SYSTEM OPERATOR

ANNUAL REVIEW 2004/05

TRANSPOWER NEW ZEALAND LIMITED

Period: 1 March 2004 to 28 February 2005

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1 PRINCIPAL PERFORMANCE OBLIGATIONS

1.1 Time Error

There were five instances of time error exceeding the +/- 5 second limits during the review period. These occurred in April, June, and July and twice in August. There were no instances where daily time error elimination was not achieved during the review period.

1.2 Voltage Disturbance

For the review period, there was an average of 94 voltage disturbances per month. These disturbances can be broken down to localised disturbances, where a fault occurs within a distribution company network (an average 67 per month) and regional disturbances due to faults on grid equipment (an average 27 per month). Typically, voltage disturbances are more frequent during times of strong winds and/or electrical storms.

Voltage Disturbance	2004										2005		Monthly	12 month
	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Average	cumulative
Regional														
North Island	22	21	18	13	18	45	7	16	12	12	16	15	17.9	215
South Island	8	10	14	13	11	12	7	6	10	6	10	5	9.3	112
Total	**30**	**31**	**32**	**26**	**29**	**57**	**14**	**22**	**22**	**18**	**26**	**20**	**27.3**	**327**
Local														
North Island	34	34	41	61	34	63	27	41	60	62	57	75	49.1	589
South Island	17	10	12	12	11	16	23	14	22	24	27	23	17.6	211
Total	**51**	**44**	**53**	**73**	**45**	**79**	**50**	**55**	**82**	**86**	**84**	**98**	**66.7**	**800**

1.3 Voltage violations 220kV & 110kV

There were no instances of 220kV and 110kV grid voltages exceeding the allowed +/- 10% limits for the March 04– February 05 period.

1.4 Frequency

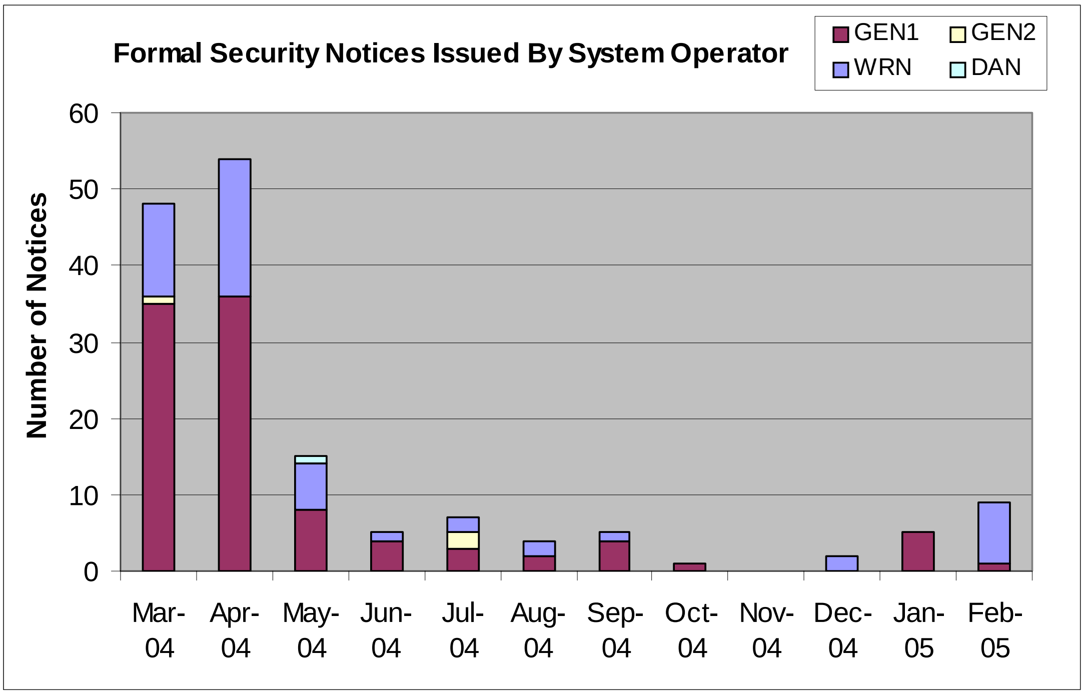
Frequency excursions for the twelve month period also remained within the annual frequency performance targets, with no excursions occurring below 48Hz or above 52Hz in either island. The most significant under frequency event occurred on 16 Jan 2005 when a tripping of HVDC Pole 2 and subsequent tripping of Pole 1 caused the North Island frequency to drop to 48.67Hz. This event was caused by a large fire under the HVDC lines in the North Canterbury region.

New Zealand System Frequency Performance	Year 2004										Year 2005		Cumulative total last 12 months	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	1	0	0	1	0	0	0	0	0	1	2	0	5	7
51.25 > Freq >= 50.50	0	3	1	0	1	0	1	1	0	0	1	2	10	50
50.50 > Freq >= 50.20	88	112	96	89	122	186	78	102	69	94	75	59	1170	-
50.20 > Freq > 49.80	Normal Frequency Band													
49.80 >= Freq > 49.50	94	108	80	98	140	183	66	127	52	76	75	70	1169	-
49.50 >= Freq > 48.75	2	1	2	3	0	5	0	5	0	2	2	2	24	60
48.75 >= Freq > 48.00	0	0	0	0	0	0	0	0	0	0	1	0	1	6
48.00 >= Freq > 47.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0.2
47.00 >= Freq > 45.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0.2

1.5 Security Notices

155 formal security notices were issued between 1 March 2004 and 28 February 2005.

Notice Type	Number of Notices Issued*
GEN1 – Grid Emergency Level 1	99
GEN2 – Grid Emergency Level 2	3
WRN - Warning Notice	52
DAN – Demand Allocation Notice	1



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

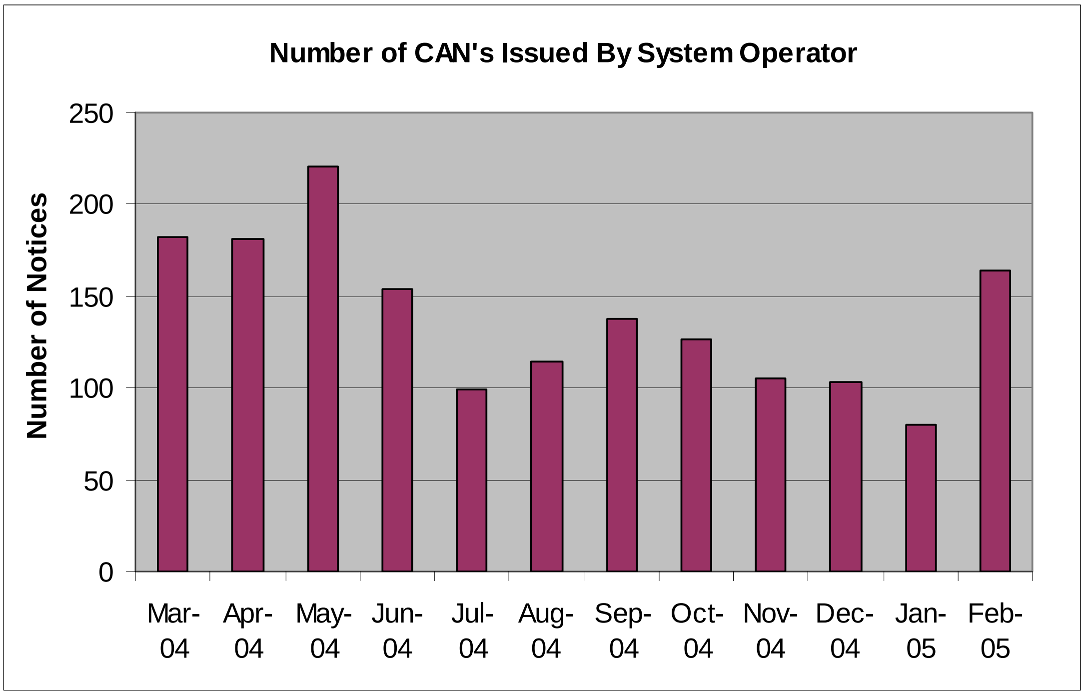
Of the grid emergencies declared during this period the majority were issued in March and April 2004 for the Nelson / Marlborough region where the SO was unable to maintain post contingent loading within advised capability. The Grid Owner has since alleviated the problem in the area by installing a post-contingent load intertrip scheme at Blenheim.

Other notable grid emergencies in the review period were:

- 29th and 30th June 2004: forecast demand in North Island exceeded the available energy and reserve offers along with transmission offers.
- 20th August 2004: a risk of exceeding the capability of the Hawera-Stratford 110kV circuit in real time caused by a severe storm. Factors contributing to the grid emergency included increasing local demand, unavailability of local generation at Hawera and increased south transfer to meet Wellington demand arising from a forced outage of the Bunnythorpe-Brunswick 220kV circuits.
- 16th January 2005: a HVDC tripping due to fire under the HVDC circuits near Balmoral, north of Canterbury. There was a North Island frequency excursion to 48.67Hz.

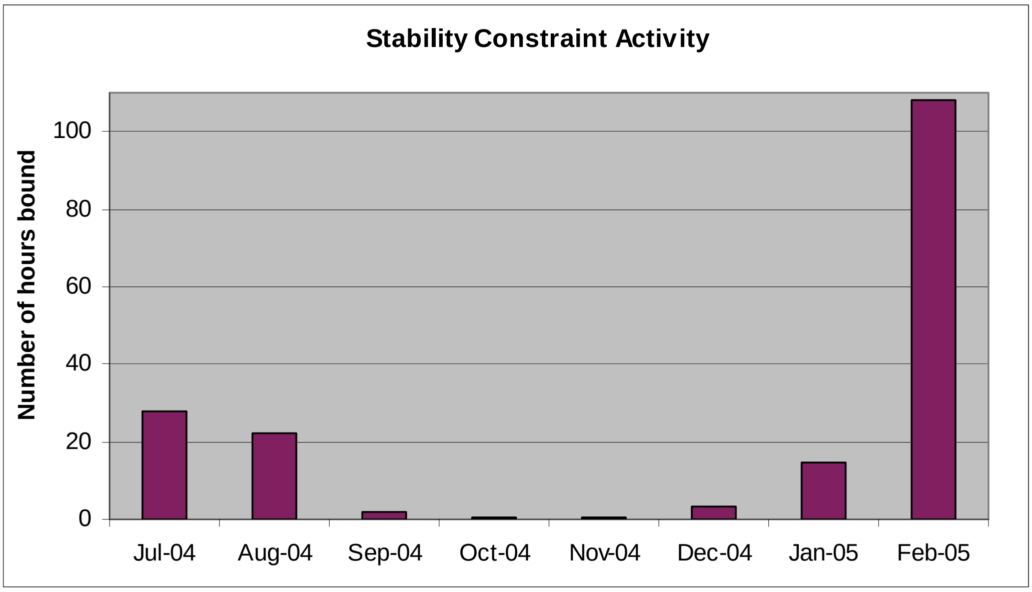
1.6 Participant Advice Notices

1668 participant advice notices (CANs) were issued in the review period. The majority of these notices 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 May 2004.



1.7 Stability Limits

There were no instances of stability limits being exceeded on the grid during the review period. During this time there were 22 stability constraints that bound for a total duration of 178hours. Of these the most significant was the voltage stability constraint required for the 19 day outage of the ISL_LIV cct during Jan-Feb 2005.



2 SECURITY ISSUES

2.1 Real Time Security Issues

There were two significant situations during the year when the System Operator invoked the controls described in the emergency section of the Policy Statement. In both cases, the area affected was the whole North Island. On both occasions, the System Operator ceased to dispatch instantaneous reserves to ensure the PPO's could continue to be met without demand shedding. These actions freed up all available generation that had been dispatched as reserve. In taking these actions, the System Operator was relying on Automatic Under-frequency Load Shedding Systems (AUFLS) to cover contingent events and ensure the 47 Hz under frequency limit was, in each situation, not breached.

The two occasions were:

- 9 and10 March 2004 where there was insufficient North Island generation and HVDC capacity offers following the loss of HVDC Pole 1
- 29 June 2004 where there was insufficient North Island generation and HVDC capacity at winter evening peak, resulting from a major generating plant not being offered and reduced HVDC capacity.

On both occasions additional generating capacity could have been available but was not offered. As some thermal generation requires long start up times, if not already generating, it cannot respond immediately to a shortfall in offered generation capacity. The System Operator suggests improved reporting of the remaining offered but un-dispatched generation, likely to be available given the load forecast. This would provide participants with earlier notice of situations where additional generation offers could be required to meet forecast demand, ahead of the formal issue of Warning and Grid Emergency notices.

2.2 Short Term Security Issues

Upper South Island Winter Security (USIWS)

In April 2004, the System Operator organised a stakeholder group to evaluate the upper South Island supply situation in an operational context and to co-ordinate an operational response to any security of supply issues identified for winter 2004. The 2002 System Security forecast identified demand in the upper South Island could, by 2005, reach the power system capacity limit of existing generation and transmission limits.

Given the level of concern raised by participants and resulting public perception of the security of supply situation in the upper South Island, a higher level co-ordination group was established in addition to the operationally focussed stakeholder group. The co-ordination group was expected to put in place a range of initiatives to ensure any supply situation was successfully managed.

Despite periods of colder weather not seen in recent years, demand peaks within the upper South Island were below the predicted maximum, As a result of the management plans put in place and the co-ordination process undertaken for the South Island in winter 2004, the System Operator has adopted a number of recommendations for managing similar short term issues in the future. The recommendations are set out in the USIWS close out report. This is available at http://www.transpower.co.nz/?id=5255

The implementation of a number of tactical transmission upgrades in the upper South Island by Transpower Grid Owner, including transmission line re-ratings and capacitors, has been accelerated. These upgrades are intended to ensure a reasonable margin between the power system capacity limit and forecast demand in the next few years.

2.3 Top of the South Island Security

The process used to manage the upper South Island identified potential issues in meeting both winter and summer demand in the Nelson/Marlborough/Buller areas, given power system limits. The 2004 winter situation in the top of the South Island was successfully managed through a co-ordinated approach with affected participants using the same processes adopted for the upper South Island.

The System Operator identified a potentially negative impact on power system limits into the top of the South Island due to the offtake power factor in this region.

The recent commissioning of additional capacitors at Stoke will provide sufficient margin for the supply situation in the top of the South Island to remain manageable over winter 2006 until further grid upgrades occur.

2.4 Upper North Island Security

For the sixth successive year, the System Operator organised a participant group to plan a response to power system capacity issues that may arise in the upper North Island over the 2004/2005 summer months. The response reflected experience gained from the 2004 winter management of upper South Island security issues

An Industry Response Group was established, with four work streams. The objective of the group was to plan the avoidance of any interruption of supply to end users for credible supply and demand scenarios. From six scenarios, potential security of supply issues were identified. Options for resolution devised for each credible scenario.

One major initiative was the procurement of additional voltage support from Marsden, Otahuhu and Huntly to mitigate situations where generation in the region was constrained or unavailable.

The upper North Island situation was successfully managed with only one grid emergency being declared. This occurred when Huntly was severely constrained in mid February by abnormally high water temperatures. No involuntary demand shedding was required.

A close out report is being prepared and will be available on the System Operator's website.

Construction of a cooling tower at Huntly power station, due to be completed by December 2005, should remove the need to prepare contingency plans for the more onerous scenarios in summer 2006.

The System Operator is reviewing power system limits into the Upper North Island for winter 2005. An industry response group will be organised to consider and make necessary arrangements for the 2005 winter.

3 RULE CHANGES

3.1 Proposed by System Operator

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

3.1.1 Voltage dispatch instructions

In April 2004 the System Operator identified the EGRs did not provide for the System Operator to issue dispatch instructions for voltage support to any generator that did not have a specific ancillary services contract (to provide the voltage support). The System Operator subsequently proposed a rule change to enable it to issue voltage dispatch instructions to generators in a manner consistent with asset owner performance obligations.

3.1.2 Intermittent generation

The System Operator actively participated with the working groups and other service providers that prepared and implemented rule changes to facilitate dispatch of intermittent generation and establish offer processes under Part G. In particular, the System Operator identified difficulties in the rules formulated under the earlier NZEM regime for incorporation of intermittent generation information in final pricing.

The new rules were implemented in July 2004. The System Operator has recently commenced a review of the operation of those rules and will propose any needed changes.

3.1.3 Publication of asset capability information

In September 2004 the System Operator proposed a rule change entitling it to publish asset capability information received under the rules. This would include asset capability statements and standing data. The System Operator is currently required to keep this information confidential as it is "excluded rulebook information" for the purposes of the rules. The rule change proposal supports the concept of a common information base available to industry participants.

3.1.4 Information about outage constraints

The System Operator and the Reconciliation Manager jointly proposed a rule change to clarify the System Operator's obligations to provide outage constraint information to the Reconciliation Manager within two hours after publication of final prices. The July 2004 rule change proposal was necessary as the existing rules mandated provision of information (in both content and form) that did not actually facilitate the reconciliation process.

In practice, the System Operator supplied only the outage information required by the Reconciliation Manager to perform the reconciliation process. In doing so, the error in the EGRs meant the System Operator was in breach of the rules each month when it provides the necessary information to the Reconciliation Manager.

3.1.5 Variable reserves

In October 2004 the System Operator proposed a rule change regarding variable reserves. The proposal addressed:

- the desirability of allowing a partial dispatch of reserves where there are insufficient energy and reserve offers
- there is a need for appropriate market price signals
- the need to not compromise the System Operator's ability to meet its PPOs.

Participants had expressed concern that when a shortage of energy and reserves existed, the System Operator's inability to dispatch the offered reserves meant available generation was not being dispatched. They believed such generation, if dispatched, would in some measure improve system security as well as meet part G market expectations.

The rule change proposal followed the Board having adopted a settlement agreement made between the System Operator and nine other participants arising from a breach allegation. That agreement required the System Operator to undertake certain investigation works and provide a rule change proposal to the Electricity Commission.

3.1.6 HVDC component flow publication

Under the NZEM regime, the Market Pricing Working Group (MPWG) finalised a draft rule change to require publication of the HVDC component flows in the schedule of dispatch prices and quantities (SDPQ). This change was proposed as a result of HVDC formulation changes (in late 2003) intended to provide participants with more information about the quantity of reserves scheduled. Whilst the majority of the work was completed prior to the coming into force of the EGRs, the rule change has only just been finalised and is due for implementation in May 2005.

3.1.7 Unit commitment

The System Operator is concerned about the security implications of dispatching certain thermal generating plant to zero where the optimal dispatch solution solves for levels of generation below such generators' minimum running range (the unit commitment threshold). Dispatching a large thermal plant to zero in the early hours of the morning means, due to the re-start time, a plant may not be available for the morning peak. This creates security of supply concerns.

Using the SPD software, the System Operator maximises net overall benefit for each trading period. This means the decision to dispatch the thermal plant to zero will often be the most economic solution for the current trading period. However, such a solution may also limit the System Operator's options for security and optimal dispatch during ensuing periods (depending on the return time of the plant dispatched to zero).

To help resolve its concern, in January 2005 the System Operator proposed a rule change dealing with generation unit commitment. If accepted, the proposal would see applicable generators being awarded a status entitling them, in defined circumstances, to submit minimum offers.

3.2 Other

3.2.1 Capacity reserves

Under the New Zealand Energy Market (NZEM) regime, the MPWG proposed a rule change to provide for the offer and dispatch of capacity reserve schemes (e.g. demand inter-trips and generation run-back schemes) in the NZEM scheduling and dispatch rules. This rule change went to consultation under the EGR regime in August 2004.

In principle the System Operator supports the use of capacity reserve schemes under existing bilateral arrangements. It incorporates these existing schemes into its security processes. However, it has reservations about the variable demand inter-trips proposed as part of the rule change proposal. This view was reflected in its consultation paper response.

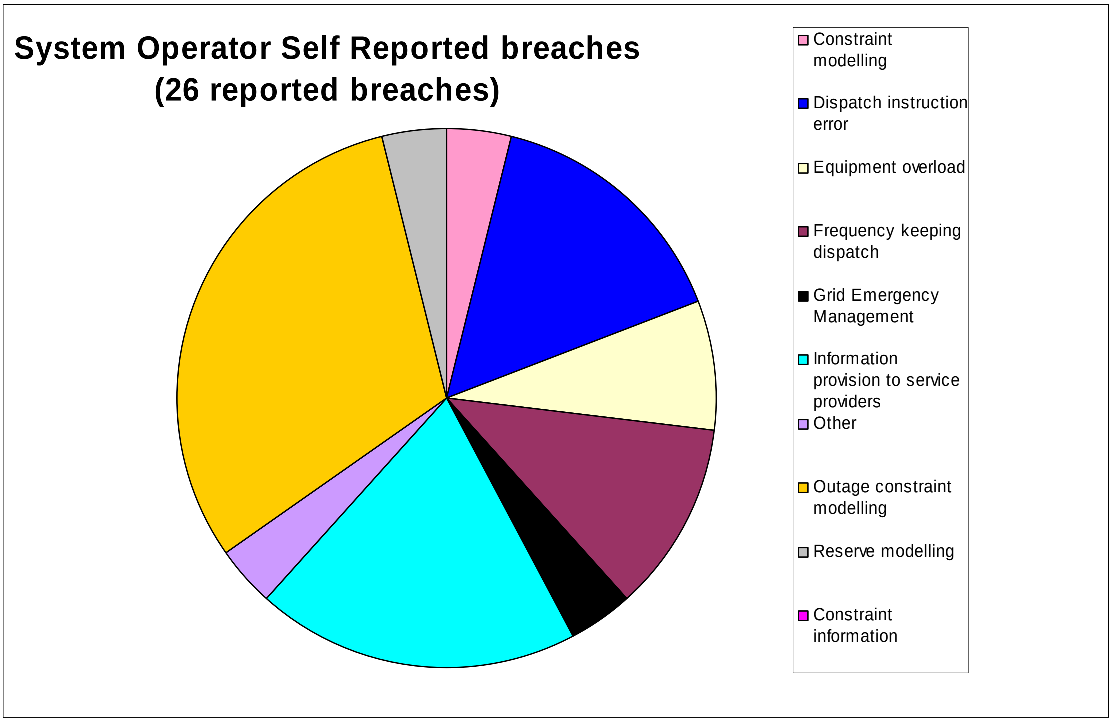
3.2.2 Centralised data set

The System Operator supports the concept of publication and transparency of information to support efficient operation of the electricity market. However, it expressed concern regarding elements of the centralised data set proposal. These concerns included confidentiality, liability and intellectual property issues, the proposed format requirements and the proposed implementation timeframe. The System Operator proposed an enhancement that, if adopted, would see preparation and publication of an industry power system load flow model (in addition to publication of the raw data).

4 BREACHES

4.1 System operator self reported breaches

The following graph categorises 26 breaches of the Electricity Governance Regulations and Rules (EGRs) by the System Operator it has reported to the Electricity Commission during the review period. No breaches have been referred to the Rulings Panel.



The number of breaches and the short history of operating with the EGRs mean the breach data does not provide a strong basis on which to perform a meaningful analysis. Nevertheless, the System Operator makes the following observations:

4.1.1 Outage constraints

There have been a number of self reported breaches relating to incorporation of grid owner information into the dispatch schedule. The majority of breaches relate to outage changes notified to the System Operator at short notice. The process by which this information is incorporated into the schedule is a manual one and such changes occur on average 420 times per month. Whilst all of the reported breaches in this category have had minimal market impact, the System Operator is concerned about the number of similar breach events and is developing a strategy to reduce occurrence of such errors to the lowest possible level.

4.1.2 Information to service providers

The majority of the breaches in this category have arisen as a result of the anomaly in the rules relating to the provision of outage constraint information to the Reconciliation Manager. The information that has been provided to the Reconciliation Manager was the information actually required to complete the reconciliation process. However, this information was not that actually specified in the rules; the rules incorrectly required information of no actual use in the reconciliation process. The System Operator proposed a rule change in July 2004 (noted above) and implemented a technology solution that has eliminated the risk of recurrence of similar breaches.

4.1.3 Dispatch instruction error

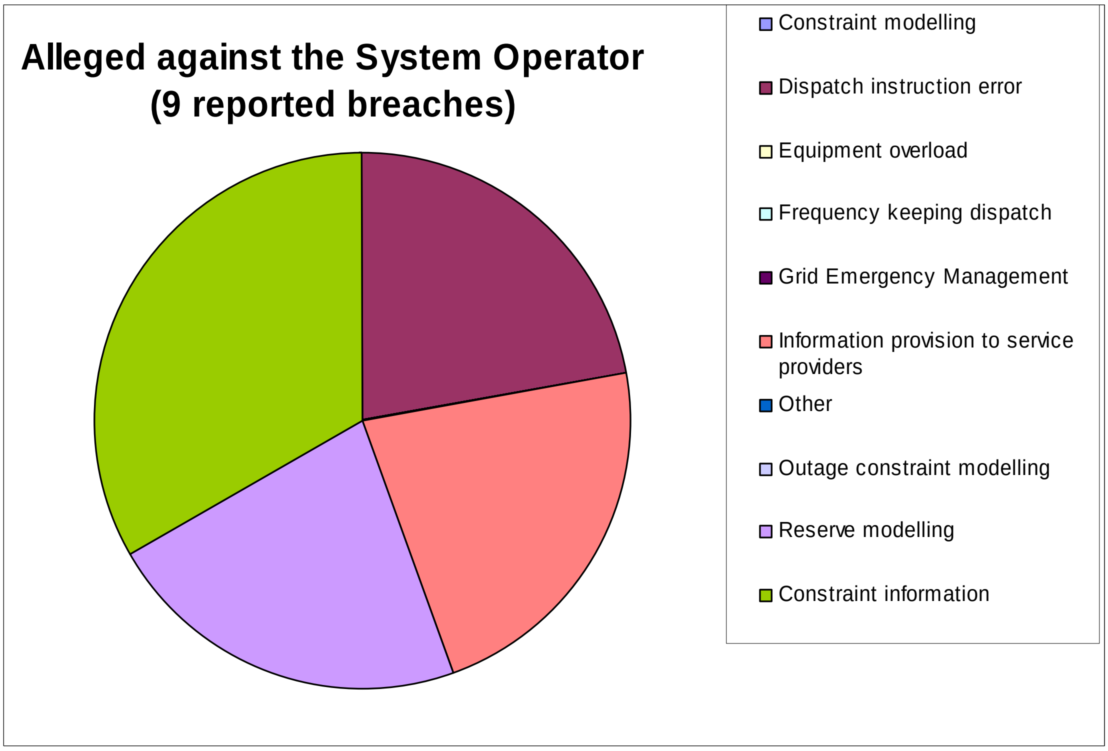
These four errors were each caused by different factors and were in respect of different rules. Two were a result of information technology errors that have been rectified. The other two were System Operator responses to participant breaches of the rules. The System Operator responses were not the appropriate ones to make in the circumstances and breaches of the rules, by both the System Operator and the relevant participants, were reported as a result. System Operator process changes have been made as a result of these two breaches.

4.1.4 Frequency keeping

Whilst there were only 3 breaches relating to frequency keeping dispatch, a near misses was also experienced. As a result, the System Operator and frequency regulating reserve {FRR} providers have changed the manner in which frequency keeping is dispatched. The final stages of this solution are being implemented and no breaches have been reported since November 2004.

4.2 Breaches alleged against the System Operator

The following graph categorises 9 alleged breaches made against the System Operator by other participants during the year.



The System Operator has denied all allegations. The Electricity Commission has closed four of the nine cases. The System Operator makes the following observations:

4.2.1 Constraint information

One participant alleged three separate breaches against the System Operator for failing to issue prompt notifications of outage constraint changes. One allegation was withdrawn. An investigation process is underway for one occurrence, with a settlement meeting scheduled for after the period of this review.

4.2.2 Reserve modelling

These two breaches related to the System Operator's practice of reducing reserve requirements to zero where generation and reserves were insufficient and a feasible dispatch solution could not be obtained. One allegation was investigated. The settlement meeting held in the course of the investigation was the first to be held under the EGRs. That meeting was attended by most of the ten parties who joined or were parties to the investigation.

The settlement agreement arising from that meeting was adopted by the Board. That agreement required, amongst other things, the System Operator to propose a rule change in relation to the systems and processes for reserve dispatch and final pricing. This condition was satisfied, with the rule proposal being delivered to the Board in October 2004.

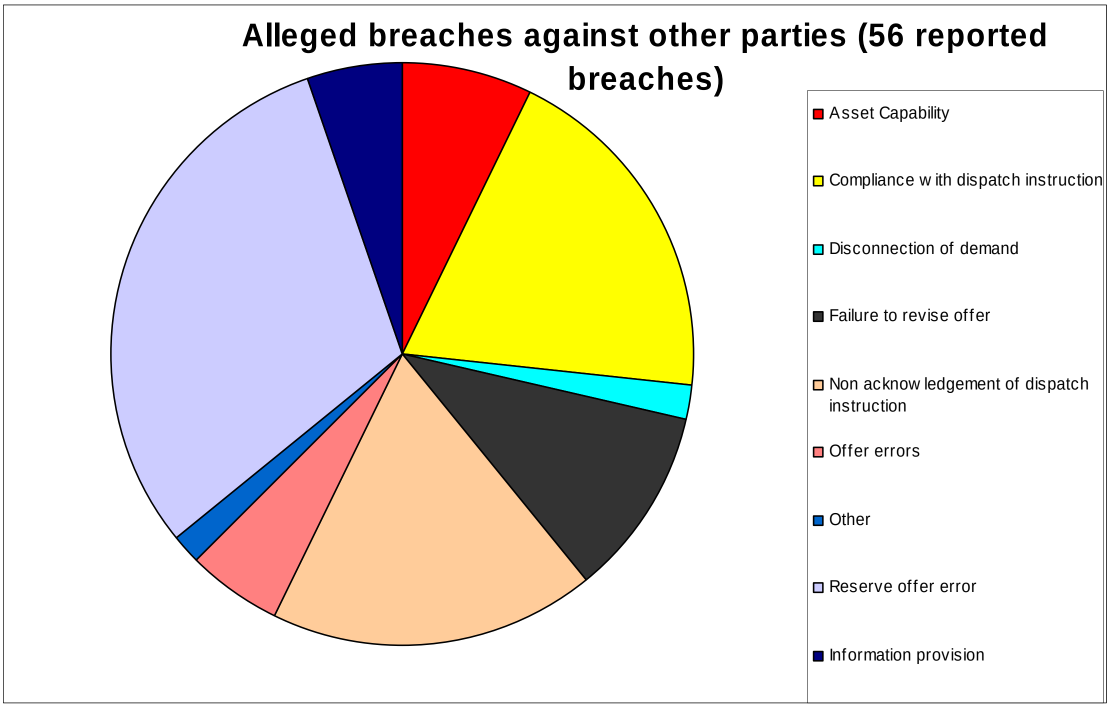
4.2.3 Other

The remaining breach allegations relate to the undesirable trading situation that occurred in April 2004. One allegation is currently subject to investigation. A settlement meeting is scheduled.

All other breaches were minor and the cases are now closed.

4.3 Breaches alleged by System Operator against other participants

The following categorises 56 breach allegations by the System Operator in respect of other participants during the review period.



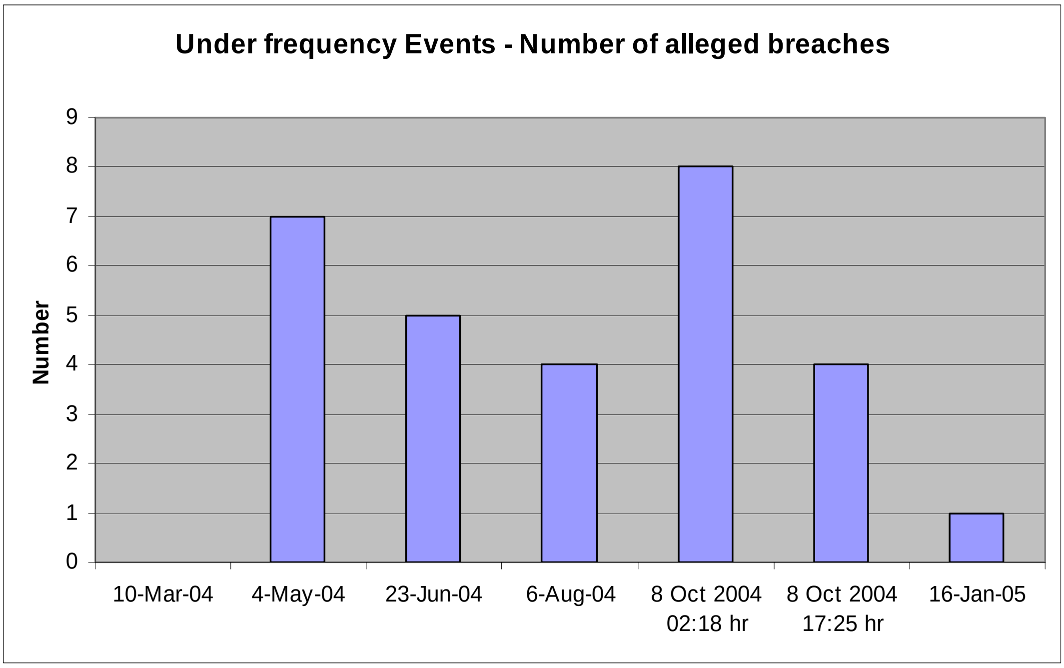
The System Operator makes the following observations:

4.3.1 Reserve offer errors

These alleged breaches relate to 3 under-frequency events that occurred during 2004. The alleged breaches were mainly by providers of interruptible load and in respect of under-provision of contracted reserves. The breaches are now the subject of settlement agreements and await adoption by the Board.

The graph summarises the number of alleged breaches by Interruptible Load (IL) service providers during the review year.

There has been only one under frequency event since the 1 November 2004 introduction of the procurement plan. The graph indicates a marked improvement in performance by IL service providers during that event.



4.3.2 Compliance with dispatch and offer-revision

For some time the System Operator has been concerned about the number of occasions on which participants have failed to comply with dispatch instructions and neglected to revise offers following a change in generation capability. An example is where a generator tripping occurs. It is instructive to consider these non-compliances together.

A large number of the breaches that relate to rule 4.11 of section III of part G have also resulted in non-compliance with rule 3.15 of section III of part G, and vice versa. For the purposes of this review each 'event' has been regarded as representing one alleged breach rather than several. The breach allegations are not limited to any one group of generators. They can not be said to be the result of unfamiliarity with the rule requirements.

The issues arising from the breaches relate to offer inaccuracy and non-compliance with dispatch instructions that, in the System Operator's view, can be detrimental for system security. The consequences of continued inaccuracy and non-compliance may oblige the System Operator to take discretionary action and impact the System Operator's ability to meet the dispatch objective. The issues are of real concern to the System Operator.

4.3.3 Failing to acknowledge dispatch instructions

The System Operator reported a number of breaches by participants for failing to acknowledge dispatch instructions. The majority of these non-compliances occurred in the first part of 2004. There has been a marked improvement in the later part of the review year following discussions between System Operator and participants.

4.4 Settlements

The System Operator was party to two settlement meetings held as part of the investigation of breach allegations. One of these was an allegation against the System Operator.

The first of the settlement meetings resulted in an agreement subsequently adopted by the Board (as noted above in 3.1.5). The second has resulted in an agreement for review and possible adoption by the Board after the date of this review.

Eight other settlement proposals were in discussion as at the 28th of February 2005, four of which are in respect of allegations against the System Operator.

5 NEAR MISSES

The System Operator had one near miss of significance, reported in the System Operator monthly report in August 2004. The event related to frequency regulating reserve (FRR).

When, for a relevant trading period, a new FRR provider is to be dispatched the mandated process in the ancillary services contracts (prior to 1 November 2004) required the System Operator to undertake a number of manual actions.

For one trading period on 27 June 2004, the System Operator neglected to provide some of the required manual dispatch instructions to the new and existing FRR providers. On this occasion, the FRR constraints did not bind, allowing the status quo to continue and resulting in the then current FRR provider continuing to provide the service until the next trading period.

During the review period the System Operator self reported three breaches where it failed to send a dispatch instruction to the selected FRR provider. Concern about these breaches led the System Operator to revise its FRR dispatch process. It has also made some technology changes to minimise the likelihood of recurrence by reducing manual actions. A final change is to be implemented in April 2005.

6 SPECIFIC COMPLIANCE REQUIREMENTS UNDER THE RULES

6.1 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 Board.

6.2 System Security Forecast

The rules require the System Operator to publish a System Security Forecast every two years and review the need to revise the latest SSF every six months. The first System Security Forecast under the rules was provided to the Electricity Commission on 1 December 2004. The report was published on the System Operator website soon after. A review of the need to revise the December 2004 SSF is underway.

6.3 Procurement Plan

The System Operator developed and submitted the initial draft procurement plan to the Board by 1 June 2004. The plan was developed successfully in consultation with industry participants. The System Operator received considerable assistance and co-operation from industry participants. A similar consultation process will be followed in the future.

Implementation of the plan was completed in time for the 1 November 2004 operative date. Tendering and procurement processes under the plan were successfully completed for all five ancillary services. The five ancillary services are: instantaneous reserves, over frequency reserves, frequency regulating reserve, voltage support and black start. Implementation of the plan also required development of new, standard form ancillary service procurement contracts. The contracts were also developed in consultation with industry participants.

The following table summarises the contracted services as at 1 November 2004:

Ancillary Service Agent	FRR	IR	OFR	BS	VS
Meridian Energy	√	√	√	√	
Contact Energy	√	√	√	√	√[1]
Mighty River Power	√	√		√	
Genesis Power	√	√		√	
Trustpower		√			
Vector		√			
Powerco		√			
Northpower		√			
Unison		√			
WELNetworks		√			
CountiesPower		√			
NZ Steel		√			
Pan Pac		√			
Winstones		√			
Norske Skog		√			

[1] Contact Energy - long term contract for the provision of voltage support (contract expires 2007).

The System Operator has recently commenced work on reviewing the procurement plan for the year 2005/06. Input from industry participants will be sought as part of the consultation process.

6.4 Policy Statement

As at the date of this review the System Operator is completing the first annual review of the policy statement required under the rules. Issues for consideration in the review were collected by the System Operator from operational experience throughout the review period. Requests for advice on relevant issues were made directly to participants. An initial consultation draft was made available in February and the System Operator solicited and received many comments and suggestions.

The final draft policy statement was in active development as at 1 March 2005. Most of the important proposed changes have already been signalled to participants and participant consultation comments have been taken into account in developing the final draft.

6.4.1 Departures from Policy Statement

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

6.5 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.

6.5.1 RMT

- RMT Opinion provided by PA Consulting on 16 April 2004.
  Changes included: additional generating stations modelled using existing modelling structures and billing for non-compliance during extended contingent events that required additional data from RMT to be written into the database.

- RMT Opinion provided by PA Consulting on 5 May 2004.
  Changes included: reporting on non-compliant plant from online RMT and introduction of import and solve RTD capability to allow real time changes to be reflected into dispatch. Two additional changes were removal of HVDC cable overload and a correction of HVDC halfpole inverter voltage. Neither of the later two changes were matters that affected market outcomes.

- RMT Opinion provided by PA Consulting on 10 June 2004.
  The change was to amend the AUFLS blocks and use of Interruptible Load (IL) blocks for the South Island. This change had no affect on market outcomes as there is no IL contracted in the South Island.

- RMT Opinion provided by PA Consulting on 20 August 2004.
  Changes were made to modelled data for some small generation plants, including where such generators do not respond automatically to changes in frequency or asset capability changed. Also added were additional model slots for future plant and IT changes to make the model easier to use for Transpower support staff.

- RMT Opinion provided by PA Consulting on the 20 September 2004.
  Changes made were to allow an off-line study mode version of RMT to be operated for technical studies and event analysis.

6.5.2 SPD

- SPD TP37.30. Opinion provided by PA Consulting on 2 September 2004. This version of SPD was implemented to allow time-stamping of buses and branches.

- SPD TP37.31. Opinion provided by PA Consulting on 2 November 2004. This version of SPD was implemented to amend bus time-stamping.

6.5.3 Annual RMT and SPD Certification

- RMT/SPD Opinion provided by PA Consulting on 22 February 2005. This was the annual certification of the Scheduling, Pricing and Dispatch (SPD) Software and the Reserve Management Tool (RMT) as specified in the System Operator Service Agreement and in regulation 51 (1).

6.6 Test Plan

The rules require the System Operator to agree a routine asset test plan with the Electricity Commission. The System Operator undertook two consultation rounds with asset owners before a draft test plan was provided to the Board in late October 2004. Two drafts test plan proposals were made available in the consultation rounds.

At the date of the review the Board was considering the test plan submitted by the System Operator.

6.7 Other Rule Obligations

Undesirable Trading Situations

There were three claims during the year by participants that undesirable trading situations occurred. These were:

- 24 April 2004, where transmission was unnecessarily constrained, causing a 'spring washer' effect in the Bay of Plenty. The Board determined an undesirable trading situation existed. Final prices were published without the constraint
- 29 June 2004, where the System Operator reduced reserve requirements to zero to enable sufficient generation to be dispatched. An undesirable trading situation was found not to have occurred
- 21 August 2004, where the final provisional prices published produced extremely high prices in Wellington and negative prices in Tokaanu. An undesirable trading situation was found not to have occurred.

The System Operator provided information to the Electricity Commission regarding each situation. In each case a detailed contribution was provided to assist the Electricity Commission in making a decision.

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

7.1 Disaster Recovery Plan

The System Operator's Disaster Recovery Plan was submitted to the Electricity Commission to meet the requirements of the System Operator Service Provider Agreement. External experts, selected for their understanding of both emergency and continuity planning issues as well as their electricity industry experience, assisted the System Operator in developing the plan.

The plan was approved by the Board in February 2005.

7.2 Warranties

The System Operator provided the Board with certain warranties at the date the SOSPA was entered into. The System Operator believes that, at 1st March 2005, it:

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

8 SPECIFIC COMPLIANCE ACTIVITIES

8.1 Dispensation and Equivalence Applications

The System Operator received 20 applications for dispensations and equivalence arrangements. Of the applications, 12 related to the requirements of rule 4.1 of Schedule C3, Technical Code C (required indications and measurements).

Of the 20 applications, 16 have been granted, 3 are subject to draft decisions, and 1 is being processed.

8.2 Exemptions

The System Operator assisted the Electricity Commission in 3 exemption applications made by participants, each made in respect of the section III part G dispatch rules.

Carter Holt Harvey, together with TrustPower (as its trader), requested an exemption from compliance with dispatch instructions under rule 4.11 of section III part G. This was on the basis that its generation was linked to an industrial process and could not easily be changed at short notice. The System Operator, Carter Holt Harvey and TrustPower resolved the matter through a clarification of the bona fide re-offer process. The System Operator supported an exemption from dispatch instruction compliance within +/- 5MW. The Board granted the exemption application.

The System Operator assisted with two other applications for exemptions from part G rules. One of these was not pursued by the applicant; the other is pending.

8.3 Applications to Treat Two GXPs as One

No applications have been approved.

8.4 Ancillary Service Provider Performance

The System Operator alleged a number of breaches by ancillary service agents delivering instantaneous reserves for failing to follow dispatch instructions. The alleged breaches related mostly to the delivered quantities not complying with the offered and dispatched quantities during an under frequency event.

Notably, since the procurement plan come into effect on 1 November 2004, there has been a marked performance improvement by the contracted participants. The System Operator has gone to some lengths to make instantaneous load providers aware of the need to confirm the accuracy of their reserve offers. Compliance has important consequences for system security.

9 INDUSTRY CONSULTATION PAPERS

9.1 Contributions and Submissions

The System Operator contributed to a wide range of industry consultation papers issued by the Electricity Commission. These were additional to the responses provided to the Commission on proposed rule changes, as noted above in section 3. The System Operator's contributions have been expressed in responses provided by Transpower New Zealand Limited

Included among the responses to which the System Operator has contributed are:

- Analysis of the state of competition and investment entry barriers to New Zealand's wholesale and retail electricity markets. Feb 05.
- Draft grid reliability standards. Feb 05.
- Double charging of dispensation costs. Feb 05.
- Dispatch of generators for voltage support. Jan 05.
- Limitation of liability and force majeure. Jan 05.
- Developing emergency security of supply provisions. Jan 05.
- Process for Transpower to develop transmission pricing methodology. Jan 05.
- Recommended approach regarding dispatch of generators for voltage support. Dec 04.
- Proposed guidelines for Transpower's pricing methodology. Nov 04.
- Group offer and dispatch of interruptible load. Nov 04.
- Capacity reserves. Aug 04.
- Ancillary services procurement plan. Aug 04.
- Intermittent generation. May 04.

10 GENERAL ITEMS OF INTEREST / CONCERN

10.1 Development report

From a development perspective, the early span of the Board's governance was marked by a substantial effort, by both the Electricity Commission and System Operator, to establish the momentum needed to implement rule and process changes for intermittent generation. This was required prior to the commissioning of Meridian Energy's Te Apiti wind farm in June 05. The rule changes were gazetted on 24th June. The software and process changes were commissioned on 22nd of July, ahead of Te Apiti's commissioning.

The System Operator has initiated a number of software and process developments designed to enhance System Operator service delivery capabilities. Significant amongst these has been the introduction of time stamping in the SPD software. This has greatly enhanced the management of data changes associated with transmission plant.

The System Operator has also implemented the commissioning of a state of the art voltage stability analysis tool (known as VSAT). VSAT will be in service from the end of March 2005 and extend the System Operator's capabilities to manage voltage on the grid.

The System Operator has made contributions to the industry demand side participation and constraint management investigations. Both matters are expected to lead to improvement and enhancement of the wholesale market process in the near future.

In August 2005 the System Operator provided a paper to the WMAG initiating a discussion with the Board regarding the System Operator's intention to upgrade SPD and the market systems. A dialogue ensued with the WMAG and the Electricity Commission that has explored and defined the System Operator's intentions and plans in respect of the market systems.

An important purpose of the dialogue was to make clear the window of opportunity available to the Board to have its own development requirements met. The dialogue established that the System Operator's proposals do not require rule changes but will provide a flexibility to enable potential changes initiated by the Electricity Commission.

10.2 Workshops and Newsletters

During the year the System Operator adopted a practice of issuing a two-monthly newsletter to the industry. Five newsletters were issued. These commented on a variety of issues and updated participants on current System Operator activities. The System Operator will continue this practice.

The first of a regular series of industry workshops was held in late September 2004. They were held in Christchurch, Wellington and Auckland and attracted over 80 attendees. Topics covered were: an overview of forthcoming System Operator matters; constraint design; infeasibilities; reserve dispatch and the future of system operations.

The System Operator plans to hold two workshop series each calendar year.

11 FINANCIAL REVIEW (SOSPA)

11.1 Base Contract

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

Financial review SOSPA 1 March 2004 to 28 February 2005	
System Operator Service Provider Contract Base Fee	21,351,999.96
Information System Access Fee*	1,489,488.00
RMT Audit Fees*	25,221.88
Total fees paid under the SOSPA	22,866,709.84

* 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.

11.2 Additional Fees Revenue

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

Variable Revenue 1 March 2004 to 28 February 2005	
Electricity Commission exemption requests	17,876.00
Software and rule changes for intermittent generation	100,406.00
Rule changes	12,573.50
Breach investigations	82,765.50
Constraints investigation group responses	22,000.00
EC advice IR monitoring and KVar residual charge	11,020.00
Total variable revenue	246,641.00

In addition, fees charged for dispensation and equivalence arrangement applications totalled $1410.00.