Frequency Control in Low Inertia Power Systems

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Agenda

What we will cover in this deck:

- Inertia fundamentals
- System inertia around the world
- Estimation of system inertia
- Frequency control modelling during large disturbances
- Approaches for managing system security
- Real-time monitoring

INERTIA FUNDAMENTALS

Inertia is (stored) energy

- Inertia is traditionally defined as the kinetic energy stored in the rotating masses of generators and motors synchronously connected to a power system.

- This kinetic energy is exchanged with the power system (either released or absorbed) whenever there are instantaneous imbalances between generation and load (referred to as an *inertial response*).

- Non-synchronous devices interfaced to the system via power electronic inverters (such as solar PV inverters) have zero inertia.

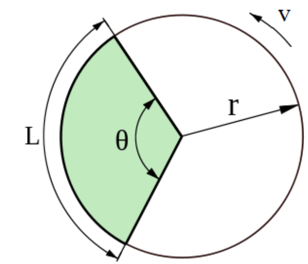
- Fixed-speed induction generator wind turbines are also inertially coupled and provide an inertial response [1].

Inertially coupled	**No inertial coupling**
• Synchronous machines (generators, motors, condensers) • Fixed-speed induction generator wind turbines [1]	• Static converters, e.g. solar PV inverters • Variable speed wind turbine generators [1]

[1] E. Muljadi, V. Gevorgian, M. Singh and S. Santoso, "Understanding inertial and frequency response of wind power plants," *2012 IEEE Power Electronics and Machines in Wind Applications*, Denver, CO, 2012, pp. 1-8, doi: 10.1109/PEMWA.2012.6316361.

Inertia of rotating cylindrical masses

Consider a rotating cylindrical mass, e.g. generator shaft:



Note that θ is in radians

- Length of an arc of a circle: $L = \theta r$ (in m)
- Rotational velocity of rotating mass: $v = \dfrac{\theta r}{t}$ (in m/s)

  or alternatively: $v = \omega r$ where $\omega = \frac{\theta}{t}$ is angular velocity

- Kinetic energy (general form): $KE = \dfrac{1}{2} m v^2$ (in Joules or kg.m^2/s^2)
- Rotational inertia / kinetic energy: $KE = \dfrac{1}{2} m (\omega r)^2$ (in power systems, we use MW.s which is equivalent to Joules)

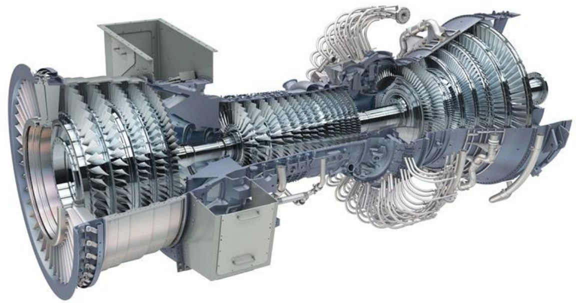
  or alternatively: $KE = \dfrac{1}{2} J \omega^2$ where $J = mr^2$ is the "moment of inertia" (in kg.m^2)

- For synchronous power systems operating at nominal frequency f_n: $\omega = \omega_n = 2\pi f_n$

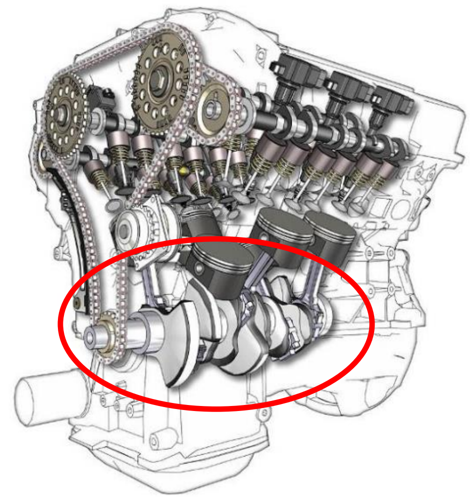
Generator moment of inertia

The moment of inertia ($J = mr^2$) for generator shafts is proportional to its mass and the square of its radius, i.e. heavier and bigger = higher inertia

Steam turbine

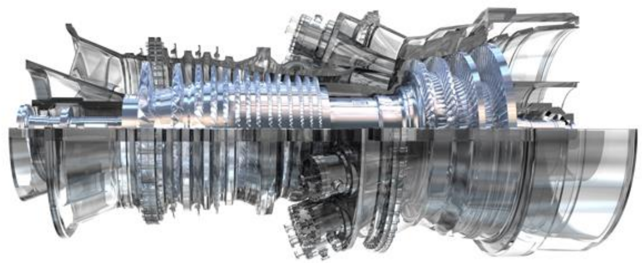


Aeroderivative gas turbine



Combustion engine

Hydro turbine



Industrial gas turbine

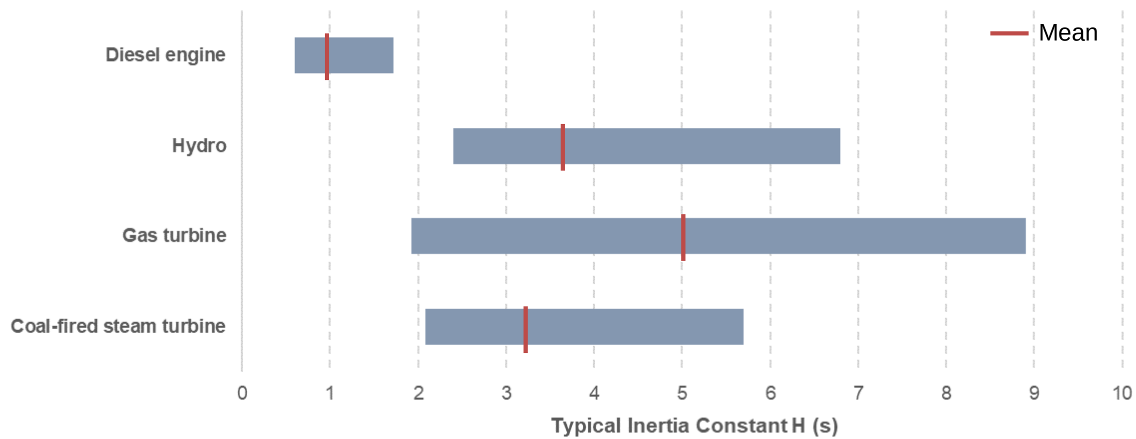
Inertia constant

The inertia of a generator can also be expressed as a normalised quantity, known as the inertia constant H (in s):

$$H = \frac{1}{2}\frac{J\omega^2}{S_n} = \frac{KE}{S_n}$$

where S_n is the nominal apparent power of the generator (in VA)

The inertia constant gives insight on how much inertia different types of generation technologies provide:



Total system inertia

The total inertia in the power system is the aggregate sum of all individual inertia components (in MW.s) currently coupled to the system:

$$KE_{sys} = \sum_{i=1}^{N} KE_{gen,i} + \sum_{i=1}^{M} KE_{load,i}$$

where KE_{gen} is the inertia for a synchronous generator and KE_{load} is the inertia for a load.

<u>Points to note</u>

- Individual inertia components can come from generators, (motor) loads and condensers.
- Calculating system inertia by summing individual components is generally not practical in all but small systems as the connection status and inertia parameters for all components need to be known.

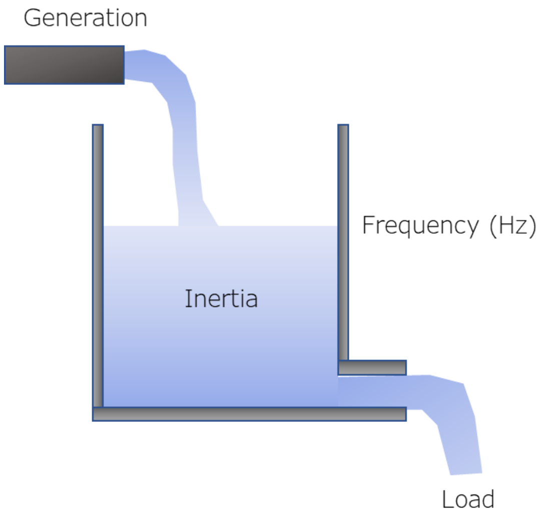
Inertia and system frequency

In synchronous power systems, inertia is the energy that is exchanged with the system whenever there is an instantaneous mismatch in generation and load

- When load > generation, kinetic energy from inertia supplies the energy deficit, but the rotating machines slow down, i.e. system frequency declines

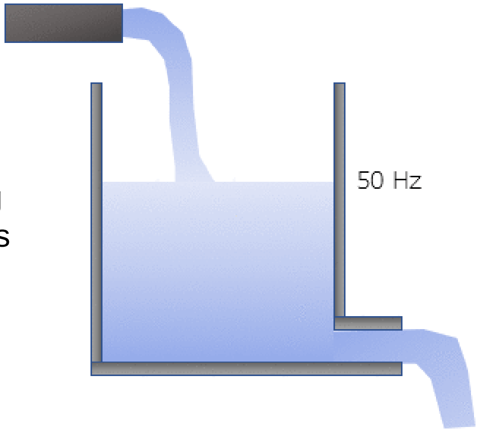
- When generation > load, the excess generation is converted to kinetic energy and the rotating machines speed up, i.e. system frequency rises

- When generation = load, there is no inertial energy exchange and system frequency is stable, e.g. 50 Hz



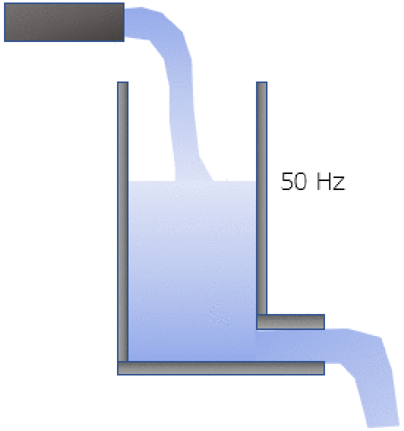
Inertia and system frequency

What happens if generation is suddenly withdrawn?



Energy from inertia supplies the load, but rotating masses start to slow down and frequency declines

What if the tank was smaller, i.e. lower inertia?



Lower inertia = less energy in rotating masses and frequency declines more rapidly, i.e. higher rate of change of frequency (RoCoF)

Inertia and system frequency

Mathematically, the relationship between inertia and system frequency can be approximated by a first-order differential equation known as the *swing equation*:

Nominal frequency

$$\frac{d\Delta f}{dt} = \frac{f_n}{2KE_{sys}}(P_m - P_e) = \frac{f_n}{2KE_{sys}}\Delta P$$

Rate of change of frequency (RoCoF)

System inertia

Generation

Load

Generation and load imbalance

Load damping effects can also be included explicitly in the swing equation (more on this later):

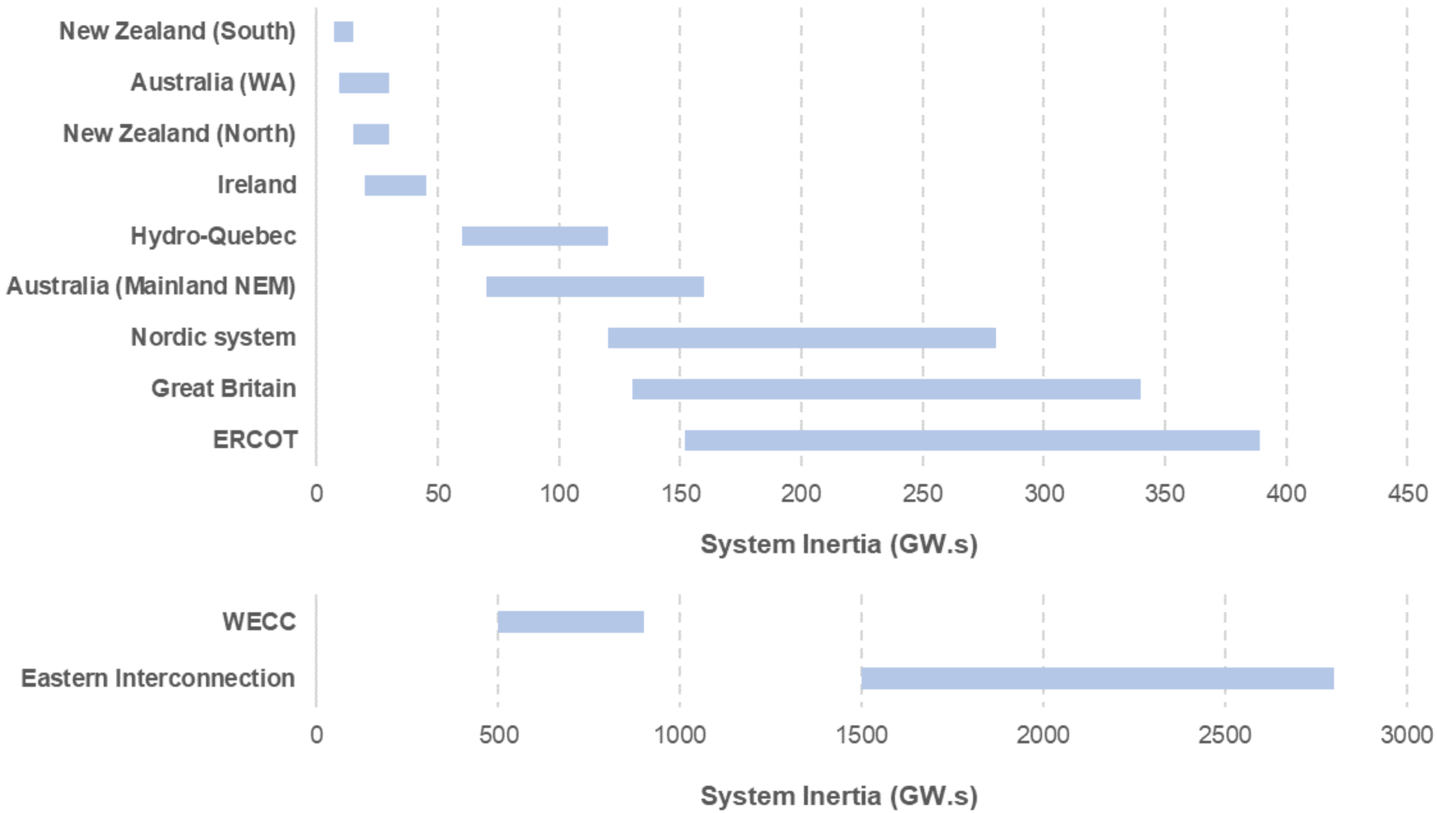
$$\frac{d\Delta f}{dt} = \frac{f_n}{2KE_{sys}}(\Delta P - DP_{load}\Delta f)$$

where D is the load damping / relief factor (in % MW/Hz) and P_{load} is the pre-disturbance system load (in MW)

SYSTEM INERTIA AROUND THE WORLD

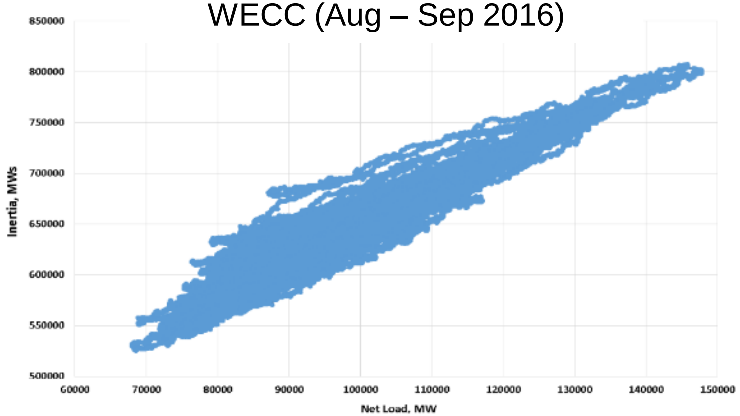
System inertia around the world

System inertia is largely a function of system size (generation capacity) and demand. Estimates for medium-to-large systems around the world are shown below:

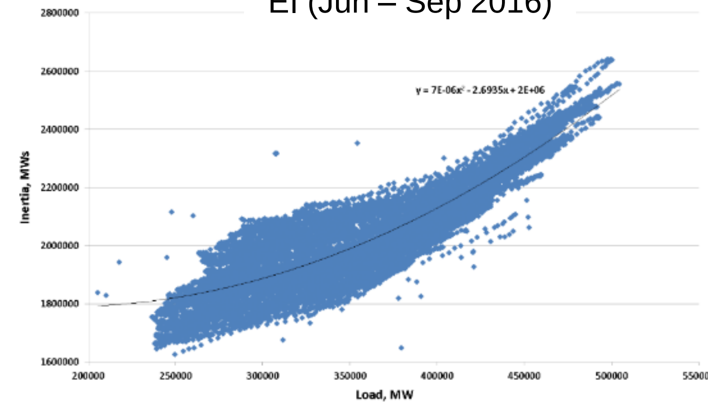


System inertia vs load in North America

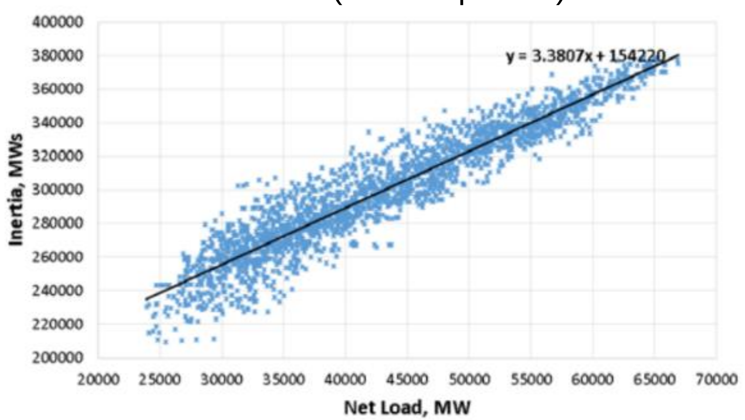
WECC (Aug – Sep 2016)



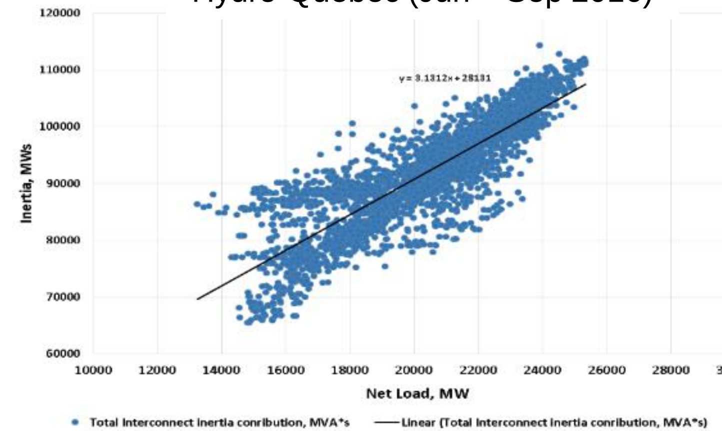
EI (Jun – Sep 2016)



ERCOT (Jul – Sep 2016)



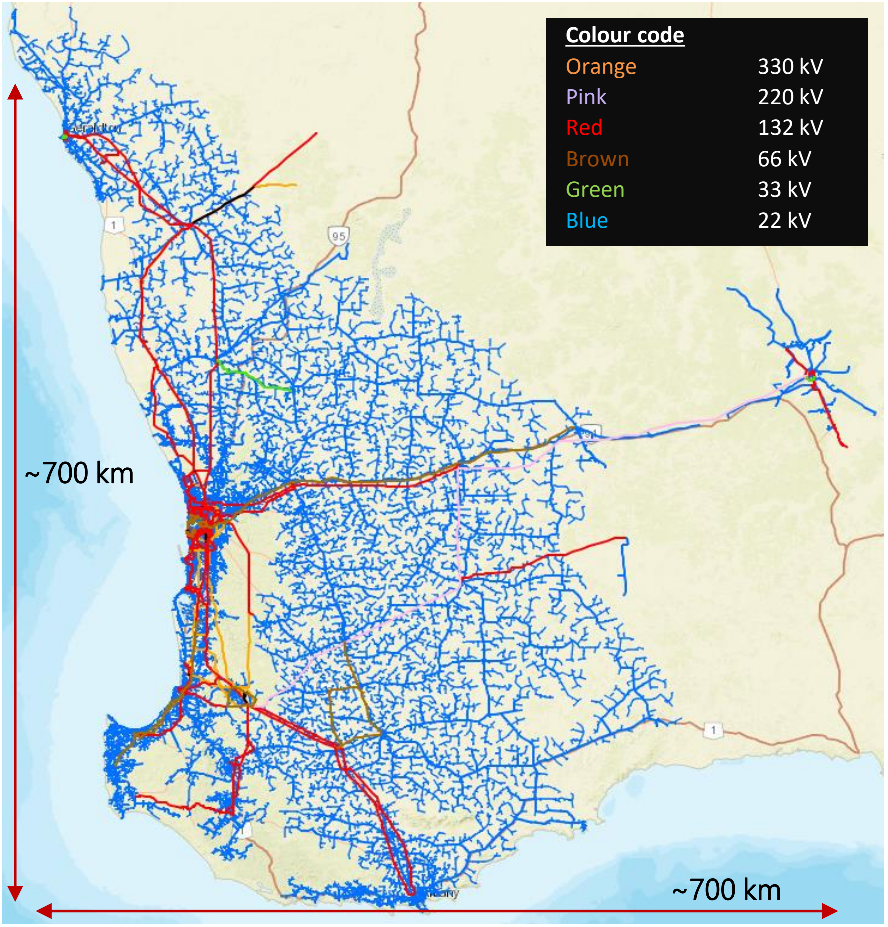
Hydro-Quebec (Jun – Sep 2016)



[1] J. Matevosyan, “Inertia Data”, Presentation to NERC Resources Subcommittee, 2016, https://www.nerc.com/comm/OC/Resources%20Subcommittee%20RS%202013/RS_Meeting_Presentations_October_2016.pdf

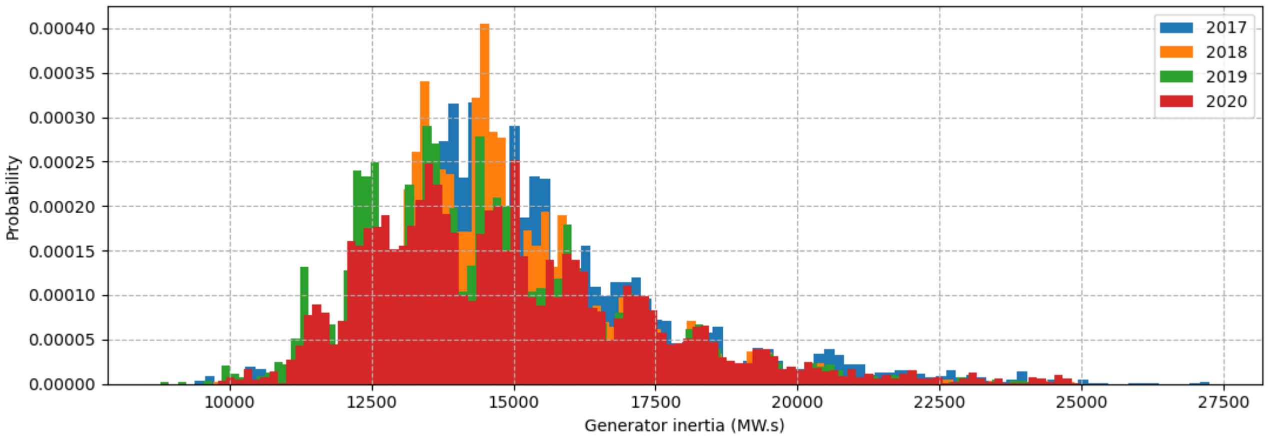
Case study: South West Interconnected System (SWIS)

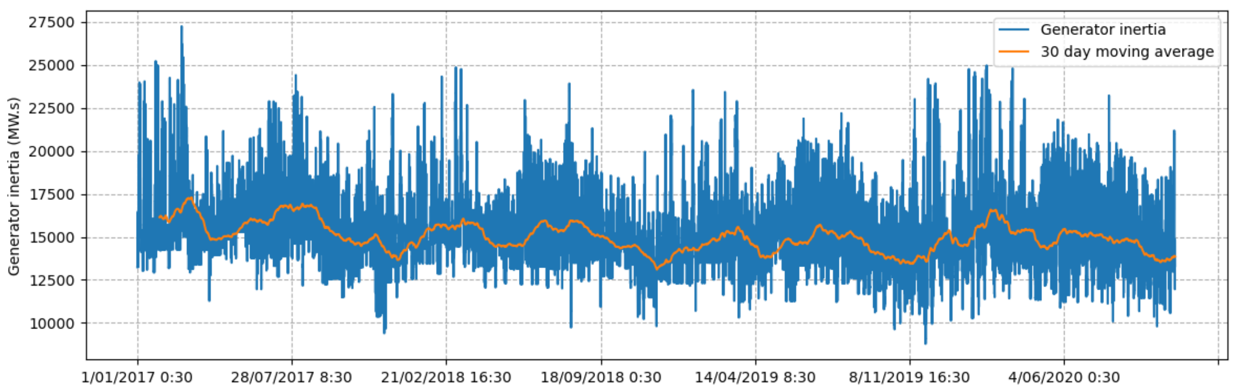
- The South West Interconnected System (SWIS) is a medium-scale islanded power system that services the southwest of Western Australia
- The system has an average demand of ~2.4 GW and a highest ever recorded demand of just 4.3 GW (in 2016), yet covers a vast geographic area of approximately 261,000 km^2 (greater than the land mass of the UK)
- Growing share of non-synchronous generation (primarily from rooftop PV and large-scale wind / solar farms) with instantaneous renewable penetration reaching 61.5% (recorded in 3 October 2020



Case study: Generator inertia in the SWIS

Generator inertia in the SWIS has been slowly decreasing in recent years due to the growth in rooftop PV (>1500 MW), as well as new utility PV and wind farm connections (>550 MW recently added in 2020)



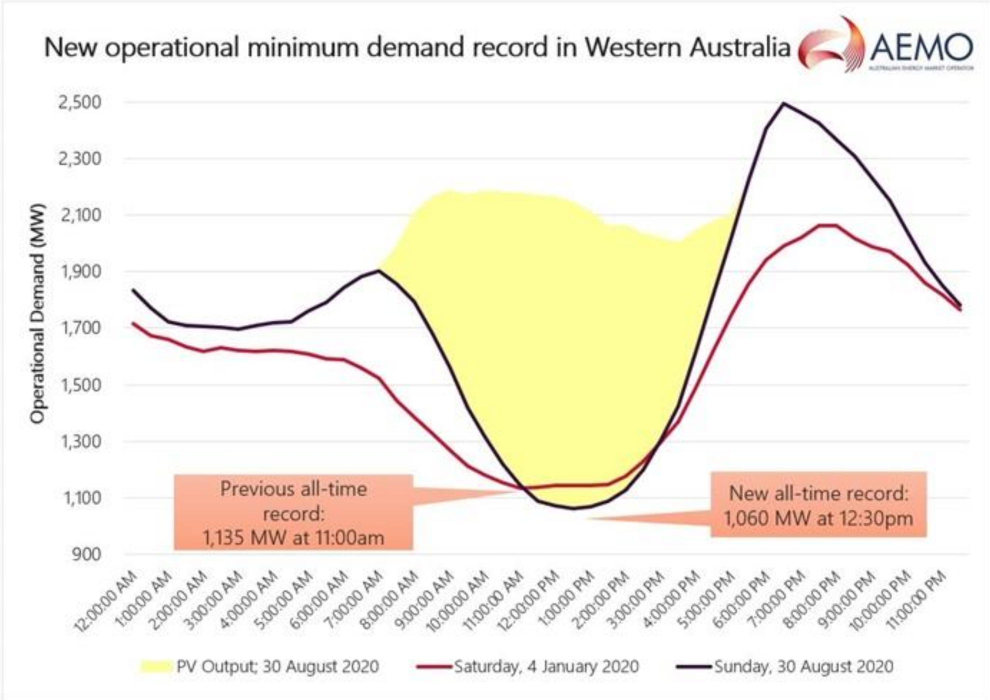


Typical inertia range	12,000 – 17,000 MW.s
Maximum inertia	24,722 MW.s (7:43pm Jun 2018)
Minimum inertia	8,779 MW.s (10:20am Nov 2019)

Case study: Typical low inertia day in the SWIS

Characteristics of a typical low inertia day:

- **Weekend:** lower load due to reduced commercial and industrial activity
- **Shoulder season (Sep-Nov):** traditional period for planned major outages on large thermal power plants, while the position of the sun (solar declination angle) is shifting towards the Summer equinox leading to increased rooftop PV outputs
- **Mild temperatures (18-25°C):** no need for heating and cooling leads to lower residential load, while also being cool enough for efficient PV performance
- **Clear skies:** maximum rooftop PV output
- **Low market prices:** due to low loads leads to decommitment of large thermal plant to prevent market prices from falling to the market floor



[1] https://aemo.com.au/newsroom/news-updates/min-op-demand-records

ESTIMATION OF SYSTEM INERTIA

Lower bound estimate of system inertia

Early estimates for inertia only included the known contributions from large transmission-connected synchronous generators (and possibly condensers):

$$KE_{sys} = \sum_{i=1}^{N} KE_{syn,i} = \sum_{i=1}^{N} H_i S_i$$

where KE_{syn} is the inertia for a synchronous machine (in MW.s), H is the generator inertia constant (in s) and S is the generating rating (in MVA).

However, this method can only set the ***lower bound*** of total system inertia as the inertia contribution from smaller distribution-connected or embedded generators, as well as synchronous motor loads, are neglected.

The inertia excluded from transmission-connected generators varies in different systems and under different system conditions, but can constitute a material portion of total system inertia:

- In Great Britain, demand side inertia was estimated to vary between 17% and 25% of total system inertia [1]
- In Ireland, it was estimated to be between 2% and 17% [2]
- In the SWIS, experience has shown that the excluded inertia is between 20% and 30%

[1] Y. Bian, H. Wyman-Pain, F. Li, R. Bhakar, S. Mishra and N. P. Padhy, "Demand Side Contributions for System Inertia in the GB Power System“, *IEEE Transactions on Power Systems*, vol. 33, no. 4, pp. 3521-3530, July 2018
[2] M. R. B. Tavakoli, M. Power, L. Ruttledge, D. Flynn, “Load Inertia Estimation Using White and Grey-Box Estimators for Power Systems with High Wind Penetration”, IFAC Proceedings Volumes, Volume 45, Issue 21, 2012

Theoretical basis for (most) system inertia estimates

Most system inertia estimation methods are based on a linearised representation of the swing equation:

$$\overline{KE_{sys}} = \frac{1}{2} \times \frac{f_n \Delta P}{\overline{\frac{d\Delta f}{dt}}\bigg|_{t=0}}$$

where ΔP is a known active power disturbance (in MW) and $\overline{\frac{d\Delta f}{dt}}\Big|_{t=0}$ is an estimate of the rate of change of frequency (RoCoF) evaluated at the onset of the disturbance, i.e. $t = 0$ (in Hz/s)

Key assumptions

1. The disturbance is instantaneous and can be measured accurately, e.g. a generator contingency
2. The system frequency (and its first derivative, the RoCoF) can be measured accurately and at high temporal resolution
3. The onset of the disturbance can be accurately determined
4. The effects of load relief and primary frequency response are neglected so this method is only valid in a short period after the onset of the contingency

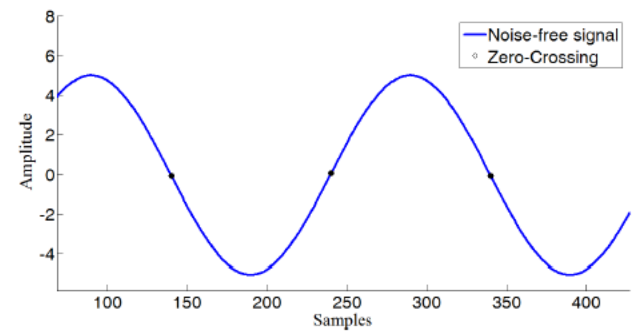
Measurement of power system frequency

Frequency in an AC power system is not directly measured, but is estimated from voltage and/or current measurements, for example using the following common methods:

- **Zero-crossing method:** simple and intuitive method based on counting zero-crossings of sinusoidal waveform:

$$\hat{f} = \frac{N_{ZC}}{2\Delta t}$$

where N_{ZC} is the number of zero crossings counted and Δt is the observation window (s)



- **Phase Locked Loop (PLL) based estimates:** using the time-derivative of the voltage phase angle [1]:

$$\hat{f} = f_n + \frac{d\delta}{dt} \times \frac{f_s}{360}$$

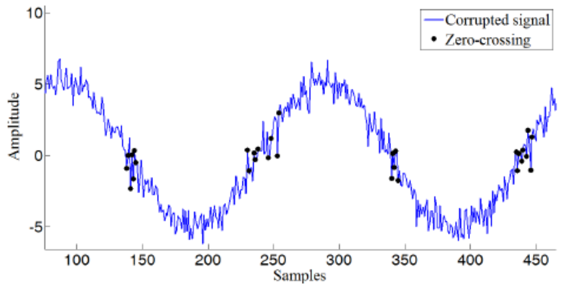
where δ is the voltage phase angle and f_s is the sampling frequency (Hz)

[1] A. G. Phadke, J. S. Thorp, and M. G. Adamiak, “A new measurement technique for tracking voltage phasors, local system frequency, and rate of change of frequency,” *IEEE Trans. Power App. Syst.*, vol. PAS-102, no. 5, pp. 1025–1038, May 1983.

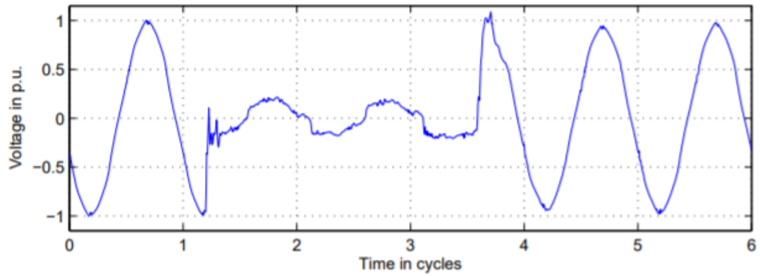
Measurement of power system frequency

However, frequency measurement methods are prone to transient errors when the raw voltage / current signal is not very sinusoidal, e.g. distorted by noise, harmonics, voltage dips from faults and phase jumps

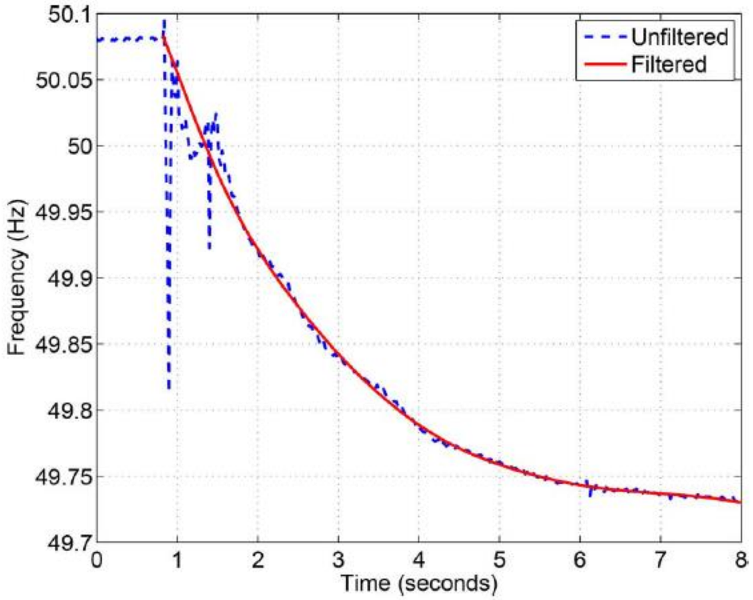
Errors with zero-crossing method on a distorted signal [1]:



Voltage dip and phase jumps from a fault [2]:



Measured frequency showing transients [3]:



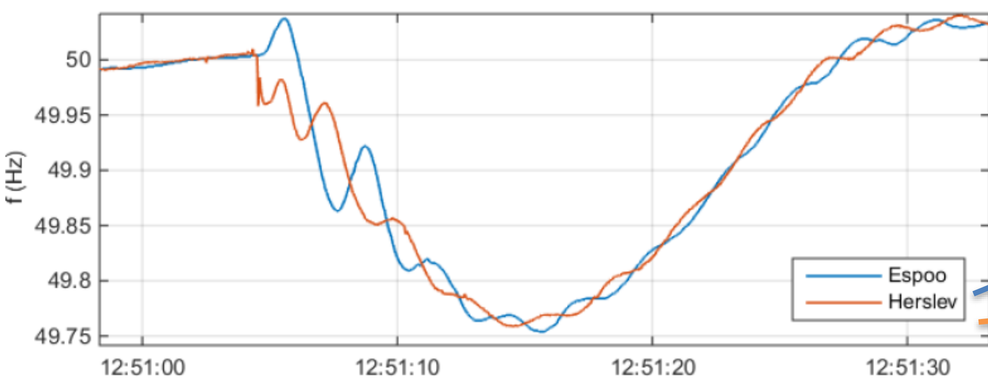
[1] Mendonca, T., M. F. Pinto and C. Duque. "Least squares optimization of zero crossing technique for frequency estimation of power system grid distorted sinusoidal signals." 2014 11th IEEE/IAS International Conference on Industry Applications (2014): 1-6.
[2] M. Wämundson, Calculating voltage dips in power systems using probability distributions of dip durations and implementation, MSc thesis, 2007
[3] P.M. Ashton, C.S. Saunders, G.A. Taylor, *et al.*, "Inertia estimation of the GB power system using synchrophasor measurements," *IEEE Trans. Power Systems*, vol. 30, no. 2, pp. 701-709, 2015

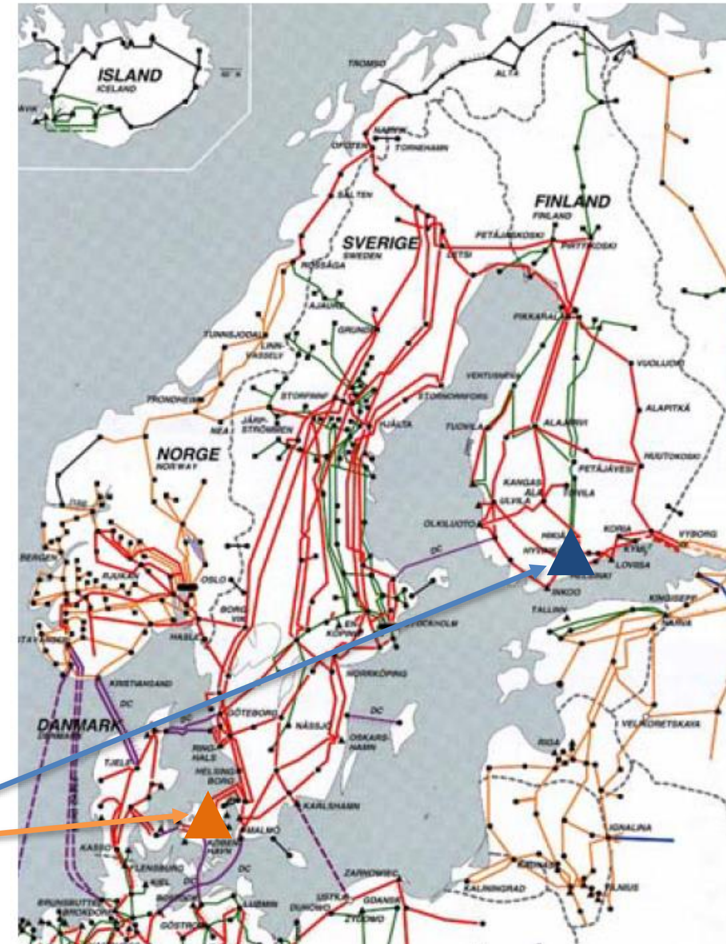
Locational variations in frequency

The assumption that frequency is the same every in a power system does not always hold, particularly when there are clusters of generators that swing against each other (inter-area oscillations caused by synchronising power exchange)

This is more common in systems that are not strongly meshed (electrically) and generation clusters are weakly linked, e.g. cross-border interconnectors between countries or states

Example 1: the plot below shows frequency measurements at two locations in the Nordic power system after a 580 MW generation contingency [1]

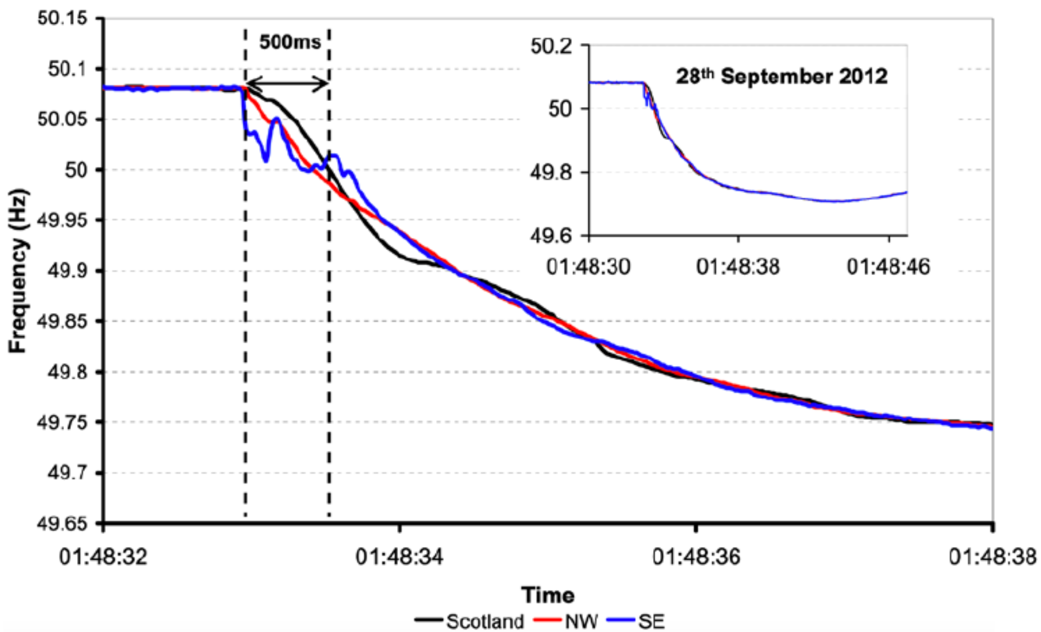


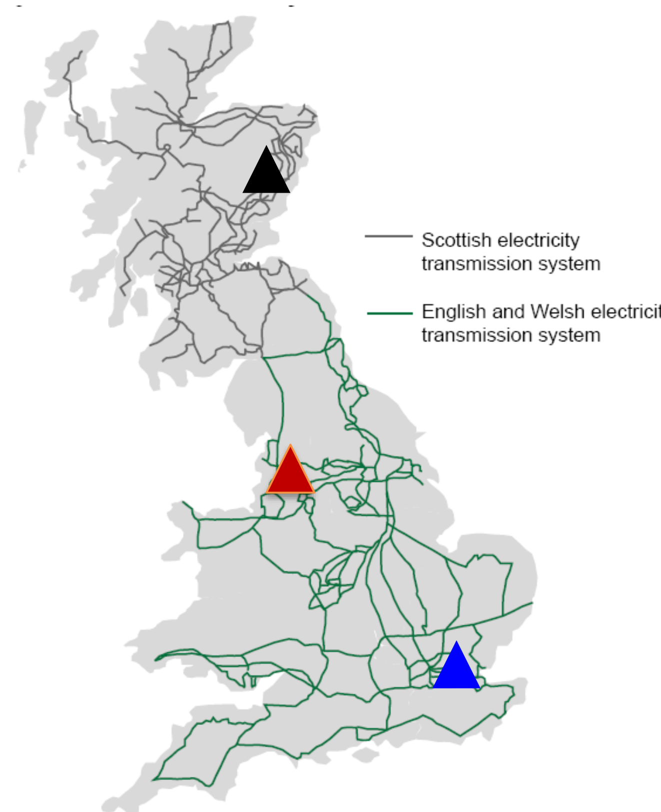


[1] ENTSO-E, Nordic Future system inertia v2, https://www.entsoe.eu/Documents/Publications/SOC/Nordic/2018/System-inertia.zip

Locational variations in frequency

Example 2: the plot below shows frequency measurements at three locations in Great Britain after an interconnector trip in the south east resulted in an instantaneous infeed loss of 1,000 MW [1].



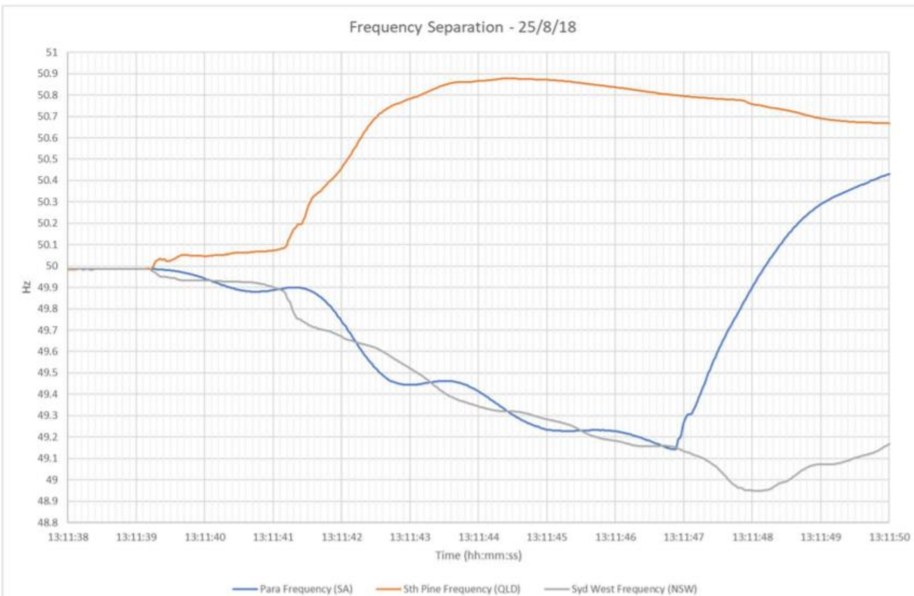


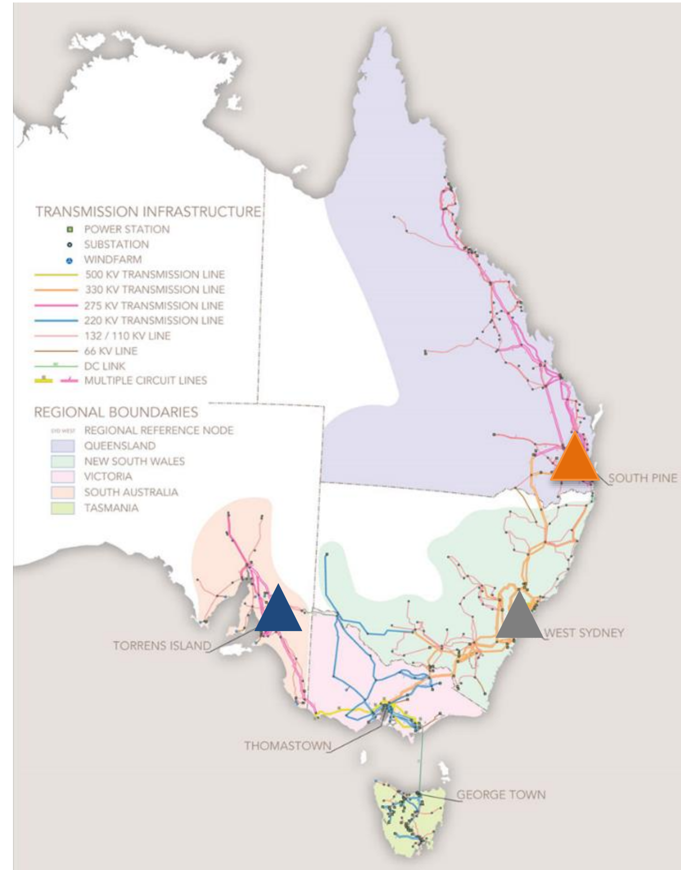
[1] National Grid, https://www.nationalgrid.com/sites/default/files/documents/16943-Industry%20Consultation.pdf

Locational variations in frequency

Example 3: the plot below shows frequency measurements at three locations in the NEM after a lightning strike on an interconnector led to the separation of QLD and then SA from the rest of the NEM [1].

Figure 8 Measured frequency in QLD, NSW, and SA





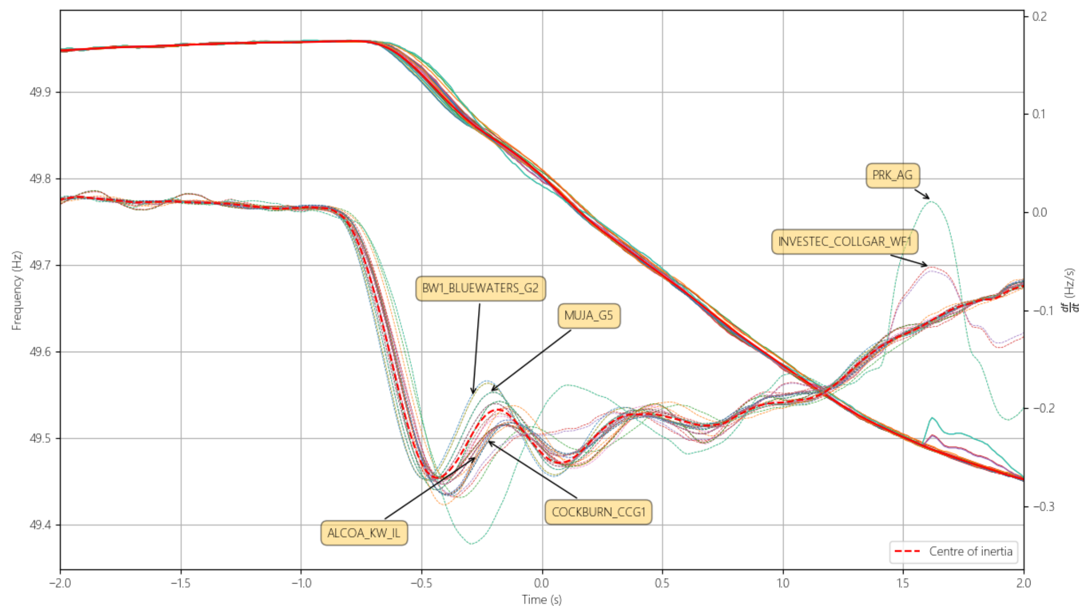
[1] AEMO, “Final Report – Queensland and South Australia system separation on 25 August 2018”, 2018, https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2018/Qld---SASeparation-25-August-2018-Incident-Report.pdf

Centre of inertia

Rather than selecting a specific location to measure frequency, a single “system” frequency can be calculated by a weighted sum of frequency measurements at each generator location (weighted by generator inertia constant):

$$f_{COI}(t) = \frac{\sum_{i=1}^{N} H_i f_i(t)}{\sum_{i=1}^{N} H_i}$$

Example: the plot on the right shows frequency measurements and calculated RoCoFs at multiple locations in the SWIS along with the frequency and RoCoF using the COI.

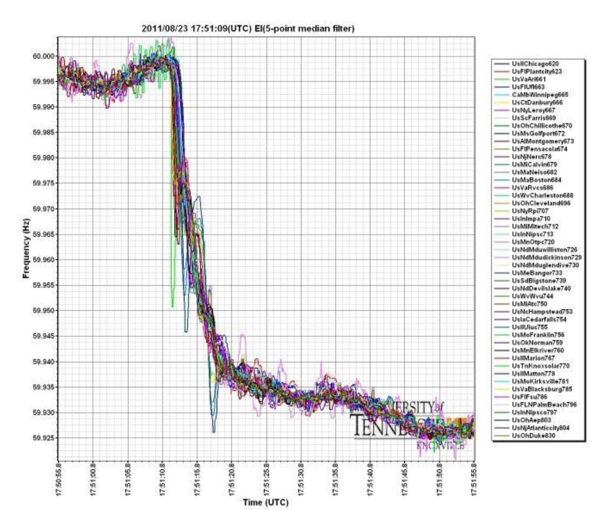


Use of wide area measurements

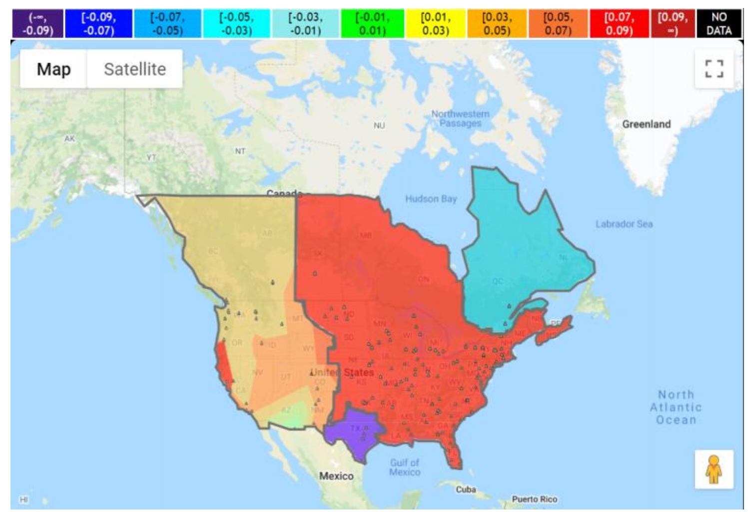
Wide area measurement systems (WAMS), e.g. using phasor measurement units (PMUs) can be used to provide real-time measurements of frequency time-synchronised at different locations in the power system.

An alternative to the centre of inertia frequency is a generalised weighted frequency, where the weight w_i reflects any known distribution of inertia in the area around the measurement location i [1]:

$$f_{ave}(t) = \frac{\sum_{i=1}^{N} w_i f_i(t)}{\sum_{i=1}^{N} w_i}$$



Source: University of Tennessee (FNET Grideye)



Source: http://fnetpublic.utk.edu/frequencymap.html

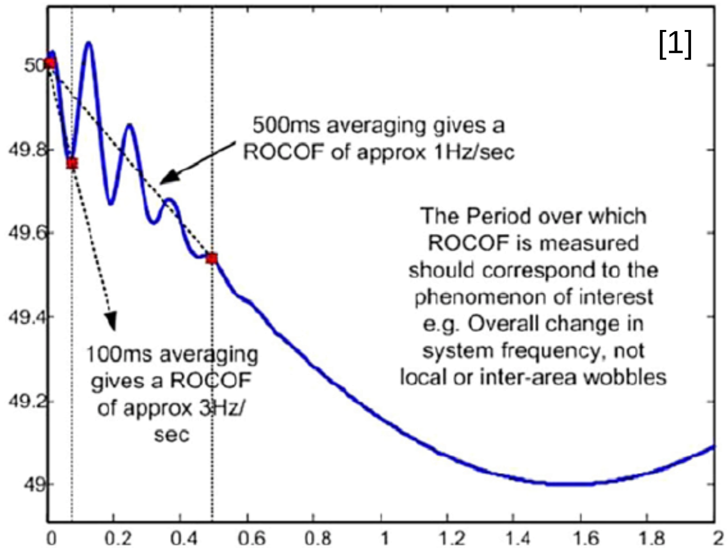
[1] K. Tuttelberg, J. Kilter, D. Wilson, and K. Uhlen, “Estimation of Power System Inertia From Ambient Wide Area Measurements,” *IEEE Transactions on Power Systems*, vol. 33, no. 6, pp. 7249–7257, 2018

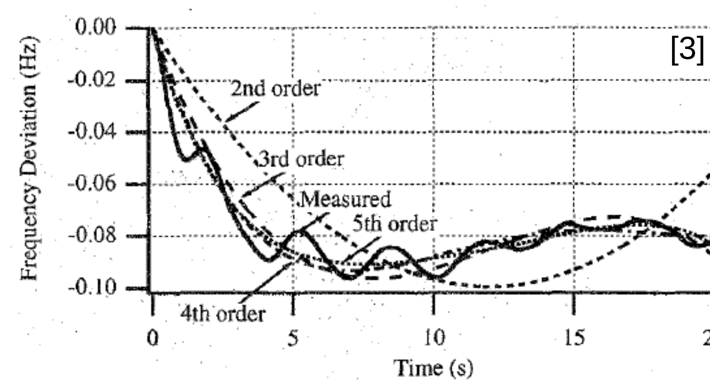
Measurement of RoCoF

The inertia estimate is very sensitive to the measured RoCoF, but since RoCoF is measured from frequency, a sample-by-sample measurement ($\frac{\Delta f}{\Delta t}$) is in turn sensitive to the quality of the frequency measurement. The effects of distortions such as noise and oscillations can have a material impact on the measured RoCoF. Methods for mitigating these issues include:

- **Averaging window**: the RoCoF is calculated by averaging the sample-by-sample RoCoF measurements over a pre-defined averaging window, e.g. 500 ms is commonly used in Europe [1] [2]. Note that the larger the window, the less accurate the RoCoF measurement is (as the effects of PFR and load damping take effect)

- **Polynomial fit:** the frequency trace is fitted to an n-th order polynomial equation (e.g. 5-th order [3]) and the RoCoF is calculated directly from the derivative of the polynomial. The polynomial fit may be adversely influenced by frequency effects outside of the inertial window [2]



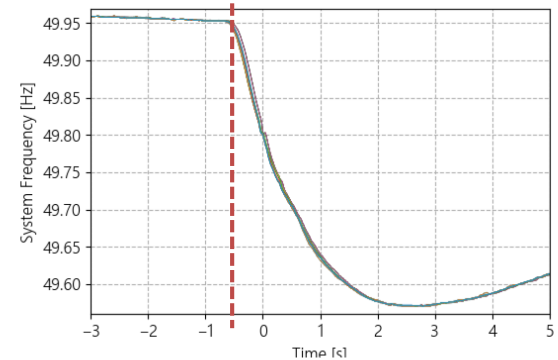


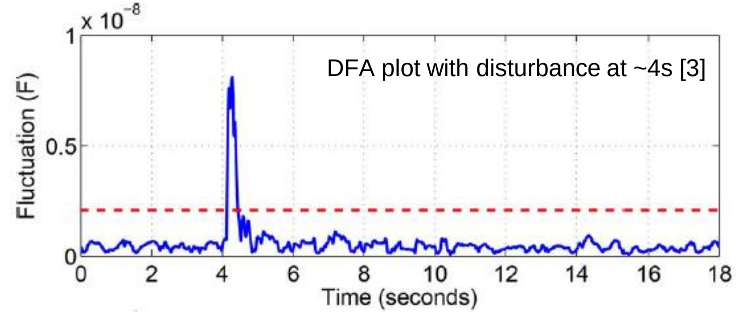
[1] SONI, RoCoF Modification Proposal - TSOs' Recommendation, 2012 http://www.soni.ltd.uk/media/documents/Archive/RoCoF%20Modification%20Proposal%20TSOs%20Opinion.pdf
[2] P.M. Ashton, C.S. Saunders, G.A. Taylor, et al., "Inertia estimation of the GB power system using synchrophasor measurements," IEEE Trans. Power Systems, vol. 30, no. 2, pp. 701-709, 2015
[3] T. Inoue, H. Taniguchi, Y. Ikeguchi, and K. Yoshida, "Estimation of power system inertia constant and capacity of spinning-reserve support generators using measured frequency transients," *IEEE Transactions on Power Systems*, vol. 12, no. 1, pp. 136–143, 1997.

Determining onset of disturbance

The onset of the disturbance is crucial in inertia estimates to determine when the RoCoF measurement should be taken. There are several methods for determining the disturbance start time, for example:

- **Manual:** the easiest method is to determine the start time manually by inspection from the frequency trace. Accurate, but not scalable.
- **RoCoF threshold:** a moving average filter is applied to the sample-by-sample RoCoF calculation and a disturbance is deemed to have occurred if it exceeds a certain threshold, e.g. 0.04 Hz/s [1] or 0.035 Hz/s [2]. Note that the appropriate threshold is system dependent.
- **Detrended fluctuation analysis (DFA) [3]:** the frequency trace is divided into time windows of N samples and the root-mean squared deviations from a linear least-squares trend line (for each window) are calculated. An event is deemed to have occurred if the fluctuation exceeds a certain threshold.





DFA plot with disturbance at ~4s [3]

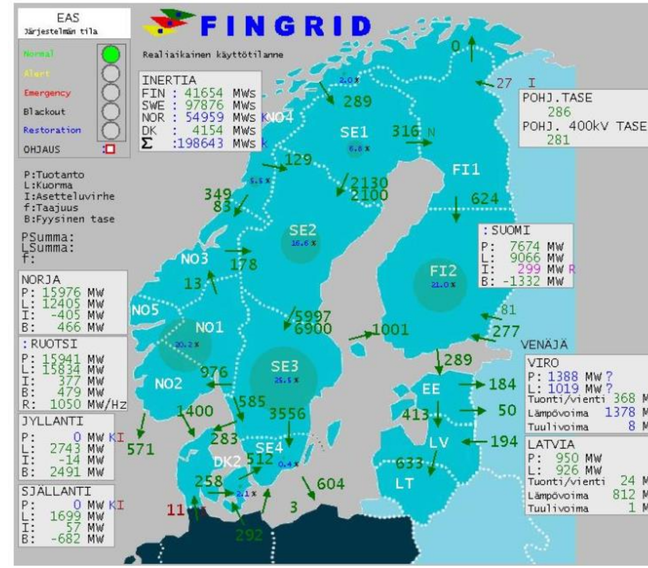
[1] T. Inoue, H. Taniguchi, Y. Ikeguchi, and K. Yoshida, “Estimation of power system inertia constant and capacity of spinning-reserve support generators using measured frequency transients,” *IEEE Transactions on Power Systems*, vol. 12, no. 1, pp. 136–143, 1997.
[2] ENTSO-E, Nordic Future system inertia v2, https://www.entsoe.eu/Documents/Publications/SOC/Nordic/2018/System-inertia.zip
[3] P.M. Ashton, C.S. Saunders, G.A. Taylor, et al., “Inertia estimation of the GB power system using synchrophasor measurements,” IEEE Trans. Power Systems, vol. 30, no. 2, pp. 701-709, 2015

Online inertia estimation

Real-time system inertia estimation is desirable for system operators to monitor and track the inertia trends, identify risky scenarios and as an input into the procurement of frequency control reserves. Examples of online methods include:

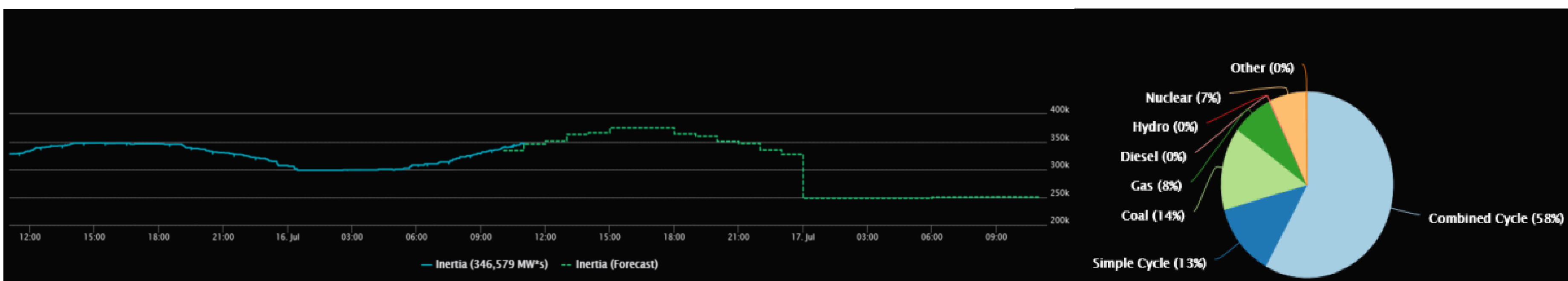
- **Real-time generator inertia monitoring:** based on SCADA breaker statuses of transmission-connected synchronous generator and known generator inertia parameters. This is a lower bound estimate that excludes generators unobservable by SCADA as well as loads.

  This method for online inertia estimation is standard among system operators that monitor inertia, for example ERCOT, Eirgrid, the Nordic TSOs (Fingrid, Statnett, Energinet and Svenska Kraftnät) and AEMO.



Source: ENTSO-E, Nordic Future system inertia v1

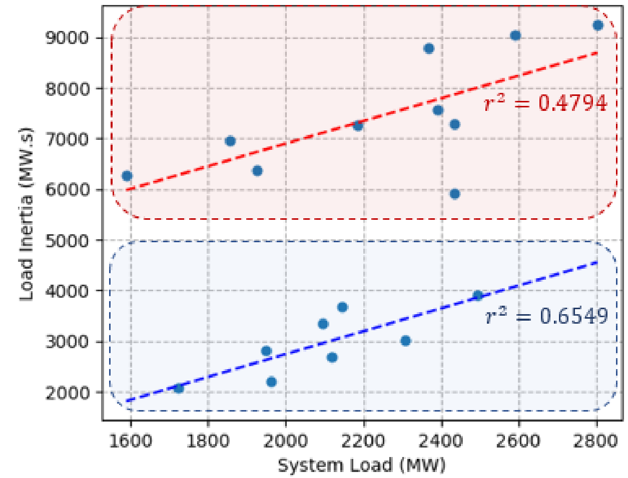
ERCOT inertia monitoring system



[1] ERCOT, https://www.esig.energy/event/webinar-evolution-of-ercots-frequency-control-and-ancillary-services-while-integrating-a-high-share-of-inverter-based-generation/

Online inertia estimation

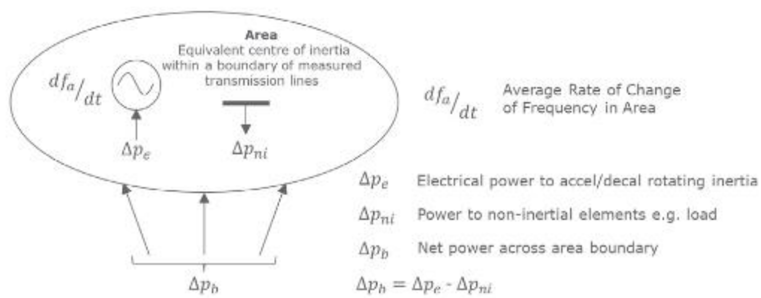
- **Real-time generator inertia monitoring with load inertia estimates:** same as the previous method, but including an estimate of load inertia (and inertia from other unobservable inertia) based on linear correlations with system load, derived from offline studies. The plot to the right shows an example from the SWIS.



- **WAMS based estimates:** uses strategically located PMUs to detect and measure disturbances in real-time. The WAMS can estimate both the frequency deviations and active power imbalances (e.g. changes to interconnector flows) for direct application in inertia estimates.

- **Effective area inertia [1]:** is a concept developed by GE to estimate (in real-time) the inertia in a bounded area where flows across the boundary can be monitored by PMUs, e.g. an area bounded by regional interconnectors:

$$KE_{EA} = \frac{1}{2} \times \frac{f_n \Delta p_b(t)}{\frac{df_a}{dt}}$$

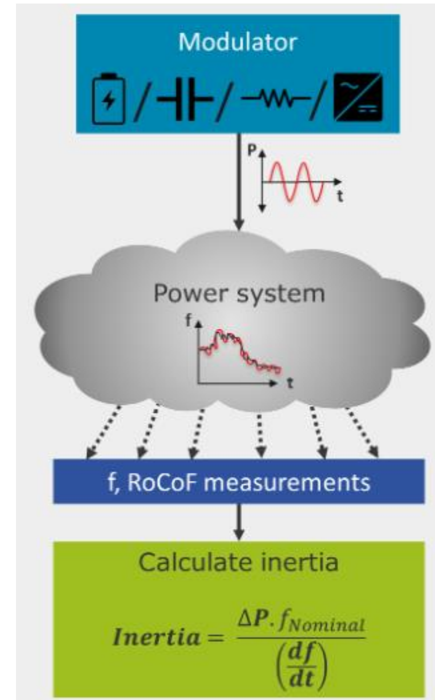


[1] D. Wilson, J. Yu, N. Al-Ashwal, B. Heimisson and V. Terzija, “Measuring effective area inertia to determine fast-acting frequency response requirements”, International Journal of Electrical Power & Energy Systems, 113, 2019

Online inertia estimation

- **Periodic active power perturbations:** a small modulator (e.g. controllable load banks or battery) with capacity of ~0.1% the system size is used to inject periodic active power perturbations. The system inertia is estimated by measuring the corresponding frequency deviations with measurement units scattered around the system.

  This method is patented and commercialised by UK firm Reactive Technologies in their GridMetrix product. Trials have been undertaken in the UK (National Grid ESO) and Japan (TEPCO).



Source: Reactive Technologies, https://www.reactive-technologies.com/grids/gridmetrix/

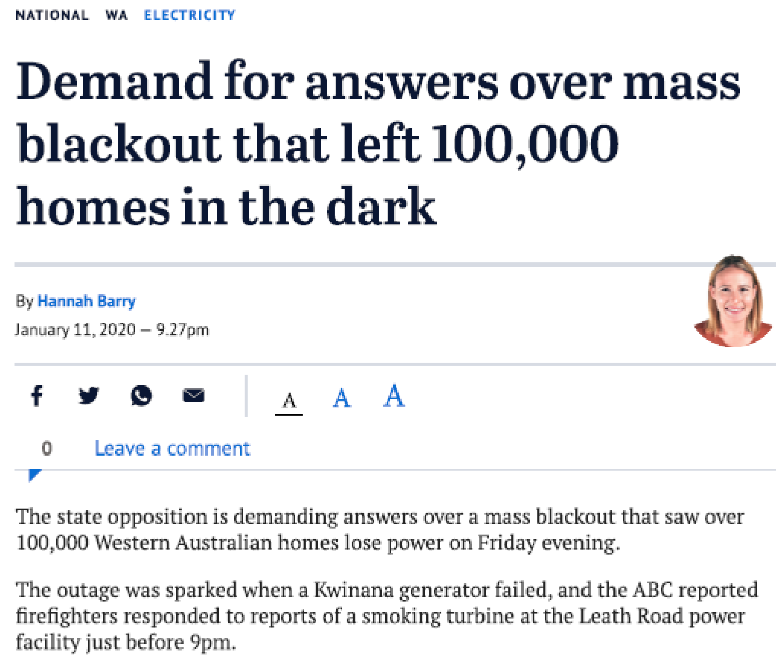
FREQUENCY CONTROL MODELLING DURING LARGE DISTURBANCES

Large disturbances in a power system

In the context of frequency control and inertia, large disturbances refer to contingency events that cause material active power imbalances, e.g.

- Large generator trip (*generator contingency*)
- Loss of an interconnector (infeed loss)
- Network fault leading to disconnection of multiple generators, e.g. trip of radial section of the network containing generation
- Transmission line fault leading to large loss of load (*load rejection*)
- Significant network fault leading to loss of distributed rooftop PV (*DER tripping*)
- Combinations of the above (*multiple contingency*)

Note: in this section, the focus is on loss of generation contingencies, but the underlying concepts are equivalent for loss of load contingencies as well.


NATIONAL WA ELECTRICITY

Demand for answers over mass blackout that left 100,000 homes in the dark

By Hannah Barry
January 11, 2020 — 9.27pm

0 Leave a comment

The state opposition is demanding answers over a mass blackout that saw over 100,000 Western Australian homes lose power on Friday evening.

The outage was sparked when a Kwinana generator failed, and the ABC reported firefighters responded to reports of a smoking turbine at the Leath Road power facility just before 9pm.


Thousands of WA properties without power after Western Power reports 'generator issue'

Joanna Delalande | The West Australian
Friday, 10 January 2020 9:11PM

Joanna Delalande

Frequency control during a generation contingency

1. Inertial Response (IR)

A rapid and automatic injection of energy to suppress rapid frequency deviations, slowing the rate of change of frequency.

2. Primary Frequency Response

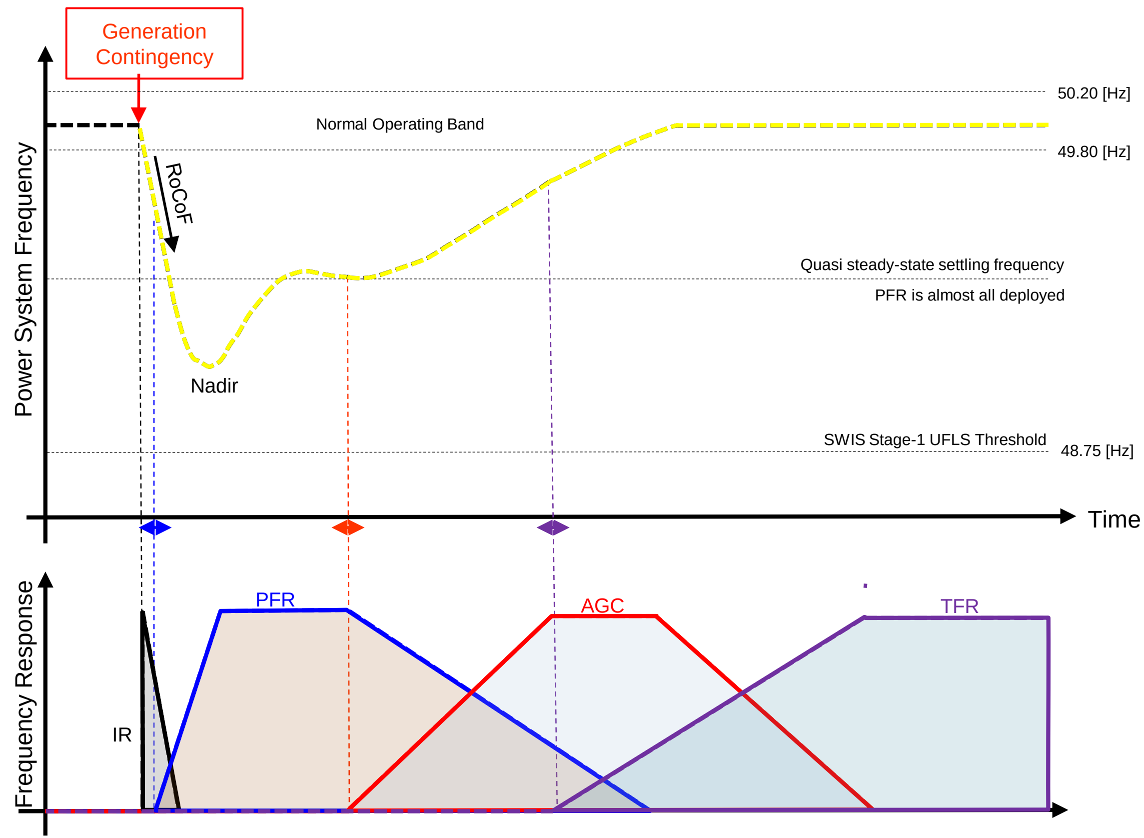
Local active power controls act in a proportional manner to respond quickly to measured changes in local frequency and arrest deviations (governor speed-droop control).

3. Secondary Frequency Response

Automatic Generation Control (AGC) signals act to restore frequency to nominal frequency and relieve providers of primary frequency response.

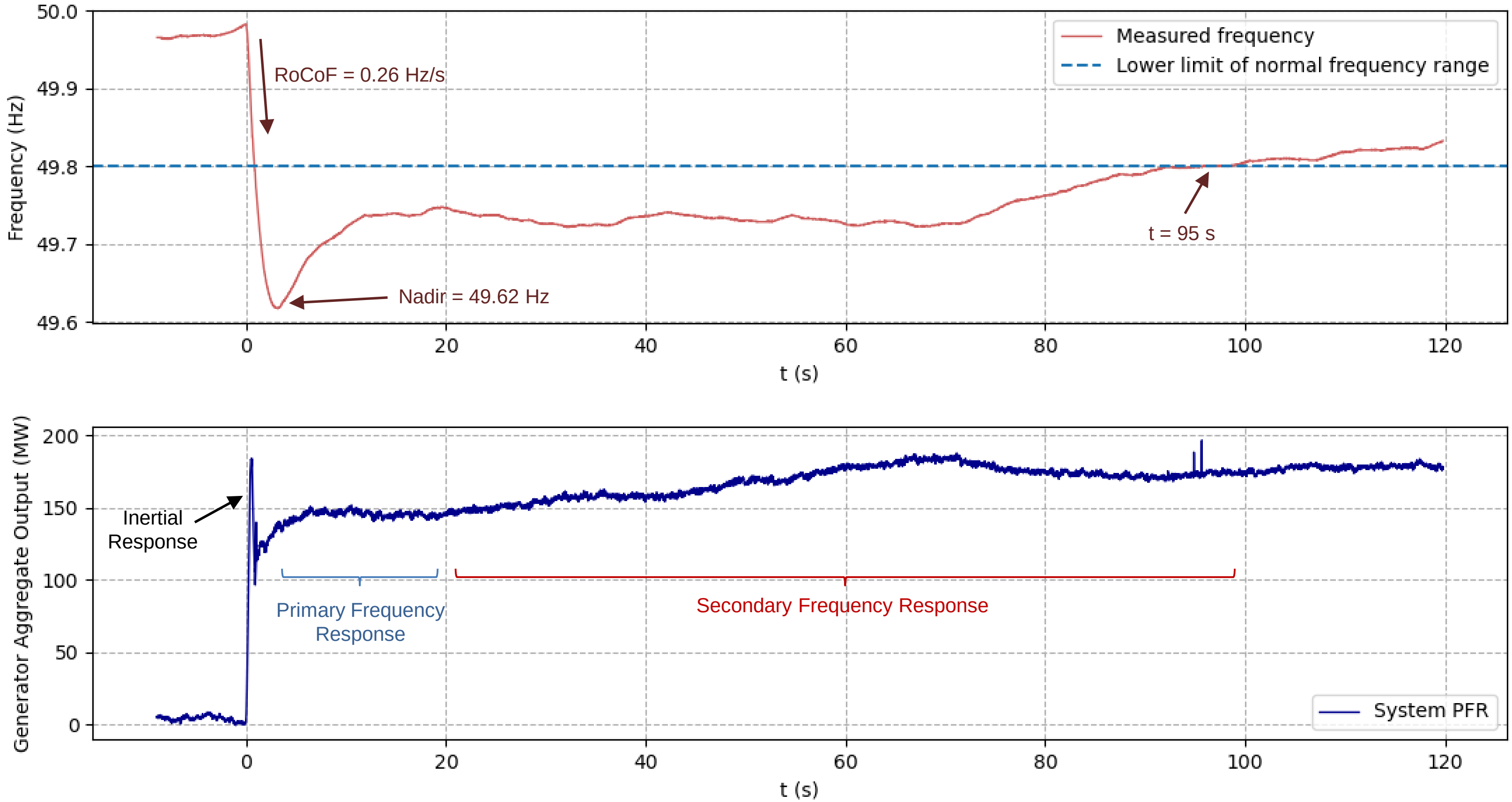
4. Tertiary Frequency Response (Redispatch)

Active power controls, such as the start-up of new units or set point changes on operating units, act to replace depleted secondary frequency control resources to ensure the system continues to remain within its normal operating band.

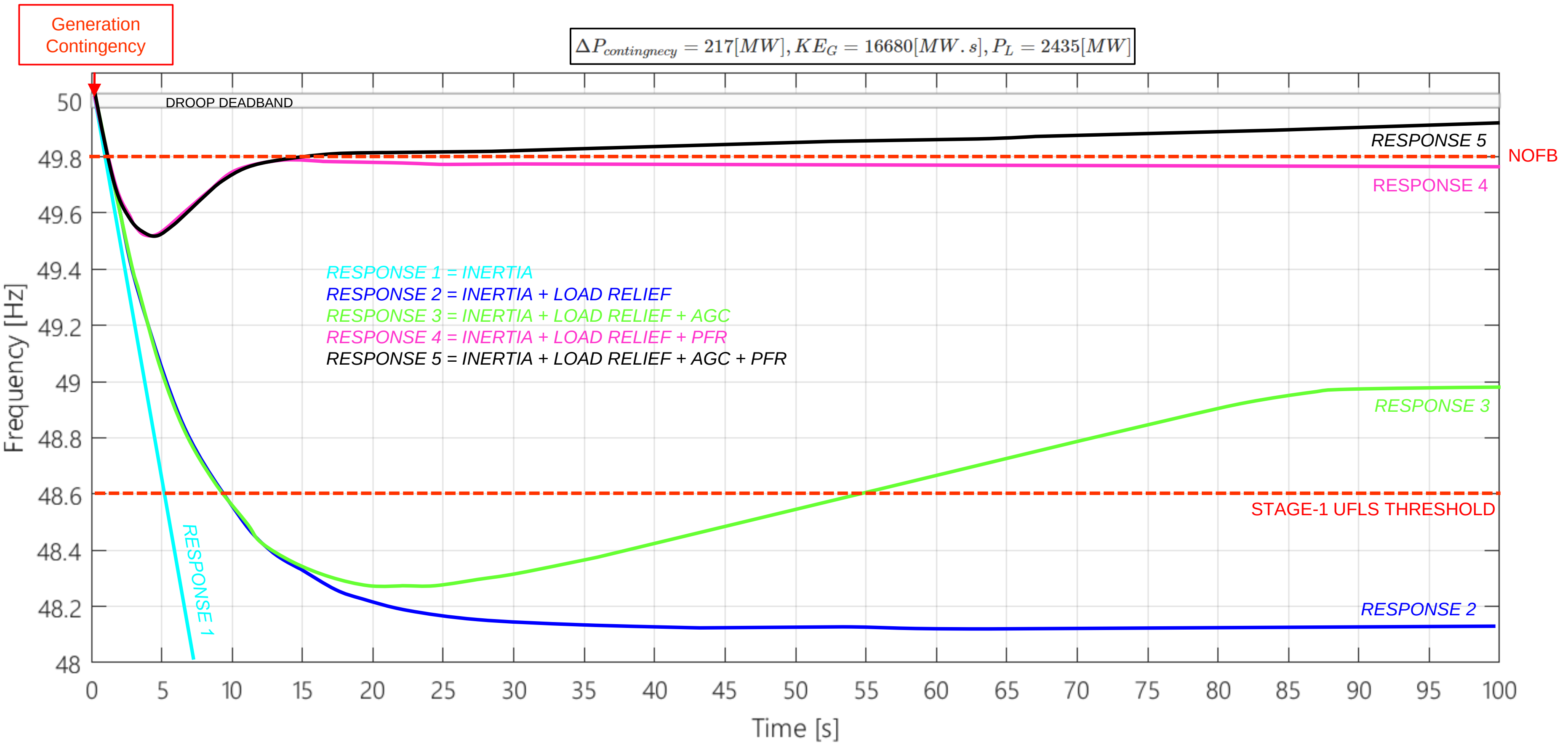


Example of a generator contingency

Example of a 160 MW generator contingency in the SWIS from January 2020:

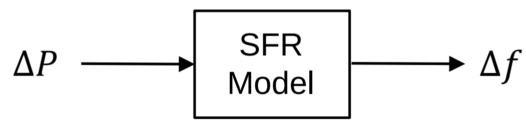


Breakdown of frequency response components



System frequency response (SFR) modelling

A system frequency response (SFR) model describes the aggregate behaviour of system frequency to active power disturbances, e.g. generator contingencies:



In the early days, SFR modelling was based on simple linear metrics such as the composite power/frequency characteristic [1]:

$$K = -\frac{\Delta P}{\Delta f} = -\frac{\Delta P_G}{\Delta f} + \frac{\Delta P_L}{\Delta f}$$

Where ΔP is the active power disturbance (in MW), Δf is the change in frequency (in Hz), ΔP_G is the change in generation (in MW) and ΔP_L is the change in load (in MW)

The parameter K represents the composite effect of an active power disturbance on the system frequency (in MW/Hz), typically estimated with experimental tests, e.g. line and generator trips in [1] and [2].

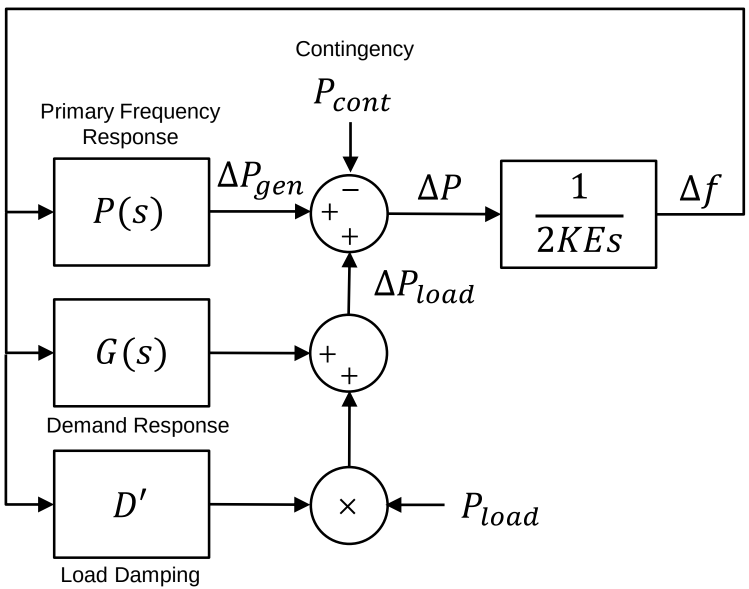
Note that system inertia is not an explicit parameter in K, but is implicitly included as K is "catch-all" metric.

[1] M. Davies, F. Moran and J. I. Bird, "Power/frequency characteristics of the British grid system", *Proceedings of the IEE - Part A: Power Engineering*, vol. 106, no. 26, pp. 154-162, 1958
[2] G. J. Berg, "System and load behaviour following loss of generation. Experimental results and evaluation", *Proceedings of the Institution of Electrical Engineers*, vol. 119, no. 10, pp. 1483-1486, 1972

System frequency response (SFR) modelling

Most modern approaches tend to adopt an SFR model that is developed by expanding out the terms of the swing equation and treating the system as a single machine (with a single frequency).

A generic SFR model structure is shown below (quantities in MW and Hz):



The underlying assumptions for such an SFR model are as follows:

- The model ignores network topology, i.e. all generators and loads are lumped at one node. One implication of this assumption is that if there are network constraints that limit the ability for a unit to deliver PFR, then this is not captured.
- Only one (average) frequency in the system (not a bad assumption for smaller highly meshed systems).
- Assumes voltages in the system are well regulated pre- and post- disturbance.
- Simplified dynamic models for governors / primary frequency response.

System frequency response (SFR) modelling

One of the earlier SFR models (Anderson and Mirheydar [1]) is based on the following assumptions:

- PFR is assumed to be dominated by steam-reheat turbine governors modelled as lead-lag blocks with droop feedback, i.e. $P(s) = \frac{K_m(1+F_H T_R s)}{R(1+T_R s)} \Delta\omega$
- Load relief / damping is built into the inertia block, i.e. $\Delta P_{load} = D\Delta\omega$
- No other consideration of demand response, i.e. $G(s) = 0$

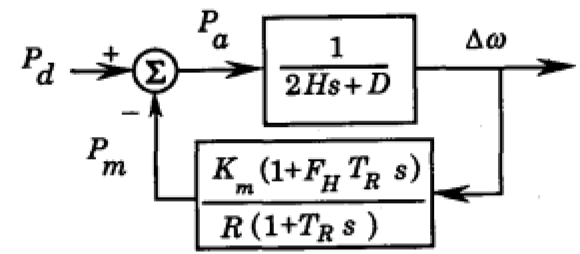
There is a closed-form solution for the frequency deviation $\Delta\omega$:

$$\Delta\omega(t) = \frac{RP_d}{DR + K_m}\left[1 + \alpha e^{-\xi\omega_r t}\sin(\omega_r t + \phi)\right]$$

where:

$$\alpha = \sqrt{\frac{1 - 2T_R\xi\omega_n + T_R^2\omega_n^2}{1-\xi}} \qquad {\omega_n}^2 = \frac{DR + K_m}{2HRT_R} \qquad \omega_r = \omega_n\sqrt{1-\xi^2}$$

$$\phi = \tan^{-1}\left(\frac{\omega_r T_R}{1 - \xi\omega_r T_R}\right) - \tan^{-1}\left(\frac{\sqrt{1-\xi^2}}{-\xi}\right) \qquad \xi = \left(\frac{2HR + (DR + K_m F_H)T_R}{2(DR + K_m)}\right)\omega_n$$



P_d is the active power disturbance (pu)
P_a is the accelerating power (pu)
P_m is the PFR mechanical power (pu)
$\Delta\omega$ is the change in angular frequency (pu)
K_m is the PFR power gain factor (pu)
F_H is the fraction of power generated by the HP turbine (pu)
T_R is the reheat time constant (s)
R is the PFR droop coefficient (pu)
H is the system inertia constant (s)
D is the load relief / damping factor (pu)

[1] P. M. Anderson and M. Mirheydar, "A low-order system frequency response model“, *IEEE Transactions on Power Systems*, vol. 5, no. 3, pp. 720-729, 1990

System frequency response (SFR) modelling

A simpler and more practical SFR model is presented here based on the following assumptions:

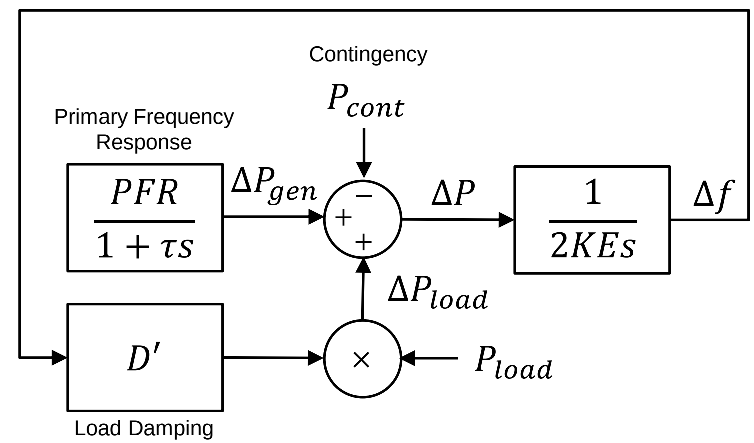
- PFR is assumed to be a generic active power injection with no frequency feedback modelled as a first-order lag block , i.e. $P(s) = \frac{PFR}{(1+\tau s)}$
- No other consideration of demand response, i.e. $G(s) = 0$

There is a closed-form solution for the frequency deviation Δf :

$$\Delta f(t) = \frac{PFR - P_{cont}}{D}\left(1 - e^{-\frac{D}{2H}t}\right) - \frac{PFR\,\tau}{D\tau - 2H}\left(e^{-\frac{t}{\tau}} - e^{-\frac{D}{2H}t}\right)$$

where:

$$D = D' P_{load} \qquad H = \frac{KE}{f_n}$$



P_{cont} is the active power disturbance (MW)
PFR is the PFR quantity (MW)
τ is the PFR time constant (s)
KE is the system inertia (MW.s)
D' is the load relief / damping factor (% MW/Hz)

An analytical expression for the frequency nadir can also be found:

$$\Delta f_{nadir} = \frac{PFR}{D}\left[(C + K - 1)B^{-C} - CB^{-\frac{C}{A}} - K + 1\right]$$

where: $K = \frac{P_{cont}}{PFR}$ $\quad A = \frac{D\tau}{2H}$ $\quad C = \frac{A}{A-1}$

$$B = 1 + K(A - 1)$$

[1] J. Susanto, A. Fereidouni, P. Mancarella and D. Sharafi, “Closed-Form Solutions for a Low-Order System Fast Frequency Response Model”, arXiv preprint arXiv:2010.13401, 2020, https://arxiv.org/abs/2010.13401

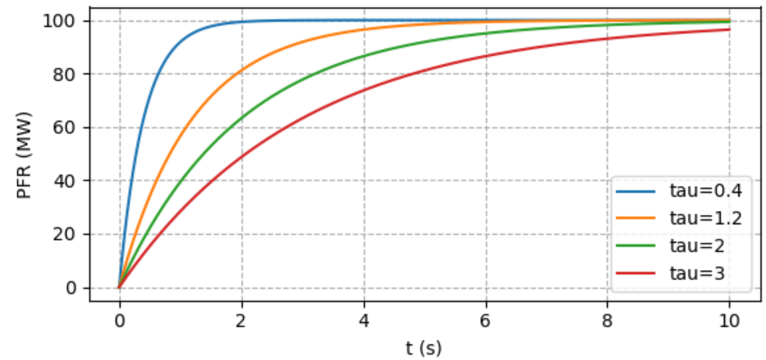
System frequency response (SFR) modelling

Modelling PFR as a first-order lag provides a practical approximation for the aggregate PFR that has reasonable fit with actual responses.

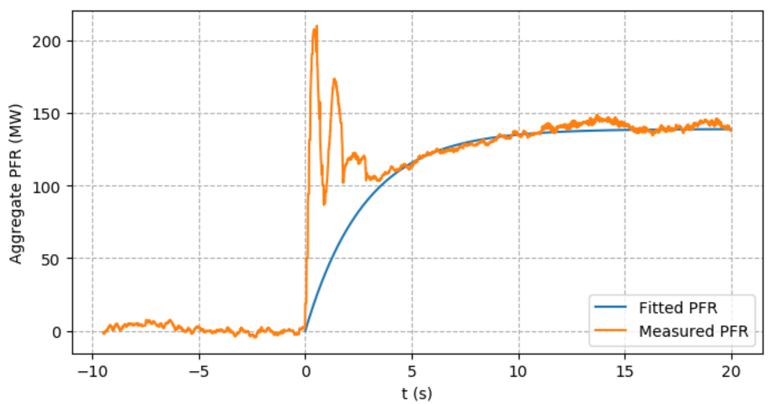
The time-domain expression for the PFR is:

$$PFR(t) = PFR\ (1 - e^{-\frac{t}{\tau}})$$

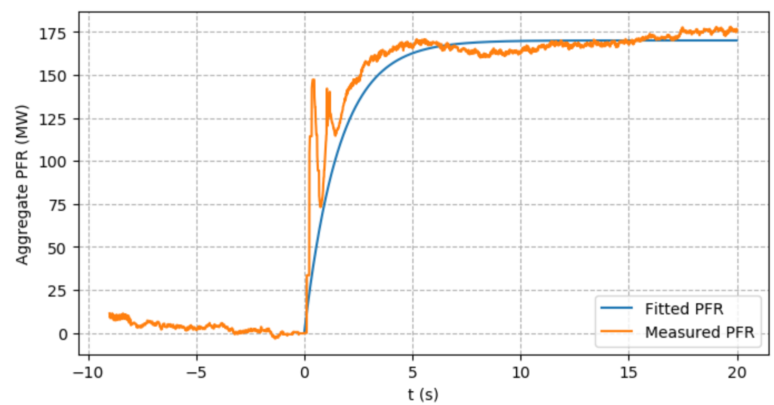
The plot on the right shows how the speed of response parameter τ affects the PFR trace.



Two past contingency events in the SWIS with two different generating fleet compositions are shown below with fitted first-order lag PFR traces overlaid:



“Slower” Fleet ($\tau = 2.8$)



“Faster” Fleet ($\tau = 1.6$)

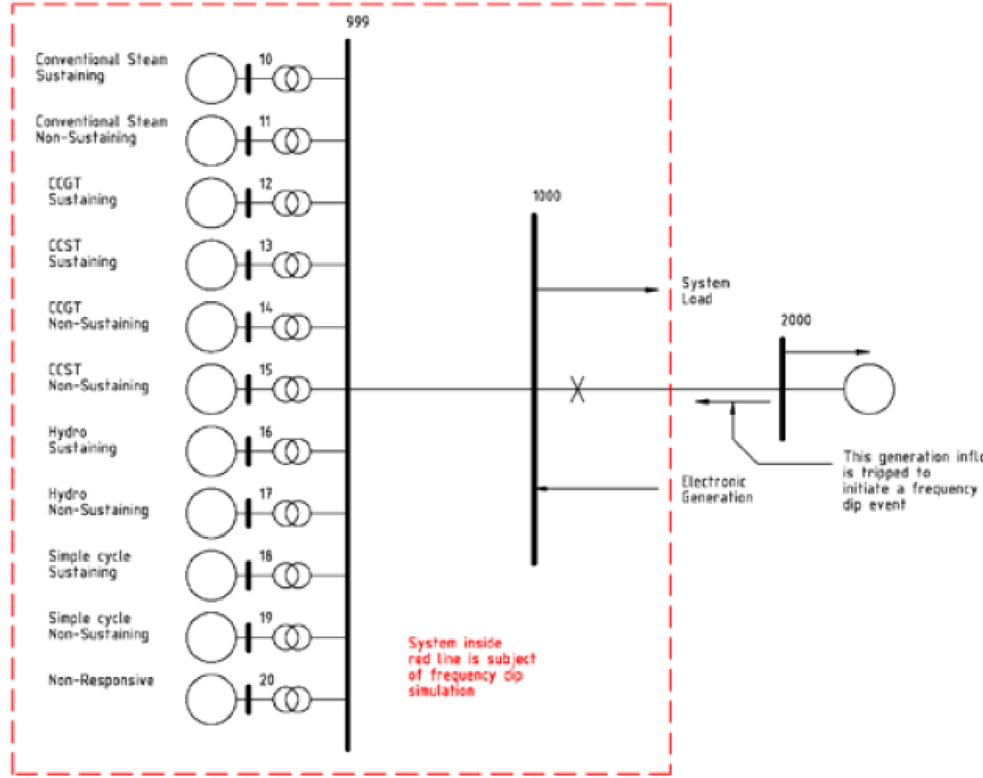
System frequency response (SFR) modelling

More complex SFR models include more detailed representations of PFR, often breaking up the aggregate PFR into separately parameterised PFR models based on technology type, e.g. Microcosm model [1] [2].

Other SFR models used in practice include full dynamic models for generators providing PFR, as well as demand response / load resources that are tripped via under-frequency relays [3].

These more complex SFR models generally do not have analytical solutions and are solved numerically.

Microcosm SFR model [1]:



[1] J. Undrill, "Primary Frequency Response and Control of Power System Frequency", Lawrence Berkeley National Laboratory, 2018
[2] J. Undrill, P. Macklin and J. Ellis, "Relating the Microcosm Simulations to Full-Scale Grid Simulations", Lawrence Berkeley National Laboratory, 2018
[3] G. A. Chown, J. Wright, R. van Heerden and M. Coker, "System inertia and Rate of Change of Frequency (RoCoF) with increasing nonsynchronous renewable energy penetration", CIGRE 2017 8th Southern Africa Regional Conference, 2017

Load relief / damping factor

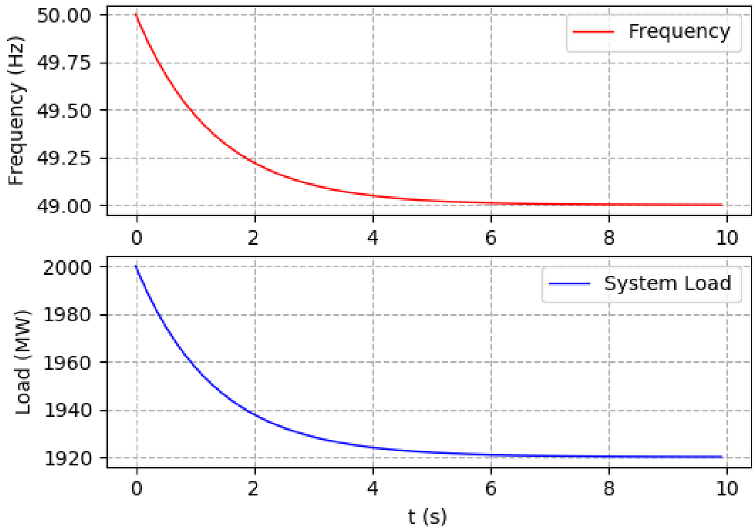
Load relief (or damping) is a crucial element in the SFR model and reflects the natural sensitivity of demand / loads to changes in frequency, the most common mechanism being the proportional relationship between frequency and power consumption in induction motors.

The total load in a system tends to decrease when frequency decreases (and vice versa) and is typically expressed as some variant of the following equation in SFR models:

$$P_{load}(f) = P_{load,0}(1 + D'\Delta f)$$

where

- $P_{load}(f)$ is the system load at frequency f (MW)
- $P_{load,0}$ is the system load at nominal frequency f_n (MW),
- D' is the frequency-dependent load relief factor (% MW per Hz)
- $\Delta f = f - f_n$ is the frequency deviation from nominal frequency (Hz)
- f_n is the nominal frequency (e.g. 50 Hz)

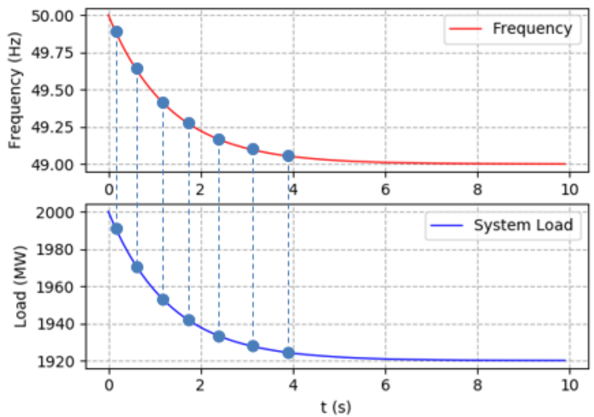


Estimating load relief factors

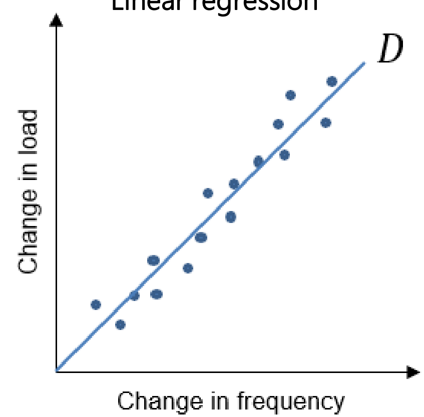
Some early estimates of load-frequency characteristics were done by conducting live tests on the system, such as the intentional tripping of generators and transmission lines, e.g. Great Britain in the 1950s [1], Norway in the 1970s [2] and Ireland in the 1990s [3].

The standard estimation approach has evolved to taking sample measurements of frequency and aggregate system load from the SCADA system post-contingency [4]. Because load relief is modelled as a linear function of frequency, then the load relief factor can be estimated by a linear regression (with zero-intercept):

Measurement and sampling



Linear regression



[1] M. Davies, F. Moran and J. I. Bird, "Power/frequency characteristics of the British grid system“, *Proceedings of the IEE - Part A: Power Engineering*, vol. 106, no. 26, pp. 154-162, 1958
[2] G. J. Berg, "System and load behaviour following loss of generation. Experimental results and evaluation“, *Proceedings of the Institution of Electrical Engineers*, vol. 119, no. 10, pp. 1483-1486, 1972
[3] J. W. O'Sullivan and M. J. O'Malley, "Identification and validation of dynamic global load model parameters for use in power system frequency simulations“, *IEEE Transactions on Power Systems*, vol. 11, no. 2, pp. 851-857, 1996.
[4] R. Pearmine, Y. h. Song, T. G. Williams and A. Chebbo, "Identification of a load-frequency characteristic for allocation of spinning reserves on the British electricity grid“, *IEE Proceedings - Generation, Transmission and Distribution*, vol. 153, no. 6, pp. 633-638, November 2006.

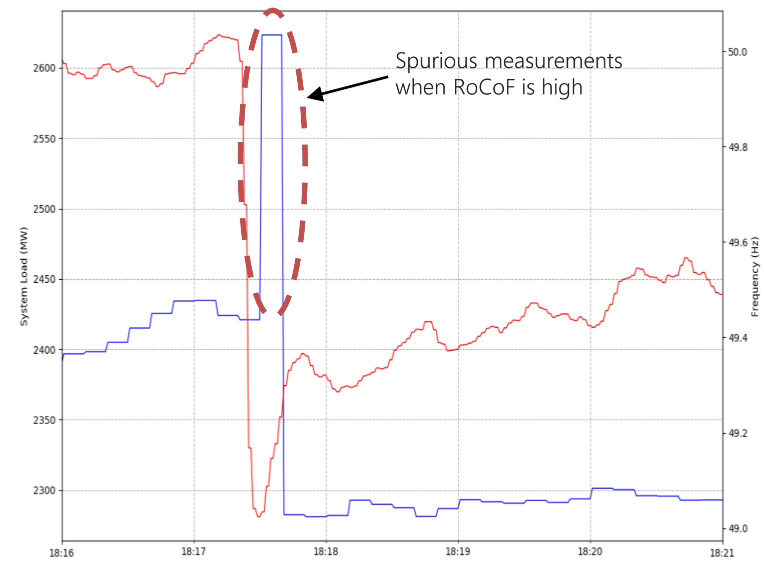
Estimating load relief factors

The aggregate system load is generally not directly measurable, but is typically a composite sum of all generation in the system ("as-generated" values). This leads to a number of problems in with the standard estimation approach:

- SCADA measurements have low sample resolution (e.g. 4s), are not time-synchronised and subject to the effects of time averaging as generators are spread out across a relatively large geographic area
- Measurement of as-generated values is actually a measurement of electrical output, which is not equivalent to mechanical output under transient conditions, i.e. when rate of change of frequency is high, due to speed-voltage terms in synchronous machine stator flux equations
- The effects of load resource PFR (triggered by under-frequency relays) needs to be manually removed from the system load trace

It is difficult to reliably select ordered pairs of frequency and system load post-contingency without significant amounts of subjective inference.

Actual SCADA measurements from a generator contingency



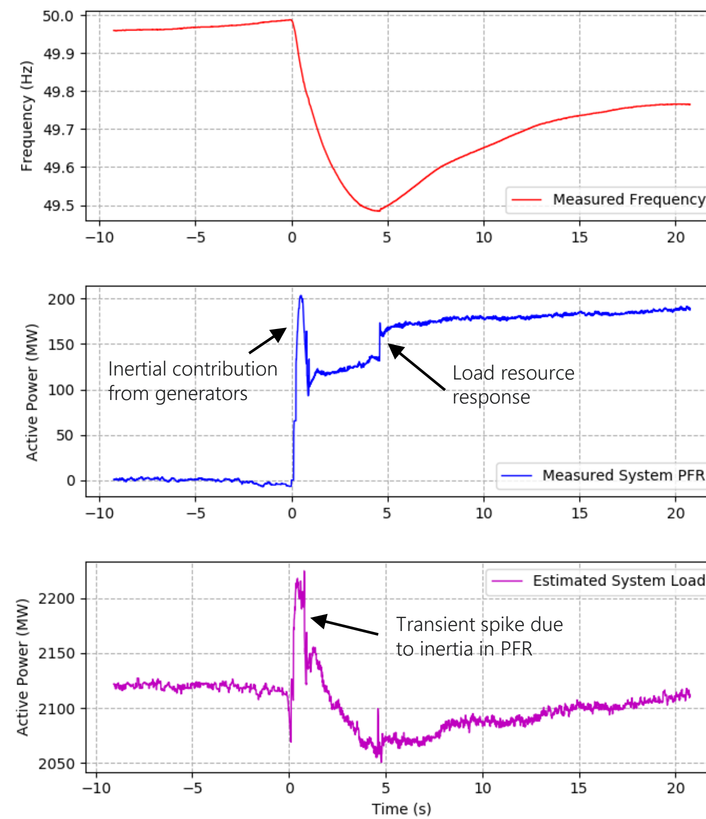
Estimating load relief factors

If high-resolution measurement data for major generators or PFR sources is available (e.g. from fault recorders or PMUs), then an alternative method for estimating the aggregate system load trace is to work backwards from the swing equation [1]:

$$\Delta P_{load}(t) = \Delta PFR(t) + \Delta P_{cont}(t) - \left(\frac{2\,\overline{KE}}{f_n}\right)\left(\frac{\Delta f}{\Delta t}\right)$$

where

- $\Delta PFR(t)$ is the sum of measured active power changes for all PFR sources (in MW)
- $\Delta P_{cont}(t)$ is the measured active power change for the tripped unit (in MW)
- $\overline{KE}$ is the estimated system inertia (in MW.s)
- $\frac{\Delta f}{\Delta t}$ is the sample-by-sample measured RoCoF (in Hz/s).



Note that the transient spike at the onset of the contingency (t = 0s) occurs because the measured system PFR from the high speed data also includes the inertial responses of the generators (but should theoretically be removed).

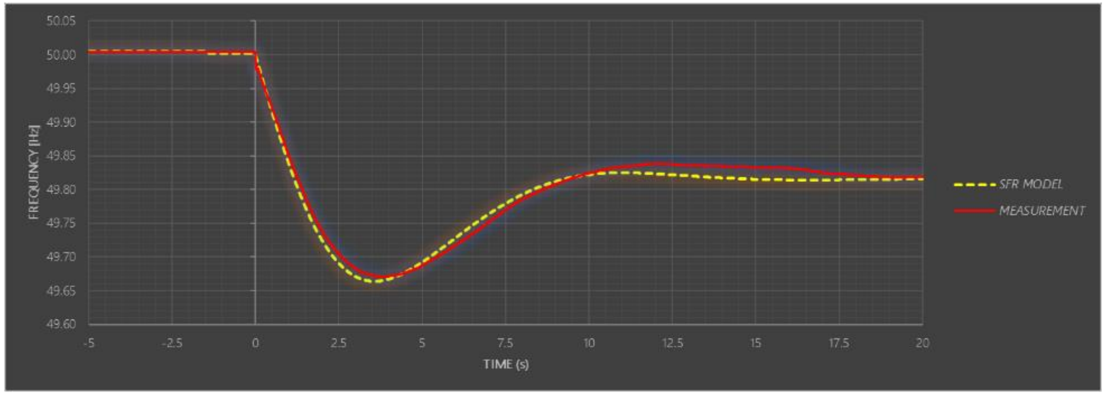
[1] J. Susanto, F. Shahnia, D. Sharafi and L. Kwek, "Estimating a Power System's Load Relief Factor Using the High-Resolution Data of Fault Recorders", *2019 9th International Conference on Power and Energy Systems (ICPES)*, Perth, Australia, 2019

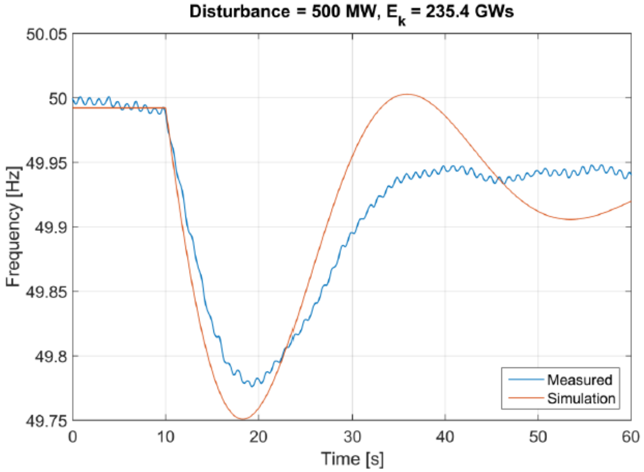
Validity of SFR models

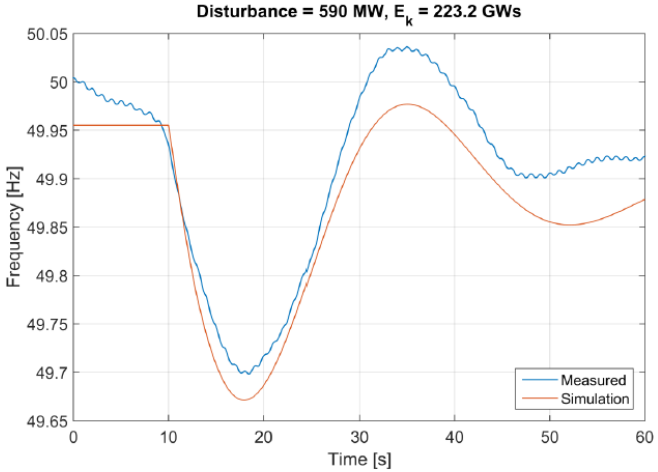
SFR models can be benchmarked against actual events to test the validity of the model.

- **Nordic system:** the SFR model developed for the Nordic system was validated against several large historical disturbances between August 2015 and August 2016. Two of these validation exercises are shown in the plots on the right [1].

- **SWIS:** the plot below shows a comparison of the developed SFR model against measured frequency for a generator contingency event in May 2020:







[1] ENTSO-E, Nordic Future system inertia v2, 2018, https://www.entsoe.eu/Documents/Publications/SOC/Nordic/2018/System-inertia.zip

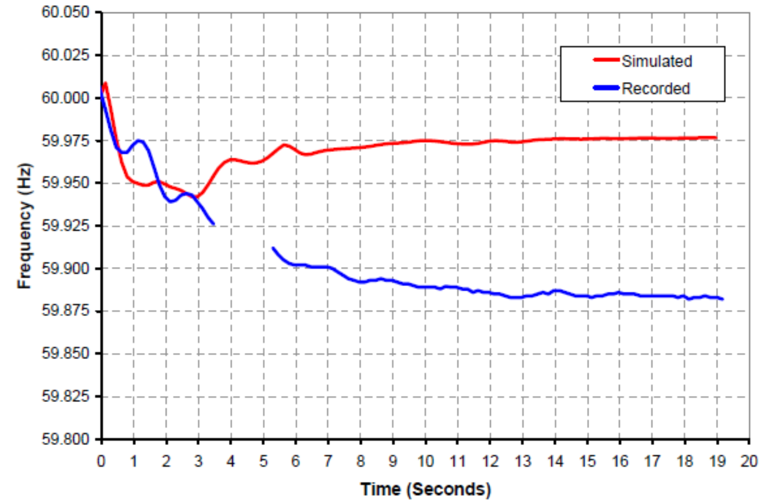
The case against using full network models

There is a temptation to think that that more detailed models are always better, but experience in different jurisdictions (e.g. Eastern Interconnection, AEMO, etc) suggest that this is not necessarily true for frequency stability analysis.

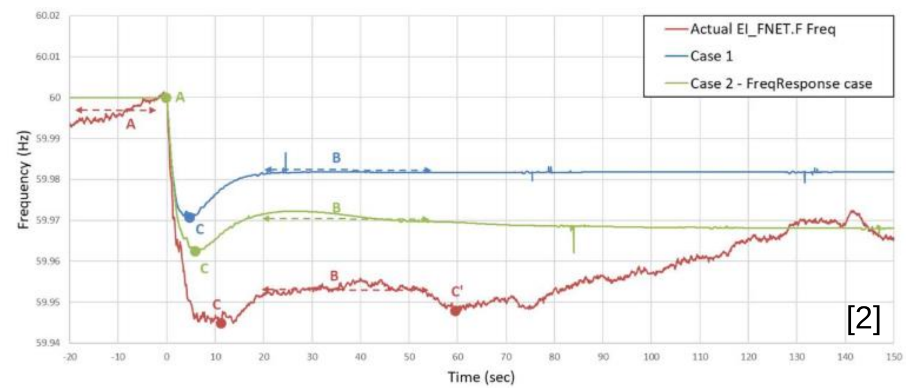
For example, the plot on the right shows a loss of 4,500 MW of generation in the Eastern Interconnection (EI) [1], indicating a material divergence of the measured system frequency against the simulated frequency (using a full network model).

The Eastern Interconnection Planning Collaborative (EIPC) created a Frequency Response Task Force (FRTF) in 2017, partly to improve the simulation models.

While progress has been made, the latest EIPC report from October 2020 [2] continues to encounter difficulties in aligning the base case model simulations with actual historical events. The plot on the right shows a benchmarking exercise for an event in March 2019. Note that there are two Base Cases, reflecting different levels of non-responsive / de-tuned governor models (39% and 53% respectively).



[1]



[2]

[1] J. Eto et al, “Use of a Frequency Response Metric to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation”, Lawrence Berkeley National Laboratory, 2010

[2] EIPC Technical Committee, “Frequency Response Working Group 2020 Final Report”, EIPC, 2020

The case <u>against</u> using full network models

Interesting observations by John Undrill [1]:

- Production-grade network models were historically developed to analyse transmission issues and are generally ill-suited for frequency control issues, with many dynamic models largely based on assumptions.

- There are many operating modes for thermal plant, chosen at the discretion of plant operators, that are not accurately captured in standard network models. Dynamic models tend to be overly detailed with regard to the internal operation of power plant components (e.g. turbines, governors, etc), but lacking detail in the modes of operation that may be in effect, e.g. mill configurations, steam bypass in combined-cycle gas power plants.

Drawing on AEMO's experience in the SWIS, the following observations are also made on the use of full network models:

- **Dynamic models not reflective of reality**, where the PFR performance of generating units in the full network model were generally not tuned correctly, and in nearly all cases, were misaligned with measurements from actual events (often overestimating the PFR capability in the dynamic model).

- **Study case configuration was cumbersome**, particularly when trying to set up the full model for edge cases or future scenarios where loads and generation dispatch have to be scaled. Configuring the full model required careful consideration of many parameters that were largely irrelevant to frequency stability and control, e.g. load diversity, transformer tap positions and control, reactive plant settings, etc.

- **Numerical (non-convergence) and/or dynamic model errors**, often due to case configuration issues (e.g. voltage stability / control issues due to inappropriate load scaling), rather than genuine frequency stability issues. EIPC reported similar problems in their scaled up 10,000 MW benchmark simulation test [2].

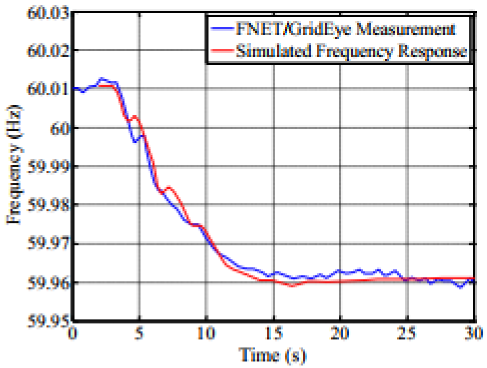
[1] J. Undrill, P. Macklin and J. Ellis, "Relating the Microcosm Simulations to Full-Scale Grid Simulations", Lawrence Berkeley National Laboratory, 2018
[2] EIPC Technical Committee, "Frequency Response Working Group 2020 Final Report", EIPC, 2020

The case for using full network models

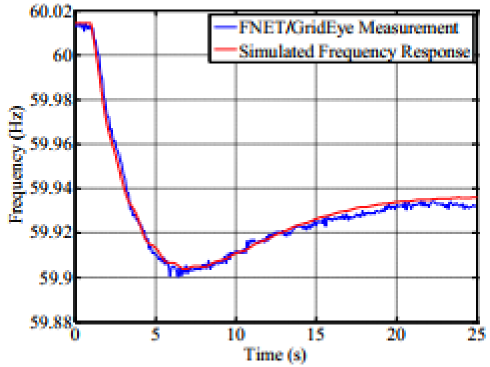
The significant efforts (ongoing since the mid-1990s) by WECC in tuning and validating their models has shown that full network models can also accurately simulate system frequency response [1].

Moreover, there is evidence to suggest that full network models can be tuned to yield acceptable results. For example, the EI and ERCOT base case models were adjusted by Liu et al as follows [2]:

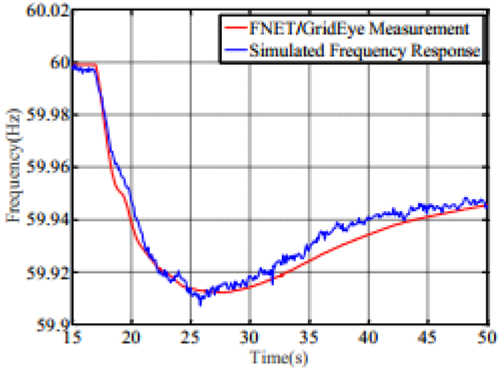
- Inclusion of deadbands into governor dynamic models
- Adjusting generator inertia values to align with the NERC database
- Tuning of governor non-responsive ratios based on operational data



Eastern Interconnection



ERCOT



WECC

[2]

[1] Western Electricity Coordinating Council Modeling and Validation Work Group, "Model Validation and System Performance Analysis for PDCI RAS Event that Occurred on May 30, 2013," Feb. 2014.
[2] Y. Liu, S. You, J. Tan, Y. Zhang and Y. Liu, "Frequency Response Assessment and Enhancement of the U.S. Power Grids Toward Extra-High Photovoltaic Generation Penetrations—An Industry Perspective“, IEEE Transactions on Power Systems, vol. 33, no. 3, pp. 3438-3449, 2018

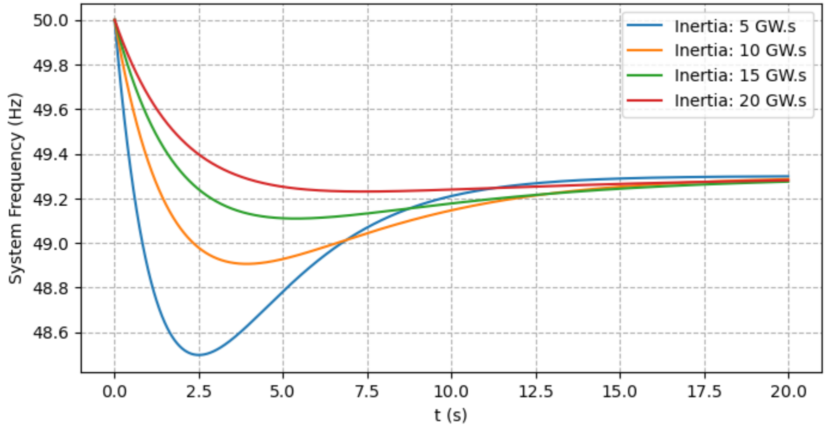
APPROACHES FOR MANAGING SYSTEM SECURITY

Factors affecting system frequency response

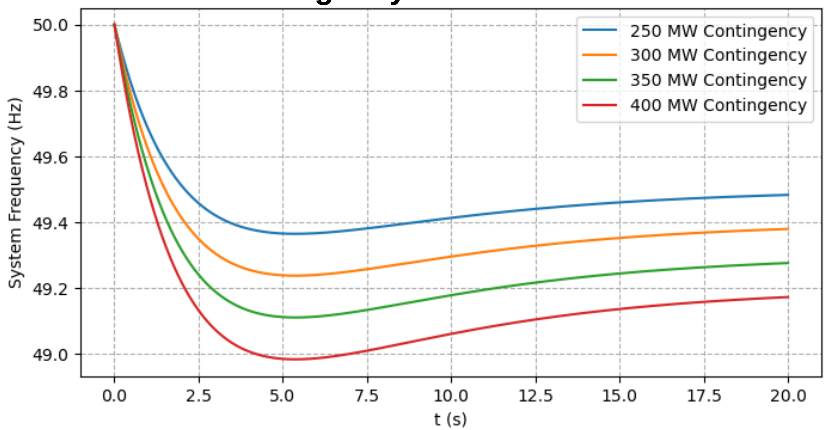
The key factors affecting system frequency response are illustrated using an SFR model and performing sensitivities on the following base case:

- System inertia, KE — $15\ GW.s$
- System load, P_{load} — $2.5\ GW$
- Load relief factor, D — $4\ \%\ MW/Hz$
- Contingency size, P_{cont} — $350\ MW$
- PFR quantity, PFR — $0.85 \times P_{cont}$
- PFR speed of response, τ — 2

Effect of system inertia

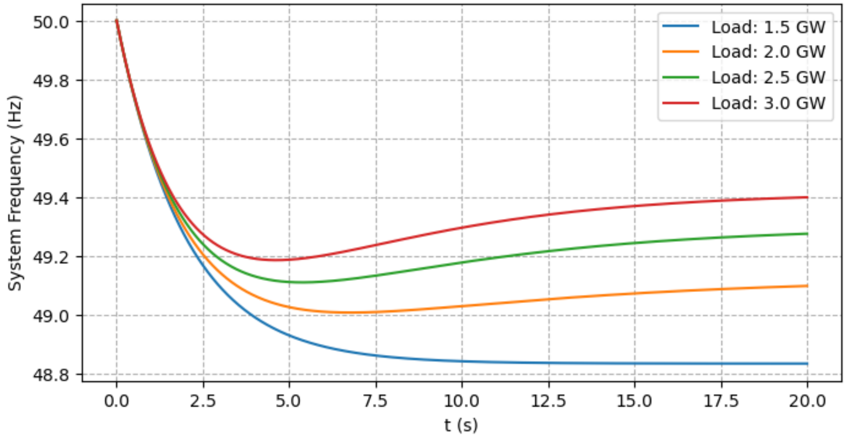


Effect of contingency size

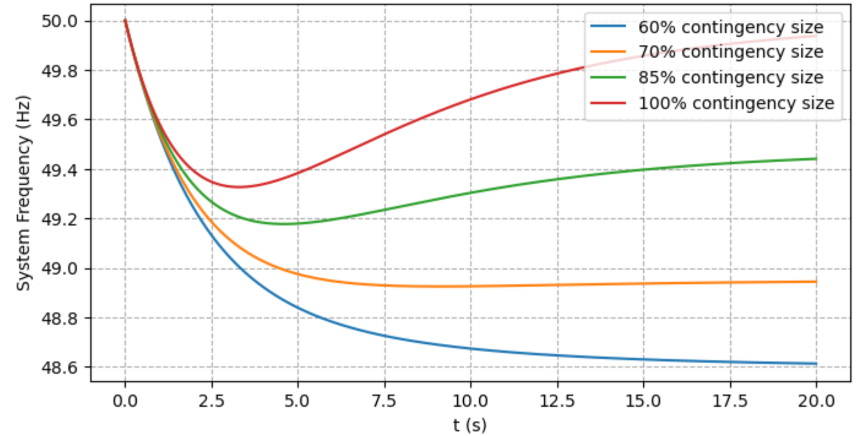


Factors affecting system frequency response

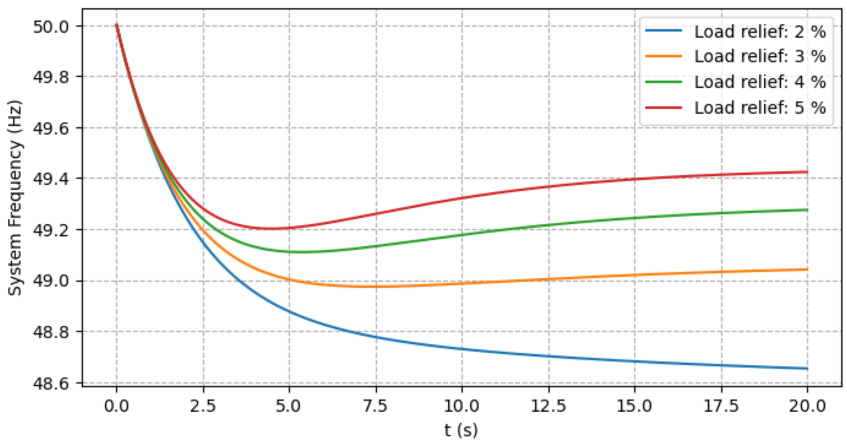
Effect of system load



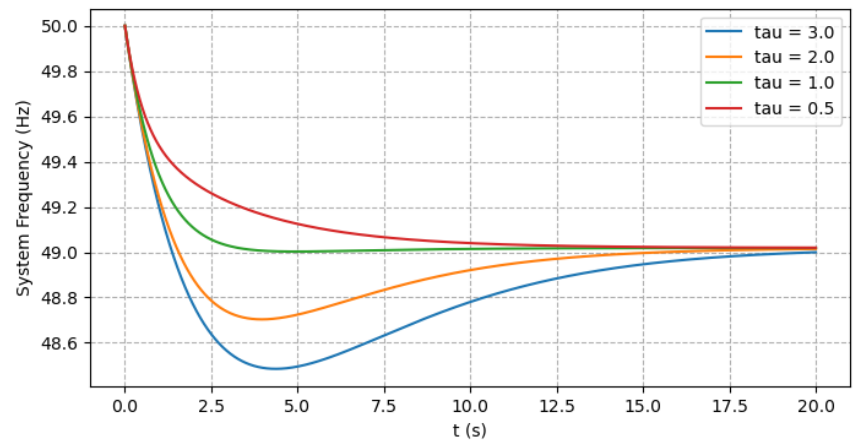
Effect of PFR quantity



Effect of load relief factor



Effect of PFR speed of response



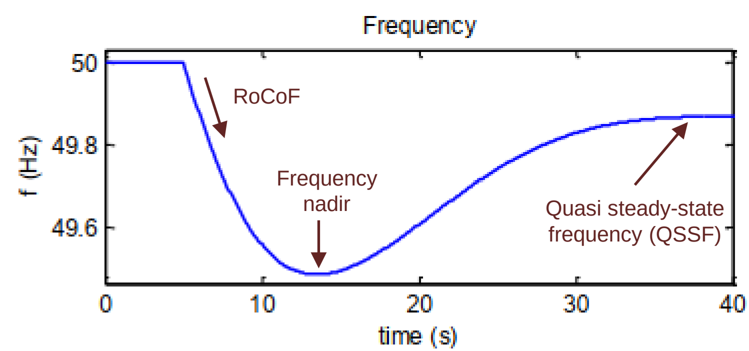
Factors affecting system frequency response

Summary of the main factors affecting system frequency response (*ceteris paribus*):

Factor	Higher Frequency Nadir	Lower RoCoF	Higher QSSF (settling frequency)
System inertia	Higher inertia	Higher inertia	No effect
System load / load relief	Higher load / load relief	Higher load / load relief	Higher load / load relief
Contingency size	Smaller contingency	Smaller contingency	Smaller contingency
PFR quantity	Higher PFR quantity	Negligible effect (unless coupled with fast PFR response)	Higher PFR quantity
PFR speed of response	Fast PFR response	Very fast PFR response	No effect

Points to note:

- In many ways, the factors affecting system frequency response are inter-related, e.g. low system loads will tend to result in lower system inertia, but also smaller contingency sizes
- System inertia by itself is not the most critical factor – there are multiple levers that can be pulled to maintain system security



Operational implications of poor system frequency response

Operational implications and consequences for not properly managing system frequency response performance:

Frequency Performance	Operational Implications and Risks

Lower frequency nadir	• Increased system security risks after a contingency:
	  • Risk of under-frequency load shedding (UFLS)
	  • Risk of system black event (e.g. South Australia in 2016)

Higher RoCoF	• Increased risk of sympathetic generation tripping on RoCoF-based anti-islanding protection (including rooftop PV inverters) • Increased risk of RoCoF protection relay activation • Risk of synchronous generator pole slipping at high RoCoFs, e.g. 1.5 – 2 Hz/s [1] • Risk that UFLS doesn't work properly because frequency decline is too fast

[1] KEMA / DNV GL, "RoCoF—An Independent Analysis on the Ability of Generators to Ride Through Rate of Change of Frequency Values up to 2 Hz/s," 2013, http://www.eirgridgroup.com/site-files/library/EirGrid/DNV-KEMA_Report_RoCoF_20130208final_.pdf

Operational levers for managing system security

For each factor affecting system frequency response, the following operational levers are possible for improving frequency performance:

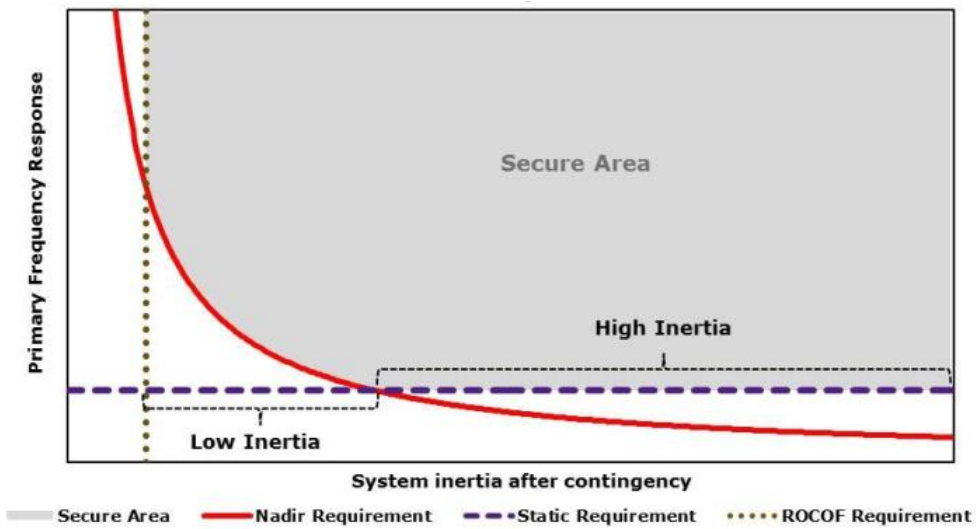
Factor	Operational Levers	Possible Mechanisms
System inertia	Increase system inertia	• RoCoF limits / inertia floor constraints • Must-run synchronous unit constraints • Synthetic / virtual inertia services • Special inertia services, e.g. condensers • Out of market interventions (dispatch out-of-merit)
System load / load relief	Increase system load	• Demand flexibility services
Contingency size	Reduce largest contingency size	• Contingency size constraints • Out of market interventions (dispatch out-of-merit)
PFR quantity	Increase PFR reserves	• Dynamic PFR reserve constraints based on system conditions • Mandatory PFR requirements
PFR speed of response	Increase PFR speed of response	• Fast frequency response • Fast load resources (e.g. under-frequency relays) • Decrease deadbands on PFR response

Frequency response security maps

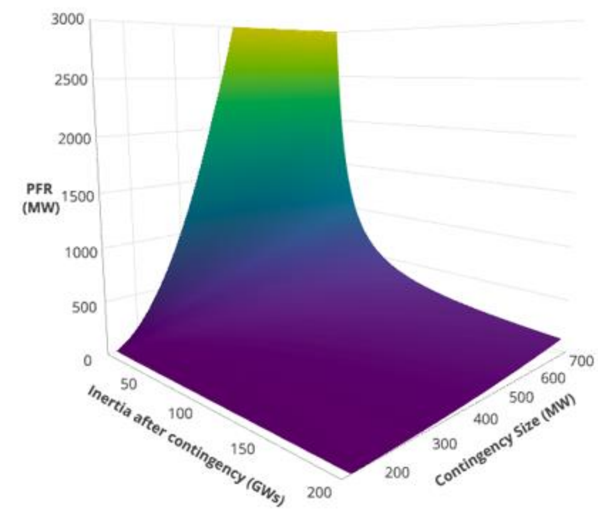
A key point to highlight again is that managing system security is a **multi-dimensional problem** that involves balancing a series of trade-offs, e.g. higher inertia vs lower contingency size vs more PFR reserves vs faster speed of response, etc.

One way to visualise some of the trade-offs is through frequency response security maps:

Conceptual diagram of a security map [1]:



Security map taking contingency size into account [2]:



Note that in this security map, the contingency size, system load and PFR speed of response is constant.

[1] P. Mancarella et al, “Power system security assessment of the future National Electricity Market”, Melbourne Energy Institute, 2017
[2] S. Püschel-LØvengreen and P. Mancarella, "Frequency Response Constrained Economic Dispatch with Consideration of Generation Contingency Size," 2018 Power Systems Computation Conference (PSCC), Dublin, 2018

RoCoF limits and inertia floor constraints

An increasing number of jurisdictions are imposing more stringent RoCoF withstand requirements (see table right) [1].

Based on the linearised swing equation at the onset of a disturbance, a RoCoF limit can be translated into an inertia floor constraint:

$$KE_{sys} \geq \frac{f_n}{2} \times \frac{\Delta P_{cont,max}}{\left[\frac{d\Delta f}{dt}\right]_{limit}}$$

where $\Delta P_{cont,max}$ is the maximum credible contingency size (MW)

The RoCoF limit can also be framed as a contingency size constraint:

$$\Delta P_{cont} \leq \frac{2}{f_n} \times \frac{\left[\frac{d\Delta f}{dt}\right]_{limit}}{KE_{sys}}$$

Rule changes for RoCoF withstand requirements [1]

Country/ region	Australia [4]	Great Britain [6]	Ireland/No-rth Ireland [26]
Current requirement	Automatic access standard: ±4 Hz/s for 0.25 s, minimum access standard: ±1 Hz/s for 1 s	0.125 Hz/s for 0.5 s	0.5 Hz/s for 0.5 s
Future requirement	Non-synchronous systems: ±4 Hz/s for 0.25 s & ±3 Hz/s for 1 s Synchronous systems: automatic access standard: ±4 Hz/s for 0.25 s & ±3 Hz/s for 1 s, minimum access standard: ±1 Hz/s for 1 s	New synchronous units and non-synchronous units: 1 Hz/s for 0.5 s Incumbent synchronous units: 0.5 Hz/s for 0.5 s	1 Hz/s for 0.5 s

Examples of jurisdictions with inertia floors:

- Australia NEM (variable by state)
- ERCOT (“critical inertia level”)
- Eirgrid
- Great Britain
- Nordic

[1] J. Fang, H. Li, Y. Tang and F. Blaabjerg, "On the Inertia of Future More-Electronics Power Systems“, *IEEE Journal of Emerging and Selected Topics in Power Electronics*, vol. 7, no. 4, pp. 2130-2146, 2019

Dynamic PFR reserve requirements: ERCOT case study

Pre-2015, ERCOT carried a constant 2,800 MW of PFR reserve all the time, but this has since changed to be a dynamic requirement based on system inertia.

The PFR reserve requirements were calculated via offline studies [1].

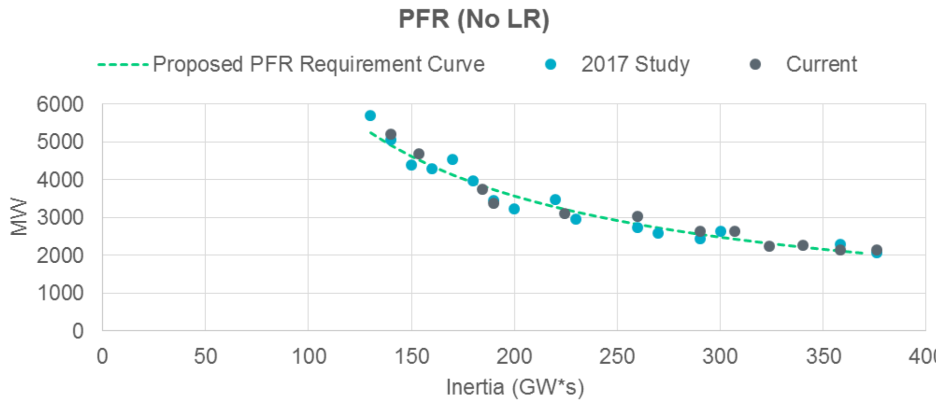
- The PFR reserve requirement follows a familiar exponential relationship with respect to inertia:

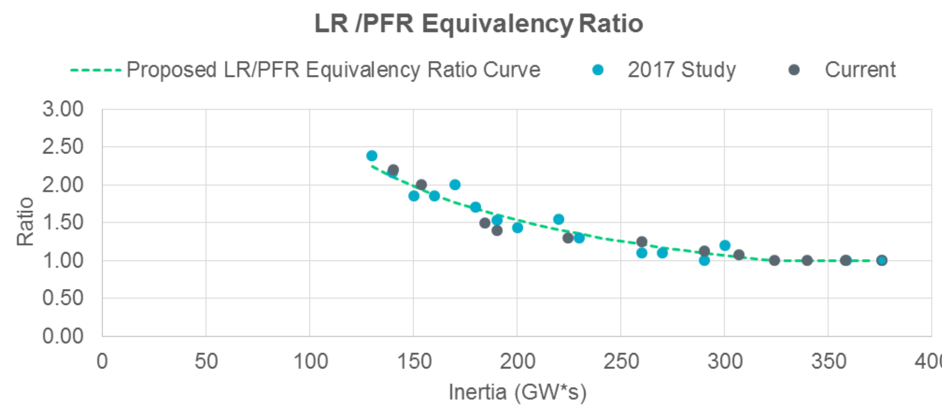
$$PFR\ (No\ LR) = 399275 \times KE^{-0.890}$$

- The studies include an equivalency ratio for load resource PFR (which are tripped via under-frequency relays hence very fast) vs normal generation PFR:

$$L\,R/P\,FR = 173.28 \times KE^{-0.892}$$

Example: at inertia of 200 GWs, 1 MW of load resource PFR is worth 1.535 MW of generation PFR





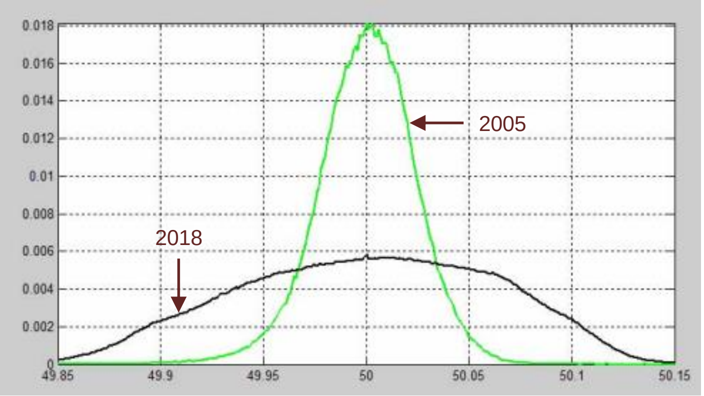
[1] ERCOT,"2017 Responsive Reserve (RRS) Study", 2017, http://www.ercot.com/content/wcm/key_documents_lists/108744/05._RRS_Study_2017_Methodology_11022017.docx

Mandatory PFR requirements

For a number of years, the Australian NEM saw a degradation in frequency control performance, driven in large part by synchronous generators decreasing (or removing) their responsiveness to frequency deviations (e.g. by de-tuning / disabling speed-droop controls and/or widening deadbands) in order to avoid dis-incentives associated with being responsive to frequency, e.g. dispatch target non-compliances [1].

In June 2020, the rules were changed to require mandatory PFR for scheduled and semi-scheduled generators with a deadband of 50 Hz ± 15 mHz.

Frequency distribution in the NEM [1]



Mandatory PFR requirements are also in effect in the following jurisdictions:

- Brazil
- Great Britain
- Ireland
- Singapore
- Spain
- United States (via FERC order 842) [2]
- Western Australia (SWIS)

[1] AEMC, "Consultation Paper: Primary Frequency Response Rule Changes" 2019, https://www.aemc.gov.au/sites/default/files/2019-09/Primary%20frequency%20response%20rule%20changes%20-%20Consultation%20paper%20-%20FOR%20PUBLI..._1.pdf
[2] FERC order No. 842 (RM16-6-000), February 15, 2018. Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response (Final Rule), https://www.ferc.gov/news-events/news/ferc-revises-requirements-provision-primary-frequency-response

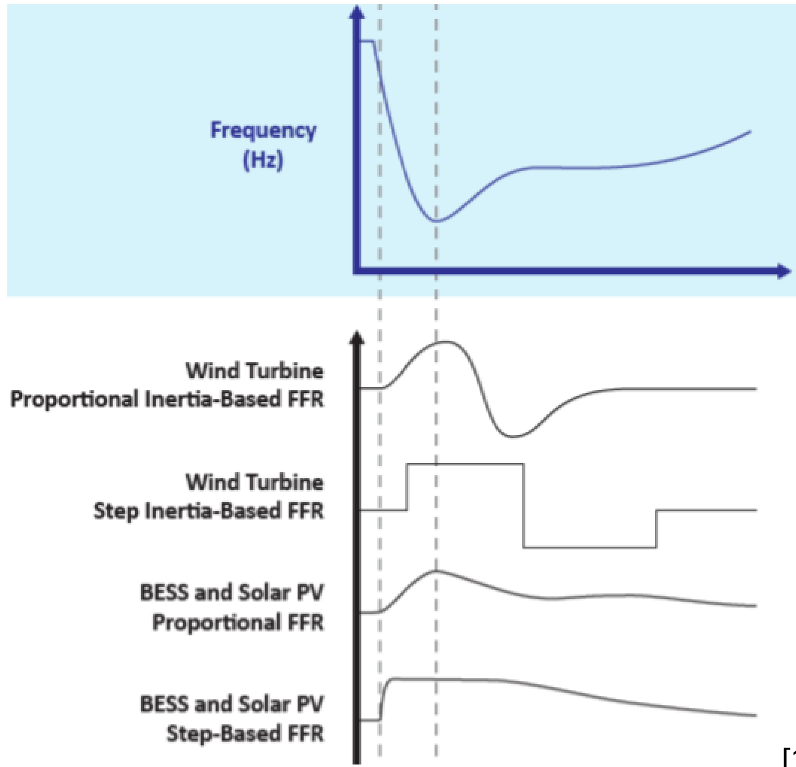
Fast frequency response (FFR)

As the name suggests, fast frequency response is PFR delivered very quickly with the aim of improving the frequency nadir and RoCoF.

FFR can be provided by a variety of generation resources, but is typically activated by fast acting control systems based on measured local frequency, and may include one or a combination of the following methods [1]:

- **Proportional response:** injection of active power that is proportional to the measured frequency deviation
- **Step response:** injection of constant amount of active power once measured frequency and/or RoCoF reaches a preset threshold
- **Derivative response:** injection of active power that is proportional to the measured RoCoF, e.g. inertia emulation

Note that load responses and inertial responses are sometimes included in the definition of FFR, but these responses are treated separately in this discussion.



[1]

[1] NERC IRPTF, "Fast Frequency Response Concepts and Bulk Power System Reliability Needs", NERC, 2020, https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf

Fast frequency response (FFR)

For the specification and assessment of FFR, the following parameters should be considered [1]:

- Type of response, i.e. proportional, step or derivative
- Magnitude of response
- Activation delay
- Response time
- Sustaining time
- Availability of response, e.g. unavailable operating conditions

It is important to note that **FFR is not equivalent to inertia**:

- FFR is not an intrinsic, but a control response, requiring the measurement of frequency (and/or calculation of RoCoF) and control logic to deliver the response (with an inherent activation delay)

- FFR can fail to activate (e.g. control system failure) or activate incorrectly (e.g. due to measurement or control logic errors)

[1] NERC IRPTF, "Fast Frequency Response Concepts and Bulk Power System Reliability Needs", NERC, 2020, https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf

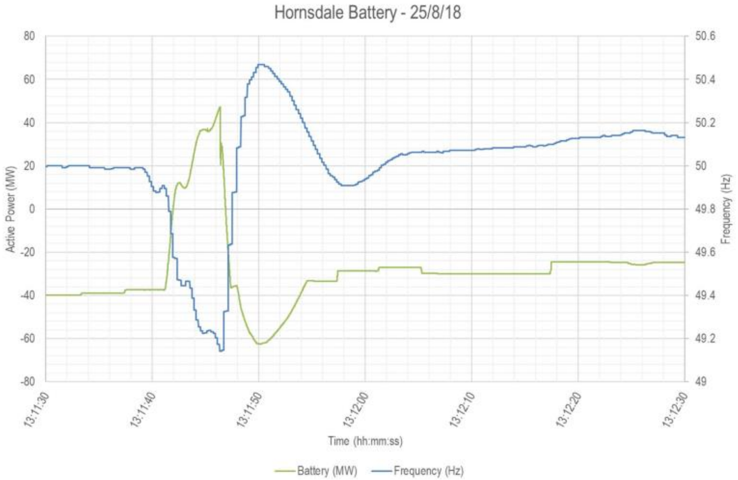
Fast frequency response (FFR): Hornsdale case study

The **Hornsdale Power Reserve (HPR)** is a 100 MW / 129 MWh Li-ion battery energy storage system (BESS) co-located with the 316 MW Hornsdale wind farm in South Australia (SA). A 50 MW / 64.5 MWh expansion is currently under construction.

HPR participates regularly in the NEM frequency control ancillary service (FCAS) markets.

During the SA separation event on 25 August 2018 when frequency in SA dropped to below 49.2 Hz, HPR provided a proportional FFR active power injection [1]:

- Going from absorbing 38 MW to injecting 10 MW within the first second after the frequency fell below the non-island normal operating frequency band (49.85 Hz)
- Injecting a further 40 MW in the following 3-4 s as frequency continued to decline before backing off proportionally as frequency recovered



[1] AEMO, “Final Report – Queensland and South Australia system separation on 25 August 2018”, 2018, https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2018/Qld---SASeparation-25-August-2018-Incident-Report.pdf

Synthetic inertia

Power electronic inverters can be configured to mimic the inertial response of synchronous machines and provide ***synthetic inertia*** (also referred to as virtual, emulated or artificial inertia).

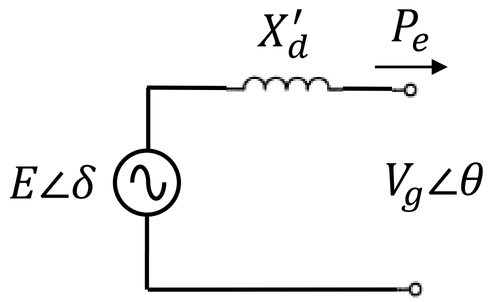
In order for an inverter to provide synthetic inertia that is equivalent to normal inertia, it needs to act like a voltage source and form its **own voltage reference**, i.e. be grid-forming as opposed to grid-following.

The inverter is typically configured based on a classical synchronous machine model (e.g. such as Tesla / ABB's virtual synchronous machine and Synvertec's synchroverter)

High-level principles of operation:

i. A frequency disturbance on the system causes the grid voltage phase angle θ to change
ii. Change in voltage grid phase angle causes active power from the inverter P_e to change according to Eq. (1)
iii. Change in P_e causes the inverter frequency ω and inverter phase angle δ to also change according to Eq. (2) and Eq. (3)
iv. Change in inverter phase angle δ causes active power P_e to change again per Eq. (1)
v. Go back to step iii until a new steady-state is reached

Classical synchronous machine model



$$P_e = \frac{EV_g}{X'_d}\sin(\delta - \theta) \qquad \text{Eq. (1)}$$

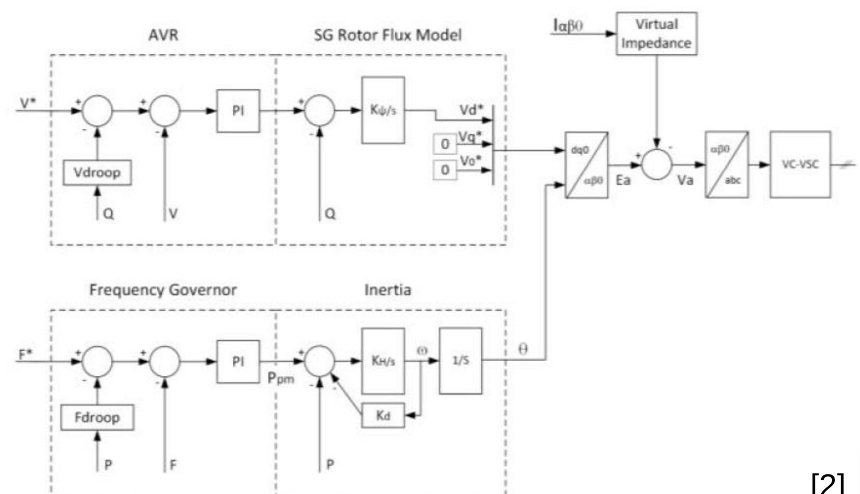
$$\frac{d\omega}{dt} = \frac{1}{2H}(P_m - P_e) \qquad \text{Eq. (2)}$$

$$\frac{d\delta}{dt} = \omega \qquad \text{Eq. (3)}$$

Synthetic inertia: Dalrymple ESCRI-SA case study

Dalrymple ESCRI-SA (Energy Storage for Commercial Renewable Integration, South Australia) is a 30 MW / 8 MWh battery energy storage system in South Australia to provide ancillary services and improve grid reliability in the Yorke Peninsula [1].

The Dalrymple ESCRI-SA inverters were manufactured by ABB using their PowerStore product with grid-forming capabilities and virtual synchronous machine / synthetic inertia functionality.

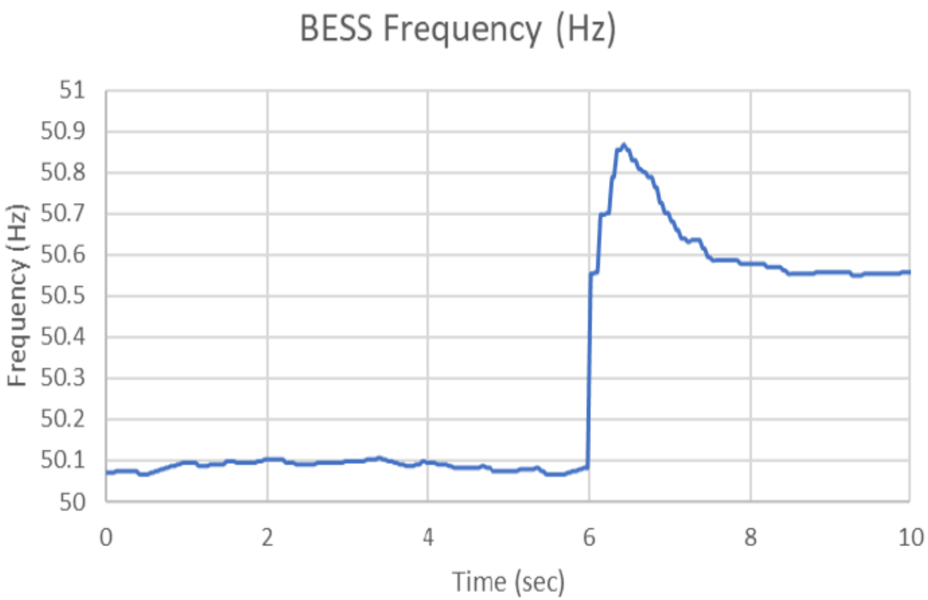


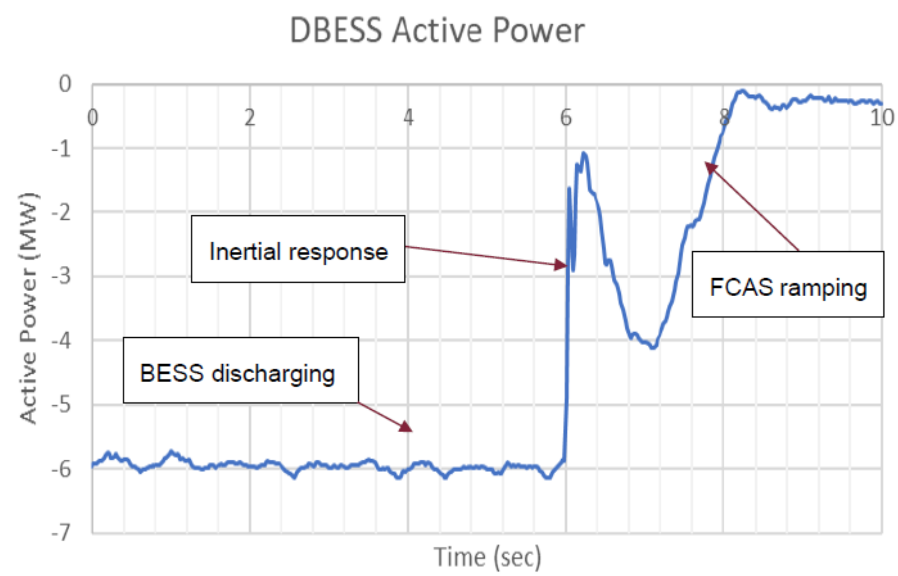
[2]

[1] Electranet, “Dalrymple ESCRI-SA Battery Project”, https://www.escri-sa.com.au/knowledge-sharing/
[2] S. Cherevatskiy, S. Zabihi, R. Korte, H. Klingenberg, S. Sproul, J. Glassmire, B. Buchholz and H. Bitaraf, “A 30MW Grid Forming BESS Boosting Reliability in South Australia and Providing Market Services on the National Electricity Market”, 2019, https://www.escri-sa.com.au/globalassets/reports/wind-interation-workshop---30mw-bess---october-2019.pdf

Synthetic inertia: Dalrymple case study

During the SA separation event on 16 November 2019 when the 500 kV Heywood interconnector tripped after a fault, the Dalrymple ESCRI-SA provided both an inertial and FFR response [1]:





[1] Electranet, "ESCRI-SA Battery Energy Storage Project Operational Report #2", 2020, https://www.escri-sa.com.au/globalassets/reports/escri---sa-operational-report-no.2---february-2020.pdf

Load resources as PFR

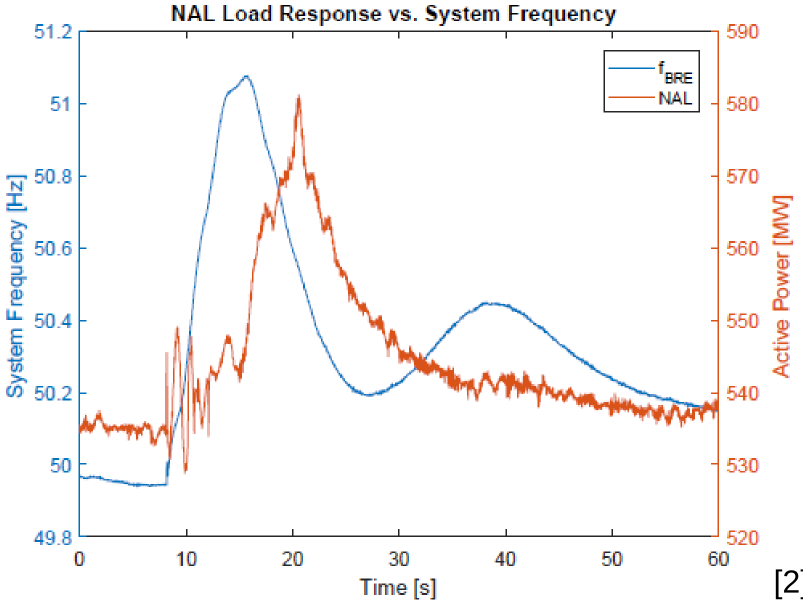
End-use load resources can be used as PFR by adjusting demand or tripping off completely during frequency changes. Distinct from under-frequency load shedding (UFLS), these load resources are typically compensated for providing PFR.

There are two types of load resources that can be used as PFR [1]:

- **Load tripping:** based on preset under-frequency or RoCoF relay thresholds, these load resources provide very fast and reliable PFR. Larger industrial or commercial loads are typically used for load tripping, e.g. smelter potlines. Smaller loads can also participate via aggregators such Enel X.

- **Controllable loads:** respond to frequency changes by a controlled change in demand, e.g. via process control systems. Examples include the control of water heaters and HVAC and more recently the power management of data centres.

  The plot on the right shows the Norðurál (NAL) aluminium smelter in West Iceland that is fitted out with a dynamic load control scheme [2].



[2]

[1] NERC IRPTF, "Fast Frequency Response Concepts and Bulk Power System Reliability Needs", NERC, 2020, https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf
[2] G. I. Valdimarsson, "Real-time Security Assessment for the Icelandic Electrical Power System using Phasor Measurements", Reykjavik University, MSc Thesis, 2016

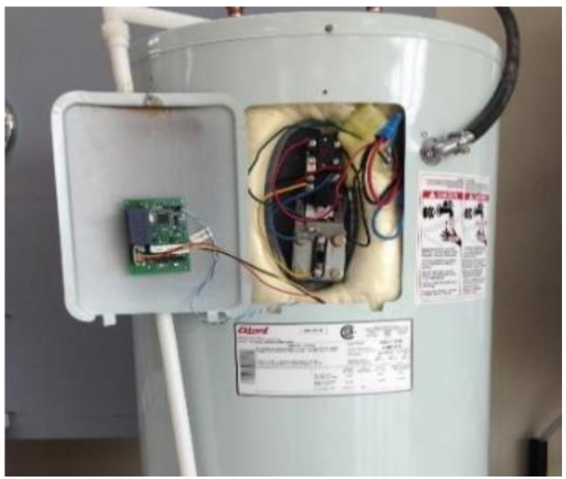
Load resources as PFR: Hydro-Quebec smart loads

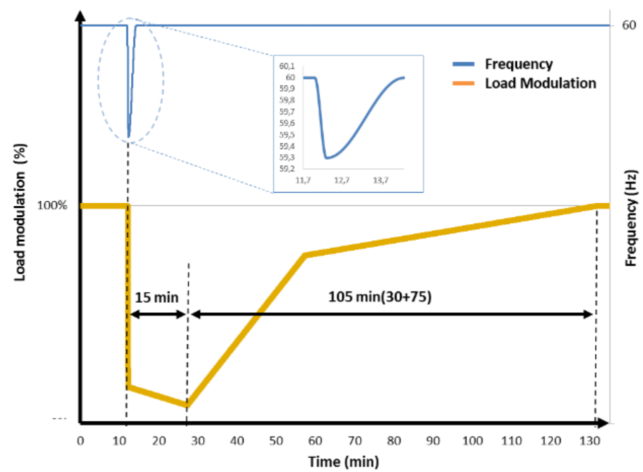
In 2015, Hydro-Quebec ran a trial to use residential electric water heaters as a form of distributed PFR [1].

The water heaters are retrofitted with a local controller to measure frequency and provide a proportional FFR (as opposed to on/off) activating within 250 ms of a frequency disturbance below 59.8 Hz.

The control strategy was as follows:

- Initial load modulation with a linear droop of 1% between 59.8 Hz and 59.2 Hz
- Load modulation management for a period of 15 minutes with a progressive return to normal operation thereafter





[1] F. Monette, "Using Smart Loads to Provide Primary Frequency Response at Hydro-Quebec", Presentation to NERC Resources Subcommittee, 2016, https://www.nerc.com/comm/OC/Resources%20Subcommittee%20RS%202013/RS_Meeting_Presentations_October_2016.pdf

Demand flexibility services

Demand flexibility refers to the time-shifting of discretionary electricity consumption to better align with system conditions, e.g. increase load when there is high output from variable renewable energy generation.

The following types of discretionary loads have been identified for flexible schemes [1]:

- Electric water heating
- Electric vehicle charging
- Space heating
- Cooling, e.g. ice storage or commercial air conditioning

Ideally for managing system security, it is desirable to bring on loads that provide load relief, e.g. motor-driven loads such as compressors.

TECHNOLOGY	UTILITY	HOW IT WORKS
SMART ELECTRIC VEHICLE CHARGING	San Diego Gas & Electric (SDG&E)	In 2015, SDG&E launched a 10-month project utilizing a combination of stationary storage systems and electric-vehicle (EV) charging sites to participate as a distributed energy resources provider (DERP) in the California Independent System Operator (CAISO) market. The utility controlled these systems remotely, charging EVs during off-peak hours according to wholesale energy prices.
ICE BEAR STORAGE SYSTEMS	Southern California Edison (SCE)	SCE has entered into a contract with Ice Energy to deploy about 1,800 Ice Bear 30 behind-the-meter units to industrial and commercial customers across Orange County. The devices will provide a total of up to 25.6 MW of peak storage capacity to SCE.
GRID-INTERACTIVE WATER HEATERS	Hawaiian Electric (HECO)	In 2014, HECO commissioned a yearlong project to assess how grid-interactive water heaters could provide grid services by using software and controllers to manage the units. HECO found the project was able to provide sustained and precise voltage regulation and had a minimal impact on customer energy use or comfort.
SMART-THERMOSTAT AND GRID INTERACTIVE-WATER HEATER CONTROLS	Green Mountain Power (GMP)	In May 2017, GMP launched a pilot program that offers customers a 99-cents-per-month payment plan for using Aquanta smart water-heater controls and Nest smart thermostats to help reduce peak loads and defer distribution upgrades. Participants also allow GMP to access the these smart controls in aggregate, within certain parameters, to maintain comfort, allowing GMP to use these devices to meet its larger grid needs (e.g., to reduce system-wide capacity charges, to mitigate congestion on distribution circuits, etc.)
ELECTRIC THERMAL STORAGE	Tri-County Rural Electric Cooperative	Tri-County offers a rebate of $50 for every kW of installed electric thermal storage (ETS) to homeowners. The ETS units are expected to use lower-cost off-peak electricity to heat ceramic bricks in an insulated cabinet and then release this heat continuously. The utility offers a time-of-use ETS Rate for participating customers.

[1]

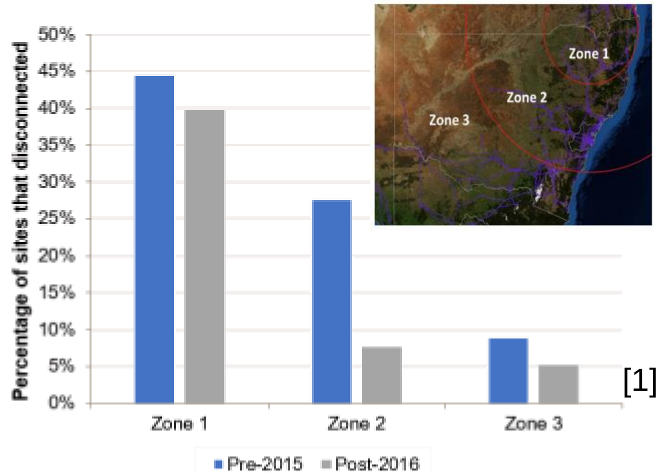
[1] Rocky Mountain Institute, "Demand Flexibility: The key to enabling a low cost, low carbon grid", 2018, https://rmi.org/wp-content/uploads/2018/02/Insight_Brief_Demand_Flexibility_2018.pdf

Emerging risk: widespread DER tripping

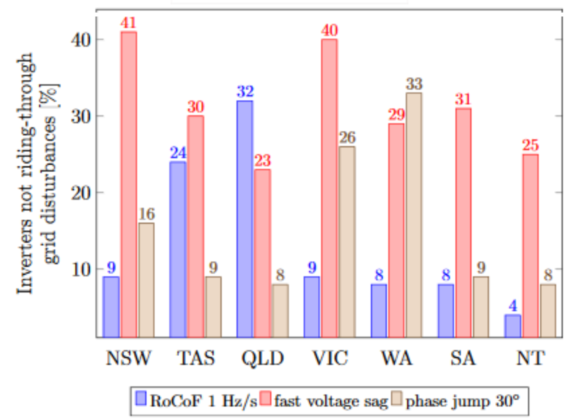
The widespread tripping of DER during system disturbances (e.g. from network faults) has been identified as an emerging risk in systems with high DER / rooftop PV penetration such as the NEM and SWIS. DER tripping can lead to much larger contingency sizes during clear-sky daytime hours.

Case study: QLD-SA separation event in the NEM

- On 25 August 2018, a lightning strike on an interconnector triggered a series of faults leading to roughly 415 MW of rooftop PV inverters (~165 MW in QLD, 100 MW in NSW, 90 MW in VIC and 60 MW in SA) did not ride through the fault and tripped [1].
- The majority of PV inverters that were not electrically close to the fault location (zones 2 and 3 on the map in the top-right) were designed to the 2005 edition of the inverter requirements standard AS/NZS 4777.2 (which was revised in 2015).
- Bench testing of PV inverters by UNSW indicate that depending on state, 20-40% of PV inverters will not ride through deep voltage sags, 8-33% will not ride through 30° voltage phase jumps and 4-32% will not ride through RoCoFs of 1 Hz/s [2].



[1]



[2]

[1] AEMO, “Technical Integration of Distributed Energy Resources”, 2019, https://www.aemo.com.au/-/media/Files/Electricity/NEM/DER/2019/Technical-Integration/Technical-Integration-of-DER-Report.pdf
[2] L. Callegaro, G. Konstantinou, C. A. Rojas, N. Avila, and J. E. Fletcher, “Testing evidence and analysis of rooftop pv inverters response to grid disturbances”, IEEE J. Photovol., 2020

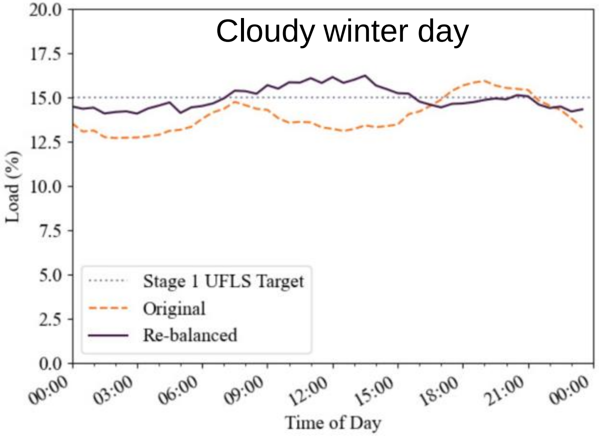
Emerging risk: diminished UFLS availability due to DER

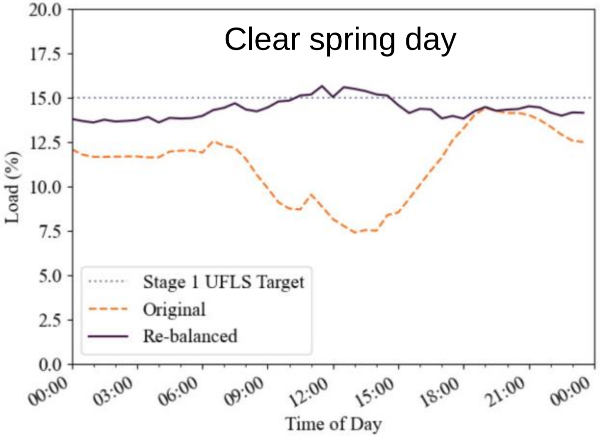
Another emerging risk due to high penetration of DER is the reduced availability of UFLS during peak sun hours (9am – 3pm) on clear-sky days as the load used for UFLS is being offset by generation from rooftop PV.

In the worst case, the UFLS scheme could be tripping feeders with net generation, i.e. exacerbating the problem.

Rebalancing UFLS feeders by mixing in loads without high PV penetration, e.g. commercial loads in central business districts is one option for mitigating the risk of reduced UFLS availability.

The two plots on the right from the UFLS scheme in the SWIS show how rebalancing can maintain the load availability of the UFLS scheme during clear-sky days [1].





[1]

[1] R. Frost, L. Zieland, D. Sharafi and J. Susanto, “Impact of Reverse Power Flow in Distribution Feeders on Under-Frequency Load Shedding Schemes”, International Conference on Smart Grids and Energy System (SGES), Perth, Australian, 2020

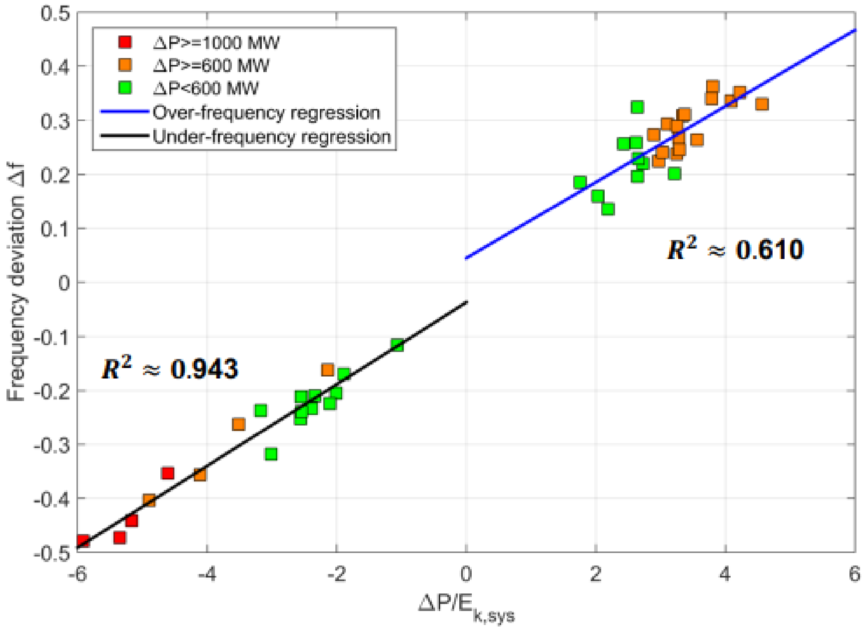
REAL-TIME MONITORING

Nordic online frequency deviation estimation

A simple online approach used in the Nordic system is to estimate the maximum frequency deviation after a generator contingency based on linear regression from past events – see plot on the right [1].

The estimate is implemented in the SCADA / EMS by calculating the maximum frequency deviation in real-time based on the maximum generation contingency / infeed loss.

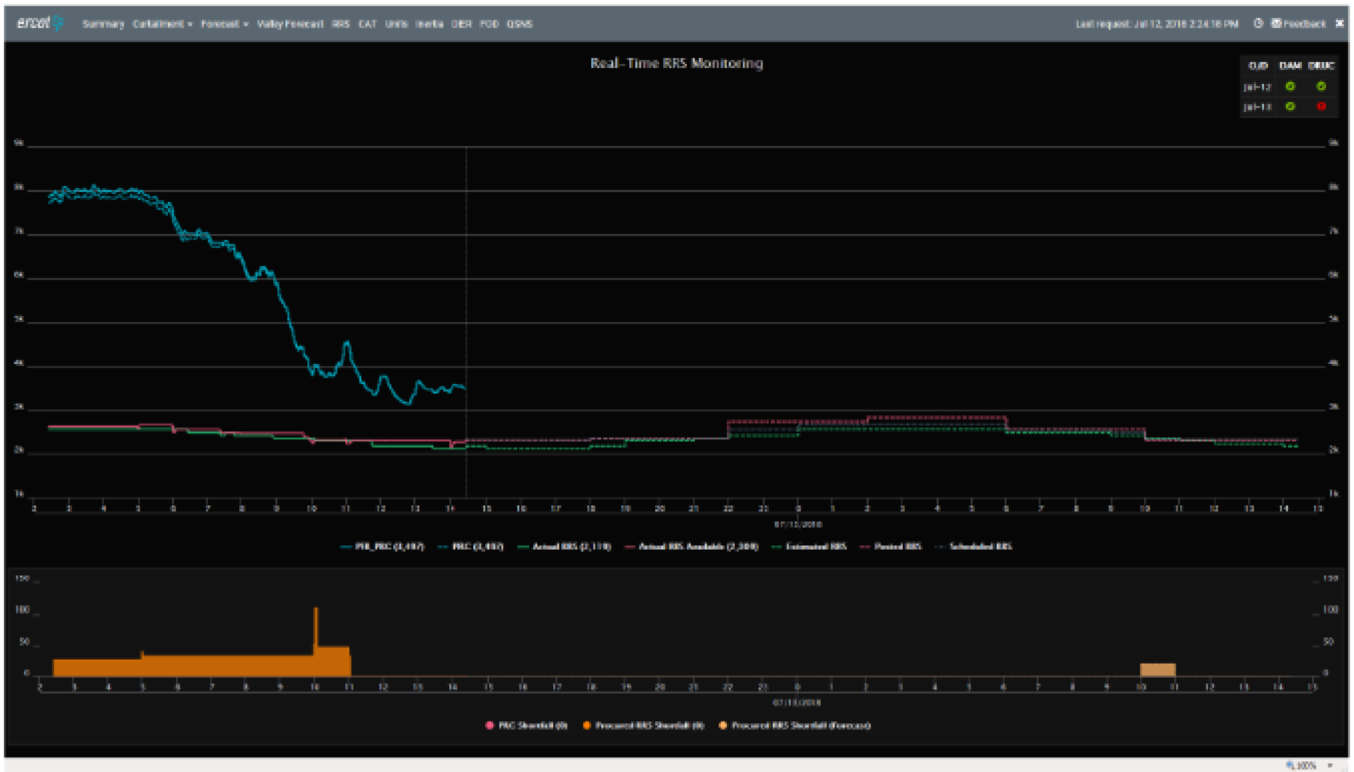
While the estimate is acknowledged to be limited (in particular, the linear relationship assumed between the contingency size, inertia and frequency nadir), the results reported in the months after it was made operational (in June 2017) were encouraging [1].



[1] ENTSO-E, Nordic Future system inertia v2, https://www.entsoe.eu/Documents/Publications/SOC/Nordic/2018/System-inertia.zip

ERCOT Reserve Sufficiency tool

Real-time situational awareness tool to allow operators to track PFR reserves (and other frequency responsive capacity) and verify that it is sufficient for current system conditions, e.g. inertia [1]

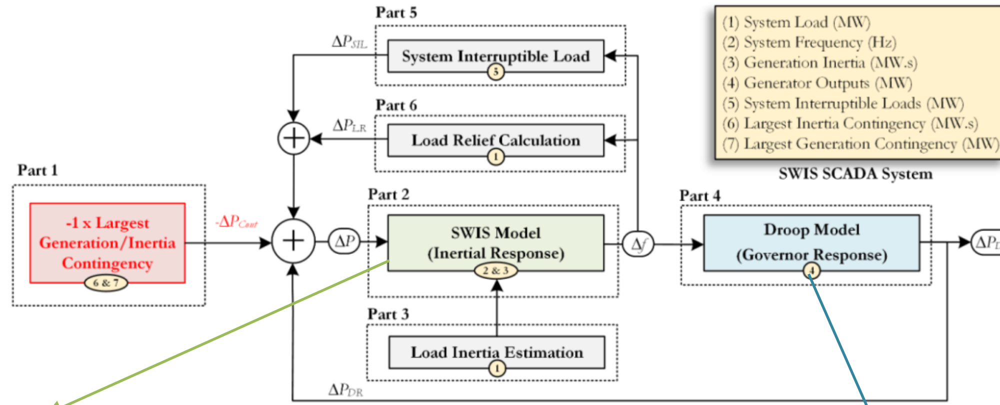


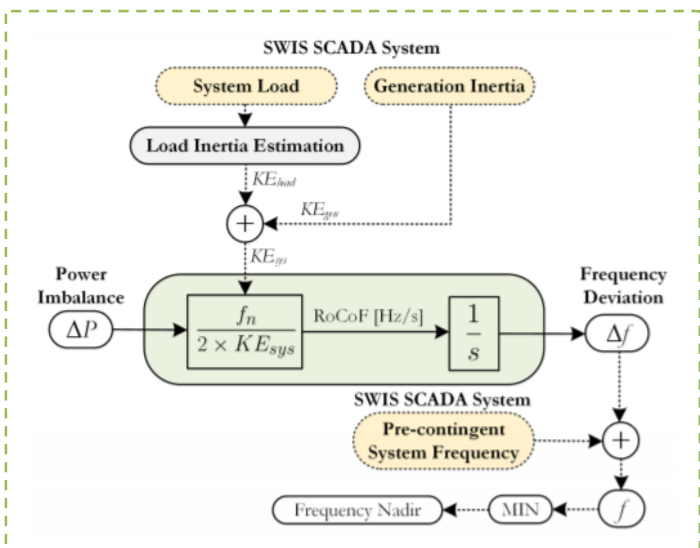
[1] ERCOT, https://www.esig.energy/event/webinar-evolution-of-ercots-frequency-control-and-ancillary-services-while-integrating-a-high-share-of-inverter-based-generation/

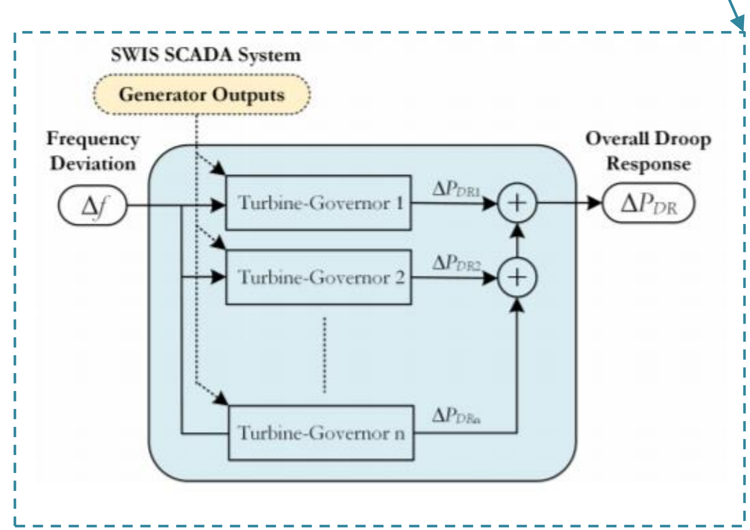
SWIS Real-Time Frequency Stability (RTFS) tool

The RTFS tool is an online situational awareness control room tool developed in the SWIS for monitoring and predicting frequency stability in real-time.

The tool is based on an SFR model with SCADA data providing real-time inputs, e.g. system load, generator inertia, largest contingency, generator operating state, pre-contingent frequency, etc.







SWIS Real-Time Frequency Stability (RTFS) tool

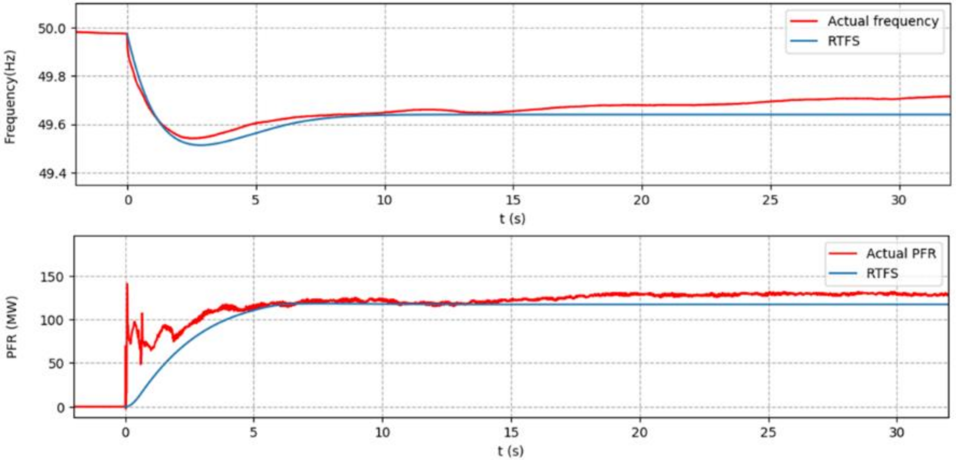
The RTFS tool was deployed for use in the SWIS control room in September 2019.

The tool raises audible and visual alarms if predicted frequency stability limits are breached, e.g. frequency nadir reaches UFLS threshold.

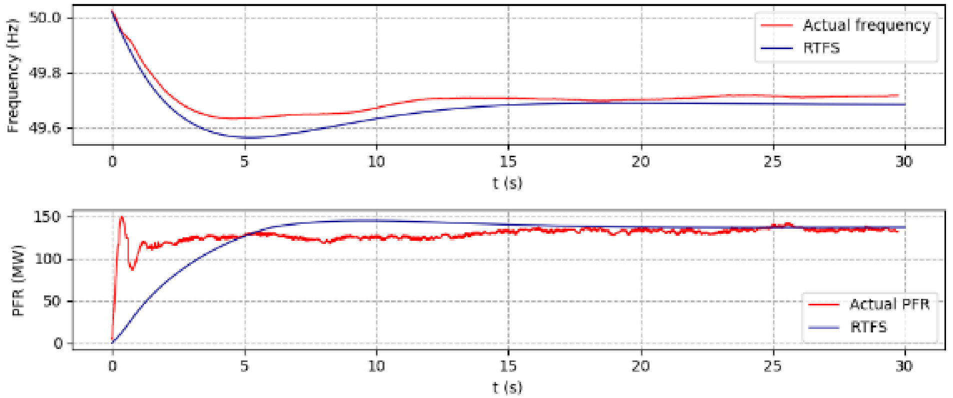
The tool has a “test mode” that allows the controller to test the frequency response of hypothetical generator redispatch scenarios, i.e. to resolve a frequency stability risk.

The figures on the right show the simulated vs actual frequency from two generation contingencies indicating relatively good alignment. Note that the simulated traces are **predictions**, not fitted post-event.

February 2020: 244 MW loss



November 2019: 175 MW loss



[1] A. Fereidouni, J. Susanto, P. Mancarella, N. Hong, T. Smit and D. Sharafi, “Online Security Assessment of Low-Inertia Power Systems: A Real-Time Frequency Stability Tool for the Australian South-West Interconnected System”, arXiv preprint arXiv:2010.14016, 2020, https://arxiv.org/abs/2010.14016

Thank you!

Questions?
Comments?

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