

System Operator TASC Report

Multiple Frequency Keepers Project – Report 2

Alternative Market Designs Alternative Market Designs

1/10/2010



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1 Executive Summary

The EC have a multiple frequency keepers project and as part of that project formed an Automatic Generation Control (AGC) Technical Stakeholders Group (TSG). The function of the group is to investigate how AGC might be implemented as a means to allow multiple frequency keepers in each half hour. At the EC's request Transpower previously put to the TSG a strawman proposal on how AGC might be implemented. The TSG reviewed the strawman and asked Transpower to investigate an alternative (simpler) approach. Specifically:

- Could AGC control of regulation be implemented at a block level (as per energy) with all blocks providing a minimum guaranteed ramping capability¹?
- Could AGC control of regulation be implemented separate to the current energy dispatch arrangements?; and
- Are alternative technical interfaces possible?

The EC also asked Transpower to investigate different (more complicated) offer and dispatch arrangements:

- What would be involved in implementing alternative offer fan form of offers or separate raise and lower offers; and
- Could real time dispatch arrangements account for energy costs?

On the first two issues our overall conclusion is that the alternative approach is technically feasible, and may be simpler to implement than our proposed strawman AGC design. However, we are concerned that it may result in a higher cost of frequency regulation relative to our previous strawman AGC design². It is difficult to fully assess the trade off between market sophistication (and associated implementation difficulties) and economic gains of more sophisticated markets³. A pragmatic way forward may be to undertake a technical trial of AGC. It would be good to discuss with the TSG the level of support for a trial and what form the trial should take.

The alternative technical interfaces are possible but would need to meet appropriate performance standards. It is suggested that we could commence work on draft interface standards now, but refine them after any trial.

Alternative offer and dispatch arrangements are possible but would be difficult to implement before co-optimisation. It is recommended further investigation of such alternative offer and dispatch arrangements are delayed till after any trial of the basic AGC arrangements.

1.1 Block Control of Regulation

Block control of regulation is possible. However, there may be a trade off between the level of sophistication of the regulation market design and the costs of frequency regulation.

The simple approach suggested by the TSG, with a minimum guaranteed ramp rate and uniform participation factors, could lead to more expensive frequency

¹ Effectively meaning all blocks would be assigned the same participation factor. As there would be no differentiation of participation factors based on the technical capabilities (e.g. ramp rates) of different blocks.

² These concerns are based on the apparent trade off between ramp rate and procured regulation quantity from the simple modelling done as per Appendix 1 (refer final chart at end of Appendix 1). However this modelling is a rather limited representation of the complexity of the real power system and market behaviour.

³ We are of the view that more and more sophisticated modelling is unlikely to yield more information about how the more sophisticated market may work, as it would require an intractable amount of information about both how generating companies would implement AGC controls in detail and how they might vary their offer strategies as the market evolves.



regulation, compared to if variable participation factors, based on ramp rate offers, were used.

The simple modelling done so far seems to indicate a trade off between frequency quality, control system latency, and generator ramp rates. Introducing latency in the control loop, such as may arise from block level control, reduces frequency quality. This reduction in frequency quality may be able to be offset by utilising the full ramping capability of faster ramping blocks. However, the approach suggested by the TSG was based on a minimum entry standard (including ramp rate capability) and uniform participation factors for all blocks. Compared to using the full ramping capability of all blocks this is might increase frequency regulation costs, as we might need to either set a high entry standard (and reduce competition) or procure more regulation⁴.

This possible increase in frequency regulation costs may be able to be minimised by:

- Minimising the delays in the control loop; and
- Maximising the level of information the AGC system has about ramp rate capabilities of a block.

However, taking advantage of the greater ramping capability of some blocks is likely to require a more sophisticated market design. For example participants could offer their block ramping capability and participation factors would be calculated from such ramping capability and be used for scheduling, dispatch and payment. So more capable blocks would be used more and paid appropriately. Although a more sophisticated market design is likely to result in a more efficient market, and hopefully lower frequency regulation costs, it is likely to be more expensive and timely to implement.

1.2 Separation of Energy and Regulation Dispatch

It is possible to dispatch regulation and energy separately, as we do at the moment. However, this is likely to be more expensive in frequency regulation costs, relative to a situation where we co-ordinated energy and regulation dispatch. Two options for such co-ordination would be either an agreed energy ramping profile within the 5 minute dispatch, or dispatching energy and regulation on a 10 second basis.

If energy is dispatched on a 5 minute basis and regulation on a shorter (10 second) basis then it is difficult for the SO to monitor when a regulation provider is not responding to regulation dispatch instructions. Also timing of how generators ramp within the 5 minutes can cause frequency bumps if they are not co-ordinated. Both problems lead to the SO needing to procure more regulation than they would otherwise (if regulation and energy dispatch were co-ordinated at a 10 second level).

The monitoring problem is that we can only measure aggregate total MWs that a block is providing. To decompose this into response to energy dispatch and response to regulation dispatch we need to know how they are responding to energy dispatch within the 5 minute period.

To address this problem we would thus need either an agreed 5 minute ramping profile, or to dispatch energy on the same (10 second) dispatch period as regulation, for regulation providers. Our preference would be for regulation providers to be dispatched on a 10 second basis for energy as well as regulation.

⁴ Either by setting a greater quantity of regulation to be procured total or by requiring a certain total aggregate ramp rate to be met collectively by all cleared offers, which in turn might lead to a need to procure a greater total quantity.

1.3 Alternative Interfaces

The use of third party communications channels for the AGC interface is technically possible but they would need to meet appropriate standards of security, reliability and latency.

Alternative physical interfaces, such as via an RTU, for receipt of regulation orders are possible for any trial of AGC, but are not recommended as an operational solution, due to difficulties in maintaining and supporting interfaces on other parties property.

1.4 Alternative Offer and Dispatch Arrangements

Fan form offers and separate raise and lower offers are possible but would require additional work in the security assessment process (as the quantity of regulation offer available depends on the cleared energy quantity). It is suggested that such alternative offer forms are best left for consideration as part of any move towards co-optimisation.

AGC is able to assign participation factors, for real time dispatch of regulation, based on constrained on energy costs. However this is unlikely to lead to any significant reduction in constrained on costs. Also it implies different providers would contribute differently to frequency quality, i.e. have different participation factors assigned. As with ramp rate based participation factors this may need to be taken into account in settlement. So it is recommended this be delayed till after AGC and co-optimisation are bedded in.

1.5 For Discussion with TSG

Given the results of this further investigation it would be good to discuss the following questions with the TSG:

- *Level of regulation market sophistication*
 - *What level of regulation market sophistication should we adopt for the initial market design (or trial)? I.e. Should we allow for different block ramp rates, and assign participation factors based on ramp rates, or not?*
 - *If we do wish to allow different block ramp rates then:*
 - *What are the difficulties (and costs) associated with provision of information on block ramping capability and how often this information would need to be updated?*
 - *Whether they consider the market design needs to be modified to account for the extra “work” (higher participation factors) fast ramping blocks would do compared to slow ramping blocks?*
- *Implementation of block dispatch of regulation:*
 - *If AGC control of regulation is implemented at a block level then how generating companies intend to process regulation instructions within their block controls?*
- *Co-ordination of energy and regulation dispatch:*
 - *What level of market sophistication, on co-ordinating energy and regulation dispatch should we adopt for the initial regulation market design (or trial)?*
 - *If we do wish to co-ordinate energy and regulation dispatch then should this be by an agreed ramping profile with the 5 minute dispatch period or energy dispatch moving to a 10 second basis?*
- *Alternative interfaces*
 - *What issues do members see with third party communication providers meeting minimum standards for latency, reliability and security?*
 - *Do members see any issues with implementing an ICCP interface?*
- *Alternative offer and dispatch arrangements*



- *Do members agree more detailed investigation of alternative offer and dispatch arrangements should be left till after some basic form of AGC, and co-optimisation of energy regulation and reserves, has been implemented?*
- **AGC Trial**
 - *Should we proceed to a trial of AGC?*
 - *If so what should be the basis of such a trial?*

2 Introduction

A proposed AGC project scope was developed by the System Operator (SO) at the request of the Electricity Commission⁵. This scope was reviewed by the AGC Technical Stakeholders Group (TSG), who raised a number of technical issues.

The Commission initiated a TASC request for the SO to investigate the following issues raised by the TSG⁶:

| | | |
|-----|---|--|
| 3.1 | Coordination of block dispatch and frequency regulation | Consider the workability of keeping block dispatch intact and offering frequency regulation at the same level as for energy and reserve. What would be the consequences of failure of SCADA for a station or station block for AGC? |
| 3.2 | Coordination of central and generator AGC systems | Consider continuing to issue separate instructions for energy, reserve, and frequency regulation. Why does an AGC system require a single instruction? |
| 3.3 | Provision of unit level FR information | Consider the alternative of standard ramp rate associated with a frequency regulation offer. |
| 3.4 | Provision of short term ramp rates | The group would like to understand the reasons for 10 second and 60 second ramp rates being required in real time from each unit? What are the advantages/benefits in having them? |
| 3.5 | Calculation of participation factors | Consider consequences of the alternative to the requirement for participations factors - raise/lower output of all stations dispatched for frequency regulation at the same rate. |
| 3.6 | Dispatch order interface | Will the SO implementation of ICCP allow for third party communication links? Does ICCP need to be mandatory for frequency regulation dispatch? Are there alternatives that could be accommodated (e.g. DMT via SCADA, Genco)? |
| 3.7 | FR selection and co-optimisation | Can/should dispatch of frequency regulation take energy costs into account? |
| 3.8 | Form of FR offer | Consider implications of fan-form offers in fully realised frequency regulation market as alternative to frequency minimum and maximum constraints. |
| 3.9 | Separate raise and lower products | What implications can the SO foresee with separating raise and lower services? |

This report provides a response on each of the issues raised by the TSG and identifies further issues arising from this investigation. It is suggested that these should be further discussed with the TSG.

⁵ TASC Request TASC001

⁶ Issue numbers are as per the EC request TASC006

3 Approach

In accordance with the EC request⁷, the investigations are only to identify if the alternative AGC design proposed by the TSG is technically feasible. Accordingly we have not attempted to cost this alternative.

The issues raised by the TSG were grouped into related topics. Issues 3.1 to 3.5 are reasonably complicated and a two stage approach will be required. Issues 3.6 to 3.9 are relatively straight forward and can be addressed in a single step.

3.1 Block, or Unit Level Control (Issues 3.1 to 3.5)

Issues 3.1 to 3.5 relate to whether AGC control is at block, station or unit level. The SO strawman design was based on unit level control and combining energy and frequency dispatch orders⁸. This was due to concerns that uncertainty about ramping capabilities of generators at the block level, including delays in the control loop, could lead to poor frequency quality or instability in the AGC control loop⁹. The TSG expressed concern at this approach and requested the SO investigate an alternative approach based on block level control, a set minimum ramp rate, and separating energy, reserve and FR dispatch orders.

Investigation of this issue involved a two step approach:

1. International Investigation
2. Power System Dynamic Stability Modeling

In the international investigation stage discussions were held with other power system operators that currently operate AGC to find out if any of them have implemented AGC control at a block level and determine issues that need consideration.

Following the international investigations some high level modelling to determine the nature of the tradeoffs between power system quality and AGC control arrangements was carried out.

3.2 Dispatch Interface Issues (Issue 3.6)

Issue 3.6 relates to how the ICCP interface might be implemented and whether alternatives are possible. This is a relatively simple issue and was discussed and resolved with our market systems experts.

3.3 Offer and Dispatch Issues (Issues 3.7 to 3.9)

It is assumed that issue 3.7 relates only to the dispatch of individual frequency keeping providers in real time by RTGEN and therefore relates to how RTGEN accounts for energy costs in calculating participation factors. This was also a relatively simple question on whether RTGEN can account for energy costs and if so how they could be passed to RTGEN from 5 minute dispatch.

Issue 3.8 and 3.9 relate to whether the FR selection process could be modified to take account of fan form of offers and separate raise and lower offers. These were relatively straight forward questions that can were addressed by our market services team.

⁷ Noted in section 4 of AC TASC006.

⁸ It is noted that the SO strawman approach (block dispatch of energy but unit dispatch of regulation) would have required further modification to address how energy and regulation dispatch were to be co-ordinated at a unit level.

⁹ Instability issues mainly arise where AGC assumes faster ramp rates or longer delays than a generator is actually capable of delivering. In general such instability can usually be eliminated by careful testing of actual control loop characteristics during commissioning of the AGC system.



Issue 3.9 also impacts on dispatch of frequency keeping and is a question of whether RTGEN could accommodate separate raise and lower constraints on dispatch of providers. This was a relatively straight forward question on the capability of the RTGEN software.

4 Response to EC Questions

4.1 Block, Station or Unit Level Control Issues

Items 3.1 to 3.5 are all related and hinge on whether the alternative approach, as proposed by the TSG, of block dispatch with all blocks having minimum guaranteed ramp rates and uniform participation factors, can provide a reasonable level of frequency quality. Both international investigations and high level modelling studies has been undertaken.

Overall our conclusion is that dispatch of regulation by AGC at the block level (or the same level as energy is dispatched) may result in a higher frequency regulation costs, compared to AGC dispatch with variable participation factors (based on ramp available ramp rate). The magnitude of any such increase in costs is difficult to quantify, short of a trial of AGC, and would be dependent on the details of how the block control is implemented, regulation offer strategies etc. Specific questions, on how block control might be implemented, are further discussed in section 5.

The TSG approach effectively proposes dealing with any possible instability issues by adopting a lowest common denominator approach where by all regulation providers would guarantee to meet a certain minimum ramp rate and maximum response time. This should avoid control loop instability problems, although it would be difficult to be certain without extensive field trials. However it does mean that many blocks may well be capable of delivering greater ramping capability, or shorter response times, than these guaranteed minimums. If this extra capability is not utilised it may result in the need to procure greater quantities of frequency regulation and possibly higher frequency regulation costs. It would be difficult to properly quantify these concerns short of a trial.

On the related issue of consequences of a failure of the SCADA associated with a block our assumption is that SCADA failure would render that block unavailable for regulation and the duty would have to be taken up by other frequency regulation providers.

4.1.1 International Investigations

Australia - AEMO

On the international investigations front we note AEMO have implemented block dispatch of stations in the Snowy hydro scheme, and of hydro stations in Tasmania. Key issues for NZ identified in the discussions with AEMO include:

- AGC manages both energy dispatch and frequency management in Australia. We will need to think about how to manage the interaction of generating companies not providing regulation, and those who are providing regulation but are also the marginal energy provider, to avoid “bumps” at the 5 minute (or half hour) change over.
- Managing ramping of generators via AGC has enabled them to manage frequency with a relatively small quantity of regulation (FCAS) service.
- The use of the Basslink frequency control service (mode of HVDC frequency control suggested for NZ) means that the time error in Tasmania is sometimes “at the mercy of the Basslink frequency controller”.



- Modeling of the block dispatch groups (Snowy and Tasmanian stations) as a single unit for frequency control does raise some issues wrt managing transmission constraints within a block and the accuracy of the model from a frequency control point of view. We may need to think about how constraints within a block are managed for frequency control (possibly simply replicating the current block dispatch rules for energy).
- The frequency quality, particularly in the low inertia Tasmanian island, is lower under AGC than it was when controlled directly by the local generating company.

Other Jurisdictions

Discussions with AREVA identified ERCOT in Texas and AESO in Alberta as two other utilities that had implemented block frequency management via AGC. They did identify some specific issues with managing stability with block management and slow ramping units. Customisation of RTGEN is assumed to be outside this investigation and will, presumably, be addressed at a later stage in the process.

Ongoing Investigations

Both national and international investigations are continuing in parallel to this report being provided. We continue to discuss with both AEMO and Meridian (who manage frequency in the SI by managing their block via AGC when they are responsible for SI frequency) the details of how they implemented AGC and any specific problems they encountered in frequency management via AGC.

Modelling

On the modelling front we undertook some high level modelling to identify the likely key parameters that may impact the frequency quality under block dispatch of regulation. Modelling results are provided in Appendix 1. These appear to show that the key trade off will be between overall control system end to end loop latency, and ramping capability. This is particularly sensitive for times when the system inertia is low, e.g. when the SI is islanded from the NI. There may also be a trade off between aggregate total ramping capability and the quantity of regulation needed for a given frequency quality.

4.2 Dispatch Interface Issues

Addressing each of the interface issues raised by the TSG:

4.2.1 *Third Party Comms*

Although there are no intrinsic reasons third party comms links could not be used for the AGC dispatch interface, there are likely to be practical limits on end to end delay, link reliability and security. Development of standards for such third party comms links should be part of the next stage of investigation.

4.2.2 *ICCP Mandatory or Alternative Interfaces*

Although ICCP may not need to be mandatory a key issue for any alternative interface would be maintaining the security and reliability of the proposed alternative. AGC is a real time control of the power system and as such will be implemented within the secure SCADA level environment in Transpower. We can implement the interface in a manner which isolates external links from our secure environment.

One possible alternative would be to implement AGC controls via RTUs, as this maintains the secure SCADA environment. However, this alternative may have its own problems in terms of support and ongoing maintenance as it inevitably involves connection across physical ownership boundaries with all the attendant access issues.



So although such alternatives may be acceptable for an initial trial of AGC Transpower's preference would remain for the final AGC implementation arrangement to be based on an ICCP interface.

4.2.3 Back Up Arrangements

The current frequency keeping arrangements do not have any back up arrangements should the assigned frequency keeper fail, other than relying on free governor action and dispatch to control frequency. The proposed AGC based regulation arrangements depend on a central control element in the AGC platform itself. The question was asked as to whether it would be worthwhile considering whether some sort of back up arrangement, as we have for dispatch, might be needed. Overall our assessment is that it is unlikely to be worthwhile developing back up arrangements for AGC based regulation arrangements, due to the increased diversity of multiple providers and the high (SCADA level) availability of the centralised control system.

4.3 Offer and Dispatch Issues

4.3.1 FR Dispatch Accounting for Constrained on Energy Costs (3.7)

Initial investigations suggest it should be possible for the real time dispatch of FR to assign participation factors that account for energy costs, based on cleared offers. That is RTGEN is able to accept an energy cost input into its dispatch algorithm¹⁰ in the form of participation factors. We presume these marginal energy costs could be derived from the generator offers in some way, e.g. by looking at energy costs in next tranche, but have not investigated in detail exactly how this would be done, as this is a preliminary feasibility investigation only at this point.

It is not clear that this approach would significantly lower constrained on costs. Particularly if other measures aimed at reducing constrained on costs, such as co-optimisation, were in place.

It also raises an issue on how we should pay regulation providers, based on their participation factors. If a particular regulation provider has a high participation factor assigned it will do more regulation duty than a provider with a low participation factor. Should regulation providers with high participation factors be paid more than those with low participation factors?

In summary this approach could be relatively complicated to implement and may not bring significant additional benefit. It is recommended that consideration of this approach be delayed till after AGC is bedded in and co-optimisation is in place.

4.3.2 Fan Form of Offer and Separate Raise and Lower Products (3.8 and 3.9)

Both fan form of offers and separate raise and lower products are possible but would be difficult to implement because of the need to more frequently perform the security assessment to ensure we have enough regulation available in real time. Both fan form offers and separate raise and lower products imply the level of regulation offered is dependent on the level of energy dispatched. For fan form of offer the relationship between energy dispatched and regulation available is inherent in the offer. With separate raise and lower products the relationship between regulation available and energy dispatched is implied as the ability to provide to offered level of regulation depends on whether the energy dispatch has sufficient room above (for lower) or below (for raise) the operating limits of the generator. For example consider a wind

¹⁰ It is assumed half hourly scheduling process already accounts for energy cost impacts of regulation via either a separate process or as part of co-optimisation. This issue is solely about how the real time dispatch (10 second AGC cycles) of regulation deals with energy cost impacts.

generator providing a lower regulation offer. It would not be known till near real time what level of energy it would be providing and what level of lower regulation it could provide.

So both fan form or offers and separate raise and lower products would require changes to the security assessment process as the level of regulation available depends on the energy dispatch for each generator. That is the security assessment process would need to be more iterative than it is at present, effectively imitating what would happen in co-optimisation. This would be a significant change to our current systems and could take some time to implement.

Given the above we suggest these issues might be better delayed till a second stage of market development, perhaps as part of co-optimisation.

5 Issues Arising

Three key issues arise from these investigations:

1. A possible tradeoffs between sophistication of the regulation market and frequency regulation quantities / costs;
2. The tradeoffs between co-ordinating regulation and energy dispatch and frequency regulation costs; and
3. The tradeoffs between total control loop delay and frequency quality.

5.1 Regulation Market Sophistication and Frequency Regulation Cost

The proposal from the TSG is for a simple regulation market with a minimum ramp rate requirement and uniform participation factors. Although this would be a simpler market to implement the SO is concerned that this approach could lead to higher frequency regulation costs relative to a slightly more sophisticated regulation market¹¹.

5.1.1 Ramp rates, Participation factors, and frequency quality / cost

As proposed by the TSG, generating companies would just have to meet a minimum ramp rate to participate in the regulation market and all participants would be assigned the same, uniform, participation factor based on this minimum ramp rate. This has the advantage that it makes for a simple regulation market design and is consistent with the current frequency keeping market design.

However it is likely to lead to a lowest common denominator approach to provision of regulation service. That is if all participants are to be paid the same, regardless of their ramping capability, then they have little incentive to ramp above the minimum required. The modelling done to date (Appendix 1) suggests that, all else being equal, the level of frequency quality that might result from this simple market design, could be worse than the current frequency quality achieved. (This appears to suggest some current frequency keeping providers may actually be providing ramping capability considerably above the minimum 10MW/min). Alternatively we may need to procure more regulation¹² to achieve the same quality and thus increase costs.

An alternative, more sophisticated, regulation market could lead to lower frequency regulation costs. For example a slightly more sophisticated frequency regulation market might involve participants offering ramp rates, as well as quantity and price in

¹¹ And possibly higher costs relative to the current arrangements.

¹² That is we are assuming that if a certain aggregate ramp rate across all offers cleared then we may need to clear more total offers to achieve this ramp rate.



their offers. The ramp rate information would be used to develop participation factors for each block. The total cleared regulation would have to meet both a total quantity and a total aggregate ramp rate requirement. (The current frequency keeping market has both a quantity and ramp rate requirement but achieves the ramp rate by setting an entry requirement. This is necessary where only one provider is scheduled. With multiple providers in a given period the total aggregate ramp rate can be met by combinations of blocks with different ramp rates, so long as the aggregate ramp rate meets the requirement¹³).

Dispatch of regulation providers would be based on their cleared quantity and a participation factor based on ramp rate capability. Payment would be based on the product of cleared quantity, participation factor, and final regulation market price.

Such an alternative approach would be more complicated to implement but is likely to result in a more efficient frequency regulation market, i.e. a better cost quality trade off.

It should be noted that such an approach, of using non-uniform participation factors, is still consistent with co-optimisation of regulation with reserves and energy and is more consistent with international practice with AGC.

What is not clear from this investigation is whether the extra market sophistication is justified in terms of any (uncertain) reductions in total market costs. It may be that the most pragmatic way forward is to undertake a technical trial of the simple market suggested by the TSG to see how frequency quality varies under different situations.

It would be good to discuss with the TSG:

- *Whether the extra market sophistication, to account for different ramp rate capability and assign different participation factors, would be justified? (i.e. Are the possible benefits, of lower frequency keeping costs, likely to justify higher implementation costs and time?)*
- *If it is likely to be justified then:*
 - *What are the difficulties (and costs) associated with provision of information on block ramping capability and how often this information would need to be updated?*
 - *Whether they consider the market design needs to be modified to account for the extra “work” (higher participation factors) fast ramping blocks would do compared to slow ramping blocks?*

5.2 Co-ordinating Regulation and Energy Dispatch

One issue arising from the international research on block dispatch of regulation by AGC is the need to co-ordinate energy and regulation dispatch. We understand the proposal from the TSG is that energy dispatch would continue to be every 5 minute, from Genco, where as regulation dispatch would be incremental every 10 seconds (or so) by AGC. This leads to two problems for the SO:

- Co-ordinating ramping between different generators; and
- Monitoring performance of regulation providers.

Both problems relate to how we co-ordinate regulation and energy dispatch.

5.2.1 Co-ordinating ramping between generating companies

This problem exists today. When the marginal generator changes one generator might start to ramp down and one start to ramp up within the 5 minute dispatch period.

¹³ It is possible that trade offs between total cleared quantity and cleared ramp rate are also possible. For example a smaller quantity with a higher ramp rate might provide the same level of frequency quality as a larger quantity with a higher ramp rate. But we haven't investigated this added sophistication yet.

If these ramps are not synchronised a bump in frequency can result. One way of dealing with these bumps would be for all ramping to be controlled, via AGC, by the SO. Although this may not be part of the current AGC scope it should be borne in mind as a longer term solution to the current dispatch problem as it may influence the choice of Genco replacement.

5.2.2 **Monitoring performance of regulation providers**

If the SO cannot monitor performance of frequency regulation providers in real time we are likely to need to procure additional regulation to allow for non-performance of some providers. This could increase frequency regulation costs.

To know whether a regulation provider is responding we need to compare actual response to dispatched response. But we can only measure total MWs for the block. So to figure out what portion of total MWs was due to regulation we need to deduct the energy dispatched quantity. But if energy dispatch and regulation dispatch are on different time frames (5 minutes and 10 seconds) it is hard to deduct one quantity from the other if the energy dispatch is not constant, i.e. it is ramping. To do this we would need to make assumptions about how the generator was ramping within the 5 minutes to deduce what the 10 second energy dispatch component of the measured total MWs was.

Two alternative approaches to address this problem are possible:

1. Participants could provide information on how they intend to ramp within the 5 minute energy dispatch period; or
2. Energy and regulation dispatch could both be on the same time basis (nominally 10 seconds) for regulation providers.

The second option would, in practice, require energy dispatch via AGC for regulation providers. This seems to be the international practice.

It would be good to discuss with the TSG the best way for the SO to co-ordinate energy and regulation dispatch.

5.3 **Total Control Loop Delay**

The level of control loop delay within the block will depend on how generating companies implement the regulation block control. In AEMO it appears generating companies determine at the start of every 5 minutes which units or stations within their block will be providing regulation for that 5 minutes and then pass regulation instructions straight through their block controls with minimal processing. This minimises total control loop delays for FR. This is an option that warrants exploration in a NZ context.

It would be good to discuss with the generating companies in the TSG how they intend to process regulation instructions within their block controls.



Appendix 1 – High Level Modelling

Limitations

This rather simple model is a best case scenario because it over simplifies the system down into one lumped load and one lumped generator and does not look at the complexities of how the AGC systems and the different generation and HVDC control systems would interact. Also it did not investigate control loop stability problems that might arise between these systems or if AGC has incorrect (optimistic) information about the ramping capabilities or response times of a generation block. This was partly because the initial brief was based on a “guaranteed minimum” approach to ramping capability and response times, and partly because such issues may be better studied during a trial of actual AGC arrangements.

Methodology

A very simple model was constructed as follows:

Simplifying Assumptions

Problem Definition

We assumed the fundamental problem is that block dispatch of AGC will add a delay (latency) in the AGC control loop. This could mean the control system is unable to respond sufficiently fast to adequately control the frequency change. This problem definition assumes the main difference between block and unit level control of generators by AGC is the additional control loop delay.

Small Signal Study

We limited the study to just the job AGC frequency regulation is trying to do. That is managing frequency error in response to load “noise” (difference between dispatch and actual load). Chris Callaghan has already prepared a load “noise” file from a few sample time periods. I suggest we could use this, or a similarly derived input file for the appropriate low inertia (SI) case.

Sensitive to Inertia

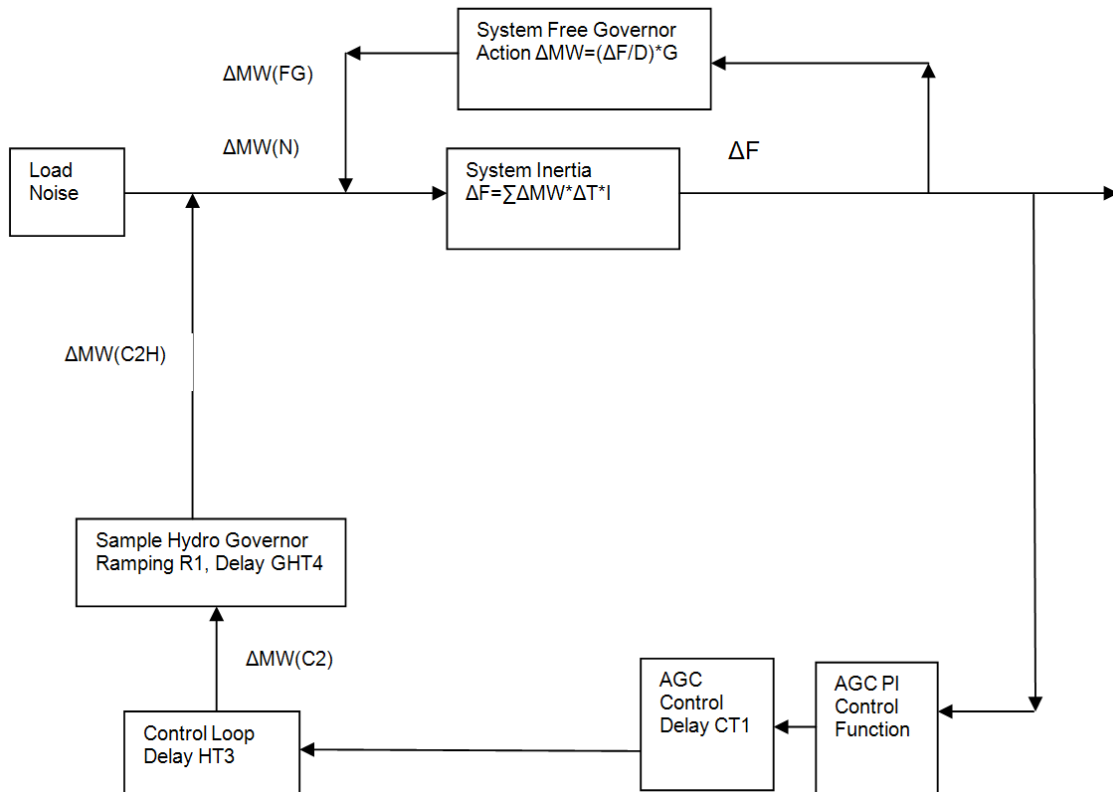
It is assumed that frequency deviation for a given load variation or control error (due to control loop delay) is related to the level of system inertia. System inertia, seems to typically vary between 0.001 HZ/MW/Sec (North Island) and 0.005Hz/MW/Sec (South Island with no HVDC frequency support). These figures are derived from the System Operator AUFLS Technical Report (table 7-1). This shows a SI initial df/dt of 1.6 Hz/sec for a risk of 34.2% of load. So assuming a SI load of just under 1000MW gives an inertia of $1.6/342 = 0.005\text{Hz/MW/Sec}$.

Simplified System Model

I suggest we adopt a simplified system model with just 4 blocks:

- System Inertia (worst case as above);
- Typical Block Generator Model (variable penstock delay, variable control system delay, and variable ramping);
- AGC controller (assumed PI¹⁴) with Variable control system delay; and
- Lumped other generators with free governor action (but assume very high droop, e.g. 25%).

¹⁴ A simple proportional and integral controller, without any differential element was assumed. It was assumed any differential element of control could lead to control loop instability with long delays in the control loop.



I = System Inertia
G = System Generation

Input Data

Sample input data was used for 1 September 2010. Separate data was provided for each island. The load noise was derived by looking at the difference between a rolling 5 minute average load compared to the 5 second load. This is an optimistic measure of the mismatch between dispatched generation and load, which regulation has to manage, because it assumes the dispatch perfectly matches average energy on a 5 minute basis.

Results

The following charts show the general shape of the tradeoffs between control loop delay and frequency quality, and generator ramping capability and frequency quality. It is emphasised that these results are indicative of the shape of the tradeoffs only and should not be taken as providing any quantitative results. It is suggested that quantitative results can only be obtained via a trial of AGC.

However for interest the following observations are noted:

Actual STD of Frequency Error (current frequency keeping arrangements):

NI = 0.052Hz, SI = 0.030Hz.

These results were only met or bettered for assumed ramp rates greater than 100MW/min in the NI and 30MW/min in the SI (with best case inertia, and shorter control loop delays).

This compares to the current frequency keeping qualifying standard of 10MW/min.

This suggests that some current frequency keeping providers may well ramping capability significantly greater than the current minimum standard.



Conclusions

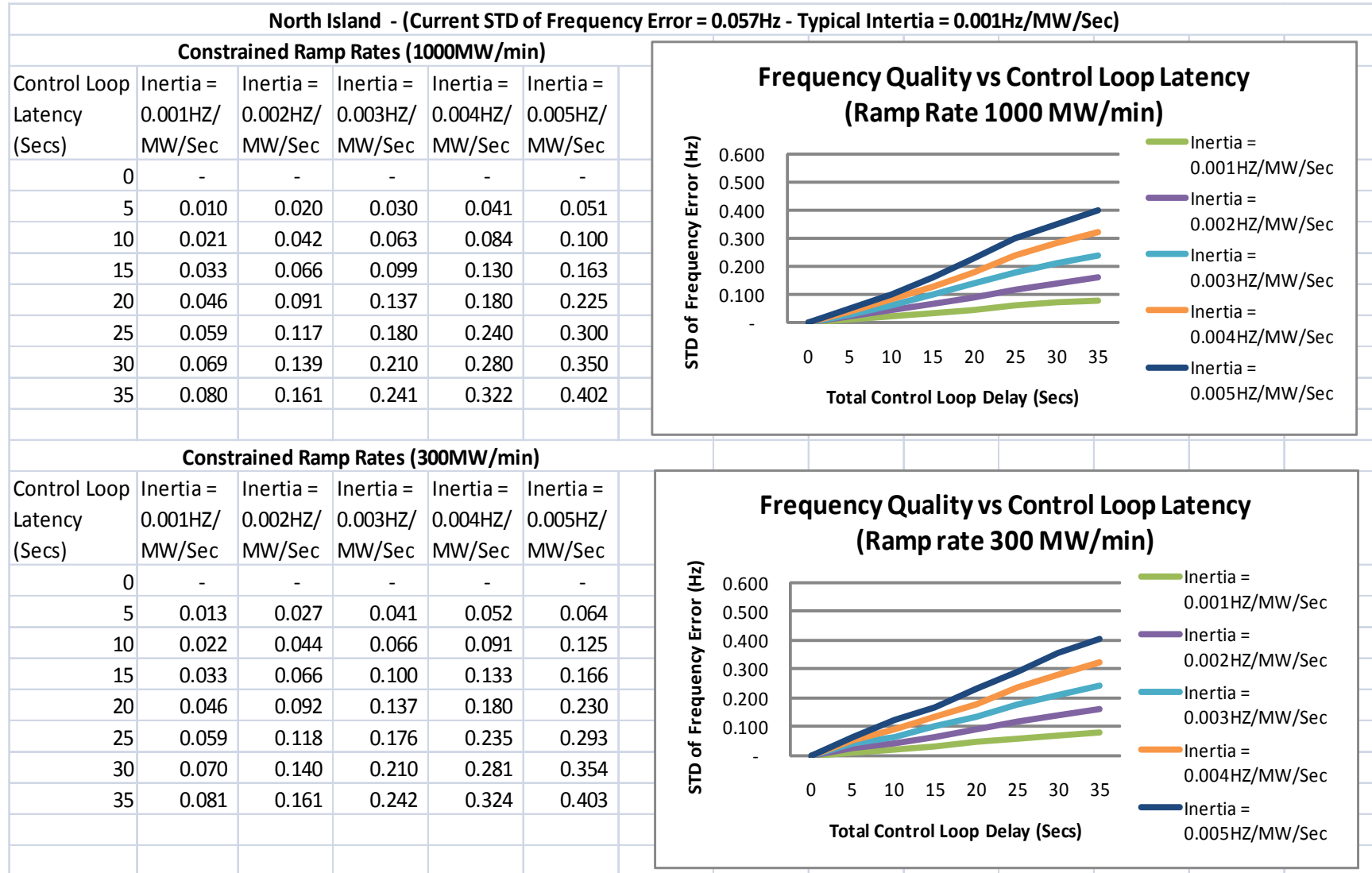
This model is too simplistic to be used for anything other than providing indicative trend results. Conversely it would be extremely difficult to construct a more accurate model as it would need to correctly account for all the (unknown) details of how each generator would implement its AGC controls, and the infinite different combinations of power system, and control system, conditions that can arise. It is suggested that it would be more productive to trial AGC with those generators that have current capability than to try and construct more and more complicated models, with an associated risk that we may still not get realistic results.

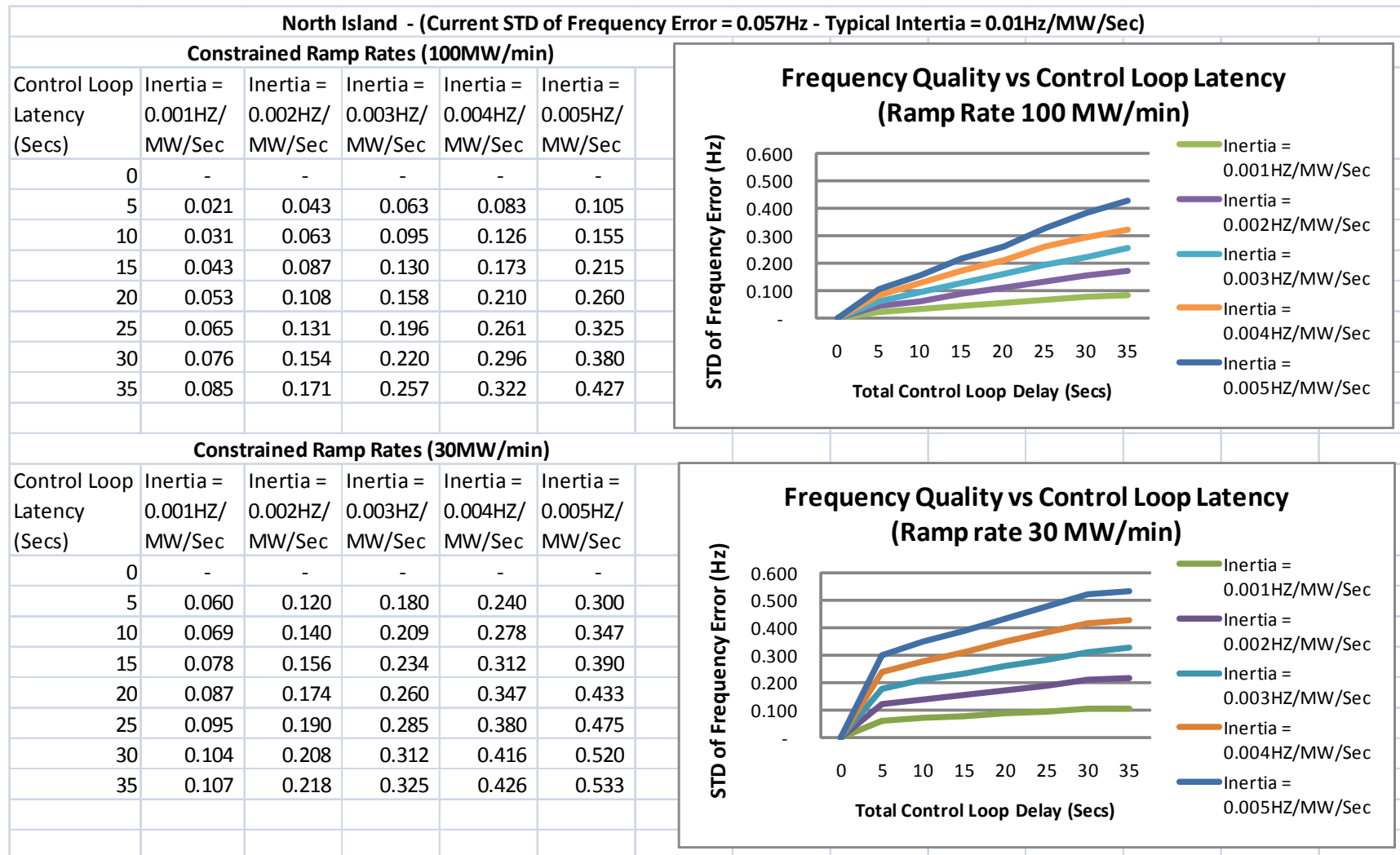
However these tentative results from our simple model suggest that there will be a clear trade off between available ramp rate, control loop delay and frequency quality. Also for any realistic levels of control loop delay it is likely that the collective ramp rate, from all regulation providers, will need to be significantly higher than the current 10 MW/min standard, if the current frequency quality standard is to be maintained.

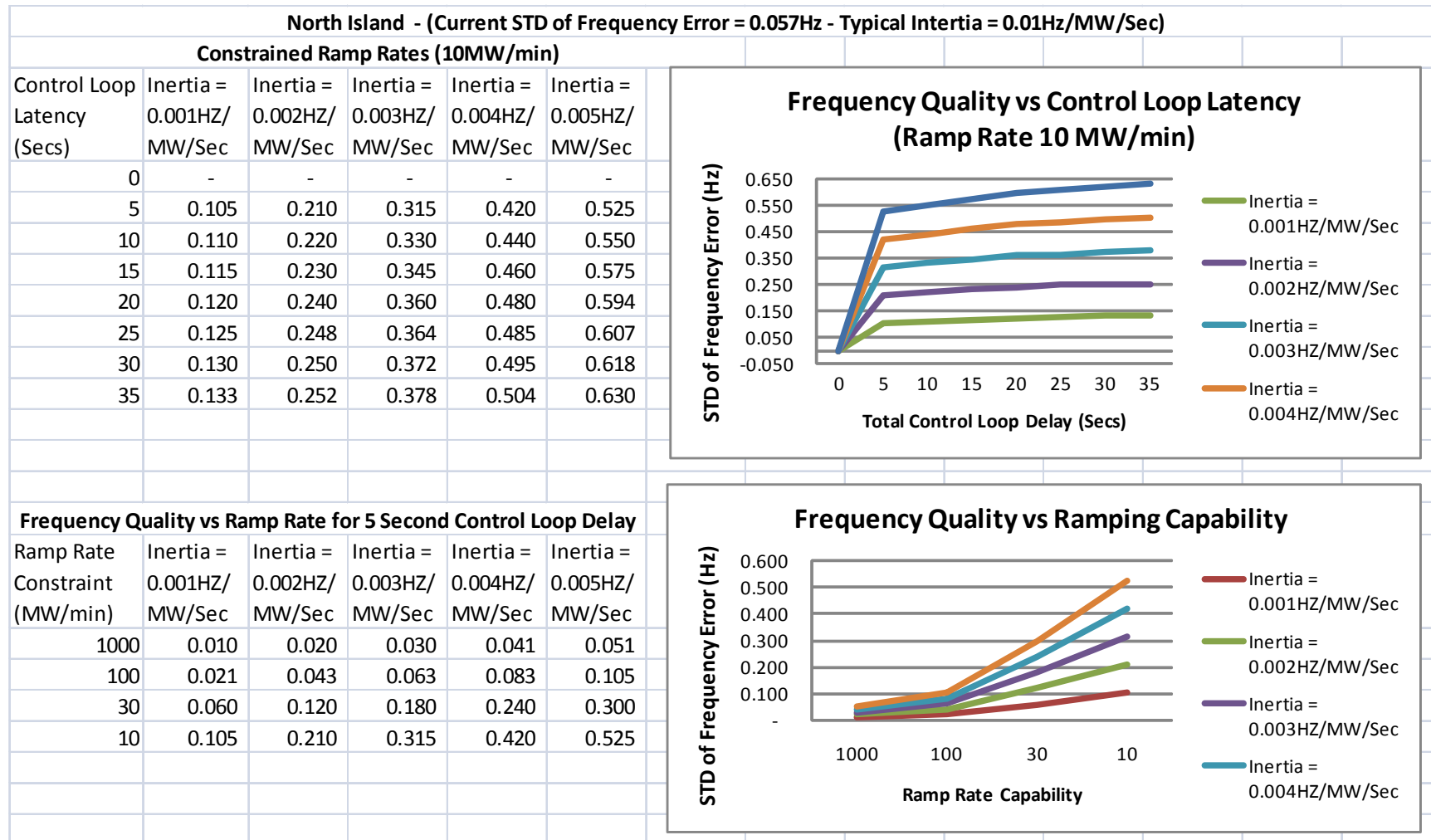
It is suggested the TSG should consider:

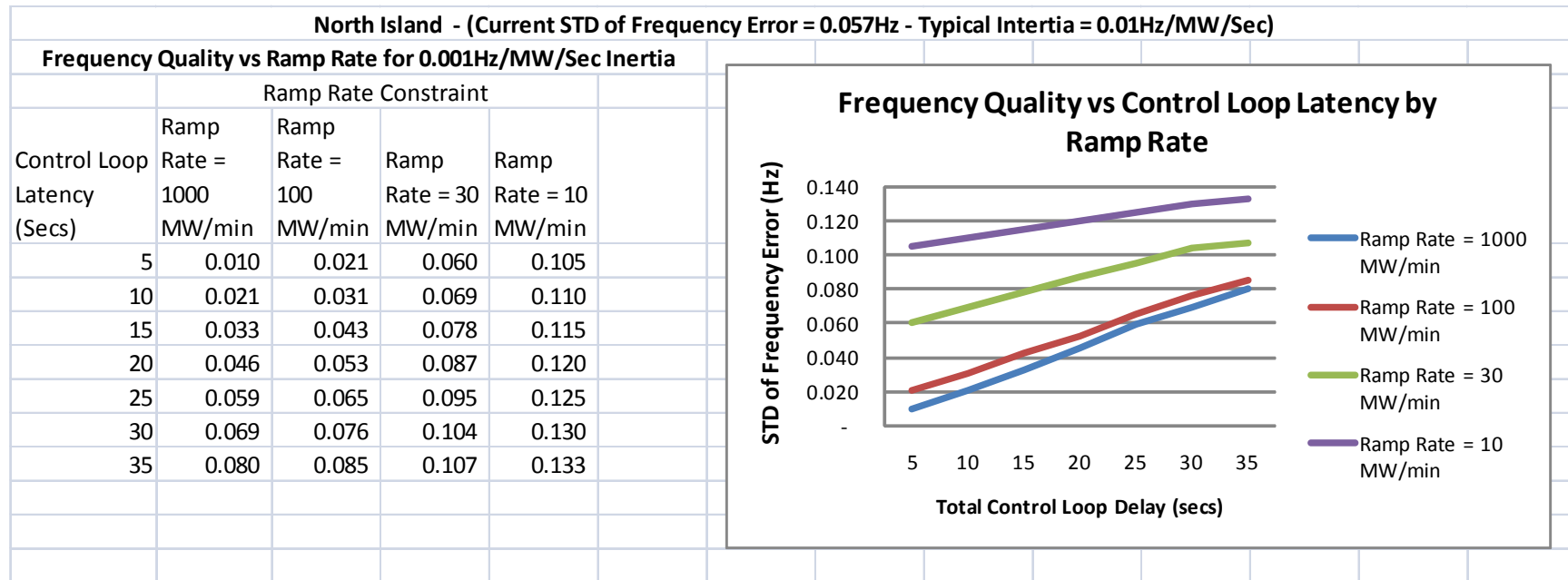
- What level of frequency quality is required?
- What aggregate total ramp rate is likely to be available?
- What total end to end control loop delays are likely to be?

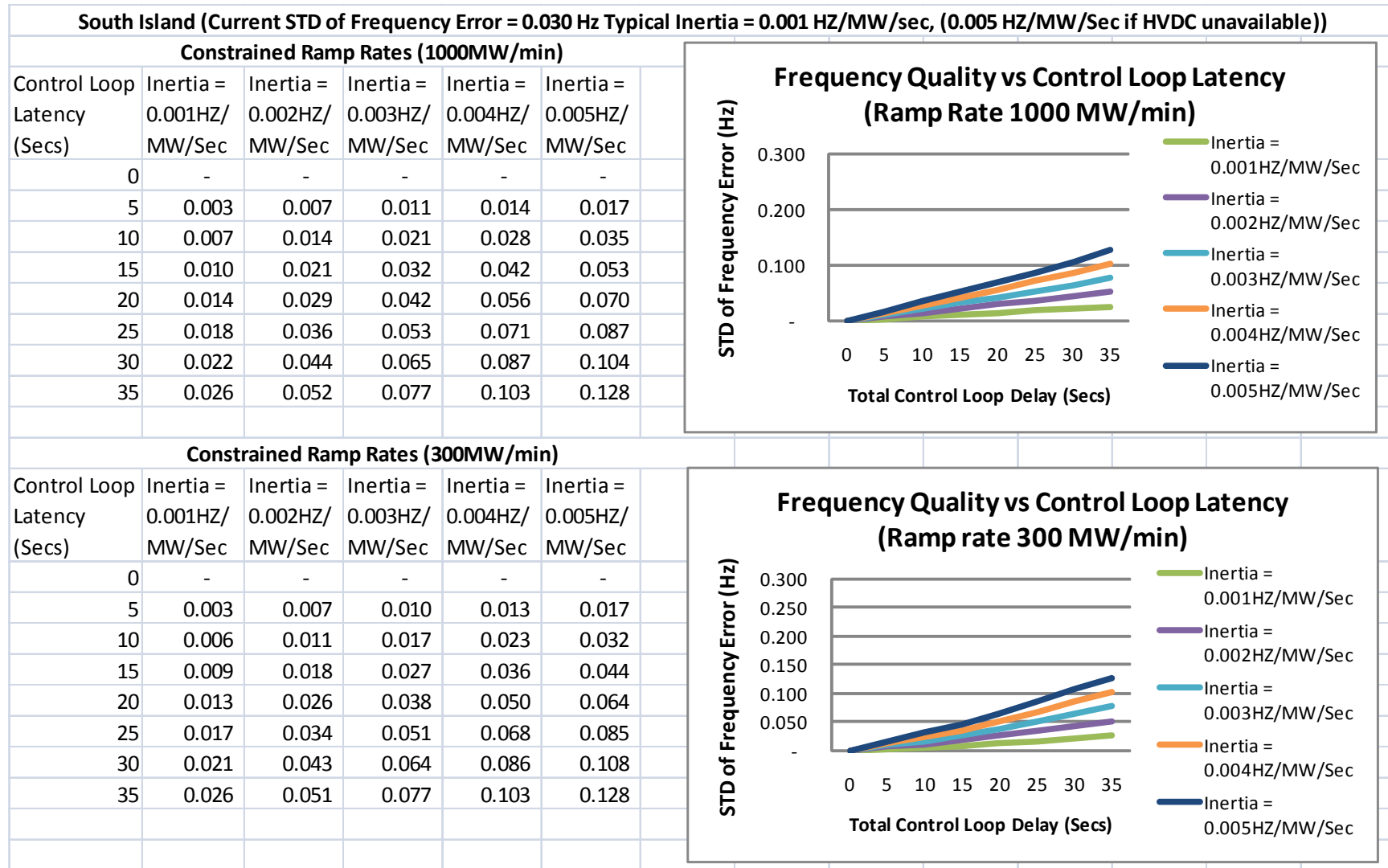


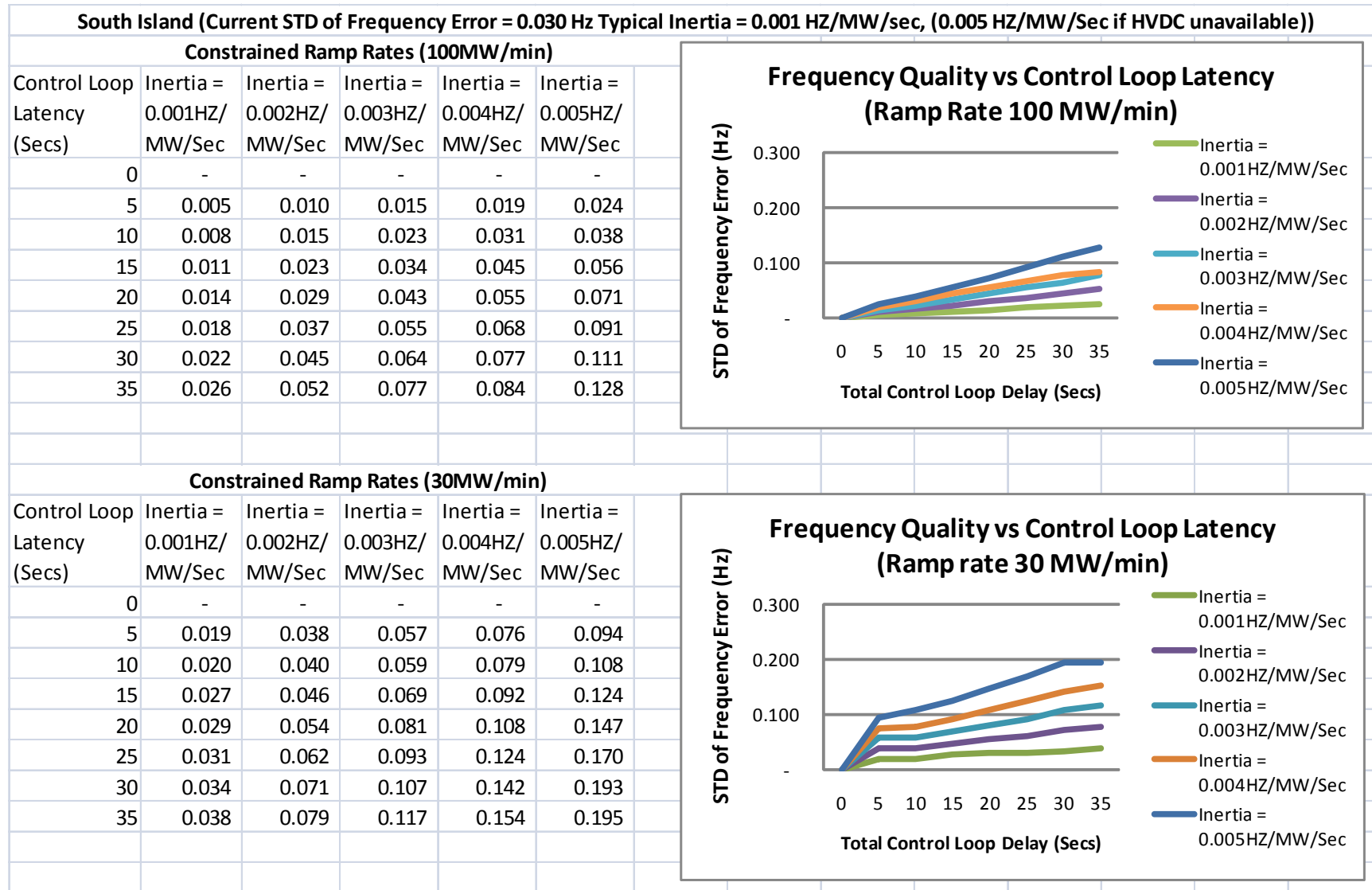


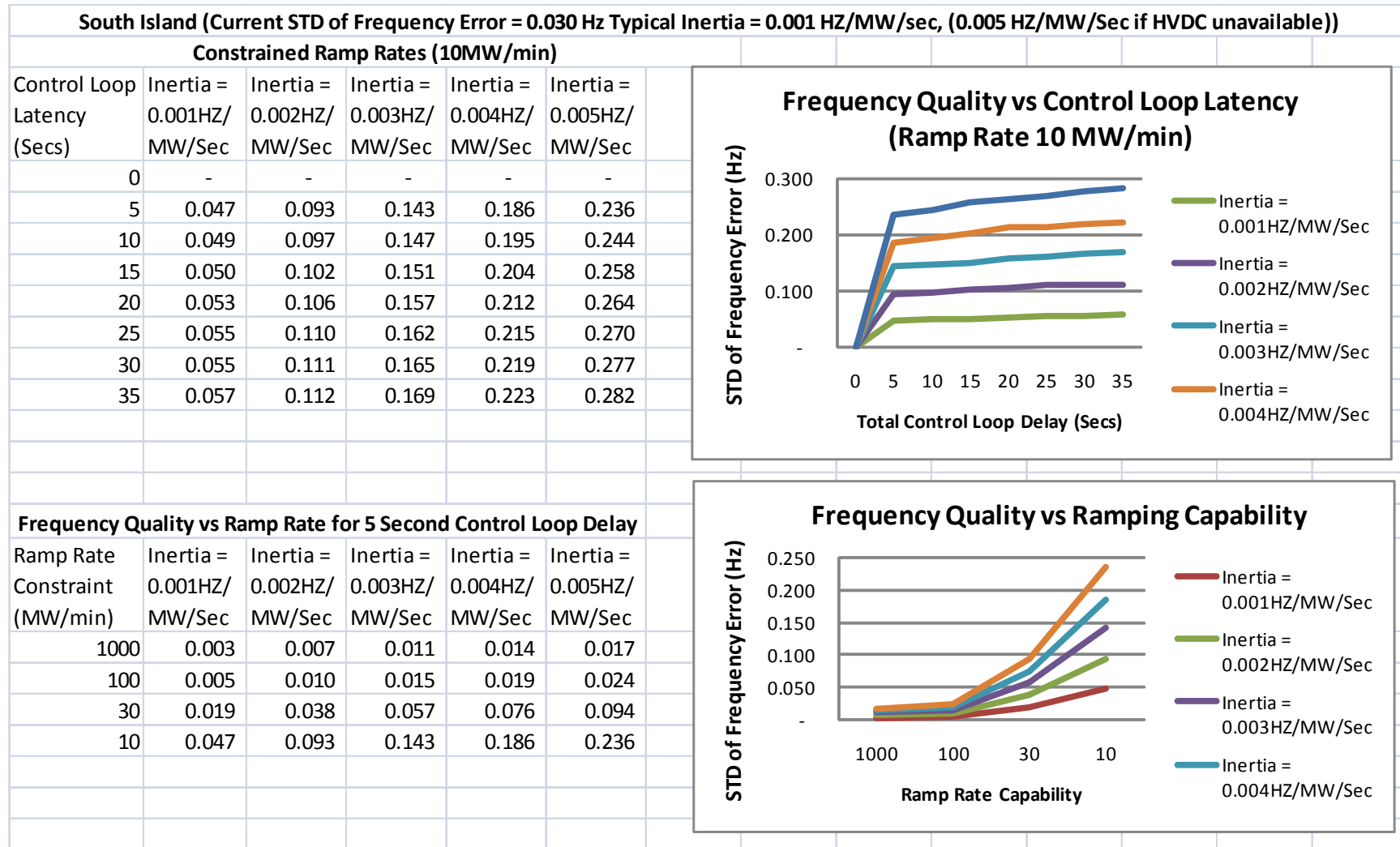


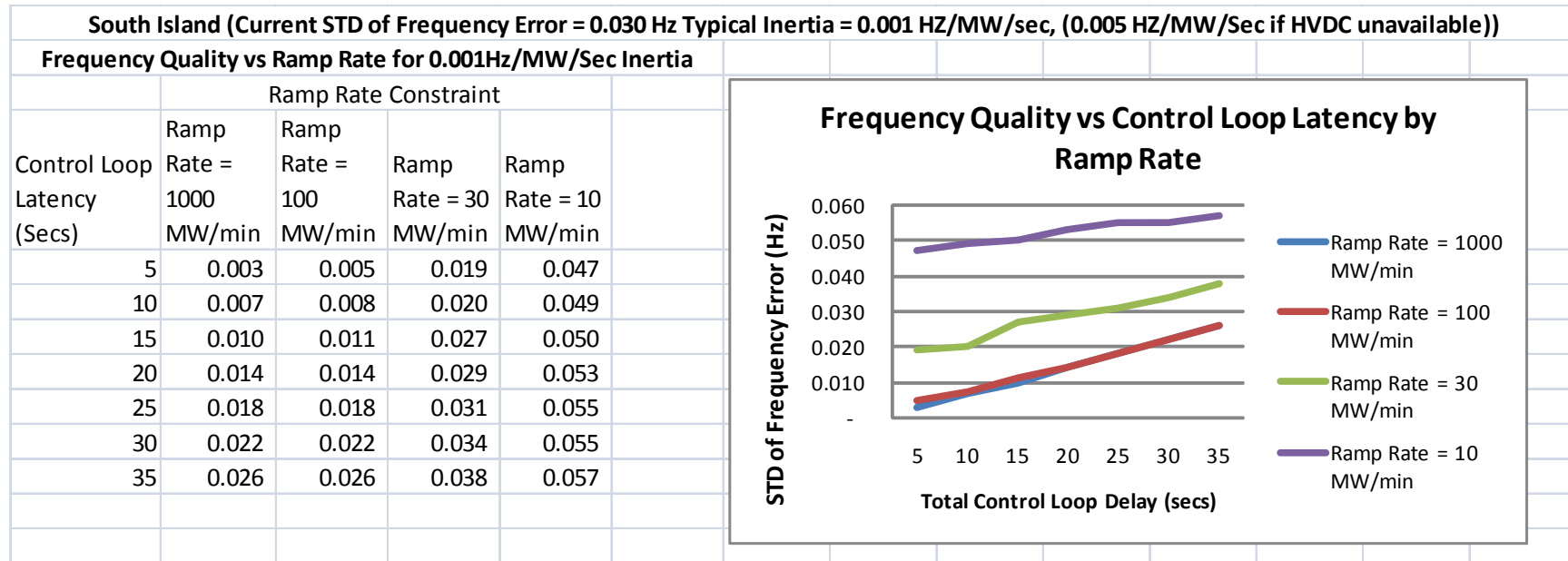












NI, Latency = 20 Secs, Inertia = 0.002 HZ/MW/Sec

Std of Frequency Error as a Function of Ramp Rate

| | | FR Band Quantity | | | | |
|--------------------|-----|------------------|-------|-------|-------|-------|
| | | 10 | 20 | 30 | 40 | 50 |
| Ramp Rate (MW/Min) | 10 | 0.126 | 0.110 | 0.110 | 0.110 | 0.110 |
| | 30 | 0.123 | 0.102 | 0.088 | 0.074 | 0.074 |
| | 50 | 0.128 | 0.103 | 0.081 | 0.070 | 0.065 |
| | 70 | 0.128 | 0.110 | 0.083 | 0.069 | 0.068 |
| | 90 | 0.127 | 0.112 | 0.083 | 0.064 | 0.047 |
| | 110 | 0.129 | 0.112 | 0.083 | 0.069 | 0.046 |

