5 March 2018

Ms Suzanne Falvi
Executive General Manager, Security and Reliability
AEMC
Level 6 201 Elizabeth Street
Sydney, NSW, 2000

Dear Ms Falvi

Frequency control frameworks review

The Generator Group consisting of Snowy Hydro, Stanwell Corporation, Engie, Origin Energy, AGL, Alinta Energy, Delta Electricity, and Intergen have commissioned SW Advisory Pty Ltd and DIgSILENT Pacific Pty to address related issues identified in AEMC's frequency control frameworks review.

The Consultant concludes that:

- The NEM does have some frequency control issues but the way to address these is not via mandatory requirements but by adapting the market processes for the new environment of greater variable renewable energy penetration and generators greater control of their generation units' governor responses.

- Market solutions to frequency control should recognise the changing nature of the power system, especially the acute changes in sub-regions of the NEM. Revised FCAS arrangements should take into consideration the projected technical and performance capabilities of new technologies and not hold onto historical systems and structures that will be inappropriate in the future.

- The solution to the frequency control issues is to fix up the market arrangements and to avoid regulation requiring compulsory capabilities and provision of services. Regulation is a costly and economically inefficient approach that does not satisfy the NEO.

The market arrangements that the Consultants are suggesting will require more detailed analysis and testing and probably some refinements before they are suitable to be implemented as operational systems in the NEM. Nonetheless they do provide a vision of how an effective FCAS market could operate in the future.

If FCAS market arrangements along the lines suggested in the Consultant's report are adopted, then most of the current and future frequency control issues in the NEM will be able to be managed via efficient market arrangements that value services correctly and provide appropriate incentives for behaviour that assists with managing frequency.

The Generator Group formally submits the Consultant's report titled, "Frequency Control Frameworks Review - Market-based Solutions - Final Report, Tuesday, 27 February 2018" as a submission to the AEMC's frequency control frameworks review. For the avoidance of doubt this report is public.

Yours sincerely,

The Generator Group.

Frequency Control Frameworks Review

Market-based Solutions

Final Report

Tuesday, 27 February 2018

Author(s): Stephen Wallace, SW Advisory
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Disclaimer

This report has been prepared by SW Advisory Pty Ltd and DIgSILENT Pacific Pty Ltd and is supplied in good faith. It reflects the knowledge, expertise and experience of the consultants involved in its preparation. SW Advisory and DIgSILENT Pacific make no representations or warranties as to the accuracy of the assumptions, models or estimates on which any forecasts, calculations or conclusions are based.

Executive Summary

Introduction

SW Advisory and DIgSILENT Pacific were contracted by a group of generators (the Generator Group[1]) to:

- assess the materiality of the current concerns from some stakeholders with the frequency control performance in the NEM;
- suggest market-based solutions to the frequency control issues in the normal operating frequency band (NOFB) raised in the DIgSILENT report[2] prepared for AEMO and Pacific Hydro's submission to AEMC's System Security Frameworks Review;
- provide a set of market-based solutions / incentives to address any other material shortcomings in frequency control in the NEM; and
- address related issues identified in AEMC's frequency control frameworks review.

Based on the meeting that SW Advisory and DIgSILENT Pacific had with the Generator Group, we agreed that the focus of our review was to be on providing a set of market-based solutions to identified frequency control problems in the NEM.

Background

Since the original FCAS markets were set up in 2001 there have been substantial changes to the power system. There has been a substantial increase in large scale variable renewable energy (VRE), a reduction in load growth, increased PV penetration at the household level and retirements of a number of coal power stations.

The purpose of the AEMC's review is to address current concerns with frequency performance in the NEM and to consider:

- whether primary frequency response should be mandatory; and
- how best to integrate faster frequency control services offered by new technologies into the current regulatory and market arrangements.

This review has been prompted by the changing generation mix in the NEM and the changing distribution of frequency within the normal operating frequency band (NOFB).

With the greater penetration of large scale variable renewable energy (VRE) generation and other new technologies such as batteries, fast FCAS, synthetic

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[1] The Generator Group includes Snowy Hydro, Stanwell Corporation, Engie, Origin Energy, AGL, Alinta Energy, Delta Electricity, and Intergen.
[2] DigSILENT Pacific, 2017, "Review of Frequency Control Performance in the NEM under Normal Operating Conditions"

inertia etc. the current approach for frequency control in the NEM is no longer always appropriate. With the new technologies there are potential requirements and opportunities to introduce new services. However, the NEM is facing some crucial decisions as to whether to adopt market-based approaches or approaches based on increased regulation and mandatory requirements.

Terminology: "Governor Response"

Throughout the report where the term "governor" or "governor response" is used it should be interpreted as a locally triggered and proportional response to frequency deviations from the rated frequency. "Governor" responses could be provided by many potential service providers, including synchronous generators, battery systems (charging or discharging), wind generators, PV generators and large industrial loads. In fact, any inverter-based system with a power controller could potentially provide "governor" responses. It is just a matter of software to get the desired performance.

The Distribution of Frequency Within the Normal Operating Frequency Band (NOFB)

Based on our review of NEM frequency issues, there is clear evidence that the distribution of frequency within the NOFB has got wider over time. In 2001, the distribution of frequency was tight around the 50 Hz standard and approximated a normal distribution. Today the distribution is much wider and flatter in the NOFB.

Causes of the Wider Frequency Distribution

The factors contributing to this wider distribution are likely to be that:

- AEMO is not purchasing enough regulation to manage frequency;
- AEMO's AGC system is not performing as well as it should:
  - Key parameters, such as the 'bias estimate' may need updating to reflect the changes in the power system characteristics;
  - The response of the system to regulating FCAS may need to be reviewed and parameters of the controller adjusted to ensure stability;
  - The relative weightings of additional control inputs, such as the Time Error, may need to be reviewed as these have the potential to dominate the response if weighted too high;
- There has been a reduction in governor frequency response within the NOFB because:
  - Providing governor response represents a cost in terms of wear and tear and efficiency but there is no financial benefit in providing the service;
  - A reduction in primary FCAS service providers in the NOFB increases the 'workload' on the remaining generators providing this service which in turn encourages these generators to stop providing the service;

- The “causer pays” mechanism for recovery of regulation costs has discouraged generators from providing governor control and encouraged them just to follow their energy targets.; and
    - The AER’s approach to strict compliance of dispatch targets has meant that that generators face a regulatory compliance risk with deviations from dispatch targets.
- There are problems with forecasting, particularly VRE generation forecasting.
- The nature of the power system is changing, including:
    - Retirement of some conventional generation;
    - Increases in inverter-based generating systems that:
        - Reduce the inertia;
        - Do not typically contribute to primary frequency control; and
        - Have an output that varies with sun/wind and are thus difficult to forecast accurately; and
    - Increases in inverter-based loads, which act to reduce the amount of load relief as frequency changes.

Costs of the Wider Frequency Distribution

The main power system impacts of deteriorating frequency control are:

- Power system security risks; and
- Increased frequency control costs.

Greater probability of load shedding

A stable frequency provides the basis for the design of defensive control schemes that protect the system from low probability events outside of the credible contingencies that the power system is planned and operated to survive.

In the NEM, non-credible contingencies, including multiple events, may have very high consequences and these have traditionally been mitigated using controls such as automatic under-frequency load shedding (AUFLS). AUFLS is a relatively low cost and effective distributed control system.

AUFLS schemes have a specific frequency setting. If the first level of operation is at, say 48.9 Hz, then an objective of overall frequency control of the power system will be to avoid this frequency at all times, including following a credible contingency. If the frequency at the time of a contingency is 49.9 Hz, the margin to the AUFLS operating point is reduced from 1.1 Hz to 1.0 Hz. This reduces the headroom and time available for the contingency FCAS to respond and compensate for a credible contingency and consequently increases the probability of load shedding or increases the amount of quick acting FCAS that needs to be enabled. These are both quite material costs.

Greater contingency FCAS costs

The amounts of contingency FCAS enabled by AEMO are based on an estimated amount of load relief that assumes that the starting frequency at the time of the contingency is 50 Hz. For a generator contingency, AEMO calculates the permissible frequency drop of (50 Hz – 49.5 Hz) = 0.5 Hz which leads to an estimate of the contingency FCAS requirement (ignoring the impact of Tasmania) of:

$$
\begin{aligned}
FCAS &= \Delta_g - mainland\ demand * \frac{1.5\%}{1.0\%} * \frac{\Delta_f}{50Hz} \\
&= \Delta_g - 0.015\ x\ mainland\ demand
\end{aligned}
$$

Where Δ_g is the loss of generation corresponding to the largest credible generation contingency event.

If frequency is widely spread across the NOFB then AEMO should use as the starting frequency 49.85 Hz not 50 Hz[3]. If this is done then it leads to an estimate of the contingency FCAS requirement of

$$FCAS = \Delta_g - 0.0105\ x\ mainland\ demand$$

Thus for every dispatch period there needs to be an increase in the amount of contingency 6s and 60s FCAS enabled of 0.0045 x mainland demand, which for a 20,000 MW system load equates to an extra 90 MW.

Other costs

The DIgSILENT report identified several other sources of additional costs that may be attributed to poor frequency control, including:

- Wear and tear on equipment that is providing primary control and responding to frequency variations;
- Larger than necessary operating margins; and
- Potentially reduced operating life where equipment such as turbines are subject to increased vibrations that are exacerbated by frequency variations.

Managing Frequency in Low Inertia Environment

With increasing levels of inverter-based generation, the inertias of some subsystems like north Queensland, Tasmania and South Australia are already low at times of high VRE generation. This will get worse in the future.

As the inertia reduces, frequency control becomes more challenging as there is less time available to address imbalances in supply and demand. As a result, the 6s contingency services will not be able to contain any frequency excursion should

[3] Even though AEMO can use the current frequency at the start of the dispatch interval as an input to the amount of contingency FCAS enabled this does not materially change the amount of contingency FCAS that is required since a contingency event could occur at the end of the dispatch interval when frequency is unknown within the NOFB and thus the conservative value of 49.85 Hz should be used.

these subsystems separate from the main power system[4, 5 and 6], even if contingency FCAS are enabled within the region. This problem can be readily seen in SA where inertia and system strength can be problems with large amounts of wind generation.

Solution to Frequency Control Issues in the NEM

Principles

The NEM is facing frequency control issues and so some changes are required. These changes should be based on the National Electricity Objective (NEO) and the NER's market design principles. As well, the changes should support the general principle that the management of the power system should be based on the power system's standards.

Regulation versus markets

The general principle in electricity markets is that the natural monopoly components of the electricity supply industry are regulated and the potentially competitive elements compete via the wholesale and retail competitive electricity markets. Where a competitive market can provide an electricity service, there is no good reason to choose to regulate its provision instead. Regulation is very much a second best option when compared to using a competitive market. A free and competitive market is self-regulating and is likely to provide goods and services at a lower cost in the long term when compared to regulated arrangements. Since the start of the NEM, the NEM's regulation of the monopoly TNSP elements has facilitated gold plating of networks and steep rises in costs in these areas whereas the competition in generation has delivered prices decreases in real terms over the long run.

In an electricity market, the only time mandatory performance requirements should be applied is where analysis shows that the power system needs to be protected against a cascading collapse caused by:

- Unusual and unexpected events that may happen too quickly for the system and market operator, the SMO (AEMO), to respond
- High impact low probability events, such as multiple contingencies, that are too costly to be mitigated through market services.

Examples include:

- Under frequency load shedding (for low frequency events); and
- Generator tripping (for high frequency events).

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[4] T. George, S. Wallace, S. Hagaman and H. Mackenzie (2017) "Market mechanisms for frequency control" 16th Wind Integration Workshop, Berlin
[5] Tielens, P. and Van Hertem, D.(201). "Grid inertia and frequency control in power systems with high penetration of renewables" https://pdfs.semanticscholar.org/1cd1/9e3ae4b3ff6919570cf6faa693a13d21652a.pdf
[6] Ulbig, A., Borsche, T.S. and Andersson, G (2014) "Impact of low rotational inertia on power system stability and operation" IFAC Proceedings Volumes, 47(3), pp.7290-7297.

In the above cases, the mandated performance is for conditions outside of the normal contingency bands in the frequency standard. Credible contingencies are not unexpected or unusual events and should not have mandated performance requirements from each generator. It is, however, quite reasonable to require performance service levels from any service providers that offer into the FCAS markets.

The benefit of having a market-based approach to security and reliability services is that the participants best able to provide the services are appropriately incentivised. Those participants with technologies not suited to providing the services can elect not to provide the services and have the market purchase them off more efficient providers.

Also, markets encourage innovation, as opposed to prescriptive approaches which can become obsolete as technology changes. Therefore, the most efficient approach is to define standards for security and reliability, including stability, frequency, unserved energy, or loss of load probability etc., and then provide flexibility in how the market and the SMO (AEMO) deliver these outcomes.

Regulatory approach with mandatory capabilities and provision of services

To address some of the frequency and power system issues in the NEM, several changes to the NER technical standards have been proposed. These changes include requirements for all generation to have the capability to provide contingency FCAS and the mandatory provision of governor control for no payment. This mandatory approach may be easily administered but such a regulated approach is not likely to be economically efficient and hence is not consistent with the NEO.

The key points to note about mandating requirements are:

- Mandating capacity and potentially competitive services is not consistent with the NEO;
- Mandating governor control, or any form of primary control of active power, has the potential to overlap with the existing contingency FCAS, changing volumes in an uncontrolled manner[7]; and
- Any mandated requirements for security or reliability purposes should be subjected to a cost-benefit analysis.

The demonstrated deterioration in frequency control in the normal operating frequency band can be addressed by a market-based approach and does not require the economically inefficient approach of mandating equipment upgrades.

[7] For example, if primary control of active power is mandated, the requirements for, say, 6 second FCAS may change. Typically, in the NER there is no time specified for response to frequency variations – a mix of slow and fast services is expected. Calculating the required 6s FCAS quantities will either have to ignore the mandatory service (inefficient), or a lot of detail will need to be provided so the actual response times are understood (bureaucratic).

The performance of the FCAS markets and the basic thrust of the contingency services have worked quite well. The main issue now is that the current categorisations of the FCAS contingency services are currently not always fit for purpose, particularly in potential islanding areas where there can be large amounts of VRE generation and low inertia. However, these problems should be readily overcome with a more flexible FCAS model that will work for all levels of inertia and technology. There does not appear to be a market failure, or a risk of market failure, that justifies the mandating of any contingency frequency services via mandating the free provision of primary governor control. There is also a risk that mandating primary frequency control in the NOFB will impact the existing contingency FCAS markets unless this mandated control is limited to within the NOFB.

NOFB market

It is in management of frequency under normal conditions when there are no contingency events, that there appears to be a growing problem. This is compounded by the, arguably, faulty operation of the “causer pays” cost recovery mechanism for regulation FCAS.

Rather than mandate some or all FCAS services, a better and more efficient NOFB solution may be to create a proper market for governor responses, demand responses or other linear responses to frequency within the NOFB rather than adopt a compulsory provision approach.

The desired output of a NOFB frequency control is an automatic corrective response to frequency deviations within the +/- 0.15 Hz band around 50 Hz. This can be achieved by a wide range of service providers, including the demand side (large industrial loads), battery systems (charging or discharging) and renewable energy generating systems. In fact, any inverter-based system with a power controller could potentially offer these NOFB services (i.e. load or generator). This service, Primary NOFB FCAS, would operate in parallel with the regulation service.

Properly specified, the Primary NOFB FCAS would be separate from the contingency FCAS services and would not affect the volumes in these markets.

The Primary NOFB FCAS would be offered into the market and co-optimised like the other FCAS and it would be included in the joint capacity constraints used to manage the other services to ensure that units are dispatched to physically feasible dispatches for energy and all of the FCAS. The co-optimisation would determine Primary NOFB FCAS prices. If there were global and local NOFB requirements then there would be global and local Primary NOFB FCAS prices.

The cost recovery mechanism for the Primary NOFB FCAS would be via a substantially revamped “causer pays” method which would be based on system frequency measurements rather than on the current “causer pays” methodology which is based on AEMO’s AGC’s calculation of the area control error (ACE). The

ACE is used to determine the amount of corrective action to restore frequency to nominal.

Revised contingency FCAS market

In the NEM, the contingency FCAS are procured using rigidly defined categories of services which are split into the discrete timeframes 6s, 60s and 5 minutes.

With increasing levels of inverter-based generation, the inertia of some subsystems like north Queensland, Tasmania and South Australia is already low at times of high VRE generation. This will get worse in the future. As a result, the 6s contingency service will not be able to contain any frequency excursion should these sub-regions separate from the main power system, even if contingency FCAS are enabled within the region.

Adding a new ‘very fast’ contingency service will help the situation but remains inflexible and performance will depend on how well the service matches the actual dynamics of the sub-region power system.

Location of fast acting FCAS providers is mainly needed in potential sub-regions, which have low inertia. In stronger parts of the system, the higher costs associated with very fast responding systems is difficult to justify. Adding a ‘very fast’ contingency FCAS service is probably of questionable value unless it is located in a part of the network that could be isolated and where fast response times are required. A very fast acting service in Victoria will not help a potential islanding of South Australia or North Queensland, for example.

With the increase in inverter technologies and the potential for their software to give these systems a wide range of frequency response characteristics, it would appear preferable to model each system’s response to frequency in the co-optimisation. The dispatch algorithm could then choose the services that best meet the frequency standards at lowest cost rather than try to bundle them into pre-set buckets such as the NEM’s current categories of 6s, 60s, 5 minutes.

A more flexible approach would be to directly model each unit’s FCAS response function to a frequency excursion as a continuous response function from 0 s to, say, 300 s and directly model frequency in the security constrained dispatch optimisation (NEMDE). This approach, as discussed in section 7, would:

- Select the least cost set of service providers to directly meet the frequency standards;
- Co-optimise flows on interconnections when islanding is a credible contingency;
- Directly take into account the current inertia of the system and any potential islands;
- Price contingency FCAS on a large number of time scales from tenths of seconds to minutes; and

- Value (price) inertia as part of the co-optimisation.

This approach was demonstrated using a prototype dispatch optimisation and a simulated power system[8] to check whether the enabled amounts of contingency FCAS from the dispatch optimisation did indeed result in the post contingency frequency performance as expected. The enabled FCAS from the dispatch optimisation resulted in system and island frequencies in the simulated power system being very close to the post contingency event frequency standards. The approach explicitly values time of response, with faster responses being highly valued where low inertia conditions are expected. However, in higher inertia conditions or islands, it may be lower cost to dispatch slower responding services.

The benefits of this enhanced co-optimisation approach are that it:

- Appropriately rewards service providers based on their response profiles and inertia; and
- Prices contingency FCAS on a continuum of time scales and thus signals the market values of different response capabilities at different times and in different locations.

The suggested approach outlined above for a revised contingency FCAS market will require more detailed investigation to see that it works as expected over a full range of scenarios and to ensure it has no unintended consequences.

Statistical Approach to Determining Regulation Quantities

One contributing factor to the decline in frequency outcomes within the NOFB appears to be that AEMO is not enabling enough regulation FCAS and there is not enough regulation FCAS response (ramp rate) at the start of the dispatch interval. Both of these issues can be addressed through a proper statistical analysis of regulation requirements and regulation ramp rate requirements.

With the greater introduction of VRE generation, AEMO needs to develop a better system for determining the requirements for regulation FCAS based on a proper probabilistic / statistical approach. In this report we outline how this can be done.

Further, with an effective statistical approach to determining the amounts of regulation required we outline how regulation FCAS costs could be allocated efficiently and fairly to those who cause the requirements.

Improved “Causer Pays”

With the introduction of a new Primary NOFB FCAS market and the introduction of a statistical analysis approach to determining the required amounts of regulation, the current “causer pays” cost recovery mechanism could be substantially improved. The existing “causer pays” approach could be adapted to provide an

[8] T. George, S. Wallace, S. Hagaman and H. Mackenzie (2017) “Market mechanisms for frequency control” 16th Wind Integration Workshop, Berlin

efficient cost recovery mechanism for the Primary NOFB FCAS and a new “causer pays” methodology based on the statistical analyses used to determine the regulation requirements could be developed to recover the costs of the regulation FCAS.

Other Potential Improvements to Frequency Control

The other areas that could improve frequency control in the NEM are:

- Improvements to AEMO’s AGC tuning and input parameters like the system frequency bias;
- Better forecasting methods for loads and VRE generation; and
- Improvements to the NEM’s security constrained dispatch.

Our understanding is that AEMO may be using similar parameter values for its AGC system now as it did a number of years ago. For the BIAS setting, AEMO currently uses a constant 280MW/0.1 Hz. However, both load and generator responses to frequency have changed. The system BIAS is likely to be less than what it was years ago and could change with the time of day. We recommend that AEMO adopt an approach that calculates the BIAS on a dynamic basis, taking into account the units online and their governor settings.

CS Energy has identified that some regulation issues are related to units enabled for regulation not responding to their targets. AEMO could improve this situation by:

- identifying units which are not responding to AGC signals and restricting them from being enabled for regulation and
- avoiding enabling units for regulation and energy in excess of a unit’s maximum availability.

Improved load and VRE forecasts would both reduce the dispatch interval forecast errors and hence the amount of regulation required. There is evidence that there may be better approaches available than what AEMO is using.

The NEM dispatch engine (NEMDE) is used to provide a security constrained dispatch. When it was developed for the start of the NEM it was a state of the art system. It is now 20 years old and showing its age. All the major vendors: GE/Alstom, ABB and Siemens have systems that could more efficiently and transparently provide a security constrained dispatch for the NEM. Further since the vendors are working in many markets they are continually improving their products.

Conclusions

There is evidence for:

- Distribution of frequency within NOFB changing over time and becoming flatter. This does have some costs;
- The current contingency FCAS arrangements are now not always fit for purpose, particularly in potential islands of low inertia;
- AEMO may not be enabling enough regulation;
- The current “causer pays” cost recovery mechanism for regulation may be creating some perverse incentives which do not help the management of the power system; and
- AEMO’s AGC is probably not optimally set up.

The NEM does have some frequency control issues but the way to address these is not via mandatory requirements but by adapting the market processes for the new environment of greater VRE penetration and generators greater control of their generation units’ governor responses.

Market solutions to frequency control should recognise the changing nature of the power system, especially the acute changes in sub-regions of the NEM. Revised FCAS arrangements should take into consideration the projected technical and performance capabilities of new technologies and not hold onto historical systems and structures that will be inappropriate in the future.

The solution to the frequency control issues is to fix up the market arrangements and to avoid regulation requiring compulsory capabilities and provision of services. Regulation is a costly and economically inefficient approach that does not satisfy the NEO.

Revised FCAS market arrangements should take into account the following.

- Better modelling of frequency response characteristics will improve AEMO’s confidence that the frequency standards, and therefore security, will be met.
- Location of fast acting FCAS providers is mainly needed in potential subsystems, which have low inertia. In stronger parts of the system, the higher costs associated with very fast responding systems is difficult to justify. Revised FCAS systems should reflect the locational value of fast responding systems. Consequently, the value of faster acting FCAS responses is higher in potentially islanded subsystems.
- Co-optimisation across all FCAS and energy markets will lead to the maximisation of value in the NEM and satisfy the NEO. Mandating provision of some services that will overlap with market-based systems is likely to devalue the markets and increase costs overall, leading to upward pressure on energy costs.
- Modern generation control systems can be configured to provide a range of market-based services and thus encourage efficient providers into the FCAS market and create incentives for innovation, both of which are absent in any mandated service provision.

- New optimisation methods and software can be applied to deliver real efficiency improvements in the NEM. It is important to critically review systems that were developed in the early NEM against the improved computational and optimisation tools of today and to assess the efficiency improvements possible.

Taking into account the points above, our suggested market solutions will require some changes to the current FCAS arrangements:

- Create a new Primary NOFB FCAS market.
- Create more flexible contingency FCAS arrangements that don't require simple buckets of 6s, 60s and 5min services:
  - For each provider of contingency FCAS, model their response over time to a large frequency change as a continuous function of MW response versus time after event;
  - Model post contingency frequency explicitly in NEMDE using the swing equation;
  - Use NEMDE to choose the optimal combination of FCAS response curves to ensure that frequency remains within the standards for both the system and any potential island post credible contingencies; and
  - Incorporate proper co-optimisation of requirements into NEMDE including co-optimisation of interconnector flows.

  Note that if this approach is adopted then the 6s, 50s and 5 minute contingency services and the proposed very fast contingency FCAS would all be subsumed into continuous contingency FCAS market.
- Determine the amounts of regulation to be enabled each dispatch interval based on transparent statistical analysis of what causes the deviations of actual loads and generation from their linear trajectories. Determine the amount of regulation based a probability distribution which ties back to the requirement that frequency should be in the NOFB 99% of the time.
- Improve "causer pays" by swapping it to a cost recovery mechanism for Primary NOFB FCAS based on actual frequencies not the AGC's ACE and turn it into an arrangement so that participants who are not enabled for either Primary NOFB FCAS or regulation FCAS who contribute positively to managing frequency receive some payments.
- Develop a new "causer pays" for regulation based on the statistical analysis of the factors that contribute to the size of the regulation amount.
- Improve AEMO's AGC, NEMDE and forecasting systems.

The market arrangements that we are suggesting will require more detailed analysis and testing and probably some refinements before they are suitable to be implemented as operational systems in the NEM. Nonetheless they do provide a vision of how an effective FCAS market could operate in the future.

If FCAS market arrangements along the lines suggested are adopted, then most of the current and future frequency control issues in the NEM will be able to be managed via efficient market arrangements that value services correctly and provide appropriate incentives for behaviour that assists with managing frequency.

Table of Contents

1 Introduction

SW Advisory and DIgSILENT Pacific were contracted by a group of generators (Generator Group[9]) to

- assess the materiality of the current concerns from some stakeholders with the frequency control performance in the NEM;
- suggest market-based solutions to the frequency control issues in the normal operating frequency band (NOFB) raised in the DIgSILENT report[10] prepared for AEMO and Pacific Hydro's submission to AEMC's System Security Frameworks Review; and
- provide a set of market-based solutions / incentives to address any other material shortcomings in frequency control in the NEM.

Based on the meeting that SW Advisory and DIgSILENT Pacific had with the Generator Group, it was agreed that the focus of our review was to be on providing a set of market-based solutions to identified frequency control problems in the NEM.

1.1 Background

The AEMC has initiated a Review into market and regulatory arrangements necessary to support effective control of system frequency in the NEM. The scope of the AEMC's review includes but is not limited to the following:

A. *assessing whether mandatory governor response requirements should be introduced and investigating any consequential impacts including on the methodology for determining causer pays factors for the recovery of FCAS costs*

B. *reviewing the structure of FCAS markets, to consider:*

   a. *any drivers for changes to the current arrangements, how to most appropriately incorporate FFR services, or alternatively enhancing incentives for FFR services, within the current six second contingency service*

   b. *any longer-term options to facilitate co-optimisation between energy, FCAS and inertia provision*

C. *assessing whether existing frequency control arrangements will remain fit for purpose in light of likely increased ramping requirements, driven by increases in solar PV reducing operational demand at times and therefore leading to increased demand variation within a day*

[9] The Generator Group includes Snowy Hydro, Stanwell Corporation, Engie, Origin Energy, AGL, Alinta Energy, Delta Electricity, and Intergen.
[10] DigSILENT Pacific, 2017, "Review of Frequency Control Performance in the NEM under Normal Operating Conditions"

D. *considering the potential of distributed energy resources to provide frequency control services and any other specific challenges and opportunities associated with, their participation in system security frameworks.*

1.2 Terms of Reference

The initial terms of reference we were given by the Generator Group were to assess the materiality of the current concerns from some stakeholders with the frequency performance in the NEM and to provide a set of market-based solutions or incentives to address any material shortcomings in frequency control in the NEM. In particular, The Generator Group wanted the consultant to address specific issues relating to AEMC's review.

In respect to item A of the AEMC review:

A. *assessing whether mandatory governor response requirements should be introduced and investigating any consequential impacts including on the methodology for determining causer pays factors for the recovery of FCAS costs;*

The Generator Group wanted the consultant to:

1. reference and use relevant material in the work presented in the Pacific Hydro submission to the AEMC's System Security Frameworks Review and the DIgSILENT Review of Frequency Control Performance in the NEM under Normal Operating Conditions prepared for AEMO;
2. provide advice on demonstrable economic impacts and materiality of wider frequency distributions around 50Hz by assessing the adequacy of the current Normal Operating Frequency Band (NOFB);
3. provide advice on AEMO's role in the frequency outcomes observed, including assessing:
    a. the role of AEMO's AGC system,
    b. AEMO's forecasting function; and
    c. the amount of enabled regulation services;
4. provide recommendations to improve the frequency outcomes observed with particular reference to:
    a. the shortcomings with current incentives from Causer Pays,
    b. generators not getting paid to provide governor response in the NOFB,
    c. AGC tuning, and
    d. load and VRE generation forecasting;
5. provide a set of market-based solutions / incentives to address any material shortcomings in frequency control in the NEM.

In respect to items B and C of the AEMC review:

B. *reviewing the structure of FCAS markets, to consider:*

   a. *any drivers for changes to the current arrangements, how to most appropriately incorporate FFR services, or alternatively* *enhancing incentives for FFR services, within the current six second contingency service*

b. *any longer-term options to facilitate co-optimisation between energy, FCAS and inertia provision*

C. *assessing whether existing frequency control arrangements will remain fit for purpose in light of likely increased ramping requirements, driven by increases in solar PV reducing operational demand at times and therefore leading to increased demand variation within a day*

The Generator Group wanted the consultant to provide a high-level critique of each topic area and provide set of high-level recommendations which are grounded in market-based principles and incentives to allow the Proponents of this project to converse with the AEMC.

Tim George of DIgSILENT Pacific and Stephen Wallace of SW Advisory attended an AEC generators' meeting and discussed the terms of reference and approach. Based on the meeting we had with the Generator Group, it was agreed that the focus of our review was to be on providing a set of market-based solutions to identified frequency control problems in the NEM.

1.3 Structure of Report

The report is structured as follows:

- Section 1 Introduction: provides general background information and the terms of reference;
- Section 2 Framework for Managing Frequency: sets out a logical framework for how frequency can be managed in an electricity market and how in particular it is managed in the NEM;
- Section 3 Frequency Control Issues in the NEM: outlines a number of frequency control issues identified and analysed by AEMO, DIgSILENT Pacific, Pacific Hydro, CS Energy and other market participants;
- Section 4 Market-based Solutions: discusses the merits of market-based solutions to frequency control issues in the NEM compared to regulatory approaches and outlines a logical framework for refining the FCAS market to address the frequency control issues in the NEM;
- Section 5 Markets for Management of Frequency in the NOFB: outlines a new FCAS service that would assist in the management of frequency within the NOFB;
- Section 6 Management of Frequency in the NOFB outlines a logical and more transparent approach to determining the amounts of regulation required;
- Section 7 Markets for Management of Contingency Events and Large Frequency Deviations describes a more general approach to the management of contingency FCAS that can flexibly operate in the NEM with a changing generation mix and low inertias in potentially islanded areas;

- Section 8 Improvements to “Causer Pays” outlines improvements to the “causer pays” methodology for the recovery of regulation costs and provides a framework for recovery the costs for the proposed new FCAS, Primary NOFB FCAS, which provides incentives for all participants to respond to frequency deviations within the NOFB;
- Section 9 General NEM Improvements outlines general improvements that could be made to AEMO’s energy management systems including the AGC, forecasting and NEMDE systems that would provide improve the efficiency of the NEM’s operation in general and improve frequency management in particular.
- Section 10 Conclusions sets out our conclusions as to how frequency management in the NEM can be improved through market mechanisms.

The reader familiar with how frequency is managed in electricity markets in general and the NEM in particular, can skip section 2. The reader familiar with the frequency control issues in the NEM can skip section 3. Those familiar with both can start reading at section 4.

1.4 Terminology: “Governor Response”

Throughout the report where the term “governor” or “governor response” is used it should be interpreted as a locally triggered and proportional response to frequency deviations from the rated frequency. “Governor” responses could be provided by many potential service providers, including synchronous generators, battery systems (charging or discharging), wind generators, PV generators and large industrial loads. In fact, any inverter-based system with a power controller could potentially provide “governor” responses. It is just a matter of software to get the desired performance.

2 Framework for Managing Frequency

2.1 Introduction

This section discusses a general conceptual framework for managing frequency in a power system and outlines how this is done in the NEM. The section includes general discussions on:

- A framework for an efficient FCAS market;
- Frequency standards;
- Mandatory requirements versus market-based approaches;
- AGC and governor control;
- Management of frequency following a contingency;
- Co-optimisation.

2.2 Frequency Control Ancillary Services (FCAS)

Frequency control ancillary services (FCAS) are services that are used to manage the frequency of the power system. In different markets, frequency control ancillary services can be called a variety of names, but they can generally be categorised in the following way:

- Primary response (generally units synchronised and providing a rapid autonomous response via their governors if the frequency is lower or higher than nominal but could include other proportional responses from inverter based generation or step responses such as may be provided by loads though this is unlikely because the load would be continuously switched on and off since frequency could regularly cross a pre-set frequency value in the NOFB);
  - In the NEM the primary response can include a switched response which is not proportional to the frequency. The NEM's primary response is comprised of:
    - the fast and slow contingency FCAS which are co-optimised with the energy dispatch; and
    - the responses of units whose governors are enabled irrespective of being dispatched (enabled) in the FCAS spot market. These generators are not paid for the services they deliver.
  - Within the NEM's normal operating frequency band (NOFB), only generators with enabled governors **and** very small deadbands will contribute to frequency control. Since there is no market for this frequency control in the NEM, these generators are not paid for the service they deliver.
- Secondary response (units operating on AGC responding to a centralised frequency measurement with the objective to return the system to nominal frequency);
  - In the NEM the secondary response is comprised of regulation FCAS; and

- Tertiary response (generating units, loads or other service providers that can be dispatched quickly to respond to a frequency event due to a forced outage of a generator, load or network element).
  - In the NEM the tertiary response is comprised of the delayed contingency FCAS.

2.3 Frequency Control

Frequency control is considered a power system security requirement and is therefore part of the security constrained dispatch in an electricity market. In a security constrained dispatch optimisation, constraints are included in the optimisation to ensure the required frequency control ancillary services (FCAS) requirements are met.

Co-optimised dispatch is used to jointly determine the energy and FCAS dispatch. The marginal cost or shadow price of each FCAS requirement constraint in each dispatch interval determines the market price for that service and dispatch interval.

2.4 Frequency Control in the NEM

At the start of the FCAS market in 2001, synchronous generators (hydro, thermal and to some extent GTs and CCGTs) were the main providers of primary control through their governor control systems. Governors were typically set to 'standard' droop levels of 4-5%.

Since then, three things have been happening with respect to primary control:

- The amount of primary control response is now more easily controlled with digital governors allowing all parameters (droop, deadbands, limits) to be dynamically adjusted. Providing droop control creates additional O&M costs, greater control burden on operators and potentially lower operating efficiencies. For these reasons, many generators are disabling droop control.
- The amount of conventional primary control is reducing as more traditional providers (synchronous generators) are being retired and displaced by VRE generators; and
- The inertia of the power system, and the inertia in some subsystems with high VRE penetration, is reducing. This in turn is increasing the rate of change of frequency and requiring more fast-acting primary control to manage power system frequency.

Technology is also changing. There are now fast acting inverter and storage systems, particularly battery energy storage systems (ESS), which can respond to a frequency change within tens of milliseconds. Some of these systems have short-term overload capabilities of around 10 seconds, which is valuable in reducing the magnitude of frequency excursions.

Further, with the flexible power electronics used in many large-scale wind, PV and battery systems, generation from these sources can be given governor like proportional responses and even provide regulation capability. However, this capability may come with extra capital and operating costs. Thus, it is unlikely to be economically efficient to insist that all generating units have primary frequency control capability via mandatory connection requirements. A better solution would be for the market to determine the most economic way of meeting the NEM's frequency control requirements in the short and long term.

A final observation is that the existing FCAS arrangements appear to have been designed specifically around the plant mix at the time (late 1990s, early 2000s) where high inertia coal, gas and hydro predominated. The frequency nadir during a contingency was typically close to six seconds, leading to the categorisation of the frequency markets as six seconds, to control the depth of the nadir, 60 seconds for slower responding plant (like hydro) to take over from the (now flagging) coal units, and to restore frequency to the NOFB. The whole FCAS market was, arguably, designed around the characteristics of the power system at the time that the FCAS arrangements were developed. The markets have worked well. However, the arrangements do not reflect the reality of the evolving power system nor the increased ability of the demand side to respond and assist in frequency control.

2.5 General Framework for an Efficient FCAS Market

A conceptual framework for an efficient market that co-optimises energy and FCAS requires the following:

- Frequency standards that are defined sufficiently well to ensure that the requirements for frequency control for different timescales can be clearly and unambiguously determined from the frequency standards and power system's characteristics;
- A non-discriminatory and technological neutral approach to the FCAS market including connection requirements;
- FCAS definitions should:
  - not be linked to historical system characteristics
  - be in a form suitable for a co-optimised energy and FCAS dispatch;
  - enable the efficient management of frequency over all time periods within the dispatch interval; and
  - facilitate the valuation of a services response time and duration;
- An efficient and effective approach to the determination of the requirements for each frequency control ancillary service for each dispatch interval which accounts for: the power system's real-time operating characteristics including the dispatch of generators, loads and network elements, credible contingencies, the inertia of the system and any potential islands, the variability of loads, VRE outputs and dispatchable generator outputs etc.;
  - There is an emerging need to establish just how much primary control is required to meet the frequency standard and in what timeframe the

service must be provided and over what frequencies the service should operate.
  - Similarly, there is a need to establish how much secondary control is required to meet the frequency standard and at what times given the increasing penetration of VRE generation, more variable loads and increasing levels of PV and batteries at the household and commercial level.
- The determination parameters that describe the capabilities of generators, batteries and loads to provide and meet the various FCAS requirements;
- An effective formulation and transparent implementation of a dispatch and pricing co-optimisation including the co-optimisation of both global and local requirements[11];
- An effective mechanism to take co-optimised regulation targets for generators and other providers and current system frequency deviations and turn these into appropriate AGC targets for generators enabled (dispatched) for regulation;
  - The effective management of regulation may require at times the co-optimisation of regulation on a locational basis and the appropriate use of participation factors / regulation targets to manage transmission flows within their limits;
- Effective cost recovery mechanisms and incentives that encourage behaviours that assist with managing frequency; and
- Mechanisms to monitor the performance of FCAS providers.

2.6 NEM FCAS Framework

The NEM's FCAS arrangements largely satisfy the general framework but there are weaknesses in a number of areas:

- The NEM's FCAS definitions and the set of services being co-optimised are based on historical power system characteristics and should be revised in light of the changes occurring to the power system;
- AEMO's current approach to determining the amount of regulation FCAS could be substantially improved and made more transparent;
- Along with improvements to the NEM's FCAS definitions, there should be better parameterisation of FCAS which is being provided;
- AEMO's formulation and implementation of dispatch and pricing co-optimisation is arguably out-dated. It does not explicitly include the co-optimisation of both global and local requirements, though it does use generic constraints to sometimes try to co-optimise requirements. The co-optimisation of requirements should be an explicit mathematical programming formulation

[11] Local requirements could, for example, reflect a potential sub-system that has high VRE / low inertia, but is still required to meet the frequency standard.

rather a formulation which uses generic constraints as these are not audited and unlikely to lead to optimal dispatches all of the time;

- The “causer pays” cost recovery mechanism for regulation FCAS is generally regarded, on occasion, as creating perverse incentives for generator behaviour.

2.7 Power System Standards

Power system standards are the key to managing a power system in a secure and reliable fashion. The standards provide the mechanism for the system and market operator (SMO), in the case of the NEM – AEMO, to manage the power system. A well thought out, complete and consistent set of standards should rarely require changes and should provide a framework such that:

- Every decision made by the SMO should be linked back to the standards;
- Transparent procedures define how the SMO will meet the standards;
- Technology changes should generally only require changes to SMO’s procedures;
- Planning is based on meeting the standards; and
- Connections are required to meet the standards.

2.8 NEM Frequency Standards

A frequency control standard specifies the required power system performance under both normal operating conditions and also under contingency conditions. The NEM frequency standards are a good international example of frequency standards. The NEM’s frequency control standard for the interconnected system is presented in Table 2-1.

Table 2-1 NEM Mainland Frequency Operating Standards – interconnected system

Condition	Containment (Hz)	Stabilization	Recovery
accumulated time error	5 seconds		
no contingency event or load event	49.85 to 50.15 Hz – 99% of the time		
	49.75 to 50.25 Hz	49.85 to 50.15 Hz within 5 minutes	
generation or load event	49.5 to 50.5 Hz	49.85 to 50.15 Hz within 5 minutes	
network event	49.0 to 51.0 Hz	49.5 to 50.5 Hz within 1 minute	49.85 to 50.15 Hz within 10 minutes
separation event	49.0 to 51.0 Hz	49.5 to 50.5 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes
multiple contingency event	47.0 to 52.0 Hz	49.5 to 50.5 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes

Note that the frequency standard for normal operations when there is no generation, load or network contingency event is for the frequency to be 49.85 to 50.15 Hz for 99% of the time. That is for frequency to be in the normal operating frequency band (NOFB) for 99% of the time. This is a probabilistic standard, which reflects the fact that frequency within the NOFB is the result of random variations of load, dispatched generator outputs, VRE outputs etc. and the AGC and primary governor responses to frequency deviations from the nominal frequency of 50 Hz.

The standard for the probability of being in the NOFB or the size of the NOFB could be changed and this would have implications for the amounts of AGC regulation enabled and the desired governor responses of generating units.

On the other hand, note that the frequency standards for the rest of the system conditions do not use probabilities. In reality, it is impossible to ensure that these standards are met with 100% probability but not specifying a probability implies that the standards should be met with a very high probability, say, 99.99% of the time when the event occurs.

The NEM frequency standard is comprehensive and clear. Aside from the above discussion on probabilities, delivery of the standard should ensure high quality frequency control and give AEMO the ability to manage safety and reliability in the event a non-credible contingency occurs.

2.9 Mandatory Connection Requirements versus a Market-based Approach

In a market, the only time mandatory performance requirements should be applied is where analysis shows that the power system needs to be protected against cascading collapse caused by:

- Unusual and unexpected events that may happen too quickly for the SMO (AEMO) to respond
- High impact low probability events, such as multiple contingencies, that are too costly to mitigate through market services.

Examples include:

- Under frequency load shedding (for low frequency events)
- Generator tripping (for high frequency events)

In the above cases, the mandated performance is for conditions outside of the normal contingency bands in the frequency standard. Credible contingencies are not unexpected or unusual events and should not have mandated performance requirements from each generator. It is, however, quite reasonable to require performance service levels from any service providers that offer into the FCAS markets.

The benefit of having a market-based approach to security and reliability services is that the participants best able to provide the services are appropriately incentivised. Those participants with technologies not suited to providing the services can elect not to provide the services and have the market purchase them off more efficient providers.

Also, markets encourage innovation, as opposed to prescriptive approaches which can become obsolete as technology changes. Therefore, most efficient approach is to define standards for security and reliability, (including stability, frequency, unserved energy or loss of load probability etc.) and then provide flexibility in how the market and the SMO (AEMO) deliver these outcomes.

For example, there is no standard at present for inertia and there probably shouldn't be one as the importance of inertia is indirect based on how it can affect the management of frequency. However, a shadow cost/price for inertia could possibly be determined based on the frequency standard and an effective co-optimisation of FCAS. This co-optimisation could include very fast frequency responses, the current inertia of the system and any potential islands. Since inertia and very fast FCAS responses are to some extent substitutable, inertia could be included as part of an improved FCAS market and market participants providing inertia or inertia like services (responses to rate of change of frequency) could be paid for these services.

Trying to make everything look and perform according to historic system characteristics by defining mandatory requirements for inertia and governor responses is unlikely to deliver the most efficient outcome compared to creating appropriate market arrangements.

2.10 The Elements of AGC and Governor Control

There has been recent discussion about the frequency performance of the NEM in the NOFB and whether the automatic generation control (AGC) system in conjunction with generators' governor controls are operating correctly[12, 13 and 14].

The following two sections discuss the elements of AGC operation.

In this section we will use a very simple example to illustrate the key elements of the interaction of governor responses to deviations of frequency and AGC's role in returning frequency to the rated frequency.

In example 1 the power system consists of three generating units and a load of 350 MW. The capabilities of the units and their set points to meet the 360 MW load are presented in the table below.

Table 2-2 Example 1: Power System

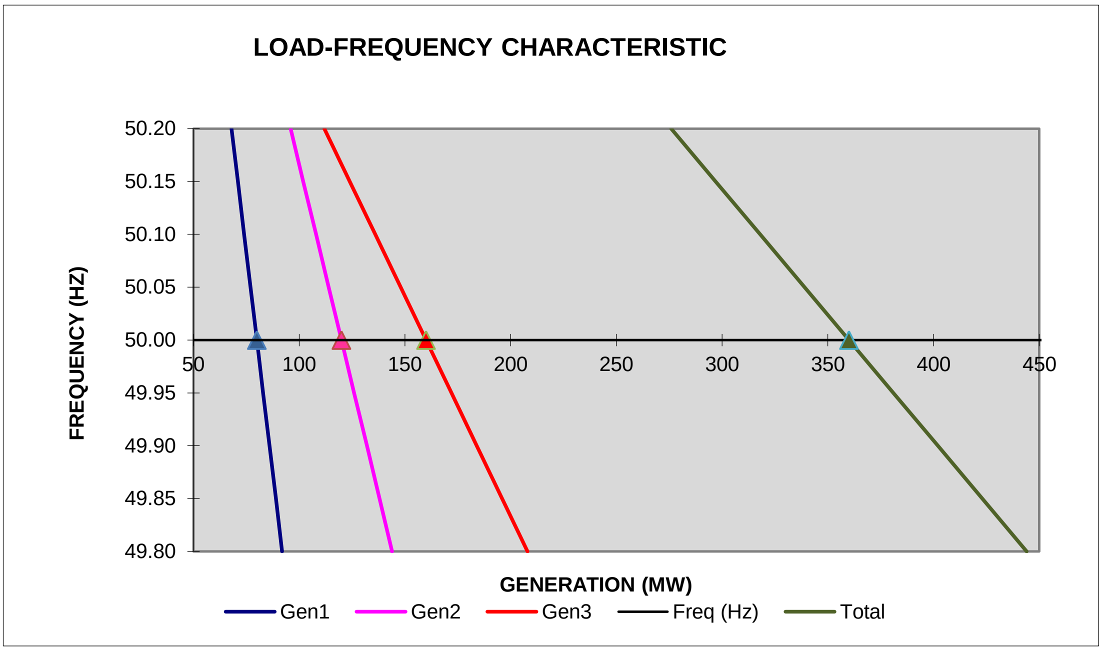
Unit	Gen1	Gen2	Gen3	Total
Generation (MW)	80.0	120.0	160.0	360.0
Set point (MW)	80.0	120.0	160.0	360.0

[12] Pacific Hydro submission to AEMC's System Security Frameworks Review
[13] DigSILENT Pacific, 2017, "Review of Frequency Control Performance in the NEM under Normal Operating Conditions"
[14] CS Energy and PD View (2017) submission to AEMC's Review of the Frequency Operating Standard

Rating (MW)	300.0	450.0	600.0	1,350.0
Droop (%)	10.0%	7.5%	5.0%	6.4%
Governor (MW/Hz)	60.0	120.0	240.0	420.0

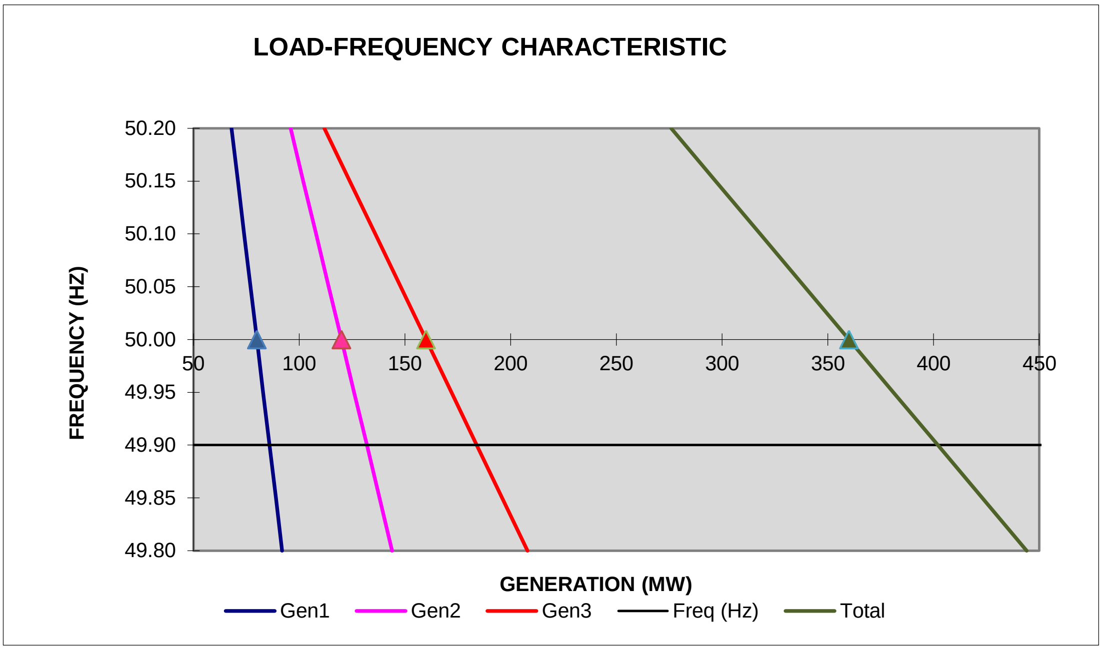
The unit set points and their governor response curves are presented in Figure 2-1. The set points for each unit are represented by a triangle along the unit's governor response line. The total system generation and total of the set points is represented by the triangle on the Total line.

Figure 2-1 Example 1: Generator set points for 360 MW load



If the demand increases from 360 MW to 402 MW, the frequency will begin to reduce (at a rate determined by the inertia -not relevant in this discussion). As the frequency decreases, the governors of the generators will act to increase their output. An equilibrium will be established where the governor responses match the increase in demand. However, in order to sustain this increase in generation, the frequency must stay below nominal. The results are shown in Figure 2-2 and the offset required from nominal to sustain the required governor response is shown to be 0.1 Hz. Note that in this example, the frequency sensitivity of the load –is being ignored.

Figure 2-2 Set points and system frequency for an increase in load



The set points and new outputs of the generating units are shown in Table 2-3.

Table 2-3 Generation outputs and set points for increased load

Unit	Gen1	Gen2	Gen3	Total
Generation (MW)	86.0	132.0	184.0	402.0
Set point (MW)	80.0	120.0	160.0	360.0

To return the system back to 50 Hz the AGC system must increase the total of the set points for all units. To do this the AGC does the following.

1. It calculates the shortfall of the set points compared to the load using the current system frequency and aggregate generation frequency sensitivity as follows:
   a. The frequency deviation is 50 Hz – 49.9 Hz = 0.1 Hz
   b. The frequency sensitivity of the system is 420.0 MW/Hz or 42 MW/0.1 Hz[15]
   c. Therefore, the set points have to be increased by 42MW to return the system to 50 Hz (the 42 MW is the Area Control Error – ACE);
2. The AGC system allocates the increase of 42 MW in set points to the three generators as follows:
   a. First it determines or is given allocation factors for each generating unit. The allocation factors could depend on the offers made by the generator or could be based on marginal costs around the current energy targets

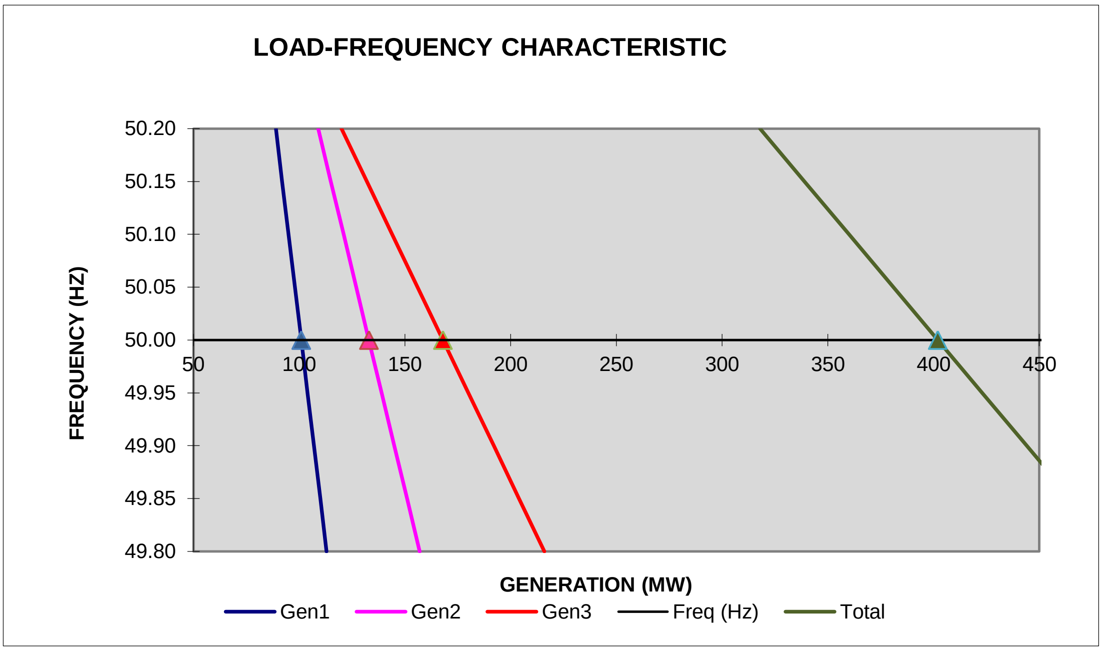
[15] Normally this is a characteristic of the whole power system and thus would include the frequency sensitivity of the system load which has not been included in this example.

and would take into account ramp rates. These factors are called participation factors. For this example, suppose the participation factors for Gen1, Gen2 and Gen3 are 50%, 30% and 20%[16].

b. It then multiplies the 42 MW by each unit's participation factor to determine the change in the unit's set point. In this example the set points of the units would be increased by 21 MW, 12.6 MW and 8.4 MW respectively.
c. Finally, the AGC sends signals to the units to change their outputs to the new set points.

The new set points and generation outputs of the units are presented in Figure 2-3.

Figure 2-3 New set points and system frequency for an increase in load



This simple example illustrates the basics of governor action or other linear responses to frequency and AGC. For a change in load the system frequency changes and the outputs of the system's units change with the action of their governors. This is the primary frequency control. The AGC then changes each unit's setpoint to restore the frequency to 50 Hz. This is the secondary frequency control. Thus, to control frequency to within the NOFB requires both primary control (governor action) and secondary control (AGC).

AGC and primary control can be coordinated to provide good frequency control, with primary control providing the initial response (fast acting) and the AGC

[16] In the NEM the participation factors are calculated from the amounts generating units are enabled for regulation. In other systems the participation factors may be calculated based on the marginal costs of units around their energy dispatch.

providing the regulating function of restoring the frequency to nominal and 'reset' the primary control responses .In the absence of the fast acting primary control, the regulating function can provide good control of average frequency but may suffer short-term deviations, which is the behaviour currently experienced in the NEM. The observed NOFB control issues are due to a number of factors. Enabling primary control will improve the ability to respond to faster deviations in frequency that are outside the bandwidth of the regulation control, which has time delays due to SCADA etc. It is not possible to estimate the degree to which primary control will improve NOFB performance without some analytical studies, which would need to consider different levels of response (number of MW enabled) and the response speed of the service providers. Clearly, if hundreds of MW of fast acting primary control are activated, the NOFB control will improve markedly. The cost of this action and the benefits obtained clearly need to be weighed.

2.11 AGC Systems

Automatic Generation Control (AGC) can adjust the setpoints of generating units in order to match dispatch targets and provide a regulating service (secondary control) that will attempt to maintain the power system frequency and/or control area net interchange. In the NEM, only one area is considered so the regulating service does not attempt to regulate inter-area flows.

In other countries with large and sometimes cross border power systems, the regulating services are biased to control inter-area flows and frequency. Note that this requires either inter-area flows or frequency to be nominated as the priority. Usually inter-area flows are prioritised because in large systems it is not practical for one sub-system to provide all the control action to address a frequency deviation.

The standard functions for a modern AGC system are for it to monitor and control power generation with these overall objectives:

- Maintain generation at fixed (baseload) values (these fixed levels would generally be determined by economic dispatch software);
- Ramp generation in a linear fashion, according to a schedule specified by the operator or from the economic dispatch software
- Deliver secondary control (i.e. regulation services) that:
  - Minimises the area control error, including prioritising one of:
    - Control of inter-area flows
    - Maintaining frequency at nominal in accordance with the standard
  - Adjusts setpoints of dispatched FCAS generators (regulating service) in accordance with calculated participation factors.

AGC systems generally provide a number of operational control modes, each using a different method for calculating the area control error (ACE)[17]. These control modes include:

- Constant Frequency (CF) – ACE is determined based on the actual frequency compared to the scheduled or rated frequency;

  ACE = - 10 x B x (F – Fs)

  Where:

  B = area frequency bias (MW/0.1 Hz)

  F = current measured frequency (Hz)

  Fs = scheduled frequency (Hz); normally 50.0Hz

  The frequency bias constant, B, can be pre-set or can be calculated as follows:

  B = D + $\sum_{g=1}^{n} b_g$

  Where:

  D is the area load bias contribution (MW/0.1Hz)

  b_g is the bias contribution (MW/0.1Hz) of generating unit g due it being online and its governor droop setting
- Constant Frequency and Time Error Correction (CF-TEC) – ACE is calculated as for CF but with an additional term which takes into account the current time error;
- Constant Net Interchange (CNI) – ACE is determined based on the difference between the net of the actual tie line[18] flows compared to the scheduled of tie line flows;
- Tie-Line Bias (TLB) – ACE is calculated based on a combination of frequency deviation and tie line deviation;
- Tie-Line Bias with Time Error Correction (TLB-TEC) – ACE is calculated as a combination of tie line bias with an additional term which takes into account the current time error.

AGC systems generally provide facilities for smoothing of filtering inputs and outputs such as filtering frequency, generator SCADA[19] data, ACE etc. The algorithms for filtering and smoothing are generally simple algorithms which can be iteratively calculated like exponential smoothing. AGC system software has its origins in the 1970s and is well tested, simple and reliable.

Most AGC systems can simultaneously control multiple areas.

2.12 NEM's AGC Setup

AEMO runs its AGC system using a Constant Frequency and Time Error Correction (CF-TEC) mode of operation. AEMO's AGC system is described in chapter 2.3 of

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[17] A. Wood, B. Wollenberg, G. Sheble (2013) "Power Generation, Operation, and Control" 3rd Edition

[18] A tie line is a transmission line or set of lines connecting two different control areas.

[19] SCADA is short for supervisory control and data acquisition. Wikipedia states that SCADA is a control system architecture that uses computers, networked data communications and graphical user interfaces for high-level process supervisory management, but uses other peripheral devices such as programmable logic controllers and discrete PID controllers to interface to the process plant or machinery.

DIgSILENT report "Review of Frequency Control Performance in the NEM under Normal Operating Conditions".[20]

The key features of AEMO's AGC system are as follows:

- The AGC system determines an estimate of the MW amount that the current set points of units have to be changed in order to return the system frequency to its rated frequency (50Hz). This is done via calculating ACE as follows:

  ACE = - 10 x BIAS x (F – Fs– Fo)

  Where:
  BIAS = area frequency bias (MW/0.1 Hz)
  F = current measured frequency (Hz)
  Fs = scheduled frequency (Hz); normally 50.0Hz
  Fo = frequency offset for system wide time error correction (Hz)
  = - Time_error_BIAS (Hz/s) x Time_error (s)

  For the BIAS setting, AEMO currently uses a constant 280MW/0.1 Hz and we believe that this has not been changed for years. The AEMO does not do a dynamic calculation of the BIAS and use this in the AGC system.

- AEMO's AGC system also includes an ACE Integral which is used to reduce the frequency deviation when ACE is very small and at the same time reduce the time error. The ACE Integral is calculated by integrating ACE values for every AGC execution cycle which is currently set to 2s for AEMO. The ACE integral is capped to +/-140MW.

  ACE Integral(t_n) = ACE Integral(t_{n-1}) + ACE(t_n) x (t_n - t_{n-1}) / 60 x 60 (MWh)
  Where t_n is the time which ACE was calculated and (t_n - t_{n-1}) = 2 s

- AEMO determines ACE for NEM south and NEM north and also calculates a filtered ACE for NEM south and NEM north using exponential smoothing, acting as a low pass filter, with an equation something like:

  ACEFIL(t) = 0.8 ACEFIL(t) + 0.2 ACE(t).

- The ACE and ACE Integral are used to calculate the total amount of regulation required by the power system, using the following formula:

  Total Raw Regulation = ACE * Gain + ACE Integral * Integral Gain

  The values of the gain applied to ACE and ACE Integral are different and change according ACE control region. Higher gains are used for higher values of ACE.

2.13 Participation factors

Once an AGC system calculates ACE, it must allocate the ACE to each generator within the control area. This is done via participation factors. The change in each generator's set point is calculates as follows:

[20] http://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Working_Groups/Other_Meetings/ASTAG/371100-ETR1-Version-30-20170919-AEMO-Review-of-Frequency-Control.pdf

$\Delta P_g = \alpha_g \times ACE$

Where ΔP_g is the change in setpoint of generator g

α_g is the participation factor for generator g

2.14 NEM participation factors

In the NEM all dispatchable generating units, other than those enabled for regulation, are ramped linearly by the AGC system from the current generation output at the start of the dispatch interval to their energy generation target at the end of the dispatch interval. Those units enabled for regulation are allocated participation factors for increasing and decreasing their outputs relative to the energy targets based on how much they were enabled for raise and lower regulation FCAS.

The participation factor for a unit to have its output increased relative to its energy target is based on how much it was enabled for raise regulation compared to the total amount of raise regulation enabled and is

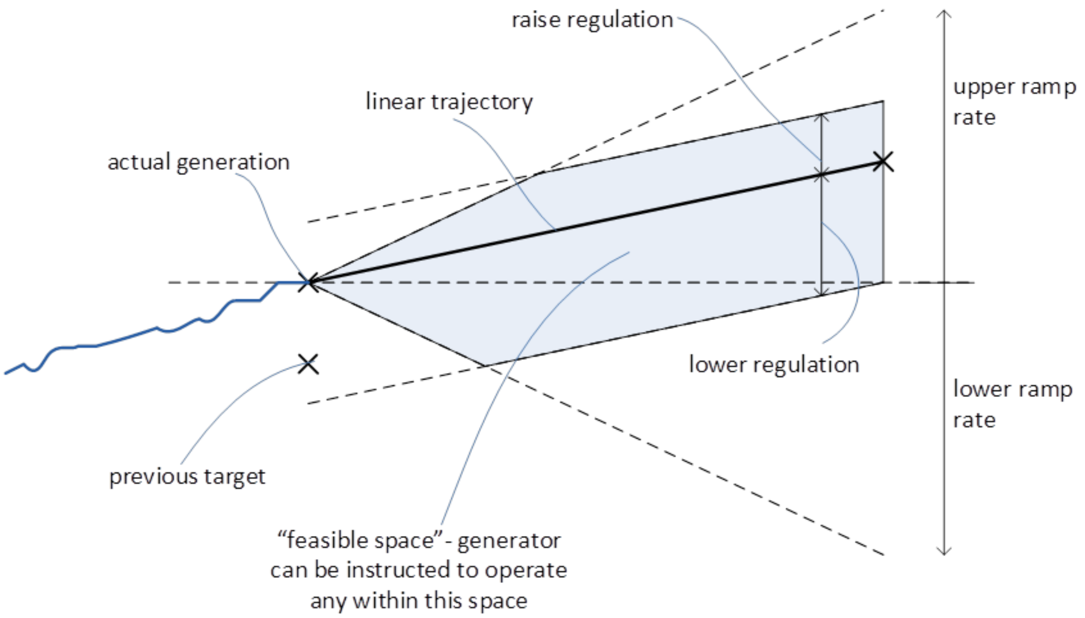
$$\alpha\_raise(g) = \frac{\mathrm{reg\_raise\_enabled(g)}}{\sum_{i=1}^{n} \mathrm{reg\_raise\_enabled(i)}}$$

Similarly, the participation factor for a unit to have its output decreased relative to its energy target is based on how much it was enabled for lower regulation compared to the total amount of lower regulation enabled and is

$$\alpha\_lower(g) = \frac{\mathrm{reg\_lower\_enabled(g)}}{\sum_{i=1}^{n} \mathrm{reg\_lower\_enabled(i)}}$$

AEMO's AGC system then attempts to manage frequency by allocating set points to units which are enabled for raise and lower such that they fall in the feasible space shown in Figure 2-4.

Figure 2-4 Feasible space for AGC set points for a unit enabled for regulation



2.15 Managing Frequency Following a Contingency

It is important to manage frequency in a way that satisfies the frequency standards. A key component of this is managing frequency after a contingency event. To manage frequency following a contingency an understanding of the frequency dynamics of the power system is required, particularly in situations where there is low system inertia. The swing equation, given below, determines the frequency dynamics of the power system and is dealt with extensively for low inertia systems in Ulbig, "Impact of Low Rotational Inertia on Power System Stability and Operation[21].

$$2H\frac{d^2\delta}{dt^2} = P_{mech} - P_{elec}$$

Where:

P_{mech} is the mechanical power input from generating units

P_{elec} is the electrical power consumed on the power system

H is the inertia of the synchronous power system (in seconds)

δ Rotor angle measured against an external reference. The first derivative of rotor angle is speed, ω, which is the same as frequency in unitised terms.

While the supply (P_{mech}) matches exactly the demand (P_{elec}), the power system acceleration is zero and the frequency is unchanging. A disturbance that produces

[21] T. B. G. A. Andreas Ulbig, "Impact of Low Rotational Inertia on Power System Stability and Operation," IFAC Proceedings Volumes, vol. 47, no. 3, pp. 7290-7297, 2014.

an unbalance on the right hand side of the equation, results in acceleration, with the dynamics being defined by the power system inertia, H.

The swing equation can be rewritten to give the change in frequency as a function of inertia and the mechanical input power and electrical power consumed.

$$\frac{d \quad frequency}{dt} = \frac{P_{mech} - P_{elec}}{2H}$$

From the equation above it is quite clear that the change in frequency is higher for lower inertias when $P_{mech} \neq P_{elec}$. Thus for subsystems with low inertias there can be rapid changes in frequency for credible contingencies in contrast to systems with high inertias.

Typically, a frequency standard will specify the maximum permissible frequency excursion for a credible contingency as well as a time within which the frequency must be restored to the continuous operating band tolerance. This is the case for the NEM frequency standards given in Table 2-1.

From the swing equation, it is relatively straight forward to calculate the required contingency FCAS to meet the frequency standard. What is less straightforward is to determine when this FCAS must be provided and, for a market, which service providers should be dispatched.

There is a maximum permissible frequency deviation for a contingency. The amount of FCAS required to ensure this deviation is not exceeded can be calculated based on the largest credible contingency for both the supply side and the demand side (frequency fall and rise, respectively). The supply side contingency will be discussed in this report, but similar concepts apply to demand side contingencies.

The demand is frequency sensitive. Internationally this is between 1% and 2% reduction in load for each 1% reduction in frequency, with the lower figure being more conservative. It is understood that AEMO is using 1.5%. Some generation may be frequency sensitive and allowance must be made for these and any similar impacts in the swing equation. The load frequency dependency is referred to here as LD and the generator frequency dependency as GD. The demand, L, and any frequency sensitive generation, G, are adjusted as frequency changes.

In the NEM's frequency standard (Table 2-1), the largest frequency deviation for a supply-side contingency is 0.5 Hz. In practice, allowance should be made for the starting frequency to be at the lower end of the normal frequency operating band.

The decline in frequency for the largest credible contingency reaches its nadir when the acceleration in the swing equation is zero. At this time, the supply is equal to the demand. The conditions for this to occur are as follows:

$$P'_{mech} * \left(1 + GD * \Delta_f\right) + FCAS = L * \left(1 + LD * \Delta_f\right)$$

$$where$$

$$P'_{mech} = P_{mech} \quad - \quad \Delta_g$$

$$P_{elec} = P_{mech} = L$$

Since the maximum value of Δ_f is specified by the standard, and P_{mech} is assumed to equal the demand prior to a contingency, the primary FCAS response required can be calculated as.

$$FCAS = \Delta_g + L * LD * \Delta_f - P'_{mech} * GD * \Delta_f$$

Where:

FCAS = the amount of FCAS required at the specified time

Δ_g = the loss of generation from the contingency event (MW)

Δ_f = acceptable change in frequency at the specified time based on the frequency standards (Hz), sign is -ve for a reduction

LD = load frequency dependency (%/%)

GD = generation frequency dependency (%/%)

2.16 NEM's Management of Contingency FCAS

In the NEM contingency services are split up into three time frames: 6 seconds, 60 seconds and 5 minutes. These categories were largely based on the predominant coal and hydro generation in the 1990s and the capabilities of this generation. The 6s category reflected the governor responses of coal steam units and the 60s response reflected what the hydro units could readily provide. The 5 minute services reflected what fast start units could provide, particularly hydro and some gas units.

For the 6s and 60s services AEMO calculates the amount of FCAS required in the mainland as follows[22]:

- For each region, the size of the largest generation event is determined as the size of the largest single generating unit or where the loss of generation could be the result of losing a network element the size of the set of units potentially affected;
- The largest single generating unit event in the NEM, Δ_g, is the maximum of the largest single generating unit event in all of the regions;
- AEMO calculates the FCAS requirements for 6s and 60s contingency services for a generation contingency event as follows:

$$FCAS = \Delta_g - L * LD * \Delta_f$$
$$= \Delta_g - mainland\ demand * \frac{1.5\%}{1.0\%} * \frac{\Delta_f}{50Hz} - 4\ x\ Tas\ demand * \frac{1.0\%}{1.0\%} * \frac{\Delta_f}{50Hz}$$
$$= \Delta_g - 0.015\ x\ mainland\ demand - 4\ x\ 0.01\ x\ Tas\ demand$$

What is interesting to note is that in this calculation AEMO explicitly assumes that the starting frequency is at 50 Hz or greater and hence Δ_f = 50 Hz - 49.5 Hz = 0.5

[22] AEMO, 2015, Chapter 4 "Constraint Implementation Guidelines" and AEMO, 2015, Chapter 8 "Constraint Formulation Guidelines"

Hz rather than the more conservative and appropriate assumption that frequency is at the lower end of the NOFB, 49.85 Hz.

As discussed earlier, the NEM frequency standards imply that the system should be run such that the probability of the power system frequency dropping below 49.5 Hz should be almost zero. Since the actual frequency can be anywhere in the NOFB, it implies that Δ_f should be calculated as Δ_f = 49.85 Hz - 49.5 Hz = 0.35 Hz. The nearly flat distribution of the NOFB frequency currently indicates that there is a nearly equal probability of being anywhere in the NOFB at any time.

For the 5 minute service, AEMO calculates the FCAS requirements assuming a load relief based on a drop in frequency from 50 Hz to 49.85 Hz. As we discussed for 6s and 60s, it would seem logical that frequency should be assumed at 49.85 Hz just prior to the contingency event and hence as Δ_f = 49.85 Hz - 49.85 Hz = 0.0 Hz and hence they should not assume any load relief for the 5 minute services.

AEMO performs similar calculations for loads and transmission elements / interconnectors when they are single contingencies.

2.17 Co-optimisation

Co-optimisation of energy and reserves (FCAS) is the process of finding the lowest cost dispatch that meets the load forecasts at all locations and meets the global and regional FCAS requirements. In most market dispatch optimisation systems which do co-optimisations of energy and FCAS the systems co-optimise:

- **The plant**: each unit or service provider's dispatch of energy and FCAS such that its capacity limits (minimum loading levels and maximum available capacity) and ramp rate limits are managed for all services. This is done for the joint supply of energy and all of the services and is managed in the optimisation via a series of plant ramping and capacity constraints; and
- **The requirements**: the determination of requirements such as the sizes of the largest contingencies (generator or an interconnector that is a credible contingency) are co-optimised with the dispatch of energy and FCAS.

The co-optimisations are generally done as linear programming optimisations, though some may include binary variables to determine whether a unit should supply a service or not. The binary variables are used a bit like unit commitment binary variables in some security constrained unit commitment optimisation software.

The co-optimisation of an FCAS, such as regulation or a contingency FCAS, is essentially done as follows, though in practice there may be many other additional constraints for load and network contingencies and the constraints below may be refined into a number of additional constraints:

- The offered costs of the services are included in the objective function of the dispatch optimisation so the total cost of providing energy and ancillary services will be minimised; and
- The following constraints are added to the optimisation:

Service provider capability constraints

- For each potential provider of a service and each service:
  - the dispatch of the service <= the service provider's capability for that service;
- For each potential provider of a service and each contingency service, assuming that the supply of one contingency services doesn't conflict with the supply of another:
  - the total dispatch of energy + raise regulation + raise contingency service <= generator's capacity (Pmax)
  - the total of dispatch of energy - lower regulation - lower contingency service >= generator's minimum loading (Pmin);
- For each provider and for the services where there is a joint ramp rate issue such as for regulation:
  - the total of energy + sum of raise reserve services enabled
    <= generator's starting state[23] + ramp rate x dispatch interval;
  - the total of energy – sum of lower reserve service enabled
    >= generator's starting state - ramp rate x dispatch interval; and

Minimum market requirement constraints

- For each service in the market:
  - the total amount of service enabled in the market = sum for all plant of the amount of service enabled;
  - the total amount of service enabled in the market >= minimum global requirement;
- For each service in the market that has regional requirements:
  - the total amount of service enabled in the region >= minimum regional requirement;

Co-optimised market requirement constraints

- For contingency FCAS to manage a generation contingency event, the co-optimised requirement constraints are:
  - the contingency service's requirement >= largest contingency – any load relief
  - largest contingency >= total dispatch of energy + raise regulation + raise contingency service for each unit and each contingency service
- For potential islanding constraints that trade-off credible contingency transmission flows with contingency sizes in the potential islands
  - Largest local contingency >= transmission line flow

Other constraints

[23] That is, measured output level of the generator.

- As well as the above general constraints there may also be other constraints to manage plant capabilities and any other location or portfolio requirements for FCAS.

Generally, market dispatch optimisations have an explicit mathematical programming formulation that is readily understood and audited. A good example is the formulation used by Singapore which includes a co-optimisation of energy and FCAS for arrangements similar to the NEM (see Appendix 6D: Market Clearing Formulation of the Singapore Market Rules[24])

2.18 Co-optimisation and FCAS Prices

The price for each reserve service for each dispatch interval is determined from the co-optimisation and is equal to the shadow price (marginal cost) of the particular FCAS's requirement constraint. The shadow price automatically includes any opportunity cost if a generator is backed off in the energy market in order to provide the FCAS. Based on each generator's offers for energy and FCAS (assuming they reflect the generators costs) and the prices determined from the co-optimisation, no generator can be better off if it determined a different dispatch for energy and FCAS for that dispatch interval.

2.19 NEM's Co-optimisation

The NEM co-optimisation is done using the NEM dispatch Engine (NEMDE). NEMDE co-optimises the energy and FCAS dispatch of plant but generally does not do the co-optimisation of requirements, though there are times when this is done via the clumsy method of using generic constraints (chapter 8.19 of AEMO's "Constraint Formulation Guidelines").

The NEM dispatch of contingency reserves may be enabling too little of the services because it is assuming too much load relief as discussed in section 2.16. This means that the amount of contingency FCAS enabled through the co-optimisation may not have a sufficiently high probability of meeting the frequency standards.

Also, AEMO's approach to enabling delayed contingency assumes that all of the enabled regulation FCAS is available to be used to meet the 5 minute contingency FCAS requirements (chapter 8.4 of AEMO's "Constraint Formulation Guidelines"). This assumption is clearly wrong. At the time which a contingency event occurs the probability that no raise or lower regulation is being used is almost zero, much the same as the probability that frequency will be exactly 50 Hz. Approximately 50% of the time some lower or raise regulation will be used just prior to a contingency occurring. Further, as we pointed out earlier in section 2.8, for frequencies following a contingency event there is an implied very high probability that the system should remain within the frequency standards. To satisfy this high probability, it would seem prudent to assume that there is no available regulation

[24] https://www.emcsg.com/marketrules

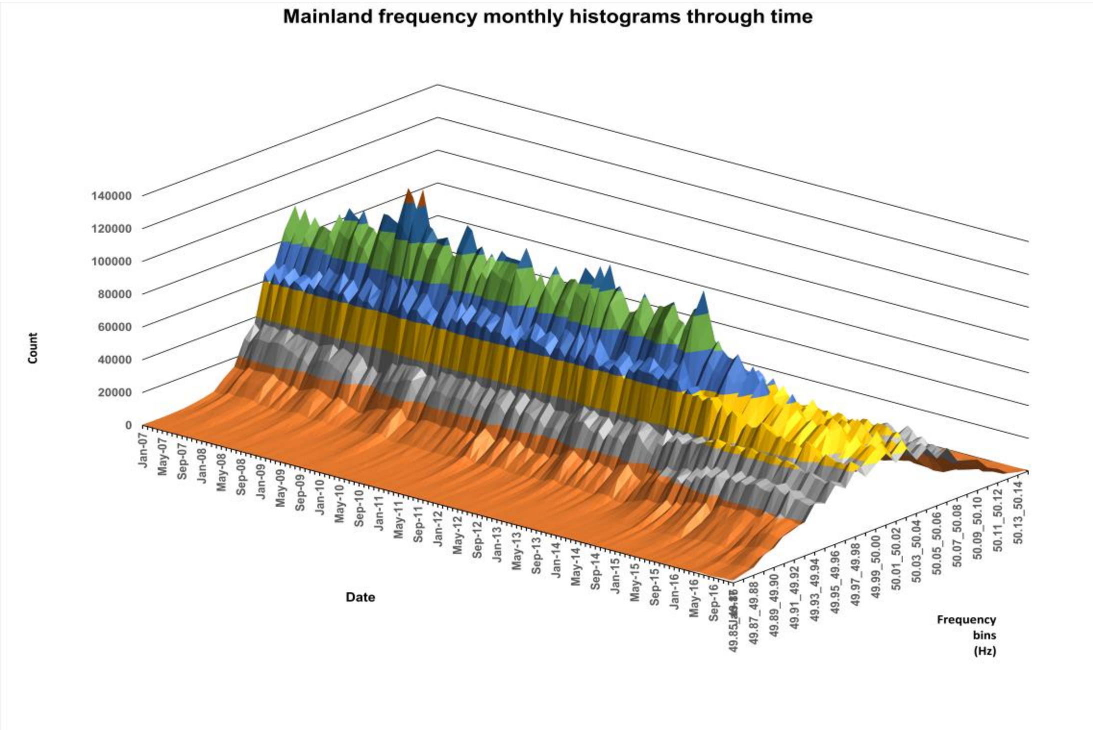
to contribute to delayed reserve and also assume that frequency is on the boundary of the NOFB.

3 Frequency Control Issues in the NEM

3.1 Frequency Distribution

DigSILENT has investigated the deterioration of the 'quality' of the frequency control in the normal operating frequency band (NOFB), being from 49.85 to 50.15 Hz[25]. It is evident from an analysis of records over a multi-year period that the distribution of frequency within the NOFB has changed from a fairly narrow distribution centred around 50 Hz to a flatter distribution across the band. Whereas there was a high probability of frequency being very close to 50 Hz, the current performance shows there is a fairly even probability for the frequency to be anywhere within the NOFB. Figure 3-1 from the DigSILENT report illustrates this change in probability.

Figure 3-1 Spread of frequency by month from 2007 to 2016 - mainland. Source: AEMO



Pacific Hydro in their submission to AEMC's System Security Frameworks Review have also provided similar evidence to how much the distribution of frequency has flattened out from 2001 to 2016, this is presented in Figure 3-2.

The DigSILENT report also shows the increase in the standard deviation of frequency for the mainland NEM power system - Figure 3-3.

25 DigSILENT Pacific, 2017, "Review of Frequency Control Performance in the NEM under Normal Operating Conditions

Figure 3-2 Example of the change in the distribution of frequency from 2001 to 2016. Source: Pacific Hydro

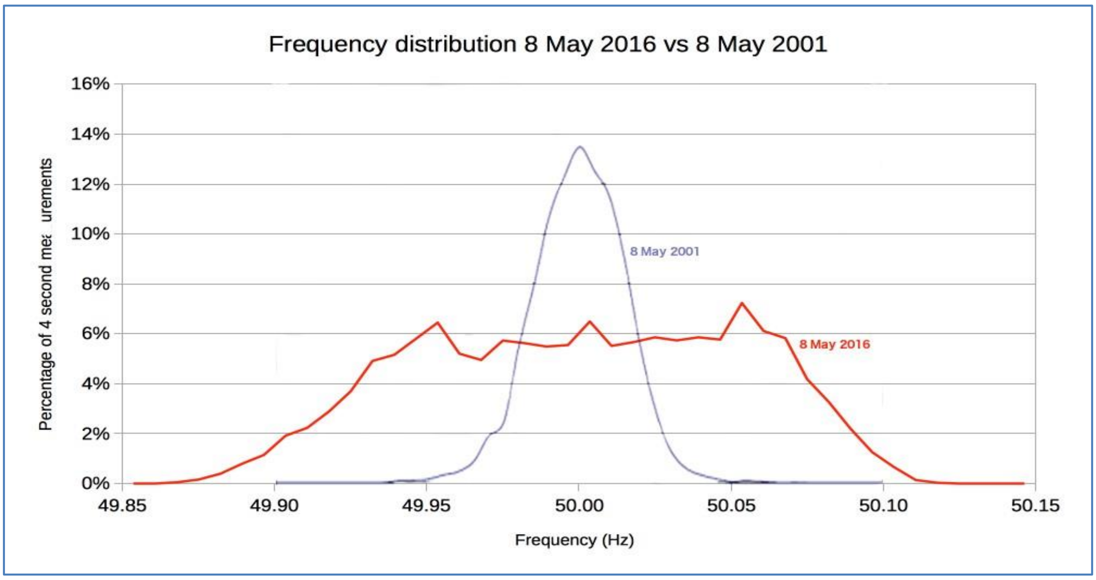
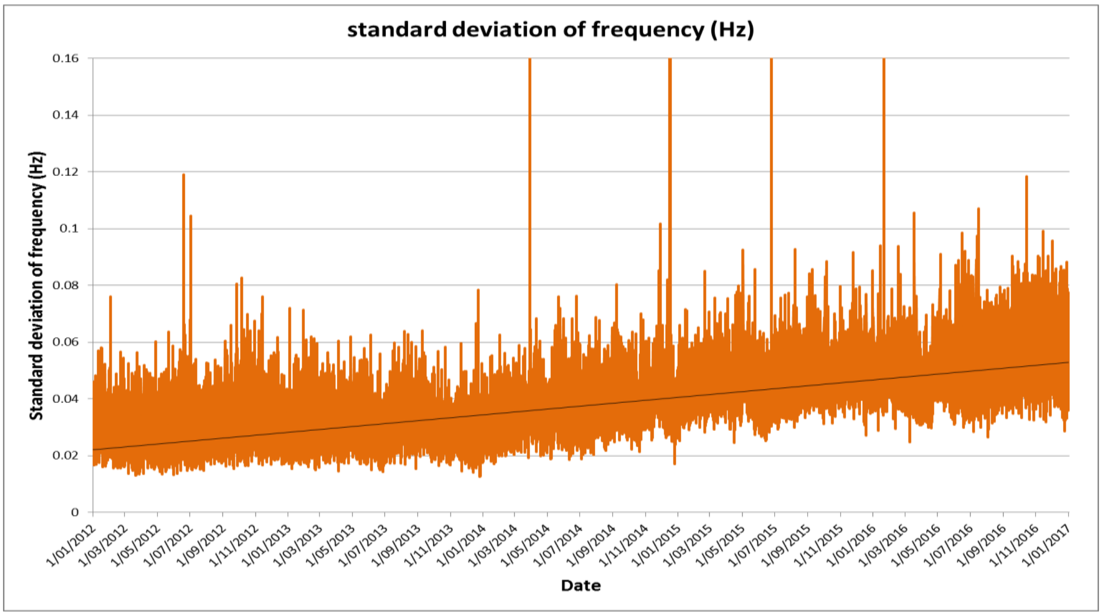


Figure 3-3 Hourly standard deviation of frequency for the mainland. Source DigSILENT



CS Energy argued in its submission to AEMC's Review of the Frequency Operating Standard[26] that using Tasmanian generators to provide regulation for the mainland and the operation of Basslink have resulted in poorer frequency

[26] CS Energy and PD View (2017) submission to AEMC's Review of the Frequency Operating Standard, http://www.aemc.gov.au/getattachment/40ed39ab-8f24-402b-939c-8a8fd6dc8979/CS-Energy.aspx.

outcomes for the mainland. In its graphical representation of mainland system frequency using heat maps, CS Energy showed that the distribution of the mainland system frequency had widened since the return of Basslink.

CS Energy argued that the arrangements that AEMO is using for AGC control of Tasmanian generators enabled for providing regulation for both Tasmanian and the mainland systems and their interaction with the Basslink controller are not working properly in the control of mainland frequency.

Several reasons are suggested in the DigSILENT report to explain the deteriorating frequency control in the NOFB, including:

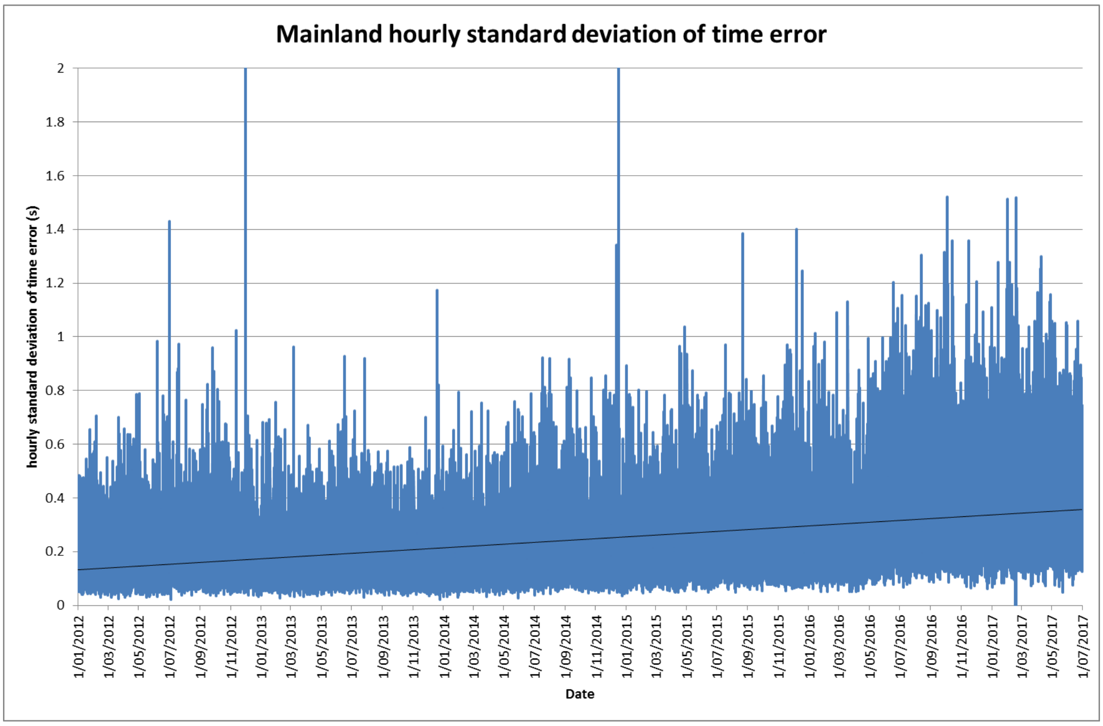
- A reduction in the number of generators providing (free) primary frequency control (governors enabled, small deadbands)
- A reduction in the inertia of the power system, or in defined sub-systems
- Inverter-based generation not offering primary control

As more conventional generators shut down and, to the extent these are replaced by inverter based generators, it is likely this trend of reduced primary frequency control will continue.

3.2 Time Error

Similar to the flattening of the distribution of frequency and an increase in its standard deviation, there has been an increase in the hourly standard deviation of the time error (see Figure 3-4).

Figure 3-4 Standard deviation of time error (calculated month by month). Source DigSILENT

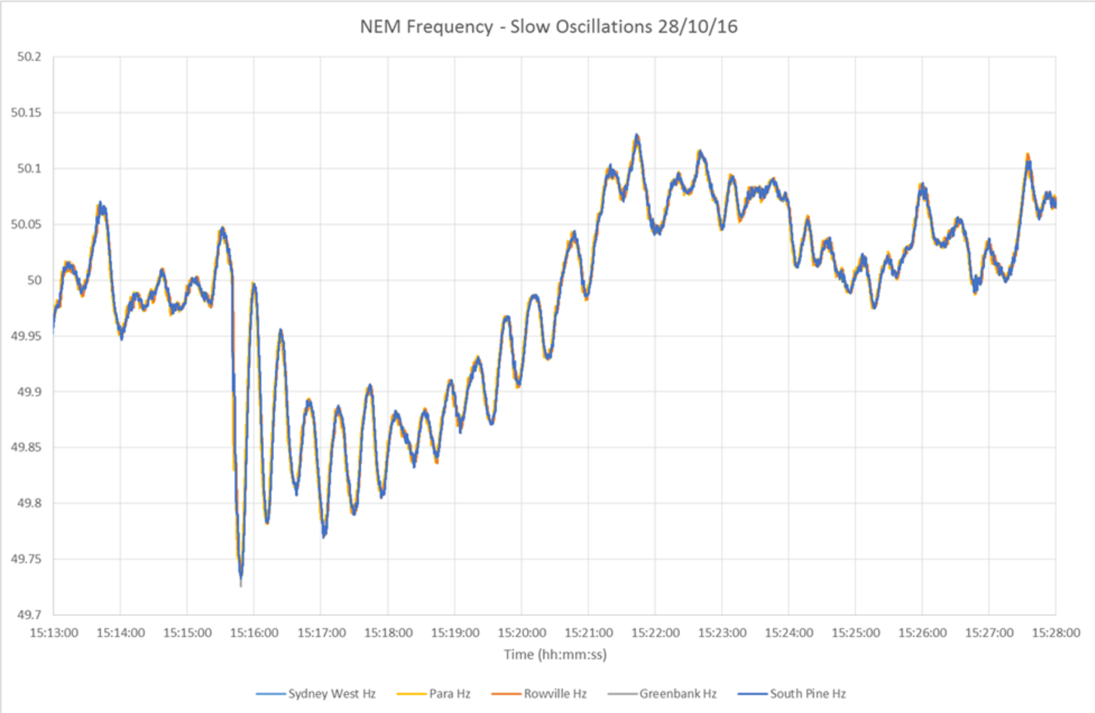


3.3 Frequency Oscillations

In recent years there have been some frequency oscillations recorded on the power system. Figure 3-5 shows an example where the time period of the oscillations was about 25s.

The analysis of frequency oscillation events has not been conclusive. The existence of any lightly damped oscillation is a concern as there may be risk that, if the damping deteriorated further, an instability could arise with the potential to threaten security.

Figure 3-5 Frequency oscillations on 28 October 2016. Source DIgSILENT



3.4 Interconnector Flows

The transmission constraints used in the NEM dispatch process are constructed based on many studies that determine the transmission limits for a wide range of operating conditions. These limits are converted to constraint equations.

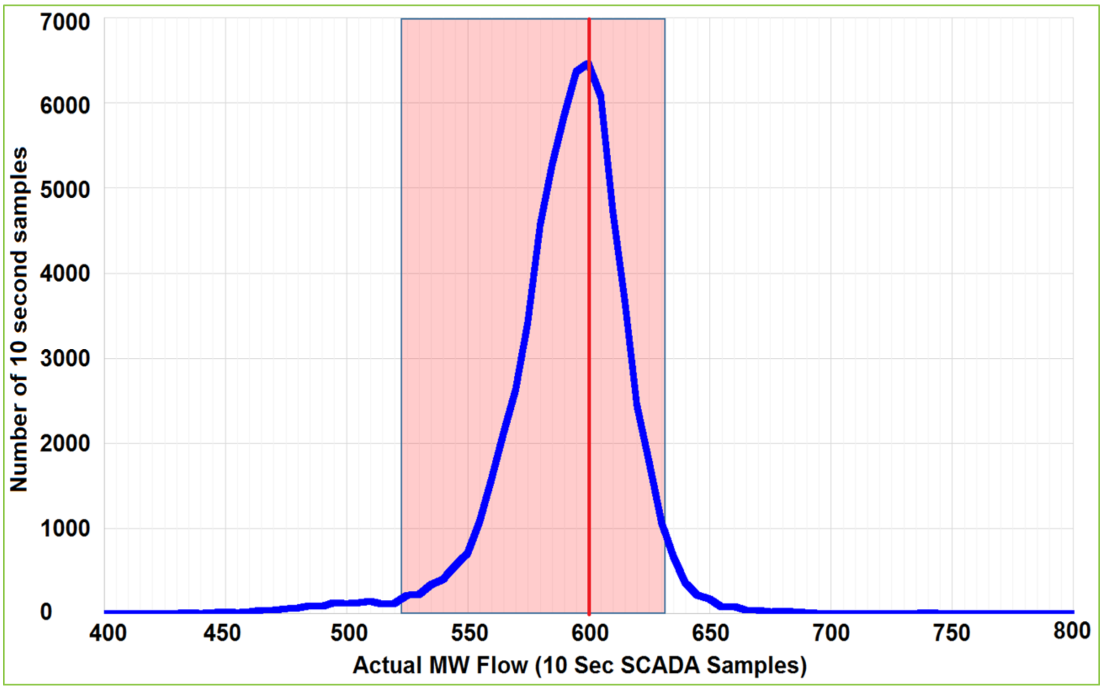
As part of the development of a constraint equation, one or more margins may be introduced to account for the imprecise nature of the data used to calculate the constraint (i.e. SCADA data) and the general level of ‘noise’ observed on the interconnection. These margins may include:

- statistical margins or confidence levels that ensure that, say, 99% of critical cases had limits less than the proposed limit equation; and
- operating margins that manage:
  - modelling approximations,
  - measurement and instrumentation errors and delays,

- use of substitute variables (for example, MW signals may be used instead of MVA); and
- dispatch errors / control error margins.

It appears that there are still occurrences of actual interconnector flows exceeding their dispatch targets. An example of this was provided in a paper delivered at the 17th Wind Integration Workshop in Berlin. The histogram of actual interconnector flows versus the notional limit of 600 MW is reproduced in Figure 3-6. In this example, the flows exceeded 600 MW for 31% of the time and the flows regularly exceed 630 MW.

Figure 3-6 Actual Heywood Interconnector flows with a dispatch target of 600 MW. Source Pacific Hydro



This example illustrates how much interconnector flows can deviate from their dispatch target when the target is at a flow limit. Deviations in flow when operating at, or close to, the limit may represent a security risk. Alternatively, more conservative margins may need to be applied to avoid this security risk.

Either way, there is an argument that better control of real time dispatch and frequency via the use of regulation FCAS via AGC in a mode similar to tie line bias may offer an opportunity to reduce the size of these safety margins and deliver material benefits through increased utilization of existing network assets. If AEMO operated its regulation service using multiple control areas in a control mode similar to tie line bias then in some control areas (subsystems) some units may have their AGC targets raised and in some adjoining areas units may have their AGC targets lowered to ensure interconnector and other transmission flows are managed closer to their limits whilst at the same time managing frequency across the system.

3.5 Managing Frequency in Potential Islands of Low Inertia

Increasing levels of inverter-based generation are causing the overall inertia in the NEM to be slightly reduced. Importantly, in some parts of the network with high densities of variable renewable energy (wind and solar), the inertia of the subsystem can fall more significantly. This is observed in South Australia (SA) and Tasmania.

As the inertia reduces, frequency control becomes more challenging as there is less time available to address imbalances in supply and demand[27]. This problem can be readily seen in SA where inertia and system strength can be problems with large amounts of wind generation.

Following the system black event in South Australia in 2016, the spot market in South Australia was suspended. During the market suspension, AEMO put in place a power system security requirement to maintain a minimum of three thermal synchronous generation units (each not less than 100 MW) online at all times. It appears the objective of this security constraint is to maintain minimum levels of inertia in SA and to address the 'system strength' issue. To some extent this solution is also to support the existing contingency FCAS arrangements in the NEM. When there is a credible contingency that could island South Australia and there is high proportion of VRE generation then the inertia in South Australia can be very low and the rate of change of frequency can be very fast following an islanding event. The NEM's 6s contingency FCAS would not be guaranteed to act fast enough to contain the South Australian frequency within the frequency standards if it is isolated. To address this potential problem, an ad hoc solution is to increase the inertia in South Australia to reduce the potential rate of change of frequency in an islanded South Australia to an extent that the 6s contingency services are adequate to maintain frequency.

In the NEM, the contingency FCAS are procured using pre-defined categories of services which are split into the discrete timeframes 6s, 60s and 5 minutes. These service categories were set up in 2001 with the new FCAS spot market and were based on the historical generation mix of coal, hydro and some gas generation at the time. That generation mix had higher inertia levels than now.

With projected increases in the levels of Variable Renewable Energy (VRE) penetration, there now appears to be a strong justification to review these frequency control ancillary services, including consideration of categories and services, to ensure the correct quantities are procured in the appropriate time frames to meet the power system frequency standards.

The justification for this lies in the fact that, in order to arrest a frequency decline (within the Frequency Standard), the fast contingency FCAS must be provided before the bottoming frequency (nadir) is reached. Anything provided after this point will help to restore frequency but will have no influence of the extent of the

[27] Tielens, P. and Van Hertem, D., 2012. Grid inertia and frequency control in power systems with high penetration of renewables.

frequency deviation. The nadir occurs at a time that depends on the inertia of the power system. If the inertia of the power system reduces to a point where the nadir for a credible contingency will occur substantially before 6 seconds, then only that part of the fast FCAS that is delivered prior to the nadir will have any effect in keeping the frequency excursion within the standard. While inertia levels remain relatively high, this nadir will occur close to, or even after, 6s. Where inertia levels are low, such as in an isolated South Australia, the nadir could occur after 1-3 seconds, depending on how much synchronous plant is operating at the time.

3.6 Reasons for Changes to the Frequency Distribution

The DigSILENT report[28] considers a range of contributors to the current performance of the NOFB frequency control

In essence, the potential contributors include:

- Declining primary frequency control, currently an unpaid service, delivered by existing synchronous generators;
- The regulation service, implemented via the energy management system (EMS) and AGC systems, including:
  - The quantity of service being procured; and
  - The dynamic performance of the control system;
- The changing nature of the power system, including:
  - Retirement of some conventional generation;
  - Increase in inverter-based generating systems that:
    - Reduce the inertia;
    - Do not typically contribute to primary frequency control; and
    - Have an output that varies with sun/wind and are thus difficult to forecast accurately; and
  - Increased inverter-based loads, which act to reduce the amount of load relief as frequency changes.

3.6.1 Participant feedback

In support of these potential contributors, industry submissions to AEMC's Review of the Frequency Operating Standard, commented on potential factors.

CS Energy and their consultant PD View argued that:

- AEMO is not purchasing enough regulation to manage frequency;
- AEMO's AGC system is not performing as well as it should; and
- AEMO's operation of two independent AGC systems for the mainland and Tasmania combined with the Basslink's controls is not leading to the optimal management of frequency.

[28] DigSILENT Pacific, 2017, "Review of Frequency Control Performance in the NEM under Normal Operating Conditions"

Pacific Hydro[29] and others argued that:

- The “causer pays” mechanism for recovery of regulation costs has discouraged generators from providing governor control and encouraged them just to follow their energy targets.

3.6.2 Drivers affecting frequency control effort

The DigSILENT report identified several drivers for the reduction in governor frequency response within the NOFB:

- Providing governor response represents a cost in terms of wear and tear and efficiency and it is not a requirement to provide this service;
- A reduction in primary FCAS service providers in the NOFB increases the ‘workload’ on the remaining generators providing this service, increasing the magnitude of swings in output power in alignment with observed deviations shown in Figure 3-1;
- There are strong incentives on generators to follow their dispatch targets and this may be more difficult to control if the output of a generator is moving about in response to primary control service provision; and
- The “causer pays” system penalises generators that are found to contribute to frequency excursions. Generators may find that following their dispatch targets and avoiding causer pays penalties is easier when the generator is operating at a stable output with no frequency influence.

3.6.3 Factors Affecting AGC Performance

The other factor that affects the management of frequency within the NOFB and management of the time error is the performance of secondary FCAS provided via the EMS and AGC. The secondary FCAS systems are not well documented (in the public domain) so it is difficult to provide a confident diagnosis but there may be some deficiencies:

- Key parameters, such as the ‘bias estimate’ may need updating to reflect the changes in the power system characteristics
- The response of the system to regulating FCAS may need to be reviewed and parameters of the controller adjusted to ensure stability.
- The relative weightings of additional control inputs, such as the Time Error, may need to be reviewed as these have the potential to dominate the response if weighted too high.
- The amount of regulating service that is procured may need to be re-assessed. This assessment could take into account changes in the forecasting errors across various timeframes and each of the variables currently used to determine the quantum for each service (raise/lower).

[29] Pacific Hydro submission to AEMC’s System Security Frameworks Review.

3.6.4 Load Forecasting

The DIgSILENT report discusses at length several potential issues with forecasting and how these contribute to issues in the quality of NOFB frequency control.

It is understood that AEMO's neural network load forecast system has been in place for many years and thus may not be optimal for load forecasting given the ongoing changes in the power system. The Australian Photovoltaic Institute has estimated that the rooftop solar capacity has now reached 5.6 GW in Australia, and large scale solar is now 496 MW[30], with the bulk of this being in the NEM.

3.6.5 VRE Generation Forecasting

The issues of forecasting VRE generation in the NEM have been analysed in two papers by Dyson and Mackenzie[31] [32], a summary of their analyses and personal communications with them is presented below.

The AEMO AWEFS (wind forecasting) and the ASEFS (solar forecasting) systems were developed to enable AEMO to provide long and medium term forecasts for the estimation of future intermittent generation and to determine system reserve and generation capability for the market without substantive change to the existing NEMDE dispatch process. For time frames for the next dispatch day and up to the limit of the STPASA time frames both the AWEFS and the ASEFS systems provide reasonable forecasting performance and do not present many issues for the intermittent generator participants.

Although not part of the original requirements for either of these forecasting systems, an unintended application of both the AWEFS and ASEFS forecasting systems has been to determine the short term forecast of generation for each intermittent generator for the next 5 minute dispatch interval. These systems are really not designed for very short term forecasting and that affects the amount of regulation required and "causer pays" cost allocations of regulation costs to VRE generators.

Both the AWEFS and ASEFS forecasting systems use a set of SCADA signals provided by the generator through the TNSP/DNSP DNP3 communications links that send an indication of availability as the number of available and generating turbines or inverters, current generation and a single measurement of the primary resource being either wind speed for wind farms or irradiance for solar farms.

From the collected history of generation vs primary resource for each generator, a short term forecast is produced that is fed back to the generator as the dispatch TOTALCLEARED and AVAILABILITY fields of the DISPATCHLOAD record. When there is no semi- dispatch cap, the TOTALCLEARED and AVAILABILITY fields are the forecast generation, and when there is a semi-dispatch cap set, the

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30 G. Parkinson, "Renew Economy," 27 April 2017. [Online]. Available: http://reneweconomy.com.au/australian-solar-capacity-now-6gw-to-double-again-by-2020-2020/

31 Dyson, J., Mackenzie, H., Engerer, N., and Luffman, J., 2017, October, Utility scale solar short term generation forecasting for improved dispatch and system security, 16th Wind Integration Forum, Berlin.

32 Dyson, J., and Mackenzie, H.,2017, October, Short term forecasting of wind power plant generation for system stability and provision of ancillary services, 16th Wind Integration Forum, Berlin.

TOTALCLEARED field is the cap value and the forecast is recorded only in the AVAILABILITY field.

When no semi-dispatch cap is present for a generator, the forecast is significantly influenced by the recorded generation at the start of the dispatch interval but this forecasting approach is not valid when a semi-dispatch cap is set, as the generator may be significantly constrained. For dispatch intervals with the semi-dispatch caps set, the forecast is determined from the history of generation vs wind speed for wind forecasts and generation vs irradiance for solar farms.

For wind farms, the use of a single wind speed without consideration of wind direction is a very simplistic and limited forecasting approach. Wind farms can be located in regions with a large range of diverse geographic conditions and wind direction is a critical parameter that can significantly affect the generation capability of the wind farm. Recently, AEMO has allowed the single wind speed measurement to be an aggregation of multiple sources and this has improved the AWEFS forecasting performance but the single parameter forecasting approach will always be a poor method for predicting short term wind farm generation.

For solar farms, the presence of transient cloud cover is a major cause of fluctuating generation and the ASEFS forecasting makes no attempt to model these effects and account for the cloud cover except for an average single irradiance measurement for the entire site. The present ASEFS approach is only valid for cloudless or consistently cloudy days and considering that many solar farms are presently being constructed in tropical regions in central Queensland, likely to poorly predict short term solar farm generation.

As part of a review process of the AWEFS and ASEFS forecasting systems and the perceived significant detrimental impact that these forecasting systems were thought to be having on the calculation of FCAS causer pays factors and subsequent “disproportionate” allocation of regulation costs to intermittent generators, AEMO has proposed that wind and solar farms can supply their own "Estimated Power" value through the TNSP/DNSP DNP3 link and that forecast may be used by AEMO rather than the AWEFS/ASEFS forecast.

Dyson and Mackenzie think that the use of satellite images and sky cameras for short term solar generation forecasting will allow for much improved forecasting performance for solar farms leading to both reduced FCAS costs for the generators and improved system security outcomes for AEMO. Short term wind farm generation forecasting is a much more difficult problem, but recent advances in using sophisticated machine learning approaches have produced promising results and will potentially lead to better outcomes for both the individual generators and the system operator.

3.7 Impact of the NEM’s Frequency Issues

The power system impacts of deteriorating frequency control include:

- Power system security risks;

- Increased frequency control costs; and
- Reduced 'power quality'.

Of these impacts, there does not seem to be evidence of material impacts for loads as a result of 'power quality'.

In this section consideration is given to both primary and secondary FCAS control.

3.7.1 Impact on power system security

A stable frequency provides the basis for the design of defensive control schemes that protect the system from low probability events outside of the credible contingencies that the power system is planned and operated to survive.

Multiple contingencies do occur and can have high impacts. The low probability of a very high impact event justifies the investment to control and contain impacts or to minimise, within reason, the impacts. It is generally not economic to mitigate all potential impacts as the cost of improving reliability typically escalates quickly.

To be clear, economic rationalism would suggest that the expected cost of a low probability / high consequence event would support investment up to the level of the expected cost to mitigate the impact of the event. The issue is that the enumeration of every low probability event is pretty much impossible and many generalisations are required. However, the underlying economic rationalism should be considered when implementing controls and protections.

So it is with under-frequency events. Credible contingencies are assessed and the power system is designed and operated to survive these events. Non-credible contingencies, including multiple events, may have very high consequences and have traditionally been mitigated using controls such as automatic under-frequency load shedding (AUFLS). AUFLS is a relatively low cost distributed control system and is deployed routinely, having proved itself effective over many decades.

AUFLS typically includes at least a frequency setting and a time setting and may have several stages of operation, each tripping on increasing amount of load. There are some variations on the theme, including acceleration using a measured rate of change of the frequency, with higher rates of change indicating bigger supply-demand imbalances and therefore a need for a greater response (i.e. shedding of more load).

The issue with frequency control, and therefore the security impact, is that the AUFLS schemes have a specific frequency setting. If the first level of operation is at, say 48.9 Hz, then an objective of overall frequency control of the power system will be to avoid this frequency at all times, including following a credible contingency.

A given contingency will, all other things being equal, deliver a pre-definable frequency deviation and FCAS requirement as described in section 2.15. If the frequency at the time of the contingency is 49.9 Hz, the margin to the AUFLS operating point is reduced from 1.1 Hz to 1.0 Hz (50.0 Hz-48.9H and 49.9 Hz-48.9

Hz respectively). This reduces the headroom and time available for the contingency FCAS to respond and compensate for a credible contingency.

Noting in the NEM frequency standard (Table 2-1) that the contingencies considered include:

- generator or load contingencies – must be contained within 49.5 Hz
- network or separation events – must be contained within 49 Hz

If the power system is planned and operated to survive a 1 Hz deviation, an initial frequency of 50 Hz would yield a survivable event. However, if the initial deviation is more than 0.1 Hz below nominal, the same incident may trigger, incorrectly, load shedding via the AUFLS scheme. This is a potential security violation if the event is considered credible.

Since security is clearly defined as the survival of credible contingencies, other events that cause operation of the AUFLS scheme have reliability rather than security impacts. Unfortunately, security and reliability are used interchangeably in increasingly diverse documents issued in the NEM.

The difference is that AEMO must operate securely, but the response to non-credible contingencies is (or should be) a matter of economics. The dispatch of adequate FCAS to control frequency such that it meets the standard is thus a security requirement. Beyond this, control schemes such as AUFLS, can be used to control and protect from cascading events (not credible contingencies).

Note that there are other protective schemes that are used to control frequency, including inter-trips, generator tripping (for high frequency) and special protection schemes.

3.7.2 Increased costs associated with frequency control

The DIgSILENT report discusses several potential sources of additional costs that may be attributed to poor frequency control, including:

- Wear and tear on equipment that is providing primary control and responding to frequency variations;
- Larger than necessary operating margins;
- Potentially reduced operating life where equipment such as turbines are subject to increased vibrations that are exacerbated by frequency variations; and
- Higher costs of FCAS.

Of these, the higher costs of FCAS are more easily assessed as a direct and ongoing cost.

The frequency operating standard (Table 2-1) states that generating events must be contained at 49.5 Hz. Sufficient FCAS must be procured to cover the largest credible contingency to meet this requirement.

Calculating the contingency FCAS requirement is relatively straight forward, as described in section 2.15. A critical parameter in defining the amount of fast FCAS is the permissible frequency deviation, Δ_f. It is important to note that this is a relative quantity, whereas the frequency standard specifies an absolute frequency for containment.

In order to deliver a highly reliable response that meets the standard (very low probability of violating the standard), the initial starting point of the frequency should be considered. Two cases are considered:

- Frequency control where f>49.95 for more than 99% of the time
- Frequency control where f>49.85 for more than 99% of the time

In case 1, the allowable frequency deviation, Δ_f, for a credible contingency is 0.45 Hz, whereas case 2, it is 0.35 Hz. Case 2 will require more 6s raise service for a given contingency than case 1.

There is an ongoing requirement to dispatch more contingency FCAS where frequency control is poor, representing an ongoing cost to the market.

Similarly, if poor real time generation and frequency control is resulting in issues controlling interconnector flows, margins to prevent security issues may need to be increased (see Figure 3-6). If the margins are inadequate, there would be a risk to security as a credible contingency at a time when flow exceeded the limit could potentially result in the power system ending up in a non-satisfactory state.

Assuming the margin for an interconnector is correctly sized, then improving real time generation and frequency control and thus the accuracy of interconnector flow control would open the possibility of reducing the margin and releasing additional inter-regional capacity on the interconnector. The marginal value of interconnector capacity is likely to be high, considering RIT-Ts are being assessed to justify projects in the $billion cost categories.

3.8 Conclusion

The quality of frequency control, both for NOFB and contingencies, can have security and cost implications.

The assumption should be made that prudent operation of the power system will ensure the security issues are addressed. However, there is a cost associated with this relating to:

- The amounts of contingency FCAS required to keep frequency within the standard will increase as the probability of operating away from nominal increases
- Operating margins, to the extent they are affected by AGC frequency control, may be higher than they could be with improved AGC interconnector control.

In addition to the aforementioned costs, there are additional market costs associated with poor frequency control including increased wear and tear, reduced maintenance intervals and reduced plant life.

4 Market-based Solutions

We feel that there is a lot of potential for market-based solutions. We have undertaken some proof of concept modelling that demonstrates that AEMO can manage frequency with a proper co-optimisation of FCAS based on plant FCAS performance curves and directly modelling frequency and inertia in the dispatch optimisation. Such a framework would allow market prices to be determined for a wide range of FCAS responses based on system and island inertias and would also be able to price/value inertia in the spot market.

Similarly, we think the market and incentives can be improved to encourage tighter governor control of frequency. This would be done via:

- creating a new FCAS of governor control or similar linear frequency response to frequency deviations in the NOFB and paying for this governor control via a spot market in this FCAS; and
- determining a better cost allocation than the current “causer pays” for regulation.

4.1 Objectives for the management of frequency and FCAS

In order set up a framework for looking at what are the best ways to manage frequency and related security issues in the NEM it is worthwhile going back to the National Electricity Objective (NEO), which is:

> “to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to – price, quality, safety, reliability, and security of supply of electricity; and the reliability, safety and security of the national electricity system”.

Fundamental to the NEM’s approach to meeting the NEO has been to use markets where possible and only use regulation for natural monopolies.

The NER states:

3.1.4 *Market design principles*

a. *This Chapter is intended to give effect to the following market design principles:*
   1. *minimisation of AEMO decision-making to allow Market Participants the greatest amount of commercial freedom to decide how they will operate in the market;*
   2. *maximum level of market transparency in the interests of achieving a very high degree of market efficiency, including by providing accurate, reliable and timely forecast information to Market Participants, in order to allow for responses that reflect underlying conditions of supply and demand;*
   3. *avoidance of any special treatment in respect of different technologies used by Market Participants;*

4. *consistency between central dispatch and pricing;*
5. *equal access to the market for existing and prospective Market Participants;*
6. *market ancillary services should, to the extent that it is efficient, be acquired through competitive market arrangements and as far as practicable determined on a dynamic basis. Where dynamic determination is not practicable, competitive commercial contracts between AEMO and service providers should be used in preference to bilaterally negotiated arrangements;*
7. *the relevant action under section 116 of the National Electricity Law or direction under clause 4.8.9 must not be affected by competitive market arrangements;*
8. *where arrangements require participants to pay a proportion of AEMO costs for ancillary services, charges should where possible be allocated to provide incentives to lower overall costs of the NEM. Costs unable to be reasonably allocated this way should be apportioned as broadly as possible whilst minimising distortions to production, consumption and investment decisions; and*
9. *where arrangements provide for AEMO to acquire an ancillary service, AEMO should be responsible for settlement of the service.*

The key principles that are particularly relevant to any changes to the FCAS arrangements are 3.1.4 (a) 3, 6, 8 and 9. Combined these principles require non-discriminatory and competitive market-based arrangements.

Based on the NEO, NER market design principles and the general principle that the management of the power system should be based on the power system's standards we developed the following set of principles for the evaluation of various potential changes to the FCAS arrangements:

- The management of FCAS should be driven by the frequency standards;
- Competitive market arrangements should be pursued in preference to TNSPs contracting for services or compulsory provision of services via mandated response requirements;
- The market arrangements should:
  - be non-discriminatory and technology neutral;
  - be flexible enough to efficiently cater for a changing power system with greater inverter based VRE penetration;
  - appropriately reward the provision FCAS and inertia based on the value it provides to the market;
  - use co-optimisation as much as possible including proper co-optimisation of FCAS, inertia and interconnector flows
  - minimise AEMO's discretion and the use of directions;
  - manage the power system security in a transparent manner

  - allocate costs using appropriate causers pay methodologies that encourage efficient behaviour
    - Note we don't think the current allocation of regulation FCAS satisfies this criterion

4.2 Logical Approach to FCAS

Based on the objectives outlined in the previous section the logical approach to managing FCAS in the NEM is as follows:

- The frequency standards define what AEMO has to achieve via FCAS;
- A combination of statistical analyses and power system modelling are used to define FCAS requirements;
- The FCAS services should be defined in a way that allows the optimum use of the FCAS providers offering a potentially wide range of competitive services to meet the FCAS requirements;
- Real time analysis and monitoring of power system plus optimal dispatch are used to determine the co-optimised dispatch of both FCAS requirements and dispatch of individual facilities (generating units, interruptible loads, batteries etc.);
- The co-optimised dispatch determines spot prices, quantities and costs for both global and local/regional requirements; and
- The allocation of FCAS costs is designed to encourage behaviour that assists managing power system frequency and is based on each participant's impacts on the FCAS requirements (causer pays).

4.3 Mandatory Connection Requirements and the National Electricity Market Objective

To address some of the frequency and power system issues in the NEM a number of changes to the NER technical standards have been proposed. The proposed changes to the NER technical standards include requirements for all generation to have the capability to provide FCAS and the mandatory provision of governor control for no payment. This Grid Code based approach may be easily administered but such a regulated approach is not likely to be economically efficient and hence is not consistent with the NEO.

4.3.1 Mandating requirements in the Rules

Mandating the infrastructure to provide a Primary NOFB FCAS will result in costs to the market and place upward pressure on prices.

Reactions to severe events, like partial blackouts, can result in overly conservative decisions and costly over-investment, similar to the over-investment seen in networks over the past few decades, and for similar reasons.

It may be of interest to consider the disciplines in the NEM for transmission investment. Transmission network investment is strongly governed by a probabilistic approach that requires expected costs to be assessed for credible and non-credible faults and other low probability events such as bus faults. For any security event beyond the current definitions of credible contingency, there needs to be a cost-benefit assessment to demonstrate the efficiency of the approach (i.e. NEO compliance).

A similar approach should, arguably, be required to justify any form of mandatory investment in the NEM. A cost-benefit analysis supporting the proposed changes to primary frequency control infrastructure would be highly desirable ahead of any mandated requirements.

4.4 Regulatory versus Market Approach

The performance of the FCAS markets and the basic thrust of the contingency services have worked quite well. The main issue now is that the categorisations of the FCAS contingency services are currently not always fit for purpose, particularly in potential islanding areas where there can be large amounts of VRE generation and low inertia such as in SA and to some extent Tasmania. However, these problems should be readily overcome with a more flexible FCAS model that will work for all levels of inertia and technology. There does not appear to be a market failure, or a risk of market failure, that justifies the mandating of any frequency services.

It is the area of management of frequency under normal conditions when there are no contingency events, that there appears to be a growing problem which has a number of causes including the decline in governor responses and insufficient regulation being enabled (see discussion of causes in section 3.6). This is compounded by the, arguably, faulty operation of the “causer pays” cost recovery mechanism for regulation FCAS.

Rather than mandate some or all FCAS services, a better and more efficient NOFB solution may be to create a proper market for governor, demand response or other linear responses to frequency within the normal operating frequency band rather than adopt a compulsory provision approach.

A concern with any mandated NOFB response is that primary frequency control operating in the NOFB is likely to also operate in the same frequency bands as contingency FCAS, i.e. on either side of the NOFB. This in itself suggests that the economic impacts of a mandated service are probably wider ranging than first thought.

The benefit of having a market-based approach to security and reliability services is that the participants who are best able to provide the services are appropriately incentivised. Those participants with technologies not suited to providing the services can elect not to provide the services and have the market purchase them off more efficient providers. Market-based approaches also encourage innovation and a key area of potential response here is the demand side, particularly embedded battery systems with smart controls.

Mandating the purchase of ancillary service capabilities by TNSPs that could be provided by the market is likely to lead to less efficient and more costly outcomes. One of the main problems in the NEM has been the less than optimal regulation of TNSPs. Thus, the option of using regulated TNSPs as a vehicle to supply FCAS and other ancillary services compared to the market providing these services should be avoided as much as possible.

In conclusion, adopting a regulatory approach of mandating uneconomic FCAS responses and using TNSPs to purchase or provide FCAS capabilities is unlikely to be the most economical approach and does not satisfy the NEO or the NER's market design principles.

5 Markets for Management of Frequency in the NOFB

Clearly the NEM's management of frequency within the NOFB could be improved. We suggest that a new FCAS be created which would supply a linear response to frequency deviations in the NOFB[33]. This service should be seen as a complementary primary control service to the secondary control service of regulation which is managed via AGC.

Further improvements in frequency management within the NOFB could be achieved by increased amounts of regulation FCAS being enabled at different times based on a proper and transparent statistical analysis of the sources variation which require generation units to deviate from their linear trajectory energy targets to maintain frequency at 50 Hz.

5.1 Overview of a market solution to NOFB frequency control

The desired output of a NOFB frequency control is an automatic corrective response to frequency deviations within the +/- 0.15 Hz band around 50 Hz. This can be achieved by a wide range of service providers, including the demand side and renewable energy generating systems.

This service should operate in parallel with the regulation service. With the 4s cycle times for SCADA used in the regulation service, coupled with filtering and other delays, the bandwidth of the service is quite restricted. The Shannon sampling theorem requires a minimum of two samples per cycle. Practically, this is closer to four samples per cycle to achieve good control. In the most optimistic assessment using 4s sampling times, the bandwidth of the secondary control is around 1/16s. Therefore, the regulation service should not be expected to respond and control frequency deviations that have periods shorter than about 15s. The deployment of a NOFB primary control service, with automatic response to frequency deviations, would complement the regulation service by providing good control of the fast frequency deviations.

To constrain this primary control service within the required NOFB, the control system parameters would be set to limit the response to frequencies within the NOFB. Anything outside the NOFB would not result in an additional response. This has two properties:

- It limits the excursions that will be seen in the output of the service providers. This is important for some plant that is not well suited to providing larger excursions.
- It provides a logical service boundary between the NOFB market FCAS and the contingency FCAS

[33] This service could possibly include a component of switch responses that are individually small and are activated at different frequencies giving a linear like aggregate response that AEMO can model in its AGC's frequency bias calculation.

In terms of control system characteristics, referring to Figure 5-1, the NOFB control characteristic would have no or very small deadbands and limiters set to the NOFB boundaries. Of course, the Primary NOFB FCAS market should also be two-way, with raise services and lower services.

In support of the above argument, inverter-based equipment on renewable generating systems can easily respond to positive frequency deviations. Reported experiments, with only enabling this service, show a marked increase in NOFB frequency control accuracy[34]. A complimentary service from demands (large industrial loads) could potentially see quite effective NOFB control from a wide range of service providers, rather than those mandated to provide the capability in a grid code solution.

5.2 Governor response like FCAS in the NOFB

NOFB governor FCAS would require small or no deadbands[35] but their limiters could be set to NOFB boundaries (see Figure 5-1). To complement this, the contingency FCAS could have deadbands of +/- 0.15 Hz, which appears to be current practice anyway. Thus, the Primary NOFB FCAS and the contingency fast and slow FCAS could supply a continuum of governor like responses to frequency. The Primary NOFB FCAS would operate in the range of the NOFB and the contingency services would only operate outside the range.

With respect to the deadbands, it is worth noting the NERC Primary Frequency Control Guideline (2015), which recommends deadbands of 0.036 Hz (60 Hz system). ISO New England and PJM have adopted these deadbands while ERCOT use 0.034 Hz (conventional generators) and 0.017 Hz (other generators). In the NEM, this would translate to around 0.03Hz and 0.015 Hz.

For example, if you had a 500 MW unit with a governor droop of 4%, the response at the extremities of the NOFB would be 37 MW (0.3%/4% * 500 MW)[36].

Without the limiters, a 1% frequency drop of 0.5 Hz would correspond to a response of:

500 MW * 1% / 4% = 125 MW

The setting of limiters is thus important if the response is to be constrained within the NOFB. As stated, the use of small limits may encourage providers that do not wish their plant to be subject to major excursions to participate in the NOFB market.

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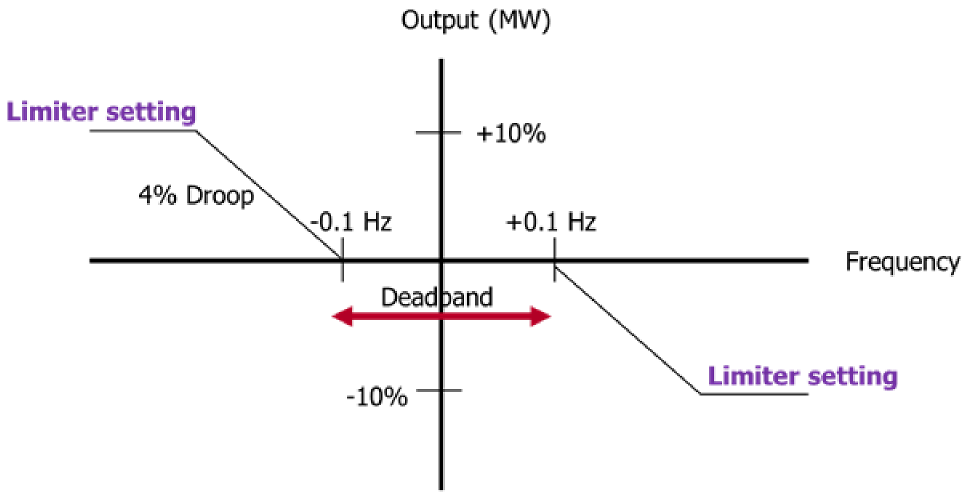
[34] No formal reference is available for this statement made at a conference. However, the theory is that any oscillations that are inducing fast variations to NOFB frequency, would be (heavily) damped in in one direction (the frequency upswing), which would reduce the amplitude of the frequency down swing. This should be something that can be demonstrated in analytical studies or even in trials.

[35] Power electronic plant can operate with zero deadbands with penalty. Most governor systems on synchronous machines have some deadband due to the measurement of the input signal. Digital governors can have very small deadbands and examples exist in Australia where deadbands below 50 mHz are used. Older mechanical governors have more difficulty and maintenance cost issues when operating with small deadbands.

[36] A 4% droop means that for a 4% drop in frequency the unit's output would change from zero load to full output. Since the governor response of a generating unit is linear in frequency a drop in frequency of 0.15 Hz / 50 Hz = 0.3% will result in an increase in output of 0.3% / 4% x 500 MW = 37.5 MW

Figure 5-1 Example governor response with deadbands and limiter settings



5.3 Primary NOFB FCAS market arrangements

In setting up a market for Primary NOFB FCAS you would need to consider how you would achieve it using governors or other linear responses to frequency. Probably, the easiest way to do this is that a participant would determine how many MW they want to provide at 0.15hz deviation, they would then set the droop and limiters to deliver the offered response for this frequency. This would reduce interaction with the contingency FCAS and be attractive to providers as it limits the output variations of the plant. Asymmetric offerings would also be possible if one of the limits was set to zero.

Note that although the term governor is used here, there are many potential service providers, including battery systems (charging or discharging), wind generators, PV generators and large industrial loads. In fact, any inverter-based system with a power controller could potentially offer these NOFB services (i.e. load or generator).

The Primary NOFB FCAS would be managed like the other FCAS in that service providers would:

- have to have their capability verified;
- make offers to supply the service;
- could specify the feasible operating domain of the service via an FCAS trapezium;
- etc.

The Primary NOFB FCAS would be co-optimised like the other FCAS and it would be included in the joint capacity constraints used to manage the other services to ensure that units were dispatched for physically feasible dispatches for energy and all of the FCAS. The co-optimisation would determine Primary NOFB FCAS prices. If there were global and local NOFB requirements then there would be global and local Primary NOFB FCAS prices.

Some participants might like to make a joint offer to supply both Primary NOFB FCAS and a contingency FCAS for a plant. In cases where multiple services are offered, the participant would make an offer for a combined service and any MW enabled would be the same for both services. The distinction between the two services is the NOFB boundaries and if the limiters in Figure 5-1 were to be extended beyond NOFB limits of 0.15 Hz, the same generator would be capable of supplying NOFB services and contingency FCAS. The latter would depend on the setting of the limiters and the operating point of the generator. This coupled service could be easily managed in the co-optimisation.

Note that secondary frequency control (regulation) services could also be provided by the same participant. This capability arises because the regulation service acts on the power setpoint, which can be changed at the same time as the generating unit is operating in a frequency responsive mode (e.g. governor control for active power).

The cost recovery mechanism for the Primary NOFB FCAS would be via a substantially revamped “causer pays” method which would be based on system frequency measurements rather than on the AGC’s ACE (see section 8.2).

6 Management of Frequency in the NOFB

6.1 Amounts of regulation service being enabled

AEMO/NEMMCO has been reducing the amounts of enabled regulation service (secondary control) since the start of the FCAS spot market in 2001. There is now evidence that AEMO is currently not enabling enough regulation. The chart in Figure 6-1 presents data from the 17th January 2017 and comes from CS Energy's submission to AEMC's Review of the Frequency Operating Standard[37]. The raise regulation enabled excluding those providers <3MW is presented in the light grey. AEMO's filtered ACE, ACEfil, is a measure of the underlying MW quantity that the current set points of units on AGC need to be changed to return the mainland system to 50 Hz.

From the graph it can be seen that the ACEfil is essentially a smoothed version of {50 Hz – the actual system frequency (in red)}. The underlying amount of regulation required to instantaneously return the system to 50 Hz is the current amount of regulation used plus the ACEfil. Since the values of ACEfil are serially correlated it is reasonable to assume that part of the way into the time intervals where there are extended periods of high values of ACEfil there would be positive amounts of regulation used. Thus the ACEfil estimates during the latter parts of runs of positive or negative ACEfil provide underestimates of the amounts of regulation that would be required to instantaneously return frequency to 50 Hz.

What is clear in this figure is the amount of regulation enabled is materially less, at times, than the underlying regulation requirements. Clearly the system's inertia smooths this problem out to some extent but, never the less, there are extended periods of time when the system frequency is near or below 49.85 Hz.

Figure 6-2 presents the amount of mainland regulation enabled by AEMO for 2016-17. During this period AEMO operated the system based on the requirements of 130 MW raise regulation and 120 MW lower regulation and additional amounts of regulation to correct for time errors. A visual perusal of the figure shows that the amount of regulation required often exceeds 200 MW which suggests that the normal amount of raise regulation that AEMO is enabling is insufficient to manage frequency and time error.

[37] CS Energy and PD View (2017) submission to AEMC's Review of the Frequency Operating Standard, http://www.aemc.gov.au/getattachment/40ed39ab-8f24-402b-939c-8a8fd6dc8979/CS-Energy.aspx.

Figure 6-1 Comparison of the amount of raise regulation enabled versus underlying regulation required based on ACEfil. Source Energy CS Submission

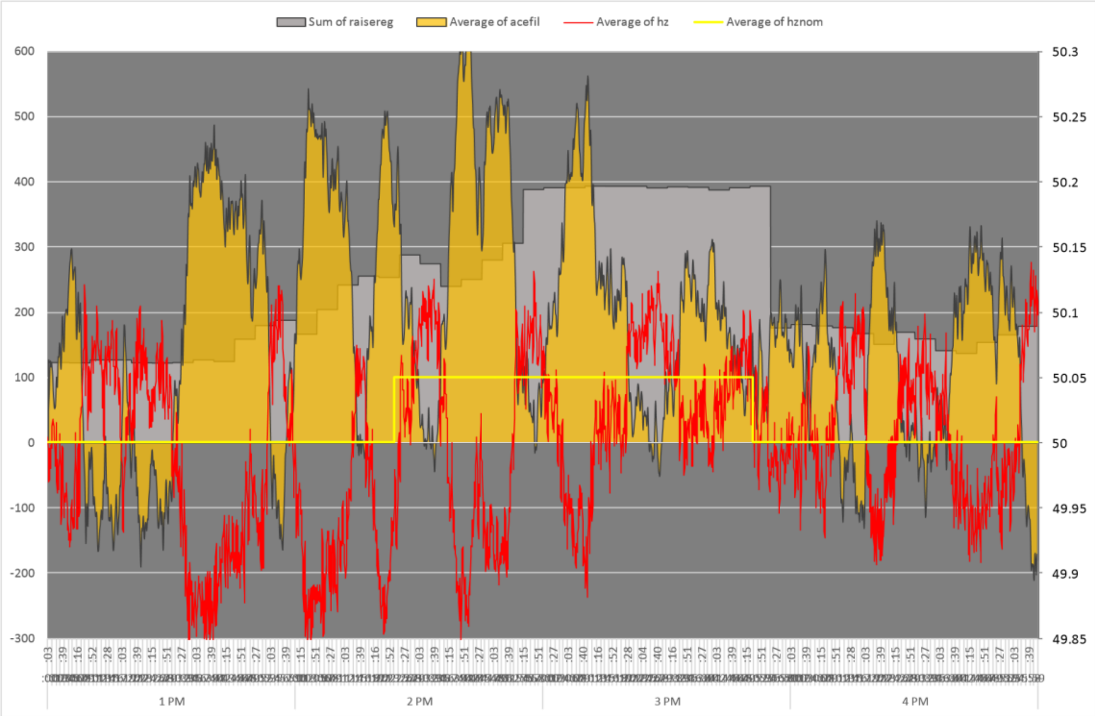
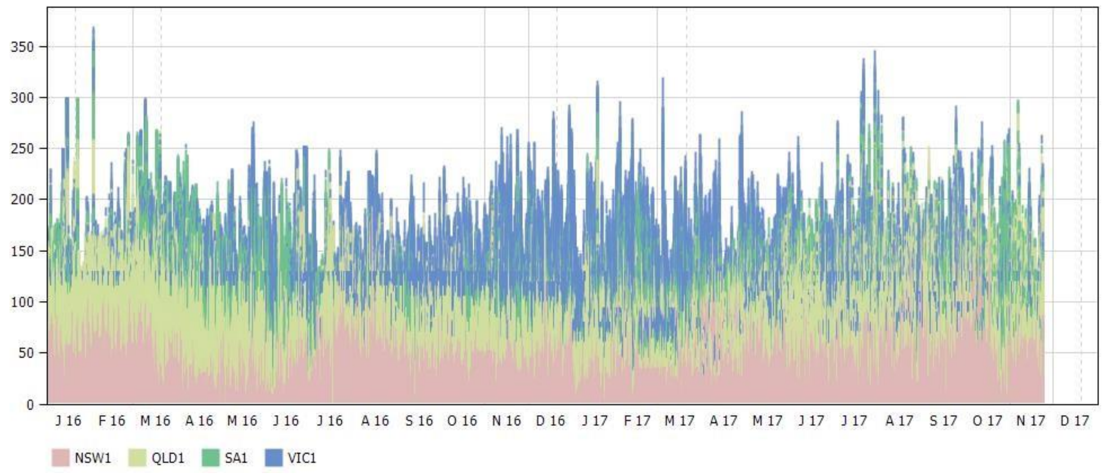


Figure 6-2 Mainland raise regulation enabled for 2016-17. Source AEMO



Also, CS Energy in their submission identified that AEMO at times was enabling regulation FCAS in excess of a unit's bid availability.

6.2 Better approach to determining amounts of regulation to be enabled

With the greater introduction of VRE generation, AEMO needs to develop a better system for determining the requirements for regulation FCAS based on a proper probabilistic / statistical approach. With an effective statistical approach regulation FCAS costs could be allocated to those who cause the requirements. Based on the analyses in the previous sections there are issues of enabling enough regulation FCAS and having enough regulation FCAS response (ramp rate) at the start of the dispatch interval. Both of these issues can be addressed through a proper statistical analysis of regulation requirements and regulation ramp rate requirements for the start of dispatch intervals or a regulation requirement for say the first minute of the dispatch interval.

If you assume to a first approximation that the sum of the deviations of loads, VRE generators, dispatchable generators etc. follows a random walk (Wiener process / Brownian motion) then the variance of the deviation is proportional to the time that the process has been running, in our case the time from the start of the dispatch interval. Thus if the variance at the end of the dispatch interval was (125 MW)^2 then the variance one minute into the dispatch interval would be 0.2 * (125 MW)^2 = (56 MW)^2. Consequently, if 250 MW[38] of regulation FCAS was enabled and much of this was limited by its ramp rate so that the aggregate ramp rate was, say, 60 MW / min then there would be inadequate amounts of regulation FCAS to meet the regulation requirements in the first minute (60MW available versus a requirement of 112MW) and this would be further exacerbated if frequency was not at 50 Hz at the start of the dispatch interval.

6.3 Statistical approach to determining amounts of regulation required

The following outlines a transparent and evidence based approach that AEMO could adopt for determining the amounts of regulation FCAS that should be enabled to meet the NEM's frequency standard for normal operations.

AEMO could determine the amount of regulating FCAS required to be enabled based on periodic statistical analyses of the sources of variability that drive the need for regulating FCAS including:

- load forecasts errors (LFerr) for the end of the dispatch interval;
- semi-dispatchable and non-dispatchable generating unit generation forecasts errors (ReFerr) for the end of the dispatch interval;
- second by second load variation (LV) over the dispatch interval;
- second by second variation of semi-dispatchable and non-dispatchable generation (ReV) over the dispatch interval;
- generating unit deviations from dispatch targets and trajectories (GV) over the dispatch interval; and

[38] If 2 x the standard deviation of the regulation requirement is enabled this would give a probability of about 95% that there is an adequate amount of regulation to return the system frequency to 50 Hz.

- possibly frequency and the amount of regulation used at the end of the previous dispatch interval, though these amounts would probably be better incorporated into the energy dispatch for the current dispatch interval.

The analysis would need to remove any generating units providing regulation FCAS for the time periods they were providing it.

When undertaking the statistical analysis of the sources of variability, AEMO should take into account whether there are any significant impacts on the means or standard deviations of the sources of variability which are the result of any of the following:

- time of day, month or year;
- periods of rapid ramping up or down;
- regulation requirement and frequency at the end of the previous dispatch interval;
- system demand;
- measurements of intermittent generation; and
- any other possible explanatory variables the AEMO or participants identify.

Based on the statistical analysis, AEMO would estimate the mean and variance of the total second by second deviations Y(t) over the dispatch interval t, where:

$$\begin{aligned} \mathrm{Y(t)} &= \mathrm{LFerr(t)} + \mathrm{ReFerr(t)} + \mathrm{ExFerr(t)} + \mathrm{LV(t)} + \mathrm{ReV(t)} + \mathrm{GV(t)} \\ &\approx \ regulation\,used(t) + ACE(t) \end{aligned}$$

$$\begin{aligned} \mathrm{mean} &= \mathrm{E[Y(t)]} = \mathrm{u(t)} \\ \mathrm{variance} &= \mathrm{V[Y(t)]} = \mathrm{v(t)} \\ \mathrm{standard\ deviation} &= \mathrm{sd(t)} = \mathrm{v(t)}^{\frac{1}{2}} \end{aligned}$$

If there are significant mean effects then these should generally be incorporated into the load forecasts and thus into the energy market.

If we assume that the distribution of Y(t) is symmetric, then the amounts of raise and lower regulation required to meet the frequency standard will be the same. To remain in the NOFB 99% of the time, the raise deviations should only be greater than or equal to the raise regulation enabled 0.5% of the time and the lower deviation should only be lower or equal to minus the lower regulation enabled 0.5% of the time to ensure that the NOFB frequency standard is met. If we assume that the deviations follow a normal distribution then AEMO can determine the required quantities of lower and raise regulation for the end of t as follows:

$$\mathrm{P[Y(t) <= -regulation\ lower(t)]} = 0.5\%$$

implies

$$\begin{aligned} \mathrm{regulation\ lower(t)} &= \mathrm{u(t)} - \mathrm{sd(t)x\,Z} \\ &= \mathrm{u(t)} - 2.57\,\mathrm{sd(t)} \end{aligned}$$

$$\mathrm{P[Y(t) >= regulation\ raise(t)]} = 0.5\%$$

implies

$$\begin{aligned}\text{regulation raise}(t) &= u(t) + sd(t) \text{x } Z \\ &= u(t) + 2.57\, sd(t)\end{aligned}$$

where Z is determined from the normal cumulative distribution and P(standard normal variable > Z) = 0.5%

Now if the amount of effective enabled regulation FCAS at the start of the dispatch interval is a problem due to ramping constraints, as it appears to be, then the same calculation can be done for, say, 1 minute into the dispatch interval and this would then become an additional regulation requirement and be incorporated into NEMDE's co-optimisation.

6.4 Improvements to AGC operation

There are a number of areas where we think AEMO's AGC operation could be improved. These include reviewing and, as required, updating control parameter values and better identification of units that are not responding to AGC signals and removing them from being enabled for regulation.

6.4.1 BIAS calculation

Our understanding is that AEMO is largely using much the same parameter values for its AGC system now as it did a number of years ago. For the BIAS setting, AEMO currently uses a constant 280MW/0.1 Hz. However both load and generator responses to frequency have changed. The system BIAS is likely to be less than what it was years ago and if AEMO is using a BIAS in its AGC which is materially larger than the actual system bias then the AGC may overestimate ACE and this could possibly contribute to oscillations in frequency.

We recommend that AEMO adopt an approach that calculates the BIAS used in the ACE calculations on a dynamic basis where:

BIAS $= D + \sum_{g=1}^{n} b_g$

Where:

D is the area load bias contribution (MW/0.1Hz)

b_g is the bias contribution (MW/0.1Hz) of generating unit g due it being online and its governor droop setting

6.4.2 Monitoring and removal of non-performing units

CS Energy has identified that some regulation issues are related to units enabled for regulation not responding to their targets. AEMO could improve this situation by dynamically identifying units which are not responding to AGC signals and restricting them from being enabled for regulation. AEMO could also avoid enabling units for regulation and energy in excess of a unit's maximum availability by ensuring that it is using the most recent declared maximum availability, SCADA maximum capacity and upper limit in its FCAS trapezium and that generators are properly updating their capabilities and offers.

6.4.3 Better integration of AGC and the operation of Basslink

CS Energy has identified that there are some issues related to the provision of regulation services by Tasmanian generators and the operation of AEMO's AGC system and its interaction with the Basslink controller. These issues could possibly be addressed with AEMO running its AGC with multiple control areas and providing Basslink with a notional changes in "setpoints" that facilitate the transfer of regulation between Tasmania and the mainland rather than just relying on Basslink's frequency equalising controller. However, before any proposed solution is implemented some power system studies should be undertaken to investigate the system dynamics of potential solutions.

7 Markets for Management of Contingency Events and Large Frequency Deviations

In addition to the NOFB market arrangements, the contingency FCAS arrangements require a re-design to adapt to the new technologies and changing dynamic behaviour of the power system.

7.1 Introduction

In the NEM, the contingency FCAS are procured using rigidly defined categories of services which are split into the discrete timeframes 6s, 60s and 5 minutes. These service categories were set up in 2001 with the new FCAS spot market and were based on the historical generation mix of coal, hydro and some gas generation at the time. That generation mix had higher inertia levels than now. With increasing levels of Variable Renewable Energy (VRE) penetration, there is now a need to review these frequency control ancillary services categories to ensure the correct quantities are procured in the appropriate time frames to meet the power system frequency standards.

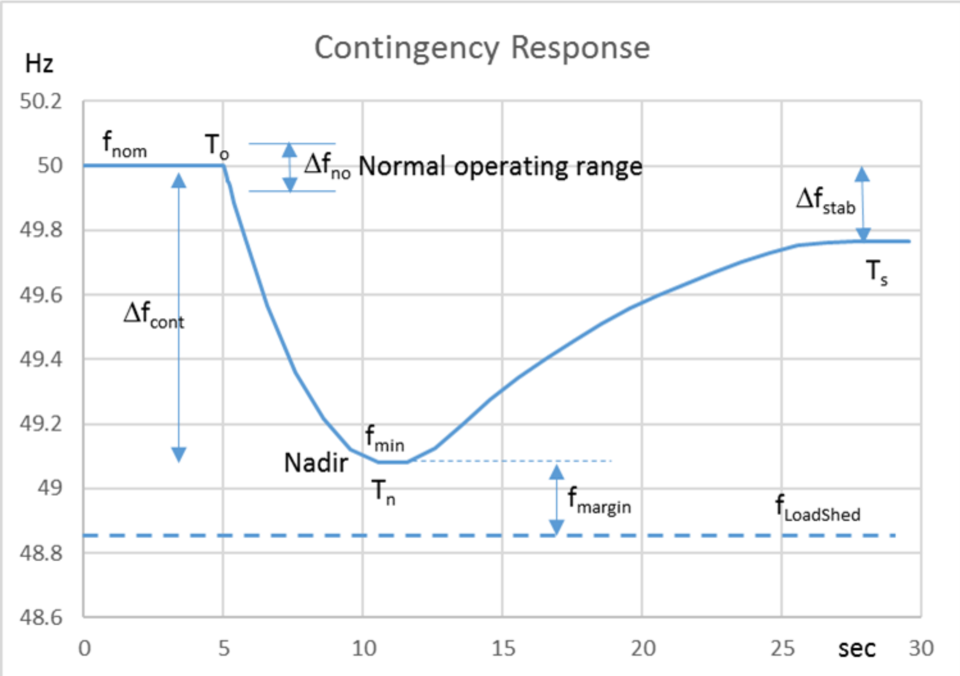
Currently AEMO is looking at the possibility of creating a very fast contingency FCAS to address situation were inertia is low and the rate of change of frequency is high. The difficulty with this approach is, what is the appropriate time frame for the service and will it be still appropriate 10 to 20 years in the future? Our suggested approach to dealing with the changing characteristics of the power system now and into the future is to model the frequency responses of FCAS providers as continuous functions over time rather have discrete buckets of contingency FCAS and to directly model frequency in NEMDE. Adopting this approach would mean that the 6s, 50s and 5 minute contingency services and the proposed very fast contingency FCAS would all be subsumed into the same continuous contingency FCAS market.

7.2 Discretisation of FCAS Responses versus Continuous Model

This section discusses some issues in relation to the approach of dividing contingency FCAS into discrete bucks, such as the 6 second and 60 second and proposed ‘very fast’ contingency FCAS service. The emphasis is on the first part of the response, which is intended to arrest a frequency decline within the requirements of the Frequency Standard.

As inertia changes, the time of the frequency nadir following a contingency will change. Historically, with the inertia associated with the thermal and hydro units in the NEM, the nadir for a large contingency was at around 6s (shown as T_n in Figure 7-1). If the inertia reduces, the time to the nadir will similarly reduce. The fast contingency FCAS is designed to arrest the frequency in order to meet the frequency standards, which states the maximum frequency deviation, Δf_{cont}, for a credible (generation/load) contingency is 0.5 Hz. Using the swing equation, load frequency dependency, size of largest contingency, and the system inertia, the amount of FCAS can be calculated that will [exactly] meet the standard. However, this FCAS amount must be provided BEFORE the frequency nadir. Anything provided after the nadir only serves to assist in the recovery of the frequency.

Figure 7-1 Typical frequency response following a contingency



If the timing of the frequency nadir drops to, say, 4 seconds, calculating the "6s FCAS requirement" and enabling the 6s FCAS provides no guarantee that the standard will be met. Since the fast contingency FCAS is specifically required to meet the Frequency Standard, the 6 second service will not be adequate. The timing of T_n could be maintained by investing in synchronous condensers or other synchronous machines, but this is unlikely to be economically efficient. Adding another 'very fast' contingency FCAS bucket will work as long as the inertia is such that the time of the nadir never reduces below the nominated bucket time of this service.

If a 4s 'very fast' contingency FCAS service was introduced, current providers would need to re-assess their response profiles to see what they could offer into this new market. The approach suggested in our report is to consider the actual response profile, rather than a discretised form of this profile. This will intrinsically value very fast responses (and possibly even inertial response since this can be considered in the co-optimisation). However, in situations where there is plenty of inertia, the slower contingency FCAS, if it was offered at a lower cost, would be dispatched ahead of the more expensive fast and very fast FCAS.

The ability to sustain the response should also be valued. A battery can provide an overload rating for around 10s, which is very valuable in a low inertia situation.

A hydro can provide a slower initial response but it can be sustained for greater than 5 minutes, or even indefinitely. In different situations, these services offer different values and thus the co-optimisation may enable them for some situations and not in others.

The existing FCAS arrangements, and the proposed addition of a 'very fast' service will likely work, provided the 'very fast' service is always delivered before the lowest value of the time of the frequency nadir, T_n , in the power system. However, manipulating the inertia so that T_n matches the arbitrary selection of FCAS buckets is unlikely to be the most economic approach. If the predefined bucket approach is used, a cost-benefit analysis showing the merit this approach compared to using a more continuous, general purpose and adaptive approach should be undertaken and that it is the best option.

7.3 Modelling of FCAS responses

Figure 7-2 shows the models that the NEM uses for the FCAS response profiles. Figure 7-3 highlights the model profile for the 6s fast contingency service. These profiles are very stylised and don't look very much like actual response profiles, though these inaccuracies are smoothed out with the power system inertia.

The 6s profiles seem to reflect the initial, and unsustained, fast responses associated with steam turbines utilising energy stored in their boilers. As the flow into the turbine increases, pressure gradually drops, causing the reduction in output.

The question is whether these profiles have any place in a power system where the amount of steam turbine driven capacity is projected to fall and reducing inertia levels are likely to change the time by which the fast service must be provided. For example, if the frequency nadir, because of reducing inertia, reduces from 6s to 5s, any FCAS response provided between 5 and 6 seconds will have no impact on reducing the initial frequency excursion.

The rate of reduction of inertia in the NEM as whole is likely to be slow but in some sub-regions, like north Queensland, Tasmania and South Australia, the inertia is already low at times of high VRE generation. As a result, the 6s contingency services will not be able to contain any frequency excursion should these sub-regions separate from the main power system, even if the FCAS dispatch algorithm did schedule FCAS resources within the region. Adding a new 'very fast' contingency service will help the situation but remains inflexible and performance will depend on how well the service matches the actual dynamics of the sub-region power system. For example, there is little point in having a very fast service in a part of the NEM that has sufficient inertia to keep the frequency nadir time around 5-6 seconds. Lower cost slow-acting FCAS is sufficient in such circumstances. Fast acting FCAS is required mainly in the potential sub-regions.

Figure 7-2 NEM Model of FCAS Response Profiles

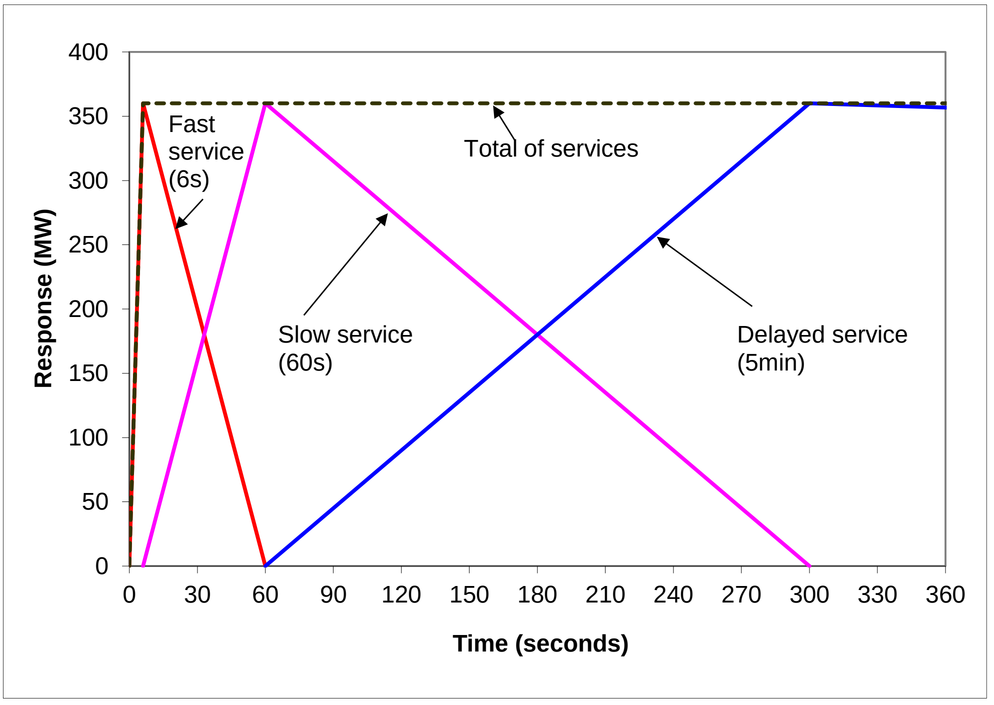


Figure 7-3 NEM Model for Fast FCAS Response Profile

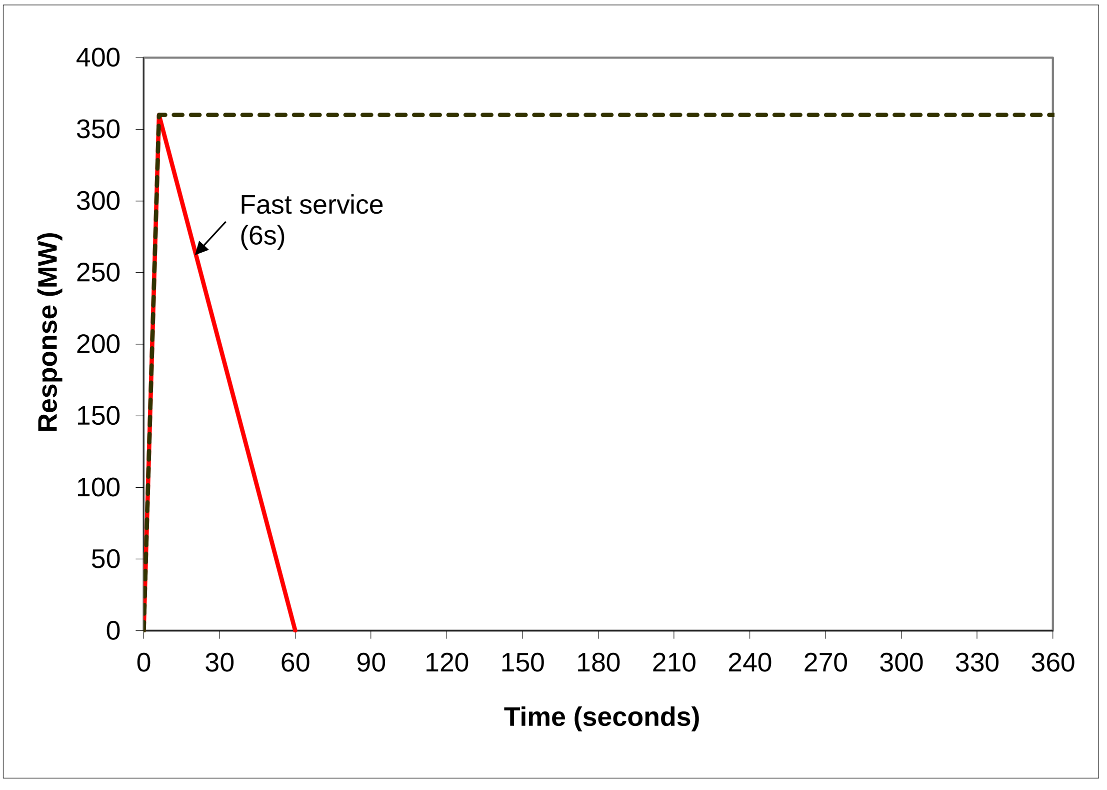
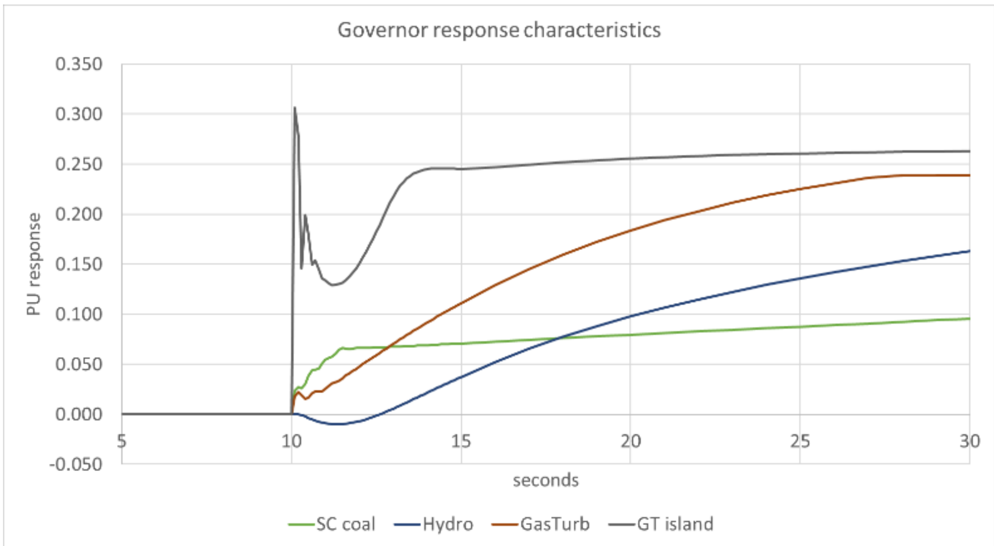


Figure 7-4 shows the response curves for coal, hydro and gas turbine unit in a large system and a small, low inertia sub-region environment. For a contingency occurring at 10s, the large system has a relatively slow change in frequency (SC Coal, Hydro, Gas Turbine), which results in the per unit (P.U)[39] responses shown. For a gas turbine in a low inertia sub-region (GT Island), the rate of change of frequency is high and the unit's response comprises a larger inertial component plus a reasonably fast turbine response.

Figure 7-4 Example response curves for different technologies to a frequency drop off corresponding to the largest contingency in a simulated system



With the increase in inverter technologies and the potential for their software to give these systems a wide range of frequency response characteristics, it would appear preferable to model each system's response in the co-optimisation. The dispatch algorithm could then choose the services that best meet the frequency standards at lowest cost rather than try to bundle them into pre-set buckets (e.g. 6s, 60s, 5 minutes). George, Wallace, Hagaman and Mackenzie investigated this approach in their paper "Market mechanisms for frequency control"[40]. Their suggested approach is very flexible and can:

- Select the least cost set of service providers to directly meet the frequency standards;
- Co-optimise flows on interconnections when islanding is a credible contingency;
- Directly take into account the inertia of the system and any potential islands; and

[39] In the power systems analysis, a per-unit system is the expression of system quantities as fractions of a defined base unit quantity, often 100 MVA. In this example the P.U. is the proportion of the unit's capacity.
[40] T. George, S. Wallace, S. Hagaman and H. Mackenzie (2017) "Market mechanisms for frequency control" 16th Wind Integration Workshop, Berlin

- Price FCAS on a large number of time scales from tenths of seconds to minutes; and
- Value (price) inertia as part of the co-optimisation.

The key ideas behind the approach are that

- the swing equation is a linear equation in terms of the amounts of FCAS enabled and the size of the contingency and it explicitly takes into account inertia (see section 2.15);
- the dynamics of the swing equation over time can approximated by a set of difference equations using many time points;
- if the swing equation is used in the dispatch optimisation then the optimisation can directly model frequency and the optimisation can directly ensure that FCAS providers enabled will meet the frequency standards by incorporating the frequency standards as constraints on the modelled frequency; and
- since frequency is being modelled directly there is no need to categorise FCAS into buckets and thus continuous FCAS response functions can be modelled.

With a modest amount of effort this approach could be incorporated into NEMDE. This section outlines the key features of the approach.

7.4 Co-optimisation approach

Our suggested approach to co-optimizing energy and contingency FCAS is slightly different to the usual approaches to co-optimisation.

The normal approach is to categorize the contingency FCAS into categories of fast, slow and delayed contingency services. For each category, the dispatch process determines the requirements directly as an input or indirectly via the co-optimisation of requirements. Both of these approaches would take into account any load relief or frequency responsive generation for frequency changes within the frequency standards for the system. The co-optimisation of requirements is the more efficient approach as it can trade-off the size of contingencies with the costs of FCAS.

The other part of the co-optimisation is to determine the least cost way of simultaneously meeting the requirements for each contingency service, the regulation services and energy taking into account each generating unit’s capabilities to provide FCAS and energy and the offered prices for these services.

The co-optimisation of requirements and the co-optimisation of the provision of the services (enabling of the services – reserving the capability) and energy are normally done as a single optimisation.

The problem with this approach is that with the introduction VRE technologies and batteries and a corresponding drop in system inertia, the simple categories of contingency FCAS and the assumption that all service providers within a category are providing an equivalent service are no longer fit for purpose.

Our proposed approach to co-optimizing energy and FCAS is to directly model system and island frequency following the most severe credible contingency in the co-optimisation. This can be done by:

1. Determining what are the credible contingencies that could affect frequency and/or islanding and their location;
2. Determining potential islands in near real time based on the credible contingencies and network topological analyses of the post contingent network states;
3. Determining inertia for the whole system and any potential islands in near real time by using the EMS system to determine what units and loads with significant inertia are online and then calculating system and potential island inertias;
4. Using measured performance profiles for a benchmark change in frequency over a time period from 0s to, say, 300s for each generator, load or other facility that is in the market to provide contingency FCAS (the measured profiles should be sampled at a small time interval, say, 0.05s for the first 2-4s and then 0.1s for the following 20s);
5. Using the NEM's defined frequency levels in the frequency standards for system and island frequencies post contingency, including permissible times at these frequencies before being restored to nominal (as per Table 1);
6. Formulating the co-optimisation such that it
   a. directly models system and island frequencies via the swing equation at many discrete times post contingency (this is done via a set of difference equations that relate the changes in frequency at time t to the power loss at time t considering load relief and FCAS responses);
   b. selects the contingency services based on measured performance profiles:
      - if the performance profiles are based on a fixed change in frequency, say, -0.5 Hz, then their governor responses have to be modelled in the optimisation such the expected FCAS response is determined by the amount enabled x profile x constant x [nominal frequency – frequency]); or
      - alternatively, if the profiles were determined using a frequency profile that reasonably approximates how frequency would change over time with a major contingency then the fixed profiles could be used directly and no modelling of the proportional governor response would be required;
   c. has constraints to ensure that system and island frequencies are within the frequency standard for each time point and frequency returns to the rated frequency within the required period;
   d. co-optimizes the provision of energy and FCAS;
   e. co-optimizes the FCAS requirements in near real time by location, based on credible contingencies, inertia and the potential for islanding (in low inertia situations it may be better to reduce the output of a larger

generating unit or reduce imports and correspondingly reduce the need for very fast response FCAS capability); and

f. produces shadow prices from constraints associated with the swing equation that can be used to determine spot prices and the value of FCAS at different times.

The co-optimisation is a non-linear programming optimisation if it incorporates a simple model of governor response which then involves the product of two decision variables, the frequency at time t and the amount of contingency FCAS enabled for a generator. If the governor responses are incorporated into the performance profiles then the problem remains a linear programming problem.

This approach was demonstrated using a prototype dispatch optimisation and a simulated power system to check whether the enabled amounts of FCAS from the dispatch optimisation did indeed result in the post contingency frequency performance as expected. The results from the dispatch optimisation resulted in system and island frequencies in the simulated power system being very close to the post contingency event frequency standards.

Benefits of the co-optimisation approach are that it:

- Appropriately rewards service providers based on their response and inertia; and
- Prices contingency FCAS on a continuum of time scales and thus signals the market values of different response capabilities.

7.5 EMS and Other Requirements

To make the suggested approach work AEMO's EMS/SCADA system must estimate in real time the system inertia and the inertia of any potential islands post credible contingency events. This could be done by having global and local calculations based on generator status (on/off) and their known inertias. Load inertia is typically of second order importance, but a similar approach could be made, possibly relying more on estimates based on measurements of background frequency deviations.

Further some providers may have different FCAS response functions given the state or mode of their plant such as online and generating, operating synchronous condenser mode, offline etc. If this is the case the mode of such a unit would need to be picked up by AEMO's SCADA system and used as an input to NEMDE.

7.6 Recommended improvements for contingency FCAS

Our recommended improvements to the contingency FCAS are as follows:

- Move to using continuous response functions rather than discrete buckets for contingency FCAS providers;
- Apply the frequency standard as a set of constraints in the dispatch optimisation

- Explicitly model frequency in NEMDE via the swing equation and frequency constraints at a number of points in time, say, 0.1 s intervals for the first 10s, then at 1s intervals for the next 50s and then at 10s intervals out to 300s to 600s;
- Use the co-optimisation to price contingency FCAS both globally and locally at all of the time points modelled;
- Pay each provider the sum of the amount of contingency FCAS they provide at each time point multiplied by the FCAS price at that time point (the optimisation and this payment method will ensure that each provider enabled will receive at least their offered price};
- Use the co-optimisation to price inertia via incrementing the amount of inertia and determining the changes in dispatch costs (if the problem was kept as a linear programming problem, integer variables for inertia could be introduced to determine whether it’s worthwhile to have additional synchronous units to start up); and
- Possibly, pay for the provision of inertia via using the inertia shadow prices.

8 Improvements to "Causer Pays"

8.1 Introduction

The "causer pays" approach to the recovery of costs for regulation is generally regarded as not working very well. It is viewed as providing perverse incentives to generators with respect to the operation of governors on their units and it is producing some unexplained outcomes for VRE generators. The sources of these problems are as follows:

- The causer pays assessment uses AEMO's AGC regulation requirement, but this requirement is not known to participants in real time and is not always highly correlated with frequency;
- Because the causer pays calculation only charges participants for costs and does not pay participants for providing beneficial behaviour, it is essentially a non-linear function, like a max() or min() function, and this is compounded by only doing the "causer pays" calculation on a portfolio basis. The results of these arrangements are that if you rearranged the loads and generation into different portfolios you would get quite different causer pays charges.

One solution to this problem is to swap the causer pays approach from one that recovers the costs of the enabled regulation FCAS to one used for the cost recovery of the proposed Primary NOFB FCAS. This has the advantage that everyone can see what the frequency is and thus take action to reduce their causer pays charges. Further, this arrangement could be expanded to an arrangement whereby the plant/loads not enabled for either Primary NOFB FCAS or regulation FCAS could be charged if they contributed adversely to frequency or paid if the contributed positively to frequency.

8.2 Causer Pays for Primary NOFB FCAS

If the "causer pays" approach were adapted and used for the cost recovery of the costs for enabling generators to provide Primary NOFB FCAS it would work something like this.

- AEMO's SCADA system and historical SCADA data storage system would be set up to capture snapshots of frequency measurements for north and south NEM, the generation outputs of all participating generators and the loads at all connection points. The data for all these sources should be timestamped for the measurement time to allow for adjustments for any delays in the SCADA system.
- For all the units and other facilities not enabled for Primary NOFB FCAS or regulation FCAS, AEMO:
    - determines a 4s linear trajectory of their desired energy ramp from the start of the dispatch interval to the end of the dispatch interval, a set of notional 4s dispatch targets (MW);

- calculates the 4s deviations of actual generation and loads from their notional dispatch targets(MW);
- calculates a total amount of undesirable deviations:

$$\text{total adverse deviations} = \sum_{t\ in\ T}\left\{sign(Fs(t)-Fa(t))\sum_{r\ in\ R}(Xa(r,t)-Xs(r,t))\,4s\right\}$$

where $Fs(t)$ is the scheduled frequency at time t
$Fa(t)$ is the actual frequency at time t
$Xs(r,t)$ is the scheduled load (-generation) at time t
$Xa(r,t)$ is the actual load (-generation) at time t

the total adverse deviations would be expressed in MWh;

- calculates the NOFB cost allocation ($/MWh) by dividing total cost of the enabled Primary NOFB FCAS by the total adverse deviations to get a NOFB cost ($/MWh) for deviations;
- Each generator or load resource, r, pays or is paid a frequency deviation payment of:
- $= \text{NOFB cost}\ x \sum_{t\ in\ T}\{sign(Fs(t)-Fa(t))\ (Xa(r,t)-Xs(r,t))\ 4s\}$

This cost recovery provides revenues for generators that are not enabled for Primary NOFB FCAS but allow their governors to respond to frequency. In that sense it is a bit like a two-way market where there are buyers and sellers but the price has been determined by the cost of enablement. Also, this cost recovery mechanism will result in the same outcomes in terms of payments or charges for loads and generating units no matter what the portfolio aggregation is used because the payment / charging function is a linear function unlike the current causer pays function.

This cost recovery mechanism combined with creating a Primary NOFB FCAS should provide considerable incentive for having an effective governor response in the NEM within the NOFB. The charging could be done on a dispatch interval basis but a more prudent approach from a risk management point of view would be to charge on a longer time interval basis such as trading interval or day or week to reduce the volatility of these charges.

8.3 Causer Pays for Regulation FCAS

As discussed earlier the current "causer pays" approach to the cost recovery of enabled regulation FCAS doesn't work very well and has created some perverse incentives. In the original discussion about the "causer pays" during the NEMMCO's review of ancillary service arrangements it was originally thought that it would apply to frequency deviations rather than to the AGC 4s regulation requirements. With the introduction of a Primary NOFB FCAS this original idea can be implemented as the causer pays mechanism for Primary NOFB FCAS. A different approach is therefore required for causer pays for regulation FCAS.

In section 6.3 we outlined a statistical approach to the determination of regulation requirements. A key part of this was determining the mean and variance for the total deviations. Now for each load or generator resource or portfolio as part of the statistical analysis outlined earlier, in section 6.3, it is possible to not only calculate the variance of the total deviations and the variance of the load, unit or portfolio but the covariance of the load, unit or portfolio with the total deviations. This leads to a simple and fair regulation cost allocation to a generator or load, r:

$$cost(r) = \frac{Cov(X(r), Tot)}{V(Tot)} x\ total\ regulation\ enablement\ cost$$

Where:

X(r) is the random variable corresponding to the deviation of resource r from its linear energy ramp trajectory;

Tot is the random variable corresponding to the total deviation of all resources from their linear energy ramp trajectories, Tot = ∑ X(r)

V(Tot) is the variance of Tot

Cov(X(r), Tot) is the covariance of X(r) and Tot.

Note that

$$\sum_{r\ in\ Resource} \frac{Cov(X(r), Tot)}{V(Tot)} = 1$$

One of the advantages of this cost recovery mechanism is that doesn’t so much penalise high degrees of variability on their own but more high degrees of variability which are highly correlated with the total deviations. For example, one windfarm could have a highly variable output but be near no other windfarms and have a low correlation with the total output of VRE generation in the NEM while another windfarm could have much less variable output but be near other windfarms and have a much higher correlation with the total output of VRE generation in the NEM. In this example if both windfarms had the same average output the first windfarm would pay a much smaller proportion of the regulation FCAS costs than the second one would because it contributes far less to the variance of the total of the VRE generation than the second windfarm.

This is because variance of a sum of random variables is

$$V\left(\sum_{i=1}^{n} X_i\right) = \sum_{i=1}^{n} V(X_i) + \sum_{i=1}^{n}\sum_{j\neq i}^{n} Cov\left(X_i, X_j\right)$$

and the variance of the sum is dominated by the sum of the covariances when the random variables are correlated and n is greater than 10 or so.

9 General NEM Improvements

9.1 Introduction

These improvements would assist with frequency management and would provide improvements in many other areas.

9.2 AGC with multiple control areas and locational regulation

In order to get more capability out of the transmission network in general and in particular manage interconnector flows using justifiably smaller safety margins we recommend that AEMO set up its AGC and regulation services so there can be multiple control areas in tie line bias modes or similar modes. This would improve the capability to fully utilise interconnectors and other transmission elements therefore reducing capital costs and therefore costs to consumers. Also, the multiple control areas approach would be useful if a credible contingency could cause islanding.

When multiple control areas are used, local regulation FCAS would need to be enabled. This would be done along similar lines to local and global contingency FCAS requirements. In some cases, the AGC control of local regulation FCAS would in effect also be providing a network control service and thus could be classified as network support and control ancillary service.

If the AGC system is used to assist to provide a more precise and efficient real time management of interconnector flows and transmission flows in general then this could be facilitated by using a real time optimisation that is run every two seconds or so to allocate the changes in setpoints to units providing global and local regulation whilst ensuring power flows remain within their limits and units are given setpoints that are within their feasible dispatch space based on their physical capabilities, energy targets and the amounts of regulation FCAS enabled.

The multiple control areas approach may increase regulation costs, but these additional costs should be more than outweighed by savings from more efficient transmission use.

9.3 Forecasting

As discussed earlier, we understand that AEMO's neural network load forecast system has been in place for many years and thus may not be optimal for load forecasting given the ongoing changes in the power system. With the increases in penetration of rooftop solar, growing use of batteries and the changing patterns of power usage, a review of AEMO's short term forecasting approach would be appropriate. Further, we think that it would be sensible for AEMO to start forecasting at a connection point level as this would facilitate the development of better models for embedded PV generation, load and embedded batteries and their price responses. Connection point forecasts would also facilitate better use of the transmission system since the safety margins in many constraints could be reduced.

Most EMS vendors provide a range of potential forecasting methods including similar day forecasts, time series forecasts, regression based forecasts and neural network forecasts. In addition to the EMS vendors there are a range of other vendors of load forecasting software. To our understanding, AEMO's current neural network approach has never been openly compared with other potential forecasting methodologies. We recommend an open evaluation of a variety of methods for short term forecasting methods including time series, neural network, Bayesian models, Kalman filters etc. and a comparison of their results. A potentially very useful approach for AEMO could be to get Kaggle to run a NEM load forecasting competition (https://www.kaggle.com/). Kaggle runs data analysis competitions for a wide range of industries and reputable organisations, including the US Government. Competitions have prize money up to the millions of dollars and have had great results for the organisations sponsoring the competitions.

9.4 Forecasting VRE

Detailed analysis of specific VRE projects shows that the ability of the mass forecasting approach to represent wind shadows and other factors is limited. More precise energy conversion models may be one approach to addressing this problem.

In section 3.6.5 we outlined a number of the recognised problems with AEMO's VRE forecasting. To address some of the problems AEMO has proposed that wind and solar farms can supply their own forecasts and that these forecasts may be used by AEMO rather than the AWEFS/ASEFS forecast. If these VRE generators can produce better forecasts than AEMO then it would seem prudent for AEMO to adopt some of their approaches and forecasting systems.

9.5 NEMDE

The NEM dispatch engine (NEMDE) is used to provide a security constrained dispatch. When it was developed for the start of the NEM it was a state of the art system. It is now 20 years old and showing its age. All the major vendors: GE/Alstom, ABB and Siemens have systems that could more efficiently and transparently provide a security constrained dispatch for the NEM. Further, since the vendors are working in many markets they are continually improving their products. Some vendors have their own operations research departments.

All the vendors have systems that could provide an optimal security constrained dispatch where they co-optimised FCAS, including requirements, and could automatically generate constraints for thermal limits based on the current network topology. For instance, a Siemens system is being used by Californian Independent System Operator (CA ISO) and solves for over 10,000 buses / nodes and their real-time contingency analysis system can support up to 10,000 contingencies simulated every two minutes.

One advantage of using a system developed in house is that it is easy to change and you have access to the source code. However, this issue can be overcome. We were recently involved in the tendering process for the Philippines new market management system including the security constrained dispatch and all vendors agreed to:

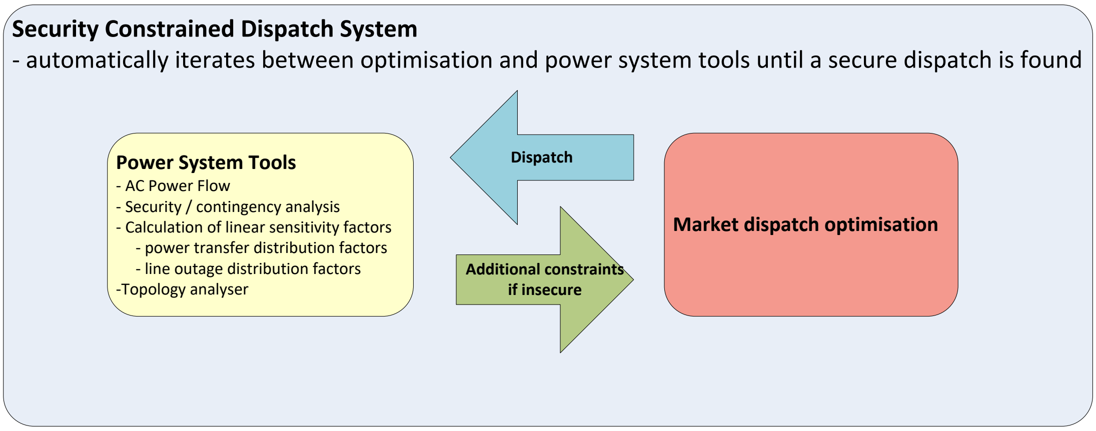
- provide source code to their optimal security constrained dispatch model and documentation of the model ;
- allow the SMO (Philippines Electricity Market Corporation) to change the model; and
- allow the SMO to publish the formulation of the model

These conditions provide the Philippines SMO with great flexibility to enhance the model and change it in response to market rule changes

These modern security constrained dispatch systems

- manage security by iterating between the optimisation and the power system tools in a tightly coupled suite of software (see Figure 9-1);
- can manage thermal constraints, FCAS and locational FCAS/NCAS; and
- in future systems, voltage constraints and reactive dispatch

Figure 9-1 Modern security constrained economic dispatch software



In contrast to the more automated approaches to managing a security constrained dispatch the NEM's approach to managing a secure dispatch is very cumbersome and not particularly efficient:

- The NEM uses a very large pre-calculated set of "generic constraints" to determine a secure dispatch;
- The selection of which constraints to use in addition to the "system normal" constraints is largely a manual process;
- The left hand sides (LHs) coefficients of the constraints equations are not updated or revised in realtime;

- The right hand side (RHs) constants of the constraint equations are generally updated online based on SCADA measurements;
- Thermal constraints are often of the feedback type which adjusts the RHS based on generator outputs and transmission line flows;
- The system does not automatically respond to a network outage and thus there can be a number of inappropriate constraints included in the dispatch;
- Instead of properly formulating the dispatch of FCAS as part of NEMDE's mathematical programming, much of the FCAS dispatch is managed by a large number of FCAS "generic constraints";
- Even though NEMDE has been regularly audited there is no guarantee that the dispatch process is optimal due to the large number of "generic constraints"

The NEM's dispatch of energy and FCAS could be substantially improved and made more transparent with improvements to NEMDE or the purchase and adaptation of a new security constrained dispatch. Key areas to improve are:

- All network security constraints should only be based on the current network configuration taking into account outages and switching and should be automatically generated as much as possible; and
- Nearly all FCAS constraints should be explicitly formulated as part of the dispatch optimisation. Input data for this could come from network topology analysis, SCADA data etc.

10 Conclusions

There is evidence for:

- Distribution of frequency within NOFB changing over time to be flatter and this does have some costs;
- The current contingency FCAS arrangements are now not always fit for purpose, particularly in potential islands of low inertia;
- AEMO is not enabling enough regulation;
- The current "causer pays" cost recovery mechanism for regulation is creating some perverse incentives which do not help the management of the power system; and
- AEMO's AGC is probably not optimally set up.

The NEM does have some frequency control issues but the way to address these is not via mandatory requirements but by adapting the market processes for the new environment of greater VRE penetration and generators' greater control of their governor responses.

Market solutions to frequency control should recognise the changing nature of the power system, especially the acute changes in sub-regions of the NEM. Revised FCAS arrangements should take into consideration the projected technical and performance capabilities of new technologies and not hold onto historical systems and structures that will be inappropriate in the future.

The solution to the frequency control issues is to fix up the market arrangements and not to regulate compulsory capabilities and provision of services. Regulation is a costly and economically inefficient approach that does not satisfy the NEO.

Revised FCAS market arrangements should take into account the following.

- Better modelling of frequency response characteristics will improve AEMO's confidence that the frequency standards, and therefore security, will be met.
- Location of fast acting FCAS providers is mainly needed in potential subsystems, which have low inertia. In stronger parts of the system, the higher costs associated with very fast responding systems is difficult to justify. Revised FCAS systems should reflect the locational value of fast responding systems. Consequently the value of faster acting FCAS responses is higher in potentially islanded subsystems.
- Co-optimisation across all FCAS and energy markets will lead to the maximisation of value in the NEM and satisfy the NEO. Mandating provision of some services that will overlap with market-based systems is likely to devalue the markets and increase costs overall, leading to upward pressure on energy costs.
- Modern generation control systems can be configured to provide a range of market-based services and thus encourage efficient providers into the FCAS market and create incentives for innovation, both of which are absent in any mandated service provision.

- New optimisation methods and software can be applied to deliver real efficiency improvements in the NEM. It is important to critically review systems that were developed in the early NEM against the improved computational and optimisation tools of today and to assess the efficiency improvements possible.

Taking into account the points above, our suggested market solutions will require some changes to the current FCAS arrangements:

- Create a new Primary NOFB FCAS which provides a market for primary frequency response within the NOFB.
- Create more flexible contingency FCAS arrangements that don't require simple buckets of 6s, 60s and 5min services:
  - For each provider of contingency FCAS, model their response over time to a large frequency change as a continuous function of MW response versus time after event;
  - Model post contingency frequency explicitly in NEMDE using the swing equation;
  - Use NEMDE to choose the optimal combination of FCAS response curves to ensure that frequency remains within the standards for both the system and any potential island post credible contingencies; and
  - Incorporate proper co-optimisation of requirements into NEMDE including co-optimisation of interconnector flows.
- Determine the amounts of regulation to be enabled each dispatch interval based on transparent statistical analysis of what causes the deviations of actual loads and generation from their linear trajectories. Determine the amount of regulation based a probability distribution which ties back to the requirement that frequency should be in the NOFB 99% of the time.
- Improve "causer pays" by swapping it to a cost recovery mechanism for Primary NOFB FCAS based on actual frequencies not the AGC's ACE and turn it into an arrangement so that participants who are not enabled for either Primary NOFB FCAS or regulation FCAS who contribute positively to managing frequency receive some payments.
- Develop a new "causer pays" for regulation based on the statistical analysis of the factors that contribute to the size of the regulation amount.
- Improve AEMO's AGC, NEMDE and forecasting systems.

The market arrangements that we are suggesting will require more detailed analysis and testing and probably some refinements before they are suitable to be implemented as operational systems in the NEM. None the less they do provide a vision of how an effective FCAS market could operate in the future.

If FCAS market arrangements along the lines suggested are adopted then most of the current and future frequency control issues in the NEM will be able to be managed via efficient market arrangements that value services correctly and provide appropriate incentives for behaviour that assists with managing frequency.

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