PSCAD assessment of the effectiveness of a centralised synchronous condenser approach

October 2020

Acknowledgement

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The views expressed herein are not necessarily the views of the Australian Government, and the Australian Government does not accept responsibility for any information or advice contained herein.

1. Executive summary

Powerlink Queensland with its project partners Pacific Hydro, Sun Metals and GHD applied for and obtained funding from the Australian Renewable Energy Agency (ARENA) to develop materials to help promote a better understanding of system strength. This is the second report in the project. It builds upon the findings of the first report by validating the effectiveness of different approaches to using synchronous condensers to mitigate system strength using detailed PSCAD analysis in a specific real world situation. This second report also establishes a baseline for a third report which will follow, to document PSCAD analysis to assess the effectiveness of grid-forming inverters.

To ensure that the findings are accurate, the analysis is based on the detailed simulation of real generation and network, and has been conducted in the same manner that a “full impact assessment” for a new generator connection. This study considered three Inverter-Based Renewable (IBR) generators, totalling around 400MW, all connected to Powerlink’s 275kV network, separated by about 400km. Certain details of the generators and network have been abstracted in this report to avoid identifying of any of the generators or disclosing any confidential or commercial information. This abstraction does not in any way impact upon the validity of the report’s conclusions.

Each of the three generator connections considered in this report require some form of system strength remediation to operate stably themselves and to not induce instability in other generators. Our analysis focussed on comparing the technical effectiveness of using separate synchronous condensers for each connection, versus a single centralised synchronous condenser that is adequate to support all three generators.

The investigation found that both approaches to synchronous condensers are technically feasible, but the centralised solution would yield significant economies. Three smaller synchronous condensers (rated at 65MVAr, 130MVAr and 130MVAr) would be required under the decentralised approach, compared to a single larger (230MVAr) unit at a centralised location. Given the significant economies of scale which apply to synchronous condensers, a centralised approach would result in an approximate 40% saving in overall capital expenditure to address the collective system strength limitations. One of the other contributing factors to this economic result is that given synchronous condensers are typically available in a finite number of standard sizes, which may not exactly align with the specific need at each location, and could result in a degree of overbuild under the distributed model.

Of particular note is that the centralised solution required less overall synchronous condenser capacity even though the generators were separated by 400km. In this case, the physical distance between the generators was mitigated by the fact that all three generators were directly connected to the main transmission backbone, and so the “electrical distance” (i.e. impedance) between the generators was still relatively low. Whilst there was still some “tyranny of distance” penalty being incurred, this effect was found to be less significant than the inefficiency introduced by matching the specific system strength requirement at each location to standard synchronous condenser sizes. As a result, the overall quantum of system strength remediation is in fact less than when using a centralised approach (230MVAr) compared to the aggregate capacity of the distributed approach (65 +130+130 = 325MVAr). The “over the horizon” effect, in which settling the response of one generator also helps to settle the response of another remote generator which would otherwise interact with it, may also be contributing some benefit although this is difficult to quantify.

A centralised solution means that there are network outages which can significantly increase the impedance between each generator and synchronous condenser. This means that the effectiveness of the centralised solution is significantly reduced whenever the network is in certain outage conditions. To manage this, special protection schemes could be implemented. These schemes would be armed whenever these problematic outage conditions occurred to enable each generator to keep operating, but would automatically trip the generator should another concurrent network outage occur (i.e. rapidly tripping the generator before it had an opportunity to go unstable and/or induce instability in another generator).

A special case of this is an outage of the centralised synchronous condenser itself, which would simultaneously impact on all three generators which were relying upon it. Whilst the generators would not immediately become unstable under this condition, each generator would require special protection to enable them to continue generating. The relatively simple configuration of the network and the availability of telecommunications and control infrastructure in the area considered by this study means that the required special protection would be practical and economic, and thus a centralised approach would be viable. However, like all aspects of this report, this would need to be investigated on a case by case basis.

The investigation also found that the inertia of the synchronous condenser was an important consideration, even where the synchronous condensers were being implemented solely for the purpose of supporting the connection of inverter based renewables. Specifically it was found that a 3 second inertia constant (likely necessitating a flywheel) was required to ensure that the 230MVAr synchronous condenser in the centralised model operated stably.

Readers are referred back to the first report[1] in this series for more thorough explanation of the general principles which are illustrated here, and for exploration of additional commercial or regulatory considerations related to the use of a centralised versus distributed approach to addressing low system strength.

A third and final report is planned to be published by late 2020 outlining Powerlink's PSCAD-based assessment of the effectiveness of grid-forming inverters.

[1] Managing System Strength During the Transition to Renewables, available online at: https://arena.gov.au/knowledge-bank/?keywords=Powerlink+Cost-Effective+System+Strength+Study

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2. Background

Powerlink Queensland with its project partners Pacific Hydro, Sun Metals and GHD applied for and obtained funding from the Australian Renewable Energy Agency (ARENA) to develop materials to help promote a better understanding of system strength throughout the power industry. The project consists of three main work packages outlined below:

- The first report[2] focused on explaining system strength, and outlining the range of remediation options available to manage low system strength and the circumstances in which they might be applicable. It also explored the economic merit and commercial and regulatory issues associated with a shared and scale-efficient model for implementing system strength remediation. It undertook a fault level study to explore how system strength flows throughout the network and identified a number of implications that should be considered when developing renewable connections. The report noted that fault level based analysis may significantly understate the effectiveness of synchronous condensers in dealing with situations in which multiple inverters are interacting with each other.
- This second report aims to expand on the first report by illustrating the general principles and validating the high level analysis with more comprehensive PSCAD analysis, reflective of what would be undertaken to assess the connection of a new renewable generator.
- The third and final report will investigate current grid forming inverter technology through detailed PSCAD analysis to determine their effectiveness in remediating issues associated with low system strength.

3. Study Overview

3.1 Approach to Modelling

The first report highlighted the limitation of conventional forms of power system analysis to identify the issues associated with low system strength and especially the potential for adverse interactions between multiple renewable generators. This is because traditional 'load flow' and transient stability analysis, which has historically been used to analyse network connections (using applications like PSSE and PSS Sincal) do not model the power system with sufficient detail. Rather electromagnet transient (EMT) modelling using tools such as PSCAD must also be used.

EMT analysis is performed using extremely detailed models of each generator and the network (e.g. with a full representation of the control system for each inverter, synchronous plant, Static VAr Compensators and STATCOMs) to assess the potential for unstable interactions between multiple inverters. Due to the detailed nature of these models, they are typically provided by equipment manufacturer on a confidential basis.

The modelling in this report was undertaken using PSCAD analysis.

3.2 AEMO System Strength Assessment Methodology

AEMO's 'System Strength Impact Assessment Guidelines' sets out two different forms of assessment:

1. The preliminary assessment is a simple screening tool to identify where there is enough risk of instability to warrant detailed investigation. It is based on comparing the size of a new project with the available fault level.
2. The full assessment involves a detailed assessment based on PSCAD analysis, which models the complex interactions between multiple inverters.

The Preliminary Assessment methodology was developed based on the best available knowledge of system strength at that time. Over the last couple of years, we have gained a greater understanding of system strength related issues and now believe that this fault level based methodology does not provide sufficient confidence as a screening methodology as originally intended.

We now understand that an important limitation to the hosting capacity for inverter based renewables is the potential for multiple generators, and other transmission connected dynamic plant, to interact with each other in an unstable manner. These dynamic plant control interactions manifest as an unstable or undamped oscillation in the power system voltage. The frequency of the oscillation is dependent on the participating plants, but is

[2] Managing system strength during the transition to renewables - https://arena.gov.au/projects/powerlink-cost-effective-system-strength-study/

broadly characterised as between 8Hz and 15Hz. The only way to gain an understanding of these oscillations is through detailed EMT system-wide modelling.

The analysis undertaken for this report has been in line with AEMO's full Assessment Methodology.

3.3 Guide to Interpreting the Results

The analysis provided in this report will examine the response of electrical network properties such as Active Power, Reactive Power and Voltage under fault conditions.

- Active Power is provided by generators and is the portion of electricity that supplies energy to the load.
- Reactive Power can be provided by generators, synchronous condensers and other equipment and directly influences electric system voltage. It is the portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment.
- Voltage in a power system is analogous to water pressure in a hydraulic system, and is the force that causes an electrical current to flow. In all of the plots in this report, the voltage is shown as:
  - RMS voltage, is a representation of the amplitude of the voltage waveform. In practice the voltage is a sinusoid shape and is constantly varying. If the magnitude of the voltage sinusoid is constant, a plot of the RMS voltage would appear as a flat horizontal line.
  - "per-unit" (pu), is an engineering concept but simplistically can be thought of as percent, where 1.0pu equals 100% of the network's nominal voltage. Note: It is common for the transmission system to be operated between 1.0pu and 1.1pu (i.e. 100% to 110% of its nominal voltage). Whilst this voltage might seem to be too high, this is standard and best practice to maximise the network's capacity and minimise losses. It is also within the network's design envelope (i.e. whilst 100% is the 'nominal' voltage, it is not the design limit). The voltage can be adjusted down to 100% of nominal as power leaves the transmission network through transformers.

When the power system is stable, these quantities will return to a new satisfactory equilibrium level over time, following disturbances, including changes in the load or generation. There are various forms of instability in the power system, and one form of instability is where these parameters begin to oscillate. The National Electricity Rules (NER) require that the power system is effectively dampened, so that any oscillations that start quickly decay. This situation is illustrated in the plot on the left where an initial disturbance (where the voltage suddenly drops and then recovers) initially creates an oscillation but this quickly decays. The opposite situation is illustrated on the right where the same initial disturbance creates an oscillation, but instead of decaying the oscillation is sustained and in fact grows over time.

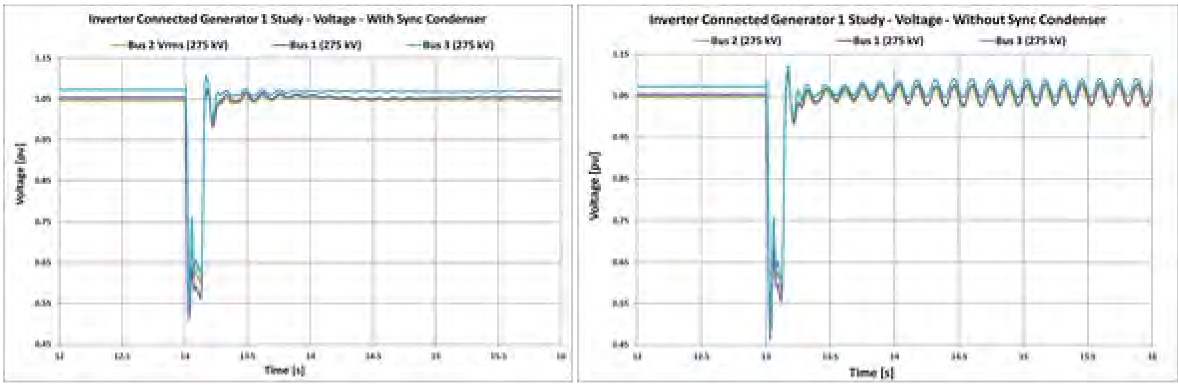

Figure 1 – Example of a stable (left) and unstable (right) response to a disturbance.

The practical consequence of a sustained or growing oscillation is that the control systems of generators and other network equipment are fighting to retain control of the system voltage. A sustained or growing oscillation can lead to the unplanned tripping of generation (to protect itself), which could further exacerbate the instability and lead to a snowballing failure of the power system.

Section S5.1.8 of the NER requires that power system oscillations be adequately damped. The rate at which the oscillation needs to decay depends on the oscillation's frequency. Damping is considered adequate if any oscillatory response at a frequency of:

(a) 0.05 Hz or less, has a damping ratio of at least 0.4;

(b) between 0.05 Hz and 0.6 Hz, has a halving time of 5 seconds or less (equivalent to a damping coefficient –0.14 nepers per second or less); and

(c) 0.6 Hz or more, has a damping ratio of at least 0.05 in relation to a minimum access standard and a damping ratio of at least 0.1 otherwise.

Any control interactions that result in sustained or growing oscillation of active power, reactive power or voltage magnitude between any items of plant would fail to meet the NER's stability requirements.

The effectiveness of the synchronous condenser can be assessed by modelling the response of these power system quantities to network disturbances[3] with and without a synchronous condenser. An effective response with a synchronous condenser connected will dampen any oscillations at the rate required by the NER and return it to a new satisfactory equilibrium state.

4. Assessing the Required Size of Synchronous Condensers

4.1 Methodology

This report will take the approach of examining three Inverter Based Renewable (IBR) generation projects and identify any adverse system strength impact due to individual connections.

It will then consider remediation options based on a:

i. decentralised approach where each generator will provide its own synchronous condenser to meet its system strength obligations; and a
ii. centralised approach where a single, larger synchronous condenser will provide a shared system strength remediation for all three connections.

4.2 Network Configuration

A simplified representation of the network under consideration for this analysis is shown in Figure 2. It shows a double circuit 275kV line (purple) in parallel with a double circuit 132kV line (orange). The IBR generators have a total aggregate output of around 400MW and are connected to the 275kV buses. The IBR generators are geographically dispersed by approximately 400km.

The synchronous condenser sizes considered were restricted to the standard sizes identified in the previous report, given that this is a practical limitation and also to minimise the number of study iterations required.

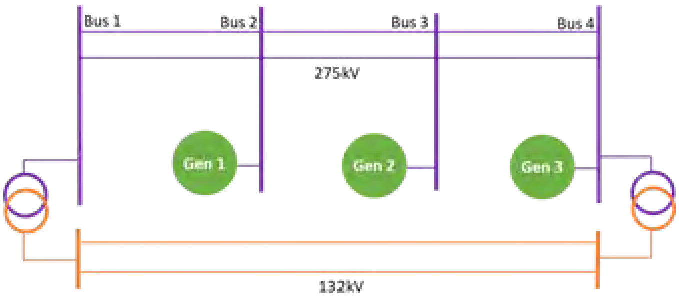

Figure 2 – Network under consideration for study

4.3 Decentralised System Strength Assessment

Under the decentralised model, each connecting generator implements its own synchronous condenser to mitigate the adverse consequences of its connection. Thus there are effectively three different studies to appropriately size the synchronous condenser required to mitigate the adverse impact caused by each generator connection in isolation.

Under this model, it makes sense for each generator's synchronous condenser to be co-located with the generator whose connection it is mitigating, in order to maximise its effectiveness.

[3] A network disturbance generally results from a network fault and results in outages, forced or unintended disconnection or failed re-connection of circuit breaker.

4.3.1 Inverter Connected Generator

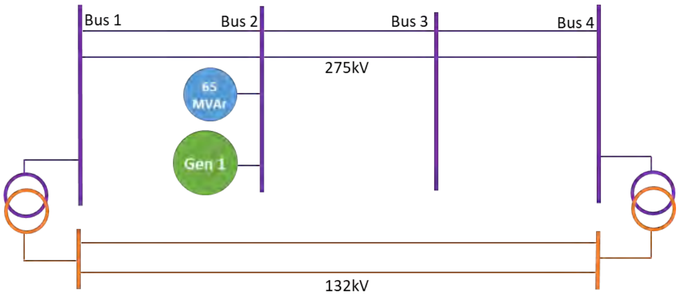

Figure 3 – Network Diagram of Generator 1 and Synchronous Condenser

Generator 1 connects to the 275kV Bus 2 of the network. PSCAD studies were undertaken to determine the active and reactive power and voltage response for Generator 1 under credible fault conditions. These studies identified an adverse system strength impact due to Generator 1. The Active and Reactive power plots are shown in blue in Figure 4 (a) and (b) and for voltage (for a number of locations in the network) in Figure 5 (a).

A 65MVAr synchronous condenser, connected into Bus 2, was found to be effective to remediate the system strength adverse impact caused by Generator 1. Generator 1's response was modelled for the same fault and are shown in Red in Figure 4 (a) and (b) and for the voltage in Figure 5 (b).

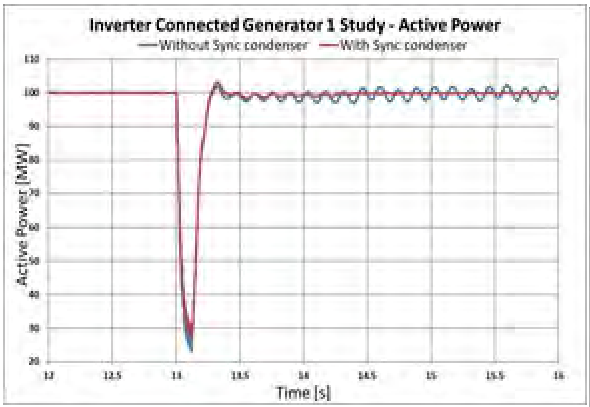

Figure 4 (a) Active Power plots for Generator 1 with and without synchronous condenser connected

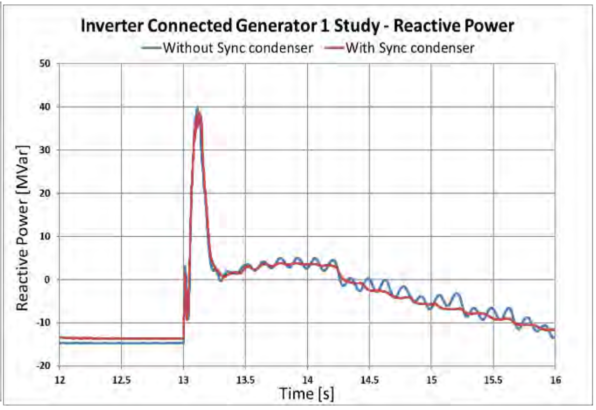

Figure 4 (b) Reactive Power plots for Generator 1 with and without synchronous condenser connected

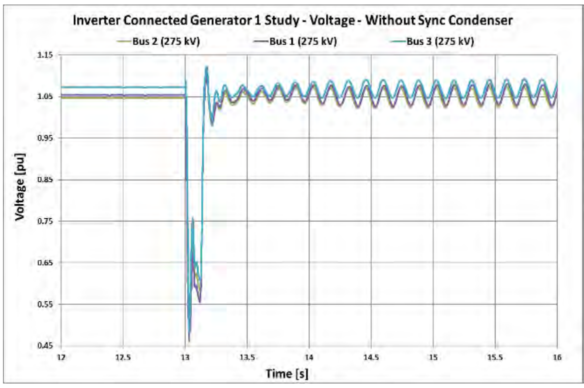

Figure 5 (a) Voltage response at network locations without synchronous condenser connected

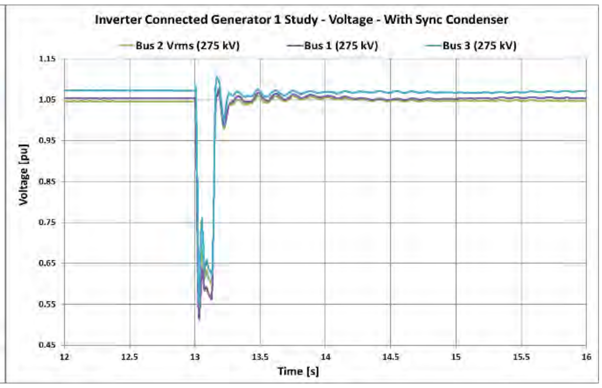

Figure 5 (b) Voltage response at network locations with synchronous condenser connected

4.3.2 Inverter Connected Generator 2

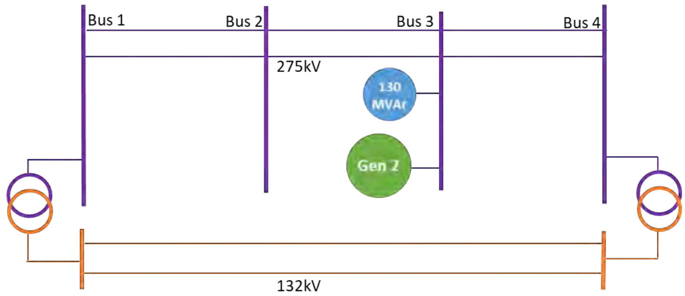

Figure 6 – Network Diagram of Generator 2 and Synchronous Condenser

Generator 2 connects to the 275kV Bus 3 of the network. PSCAD studies for Generator 2 were undertaken without a synchronous condenser connected to the transmission system. The plots for Active and Reactive Power are shown in blue in Figure 7 (a) and (b) and for voltage (in a number of locations in the network) in Figure 8 (a). A 130MVAr synchronous condenser was found to appropriately mitigate the system strength issues. This is shown by the dampened plots in Figure 7 (a) and (b) and for the voltage in Figure 8 (b).

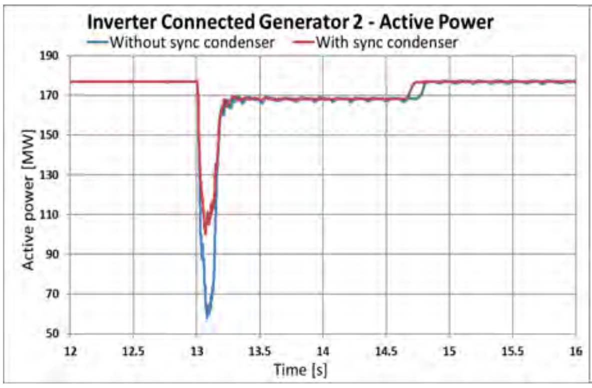

Figure 7 (a) Active Power plots for Generator 2 with and without synchronous condenser connected

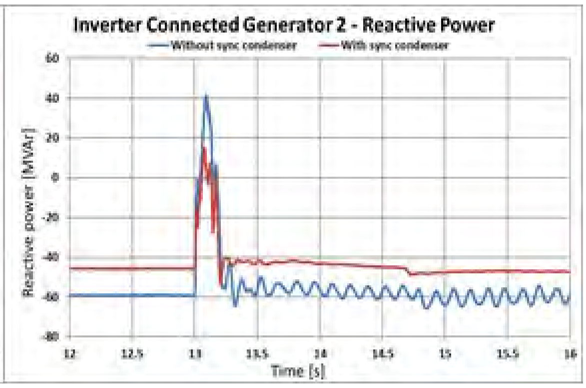

Figure 7 (b) Reactive Power plots for Generator 2 with and without synchronous condenser connected

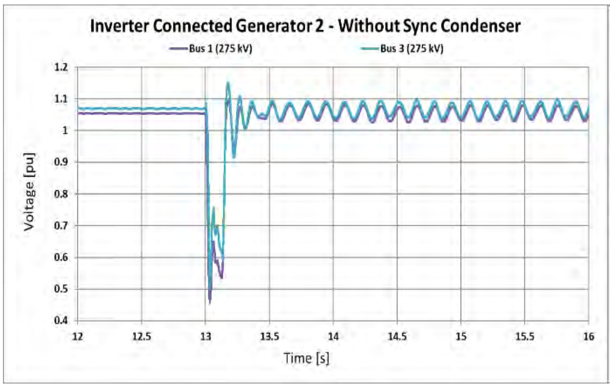

Figure 8 (a) Voltage response at network locations without synchronous condenser connected

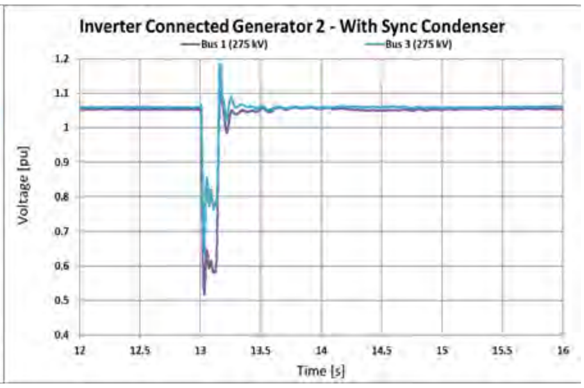

Figure 8 (b) Voltage response at network locations with synchronous condenser connected

4.3.3 Inverter Connected Generator 3

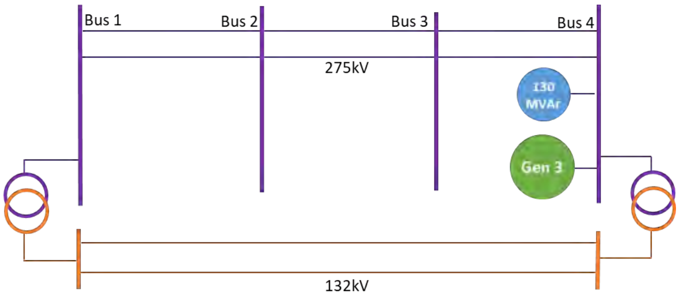

Figure 9 – Network Diagram of Generator 3 and Synchronous Condenser

Generator 3 connects into the 275kV Bus 4 of the network. PSCAD studies for Generator 3 were undertaken without a synchronous condenser connected to the transmission system. The plots for Active and Reactive Power are shown in blue in Figure 10(a) and (b) and for voltage (in a number of locations in the network) in Figure 11 (a). For Generator 3, a 130MVAr synchronous condenser was found to appropriately mitigate system strength issues. This is shown by the red dampened plots in Figure 10 (a) and (b) and for the voltage in Figure 11(b).

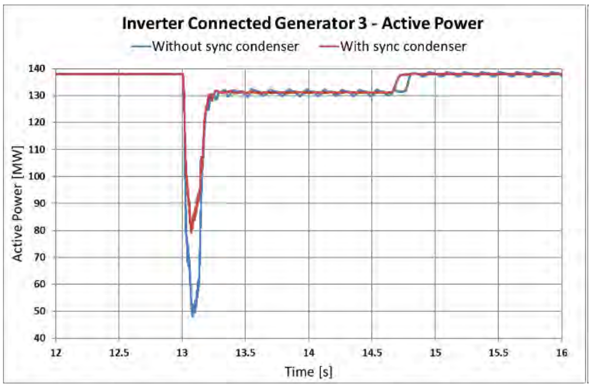

Figure 10 (a) Active Power plots for Generator 3 with and without synchronous condenser connected

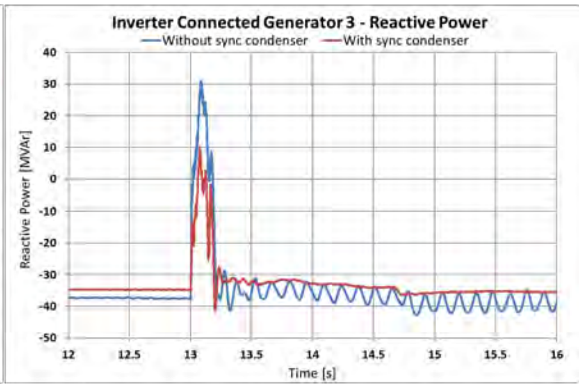

Figure 10 (b) Reactive Power plots for Generator 3 with and without synchronous condenser connected

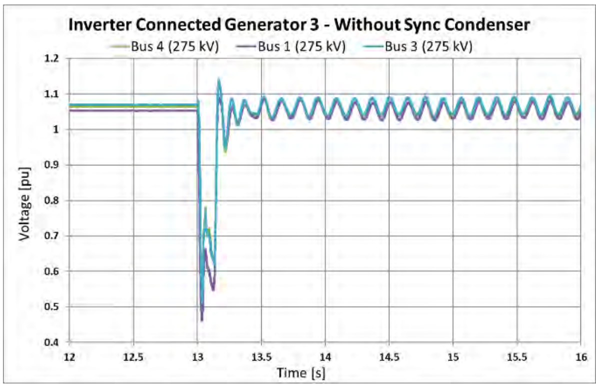

Figure 11 (a) Voltage response at network locations without synchronous condenser connected

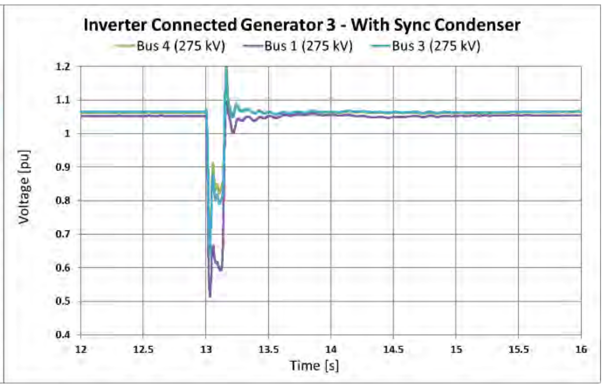

Figure 11 (b) Voltage response at network locations with synchronous condenser connected

4.3.4 Overall results of decentralised approach

Using a decentralised approach, Generator 1 requires a 65MVA synchronous condenser and Generators 2 and 3 each require a 130MVA synchronous condenser, in order to comply with the damping requirements of the NER.

4.4 Centralised System Strength Solution

This section investigates how a single centrally located synchronous condenser could be used to address the system strength requirements of all three generators.

4.4.1 System Strength Response

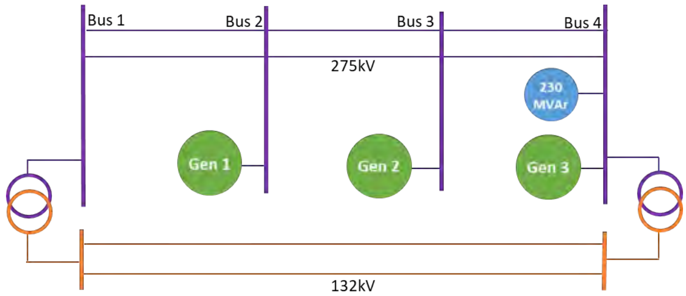

Figure 12 – Network Diagram for Centralised Synchronous Condenser

The centralised synchronous condenser was assumed to be connected into Bus 4 as shown in Figure 12. PSCAD studies determined that a 230MVAr synchronous condenser would be required to remediate the system strength issues for all three generators. The plots for each generator's Active and Reactive Power are shown in blue in Figure 13 (a) and (b), and for voltage in Figure 14. These demonstrate that a centrally located synchronous condenser (230MVAr) is able to provide sufficient system strength services to manage network oscillations during fault conditions.

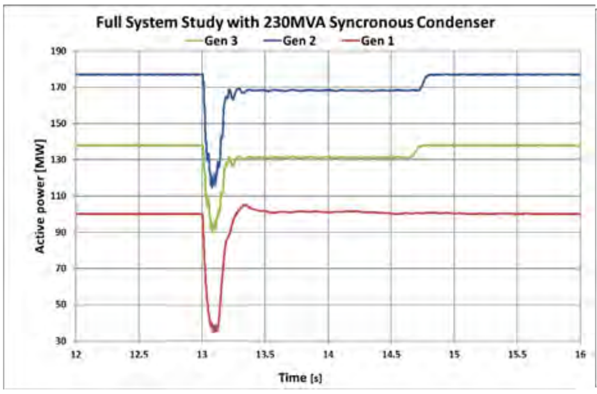

Figure 13 (a) Active Power plots for all 3 generators with 230MVAr synchronous condenser connected

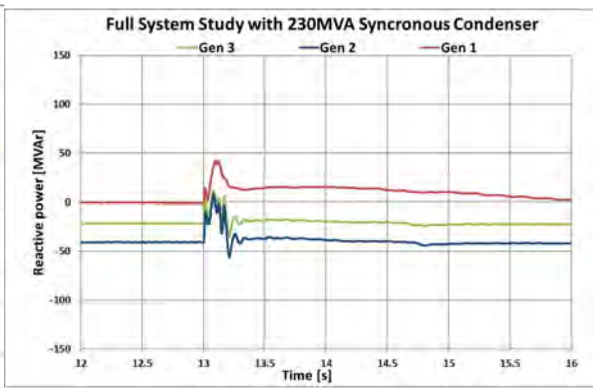

Figure 13 (b) Reactive Power for all 3 generators with 230MVAr synchronous condenser connected

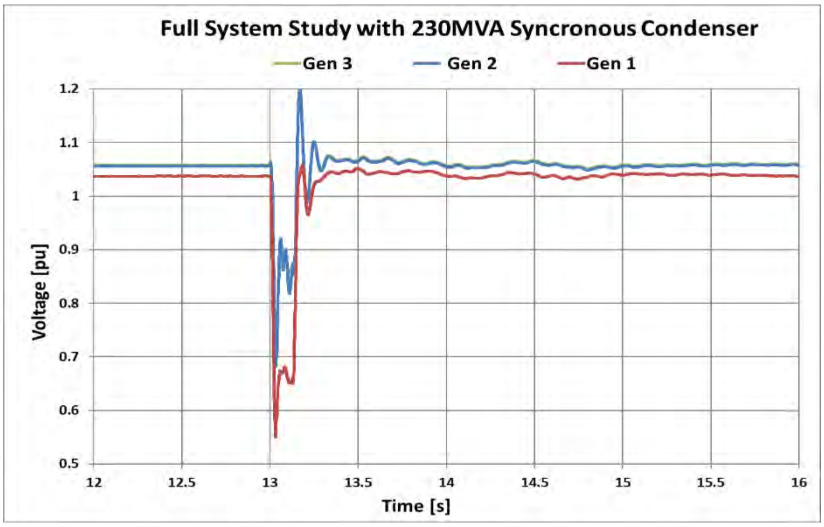

Figure 14 - Voltage response for 3 generators with 230MVAr synchronous condenser connected

Finding 1 – From a detailed modelling perspective, it is possible for a centralised solution to provide system strength services to a number of generators.

4.5 Overall Implications for Synchronous Condenser Sizing

The investigation found that both approaches to synchronous condensers are technically feasible. The decentralised approach would require three synchronous condensers rated at 65MVAr, 130MVAr and 130MVAr (for a combined total of 325MVAr), compared to a single 230MVAr unit for the centralised option.

It is particularly interesting that the overall quantum of system strength remediation is actually less under the centralised scenario, and especially since the generators are physically separated by 400km.

- One of the contributing factors is that synchronous condensers are typically available in a finite number of standard sizes, which may not exactly align with the specific need at each location, and could result in a degree of overbuild. This will be most pronounced under the distributed model where overbuild might occur three times (i.e. once for each synchronous condenser built), compared to only once under the centralised model.
- The physical distance between the generators was mitigated by the fact that all three generators were directly connected to the main transmission backbone and so the “electrical distance” (i.e. impedance) between the generators was still relatively low.
- The “over the horizon” effect, in which settling the response of one generator also helps to settle the response of another remote generator which would otherwise interact with it, may also be contributing some benefit although this is difficult to quantify.

5. Cost Effectiveness of Central Solution

Life cycle cost data for synchronous condensers was developed by GHD for the first report into system strength (see Figure 15). Using this data, it is possible to make a high level assessment of the cost effectiveness of the centralised solution compared to the distributed network solution.

By comparing the total life cycle costs for the distributed synchronous condenser portfolio to that of the centralised solution, there could be a 40% reduction in overall costs (see Table 1). While this is a rough guide, it is recommend that inverter based renewable developers talk to individual synchronous condenser manufacturers for more specific pricing that is consistent to their individual circumstances.

However, it should not be assumed that this result is indicative of all situations as the results are highly dependent on the specific details of each circumstance.

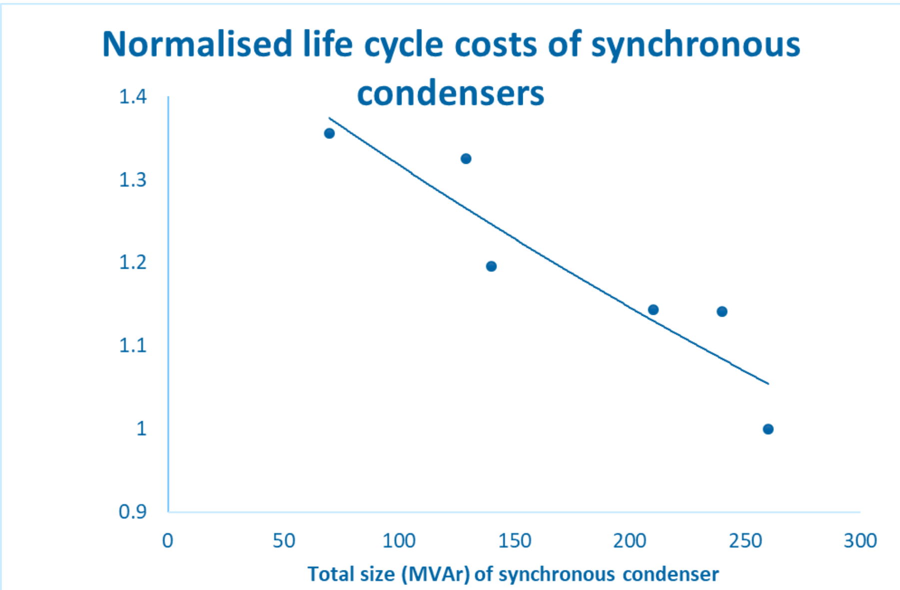

Figure 15 - Life cycle costs of synchronous condenser

Source: GHD Analysis, 2020

	MVAr	Life Cycle cost pu	Relative cost
Gen 1	65	1.38	89.7
Gen 2	130	1.28	166.4
Gen 3	130	1.28	166.4
Total lifecycle cost of portfolio			422.5
Centralised Option	230	1.10	253
% differential			40.1%

Table 1 – Lifecycle Cost differential of Distributed vs Centralised option

Finding 2 – In certain circumstances, the centralised synchronous condenser approach can provide cost efficiencies for generators when compared to the distributed model.

6. Complementary Role for Special Protection

While the PSCAD analysis has shown there is merit in a centralised synchronous condenser model, there are also some challenges that should be highlighted.

A centralised solution means that there are network outages which can significantly increase the impedance between each generator and synchronous condenser. This means that the effectiveness of the centralised solution is significantly reduced whenever the network is in certain outage conditions. To manage this effect, special protection schemes could be implemented.

The first report (Section 3.2) outlined the use Special Protection Schemes (SPS) to trip off or run down generation in unfavourable network conditions to maintain overall system security. These schemes would be armed whenever these problematic outage conditions occurred to enable each generator to keep operating, but would automatically trip the generator should another concurrent network outage occur (i.e. rapidly tripping the generator before it had an opportunity to go unstable and/or induce instability in another generator).

With generators located at buses 2, 3, and 4, and with a synchronous condenser located only at Bus 4, special protection would be required to enable the generators to keep operating during:

i. The unplanned outage of the 275kV network connecting the generators to the centralised synchronous condenser.
   - Generator 2 would be impacted by the outage of a 275kV circuit between buses 3 and 4.
   - Generator 1 would also be impact by the outage and would also be impacted by the outage of a circuit between buses 2 and 3.

ii. The loss or failure of the centralised synchronous condenser. This would apply to all three generators.

The following discussion is a worked example of the impact on Generator 1 due to the outage of a circuit between Bus 2 and Bus 3. The network is illustrated in Figure 16 below.

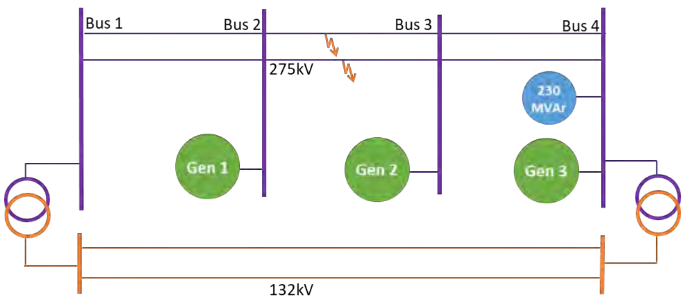

Figure 16 – Network Diagram modelling a 275kV network fault

Although only a single circuit is out of service, AEMO is required to return the power system to a secure operating state within 30 minutes of an unplanned outage. This means that the power system needs to be braced to sustain any single subsequent contingency, which could include the loss of the second parallel circuit. If this were to happen, the 275kV network would be entirely severed, and the only connectivity between Generator 1 and the synchronous condenser would be via the 132kV network. As highlighted in the first report, system strength does not travel well between different voltage levels, and so the residual support provided by the synchronous condenser would be negligible and Generator 1 would likely become unstable. With the potential for Generator 1 to become unstable following a subsequent contingency, the power system would not be in a secure state.

If there was no special protection scheme in place, then AEMO would be required to pre-emptively constrain Generator 1 offline in order to re-secure the power system. However, if protection was in place that could be armed, this would ensure that for a subsequent contingency the generator would be tripped automatically and instantaneously. Thus the special protection would enable Generator 1 to continue operating during this outage condition. And whilst it is necessary for the power system to always be operated in a secure state, the actual likelihood of the subsequent contingency occurring would typically be very low, and so that incidence of the generator actually being tripped by the special protection would also be very low (notwithstanding some common threat such as a bushfire affecting multiple circuits, or the maloperation of the special protection scheme itself).

The design of the special protection scheme would need to take account of all of the different patterns of outages which could occur. For example, Generator 1 would also be severely impacted by the concurrent outage of both circuits between Bus 3 and Bus 4, and so these circuits would likely also need to be included in the special protection scheme. The practical viability of a special protection scheme therefore depends strongly on the configuration of the network, and is more likely to be viable with a simple network configuration that has a small number of critical contingencies. The practical viability of a scheme also depends on the availability of reliable and fast communications infrastructure to underpin the scheme.

The viability of a special protection scheme does not ultimately dictate whether a centralised synchronous condenser solution is viable, but without such a scheme any generators which are remote from the synchronous condenser may face occasional outages in response to network outages (both planned and forced). This issue is reduced under the decentralised model, as each generator would typically install their own synchronous condenser at the same location as the generator it is supporting. However, there is still the unavoidable risk associated with the outage of the synchronous condenser itself.

Finding 3 – A network fault or outage on network between the synchronous condensers and the Inverter Based Renewable generator may require some or all of the generation using the system strength to reduce output or disconnect. In these circumstances, special protection schemes will be required to trip generation to ensure stable operation of the network.

An additional consideration when using special protection schemes, is that the power system needs to be able to manage with the combined loss of the network element and the generation which is automatically tripped along with it. Whilst it may be advantageous to trip the generator to avoid it becoming unstable or inducing instability in other generators, the loss of this generator will nevertheless impact upon the power system frequency, and power flows in other parts of the network. Therefore care needs to be taken when assessing the viability for a scheme to ensure that the effect of the scheme (individually, or together with other pre-existing schemes) does not result in an adverse consequence elsewhere such as the system frequency dropping below critical thresholds, or a power flow exceeding a line’s capacity or the network’s secure transfer limit. This effect limits the amount of IBR generation that could be connected as part of a centralised solution, although what that limit is will vary between contexts.

Finding 4 – A centralised synchronous condenser approach could be limited by system operating conditions such as network capability limits.

If the centralised model is developed to the point where multiple synchronous condensers were required, it might be possible to provide partial redundancy even during outage conditions. For instance, if future IBR generator connections warranted a second centralised synchronous condenser in the area under consideration and were located at Bus 1, then the two synchronous condensers might be able to work as a system providing an overall supply of system strength from diverse locations that is less susceptible to particular outage conditions. Even during the outage of a synchronous condenser itself, it might be possible to facilitate a lower level of disruption to be spread across a wider base of generators.

7. Importance of Inertia

The first report highlighted that a synchronous condenser could be configured to provide both system strength and inertia (through the connection of a flywheel). Historically it has been thought that whilst inertia is important to the power system overall, that it is largely irrelevant to stable operation of IBR generation and so the use of flywheels is unnecessary on synchronous condensers being used to support IBR generation. However, this assumption has been increasingly demonstrated not to be entirely accurate, and this effect is apparent in the analysis undertaken for this report.

As part of the study for the centralised model, the inertia constant of the synchronous condenser was varied to understand its impact on the synchronous condenser's own response and also the impact on other synchronous generators. The inertia constant is the relationship between the size of the rotor and the capacity rating (in MVAr) of the machine. The larger the inertia constant, the greater amount of inertia is available to be supplied to the network.

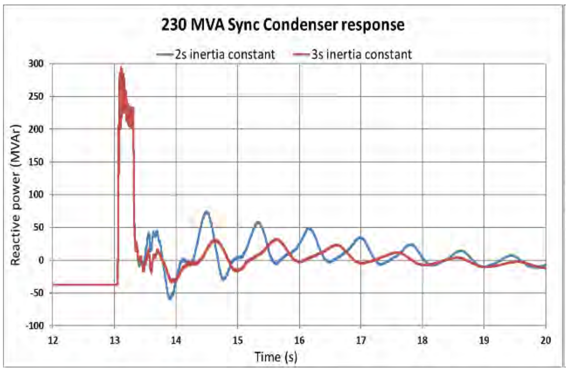

Figure 17 (a) Reactive Power response for 230MVAr synchronous condenser with a 2s and 3s inertia constant.

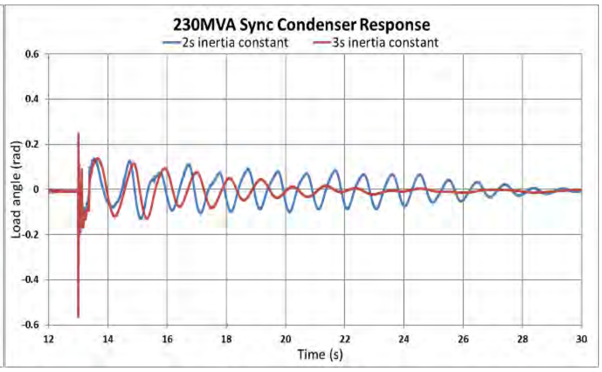

Figure 17 (b) Load Angle response for 230MVAr synchronous condenser with a 2 second and 3 second inertia constant.

Figure 17 shows the Reactive Power and Load Angle response of the 230 MVAr synchronous condenser following the 275kV fault between Bus 2 and Bus 3. The plot shows that the synchronous condenser model with a 3 second inertia constant provides a significantly dampened response when compared to the 2 second model. This would indicate, that for the central synchronous condenser model, an inertia constant of at least 3 seconds should be adopted to achieve compliance with NER damping requirements.

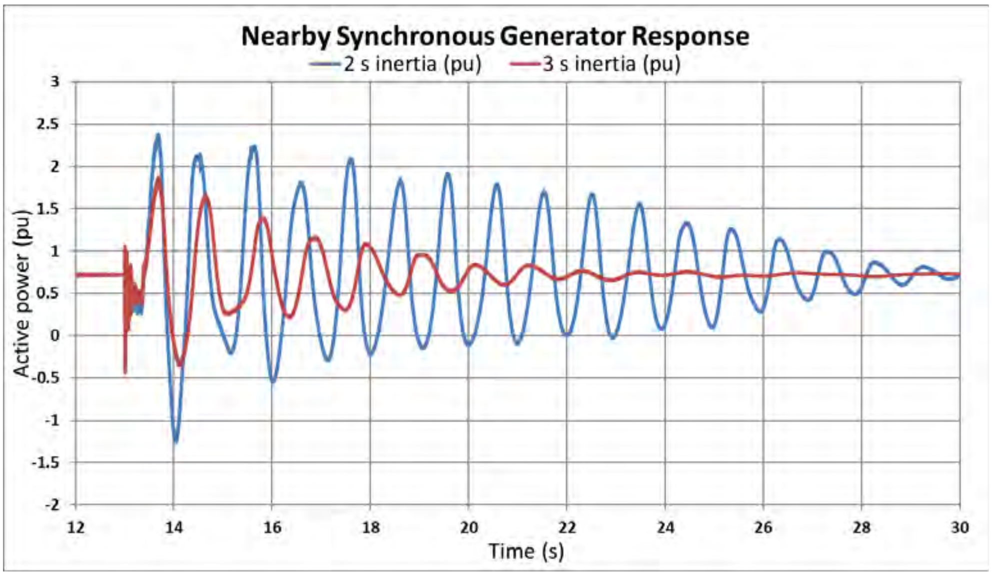

Figure 18 – Nearby generator active power output with different inertia constant of synchronous condenser

To provide an example of the impact of the inertia characteristics of the synchronous condenser on other plant in the network, the active power at a nearby synchronous generator was assessed for both 2 second and 3 second synchronous condenser inertia constants. The response in Figure 18 clearly shows the improved dampening of the synchronous generator for the synchronous condenser model with the higher inertia constant.

Although the example above demonstrates the benefits of detailed system performance analysis to inform the design characteristic of the centralised synchronous condenser, the same principles would also apply when assessing the required characteristics of synchronous condensers being implemented under a distributed model.

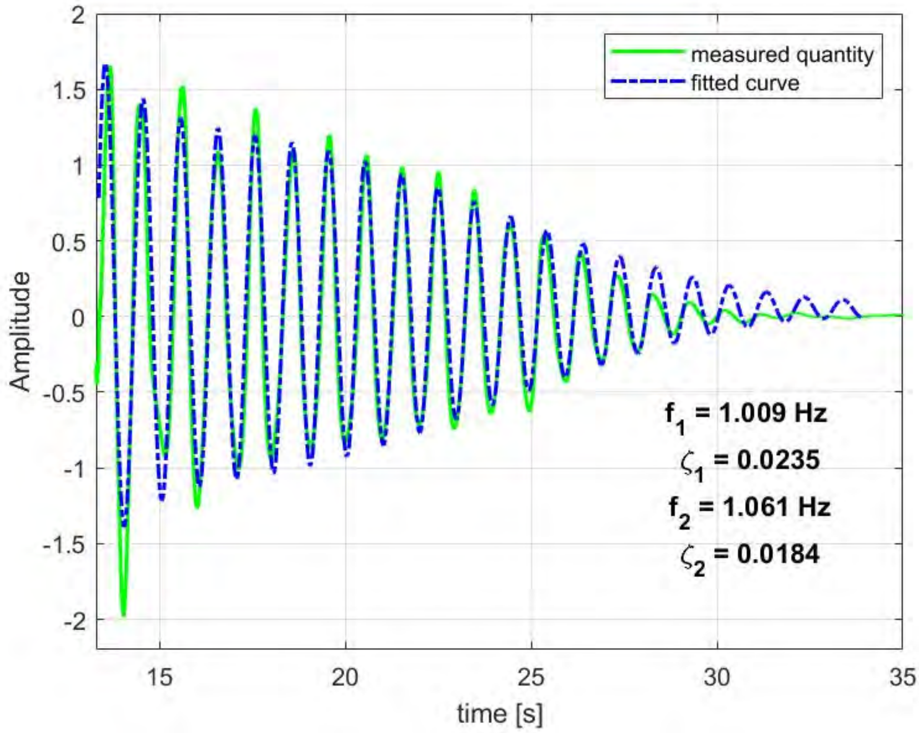

Figure 19 – Nearby generator active power output with synchronous condenser inertia constant of 2 seconds

From the analysis of the data presented in Figure 19, it was identified that the response consisted of two different frequencies 1.01 Hz and 1.06Hz with respective damping factors of 0.0235 and 0.0184. As per the NER, the damping ratio requirements for the frequencies higher than 0.6Hz is minimum of 0.05. Therefore, inertia constant of 2 seconds is not sufficient for a synchronous condenser that is being considered as a centralised solution here.

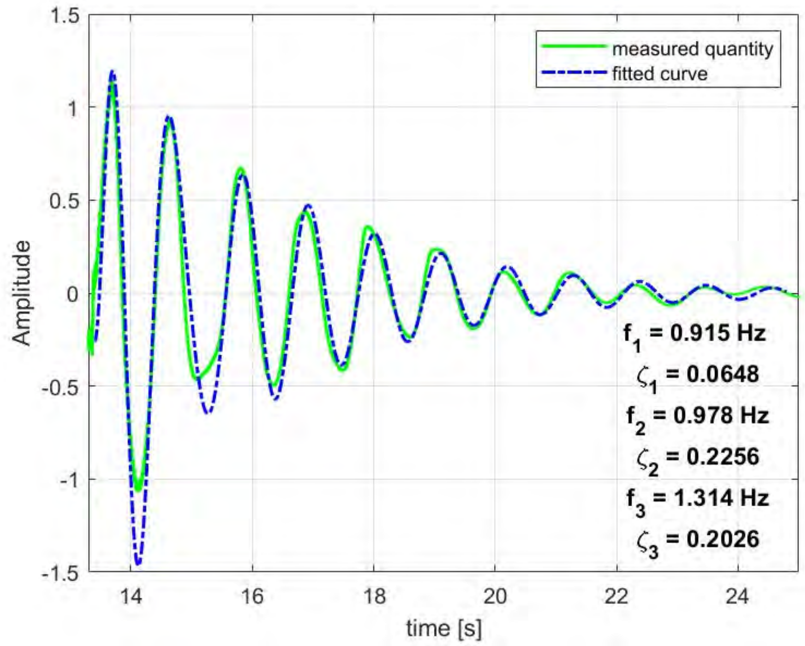

Figure 20 – Nearby generator active power output with synchronous condenser inertia constant of 3 seconds.

Similar analysis was performed for the data presented in Figure 20. It was identified that a response consisted for three different frequencies 0.92 Hz, 0.98 Hz and 1.32 Hz with respective damping factors of 0.065, 0.226 and 0.203. As per the NER, the damping ratio requirements for the frequencies higher than 0.6Hz is minimum of 0.05. Therefore, an inertia constant of 3 seconds is considered sufficient for a synchronous condenser that is being considered.

Damping of different oscillation frequencies caused by synchronous condenser may also be improved by modification of excitation control systems, but have not been considered as part of this analysis.

Although the example above demonstrates the benefits of detailed system performance analysis to inform the design characteristic of the centralised synchronous condenser, the same principles would also apply when assessing the required characteristics of synchronous condensers being implemented under a distributed model.

Finding 5 – When selecting a synchronous condenser for a centralised solution, consideration should be given to other characteristics of the synchronous condenser such as the inertia constant and the impact it can have on its own stability and other plant in the network.