AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

Contingency Frequency Response in the SWIS (Draft)

March 2019

Technical Proposal for the Power System Operation Working Group

A proposal for system modelling and security limits for use in the Wholesale Energy Market Ancillary Service framework design

Executive summary

Western Australian Energy Industry Reform

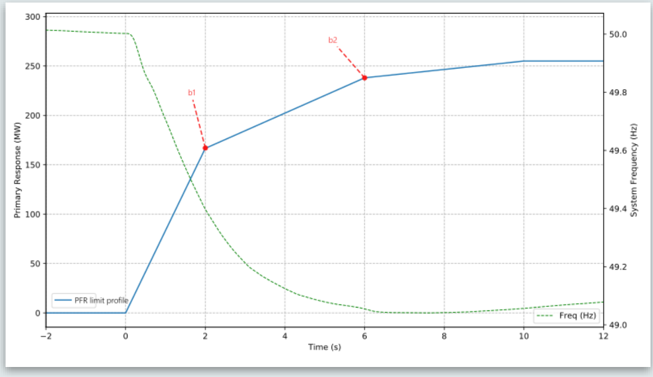
This report presents a framework and approach to system modelling that allows clear visibility of the trade-offs (i.e. co-optimisation) between inertial and traditional primary spinning reserves. The proposed approach can be used to establish practical operational security limits which can be used to define contingency ancillary reserve requirements in the reformed Wholesale Electricity Market (WEM) constrained dispatch design.

In optimising contingency reserves, the complexity of machine characteristics and forecast uncertainty must be balanced with operational requirements of simplicity and robustness. AEMO proposes that these requirements can be met through a simplified aggregate facility power system model and implementation of an inertial-primary frequency secure zone concept originally proposed in the *Independent Review into the Future of the National Electricity Market* (the Finkel Review).

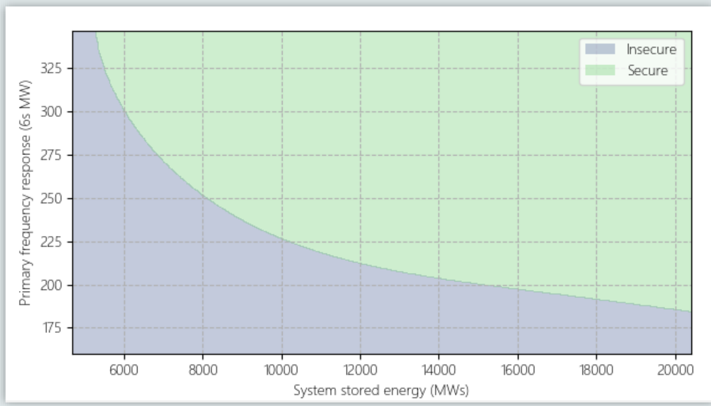
Contingency Frequency Control in the South-West Interconnected System (SWIS)

The approach and validation to date has two key outputs:

1) A primary frequency response "dual-break" (defined in terms of break points b1 and b2) profile, that defines a security limit in terms of required total system MW speed and quantity:



2) A secure operating zone calibrated to the SWIS, defined in terms of system stored energy (inertia) and primary frequency response:



Important notice

PURPOSE

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Version Control

Version	Release date	Name / Role	Status	Release Notes
0.1	10/OCT/2018	L. Kwek / Author	Prepared	Draft release of analysis to GHD and Public Utilities Office
0.2	06/MAR/2019	L. Kwek / Author C. James / Workstream Lead	Approved	Draft release to the Power System Operation Working Group (PSO-WG) for consideration

Contents

Figures

1. Introduction

1.1 Purpose

This report presents a framework and approach to system modelling that allows clear visibility of the trade-offs (i.e. co-optimisation) between inertial and traditional primary spinning reserves. The proposed approach can be used to establish practical operational security limits and to support determining ancillary reserve requirements in the reformed Wholesale Electricity Market (WEM) constrained dispatch design.

The proposal applies specifically to contingency frequency control reserves and is designed to function independently of any scheme for frequency regulation during normal operation. It has been described in this paper in terms of response to a generation contingency, however the same method can equally be adapted for over-frequency events.

In addition to laying out common terminology and describing the concept, the report includes an initial validation and limit formulation using recent SWIS data. It is intended to be circulated within the Power System Operation Working Group for discussion and consideration.

1.2 Background

1.2.1 Reform and proposal context

In August 2018, the Western Australian (WA) government announced[1] a timeline and planned legislative changes to introduce constrained access and co-optimised dispatch to the WEM. The scope of these reforms includes improvements to the Ancillary Service (AS) framework to facilitate the changes to the dispatch processes, and ensure the system remains secure and robust in response to upcoming changes to the operational and market environment.

The current rule structures and operating practices for WEM frequency control – while secure in managing present system conditions – are based on a very simple overarching framework (see Appendix A1 for detail) that relies on assumptions about:

- available inertial and load response reserves; and
- the specific characteristics of contingency response from plant in the Synergy Portfolio.

790 megawatts (MW) of additional utility-scale inverter-connected generation is expected to come online through 2018 – 2021.[2] Through the same period, AEMO also forecasts approximately 450 MW of additional distribution-connected generation to come online.[3] With an average demand around 2.5 gigawatts (GW) and a 4 GW peak, this puts the SWIS on a trajectory where average inertial reserves will be reduced by over 60%.

The reform also seeks to remove the dependence on and market imbalance due to the Synergy Portfolio, through disaggregation of the group into individual facilities.

Overall, the existing ancillary service framework is unlikely to ensure ongoing system security in the WEM, especially given upcoming changes in technology and electricity customer habits.

[1] This announcement and further information regarding the reform program are available on the Public Utilities Office website: https://www.treasury.wa.gov.au/Public-Utilities-Office/Industry-reform/Electricity-network-reform-work-program-Western-Power-network/.

[2] Projects that have either signed a network connection contract (including Generator Interim Access) with Western Power or are being developed by a Marker Participant that is a retailer in the SWIS.

[3] AEMO 2018 WEM Electricity Statement of Opportunities. Available at https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Planning-and-forecasting/WEM-Electricity-Statement-of-Opportunities.

1.2.2 National Electricity Market Ancillary Services framework

Unlike previous efforts at market reform, the current government initiative does not explicitly seek to adapt aspects of the NEM, but aims to leverage technology, skills and design concepts where appropriate. There are benefits in efficiency and proven functionality in directly adopting the NEM frequency control framework, however AEMO initiated the analysis for this proposal on the premise that a modified approach and additional complexity is justified in that:

- the reform creates an opportunity to update and refine the NEM approach in a less complex market (while the NEM is currently undergoing a significant ancillary service review[4]); and
- the smaller size of the SWIS (lower inertia and load relief relative to contingency size) necessitates a more technically sophisticated approach.

1.3 Design requirements

The new AS framework should align with the reform objectives and principles, in particular:

- Provide mechanisms for management of current and emerging power system security issues
- Work cohesively with other key elements of the reform program:
    - 5-minute dispatch
    - Disaggregation of the Synergy Portfolio
    - Co-optimisation of ancillary services under security-constrained dispatch
- Incentivise efficiency and market competition
- accommodate new or alternative technologies
- balance changes to the existing framework and impact to existing plant, with the need for flexibility and robustness to future uncertainty
- be appropriate for the SWIS.

[4] Australian Energy Market Commission (AEMC) 2018 Frequency Control Frameworks Review. Available at https://www.aemc.gov.au/markets-reviews-advice/frequency-control-frameworks-review

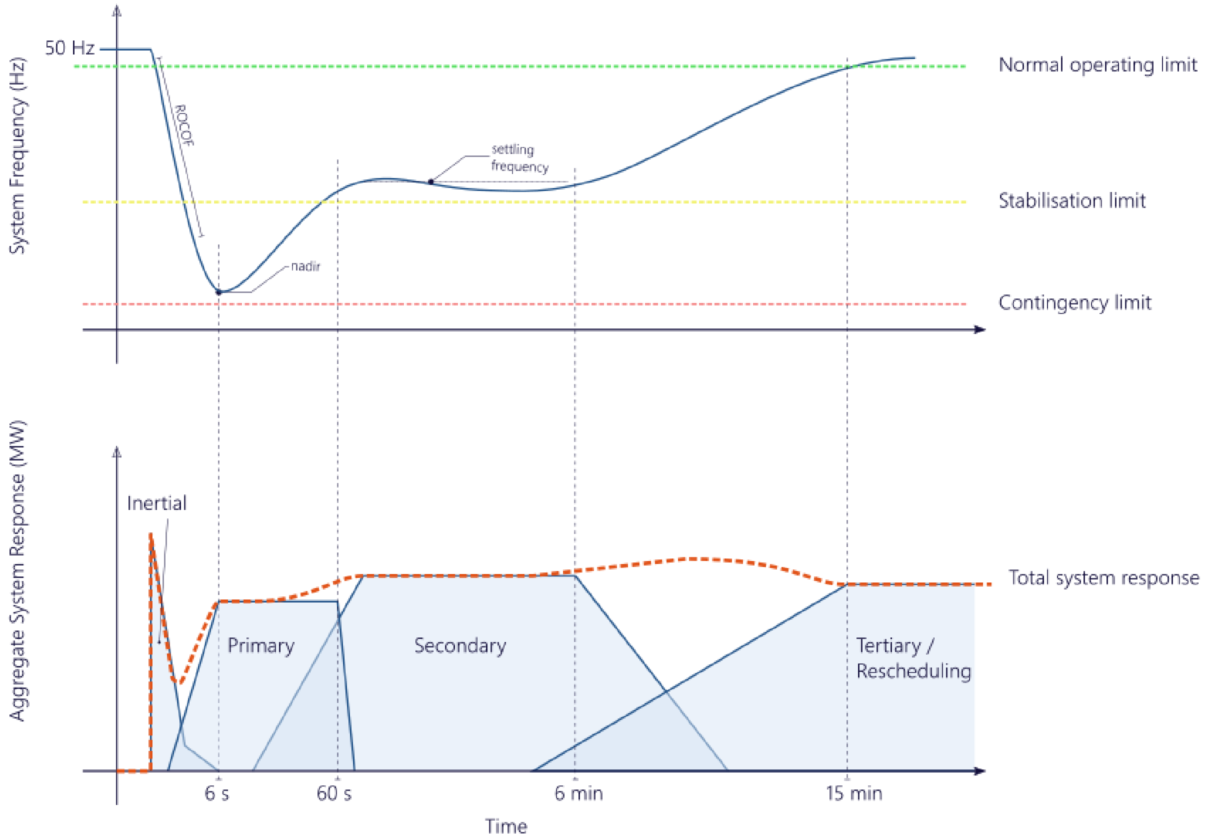
2. Proposed approach

This section introduces the generic terminology and problem formulation used to establish the proposed approach for contingency frequency control security limits. It is limited to discussion of a single-region system (one without scheduled interconnection exchanges) but does not apply specifically to the WEM.

2.1 Frequency Response

Figure 1 shows a stylised sketch of system frequency and typical ancillary reserves deployed in the response to a generation contingency.

Figure 1 Idealised system response to a generation contingency



The system frequency has three key characteristics labelled: ROCOF, nadir and settling frequency. These must be managed to limits (set by a frequency operating standard) by adjusting the real power (MW) balance of the system in response to frequency changes.

The combined response of all facilities contributing frequency control services is shown in the lower plot as the *total system response*. In designing and allocating reserves across a generation fleet, this aggregate quantity can be broken up according to different performance requirements for deployment and sustainability of power output into inertial, primary, secondary and tertiary response. These distinctions are not fundamental but reflect control structures formed around physical properties and useful trade-offs that need to be optimised in the allocation of power system resources.

This section describes each of these characteristics and structures in the context of a generation contingency, however the same framework applies equally to over-frequency events.

2.1.1 Frequency characteristic security limits

General power system practice allows for sufficient frequency control reserves to cater for any single credible contingency without load shedding. This sets a hard minimum or nadir frequency limit at (or just above) the first threshold for involuntary under-frequency load-shedding.

Under-frequency load shedding thresholds also set a hard upper bound to the rate of change of frequency (ROCOF) immediately following a contingency: at too high a rate, system frequency may blow through frequency bands too quickly for shedding schemes to operate. With typical system settings and conditions, this occurs around 3 Hz/s; in high-inertia systems (with low PV and other inverter-based generation penetration) even extreme generation contingencies may have ROCOF < 1 Hz/s.

Sustained ROCOF at lower levels can also cause instability in synchronous machines. Under these conditions, generators will normally disconnect rapidly to prevent damage and unstable operation, cascading further frequency control issues. The withstand capability of a machine can vary significantly with the type (e.g. steam or gas turbine), design and age, however this limit is not well established or operational in most power systems; Recent analysis[5] suggests around 1 Hz/s sustained for a full second may impact older turbines but does not cite any recorded instances.

The settling frequency defines a quasi-steady state where the system can stabilise for a short duration (~minutes) outside the normal operating band. It is set to account for short-term phenomena that would otherwise push system frequency further (e.g. wind generation or load movements) and allows time for other (typically slower) control mechanisms to initiate restoration of frequency to the normal secure operating conditions.

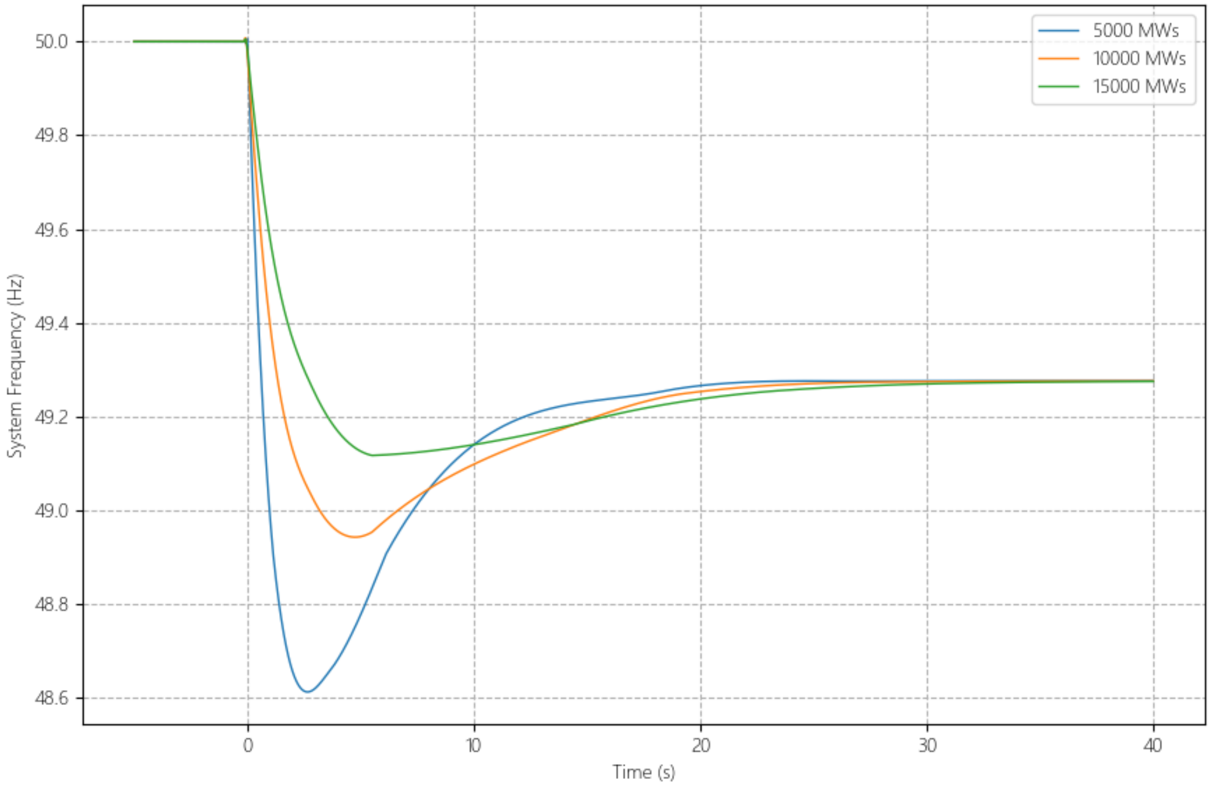
2.1.2 Inertial response

System inertia determines how quickly the system frequency changes immediately in response to load or generation movements. At the system operations level, a convenient measure of inertia is the total stored energy, expressed in MWs. Traditionally, the inertial response of power systems comes mainly from the rotating machinery (turbines, compressors) in synchronous facilities. In that instance, the inertial MWs represents the combined stored rotational kinetic energy of the masses spinning at 50 Hz.

Figure 2 shows the frequency response of a system at decreasing levels of inertia following the loss of a large generator at t=0 seconds (all with the same levels of slower ancillary services).

[5] DGA Consulting, 2016 *International Review of Frequency Control Adaption*. Available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/FPSSP-Reports-and-Analysis

Figure 2 Frequency characteristics at decreasing levels of system inertia.



All things being otherwise equal, a lower inertia directly results in a greater ROCOF in the immediate seconds following the generation contingency. Due to the greater rate of decline, the system also reaches a lower absolute minimum or nadir frequency but will ultimately reach the same settling frequency irrespective of inertia.

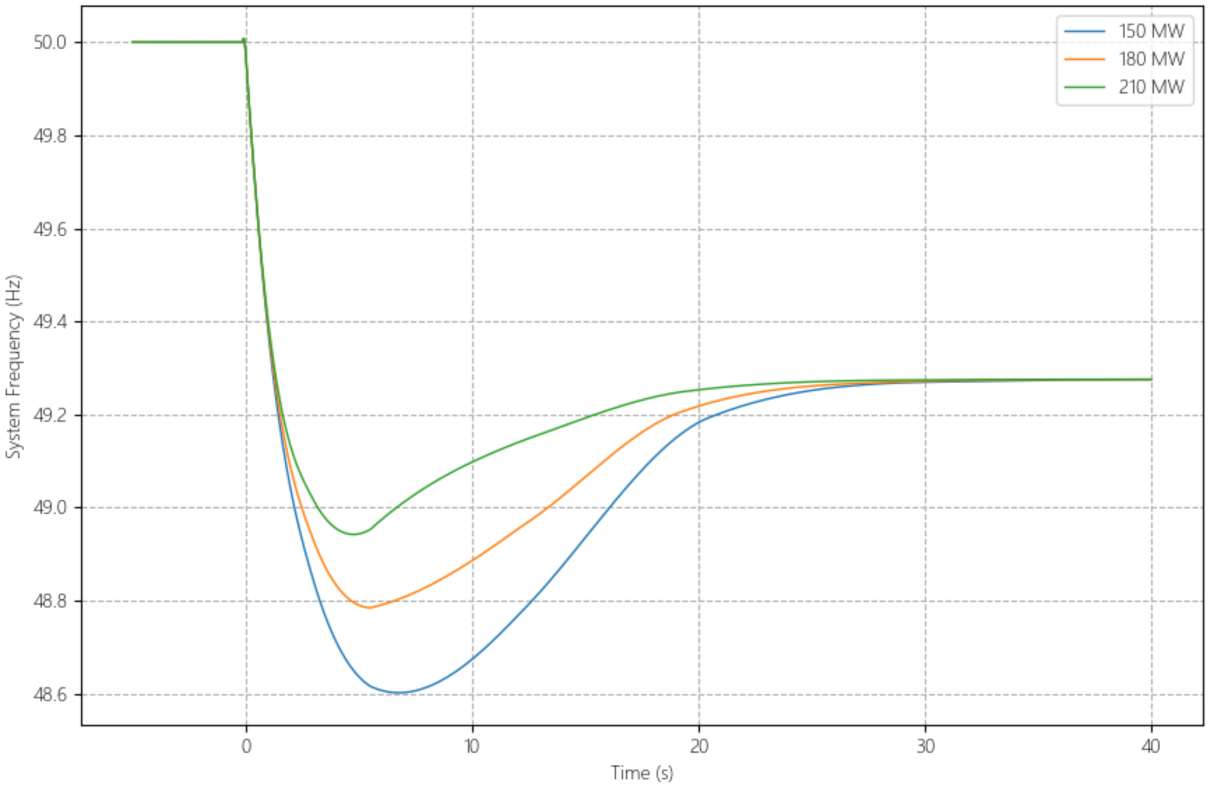
2.1.3 Primary Frequency Response

Facility primary control refers to changes in output made in response to local detection of conditions, i.e. independent of any system-wide generation control scheme. Examples include:

- the primary control loop (droop) of a synchronous turbine, which can feed local speed variations immediately back into a turbine governor and trigger (pre-set) proportional changes in valves, gates etc.
- a rapid increase in power output of an inverter-connected facility, driven e.g. by a battery bank or "spilling" intermittent generator (running below maximum possible instantaneous output);
- block load shedding at pre-set frequency thresholds above the nadir limit

Figure 3 shows the frequency response of a system at decreasing levels of primary frequency response (PFR) following the loss of a large generator, with all other contingency reserves held constant.

Figure 3 Frequency characteristics at decreasing levels of PFR



PFR is available relatively quickly: it acts to arrest the rapid decline of frequency and establish a temporary stable operating state. Due to the delay in translating a primary control signal into output MW, the critical (maximum) ROCOF is independent of PFR, however the nadir frequency is strongly impacted. Eventually, slower and more sustainable reserves take over, giving the same setting frequency.

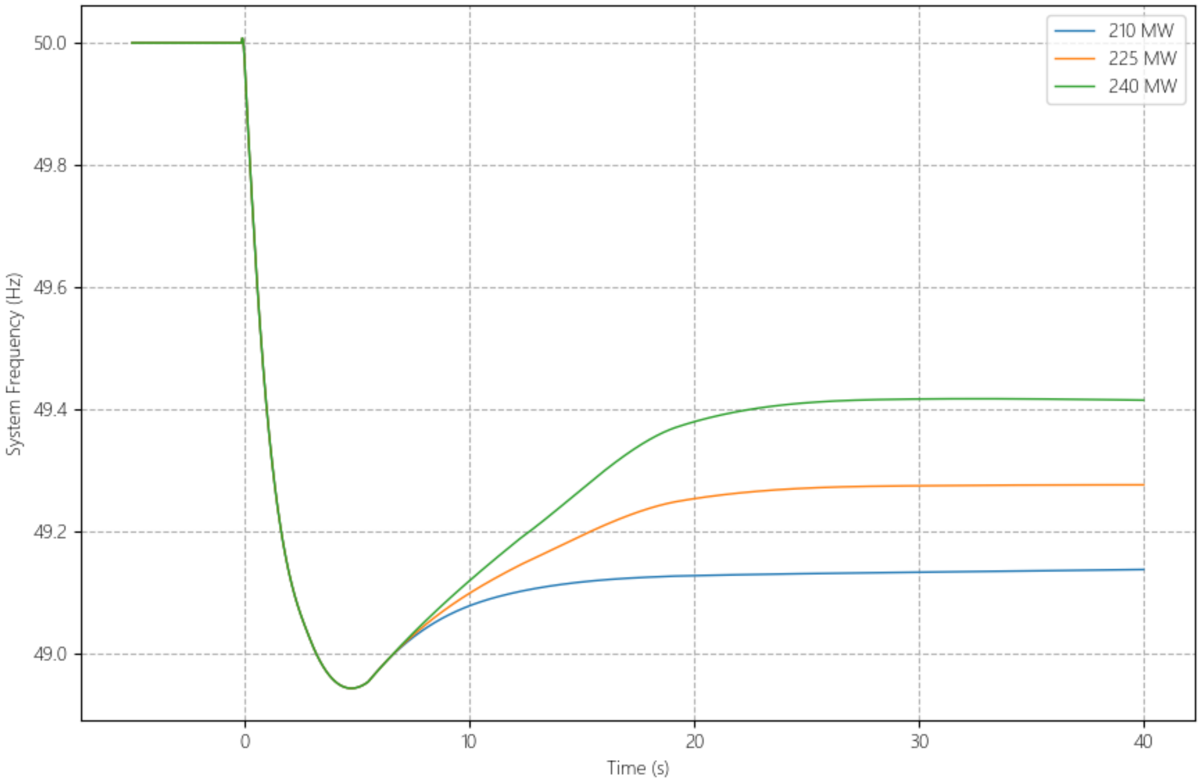
2.1.4 Secondary Frequency Response

Secondary frequency response (SFR) is characterised by system-wide control, typically through coordinated changes to the setpoints of multiple facilities (e.g. via an Automatic Generation Control system). Its reaction time is limited to the refresh rate of the control system (on the order of 4 – 20s) and draws on rate-limited but more stable and sustainable machine processes.

It acts in part to replenish PFR and restore the security of the system for further events, but the leading objective of SFR is to correct the remaining frequency error after the primary response. Depending on the severity of the contingency, available reserves and design of the system, the SFR may return system back to the normal operating range or to a temporary intermediary level.

Figure 3 shows the frequency response of a system at decreasing levels of SFR following the loss of a large generator.

Figure 4 Frequency characteristics at decreasing levels of SFR



The speed of the secondary response has been exaggerated in the diagram, however the concept is the same: secondary reserves arrive after the initial ROCOF and frequency nadir, but strongly influence the settling frequency.

2.1.5 Tertiary Frequency Response and Re-scheduled generation

Tertiary reserves generally fulfil the same role SFR but are deployed manually after a delay to re-establish scheduled market generation and replenish ancillary services. For example, a system operator may call on tertiary reserves in response to a sudden change in system load or intermittent generation following the contingency. A detailed discussion of TFR characteristics is not required to set security limits under the proposed ancillary service framework.

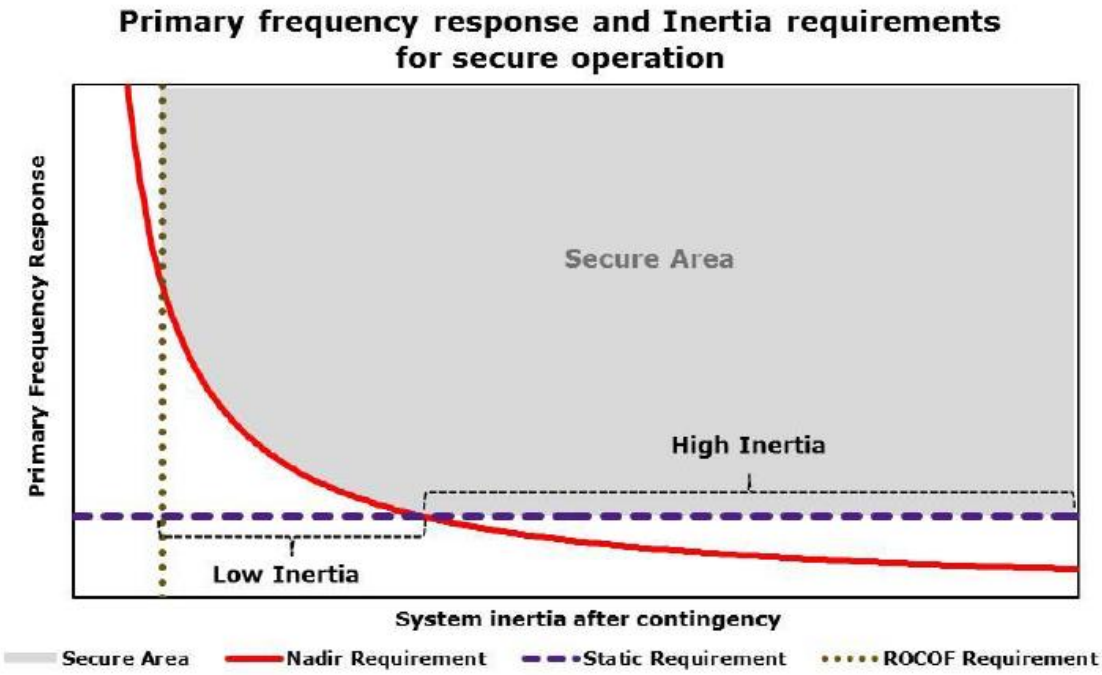
2.2 Inertia-PFR Secure Zone

System inertia and PFR are coupled in such a way that the nadir frequency is strongly dependent on both inputs. The relationship is non-linear, and there is no optimal way to specify limits that meet the design requirements (section 1.3) while also accounting for the other critical frequency characteristics.

Recent analysis[6] has shown with a simplified system model, the relationship between fast reserves and the critical frequency characteristics can be mapped and cleanly visualised in the diagram reproduced in Figure 5.

[6] Melbourne Energy Institute, 2017 *Power System Security Assessment of the future National Electricity Market*. Available at https://www.energy.gov.au/publications/power-system-security-assessment-future-national-electricity-market

Figure 5 Inertia-PFR secure operation zone concept and diagram originally presented to support the *Finkel Review*



The key post-contingency frequency characteristics map to the Inertia-PFR axes as a:

1) vertical line for the maximum tolerated ROCOF, indicating a minimum critical system inertia, independent of PFR;
2) hyperbolic curve for the nadir requirement, quantifying the trade-off between the two reserves;
3) horizontal line for the settling frequency (called "Static Requirement" in the diagram), independent of system inertia as expected.

The three lines define a secure area in the inertia-PFR space, wherein a system will ride through a generation (or load) contingency and meet all three frequency performance requirements.

It is proposed that this formulation of the security limits can be implemented for the WEM, meeting the design requirements in Section 1.3.

2.3 Aggregate Single Frequency Model

Two key inputs underpin the analysis that gives rise to the limit formulation in Figure 5:

1) The system is represented by an *aggregated single frequency model* (see Appendix A1), in which the system-wide frequency dynamics are reduced to a single equivalent load-generator bus; and
2) PFR is input as a simple linear ramp to the level along the axis (MW at 6 seconds).

Changing these does not invalidate the approach but may alter the shape of the secure zone.

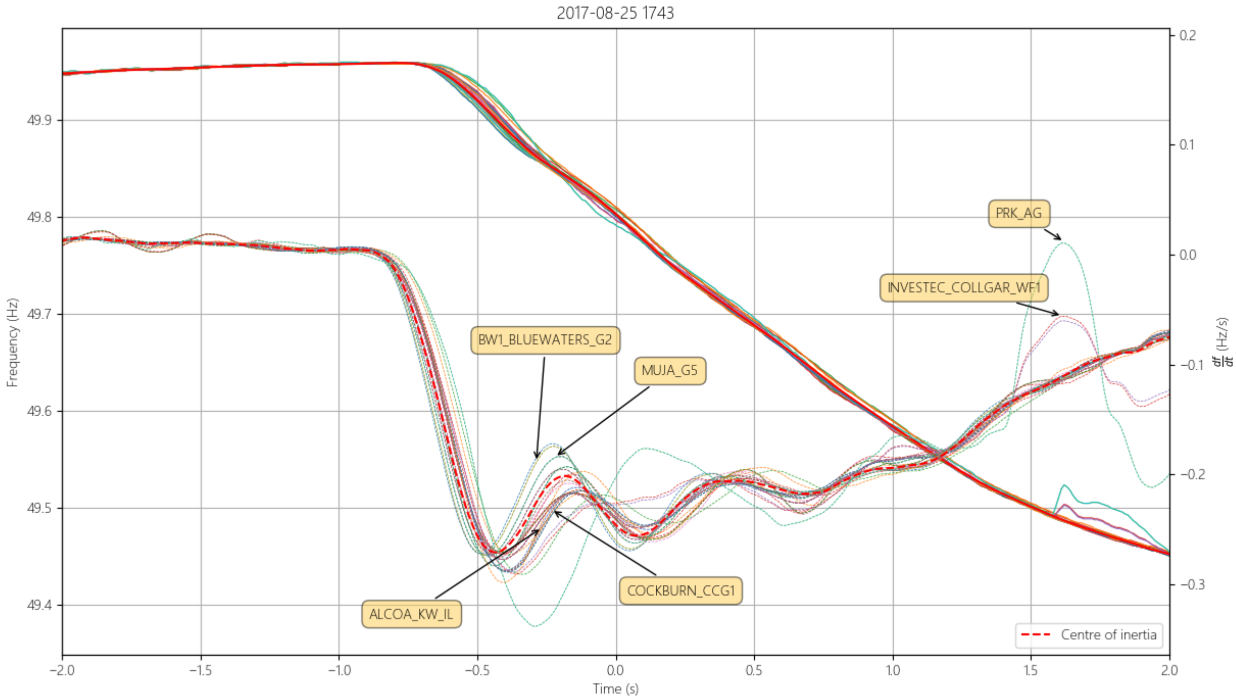
For the WEM, the first of these is reasonable, however a more complex representation of PFR may be required due to the (small) system size and limited availability of facility capability. These assumptions are validated in Section 3.

3. SWIS Validation

3.1 Single Frequency Assumption

For an aggregated system model to give valid results, load and generation centres must be sufficiently coupled such that the frequency at all locations effectively moves in unison. The SWIS is relatively well-meshed but has several significant load centres separated by hundreds of kilometres. Due to a wide fleet of high-speed recording devices maintained by Western Power at all generation locations, this coupling can be measured directly, as shown during the first two seconds of a generation contingency in Figure 6.

Figure 6 System-wide (approximately 30 locations shown) high-speed frequency and df/dt traces from a single generation contingency, overlaid with the centre of inertia (red).



On the x-axis, t=0 s corresponds to the 49.8 Hz threshold trigger; the contingency occurs at approximately -0.6 s. Each trace is labelled with the facility connected at that location, allowing for geographic identification of any local oscillations.

The plot also shows the rate of change (df/dt) of each trace (using the right-hand y-axis), where variations are amplified and more apparent. The data initially show some variation (approximately +/- 25 mHz/s), and two distinct groupings begin to form, corresponding roughly to the major generation clusters around Muja and Kwinana. All traces converge at -0.2 s, before the system has left the Normal Operating range, supporting the assumption that system-wide generation coherence is generally reasonable. This pattern is consistent across 15 events inspected from the last two years.

Figure 6 also shows the inertia-weight average of all sites, as would correspond to the output of an aggregate single-frequency model of the system. Some oscillation about the centre can be observed in remote areas with relatively small connected capacity. PRK_AG for example, is a remote facility with a radial connection over 600 km from the major generation clusters and had a single 40 MVA unit synchronized at the time of the event. A subsequent loss of 20 MW nearby load (at approximately 14 s) resulted in a localized over-frequency swing but did not propagate to the remainder of the system.

3.2 Case studies

3.2.1 25 August 2017: 270 MW contingency

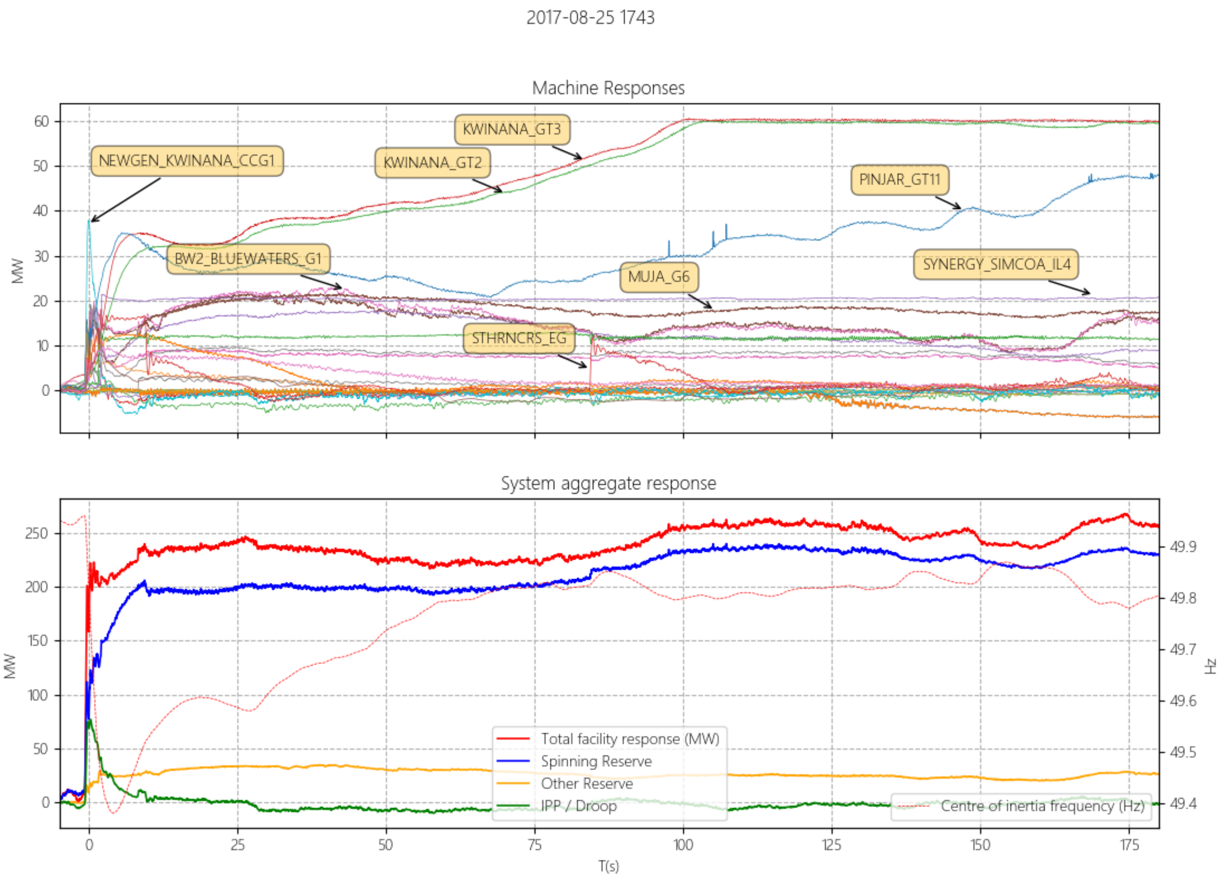
Measured responses

On 25 August 2017, the system lost a major generator during the ramp up to the evening peak. Although the facility was at maximum output, the contingency was reduced to 270 MW as the unit held at approximately 70 MW for 8 minutes after the initial event. The event is used as a case study owing to the high quality of data recorded.

Figure 7 shows two plots of the high-speed data from the first three minutes following the event:

- individual responses (change in MW post-contingency) from all facilities (top)
- combined aggregate system response and centre of inertia frequency

Figure 7 Machine and aggregate system response following a 270 MW contingency (25 August 2017).



In the lower plot, the total facility response is also shown broken down as follows:

- Spinning Reserve: Synergy and any facilities contracted to provide spinning reserve
- Other Reserve: PFR from facilities without obligation:
  - BW2_BLUEWATERS_G1: 13 MW synchronous PFR (since contracted as of July 2018)
  - PRK_AG: 11 MW facility load lost (undirected)
- IPP / Droop: all other facility contributions

Mapped to the "frequency response" framework, the required primary response (at the nadir) was approximately 210 MW. Droop and "Other" sources provided approximately 50 MW of this[7], however a further 100 MW of unused Spinning Reserves was available from registered sources. This is expected, given that the contingency was <80% of the maximum credible value. Under the configuration of the SWIS AGC system, the portion of this remaining reserve available on Synergy plant was effectively deployed as secondary response.

Before the end of the 3 minutes, frequency had returned to the normal operating band, but all reserves were exhausted. An additional Synergy fast-start unit (tertiary response) was required to restore the system to a secure state (also in anticipation of loss of remaining 70 MW of the faulted unit).

Aggregate model fit

Linear ramp

Using the measured output from the faulted generator as input, an attempt was made to fit the single frequency model. Each of the input parameters:

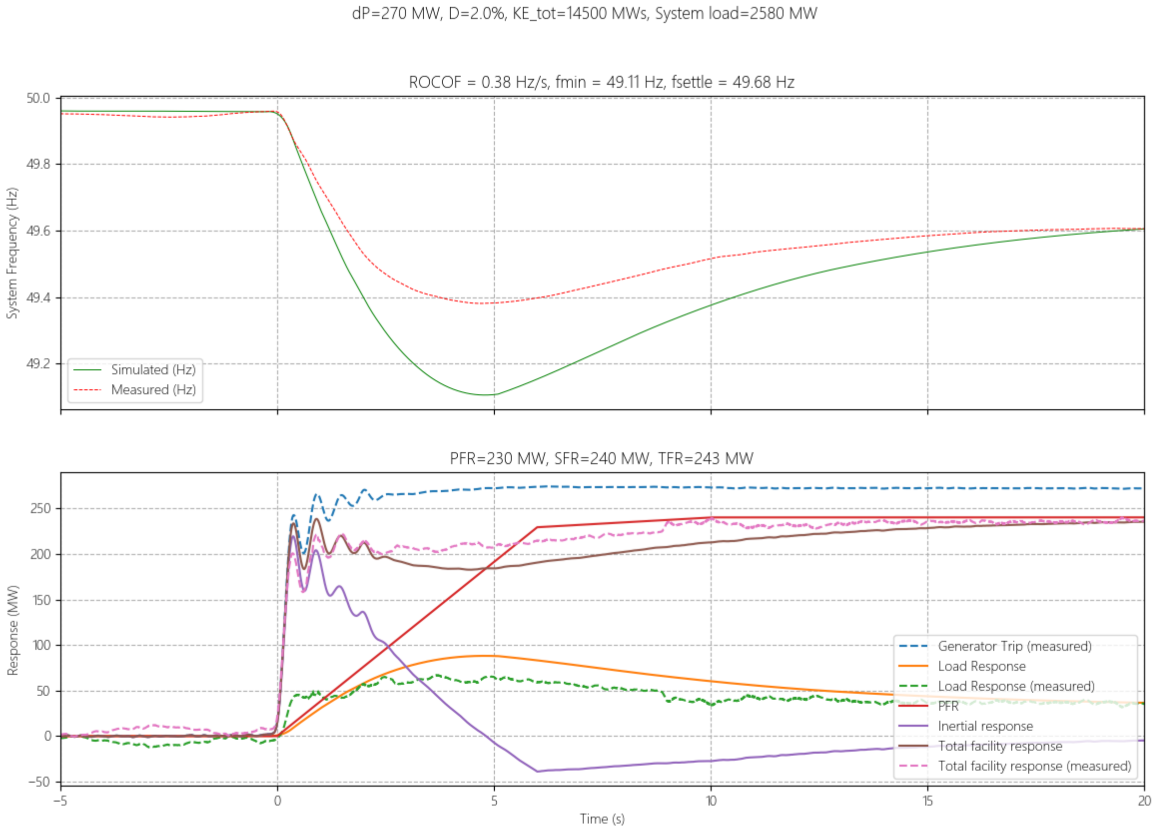
- load relief factor D;
- system inertia; and
- PFR profile

were simultaneously varied to achieve as close match as possible between the simulated and measured frequency timeseries across the entire 3-minute sequence.

Figure 8 shows a comparison of simulation results from the 25 August 2017 event, using a single linear ramp PFR profile (as was used in the original formulation of Figure 5). The lower panel shows the best-fit profile along with various other signals of interest.

[7] Note the rapid decrease of this source after the frequency nadir; mandatory response must only sustain for (a minimum of) 10 seconds under the Technical Rules.

Figure 8 Fit of the aggregate single frequency model to the 25 August 2017 event, using a linear PFR profile



In these plots, dashed lines are measured values, while solid lines show simulation output. The "Total facility response" again corresponds to the aggregate measurements of all connected facilities (red curve in Figure 7).

The remaining power difference between the lost generator and the total facility response is attributed to "Load Response": this includes true load relief, but also any frequency-independent change in system load and response from any unaccounted generation facilities (smaller generators without fault recordings, or unknown "behind the fence" machines). The inertial component is also shown but for the simulation only: this cannot be easily separated in measurements available at the system level.

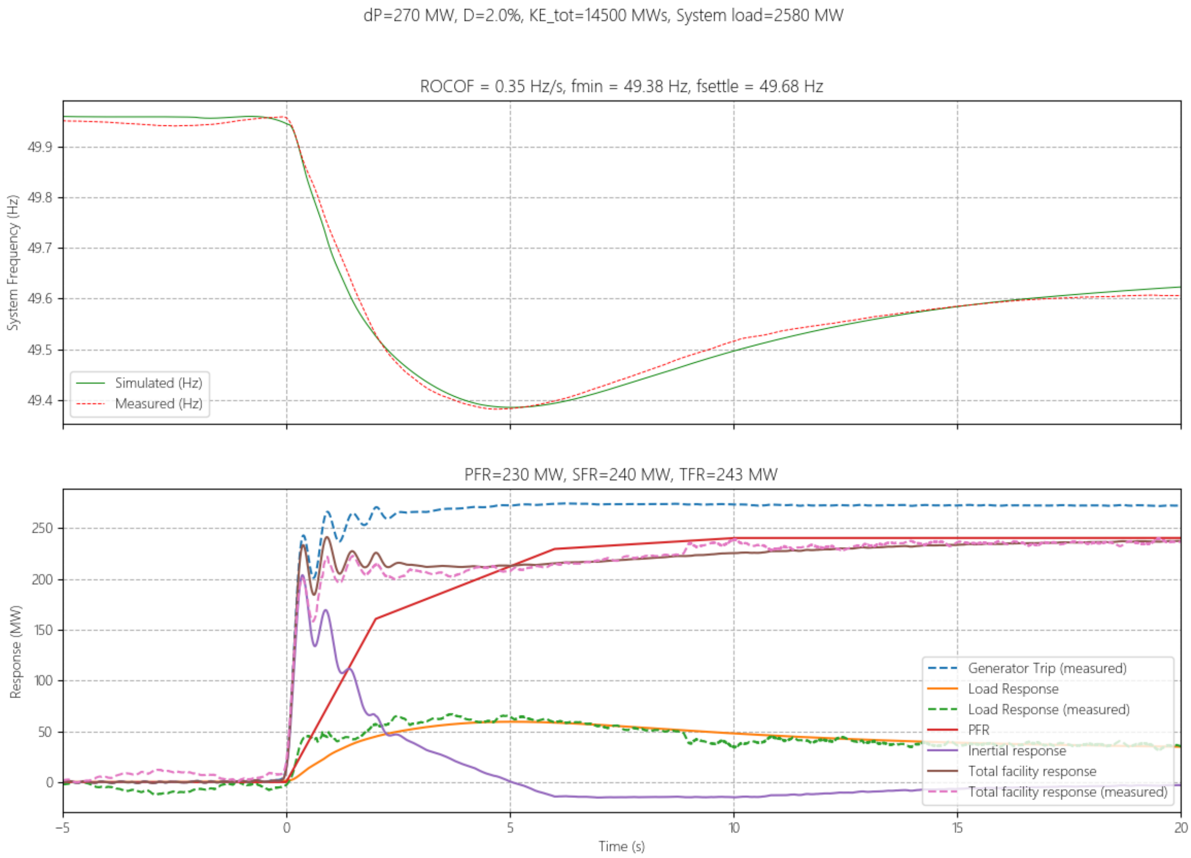
To further constrain the possible combinations of D and the PFR for fitting, the target value and timing of each was varied to give a reasonable match between the measured and simulated Total facility response (in addition to the overall frequency characteristics).

Within these constraints, it was not possible to fit the observed response. At the point shown in Figure 8, the nadir frequency is under-estimated while the portion of response attributed to load relief is already excessive, and the system inertia is fixed it match the initial ROCOF. The remaining free variable is an increase in the speed of the primary response.

Dual-break PFR profile

Through experimentation, a robust fit was found using a "dual-break" PFR profile, characterised by an initial fast ramp from 0 – 2 seconds, followed by a slower ramp to 6 seconds. The best-fit profile is shown in Figure 9.

Figure 9 Fit of the aggregate single frequency model to the 25 August 2017 event, using the "dual break" PFR profile

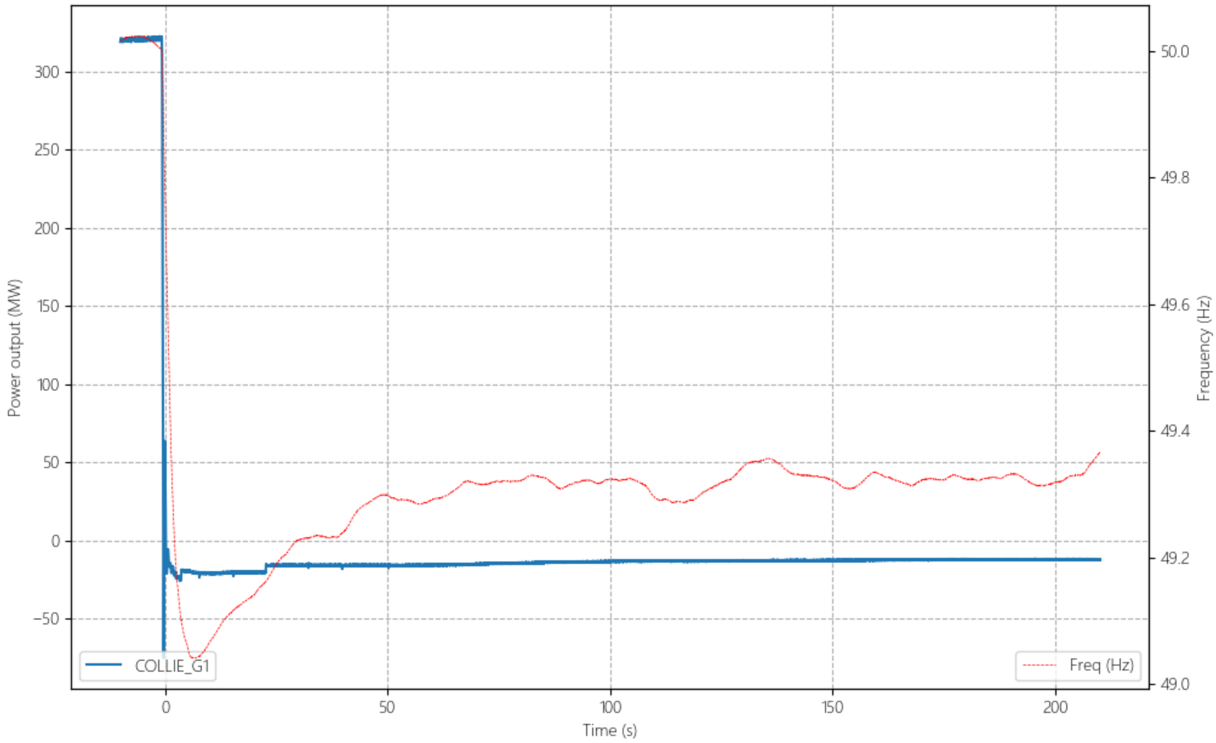


The simulated output from the proportional load relief model is also plotted. It shows relatively good agreement with D = 2 at the nadir, however the measured signal responds much faster in the 2 seconds immediately after the contingency. A likely explanation is the inertial response of unregistered smaller machines, but it may also reflect an inertial component in the system load. This has not been investigated in detail as further validation and refinement of the load model is suggested as key follow on work to this analysis.

3.2.2 12 October 2016: 340 MW contingency

On 12 October 2016, the system lost COLLIE_G1 at full facility output. The unit cleared at the generator circuit breaker, resulting in an instance of the maximum 340 MW contingency. Due to the limited availability of the high-speed recorder fleet at the time, a full aggregate response measurement is not available for the event. Figure 10 shows the single facility output and local frequency trace.

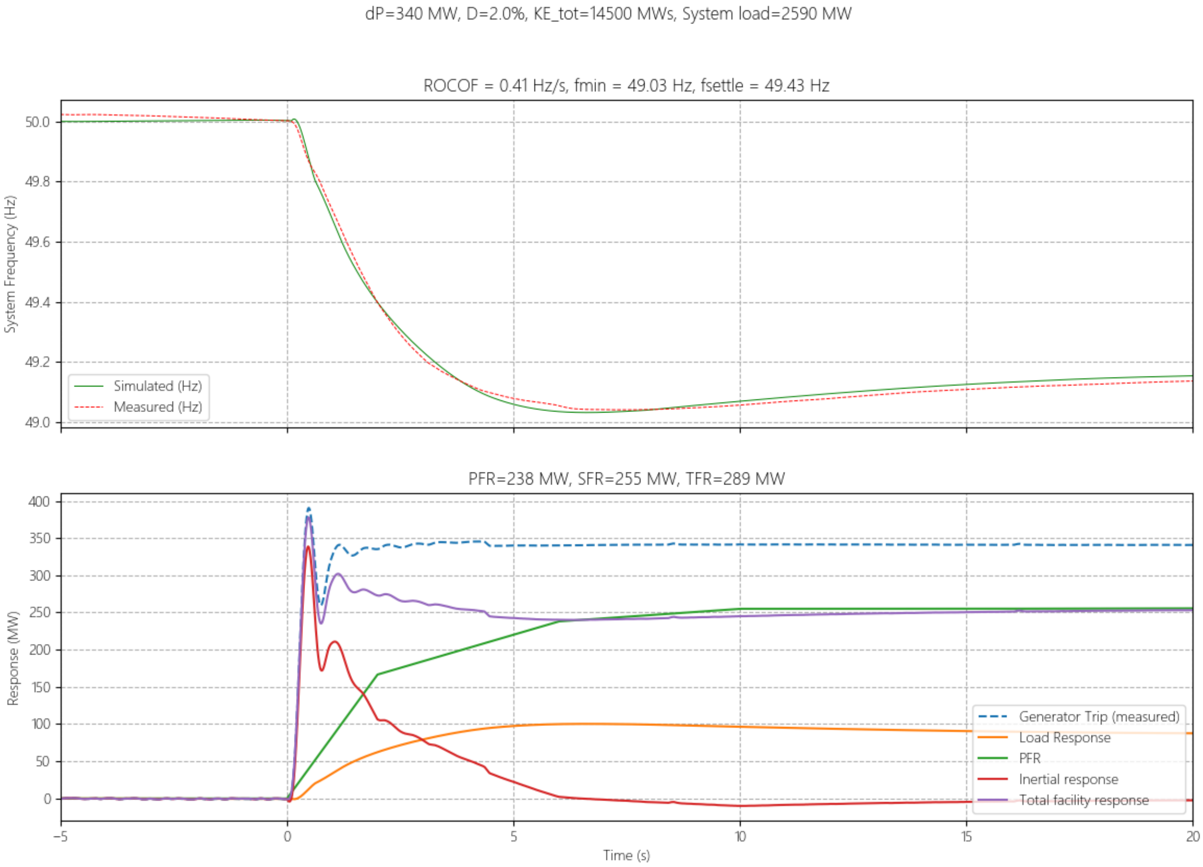
Figure 10 Lost unit output and frequency trace from the 12 October 2016 event



The existing (and current) primary reserve policy was sufficient to keep the nadir above 49.0 Hz, with frequency settling at 49.3 Hz and secondary reserves exhausted (a fast-start tertiary unit was again required to re-secure).

Absent high-speed response data from all facilities, the single frequency model was fit by adapting the approach developed from the 25 August 2017 data: a dual-break PFR profile in the same proportion but scaled to the available spinning reserve capacity at the time. The simulation output is shown in Figure 11.

Figure 11 Fit of the aggregate single frequency model to the 12 October 2016 event, using the "dual break" PFR profile



In this case, the single-frequency model with dual-break PFR profile also gives a reasonable approximation of SWIS dynamics. Switching to the linear PFR profile again reduces the nadir by approximately 0.3 Hz, within 0.1 Hz of the first under-frequency load-shedding threshold.

4. SWIS limit formulation

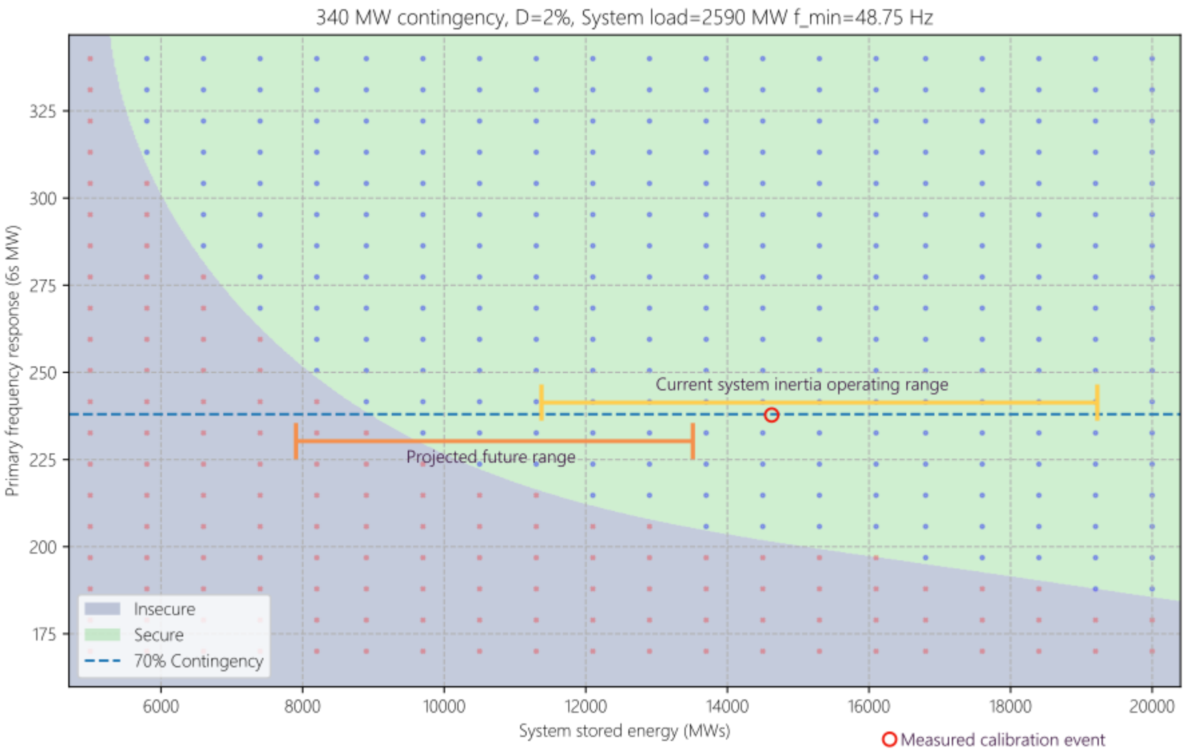
With the aggregate single-frequency model formulated as in Section 3.2.2, the dual-break PFR profile defines the security limit which aggregate facility response must exceed to ensure a minimum nadir frequency.

By scaling the profile and adjusting inertia, an inertia-PFR secure operating zone can be mapped for the SWIS, as shown in Figure 12 (section 4.1 describes and illustrates this scaling process in more detail).

The diagram also shows the current 70% PFR operating practice (including the implicit 2 second response available from the Synergy Portfolio), along with two highlighted ranges (post-contingency) along the inertia-axis, the:

- current operating range, estimated from known machine parameters (see Appendix A3); and
- projected future range (5 – 10 years), based on the current connection pipeline and likely displacement of existing synchronous machines.

Figure 12 Inertia-PFR secure operation zone for a 340 MW contingency using the model tuned to the 12 October 2016 event



In the figure, the blue and red points indicate simulations with nadir frequency above and below the first load shedding threshold (48.75 Hz) respectively. A boundary has been fitted to show the secure zone in green. The red circle shows the simulation conditions used to fit to the measured event and calibrate the model (i.e. the results shown in Figure 11).

Following the PFR = 70% / 238 MW line, the model:

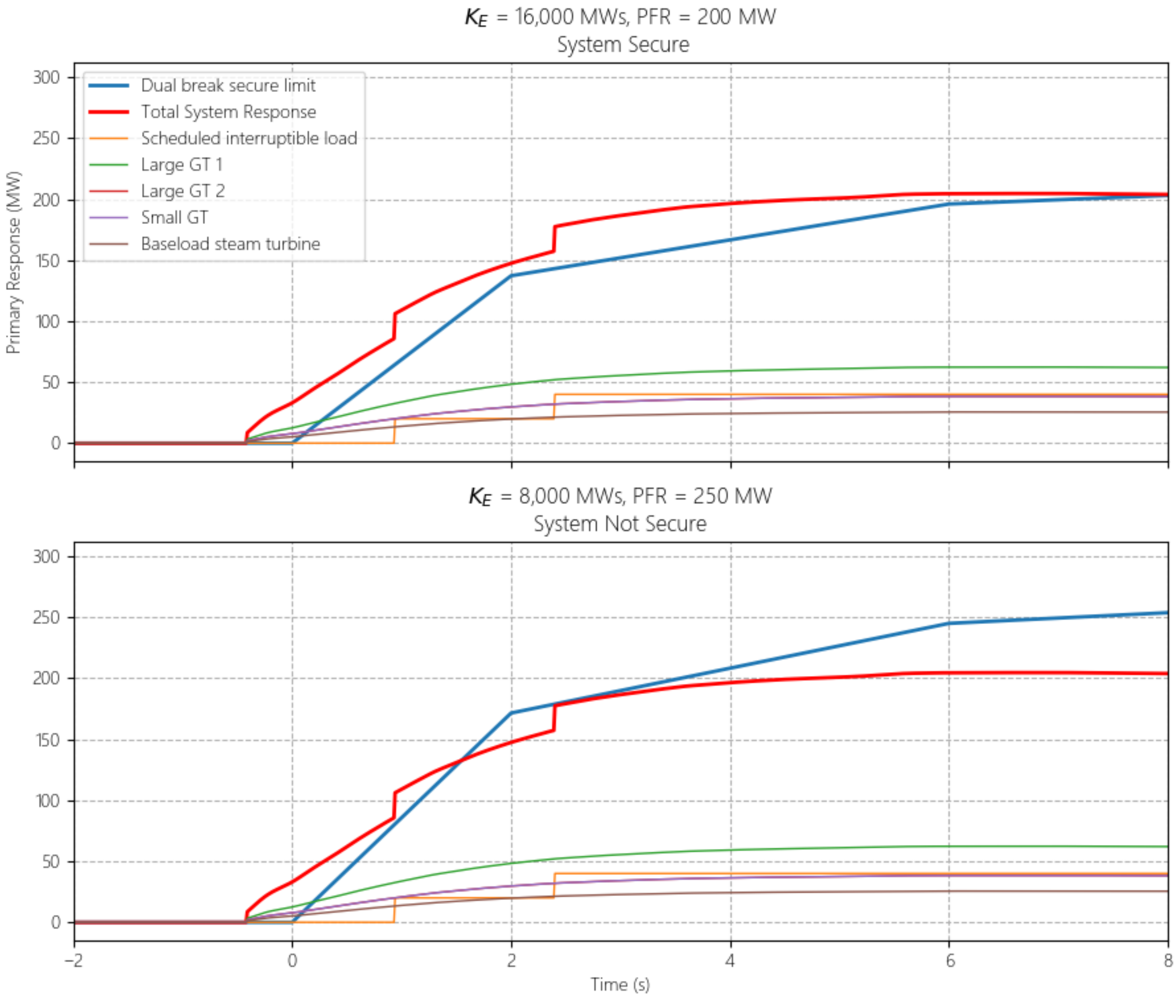
- confirms that the system is secure under existing practice (as expected) for the range inertial reserves currently available in the SWIS; and
- quantifies at what point this assumption would no longer hold.

Maximum ROCOF does not exceed 1 Hz/s until approximately 5,000 MWs, and hence does not appear in the diagram. No settling frequency limit has been drawn but is also readily available from the model. For example, simulations show that stabilisation at 49.5 Hz requires a SFR of at least 290 MW.

4.1 Example Application 1: Market Engine Dispatch

Figure 13 shows an illustration of the intended application of the security limit concept in a market dispatch engine.

Figure 13 Illustration of a PFR limit dispatch implementation



In both panels, the secure limit (as defined by the dual-break PFR curve) is shown in blue alongside several hypothetical generation responses. The aggregate sum of the various response types is shown in red as the "Total System Response".

The first panel shows the case corresponding to the edge of the secure zone in Figure 12 where (System stored energy, PFR) = (16,000 MWs, 200 MW). The aggregate response of all machines exceeds the secure limit, and thus the system frequency nadir would remain above the contingency limit for a 340 MW generation loss.

The second panel shows the same primary reserve configuration against the limit for the system with only 8,000 MWs of inertia. In this instance, the dispatch optimisation process would need to either:

- add additional primary response;
- increase system inertia;

- reduce the maximum contingency size;

(or a combination of all three) to resecure the system. The trade-off between these options is non-trivial and as much a function of market design and dispatch engine capability as the physical detail of the power system; it has not been investigated as part of this proposal and is suggested as critical future work.

Similarly, application of the inertial-PFR concept would require a structured means of testing and certifying machine response profiles for use in the co-optimisation process. The responses shown in Figure 13 are typical of current technology (proportional generation control and "switched" load shedding), however future facilities may have greater flexibility and/or limitations in their response profile. At least two solution approaches exist:

- definition of separate 2 second and 6 second primary ancillary service categories;
- a "scaled" dual-break response profile for each individual facility.

Again, the two options have benefits to trade-off, and would need further consideration for practical dispatch implementation.

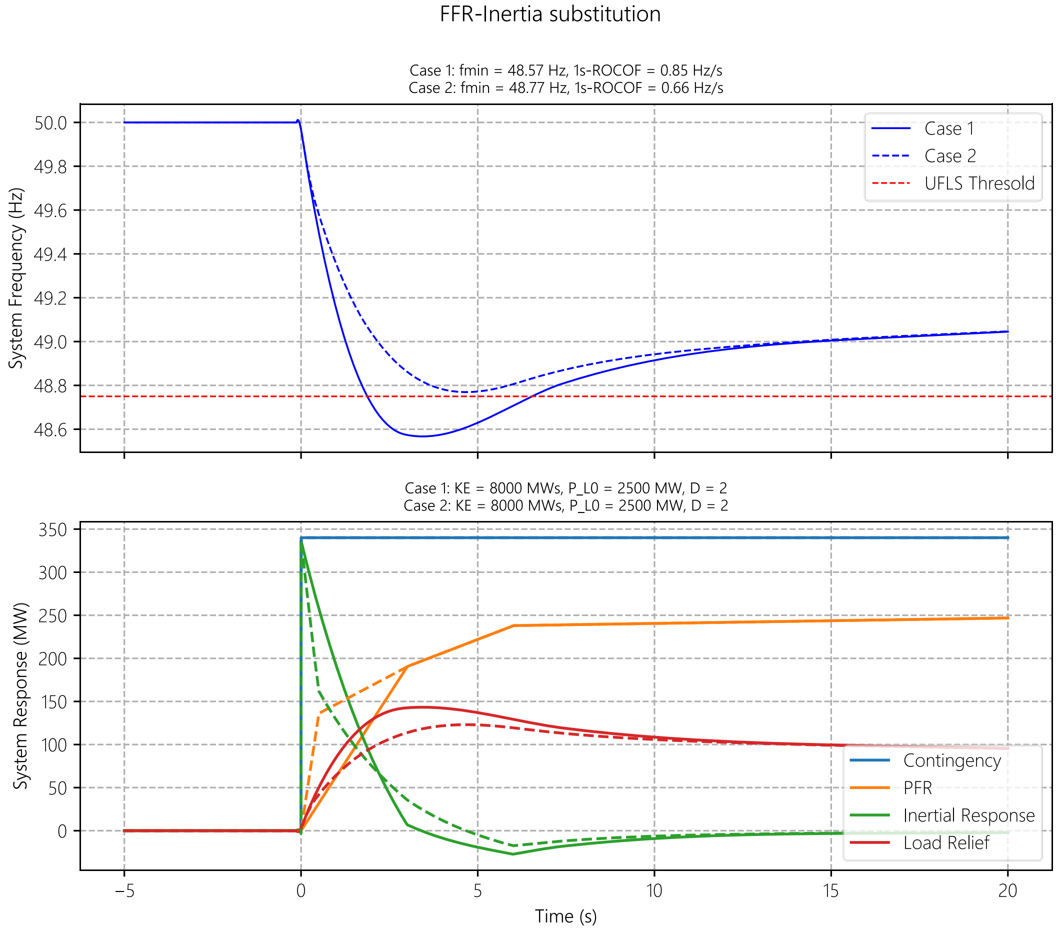
4.2 Example Application 2: Substitute or Synthetic Inertia

The terms "fast frequency response" (FFR) and "synthetic inertia" both refer to the concept of technology with a contingency response fast-enough to limit system ROCOF, and thereby serve as a substitute for system inertia. While the 2 second breakpoint was chosen to match the observed capability of facilities currently active in the WEM, the aggregate model provides a straight-forward means to investigate and quantify the impact of introducing faster contingency responses to the overall mix.

Figure 14 shows an example case investigating the impact of a theoretical 100 MW, 500 ms response, as is readily achievable with current operational and demonstrated battery technology[8].

[8] Refer for example: Aurecon 2018, *Hornsdale Power Reserve: Year 1 Technical and Market Impact Case Study*. The 500 ms threshold allows an operating margin in detection of the system event, in addition to the 150 ms response of the facility. Available online https://www.aurecongroup.com/markets/energy/hornsdale-power-reserve-impact-study

Figure 14 Investigation of a 500 ms FFR service to substitue for system inertia.



At 8000 MWs of inertial reserve, the current practice of maintaining Spinning Reserves to 70% of a 340 MW contingency will no longer prevent under-frequency load shedding. A 100 MW fast battery response would prevent this, equivalent to approximately 1000 MWs of substitute inertia (a battery would likely also sustain full output, contributing to PFR).

5. Conclusions

The aggregate single frequency model and inertia-PFR secure zone concept was presented and validated using contingency event data from the SWIS. The results of the analysis suggest that the framework may be a viable approach to managing contingency frequency control reserves for the reformed WEM.

5.1 Future work

This analysis has demonstrated the framework to a conceptual level only. In addition to extension of the approach to over-frequency events, an operational implementation would require further investigations of the following:

- Validation of the aggregate model over larger range of contingencies
  - The impact of unregistered generators and load response is not well understood over a broader range of conditions; how can load relief (or the security margin) be adapted for lower system load?
- "Fast frequency" and inertial reserve trade-off
  - The frequency response profile concept creates a straightforward means of defining and quantifying security limits for possible fast frequency or synthetic inertia technology; can these technologies be integrated into the "secure zone" concept without excessive complexity?
- Dynamic contingency response
  - The contingency response should scale with the credible contingency size; it may make economic sense to constrain the largest contingency rather than maintain reserves. How should this be implemented for both market and real-time security operations?
- Operational safety margin
  - The secure operating zone boundary has been presented (Figure 12) at the extreme limit of simulation. How should the appropriate level of operational safety be determined?
- Practicality of dispatch engine implementation
  - How should machines be certified / co-optimised against a PFR profile? How should non-market facilities be incorporated in dispatch?
- Non-credible contingencies
  - The model should be extended to investigate for non-credible events, such as dual generation unit losses, to ensure sufficient capability is enabled to allow for last resort mechanisms to operate (e.g. UFLS). This will likely require implementation of Under-Frequency Load-shedding and other emergency responses.
- DER
  - Market and power system developments are likely to include significant distributed generation sources and other forms of load control; how can the model be adapted to anticipate inverter-connected devices and other distributed forms of frequency control?

A1. Current WEM reserve framework

Contingency reserves for the SWIS are defined in the WEM Rules as "Load Rejection" and "Spinning Reserve" ancillary services for over- and under-frequency control respectively.

Under the WEM Rules:

3.11.7A. Synergy must make its capacity to provide Ancillary Services from its Facilities available to System Management to a standard sufficient to enable System Management to meet its obligations in accordance with these Market Rules.

3.11.8. System Management may enter into an Ancillary Service Contract with a Rule Participant other than Synergy for Spinning Reserve Ancillary Services, where:

(a) it does not consider that it can meet the Ancillary Service Requirements with Synergy's Registered Facilities; or

(b) the Ancillary Service Contract provides a less expensive alternative to Ancillary Services provided by Synergy's Registered Facilities.

Synergy is the entity that has inherited the previous state-managed generation fleet and owns a portfolio of 2.8 GW capacity (approximately 50% of the 5.5 GW system total).

The WEM Rules grant AEMO broad freedom to specify varied Ancillary Service requirements with location, season or system conditions (subject to approval by the Economic Regulation Authority); however, in practice this freedom is not currently utilised.

A1.1 Spinning Reserve Service

The Rules define three possible classes of Spinning Reserve:

3.9.3. Spinning Reserve response is measured over three time periods following a contingency event. A provider of Spinning Reserve Service must be able to ensure the relevant Facility can:

(a) respond appropriately within 6 seconds and sustain or exceed the required response for at least 60 seconds; or

(b) respond appropriately within 60 seconds and sustain or exceed the required response for at least 6 minutes; or

(c) respond appropriately within 6 minutes and sustain or exceed the required response for at least 15 minutes,

for any individual contingency event.

The required quantity is directly specified:

3.10.2. The standard for Spinning Reserve Service is a level which satisfies the following principles:

(a) the level must be sufficient to cover the greater of:

i. 70% of the total output, including Parasitic Load, of the generation unit synchronised to the SWIS with the highest total output at that time; and

ii. the maximum load ramp expected over a period of 15 minutes;

(b) the level must include capacity utilised to meet the Load Following Service standard under clause 3.10.1, so that the capacity provided to meet the Load Following requirement is counted as providing part of the Spinning Reserve requirement;

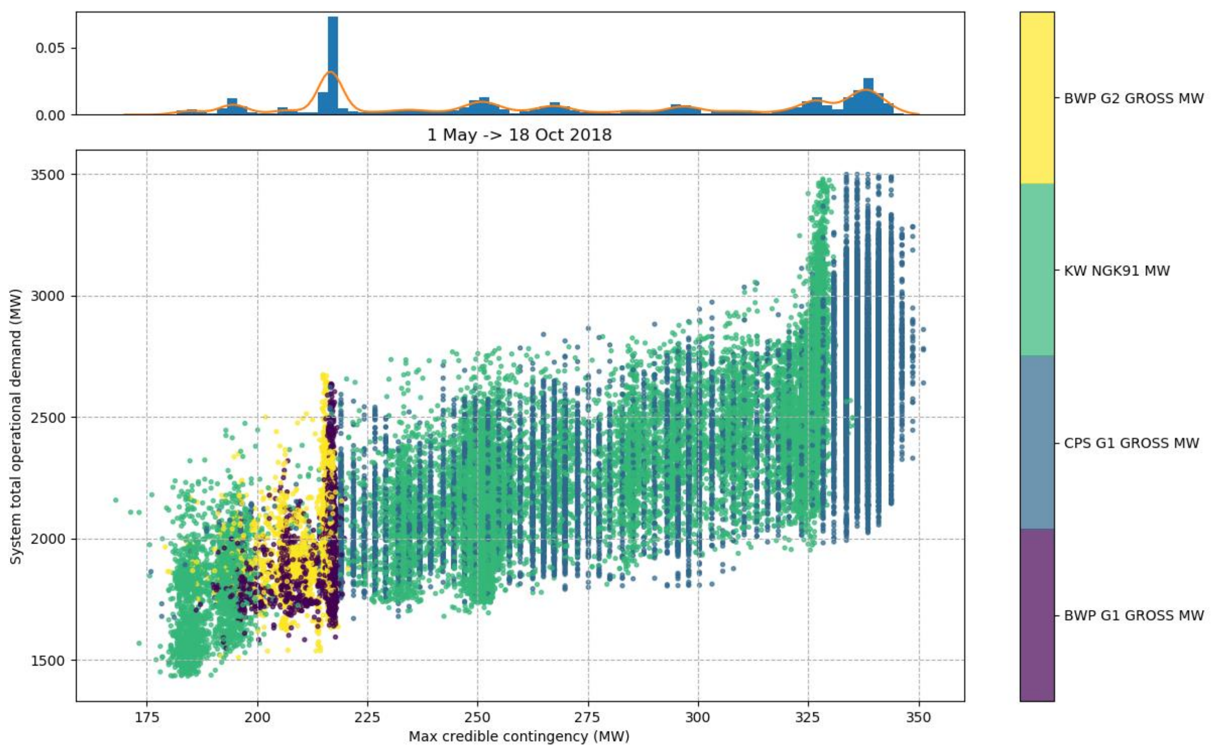
(c) the level may be relaxed by up to 12% by System Management where it expects that the shortfall will be for a period of less than 30 minutes; and

(d) the level may be relaxed following activation of Spinning Reserve and may be relaxed by up to 100% if all reserves are exhausted and to maintain reserves would require involuntary load shedding. In such situations the levels must be fully restored as soon as practicable.

where "Load Following Service" refers to frequency control during normal operation (regulation).

Figure 15 shows how the maximum generation contingency varies with operational demand under recent conditions.

Figure 15 Maximum credible generation contingency variance with operational demand



At present, the requirement is driven primarily by a small number of baseload generators. The largest single 340 MW unit routinely sets the SR requirement to approximately 70% x 340 MW = 238 MW.

Under current reserve management philosophy, reserves are sourced with 68 MW from contracted IPP facilities (26 MW from two coal units and 42 MW in interruptible block loads), and the remainder from the Synergy Portfolio. Apportioning between the various Rule time classes is managed informally, as AEMO has direct control of the Portfolio machines.

A1.2 Load Rejection (LR) Service

Two classes are defined for LR service:

3.9.7. Load Rejection Reserve response is measured over two time periods following a contingency event. A provider of Load Rejection Reserve Service must be able to ensure that the relevant Facility can:

(a) respond appropriately within 6 seconds and sustain or exceed the required response for at least 6 minutes; or

(b) respond appropriately within 60 seconds and sustain or exceed the required response for at least 60 minutes,

for any individual contingency event.

And the following requirements:

3.10.4. The standard for Load Rejection Reserve Service is a level which satisfies the following principles:

(a) the level sufficient to keep over-frequency below 51 Hz for all credible load rejection events;

(b) may be relaxed by up to 25% by System Management where it considers that the probability of transmission faults is low.

Current operating practice is to maintain a constant LR target of 120 MW, inclusive of reserves otherwise enabled for Load Following service, such that level regularly fluctuate down to 90 MW under high load variability conditions. The target value is matched to the largest single point load in the SWIS.

A2. Aggregate Single Frequency model

The “principle” or “single frequency” dynamics of a highly-meshed power system can be represented as[9]

$$\frac{d\omega}{dt} = \frac{\omega_0^2}{2HS_B\omega}(P_G - P_L)$$

where ω_0 is the nominal angular frequency, and all other variables are aggregate quantities defined in terms of parameters of each of the i^{th} of all n (synchronised) machines in the system:

$S_B = \sum_i S_{Bi}$	Total system base (MVA)
$H = \frac{\sum_i H_i S_{Bi}}{S_B}$	Total system inertia (MW/MVA s)
$P_G = \sum_i P_{Mi}$	Total system input mechanical power (generated MW)
$P_L = \sum_i P_{Ei}$	Total system electrical power (load or demand MW)

and ω is the weighted-average Centre of Inertia angular frequency:

$$\omega = \frac{\Sigma_i H_i S_i \omega_i}{\Sigma_i H_i S_i}$$

For intuitive understanding, HS_B has units of MWs and represents the total stored rotational kinetic energy of the system at the nominal synchronous frequency. Denoting this quantity as K_E and expressing in terms of non-angular frequency $f = \omega/2\pi$ gives:

$$\frac{df}{dt} = \frac{f_0^2}{2K_E f}\big(P_G(t) - P_L(t)\big) \tag{1}$$

In a generation contingency, for example, $P_G(t)$ includes the initial unit loss and subsequent (non-inertial) frequency response of the remaining machines. $P_L(t)$ includes a term proportional to the frequency deviation $\Delta f = f - f_0$ for load relief:

$$P_L(t) = P_{L,0}(1 + D\frac{\Delta f}{f})$$

$P_{L,0}$ is the total system load just prior to the contingency, and D is the (dimensionless) load relief factor, with typical values of 1 – 2.

A2.1 Why aggregate model?

A detailed dynamic PowerFactory model of the SWIS is already available through Western Power, which includes both a network model and the individual facility models required as part of the connection process. Western Power maintains the model primarily for the assessment of generation connections and long-term network augmentation. It includes an extensive database of low-level equipment ratings and settings, which is essential for the investigation of localised network security issues, such as protection coordination or dynamic voltage stability.

While Western Power uses the PowerFactory as the reference for facility data and response characteristics (i.e. the repository for parameters validated during “R2” commissioning), it does not apply or maintain the model for system-wide frequency control analysis. A highly detailed dynamic model can be tuned to recreate the

[9] See for example G. Anderson 2012 *Dynamics and Control of Electrical Power Systems*.

response of a given system configuration with a high degree of accuracy, but tends to be too fine-grained as far as the practical process of establishing system-wide security limits for several reasons:

1) Screening for a security limit (as opposed to validating a single configuration) requires consistent investigation across a wide range of operating conditions. In true operation, many components of the power system must be constantly monitored, adjusted and tuned differently to meet specific conditions.

   For example, changing the load in a detailed system model requires consideration of how and where load is redistributed. In addition to the range of possible generation redispatch configurations, network equipment (transformer stepping, reactive devices, line switching) must also be re-tuned to prevent localised voltage and equipment loading issues.

   The design of the PowerFactory model is to accurately represent these location-specific issues and investigate corrective measures. For frequency control analysis however, the management of the dozens (or hundreds) of control variables across the full range of interest quickly becomes cumbersome for the simulation operator. From the system level, it is reasonable to assume that these localised issues will be managed independently in practice.

2) Many facility models need to be reconfigured under different operating conditions, especially to reflect post-contingent performance. For example, the response of a steam unit may depend on environmental conditions or the state of auxiliary equipment, such as feed pumps, cooling apparatus, ambient temperatures or fuel supply.

   During true operation, these systems are maintained by local staff and/or additional control systems to ensure a consistent output. For simulation, while there is some consistency in the use of industry-standard models, most facility models implement some degree of customisation and sophistication necessary to accurately represent true performance. Again, this detail adds significant complexity to the simulation process, but does not improve accuracy or clarity of results at the system level.

   In the worst case, incorrect configuration results in facilities responding beyond their operating range (giving an incorrect indication of system performance), but these errors are buried in the mass of simulation data and difficult to control across the large range of required input conditions.

3) The PowerFactory model is designed to accurately recreate electrical equipment but consequently is necessarily less suited to practically implement abstract or simplified facility responses. Any addition to the system model requires a non-trivial base level of complexity to determine how more detailed components can interact and ensure the simulation mathematics remain consistent.

   In setting limits for use in a market system and the reform context, it is desirable to specify limits in a simplified, self-contained and generic format. While this likely results in conservatism and loss of low-level efficiency, it allows for more robust and legible systems to be built on top. Commercial and legislative frameworks require consistency, and generic security limits enable these frameworks to be effective irrespective of specific power system technology.

In principle, the existing PowerFactory model could be adapted e.g. by simplifying the network topology, modifying/lumping generators, implementing automated control systems (simulated market dispatch, load movements and network tuning) and introducing fictional facilities to both supress unrealistic compensation and represent new connections. The single-frequency model is simply the optimised result of this process, wherein all system detail has been reduced to only the aggregate parameters that have meaningful impact on the overall frequency dynamics.

A3. Synchronous Inertial Reserves in the SWIS

The following plots show estimates inertial reserves from synchronous machines throughout the SWIS, as per machine data from the October 2017 release of the Western Power SWIS PowerFactory model.

Figure 16 Distribution of inertial reserves for synchronous machines throughout the SWIS.

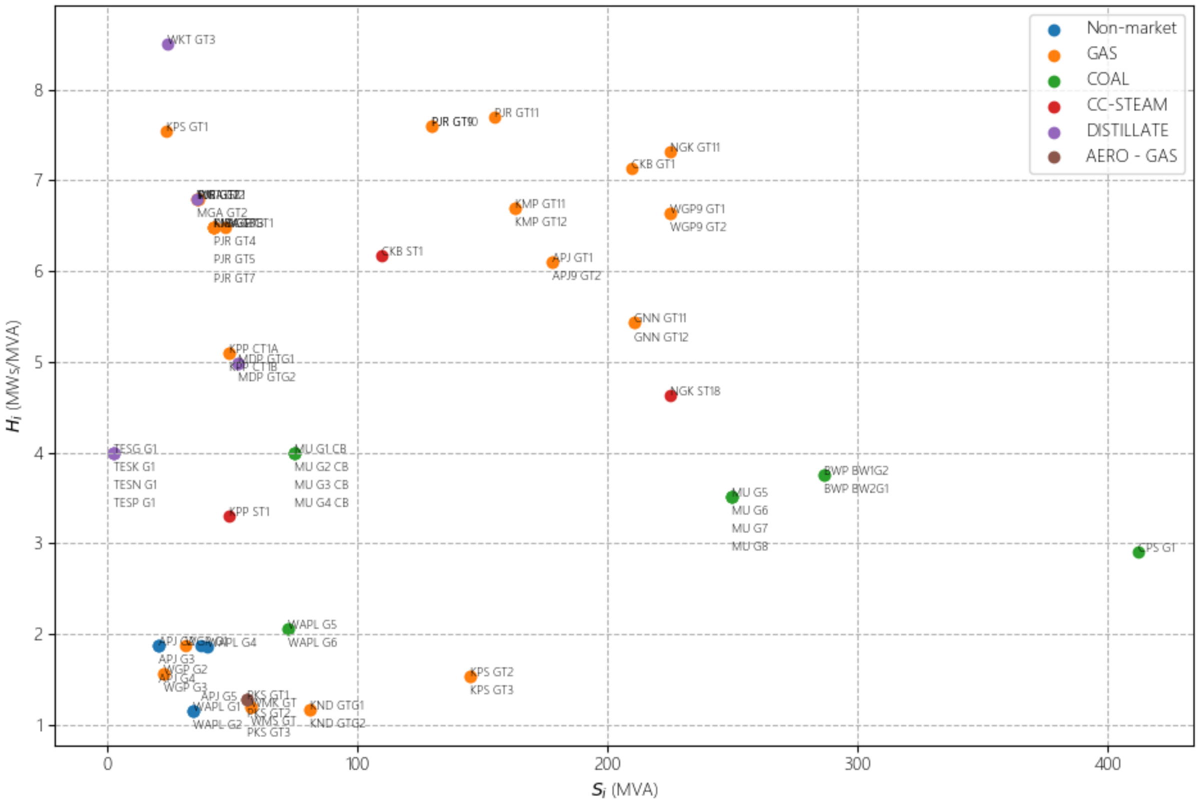


Figure 17 Typical total generator stored energy level movement (averaged over market intervals from 27 - 31 May 2018)

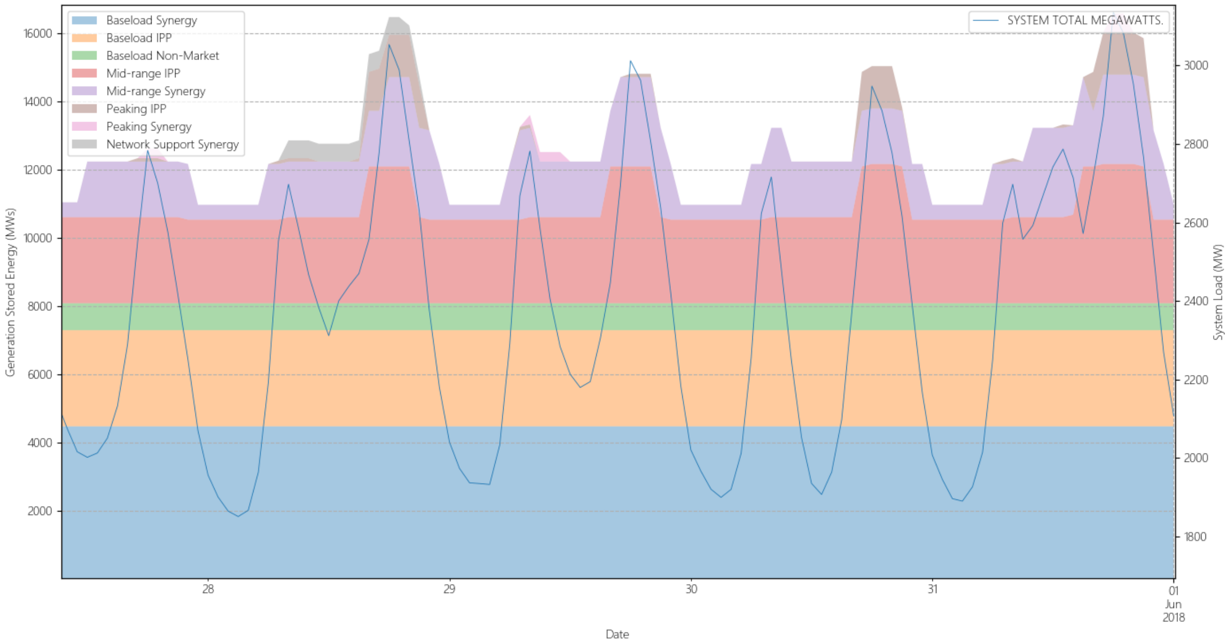


Figure 18 Total system stored energy distribution 1 May – 1 October 2018