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System inertia and Rate of Change of Frequency (RoCoF) with increasing non-synchronous renewable energy penetration

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Summary

This paper explores the relationship between system inertia and Rate of Change of Frequency (RoCoF) in a changing world with increased penetration of non-synchronous renewable energy power generation (wind and solar PV).

Research performed for the Irish Regulator (CER) showed that a RoCoF of 1 Hz/s measured over 500 ms can be tolerated by consumers and generators alike. Simplified dynamic studies determined that RoCoF of greater than 1 Hz/s can result in pole slip to selected generators. Measurement of the RoCoF also showed that 500 ms was the shortest period for the Irish system to avoid spurious trips due to inter-area oscillations.

For South Africa, using conservative assumptions for RoCoF (1 Hz/s) and a slightly larger than expected credible multiple contingency, the minimum system inertia was determined. A production cost model was then used to solve the unit commitment and economic dispatch problem with hourly time resolution for 2030 and 2050 for a range of scenarios. Applying typical inertia constants for all generators, the system inertia for each hour was determined for each scenario. The minimum system inertia was then overlaid following which it was determined when there was insufficient system inertia and for how many hours. As expected, in relatively high non-synchronous generation scenarios, there was insufficient inertia by 2030 for a small number of hours of the year (≈5%) with worst-case inertia being ≈35% below minimum inertia while by 2050 there was insufficient system inertia for almost half of the year with worst-case inertia being 90% below minimum required inertia. Various technologies were presented to improve inertia (synchronous and synthetic) with the most expensive synchronous technology (rotating stabilisers) costed for the scenarios considered. In this regard, provision of additional system inertia was always <1% of total system costs. These static calculations were then supplemented by dynamic simulations in a System Frequency Model (SFM) of the South African network using the industry accepted DIgSILENT PowerFactory tool. Good alignment between static and dynamic calculations were found where the 1 Hz/s RoCoF was ensured when the required additional inertia was added as calculated.

Future work needs to include an analysis of frequency stability under disturbances (frequency nadir, settling frequency, frequency restoration time) as well as frequency control under normal conditions and not just RoCoF to ensure these remain within acceptable limits. This will include aspects of additional reserve requirements (due to supply-side variability), the probability of larger contingencies on the system and impact on under frequency load shedding schemes.

Key words

Rate of Change of Frequency (RoCoF), system inertia, high penetration non-synchronous supply, frequency measurement, synchronous inertia, synthetic inertia

1 Introduction to Inertia and Rate of Change of Frequency (RoCoF)

Synchronous Inertia is the rotating mass of power plants synchronously connected to the network. The speed of rotating mass will change if the instantaneous supply is greater than demand (accelerating and increasing frequency) or if the instantaneous demand is greater than supply (decelerating and decreasing frequency). The rate at which frequency (and speed of the generator) will change is defined by the well-known swing equation [1]. The swing equation relates the response of the generator rotor speed to an accelerating or decelerating torque:

$$J\frac{\mathrm{d}\omega_m}{\mathrm{dt}} = T_a \qquad (1)$$

where:

J is the moment of inertia in kg.m^2 of all rotating masses attached to the shaft

ω_M is the mechanical speed of the shaft;

T_a is the accelerating torque in N.m. acting on the shaft

and

$$T_a = T_m - T_e \qquad (2)$$

where:

T_m is the shaft torque produced by the prime mover;

T_e is the electromagnetic torque resulting from the generator providing electrical power.

The swing equation is often expressed in terms of the inertia constant H:

$$H = 0.5J\omega_m^2 / VA_{base} \qquad (3)$$

where:

ω_m is the rated angular velocity in mechanical radians per second;

VA_{base} is the base rating of the machine.

Substituting for J in Equation (2) gives:

$$\frac{d\omega_r}{dt} = T_a / 2H \qquad (4)$$

where:

ω_r is the angular velocity of the rotor in electrical radians per second.

From Equation (4) it can be deduced that the maximum rate of change of speed (and resulting system frequency) occurs when T_a is at its maximum (the time when a sudden change is initiated). Typical values for the inertia constant H are in the range of 2.5 – 6 MWs/MVA for thermal units (at 3000 rpm), 4 – 10 MWs/MVA for thermal units at 1500 rpm and 2 – 4 MWs/MVA for hydro units. The values of H vary with the moment of inertia (J), generator rated speed and unit size (MW) [1].

As can also be seen in Equation (4), the two key factors that influence the rate of change of frequency (RoCoF) are the relative size of a disturbance and the inertia of the system at the time of the disturbance.

Non-synchronously connected power plants (such as inverter connected wind and solar PV power plants) as well as HVDC interconnections by definition cannot provide inertia naturally to the system. However, on detecting a sudden change in frequency over a particular time period they can inject (or withdraw) power if control loops for this are included in their design and there is sufficient power available for injection (withdrawal is not considered a limitation as curtailment and/or downward control of HVDC interconnections is technically feasible with no pre-requisite requirement for available power other than operating above zero power output). The net-effect of this is that the size of the disturbance (T_a) over a particular time period is decreased and subsequently the RoCoF decreases. The fast injection (or withdrawal) of power by these non-synchronously connected power plants (and HVDC interconnections) in response to the RoCoF is known as 'synthetic inertia' (not to be confused with fast frequency response).

Higher penetrations of these non-synchronously connected power plants and/or HVDC interconnections results in less synchronous power generators being on the network for less of the time. As a result, a number of power systems globally are beginning to mandate for the provision of synthetic inertia by these resources to maintain acceptable RoCoF and resulting frequency stability.

2 Measurement of Rate of Change of Frequency (RoCoF)

The measurement of frequency typically looks at the time difference between zero crossings of the voltage waveform. Accurate and reliable frequency measurement can be determined by measuring more than two zero crossings. The time taken for two zero crossings is 40 ms (on a 50 Hz system) and 33 ms (for a 60 Hz system). In the measurement process, filters are applied as we know the frequency should be within a narrow band and the RoCoF should not exceed certain values for the system being studied. Thus, it is normally assumed that frequency and RoCoF can be calculated within 100 ms. Another technique that can be used for frequency measurement that may enable quicker measurement is the translation of the time-domain voltage waveform measurement into the frequency domain via Fast Fourier Transform Analysis (FFTA). FFTA determines the frequency based on well-known and accepted Fourier analyses making it possible to measure frequency using only a part of the voltage waveform.

However, there are other factors that need to be taken into consideration before the time frame over which frequency should be measured is decided upon (and which protection schemes act upon). The first is single or three-phase faults near the measurement of frequency. The distorted voltage waveform could result in erroneous detection of the zero crossings. A second consideration is inter-area oscillation phenomena which result in a sudden change in frequency which could also result in erroneous frequency measurements. A recent publication [2] showed an example of frequency with inter-area oscillations (shown for reference in Figure 1). In this example the RoCoF will be incorrectly measured at 3 Hz/s if measured over a rolling window of 100 ms and correctly measured at 1 Hz/s if measured over a rolling window of 500 ms. The alternative is to combine the measurement of frequency with RoCoF and thus a combination of RoCoF over 500 ms and frequency below 49.6 Hz in the example would ensure a correct and complete measurement. A similar analysis will have to be done for system frequency in Southern Africa before deciding on the time frame to measure RoCoF and frequency otherwise protection schemes will trigger spuriously.

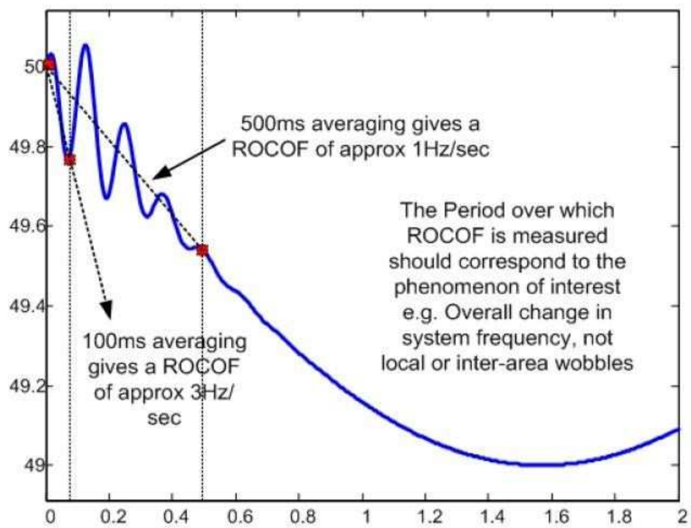

Figure 1 Example of RoCoF measurement with inter-area oscillations (taken from [2])

3 What level of Rate of Change of Frequency (RoCoF) is acceptable?

Research performed by PPA Energy for the Irish Energy Regulator, the Commission for Energy Regulation (CER), showed that a RoCoF of 1 Hz/s measured over 500 ms can be tolerated by Irish consumers and generators alike [2]. The change from the previously determined 0.5 Hz/s to 1 Hz/s will significantly assist the Irish system operator, EirGrid, along with a range of other technical enablers in achieving the mandated 40% renewable electricity target by 2020 for Ireland (75% non-synchronous instantaneous penetration) [3], [4]. Power plants in Ireland are in the process of checking for compliance before the abovementioned grid code change becomes final and binding. Simplified dynamic studies summarised in [5] determined that frequency changes of greater than 1 Hz/s (as measured over a 500 ms sliding window) can result in pole slip to combined cycle gas turbines and other thermal generators (as summarised in Table 1).

The CER has required all generators to prove compliance to ROCOF of 1 Hz/s and at the time of writing, all high-priority conventional generators have tested for compliance while most medium-priority and low-priority generators are ahead of schedule. Protection setting changes were required on wind farms and these are over 80% complete [6].

Table 1 Summary of transient stability analysis summarised in [5]

Generator Type	Unit Size (MW)	Stable during ROCOF event?		
		0.5 Hz/s	**1.0 Hz/s**	**2.0 Hz/s**
CCGT Single-shaft	400	Y	Y*	N
CCGT Dual-shaft	260	Y	Y*	N
CCGT Dual-shaft	140	Y	Y*	N
Steam Thermal (Reheat)	300	Y	Y*	N**
Steam Thermal (Once Through)	150	Y	Y*	N
Steam Thermal (Fluidised Bed peat)	150	Y	Y*	N
OCGT	50	Y	Y*	Y*
Salient-pole Hydro	30	Y	Y	Y

Key: Y is used to indicate stable operation
Y* is used where a pole slip is only observed for a 0.93 leading power factor operating mode
N is used when a pole slip is also observed for power factors of unity and/or 0.85 lag
N** is used when no pole slip is observe for power factors of unity and/or 0.85 lag, but negative power generation is detected.

For conventional synchronous generators, the South African Grid Code (more specifically the Network Code wherein generator connection conditions are defined) does not currently have any explicit requirement for RoCoF [7]. The Renewables Grid Code [8] requires renewable power plants to be capable of tolerating a 1.5 Hz/s RoCoF provided the network frequency is still within the operating range of 47.0 Hz to 52.0 Hz. There is no time window for the frequency measurement provided but a realistic time window would need to be determined to avoid spurious trips (as previously mentioned).

Although a definition of RoCoF for renewable power plants has already been defined, the level of tolerance of current and future planned power stations in the South African and Southern African interconnected region will need to be studied in detail (as has been the case for Ireland) before an acceptable RoCoF can be agreed upon. This is as a result of system frequency being common throughout an interconnected power system and thus the Southern African region and all countries interconnected would have to agree on an acceptable RoCoF.

4 RoCoF and contingency size for South Africa

With an appreciation of the relationship between system inertia, RoCoF and disturbance size; conservative assumptions for both RoCoF and disturbance size for the South African power system need to be made.

For RoCoF, 1 Hz/s is chosen which is based on the previously discussed RoCoF defined for Ireland [2]. This is more conservative than the existing requirement for South Africa in the South African Renewables Grid Code [8] where a RoCoF of 1.5 Hz/s is defined (as previously discussed). For any particular disturbance size, a higher allowed for RoCoF will require less system inertia.

The South African Grid Code (more specifically the System Operations Code wherein ancillary services for South Africa are defined) [9] along with the Ancillary Services

Requirements for 2017/18-2021/22 [10] are considered as the basis for determining future credible multiple contingency requirements. In these, the system frequency should be contained above 49.5 Hz for a single contingency (a trip of the largest unit on the South African system i.e. one Koeberg nuclear unit of 920 MW). The system frequency should also be contained above 49.0 Hz after credible multiple contingency events (the worst-case of either the Cahora Bassa infeed of 1800 MW or three coal-fired units at 2007 MW i.e. 3 x 669 MW). As defined in [10], this changes from 2018 onwards to be 2166 MW i.e. 3 x 722 MW (three units at either Medupi or Kusile). On this basis, future credible contingency events are considered to be the worst-case of three coal-fired units or the HVDC infeed with an additional 10% added in order to remain conservative and be comfortable that sufficient inertia would need to be present to make sure acceptable RoCoF is maintained i.e. 2 400 MW.

5 Minimum inertia requirements for South Africa

Based on the previously defined acceptable RoCoF and credible multiple contingency events for South Africa going forward, the minimum inertia requirement for all hours of the year for South Africa can be calculated. This is calculated as follows (based on the background previously provided) and linearised over the small frequency disturbance range:

$$.(\quad) = \frac{\quad}{(\quad)} + (\quad .) \tag{5} $$

where:

.( )	=	Minimum system inertia required (MW.s);
	=	Worst case size of largest credible multiple contingency (MW));
	=	System frequency (50 Hz);
	=	Pre-defined acceptable RoCoF (Hz/s); and
(.)	=	Amount of system inertia lost in credible multiple contingency.

Knowing the acceptable RoCoF (1 Hz/s) and the largest credible multiple contingency (2400 MW), the minimum amount of system inertia required for all hours of the year is 64 800 MW.s.

6 Inertia requirements for selected future scenarios in South Africa

The minimum amount of system inertia required on the network is an important parameter to know going forward as South Africa's power system grows and new technologies are introduced into the power system. In the work performed in [11], [12] a production cost model is run where the unit commitment and economic dispatch problem is solved with hourly resolution for the South African power system annually. From this, the amount of system inertia that is on the system for every hour of the year is calculated based on typical inertia constants for all generator technologies (these are summarised in Table 2). As previously discussed (and in order to remain conservative in approach), non-synchronously connected generators are assumed to have no inertia (no 'synthetic inertia' either) and thus do not contribute to system inertia. The system inertia is then ordered in a similar manner to a LDC to obtain an inertia duration curve. The previously calculated minimum system inertia is then overlaid onto this for comparative purposes.

Table 2 Typical inertia constants assumed for all generation technologies

Technology	Inertia constant [MW.s/MVA]
Coal (old/existing)	4.0
Coal (new)	2.0
Open-Cycle gas Turbine (OCGT)	6.0
Closed-Cyce Gas Turbine (CCGT)	9.0
Cogeneration	2.0
Biomass	2.0
Hydro/Pumped Storage (PS)	3.0
Imports	-
Nuclear	5.0
Wind	-
Solar PV	-
Concentrated Solar Power (CSP)	2.5
Demand Response (DR)	-

Three scenarios based on the work in [11]–[13] were selected for comparison to get an idea of the expected system inertia in the medium term (2030) and long-term (2050) in the South African power system. These scenarios include a "Base Case" and "Carbon Budget" scenarios taken directly from [13] as well as a "Least-Cost" scenario taken from [11], [12]. The energy mixes and more importantly the synchronous and non-synchronous generation capacity resulting from these scenarios are summarised in Table 3 and Table 4 for 2030 and 2050 respectively.

Table 3 Scenario summary of energy mix for 2030 as taken from [11]–[13]**.**

Technology	Installed capacity [GW]						Energy generated [TWh]					
	BC		CB		LC		BC		CB		LC	
Coal	37.9	*45%*	32.6	*34%*	32.6	*33%*	236.8	*68%*	165.6	*47%*	190.3	*54%*
Nuclear	1.9	*2%*	7.3	*8%*	1.9	*2%*	14.6	*4%*	54.5	*16%*	14.6	*4%*
Gas	7.7	*9%*	4.1	*4%*	3.4	*3%*	15.8	*5%*	8.5	*2%*	8.7	*2%*
Peaking	8.5	*10%*	9.8	*10%*	13.1	*13%*	0.6	*0%*	0.6	*0%*	3.9	*1%*
Hydro	3.2	*4%*	4.7	*5%*	2.2	*2%*	18.4	*5%*	22.4	*6%*	12.6	*4%*
Wind	11.1	*13%*	19.6	*20%*	25.1	*25%*	35.6	*10%*	62.9	*18%*	80.3	*23%*
CSP	1.1	*1%*	1.1	*1%*	1.1	*1%*	5.1	*1%*	5.1	*1%*	5.1	*1%*
Solar PV	7.5	*9%*	12.7	*13%*	15.3	*15%*	13.3	*4%*	22.5	*6%*	27.2	*8%*
Biogas	0.3	*0%*	0.1	*0%*	0.1	*0%*	2.1	*1%*	0.4	*0%*	0.4	*0%*
Biomass	0.4	*0%*	0.4	*0%*	0.4	*0%*	2.6	*1%*	2.6	*1%*	2.6	*1%*
DR	1.0	*1%*	1.0	*1%*	0.6	*1%*	0.1	*0%*	0.1	*0%*	0.0	*0%*
Pumped storage	2.9	*3%*	2.9	*3%*	3.2	*3%*	5.1	*1%*	4.9	*1%*	6.4	*2%*
Total	**83.5**		**96.3**		**99.0**		350.2		350.0		351.9	
% synchronous	**77%**		**65%**		**59%**		**86%**		**76%**		**69%**	
% non-synchronous	**23%**		**35%**		**41%**		**14%**		**24%**		**31%**	

BC = Base Case; CB = Carbon Budget; LC = Least-Cost

Table 4 Scenario summary of energy mix for 2050 as taken from [11]–[13]**.**

Technology	Installed capacity [GW]						Energy generated [TWh]					
	BC		CB		LC		BC		CB		LC	
Coal	25.2	*19%*	10.2	*7%*	10.2	*4%*	172.6	*33%*	69.4	*13%*	59.5	*11%*
Nuclear	20.4	*15%*	25.8	*17%*	0.0	*0%*	147.9	*28%*	185.3	*35%*	0.0	*0%*
Gas	22.4	*16%*	33.4	*22%*	19.5	*8%*	49.2	*9%*	83.0	*16%*	55.3	*10%*
Peaking	13.3	*10%*	10.3	*7%*	36.8	*16%*	0.8	*0%*	0.8	*0%*	11.6	*2%*
Hydro	4.7	*3%*	4.7	*3%*	4.7	*2%*	27.9	*5%*	28.2	*5%*	26.9	*5%*
Wind	30.4	*22%*	36.0	*24%*	85.1	*36%*	93.1	*18%*	110.2	*21%*	257.1	*48%*
CSP	0.0	*0%*	0.0	*0%*	0.0	*0%*	0.0	*0%*	0.0	*0%*	0.0	*0%*
Solar PV	15.8	*12%*	24.9	*17%*	74.0	*31%*	28.0	*5%*	44.2	*8%*	110.4	*21%*
Biogas	0.3	*0%*	0.0	*0%*	0.3	*0%*	1.7	*0%*	0.0	*0%*	1.5	*0%*
Biomass	0.3	*0%*	0.3	*0%*	0.3	*0%*	1.6	*0%*	1.7	*0%*	1.6	*0%*
DR	0.5	*0%*	1.0	*1%*	3.0	*1%*	0.1	*0%*	0.1	*0%*	0.0	*0%*
Pumped storage	2.9	*2%*	2.9	*2%*	3.6	*2%*	4.8	*1%*	4.1	*1%*	7.5	*1%*
Total	**136.2**		**149.5**		**237.5**		527.8		527.0		531.3	
% synchronous	**66%**		**59%**		**32%**		**77%**		**71%**		**31%**	
% non-synchronous	**34%**		**41%**		**68%**		**23%**		**29%**		**69%**	

BC = Base Case; CB = Carbon Budget; LC = Least-Cost

The aforementioned inertia duration curves are summarised graphically in Figure 2 for 2030 and Figure 3 for 2050 for all scenarios previously described (similar information is shown in tabular format in 5). The minimum required system inertia previously calculated is compared to these to get an indication of the amount of system inertia each scenario lacks (if any at all) along with the number of hours for which the system has insufficient inertia.

As expected, the Least-Cost scenario has the lowest system inertia between all scenarios as a result of the higher levels of non-synchronous generation (solar PV and wind). In 2030, only the Base Case scenario has sufficient inertia for all hours of the year while the Carbon Budget scenario does not have sufficient inertia for 210 hours in the year (≈2.4% of the year) and in the worst case needs an additional 14 500 MW.s of inertia (≈22% below the minimum inertia needed). The Least-Cost scenario has insufficient inertia for 440 hours of the year (≈5% of the year) and in the worst case needs an additional 22 500 MW.s of inertia (≈35% below the minimum inertia needed). By 2050, the Base Case and the Carbon Budget scenarios have sufficient inertia for all hours of the year while the Least-Cost scenario has insufficient inertia for 4 320 hours (49% of the year) and in the worst case needs an additional 58 000 MW.s of inertia (90% below the minimum required inertia).

The quantification of the system inertia for these three scenarios is necessary to better understand what inertia requirements could be expected into the future following which appropriate technologies and measures can be defined and accordingly costed to ensure sufficient system inertia (this is undertaken later in this paper).

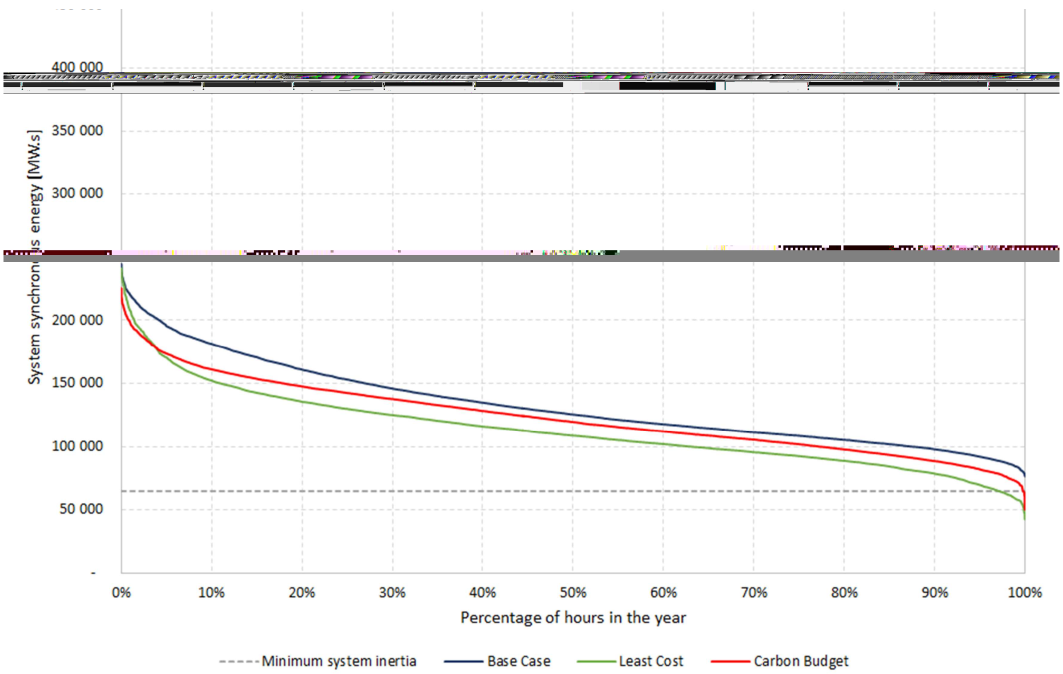

Figure 2 Inertia duration curve for 2030 (selected scenarios from [11]–[13]**)**

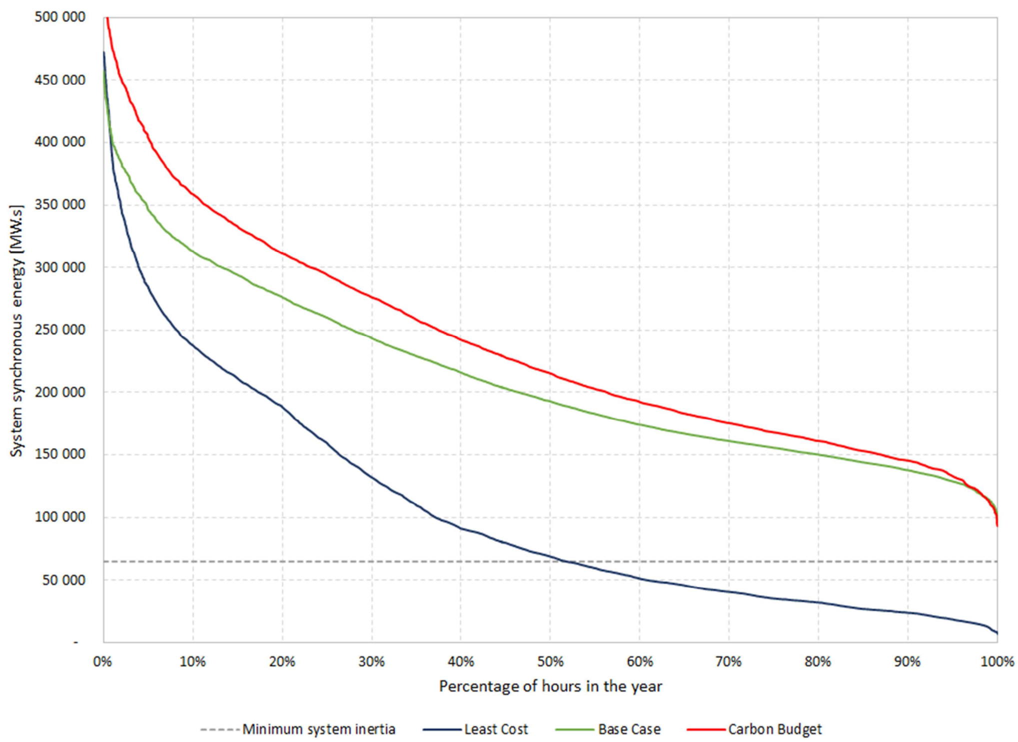

Figure 3 Inertia duration curve for 2050 (selected scenarios from [11]–[13]**)**

Table 5 Scenario summary of system inertia requirements for 2030 and 2050

7 Transient simulations for RoCoF determination

A single bus model was previously developed for the under frequency load shedding scheme review in South Africa [15]. Subsequent studies done by Eskom validated the models' accuracy for fast frequency studies. The Irish have used a similar single bus approach for RocoF studies done by ECAR using the System Frequency Model (SFM) [2]. The tool used to implement this was DIgSILENT PowerFactory and the model representation of the system used in these studies is shown in Figure 4 below.

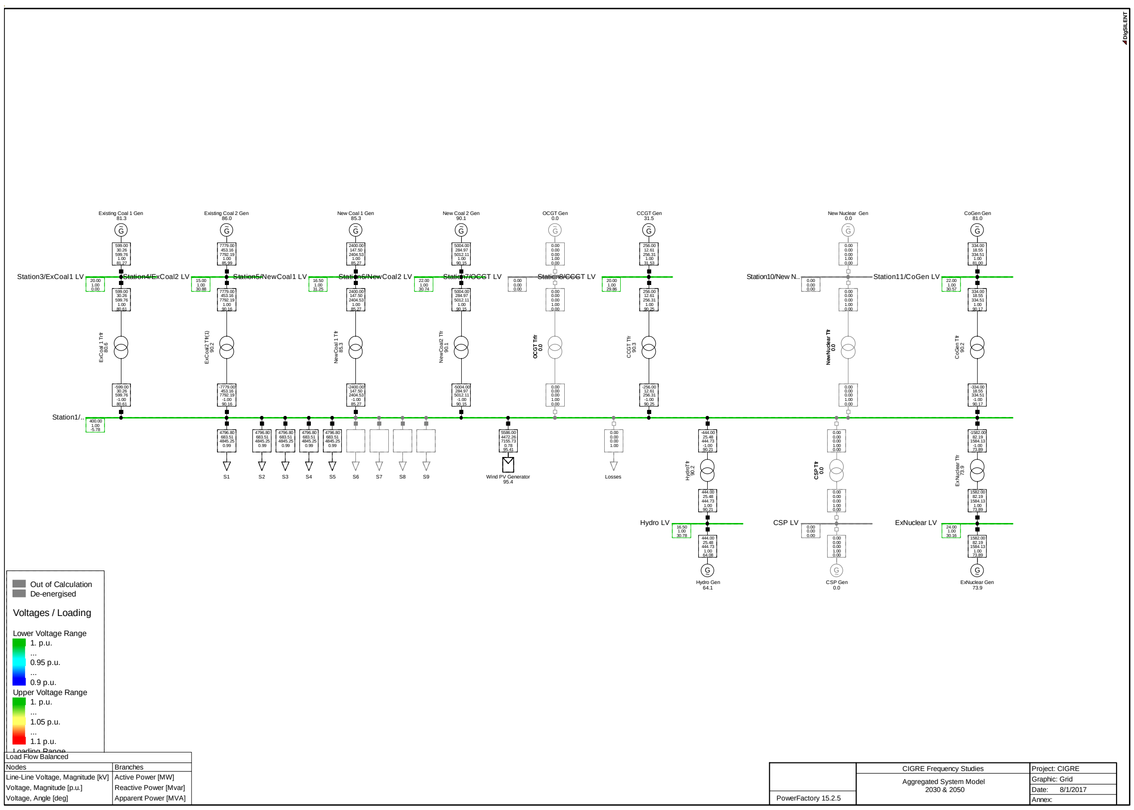

Figure 4 : Single Bus Frequency Model

The single bus model was modified to represent the various generation technology classes with corresponding dynamic information as indicated in Table 3. The Base Case, Carbon Budget and Least Cost scenarios were set-up for the years 2030 and 2050 for the system demand corresponding to the lowest system inertia for the year.

For all simulations, 2 400 MW of generation was tripped and the resulting frequency curves were analysed. A load frequency characteristic of 4% was used for the connected load. No instantaneous reserve (governing response or other) was modelled or assumed in order to remain conservative on the RoCoF.

2030 Results

The dispatch of all generation technologies for the scenarios in 2030 are shown in Table 6. The resulting system frequency curves for these scenarios using the SFM implemented in DIgSILENT PowerFactory for the loss of 2400 MW of generation are shown in Figure 5 and summarised in Table 7.

These time domain studies indicate the RoCoF requirement of 1Hz/s is not breached for the Base Case in 2030. For the Carbon Budget and Least Cost scenarios in 2030, the 1 Hz/s RoCoF is breached (as expected). The addition of inertia to the Carbon Budget and Least Cost scenarios improves the RoCoF to just below the desired value of 1 Hz/s The simulations do not show an exact 1 Hz/s RoCoF due to the influence of the modelled load frequency characteristic and actual system response. The studies for 2030 show a difference of 0.07 to 0.09 Hz/s between the calculated and simulated RoCoF (1 Hz/s).

It is important to note here that the analysis only considers the RoCoF as a defining parameter and excludes any primary frequency response (governor action or other). The resulting frequency nadir and/or settling frequency is not a focus of this paper and will be the subject of future work.

Table 6 : Dispatch of generation fleet for scenarios in 2030

Generation Type	Base Case [MW]	Carbon Budget [MW]	Least Cost [MW]
Existing Coal	8 379	0	5 064
New Coal	7 404	6 209	2 340
Nuclear	1 581	5 107	888
Hydro	444	520	396
OCGT	0	0	0
CCGT	256	0	0
CoGen/Biomass	334	313	266
CSP	0	0	0
PV & Wind	5586	16 008	18 321
Total Generation	**23 984**	**28 157**	**27 275**

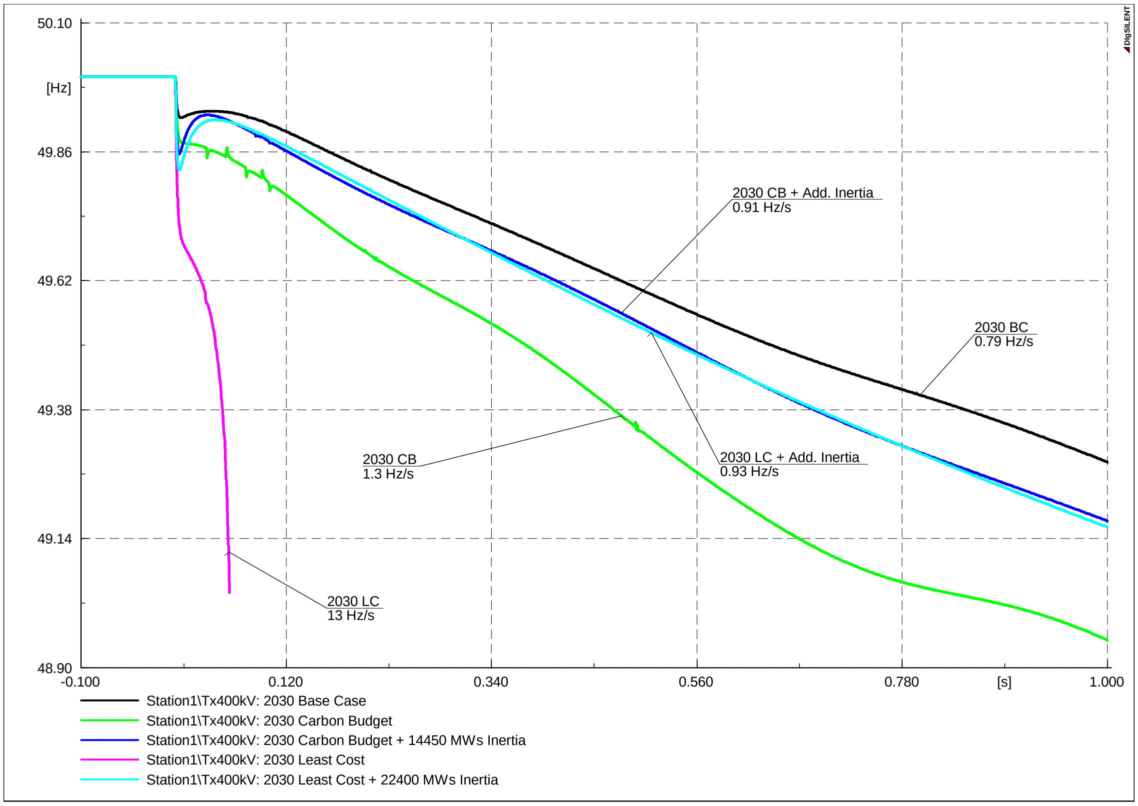

Figure 5 : 2030 system frequency curves following 2 400 MW generation contingency [1s]

Table 7 : 2030 simulation results summary.

Case	Demand [MW]	System Inertia [MWs]	Inertia Added [MWs]	RoCoF [1st 500ms]
2030 Base Case	23 984	76 500	-	0.79
2030 Carbon Budget	28 157	50 350	-	1.30
2030 Least Cost	27 275	42 300	-	> 5
2030 Carbon Budget + Inertia	28 157	50 350	14 450	0.91
2030 Least Cost + Inertia	27 275	42 300	22 400	0.93

2050 Results

The dispatch of all generation technologies for the scenarios in 2030 are shown in Table 8. The resulting system frequency curves for these scenarios using the SFM implemented in DIgSILENT PowerFactory for the loss of 2400 MW of generation are shown in Figure 6 and summarised in Table 9.

These time domain studies indicate that the RoCoF of 1 Hz/s is not breached for the Base Case and Carbon Budget scenarios in 2050. For the Least Cost scenario in 2050, simulation non-convergence is obtained at the inception of the 2 400 MW generation loss (as expected). This is as a result of the Least Cost scenario in 2050 only having approximately 6700 MWs of system inertia.

The addition of 61 660 MWs of inertia to the Least Cost scenario in 2050 results in a RoCoF of 0.90 Hz/s. This is close to the desired RoCoF of 1 Hz/s with the difference due to the system load frequency characteristic and dynamic system response. Thus, there is general agreement between the static inertia calculation requirements and the frequency stability simulations for the first 500 ms.

Again, it is important to note here that the analysis only considers the RoCoF as a defining parameter and excludes any primary frequency response (governor action or other). The resulting frequency nadir and/or settling frequency is not a focus of this paper and will be the subject of future work.

Table 8 : Dispatch of generation fleet for scenarios in 2050

Generation Type	Base Case [MW]	Carbon Budget [MW]	Least Cost [MW]
Existing Coal	0	436	0
New Coal	8 099	3 719	834
Nuclear	13 318	13 318	0
Hydro	1 526	458	453
OCGT	0	198	356
CCGT	0	0	0
CoGen/Biomass	319	117	99
CSP	0	0	0
PV & Wind	19 433	24 963	53 334
Total Generation	**42 695**	**43 209**	**55 076**

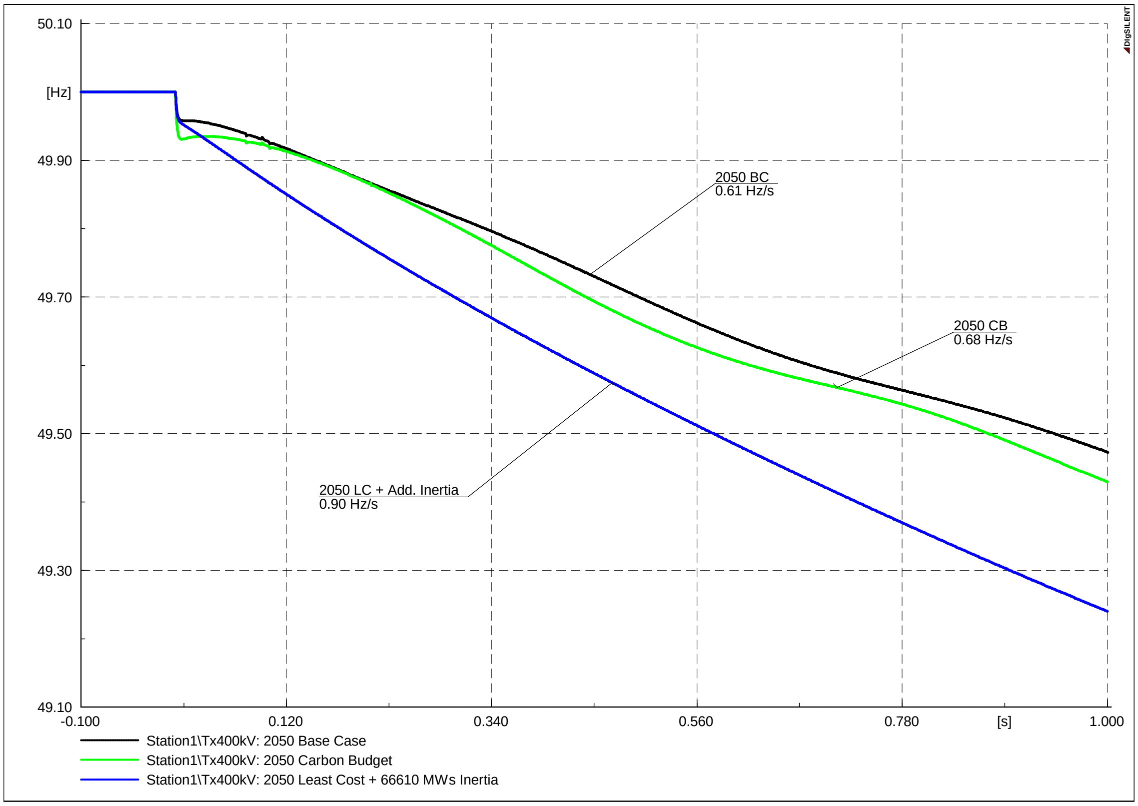

Figure 6 : System frequency curves following 2 400 MW generation contingency

Table 9 : 2050 simulation results summary

Case	Demand [MW]	System Inertia [MWs]	Inertia Added [MWs]	RoCoF [1st 500ms]
2050 Base Case	42 965	100 160	-	0.61
2050 Carbon Budget	43 209	93 120	-	0.68
2050 Least Cost	55 706	6 810	-	> 5
2050 Least Cost + Inertia	55 706	6 740	61 660	0.90

8 Options to increase inertia for South Africa

In [2], a number of technologies and measures are identified to deliver the necessary system inertia and help prevent high RoCoF events (whether synchronous or synthetic). These are:

- Synchronous:
    - *Synchronous compensators* – New or retrofit generators synchronised with the power system normally used for voltage control and reactive power support i.e. generators operating in Synchronous Condensor (SCO) mode;
    - *Rotating stabilisers* - Synchronous machine designed with a high mass;
    - Wind turbines – Synchronous provision of inertia if directly coupled (no inverter interface);
    - *Pumped hydro* – Synchronous machine online for inertia provision;
    - *Compressed Air Energy Storage* - Operates like a normal gas turbine power plant by providing inertia, primary, secondary and tertiary response;
    - "Parking" - Operating generation plant at low MW output (no provision of other system services);
    - *Reduction of unit/power station minimum generation* – Keeping more units online by retrofitting for increased flexibility;
    - *Flexible thermal power plants* - Fast response gas turbines;
    - *AC interconnectors* – Increased synchronous interconnections of South Africa to the Southern African region (increasing the synchronous area).
- Synthetic:
    - *Battery technology* - Provide "synthetic" inertia response via inverter interface to the power system with appropriate control loops;
    - *Flywheels* – High speed machines that provide synthetic inertia for short durations;
    - *Wind turbines* – Non-synchronous inverter interconnected wind turbines can provide synthetic inertia response for a few seconds with well defined and tuned control loops;
    - *HVDC interconnectors* - Provide synthetic inertia response via HVDC links.
    - *Demand Side Response (DSR)* - Demand reduction in a range of end-user loads (electric vehicle charging/discharging, electric water heating, large industrial loads, data centres, etc).

All of the above options have associated technical characteristics, geographical flexibility, technological maturity/operational experience globally, lead times, other system services they could provide as well as costs associated with them [2]. These options were ranked based on the best solution for Ireland in [2]. However, for South Africa the resulting ranking on these dimensions would likely be slightly different but the principles would still apply.

For South Africa, based on [11], [12] a conservative approach is taken to ensure sufficient system inertia wherein only synchronous inertia solutions are considered as options to increase system inertia. In addition, the most expensive option available for synchronous system inertia improvement is considered – rotating stabilisers. Thus, for all scenarios, a fleet of rotating stabilisers to ensure sufficient system inertia in all hours of the year is deployed and accordingly costed. It is appreciated that a much more elegant set of solutions including a range of technologies (both synchronous and synthetic) could be applied for

South Africa but these would all come at a lower cost relative to rotating stabilisers. For example, South Africa already has extensive experience with DSR for primary frequency response and an even faster response can easily be achieved if necessary. In addition, the European Network of Transmission System Operators for Electricity (ENTSO-E) was recently also in the process of mandating for DSR in all large thermal devices (fridges, air-conditioners, electric water heaters) as part of the Demand Connection Code [14]. This attempt was not successful but this is still a viable option (and could be applied to South Africa) for DSR with very little impact on the consumer. There is also the possibility of 'importing' inertia from flexible hydro power stations in the Southern African region as well as retrofitting of decommissioning coal power plants to act as synchronous compensators. Existing pumped hydro as well as "parking" or minimum generation reductions at existing power stations could also be feasible.

On the magnitude and costing of rotating stabilisers, the amount of additional inertia required for all scenarios is met by deploying a fleet of rotating stabilisers running for all hours of the year with cost characteristics as summarised in Table 10 (with a relative measure of total system costs included to provide an indication of the impact on total system costs). As can be seen, there is a requirement for a fleet 560 MW of rotating stabilisers by 2030 and 1 450 MW by 2050 for the Least-Cost scenario. The cost implications are R 1.7-billion/yr by 2030 and R 4.5-billion/yr (when annualised). This is <1% of total system costs in the respective years. The Carbon Budget scenario seems to require a fleet of 560 MW of rotating stabilisers by 2030 but does not need these by 2050 so it is unlikely that this scenario will deploy rotating stabilisers in reality as other technologies/options will be pursued instead (as outlined previously).

The analysis in this paper focusses on the initial RoCoF and does not assess whether the frequency nadir and/or settling frequency will be within acceptable limits. As previously mentioned, this will be the focus of future work. However, it is hypothesised that with the inclusion of generators' primary frequency response (governor action via instantaneous reserve) and/or additional system inertia (whether via rotating stabilisers or some other technologies) that the RoCoF, frequency nadir and settling frequency will likely be within acceptable limits at relatively minimal cost.

Table 10 Summary of system inertia requirements and worst-case additional costs incurred by the rollout of rotating stabilisers fleet (2030 and 2050)

Rotating stabilisers needed	[MW]	[illegible]	[illegible]		[illegible]
(% of system costs)	[%]	[illegible]	[illegible]	[illegible]	[illegible]

9 General Discussion: AC vs DC

HVDC interconnectors in Europe and Asia are used to connect synchronous areas mainly with the function of transporting large volumes power at economic levels. HVDC interconnections exist between Norway and Europe, Ireland and UK, Finland and Russia to name a few. However, the trend is now to build HVDC interconnectors to provide both energy and frequency control services. The back to back HVDC interconnection between UAE and Saudi Arabia only provides frequency control services. The HVDC interconnections from Norway are a prime example which provide frequency services to Europe and more HVDC interconnectors planned to UK and Netherlands for the same reason.

The advantage of HVDC interconnections is that a system disturbance in one region is not automatically converted to a disturbance in other regions. The HVDC can provide frequency control to the disturbed system whilst protecting the system it provide the services from by limiting the response. HVDC also eliminates inter-area oscillations and can even dampen them.

Uninterrupted power supplies and back up supplies via inverters to consumers already operate within AC networks without any inertia required. The battery is quick enough to control the frequency when there is no mains supply. If there is very little or no inertia on the network, will there be more black-outs and partial blackouts and if so what is the impact?

In South Africa there are long power lines to transport power across the country. The cost benefit analysis shows that HVDC breaks even at 600 to 800 km in length and as the price of inverters decreases the economics improves. Inter-regional power lines could easily and economically converted to HVDC lines. This could solve the frequency problem in that a major disturbance in one region could lead to a local collapse rather than a country wide collapse. Coal fired power stations with long start up times could be protected from tripping making restoration faster and easier. The recent black-out in South Australia is a prime example (unfortunately not a HVDC one) where the protection separated the network to protect the main network. The wind turbines that tripped in the black-out were quickly restarted and participated in the restoration. The South Australia system restoration took 2 hours because the remaining network remained intact. South Africans have learnt as have their neighbours a 2 hr power interruption is not the end of the world, especially if this happens infrequently.

Will synchronous networks be required in the future or are we going to be reopening AC vs DC the debate held between Nicola Tesla and Thomas Edison over a hundred years ago? Will Thomas Edison’s views that DC was better than AC be vindicated? AC won the case because it was easier and cheaper to transport power over an AC network but that is only partially true today and in the future may not be true at all.

10 Conclusion

The paper has investigated the impact of increased levels of non-synchronous generators (wind and solar PV) on the rate of change of frequency (RoCoF) in a number of future scenarios for South Africa. The initial work done on static additional inertia requirements to support a maximum RoCoF of 1 Hz/s (measured over 500 ms) were validated with dynamic studies in a System Frequency Model (SFM) implemented in an industry accepted tool (DIgSILENT PowerFactory).

Using a worst-case technology option (from a cost-perspective), sufficient rotating stabilisers were deployed to ensure the RoCoF was limited to below 1 Hz/s. The cost associated with deploying the necessary rotating stabilisers was <1% of total system costs in the respective years.

The analysis in this paper focusses on the RoCoF in the first 500 ms following an incident (loss of generation) and does not assess whether the frequency nadir and/or settling frequency will be within acceptable limits. Nor does the paper investigate possible additional reserve requirements to restore the frequency to nominal or the impact of variability on reserves required for balancing the system from minute to minute. The paper also does not investigate the probability of larger trips on the system and the impact on under frequency load shedding schemes or a network black out. These are all topics of future work. However, it is hypothesised that with the inclusion of primary frequency response (governor action via instantaneous reserve, demand side instantaneous response, and other fast frequency control techniques), additional secondary frequency reserve requirements as a result of the variable solar PV/wind and/or additional system inertia (whether via rotating stabilisers or some other technologies) that the frequency can be controlled within acceptable limits.

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