System Operator TASC Report

TASC-011: Normal Frequency Review

Version 02

28/09/2011

SYSTEM OPERATOR

TRANSPOWER

Keeping the energy flowing

Transpower New Zealand Ltd The National Grid

NOTICE

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Version	Date	Change
01	15/07/2011	Initial Drafting
02	28/09/2011	Final Report

	Position	Date
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1 Executive Summary

1.1 Time Error Requirements

The Electricity Industry Participation Code requires the error between actual time and a synchronous clock connected to the power grid to be no more than five seconds. However, the uses for which time error was originally developed have become obsolete, and there is evidence that artificially raising or lowering the frequency to correct the time error can become a system reliability issue.

Transpower recommends consulting New Zealand electricity market participants to determine whether a Code requirement for time error is still necessary. If time error is not used, Transpower recommends a six-month trial for removing the 5-second time error requirement from the Code.

1.2 Generator AOPOs Within the Normal Frequency Band

The Asset Owner Performance Obligations are included in Part 8 of the Code. This report relates to the responsiveness of generating units to frequency deviations within the normal band. Some of the requirements in the Code are unclear or have been misinterpreted. This report suggests Code changes to provide clear guidelines for asset owners with respect to dead band, droop, and proportional and integral gain settings.

Transpower suggests revising the Code to add a small dead band allowance of 25 mHz. Studies show that the system response would not be unduly affected with a small dead band, and governor stability won't be adversely affected.

For clarity, the wording in the Code about droop should be modified to specify a droop setting of no more than 7 percent. This would ensure that the droop setting of the governor reflects actual capability (adjustable over the range of 0 to 7 percent).

Transpower also suggests that the Code specifies that proportional and integral gains are as high as possible without making the governor unstable. Technology and software in use today make it possible to test and verify these settings.

1.3 Frequency keeping cost allocation

The Electricity Authority has proposed code changes to improve the allocation of the costs to better target the actual causers of frequency deviations. The original project brief for this review included a review of the changes that would allocate frequency keeping costs to non-compliant generators. This part of the review has been deferred pending consultation of the changes to the AOPOs that would make generator compliance obligations clearer.

2 Introduction and Purpose

The responsibilities of participants in New Zealand's power system are outlined in the Electricity Industry Participation Code. The Code undergoes continual review and revision in response to system changes, new technologies, and identified issues.

Currently, the Code mandates that Transpower ensures that frequency time error remains within five seconds of New Zealand standard time. This report reviews the continued need for a time error requirement to be included in the

Code as a performance obligation in light of system changes, new technologies, and other identified issues.

Additionally, recent investigations by the Electricity Authority into cost allocations for frequency keeping within the normal band (49.8 – 50.2 Hz) have identified a need for clearer guidelines for determining generator compliance with the Asset Owner Performance Obligations (AOPOs) within the Code; in particular, clarification of the obligations in respect of generator droop response. This report seeks to clarify AOPOs within the normal band with the objective of identifying an updated set of obligations that are clear, measureable, and appropriate for all generation types.

3 Time Error Requirements

3.1 Definition of Time Error

Time error is the difference between actual time and the time given by a synchronous clock receiving a signal from the electrical system frequency. New Zealand's electricity grid is set to operate at 50 Hz, which it does when demand and generation are exactly in balance. In reality there are constant slight fluctuations from 50 Hz as loads and generation fluctuate. Electric clocks that calculate time based on the frequency signal operate on the assumption that the system frequency is constant. If the frequency is higher, the clocks run faster; if the frequency is lower, they run slower.

Over time, these small deviations can result in a significant accumulation of error for synchronous clocks, necessitating a time error correction. These corrections are performed by temporarily increasing or decreasing system frequency by a small amount until the error is reduced or eliminated. In other words, the accumulated time error is reduced by intentionally creating an "error" in the opposite direction; if the system has been running "fast," then it is intentionally run "slow" for a period of time, and vice versa. In New Zealand, the frequency keeper is responsible for controlling time error.

Because time error occurs when the grid operates at a frequency that is different from nominal (50 Hz), time error can also be defined as the integral, or the sum, of frequency error. Therefore, it is also a measure of whether the grid frequency is perpetually too high or too low.

3.2 Time Error Requirements Worldwide

The following table shows the allowed time error in the grid codes of several countries worldwide, noting that many countries no longer include time error as part of their grid codes.

Country/Grid	Allowed Time Error
New Zealand	±5 seconds
Australia	±5 seconds [1]
Tasmania	±15 seconds [2]
Great Britain	±10 seconds [3]
Ireland	±10 seconds [4]
SARI/Energy (South Asia)	±10 seconds [5]
UTCE (Europe)	±30 seconds [6]
NERC-East	±10 seconds [7]
NERC-West	±2 seconds [8]
NERC-ERCOT	±3 seconds [9]
Russia	±20 seconds [10]
Ethiopia	±10 seconds [11]
Uganda	±60 seconds [12]

3.3 Time Error Background

Time error was originally and specifically developed to provide utility customers with a standardised frequency signal device for accurately and consistently measuring time. All clocks receiving a signal from the grid would show the same standardised time. The Electricity Industry Participation Code mandates that time error will not exceed five seconds.

If the time error grows too large and remains uncorrected, utilities must reduce the time error by operating at a different frequency, which is higher or lower depending on whether the time error is positive or negative.

In other countries, time error is also often used in their large and interconnected grids to track the differences in actual and scheduled interchanges between balancing areas. Time error can measure how much and which group of generators within a regional interconnection is generating higher or lower than their schedule.

New Zealand does not have a large interconnected grid and therefore has no need for this capability.

3.4 Time Error Correction and System Reliability

Time error, while it tracks frequency deviations, does not reflect system reliability. The North American Electricity Reliability Council (NERC) recently stated that it is unaware of any reason to correct time error for security and reliability reasons and supports the view that time error is corrected to ensure

[1] NEM Mainland Frequency Operating Standards, 2009, p15
[2] Development of the revised Frequency Operating Standards, 2009, p35
[3] National Grid: Frequency Response Obligations
[4] EirGrid Operating Security Standards, April 2011
[5] Regional Energy and Trade Laws in South Asia, Volume II, Appendix C
[6] Load-Frequency Control, UTCE Operation Handbook, May 2005
[7] North American Energy Standards Board, WEQ-006, 2005
[8] North American Energy Standards Board, WEQ-006, 2005
[9] North American Energy Standards Board, WEQ-006, 2005
[10] Intelligent Coordination of Operation and Emergency Control of EU and Russian Power Grids, Jan 2009
[11] Regional Power System Master Plan and Grid Code Study, Eastern Africa Power Pool, September 2010
[12] Regional Power System Master Plan and Grid Code Study, Eastern Africa Power Pool, September 2010

average frequency over a specified period of time is roughly equivalent to nominal and frequency-dependent clocks remain accurate.[13]

Studies performed by NERC indicate that time error corrections can actually *cause* system reliability issues because of the need to change the nominal frequency to reduce the time error. Over a five-year period, 44 percent of all under-frequency events logged in the United States occurred when the system frequency had already been intentionally lowered to correct the time error.[14]

3.5 Technology Dependant on Time Error Correction

Technology used in time-keeping has changed. The majority of newly produced non-networked time-keeping devices that require time accuracy utilise quartz crystal oscillators, which can produce a constant time signal based on direct current input. Other clocks are synchronised to network-based time standards such as time servers maintained by the National Institute of Standards and Technology or GPS signals.

These alternatives have largely displaced the synchronous electric clock as the preferred method of keeping accurate time. Newly produced time-keeping devices that depend on a nominal frequency signal service are generally limited to those which have limited need for fine accuracy, such as bedside alarm clocks and appliance clocks (such as those found on ovens or stoves).

The NERC Resources Subcommittee distributed a questionnaire to the National Electrical Manufacturers Association in the United States to find out if time error was still in use. Responders indicated that they currently do not have a need for the corrections in time error provided by the utility companies. As such, any requirement for this service is significantly outweighed by the risks associated with performing a correction. NERC is therefore implementing a field trial for eliminating time error correction.

Around the world, other transmission system providers have come to similar conclusions and no longer include time error in their electricity codes, deeming it unnecessary.

3.6 Code Contradictions Regarding Time Error

The under-frequency standard in Schedule 8.4 of the Code specifies that the system frequency should return to 49.25 Hz within 60 seconds following a contingent event or extended contingent event. Also, providers of Sustained Instantaneous Reserve are required to sustain output for up to 15 minutes following an event, allowing the System Operator time to re-dispatch generation. These requirements collectively indicate that the frequency could remain at 49.25 Hz for up to 15 minutes following an event—equating to a time error in excess of 13 seconds, directly contradicting the obligation to limit time error to 5 seconds.

There are two options to change the Code to make the requirements agree:

(i) Relax the time error requirement to a higher value, suspend it for a period following an event, or remove the obligation entirely

[13] NERC Project 2007-05: Balancing Area Controls
[14] http://www.nerc.com/page.php?cid=6%7C386

(ii) Change the target frequency following an event to 49.72 Hz. The System Operator would potentially have to procure significantly more ancillary services to ensure this higher target frequency is met.

Transpower supports the first option.

4 Normal Frequency AOPOs

4.1 Issues

The 'normal frequency' AOPOs are open to interpretation. The resultant inconsistent operational standards for generation plant have made it difficult for Transpower and generators to determine whether non-compliance exists and have resulted in generators carrying unequal burdens (and costs) for frequency control.

Section 8.17 of the Code requires generators to make the maximum possible injection contribution to maintain frequency within the normal band and to restore frequency to the normal band (49.8-50.2 Hz). In some cases, this clause has been interpreted by generators to mean that asset owners only have an obligation to return frequency to the normal band and have no obligation for free governor control within the normal band (if their governor is set up in such a way that the maximum possible contribution is zero). In other words, generators frequently impose restrictions on their machines and consider their maximum possible injection contribution to be based on these imposed restrictions rather than actual machine capability. For example, generators can set a dead band within the normal frequency band to limit the response within this range. Recent analysis of generation output data determined that only around 40 percent of generation currently makes free governor action available within the normal band.[15]

Speed droop is a governor function which changes the apparent generator output set point, proportional to changes in frequency. The percentage of droop refers to the amount of frequency change that is necessary to cause the output of the generator to change from zero output to full output. For example, the set point of a generator with 7 percent droop will increase from no output to full output if the frequency decreases by 7 percent. If the frequency remains constant, the generator output remains constant.

Schedule 8.3(5)(c)(ii) requires generators to have an adjustable speed droop over the range of 0 to 7 percent but doesn't require a specific droop. The existing obligation therefore only requires the droop to be adjustable over that range—it does not require it to be set to any particular values (or even to a value within that range). If a generator's droop setting is too high, the generator won't respond effectively to changes in frequency, which means the frequency keeper and other generators must compensate for the non-responsive generator. Unclear wording in the Code makes it difficult for the System Operator to identify and correct noncompliant generators.

While the droop setting changes the apparent output set point, the gain settings determine how long it takes for the generator output to reach the new set point. Without reasonably high gain settings, the generator will be slow to respond to frequency changes. Importantly, the AOPOs don't currently contain a

[15] Frequency Keeping Cost Allocation Consultation Paper, June 2010, p.36

requirement for gain settings, other than the general requirement in Schedule 8.3(5)(e); a generating unit's proportional response to frequency must not be unduly limited.

4.2 Simulation Notes

Several types of studies were performed to determine the effect of changes to governor dead band, droop, and gain settings on the power system:

- Frequency response tests model the expected response of the governor in response to changes in system frequency. Test signals over a range of frequencies were injected into the governor model and, from the system feedback response, governor stability could be determined.
- Dynamic response tests measure the transient response of the governor control system. These tests were performed by injecting a simulated frequency drop of 0.1 Hz. This step test provides a basis of comparison between the different machine tuning parameters. Step response tests have been simulated for 15 seconds only, as this was considered to be long enough for the transient response to be captured and for the frequency keeper to start responding to the frequency deviation.
- Tests to determine a generator's output in response to frequency changes were performed in Simulink using an injected curve to simulate a frequency deviation from 50 Hz to 49.8 Hz (remaining within the normal frequency band). Electrical power output was analysed for individual generators or for each generator on the network, depending on the study.

The simulations referenced in this report have been performed using DIgSILENT v13.2 and Simulink R2009a. The models used have been verified to conform to real world step and frequency response tests, as completed according to the System Operator Companion Guide to Asset Testing.

Two representative models were used for this series of tests; Machine A and Machine B. These machines are both hydro machines with detailed models submitted to Transpower. These two specific machines were chosen as representative generators for the studies because of their very different responses to system events due to governor settings and also due to inherent characteristics such as penstock length.

Frequency response test data has been plotted as Nyquist plots. (Corresponding Bode plots can be referenced in Appendix A.) Nyquist (and Bode) plots are a way of visualising the frequency responses of control systems, such as generator governors. These polar plots provide a graphical representation of machine response, and they can be used to visually determine the governor's stability.

If the Nyquist plot encircles the critical point (-1, 0), then the governor is considered to be unstable. In other words, if the graph of the machine's response falls to the right of the point where the unit circle (1) crosses the origin (0), the governor is stable. If the graph falls to the left of that point, the governor is unstable.

4.3 Frequency Baseline

To determine the average frequency stability of the power system, frequency data over one year has been statistically analysed, and it was used to construct a frequency distribution graph for both the North and South Islands, as shown in Figure 1. This chart is a visual demonstration of how well New Zealand's power system typically controls system frequency. The data can be used as a baseline against which changes to generator AOPOs can be analysed.

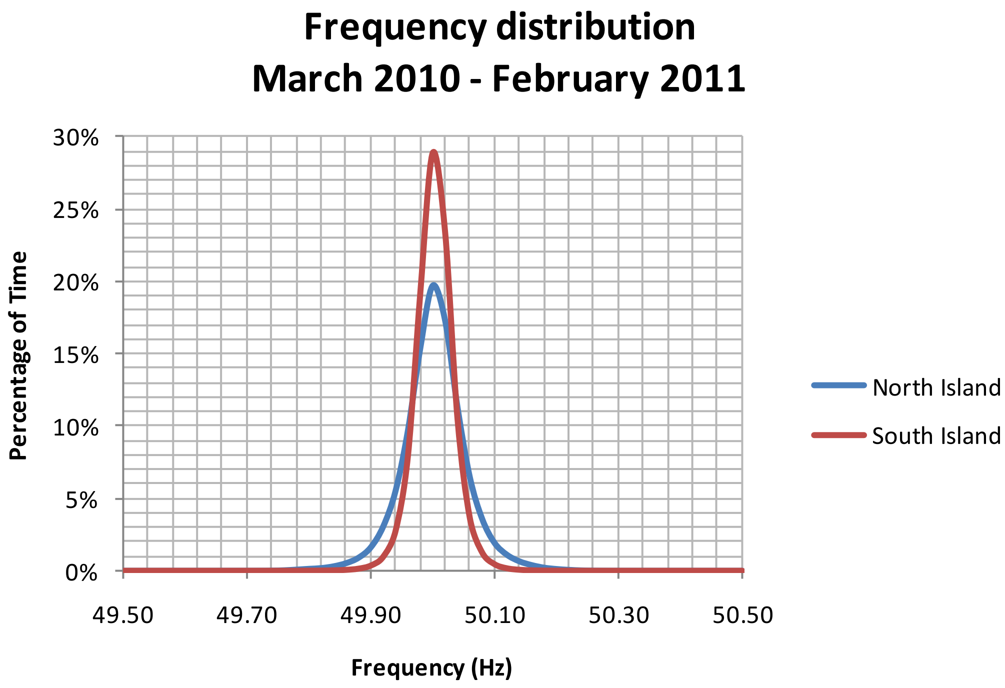

Figure 1: Frequency Distribution of the North and South Islands

The chart demonstrates that frequency for each island remains within the normal band of 50.00 ± 0.20 Hz most of the time. Each island's frequency has a mean of 50 Hz over the year. The South Island has a tighter frequency distribution than the North Island, with a standard deviation of 0.03 Hz. The North Island frequency has a standard deviation of 0.077 Hz. This gives a baseline against which to measure future changes to generator AOPOs. Any changes made should have a positive effect on the frequency quality.

4.4 Dead Band

4.4.1 Effect of Dead Band on System Response

A frequency dead band in a machine's governor halts the machine's frequency response within that band and reduces the generator's response to frequency deviations. It is becoming common for asset owners to operate their machines with large dead bands to decrease the wear and tear that occurs when a machine's output is constant changing in response to system frequency changes. If a generator is expected to contribute to controlling frequency within the normal band but is actually non-responsive due to a dead band, the frequency keeper must make up the difference. This increases frequency keeping costs and places a greater burden of wear and tear costs on compliant generators.

Many machines have a small inherent dead band built into their machines, around 10-25 mHz, making it impossible to comply with a mandate of operating with no dead band. In response to feedback from asset owners, Transpower studied the possibility of including an allowance for a small dead band in the Code.

Figure 2 and Figure 3 display the results of a study looking at the total response of all generators in the North Island and the South Island to a frequency deviation within the normal frequency band. Several small dead bands were modelled. As expected, the generator response decreases as the dead band increases.

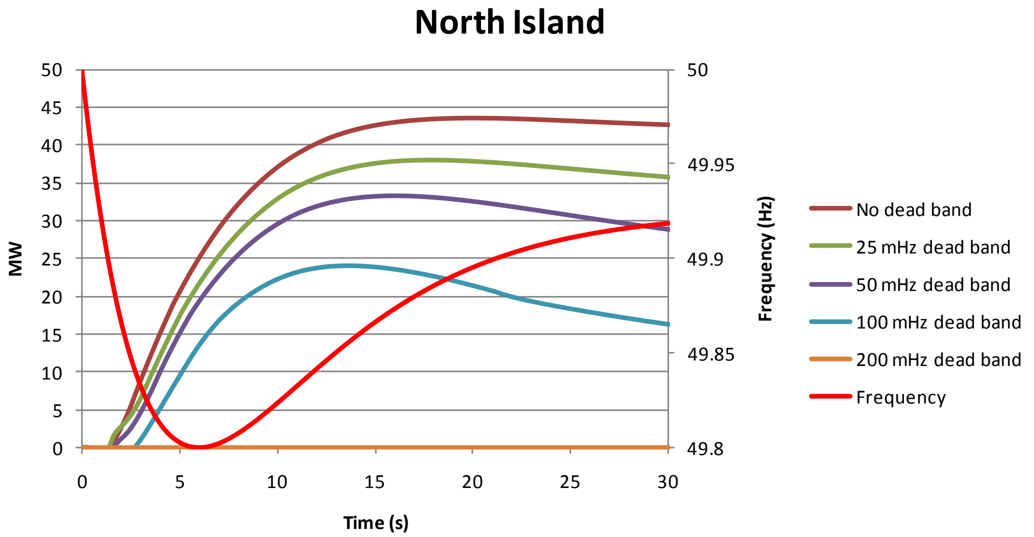

Figure 2: Effects of dead bands in the North Island

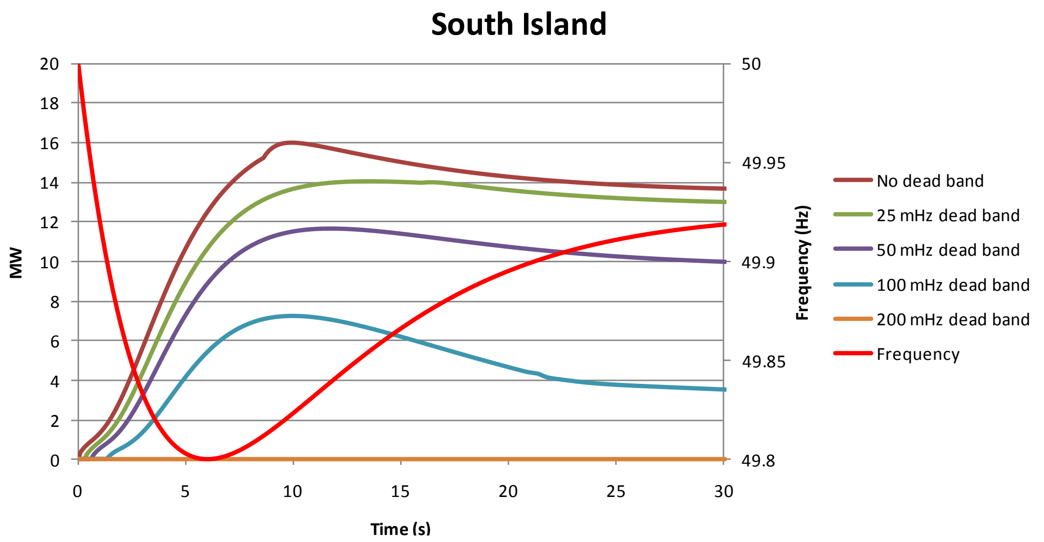

Figure 3: Effects of dead bands in the South Island

In the tools used by the System Operator to model generators and predict the behaviour of the transmission system, generators are modelled without a dead band unless they have a dispensation. In other words, the system studies undertaken by the System Operator assume a response with no dead band; this is likely to be an inaccurate assumption for a number of generators. When the System Operator is expecting a significant and fast response from generators to frequency deviations and then gets less than the expected response, the likelihood of the system frequency drifting or spiking outside the normal frequency band increases, which decreases the system-wide frequency quality. This also results in responsive generators bearing an unequal share of wear and tear costs to maintain system frequency.

4.4.2 Effect of Dead Band on Governor Stability

Dead band stability and response studies have been completed for two verified governor models; Machine A and Machine B. A dead band was introduced into the speed error signal of the governor, as illustrated in Figure 4. The effect of this dead band results in no governor action whilst the system frequency remains in the band 50.00 ± dead band Hz, while still providing governor droop response outside of this band.

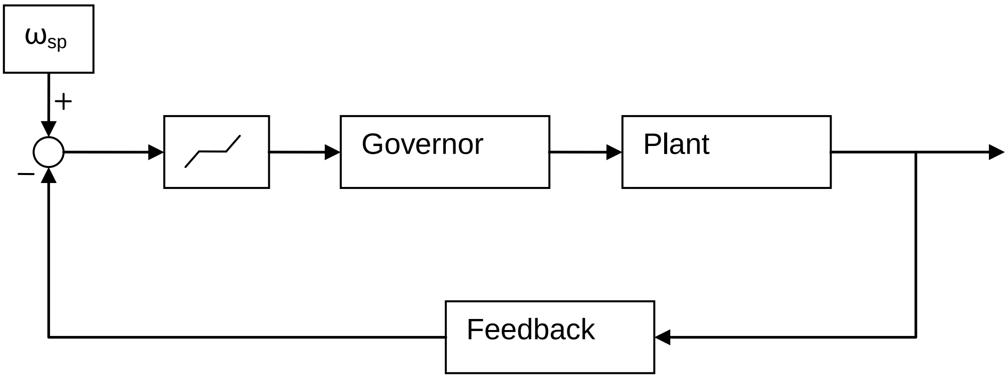

Figure 4: Introduction of dead band into governor models

The Nyquist plots in Figure 5 and Figure 6 indicate, for small dead bands, the effect on the stability of the governor is negligible. As the dead band is further increased, the overall gain of the system reduces and the governor becomes more stable. This is as expected, as the dead band reduces the responsiveness of the governor action around 50 Hz, and less responsive governors are more stable. The size of dead band that Transpower is recommending, 25 mHz, should have little or no effect on governor stability, as compared to no dead band at all. Generators which must use a larger dead band for stability purposes will now be expected to apply for dispensations, and their dead bands will be correctly modelled by the System Operator.

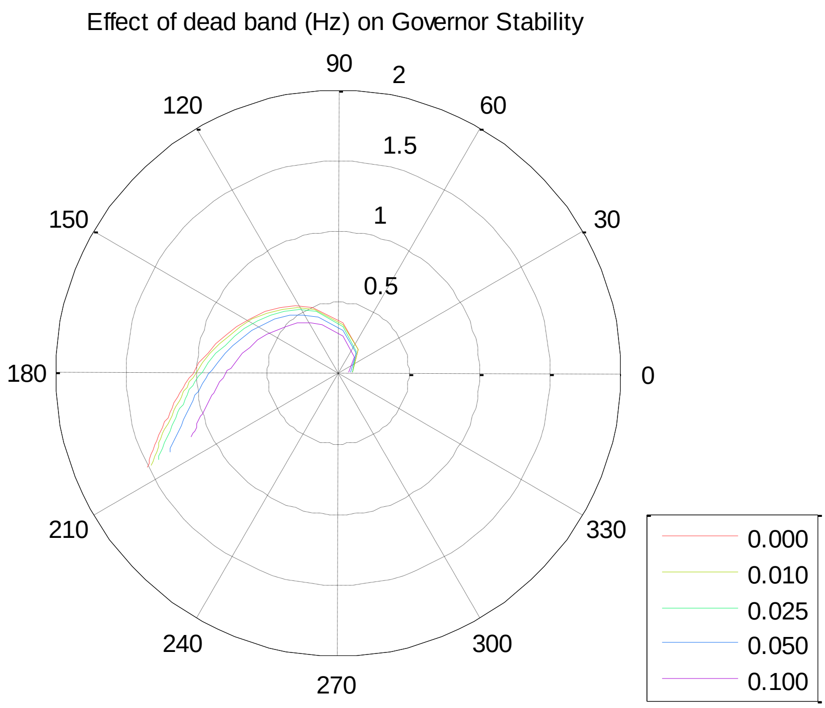

Figure 5: Nyquist plot showing the effect of dead band on machine A

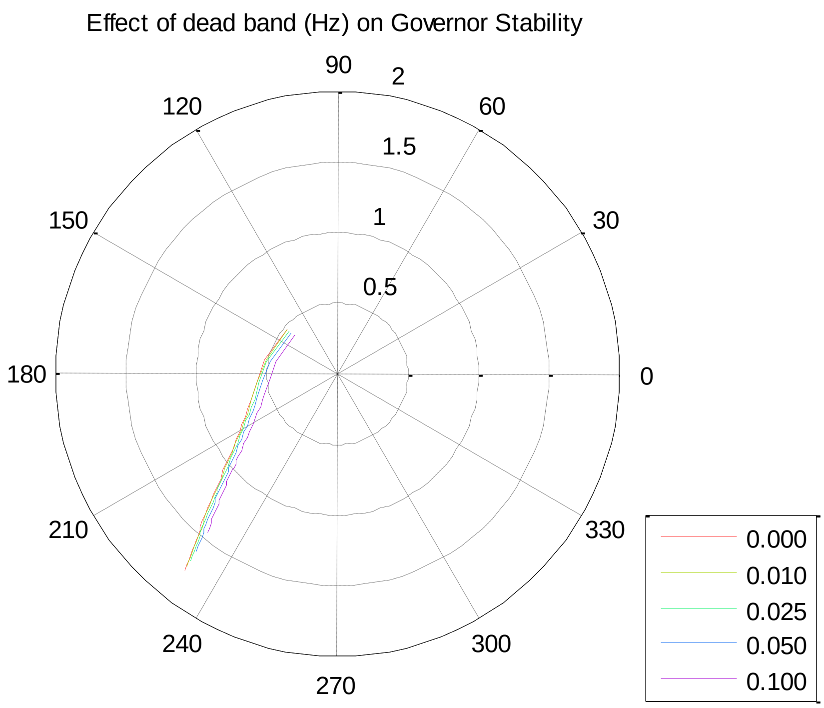

Figure 6: Nyquist plot showing the effect of dead band on machine B

The results from the introduction of a dead band are consistent across both governor models studied. From a stability perspective, a small dead band will have minimal impact on the stability of grid connected generator governors, as compared to having no dead band at all.

4.4.3 Dead Band Summary

Analysis done by the EA on generator response has determined that only around 40 percent of generation currently operates without a dead band, and it suggests that many generators operate with a larger dead band than currently proposed.

Many generators are built with an inherent, but small, dead band, between 10 and 25 mHz. However, the Code currently mandates that no dead bands should be used, automatically rendering a large percentage of generators non-compliant. Given a dispensation is then required to operate with a dead band, the size of the dead band for which the dispensation is sought is at the discretion of the generator. Operating with a larger dead band is likely to be more preferable for a generator.

An allowance for a small dead band, around 25 mHz, in the Code is recommended. A dispensation would then not be the default position for a large percentage of generators, reducing the likelihood that governors will be set with a larger-than-necessary dead band.

This will result in tighter frequency control within the normal frequency band. The dispensation process will be required for governors with larger dead bands.

4.5 Droop

4.5.1 Droop Background

The permanent droop of a governor system is a mechanism which changes the apparent output set point of a generator as a proportional response to changes in frequency. As the system frequency increases beyond the set point frequency (50 Hz), the permanent droop of the governor reduces the apparent generator output set point. Similarly, as the system frequency decreases below 50 Hz, the governor increases the apparent generator output set point.

The droop percentage refers to the percentage change in frequency that is necessary to cause the output of the generator to change from zero output to full output. For example, the set point of a generator with 7 percent droop will increase from no output to full output if the frequency decreases by 7 percent. A smaller change in frequency will result in a proportionally smaller change in generation. If the frequency remains constant, the generator output remains constant.

It is important to note that droop itself is only acting to change the apparent generator output set point, but it does not reflect how long it will take for the plant to reach that point; this is determined by the dynamic characteristics and gains of the plant.

4.5.2 Effects of Droop on Governor Response to Frequency Changes

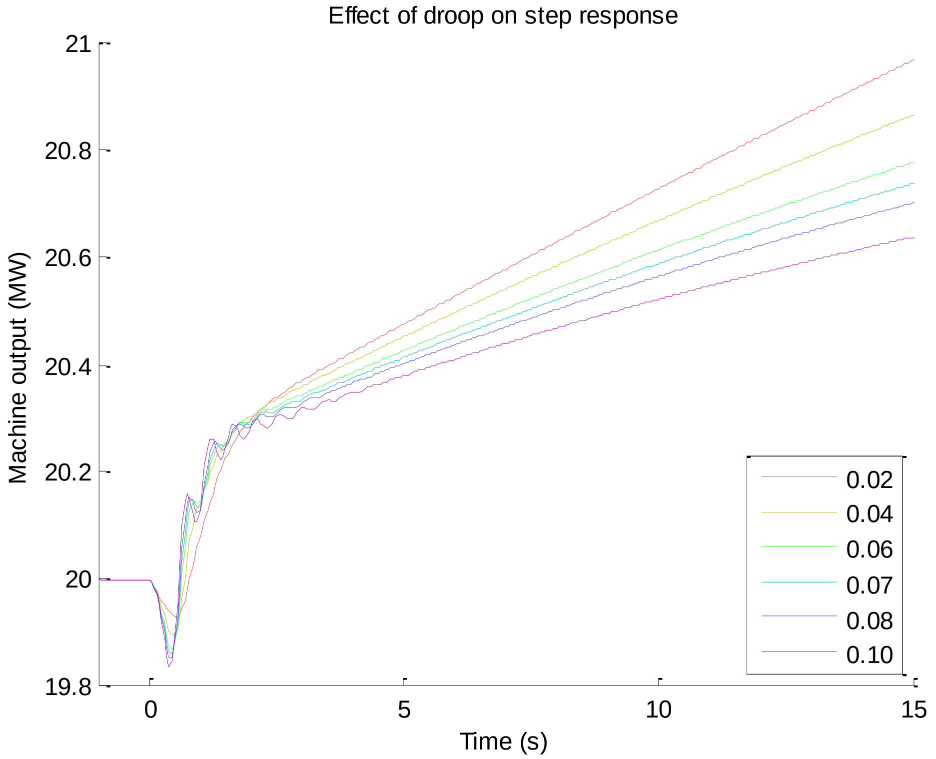

Figure 7: Step response test on machine B

Figure 7 demonstrates how changing speed droop changes the output of a machine. A frequency drop of 0.1 Hz was injected into the governor model for Machine B to show the effects of changing the droop. As droop decreases, the governor response to step changes increases, resulting in a larger power output.

4.5.3 Effects of Droop on Governor Stability

The effects on governor stability of changing the permanent droop of a hydro governor have been studied using dynamic step response tests and frequency response tests, as described in Section 4.2. As with dead band, increasing the value of the permanent droop reduces the response of a machine, making it more stable. Conversely, decreasing the permanent droop makes it less stable. The study results are shown in the Nyquist plot in Figure 8.

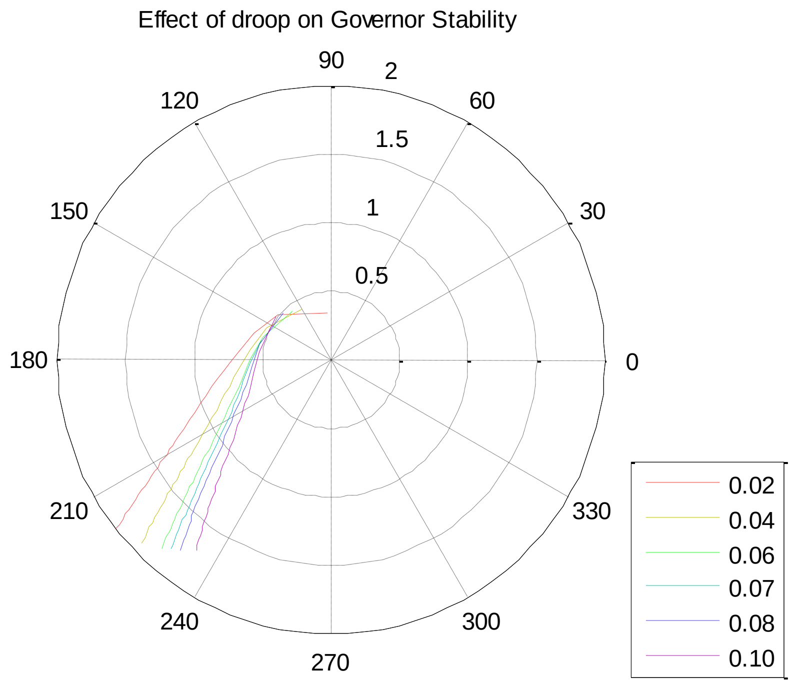

Figure 8: Nyquist plot showing the effect of droop on machine B

4.5.4 *Droop Study Results*

Several types of studies were performed in an effort to determine the optimal droop response for all generators on the New Zealand power system; these studies proved inconclusive. Droop is not an isolated parameter, and to be most effective, a change in droop must be accompanied by changes in gain settings (as seen in the next section). Also, each generator has many dynamic properties which affect the response to frequency, so modelling each generator with an identical droop does not indicate that each generator will have an identical response. Finally, initial plant generation and system loads also affect the system response to frequency deviations, and these factors are constantly changing.

Because the Code currently stipulates that governors be capable of droop settings between 0 and 7 percent, rather than specifying that the droop must be set within this range, Transpower suggests tightening the language in the Code to mandate that the droop setting should be 7 percent or less. For clarity, Transpower also recommends striking the word “adjustable” in reference to droop.

4.6 Gain

4.6.1 *Droop Versus Gain*

The Code currently contains requirements for droop settings but does not explicitly mention gain, except to say that a generating unit’s proportional response to frequency must not be unduly limited. The studies in this report confirm that gain is an important factor in maintaining system frequency, and it should be stipulated in the Code.

Both droop and gain collectively are necessary to improve the dynamic performance of a machine. As shown above, reducing droop will increase the effective dispatch point of the machine under reduced frequency conditions, but the governor's proportional and integral gains determine the time required for the machine to reach its new set point value. A machine can have a very low droop setting but still be unresponsive to changes in frequency if the gain setting is low.

4.6.2 Re-tuning Governors to Improve Dynamic Response

The majority of governors in the New Zealand power system can be described as a PI (Proportional-Integral) controller. This classical control system uses two tuneable parameters to influence the response of a system. The proportional gain, Kp, makes a change to the generator output that is proportional to the current frequency deviation from nominal. The integral gain, Ki, is proportional to both the magnitude of the frequency deviation and the duration of the deviation. By varying the values of the PI controller, the response of the governor can be altered to give an optimal result.

To demonstrate the effect of each gain parameter, studies have been done to determine the effect on generator responsiveness and governor stability of raising and lowering an individual parameter. The base case (Kp = 2.80, Ki = 0.52) has been included to provide a common reference point across studies.

4.6.3 Proportional Gain

Figure 9 shows the effects of varying the proportional gain for Machine B while keeping the integral gain constant. Because the proportional gain, Kp, is proportional to the current deviation from nominal frequency; increasing the proportional gain increases the initial response to a change in frequency.

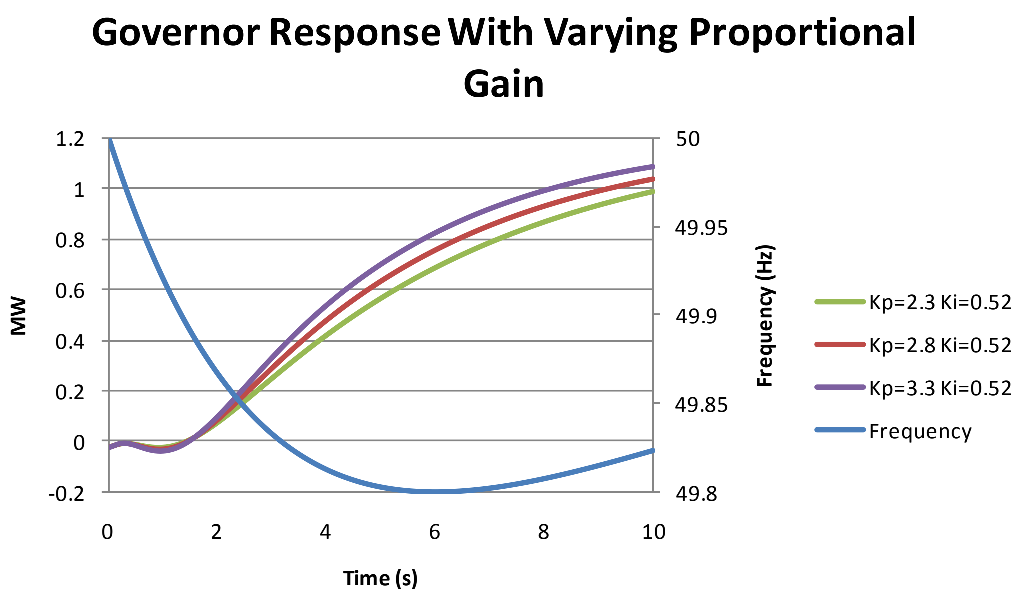

Figure 9: Machine B with Varying Proportional Gain

Figure 10 is a Nyquist plot showing the effects on Machine B of varying the proportional gain while holding the integral gain constant. The effect of proportional gain can be described as a rotation of the Nyquist plot. The plot shows that increasing the gain settings decreases governor stability, but the governor doesn't become unstable unless the plot encircles the point (-1, 0).

For Machine B the proportional gain setting can be increased without making the governor unstable.

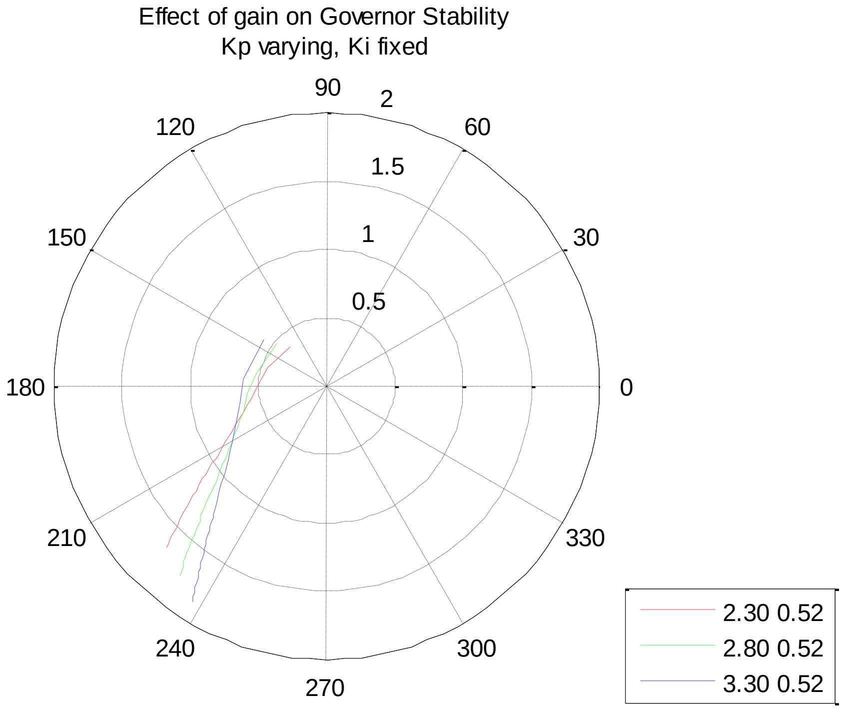

Figure 10: Nyquist plot showing the effect of Proportional gain on machine B

4.6.4 *Integral Gain*

Integral gain is proportional to the magnitude of the frequency deviation, but is also proportional to the duration of the deviation from nominal frequency. The longer the frequency is higher or lower than 50 Hz, the greater the integral gain will be. The initial response of integral gain is not as great as proportional gain, but it has a larger effect over time. Figure 11 demonstrates the response of Machine B to a frequency deviation within the normal band, with varying integral gain (Ki) and constant proportional gain (Kp).

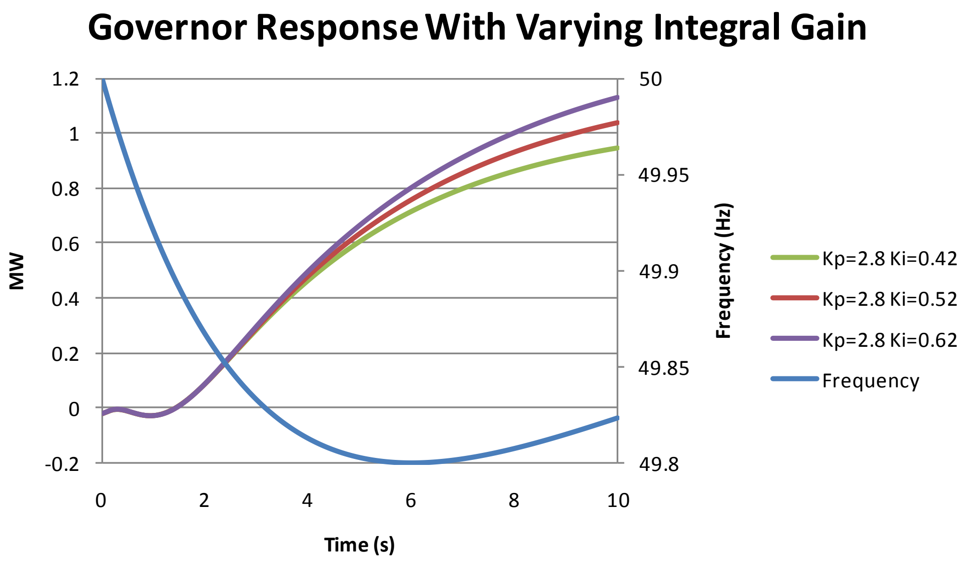

Figure 11: Machine B with Varying Integral Gain

Because integral gain is compensating for sustained errors, it has a greater impact on the machine response at lower frequencies. It has less of an impact on governor stability than proportional gain. Figure 12 shows the effects on governor stability of varying the integral gain. Again, for Machine B, the integral gain can be increased without making the governor unstable.

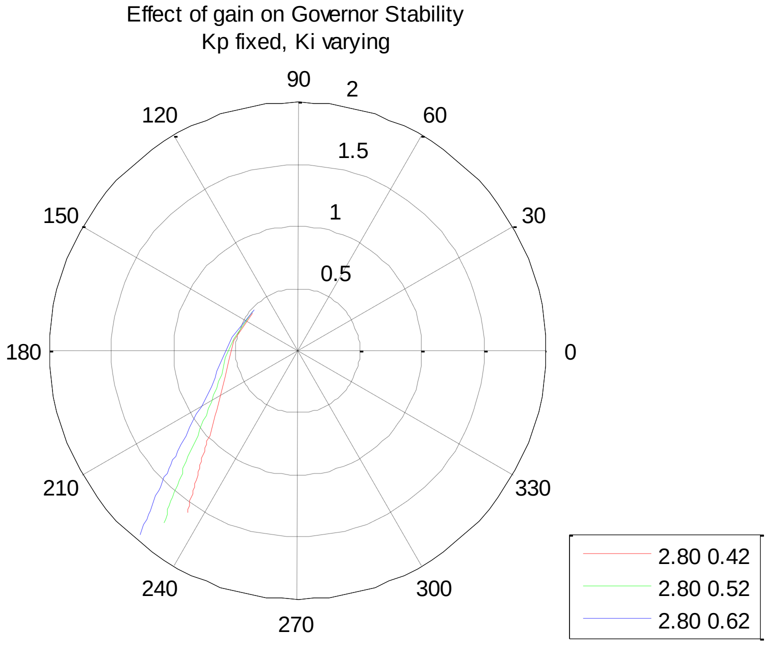

Figure 12: Nyquist plot showing the effect of Integral gain on machine B

4.6.5 *Combined Effect of Proportional and Integral Gains*

By combining the effect of the proportional and integral gains, the frequency response and governor stability of a machine can be manipulated. Figure 13 shows that by tuning both the proportional gain and integral gain parameters simultaneously, a generator can be made both more stable and more responsive to frequency deviations.

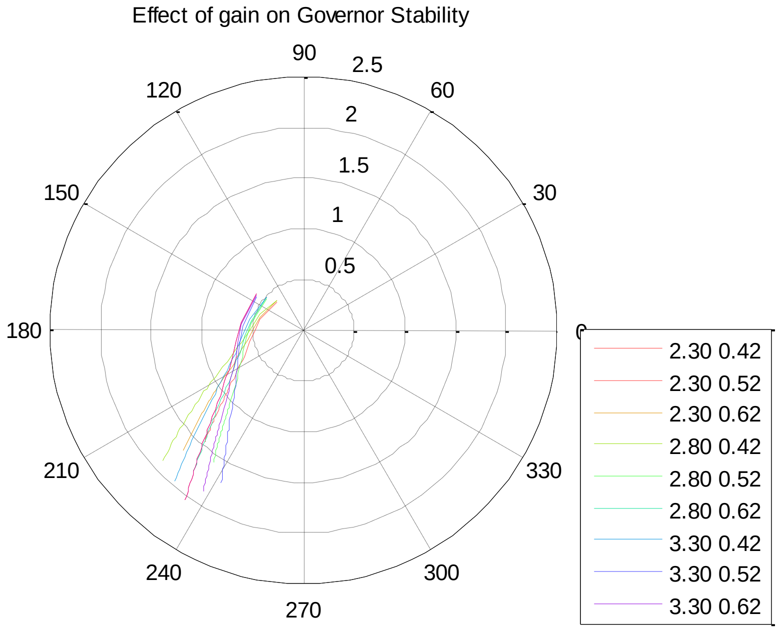

Figure 13: Nyquist plot showing the effect of Gain on machine B

4.7 Summary

Dead band, droop, and gains collectively influence the frequency response of generator governors. All of these characteristics can be used to reduce the response of a machine while droop and gain settings can also be used to improve the machine response.

From the studies performed, the effect of introducing a small dead band centred around 50.00 Hz will have minimal impact on the single machine stability and on generator responsiveness to frequency deviations. The larger the dead band, the larger the impact on both stability and responsiveness.

Tuning droop and gains can improve the responsiveness of the machines studied. Governor stability is important, so studies should be performed to ensure that the governor gives the maximum response without becoming unstable.

5 Recommendations

5.1 Time Error

Transpower believes the Electricity Authority should take steps to remove the 5-second time error obligation because it would appear that the System Operator, in meeting the time error obligation, could affect system security without a corresponding benefit to participants. The requirement to meet the time error obligation at all times directly conflicts with the collective frequency management obligations on the System Operator and generators. Appropriate consultation and perhaps a trial prior to its removal may be appropriate to ensure there are no adverse impacts on participants, or the power system, from its removal.

5.2 Generator AOPOs

The System Operator recommends the following changes to the generator AOPOs in relation to normal frequency:

- Revise the Code to add a small dead band allowance of 25 mHz. Studies show that the system response and governor stability would not be unduly affected with a small dead band.
- For clarity, modify the wording in the Code surrounding droop to specify that the droop setting should be no more than 7 percent and remove the word "adjustable" in reference to droop.
- Add a clause to the Code specifying that proportional and integral gains be as high as possible without making the respective governor unstable. Technology and software in common use today make it possible to test and verify these settings.

Appendix A: Bode Plots

This appendix contains Bode plots corresponding to the Nyquist plots in the body of this document. The same information is contained in both sets of plots, but some find the Bode representation more helpful than the Nyquist representation.

The terms “Gain Margin” and “Phase Margin” are used in the following tables to describe the relative stability of a system:

Gain margin is defined as the negative of the gain (in dB) at the frequency where phase is -180°,

Phase margin is defined as the angle between -180° and the angle where the Gain margin is 0dB.

For comparison, the Transpower Companion Guide to Asset Testing suggests a gain and phase margin of 3dB and 25° respectively as a suitable tuning target.

A.1: Dead Band Study Results

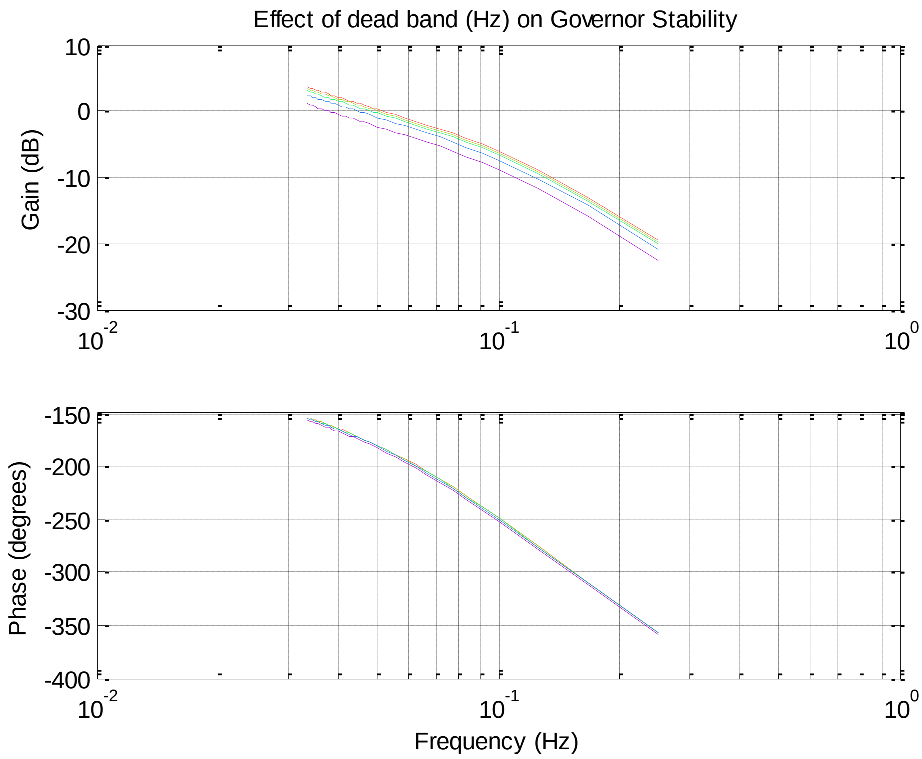

Figure 14: Bode plot showing the effect of dead band on machine A

Dead band size (Hz)	Gain Margin (dB)	Phase Margin (°)
0.000	-0.283	-2.69
0.010	-0.076	-0.70
0.025	0.245	2.26
0.050	0.802	7.18
0.100	2.011	16.26

Figure 15: Machine A dead band test results

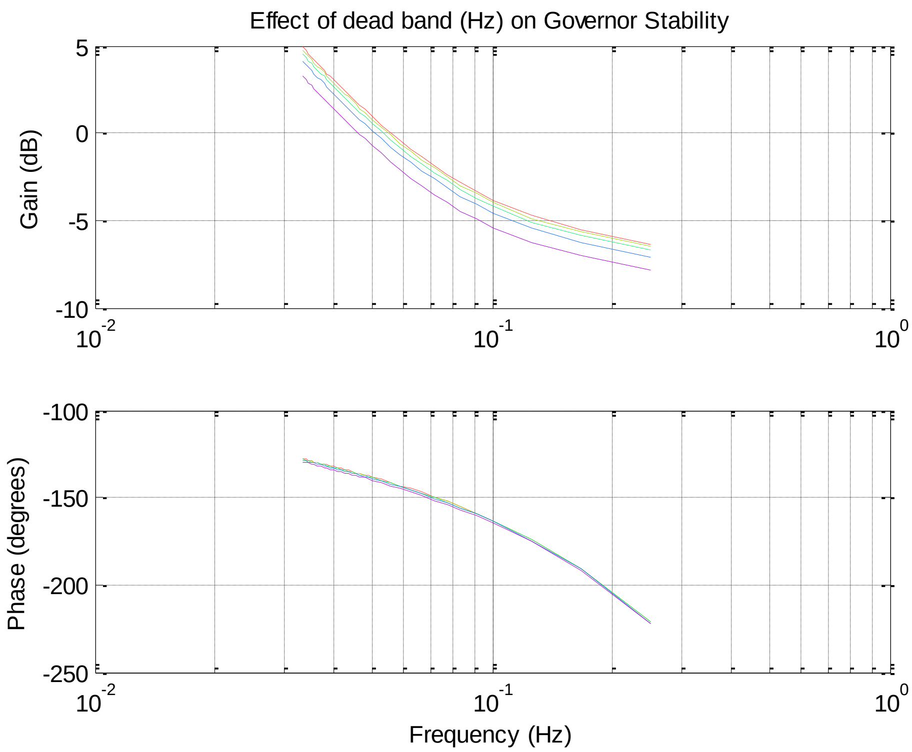

Figure 16: Bode plot showing the effect of dead band on machine B

Dead band (Hz)	Gain Margin (dB)	Phase Margin (°)
0.000	5.142	38.51
0.010	5.276	38.91
0.025	5.480	39.50
0.050	5.831	40.42
0.100	6.575	42.13

Figure 17: Machine B dead band test results

A.2 Droop Study Results

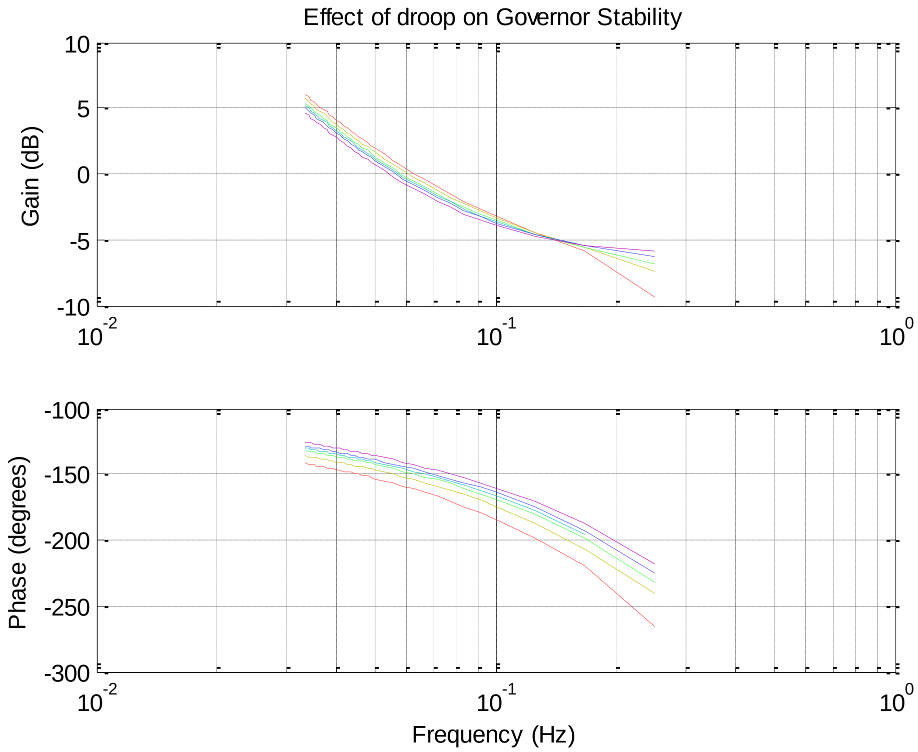

Figure 18: Bode plot showing the effect of droop on machine B

Droop	Gain Margin (dB)	Phase Margin (°)
0.020	2.745	18.60
0.040	3.905	27.16
0.060	4.508	32.74
0.070	4.760	35.16
0.080	4.969	37.42
0.100	5.273	41.63

Figure 19: Machine B droop test results

A.3 Proportional Gain Study Results

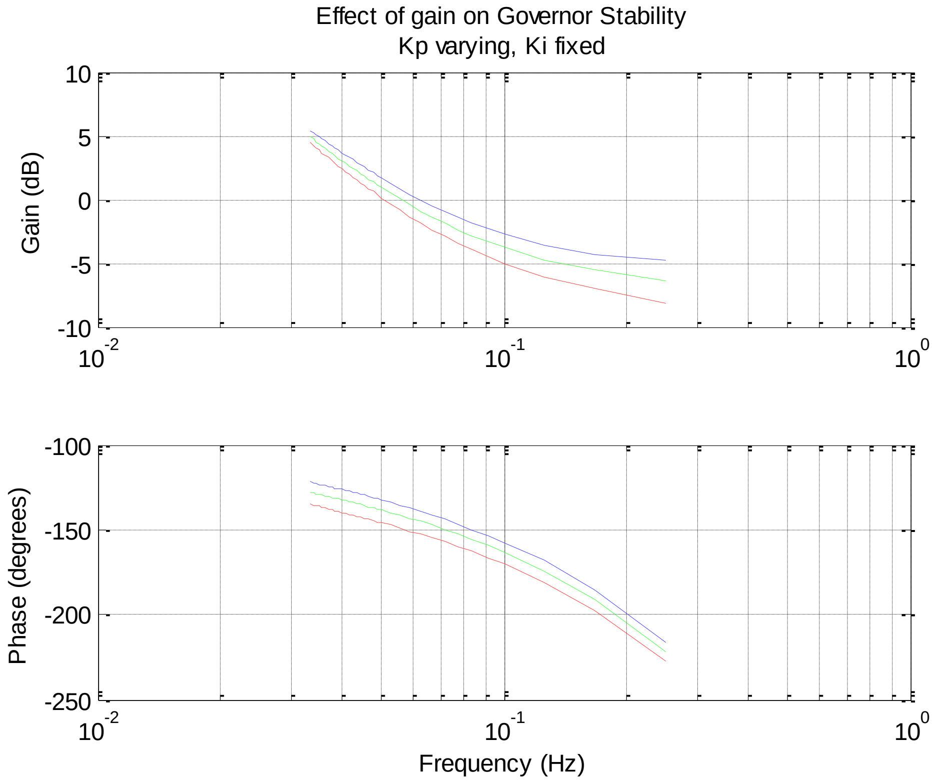

Figure 20: Bode plot showing the effect of Proportional gain on machine B

K_p	K_i	Gain Margin (dB)	Phase Margin (°)
2.30	0.52	5.962	33.62
2.80	0.52	5.111	38.40
3.30	0.52	4.169	40.92

Figure 21: Machine B proportional gain test results

A.4 Integral Gain Study Results

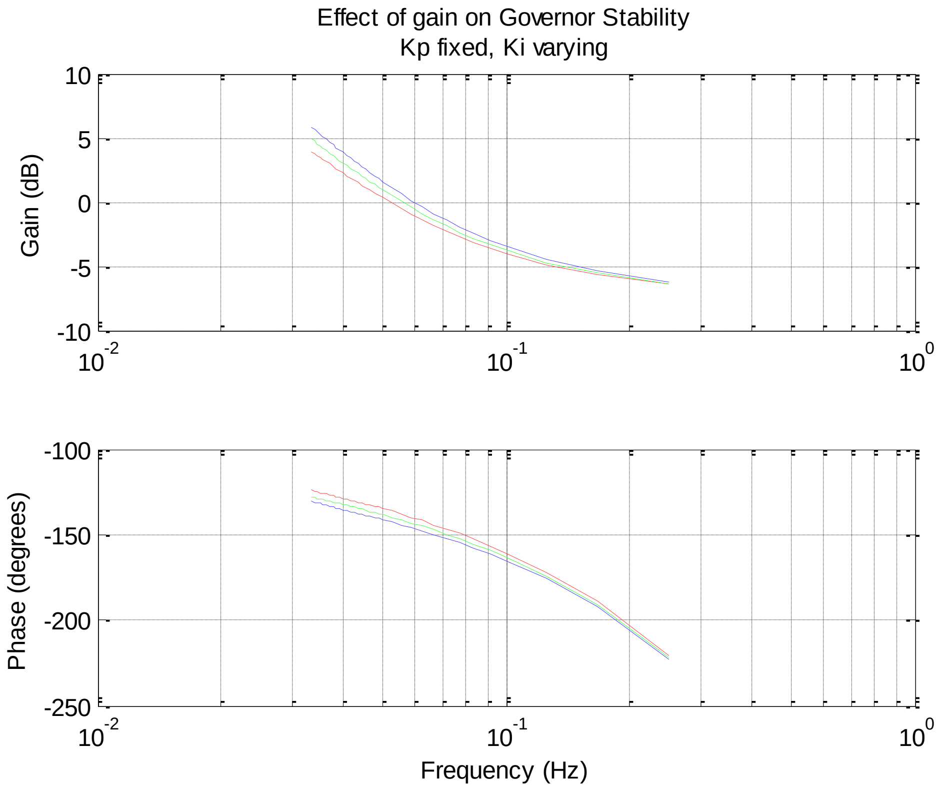

Figure 22: Bode plot showing the effect of Integral gain on machine B

K_p	K_i	Gain Margin (dB)	Phase Margin (°)
2.80	0.42	5.417	44.10
2.80	0.52	5.111	38.40
2.80	0.62	4.771	33.40

Figure 23: Machine B integral gain test results

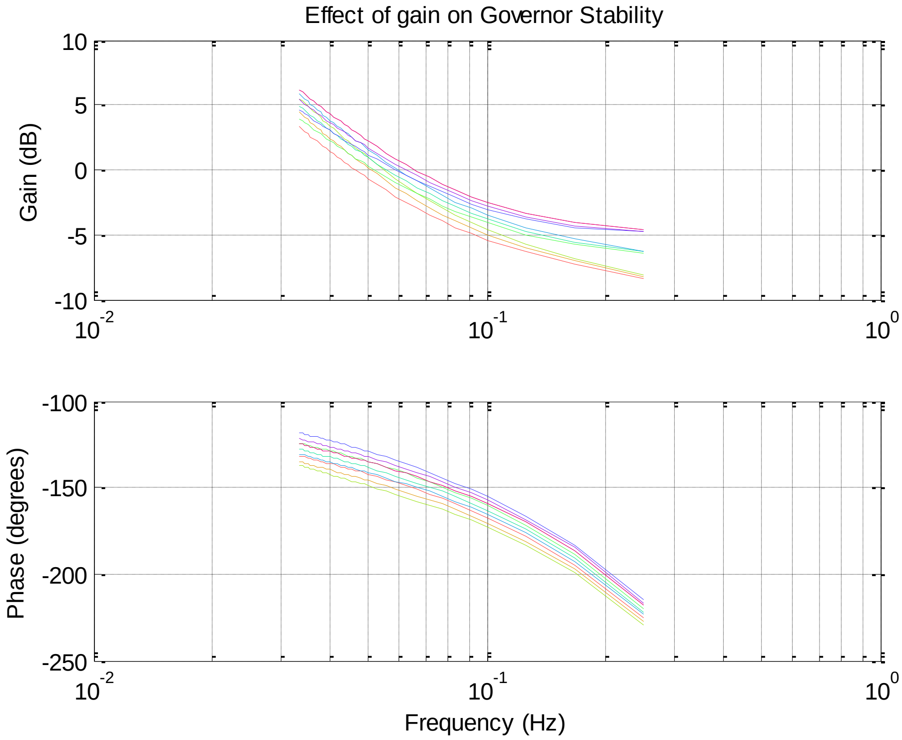

Figure 24: Bode plot showing the effect of Gain on machine B

K_p	K_i	Gain Margin (dB)	Phase Margin (°)
2.30	0.42	6.439	39.89
2.30	0.52	5.962	33.62
2.30	0.62	5.426	28.26
2.80	0.42	5.417	44.10
2.80	0.52	5.111	38.40
2.80	0.62	4.771	33.40
3.30	0.42	4.376	45.80
3.30	0.52	4.169	40.92
3.30	0.62	3.940	36.46

Figure 25: Machine B gain test results