System Inertia Requirement
with Increasing RE and HVDC infeed

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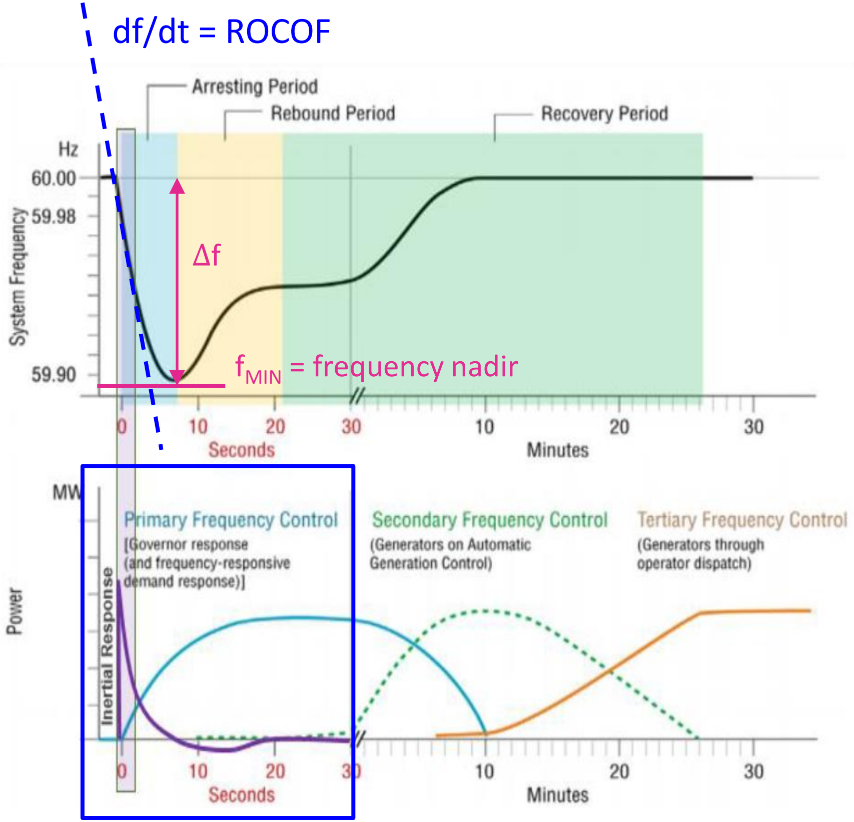
Problem Faced

- With increasing non-synchronous generation and HVDC infeed, system inertia (H) is reduced. It increases frequency nadir and ROCOF, which in turn results in cascade tripping, failure of UFLS scheme or equipment failure (due to large ROCOF).

Problem:

1. How to estimate system inertia?
2. How to provide enough system inertia?
3. What is the limit of system inertia (w.r.t. required f_{MIN} and ROCOF limit)?
4. What is the effect of inadequate system inertia?



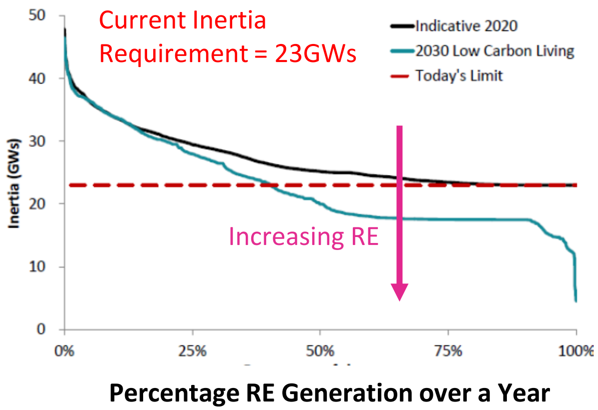
Eir-grid (Ireland Case)

- At most 1 Hz/s ROCOF and inertia floor of 23GWs are provided with minimum number of large synchronous unit / minimum generation (MW).

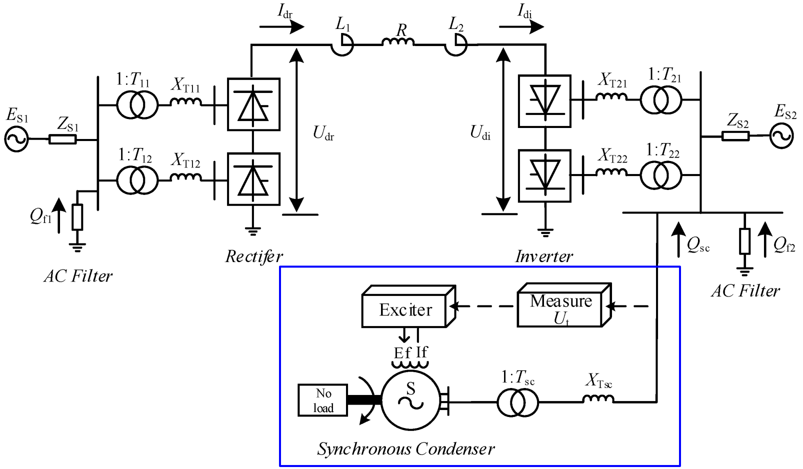
Concern:

1. **Frequency Stability**:
   ↓ inertia (with ↑ HVDC infeed) → ↑ ROCOF and ↑ Δf

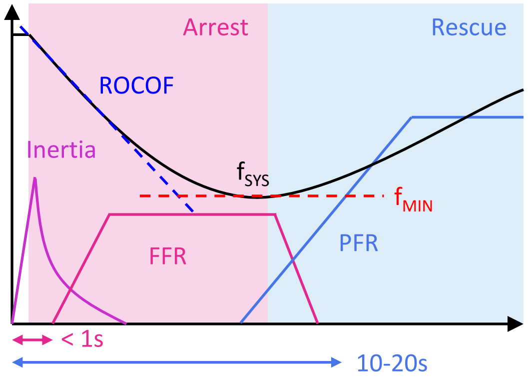
2. **Voltage Stability**:
   ↑ HVDC infeed → ↓ Local Generation → ↓ Reactive Power Reserves
   Lack of local dynamic voltage support and system reactive power scarcity at recovery stage.



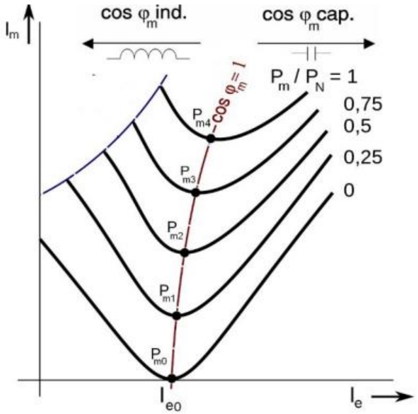
Solution of Inadequate Inertia



1. Additional Inertia (e.g. Synchronous Generator, Synchronous Condenser or Synchronous Load)
2. Fast Frequency Response (FFR)
   Note: Synthetic Inertia / inertia emulation can NOT fulfill inertia requirement
3. Grid Forming Converter with f/P droop
4. Curtailment of IBR

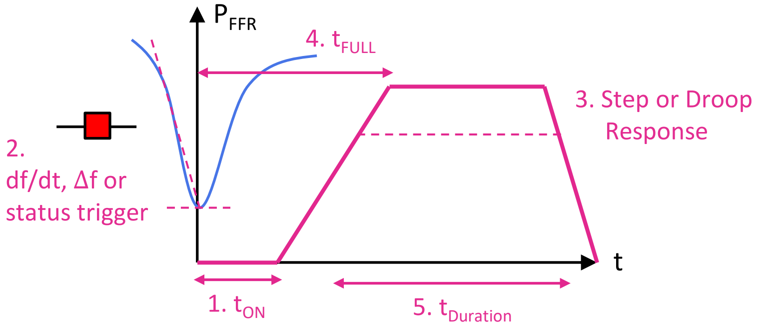


Functionality of Sync Condenser:
- Dynamic Voltage Support
- Increase System Strength
- Provide Inertia
  [Note: 20% of normal sync gen]



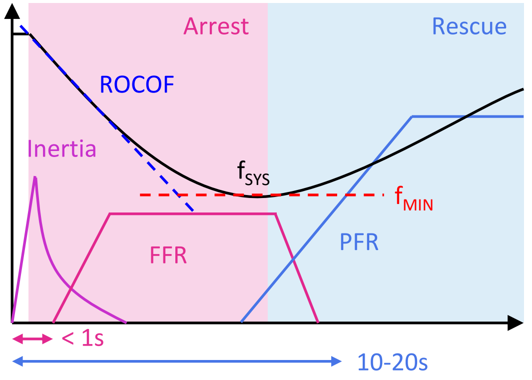
Type of Frequency Response Components

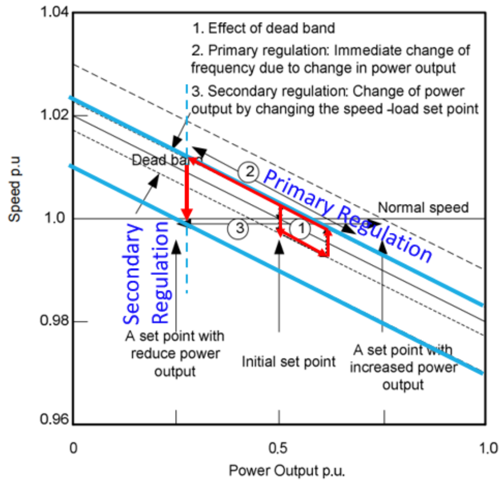
- Effective Inertia = Relief from Inertia, Synthetic Inertia and Load Relief
- Frequency Containment Response (FCR) = Primary Frequency Response (PFR) driven by governor (droop response)
  - tackle for largest secure loss without load shedding
  - need 10 – 30s to rescue frequency drop
- Fast Frequency Response (FFR) = Extra energy source (e.g. BESS or HVDC – EPC) provide fast enough depending on system needs and technology available. **Concern**:



To trigger FFR:

1. **Measure** - df/dt, Δf (which f_{SYS}?)
2. **Identify** - Frequency Event or Fault with successful clear?
3. **Signal** - Controller (release FFR or UFLS?)





Synchronous Inertia Measurement

- Based on Status of all Synchronous Generator / Condenser on board [Note: Motor is NOT counted as not controllable]
  (Requirement: known H, inertia constant, and S_B, rated power)

$$E_{sys} = \sum_{i=1}^{N} S_{B-i} H_i \qquad H_i = \frac{\frac{1}{2} J_i w_0^2}{S_{B-i}}$$

Mechanical Calculation

Rated Output

- Based on Historical Frequency Event
  (Requirement: High speed frequency measurement)
  Factor affecting its accuracy:
  1. Window Length of ROCOF
  2. Start time of event (distortion of frequency measurement with fault phasor movement)
  3. Power Measurement (low P during fault)
  4. Inertia Change (no. of event as statistical measurement)
  5. Load Damping Effect
  6. Load Frequency-Voltage Coupling

$$E_{sys} = \frac{\Delta P \cdot f_0}{2 \frac{d f_{SYS}}{dt}}$$

Swing Equation based Calculation

Load Damping Effect: (i.e. Load Relief due to ↓f)

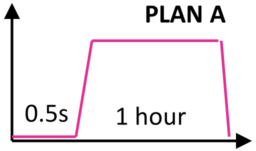
$$\frac{\Delta f(t)}{f_0} = \frac{1}{D} \frac{\Delta P_{MW}}{P_L} \left(1 - \exp\left(-\frac{1}{2} \frac{D P_L}{\sum_{i=1}^{N} H_i S_{B-i}}\right)\right)$$

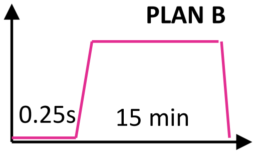
- Based on Power Modulation (UK: P_L=18-60GW, $\pm$ 10MW)
  Note: Data Asymmetry Issue (No data on fault)

Frequency Response Requirement

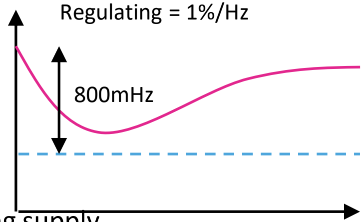
Synchronous area	Min inertia/min load	Max inertia/max load
AEMO (NEM)	3.9	4.4
Hydro Quebec	4.0	4.1
Manitoba Hydro*	5.7	2.9
EirGrid	9.2	NA
Statnett	5.0	4.4
REE*	3.0	4.3

- Size of Power System:
  Inertia [GWs] / Load [GW] = 3.0 – 5.7
- **Primary Frequency Reserve** (PFR) needed depends on:
  - Single Largest Infeed (SLI) Contingency (e.g. largest (two) generators or HVDC infeed failure)
    [Note: enough inertia to arrest ROCOF and f_{MIN}, and no constraint violation after fault isolation]
  - Percentage of Load
  - Shared Reserves (on bar? Spinning?)
- **Fast Frequency Reserve** (FFR) Product:
  ERCOT –





P_{GEN} = 3GW loss, P_L = 150GW,
Regulating = 1%/Hz



AEMO – 2.55MWs inertia per MVA installed capacity (NOT P_{GEN}), only provided when the unit is generating supply.
It is *preferred* that the plant can operate as synchronous condenser while NOT generating power to the grid.
Generator has the option to trade off inertia with FFR = Generator MVA x 5.11MVA x 0.086 [MWs] within 0.25s.

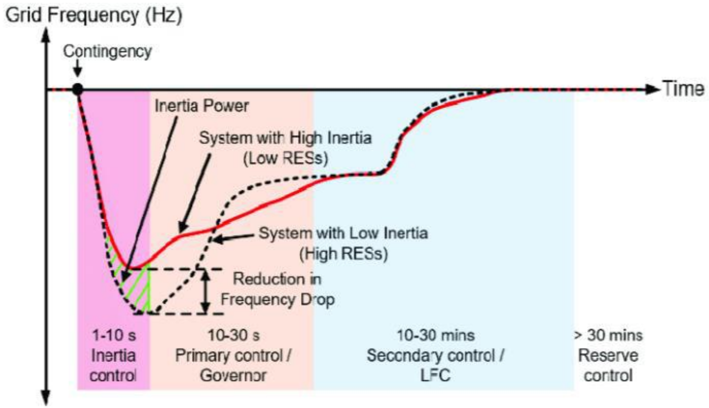
Eir-grid – Provide dynamic response to track frequency (10 steps, each < 5MW), stepped static capability (drop in droop, recover in constant), static capacity (full response at f_{SET})

Minimum Inertia Level

Eir-grid/AEMO: minimum Inertia requirement with limit on largest infeed & power flow into inertia shortage area.

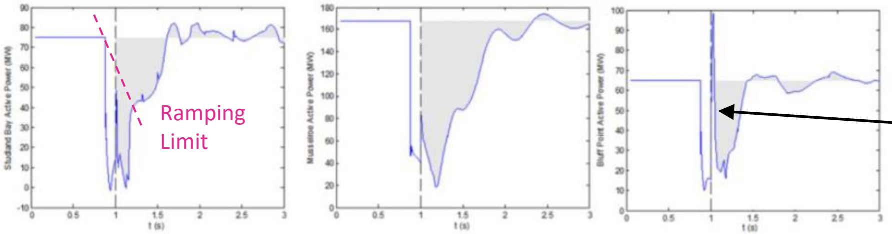
- Eir-grid: minimum inertia level to ensure df/dt < 0.5 Hz/s after loss of largest infeed.
- AEMO: inertia requirement revealed annually on system security and maintain frequency standard f_{MIN}.
  [Note – AEMO co-optimizes single largest contingency and PFR availability.]
- ERCOT: inertia with sufficient time for fastest frequency response (FFR / PFR) before it hits UFLS.
  [Note – Determine PFR needed on expected inertia and offered FFR amount, i.e. min PFR + max FFR]
- Brazil: Acceptable dynamic performance with 6 units on bar (sync gen/sync cond) at minimum dispatch and with limited exchange up to 40%.

Goal: to avoid cascade tripping



Challenges with Increasing RES

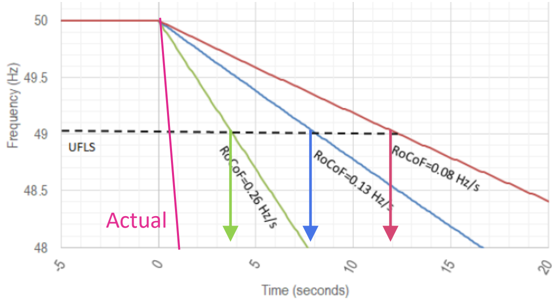
- Decommissioning old generator = reduced inertia, voltage control capability, fault current and system strength
- It also reduce power availability, ROCOF (due to reduced inertia), PFR and f_{MIN}.



Energy Deficiency under fault with **Fault Ride-through Capability** of IBR

Note: depends on **DC cap** size

- To trigger UFLS (Load > Generation, f ↓), 80ms (window to measure f_{SYS}/ df/dt) + intentional delay (should be ↓ with ↑ Δf) + 30ms (CB opening time). South Australia (low inertia grid) cannot *arrest* frequency drop with 6Hz/s ROCOF.

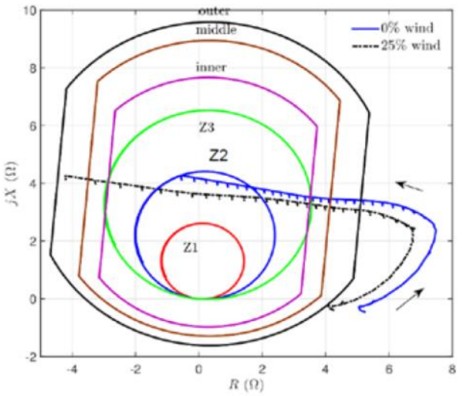


Note: reasonable ROCOF ~ 1 Hz/s

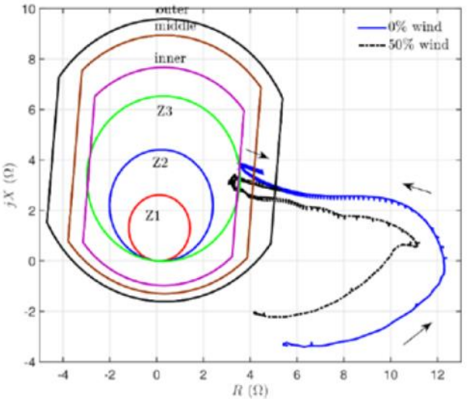
Challenges with Increasing RES (Protection)

- RES in general NOT provide negative sequence fault current (NOTE: requirement on Germany 2018)
  → affect accuracy on direction OC (I_2) for generator protection, phase detection (I_0 Vs I_2 based), unbalanced fault detection.
  → Type 3 WTG (DFIG) may have changed angular relationship (I_2 Vs I_0)
  Type 4 WTG (FRC) suppresses I_2 (in magnitude).
- With lower fault current (note: limited by IGBT rating, 1.0 – 1.5 pu), OC suffers risk of mis-coordination (esp. at electrical centre) and risk of transient stability (with weak network).
- DIST element may have reliability issues in short line (large SIR ratio from IBR) with low fault current I_F and low fault voltage V_F. It reduces impedance accuracy and lengthen trip time.
- Reduced inertia leads to faster swing, in which may lead to mis-distinguish fault with power swing
  [Note: Power Swing can be caused by Generator tripping, line tripping or load rejection and power swing blocking employs ΔZ / Δt < setting.]

PSB = Fault Vs Swing:



OST = Stable Vs Unstable Swing:



Challenges with Increasing RES (Protection)

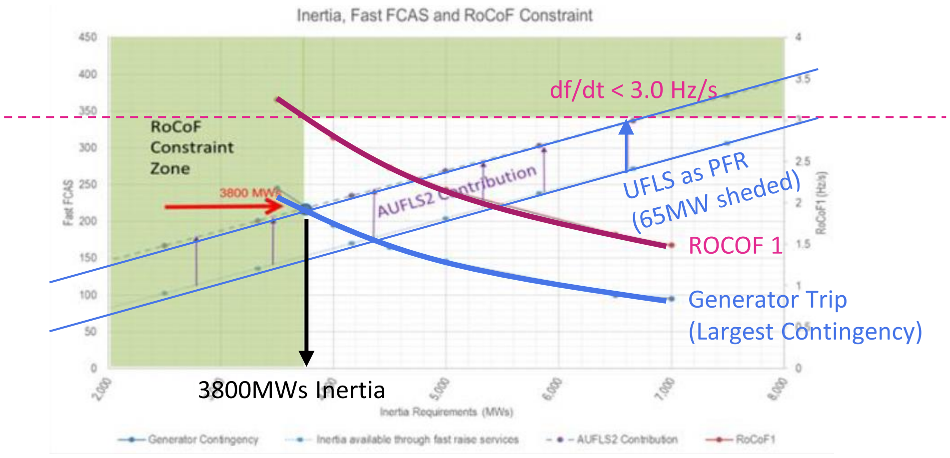
- Anti- Islanding Protection (or Loss-of-Main Protection):
  - Passive: triggered by OV/UV, OF/UF, df/dt + Δf, dP/dt, dV/dt, phase jump or THD.
    [Note - It may **NOT be detected within time frame**, dP/dt may not work with island with load = generation]
  - Active: triggered by disturbance injection with
    1. Injection of changing current to have changing voltage, and impedance seen from DER trips if $Z_{SEEN} > Z_{SET}$
    2. Positive Feedback with Voltage or Frequency Shift, i.e. to drive V or f away from stable operating point when detect a change.

    [Note – injection **interacts with other IBR** and damps down the signal.]

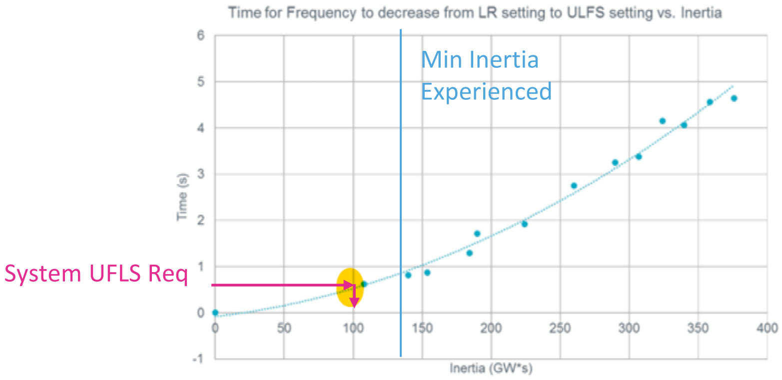
- **ROCOF ride-through requirement** with Category II DER: 2.0Hz/s; Category III DER: 3.0Hz/s

International Experience with Reduced Inertia

- **Tasmania**



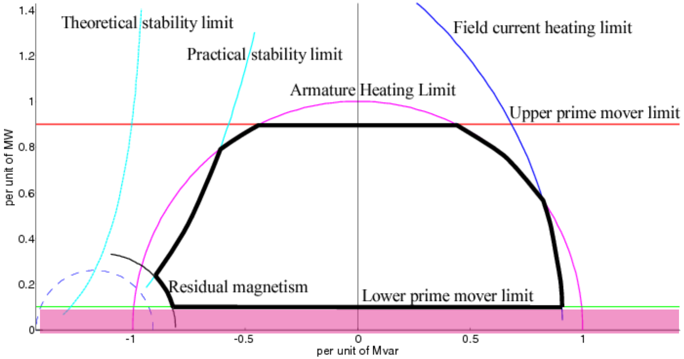
- **ERCOT**



Date and Time	2013 3/10/13 3:00 AM	2014 3/30/14 3:00 AM	2015 11/25/2015 2:00 AM	2016 4/10/16 2:00 AM	2017 10/27/17 4:00 AM
Minimum Synchronous Inertia (GW*s)	132	135	152	143	130
System load at minimum synchronous inertia (MW)	24,726	24,540	27,190	27,831	28,425

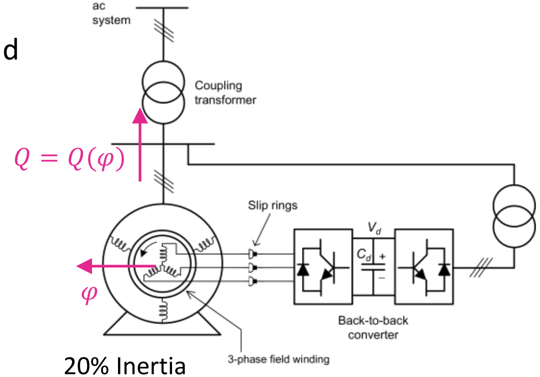
Technology to Provide Inertia / Frequency Response

- **Synchronous Generator**: $KE = \frac{J_i \omega_0^2}{2} = HS_B$
  Problem - P_{MIN} and $C(P_{MIN})$.
  Note: dispatching more generator with smaller rating does NOT necessarily leading to larger inertia.

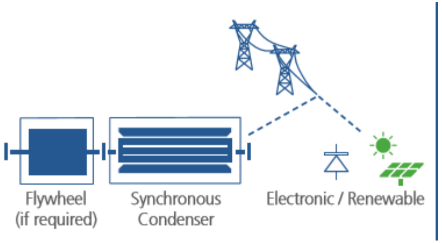


- **Motor Load**: UK – 36% motor load direct on-line (DOL) can contribute to system inertia with frequency damping. (X VVVF drives)
  Note: H is NOT available, and load damping constant/ dP/df sensitivity is needed.

- **Synchronous Condenser**:
  Denmark / Germany / Italy / USA use sync cond to increase fault level and support voltage.
  Investment Cost = $115 / kVAr
  High Inertia Sync Cond = 8MWs / MVAr

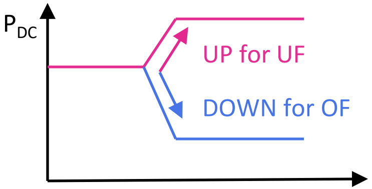


20% Inertia (vs sync gen)

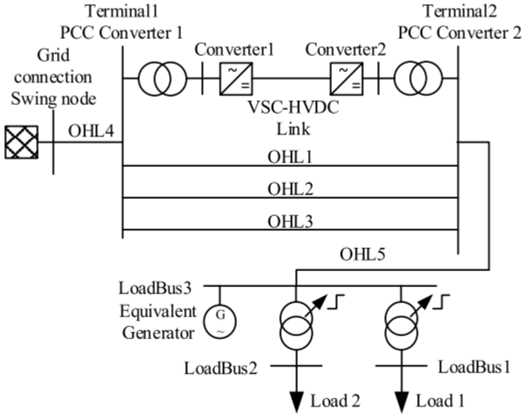


Technology to Provide Inertia / Frequency Response

- HVDC – Emergency Power Control (EPC)

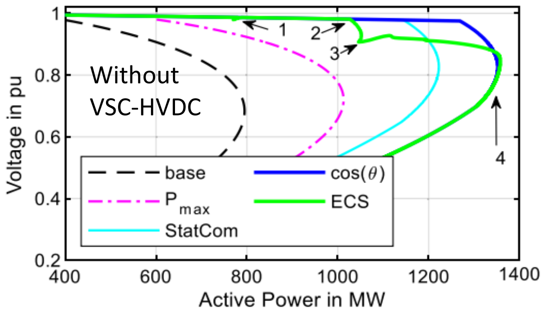


Note:
- dP/dt depends on strength of input AC system
- EPC for under-frequency (UF) can cause temporary overload of DC link
- Inertia emulation control at VSC to limit df/dt or Δf with SM capacitor charge.



- Energy Storage (BESS)

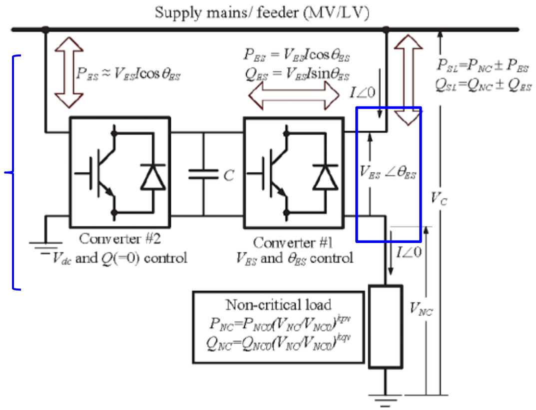
Requirement	Supercapacitors	Batteries	Hybrid
Response Time	cycles	seconds	cycles
Response Duration	seconds	minutes to hours	seconds to hours
Cycle Life	1,000,000	3000 (avg.)	>3000
System Life	12-15 years	1-10 years	>4 years



Future Technology to Provide Inertia / Frequency Response

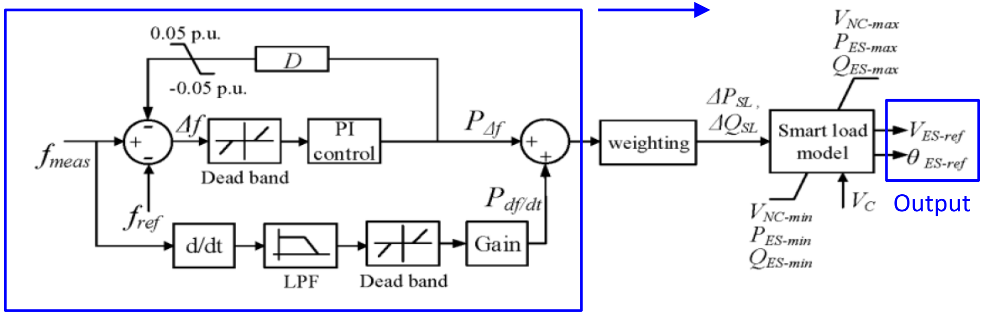
- Static Smart Load (SSL)

Electric Spring

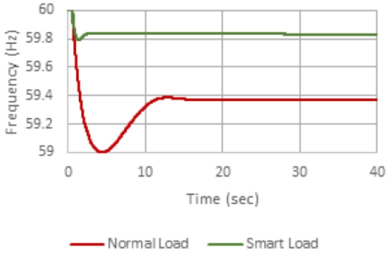


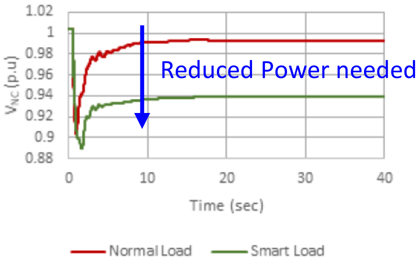
Provide series voltage with df/dt + Δf regulation:

Feeder side (depends on R/X, SIR) / Load side voltage control

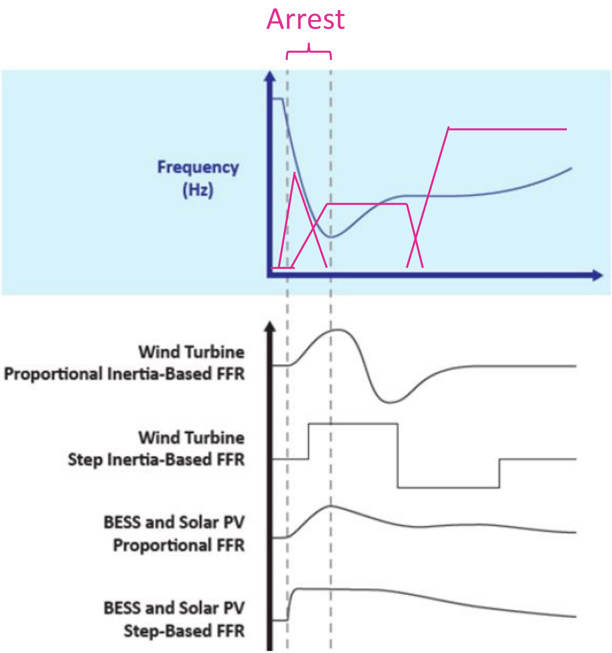


- Motor Load: similar to SSL, change P_M according to f and df/dt





Frequency Regulation Capability

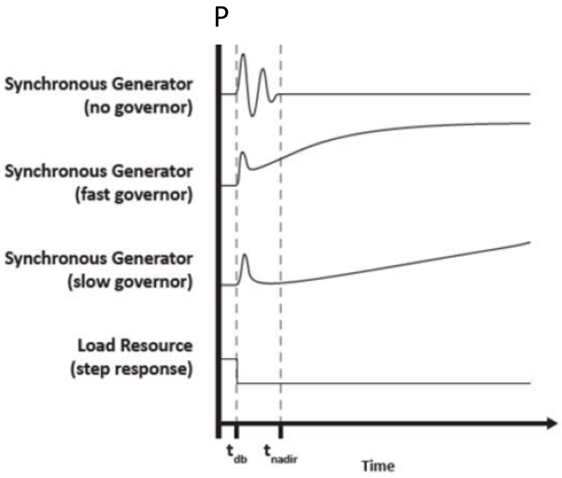


Check 1) Response Speed
2) Response Shape
3) Response Duration

for $\longrightarrow$

a) Inertia
b) PFR
c) FFR

Droop or Step to arrest df/dt or Δf ?



Operation of Inverter Based Resources (IBR)

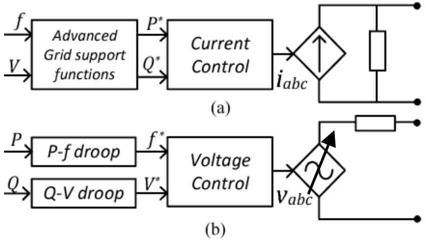
- Difference in Capability between IBR and Synchronous Generator:
  1. Synchronizing Power (SG – depends on excitation and coupling impedance, strong coupling)
  2. Overloading Capability (SG – thermal rating; IBR – IGBT rating)
  3. Frequency Control (SG – KE from rotating mass, IBR – can perform inertia emulation, but requires energy source to supply required power)
- Grid Forming to Grid Following

  f/P droop – by governor
  V/Q droop – by AVR
  Power Oscillation Damping – by PSS

$$\boxed{\delta \approx \frac{xP}{EV} \qquad \Delta V \approx \frac{xQ}{E}}$$

$$\longrightarrow \begin{cases} \omega_e^* = R_p(P^* - P) + \omega_{e,0} \\ U^* = R_Q(Q^* - Q) + U_0 \end{cases}$$

Provided by virtual impedance (possible with –R) to increase X/R ratio and time constant with higher R



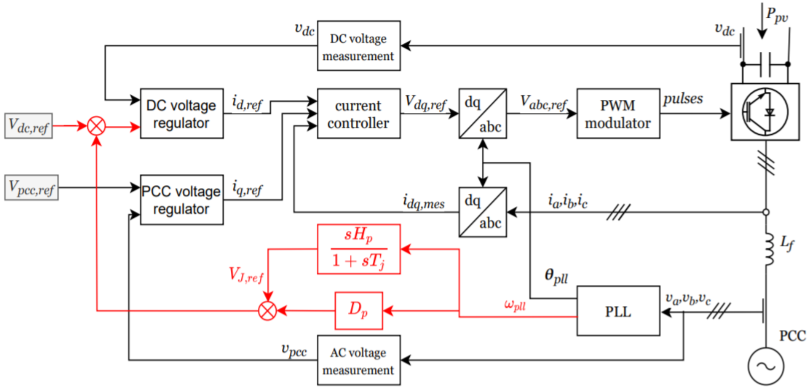
	Synchronous generator	IBR
Voltage source synthetization	Electromagnetic force, sinusoidal by design, controlled by excitation (amplitude and phase angle). Control speed: order of seconds	Semiconductors are modulated to follow sinusoidal fundamental waveform (amplitude and phase angle). Control speed: order of milli-seconds
Harmonics	Low levels of low-order harmonics, due to not absolutely perfect sinusoidal distribution of the magnetic flux.	Depending on converter topology and modulation method, harmonic distortion is generated which may or may not have to be mitigated by a filter.
Coupling impedance	Given by stator reactance and resistance (time-dependent – sub-transient, transient, steady-state – and affected by magnetic saturation)	Given by coupling reactance, e.g. reactor and/or transformer. Additionally, control loops may significantly influence the frequency dependent impedance.
Fault current	Naturally limited by the stator impedance to 2.5 pu ... 6 pu nominal generator current	Limited by converter topology and control to around 1 pu nominal converter current. It can operate either as current source or as voltage source with current limitation.
Synchronizing power (inertia contribution)	Given by maximum EMF voltage and coupling impedance.	Dependent on applied control loops (current/voltage source control) and loading of the converter. Limited to rated power of the converter for voltage source control.
Overload	Naturally given by thermal mass of the generator	Compared to a generator, the thermal mass of the power electronics is much less. Therefore, overload ability needs to be designed in if required.
Frequency control	Utilizing the governor, running on f/P droop characteristic	f/P droop characteristic can be implemented
Voltage control	Utilizing AVR, running on U/Q characteristic	U/Q droop characteristic can be implemented
Power oscillation damping	Power oscillation at low frequencies can similarly be implemented. Due to the higher control bandwidth of converters compared to synchronous generators, converters can even provide damping at torsional shaft frequencies.	
Resonance damping	Difficult / only passive damping	Active damping can be implemented for a certain frequency range
Active harmonic filtering	Not available	Can be implemented for a certain frequency range (low order harmonics)

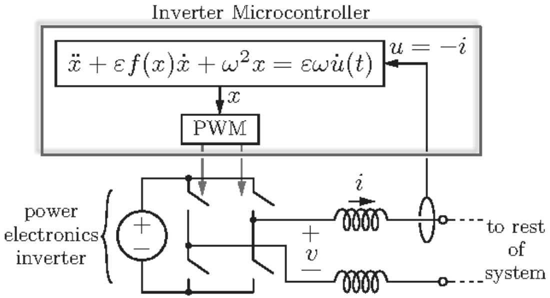
Operation of Inverter Based Resources (IBR)

- Virtual Synchronous Machine (Synchronverter)

$$\underbrace{2H_v \frac{d\omega_e^*}{dt}}_{\text{inertia}} = (P^* - P) - \underbrace{\frac{1}{R_p}(\omega_e^* - \omega_{e,0})}_{\text{Droop}} - \underbrace{K_D(\omega_e^* - \omega_{e,PLL})}_{\text{Damping}}$$

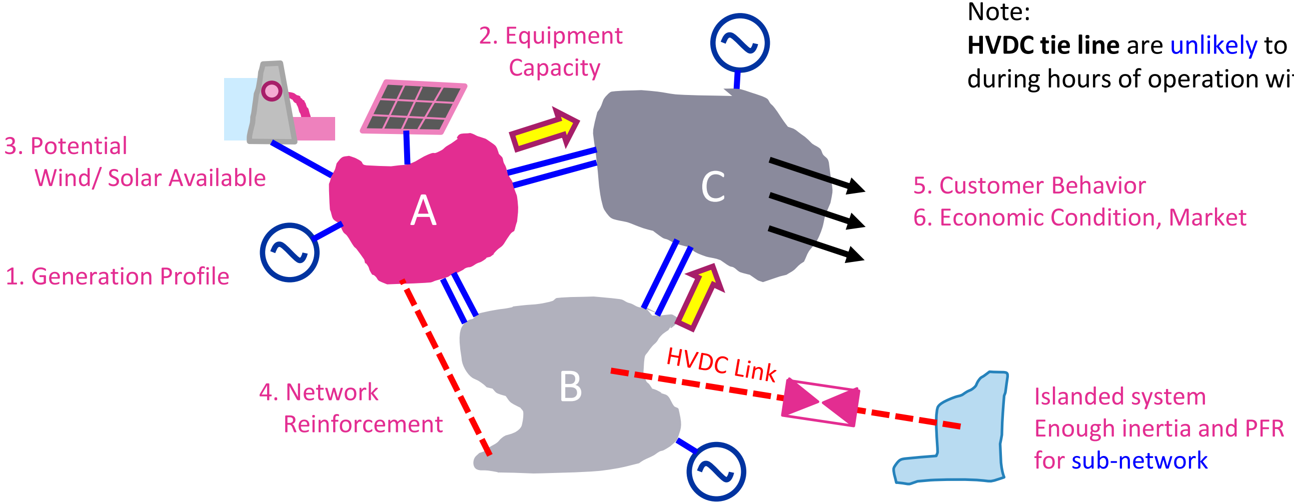
- Virtual Oscillator
  - to mimic the nonlinear behaviour of Van der Pol Oscillator
  - it provides limited response to quick transient and quickly stabilize after initial condition / load transient.
- Problem: Grid Forming Converter response to fault
  1. Change to Grid Following Mode – limited current controller setpoint + PLL
  2. Increase virtual impedance to limit output





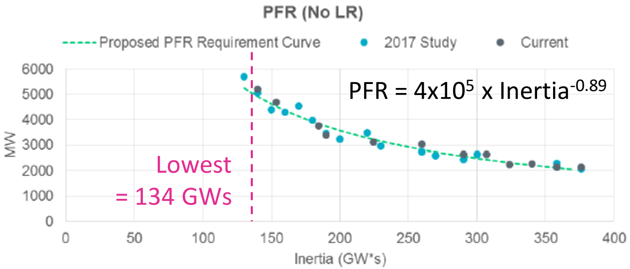
Quantifying Frequency Reserve

- To quantify – Volume and Composition of Reserve (inertia → FRR → PFR, Ramping, SFR + TFR)
- Concern: Current system topology, unit commitment, dispatch and availability of reserve
- Check – voltage stability/ transient stability: delayed power recovery from RE generation
  – converter instability, e.g. PLL instability
- Cost Modelling

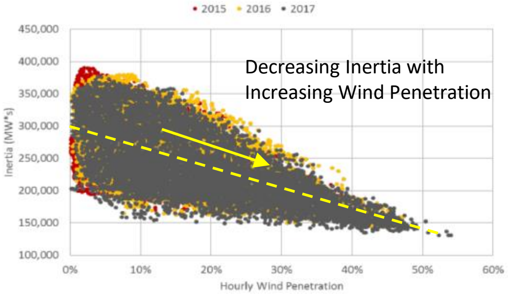


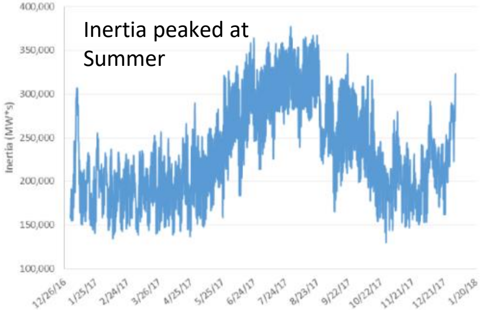
Note:
HVDC tie line are unlikely to be importing large power during hours of operation with low inertia and high RE.

Case Study - ERCOT

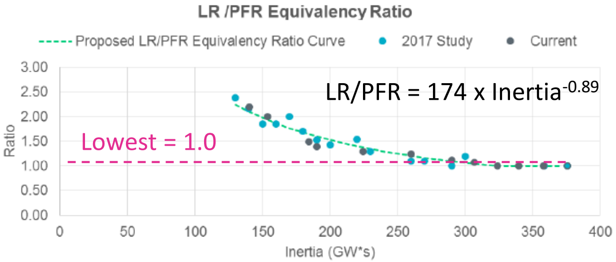


- Wind = 1/5 state total generating capacity, = 1/6 state net generation





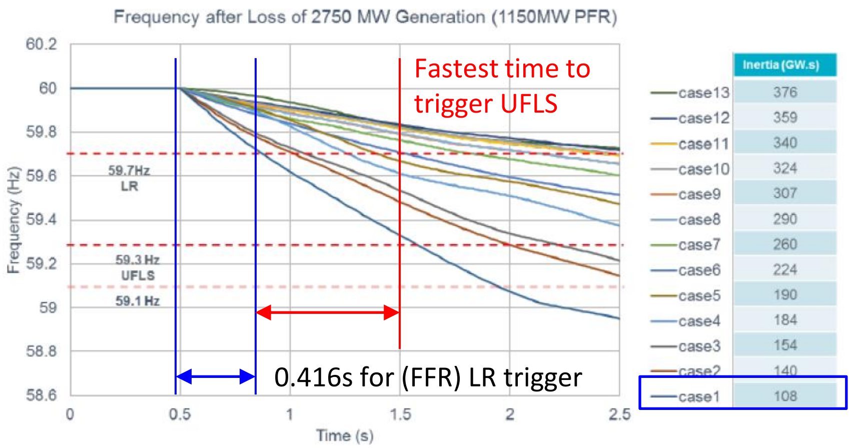
Given PFR = 1650MW:

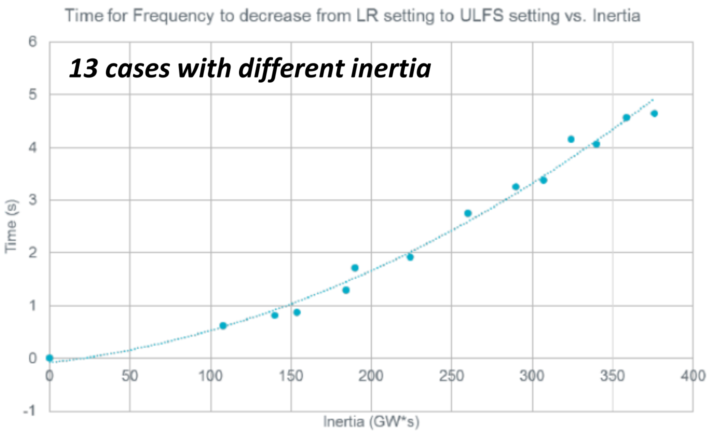


- Responsive Reserve Service (RRS) can be provided by synchronous generator or load resources within 20 cycles (frequency measurement) + 10 cycles (CB operation).
- NERC assigns interconnection frequency response obligation (IFRO) which indicates minimum frequency response required, UFLS setting = 59.3 Hz and region’s resources contingency inertia = 2750MW for ERCOT.
- ERCOT: 1) at least 1420MW of PFR from synchronous generator to provide continuous governor response between 60Hz and 59.7Hz (droop).
  2) 2750MW = simultaneous loss of two largest units on the systems.
  3) > 40% RRS from sync gen droop must be PFR, and < 50% from load response

Case Study - ERCOT

- Critical Inertia = minimum system inertia that ERCOT's Fast Frequency Response (FFR) can be effectively deployed before frequency drops below 59.3Hz in the referenced event (i.e. 2750MW loss).
- It also indicates inertia is needed to arrest frequency within 0.416s before Load Response (LR) can be provided in 0.416s.





Case Study - ERCOT

- At high wind - low load period, synchronous generator on bar inertia = 78 – 100 GWs.
  [Further study – reducing 30% inertia, assuming 30% inertia from private network with high load damping]

- Consider the following parameter changes:
  1. Faster Load Response: LR initiated after 15 cycles (instead of 25 cycle) → Critical Inertia reduces from 94GWs to 68GWs
  2. Earlier Response for LR: LR triggered at 59.8Hz (instead of 59.7Hz) → Critical Inertia reduces from 94MWs to 88GWs
  3. Lower UFLS Setting: UFLS set at 59.1Hz (instead of 59.3Hz) → Critical Inertia reduces from 94GWs to 71GWs
  4. Reduction of Contingency: SLI reduces from 2750MW to 2500MW → Critical Inertia reduces from 94GWs to 75GWs.

Case Study - Europe

$$2HS_n\frac{df}{dt}+\underbrace{Df}_{\text{Self Regulation from Load}} = P_M - P_E$$

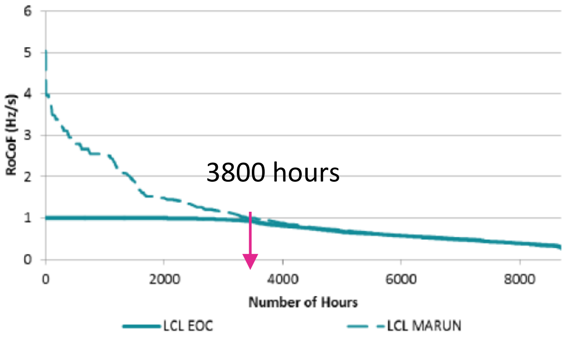
- Modelling six area with power balance:
- Δf limit = 1Hz (from UFLS), df/dt limit = 2 Hz/s (from equipment withstand level)
- Situational Study: + Single Generator Swing Equation based study
  1) interconnection (6 infeed losses) – based on two largest generators at the same busbar in the zone tripped.
  2) system split – Iberia split, Italy split and total split into 3 zones (historical split)
- **Iberia**: High RE penetration with weak connection to other zones. Δf is NOT a concern. df/dt = 1.3 Hz/s (> generator withstand = 1.0 Hz/s)
- Suggestion:
  - minimum regional inertia level + ROCOF limit
  - real time management of tie line transfer and regional inertia
  - ultra-fast frequency response to limit ROCOF (instead of f_{MIN}) within 500ms
  - study of actual withstand capability of ROCOF (peak ROCOF = 5 Hz/s, average ROCOF < 2 Hz/s)

Case Study - Nordic

- 2017 System KE = 120GWs – 280GWs (increasing level of inertia with more synchronous generator – hydro + nuclear)
- Modelling: frequency dynamic only. Assume NO voltage dynamic / frequency - voltage coupling.
- With high transmission capacities between bidding zones → NOT consider splitting case.
- FCR (PFR) activation time < 30s, FFR activation time < 1.3s
  with Emergency Power Control (EPC) provided by HVDC tieline.
- **Reference case**: 1400MW (Nordlink HVDC loss/ nuclear plant loss)
  With reduced system inertia, it is the most severe incident for frequency stability.
- Consideration: 1) Online Capacity
  2) Average Output
  3) Reserve Capacity

Case Study – Ireland (Eir-Grid)

- Peak Load 7GW connected to UK with 1 VSC-HVDC (500MW) and 1 LCC-HVDC (500MW).
- Single Largest Infeed (SLI) loss = 700MW → Full loading of Celtic HVDC link
- **Production Cost Model** with
  Constraint: ROCOF limit = 1 Hz/s, FFR requirement = 47% of LSI,
  PFR requirement = 75% of LSI.
  It requires effective inertia floor = 17.5GWs with Celtic HVDC operated with full output (700MW).
- Swing equation with power imbalance is an efficient and accurate frequency studies for system.
- Wind/PV has no contribution to frequency regulation (assumed)
- **Fast Frequency Response**:
  BESS/ HVDC response to frequency event needs 200ms. BESS output is limited to size of LSI to avoid over provision of reserve or oscillatory response.



Case Study – Ireland (Eir-Grid)

- Ireland comprises SE and LCL (with higher RE penetration).
- Special Response – Lower average Δf and more case at SE < 49.5 Hz (but LCL has more RE penetration)
  [Possible caused by load relief, FFR capacity and grid forming converter capability]
  Note: RE often provides droop < 4% (larger response).
  – Oscillatory Response in LCL (over provision of reserve – 100MW loss, 400MW reserve released)
  – Overshoot at LCL (slow response time for hydro power plant)
- Solution: 1) ROCOF limit adjusted accordingly with availability of fast response
  2) Fast Response requirement from HVDC and BESS
  3) Well designed UFLS/ OFLS limit and coordination
- It indicates the lack of reserve case – PFR (75% of LSI) is considered insufficient. It assumes certain percentage of load relief and over provision of reserves.
- Highlight:
  1. Any hidden assumption?
  2. Over-provision at small ΔP condition?
  3. Any slow response (time delay driven) oscillation behaviour?
  4. Avoid assumption on high RE penetration = worst frequency behaviour.

Case Study - Conclusion

- Modelling Practice: Full system model (Sync Gen + RE + Composite Load) Vs Single Frequency Model (Swing Equation)
- Studied incident: Single Largest Infeed (SLI) = HVDC tie-line loss or largest dispatch of generator → Regional inertia
- Key Outcome:
  - Presence and Behaviour of Fast Reserve → Reduce inertia requirement with Δf as a constraint (< 1Hz)
  - High ROCOF can be a concern → maloperation of LOM relay and violation of equipment (generator) withstand
  - ROCOF limit / inertia limit → ensure reserve response (t_{ON}, $t_{Duration}$, droop/ step output, max. output)
  - Regional inertia floor MUST be considered in low inertia region of large interconnected system, where system split is a concern.
  - Solution:
    - Inertia Floor / ROCOF limit
    - New FFR Services (e.g. BESS, HVDC – EPC)
    - Scheme to mitigate specific contingency (e.g. Japan: System Stabilizing Controller, SSC)

Inertia Product and PFR requirement

1. Ireland (Eir-grid): SIR = KE in ω_0 [MWs] of a dispatchable synchronous generator/ condenser/ load
   = stored KE x SIRF, where SIRF = stored KE / minimum generation,
   It is to tackle to expensive cost to run at minimum load.

   Governor with 4% droop and 15 mHz Deadband, inertia floor = 23MWs, max ROCOF = 1Hz/s,
   PFR (=75% SLI) must be provided within 30s, and FFR must be provided within 5s.
2. AEMO: As a generation unit commitment → secure operating inertia (security operating state – N-1) Vs
   minimum threshold inertia (satisfactory operating state, contingency + loss of load/ generator) in an islanded sub-network.

   [Note: AEMO has the constraint to limit tie-flow to region if inertia has reached a threshold.]
3. Brazil: all thermal/hydro plant must have speed governor to provide PFR, min PFR = 1% (load + exchange)
4. Canada: All generating unit > 10MW must have droop and no deadband with governor.
   UFLS requests inertial response for large Δf and limited ON time. Min PFR is calculated in real time operation.
   NO specific requirement on minimum inertia.
   New generators must be compatible with the inertia constant H of the existing generating plant
5. Chile: PFC = (load fluctuation between $\pm$ 0.2 Hz) + (Contingency $\pm$ 0.7 Hz)
   FFR must be provided within 1s and at least sustained for 5 min.

Inertia Product and PFR requirement

6. Japan: No specific requirement on inertia, procured PFR = 3% of system demand such that Δf < 0.5Hz in response to loss of generation = 3 – 4% of total system demand
7. Netherland: Δf > 0.2 Hz → 50% of full PFR < 15s, 100% of full PFR < 30s
   total PFR in Europe = 3GW → shared 3.8% (= 113MW)
   HVDC must be providing synthetic inertia.
8. Nordic: All generating resource > 10 MVA must be providing frequency regulating facilities.
   Wind Power > 10MVA must be supplying with PFR.
   Frequency Regulation between (47.5 Hz – 49 Hz) > 30 min & continuously within 49.0 Hz – 52.0 Hz.

Conclusion

- System inertia is KE from rotating elements on bar (i.e. synchronous generator, condenser, load). It can be estimated with mechanical constant J on nameplate, or estimated with swing constant by measuring df/dt and ΔP during fault, or by active injection.
- Larger system inertia tends to have limited ROCOF and frequency nadir. It becomes problematic with increasing RE as it does not provide inertia (even with synthetic inertia/ virtual inertia/ inertia emulation).
- System inertia is often dedicated to arrest frequency drop with rotating KE loss during loss of generation and load until fast frequency response (FFR, in order of 0.25 – 1.0s) from HVDC – EPC or BESS to provide further energy to rescue frequency until primary frequency response (PFR, in order of 1.0s – 30s) from governor, i.e. droop response, to further restore the frequency.
- It is difficult to provide inertia, as it requires a rotating mass possibly in high running cost. Hence, other means (e.g. limit tie-line transfer, requirement of local base generation and review of UFLS setting) are employed.
- NOT many countries set inertia floor in transmission planning. Yet, it is still bounded with the requirement on ROCOF (e.g. 1 Hz/s) and frequency range (from UFLS). Frequency based simulation (governor/generator + frequency sensitive load) or system-wise based simulation is needed to obtain the critical inertia or energy deficiency with other necessary conditions to arrest frequency before reaching UFLS setting (frequency and time) to the referenced condition.
- In the end, the goal is to avoid underfrequency load shedding (UFLS) by providing enough frequency reserve (inertia, FFR and PFR) under various situational condition (system split, single largest contingency) with reduced inertia and increased power imbalance reflected in the swing equation.

Development on Inertia Requirement in Worldwide

Entity	Country	Definition of Minimum Inertia Levels	Minimum Inertia Levels Calculation Methodology	Frequency Containment Reserves	Fast Frequency Response	Other Mitigating Measures
AEMO	Australia	YES	YES	YES	YES[1]	YES
ONS	Brazil	YES	YES	YES	YES	YES
Hydro Quebec	Canada	YES	YES	YES	NO	YES
IESO	Canada	YES	YES	YES	YES	NO
Manitoba Hydro	Canada	YES	NO	YES	YES	YES
Coordinador Electrico Nacional	Chile	YES	NO	YES	NO	NO
Amprion	Germany	YES	YES	YES	YES	YES
Eirgrid	Ireland	YES	YES	YES	YES	YES
Japanese TSO	Japan	NO	NO	YES	NO	YES
TenneT	Netherlands	NO	NO	YES	NO	NO
Statnett	Norway	YES	YES	YES	NO	YES
REE	Spain	NO	NO	YES	YES	NO
Swissgrid	Switzerland	YES	YES	YES	YES	NO
ERCOT	USA	YES	YES	YES	YES	YES
PJM	USA	NO	NO	NO	NO	NO

Note:

1. Definition of Minimum Inertia Level possibly comes from the referenced case (i.e. the single largest contingency/ single infeed loss). It does NOT necessarily have a limit on inertia level.
2. Other than providing an inertia floor, it is possible to have ROCOF or frequency nadir limit, or policy on tie-flow limits or minimum requirement on local running generator to avoid frequency drop under system split condition.
3. Primary Frequency Reserve (PFR, a.k.a. Frequency Containment Reserve) are often quantified as deadband and droop (upward / downward with different requirement) when the generator is installed > 10MW.

Frequently Asked Questions

1. **Is spinning reserve = system inertia?**
   NO. Traditional spinning reserve requirement often includes ONLY primary response from governor and secondary response from AGC + steam drum. It evolves to operation reserve requirement in which following reserves, ramping reserves and contingency reserves are concerned. Yet, system inertia is a new concern with fast frequency reserve (FFR) to arrest frequency during frequency drops to bottom. Note that the change of inertia is the main concern: $\Delta KE = J\omega$.
2. **Is high wind low load condition necessary to be the worst scenario or referenced case?**
   NOT necessary. System with inertia-based unit commitment or abundant of fast frequency response can operate safely under high wind low load. Eir-Grid concerns more on frequently occurred small frequency event which may easily cause overshoot and oscillation, while Nordic considers more on single largest infeed loss (Celtic HVDC – 700MW) as largest frequency event.
3. **Is system with low inertia must be easy to be unstable?**
   NOT necessary. Critical inertia depends on actual equipment withstand capability (f_{MIN}, $ROCOF_{MAX}$), frequency stability margin and UFLS setting. Yet, high RE penetration with grid forming converter often allows quick grid stabilization under low inertia condition (e.g. System Stabilizing Control in Japan or Virtual Oscillator based converter).
4. **What should we do if the grid has reducing thermal generator?**
   Study on grid frequency response and corresponding reserve abundancy is needed. It is often solved by limiting RE penetration or HVDC import. It is also a suggestion to review the setting of UFLS, allowed frequency nadir, RE fault ride-through requirement and include more FFR to reduce energy deficiency during fault and inertia needed. Addition of high inertia synchronous condenser also help.

Frequently Asked Questions

5. **Can we obtain system inertia value through past frequency record?**
   It is only OK with high resolution data for all past frequency record. Yet, system inertia is a stochastic variable dependent on system configuration, generator on-bar and load (e.g. sync motor with direct on line). It is noted that Icelandic Grid with high penetration of Phasor Measurement Unit (PMU) has performed a frequency study with past frequency record, it results in a model with error ranging from few percent to 40% in some cases (average error = 12%)
6. **Can synthetic inertia/ virtual inertia/ inertia emulation help arrest frequency during frequency event?**
   Synthetic inertia itself cannot provide energy during frequency event. Yet, additional power source or DC link capacitor is the sole source to drain out during energy deficiency with smoothened out output setpoint. It is only possible to provide PFR if wind turbine or PV are set to be power reserve mode. Also, HVDC tie-line could allow temporary overload to drain power to arrest and rescue the frequency.
7. **What is the difficulty in operation on frequency event?**
   It is difficult to detect and identify frequency event until it is too late. Recall frequency measurement requires 4 cycles (80ms) and CB operation requires (30ms). System with high ROCOF (low inertia, low FFR) can result in fast and large drop in frequency, in which UFLS is the unavoidable move in rescuing the frequency. It is an ideal condition to trigger frequency response on time.
8. **Is inertia floor determined with deterministic or probabilistic approach worldwide?**
   It is often set in deterministic approach with referenced case simulated with different inertia value (or combination of generator on bar.) It is noted that Eir-grid originally designed to have PFR = 75% SLI, but it results in blackout due to lack of PFR during single largest contingency, which may be a discrete case in fault history, but a fault with large consequence.