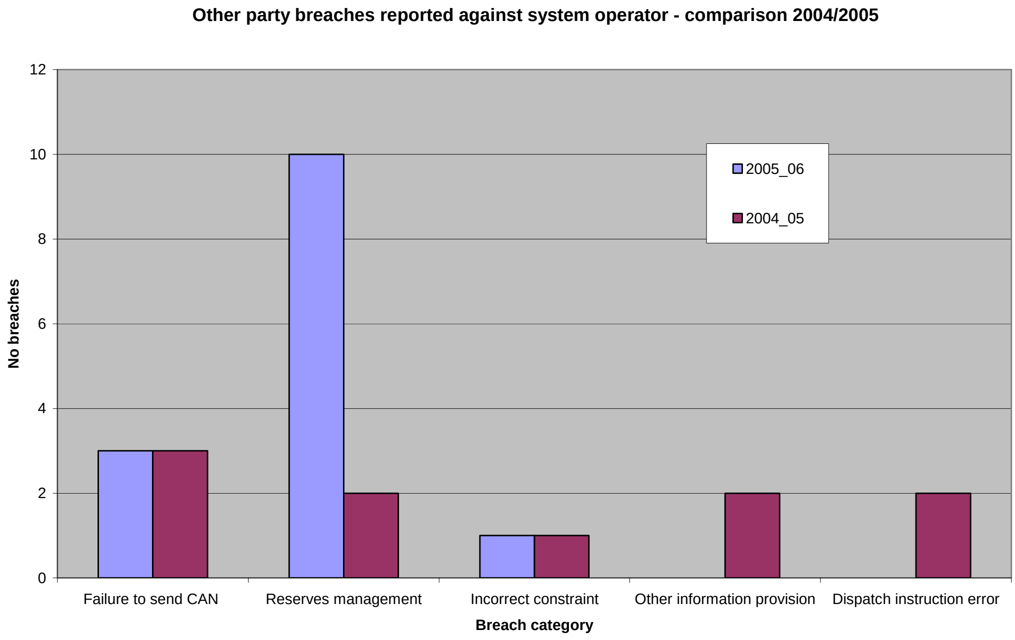
There was one System Operator breach relating to security assessment, compared to two last year. It related to the unintentional operation of the Karapiro runback scheme. Te Awamutu lost supply for a minute whilst restoration took place. As a result a number of corrective actions have been developed, including making changes to the block dispatch agreement and alterations to the manner in which Block Security Constraints are identified in advance. Under review also are possible changes to generation reserve offers.

5.2 Alleged System Operator breaches reported by other parties (including the Electricity Commission)

The following graph categorises thirteen alleged breaches made against the System Operator by other participants during the year, of which ten were alleged by the Electricity Commission. The ten breaches alleged by the Commission relate to a single incident that occurred on 10 March 2004.



The following bar chart compares 2004 data with 2005.



The System Operator denies all the allegations in respect of the 10 March 2004 incident. The Electricity Commission has closed four of the ten cases.

5.2.1 Failure to send CAN

One participant alleged three separate breaches against the System Operator for failing to issue prompt notifications of outage constraint changes. The matters were closed without further investigation after a similar alleged breach (also denied) in the previous reporting period was subject to a settlement agreement, approved by the Board. The System Operator proposed a rule change in respect of the relevant issue (refer to paragraph 4.1.3).

5.2.2 Reserve modelling

These ten breaches relate to the input information that goes into final pricing and the means used by the System Operator to determine the input information. The allegations are in respect of the previously mentioned 10 March 2004 incident. .

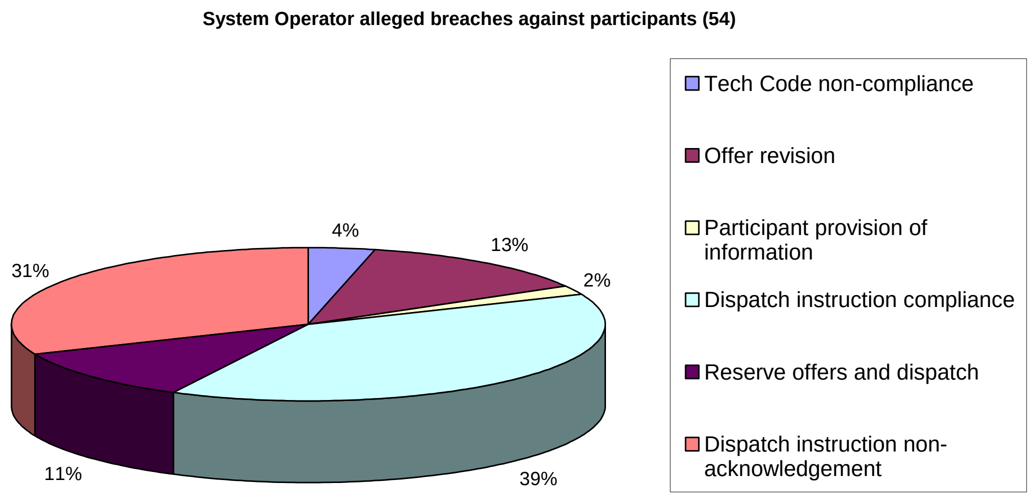
The System Operator denies the allegations.

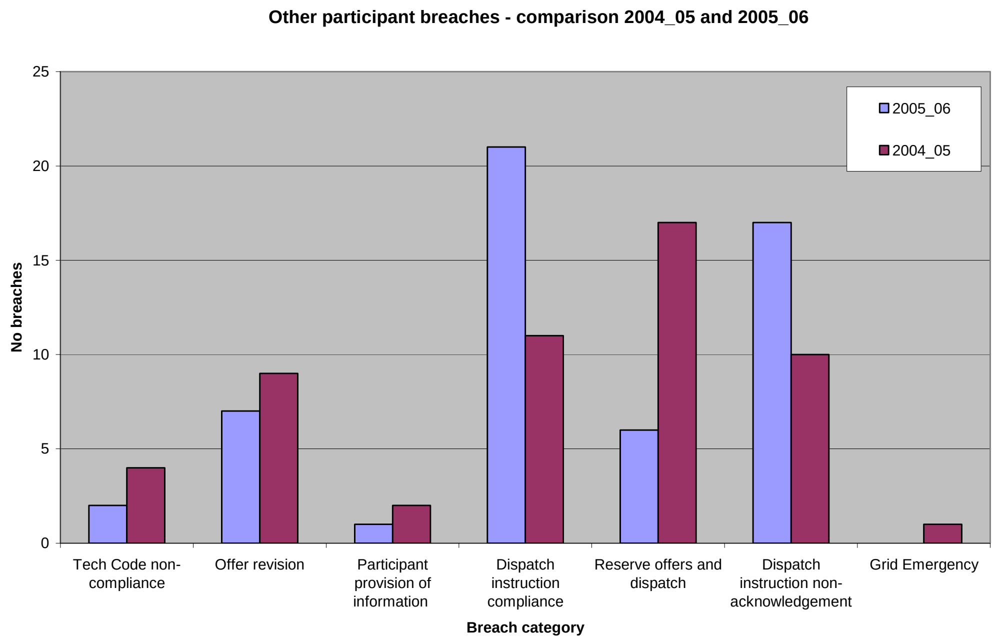
5.2.3 Incorrect constraint

One participant reported a System Operator failure to use the correct constraint in the schedules. This breach allegation duplicated one already self-reported by the System Operator.

5.3 Breaches alleged by System Operator against other participants

The following charts categorise fifty four breach allegations by the System Operator in respect of actions or inactions by other participants during the review period.





The System Operator makes the following observations:

5.3.1 Reserve offer errors

All of the allegations regarding reserve offers and dispatch relate to one participant. One of the allegations is currently under investigation and relates to provision of interruptible load during an under-frequency event.

5.3.2 Compliance with dispatch and offer-revision

The System Operator remains concerned about the number of occasions on which participants have failed to:

- comply with dispatch instructions
- neglected to revise offers following a change in generation capability.

The breach allegations are not limited to any one group of asset owners, although most relate to cogeneration plant and small geothermal plant. There has been a substantial increase in non-compliance with dispatch instructions since the last reporting period (twenty one in contrast to eleven). A similar number of breaches have been alleged in respect of offer revisions.

These breaches cause the System Operator real concern. Offer accuracy and compliance with dispatch instructions are essential elements of maintaining system security. The consequences of continued inaccuracy and non-compliance may oblige the System Operator to take discretionary action and impact its ability to meet the dispatch objective.

The System Operator is pleased the EGR Committee has asked that three of the cases be formally investigated. Two investigations are ongoing. One has been settled by participants (without a privity clause that would add the Electricity Commission as a party able to enforce the settlement obligations) and is awaiting approval by the Board.

5.3.3 Failing to acknowledge dispatch instructions

The System Operator notified a number of breaches by participants that failed to acknowledge dispatch instructions. Seventeen non-compliances were alleged in this period compared with ten in the previous year. The System Operator is pleased that in the latter part of the review year and following discussions between System Operator and participants there was a marked improvement of behaviour.

Whilst on its own each incident can be regarded as comparatively minor, the need to follow up each incident consumes valuable System Operator resources during real time is an unhelpful distraction from its other operational duties. The System Operator's workload would benefit from further improvement of participant performance in this area.

5.4 Settlements

The System Operator participated in a number of settlement meetings regarding two notifications of breach by itself and four allegations of breach by other parties. A number of settlement agreements were entered into. In the case of those agreements where the System Operator was the alleged breach party, it undertook to carry out certain actions (including promoting rule changes, operational changes and process audits). All actions agreed to be undertaken by the System Operator were completed by the specified dates.

5.4.1 System Operator Settlements

Three settlement agreements were entered into during the review period. Two were approved by the Board. One was rejected by the Board and a complaint (under regulation 93) was laid against the System Operator (see section 5 below).

One matter for which an attempt at settlement was made was not able to be agreed. That matter was also the subject of a complaint laid under regulation 93 (see section 5 below).

5.4.2 Third party settlements

The System Operator participated in four settlement agreements in which it was not the alleged breach party. Two were approved by the Board. Two have not yet been agreed by the Board and are in the course of being presented for approval. Completion of these agreements has been delayed while the parties consider the inclusion of a privity clause that, in the present absence of regulatory power, would allow the Board to enforce the obligations against a participant that arise under a settlement agreement. The inclusion of a privity clause in favour of the Board has not been universally accepted by participants. In the current context of the EGRs the System Operator does not favour such clauses.

6 RULINGS PANEL

The actions of System Operator were subject to the scrutiny of the Rulings Panel on two occasions during 2005. These were the first cases dealt with by the Panel and concerned the following:

- in November 2004 the System Operator self reported a breach of rule 4.3 of section III of part G of the EGRs. A settlement of the matter was not able to be achieved and the Electricity Commission elected to lay a complaint with the Panel. The breach concerned the failure to implement the dispatch schedule in trading periods 47 and 48 on 6 September 2004. The failure arose when, due to a computer use error, dispatch schedule data was corrupted and dispatch schedules were not dispatched while the corruption problem was resolved.

  Noting the breach as being "moderate" and having had "a relatively minor effect on other participants" and further noting "mitigating points" put by the System Operator, the Panel imposed a penalty of $2500. No order for compensation was made

- in June 2004 the System Operator self reported a breach of rule 1.3.4.5 (now rule 1.3.4.7) of schedule G6 of the EGRs. A settlement of the matter was effected with participants. However, the Electricity Commission did not approve the settlement and elected to lay a complaint with the Panel. The breach concerned the failure of the System Operator to use revised availability information from the grid owner and incorrectly modelled the Otahuhu bus tie between 1 March 2004 and 18 May 2004.

  Noting the breach was "inadvertent" the Panel imposed a penalty of $1000.

7 NEAR MISSES

There were no near misses reported during this period.

8 SPECIFIC COMPLIANCE REQUIREMENTS UNDER THE RULES

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 Board.

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 under the rules was provided to the Electricity Commission in December 2004. In the year under review, examinations of the need to revise the SSF were carried out as at 1 June and 1 December 2005. An amendment to the December 2004 SSF (based on the June 2005 review) was published in August 05. In December 2005, the System Operator notified the Board the SSF would be further updated and that update is planned to be provided and published in the first quarter of the next review period.

Procurement Plan

The System Operator submitted the 2005–06 draft procurement plan to the Board by the mandated date of 1 June 2005. In developing the draft plan the System Operator invited comment from industry participants. Notable feedback was received from industry participants and this was considered in preparing the final draft submitted to the Board.

The procurement plan consultation process was completed in time for the plan to come into operation on 1 November 2005. Similar implementation processes to those used in the first procurement plan were employed prior to 1 November.

The plan introduced minor changes to the standard form ancillary service procurement contracts. These changes were also subject to industry consultation at the same time as consultation took place on the draft plan.

Tendering of ancillary services was also completed in time for the 1 November 2005 effective plan date. The Commission had planned to have rule changes affecting limitation of liability and force majeure to be in effect by the time the procurement plan was operative; this did not occur and the changes became effective in January 2006. As a consequence, all of the required and expected contracts for provision of Over Frequency Reserve (OFR) and Voltage Support services could not be put in place by 1 November. These were negotiated and put in place after the January rule changes came into effect.

The following table summarises the contracted services as at 28 February 2006:

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

* Long term contracts for the provision of ancillary services.

Policy Statement

The first annual review of the Policy Statement was completed during the period under review. To develop the draft policy statement the System Operator employed a consultative process, seeking advice on proposed changes form selected participants. The draft policy statement was delivered to the Electricity Commission on the 31st of March 05, as required by the rules. It came into force on 1 September 05.

As at the date of this review the System Operator is completing the required second annual review of the policy statement. Issues for consideration in the review were collected by the System Operator from both operational experience throughout the review period and from input solicited directly from participants during the review period.

The material, proposed changes had been signalled to major participants and participant consultation comments have been taken into account in developing the final draft.

Departures from Policy Statement

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

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.

6.5.1 RMT

- RMT opinion provided by PA Consulting on 5 September 2005. Changes included: minor amendments to front end operator functionality and updates to models provided by Asset Owners.

6.5.2 SPD

- SPD TP37.32. Opinion provided by PA Consulting on 5 September 2005. The version of SPD was implemented to change a parameter setting for mixed integer programming tolerances and a variety of general page improvements.

6.5.3 Annual RMT and SPD Certification

- RMT/SPD opinion was provided by PA Consulting on 10 March 2006. 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).

Test Plan

In September 2005 the System Operator delivered a revised draft asset owner test plan to the Electricity Commission. This plan revised a version presented late 2004 and incorporated a number of changes resulting from additional consultation undertaken by the Electricity Commission during 2005. Due to technical drafting problems with the EGRs the test plan has not been able to be agreed with the System Operator and has consequently not been able to be brought into force. The Electricity Commission commenced work on suitable rule changes during the later part of the review period.

Other Rule Obligations

Undesirable Trading Situations

One undesirable trading situation was claimed during the review period. This was a claim by the Major Electricity Users' Group in August 2005 regarding an alleged exposure to increased frequency keeping costs and associated constrained on and off charges. An undesirable trading situation was found not to have existed.

9 SPECIFIC COMPLIANCE REQUIREMENTS UNDER THE SYSTEM OPERATOR SERVICE PROVIDER AGREEMENT (SOSPA)

Disaster Recovery Plan

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

In September 2005 the System Operator ran a business continuity simulation exercise with the key objective to test and then further develop its business continuity plan (BCP). The BCP forms the basis of the System Operator's disaster recovery plan.

The simulation was used to gain insight to how the System Operator would manage the power system in an extreme situation (defined as one that affects the System Operator, not the community at large). A full day workshop following the simulation was used to refine and complete a renewed BCP.

Warranties

The System Operator provided the Board with certain warranties at the date the SOSPA was entered into. At 1st March 2006, the System Operator:

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

10 SPECIFIC COMPLIANCE ACTIVITIES

Dispensation and Equivalence Applications

A total of 369 dispensation applications were received in the review period.
As at 28th February 2006, 239 dispensations had been granted, 11 were the subject of draft decisions (expected to be granted after the review period), 71 applications had been withdrawn and 48 applications remained under consideration.

Exemptions

The System Operator assisted the Electricity Commission in separate exemption applications made by three participants in respect of the section III part G dispatch rules.

Kiwi Cogeneration requested an exemption from the +/- 1MW threshold for compliance with dispatch instructions under rule 4.11 of section III part G. The request was made on the basis the asset owner's generation was linked to an industrial process and could suddenly inject additional unplanned and un-offered generation into the grid. The System Operator expressed some concern about potential security issues that could arise with such unplanned changes, given the circuit constraints that exist in the location of the plant. The System Operator and Kiwi Cogeneration:

- reached agreement on the meaning of the bona fide re-offer process that enabled Kiwi Cogeneration to comply with the offer revision rules
- agreed suggested conditions (intended to form part of an exemption) to ensure unplanned and un-offered generation would be for the minimum possible duration.

The exemption, including the suggested conditions, was granted subsequent to the review period.

Alinta requested an exemption from compliance with dispatch instructions under rule 4.11 of section III part G. The application was based on similar reasoning to one granted to Carter Holt Harvey Ltd in the previous review period. The Board granted the exemption application.

An application by Todd Energy Ltd and Whareroa Co-generation Ltd also for an exemption from rule 4.11 of section III part G was current at the end of the review period. The System Operator and the applicants reached agreement on suggested conditions (intended to form part of an exemption). This application was current at the end of the review period.

Applications to treat two GXPs as one

No applications have been approved.

Ancillary Service Provider Performance 2005/6

In response to concerns expressed by industry participants about materially increasing frequency keeping costs the System Operator has revised the ancillary services report it provides to the Electricity Commission. This now includes a greater level of detail relating to monthly frequency keeping costs. The information is published on the Electricity Commission website.

The alleged breaches of ancillary services (see 5.3.1. above) related mostly to the delivery of instantaneous reserves. To clarify the approach taken by the System Operator for determining compliance of dispatched and delivered reserves quantities the System Operator included its compliance assessment methodology in the 2005 - 2006 Procurement Plan.

To reduce System Operator and Ancillary Service Agent costs associated with repetitive annual tendering of ancillary services the System Operator sought to procure the services for Over Frequency Reserve, Voltage Support and Black Start on a longer, 3 -4 year basis. The System Operator was successful in procuring all three services on this basis.

The System Operator continued to work with Contact Energy toward contracting provision of dynamic reactive support to replace the Part I, long term voltage support contract which expires 31 March 2007. The need for procurement of additional dynamic reactive support in Zone 1 was identified by the System Operator in its paper "Procurement Plan Needs Assessment - Zone 1 Voltage Support Requirements to 2010 - July 2005".

11 INDUSTRY CONSULTATION PAPERS

Contributions and Submissions

In addition to the rule changes proposed during the period, the System Operator actively contributed to the following consultation documents:

- Information System Definition: April 2005
- Demand Side Bidding and Forecasting Proposal: June 2005
- Capacity Reserve Proposed Rule Change: July 2005
- Operational Communications (Tech Code C): August 2005
- AUFLS – dispensations and exemptions: Sept 05
- Water heating cuts as emergency measures: Oct 05
- various Part G amendments: Oct 05
- Energy Reserves: Jan 06
- Operational Communications: Feb 06
- Indications and Measurements: Feb 06
- Reconciliation Rule Changes: Feb 06
- Policy Statement and Procurement Plan Timelines: Feb 06
- Amendment to Schedule D of part D: Feb 06
- Instantaneous Reserves: current at end of review period

12 GENERAL ITEMS OF INTEREST / CONCERN

Development report

The System Operator's primary development focus for the year has been the upgrade of the market systems. A review of these systems was completed in April. The review was followed by issuing a request for expressions of interest to select potential vendors. A subsequent request for proposals led to a vendor being selected.

Contract negotiations with the selected vendor have been completed. Project mobilisation commenced in December 2005 and a project completion in Q3 2007 is expected. The System Operator has maintained liaison with the Electricity Commission's senior advisors during this lengthy process to ensure coordination of development requirements and the commissioning of the new systems. This liaison will be increased as the project advances and will also include market participants as the detailed schedule for development and implementation is determined and committed.

The System Operator consolidated its earlier VSAT (voltage stability analysis tool) implementation, introducing in September 2005 the routine use of this advanced analytical tool by its security and dispatch coordinators. Transpower remains one of the few users of this state of the art tool in planning processes, along with ERCOT of Texas and ESBI of Ireland. It is the only system operator to implement such a tool in real time dispatch processes. The tool has enabled the market to benefit from more accurate and precise management of system power transfers, particularly in the upper South Island and Auckland regions.

A number of enhancements to System Operator software and processes have been completed with the aim of enhancing service delivery capabilities. The most significant of these has been a SCADA Bus Load Data initiative, implemented to improve forecasting of load distributions in the dispatch process and thereby improve management of constraints in real time.

The System Operator completed rules-based changes to the market systems to enable publication of HVDC component flows. Additionally the System Operator contributed to investigations, rule change proposals and consideration of system implications for demand side participation and constraint management initiatives that are expected to contribute to the improvement and enhancement of market processes. These initiatives have included the management and pricing of variable reserves, the management and pricing of high spring washer events, the introduction of capacity reserves and the demand side bidding and load forecasting proposals. Each of these initiatives is now in the consultation/rule making process with the Commission.

Planned Outage Coordination Process (POCP)

The System Operator re-established the POCP industry forum. This forum had been used to develop an industry-backed outage planning process prior to the entry into force of the current rules. The POCP delivers on the requirements of Technical Code D. Following participant feedback on the operation of the outage co-ordination process, the System Operator believed it was timely to review the approach and business rules developed by the earlier 2003 forum.

The 2006 POCP forum comprises 14 members and an external chairman. The forum will meet for the first time in March 2006. The forum's brief is wide ranging and may recommend process changes, policy statement changes or rule changes.

Wind generation projects

The System Operator assisted the Electricity Commission with two projects to identify the impact of increased wind generation being connected to the power system.

The first, tactical project identified the impacts of the Manawatu wind generation on power system operation. A report setting out the way in which the System Operator would manage wind generation was completed and published. This report focused on management of scheduling and dispatch issues during the period the second project is underway. Some interim rule changes were proposed.

The second project is the Electricity Commission's Wind Generation Investigation Project. This longer term (two year) project (described on the Commission's website) is developing a view of the means by which large amounts of wind generation can be accommodated on the power system. The System Operator is currently providing full time personnel and technical resources to this project.

Workshops and Newsletters

Eight System Operator participant newsletters were issued during the review period.

Two participant workshop series were held in Christchurch, Wellington and Auckland during May and November 2005. Topics covered were: paralleling GXPs, wind generation investigation projects; the asset commissioning process, the System Operator's frequency management project; real time pricing; dispensations; voltage management issues; demand side participation and emergency procedures.

13 FINANCIAL REVIEW (SOSPA)

Base Contract

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

Financial review SOSPA 1 March 2005 to 28 February 2006	
System Operator Service Provider Contract Base Fee	21,351,999.96
Information System Access Fee*	1,489,488.00
RMT Audit Fees*	4,912.00
Total fees paid under the SOSPA	**22,846,399.96**

* 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.

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 2005 to 28 February 2006	
Breach investigations	102,421.00
EC exemption requests	4,307.50
Constraints advisory group responses	31,010.00
EC technical and rule changes advice	117,851.50
HVDC component flows and risk offsets IT development testing and introduction into production	26,450.00
Total variable revenue	**282,040.00**

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Constraints advisory group responses	**31,010.00**
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