Market options for frequency control in the Australian National Electricity Market

Frequency control ancillary services

Paper 52 : ISGT, Brisbane

Tuesday 7 December 2021

Motivation

- Many countries are responding to increased levels of inverter based generation
- Frequency control is an important consideration:
  - Physical inertia is reducing as fossil plants are replaced
  - Overall system inertia may become quite small
  - Future mix of generation is still likely to include some synchronous machines

- Technology is changing
  - Response times of inverters and or DFIMs is much faster than turbines driving synchronous machines
    - Zero→ Pmax in 100-200 ms for inverters
    - 10% change in 10s for a gas turbine
    - Close to two orders of magnitude

- Expectation that arrangements to control frequency will experience **significant change**

The challenge

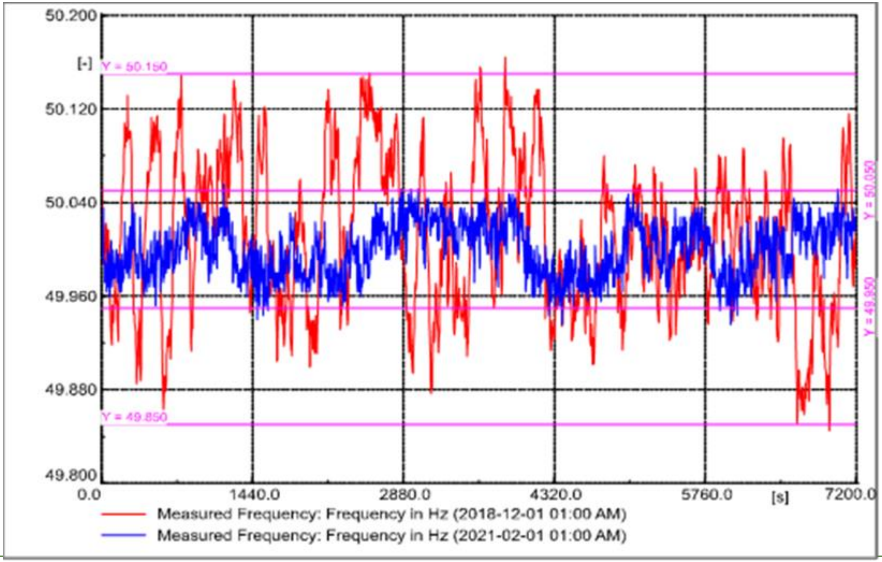
- Can we develop a ***new*** approach to frequency control that:
  - Meets the Frequency Operating Standard defined for the power system
  - Takes advantage of new technologies (rather than putting a band-aid on legacy systems)
  - Rewards the service providers that are good at providing efficient frequency control
  - Encourages innovative solutions to meet the Standard
- … recognising the likely trajectory for the energy transition currently under way in Australia?

Markets or mandate?

- A very important question in Australia is whether frequency control should be :
  - **MANDATED** in a Grid Code
  - Procured as an ancillary service via the **MARKET**

In the Australian National Electricity Market, there is an **obligation** to consider market solutions ahead of mandated solutions

- Primary frequency response:
  - Recently Mandated in Australia
  - All generating systems
    - Synchronous machines (SMs)
    - Inverter based gens
    - BESS
    - etc



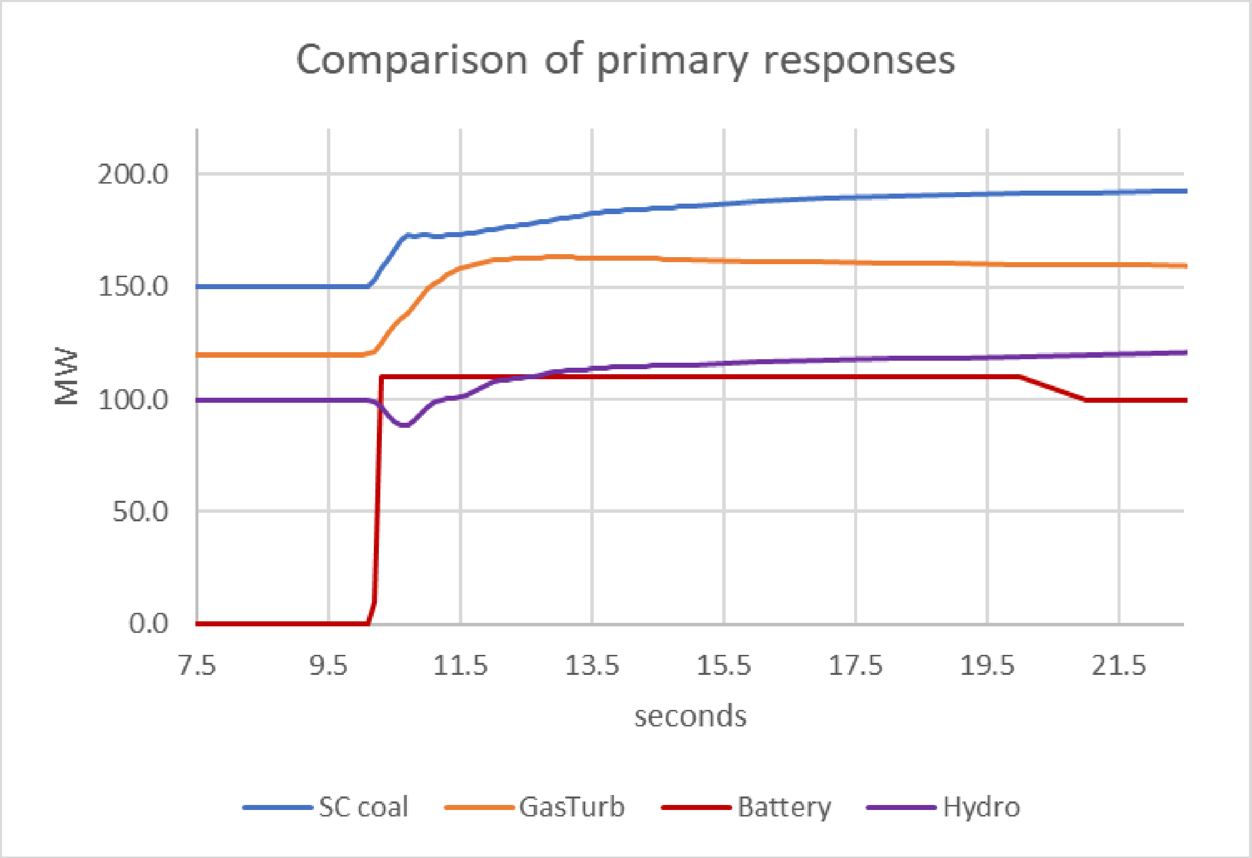
Significant challenges

- There are a number of challenges emerging for robust control of frequency
  - **Reducing inertia** implies faster rate of change of frequency
    - Inertia can change significantly over daily load cycle (e.g. solar cycle may have lower inertia during the middle of the day)
    - Systems must respond faster
  - **Reducing load damping**
    - Less offset available from load as frequency changes
    - More frequency control service is required
  - **Wide range of response times and response ranges**
    - Response from inverters at 100-150 ms to tens of seconds from Hydro
    - Range from inverter (BESS) may be 100% while steam turbines may be 10%
    - Co-ordination and optimisation is required

Significant opportunities

- Technology is providing some enhanced tools to manage the emerging challenges, including:
  - Fast responding active power sources can deliver ***synthetic inertia***:
    - Batteries etc
    - Super capacitors
  - Sustained responses
    - Batteries can deliver active power quickly and sustain the output
    - Supercapacitors can deliver an active power response as synthetic inertia without needing to re-charge until after the frequency has recovered
  - Market dispatch engines are now very good at co-optimising large scale problems
    - ***Co-optimising*** frequency control services with the energy market is feasible and practical

Comparing technology response profiles



Principles for a solution

- The solution should be:
  - Based on the Frequency Operating Standard
  - Recognise the value of response speed
  - Consider inertia and synthetic inertia
  - Be co-optimised with the energy market
  - Continuous (not discrete 'buckets')

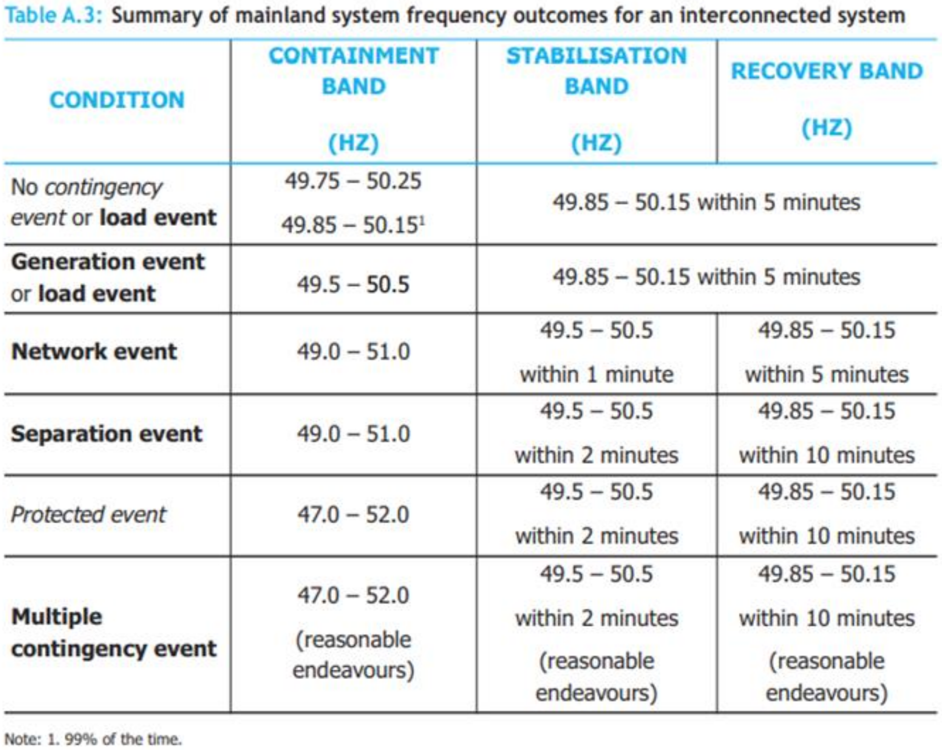


Table A.3: Summary of mainland system frequency outcomes for an interconnected system

CONDITION	CONTAINMENT BAND (HZ)	STABILISATION BAND (HZ)	RECOVERY BAND (HZ)
No *contingency event* or **load event**	49.75 – 50.25 49.85 – 50.15[1]	49.85 – 50.15 within 5 minutes	
Generation event or **load event**	49.5 – 50.5	49.85 – 50.15 within 5 minutes	
Network event	49.0 – 51.0	49.5 – 50.5 within 1 minute	49.85 – 50.15 within 5 minutes
Separation event	49.0 – 51.0	49.5 – 50.5 within 2 minutes	49.85 – 50.15 within 10 minutes
Protected event	47.0 – 52.0	49.5 – 50.5 within 2 minutes	49.85 – 50.15 within 10 minutes
Multiple contingency event	47.0 – 52.0 (reasonable endeavours)	49.5 – 50.5 within 2 minutes (reasonable endeavours)	49.85 – 50.15 within 10 minutes (reasonable endeavours)

Note: 1. 99% of the time.

Source: AEMC Reliability Panel

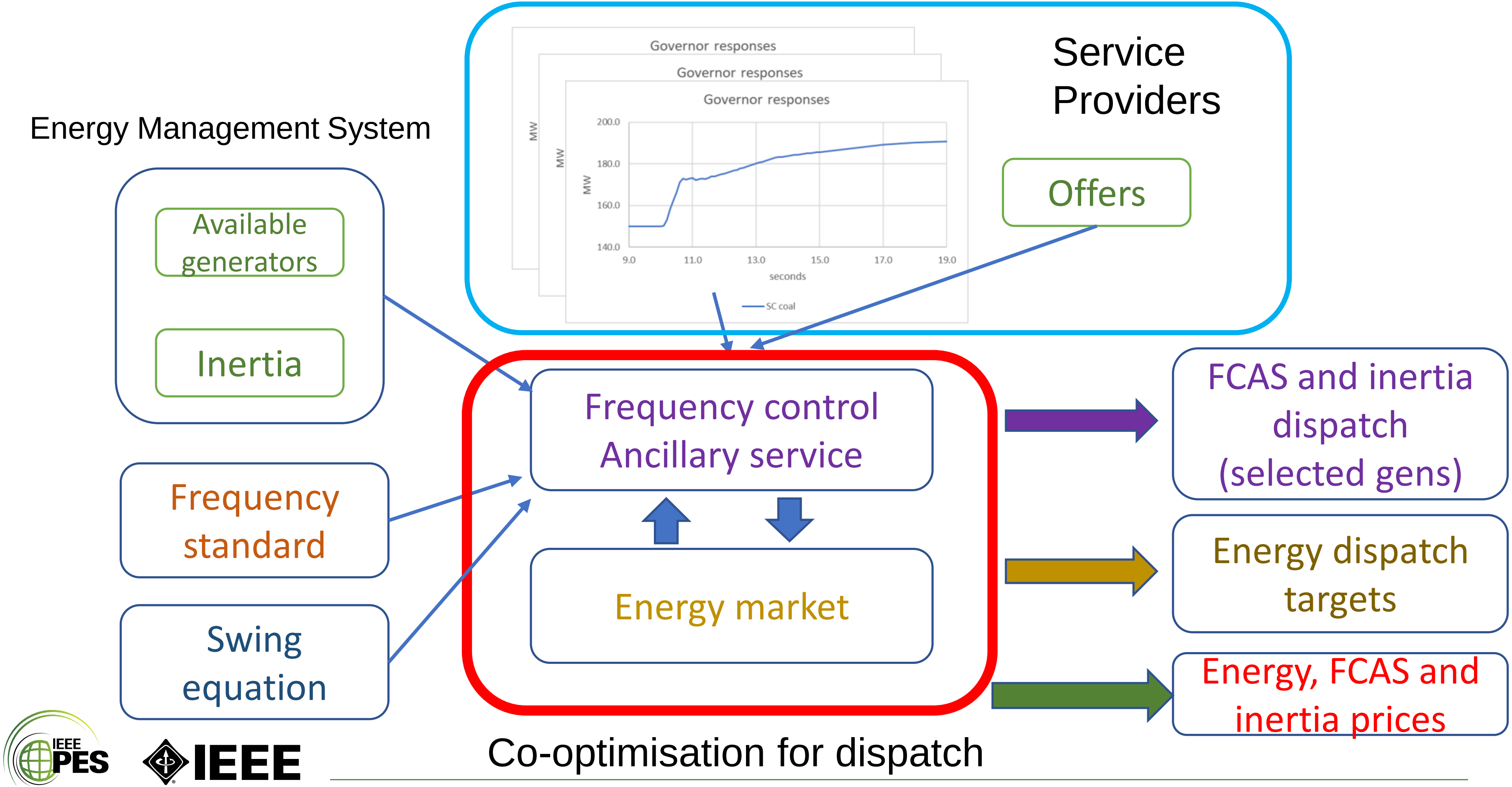
Key elements of option in paper

- Uses the Australian Frequency Standard
    - For a generation/load contingency – permissible frequency deviation is =/- 0.5 Hz
- Calculates requirements using the swing equation

$$\frac{df(t)}{dt} = \frac{\omega_o}{2H}\,(P_m - P_e) \text{ where } \omega_o = 1 \qquad [1]$$

- Considers the response profile available from generators offering the service
- Yields linear constraint equations that can be co-optimised with the energy market
- Includes inertia (as in equation 1)
- Provides shadow prices (market clearing prices) for:
    - Inertia
    - Primary frequency response

Overview of solution



Energy Management System

Available generators

Inertia

Frequency standard

Swing equation

Service Providers

Offers

Frequency control Ancillary service

Energy market

FCAS and inertia dispatch (selected gens)

Energy dispatch targets

Energy, FCAS and inertia prices

Co-optimisation for dispatch

Conclusions

- It is not perfect but the approach has many very positive attributes including:
    - Explicit valuation of inertia, providing ***investment signals*** and ***incentives*** to offer the service
    - Recognition of the whole FCAS capability over time, including:
        - Speed of response
        - Sustained responses
        - Short-term overloads
    - Ability to optimise both fast and slow responding services to deliver lowest cost service
    - Ability to trade-off inertia and fast response FCAS
    - The constraints are effectively the frequency standard
- Considering the very significant changes in the capabilities of FCAS service providers (response speed, ability to sustain output, short-term overloads), the existing FCAS arrangements are surely due a major re-design.
- There is a requirement in the Australian NEM to look for ***market*** solutions, where possible, to provide services

Questions

Supplemental slides

Derivation of FCAS constraints

Modelling inertia and FCAS

- Two key points:
    - Swing equation is the basis of the proposed formulation of a co-optimised dispatch of FCAS and inertia
        - It links frequency, FCAS provision, a contingency event and inertia
    - The frequency Standard sets the upper and lower bounds for frequency
        - Linear constraints for an optimisation can be determined by combining the frequency Standard with the swing equation
- The swing equation can be re-written as the frequency at time T given the frequency at time 0

$$f(T) - f(0) = \int_0^T \frac{1}{2H}\left(P_m(t) - P_e(t)\right) dt \quad [2]$$

- The impact of a contingency event occurring at time 0 and its mitigation through the total amount of contingency FCAS provided at time t by all providers is

$$\left(P_m(t) - P_e(t)\right) = FCAS(t) + load\ relief(t) - contingency(t) \quad [3]$$

- The frequency Standard requires that the frequency $f(T)$ is between the Standard's upper and lower bounds :

$$F_{lb}(T) \leq f(T) \leq F_{ub}(T) \quad [4]$$

Modelling primary frequency response (FCAS)

- If we assume that each contingency FCAS provider can deliver a profile of additional MWs over time, t, following a contingency and we create a standardized profile $fcas(j,t)$ at time t for provider j by dividing its profile by its maximum output over the FCAS provision period, then the FCAS co-optimization can be set up such that the amount of the FCAS profile from provider j that is enabled is a decision variable, $X(j)$.
- The total amount of FCAS enabled at time t is
  - $FCAS(t) = \sum_{j\ in\ providers} X(j) \times fcas(j,t)$ [5]
- The integral of FCAS(t) over the period 0 to T is:
  - $\int_0^T FCAS(t)\,dt = \int_0^T \sum_{j\ in\ providers} X(j) \times fcas(j,t)\ \ dt$

$$= \sum_{j\ in\ providers} X(j) \times \int_0^T fcas(j,t)\,dt \qquad [6]$$

  - Note that:
    - Dispatch variables are on left hand side of the equation
    - Equation is solved each Tm, where {Tm} is a set of time points following a contingency

Modelling Inertia and FCAS…

- If inertia is dispatched like energy and $Y(k)$ is a decision variable that determines whether provider k is selected, then
  - $H = \sum_{k\ in\ providers} Y(k) \times H(k)$ [7]
  - where H(k) is the inertia of unit k and $0 \le Y(k) \le 1$
- The upper and lower frequency standards can be converted into constraints, for the lower bound

$$F_{lb}(T) - f(0) \le f(T) - f(0) = \int_0^T \frac{1}{2H}\left(P_m(t) - P_e(t)\right) dt$$

$$2H\left(F_{lb}(T) - f(0)\right) \le \int_0^T FCAS(t) + load\ relief(t) - contingency(t)\ dt \qquad [8]$$

- If the equation above is rearranged and the decision variables are put on the left-hand side, it becomes

$$\int_0^T FCAS(t)\ dt - 2H\left(F_{lb}(T) - f(0)\right) \ge \int_0^T contingency(t) - load\ relief(t)\ dt \qquad [9]$$

  - Note that:
    - Dispatch variables are on left hand side of the equation
    - Equation is solved each Tm, where Ti is a set of time points following a contingency

Turning the FCAS and inertia model into constraints…

- If equation [6] and [7] are substituted into equation [9] then the result is a linear equation in the decision variables $X(j)$ and $Y(k)$

$$\sum_{j\ in\ FCAS\ providers} X(j) \times \int_0^T fcas(j,t)\ dt - 2\left(\sum_{k\ in\ inertia\ providers} Y(k) \times H(k)\right)\left(F_{lb}(T) - f(0)\right) \geq\ T \times contingency - \int_0^T load\ relief(t)\ dt \qquad [10]$$

- To operationalise equation [10] in a linear programming optimisation a number of discrete time points, T_m, must be chosen to ensure that the post contingency frequencies always remain within the Standard.

- One point that is worth mentioning is that for inertia the commitment variable $Y(k)$ would be a real variable on the interval [0,1], i.e. 0<= $Y(k)$<= 1 rather than a binary variable. The reason for doing this is to get marginal cost prices for inertia and FCAS. If binary variables are used this generally can't be done. Units with a partial commitment (0< $Y(k)$ <1) would be required to commit.

Outcomes from the FCAS constraint

- The response is made up of two elements:
  - An inertial component (proportional to dF/dt)
  - A contribution from FCAS provider
- In the early stages of the response, the FCAS contribution is zero and inertia is the only response
- In the later stages of the response, dF/dt is positive and the inertia increases the required FCAS response
- For each time Tm modelled in the optimisation as a constraint there will be a corresponding shadow price (marginal cost) which is the market clearing price for the services and each service provider will get paid the shadow price x their coefficient in the constraint
- A provider of an FCAS service will get paid for all of the time periods they provide a service:
  - $\sum_{T_m \; in \; T} shadow\; price(T_m) \times X(j) \times \int_0^{T_m} fcas(j,t)\; dt$ [11]
- A provider of an inertia service will get paid
  - $\sum_{T_m \; in \; T} shadow\; price(T_m) \times 2 \times H(k) \times (F(0) - F_{lb}(Tm))$ if $Y(k)$ >0 [12]

Practical implementation

- Incorporating inertia in the FCAS formulation means:
  - Pricing signals for both ***real*** and ***synthetic*** inertia
    - Tech like super-capacitors may finally see a reason for investing
    - Providers of synthetic inertia can compete with SM providers
    - SM providers may have a reason to turn on
    - Synchronous Condenser investors will have a reason to add inertia
  - Trade-offs between inertia and FCAS
    - Less very high speed FCAS required if more inertia available
- Configurable implementation
  - The response is based on time steps (selectable) at which the optimisation takes place
  - Need close spacing initially, then lengthening