



Effect of unpredictability of wind generation output on scheduling

INVESTIGATION 1 – PART B

**WIND GENERATION INVESTIGATION PROJECT
JUNE 2007**

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Executive Summary

Introduction

The Electricity Commission initiated the Wind Generation Investigation Project (WGIP) to determine what changes to the Electricity Governance Rules and Regulations (EGRs) and industry arrangements will be necessary to accommodate the connection of a large volume of wind generation. The “Implications” phase of the project is an investigation of the impacts of wind generation on the operation of the New Zealand power system and electricity market, for a specified set of wind generation development scenarios.

Nine areas where the variability of wind generation output or the technical capability of wind generation may adversely impact on the operation of the New Zealand power system and electricity market were identified. Each of these areas has been investigated to determine the likely impact under the defined scenarios and whether further analysis is required for the Options stage of the Project.

Figure 1 shows the nine areas of investigation.

Variability of wind generation output Scheduling and dispatch Wind generation technical capability Voltage and frequency management Power system stability	Investigation 1 Effect of unpredictability of wind generation output on scheduling generation	Investigation 2 Effect of variability of wind generation output on dispatch of generation	Investigation 3 Effect of variability of wind generation output on asset loading
	Investigation 4 Effect of wind generation capability on steady state voltage management	Investigation 5 Effect of wind generation capability on management of frequency excursions	Investigation 6 Effect of wind generation capability on voltage stability
	Investigation 7 Effect of wind generation capability on power system transient stability	Investigation 8 Effect of wind generation capability on oscillatory stability	Investigation 9 Effect of wind generation capability on dynamic voltage stability

Figure 1: WGIP investigation areas

Issues related to large scale wind generation development that are found to be significant will be advanced to the next phase of the WGIP which considers options for addressing these issues.

Transpower has been engaged by the Electricity Commission to undertake some of the nine investigations. This report documents Investigation One, Part B, which aimed to identify the potential effects of variability of wind generation output on scheduling generation for increased amounts of wind generation connected to the New Zealand power system.

Effect of wind generation unpredictability on pre-dispatch processes

Generation is scheduled on the New Zealand power system on the basis of offers made by generators. Generation is scheduled for the day ahead against a forecast of load and pre-dispatch schedules for generation. These schedules provide information about the price and quantity of generation output for the day ahead. Most generators can only revise their offers up until “gate closure”, which is, for most generators, two hours prior to dispatch, after which time offers can only be revised for specified reasons.

Generation with variable output, such as wind generation, has a limited ability to forecast its future output as this depends on the resources available at the time (i.e. the prevailing wind in the case of wind generators). Offers made by wind generators cannot be relied upon to the same extent as offers made by other forms of generation. The current arrangements make provision for wind generators to provide a forecast of output in place of the quantity component of their offers.

Wind generators provide updated forecasts of future output for the period from day ahead until dispatch. For the period between gate closure and dispatch, the EGRs require that a persistence forecast methodology is used. Forecasts of wind generation output include some degree of error, i.e. there will be a difference between what was forecast and what was actually produced. Load forecasts also have errors. Forecast errors can result in too little or too much generation being scheduled relative to what is required in real time. Forecast errors can impact upon the System Operator’s ability to operate a secure power system.

The pre-dispatch processes include a check that sufficient generation has been offered to meet system demand for each trading period. Forecast errors in wind generation output can lead to situations where a future generation shortfall¹ is not identified (as more wind generation output is forecast than will be produced) or situations where such a shortfall is falsely identified (as less wind generation output is forecast than will be produced).

Checks are made on the pre-dispatch schedules to ensure that the power system will be secure for the generation dispatched within the schedule period. The checks determine that transmission circuits will not exceed ratings and

¹ This is where insufficient offered generation and reserves to meet forecast system load, instantaneous reserves and frequency keeping requirements.

that system voltages will remain within target ranges during and following contingent events (e.g. loss of transmission circuits or generating units). The security check will also indicate areas of the grid where there is insufficient transmission capacity or local generation offered to meet local demand.

Forecast errors will affect the validity of the security check. For example, a pre-dispatch schedule (incorporating a certain wind generation output forecast) may indicate that no transmission circuits will exceed ratings for a contingent (credible power system) event. If wind generation output in a region is lower than forecast then the difference between actual and forecast wind output will have to be made up by other regional generation or by the transmission system. This may result in the loading on transmission circuits being higher at dispatch and exceeding circuit ratings during contingent events.

It should be noted that there are errors in the load forecast that affect power system security in the same manner as wind generation forecast errors. The scheduling processes have evolved to cope with this error.

Assumptions and approach

This investigation has been separated into two parts. This report deals with the second part.

Part A

The objective of the first part is to identify which parts of the scheduling processes will be affected by wind generation forecast error. A report describing the process has been published [1].

The Part A report recommended:

- The issues around the effects of wind generation on the scheduling of generation should be given a high priority for the next stage of the Wind Generation Investigation Project.
- The accuracy of wind generation forecasts should be likewise made a priority for the Wind Generation Investigation Project.
- Further analysis around security assessment and standby reserves check should be included in Part 2 of this investigation.

Part B

Part B of the report describes further analysis around security assessment and standby reserves check. Potential changes to the pre-dispatch processes to accommodate large scale wind generation integration are considered. The report also includes analysis of the effects of wind generation forecast on pre-dispatch prices and quantities for a simplified system.

Findings

Wind generation forecast errors predicted in the Garrad Hassan report [2] will affect the processes and tools used by the System Operator to schedule generation on the New Zealand power system. This leads us to conclude that wind generation forecast error will become the main source of error in the scheduling processes for the North Island once the total installed wind generation capacity in the North Island exceeds around 370 MW. This is likely to occur within the next 2-3 years. Pre-dispatch tools and processes will need to be reviewed and redesigned to accommodate large amounts of wind generation. It is noted that there are limitations to the Garrad-Hassan analysis arising from limitations on the input data. Wind generation forecasting is an area that requires further investigation.

The variability of wind generation output and wind generation forecast errors seem to have a minimal effect on market outcomes. The variability of nodal prices increases with increasing amounts of installed wind generation capacity.

Large wind generation forecast errors can arise from two sources. A sudden large change in wind generation output can cause timing errors (i.e. the size of the change was predicted but the predicted time of the change was early or late) or, if not predicted at all, simply a large error. Large forecast errors resulting from timing errors can be managed in a similar way to demand increases at peak times. The change is predicted to occur within a certain period and the System Operator can manage the change in a manner similar to planned changes in load.

Large forecast errors which are not predictable are managed within the dispatch processes through re-dispatch of generation. The pre-dispatch processes can incorporate a check on whether there is sufficient generation offered or available in future periods to meet a defined wind change event (i.e. a defined extreme wind generation output decrease with a certain probability of occurrence).

Managing the effects of wind generation variability

Wind generation forecast errors are a concern to the industry in New Zealand and worldwide. The accuracy of wind generation output forecasts in itself is not as important as the ability of forecast errors to significantly change the actual generation dispatch from what was forecast during generation scheduling.

The risk is that the power system can not quickly accommodate the change between a generation schedule, based on wind generation forecasts, to the actual generation dispatch required due to actual wind generation output. The issue is one of the variability of wind generation output and the System Operator's ability to accommodate the variability when scheduling and dispatching generation.

There are a number of options for accommodating wind generation output variability in the scheduling and dispatch processes. These options will be considered in the options phase of the WGIP. This report has identified some means for managing wind generation output variability in the absence of changes to current processes:

- Maximising the ability to forecast wind generation output. Changes in wind generation output which are able to be predicted can be managed in pre-dispatch processes in a manner similar to which large forecast changes in demand are currently managed. This allows large predicted changes in wind generation output to occur with minimal impacts on the power system. This will allow greater quantities of wind generation to be installed on the power system without the need for other controls on wind or other generation.
- Learning from experience. The experience with wind generation in New Zealand is very limited. There is insufficient historic information available to make accurate estimates of the probability of large wind generation output changes. Ongoing monitoring and analysis of the variability of wind generation output will provide insights into the probability of large wind generation output changes and help identify appropriate mitigation measures.
- Predicting the power system's ability to meet a large change in wind generation output. This can be done by incorporating a check as to the amount of undispached generation available to cover large changes in wind generation output and how quickly this spare generation can respond in the pre-dispatch and dispatch processes. A shortfall in either offered generation or fast starting ability can be advised to participants through warning and security notices.

When large variations in wind generation are encountered in real time dispatch, there are several options available to manage the impact of the variation. During these times, wind generation output can be controlled through options such as a ramp-rate limitation on how fast the output of a wind farm can change or by limiting the total output of the wind farm. Ramp-rate limitation is more effective for large increases in wind generation output and may be able to be used to counter predicted decreases in output as well (assuming wind generation output is being held below its potential output prior to the event). Other generation can also be re-dispatched to minimise the effect of the change in wind output on the power system in a manner similar to that used to manage the impact of large planned load changes on the power system.

Recommendations

The following areas are recommended for further investigation:

- A project to monitor and analyse changes in wind generation output over time and at a number and range of sites; and;
- Identifying wind generation forecasting capabilities and limitations and incorporation of wind generation forecasts within security processes.

1. Introduction

1.1 Background

The Electricity Commission initiated the Wind Generation Investigation Project (WGIP) to determine what changes to the Electricity Governance Rules and Regulations (EGRs) and industry arrangements will be necessary to accommodate the connection of a significant volume of wind generation.

Nine areas where wind generation may affect the operation of the New Zealand power system and electricity market were identified for investigation (see Figure 1). This report relates to Investigation 1, Part B: Effect of unpredictability of wind generation output on scheduling generation.

Transpower has been engaged by the Electricity Commission to undertake an investigation into the impact of connecting a large volume of wind generation (as envisaged in the wind generation development scenarios) on the scheduling processes and tools used by the System Operator. This investigation is based on the expected unpredictability stated in the Garrad Hassan Report [2].

1.2 Purpose

The purpose of Investigation One is to assess the effects of unpredictability of wind generation output upon the System Operator's pre-dispatch processes and tools and, where necessary, to recommend further investigations in this area.

The first part of this investigation ("Part A") reported on a review of the effects of unpredictability of wind generation output on the pre-dispatch processes and tools and recommended several areas for further investigation. This report ("Part B") investigates those areas.

1.3 WGIP approach

The WGIP has identified nine areas where the variability of wind generation output or the technical capability of wind generation technology could impact on the operation of the power system and electricity market. The potential impact on each area has been assessed through preliminary analysis.

The approach taken during the preliminary analysis was to determine, for a worst case but credible scenario, where the impact of wind generation would create stresses for operation of the power system or electricity market during the next 10 years. If the worst case, but credible, scenario shows no significant effects then further analysis is not required.

The size and urgency of the impacts of wind generation determined during the preliminary analysis will allow the issues to be prioritised for attention in the

next phase of the WGIP. For example, an issue that will have major impacts on the operation of the power system and electricity market for relatively low levels of wind generation will be given high priority whereas an issue that has no significant impacts can be assigned a low priority.

The assumptions specific to this investigation have been made so as to be consistent with the general approach of the WGIP, and are discussed in section 3.

1.4 Overall approach for this investigation

The effects of wind generation unpredictability on pre-dispatch processes can manifest in several ways:

- Changed market outcomes. This will include increased differences between forecast and final nodal prices and quantities and volatility in forecast prices.
- Reduced accuracy of security assessments. This includes security checks, such as the Standby Reserves Check, which assesses whether sufficient energy and reserves offers have been made to ensure:
 - instantaneous reserves can be restored within 30 minutes following the loss of a large generating unit
 - regional security is managed.

Figure 2 shows the investigation areas covered in this report.

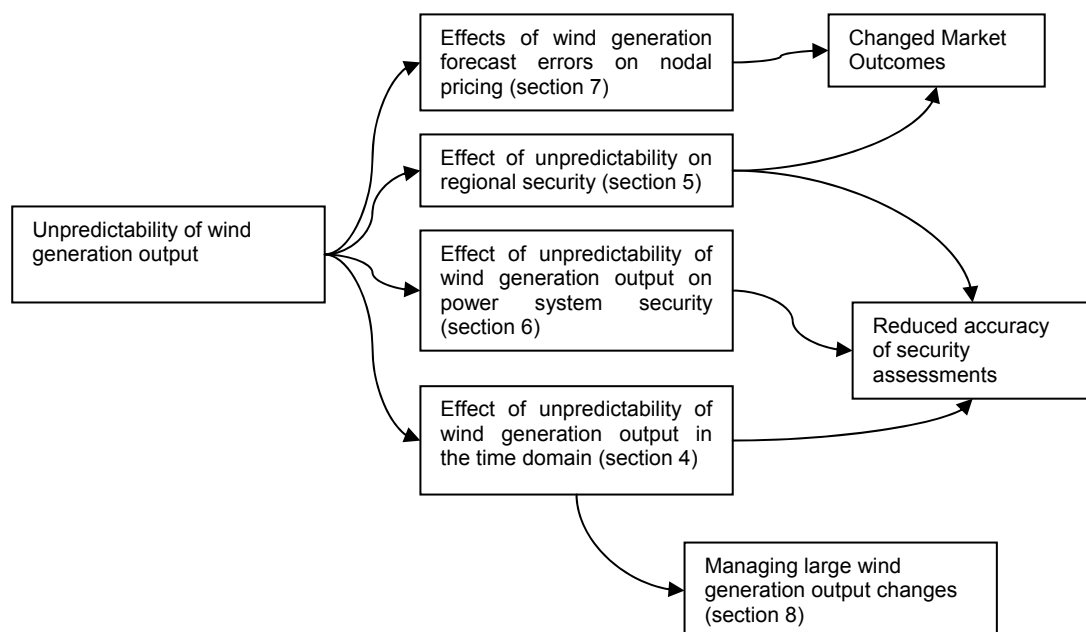


Figure 2: Investigation areas for this report

Analysis of the effects of wind generation output variability and forecast errors on nodal pricing for a simplified power system has been carried out in Section 7 to illustrate the effects of wind generation variability and unpredictability on forecast nodal prices. The simplified power system was chosen for two reasons. The first is that nodal pricing on a small system is much easier to understand. The second is that the analysis using the SPD tool will require considerable software coding to be carried out and the people with the relevant skills are currently dedicated to the System Operator's Market Systems Project.

Analysis of the effects of wind generation on the standby reserves check and regional security assessments has been carried out (see Section 6 and 5 respectively). The amount of analysis has been limited given time constraints and is intended to be illustrative only.

The nature of wind generation forecast errors is investigated further in this report (see Section 4). Large forecast errors are often associated with large unexpected changes in wind generation output over a relatively short time period. Time series analysis of wind generation output variability and forecast error has been carried out to better understand the nature of the changes and errors, and to investigate ways in which the effects may be mitigated. Some measures to mitigate the effects of large wind generation output changes are given in Section 8.

2. Background

2.1 Scheduling generation

The first report [1] of this investigation considered the effects of wind generation forecast error on pre-dispatch processes and tools in the New Zealand power system. The pre-dispatch processes and tools are described in detail in the first report and the interested reader is referred to that report.

The New Zealand wholesale market design includes offer-based merit order dispatch using locational marginal pricing (nodal pricing) to determine the overall lowest cost secure dispatch solution. All generation offered under the trading rules in Part G of the EGRs is dispatched through the offer process in real time. Dispatch occurs every five minutes through formal dispatch instructions sent electronically.

The System Operator is required to meet two objectives in scheduling generation on the New Zealand power system:

- The Principal Performance Obligations (PPOs).²
- The dispatch objective.³

Generation scheduling in the New Zealand electricity market is based on security constrained economic dispatch. At a high level, the process is quite simple:

- Generators submit energy and reserves offers for the day ahead.
- Purchasers submit load bids.
- The System Operator runs processes to produce schedules of cleared generation (energy and reserves) required to meet the forecast load.
- Most Generators and Purchasers can revise their offers and bids until two hours before dispatch.

The EGRs require wind generators to offer in a manner different to other generation. Wind generators provide updated forecasts of future output for the period from day ahead until dispatch. For the period between gate closure and dispatch, the EGRs require that a persistence forecast methodology is used. Forecasts of wind generation output include some degree of error, i.e. there will be a difference between what was forecast and what was actually

² Section II of Part C of the EGRs. The PPOs require the System Operator to act as a reasonable and prudent system operator with the objective of dispatching assets made available in a manner which avoids the cascade failure of assets resulting in the loss of demand that arises as a result of frequency or voltage excursions or supply and demand imbalances.

³ Rule 2 of Section III, Part G of the EGRs. This requires the System Operator to maximise for each half hour the gross economic benefits to all purchasers of electricity at the grid exit points less the costs of supplying the electricity at the grid injection points and the costs of ancillary services purchased by the system operator, subject to the information and offers available to it, and to some defined quality considerations.

produced. Load forecasts also have errors. Offer price for wind generation is limited to either \$0 or \$0.01 per MWh.

2.2 Pre-dispatch processes and tools

There are a number of market software tools (see [1]) which interact to determine schedules of generation dispatch:

- Scheduling, Pricing and Dispatch model (SPD). This application determines the most economic dispatch of the offered generation to meet the forecast load, taking into account security constraints and instantaneous reserves requirements. The application produces a number of generation schedules using a variety of different inputs over different timeframes.
- Standby Reserves Check Tool (SRC). This tool determines whether there are sufficient generation offers to enable generation and reserves to be restored following the loss of the largest contingent event.
- Contingency Analysis (CA). Currently, this tool is run at least every 6 hours to check power system security based on the cleared generation and central load forecast. Where necessary, security constraints are modified (in the SPD model) to ensure that the power system will be secure following a contingent event.⁴

2.3 Wind generation forecasts

Given the location of New Zealand and the nature of wind and weather patterns the wind resource and wind farm output in New Zealand is clearly difficult to accurately predict. The pre-dispatch processes make use of wind generation forecasts. Current forecasts of wind generation output can be made by a variety of means. In New Zealand, wind generators are required to provide forecasts of their output to the System Operator. Forecasts made in the period 23 hours ahead of dispatch to two hours ahead of dispatch are determined using a forecasting model of the wind generator's preference. Wind generators are required to make revised forecasts following gate closure (at two hours before dispatch) until dispatch using a persistence forecasting model.

2.3.1 Wind generation forecasting methods

Two wind generators (Meridian Energy and Trustpower) currently provide wind generation forecasts for their wind farms. The wind generation forecast methodologies used by these companies are confidential. The methodologies deployed have been acknowledged to be undergoing continuing refinement in light of operational experience (noting that wind generators have only been required to provide forecasts of their output since mid 2004). Other

⁴ The Market System Project, which is developing a replacement for the SPD model, will implement an automatic contingency analysis application which will run more frequently.

organisations such as Garrad Hassan, NIWA⁵ and MetService⁶ offer wind generation forecast services in New Zealand.

2.3.2 Persistence forecasts

Analysis of large wind generation forecast errors provide an insight as to how the consequences of forecast error might be managed in dispatch. The following example has been chosen to illustrate the nature of large wind generation forecast errors. The wind generation output is scaled from actual Te Apiti wind generation output. The time period was chosen to include two types of wind generation forecast error.

A persistence forecast (six hours ahead of dispatch) was used as this is a simple method for forecasting wind generation output which does not require knowledge of wind forecasts. The EGRs require the use of a persistence forecast for wind generation output from 2 hours prior to dispatch. The six-hour forecast assumes that wind generation output in the forecast future will be the same as current observed wind generation output of the wind farm. Figure 3 shows an example of wind generation output, wind generation forecast output using a six hour ahead persistence forecast, and the wind generation forecast error.

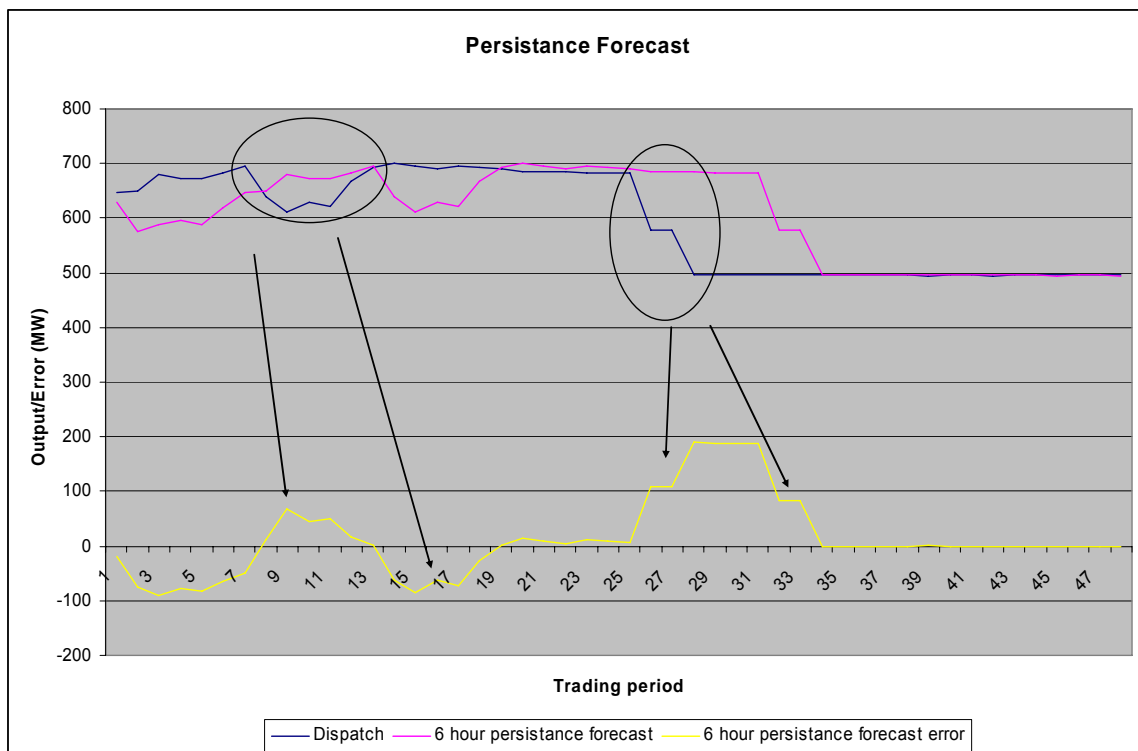


Figure 3: Persistence forecast six hours ahead of dispatch

⁵ See <http://www.niwascience.co.nz/pubs/wa/13-4/wind>.

⁶ See <http://www.metservice.com/default/index.php?alias=business-energy192743>.

The wind generation output contains two events which impact upon the wind generation forecast error:

- The first event (indicated by leftmost oval) shows a sudden drop and subsequent increase in output which is reflected twice in the wind generation forecast error trace in yellow at the bottom of the graph. The first impact is a positive error (as the wind generation initially drops away) and then six hours later the second impact is a negative error as the initial drop appears in the six hour ahead forecast. A single event in wind generation output will be appear in the wind generation forecast error as both a positive error and a negative error. This is a consequence of using a persistence forecast approach.
- The second event is an error due to the sudden drop in wind generation output ahead of that forecast indicated by the right most oval. The forecast error appears immediately as the wind generation output drops and remains over six hours.

A probabilistic analysis of the 24 hours (48 trading periods) in this example might indicate that large wind generation forecast errors (greater than 100 MW) occur for six trading periods in the day. However, these six trading period errors relate to one change in wind generation output. Caution should be used when interpreting the implications of probabilistic analysis – a relatively few events may produce a large number of large forecast errors leading to the conclusion that the situation is more serious than it actually is.

Figure 4 shows an example of persistence forecasts for different time periods ahead of dispatch. The accuracy of persistence forecasts decreases the further the forecast is made ahead of dispatch.

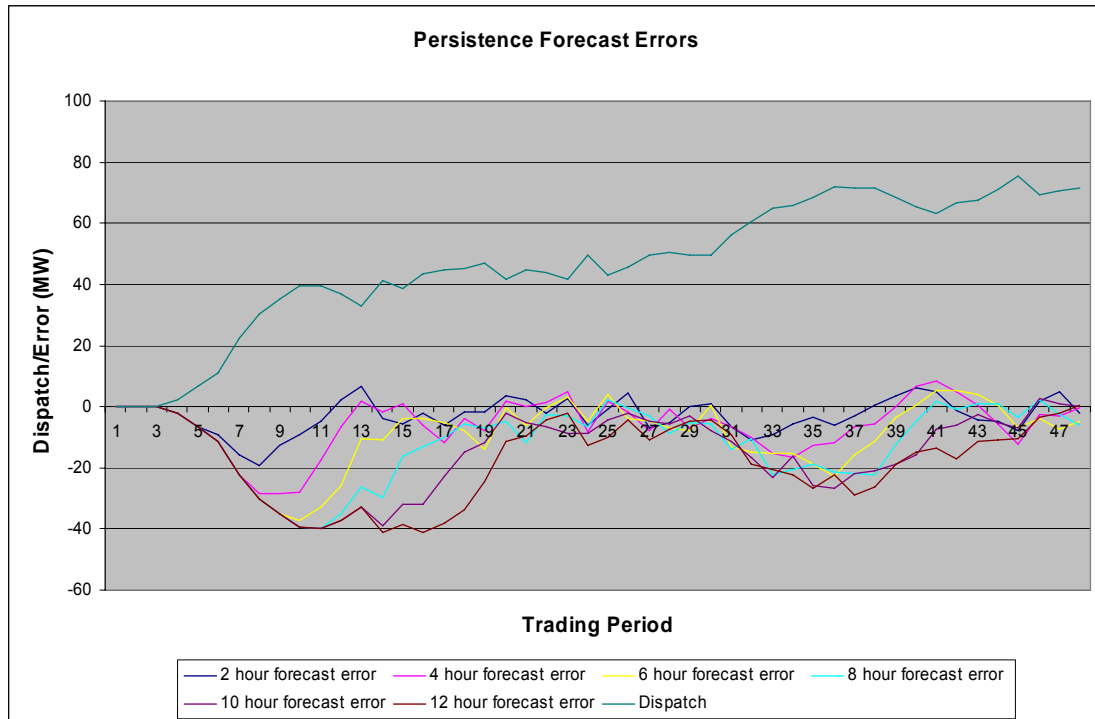


Figure 4: Persistence Forecasts

2.4 Load forecast error

Load forecast error is the difference between the load forecast for a particular trading period and the actual load for the trading period. The System Operator uses its own internal load forecast (the “SO load forecast”) for assessing power system security using the Security Dispatch Schedule (SDS).⁷

The effects of the present level of SO load forecast error are managed within the existing scheduling and dispatch processes and tools. Many of these errors are short timing errors between scheduling periods during the steep increase in early morning load. The effects can be managed by ensuring sufficient generation is available for early pick-up in load (see [1] for further details).

2.5 Predicted wind generation forecast error

Garrad Hassan [2] has calculated wind generation forecast errors for the Electricity Commission’s wind generation development scenarios [3]. The 23 hour, 12 hour and 6 hours forecasts are based on a meteorological model. The 2 and 3 hour forecasts are based on a persistence model. Limitations of the analysis are discussed in reference [1].

Figure 5 and Figure 6 show calculated wind generation forecast errors for wind generation development scenario “C” (see [3] for details) in the North and

⁷ See Part A of this report for a description of the Security Dispatch Schedule.

South Islands respectively. Figure 5 shows that wind generation forecasts for the North Island, 23 hours ahead of dispatch, can be expected to be in error on occasions by over 800 MW (50% of installed wind generation capacity in the North Island under this scenario) once per day.

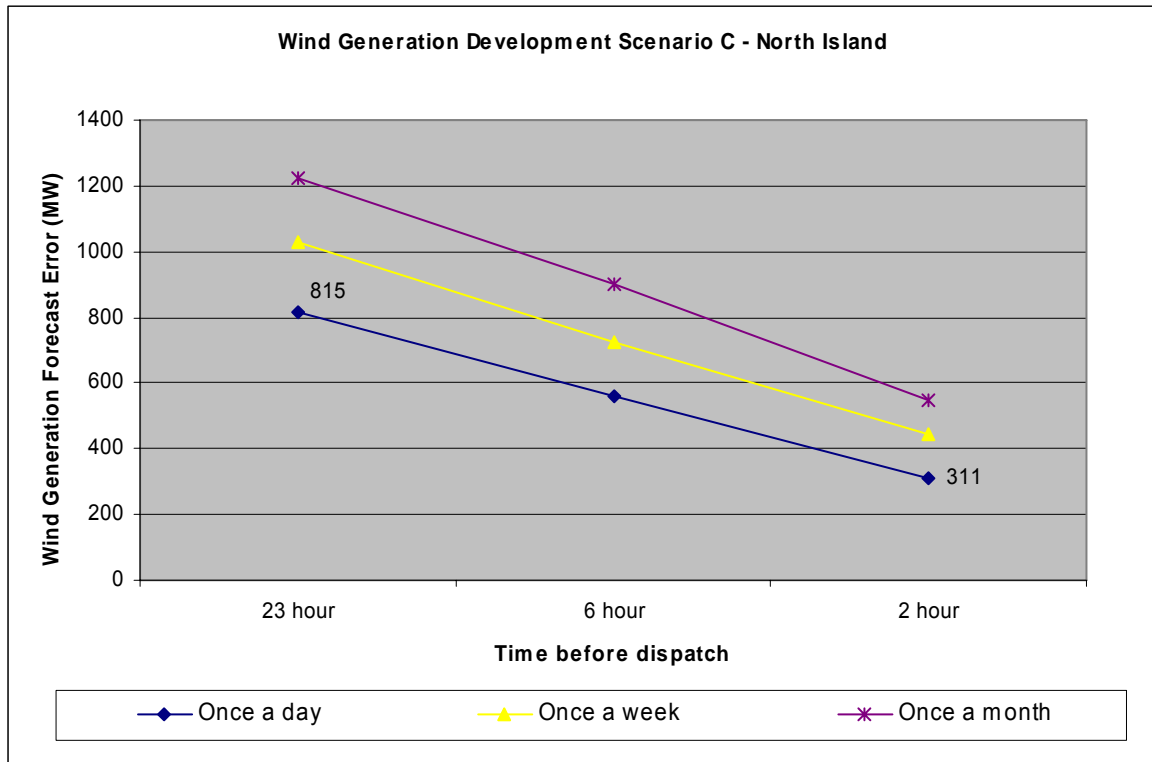


Figure 5: Wind Generation Forecast Error for North Island (scenario C adapted from Garrad Hassan Report [2])

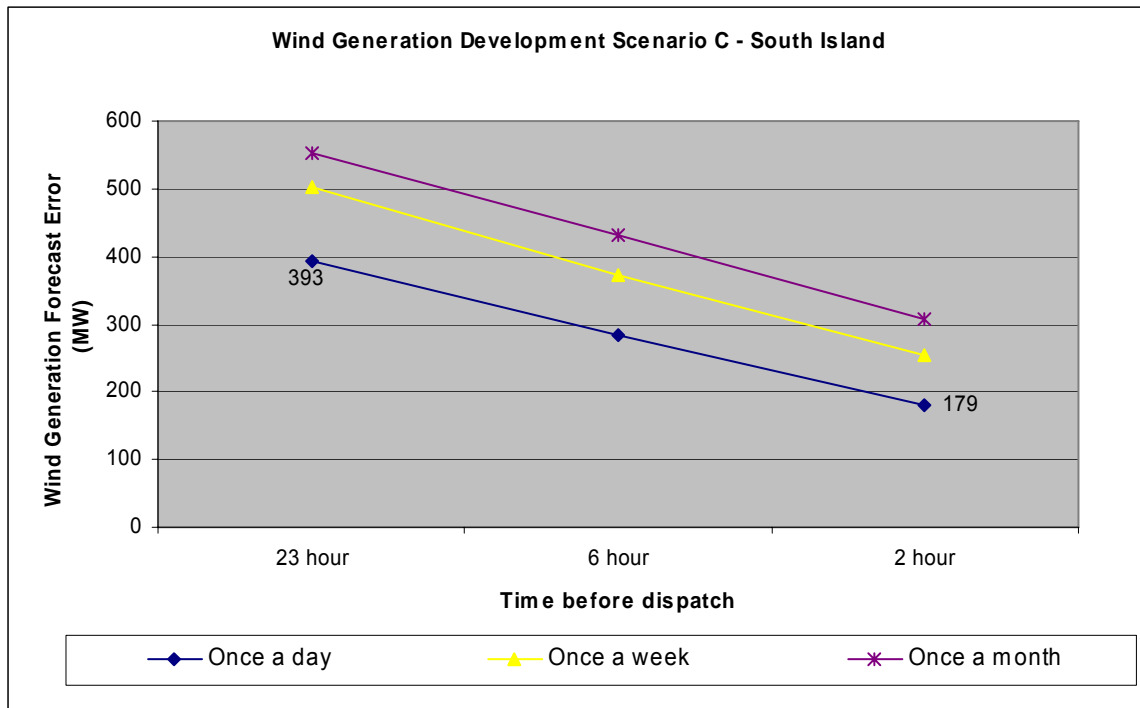


Figure 6: Wind Generation Forecast Error for North Island (scenario C adapted from Garrad Hassan Report [2])

Once per day, wind generation forecast errors for wind generation development scenario C are approximately double the existing load forecast errors observed for the North Island for the 2 hour forecast, rising to approximately four times greater for the 23 hour forecast. The calculated wind generation forecast errors for the South Island will be more than double the existing SO load forecast errors observed in the South Island. The multiples are slightly lower for the forecast error estimated to occur “once a month”.

Figure 7 shows the predicted wind generation forecast errors for all of the wind generation development scenarios and SO load forecast error in the North Island. The wind generation forecast error is greater than the load forecast error for all wind generation development scenarios except for scenario D (where the wind and load forecast errors are approximately equal). This leads us to conclude that wind generation forecast error will become the main source of error in the scheduling processes for the North Island once the total installed wind generation capacity in the North Island exceeds around 370 MW.⁸ This is likely to occur within the next 2-3 years.

⁸ Scenario D includes a total of 370MW of wind generation in the North Island. The amount of installed wind generation capacity in the North Island is currently 170 MW and will rise to 263 MW by the middle of 2007 with the commissioning of Taranua III wind farm. The commissioning of further wind generation in the North Island (which is likely to occur within the next 2 years) is likely raise the total amount to above 370 MW.

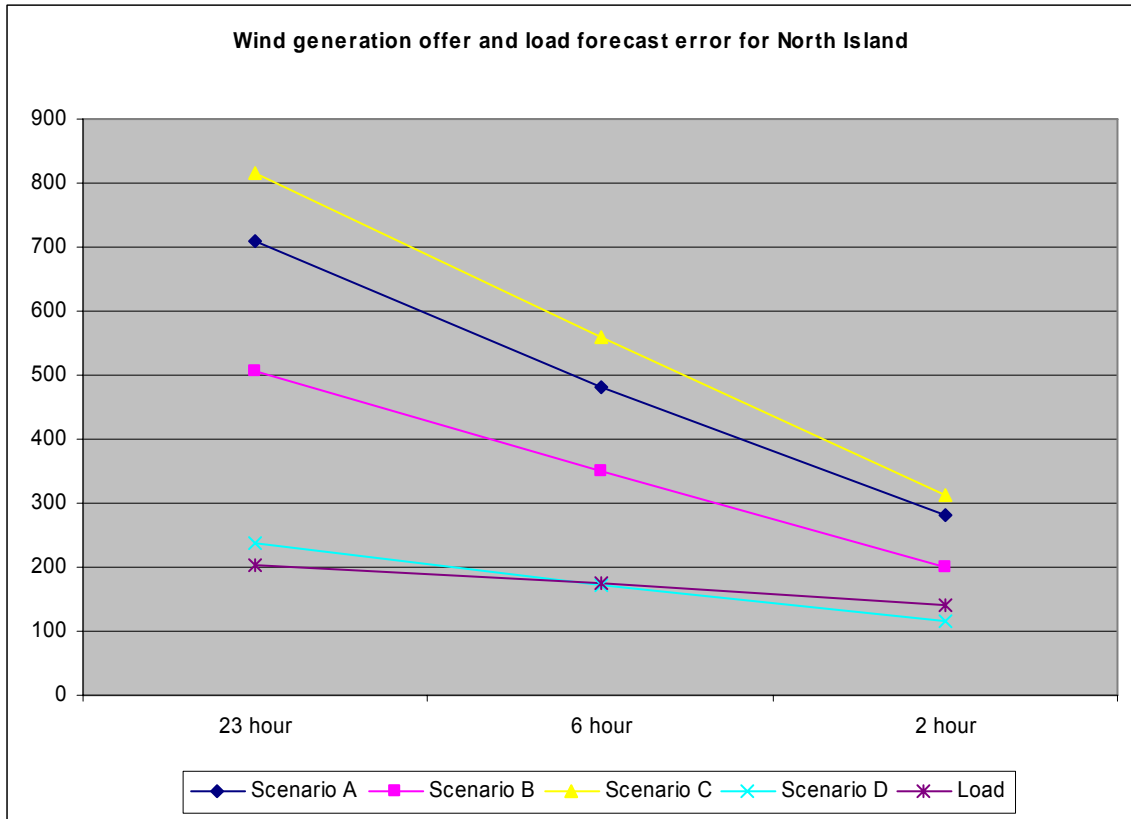


Figure 7: Wind generation forecast and SO load forecast errors for the North Island expected to occur once per day (based on Garrad Hassan [2])

3. Assumptions and Approach

3.1 Assumptions

Table 1 shows the location of new and existing wind generation as assumed in the Electricity Commission's wind generation development scenarios [3].

Island ⁹	Scenario A (high penetration, concentrated in the North Island)	Scenario B (high penetration, diversified across the country)	Scenario C (very high penetration, diversified across the country)	Scenario D (low penetration, diversified across the country)
North	1150 MW	950 MW	1600 MW	370 MW
South	100 MW	300 MW	650 MW	50 MW

Table 1: Location of new and existing wind generation in wind generation development scenarios

Garrad Hassan has constructed estimates of wind generation output variability and wind generation forecast errors based on these scenarios and historic wind speed and direction measurements [2]. Where relevant for this investigation, wind generation forecast errors based on wind generation development scenario C have been considered.

Historic wind farm output time series data from Te Apiti wind farm has been used to illustrate the effects of wind generation forecast error on pre-dispatch processes. Te Apiti wind data is used as this is the only wind farm for which appropriate historic operational data exists.

Historic power flow data and load data for certain regions in the New Zealand power system have been used to assess the effects of wind generation output unpredictability on managing regional security.

3.2 Approach

The effect of wind generation unpredictability on pre-dispatch processes is analysed in the following areas:

- Time series analysis of wind generation output;
- Security assessment;
- Standby Reserves;
- Economic dispatch – simplified model.

⁹ This includes the existing 250 MW of wind generation (Te Apiti, Tararua I, II and III) located near Bunnythorpe.

3.3 Time series analysis

The wind generation forecast errors considered in Part A of this investigation were described in terms of probability. The probability of occurrence for forecast errors of a particular size was calculated and the results expressed in the form of probability distribution functions.

This approach was useful in identifying the frequency of forecast errors but provided limited insight into the nature of the errors or how the effect of the errors might be mitigated. Garrad-Hassan [4] has carried out time series analysis on a number of the larger forecast errors.

The larger wind generation forecast errors tend to be associated with a large change in wind generation output over the period of a few hours. In some cases, the wind generation output change was predicted but the timing was out by several trading periods. This gives rise to a number of large wind generation forecast errors for a single large change. In other cases, the wind generation output change was not predicted also resulting in a number of large forecast errors over several trading periods.

Where the probabilistic analysis indicated that a wind forecast error of around 540 MW¹⁰ at two hours ahead of dispatch might be expected to occur once a month, the size of wind generation output change associated with the forecast errors might only occur two or three times a year (with each of these occasions contributing several large forecast errors).

In cases where forecast errors are caused by timing errors (e.g. it is known that a large change in wind generation output is very likely to occur over the next four hours but exactly when the change will start in the four hour period is not known) then the change can be managed in a similar way to which planned or predictable changes in load are currently managed.

In cases where forecast errors are not caused by timing errors (i.e. the large wind generation output was not predicted at all) then the change will need to be managed in the dispatch processes (i.e. frequency keeping and re-dispatch of generation). What can be done in the pre-dispatch processes is to carry out a check as to whether there is sufficient generation offered in future trading periods which can be dispatched in time to meet the large decrease in wind generation output.

3.4 Security Assessment

Power system capability limits are a limitation on demand or generation in an area or transfer between regions that will keep in the power system in a secure state should an event occur. A margin between the power system capability limit and the affected demand or generation can be calculated. For example,

¹⁰ See Table 2 on page 41.

assume that power system limit is 500 MW for a particular demand. The margin is calculated as 500 MW minus the demand at any particular time.

In a simple sense, the power system capability limit is dependent on regional generation (including wind generation). For example, consider a region where 400 MW can be supplied through the grid and with 200 MW of installed local generation capacity. There is a limit on the amount of regional demand that can be met:

- 400 MW when no regional generation is available; and
- 600 MW when full regional generation is available.

At times when regional demand is greater than 400 MW, regional generation equivalent to the amount of demand in excess of 400 MW will need to be available to avoid the need to curtail demand. The check that sufficient regional generation is available to meet forecast regional demand is part of the security assessment within the pre-dispatch processes.

Consider a region in a power system with the following characteristics:

- Installed wind generation capacity of 400 MW,
- Other generation capacity of 200 MW,
- A peak demand of 650 MW,
- Power system transfer limit of 340 MW.

Figure 8 shows an example of how forecast demand and generation in the region might vary over time. Note that the wind generation forecast output is assumed to be 200 MW (50% of installed capacity) and other generation output is 200 MW. The net regional demand is regional demand less the wind and other generation output. This demand must be supplied from the rest of the power system (with a transfer limit of 340 MW applying).

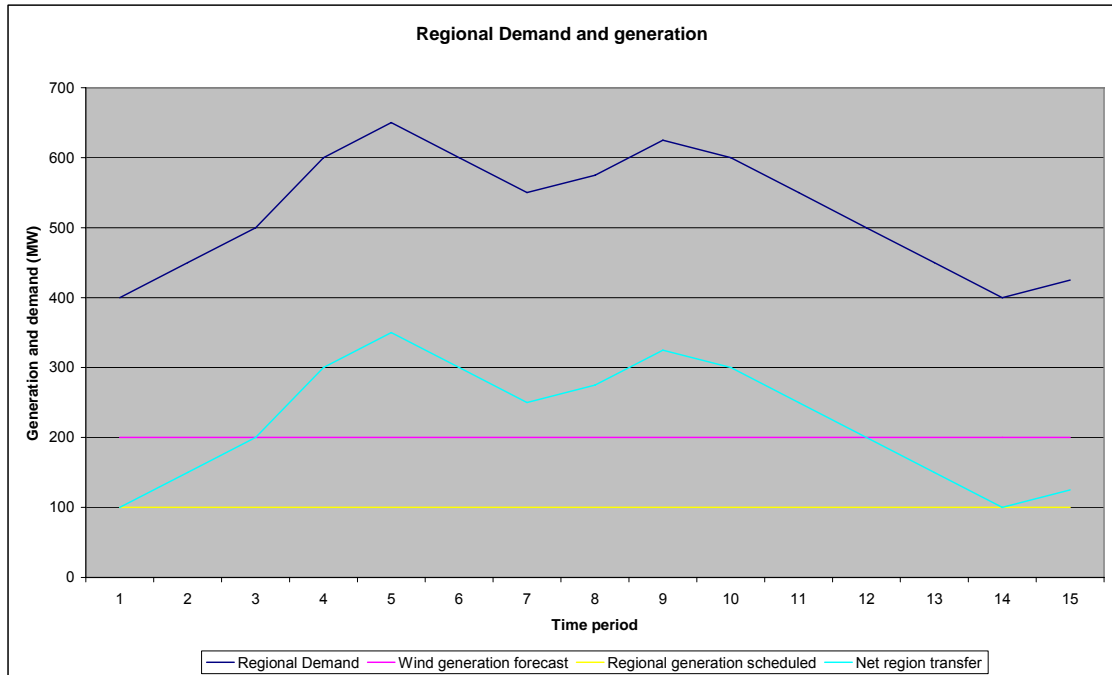


Figure 8: Regional demand and generation

The margin between the net regional demand and the transfer limit can be calculated. Where the margin is positive, there is sufficient power system capability to meet the regional demand. Where the margin is negative, there is insufficient power system capability to meet regional demand and some demand may have to be shed to ensure that the power system remains in a secure state.

Figure 9 shows the net regional demand, the power system transfer limit and the margin between net regional demand and the power system limit. Note that the margin is negative (i.e. regional demand exceeds the power system limit) for time period 5. It is assumed that the security check will identify this negative margin as the contingency analysis will indicate that some circuit will exceed its rating following a contingent event. This will highlight a lack of transmission capacity for time period 5 which will in an operational sense result in Warning Notices being advised to participants by the System Operator.

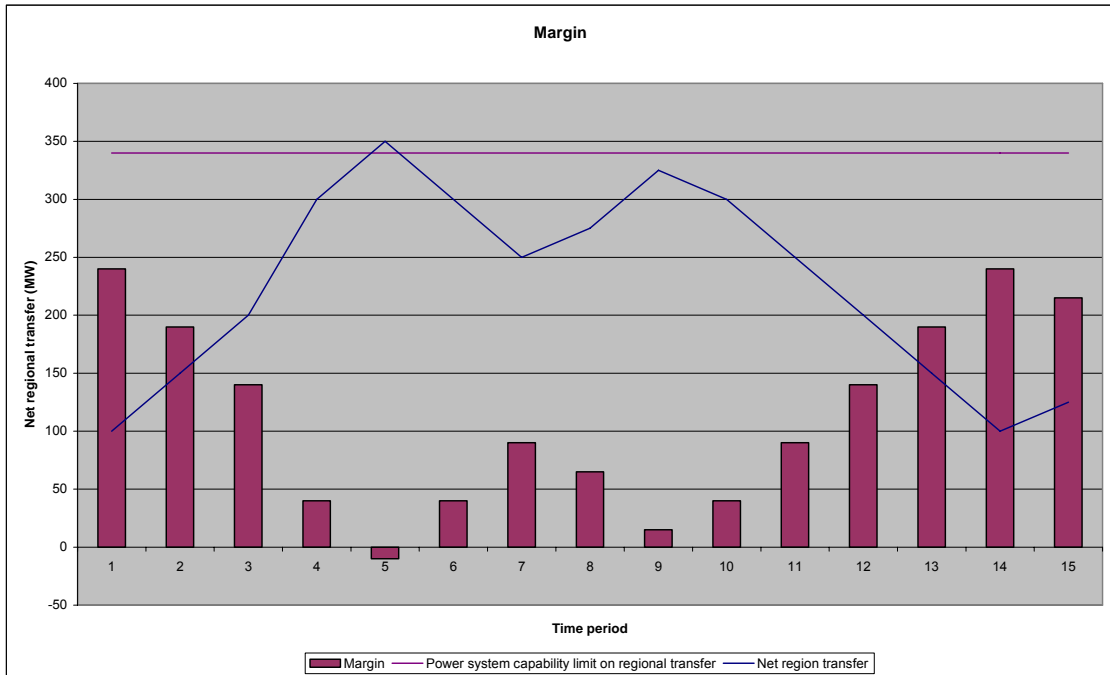


Figure 9: Regional transfer limits and margins

The ability to identify such instances will depend on the wind generation forecast error. If the forecast is too high then a negative margin will not be indicated. If the forecast is too low, then negative margins may be falsely indicated. Figure 10 shows an assumed cumulative probability distribution for regional wind generation forecast error. This cumulative probability distribution function can be used to determine cumulative probability functions for margins on regional transfer.

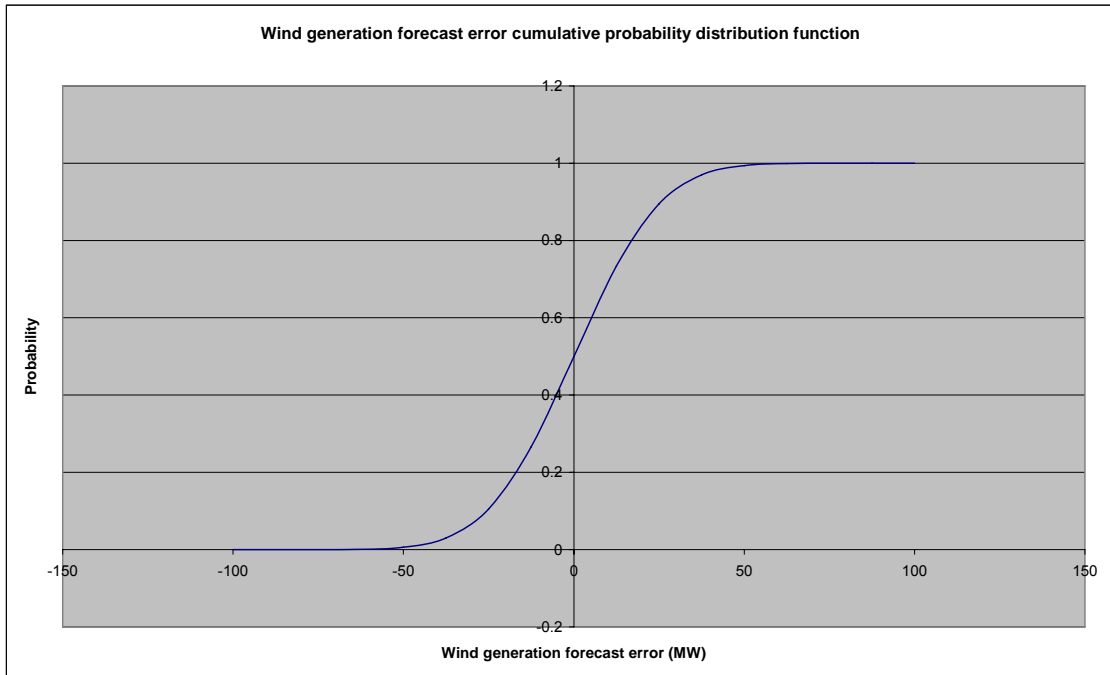


Figure 10: Assumed cumulative probability distribution for regional wind generation forecast error

Figure 11 shows cumulative probability distribution functions for margins in time periods 4 and 5. The margin for period 5 is positive (indicating no security issue) for around 27% of the time. The margin for period 4 is negative (falsely indicating a security issue) for around 3% of the time.

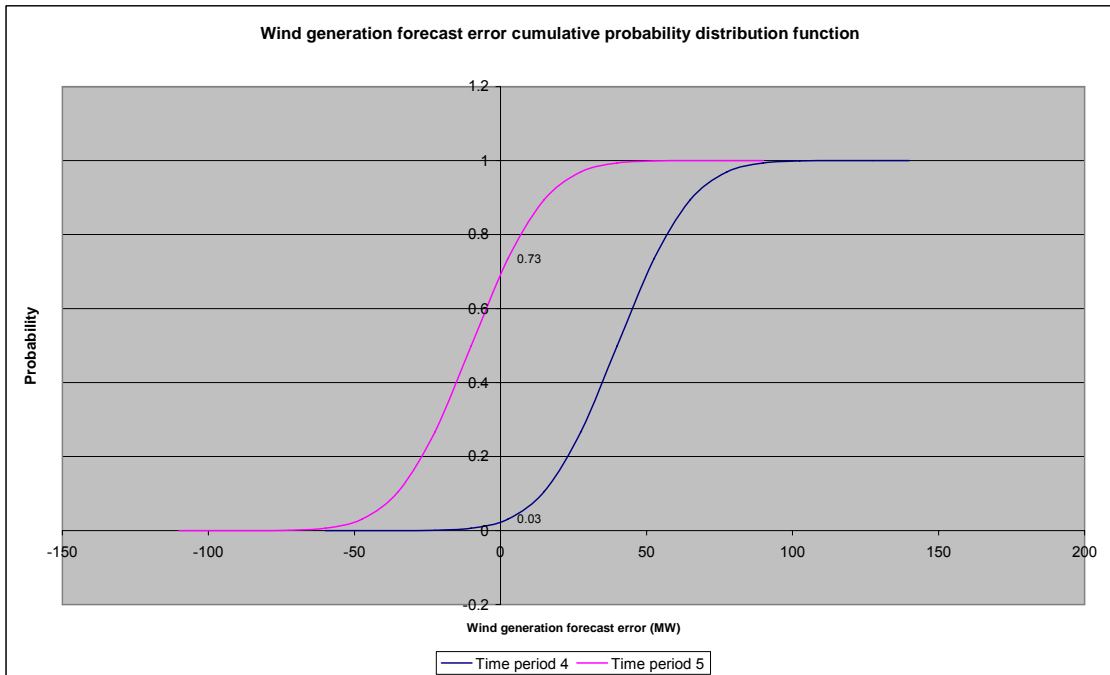


Figure 11: Cumulative probability distribution for margins

The accuracy of wind generation forecasts improves closer to dispatch. The likelihood of missed security issues or false identification of security issues resulting from wind generation forecast errors likewise will decrease closer to dispatch. The time prior to dispatch at which issues can be identified may be able to be determined as part of the analysis. This can be compared with the time required to start other generation to assess whether other plant can be made available in time following discovery of the issue.

3.5 Standby Reserves

The Standby Reserves process identifies whether there is sufficient energy and reserves offered by generators to allow reserves to be restored following the loss of a large generating unit. The Standby Reserves process will be directly affected by wind generation forecast error:

- The process may incorrectly indicate there are sufficient energy and reserves offers based on a forecast of high wind generation output.
- The process may incorrectly indicate there are insufficient energy and reserves offers based on a forecast of low wind generation output.

A “Standby Residual Check” (SRC)¹¹ is performed on the most recent Security Dispatch Schedule (SDS) results. The SDS is currently produced at least every six hours by the System Operator. The Standby Reserves Check Tool (SRC) determines whether there will be sufficient generation offers to restore generation and reserves following the largest contingent event. This tool does not hold historic results from the SRC.

Figure 12 shows an example of the SRC margin. The columns show the system requirements over a number of trading periods. The first three elements on the stack represent the trading period needs for energy¹², instantaneous reserves and frequency keeping. The top element, “largest generating unit”, shows the additional generation that would be required to restore reserves in the event of the largest generating unit tripping. The pink line shows the amount of generation offered.

A Standby Reserves deficit is indicated whenever the total column (Load forecast, instantaneous reserves, frequency keeping and largest generating unit) exceeds the offered generation (such as in trading period 17).

¹¹ See <http://www.systemoperator.co.nz/?id=6299#contentsection22319> for further detail on Standby Reserves.

¹² System Losses are included in the load forecast for simplicity.

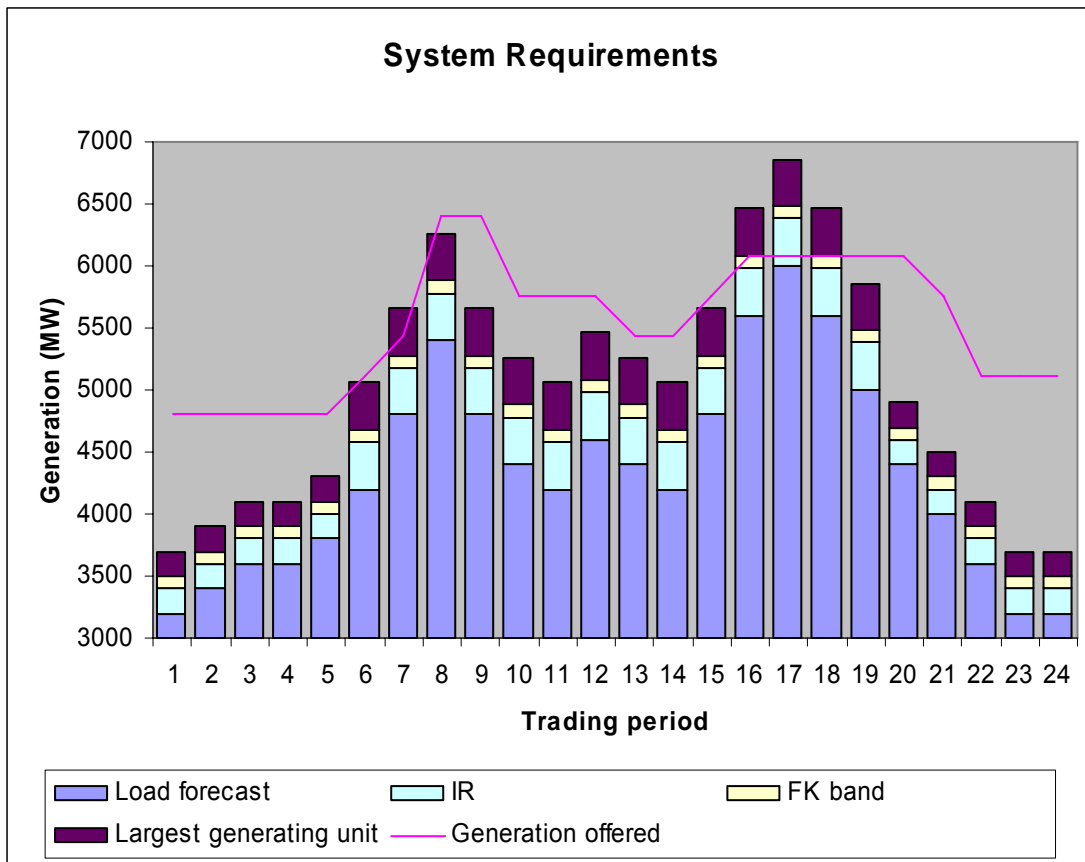


Figure 12: Standby Reserves

A Standby Reserves margin can be calculated from Figure 12 by subtracting the column height from the offered generation (pink line). This is shown in Figure 13. A deficit is shown in trading period 17. Once the deficit has been identified, a Standby Reserves notice would be sent out.

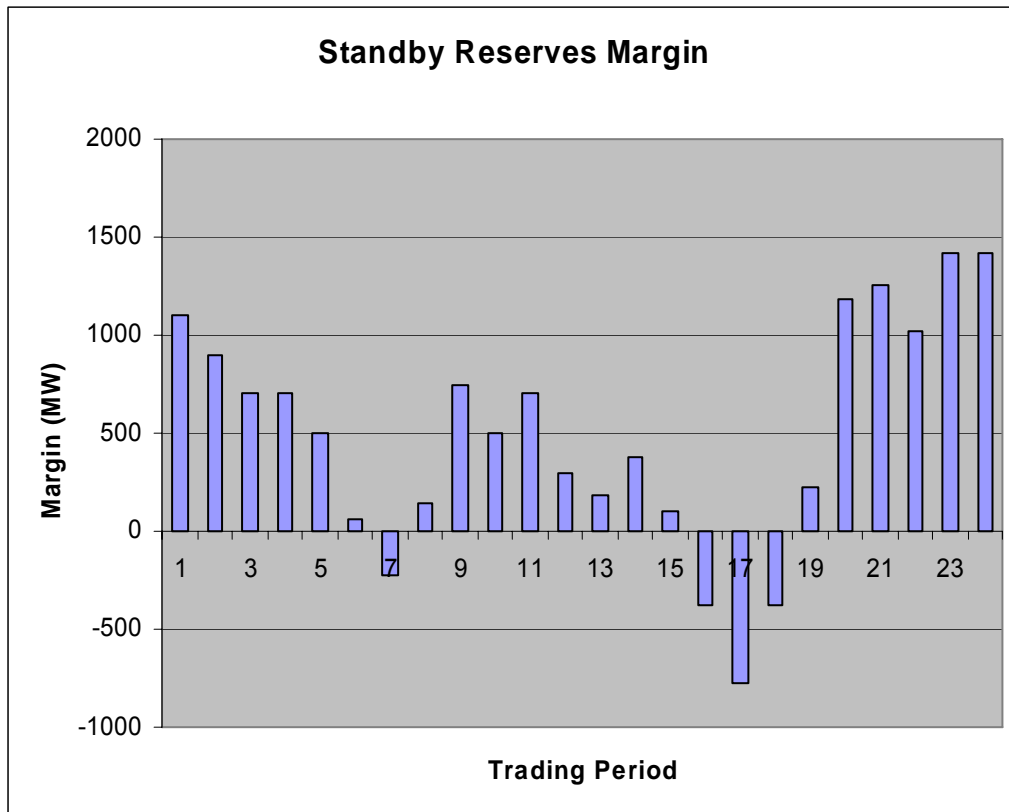


Figure 13: Standby Reserves margin

Presently, wind generation is not considered in the SRC. This is because the amount of installed wind generation capacity has been small and all located in the same region. At some stage, wind generation will need to be incorporated in the SRC. Assume that part of the generation offered is output from wind generation. Wind generation forecasts have limited accuracy. The effect of errors in wind generation forecasts will have the effect of shifting the offered generation line higher or lower. Figure 14 shows an example where actual wind generation output was 800 MW¹³ with wind generation forecasts 800 MW too high and 800 MW too low.

¹³ An installed wind generation capacity of 1600 MW is assumed.

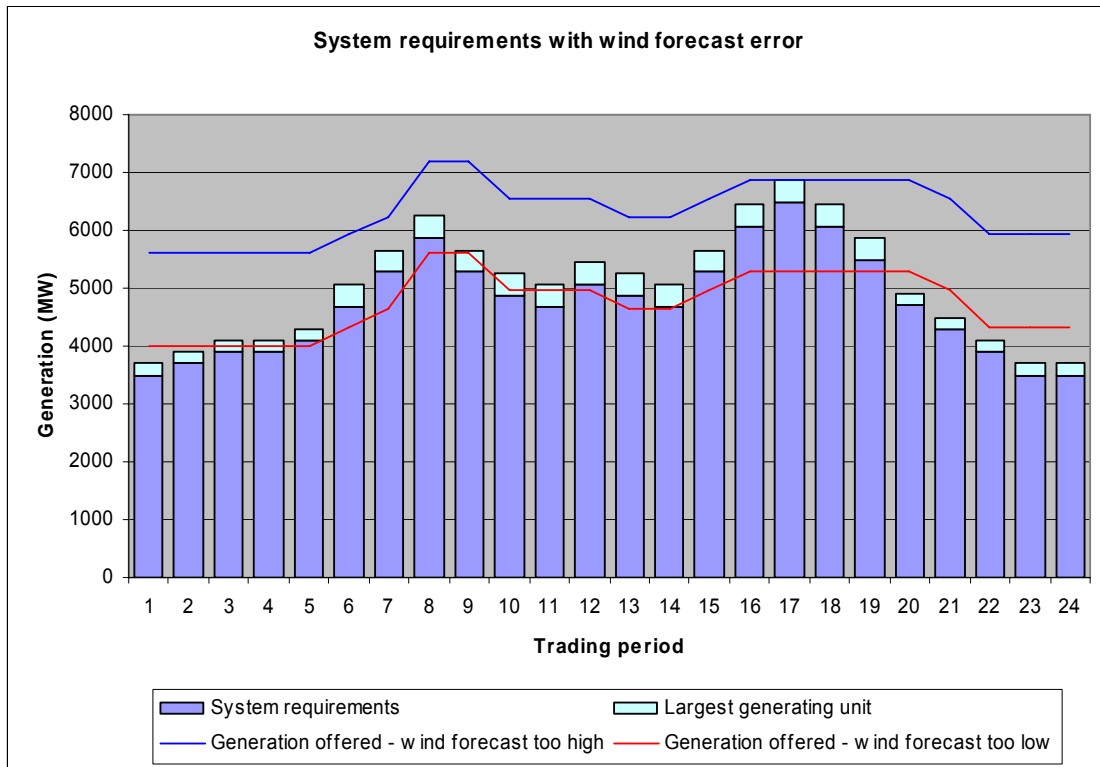


Figure 14: Standby Reserves with wind generation forecast errors – system requirements include instantaneous reserves and frequency keeping

In the case where the wind generation forecast was 800 MW too high, the Standby Reserves Check does not identify the deficit in trading period 17. In the case where the wind generation forecast was too low, deficits are incorrectly identified for trading periods 6, 7, 8, 12, 13, 14, 15, 18 and 19.

Probability analysis can be carried out (based on wind generation forecast probability distribution functions) to determine the likelihood of whether a deficit will be missed or a false alarm will occur for any trading period.

Figure 15 shows an assumed cumulative probability distribution for wind generation forecast error. A normal distribution is used for simplicity with a mean of 0 MW and a standard deviation of 50 MW. The majority of forecast errors will be less than 300 MW.

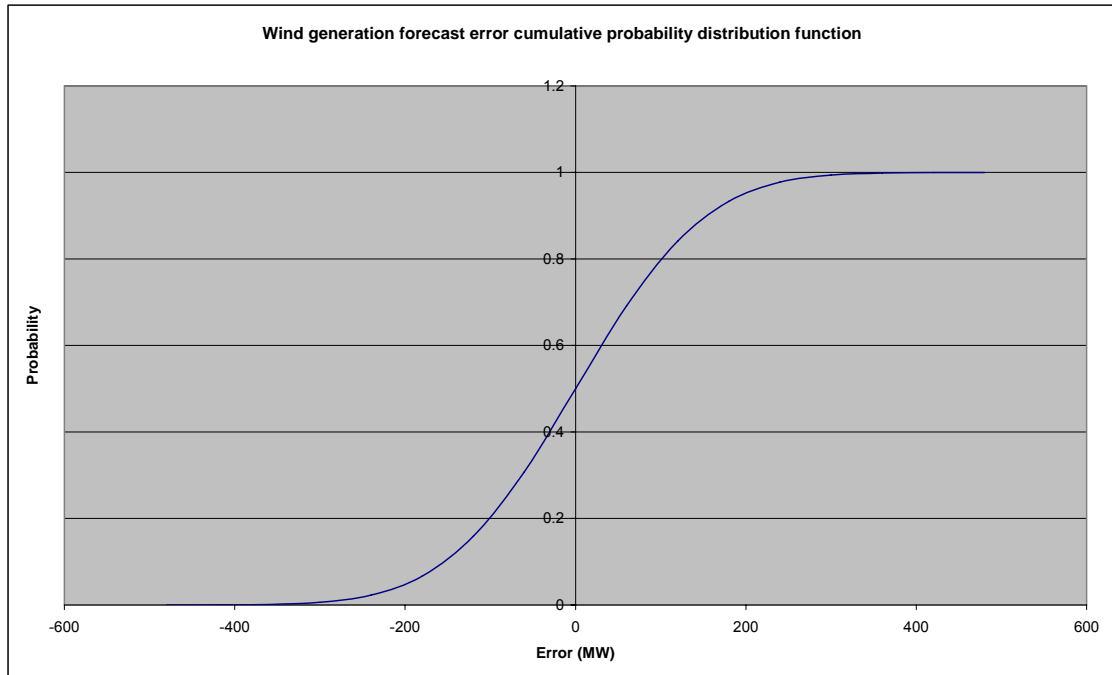


Figure 15: Assumed cumulative probability distribution function for wind generation forecast error

The wind generation forecast error cumulative probability distribution function shown in Figure 15 is used to calculate a cumulative probability distribution function for the SRC margin in trading period 6. This function is shown in Figure 16. The SRC margin in trading period 6 has a probability of being negative (falsely indicating a deficit) of about 30%.

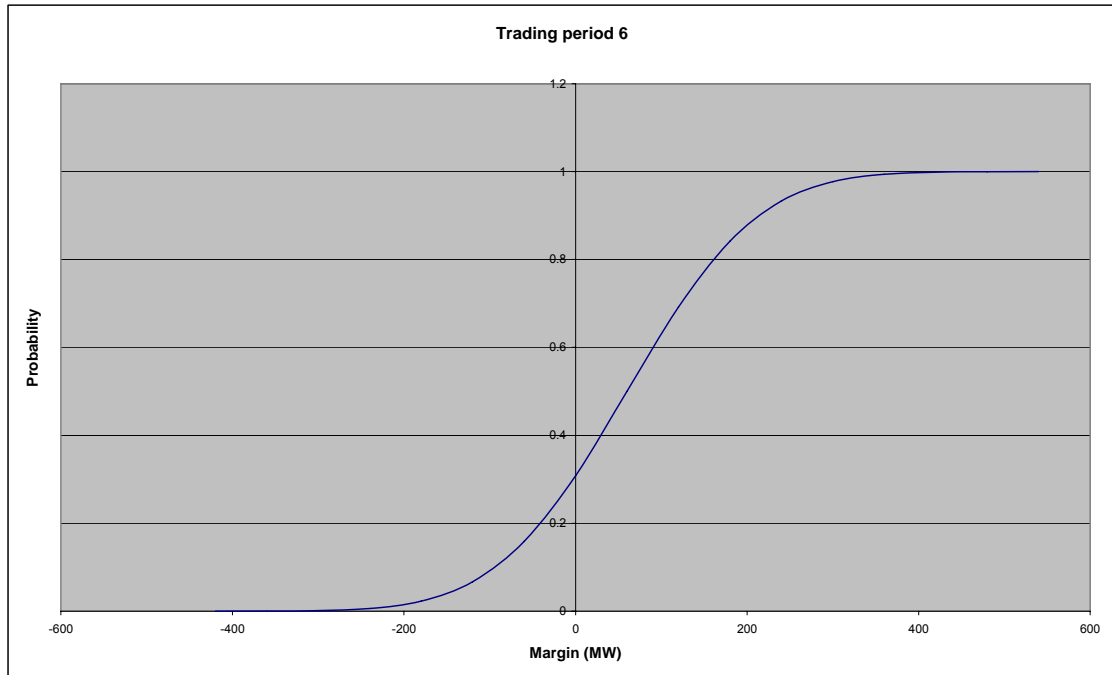


Figure 16: Cumulative probability distribution function for SRC margin for Trading period 6

The cumulative probability distribution function for the SRC margin in trading period 17 is shown in Figure 17. The SRC margin in trading period 17 has a probability of being positive (indicating no deficit) of about 3%. There is thus a 3% chance that the SRC deficit would be missed.

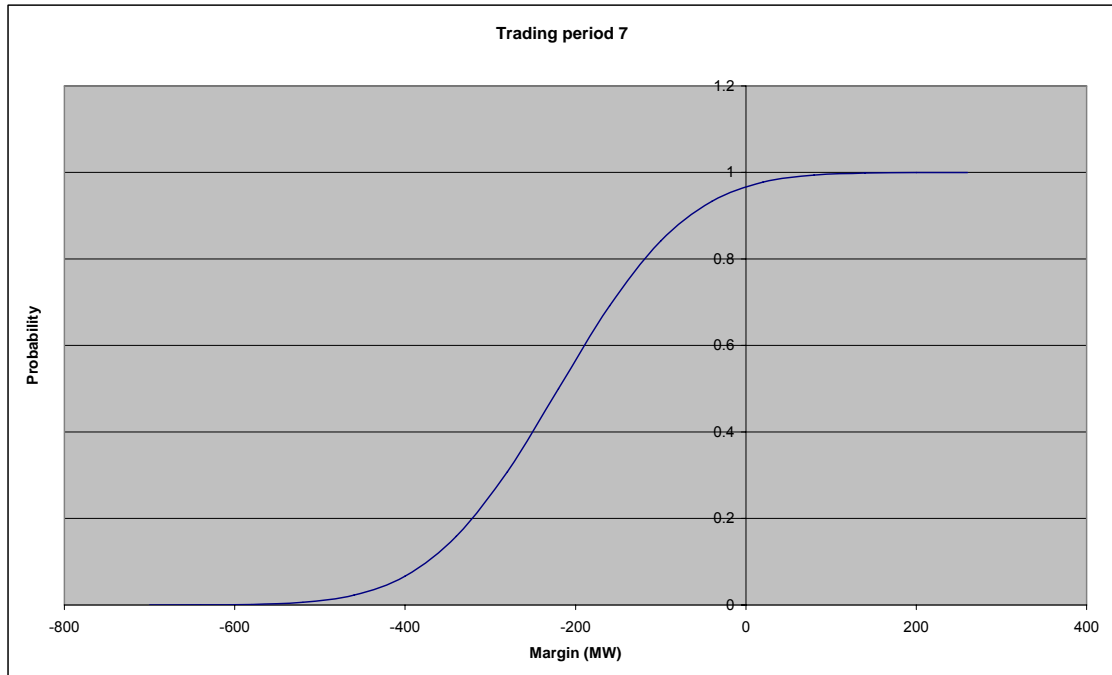


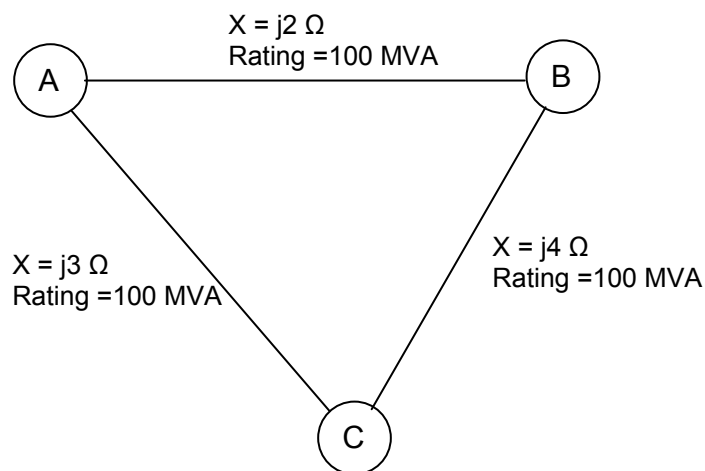
Figure 17: Cumulative probability distribution function for SRC margin for Trading Period 17

3.6 Economic Dispatch – simple example

The effects of wind generation on nodal pricing can be examined through the use of a simplified power system model. The amounts and location of wind generation, load, and other generation offers can be varied to demonstrate the effects of increasing wind generation penetration.

A three node model for a power system is shown in Figure 18. There are three nodes (A, B, and C), each representing a region with generation and load, connected by three transmission circuits. Each node is assumed to have four generating units of varying capacity and offer price. Each generating unit offers in at a certain price (\$/MWh). The wind generation offer price is zero. There is a certain amount of wind generation installed in each region. The amount of wind generation will be varied to study the effects of wind generation forecast errors. Each node has a variable load. The transmission circuits are assumed to be lossless and have ratings of 100 MVA. The impedance (X) of each transmission circuit is different.

Unit	Rating (MW)	Offer price (\$/MWh)	Unit	Rating (MW)	Offer price (\$/MWh)
A1	250	10	B1	150	0
A2	200	20	B2	100	5
A3	200	30	B3	100	15
A4	350	70	B4	100	25
A wind	variable	0	B wind	variable	0
A Load	variable		B Load	variable	



Unit	Rating (MW)	Offer price (\$/MWh)
C1	200	10
C2	200	15
C3	100	20
C4	100	30
C wind	variable	0
C Load	variable	

Figure 18: Three node system model

3.6.1 Nodal pricing formulation

The following assumptions have been made (for simplification):

- No instantaneous reserves or frequency keeping requirements have been assumed. If required, this could be included in regional loads.
- No contingency analysis has been undertaken. It can be assumed that the transmission circuits' ratings incorporate a margin to ensure that post contingency loading remains within asset capability. The ratings are in effect power transfer limits.
- There are no losses in the transmission circuits.

The dispatch of generation in the three node model is determined according to the following formulation:

Minimise the cost of generation to meet load:	<i>Minimise</i> $\sum_i \text{Gen}_i \times C_i$ where Gen_i is the output of the i^{th} generating unit in the set (A1 to A4, B1 to B4, C1 to C4, A wind, B wind, C wind) and C_i is the offer price for the i^{th} unit
Subject to the following constraints	
Generation meets load	$\sum_n \text{Gen}_n = \sum_n \text{Load}_n$ Where Gen_n is the total generation at Node n and Load_n is the total load in Node n
Each generating unit output is above minimum and below maximum rated output	$\text{Gen}_{i\text{min}} \leq \text{Gen}_i \leq \text{Gen}_{i\text{max}}$ for all i Where Gen_i is the output of generating unit i, $\text{gen}_{i\text{min}}$ is the minimum output for generating unit i and $\text{Gen}_{i\text{max}}$ is the maximum output for generating unit i
Each transmission circuit is loaded below rating	$-\text{Cctjrating} \leq \text{Cctj} \leq \text{Cctjrating}$ Where Cctj is the power flow (MW) on circuit j, and Cctjrating is the rating of the circuit
Kirchoff's voltage law is met (sum of voltage drops around nodes is zero)	$\sum \text{Cctj} \times X_j = 0$ Where X_j is the impedance of circuit j.

It is possible that infeasible solutions can be encountered. These solutions occur when system load can not be met without one or more of the constraints being violated. This can occur, for example, when load in a region can not be met by regional generation plus transfer from the other regions.

3.6.2 Example

The following example is used to illustrate how nodal pricing (as used in the New Zealand electricity market) works on a simplified power system and how a generation merit order can be derived.

Figure 19 shows an example calculation of nodal prices and dispatch quantities for offtake of 300, 600 and 400 MW at Nodes A, B and C respectively.

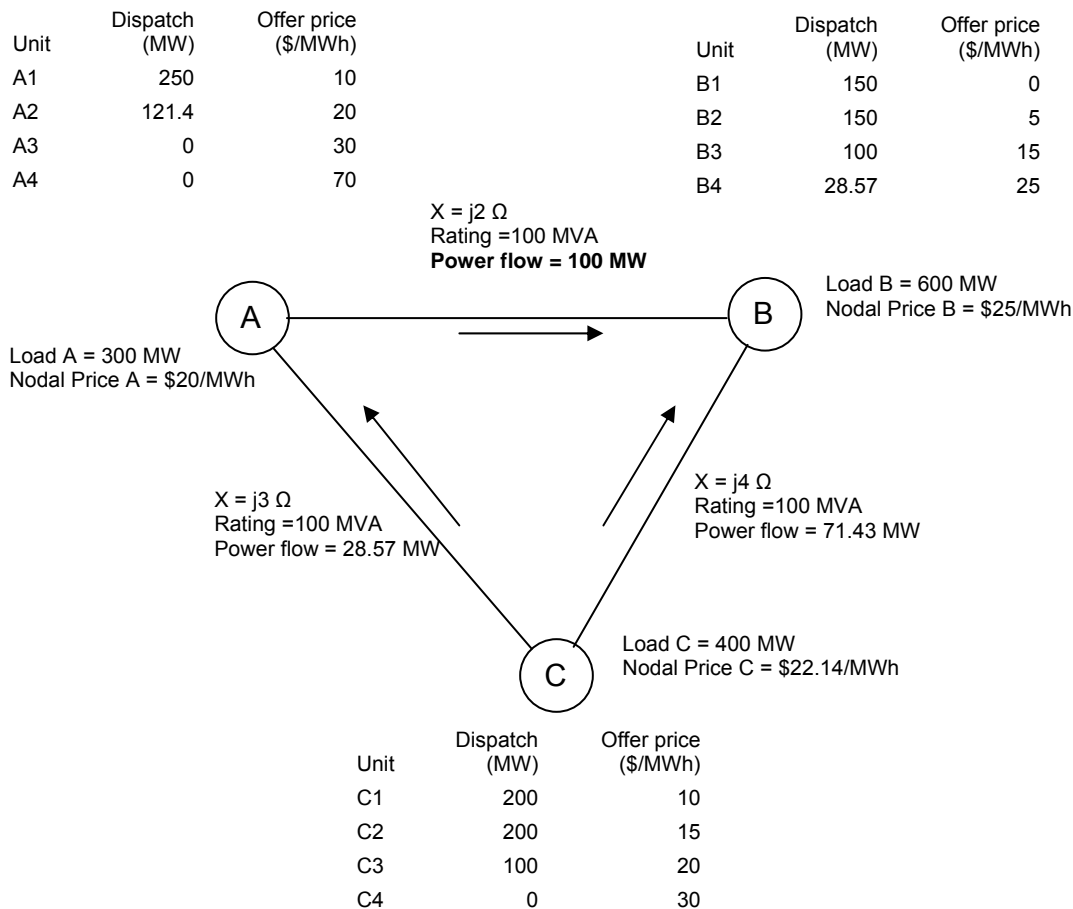


Figure 19: Three node system model example

The following points can be noted from Figure 19:

- The circuit between Node A and Node B is in constraint (power flow is equal to rating).
- The nodal price at Node A is \$20/MWh which reflects the cost of increasing the output of generating unit A2 by 1 MW (for one hour).
- The nodal price at Node B is \$25/MWh which reflects the cost of increasing the output of generating unit B4 by 1 MW (for one hour).
- The nodal price at Node C is \$22.14/MWh which reflects the cost of increasing the output of generating units A2 and B4. This is the least cost way (see below) of meeting an increase in offtake at Node C.

For the example in Figure 19, generating units A3, A4, B4, and C4 have spare capacity to meet additional offtake. The offer prices of the generating units with spare capacity are:

Unit	Offer Price (\$/MWh)
A2	20
A3	30
A4	70
B4	25
C4	30

In an unconstrained system (i.e. power transfer is not limited by circuit rating), additional offtake at nodes A, B or C can be met at least cost by increasing the output of generating unit A2. If the system is constrained (i.e. the loading on the circuit between Node A and Node B has reached the rating of the circuit) as in Figure 19 then only additional offtake at Node A can be met by increasing the output of generating unit A2. The marginal cost of increasing offtake at node A is the offer price of generating unit A2 (\$20/MWh).

Increasing the output of generating unit A2 to meet an increase in demand at Nodes B or C will result in an increase in loading of the circuit between Node A and Node B (which is already at its limit). An increase in offtake at Node B can be met at least cost by increasing the output of generating unit B4 as the offer price of B4 is lower than C4. An increase in offtake at Node C can be met at least cost by simultaneously increasing generation at Node A and at Node B.

An increase in generation output at Node A of 1 MW will increase loading on the circuit between Node A and Node B by 0.33 MW.¹⁴ An increase in generation output at Node B of 1 MW will decrease loading on the circuit between Node A and Node B by 0.67 MW.¹⁵

An increase in offtake at Node C of 1 MW can be met at least cost by increasing generation at Node A by 0.57 MW and generation at Node B by 0.43 MW (which results in no increase in loading of circuit between Node A and Node B). The marginal cost of supplying one additional MW at Node C is $0.57 \text{ MWh} \times \$20/\text{MWh} + 0.43 \text{ MWh} \times \$25/\text{MWh} = \$22.14 \text{ MWh}$.

The application of this example to wind generation is further discussed in Section 7

¹⁴ The portion is given by $X_{AC}/(X_{AC}+X_{AB}+X_{BC}) = 3/(3+2+4) = 1/3$.

¹⁵ The portion is given by $(X_{AB}+X_{BC})/(X_{AC}+X_{AB}+X_{BC}) = (2+4)/(3+2+4) = 2/3$.

4. Wind generation forecasts in the time domain

4.1 Introduction

Part A of this Investigation considered the effects of wind generation forecast errors on pre-dispatch tools and processes. Garrad Hassan [2] carried out some analysis to determine the probability of occurrence for wind generation forecast errors of a particular size.

Table 11, Table 12 and Table 13 show the estimated wind generation forecast error (for different times prior to dispatch) for each of the wind generation development scenarios.

	Scenario A			Scenario B			Scenario C			Scenario D		
<i>Return period</i>	NZ	NI	SI	NZ	NI	SI	NZ	NI	SI	NZ	NI	SI
<i>Once/ mth</i>	-497	-502	-75	-381	-356	-135	-627	-545	-306	-197	-190	-38
<i>Once/ wk</i>	-411	-397	-65	-307	-288	-118	-510	-445	-254	-168	-164	-33
<i>Once/ day</i>	-282	-280	-43	-216	-200	-80	-358	-311	-177	-118	-116	-22
<i>Once/ mth</i>	498	497	79	358	337	131	570	535	305	192	189	39
<i>Once/ wk</i>	384	386	66	311	284	110	498	428	254	169	168	32
<i>Once/ day</i>	266	265	42	210	192	78	348	300	179	115	113	21

Table 2: 2-hour derived wind forecast errors [MW] (Table 4.12 from [2])

	Scenario A			Scenario B			Scenario C			Scenario D		
<i>Return period</i>	NZ	NI	SI	NZ	NI	SI	NZ	NI	SI	NZ	NI	SI
<i>Once/ mth</i>	-733	-751	-90	-588	-553	-189	-975	-903	-432	-258	-264	-45
<i>Once/ wk</i>	-631	-624	-78	-525	-464	-163	-873	-722	-371	-228	-225	-40
<i>Once/ day</i>	-492	-481	-62	-400	-350	-125	-679	-559	-283	-177	-172	-31
<i>Once/ mth</i>	591	614	83	463	443	150	726	663	351	225	219	41
<i>Once/ wk</i>	514	517	71	368	344	127	593	529	286	186	187	36
<i>Once/ day</i>	334	338	52	251	239	90	419	372	204	126	129	26

Table 3: 6-hour derived wind forecast errors [MW] (Table 4.9 from [2])

Return period	Scenario A			Scenario B			Scenario C			Scenario D		
	NZ	NI	SI	NZ	NI	SI	NZ	NI	SI	NZ	NI	SI
<i>Once/ mth</i>	-994	-1000	-97	-838	-751	-255	-1424	-1222	-553	-322	-316	-49
<i>Once/ wk</i>	-907	-891	-95	-760	-643	-224	-1259	-1030	-501	-296	-292	-48
<i>Once/ day</i>	-718	-708	-80	-595	-507	-173	-995	-815	-393	-244	-238	-40
<i>Once/ mth</i>	942	930	96	770	642	227	1238	1043	523	313	296	48
<i>Once/ wk</i>	809	812	90	638	576	192	1054	904	430	272	275	45
<i>Once/ day</i>	578	589	67	449	408	136	735	640	305	199	201	34

Table 4: 23-hour derived wind forecast errors [MW] (Table 4.7 from [2])

The North Island load ranges from around 1700 MW to 4500 MW. The six hour ahead of dispatch forecast error for the North Island under wind generation development Scenario C (see Table 3) shows the occurrence of wind generation forecast errors of between +370 and -560 MW on a daily basis. These errors are significant if the errors occur at times of light load. The errors are between around 20% and 40% of island demand at times of light load. The wind generation forecast errors are also significant at times of high load when security checks are carried out to determine whether there is sufficient generation offered to meet system energy and reserves demand and whether there is sufficient capacity on the grid (taking into account the availability of transmission assets) to meet forecast demand.

Limitations on the amount of historic data used by Garrad-Hassan meant that the calculated probabilities of occurrence were only accurate up to return periods of a month. The frequency of occurrence of larger wind generation forecast errors can not be calculated with accuracy from the historic data available (e.g. the larger events are so rare that they do not appear over the period when historic data was collected).

Assessing the effects of a particular size of wind generation forecast error on pre-dispatch tools and processes will indicate the threshold when the effects become material. This threshold can be compared with the likelihood of wind generation forecast errors of such a size will occur for given wind generation development. This will indicate when action may be required to mitigate the effects of wind generation forecast error.

4.2 Wind generation forecast errors

Large wind generation forecast errors arise from a significant change in wind generation output or metrological conditions or wind generation capacity between the time the forecast was made and actual dispatch. A persistence based forecast will show large errors if wind generation output increases or decreases substantially between forecast time and dispatch time. A rapid

change in metrological conditions may cause a large error for wind generation forecasts which are based on metrological conditions. In a more mundane sense, large wind generation forecast errors may technically occur when faults on the wind farm equipment or high wind speeds¹⁶ causes the entire wind farm to be disconnected. This is analogous to other generating units not meeting their dispatched amounts due to unplanned disconnection.

The ability to manage large wind generation forecast errors ahead of dispatch will depend on the predictability of the change in conditions. For example, if a wind farm will be disconnected for planned maintenance then the wind generation forecast can be corrected appropriately. Forced outages will not allow time for appropriate corrections and must be managed within dispatch processes as other forced outages are managed.

In cases where a sudden change in wind generation output can be predicted (e.g. at the arrival of a weather front in a region with concentrated wind generation) over a certain period but the actual time of arrival within the time period is not certain, measures can be applied to mitigate the effects of the sudden change. Ramp rate limitations could be placed on the affected wind generating units for the period (for sudden increases) or additional generation could be made available to run to counter a decrease in wind generation output. Note that this is similar to the way in which rapid changes in system load are managed during the morning and evening peaks.

4.3 Wind generation forecasts in the time domain

Garrad Hassan used the same method to calculate wind generation forecasts in the time domain that was used to generate forecast errors for the wind generation scenarios. This method was based upon forecast errors calculated from the Te Apiti wind farm and correlation coefficients determined from inter-regional forecast errors

Garrad Hassan used the wind data provided by the Electricity Commission. One site representative of each region was selected, and a wind farm power time series generated from the wind data assuming a generic wind farm power curve. Persistence forecasts for 2, 3, 6, 12, and 23 hours ahead were generated. These persistence forecasts were then corrected using a factor determined by comparing the performance of the Garrad-Hassan forecaster predictions against forecasts generated using persistence at Te Apiti. The method employed here results in a time-series of forecasts with a total of 204 days of data.

It is instructive to consider what sort of wind generation output changes give rise to large forecast errors. Figure 20 shows an example from the Garrad

¹⁶ This kind of event has not happened recently on the New Zealand to the best of our knowledge. An event of this kind has happened at Horns Rev off shore wind farm.

Hassan time series analysis. Wind generation, wind generation forecast, and wind generation forecast error have been plotted for a case based on wind generation development Scenario C for where there is a large wind generation forecast error 12 hours ahead of dispatch. Load, load forecast, and load forecast error are included for comparison.

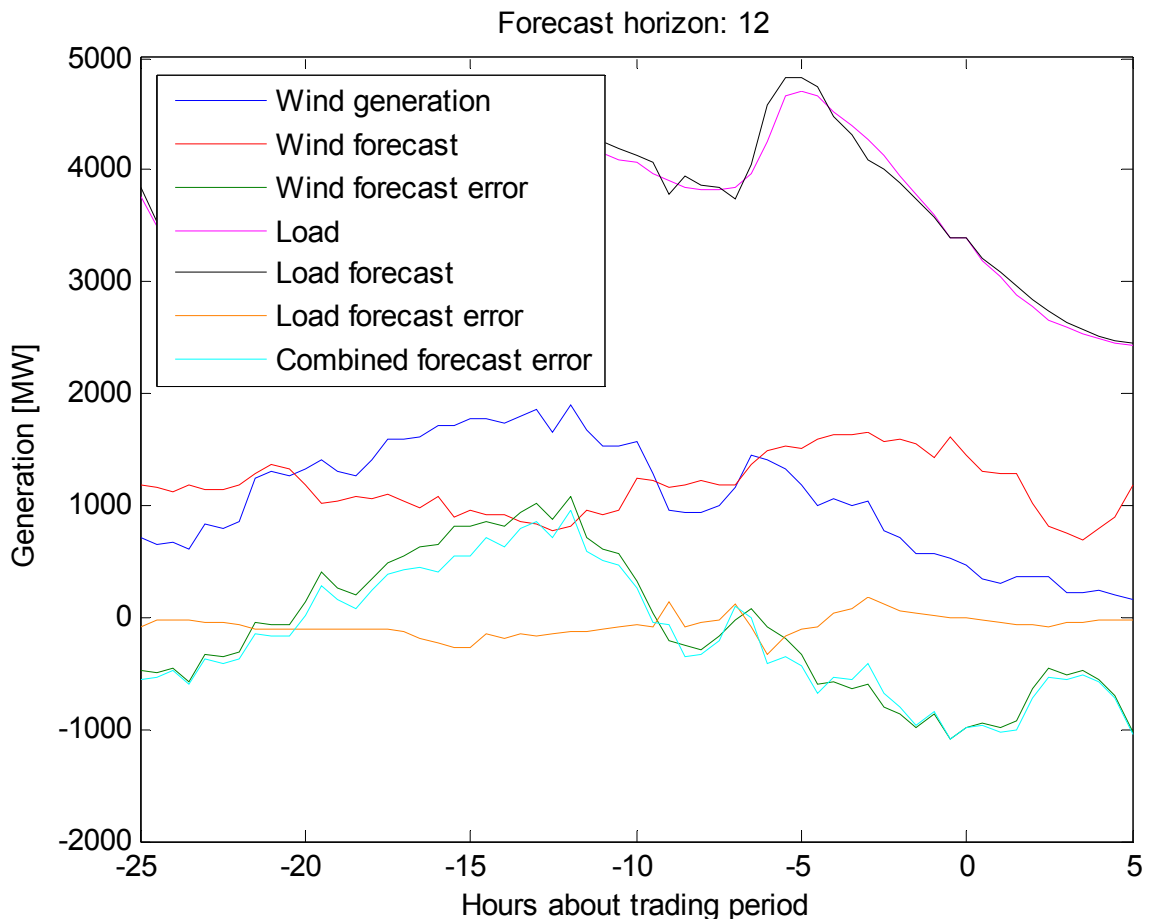


Figure 20: Time-series wind generation and load forecasts for wind generation development scenario C (from [4])

The following points can be noted from Figure 20:

- The load forecast error is quite small compared to the wind generation forecast error. The load and load forecast are very similar. The predictability of load which follows a consistent pattern over a day or a week allows a forecast that is quite accurate.
- The wind generation forecast error 12 hours ahead of dispatch (i.e. -12 hours about trading period in the graph) occurs because wind generation output 12 hours ahead of dispatch was much higher than the wind generation at dispatch. The lack of predictability of wind generation in this case leads to larger forecast errors.

Figure 21 shows forecasts and forecast errors for the time series shown in Figure 20 for different times ahead of dispatch. The wind generation forecast error 12 hours ahead of dispatch (-12 hours about trading period) is around -1000 MW. The accuracy of the wind generation forecast for the trading period improves markedly at six hours ahead of dispatch. The wind generation forecast error is still around -500 MW at 2 hours ahead of dispatch.

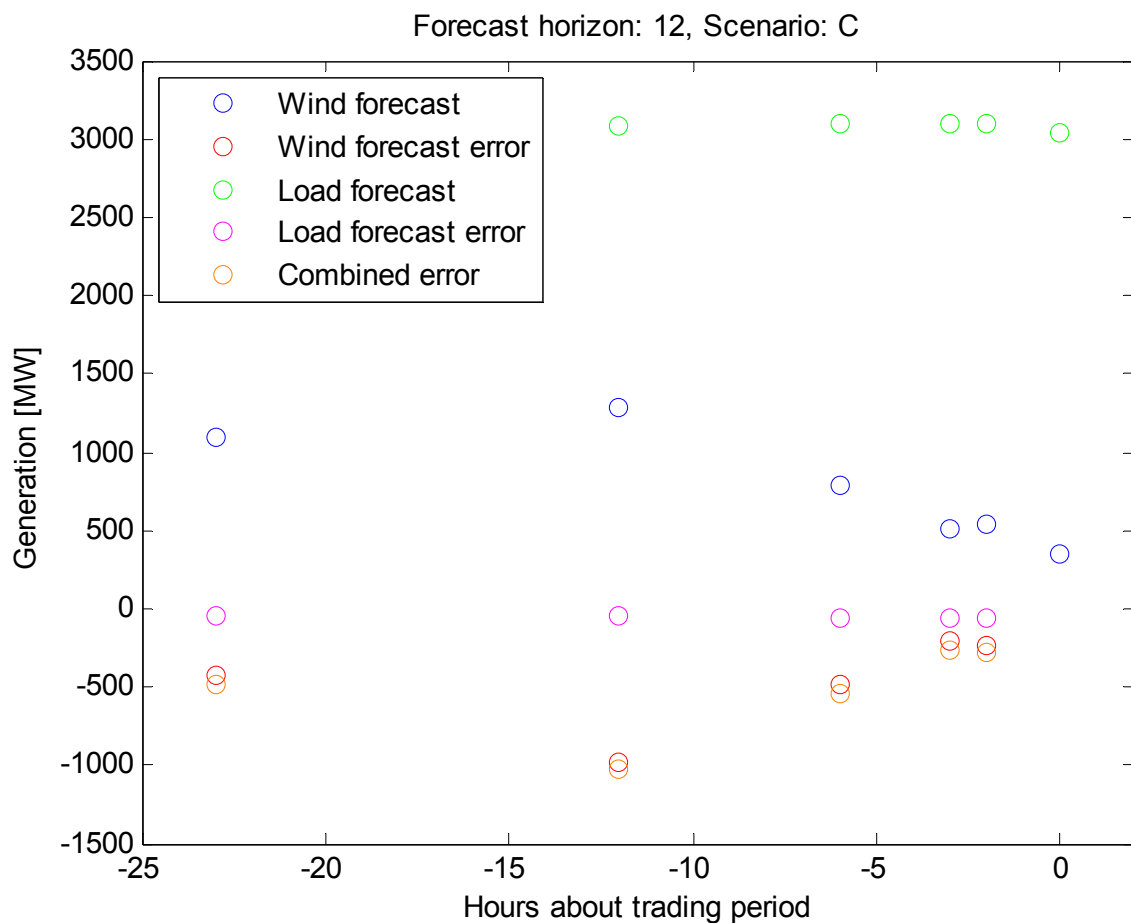


Figure 21: Time-series wind generation and load forecasts for wind generation development scenario C (from [4])

Figure 21 shows that wind generation output in a single trading period can give rise to significant and varying errors at different times ahead of dispatch. The shortfall in wind generation output will only become apparent during the four hours before dispatch.

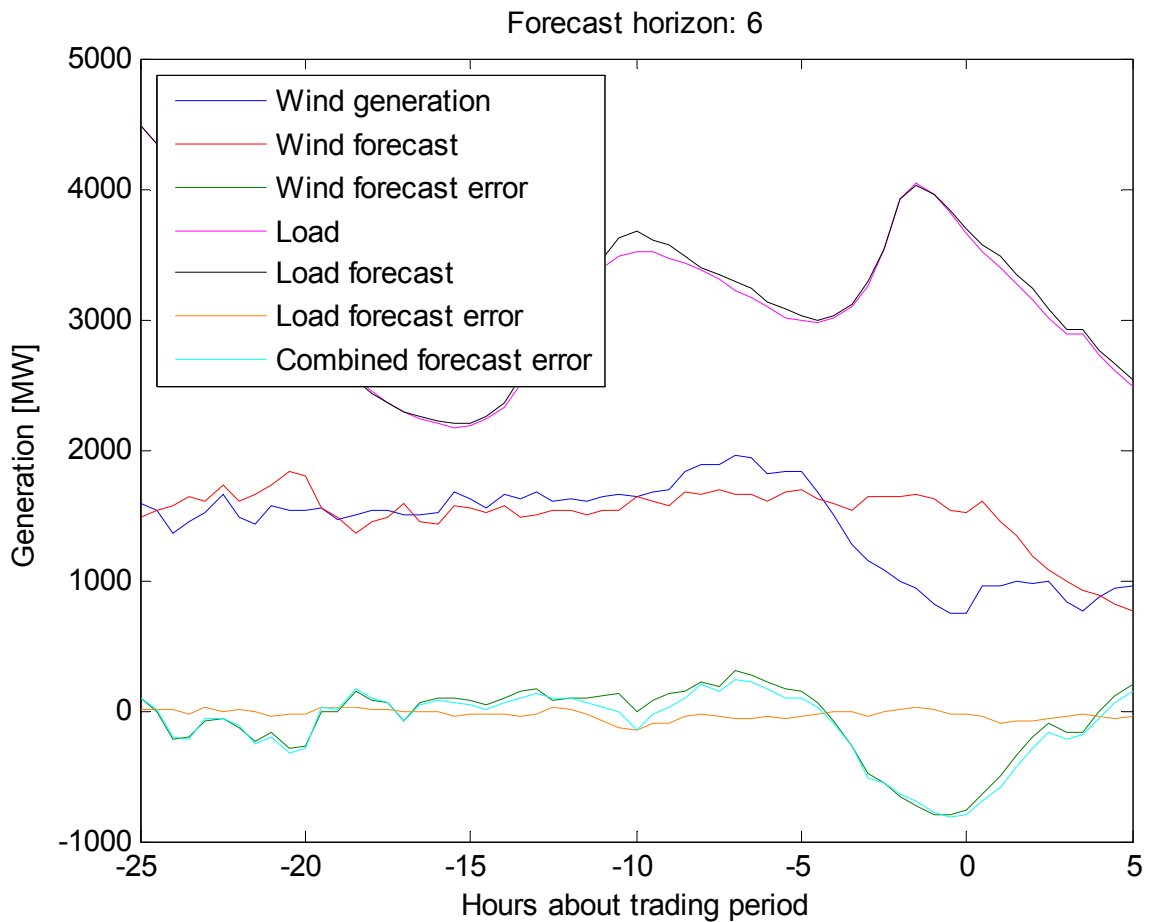


Figure 22: Multiple wind generation forecast errors from the same change in wind generation output.

Figure 22 shows an example where change in wind generation output will cause a number of wind generation forecast errors. The blue line shows the actual wind generation output while the red line shows the forecast at six hours ahead of dispatch. The significant difference between actual and forecast will manifest as large wind generation forecast errors for a number of consecutive trading periods.

Large wind generation forecast errors which still exist close to dispatch will need to be managed through dispatch processes. The System Operator's ability to manage such errors in real-time dispatch with offered generation can be determined earlier in the pre-dispatch process. Increases in wind generation output above forecast are not so problematic as other generation can be re-dispatched down quickly enough to restore the supply demand balance. The main issue, in this case, from a system operations perspective is whether generation can be re-dispatched quickly enough to avoid exceeding power system frequency exceeding quality targets.

A decrease in wind generation output below forecast is more serious as sufficient other generation must be available to increase output in time to meet the shortfall.

Different types of generation technology have different starting times (e.g. thermal plants can require hours to warm up while many hydro generating units can start quickly) and different ramping rates once connected. The amount of generation that can be brought on at the earliest opportunity is dependent on the type of generation offered or made available over future trading periods.

4.4 Load forecast errors

Figure 23 shows North Island load forecasts and actual over a week in July 2005. The load follows a highly predictable pattern. Forecast errors are larger at certain times of the day.

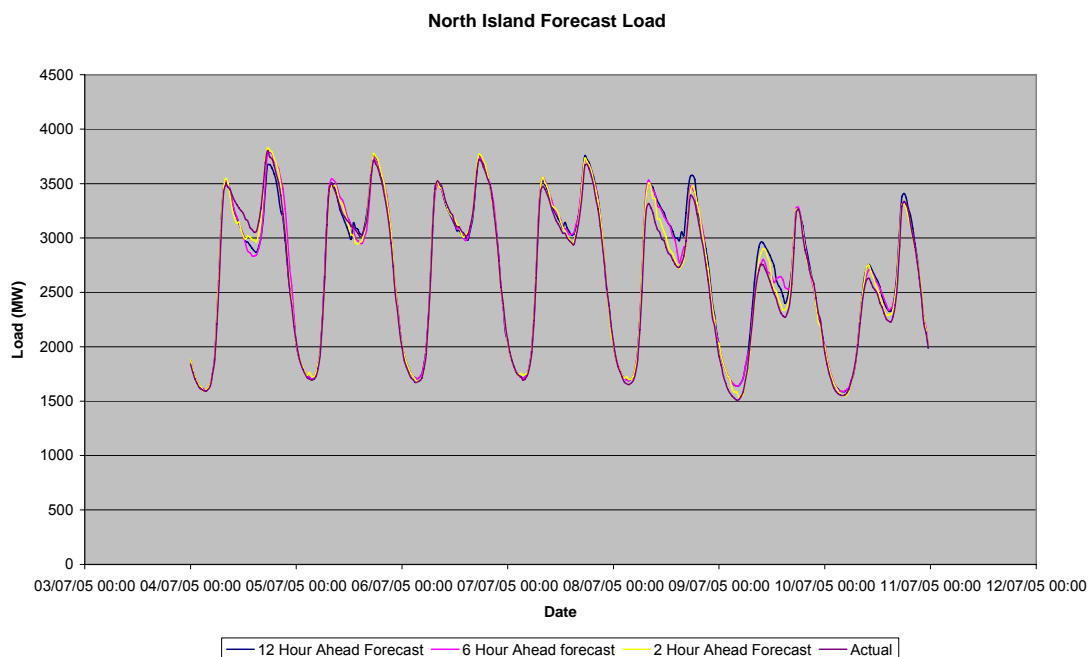


Figure 23: North Island Load Forecast

Figure 24 shows North Island load forecasts and forecast errors for a single day in July 2005. Forecast errors are low during the early hours (around midnight to 6 am). Forecast errors are higher at times of the morning and evening peaks. It should be noted that the load forecast error in this case includes the variability of the Tararua I and II wind farms. These wind farms (installed capacity 60 MW) were first dispatched in September 2005. Prior to this, the wind farms were netted against load at the Bunnythorpe and Linton grid exit points.

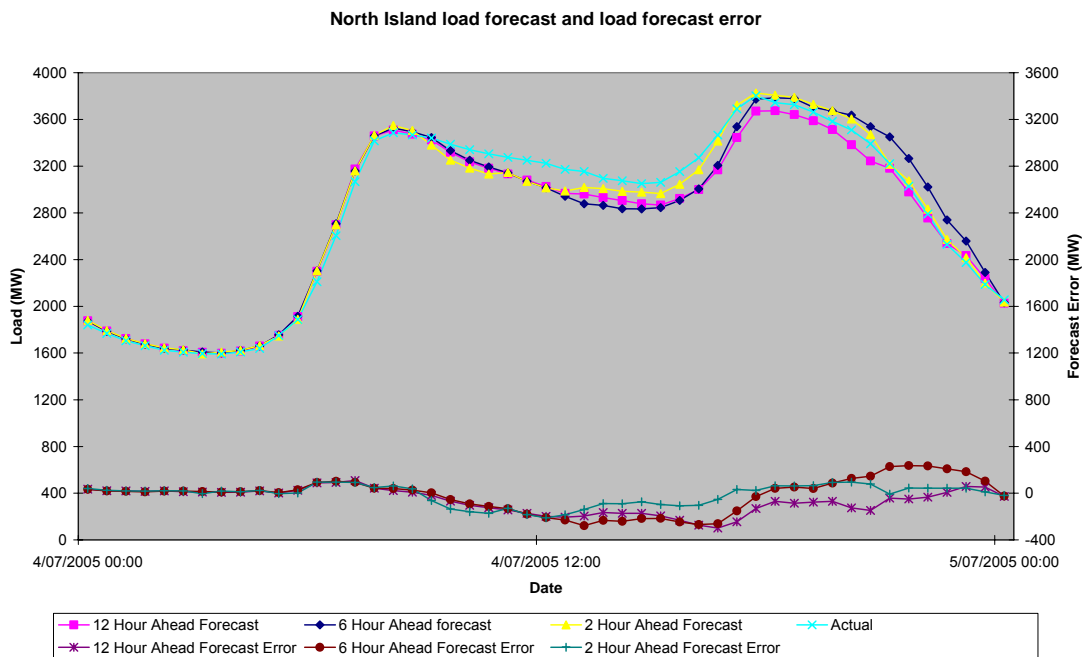


Figure 24: North Island Load Forecast and Forecast Error

Figure 25 and Figure 26 show North Island Load forecasts and forecast errors for December 2005. The forecast errors in December are lower than in July.

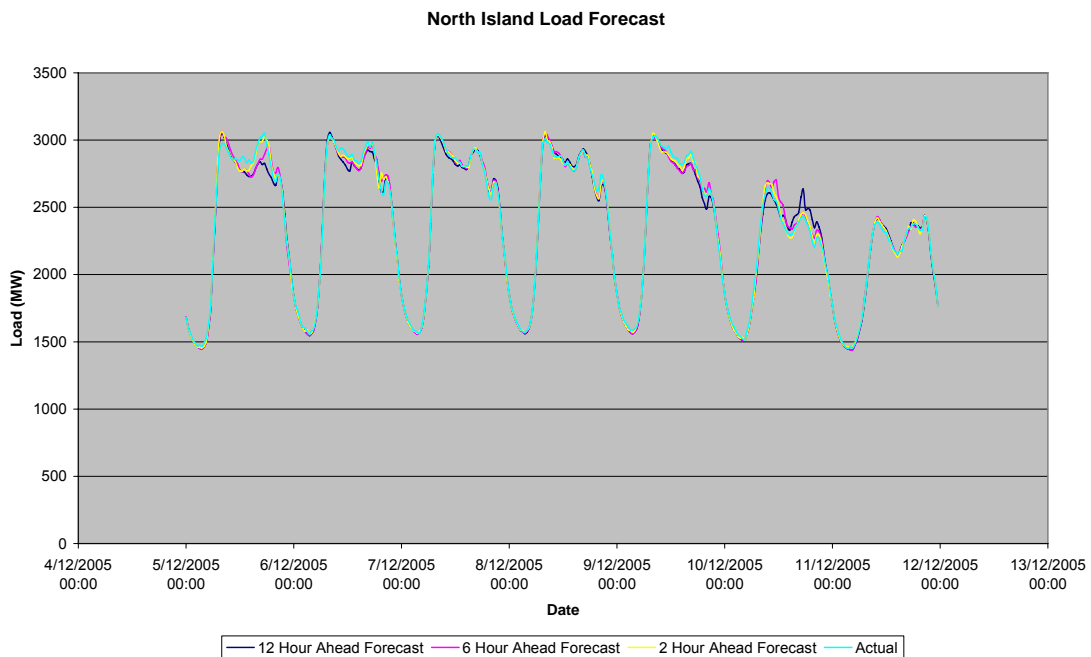


Figure 25: North Island Load Forecast

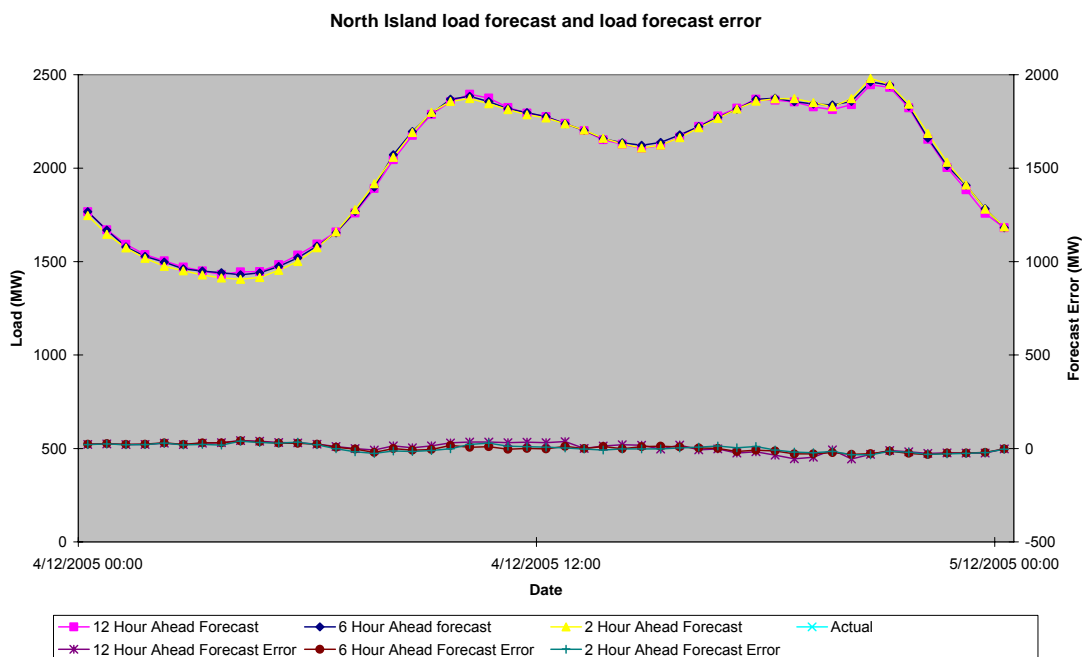


Figure 26: North Island Load Forecast and Forecast Error

4.5 Large and infrequent events

It is possible that very large sudden changes of wind generation output can occur. The probability of such occurrences can not be determined with accuracy at this stage due to the limited amount of historic wind data available. The management of very large sudden changes of wind generation output will depend to some extent on the predictability of the change prior to dispatch.

Large changes in wind generation output can result from the automatic shutdown of wind turbines when wind speeds exceed safe limits. High wind speeds across a region or an island may result in the disconnection of large amounts of wind turbines operating near peak capacity over a short time period. High wind speed conditions that might lead to widespread wind generation disconnection can be predicted with appropriate forecasting models. Such high speeds can result in the disconnection of regional wind generation output close to the installed capacity over a relatively short periods (e.g. over 15 minutes).

Large changes in Manawatu wind generation output have been observed. These were found to occur under certain weather conditions which can be predicted with some accuracy. This may be a feature unique to the topology of the Manawatu region. Figure 27, Figure 28, and Figure 29 show large sudden changes in Te Apiti wind farm output. The figures show respectively decreases of wind generation output of around 80% installed capacity over 50 minutes, 55% installed capacity over 30 minutes, and 70% over 50 minutes.

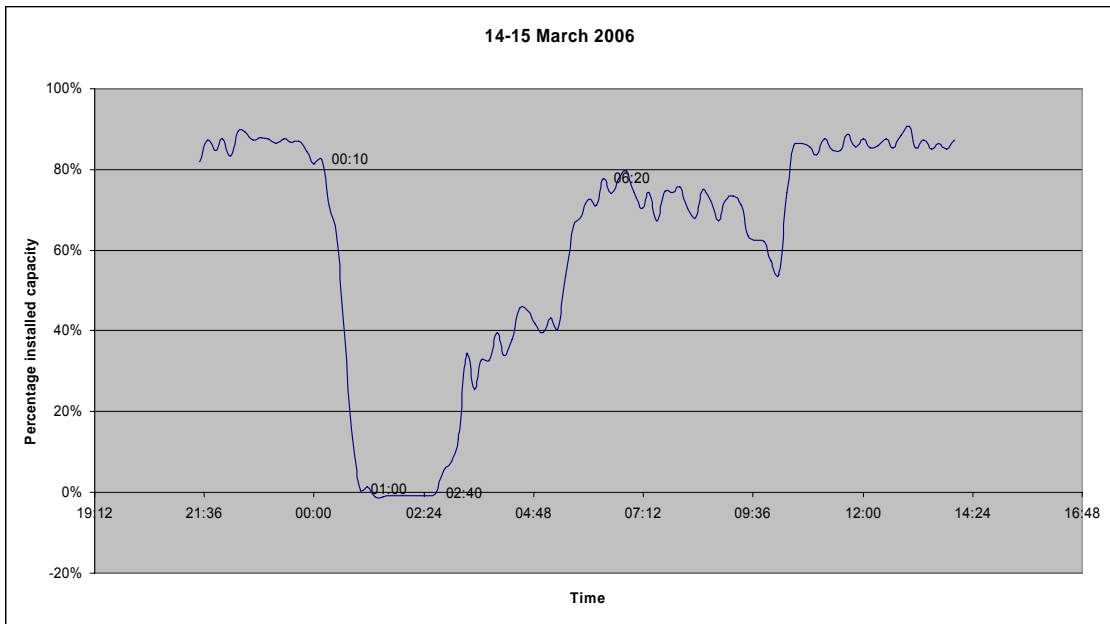


Figure 27: Te Apiti wind generation output change on 14-15 March 2006

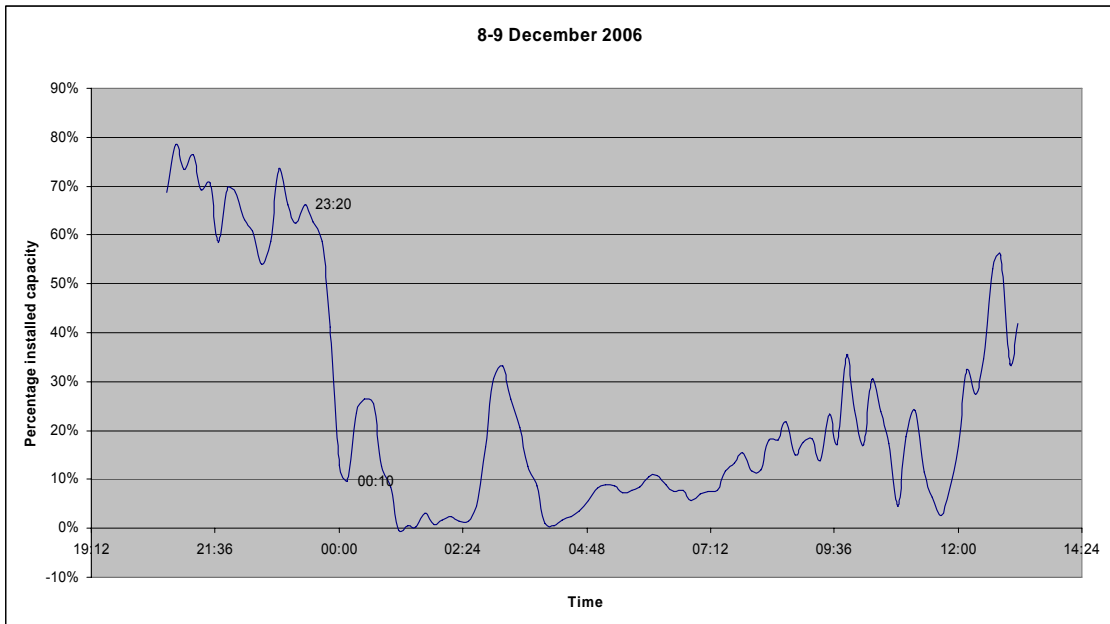


Figure 28: Te Apiti wind generation output change on 8-9 December 2006

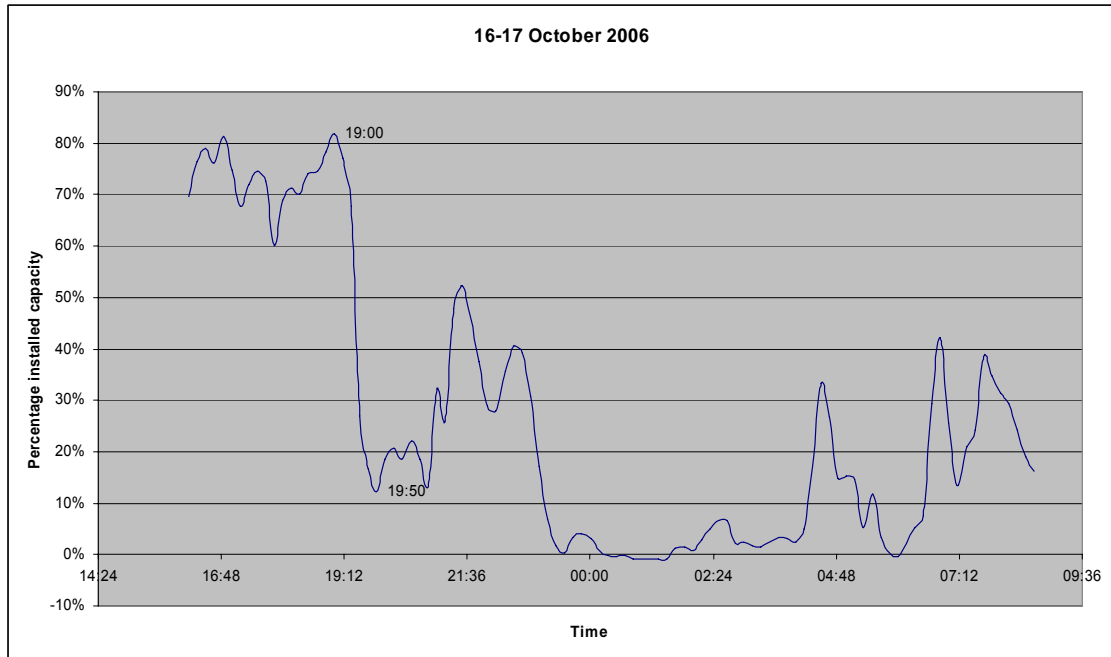


Figure 29: Te Apiti wind generation output change on 16-17 October 2006

Assuming that changes in Te Apiti output can be extrapolated to total future Manawatu wind generation (noting that there is a high degree of correlation in output between the existing wind farms) and future installed wind generation capacity in the Manawatu region of 450 MW then decreases in Manawatu wind generation output of 350 MW over an hour might be expected to occur quite frequently (probably around one event per month on average).

Changes of these types are similar in size to load changes at times of morning and evening peak. These changes are presently managed satisfactorily so it can be assumed that the power system has the capability to be dispatched at a rate which can match the potential Manawatu wind generation output changes. Given that some sudden changes will be unpredictable, an assessment of power system capability to respond (i.e. can sufficient generation be re-dispatched quickly enough to meet a decline in wind generation output) can be incorporated in pre-dispatch processes.

A large sudden decrease in wind generation output (resulting from a decrease in wind) has more serious implications for power system security than does a sudden increase in output. Large sudden increases can be managed by reducing other generation output. In cases where re-dispatch of other generation can not be accomplished in time, governor action on the other generating units will effect the reduction in output as power system frequency increases.

The sudden reduction in wind generation output will require additional generation to be quickly brought on to check a decline in system frequency. Other factors will act to check the decline in power system frequency:

- System load will slightly decrease (reducing the energy-demand imbalance) as frequency sensitive load reduces.
- Governor action on partially loaded generating units will provide some increase in output as frequency drops.
- Armed interruptible load will operate when frequency drops below 49.25 Hz.
- Some industrial loads will disconnect via the operation of under frequency protection systems.

If sufficient additional generation can not be brought on in time then frequency may decrease to the extent that load shedding (e.g. Automatic under-frequency load shedding (AUFLS) or manually effected) will be required to avoid system frequency collapse.

4.6 Managing large sudden changes in wind generation output

4.6.1 Predictable changes

In cases where large sudden changes in wind generation output can be predicted, appropriate measures can be taken in advance to mitigate the effects of the large sudden change. For example, if a large decrease in wind generation output is forecast over the next few hours, fast starting plant can be brought into service to compensate for the reduction in wind generation output. The pre-dispatch schedules will incorporate the wind generation forecast and generation shortfalls will be highlighted and advised to participants by the System Operator. The System Operator will need to ensure the amount of fast starting plant made available for future trading periods is sufficient to cover the forecast size change in wind generation output.

If a sudden increase in wind generation output is forecast over the next few hours then measures such as ramp rate limitations or constraints, as used elsewhere, can be placed on wind generation output to ensure that the rate of changes does not threaten power system security.

4.6.2 Unpredicted changes

Not all changes in wind generation output will be predictable. Such changes will need to be managed through dispatch processes (e.g. frequency keeping and re-dispatch of generation). The System Operator will need to monitor the amount of fast starting plant made available for future trading periods to ensure that sufficient plant is available to cover a certain size change in wind generation output.

4.7 Summary

The earlier probabilistic analysis of wind generation variability and wind generation forecast errors indicated that large changes in output and forecast errors can be expected at relatively frequent intervals [2]. Further investigation has indicated that several large forecast errors are associated with a single sudden change in wind generation output. In some cases, the large change is predictable and the associated large forecast errors result from differences in timing (i.e. the large change occurs earlier or later than forecast). In other cases, the change is not predicted and large forecast errors persist until the forecast is corrected at a later stage.

One of the assumptions underlying the Garrad Hassan analysis is that new wind generation will demonstrate similar behaviour to that observed at Te Apiti wind farm. The validity of this assumption can only be confirmed when sufficient data about the performance of other wind farms becomes available.

Given the variable nature of wind and wind generation output, it is inevitable that large sudden changes in wind generation output will be encountered from time to time. Where these large sudden changes are predictable, appropriate measures can be put in place in advance to mitigate the effects on power system security. Where the sudden large changes can not be predicted, the changes will have to be managed within the dispatch processes (frequency keeping and generation re-dispatch) provided that sufficient generation can be started quickly to meet any decline in wind generation output and appropriate controls exist for limiting any increase in wind generation output beyond the capability of the power system to absorb it.

There are three areas where development will enhance the System Operator's ability to run a secure power system with large amounts of wind generation:

- Accurate (as far as possible) wind generation forecasting. A more accurate prediction of large changes in wind generation output will enable the System Operator to operate the system so as to minimise the effect of the large change.
- An ability to forecast the power system's ability to meet large changes. Generation starting capability forecasts will enable the System Operator to identify times when insufficient generation is offered to meet large changes in wind generation output.
- An understanding of wind generation output variability. This needs to be gained over time and will be used to determine the probability of large changes in wind generation output, the impact upon power system operation of such changes and what mitigation measures for such changes are appropriate.

5. Security assessment

5.1 Introduction

Generation is scheduled on the basis of offers made by generators and the need to maintain power system security. The scheduling process (SPD and RMT) includes a security assessment for this purpose. A contingency analysis is carried out to assess whether the power system will be secure¹⁷ following the occurrence of a contingent event. The assessment is carried out using cleared generation offers.

The process will identify where there is insufficient generation or transmission capability to meet the forecast load. Once a security issue has been identified, a warning notice is sent to participants (if the issue was identified more than 2 hours before dispatch) or a grid emergency is declared (if identified less than 2 hours before dispatch). Participants may revise their offers or bids in response to the warning notice or can be required to take action under Technical code B of Schedule C3 (“Grid Emergencies”) of the EGRs.

Significant differences between the cleared generation quantities used in the security assessment and actual generation available at time of dispatch may result in security issues either not being identified in the contingency analysis or being flagged when there is no issue at all at dispatch time.

For example, if wind generation forecasts are higher than the amount of wind generation available at dispatch then the contingency analysis may not flag security issues that will be evident closer to dispatch. This will allow less time for generators, transmission providers, and purchasers to revise their offers or bids, making management of security issues during dispatch more difficult. If wind generation offers are lower than the amount of wind generation that is actually available at dispatch then security issues may be falsely identified in the contingency analysis, and flagged to market participants, though there will be no issue at the time of dispatch.

Section 3.4 described how analysis can be carried out to determine the effects of wind generation variability and forecast on regional security assessment. The following sections describe analysis carried out for the Southland and Hawkes Bay regions. The analysis used historic SCADA data which reflects use of the transmission grid under the present generation mix. Transmission grid usage is likely to be quite different with a generation mix that includes a large amount of wind generation.

¹⁷ The power system is deemed to be secure following a contingent event if no assets exceed their stated capability and grid voltages are within the quality targets.

The regional wind generation probability functions will have the same accuracy caveats as apply to the probability distribution functions (pdfs) determined by Garrad Hassan e.g. the pdfs can only be considered to be accurate to the level of events occurring once a month.

5.2 South transfer into Otago-Southland

5.2.1 Introduction

Figure 30 shows the Southland region. There is considerable hydro generation in the region. Scenario C includes 300 MW of wind generation capacity in the region.

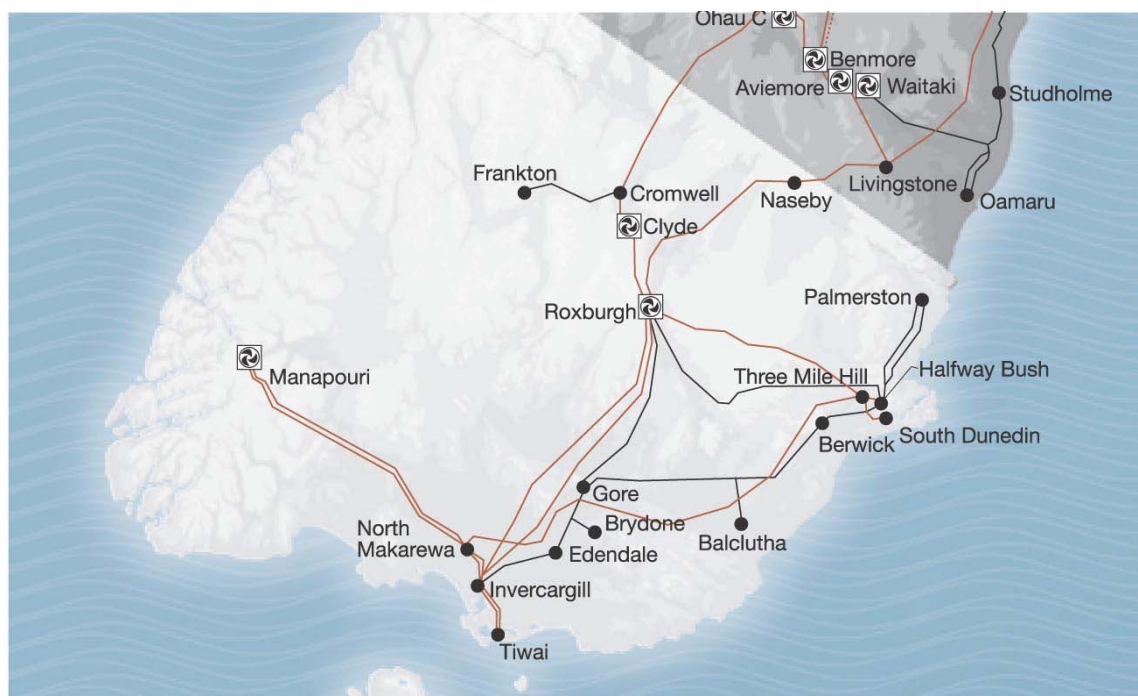


Figure 30: Southland region

Figure 31 shows the single line diagram for the Southland region.

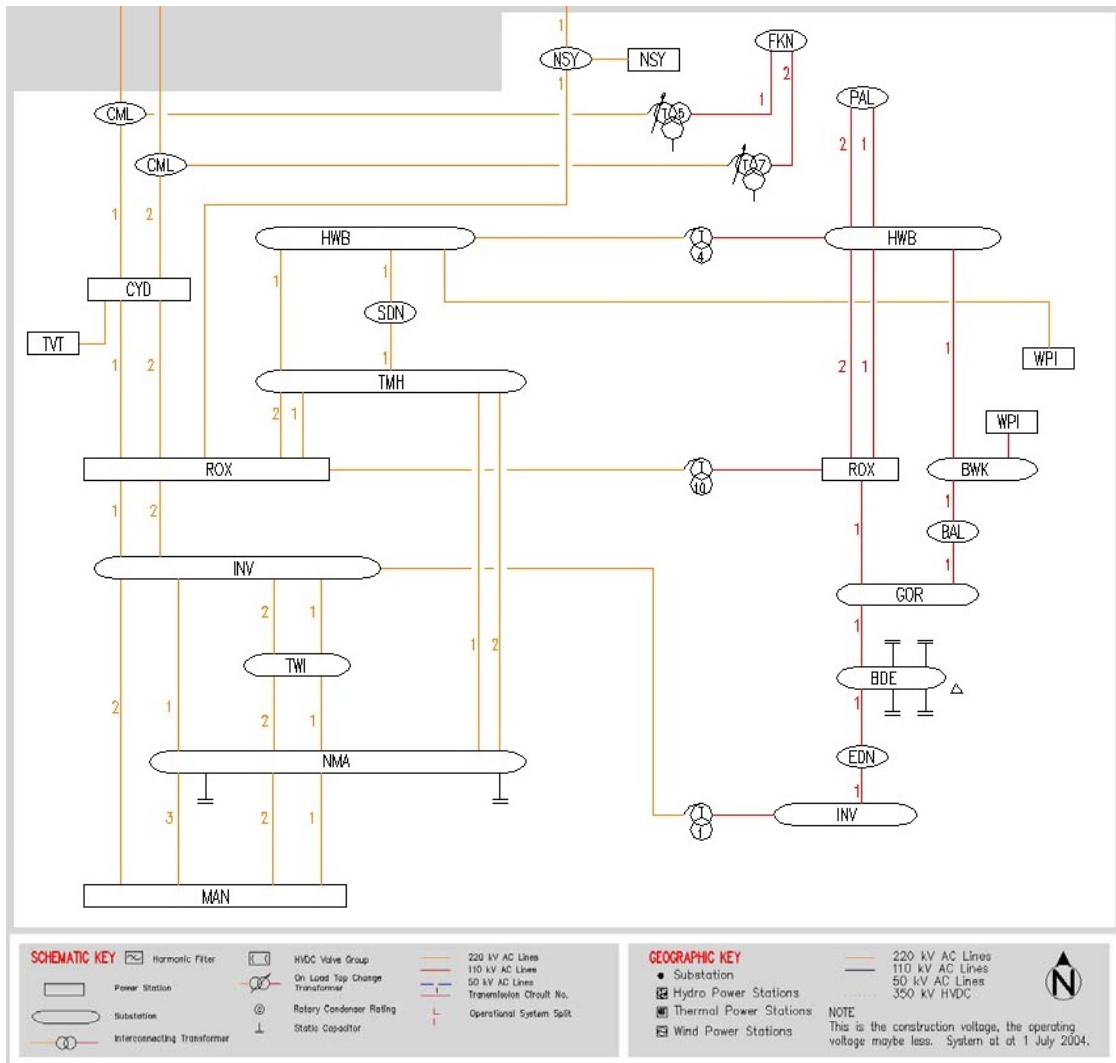


Figure 31: Single line diagram of Southland region

There are limits on the amount of power that can be transferred into the region from the North. South transfer is limited to 466 MW in summer and 525 MW in winter to avoid a Clyde-Roxburgh circuit exceeding thermal capacity following the loss of the other circuit.

Figure 32 shows duration curves for Southland load, Manapouri and Roxburgh generation. Southland load varies between around 650 MW and 925 MW. Southland load is dominated by the Rio Tinto aluminium smelter load at Tiwai (around 600 MW) which is largely a constant base load. Manapouri generation typically varies between 200 MW and 720 MW. Several Manapouri units are usually in service to provide voltage support in the region.

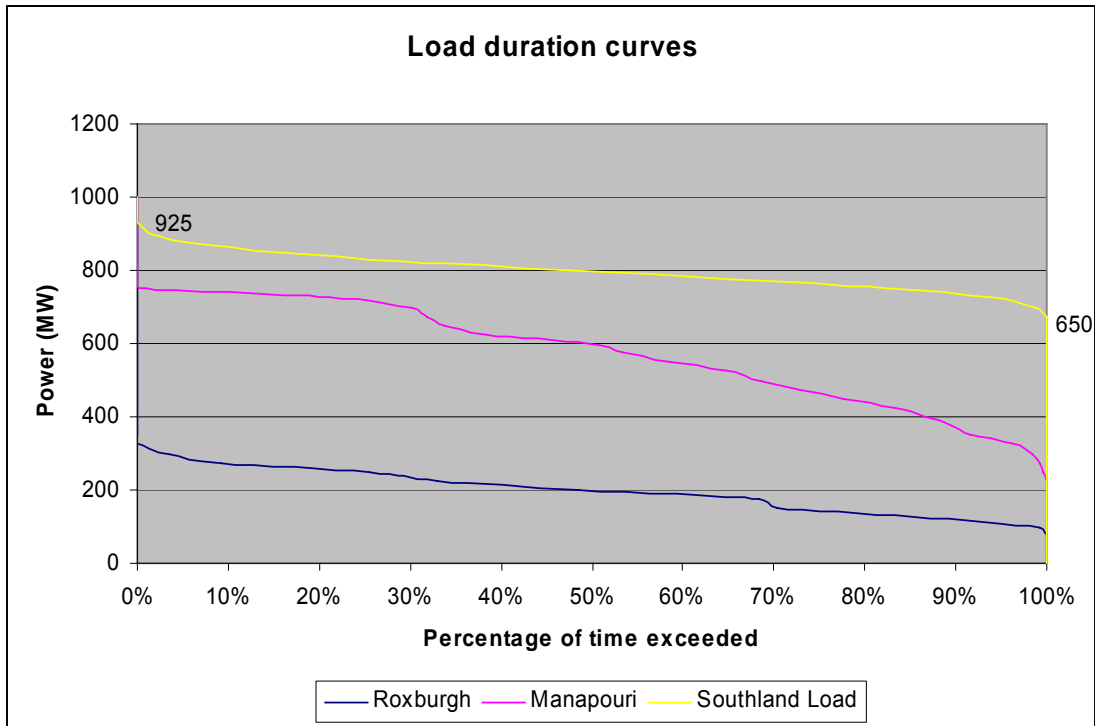


Figure 32: Load duration curves for Southland load, Manapouri and Roxburgh

5.2.2 Historic Southland transfer

Transfer from/into the Southland region has been analysed for the 2005 and 2006 calendar years. Figure 33 and Figure 34 show probability distribution functions for the periods where winter and summer ratings apply. A negative transfer amount indicates south transfer (i.e. transfer into the Southland region). A positive amount indicates north transfer.

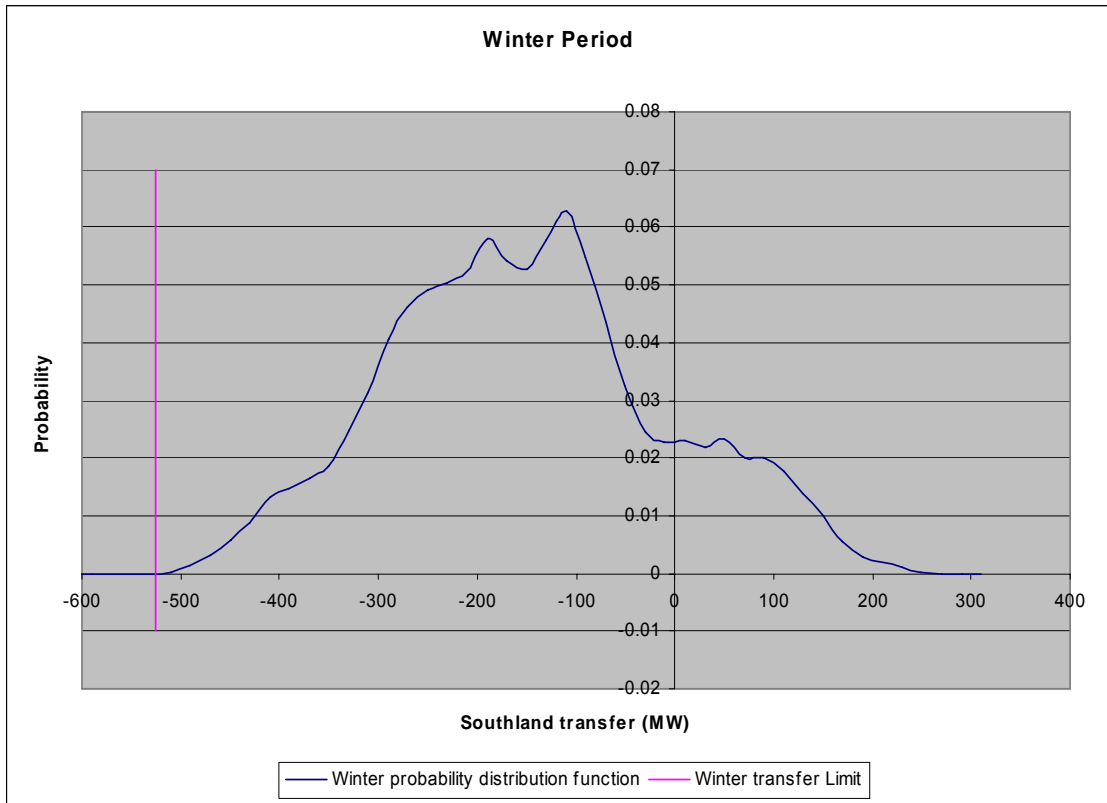


Figure 33: South transfer into Southland during winter periods in 2005 and 2006

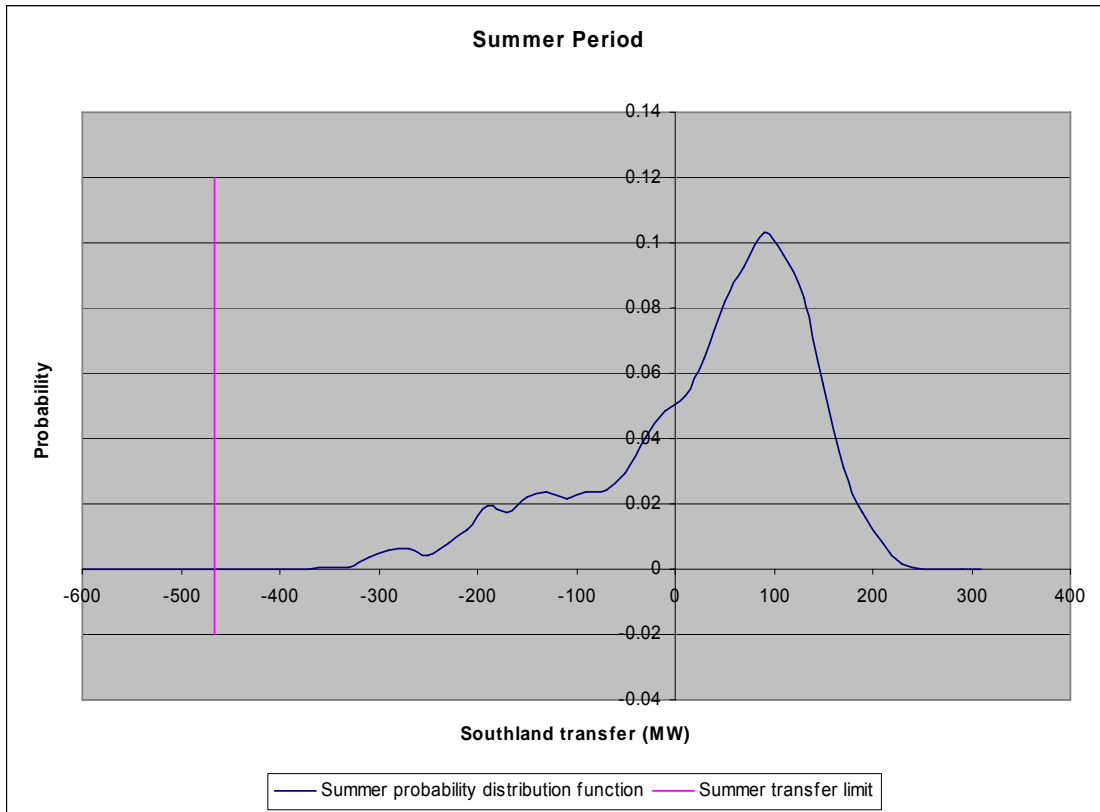


Figure 34: South transfer into Southland during summer periods in 2005 and 2006

5.2.3 Wind generation forecast error

A wind farm with installed capacity of 300 MW (as envisaged in wind generation development scenario C) is assumed to be connected at Invercargill substation. Probability distribution functions for the forecast error of the wind farm are shown in Figure 35 and Figure 36. These functions are based on the forecast error for Te Apiti scaled for the size of the 300 MW wind farm.

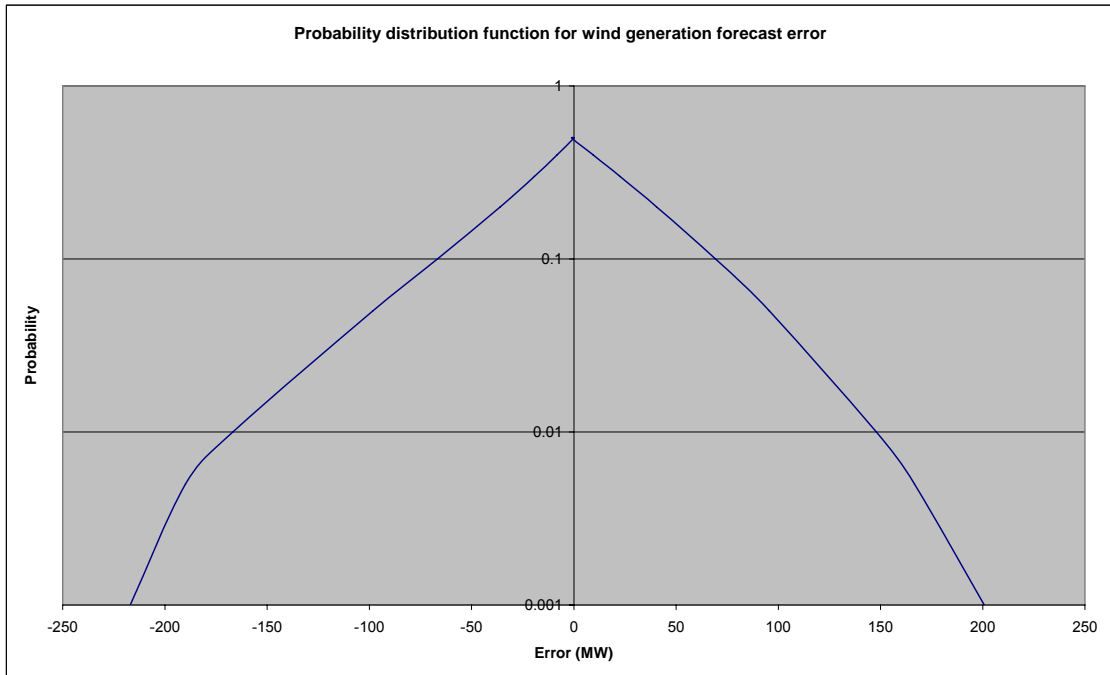


Figure 35: Assumed probability distribution function for wind generation forecast error for a 300 MW wind farm in Southland

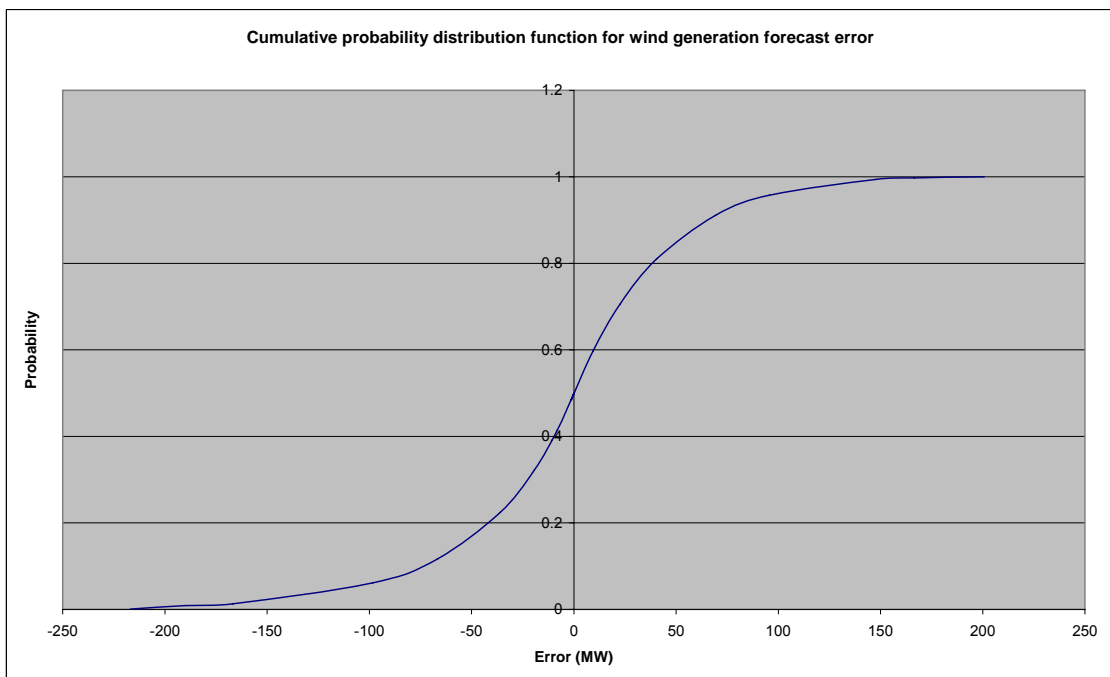


Figure 36: Cumulative probability distribution function for wind generation forecast error for a 300 MW wind farm in Southland (based on Figure 35)

5.2.4 Analysis

Figure 37 shows the number of trading periods where transfer margins (the difference between transfer into the region and the summer or winter transfer limits) were less than 50 MW.

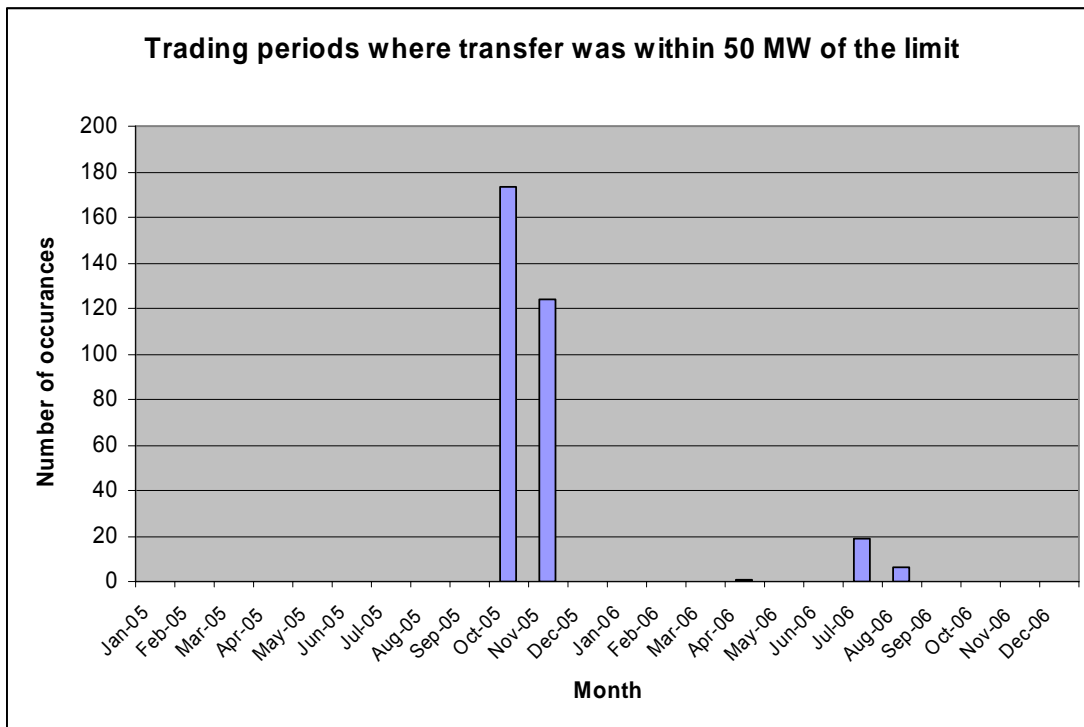


Figure 37: Trading periods where transfer margin was less than 50 MW

From Figure 37, it is apparent that transfer into the Southland region only approached the limits at certain times:

- October 2005;
- November 2005;
- April 2006;
- July 2006;
- August 2006.

These months were examined to determine what power system conditions were present when transfer was close to the limit.

5.2.5 July 6 to 16 2006

Figure 38 shows Southland load, transfer, and generation over the period 6 to 16 July 2006. Manapouri generation is low over this period. Southland transfer is close to the limit for sustained periods of time.

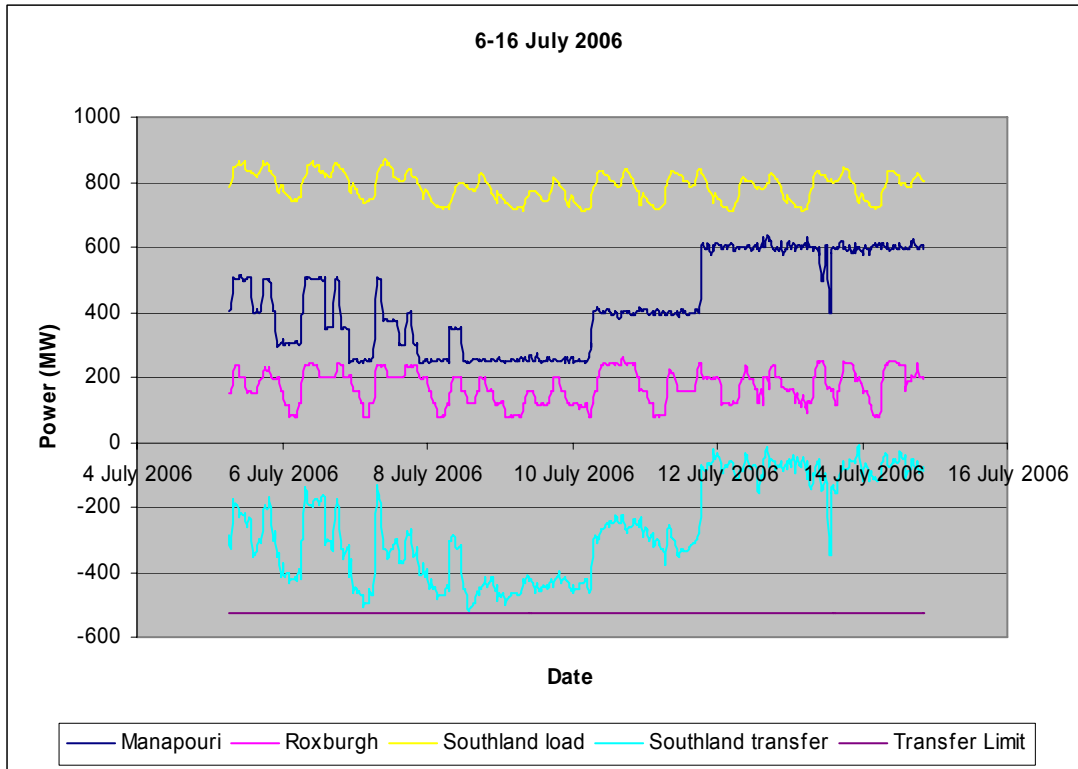


Figure 38: Southland load, transfer and generation from 6 July to 16 July

Figure 39 shows Southland load, transfer, and generation for 6 and 7 July 2006. The transfer margin is lowest for the first part of 7 July 2006. This corresponds to low Manapouri generation output and a reduction in Roxburgh output.

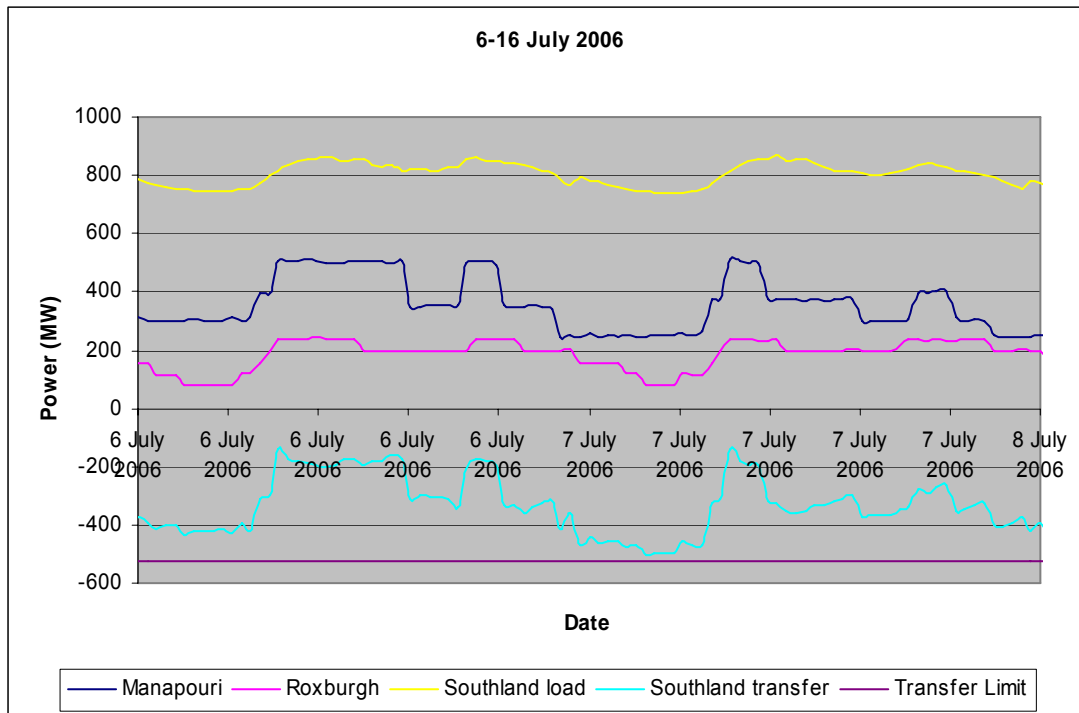


Figure 39: Southland load, transfer and generation from 6 July to 7 July

The effects of wind generation forecast error can be examined by assuming that the Southland wind generation is in operation at time of dispatch and is displacing other Southland generation. The remaining Southland generation is scheduled as per the historic records. The scheduling process includes a security check which for the purposes of this analysis will be checking if the required Southland transfer to meet regional demand exceeds the transfer limits.

The effects of wind generation forecast error can be expressed in terms of probability of exceedance (POE). Figure 40 shows the historic margin with wind generation forecast errors equal to 10% and 90% POE added. The margin with 10% POE shows the case where forecast wind generation is less than the actual amount at dispatch. The security check will indicate that the transfer limits are likely to be exceeded for a considerable number of trading periods (those periods where the margin with 10% POE line is below the transfer limit). The 10% POE indicates that there is a 10% chance of the wind generation forecast error being greater than amount used in the line.

The margin with 90% POE shows the case where the wind generation forecast is too high resulting in the security check indicating a far higher margin than will be available at dispatch. The 90% POE indicates that there is a 10% chance that the wind generation output will be higher than the amount used in the line.

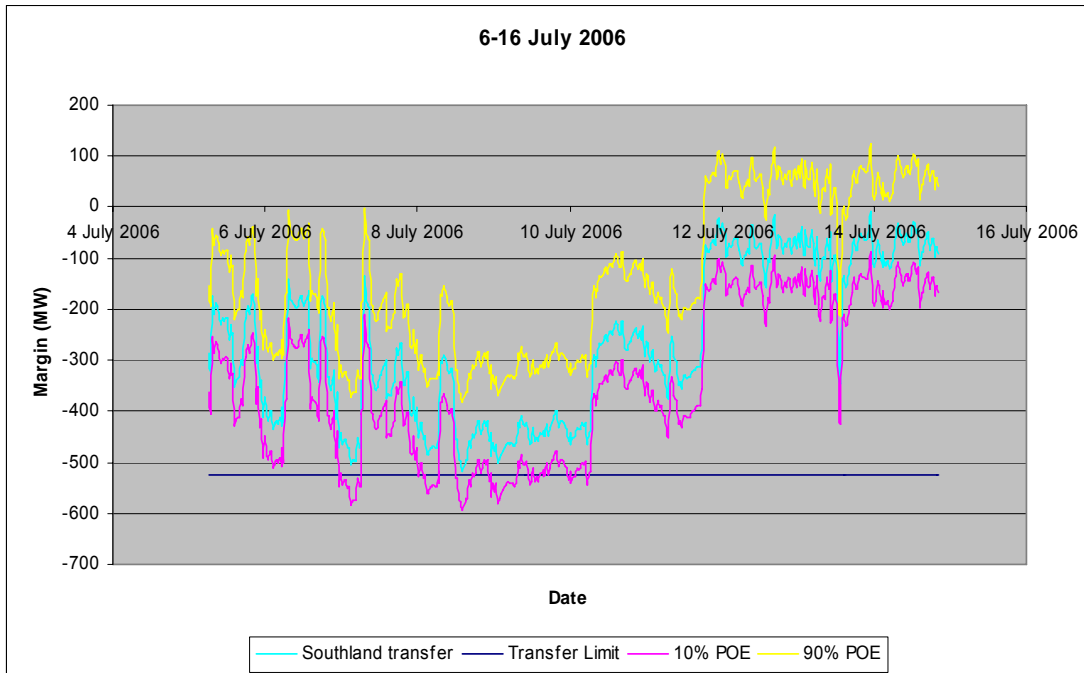


Figure 40: Transfer between 6 and 16 July with superimposed wind generation forecast error

The probability of the security check indicating that transfer will exceed the transfer limit can be illustrated by superimposing the wind generation forecast error cumulative probability function on the historic margin for certain trading periods. The resulting cumulative probability distribution function can then be used to estimate the probability of the security check indicating that transfer will exceed the transfer limit. Figure 41 shows such cumulative probability distribution functions for some trading periods on 7 July 2006.

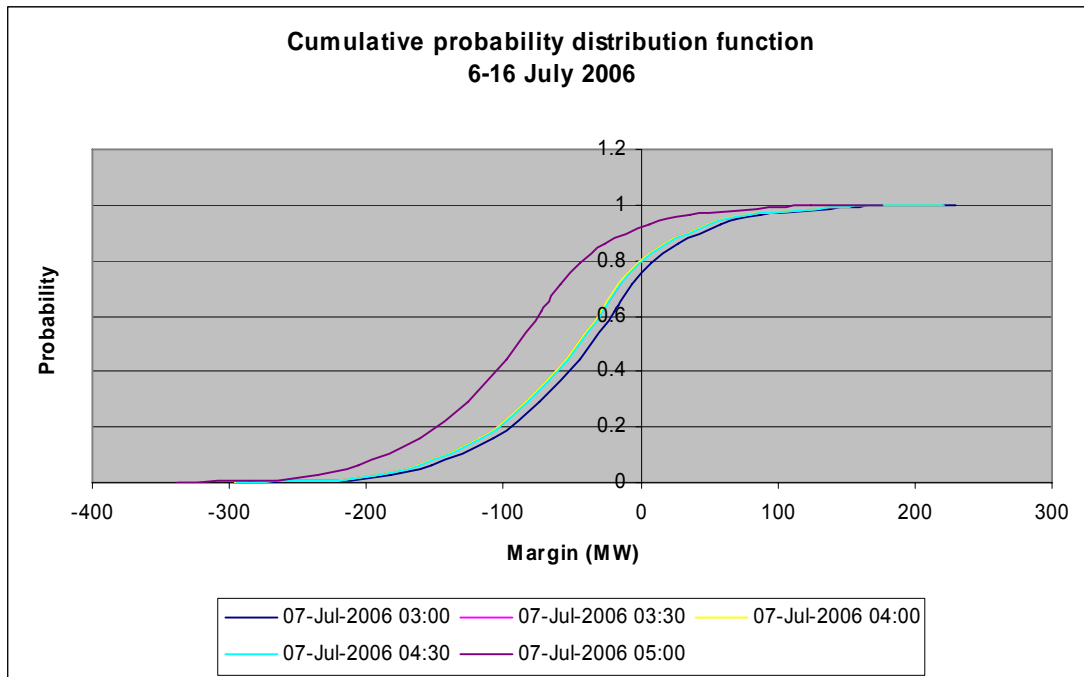


Figure 41: Transfer on 7 July with wind generation forecast error

Figure 41 shows that there is between a 10 and 20% chance that wind generation forecast error would cause the security check to indicate that the transfer limit was exceeded.

In practical terms, trading periods where the security check indicated a security issue (transfer limit is exceeded) would result in more Southland generation being scheduled (if offered). If insufficient Southland generation has been offered then a warning notice will be issued or a grid emergency declared.

In trading periods where the wind generation forecast was higher than the amount during dispatch then the security check will indicate a safe margin. This margin will decrease closer to dispatch and security issues may be identified with insufficient time to issue a warning notice or bring additional Southland generation on.

5.2.6 Monte Carlo Analysis

This analysis determines what the probability distribution function of transfer into Southland might be for varying amounts of wind generation installed in the region. The analysis was carried out using the historic Southland transfer margins and probability distribution functions for wind generation forecast error in the Southland region. The analysis uses a large number of calculations to produce a probability distribution function for transfer margins with wind generation. The calculations are determined by adding together randomly

selected values of historic transfer and wind generation output from the respective probability distribution functions.¹⁸

Probability distribution functions were scaled for 150 MW, 300 MW, and 450 MW of wind generation in Southland. Figure 42 and Figure 43 show cumulative probability distribution functions of the transfer margin for different amounts of wind generation capacity in the Southland region.

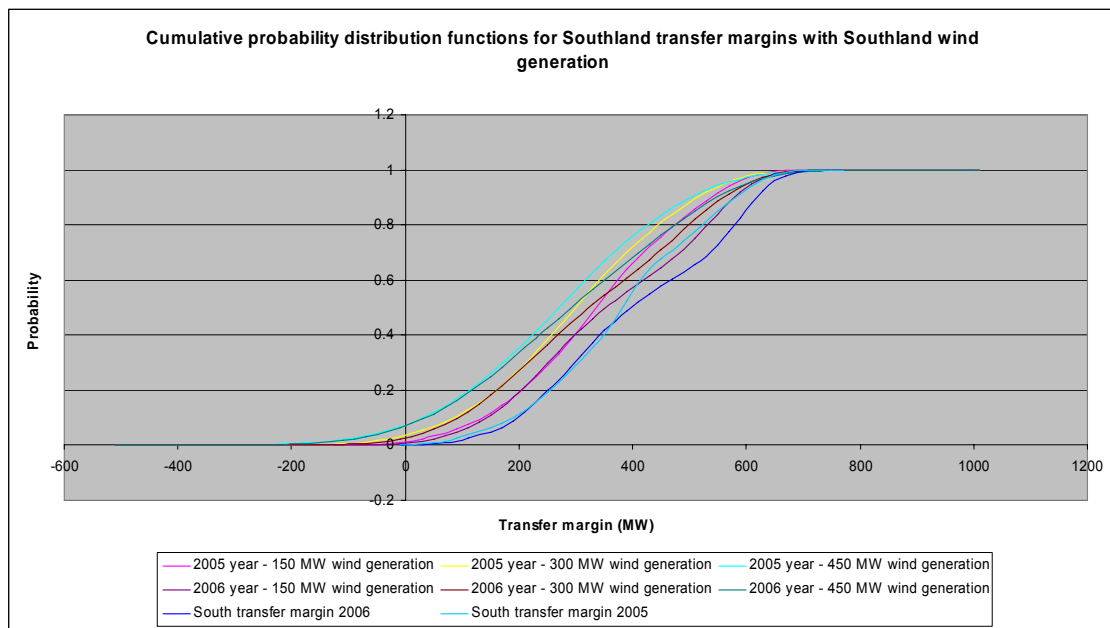


Figure 42: Cumulative probability distribution functions for Southland transfer

¹⁸ A random number between 0 and 1 is generated (this is the probability) and the corresponding value from the relevant cumulative probability distribution function is selected.

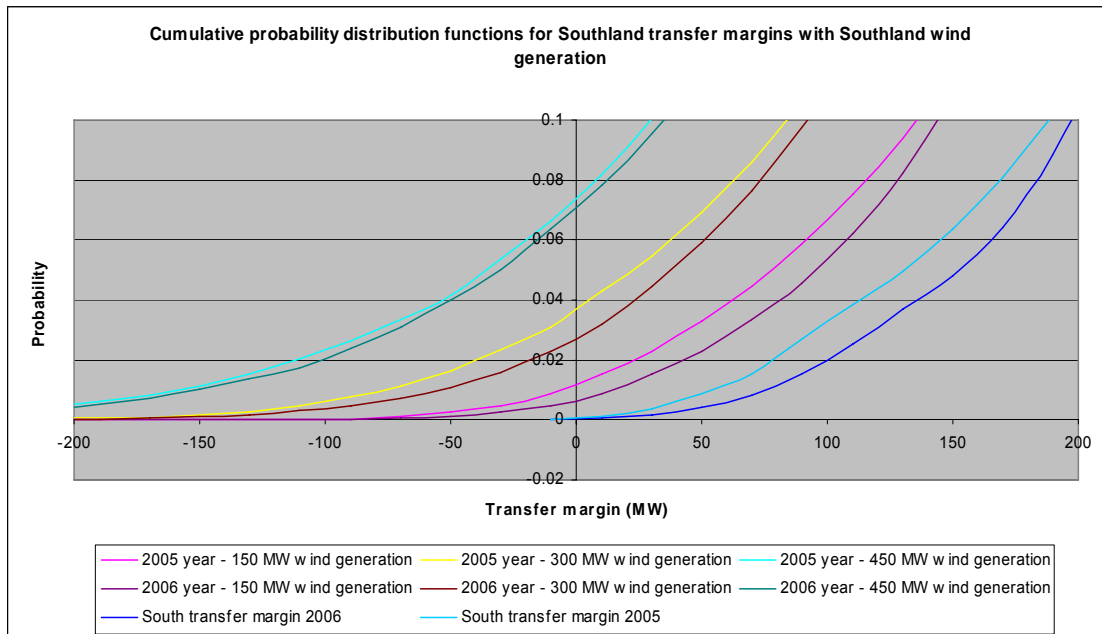


Figure 43: Cumulative probability distribution functions for Southland transfer

Figure 43 shows the proportions of time that transfer exceeds the limit (transfer margin is negative). Increasing amounts of installed wind generation capacity increases the proportion of time that transfer exceeds the limit. For the Southland region, transfer margins are not significantly affected by large amounts of installed wind generation capacity in the region.

5.2.7 Generation starting capability

Figure 38 shows a time when Manapouri generation was low and demand in the Southland Region approached the Southland transfer limit. During this time, Roxburgh generation was following load changes within the region. This suggests that some capability to change output is available within the region at other times. If effects of regional wind generation forecast errors were to cause security issues (i.e. forecast levels of wind generation output did not eventuate leading to insufficient regional generation offered to meet forecast load) then fast starting hydro plant in the region (e.g. Roxburgh or the Waipori scheme) can be brought on line to manage the shortfall in regional generation.

5.3 Hawkes Bay Transfer

5.3.1 Introduction

Figure 44 shows the Hawkes Bay region (lightly shaded). There is considerable hydro generation and thermal generation in the region. Scenario C includes 300 MW of wind generation capacity in the region, assumed to be connected at the Redclyffe bus.

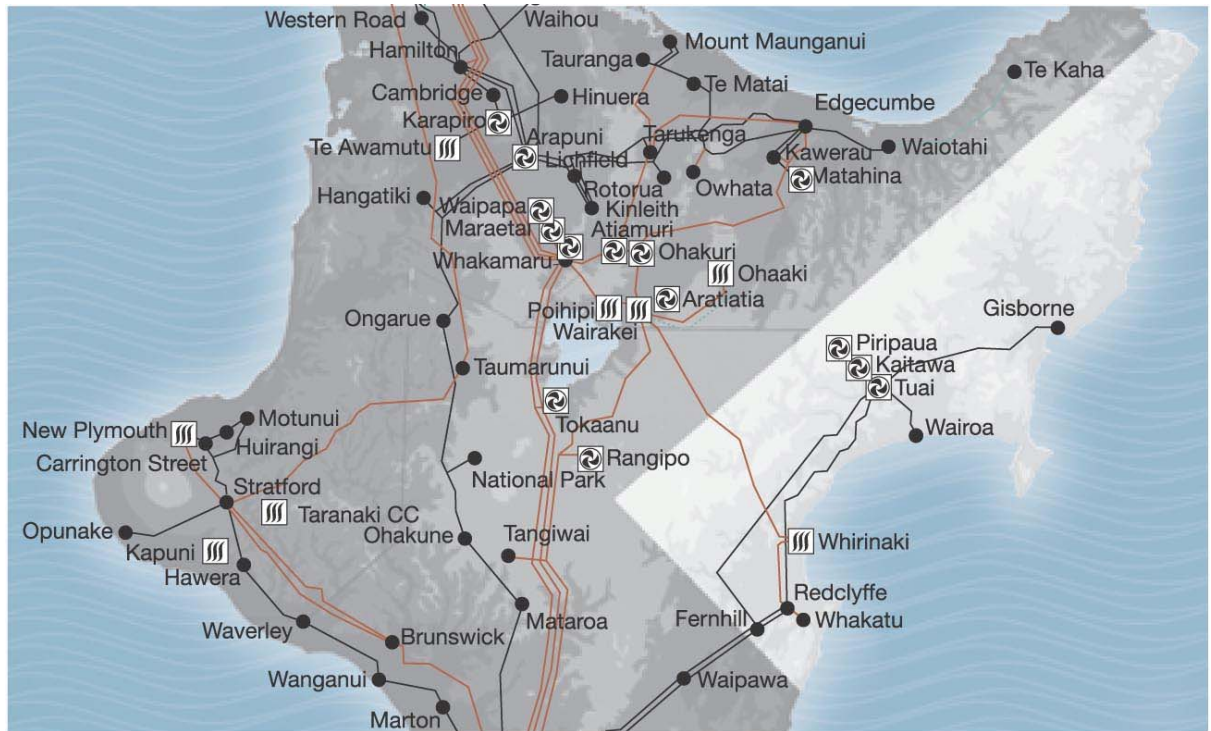


Figure 44: Hawkes Bay region

Figure 45 shows the single line diagram for the Hawkes Bay region.

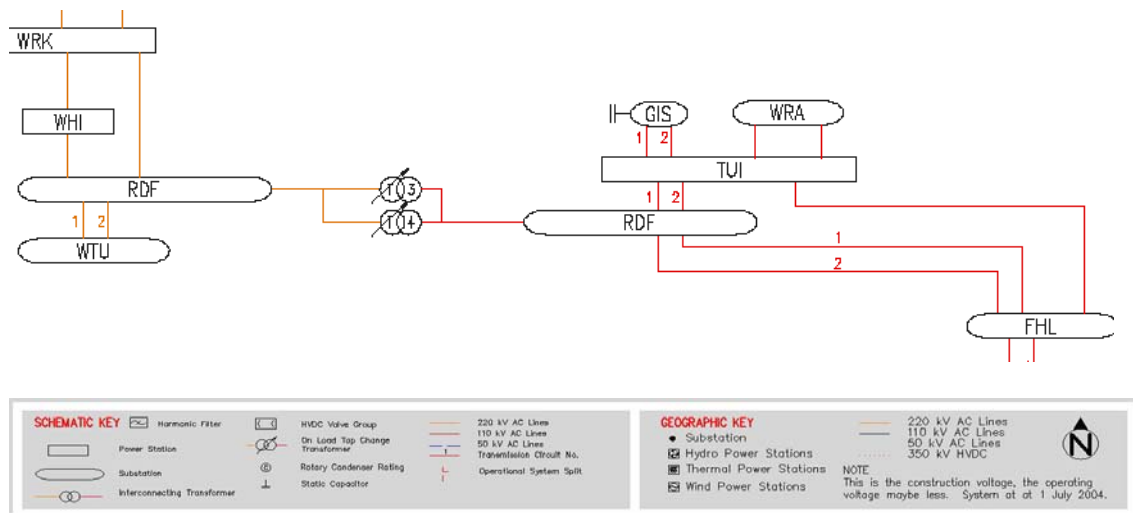


Figure 45: Single line diagram of Hawkes Bay region

The Hawkes Bay region is the area bordered by and including the Fernhill substation in the south, up to Tokomaru Bay in the north.¹⁹ It is supplied through two 220 kV circuits from Wairakei and has 220/110 kV interconnecting transformers located at Redclyffe. Reactive support in the Hawkes Bay region consists of 12 Mvar of capacitors on the 110 kV bus at Gisborne and reactive power from Tuai generation.

The existing generation in the Hawkes Bay region is connected to the Tuai bus and consists of Tuai, Piripaua, and Kaitawa hydro generation stations, collectively known as the Waikaremoana (WKA) scheme. Maximum output from the Waikaremoana scheme is about 138 MW. This is insufficient to meet the regional load, so power transfer from Wairakei into the region is required. The Whirinaki (WHI) generation in the region is meant for dry hydro year emergencies. Therefore this generation is assumed to be unavailable for normal generation.²⁰

There are limits on the amount of power that can be transferred into the region from Wairakei. Transfer into the region is limited to 286 MW to avoid voltage problems in Hawkes Bay following the loss of one of the 220 kV circuits from Wairakei. Figure 32 shows duration curves for Hawkes Bay demand. It should be noted that Hawkes Bay demand exceeds the transfer limit from Wairakei around 10% of the time, requiring that some local generation is dispatched.

¹⁹ Tokomaru Bay substation is decommissioned, and the Gisborne-Tokomaru Bay transmission line used for reactive support.

²⁰ The Reserve Energy station at Whirinaki is operated under specified arrangements developed by the Electricity Commission. These include dry year and potential dry year situations, and periods of prolonged high prices. The station is subject to the same offer and dispatch rules as other generators.

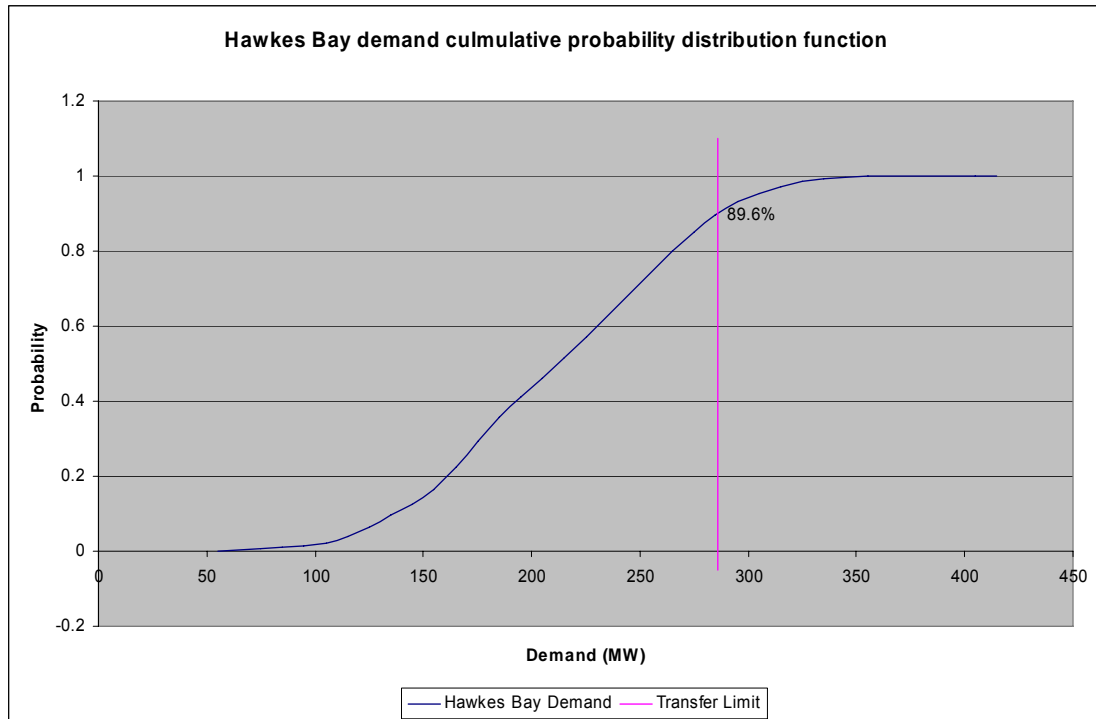


Figure 46: Load duration curves for Hawkes Bay demand

5.3.2 Historic Hawkes Bay transfer

Transfer from/into Hawkes Bay has been analysed for the period between February 2005 and January 2007. A negative transfer amount indicates transfer out of the region. A positive amount indicates transfer into of the region. Figure 47 shows probability distribution functions for transfer into Hawkes Bay.

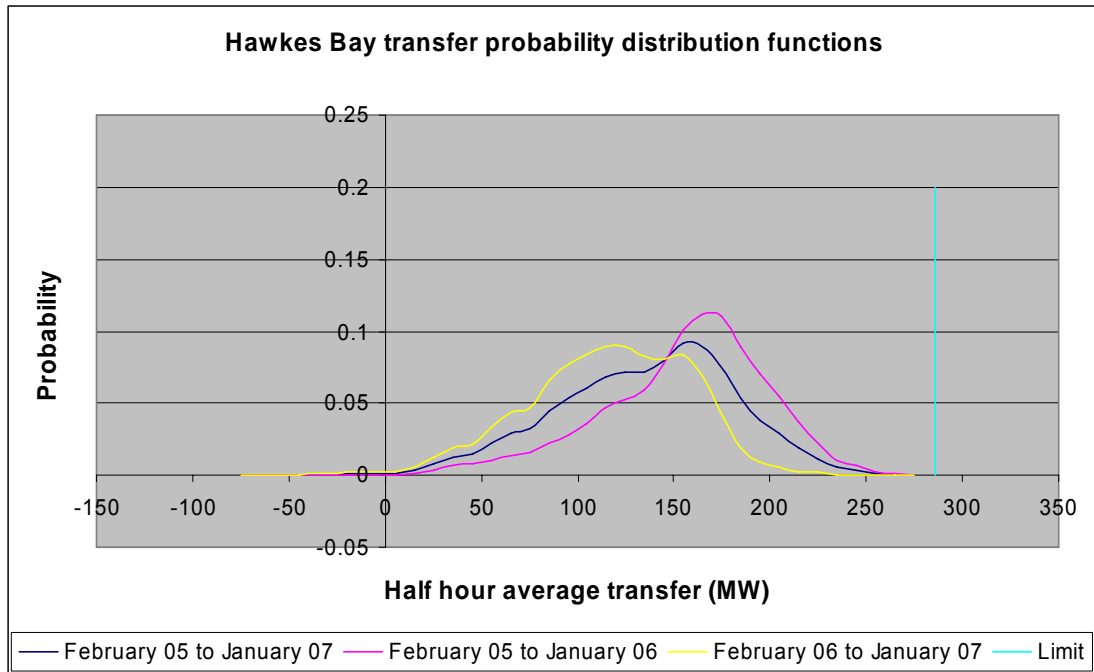


Figure 47: Transfer into Hawkes Bay during 2005 and 2006

5.3.3 Wind generation forecast error

A wind farm with installed capacity of 300 MW is assumed to be connected at Redclyffe as envisaged in wind generation development scenario C. Probability distribution functions for the forecast error of the wind farm are shown in Figure 48 and Figure 49. These functions are based on the forecast error for Te Apiti scaled for the size of the 300 MW wind farm.

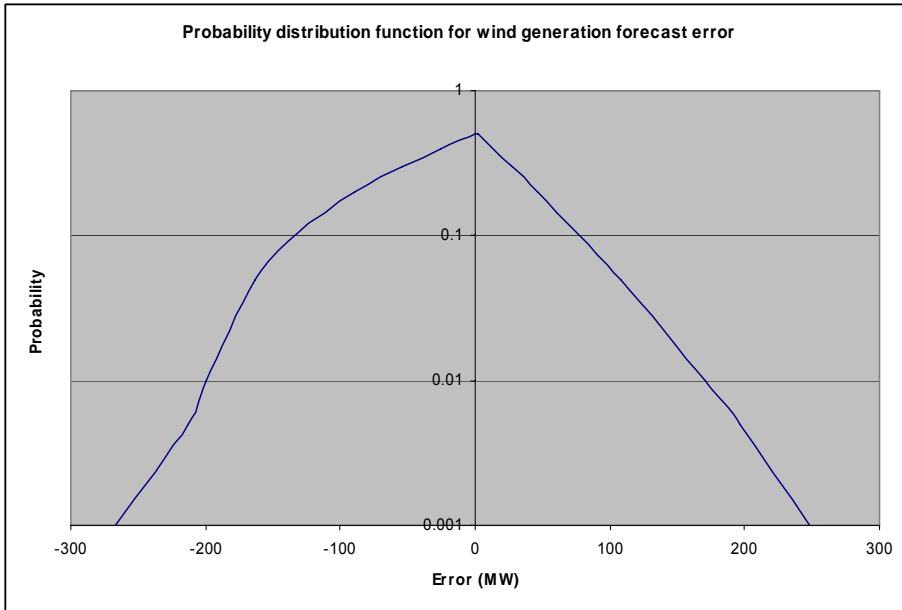


Figure 48: Assumed probability distribution function for wind generation forecast error for a 300 MW wind farm in Southland

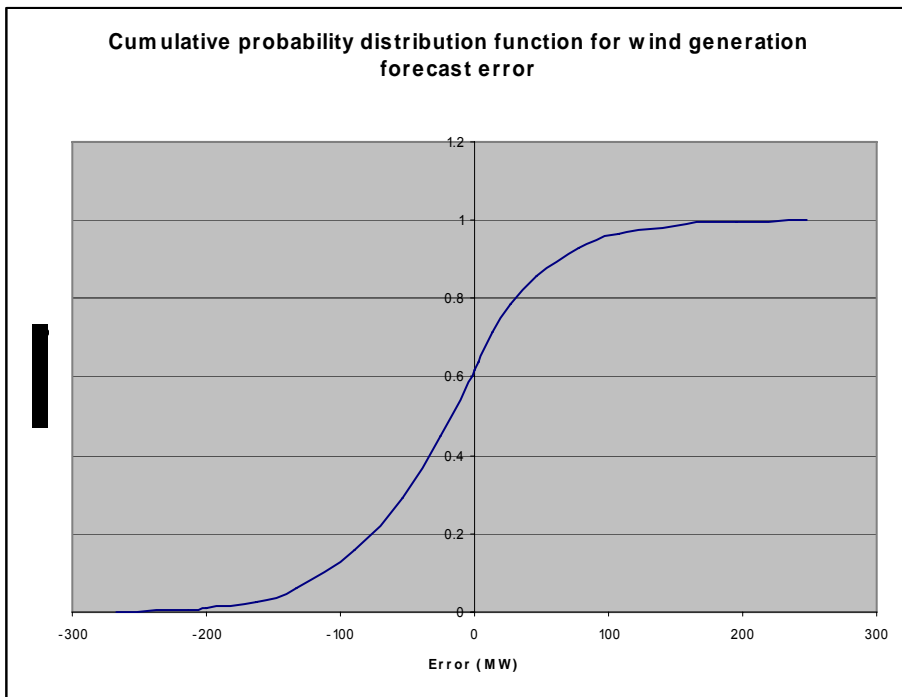


Figure 49: Cumulative probability distribution function for wind generation forecast error for a 300 MW wind farm in Southland (based on Figure 35)

Analysis

Figure 50 shows the number of trading periods where transfer margins (the difference between transfers into the region and the summer or winter transfer limits) was less than 25 MW.

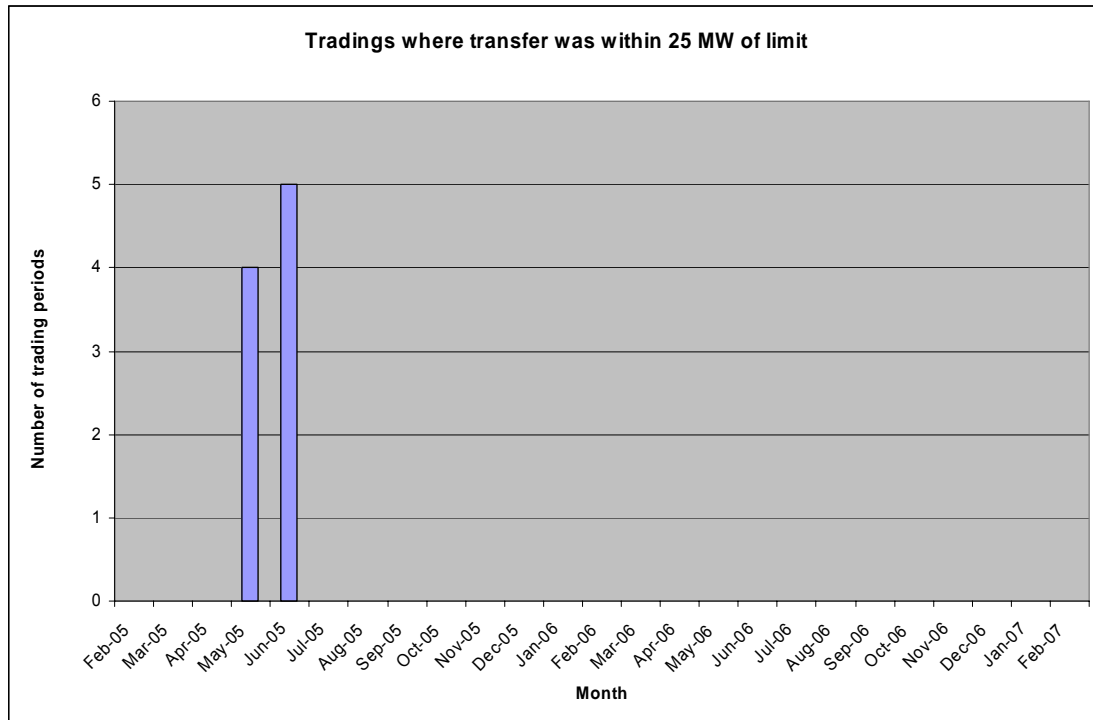


Figure 50: Trading periods where transfer margin was less than 25 MW

From Figure 50, it is apparent that transfer into Hawkes Bay only approached the limits in May and June 2005.

These months were examined to determine what power system conditions were present when margins were low. Figure 51 shows the first week of June 2005. Generation from the Waikaremoana scheme is very low except where required to meet the morning and evening peaks.

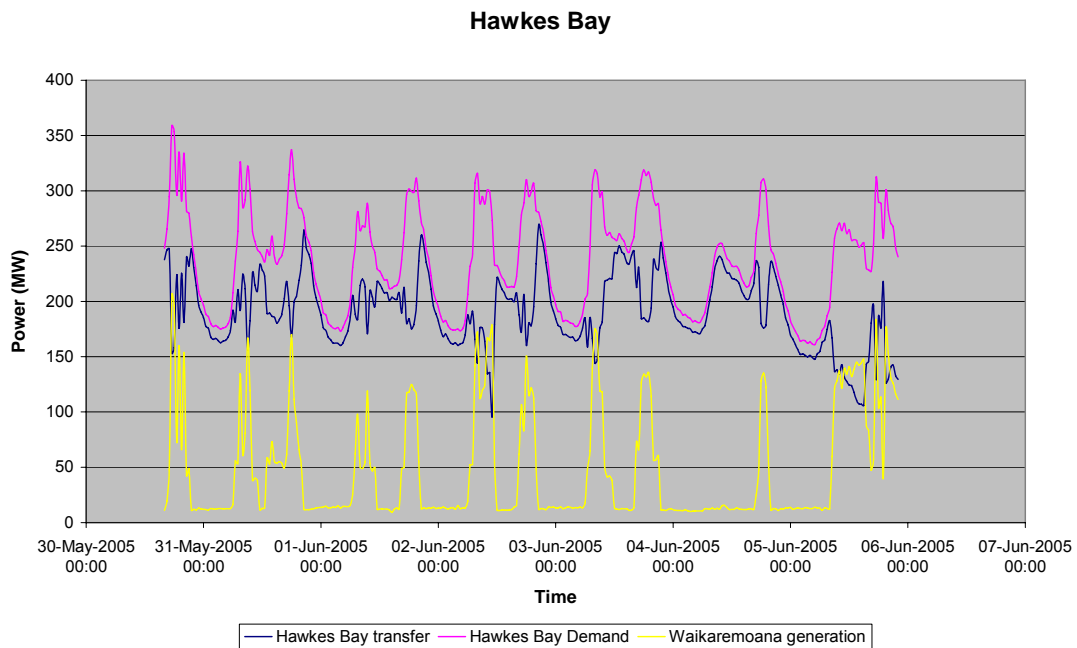


Figure 51: Generation and Demand in Hawkes Bay in June 2005

5.3.4 Monte Carlo Analysis

Monte Carlo Analysis was carried out using the historic Hawkes Bay transfer margins and probability distribution functions for wind generation forecast error in the Hawkes Bay region. Probability distribution functions were scaled for 150 MW, 300 MW, and 450 MW of wind generation in Hawkes Bay region. Figure 52 and Figure 53 show cumulative probability distribution functions for transfer into Hawkes Bay with varying amounts of installed wind generation capacity for 2005 and 2006 respectively.

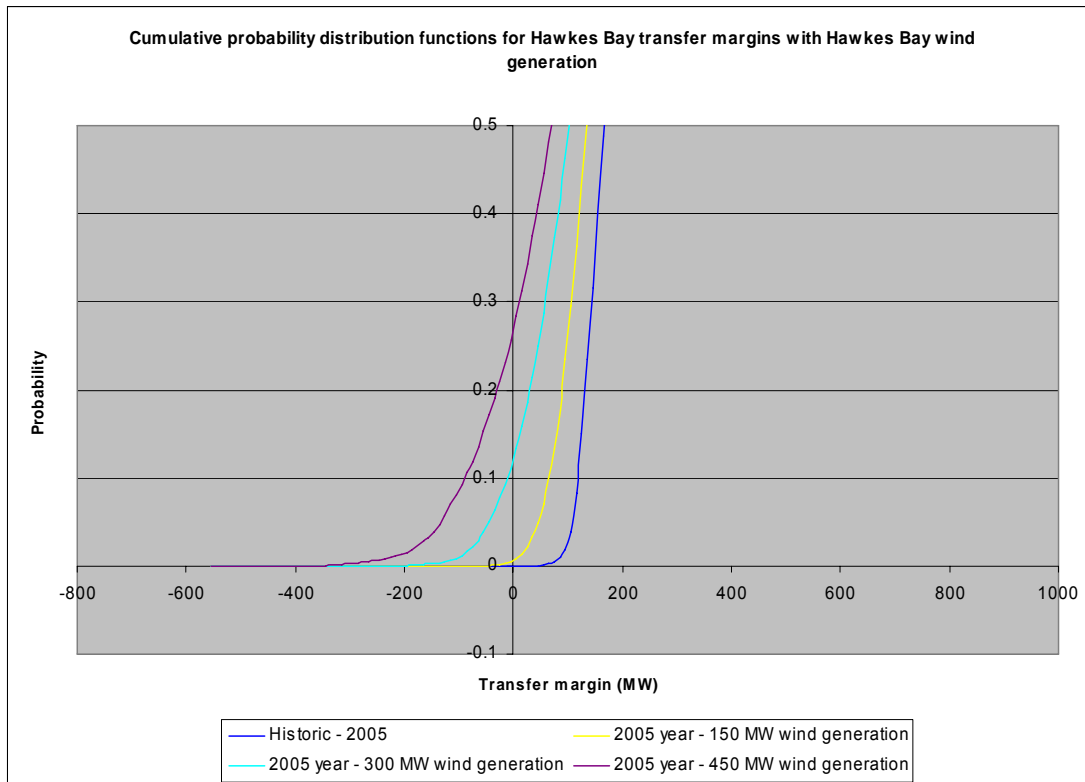


Figure 52: Cumulative probability distribution functions for Hawkes Bay transfer

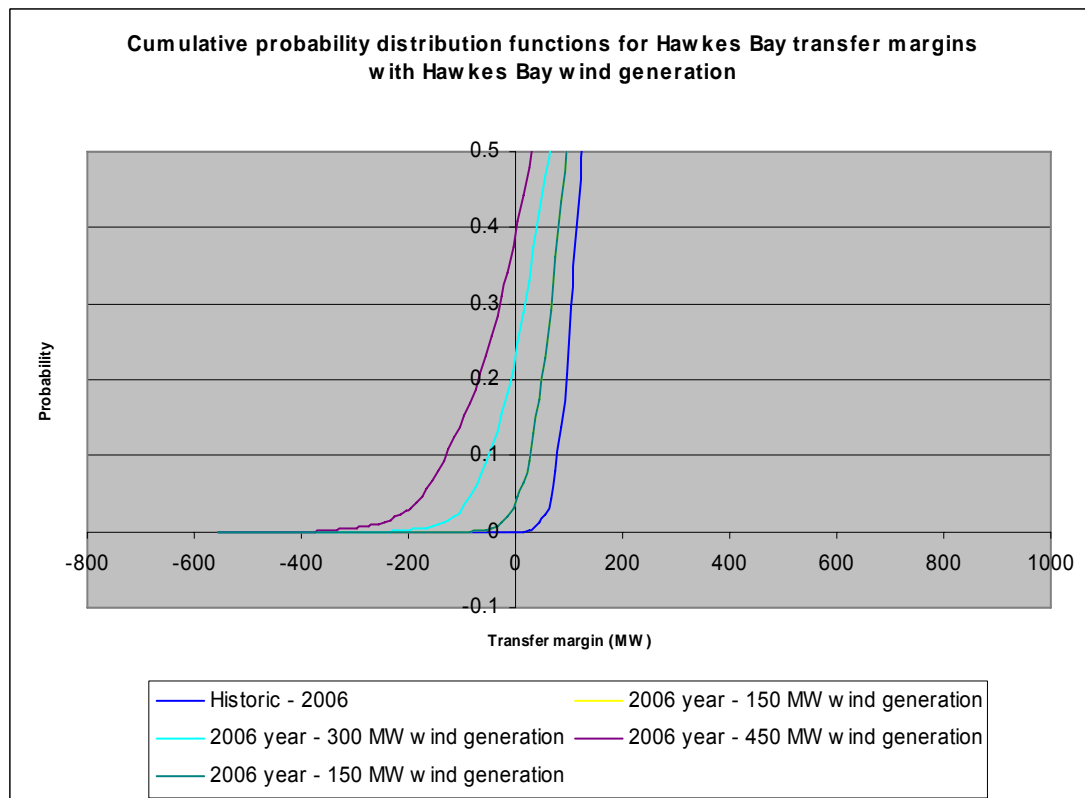


Figure 53: Cumulative probability distribution functions for Hawkes Bay transfer

The amount of time when Hawkes Bay transfer margin is negative increases significantly with increased wind generation installed capacity.

5.3.5 Effect of wind generation forecast error

Figure 54 shows an example of wind generation output forecast for Te Apiti. The blue line shows the forecast 23 hours before dispatch. This forecast is considerably different from the forecast 3 hours before dispatch (pink line). The forecast immediately before dispatch is much more accurate. This forecast is based on the amount of wind generation output at the start of the dispatch period and seems to be a good indicator for wind generation output in the following half hour.

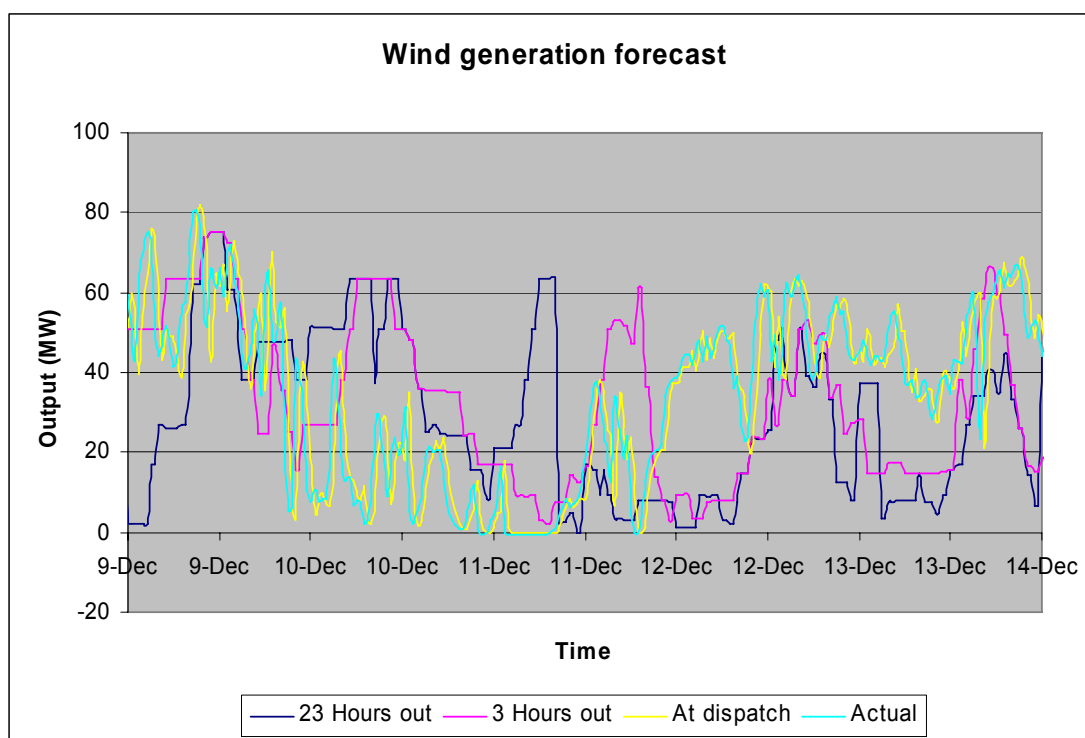


Figure 54: Example of Te Apiti wind generation forecast

Figure 55 shows forecasts for a day. The error in the forecasts can be quite large. For example, there are several trading periods in Figure 55 where the error (difference between forecast and actual) is around 60 MW (two thirds of Te Apiti’s installed capacity).

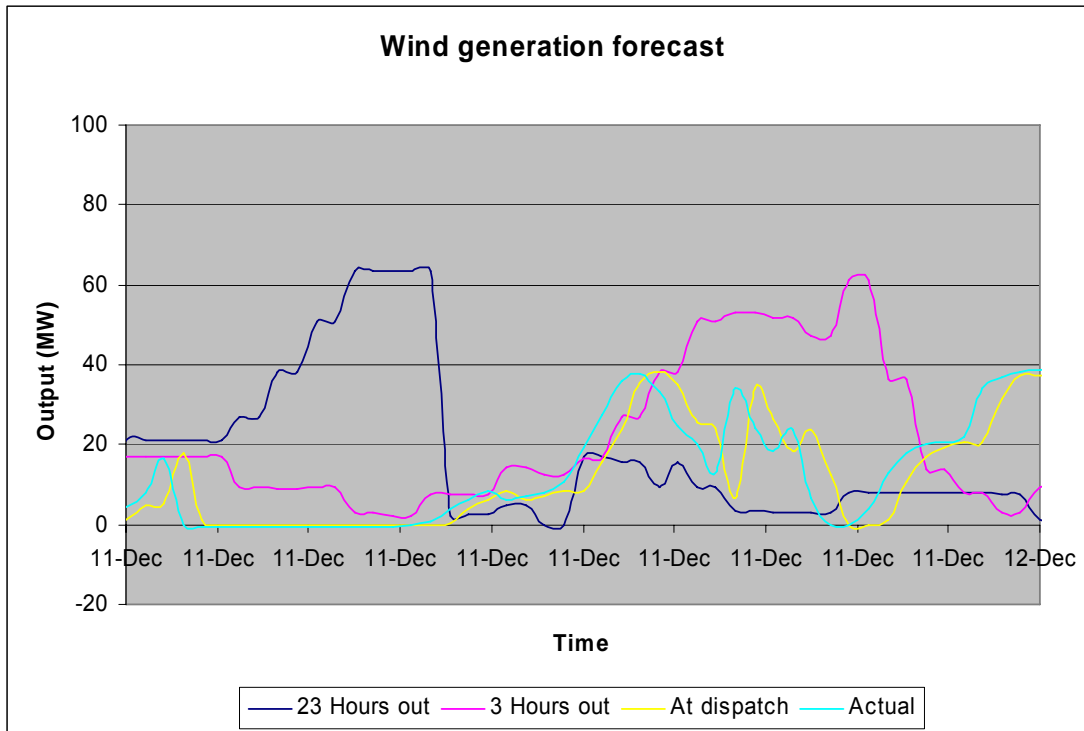


Figure 55: Example of Te Apiti wind generation forecast across a day

The installation of wind generation in the Hawkes Bay region can be used to illustrate the potential effect of wind generation forecast error on management of power system security.

Figure 56 shows the net Hawkes Bay regional demand forecast across two days. The transfer limit into Hawkes Bay is 286 MW. The net Hawkes Bay demand forecast exceeds this limit at times of morning and evening peak demand. The amount that regional demand exceeds the transfer limits indicates the minimum amount of regional generation that needs to be offered to ensure that regional demand forecast can be met. If the amount of regional generation offered is less than the shortfall then a security issue will be identified and warning notices sent to participants.

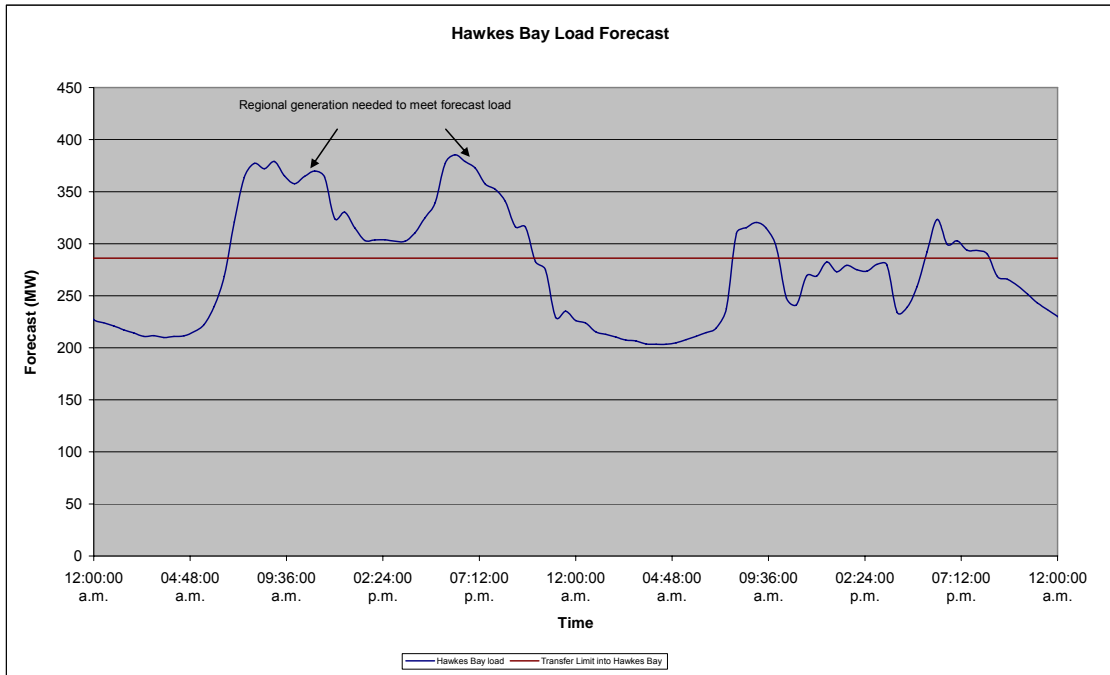


Figure 56: Net Hawkes Bay Demand

Figure 57 shows the net Hawkes Bay demand forecast for the case where a wind farm with a capacity of 300 MW is installed in the region. The forecast is based on the demand forecast shown in Figure 56 (with an adjustment for the Hawkes Bay wind generation output – the net Hawkes Bay demand is reduced by the amount of wind generation output). Hawkes Bay wind generation forecasts are scaled (for the 300 MW wind farm) from the wind generation forecasts in Figure 54. The net forecast at 23 hours before dispatch indicates that no regional generation needs to be offered to meet the forecast load.

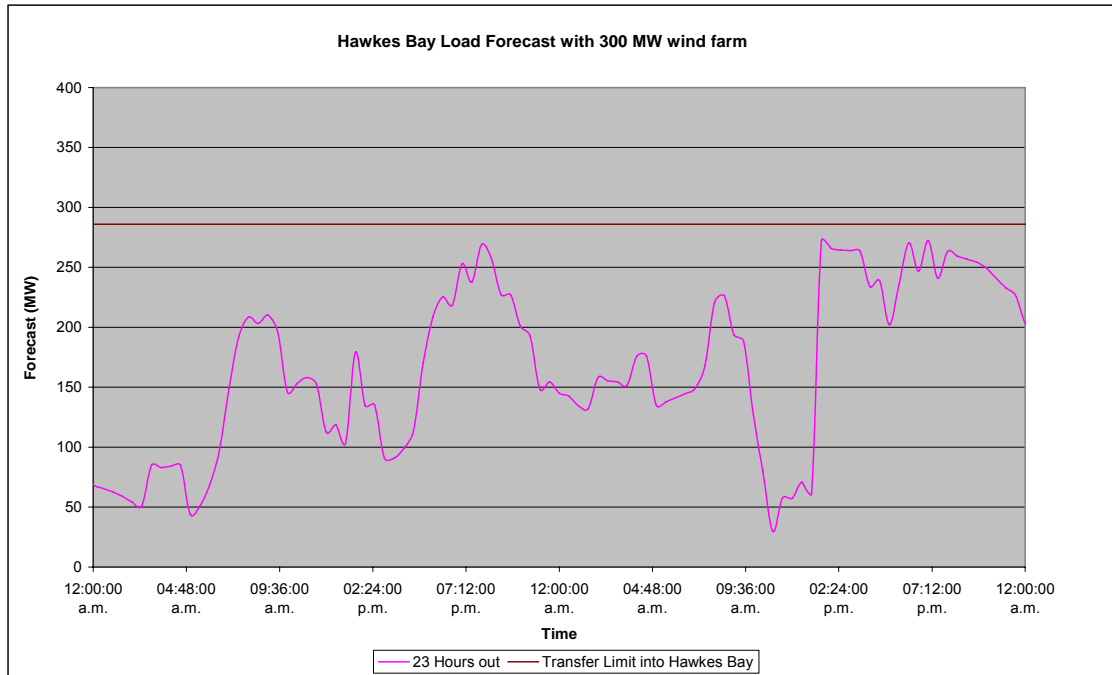


Figure 57: Hawkes Bay load and wind generation forecast at 23 hours before dispatch

Figure 58 shows the net Hawkes Bay demand forecast for 23 hours before dispatch and 3 hours before dispatch (based on scaled Te Apiti forecasts at 3 hours before dispatch). The two forecasts are similar in shape although differences of up to 150 MW occur. The forecast at 3 hours before dispatch shows that small amounts of regional generation may be required.

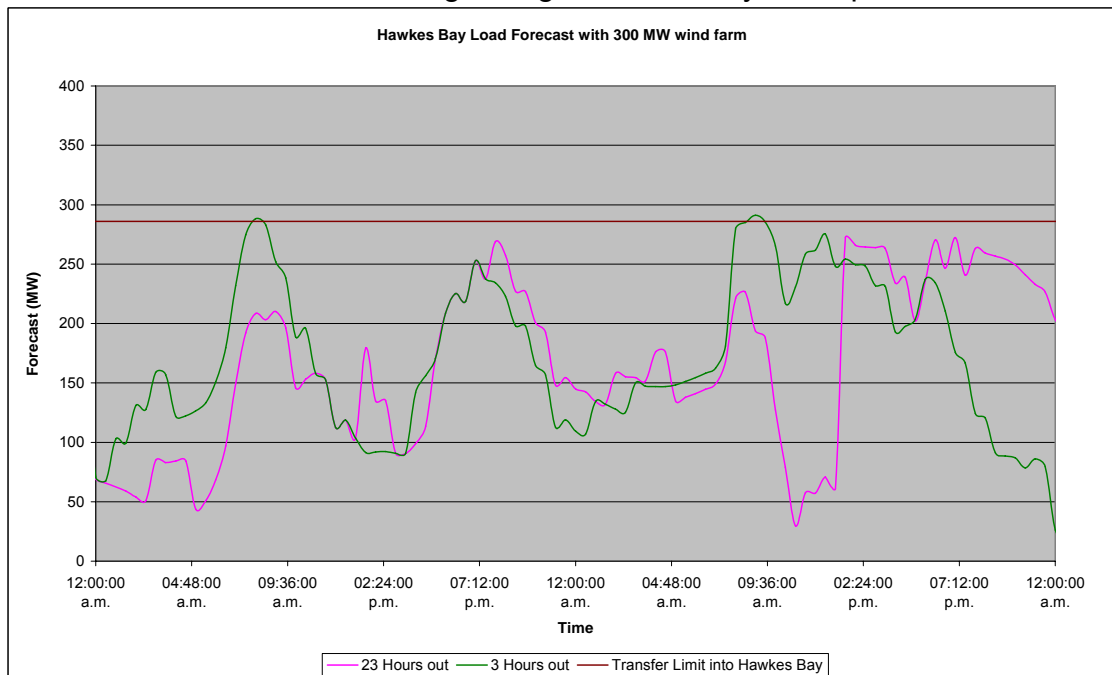


Figure 58: Hawkes Bay load and wind generation forecast at 23 hours and 2 hours before dispatch

Figure 59 shows the net Hawkes Bay demand forecast for 3 hours before dispatch and actual generation for the trading period. The forecasts and actual generation output are similar in shape but are considerably different in magnitude. A significant amount of regional generation is required at dispatch to meet regional demand. This was not indicated in the forecasts at 3 and 23 hours before dispatch.

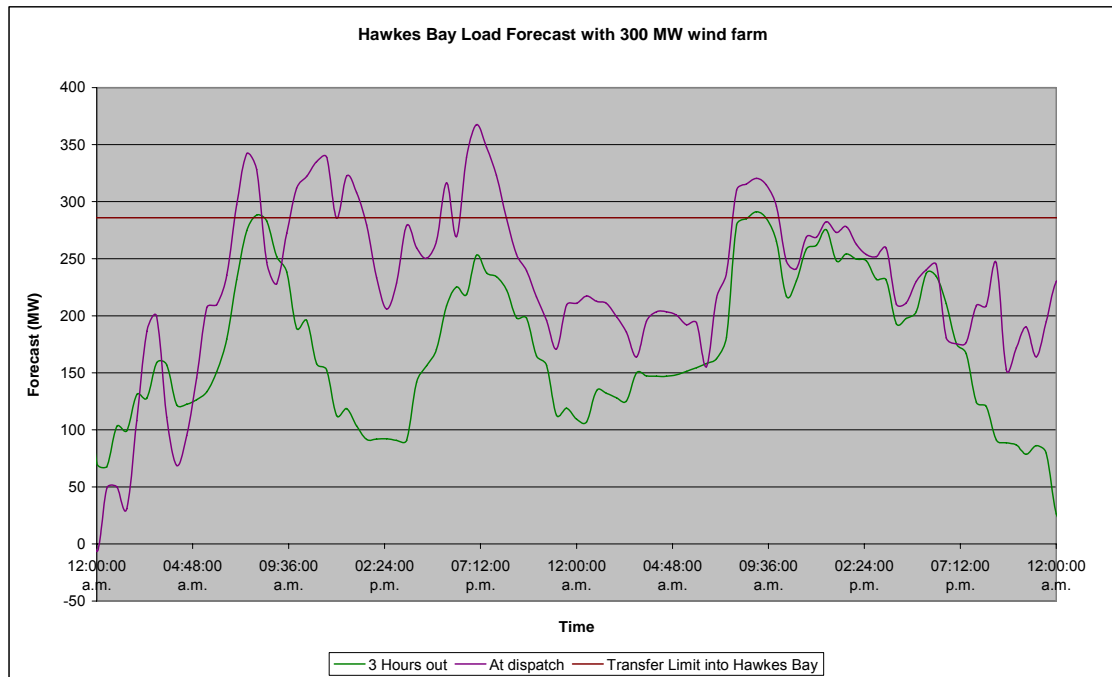


Figure 59: Hawkes Bay load and wind generation forecast at 3 hours and just before dispatch

Figure 60 shows the forecast required minimum regional generation for a different time. In this case, the 23 hours before dispatch and 3 hours before dispatch forecasts show a much smaller requirement than what is present at dispatch. The 3 hour period between the forecast 3 hours before dispatch and dispatch may leave insufficient time to make additional generation available to meet demand.

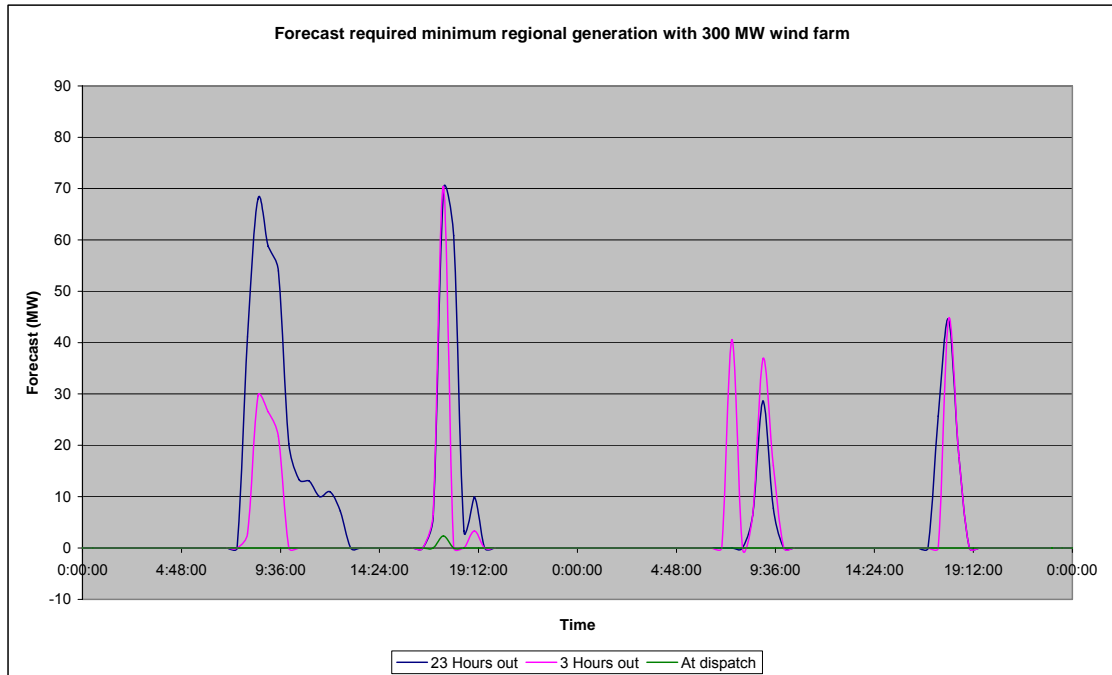


Figure 60: Forecast of minimum regional generation to meet forecast demand in Hawkes Bay

Figure 61 shows a scatter diagram of the minimum required regional generation in Hawkes Bay for the case where a wind farm of 300 MW installed capacity is installed in the region. Points on the vertical axis indicate situations where the 24 hours before dispatch or 3 hours before dispatch forecasts indicated a shortfall in regional generation but no such shortfall was present at the time of dispatch. Points on the horizontal axis indicate situations where a shortfall was present at dispatch but was not present in one of the 24 hours before dispatch or 3 hours before dispatch forecasts. Points below the 45 degree line indicate situations where the forecast shortfall is less than the shortfall at dispatch.

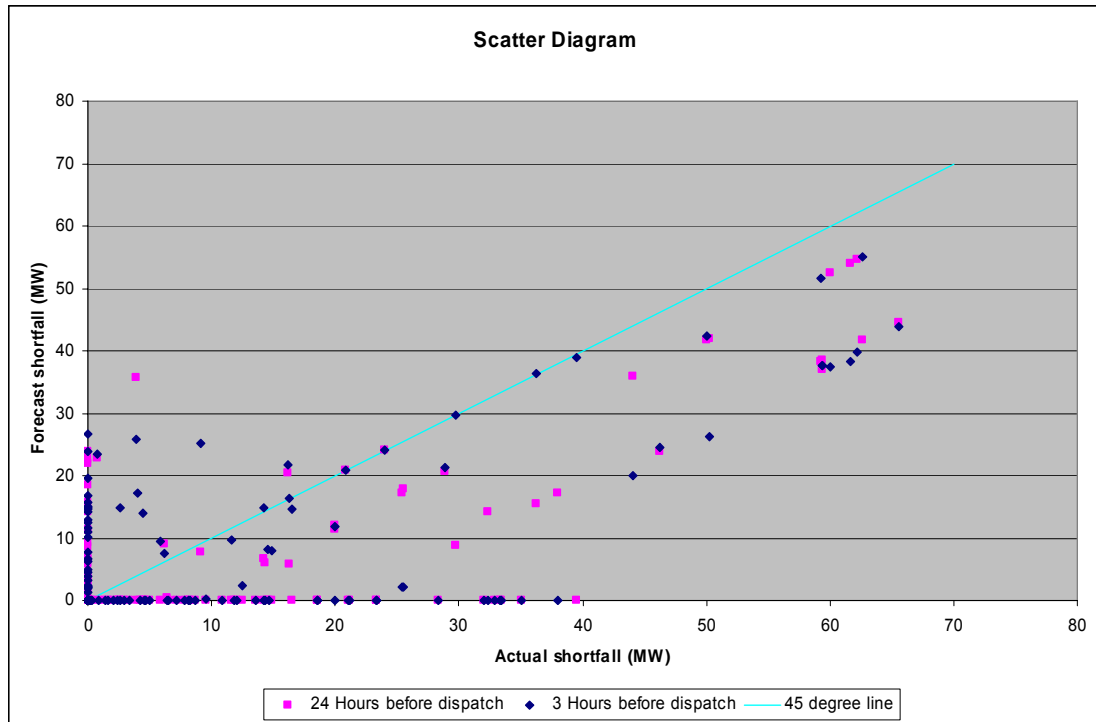


Figure 61: Scatter diagram of forecast shortfall against actual shortfall for July 2005

Table 5 shows a comparison of the 23 hours before dispatch and actual dispatch. Around 15% of shortfall situations in the 23 hours before dispatch forecast will indicate a false alarm (shortfall forecast but no present at dispatch). Around 27% of the time, no shortfall will be forecast but a shortfall will appear at dispatch. Forecast shortfall is less than actual shortfall around 68% of the time (=26.9% + 41.2%).

	Count	Percentage of trading periods
<i>Forecast indicates shortfall but no shortfall at dispatch</i>	27	14.8%
<i>Forecast indicates no shortfall but shortfall at dispatch</i>	49	26.9%
<i>Forecast shortfall is less than dispatch shortfall</i>	75	41.2%
<i>Forecast shortfall is greater than dispatch shortfall</i>	31	17.0%

Table 5: Shortfall in generation

5.4 Generation starting capability

Figure 51 shows a time when Waikaremoana generation was low and demand in the Hawkes Bay Region approached the transfer limit on the Wairakei-Redclyffe circuits. As noted previously, Waikaremoana generation increased just enough to meet the morning and evening peaks. This suggests that some

capability would be available to do so at other times. If the effects of regional wind generation forecast errors were to cause security issues (i.e. forecast levels of wind generation output did not eventuate leading to insufficient regional generation offered to meet forecast load) then fast starting hydro plant on the Waikaremoana scheme or the Whirinaki generating units can be brought on line to manage the shortfall in regional generation.

5.5 Summary

In the year to date, the System Operator has issued 15 warning notices and 73 grid emergency notices asking generators to increase generation offers. Some of the notices were updates for the same event. There were 54 events for which one or more notices were issued asking generators to increase offered quantities. On average, there are 4 to 5 events per month that require the use of warning or grid emergency notices requesting that generators increase their offered quantity.

This issue of insufficient generation offers already requires management on a weekly basis. An increase in the number of potential events or grid emergencies being missed may cause significant operational difficulty.

Analysis of the effects of wind generation output variability and forecast errors on the security of the Southland and Hawkes Bay regions has been carried out. The analysis has indicated that:

- Security issues were more likely to become apparent during times when a significant amount of regional generation was not dispatched.
- The effect of wind generation forecast error was to increase the number of times that the security check would falsely indicate issues (wind forecast less than actual generation) and miss issues (wind forecast greater than actual wind generation output).
- There was sufficient generation available in the region to follow regional demand at these times. This capability is assumedly available to meet changes in regional wind generation output.

It should be noted that the other generation in the regions is mainly fast starting hydro and fast starting thermal generation (Whirinaki) and that security issues in the region tend to occur only when a significant amount of other regional generation is out for maintenance. Regional security issues can be mitigated, to some extent, by reducing the amount of other generation in the region that is out for maintenance at any one time.

The security assessment process will need to be reviewed and possibly re-designed to cope with larger amounts of wind generation output unpredictability. Wind generation forecast error will become the dominant source of error in the security processes within the next 2-3 years. Incorporating a generation starting capability check into the security

assessment process will help identify situations where there is insufficient regional generation offered or available that can be brought on line quickly enough to meet decreases in regional wind generation so that no regional load is required to be shed.

6. Standby Reserves Check

6.1 Introduction

The Standby Reserves process identifies whether there is sufficient energy and reserves offered by generators to allow reserves to be restored following the loss of a large generating unit. The Standby Reserves process will be directly affected by wind generation forecast error.

- The process may incorrectly show that there are sufficient energy and reserves offers based on a forecast of higher wind generation output than what actually occurs.
- The process may incorrectly indicate that there are insufficient energy and reserves offers based on a forecast of lower wind generation output than what actually occurs.

The Standby Residual Check:

- sums the energy and reserve offers for each trading period in turn
- removes the single largest source of generation input within the schedule for each trading period (the “risk”) to reflect a contingent event
- compares the remaining generation with the forecast electricity demand in the trading period.

When this calculation indicates insufficient energy and reserve offers, a Standby Reserve notice is issued to the market. Standby Reserve notices advise participants of the projected deficit, and the potential implications of the shortfall. A “Standby Residual Check” (SRC) is performed on the most recent Security Dispatch Schedule (SDS) results. The SDS is currently produced at least every six hours by the System Operator.

Predicted wind generation forecast errors expected to occur on a daily basis under Scenario C are shown in Table 6.

Wind generation forecast Error	6 hours out	2 hours out
North Island	550 MW	300 MW
South Island	275 MW	180 MW

Table 6 - Wind generation forecast errors - once per day (from Garrad Hassan [2])

The North Island 2 hour forecast error is comparable to the size of the largest thermal unit. The South Island 2 hour forecast error is comparable to the size of the largest unit in the South Island.

One of the recent notable events involving the Standby Reserves Check occurred on 19 June 2006. Insufficient generation was offered to meet energy and reserves requirements for several trading periods. The problem was

identified early on and warning notices were issued. Participants responded to the warning notices but insufficient generation was available to meet both energy and reserves. No instantaneous reserves were dispatched through several trading periods. The loss of a large generating unit at these times would have likely resulted in the operation of AUFLS. The effect of wind generation forecast error can be illustrated by considering what effect wind generation forecast error would have for events similar to those of 19 June 2006.

6.2 “What if?” – Wind generation Scenario C and 19 June 2006

The effect of wind generation forecast error on the scheduling processes can be illustrated by considering the effect wind generation forecast errors (under Scenario C) would have had on scheduling processes for the generation shortfall event of 19 June 2006. A report on events on 19 June 2006 has been published on the System Operator website [5]. The following commentary was extracted from that report.

The total electricity demand for all of New Zealand during the evening peak on 19 June 2006 was the highest ever experienced at that date. The New Zealand average supplied MW recorded over the half hour period from 17:30 to 17:59 (the 17:30 market trading period) on 19 June was 6,630MW, which exceeded the previous record, set in August 2004, by 117MW. The step increase in electricity demand experienced in the evening peak of June 19 was not the result of a uniform incremental trend in demand growth over preceding weeks.

In the 17:30 trading period on 19 June, there was a shortage of offers of generation to meet the demand for electricity. By 17:34 insufficient generation offers were available to meet power system requirements – that is, to supply load, provide reserve energy and cover system frequency keeping.

By 17:34, although every generator that had offered to generate had been dispatched, there was insufficient offers to enable instantaneous reserves to be dispatched and accordingly the system operator declared a Grid Emergency at 17:34, for the period 17:34 to 20:00. A Grid Emergency is a situation (defined in the EGRs) where the System Operator can take a range of actions (under Part C of the rules) to maintain the stability of the power system. The term has a ‘technical’ meaning within the electricity industry.

Figure 1 from the report shows the generation stack for the 17:30 trading period on 19 June 2006.

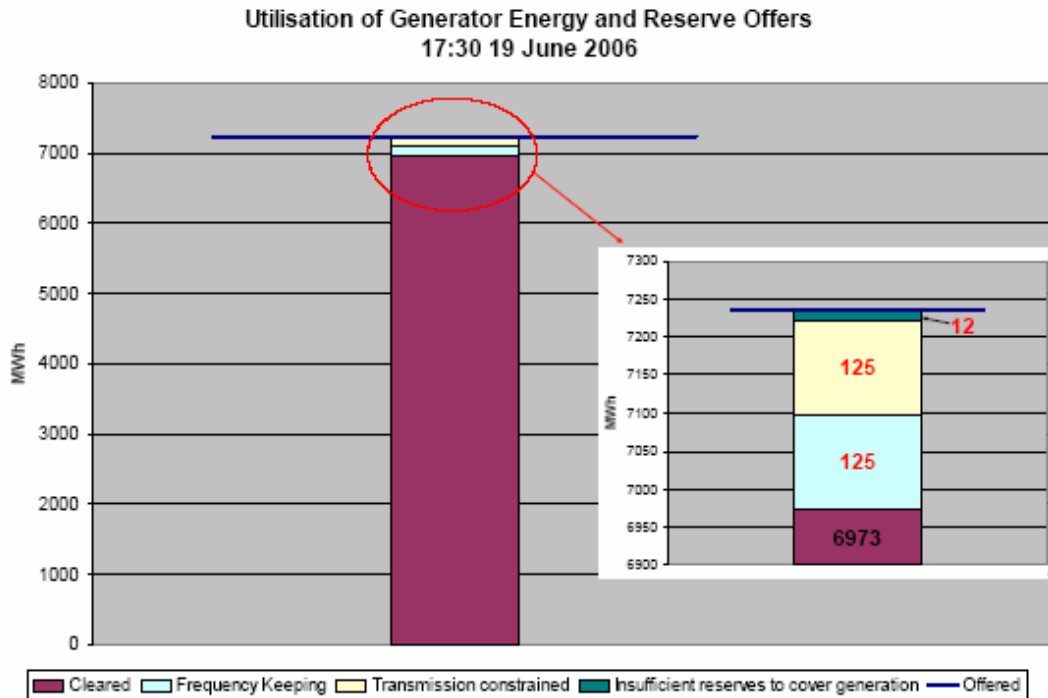


Figure 1 Final Pricing – Utilisation of generator energy and reserve offers

Figure 62: Generation and reserve offers on 19 June 2006 (Figure 1 of [5])

For the evening peak of 19 June, three Standby Reserve notices were issued to the market at 13:36 on 18 June, and 03:05 and 14:47 on 19 June.

The shortfalls forecast for the 17:30 trading period were approximately 70 MWh, 90 MWh, and 110 MWh respectively (for the three Notices). It should be noted that the first Standby Reserve notice was issued approximately 28 hours in advance of the 17:30 trading period on 19 June. The second notice (with an increased shortfall) was issued approximately 14½ hours prior to the beginning of the 17:30 trading period.

On 19 June there was a shortage of energy and reserves. On 29 June the greatest ever New Zealand power system demand of 6,748 MW was supplied without incident. The following chart details the generator energy and reserve offers from the final pricing solution for the 17:30 trading period on 29 June.

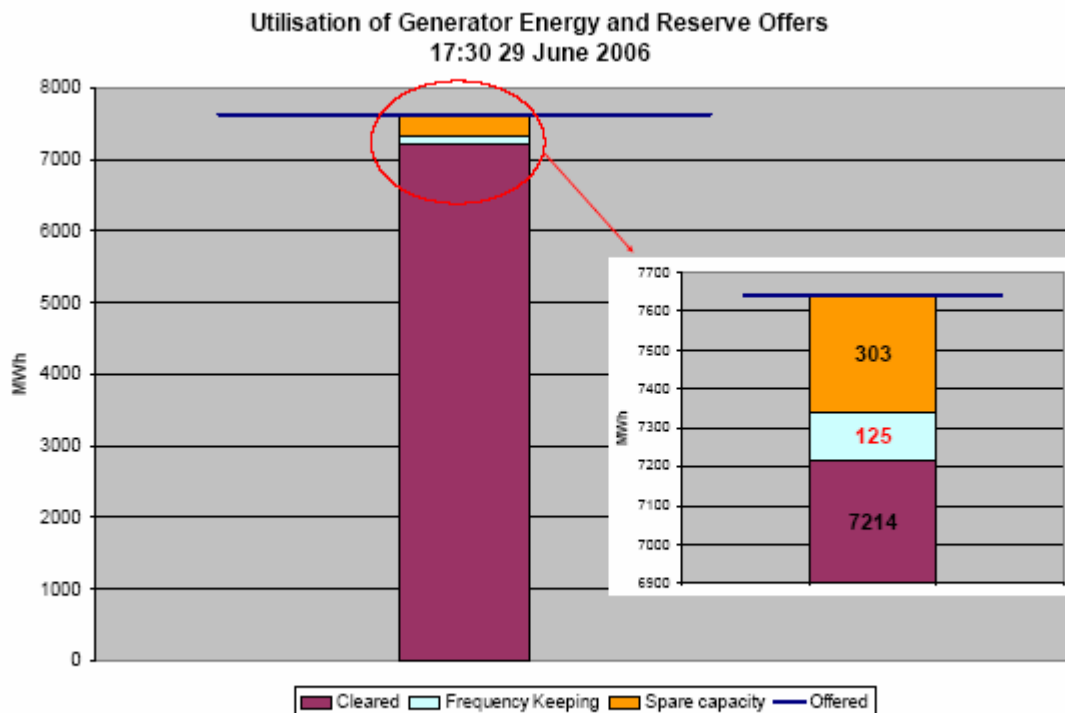


Figure 5 – Final Pricing – Utilisation of generator energy and reserve offers

Figure 63: Generation and reserve offers on 19 June 2006 (Figure 5 of [5])

Effect of wind generation forecast error

There was a 12 MW shortfall of generation for the 17:30 trading period on 19 June 2006. On 29 June there was an excess of 303 MW, while meeting the largest system peak demand experienced to date.

Analysis showed that once daily wind generation forecast errors greater than 550 MW can be expected at 6 hours out, for the North Island, under wind generation Scenario C. Once daily wind generation forecast errors greater than 280 MW can be expected at 6 hours out, for the South Island, under wind generation Scenario C. The predicted once a day wind generation forecast errors for New Zealand as a whole at 6 hours out are -680 MW and +420 MW (see Appendix 2).

If wind generation equivalent to that envisaged in wind generation Scenario C had been connected to the power system on 19 June and 29 June then the outcome of the scheduling processes on those days could have been significantly different.

If wind generation forecast for the 17:30 trading period on 19 June was 420 MW greater than actual then no shortage of generation would have indicated in the Standby Reserves Check and no Standard Reserves Notice

would have been issued. It is still likely that a Grid Emergency would have resulted.

If wind generation forecast for the 17:30 trading period on 29 June was 680 MW lower than actual then a shortage of generation would have been indicated in the Standby Reserves Check and a Standby Reserves Notice would have been issued.

6.3 Discussion

The Standby Reserves Check considers whether sufficient generation is offered to be able to restore instantaneous reserves within 30 minutes following the loss of the largest generating unit on the power system. The results of the check can be applied to consideration of whether sufficient fast starting generation is available to meet a certain size of wind event (i.e. decline in wind generation output over a certain time period).

If sufficient generation has been offered to restore reserves within 30 minutes (i.e. enough to cover the loss of the second largest generating unit) after the loss of the largest unit then there is enough generation offered to cover a wind event of a similar size (e.g. a decline in North Island wind generation output of 250-380 MW²¹ over 30 minutes).

The incorporation of a check to determine whether sufficient generation has been offered to meet a defined wind event (possibly occurring over a longer period than 30 minutes) into the Standby Reserves Check is reasonably straight forward.

The Standby Reserves Check and the wind event check are similar in nature. Both seek to confirm whether sufficient generation has been offered so that the power system can be maintained in or quickly restored to a secure state following the occurrence of particular events. Both assess whether there is sufficient generation offered which can increase output over a period of 5 to 30 minutes.

Frequency management on the New Zealand power system comprises a number of ancillary services or re-dispatch:

- Instantaneous reserves and over frequency reserves to manage instantaneous under or over frequency excursions caused by the loss of generating plant, load or HVDC link;
- Frequency keeping services to manage frequency until generation can be re-dispatched (i.e. over the 0 to 5 minute time frame);
- Generation re-dispatch based on offered generation.

²¹ The largest generating units in the North Island have a full output of around 380-400 MW (note that maximum output is dependent on ambient temperature for these thermal units).

A possible addition to the frequency management ancillary services would be a service which operates in the 5 to 30 minute range (or possibly longer). This would be generation or load which could be quickly brought on or disconnected respectively in the 5 to 30 minute time period. A certain amount of this reserve could be procured to be available for a trading period. The reserve could then be called upon following the occurrence of particular events.

7. Economic Dispatch –simple example

7.1 Introduction

The long term effects of large wind generation variability and forecast errors on market outcomes in the New Zealand electricity market is of interest to many parties but is quite difficult to determine. Analysis based on historic bids and offers by market participants will be speculative at best as other participants are likely to change their bid and offer strategies in the presence of large amounts of wind generation.

The effects of wind generation variability and forecast error on nodal prices and dispatch quantities can be illustrated relatively easily for a given trading period. A simplified analysis has been chosen to illustrate the effects of wind generation on nodal pricing. The analysis is based on the three node model presented in section 3.6. The analysis calculates scheduled and actual nodal prices and quantities in the presence of wind generation output and forecast error.

7.2 Analysis

The effect of wind generation forecast errors (based on a persistence forecast six hours ahead of dispatch) on nodal prices and dispatch quantities was calculated for varying amounts of installed wind generation capacity. Representative outputs (scaled from Te Apiti output) are used to reflect the variation of wind generation output for each trading period.

Analysis was carried out for different portions of total demand supplied by wind generation. Section 7.2.1 describes the case where wind generation supplied 11% of the total demand. Appendix 3 contains the results for cases where wind generation supplies 21%, 37% and 50% of the demand.

7.2.1 Wind generation supplies 11% of total demand

Figure 64 shows the situation where wind generation output in the three regions meets around 11% of the system demand. The installed wind generation capacities for regions A, B and C are 125 MW, 50 MW and 75 MW respectively.

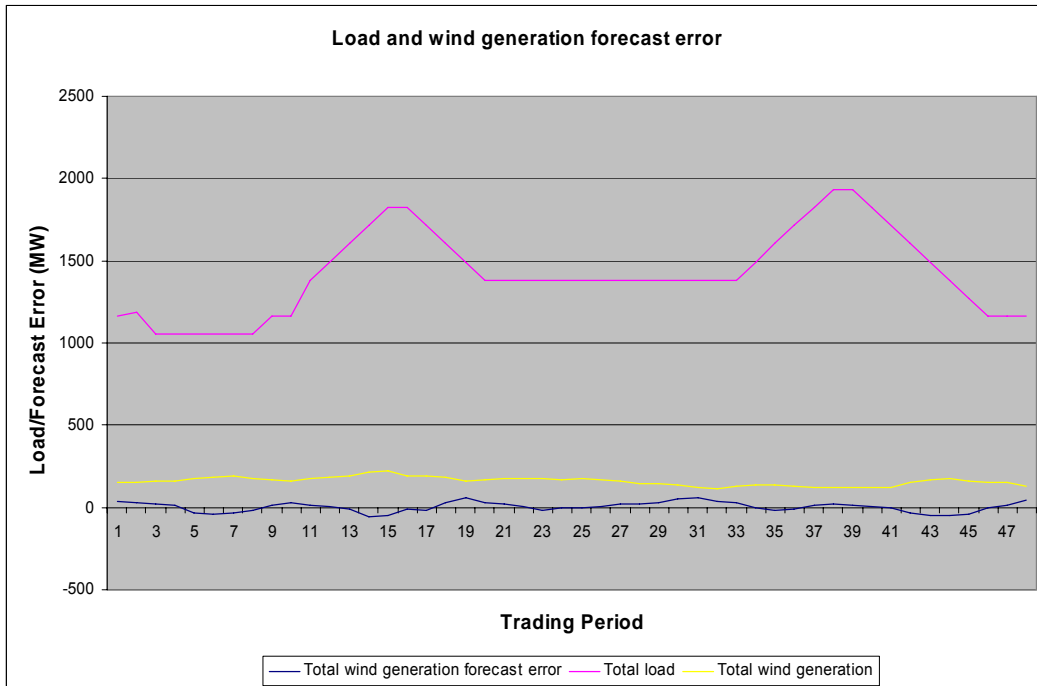


Figure 64: System load, wind generation forecast error and wind generation output

Wind generation forecasts were generated using a persistence forecast six hours ahead of dispatch. Figure 65 shows wind generation output and forecast output for each of the three regions. Figure 66 shows the wind generation forecast error for each region.

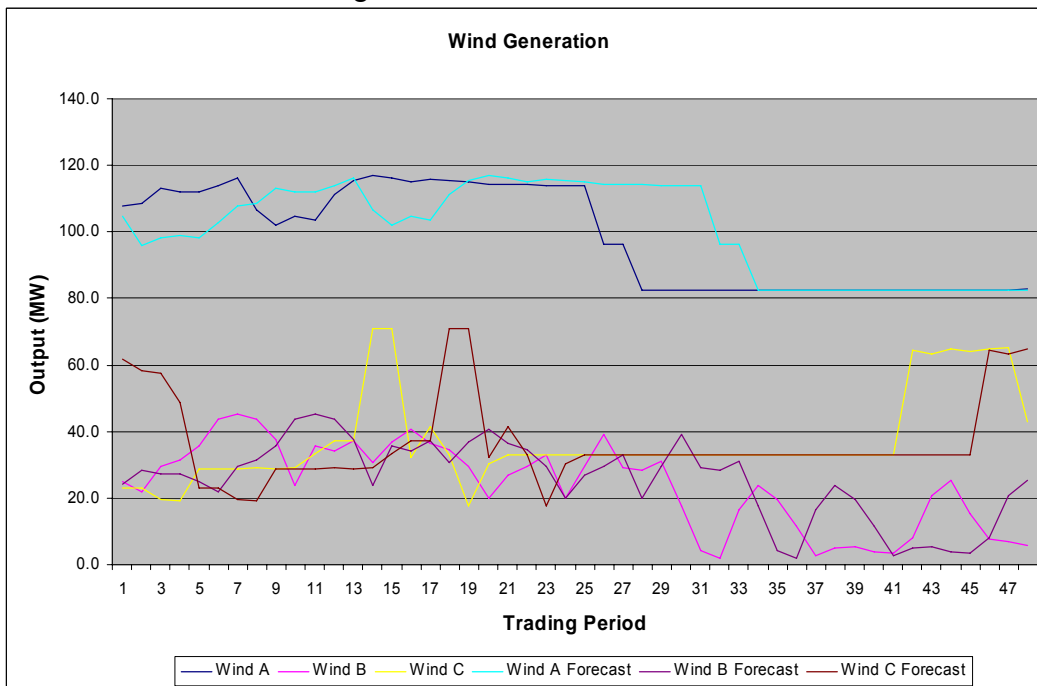


Figure 65: Regional wind generation and forecasts

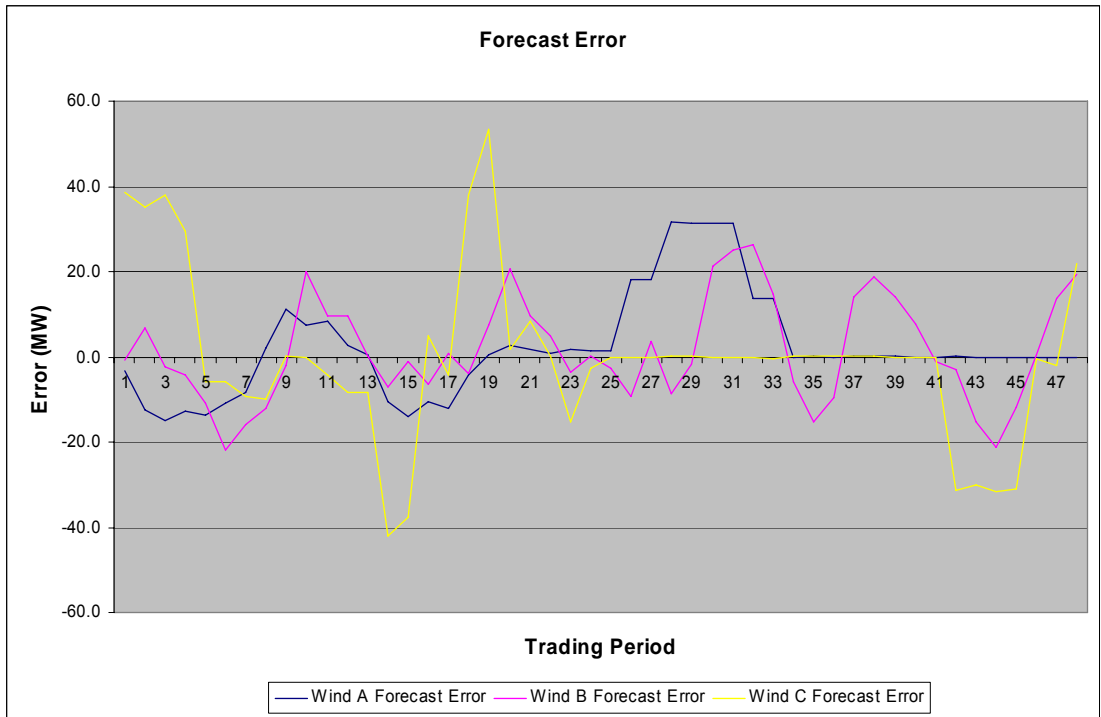


Figure 66: Regional wind generation forecast errors

Nodal prices and dispatch quantities were calculated for each region for actual and forecast wind generation output. The nodal prices at node A, B and C are shown in Figure 67, Figure 68 and Figure 69 respectively. Typically, more expensive generation is bought on to meet morning and evening peak demand (these occur around trading periods 12 to 16 and 36 to 40 respectively). The forecast and actual nodal prices are quite similar at each of the three nodes.

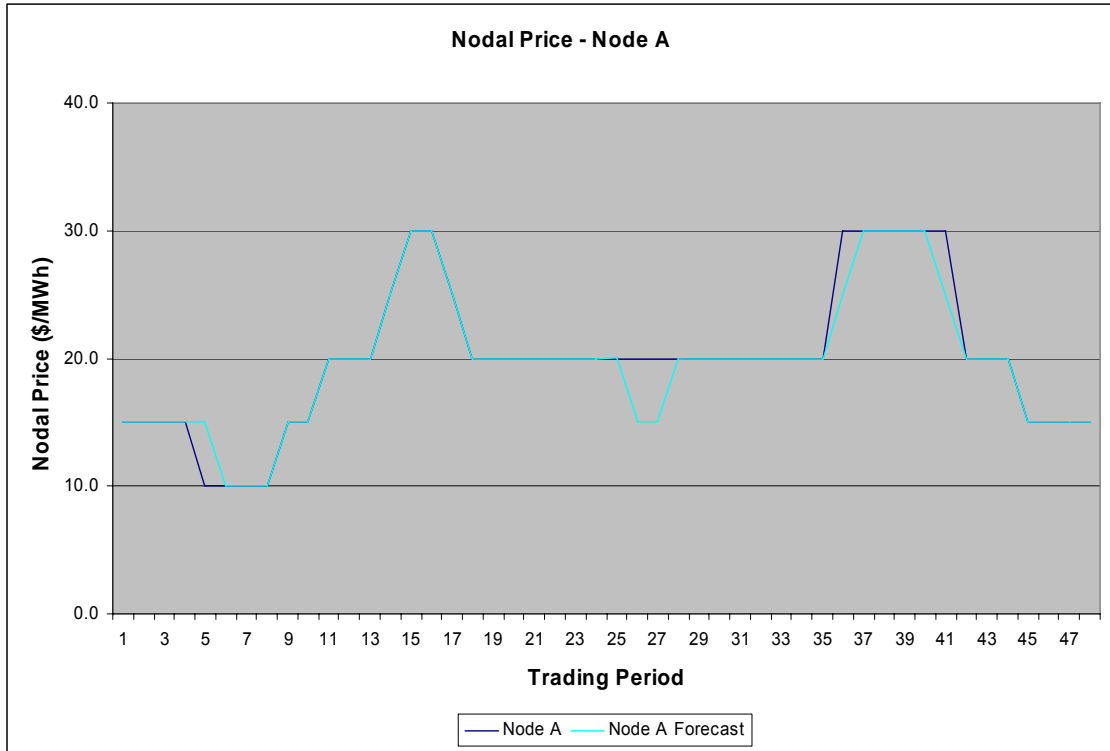


Figure 67: Actual and forecast nodal price for Node A

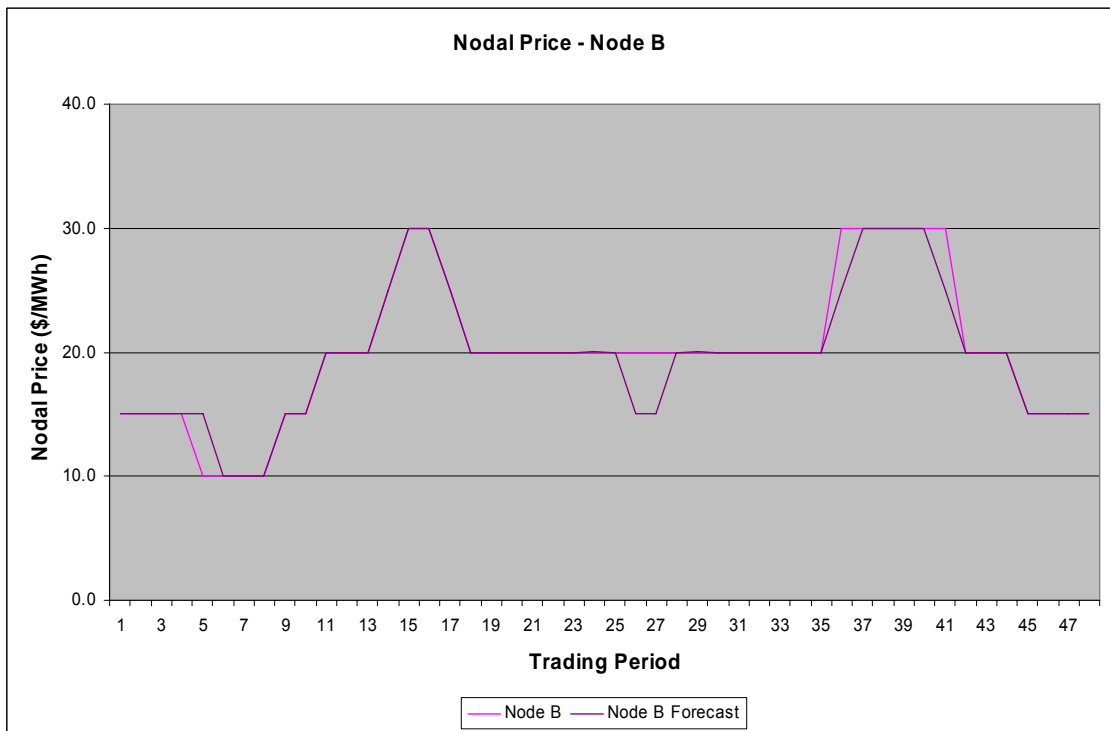


Figure 68: Actual and forecast nodal price for Node B

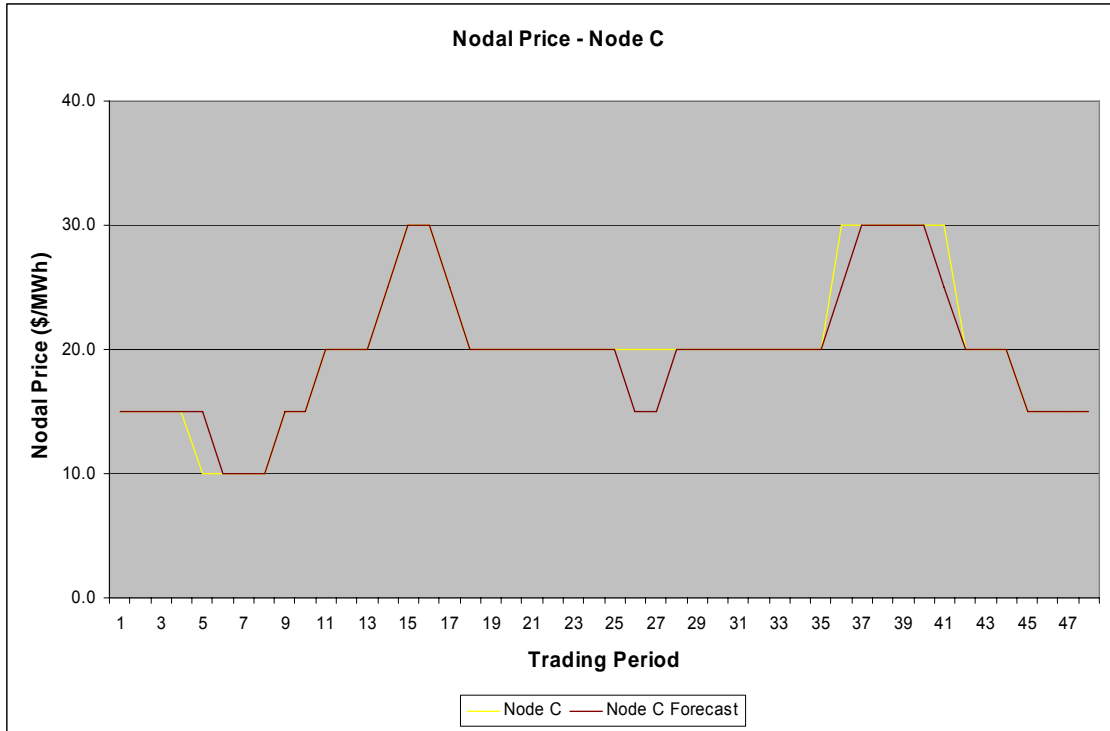


Figure 69: Actual and forecast nodal price for Node C

Actual and forecast dispatch quantities for generating units A1, A2 and A3 are shown in Figure 70, Figure 71 and Figure 72 respectively. Unit A1 is nearly base loaded with units A2 and A3 being required to meet morning and evening peak demand.

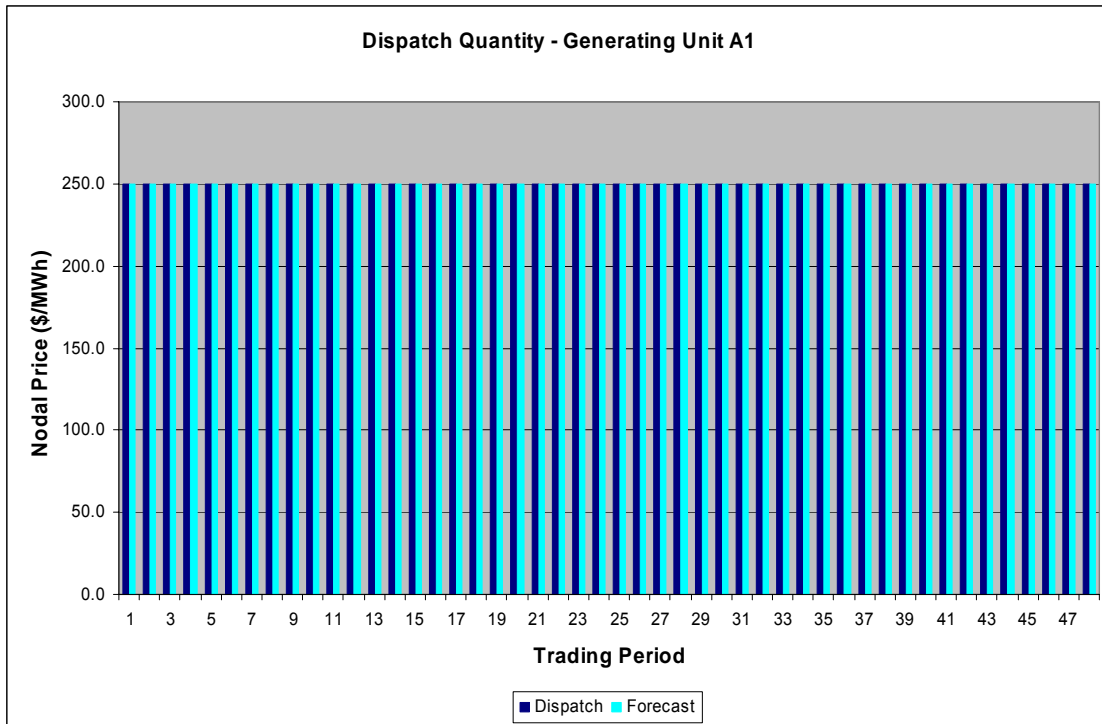


Figure 70: Actual and forecast dispatch quantities for generating unit A1

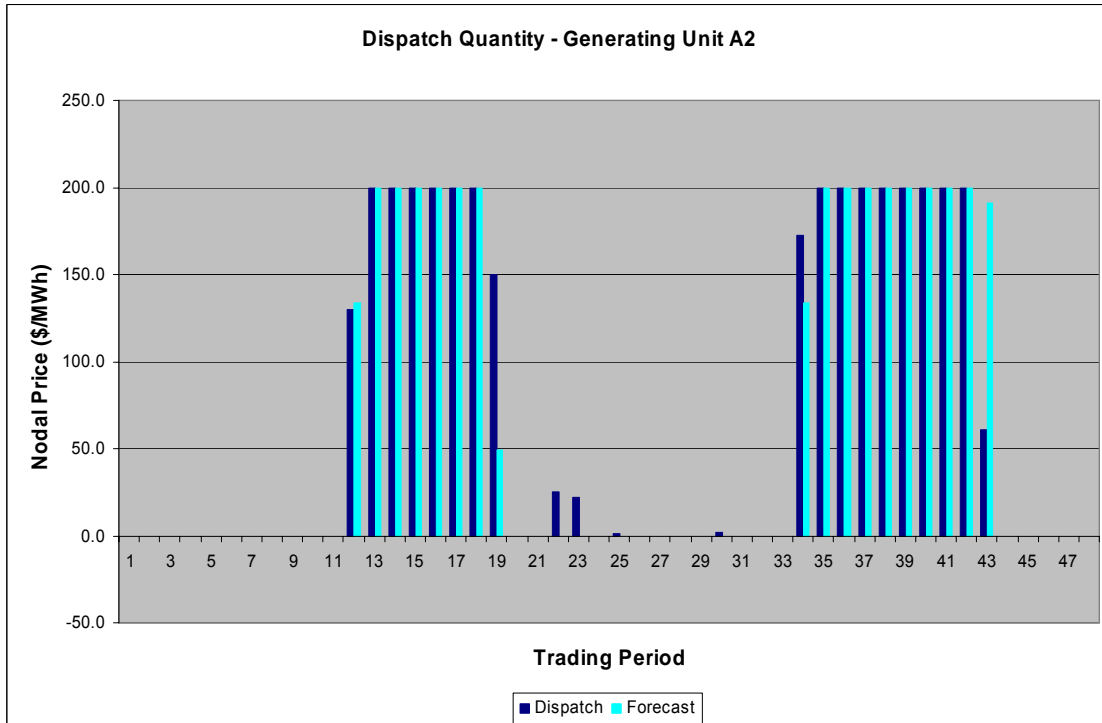


Figure 71: Actual and forecast dispatch quantities for generating unit A2

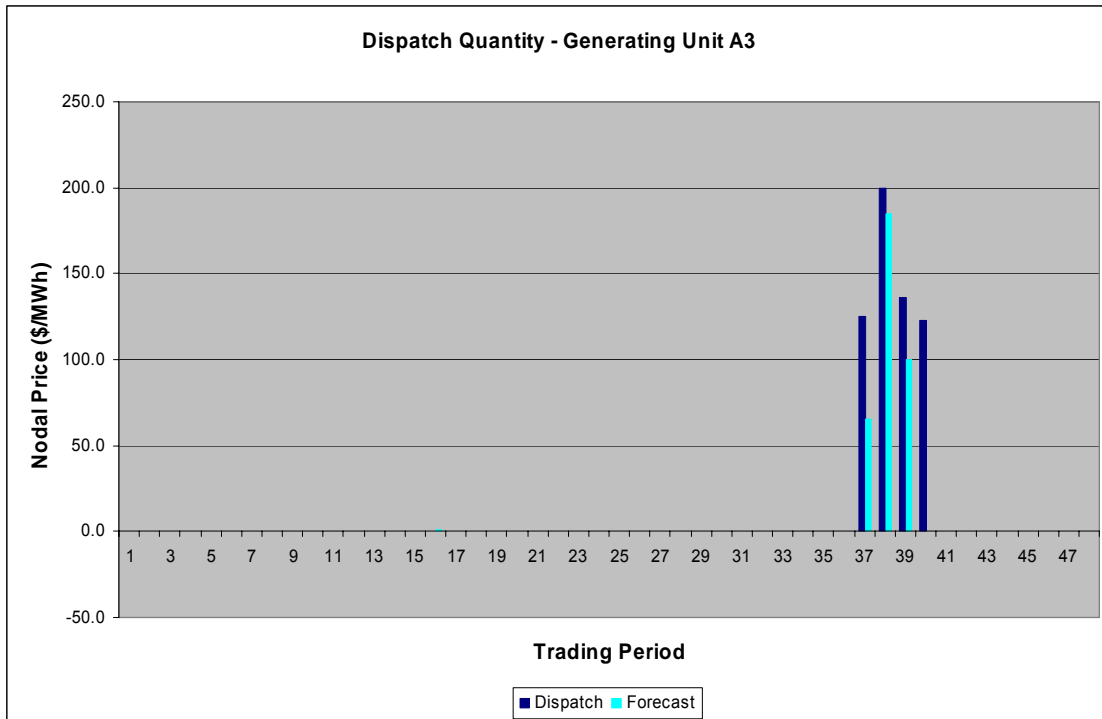


Figure 72: Actual and forecast dispatch quantities for generating unit A3

7.2.2 Different levels of wind generation supply of total load

Figure 73 and Figure 74 shows nodal price at node A and the difference between scheduled and dispatched quantities for unit A2 at Node A for different portions of total demand supplied by wind generation.

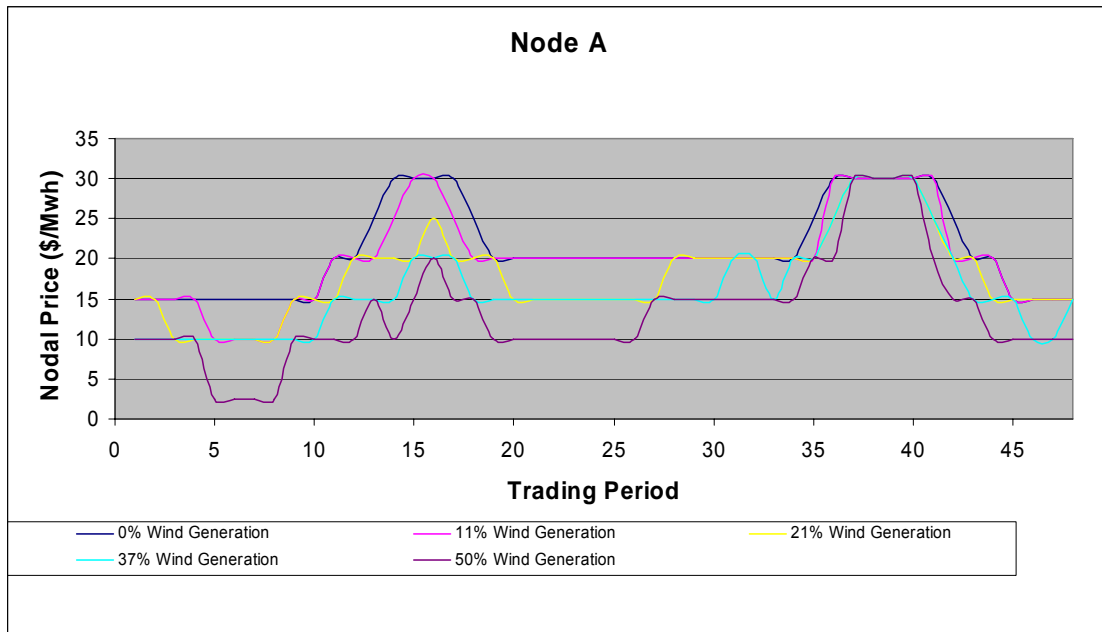


Figure 73: Nodal price at Node A for different amounts of total load supplied by wind generation output

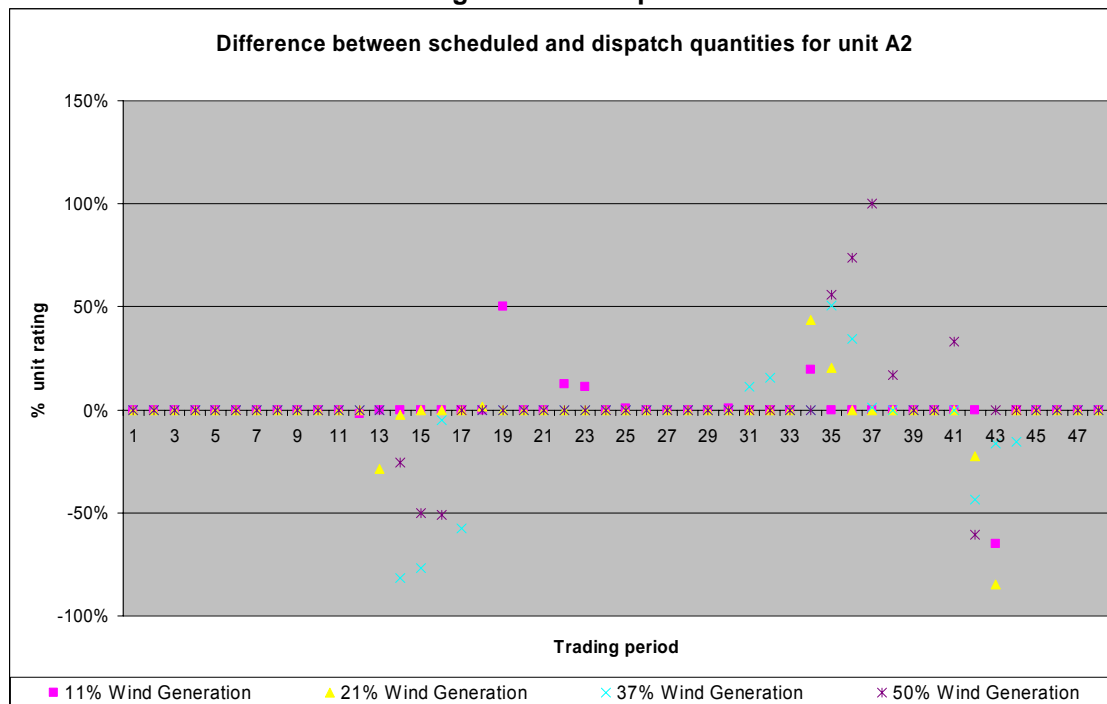


Figure 74: Difference between scheduled and dispatched quantities for unit A2 at Node A for different amounts of total load supplied by wind generation output

The daily nodal price profiles are quite similar in shape (e.g. showing higher prices at times of morning and evening peak) even for relatively large levels of wind generation in the generation mix. The difference between scheduled and dispatched quantities for unit A2 changes with increasing amounts of wind

generation in the generation mix. The size of the changes is not proportional to the amount of wind generation in the generation mix.

7.3 Discussion

The simplified analysis indicates the following points:

- The accuracy of forecast nodal prices and dispatch quantities is reduced with increasing amounts of wind generation but the effects seen in the three node model in this example are not great.
- There is an increasing difference between scheduled and dispatch quantities for increasing amounts of installed wind generation capacity. Quantity rather than timing differences are more marked (i.e. the difference between the forecast and actual amount generated by the marginal units in a trading period is different rather than whether a generating units is scheduled or dispatched in a particular trading period).

The simplified model did not consider cases where there are large discontinuities in the supply curve. It is possible that one generating unit is offered at \$200/MWh and the next generating unit is offered at \$500/MWh. When the first generating unit is partially dispatched (being the marginal generator) the nodal prices will be around \$200/MWh. When system demand increases enough that the next generating unit is dispatched, the nodal prices increase to around \$500/MWh. The variability of wind generation on the system may cause either unit to become the marginal generating unit (effectively setting the nodal prices) and large price variability could be expected at dispatch and between forecast price and quantity schedules.

The simplified model is not sophisticated enough to exhibit some behaviours experienced in the New Zealand electricity market (e.g. spring-washer effects) and observed in nodal prices. Market outcomes during maintenance outages are not considered in the simplified model. The effect of wind generation on temporary high nodal prices arising during maintenance outages has not been considered.

The dispatch objective²² for the New Zealand electricity market will continue to be achieved for increasing amounts of wind generation output. The dispatch objective is based on generator offers in effect at the time of dispatch. Economic dispatch will be achieved.

Market outcomes, however, will be affected by increasing amounts of wind generation. The reduced accuracy of forecast dispatch quantities is likely to

²² Maximise for each half hour the gross economic benefits to all purchasers of electricity at the grid exit points less the cost of supplying the electricity at the grid injection points and the costs of ancillary services purchased by the System Operator. See section III.2 of Part G of the Electricity Governance Rules.

cause changes to generator offer strategies. The displacement of other generation by lower cost wind generation will affect electricity prices.

8. Managing an unpredicted sudden decrease in wind generation output

A sustained and unforeseen decrease in total wind generation output over a relatively short period can be met by bringing other generation on line provided that there is sufficient other generation that can be connected and increase output quickly.

To give confidence that such events can be managed through the dispatch processes, the security assessment in the pre-dispatch processes can incorporate an assessment of whether there is sufficient generation offered which can be dispatched to meet a decline in wind generation output. The capability of offered plant to connect or increase output can be compared to a defined drop off in wind generation output. Should insufficient plant be offered to meet the defined wind event then participants can be advised of the potential shortfall so that they can take appropriate action.

The defined wind event could be, for example, a decrease of 1000 MW of wind generation output over a four hour period. The check of offer sufficiency could be whether the offered generation (over the four hour period) was sufficient so that an additional 250 MW of generating plant could be brought on each hour to meet the decline in wind generation output.

Alternatively, the defined event could be related to a more sudden drop off in regional wind generation output. The Manawatu wind farms have been observed to reduce from nearly full output to zero over a 30 minute period. If there is 450 MW of installed wind generation in the Manawatu region then the defined wind event may be a reduction of 450 MW of Manawatu wind generation over a 30 minute period.

The following sections discuss the components of the wind event security assessment:

- generation starting capability
- wind event definition.

8.1 Generation starting capability

8.1.1 Concept

The previous section describes how a check of the sufficiency of generation offered or available to meet a decrease in wind generation output can be made. In effect, the starting times and ramp rate of generation offered but not yet dispatched or available are used to determine a generation starting capability envelope and this envelope can be compared against potential trajectories for decreases in wind generation output.

This check can be incorporated in security assessments and standby reserves checks which currently assume wind generation output to be zero. A check can also be carried out during dispatch if required. The check could incorporate two parts:

- A check over the next two hours from the trading period in question based on offered generation.
- A check over the period from the next two to 12 hours from the trading period in question based on available generation.

To illustrate the approach, a generation starting capability calculation was carried out for a number of different system loadings based on actual generation offers and ramp rates in the North Island for a particular trading period. Figure 75 and Figure 76 show the generation starting capability compared to a defined wind event (note that the wind generation decline is shown inverted to enable comparison with the generation starting capability curves). It is assumed that re-dispatch of generation commences five minutes after the wind event begins. For low system loads there is sufficient partially loaded fast ramping hydro plant offered to meet the decline in wind generation output. At higher system loads there is insufficient generation offered to meet the decrease in wind generation output.

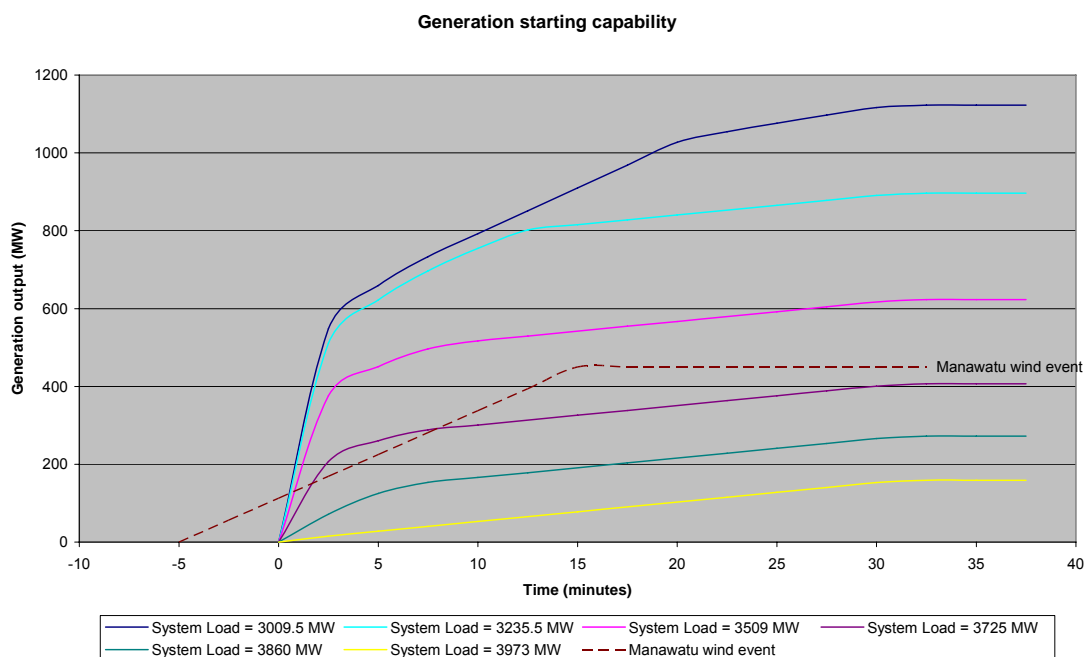


Figure 75: Generation starting capability for North Island

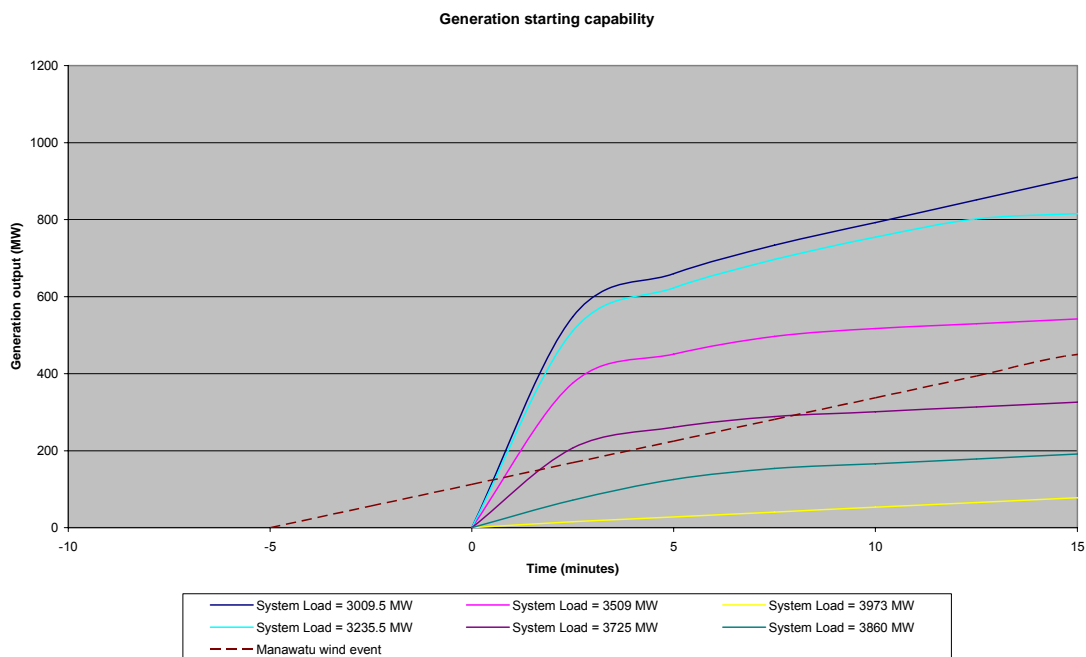


Figure 76: Generation starting capability for North Island (expanded)

8.1.2 Generation ramp rate

There are five time-frames for other generation that can increase output or be bought to meet a decrease in wind generation output:

- Frequency keeping service providing generating units. These units will instantaneously increase output (at 10 MW per minute) to meet a decrease in wind generation output.
- Partially loaded generating units. These units can be dispatched for higher output immediately. New dispatch instructions can be sent within five minutes and the plant will ramp to the new output level at its offered ramp rate.
- Fast starting hydro or gas turbines units. Fast starting hydro or gas turbine units can be brought on and up to full output in time frames of 10 and 30 minutes respectively.
- Warm thermal plant. Thermal plant which has been operational recently and is still in a warm state can be brought into service in around 4 hours.
- Cold thermal plant. Thermal plant which has not been operational recently can be brought into service within 9-12 hours.

Table 7 shows the capabilities of generation which is able to connect and increase output within the different time frames.

Time frame to start	Type	Offered ramp rates (indicative)
Instantaneous	Frequency keeping	10 MW/minute
5-10 minutes	Partially loaded units	1-70 MW/minute
10/30 minutes	Fast starting hydro or gas turbines	10-70 MW/minute
4 Hours	Warm thermal plant	3-10 MW/Minute
9-12 hours	Cold thermal plant	3-10 MW/Minute

Table 7: Generation capabilities

Figure 77 shows the maximum rate of increase in generation output as a function of time for the available generation shown in Table 8. Around 650 MW is available within 30 minutes, an additional 500 MW in around 4 hours and a further 500 MW in 12 hours.

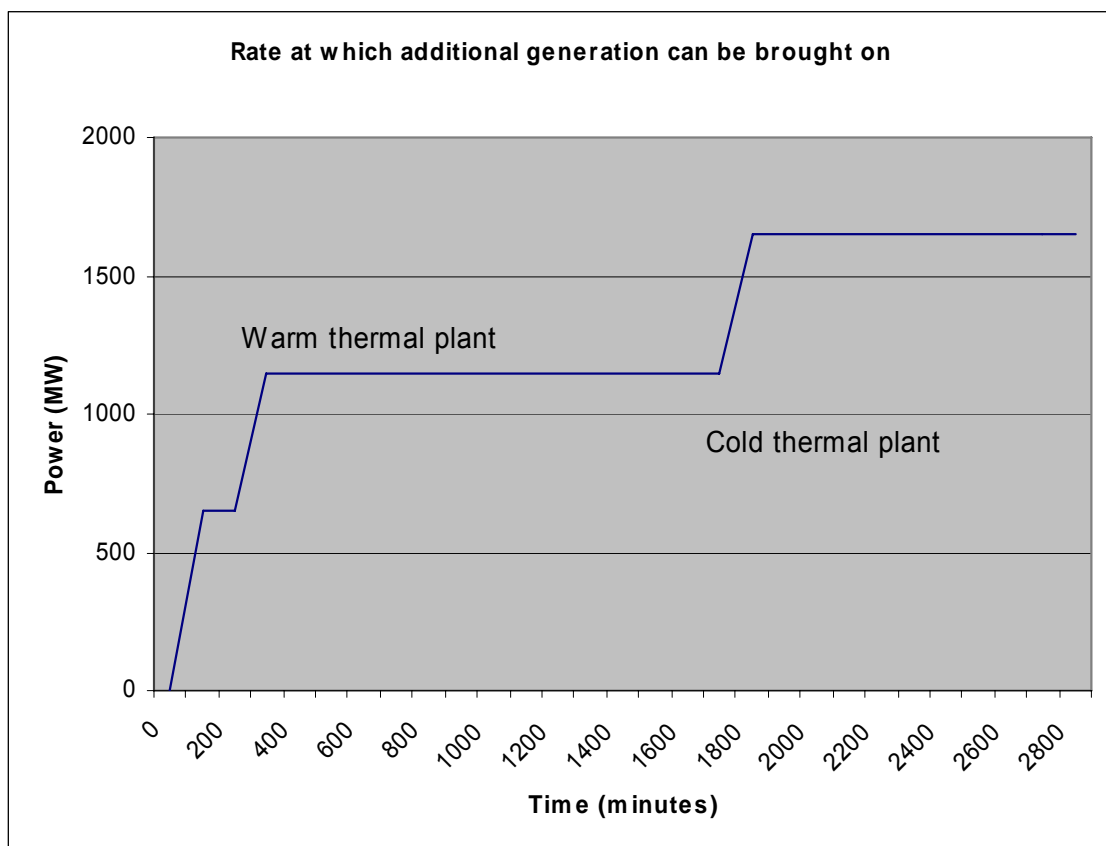


Figure 77: Maximum rate at which generation can be brought on for example in Table 7

Type	Assumed amount for example	Assumed ramp rates
Frequency keeping	50 MW	10 MW/minute (minimum)
Partially loaded units ²³	300 MW	10 MW/minute
Fast starting hydro or gas turbines	300 MW	30 MW/minute
Warm thermal plant	500 MW	40 MW/Minute
Cold thermal plant	500 MW	500 MW/Minute

Table 8: Available generation (example)

Figure 78 shows the maximum rate at which generation can be increased over 30 minutes.

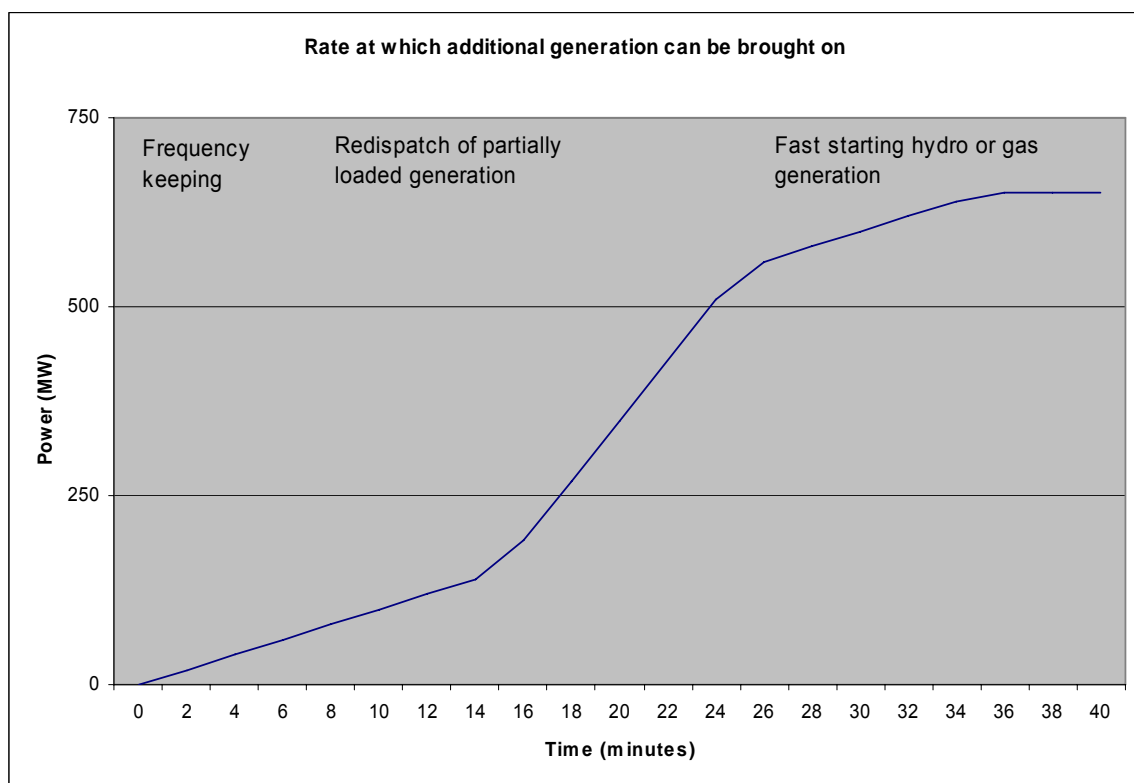


Figure 78: Maximum rate at which generation can be brought on for example in Table 2 (first 30 minutes)

The maximum rate at which other generation can be brought on provides a threshold against which potential decreases in wind generation output can be compared to determine whether the decrease can be met without needing to shed load.

²³ This does not include plant providing the partially load spinning reserves service.

Most generators are not allowed to change offers after gate closure (two hours ahead of dispatch) unless the System Operator declares a Grid Emergency. In this case, generators can change offers up until gate closure. For the purposes of determining the maximum rate that other generation can be brought on to meet a decrease in wind generation output, there are two approaches:

- The generation that can be brought on is limited to the generation offered.
- The generation that can be brought on is the available (but not necessarily offered at this time) generation.

The use of offered generation only is more conservative and has been used in the next section.

8.2 Wind event definition

8.2.1 Concept

The generation starting capability envelope for a particular set of trading periods can be compared against different wind generation decrease events for different forecast periods. This will give confidence that a particular size of wind generation decrease can be managed through re-dispatch of generation.

There is a strong analogy with instantaneous reserves. Instantaneous reserves are procured to cover the unplanned loss of a generating unit or transmission circuit. The amount of instantaneous reserves is calculated so that frequency quality targets will be met for the occurrence of a defined event (see Investigation 5 of the WGIP for further details). Contingent events are defined taking into consideration the probability of occurrence of the event, the impact of the event, and the cost of mitigation of the effects of the event.

Wind events can be defined in a similar manner. The probability of an event of a particular size can not be calculated with accuracy at this time as there is insufficient historic wind generation data available to do so. More accurate calculations will be possible as experience of wind generation on the New Zealand power system is obtained.

The impact of an event of a particular size can be estimated with some accuracy. For example, the decline in wind generation output may result in some load being required to be shed as sufficient other generation can not be brought on line fast enough. The cost of or need for load shedding can be used to quantify the impact.

8.2.2 Defining a wind event – a probabilistic method

For a given level of wind generation output at time zero, there are a range of possibilities as to how much wind generation output might change over the next few hours. For example, if the installed capacity of wind generation on the system is 2000 MW and the current level of wind generation output is

1600 MW then the wind generation output in four hours could be anywhere between 0 MW and 2000 MW. It is possible to calculate the probabilities for wind generation output being above (or below) a particular level in four hours.

Figure 79 shows a number of possible changes in wind generation output over time from an initial output of 1600 MW. These changes were calculated using a probability distribution function to calculate changes in output at each time step and are intended to be illustrative rather than representative of a particular wind farm or wind farms. Each line represents a different possible change in wind generation output from the initial amount. The installed wind generation capacity is 2000 MW.

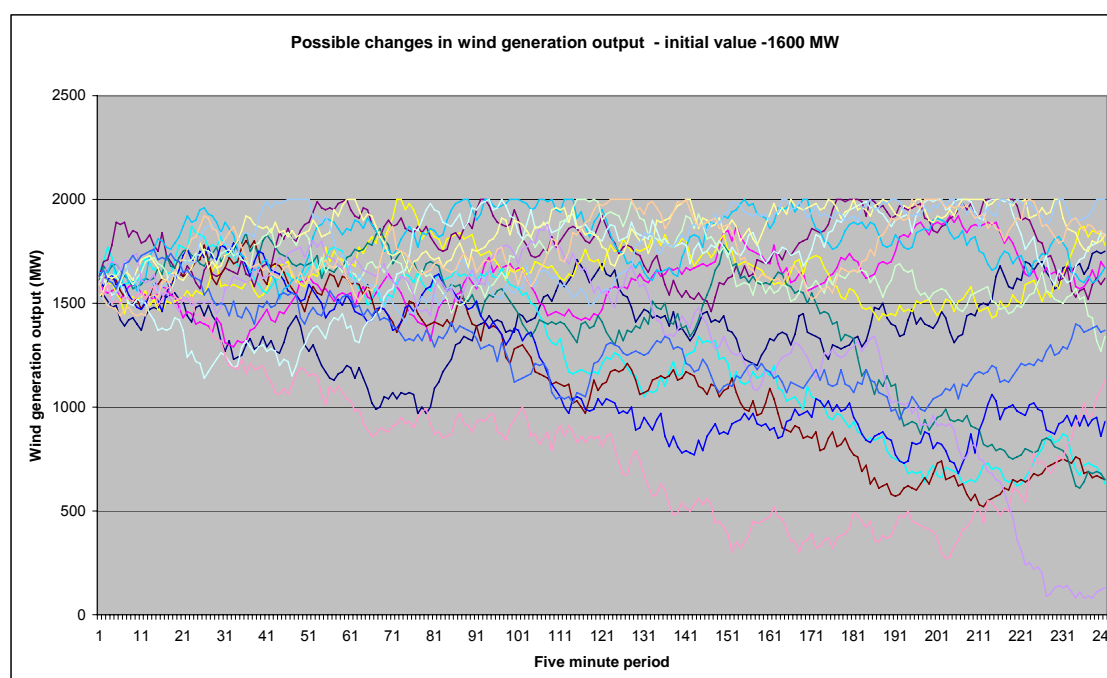


Figure 79: Initial wind generation output of 1600 MW

Given sufficient historic data, it will be possible to estimate the probability, for a given initial wind generation output and a given installed wind generation capacity, that a decrease in wind generation output from the initial amount will be less than a certain amount. For example, the line in Figure 79 which shows the lowest value after 240 five minute periods (20 hours) is around 150 MW. This reflects a decrease from the initial value of 1450 MW. The worst case decrease in wind generation output (as shown in Figure 79) can be met with out the need to shed load provided that 1450 MW of other generation can be brought on within 20 hours.

Figure 80 shows a generation starting capability envelope against three possible wind generation decrease trajectories. The generation starting

capability envelope is based on Figure 77. The three wind generation decrease trajectories are based on analysis of a large number of change trajectories. The worst case trajectory (minimum) and the first and fifth percentiles are shown. For example, the first percentile trajectory shows the value of wind generation output at a future period which it is 99% percent likely that wind generation output will exceed this amount. There is no particular reason for choosing the first or fifth percentiles – they merely indicate a trajectory where wind generation decline would be worse than only 1% or 5% of the time respectively.

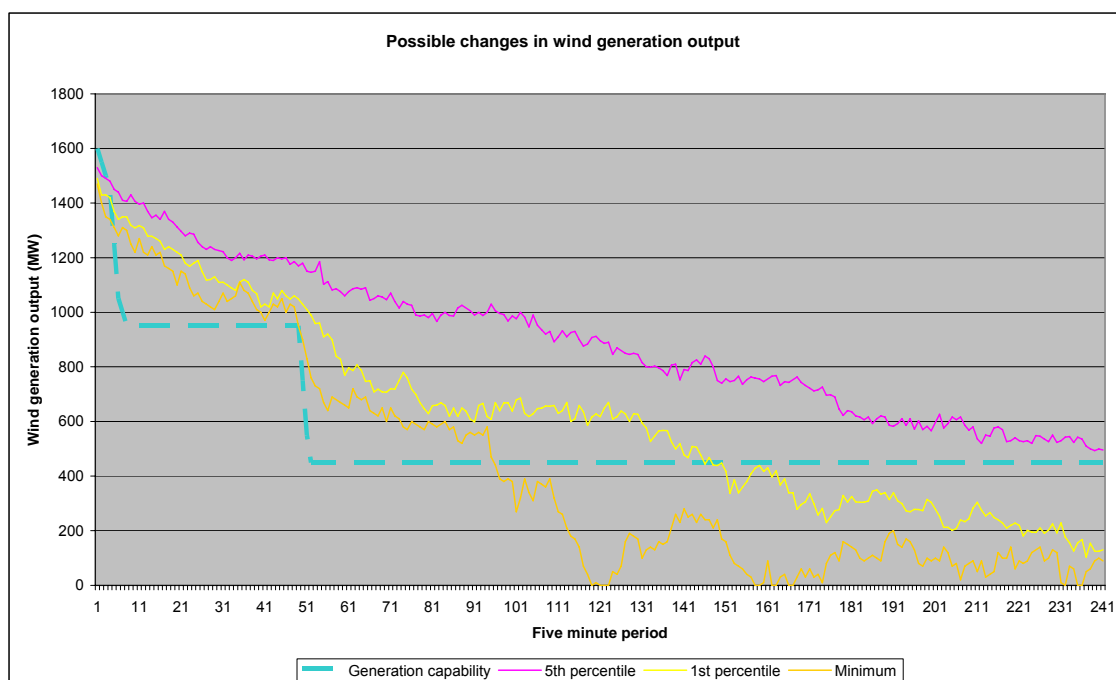


Figure 80: Generation starting capability versus cumulative probability for wind generation output decrease for an initial wind generation output of 1600 MW

Form Figure 80, it can be seen that there is sufficient generation starting capability to meet the fifth percentile but that there is insufficient generation starting capability to meet the worst case and the first percentile wind generation decrease trajectory.

Figure 81 shows a similar case to Figure 79 but where the initial wind generation output is 800 MW. Figure 82 shows the same generation starting capability curve as used in Figure 80 against the minimum (worst case), first percentile and fifth percentile wind generation decrease trajectories for the case where the initial wind generation output is 800 MW.

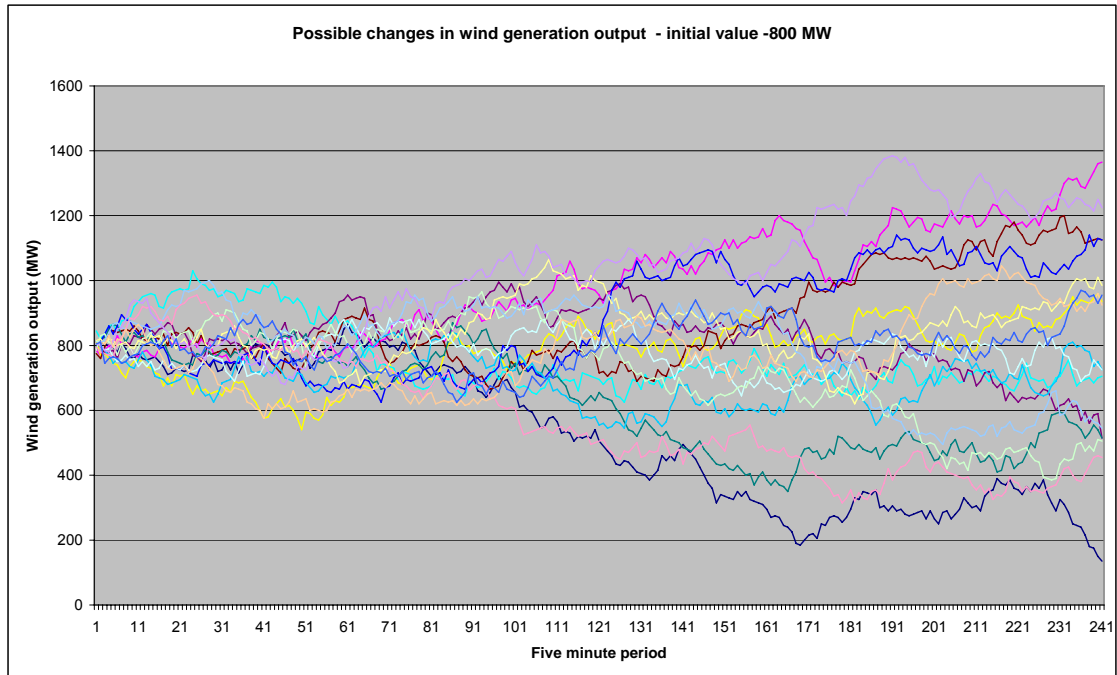


Figure 81: Initial wind generation output of 800 MW



Figure 82: Generation starting capability versus cumulative probability for wind generation output decrease for an initial wind generation output of 800 MW

In Figure 82, the wind generation output can decrease by a maximum amount of 800 MW. The generation starting capability exceeds 800 MW once the warm thermal plant has been brought on. The only part where wind generation output decrease might exceed generation starting capability is in the first four

hours. Figure 83 shows the first five hours of Figure 82. There is little risk of wind generation output decrease exceeding generation starting capability save in the first fifteen minutes or so.

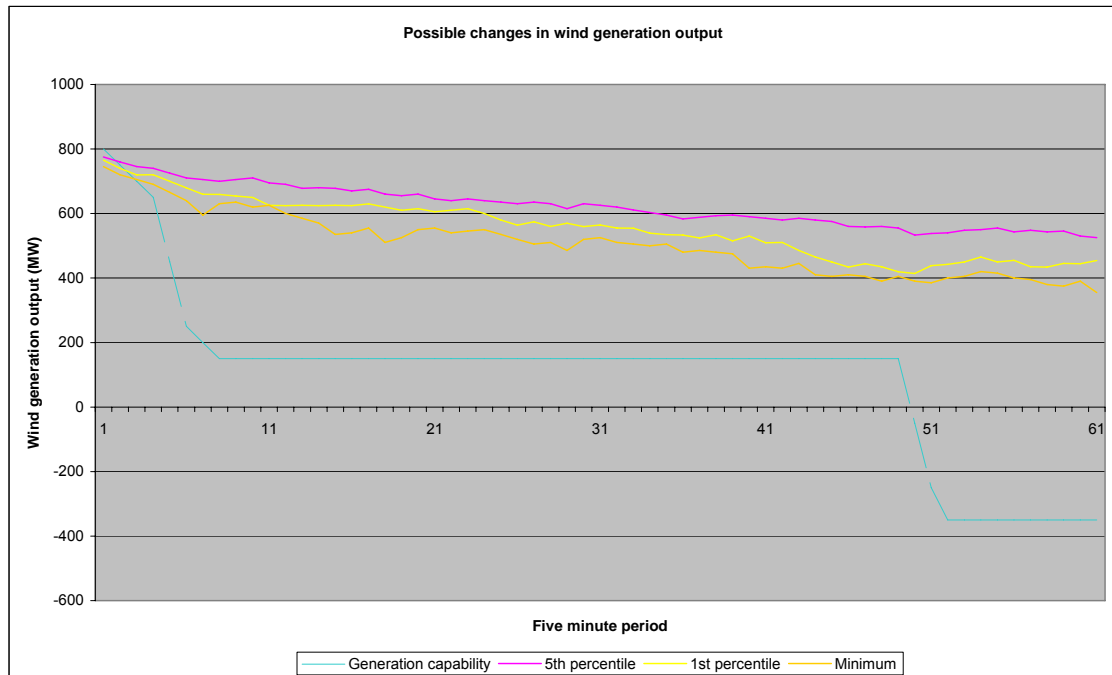


Figure 83: Generation starting capability versus cumulative probability for wind generation output decrease for initial wind generation output of 800 MW (first five hours)

Figure 84 shows a similar case to Figure 79 but where the initial wind generation output is 400 MW. Figure 85 shows the same generation starting capability curve as used in Figure 80 against the minimum (worst case), first percentile and fifth percentile wind generation decrease trajectories for the case where the initial wind generation output is 400 MW.

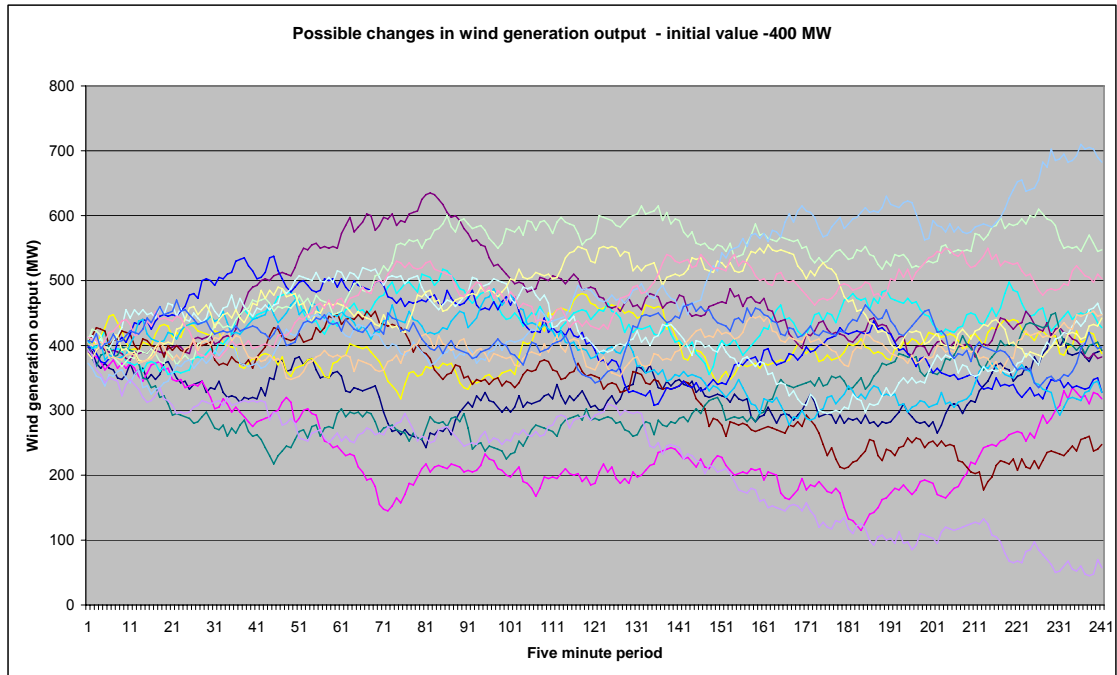


Figure 84: Initial wind generation output of 400 MW

In Figure 84, the wind generation output can decrease by a maximum amount of 800 MW. The generation starting capability exceeds 800 MW once the warm thermal plant has been brought on. The only part where wind generation output decrease might exceed generation starting capability is in the first fifteen minutes or so.

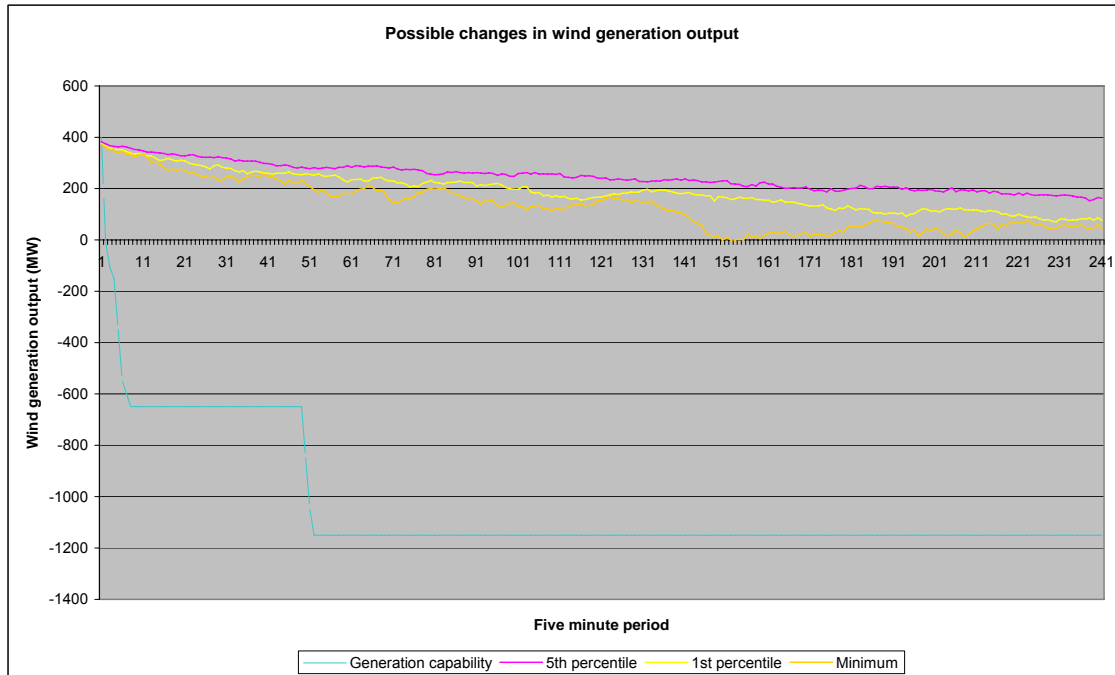


Figure 85: Generation starting capability versus cumulative probability for wind generation output decrease for an initial wind generation output of 400 MW

8.3 Discussion

The choice of a defined wind event to measure generation starting capability against will be influenced by probability of occurrence, impact of event and the costs and benefits of mitigation of the impact of the event.

Generation starting capability can be estimated from either offered generation or on available generation (i.e. offered generation and generation that is available for service but has not been offered). Both methods (offered and available) generation can be used. The use of offered generation as the basis provides a conservative estimate which can be used to warn participants of a potential shortfall in capability. This may lead to revisions to offers by participants to increase the amounts of offered generation.

The use of available generation as the basis for the generation starting capability check better reflects the true system capability to meet a decrease in wind generation output but is more risky as generators are not obliged to offer all available plant.

9. Discussion

9.1 Effect on security

Analysis of the effects of wind generation output variability and forecast errors on the security of the Southland and Hawkes Bay regions has been carried out. The analysis has indicated that security issues were more likely to become apparent during times when a significant amount of regional generation was not dispatched. This will have implications for maintenance outage plans for these regions.

The effect of wind generation forecast error was to increase the number of times that the security check would falsely indicate issues (wind forecast less than actual generation) and miss issues (wind forecast greater than actual wind generation output). Regional security issues can be mitigated to some extent by reducing the amount of other generation in the region that is out for maintenance at any one time.

9.2 Effect on pre-dispatch processes and tools

A possible addition to the frequency management ancillary services was raised in Section 6.3. This would be a service which operates in the 5 to 30 minute range (or possibly longer). This would be generation or load which can be quickly brought on or disconnected respectively in the 5 to 30 minute time period. A certain amount of this reserve can be procured to be available for a trading period. The reserve can be called upon following the occurrence of particular events.

Aside from providing confidence that sufficient generation is made available to maintain or quickly restore power system security following the occurrence of a contingent event or wind event, this new reserve may also help with the issue of unit commitment in the New Zealand power system.

The New Zealand power system has, compared to its size, a large number of large thermal generating units (see Table 9). Eight units make up nearly 50% of the North Island peak demand. The unavailability of one or more of these units can have serious implications for power system operation.

Unit	Unit size (MW) indicative	Station Capacity (MW)
Huntly Unit 1 to 4	250	1000
Huntly Unit 5	380	380
Taranaki Combined Cycle	380	380
Otahuhu B unit	380	380
Total		2140

Table 9: Large thermal generating units

Once these units have shut down, it will take between 4 and 12 hours to bring the unit back into service. The owners of these units may choose to shut the unit down over periods of low nodal prices (e.g. overnight) with the result that the units may not be available in time to meet morning demand peaks. This risk may be increased by the integration of large amounts of wind generation.

Thermal units are more expensive to operate than are hydro units and are more likely to be the marginal generation in terms of dispatch. The introduction of large amounts of low price wind generation will displace more thermal generation especially at times of low load. This may result in thermal units not being required for dispatch and being shutdown for more of the time. Once shutdown, the thermal units can not be brought on quickly in response to a situation where wind generation output has declined by a large amount.

One solution to this problem is to ensure that a certain number of thermal units are kept in a state where they can quickly increase output. The new ancillary service would help in this regard as owners of thermal plant can offer their plant for this service and receive payment to defray the costs of keeping their plant in a state where output can be increased quickly.

9.3 *Managing large sudden changes in wind generation output*

Changes to pre-dispatch processes and tools will be required to accommodate large scale wind generation integration. The addition of a generation start capability check is indicated as a first step. This check complements the currently used standby reserves check. The generation start capability check will give comfort that there is the capability to manage large unpredicted changes in wind generation output.

9.3.1 Predictable changes

In cases where large changes in wind generation output can be predicted with a high degree of certainty, management of the effects of the change on power system security can be done in a similar manner to other known large changes in generation or load. Wind generation or metrological forecasts may predict a large change in wind generation output over a certain period as a result of weather conditions moving through a certain region. The System Operator can then ensure that sufficient generation is available over the period to cover any drop in wind generation output and can re-dispatch generation in a timely manner to ensure minimal effects on the power system.

Other methods for minimising the impact of sudden increases in wind generation output include requiring wind farms to limit their rates of increase in output or hold output steady. These measures need only apply for the period over which large changes in wind generation output are expected.

9.3.2 *Unpredicted changes*

The occurrence of unpredicted large changes in wind generation output can be managed in a number of ways:

- The generation start capability check is used to confirm that generation offers are sufficient to meet a defined wind event. A potential shortfall of capability can be advised to participants who can then revise their offers.
- The rate of change of regional or national wind generation output can be monitored. At times when the rate of change exceeds defined criteria, certain actions can be taken. Generation can be re-dispatched in a manner to minimise effects on the power system. Ramp rate limitations on wind generation can be applied.

Should a lack of generation start capability occur often enough to become an operational issue, then changes to market arrangements can be considered. For example, a new ancillary service for provision of fast starting plant or interruptible load could be introduced. The generation start capability check shortfall could be used as the basis for procuring a certain amount of generation to be on line in 15 minutes or certain amounts of load that can be disconnected at short notice.

9.4 *Managing the effects of variability of wind generation output*

Wind generation forecast errors are a concern to the industry in New Zealand and worldwide. The accuracy of wind generation output forecasts in itself is not as important as the ability to shift generation dispatch from what was forecast to what has occurred in practice. Problems occur when the power system can not change sufficiently quickly from a generation schedule based on wind generation forecasts to one with actual wind generation output. The issue is one of the variability of wind generation output and the System Operator's ability to accommodate the variability when scheduling and dispatching generation.

There are a number of options for accommodating wind generation output variability in the scheduling and dispatch processes. These will be considered in the options phase of the WGIP. This report has identified some means for managing wind generation output variability in the absence of changes to present processes:

- Maximising the ability to forecast wind generation output. Changes in wind generation output which can be predicted can be managed in pre-dispatch processes in a manner similar to which large planned changes in demand are managed. This allows large changes in wind generation output to occur with minimal impacts on the power system. This will allow greater quantities of wind generation to be installed on the power system.

- Learning from experience. The experience with wind generation in New Zealand is very limited. There is insufficient historic information available to make accurate estimates of the probability of large wind generation output changes. Ongoing monitoring and review of wind generation output will provide insights into the probability of large wind generation output changes and appropriate mitigation measures.
- Predicting the power system's ability to meet a large change in wind generation output. This can be done by incorporating a generation starting capability check in the pre-dispatch and dispatch processes. A shortfall in offered starting capability can be advised to participants through warning and security notices.

Figure 86 shows a potential framework for how large changes in wind generation output can be managed in planning, pre-dispatch and dispatch processes.

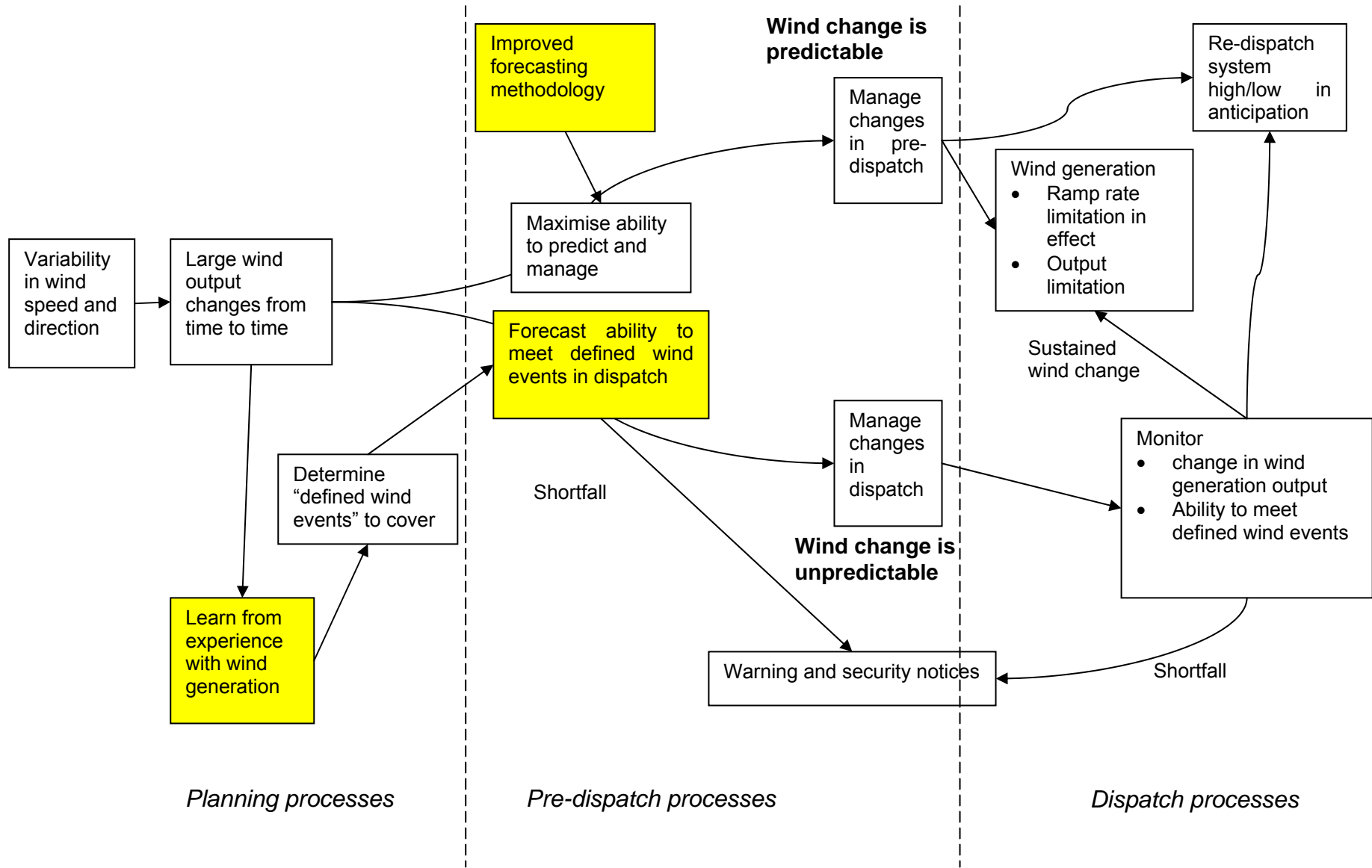


Figure 86: Managing large wind generation output changes

Experience with wind generation will allow frequent changes in wind generation output (that will benefit from mitigation measures) to be defined. The improvement of wind generation forecasting methodologies will maximise the ability to predict wind generation output and hence the ability to manage the variation through pre-dispatch processes.

In cases where the variation can not be predicted, a forecast of the power system's ability to meet the change (through dispatch processes) will indicate whether sufficient generation has been offered to meet such a variation. Shortfalls in capability can be advised to participants through warning and security notices. Such shortfalls occur frequently. The implementation of a new ancillary service (fast starting reserves) through which fast starting generation capability can be procured by the System Operator is a possible mitigating measure.

When large variations are encountered in dispatch, there are several options available to manage the impact of the variation. During these times wind generation output can be controlled through ramp-rate limitation or by limiting the total output of the wind farm. Ramp-rate limitation is more effective for large increases in wind generation output but may be able to be used to counter predicted decreases in output as well.²⁴ Other generation can be re-dispatched to minimise the effect on the power system in a manner similar to that used to manage large planned load changes.

The dispatch processes could incorporate two new features:

- A real-time wind generation output monitoring system. This system is used to alert to the inception of large unpredicted changes in wind generation output.
- A real-time check of the power system's ability to meet a defined wind event. This is similar to the check used in the pre-dispatch processes. This check will alert operators when the margin has changed following changes in the power systems (e.g. tripping of large generating units).

²⁴ In concept, wind farms in a region will have their output backed off prior to the decrease in output providing a reserve that can be used to initially buffer the decrease in output. Alternatively, the wind farms' output prior to the decrease can be limited to a size which when decreased will have minimal impacts on power system security.

10. Conclusions and Recommendations

Wind generation forecast errors predicted in the Garrad Hassan report will affect the processes and tools used by the System Operator to schedule generation on the New Zealand power system. This leads us to conclude that wind generation forecast error will become the main source of error in the scheduling processes for the North Island once the total installed wind generation capacity in the North Island exceeds around 370 MW. This is likely to occur within the next 2-3 years. Scheduling tools and processes will need to be reviewed and redesigned to accommodate large amounts of wind generation.

Large wind generation forecast errors can arise from two sources. A sudden large change in wind generation output can cause timing errors (i.e. the size of the change was predicted but the predicted time of the change was early or late) or, if not predicted at all, simply a large error. Large forecast errors resulting from timing errors can be managed in a similar way to demand increases at peak times. The change is predicted to occur within a certain period and the System Operator can ensure that sufficient other generation is available to be brought on as required.

Large forecast errors which are not predictable need to be managed within the dispatch processes through re-dispatch of generation. The pre-dispatch processes can incorporate a check on whether there is sufficient generation offered or available in future periods to meet a defined wind change event (i.e. a defined extreme wind generation output decrease with a certain probability of occurrence).

The following areas are recommended for further investigation:

- A project to monitor and analyse changes in wind generation output over time; and;
- Identifying wind generation forecasting capabilities and limitations and incorporation of wind generation forecasts within security processes.

11. References

[1] Investigation One – Part A, Effect of unpredictability of wind generation output on pre-dispatch processes, see <http://www.electricitycommission.govt.nz/pdfs/opdev/comqual/windgen/implications/Investigation-1-PtA.pdf>.

[2] Garrad Hassan Report “Wind Power variability and forecast accuracy in New Zealand”, 2 March 2007.

[3] Wind Generation Scenarios – see <http://www.electricitycommission.govt.nz/pdfs/opdev/comqual/windgen/wind-scenarios-Jun06.pdf>.

[4] Garrad Hassan. Time Domain, email from Garrad-Hassan to Transpower, 10 May 2007.

[5] Review of 19th June generation shortfall, see http://www.transpower.co.nz/upload/notion/sectionimages/20369_so-review-19-jun-2006-shortfall.pdf.

Wind Generation Investigation Project Website – see <http://www.electricitycommission.govt.nz/opdev/comqual/windgen/wgip>

Appendix 1 – New Zealand power system



Figure 87 - North Island power system



Figure 88 - South Island power system

Appendix 2

Garrad Hassan [2] has analysed present load forecast error and has made a forecast of wind generation forecast error based on the wind generation development scenarios.

Table 10 shows the load forecast (made at different times prior to dispatch) errors.

	23 hour			12 hour			6 hour		
<i>Return period</i>	NZ	NI	SI	NZ	NI	SI	NZ	NI	SI
<i>Once/month</i>	-534	-403	-227	-697	-500	-329	-613	-452	-286
<i>Once/week</i>	-456	-347	-171	-472	-360	-204	-412	-310	-187
<i>Once/day</i>	-288	-204	-116	-273	-190	-115	-236	-167	-101
<i>Once/month</i>	606	422	220	529	386	191	523	375	176
<i>Once/week</i>	423	304	154	414	307	147	384	299	140
<i>Once/day</i>	266	195	110	247	184	101	226	175	90

	3 hour				2 hour	
<i>Return period</i>	NZ	NZ	NZ	NZ	NI	SI
<i>Once/month</i>	-578	-410	-235	-526	-387	-223
<i>Once/week</i>	-371	-265	-158	-352	-243	-143
<i>Once/day</i>	-204	-146	-87	-184	-132	-80
<i>Once/mth</i>	398	323	143	363	289	131
<i>Once/wk</i>	332	255	119	309	232	110
<i>Once/day</i>	198	154	75	177	140	68

Table 10: Load forecast errors [MW] (Table 5.1 from [2])

Table 11, Table 12 and Table 13 show the estimated wind generation forecast error (for different times prior to dispatch) for each of the wind generation development scenarios.

	Scenario A			Scenario B			Scenario C			Scenario D		
<i>Return period</i>	NZ	NI	SI	NZ	NI	SI	NZ	NI	SI	NZ	NI	SI
<i>Once/ mth</i>	-497	-502	-75	-381	-356	-135	-627	-545	-306	-197	-190	-38
<i>Once/ wk</i>	-411	-397	-65	-307	-288	-118	-510	-445	-254	-168	-164	-33
<i>Once/ day</i>	-282	-280	-43	-216	-200	-80	-358	-311	-177	-118	-116	-22
<i>Once/ mth</i>	498	497	79	358	337	131	570	535	305	192	189	39
<i>Once/ wk</i>	384	386	66	311	284	110	498	428	254	169	168	32
<i>Once/ day</i>	266	265	42	210	192	78	348	300	179	115	113	21

Table 11: 2-hour derived wind forecast errors [MW] (Table 4.12 from [2])

	Scenario A			Scenario B			Scenario C			Scenario D		
<i>Return period</i>	NZ	NI	SI	NZ	NI	SI	NZ	NI	SI	NZ	NI	SI
<i>Once/ mth</i>	-733	-751	-90	-588	-553	-189	-975	-903	-432	-258	-264	-45
<i>Once/ wk</i>	-631	-624	-78	-525	-464	-163	-873	-722	-371	-228	-225	-40
<i>Once/ day</i>	-492	-481	-62	-400	-350	-125	-679	-559	-283	-177	-172	-31
<i>Once/ mth</i>	591	614	83	463	443	150	726	663	351	225	219	41
<i>Once/ wk</i>	514	517	71	368	344	127	593	529	286	186	187	36
<i>Once/ day</i>	334	338	52	251	239	90	419	372	204	126	129	26

Table 12: 6-hour derived wind forecast errors [MW] (Table 4.9 from [2])

	Scenario A			Scenario B			Scenario C			Scenario D		
<i>Return period</i>	NZ	NI	SI	NZ	NI	SI	NZ	NI	SI	NZ	NI	SI
<i>Once/ mth</i>	-994	-1000	-97	-838	-751	-255	-1424	-1222	-553	-322	-316	-49
<i>Once/ wk</i>	-907	-891	-95	-760	-643	-224	-1259	-1030	-501	-296	-292	-48
<i>Once/ day</i>	-718	-708	-80	-595	-507	-173	-995	-815	-393	-244	-238	-40
<i>Once/ mth</i>	942	930	96	770	642	227	1238	1043	523	313	296	48
<i>Once/ wk</i>	809	812	90	638	576	192	1054	904	430	272	275	45
<i>Once/ day</i>	578	589	67	449	408	136	735	640	305	199	201	34

Table 13: 23-hour derived wind forecast errors [MW] (Table 4.7 from [2])

Appendix 3

Wind generation supplies 21% of total demand

The analysis from section 7.2.1 was repeated for the case where wind generation output supplied around 21% of the total demand. Figure 89 shows wind generation, wind generation forecast error and load for the case where wind generation supplies 21% of demand.

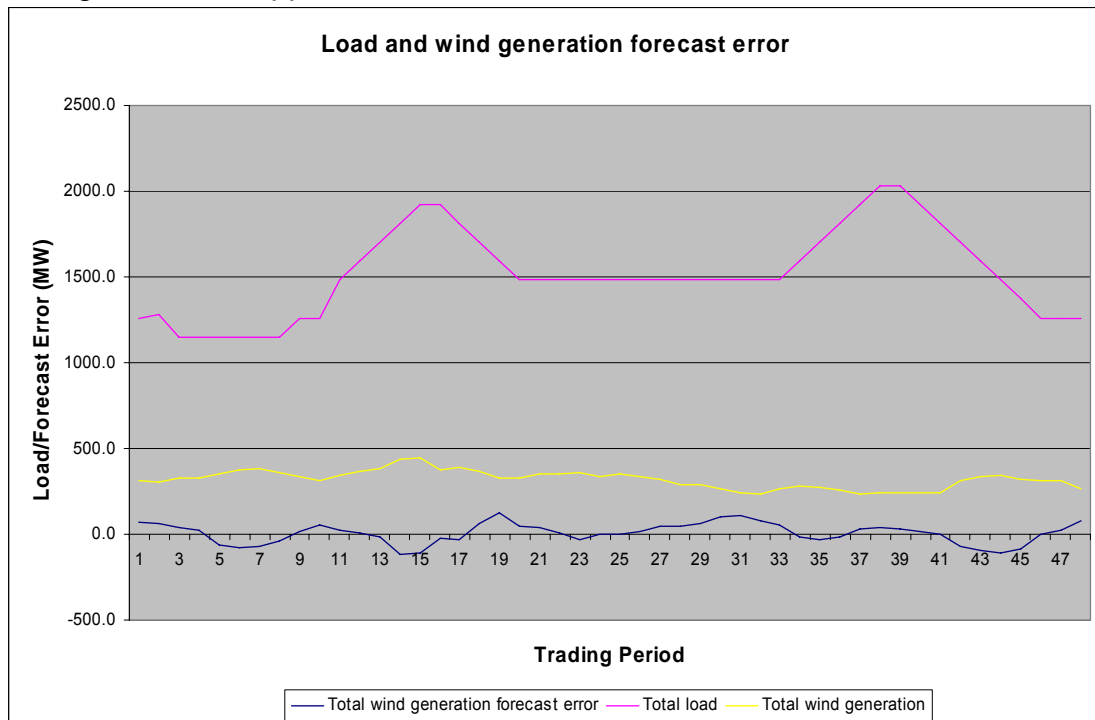


Figure 89: System load, wind generation forecast error and wind generation output

The nodal prices at node A, B and C are shown in Figure 90, Figure 91 and Figure 92.

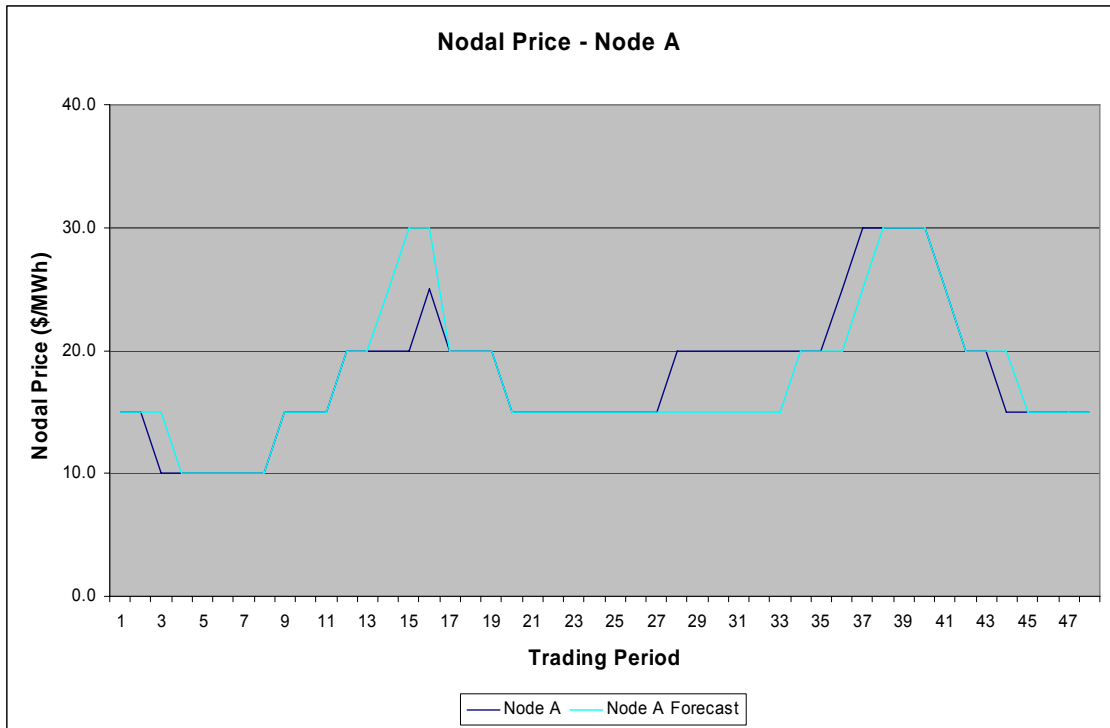


Figure 90: Actual and forecast nodal price for Node A

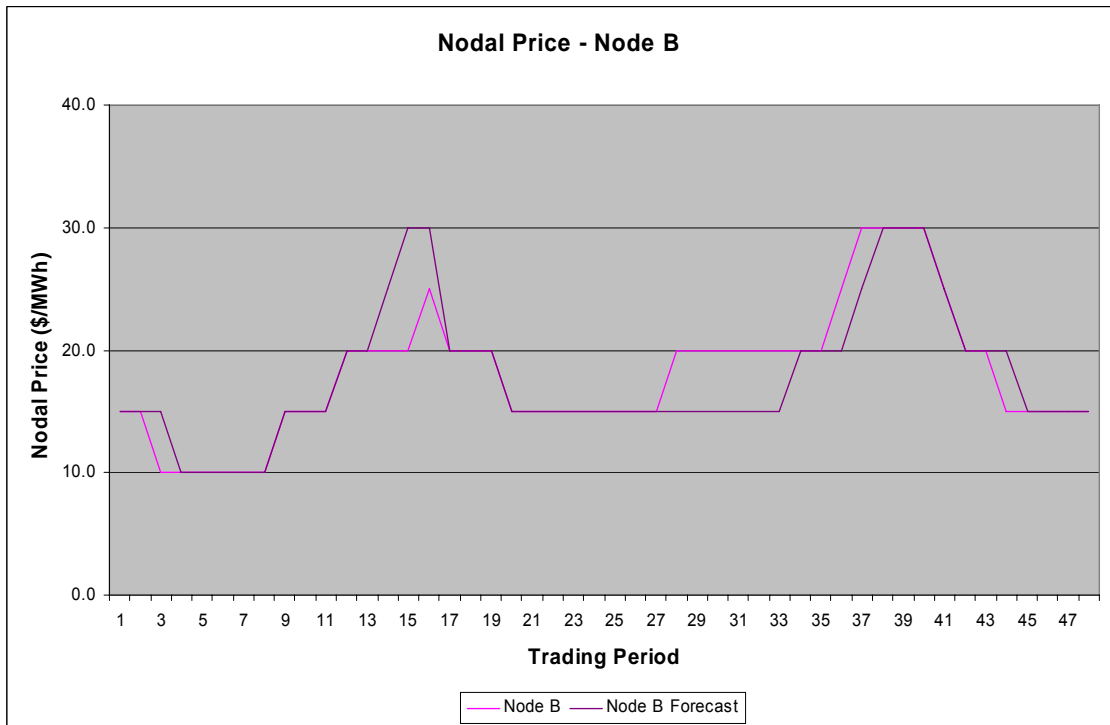


Figure 91: Actual and forecast nodal price for Node B

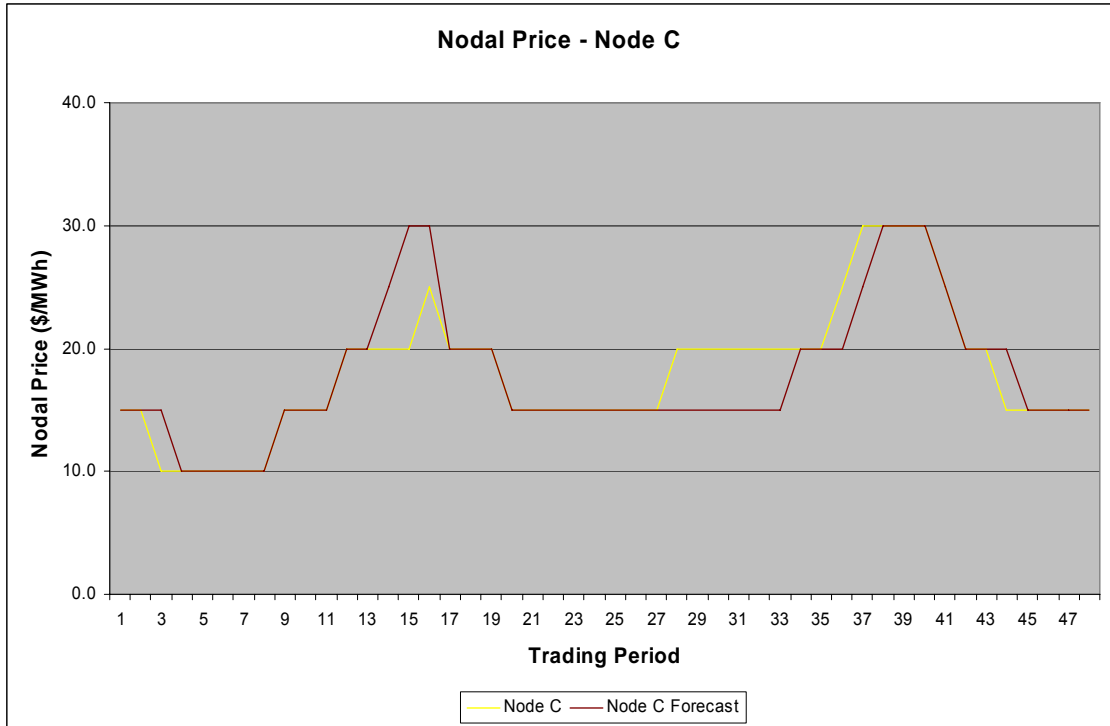


Figure 92: Actual and forecast nodal price for Node C

Actual and forecast dispatch quantities for generating units A1, A2 and A3 are shown in Figure 93, Figure 94 and Figure 95 respectively. Unit A1 is still largely base loaded with units A2 and A3 being required to meet morning and evening peak demand.

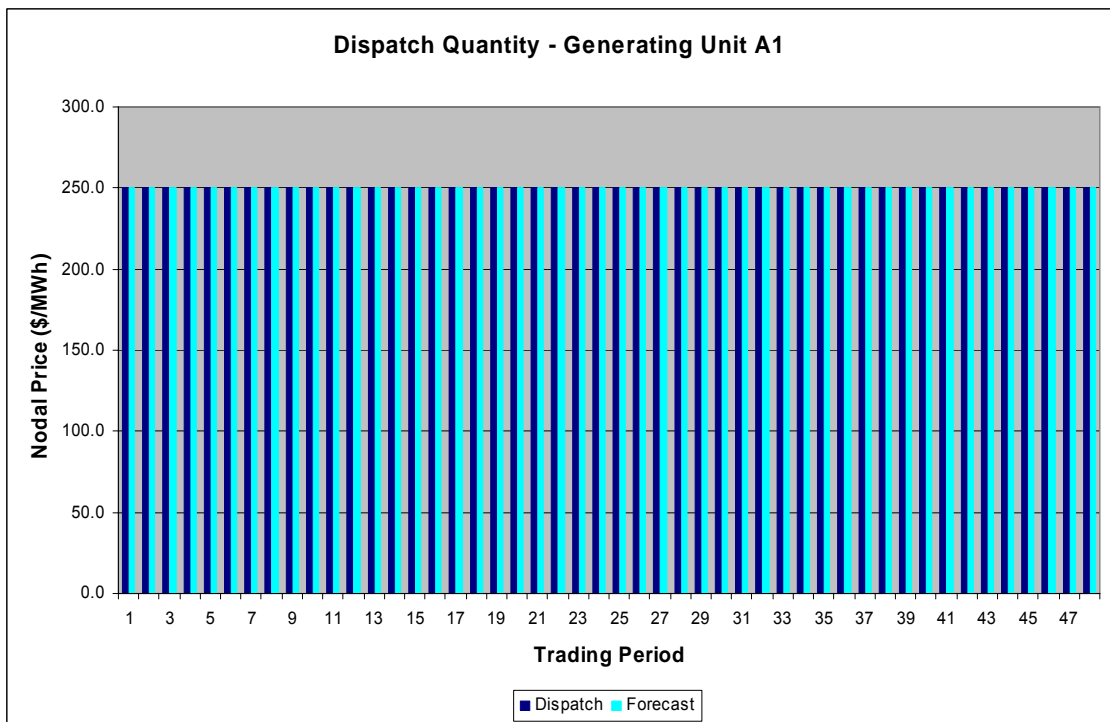


Figure 93: Actual and forecast dispatch quantities for generating unit A1

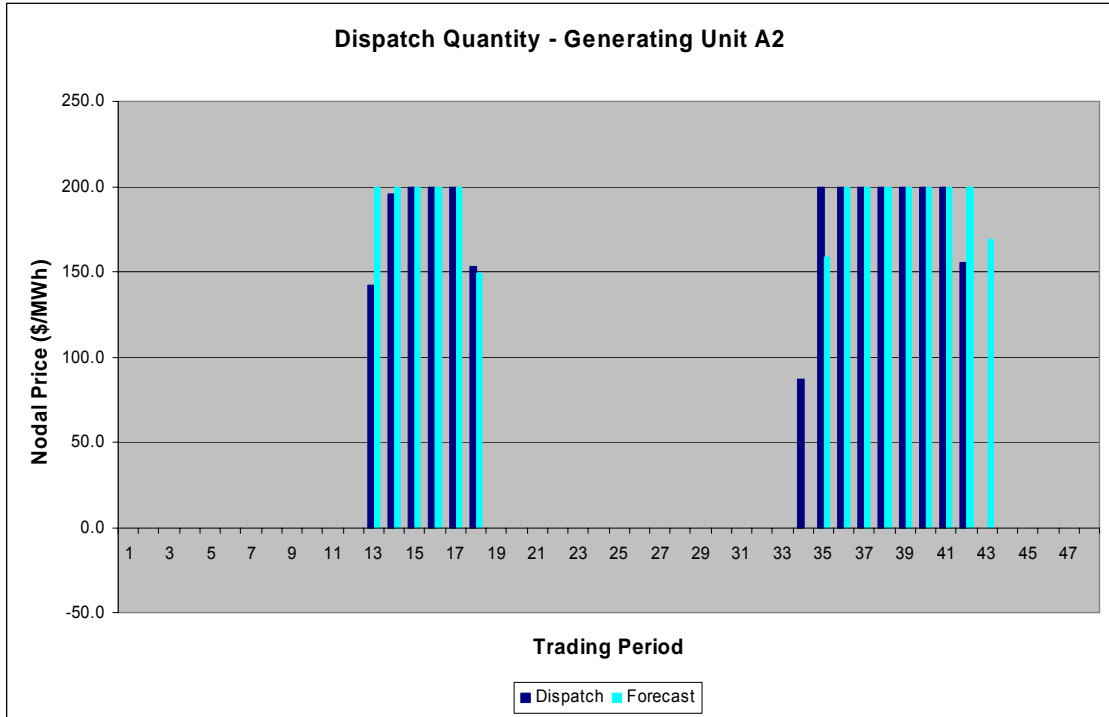


Figure 94: Actual and forecast dispatch quantities for generating unit A2

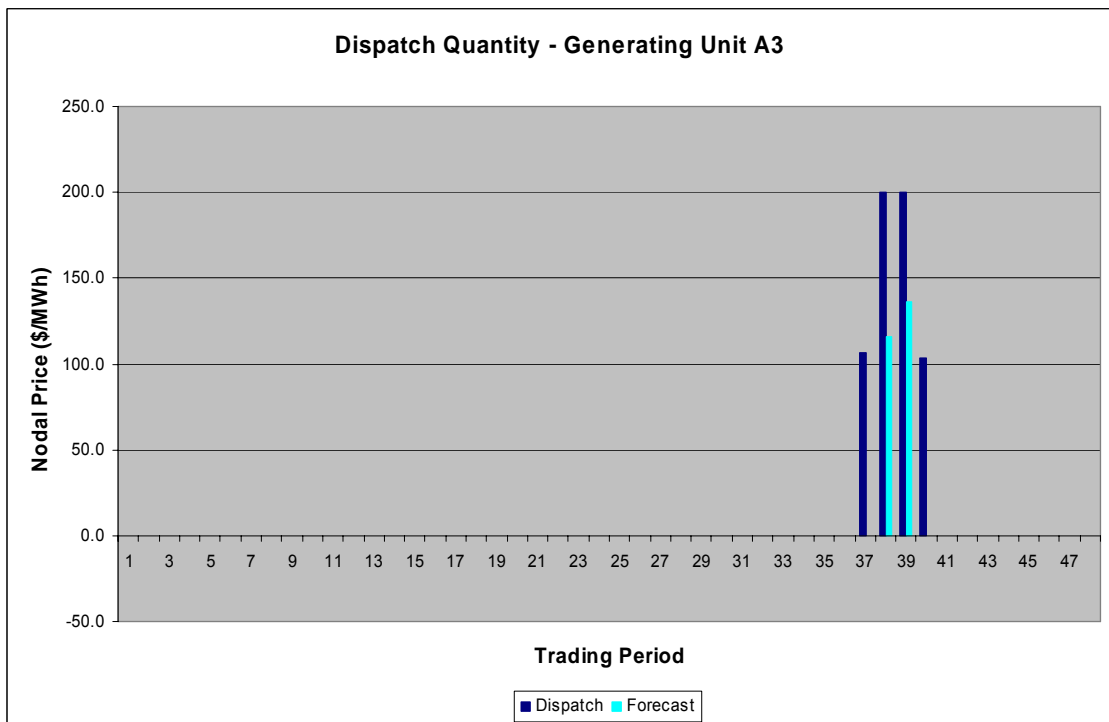


Figure 95: Actual and forecast dispatch quantities for generating unit A3

Wind generation supplies 37% of total demand

The analysis was repeated for the case where wind generation output supplied around 37% of the total demand. Figure 96 shows wind generation, wind generation forecast error and load for the case where wind generation supplies 37% of demand.

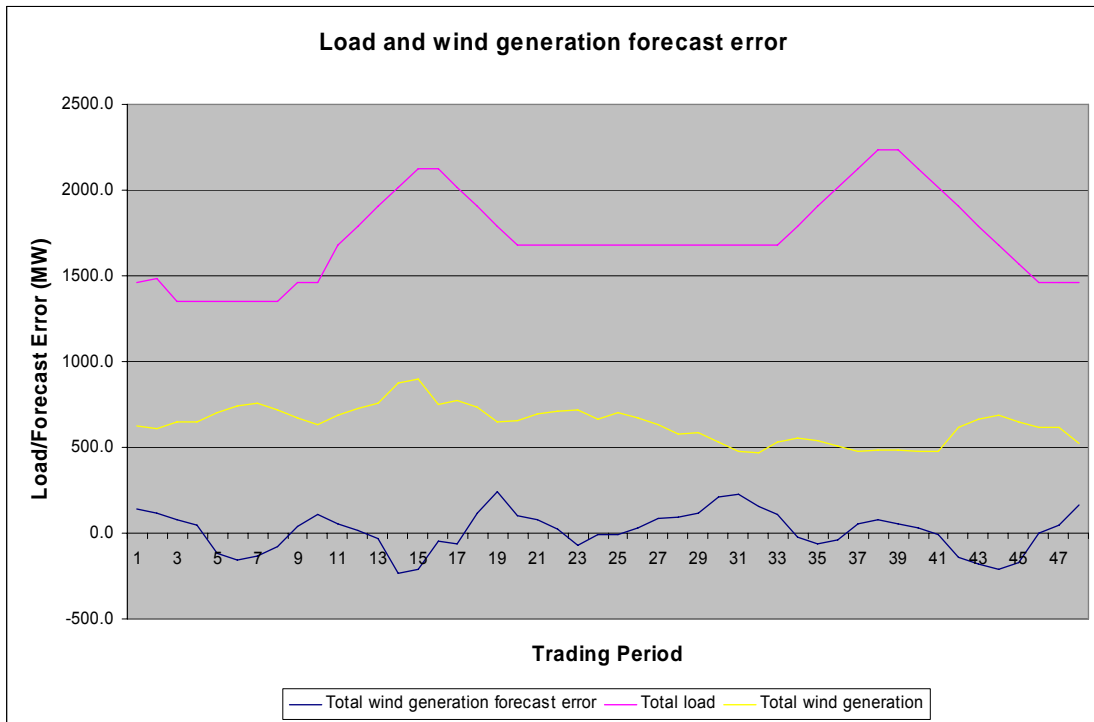


Figure 96: System load, wind generation forecast error and wind generation output

The nodal prices at node A, B and C are shown in Figure 97, Figure 98 and Figure 99.

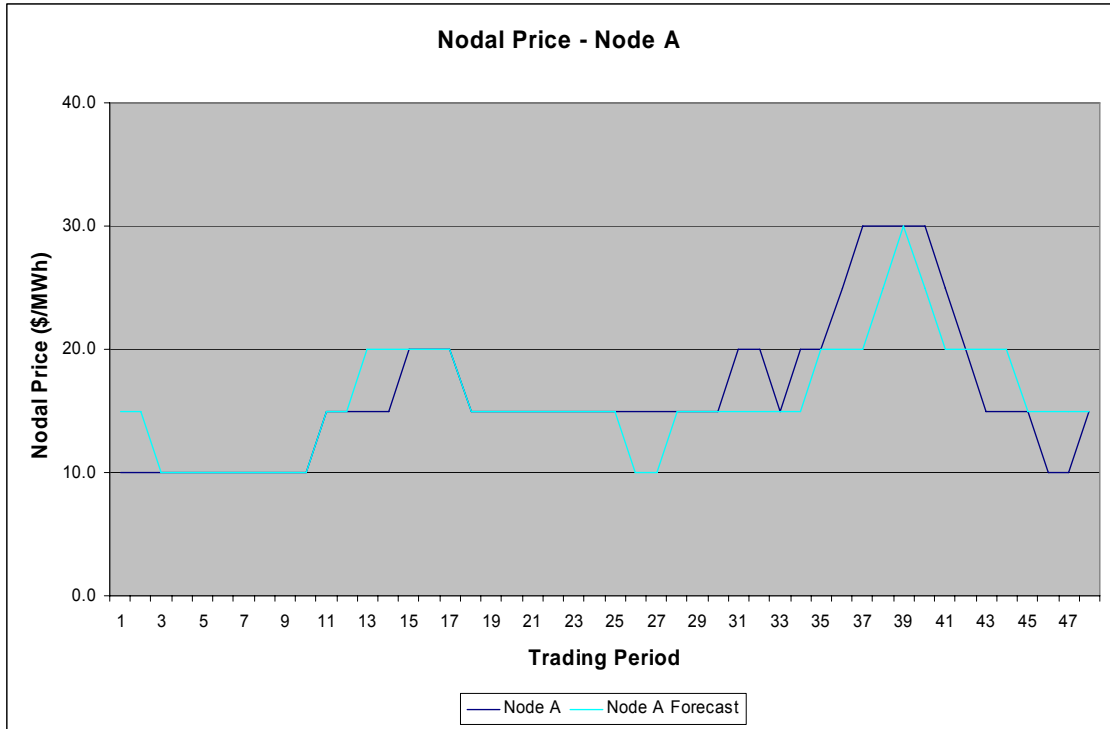


Figure 97: Actual and forecast nodal price for Node A

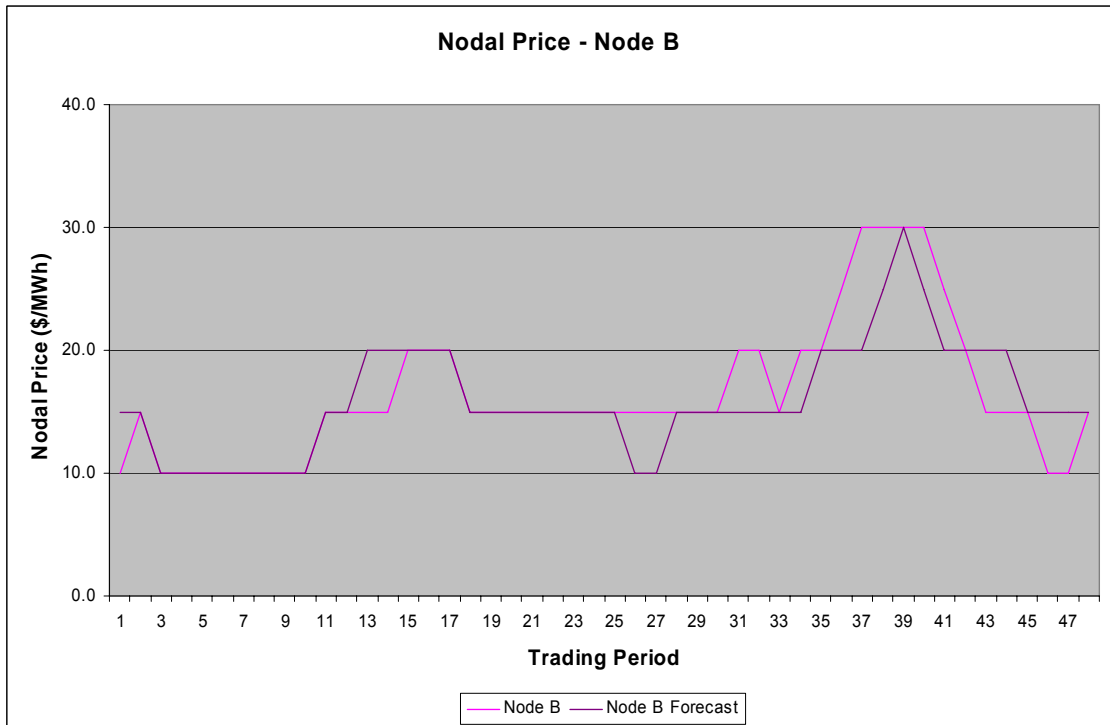


Figure 98: Actual and forecast nodal price for Node B

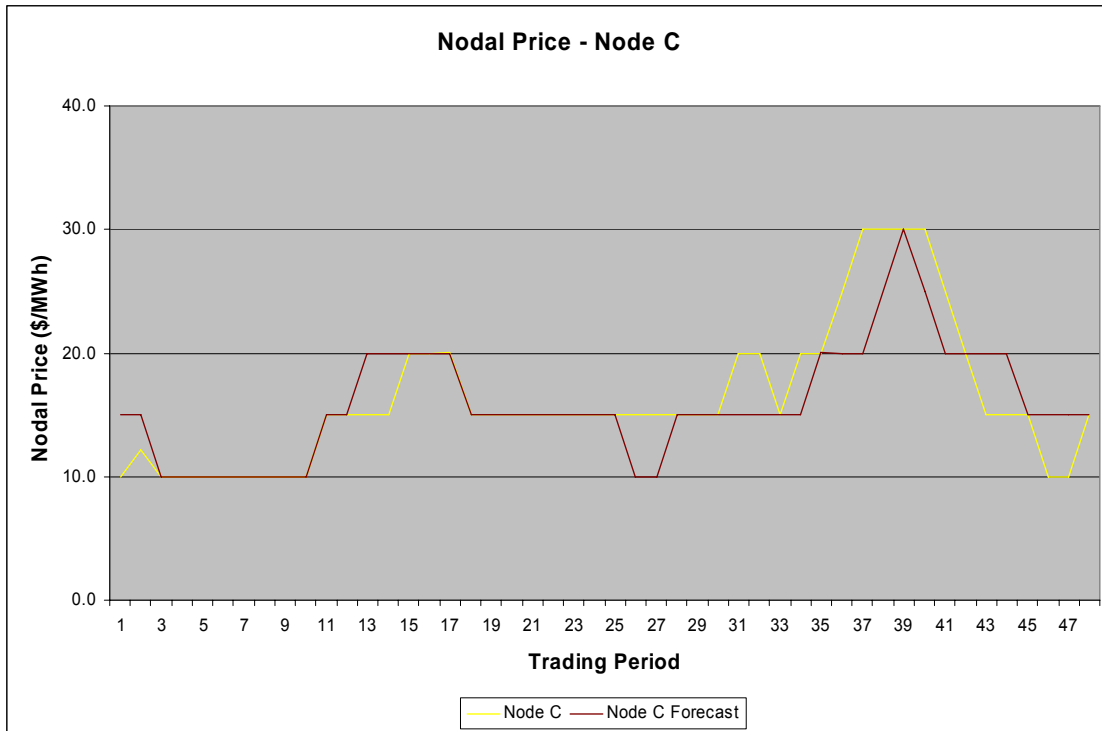


Figure 99: Actual and forecast nodal price for Node C

Actual and forecast dispatch quantities for generating units A1, A2 and A3 are shown in Figure 100, Figure 101 and Figure 102 respectively. Unit A1 is nearly base loaded with units A2 and A3 being required to meet morning and evening peak demand.

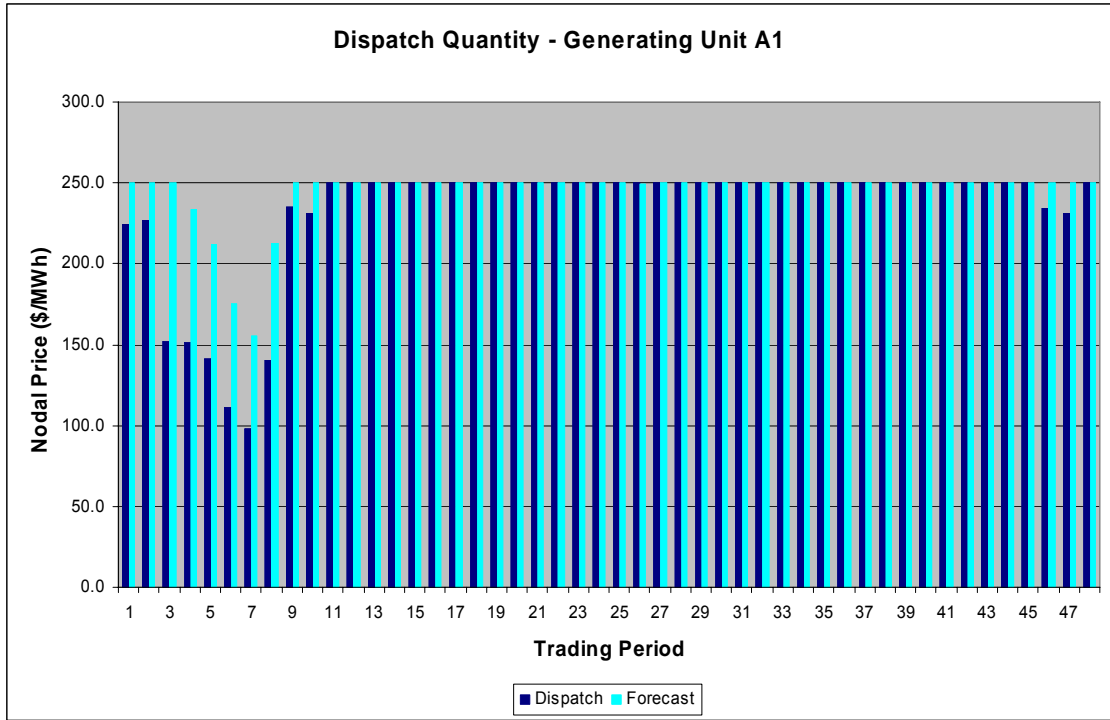


Figure 100: Actual and forecast dispatch quantities for generating unit A1

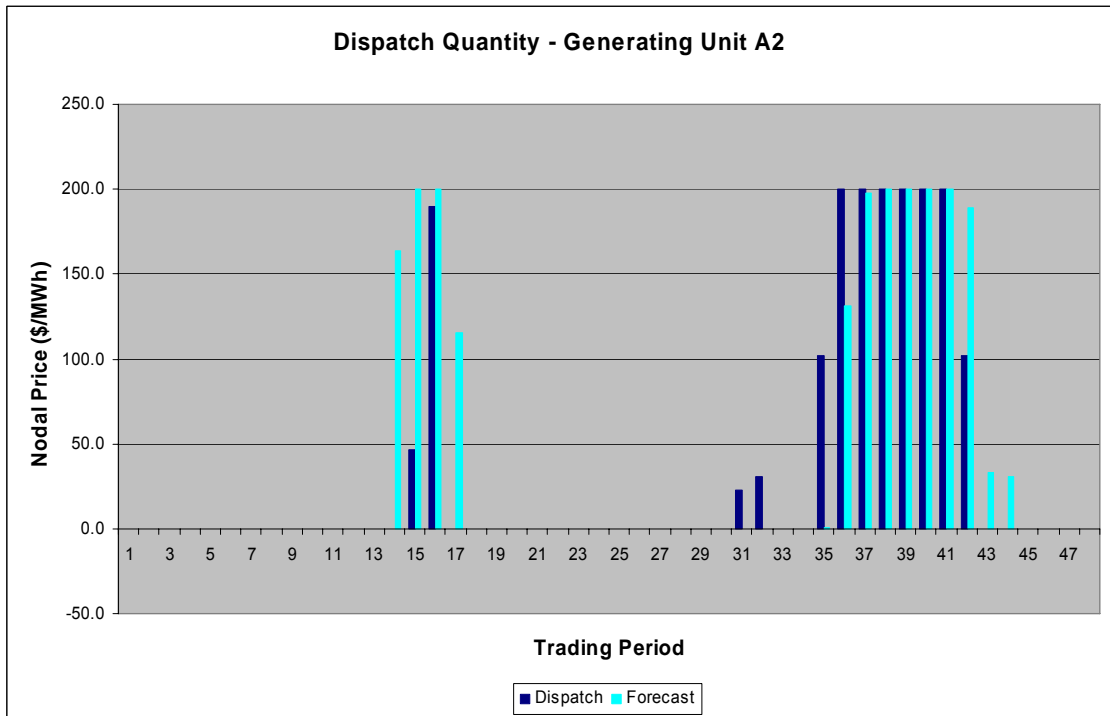


Figure 101: Actual and forecast dispatch quantities for generating unit A1

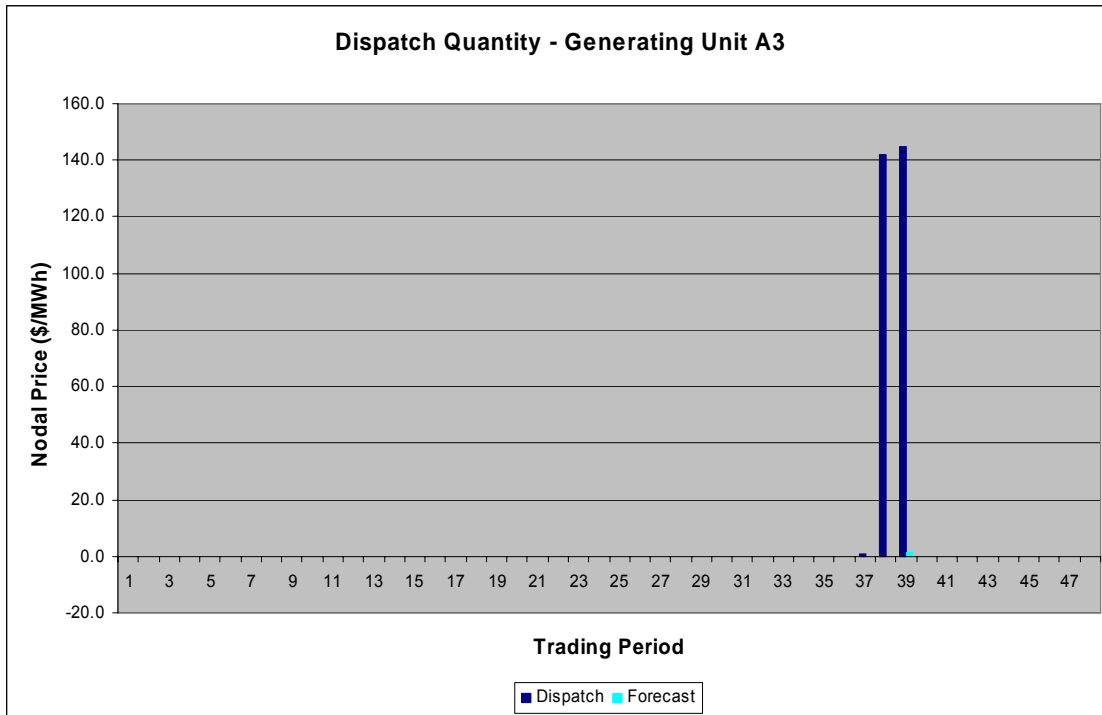


Figure 102: Actual and forecast dispatch quantities for generating unit A1

Wind generation supplies 50% of total demand

The analysis was repeated for the case where wind generation output supplied around 50% of the total demand. Figure 96 shows wind generation, wind generation forecast error and load for the case where wind generation supplies 50% of demand.

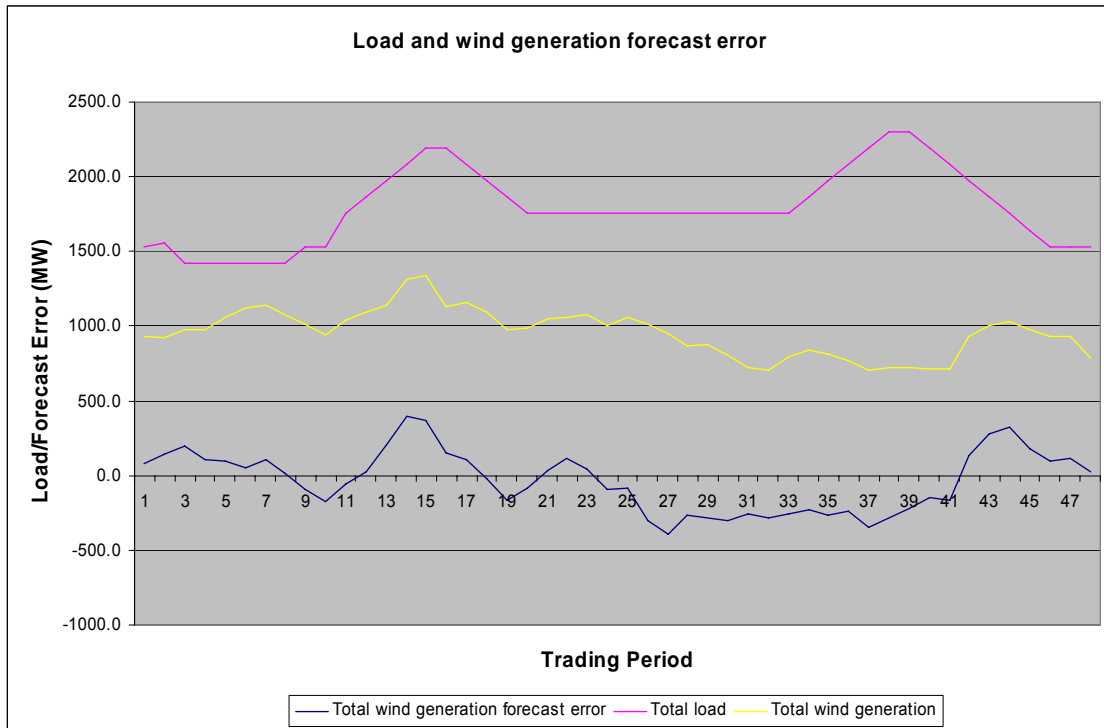


Figure 103: System load, wind generation forecast error and wind generation output

The nodal prices at node A, B and C are shown in Figure 97, Figure 98 and Figure 99.

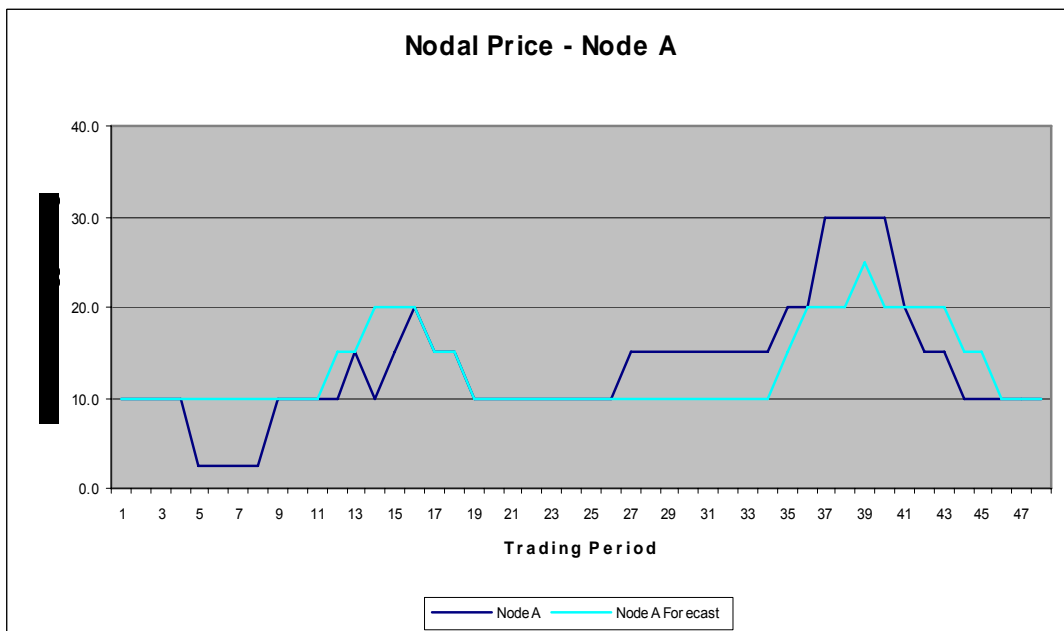


Figure 104: Actual and forecast nodal price for Node A

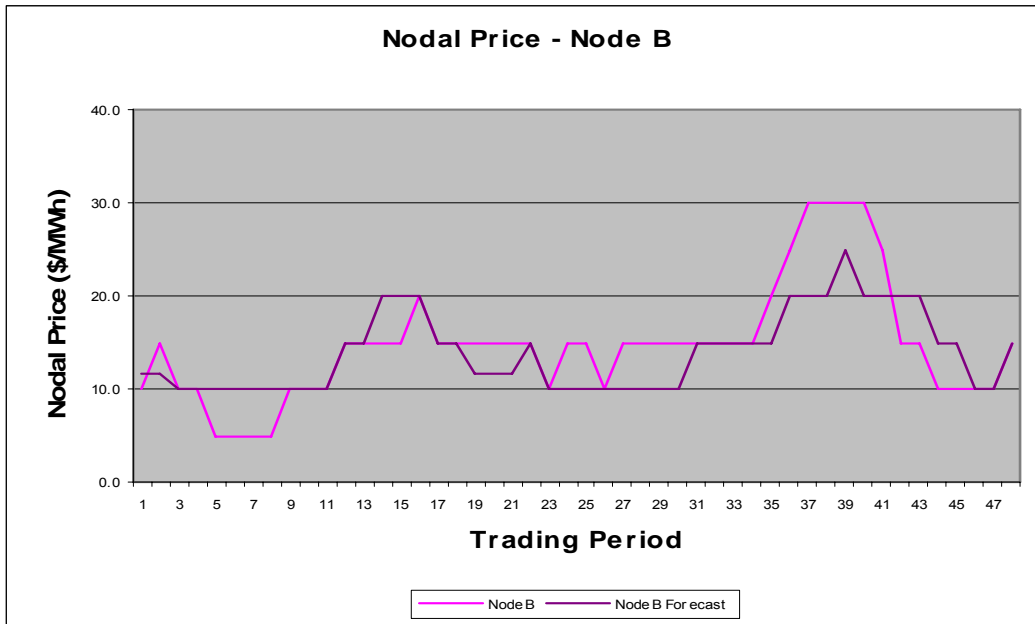


Figure 105: Actual and forecast nodal price for Node B

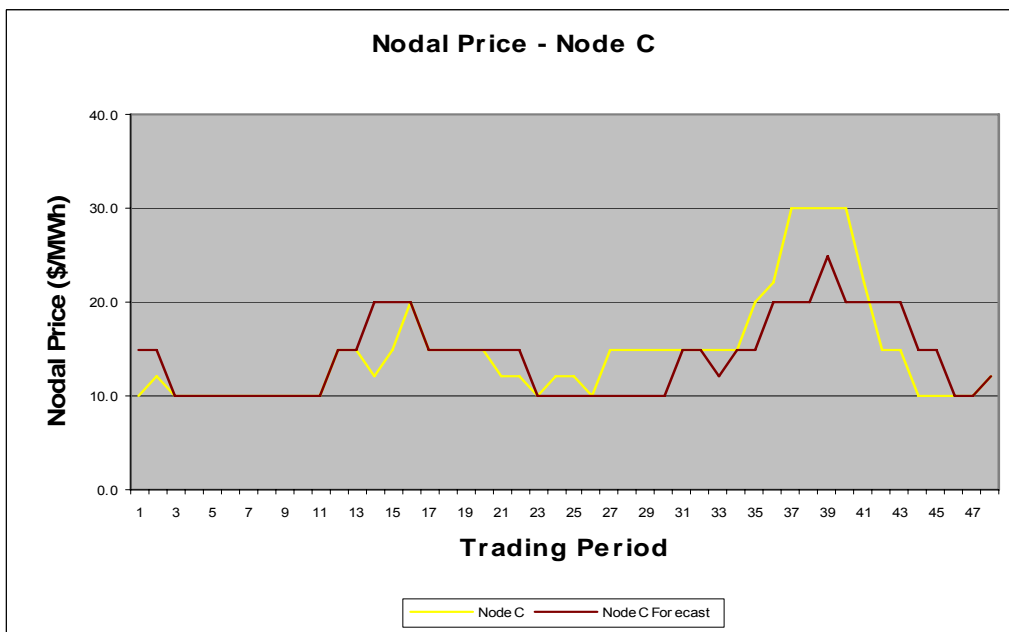


Figure 106: Actual and forecast nodal price for Node C

Actual and forecast dispatch quantities for generating units A1, A2 and A3 are shown in Figure 100, Figure 101 and Figure 102 respectively. Unit A1 is nearly base loaded with units A2 and A3 being required to meet morning and evening peak demand.

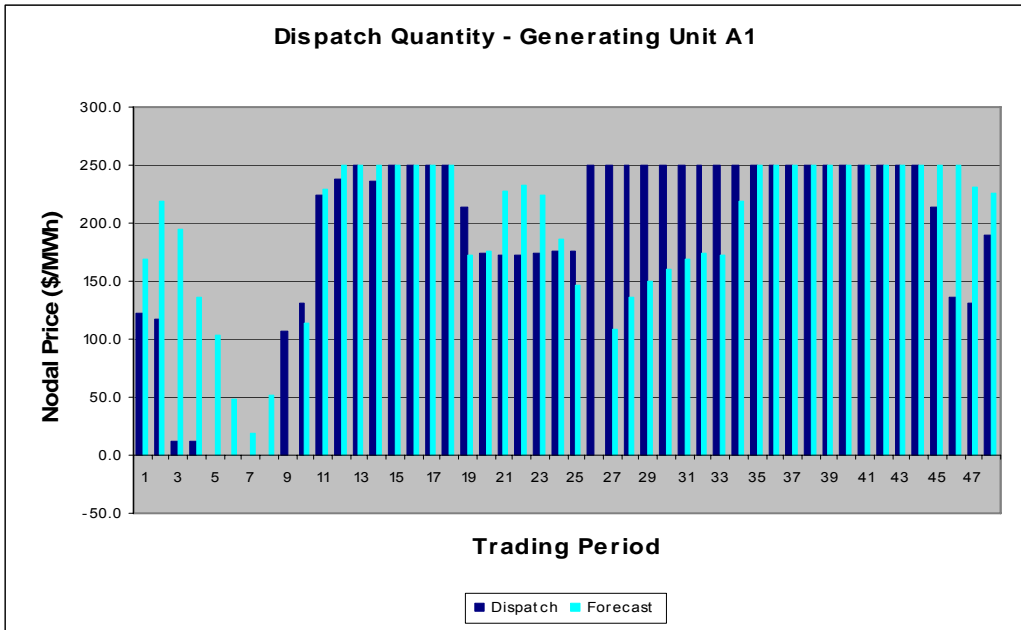


Figure 107: Actual and forecast dispatch quantities for generating unit A1

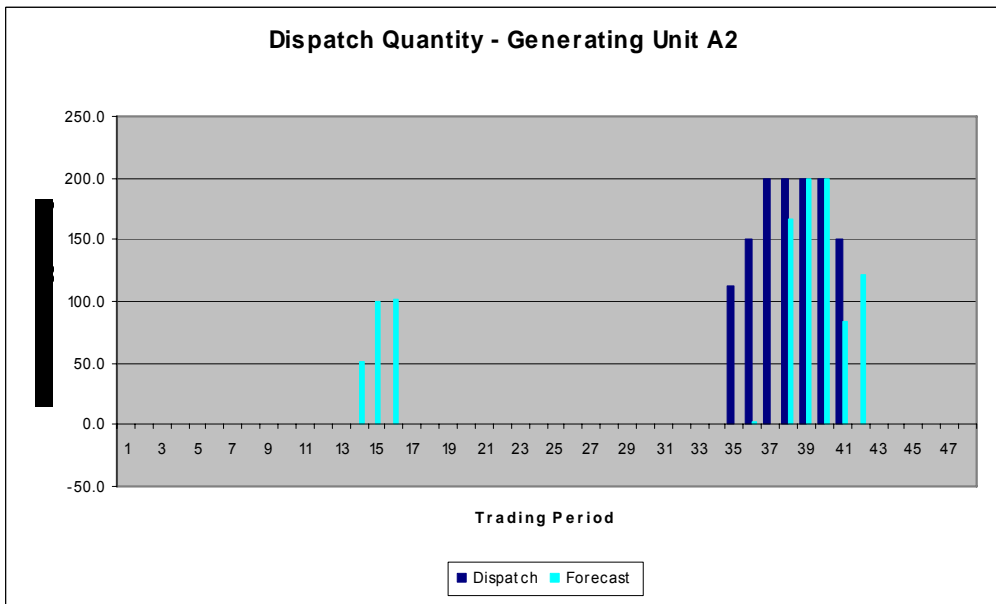


Figure 108: Actual and forecast dispatch quantities for generating unit A2

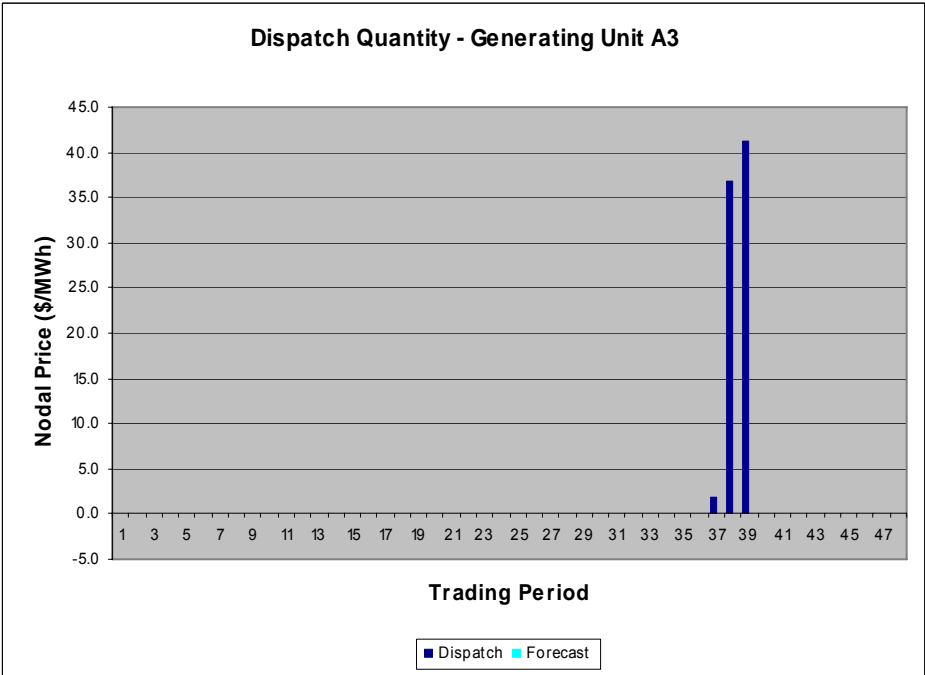


Figure 109: Actual and forecast dispatch quantities for generating unit A3