GHD Advisory

Managing system strength during the transition to renewables

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Acknowledgement

This project received funding from ARENA as part of ARENA's Advancing Renewables Program.

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Executive summary

In this report we focus on explaining system strength, outlining the range of remedial options available and the circumstances in which they might be applicable. We also explore the economic merit and commercial/regulatory issues of a shared and scale-efficient model for implementing system strength provision by use of synchronous condensers.

This report is intended to promote a broader understanding of system strength.

As Australia's power system transitions toward renewable forms of power generation, system strength has emerged as a prominent issue and has led to difficulties in developing and operating renewable generation projects.

System strength is a technical subject and an area in which Australia is on the "bleeding edge" of international experience. Generally, there is a limited understanding of the topic and it is often confused with other related power system issues such as inertia, adequacy or resilience.

This report has been developed to promote a better understanding of system strength and its implications, and the range of remedial options that may be available. It is targeted at a broad audience, including readers from non-engineering backgrounds. The goal is to establish a base level of understanding between all stakeholders involved in the power system and serve as a basis for dialogue, and informing the ongoing development of regulatory frameworks.

The report includes a "deep dive" on synchronous condensers, including the potential for a centralised approach to implementing them. Although the report uses North Queensland as a worked example, the implications are expressed in a way that should enable readers to consider how they might apply in other regions.

A clear and common understanding of the topic will allow utilities and generator proponents to work together in identifying the most optimal location and configuration for renewable energy projects as well as placement of system strength provision infrastructure. This will help prevent unanticipated expenditure and protracted project delays.

Our collective understanding of system strength is evolving over time.

Initially system strength was understood in terms of the fault level required for individual generators to be able to operate stably and to ride-through system faults.

Subsequently the potential for multiple generators to interact in an unstable fashion became the dominant concern.

More recently, it has become apparent that the "system strength issues" we are observing are also influenced by other factors including system inertia.

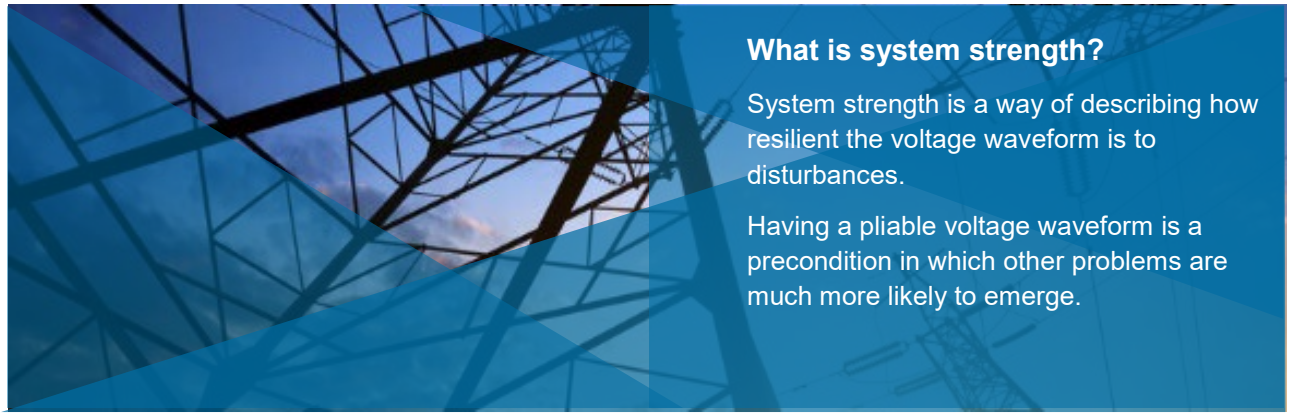
There is every likelihood that we will uncover additional aspects of system strength over time.

Our expanding understanding of system strength creates challenges for how we speak about it.

There are (at least) two options:

1. To progressively expand our definition of system strength to include these additional aspects. In this case, system strength is effectively becoming a synonym for power system stability.
2. To preserve a more focussed definition of system strength as a subset of power system stability, but recognise that system strength is interactive with other aspects of power system stability, and that these aspects are equally relevant to the connection of new generation and the secure operation of the power system.

Whilst this distinction may seem pedantic, it has a significant bearing on how system strength is described. This report has been written in terms of the latter option.



What is system strength?

System strength is a way of describing how resilient the voltage waveform is to disturbances.

Having a pliable voltage waveform is a precondition in which other problems are much more likely to emerge.

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If a transmission network location is said to be "strong" in terms of system strength, the change in voltage at that location will be relatively unaffected by a nearby disturbance. However, if a location is said to be "weak" in system strength the voltage at that location will be relatively sensitive to a system disturbance, resulting in a voltage dip that is deeper and more widespread.

Having a pliable voltage waveform is a precondition in which other problems are much more likely to emerge. This includes longstanding issues such as power quality and voltage stability, and emerging issues such as unstable interactions between inverter-based generators.

Conventional generators inherently provide system strength.

System strength is created by conventional forms of generation, not because of their fuel source (e.g. coal, gas and hydro) but because of their use of synchronous generators which are electro-magnetically coupled with the power system.

Such generators inherently respond to voltage disturbances on the power system in a manner which resists the disturbance and limits its size, thereby automatically helping to stabilise network voltages arising from a network disturbance. The ability to resist sudden changes in voltage magnitude comes from the magnetic flux in the generator's core (i.e. flowing in and between the generator's stator and rotor as a consequence of excitation (electrical energisation) of the generator's stator windings), and is a distinct process to the way in which the physical inertia of the synchronous generators resist changes in the power system frequency.

In order to provide system strength, the generators merely need to be online and synchronised to the grid – they don't have to be producing any real power.

The progressive displacement of conventional, fossil fuel powered, synchronous generators with non-synchronous generation is reducing the overall level of system strength in the power system.

System strength naturally diminishes with electrical distance from synchronous generators.

Given the scale and topology of Australia's power system, there are many locations in the network where the system strength is naturally low and has always been this way. Whilst this has given rise to some challenges, these have largely been managed internally within network service providers (NSPs).

However, such locations are often attractive for the connection of renewable generators because of good resource availability, low land costs, and the expectation of a straightforward connection to the power network. The high penetration of inverter-based renewable generators in areas with low system strength have led to new and complex issues that also impact upon generation proponents.

Currently, solar and wind technologies do not inherently provide system provide system strength.

Inverters transform the power produced by these sources into a form which is compatible with the grid. They are not driven by the physics associated with magnetic fields in the same way as synchronous generators are, but rather rely on algorithms to sense and appropriately respond to any fluctuations on the power network.

If the system strength is low there is a risk that the inverter (and the algorithm which controls it) may not respond in a stable fashion.

Even if a particular inverter operates stably, there is a risk that it may induce instability in another electrically-close inverter or similar device operating in the power system. This undesirable effect is known as inverter control interactions.

The potential for multiple inverters to interact unstably increases as system strength falls.

Inverters must operate stably under the National Electricity Market (NEM) National Electricity Rules (NER sometimes referred to as "the rules"), otherwise there is the risk of unplanned tripping of generators that could result in a cascade failure and threaten the security of the power system.

At locations where system strength is high, the power system's voltage is 'rock solid': disturbances are likely to be modest and the system voltage is effectively immune to how each inverter responds. However, in locations with low system strength, the system voltage is less like a 'rock' and more like a 'jelly' both affecting and being affected by the response of each inverter to a network disturbance.

One inverter can respond in a fashion that disturbs the voltage waveform, and this disturbance will subsequently be seen by other inverters in an area and trigger a counter response by them. This can give rise to back-and-forth interactions between multiple inverters, which could ultimately result in some of them becoming unstable and tripping.

The problem is complex because it is not necessarily a consequence of a single 'rogue' inverter, but rather a mutually-incompatible combination of inverters and network conditions.

Analysing the potential for unstable interactions between multiple inverters requires extremely detailed models of each inverter and the network, e.g. with a full representation of each inverter's control system.

Detailed modelling is now typically required for renewable generation connecting to the grid.

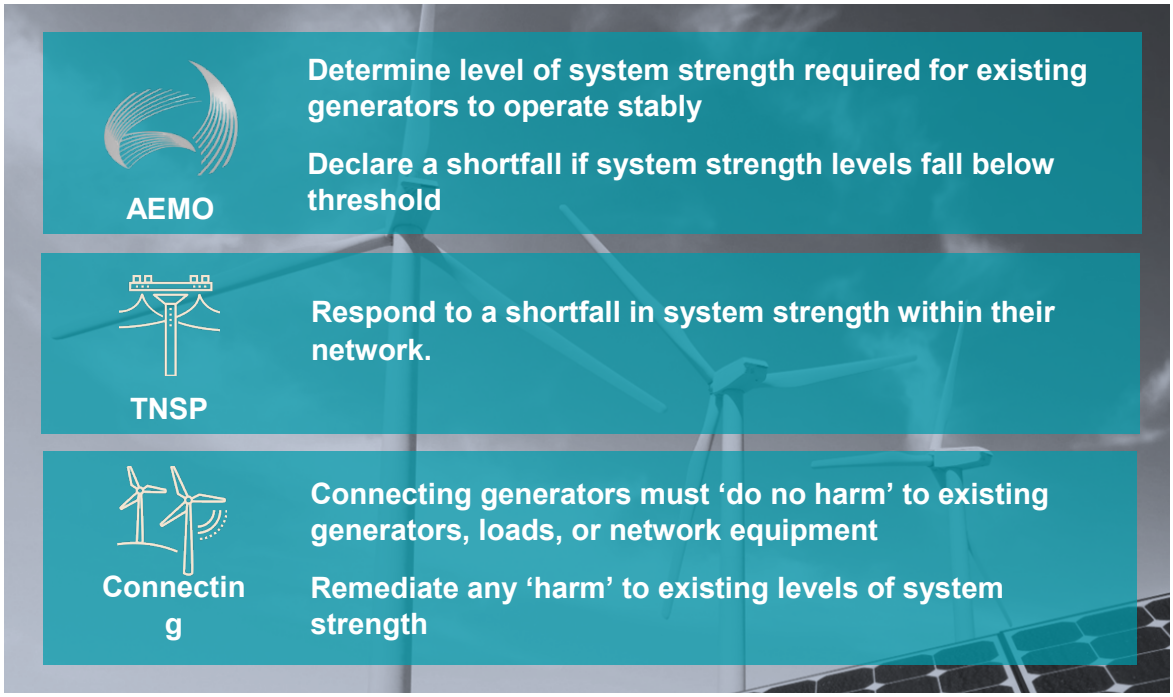
Practically, this means that the 'load flow' and 'transient' forms of analysis which were historically used to analyse network connections (using applications like PSS/E) are not sufficient. Rather electromagnet transient (EMT) modelling, using tools such as PSCAD, must also be used.

PSCAD simulation is extremely detailed and time-consuming. Further, it takes significant time for utilities and inverter-suppliers to develop and refine PSCAD models of their network and inverters. Particularly as these models need to be updated and re-verified to accommodate any changes in the network configuration and or inverter design and control system.

Developers are required to submit precise details of their project early on to facilitate detailed PSCAD modelling.

The detailed nature of PSCAD analysis also means that developers are required to submit precise details of their proposed project(s) to enable their proposed connection to be assessed. Any changes subsequently made to the design of their project, such as inverter selection, size or control system may invalidate already completed analyses, forcing the lengthy analysis to re-start.

Additionally, because each project needs to be assessed based on the power system with all existing and committed generators, the commitment of another new generator in the same area may also require that the analysis is redone to capture the updated background conditions.



System Strength Responsibilities under NER

The rules place system strength responsibilities on the Australian Energy Market Operator (AEMO), transmission network service providers (TNSPs), and generator proponents.

Australia Energy Market Operator (AEMO)

AEMO is required to determine the level of system strength required for the overall power system to be operated stably. This is expressed in the form of minimum fault level thresholds at a number of key nodes throughout the NEM.

While this level of system strength may create headroom at some locations, enabling new generators to connect without system strength remediation, this is not the intent of the rules. Where the level of system strength is forecast to drop below AEMO's thresholds, AEMO declares a system strength shortfall.

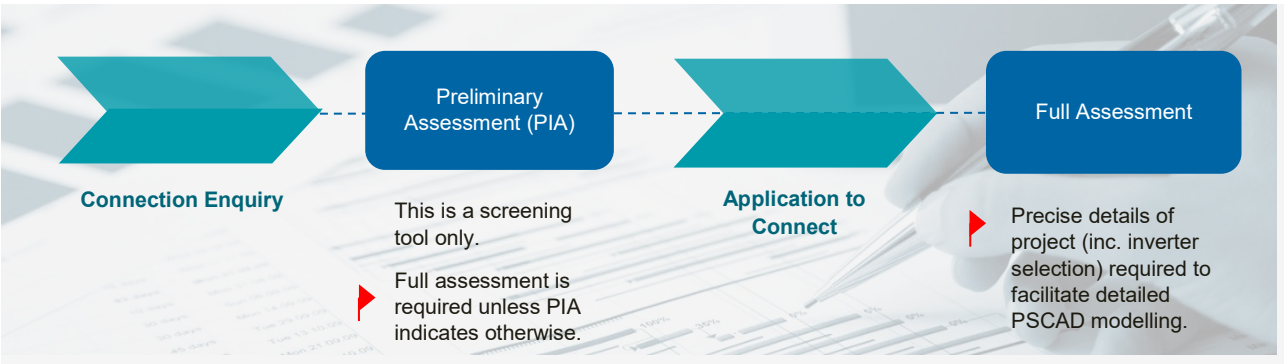
Transmission Network Service Providers

Each TNSP is responsible for addressing a shortfall declared within their area of responsibility by developing a suite of possible solutions to address the issue and then undertaking a Regulatory Investment Test (RIT-T) consultation to identify any non-network solutions and to identify the most cost-effective way to remediate the situation and address the declared shortfall.

The merits of different options need to be valued and compared as required by the Australian Energy Regulator's RIT-T guidelines.

New Generators / Generator Proponents

When a generator proponent applies to connect to the network, the relevant TNSP must establish that the proposed generator will operate stably and "do no harm" to the stable operation of existing generators, loads or network equipment. The proponent must provide the information required to enable the TNSP to conduct a connection assessment per AEMO's guidelines. If the TNSP determines that there is the potential for 'harm,' the proponent may work together with the TNSP to agree remedial measures that mitigate this risk.



System Strength Assessment and the Connection Process

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

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.

The available fault level is a very high level approximation of the remaining system strength. It based on the actual system fault level reduced by the amount of existing and committed inverter-connected generation within the area. This assessment is very approximate.

Based on the complex interactions that can occur between different plants, this preliminary assessment may not be conclusive nor give sufficient confidence to the NSP and AEMO that detailed PSCAD analysis is not required. Therefore, some transmission networks owners with a high penetration of inverter-based plant now recommend that all connections undergo detailed PSCAD assessment regardless of the preliminary assessment.

The **full assessment** involves a detailed assessment based on detailed PSCAD analysis, which models the complex interactions between multiple inverters.

As a result, developers are now required to submit precise details of their project early in the development of the project, including details of their selected inverter, to facilitate the PSCAD modelling.

Locational Considerations

One option for renewable project developers to manage system strength related issues is to site their projects in areas where there is adequate system strength. The effectiveness of this strategy is diminishing, as system strength issues become more widespread and the availability of strong locations is reduced. The cost of this option is the trade-off made against other siting considerations.

To assist with this many TNSPs publish "new generator connection capacity" geospatial datasets on the Australia Renewable Energy Mapping Infrastructure (AREMI) project. These results should be understood in the context of additional material published on each network's website, outlining the basis for the data including important assumptions and caveats.

Remediation Options

Where a generator is connecting into a location where there is inadequate system strength, there are a range of remediation options which may be appropriate under specific circumstances.

1 Contract with an existing synchronous generator

If there is a synchronous generator nearby, such as a hydroelectric power station or gas fired power station whose operation would provide sufficient system strength, it may be possible to contract with the owner to operate at times whenever there would otherwise be a system strength shortfall.

This is most likely to be viable where the existing synchronous generator is capable of (or could be retrofitted to implement) a synchronous condensing mode – in which the generator is synchronised to the grid and spinning (although no real power is being produced).

Absent a synchronous condensing mode, it could require the generator to run at times when it would otherwise be uneconomic to run (which could be expensive) and the power produced could displace another synchronous generator operating elsewhere (which could reduce the system strength provided by this source).

The long lead times for the development of new synchronous generation power stations does not make this a viable option unless an electrically proximate power plant exists. Any plant such plant captured within the existing networks system strength provision arrangements would be proscribed from entering into such an arrangement.

2 Install a synchronous condenser unit

A synchronous condenser is essentially a synchronous generator that does not produce any real power and has been specified and designed to operate for the purpose of providing system strength support in response to a power network disturbance.

The main advantage of synchronous condensers over other technologies is that, whilst other solutions may be suitable in a limited set of circumstances, an appropriately specified synchronous condenser should always work.

The main disadvantages of synchronous condensers are the upfront capital cost, long lead-time, lack of redundancy (i.e. should it fail), high operating cost (electricity for excitation) and the fact that it is an unknown technology to many renewable developers and operators.

In this report we explore the viability of a centralised and managed model for implementing synchronous condensers to achieve economies of scale and efficiency of system strength provision.

3 Synchronous storage

Where a project (or Renewable Energy Zone, REZ) also needs access to energy storage in addition to system strength, the use of synchronous pumped hydro could be considered to address both needs.

The capital cost and operational efficiency of pumped hydro is highly dependent upon each location's particular environmental factors including: topography, geology, hydrology, sensitive habitats and complementary land uses. The approval and construction process for pumped hydro is far more complicated and protracted than that of batteries.

The significant lead-time, complexity and capital requirements mean that this option is unlikely to be practical for individual project developers. However such an asset could be a very effective foundation for a REZ, supporting a cluster of nearby renewable developments through the cost effective provision of: system strength, firming, arbitrage and improvements in marginal loss factors.

4 Implement a special protection scheme

Tripping the inverter under certain conditions may be a cost-effective solution in situations where stability only becomes an issue in a very small number of detectable network conditions and these conditions are expected to be sufficiently uncommon that the generator is happy to come offline.

To facilitate this, the network will likely need to implement protection systems to monitor for these network conditions and automatically implement the appropriate action.

Parties should mutually agree on arrangements to accommodate any planned network outages needed to facilitate network maintenance and project work.

The use of special protection schemes can be highly complementary with other solutions, by reducing the scale of mitigation that would otherwise be required. However, the power system has a limited capacity to cope with the

sudden loss of generation. Therefore, the extent to which special protection schemes can be used within an area is limited.

5 Modify grid connection

If the system strength deficit is only slight or in a limited set of other circumstances, thoughtful modification of the grid connection may be sufficient to address the issue.

Specific examples could include using lower impedance conductors and transformers or for solar or wind farms to connect to a higher-voltage supply point.

6 Modify upstream grid

There may be a limited set of circumstances in which it would be cost-effective for the developer to pay for modifications to the upstream network that result in additional system strength at the project's connection point.

An example could include if there was a particular network contingency (e.g. a single transmission circuit) that markedly reduces the system strength at the project's connection point, resulting in instability. Slight modifications to the network (e.g. cutting an additional circuit into the substation) could mitigate the impact of this contingency, and the system strength constraint would shift to the next most limiting contingency.

Another example could involve modifying the control systems of active network devices such as Static VAr Compensators (SVCs).

Any modifications requested by developers to mitigate system strength issues would need to be funded by the developer and hence increase project development costs.

7 Advanced voltage controls

Inverter manufacturers have been implementing refinements to their control systems to reduce their inverter's susceptibility to unfavourable interactions with other inverters. Increasingly these enhancements may be already included as part of the supplier's default product offering.

There is always the possibility of upgrading or re-tuning the controls of existing inverters, as has recently been applied to five solar farms in the West Murray Zone[1]. Presently, this depends on mutual agreement which makes it more difficult in situations where other generators would benefit (i.e. upgrading an existing inverter's controls to increase an area's ability to host additional generation).

8 Synchronous-generator-emulating / grid-forming inverter

Synchronous generator emulating (SGE) or grid forming inverters are a new type of inverter that aims to replicate the function of a synchronous generator. They involve additional inverter capacity, a source of stored energy (i.e. a battery), and a different control philosophy.

To date grid forming inverters have predominantly been used in islanded applications. Their effectiveness in grid-connection applications is presently unclear. Various investigations and pilot projects are underway – including an ARENA supported investigation that Powerlink is undertaking, which will be published in a separate and subsequent report.

Overall Optimum Remediation

There are a range of approaches which can assist with the issues that can arise from low system strength; however, the applicability and effectiveness of each response can vary between situations. The optimal solution may involve a combination of multiple measures. Any proposed remediation must be assessed as part of the connection assessment process, and approved by AEMO.

Synchronous condensers are most likely to be effective across a wide range of situations and issues. This is the main reason that they have become the de facto 'standard' solution. The

[1] https://aemo.com.au/news/constraints-lifted-for-west-murray-solar-farms

optimal solution may often involve a synchronous condenser in combination with other responses such as reconfiguration of the upstream network, or the use of special protection.

Centralised v Decentralised Approach to Synchronous Condensers

Given the prominence of synchronous condensers in managing low system strength issues, it is worthwhile considering the most effective way of utilising them. There are a range of benefits which could flow from a centralised approach to sizing and locating synchronous condensers (reducing project lead time, reduced complexity for renewable developers/operators, the possibility of cost-effective redundancy etc.) – but the main benefit relates to scale efficiencies.

For a typical project scale device, approximately two-thirds of the capital costs relate to components that have largely fixed costs (civils, control systems, cooling systems and grid connection), and it is predominantly the remaining portion (stator, rotor, and pony motor) that scales with the size of the device. The no-load losses of the condensers constitute the bulk of the running costs and these are also more efficient with scale. Thus there are potentially significant efficiencies that could be realised by a centralised model.

However, there are also drawbacks, predominantly in the form of diminishing effectiveness with distance. This is strongly influenced by the impedance and configuration of the network. The impedance of the network affects how well system strength propagates. Also the configuration of the network can give rise to critical contingency conditions which significantly increase the electrical distance between the inverter and the main sources of system strength.

From our power system network analysis in northern Queensland we concluded that areas of the network with relatively low impedance and simple configuration, such as the 275 kV transmission backbone are most likely to benefit from planned installations of system strengthening equipment. The relatively low impedance allows system strength to propagate over a wide area.

To the extent that special protection is required to overcome any critical contingencies, the simple configuration of the network contains the cost and operational consequences of implementing this.

Conversely, areas of the network with relatively high impedance and complex configuration, such as the 132 kV sub-transmission network and voltages below this, are less likely to realise net benefits from a planned, centralised installation of system strengthening equipment. There is a greater risk that the tyranny of distance will overwhelm any economies of scale. Generators connecting to such locations are more likely to have to “bring their own” system strength remediation.

The general conclusion, summarised in the table below, is that the further a generation proponent is away from the core transmission, the less they would be able to benefit from a centralised shared solution. This is potentially another layer of information that variable renewable energy (VRE) inverter-based generator project developers may consider when identifying optimal locations to develop new renewable projects.

Ultimately, the efficacy of a specific shared synchronous condenser proposal can only be comprehensively assessed using PSCAD analysis. Particularly where the problem needing to be addressed relates to the interaction of multiple inverters, it may be effective for a synchronous condenser to create additional system strength that settles down (dampens and compensates) the response of a subset of the inverters.

By improving the stability of one inverter, other inverters in the area may also operate more stably, even if they themselves are located outside of the area that benefits from additional system strength. Thus there may be a region of effectiveness that extends beyond the region of additional system strength. This is a complex effect that depends on specific details of the area in question and can only be assessed using PSCAD.

Power network topologies that may benefit from a centralised or decentralised approach

Category	Viability of a shared solution to provide system strength	Likelihood of needing to rely on special protection to make a shared solution viable
A strongly interconnected node on the main transmission backbone.	Highest	Unlikely to be necessary
A connection into a circuit on the main transmission backbone	↑	Possible, with relatively modest complexity and cost
A connection to the lower voltage sub-transmission network, but electrically close to the main transmission backbone	↓	Probable, with moderate complexity and cost
A connection to deep within the sub-transmission network, remote from the main transmission backbone	Lowest	Very likely, with the potential for significant cost and complexity

System Strength Frameworks Review

The present arrangements for managing system strength were established in 2017 to address the immediate system strength issues and concerns. These frameworks underpin the process to assess connection applications, the process and accountabilities for implementing system strength remediation, and the complexities of implementing a scale-efficient solution.

In April 2019, the AEMC initiated a review of these arrangements, in recognition of the very fast pace of change in the industry and connection of a large number of inverter-connected generators. Stakeholder feedback identified a number of issues, which are described in a discussion paper published in March 2020, including:

- The "do no harm" requirement adds uncertain delay and cost to new generation entrants. Additionally, it is leading to many individual responses to system strength (instead of coordinated responses) forgoing potential efficiencies and increasing the complexity of the power system.
- The minimum system strength framework is reactive in nature, contributing to costly market interventions by AEMO and limiting the ability of TNSPs to provide least cost solutions
- That the separation which currently exists between the various frameworks means that the procurement of system strength cannot be coordinated fully (e.g. new entrant needs are not considered when addressing a shortfall), that the frameworks do not provide for system strength to be co-optimised with other services (e.g. using a synchronous condenser to provide both system strength and inertia) and that the potential value of additional system strength (e.g. to alleviate generation constraints) is not valued.

The AEMC's notes that "The pace of the power transition means the time has now come to adjust and expand the system strength frameworks given the rapid connection of large numbers of new non-synchronous generation. These

frameworks need to evolve and be agile and flexible given the transition underway."

The AEMC's review is wide-ranging, including how system strength can be planned, procured, priced and paid for and the AEMC has outlined four high level models by which system strength might be provided:

- A centrally coordinated model, in which a central buyer would procure system strength, likely leveraging existing planning processes such as the Integrated System Plan.
- A market based decentralised model, in which system strength is procured dynamically as part of the NEM's dispatch process.
- A mandatory service model, in which generators are obligated to contribute a certain level of system strength.
- An access standard model, in which generators are obligated to be able to operate stably in low system strength environments (but not necessarily to contribute system strength).

Readers are referred to the AEMC's consultation webpage[2] for further details, including various reports, fact-sheets, and consultation responses.

It is hoped that this document will support the AEMC's review by promoting a deeper understanding of the underlying issues among a broader range of stakeholders, and informing their responses to the consultation process.

[2] https://www.aemc.gov.au/market-reviews-advice/investigation-system-strength-frameworks-nem

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1. Introduction

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 power network system strength (system strength) throughout the power industry.

- This report (Stage 1) is focused on explaining system strength, outlining the range of remedial options available and the circumstances in which they might be applicable. It also explores the economic merit and commercial/regulatory issues of a shared and scale-efficient model for implementing system strength provision by use of synchronous condensers - the analysis for which has been conducted by GHD (we/us/our).

  Our intent in the development of this report is not to critique the National Electricity Rules (NER sometimes referred to as “the rules”) which apply in Australia’s National Electricity Market (NEM) or recommend potential changes to them. Rather our intent is to provide an objective exploration of the issues and options available to address such, to promote a common understanding between AEMO, the electricity networks, and those involved in developing, financing or otherwise supporting renewable generation projects. Sharing a common understanding is foundational to being able to identify efficient and mutually agreeable solutions – both to specific issues that arise on particular projects, as well as systemic reform of regulatory frameworks – ultimately to benefit the long term interests of electricity consumers.

- A subsequent report will be prepared by Powerlink Queensland, working with inverter manufacturers, to evaluate and demonstrate the potential use of synchronous generator emulating inverters for grid-connected applications. This report is expected to be published separately at a later date.

2. Background and issues with system strength in the NEM

In this section, we discuss what system strength is (and what it isn't), its significance in a power network system, and how it impacts connecting generators. We also discuss the National Electricity Rules (NER) which apportion responsibility for managing system strength, and the guidelines which set out how it should be evaluated.

2.1 What system strength is

An understanding of the meaning of 'system strength' is critical for this report, as the term is sometimes confused with 'fault current', 'inertia' and other power system technical parameters. The following section clarifies what system strength is (and what it is not).

Section highlights

- Our and others understanding of system strength has evolved over time, and is likely to continue evolving. There are different understandings of how to define "system strength" in relation to other aspects of power system. This doesn't change the challenges that result from low system strength, but it does impact on how we describe them.
- System strength is the sensitivity of the voltage on a transmission network to a power network disturbance.
- The voltage in an area with high system strength will be relatively unaffected by network disturbances, whereas an area with low system strength will likely experience significant voltage fluctuations. This could lead to the tripping of generators and loads and, in the worst case scenario, a cascading failure of the power system.
- Synchronous generators, such as fossil fuel or hydroelectric plants, inherently provide system strength to help stabilise voltage fluctuations following network disturbances. Whilst inverter based non-synchronous generators, such as wind and solar, are able to provide voltage support they are presently unable to provide the overcurrent need to stabilise the network following a disturbance. Further, the interaction between multiple inverters can exacerbate a network disturbance.

2.1.1 Our evolving understanding of system strength

The power sector's collective understanding of system strength has evolved over time.

- Before the advent of inverter-connected variable renewable energy (VRE) generators, almost all generation was 'synchronous', producing system strength as a consequence of their operation. System strength wasn't then an issue which warranted its own term, or required specific rules. Any issues that did present were addressed by network service providers with minimal impact on generators and loads.
- As the proportion of inverter-connected renewables increased, system strength emerged as a term to help describe the issues being encountered. Initially system strength was understood in

terms of the voltage-resilience or fault-level required for individual generators to be able to operate stably and to ride-through system faults.

- Subsequently the potential for multiple generators to interact in an unstable fashion ("controller interactions") became the dominant concern, and is commonly described as a problem with system strength. Whilst the system voltage-resilience and or fault-level is a significant risk factor for controller interactions, it is not the sole contributing factor.
- More recently, it has become apparent that the system strength related issues we are observing are also influenced by other factors including system inertia and synchronising torque.

Given this pattern, there is every likelihood that we will uncover additional aspects of system strength over time. The power sector's expanding understanding of system strength has created a challenge for how system strength is defined. There are (at least) two options:

1 To progressively expand our definition of system strength to include these additional aspects. In this case, the term system strength effectively becomes a synonym for power system stability. Using an umbrella definition of system strength may necessitate the use of more granular and precise descriptions of particular situations, given that the nature of the issue and remediation options may vary significantly depending on which aspects of system strength are involved.

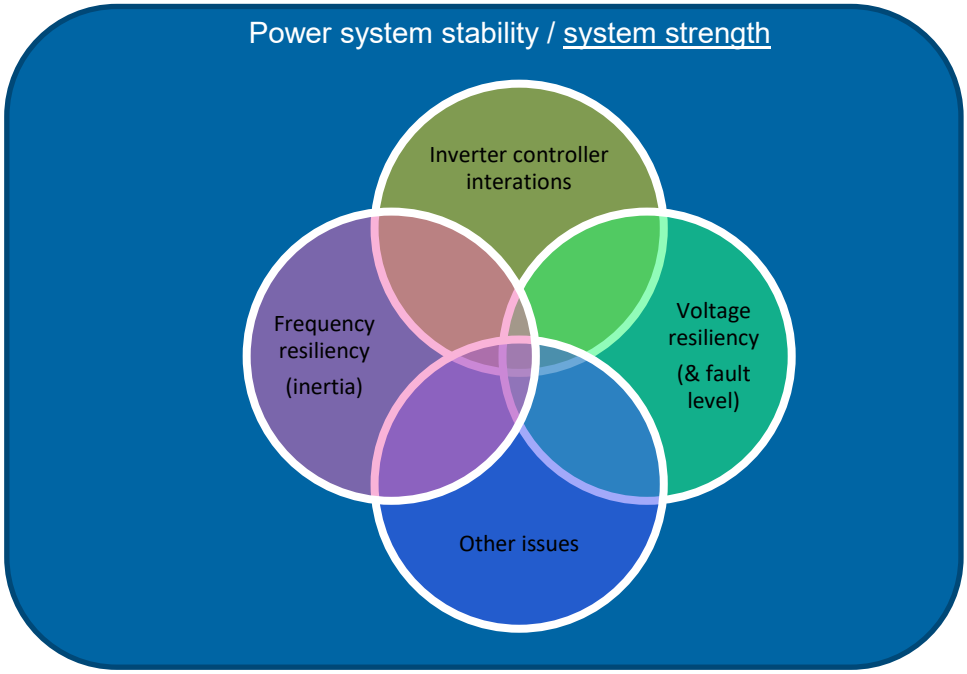

Figure 1 Power system stability / system strength

2 To preserve a more focussed definition of system strength as a subset of power system stability centred on system voltage-resiliency/fault-level. This approach requires us to recognise that system strength is interactive with other aspects of power system stability, and that these aspects are equally relevant to the connection of new generation and the secure operation of the

power system. In this case, the definition of system strength focusses on the resiliency of the voltage waveform to disturbances, a concept which is closely inter-related with system fault level.

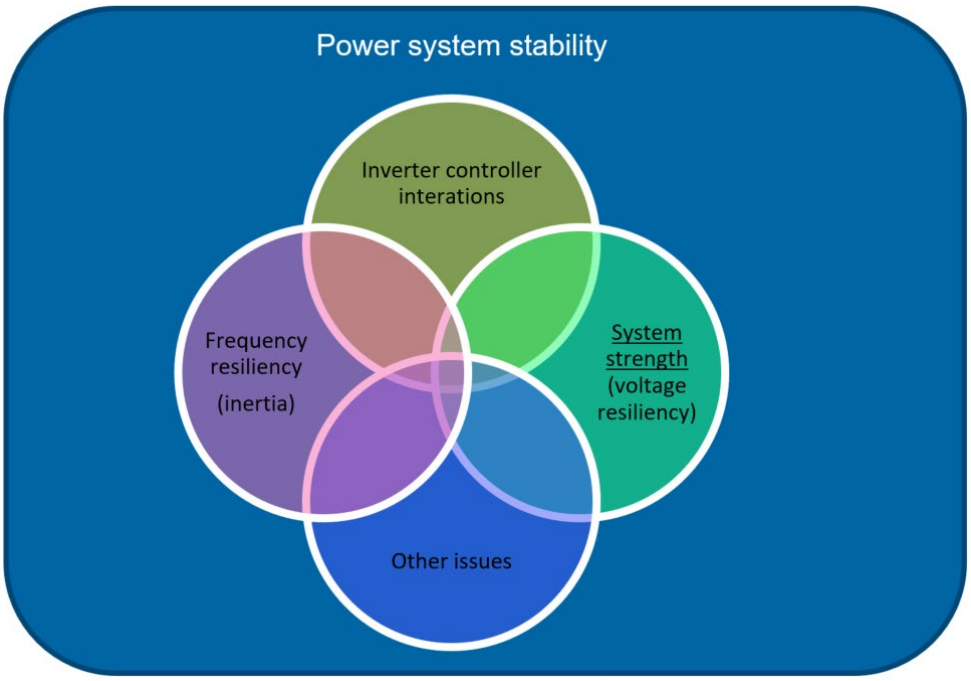

Figure 2 Power system stability

Whilst this distinction may seem pedantic, it has a significant bearing on how system strength is described:

- With the expanded definition, system strength is a measure of the overall stability of the power system, describing the system's performance and its ability to recover quickly from sudden events. Issues such as inverter-controller interactions and system inertia are be subsets of the overarching issue of system strength.
- With the more focussed definition, system strength is a quantity which propagates throughout the power system. Inadequate system strength can be said to exacerbate other issues such as inverter controller interactions, but such issues may also impacted by other aspects of the power system stability. Network connections need to be assessed for their impact on overall power system stability, not just system strength.

This report has been written in terms of the latter option. The findings are equally applicable to the former definition, but would need to be expressed differently.

There may be value in industry processes such at the AEMC's System Strength Frameworks Review reviewing the definition of system strength and seeking to establish a common understanding. In the meantime, readers should be aware of the ambiguity inherent in the term.

2.1.2 Technical definition of system strength

System strength is a measure of the sensitivity of the voltage on a transmission network in response to a network disturbance. Examples of potential network disturbances include a sudden change in generation or load; the switching of a capacitor bank or tapping of a transformer (used for voltage control); and various forms of network faults (short circuits).

If a transmission network bus (location) is said to be “strong” in terms of system strength, the change in voltage at that location will be relatively unaffected by a nearby disturbance. However, if a location is said to be “weak” in system strength the voltage at that location will be relatively sensitive to a system disturbance, resulting in a voltage dip that is deeper and more widespread.

Low system strength is a precondition in which other problems are far more likely to occur. The main concern of TNSPs and the Australian Energy Market Operator (AEMO) is that an uncontained local problem can initiate a chain-reaction of events that end up jeopardising the security of the broader system.

The particular problem that has arisen in recent years is the potential for generators to become unstable. The mechanism by which a generator can operate stably in a strong system but not in a weak system is analogous to comparing the different consequences of prodding a rock or a jelly:

System strength – rock and jelly analogy

- If you prod a rock, nothing happens. Anyone else touching the rock would be unaware that it had been prodded. This is like a strong system, where if a network disturbance occurs, there is very little voltage fluctuation. The network voltage is “rock-solid” (compared to a weak system, at least). Any generators connected to the grid would not see much of a disturbance.
- In contrast, a weak system behaves like a jelly that wobbles when prodded. The wobbling is felt throughout the jelly, and not just at the point of contact. Depending on how a person responds to the wobble (e.g. if they were trying to maintain a constant pressure against the side of the jelly), they could end up creating further wobbles.
- Like the jelly, a power network with weak system strength, voltage is highly sensitive to any network disturbance, and, depending on how generators respond to the initial disturbance they could end up creating additional disturbances. This could lead to a snowballing back-and-forth effect where the voltage distortion increases to such a state that generators start to trip (creating further disturbances) and in the worst case, result in the cascading failure of the power system.

Figure 3 - Rock and jelly analogy for network system strength

System strength – trampoline analogy

Another analogy that is sometimes used is a trampoline, [3] in which the trampoline's surface represents the system voltage, and inverter-connected generators are represented by the people standing on the trampoline:

- A strong system is analogous to a trampoline which has a full complement of springs around the outside, which hold the trampoline's surface very taut. If there are a number of people standing on the trampoline and one of them jumps (i.e. some kind of disturbance), the other people on the trampoline may experience some movement, but it will be slight and quickly settle so they should be able to keep their balance, perhaps flexing their knees to offset some of the wobble.
- Weakening the system is akin to removing some of the springs. If every second spring was removed, the trampoline may still appear flat and taut when it is unloaded, but it will flex a great deal more if someone were to jump on it. Any other person standing on the trampoline at the time would find it harder to retain their balance. If poorly timed, their efforts to flex their legs to absorb some of the wobbles could in fact cause the surface to wobble further. Should someone actually fall over, this would create further wobbles, potentially causing others to fall, until everyone is lying in a jumbled heap.

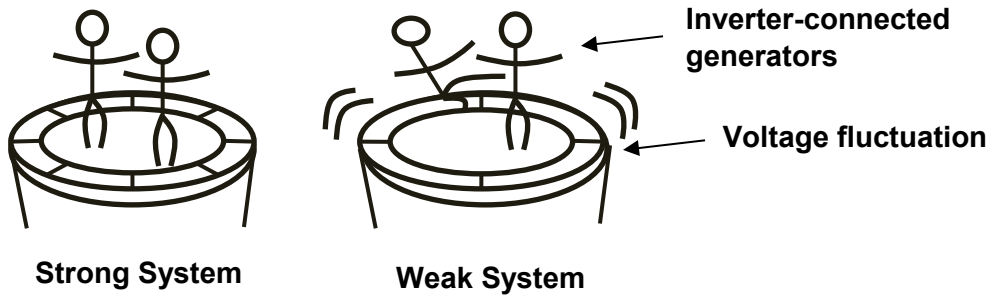

Figure 4 – Trampoline analogy for network system strength

2.1.3 Impact of generation type on system strength

Conventional (synchronous) generators

System strength is created by conventional forms of generation, not because of their fuel source (coal, gas, hydro etc.) but rather because of their 'synchronous' nature: the way their generators (synchronous) automatically react, as a consequence of the physics of the changes of magnetic fields in reaction to a system disturbance. Such synchronous generators respond inherently to disturbances on the power system in a manner which resists the disturbance and limits its size, i.e. this is a process driven by physical forces which happens automatically and instantaneously.

To provide system strength, conventional generators (synchronous) merely need to be online and synchronised to the grid, regardless of their level of output.

Non-synchronous renewable generators

On the other hand, solar panels and modern wind turbines need to connect to the grid through an inverter, which transforms the power produced by the source (which may be direct current, or variable

[3] Oahu Distributed PV Grid Stability Study - Part 3: Grid Strength
https://www.hnei.hawaii.edu/sites/www.hnei.hawaii.edu/files/Oahu%20DPV%20Grid%20Stability%20Report%20Pt3.pdf

frequency alternating current) into a form which is compatible with the grid (alternating current, with 50 cycles per second).

Inverters are not driven by the physics of magnetic fields in the same way as synchronous generators are, but rather rely on control algorithms to sense and appropriately respond to any fluctuations on the grid. If the system strength is low there is a risk that the inverter (and the algorithm which controls it) may not respond in a stable fashion.

2.1.4 Factors influencing system strength

Three factors determine system strength at a given location:

- **The number of synchronous machines connected**. Synchronous generators increase system strength. Reducing the number of synchronous generators will reduce system strength. As inverter-connected renewable generators make up a greater proportion of the generation mix and synchronous generators are displaced and go offline, the overall supply of system strength into the power system will likely reduce. This will be the case unless system strength is maintained – for example through the use of synchronous condensers (which are essentially synchronous generators that produce no real power but continue to provide system strength).
- **The electrical distance to the synchronous machines**. Load (power consumption) and generators (power production) connect to the electricity transmission or distribution networks and in doing so establish a pathway for synchronous generators to provide system strength to the power network. The impedance of the network between a connection point and significant sources of synchronous generation influences the system strength at the connection point.

  The lower the impedance the higher the system strength. The impedance is a function of the physical distance and of the capacity of the network. For example, two locations may be the same physical distance from a significant source of synchronous generation. However, if one location is connected by to higher capacity, higher voltage and lower impedance transmission network then it will enjoy a higher system strength than a location connected to a lower voltage, higher impedance transmission network. This leads to the so-called ‘tyranny of distance’ whereby system strength provision is localised and dissipates with electrical distance, depending on network impedance.

  In a low impedance network, system strength has greater electrical distance coverage as compared to a network with a, relatively speaking, higher impedance. Given the scale of Australia’s power system, there are many locations in the network where system strength is naturally low and has always been this way. However, such locations are often attractive for the connection of renewable generators because of good resource availability, low land costs, and the expectation of a straightforward connection to the grid.
- **Network contingencies and outages**. The configuration of the network can have a significant impact on the impedance between a connection point and the nearest significant source of synchronous generation. When the network is intact, two locations may be electrically close (connected by a low impedance network), but if a network outage were to occur the impedance can increase significantly, thus reducing the system strength at a point affected by the network outage.

  The impedance between two locations could change temporarily in response to a planned or forced network outage, or permanently as the configuration of the network evolves over time

(e.g. removing and not replacing an aged asset could increase the network impedance, constructing new higher capacity assets could reduce the impedance leading to an increase in system strength).

2.1.5 Related concepts

Clarity on the meaning of 'system strength' is important, as the term is often confused with other parameters or concepts. The following seeks to briefly explain some related concepts, and how (if at all) they are related to system strength:

- **Inertia** – Relates to the ability of the power system to resist changes in ***frequency*** caused by changes in generation output and load levels. Just as synchronous generators resist sudden changes in the voltage magnitude (providing system strength) so too do they resist sudden changes in the power system's frequency (as a result of the inherent high mechanical inertia of such generating plant). Both of these processes occur instantaneously and automatically as a consequence of physical forces.

  However, whilst system strength and inertia are both provided by synchronous generators, they are distinct concepts and are provided by different mechanisms. Inertia is provided by the kinetic energy stored in the spinning components of the generator (shaft, turbines and rotor), while system strength is provided by the magnetic flux in the generator's core (flowing through the stator and rotor). Increasingly, the required inertia may be able to be reduced by inverter-connected generators or batteries, providing Fast Frequency Response (FFR). This is currently not the case for system strength provision.

  Generator Stability / Controller Interactions (defined below) can be impacted both by system strength and system inertia.

- **Generator Stability / Controller Interactions –** The NER require generators to be able to operate smoothly and stably and act to dampen any oscillations which may occur in the power system. There are various mechanisms which can result in oscillations occurring in the power system and generator control systems need to be carefully designed to respond appropriately to these oscillations. Generation instability can occur in strong systems but some forms of it are more difficult to manage in a weak system.

  The unstable interaction of multiple inverters is strongly impacted by low system strength, and this issue can become so widespread that "low system strength" is sometimes used synonymously for "inverter instability". Nevertheless, it is worth clarifying that inverter instability (or controller interactions) is not the same as low system strength. This may seem pedantic, but it is a clarification worth making to help make sense of the two categories of remedial measures:

  1. Those which act upon the level of system strength – increasing it to the point where the inverters can operate stably
  2. Those which leave the system strength unchanged, but apply to the inverters themselves, helping them to respond stably in an environment of low system strength, e.g. through management of control and trip settings or through use of improved control systems that may even make them behave more like synchronous generators.

- **Fault Level (Fault Current) –** This is a measure of how much power would flow into a short circuit at that location, should one occur, and is often many multiples of the normal level of power

flow. Network equipment must be capable of withstanding this level of flow before circuit breakers open and clear the fault. Sometimes system strength is expressed in terms of fault level because the fault level is highly correlated to the level of system strength (the higher the current which will flow into a fault, the higher the retained voltage will be). Therefore fault level has become a proxy measure for system strength.

- **Available Fault Level (AFL) / Available System Strength –** AFL is a concept introduced as part of the preliminary impact assessment process[4] used to screen proposed network connections for possible system strength-related issues. The available fault level at a connection point is the fault level at a location (measured in MVA) minus the capacity of any nearby inverter connected generators. Because the measure is based on subtracting the capacity of inverter-connected generators, inverters are said to "consume" available fault level[5].
- **Short Circuit Ratio (SCR) –** SCR is the ratio between the size of a proposed generator and the available fault level at the location it is proposed to be connected. This is a screening metric used in a TNSP's preliminary impact assessment to assess whether a detailed investigation is likely to be required for the proposed connection. Generating systems have minimum SCR requirements, below which they will not operate stably. Again, this is a simple metric and not substitution for detailed PSCAD assessment.
- **Fault Ride Through –** Refers to the technical capability of a generator or load to withstand short term disturbances and remain connected to the network, resuming normal operation once the fault is cleared. This is an important characteristic to ensure that a single network fault doesn't result in the cascading failure of the power system.

  Having low system strength increases the importance of fault ride through, because with low system strength a network fault will result in a deeper voltage disturbance that is experienced over a wider area over networks with high system strength. If any generators did not ride through the fault as required, there would be a greater likelihood of a cascading failure.

  The ability for inverter-based generators to support the system voltage during a fault is limited. Due to the 'current-limited' nature of the technology over synchronous generators, the ability of inverters to generate power is significantly lower during a system voltage disturbance. This is the same reason which can make it challenging for inverter-based generators to meet the Continuous Uninterrupted Output (CUO) requirement during normal voltages (i.e. 90% to 110% of the nominal voltage), but is even more pronounced during fault conditions when the retained voltage can be much lower. Low system strength exacerbates this effect, as the voltage disturbance during a fault will become more widespread and more inverter-based generators will experience a reduction in output. The aggregate effect of this reduced generation can compound the severity of the network fault.
- **System Adequacy** – Relates to having enough available generation to supply the total electrical demand and energy requirements of end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of generators and network. This concept is largely unrelated to system strength, although network or generation constraints which

[4] AEMO System Strength Impact Assessment Guidelines

[5] The consumption of AFL is also dependent on the distance and network topology between the location in question and that of the inverter-based plant.

result from system strength can limit the output of generators and lead to a reduction in system adequacy.

- **System Resilience –** The ability of the power system to avoid, survive and recover from high impact, low probability events (events that, if they were to occur, would have a large impact in terms of quantity of load lost). Due to the changing nature of the power system and the potential for more extreme weather events, the same level of generation and network resources may not necessarily provide the same level of resilience as they did in the past.

  Falling levels of system strength is a factor which could contribute to the declining resilience of the power system.

- **Power Quality** – Although system strength relates the propensity for the voltage waveform to be deformed, any actual regular and sustained deformation in the voltage waveform is known as power quality. Power quality is measured, in part, by the extent to which voltage waveforms match up with perfect sinusoids. The performance of generators and loads can be adversely affected if the power quality is too poor. Examples of power quality issues include harmonics, flicker or phase unbalance (also known as negative phase sequence).

  Low system strength is a precondition in which power quality issues are far more likely to occur. Poor power quality is more likely to adversely impact the performance and stable operation of inverter-based plant under low system strength conditions

2.2 Why system strength is important to renewable generators

Section Summary

- Inverters, which convert wind and solar power to a form compatible with the power network, can interact with other inverters in the system in unstable ways that compromise power system stability.
- Renewable generators seeking to connect to the grid are bound by the National Electricity Rules (NER) which includes requirements regarding system strength and system stability.
- Over the last 12 months, system strength related considerations (network factors, location, cost of remediation, system strength assessment) have resulted in project delays, and large unanticipated expenditure.
- It is essential there is enough system strength at all times to keep the power system stable.

2.2.1 Regulatory compliance as a prerequisite to connection

In order to connect to transmission networks in the NEM, generators must comply with the requirements set out in the NER, especially section 5 - Network Connection, Planning and Expansion. This includes requirements that relate specifically to system strength and requirements relating to other aspects of power system stability.

It is critical for developers/connecting generator proponents to understand the system's physical limitations, the obligations imposed on them, how these obligations can be fulfilled, and the impact this has on investment and project planning decisions.

The shifting nature of Australia's generation mix also means that it may be pragmatic for renewable generation developers to go into the network connection process, assuming that some form of system strength remediation may be required. We discuss this in detail in Section 2.3.1.

2.2.2 How controller interaction (inverter instability) threatens power system security

As previously explained, low system strength is not necessarily a problem in itself, but rather is a precondition in which other issues are much more likely to emerge and become harder to deal with such as generator instability, poor power quality, fault-ride through ability.

An issue of particular concern with inverter-based generation is that of unstable controller interactions (inverter instability). If inverter controllers were allowed to do become unstable, the voltage of power network buses, to which inverter based generators are connected, may fall outside of standards defined in the NER, and ultimately could result in the unplanned tripping of generation. This, in turn, could result in further disturbances on the power network and, ultimately, the cascade tripping of generators and load, threatening the security of the power system.

Initially, the industry's focus was the stability of individual inverters in response to network disturbances (fault ride through). However, as the population of inverter-based generation on the power system has increased over recent years, interactions between multiple inverters, and certain forms of network equipment have become the dominant concern of TNSPs and AEMO. Whilst there were existing requirements in the NER regarding generator stability, inverter controller interaction issues have been particularly difficult for the industry to deal with, and have necessitated step-changes and impacts across several areas:

- AEMO, networks and inverter manufacturers have had to develop (and progressively refine) the detailed and system-wide PSCAD models used to carry out system strength full assessment, along with the guidelines and expertise needed to undertake the required analysis.
- The Australian Energy Market Commission (AEMC) has had to develop new rules to apportion responsibilities for maintaining system strength.
- Developers have been subjected to drawn-out connection assessments, changing NER requirements, variable advice as models have been progressively refined, and have incurred additional costs associated with system strength remediation.
- VRE generator operators have incurred unanticipated operating constraints, including temporary outages and/or constraints on output or capacity. An example of this is the significant and protracted constraints placed on five solar farms in New South Wales and Victoria where inverter instability and the potential for a significant capacity of distribution generation to trip following a network contingency was only identified after the solar farms were constructed[6].
- Consumers have been impacted through delays in bringing new generation supply online, and the flow-on effect of increased borrowing costs for new generation developments.

[6] Australian Financial Review, 'AEMO imposes tough conditions on new wind and solar in Victoria's 'full' transmission system'. Available at : https://www.afr.com/politics/aemo-imposes-tough-conditions-on-new-wind-and-solar-in-victorias-full-transmission system-20181012-h16l0h

2.3 Rules and the Connection Assessment Process

Section Summary

- The AEMC released a final ruling in December 2017 that apportions responsibility between generators and network service providers for the maintenance of system strength above specified minimum levels.
- Generator proponents seeking to connect to the power network ('connecting applicants') are required to 'do no harm' to existing levels of system strength, and to remediate any reductions caused by their connection.
- The preliminary assessment carried out by TNSPs is based on simplifying assumptions, and is used as a screening tool only. A full assessment involving detailed PSCAD modelling is required to determine actual system strength impact.

The AEMC is responsible for maintaining the NER that apply throughout Australia's NEM. In December 2017, the AEMC ran a consultative process to establish Rules relating to system strength. These Rules place obligations on AEMO, TNSPs and generator proponents seeking a transmission network connection and are outlined below.

AEMO

- Required to determine the level of system strength required from existing generators and networks to operate stably. This is expressed as a specified fault level at key nodes throughout the NEM.
- This level of system strength may incidentally create headroom at some locations that enable new generators to connect without system strength remediation. Where the actual level of system strength is forecast to drop below AEMO's thresholds, AEMO is required to declare a fault level shortfall.

Transmission Networks

- Each TNSP is responsible for responding to a shortfall declared (by AEMO) within their area of responsibility arising from a natural reduction in system strength (such as retirement of synchronous generators) by developing a suite of possible solutions to address the issue and then undertaking a Regulatory Investment Test (RIT-T) consultation to identify any non-network solutions and to ultimately identify the most cost-effective way to remediate the issues.
- The "system need" is addressing the declared shortfall, and the merits of different options (including any that opportunistically go above and beyond the immediate need) would be valued and compared in the manner required by the Australian Energy Regulator's (AER) RIT-T guidelines. The one exception to this could be if the additional capacity (i.e. beyond the declared need) were funded from an external source, in which case only the regulated portion of the cost would be subject to the RIT-T process.

Connecting Generators

- When a generator proponent applies to connect a new generator to the network, it is the responsibility of the TNSP to satisfy itself, through its connection assessment processes that the

inverter will operate stably itself and "do no harm" to the stable operation of any other existing and committed generators, loads or network equipment. The generator proponent must provide the information required to enable the TNSP to assess the connection, and the TNSP must conduct a connection assessment as per AEMO's *System Strength Impact Assessment* guidelines[7]. If it is determined that there is the potential for 'harm,' the proponent may work together with the TNSP to modify their proposed connection or implement remedial measures that mitigate this risk (with the cost for such borne by the generation proponent).

- Such measures can be in the form of new infrastructure (e.g. a synchronous condenser) or an operational scheme (e.g. to intentionally trip or run-back the generator under certain conditions). Registered generator proponents also have an ongoing obligation to demonstrate compliance with any system strength remediation scheme agreed with the TNSP, including the implementation, maintenance, and performance of the scheme.

2.3.1 Connection Assessment Process

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

1 Preliminary Assessment

- 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 System Strength.
- The Available System Strength is the system fault level reduced by the amount of existing and committed inverter-connected generation within the area. This assessment is very approximate and shouldn't be used to infer anything beyond the purpose for which it is described.
- This assessment was originally focused on screening for instability occurring within individual inverters during or immediately following network faults and is less effective as screening for interactions between multiple inverters. Therefore some TNSPs whose network has a high population of inverters (including Powerlink's in Queensland) now recommend that all connections undergo a detailed assessment irrespective of the preliminary assessment.

3 A detailed assessment

- Assessment is undertaken using detailed PSCAD (computer-aided design software to design and simulate electrical systems) analysis. Analysing the potential for unstable interactions between multiple inverters requires extremely detailed models of each inverter and the network (e.g. with a full representation of each inverter's control system, control systems of synchronous plant, control systems of network connected SVCs and Statcoms).
- Practically this means that the 'load flow' and transient stability analysis which has historically been used to analyse network connections (using applications like PSSE, Power Factory, and PSS Sincal) is not sufficient, and electromagnet transient (EMT) modelling using PSCAD must also be used.

[7] AEMO, System Strength Impact Assessment Guidelines, July 2018. Available at https://aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Impact_Assessment_Guidelines_PUBLISHED.pdf

- However, PSCAD simulation is extremely detailed and time-consuming. Additionally, it is taking time for utilities and inverter-suppliers to develop and refine PSCAD models of their network and inverters. In several cases this model refinement has followed an iterative fashion in which modelling of the combined power system has progressively uncovered issues with vendor-supplied inverter models. This process of ongoing model refinement has resulted in variable model outputs over time. This is expected to stabilise over time as the models become more mature, and real-data is obtained from inverters now in operation (allowing the models to be calibrated), to improve accuracy and confidence in the results.
- The detailed nature of this analysis also means that developers are required to submit precise details of the intended inverter to be used and of other electrical infrastructure (e.g. filters, transformers, switch gear, wind turbine generator (WTG) and or solar photovoltaic (PV) equipment, power reticulation system) at the time of their connection application. This is at a time when, historically, generation proponents have not sufficiently advanced the specification and design of their project to have such information available. Any changes subsequently made to the design of their project may invalidate already completed analyses, forcing the lengthy analysis process to start over. Additionally, because each project needs to be assessed based on the power system with all existing and committed generators, the fresh commitment of another generator in the same area may also require that fresh analysis is undertaken with the updated background conditions. This process is placing additional burdens in terms of cost and time on generator proponents seeking to connect non-synchronous generation plant.

The system strength assessment process is illustrated in Figure 5 below.

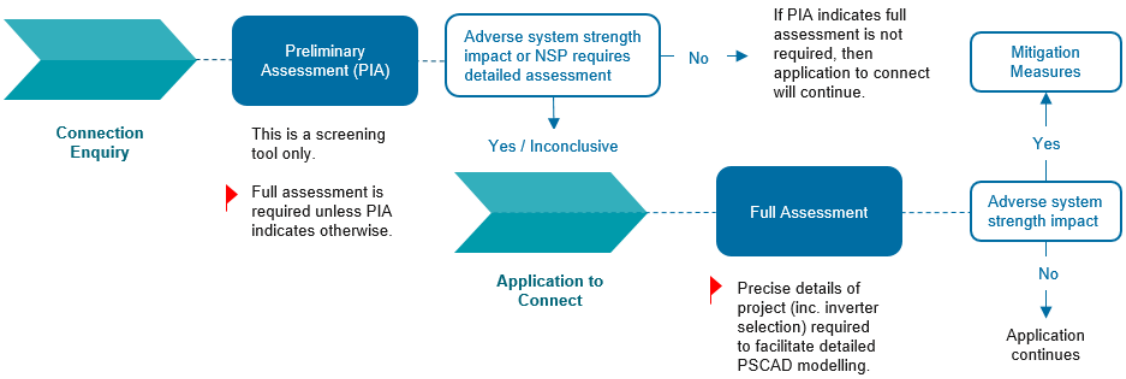

Figure 5 – Connection System Strength Assessment Process

No matter how inconvenient, such arrangements are necessary to ensure that the power system is operated securely. The alternative situation, in which inverter instability is only detected after project implementation is likely to result in worse outcomes such as curtailment for the generator proponent.

In the past, it has been possible for many VRE generation projects to be developed without system strength remediation. These instances will become increasingly rare as the penetration of inverter-connected generation continues to grow. It may be pragmatic for renewable generation developers to go into the network connection process assuming that some form of system strength remediation will be required – with the connection process used to refine the details of this requirement.

Synchronous condensers installed by VRE generator proponents

A number of synchronous condensers have either been installed or planned to be installed by VRE generator developers under the 'do no harm' requirement. These include:

- Haughton Solar Farm in Queensland (proposed)
- Kiamal Solar Farm (200 MW) in north-west Victoria – installing a Siemens Synchronous Condenser[8].
- Darlington Point Solar Farm (275 MW) in western New South Wales has installed two synchronous condensers, each rated at 42.5 MVA at the nearby Buronga substation. At time of writing, these have been installed and are awaiting commissioning[9].
- Murra Warra 2 Wind Farm in north-west Victoria plans to install a single GE 60 MVA synchronous condenser[10].

2.3.2 Case Study – South Australia Power Systems

South Australia has seen increasing use of renewable energy sources, such as wind and solar, and a decrease in traditional synchronous generator energy sources. This led to AEMO announcing a shortfall in both system strength and inertia. For the last two years, AEMO has managed this shortfall operationally through the constraints and market directions. As the responsible TSNP, ElectraNet investigated options to remediate the system strength requirements. ElectraNet undertook a RIT-T process, which identified that the most cost-effective option would be to install four synchronous condensers (with flywheels to simultaneously provide inertia) at two locations on their network. In South Australia's case, AEMO also declared an inertia shortfall (in addition to the system strength gap), and so ElectraNet will be installing high inertia synchronous condensers that simultaneously address both needs[11].

[8] https://reneweconomy.com.au/siemens-to-deliver-australias-first-solar-farm-synchronous-condenser-29609/, last accessed 22 December 2019

[9] Correspondence from Edify/ARENA, 22 April 2020

[10] Correspondence from Macquarie/ARENA, 22 April 2020

[11] https://www.aer.gov.au/system/files/ElectraNet%20-%20Application%20for%20cost%20pass%20through%20extension%20-%20Inertia%20Shortfall%20-%207%20May%202019.PDF, last accessed 21 April 2020

Figure 6 – Locations of where the synchronous condensers will be installed[12]

[12] ElectraNet, *Strengthening South Australia's power system*. Available at: https://www.electranet.com.au/what-we-do/projects/power-system-strength/

3. Responses to issues arising from low system strength

In this section, we provide an assessment of the range of responses available to manage the issues arising from low system strength. As mentioned, low system strength is a precondition in which other problems readily emerge. This gives rise to essentially two forms of responses:

1 Those which increase the level of system strength seen by the project, including:

- Selecting an alternative location with higher system strength
- Contracting with an existing nearby synchronous generator
- Implementing a synchronous condenser, on either an individual or shared basis
- Modifying the grid connection
- Augmenting the upstream network

2 Those who reduce the dependency upon system strength and manage the issues resulting from low system strength, including:

- Advanced inverter control systems
- Special protection to intentionally trip the generator (or run-back) during problematic system states
- Grid forming (synchronous generator emulating) inverters
- Other remedies particular to the issue being experienced (e.g. harmonic filters to address power quality issues).

The applicability and effectiveness of each response can vary between situations. Most of these options are mutually compatible, and the optimal solution may involve a combination of responses. Even with the options which work by increasing the level of system strength, due to individual site characteristics, there is no consistent level of system strength that will ensure that the presenting issues are mitigated. As described previously, the system strength lower limit prescribed by AEMO for which TNSPs can implement regulated solutions is intended to allow the existing grid and generators to function stably, and any capacity for the new generation is incidental and opportunistic. Therefore, detailed power systems analysis will be required to determine the scale and cost-effectiveness of each solution.

The following discussion reviews each remedial option in terms of:

- Effectiveness, including factors which may impact upon the effectiveness in different situations
- Practical considerations which may be of interest to developers such as maturity, examples in the NEM, construction times, site footprint, and lead times, and
- Cost (where possible), including both upfront and ongoing costs.

Although general in nature, this report is intended to help proponents to more-effectively engage with TNSPs, AEMO, consultants and other experts who are undertaking the detailed analysis required to identify the most efficient solution in their particular situation and for financiers to gain a greater understanding of system strength to enable the risk to be quantified.

3.1 Considering system strength when locating projects

From a generator project perspective, 'prudent avoidance' could be the most straightforward approach to managing system strength.

- Siting new generators in areas with high levels of system strength, and away from other inverter-connected generators should reduce the likelihood of system-strength related problems arising (although this is not guaranteed).
- The next-best solution is to site projects in locations that are most likely to be able to benefit from a shared or centralised response to low system strength. This issue is explored in Section 4.3.

To assist with this, many network operators publish "new generator connection capacity" geospatial datasets on AREMI[13]. These results should be understood in the context of additional material published on each TNSP's website, outlining the basis for the data including important assumptions and caveats. AREMI also provides access to a wide range of other spatial datasets which may be of interest to project developers.

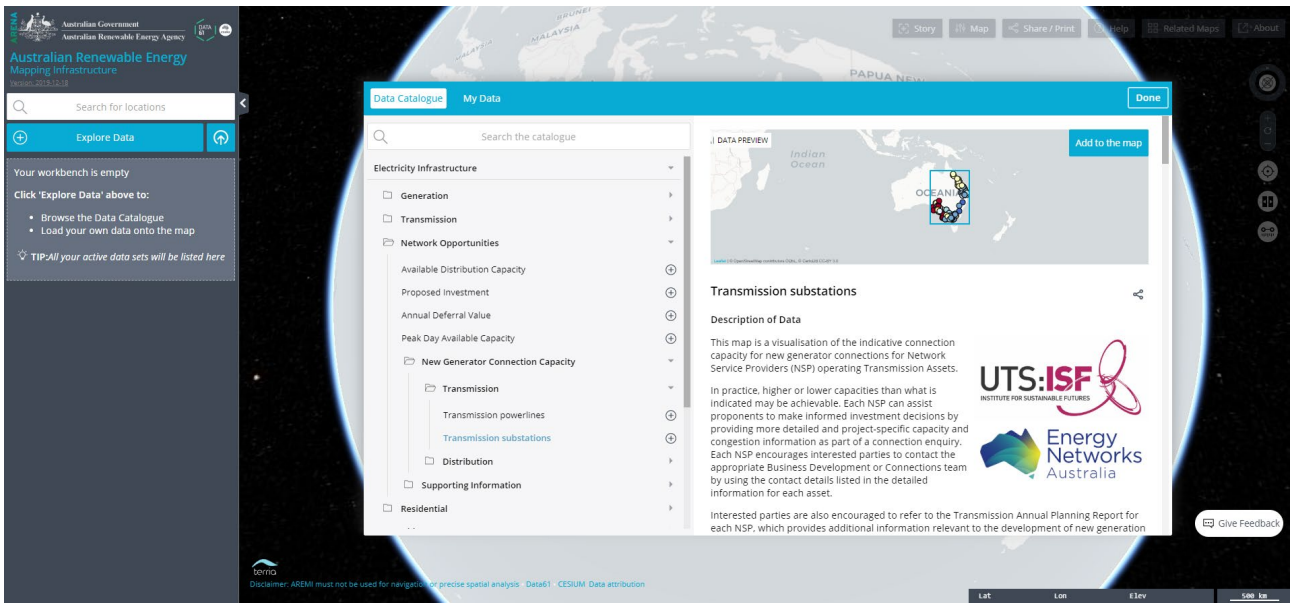

Figure 7 – AREMI new generation capacity

3.1.1 Effectiveness

Connecting into a strong part of the network may allow generators to avoid issues which can occur with connections to power networks with low system strength and the cost and delays this can introduce.

However, the effectiveness of this strategy is diminishing, as system strength issues become more widespread and the availability of strong locations is reduced. Additionally, new connections into relatively strong areas of the power system can experience inverter controller interactions with other existing inverters which are located in areas with relatively low system strength (i.e. the potential for issues is not solely dependent on the system strength at the connection point).

Nevertheless, there may still be value in giving preference to locations that are more likely to benefit from a shared or centralised solution to system strength. Doing so may allow the project to access a

[13] https://nationalmap.gov.au/renewables/

lower-cost solution to system strength (arising from economies of scale), and may help to reduce the time and complexity of the connections process.

3.1.2 Practical considerations

System strength is but one of many considerations when it comes to developing a VRE generation project. From a network perspective, the potential for future network constraints, and the sensitivity of the marginal loss factors (MLFs) to additional nearby generation should also be considered. At some point, it may be more economic to make time and cost allowance for system strength remediation.

3.1.3 Cost

The cost of this option is the trade-off made against other siting considerations and is entirely site-specific.

3.2 Special protection schemes

Special protection schemes involve implementing systems to run back automatically (reduce output) or trip (electrically disconnected from the grid) a generator under particularly problematic system conditions.

For context, the term “protection” relates to the equipment used in the power system to rapidly detect and isolate problems. A household example is the mechanical circuit breaker in the electrical switchboard which automatically trips a circuit if a fault or overload is detected. The transmission-equivalent of this involves specialised computers (known as “protection relays”) constantly monitoring system conditions, ready to fire off instructions to circuit breakers should this be required. Normal protection (which is just referred to as “protection”) relates to equipment which is guarding against faults and/or overloads on an individual item of plant. “Special” protection relates to using protection-equipment in non-conventional applications – perhaps monitoring for different types of conditions (e.g. looking for oscillations) and/or undertaking actions which are remote from the location (e.g. tripping a generator in response to an event which has occurred upstream).

3.2.1 Effectiveness

In the context of low system strength, special protection schemes are fast automated systems which trip or runback the inverter under certain conditions. They don’t create any additional system strength, but act to prevent generators from becoming unstable (and potentially inducing instability in other generators). This may be a cost-effective solution in situations where stability only becomes an issue in a very small number of detectable network conditions (preferably just one), and these conditions are expected to be sufficiently uncommon that the cost for the generator to come offline at these times is less than the cost to enable the inverter to remain online.

The use of special protection schemes can be highly complementary with other solutions. For example if another solution could cost-effectively be used to enable the inverter to operate stably across almost all system states, but there is one particularly challenging situation that necessitates a vastly larger solution which renders the overall solution uneconomic. The use of special protection to trip the generator under that particular condition would preserve the economic viability of the other solution and enable the inverter to operate most of the time, while removing the risk of the inverter becoming unstable.

The power system has a limited capacity to cope with the sudden loss of generation – in general, and especially in areas with limited system strength. Therefore, the extent to which special protection schemes can be used within an area is limited. This may be particularly true in circumstances where

the network is already depending upon special protection schemes to manage the day to day operation of their network (including facilitating planned outages). A special protection scheme is most likely to be viable where the critical network contingency is physically close to the generator and has a localised impact on the power system. Special protection is unlikely to be viable for an upstream contingency which impacts system strength over a wide area and impacts upon multiple inverter-connected generators.

3.2.2 Practical considerations

To facilitate this automatic tripping, the network will likely need to implement protection systems to monitor for these network conditions and automatically implement the appropriate action. Depending on the circumstances, it may be possible for the inverter to be run back (i.e. rapidly reduce its output, but remaining online) or it may need to be tripped (i.e. electrically disconnected from the grid).

- If the generator needs to be tripped, it may be advantageous for generators to make their low-voltage circuit breaker available to the utility to avoid tripping the main transformer and thus avoiding the issues that can sometimes be experienced when re-energising transformers with low system strength.
- If the generator can be runback, then the generator will need to integrate signals from the network into the design of their controller. Even where this isn't possible initially, it may be advantageous to preserve this functionality should it become feasible in the future.

The special protection system will require testing – both upfront during the commissioning process, and at regular intervals thereafter to verify its operability. The special protection system may need to be modified from time to time in response to changes in the power system, including any changes to the network's protection, control and telecommunications systems on which the scheme depends. Any planned or unplanned outages to the protection scheme may require the generator to pre-emptively come offline or reduce its output. We recommend that the network and generator proponent jointly agree the protocols that will apply to testing, and outages.

As with all automatic control systems, there is an inevitable risk of inadvertent operation. The more likely it is that a generator will be tripped, the greater the value in having automated or streamlined processes to re-energise the plant and resume normal operation after the condition has cleared.

3.2.3 Cost

The cost of a special protection scheme depends on a number of factors, including details of the network's protection, control and telecommunication systems. This makes it infeasible to provide any general guidance regarding the cost of a scheme.

There are potential synergies with other forms of protection (e.g. anti-islanding) that the generator may require. Thus it could be advantageous for the likelihood of a special protection scheme to be evaluated prior to design of the network connection's control and protection systems.

3.3 Contracting with synchronous generators

If there is a synchronous generator electrically nearby whose operation would provide sufficient system strength, it may be possible to contract with them to operate at times whenever there would otherwise be a system strength shortfall.

3.3.1 Effectiveness

As previous described, synchronous generators inherently produce system strength as long as they are online. The amount of system strength produced by a generator depends on the details of its design.

However, the propagation of this system strength reduces with electrical distance (an effect that we explore further in Section 4.3). Thus the option of contracting with existing synchronous generators is only likely to be effective where there is a synchronous generator in the same area (and the closer it is the better).

Under the current regulatory framework, generator proponents are not allowed to contract with the synchronous generators which form part of the generator set required to fulfil the minimum fault level specified by AEMO since these are already assumed to be online and contracting with them will not result in any additional system strength. The TNSP or its consultant conducting the network connection assessment is likely to be best placed to provide advice on these issues and the potential effectiveness of contracting with certain synchronous generators. Ultimately, under the NER, AEMO needs to approve any proposed remediation.

3.3.2 Practical considerations

Synchronous generators provide system strength whenever they are online. Some generators have a special 'synchronous condensing' mode in which they can be online (and providing system strength) without consuming fuel and producing real power.

If a generator does not have a synchronous condensing mode, it will typically have a minimum level of output at which it can operate stably (known as minimum stable operating condition). For some generators, this minimum can be a significant proportion of their full capacity and may necessitate consuming a substantial amount of fuel. With the trend towards lower wholesale electricity prices during daylight hours throughout the NEM, revenue from the sale of this power may cover a falling proportion of the cost of operating, and should the wholesale price of electricity become negative the synchronous generator would need to pay this cost to remain online. Given that the inverter-based generator may not wish to operate during negatively priced periods, it may be possible to structure a contract in which the synchronous generator does not need to run during negatively priced periods to provide required system strength. However, most fossil fuelled base load plant (as opposed to peaking plant) are unable to stop and start within a day and hence this operating mode may not be an option. Nevertheless, it is unlikely to be economic to contract with a synchronous generator which does not have a synchronous condensing mode. Relying upon a fossil-fuelled synchronous generator may also diminish the overall environmental performance of the new VRE generation project.

It may be possible to retrofit a synchronous condensing mode to an existing synchronous generator, but this would need to be explored on a case by case basis. In some instances this may require an upgrade of the generator's control systems, in other cases it may require the installation of additional hardware (equivalent to installing a clutch in a car's mechanical transmission to allow the shaft to spin freely), and in other cases it may not be possible at all. This solution was applied at Swanbank A power station in the late 1980s to address a voltage control issue in south-east Queensland. Three 60 MW coal-fired generators were modified by disconnecting the steam turbine from the generator in each case allowing each generator to operate as a synchronous condenser.

The age, condition and general economic viability of the synchronous generator may be considerations when considering the merit of retrofitting a synchronous condensing mode and/or evaluating the longevity of the solution. Where an inverter connected generator is dependent upon the operation of a particular synchronous generator or generators, it may be necessary for the TNSP to

implement a special protection scheme to detect the unexpected loss of the synchronous generator(s) and to run back or trip the inverter connected generator to prevent instability.

If there are any credible network contingency events that could significantly increase the electrical distance to the synchronous generator (significantly reducing the effectiveness of the option), it may also be worthwhile considering a special protection scheme to handle this contingency event in order to enable the VRE generator to connect without installing its own system strength supporting capital plant.

3.3.3 Cost

The cost-effectiveness of this option will depend on particular circumstances and be subject to negotiations with the synchronous generator selling the service. The synchronous generator will likely have regard to the cost of alternative options when valuing their product, although there are provisions in the NER that require system strength services to be made available at least cost.[14]

"A System Strength Service Provider required to make system strength services available under paragraph (b) must make available the least cost option or combination of options that will satisfy its obligation within the time referred to in subparagraph (c)(1) and for so long as the obligation to make the system strength services available continues."

3.4 Synchronous pumped hydro energy storage

Pumped hydro involves a pair of water reservoirs at different heights, with electrically-powered pumps used to pump water up to the top reservoir in the form of potential energy. That water is then allowed to flow downwards under gravity transforming the potential energy into kinetic energy. This is then converted to mechanical energy by a turbine and ultimately to electrical energy through the turbine driving a generator to recover the stored energy. Traditionally pumped hydro has been used to provide fast response generation to meet peak demand but is now being more commonly used to capture excess VRE generation energy output and to release that energy when demand exceeds supply from VRE generation resources.

Synchronous pumped hydro can provide both system strength and energy price arbitrage (pumping and storing energy at times of high VRE generation output and low energy prices and generating electricity at times of high demand and low VRE generation output and hence high energy prices). Therefore, in circumstances where both energy storage and system strength are required, there could be significant synergies in considering pumped hydro as a combined solution. Pumped hydro is very unlikely to be cost-effective mitigation for system strength on its own (i.e. where there is no or limited value in energy arbitrage).

Not all pumped hydro installations provide system strength. In recent years the use of variable speed drives in pumped hydro schemes has become increasingly common, due to improvements in efficiency and operational flexibility that they provide. However, the use of variable speed drives (which are themselves inverters) means that instead of producing system strength, the installation may consume available system strength, necessitating greater remediation. Therefore, to be effective at supporting system strength, the pumped hydroelectric installation must be in the form of a direct connected synchronous generator.

The significant lead-time, complexity and capital requirements mean that this option is unlikely to be practical for individual project developers. However such an asset could be a very effective foundation

[14] 5.20C.3(d) NER https://www.aemc.gov.au/sites/default/files/2019-12/NER%20v132%20full.pdf

for a REZ, supporting a cluster of nearby renewable developments through the cost effective provision of: system strength, firming, arbitrage and improvements in marginal loss factors.

The Australian National University's (ANU) STORES project has developed several resources which may assist potential developers of pumped hydro storage, including:

- Mapping of candidate pumped hydro locations throughout Australia and internationally[15];
- A model to estimate the cost of a pumped hydro installation based on several key parameters[16]; and
- Explanatory reports and webinars.

3.4.1 Effectiveness

To support system strength effectively, it is important that the installation is designed to provide system strength under all three operating modes: pumping, generating and when it is not doing either of these. This will most likely necessitate the use of a synchronous generator/motor equipped with a synchronous condenser function. The potential to de-water the turbine should also be considered to allow it to easily spin in air when not pumping or driving the generator.

The capital-cost and operational-efficiency of a pumped storage hydroelectric generator are critically dependent on favourable environmental factors, including:

- A high vertical distance between the upper and lower reservoirs (which creates a high-pressure head to drive the generator efficiently);
- A short horizontal distance between the upper and lower reservoirs (to minimise the tunnel length);
- Minimal civil works to form the reservoirs, with a preference for a narrow and deep shape over wide and shallow to minimise the amount of water lost to evaporation;
- Favourable geology;
- A reliable water supply – both initially to fill the dam and on an ongoing basis to top-up any water which is lost to seepage and evaporation;
- Complementary land-use downstream of the dams (from a dam-safety perspective); and
- Minimal community and environmental concerns.

ANU's STORES project has surveyed candidate locations throughout Australia and internationally, grading them according to a subset of the considerations listed above.

[15] Available at: www.nationalmap.gov.au/renewables > Explore Data > Renewable Energy > Hydro > Storage

[16] Available at: re100.eng.anu.edu.au/research/re/phescost.php

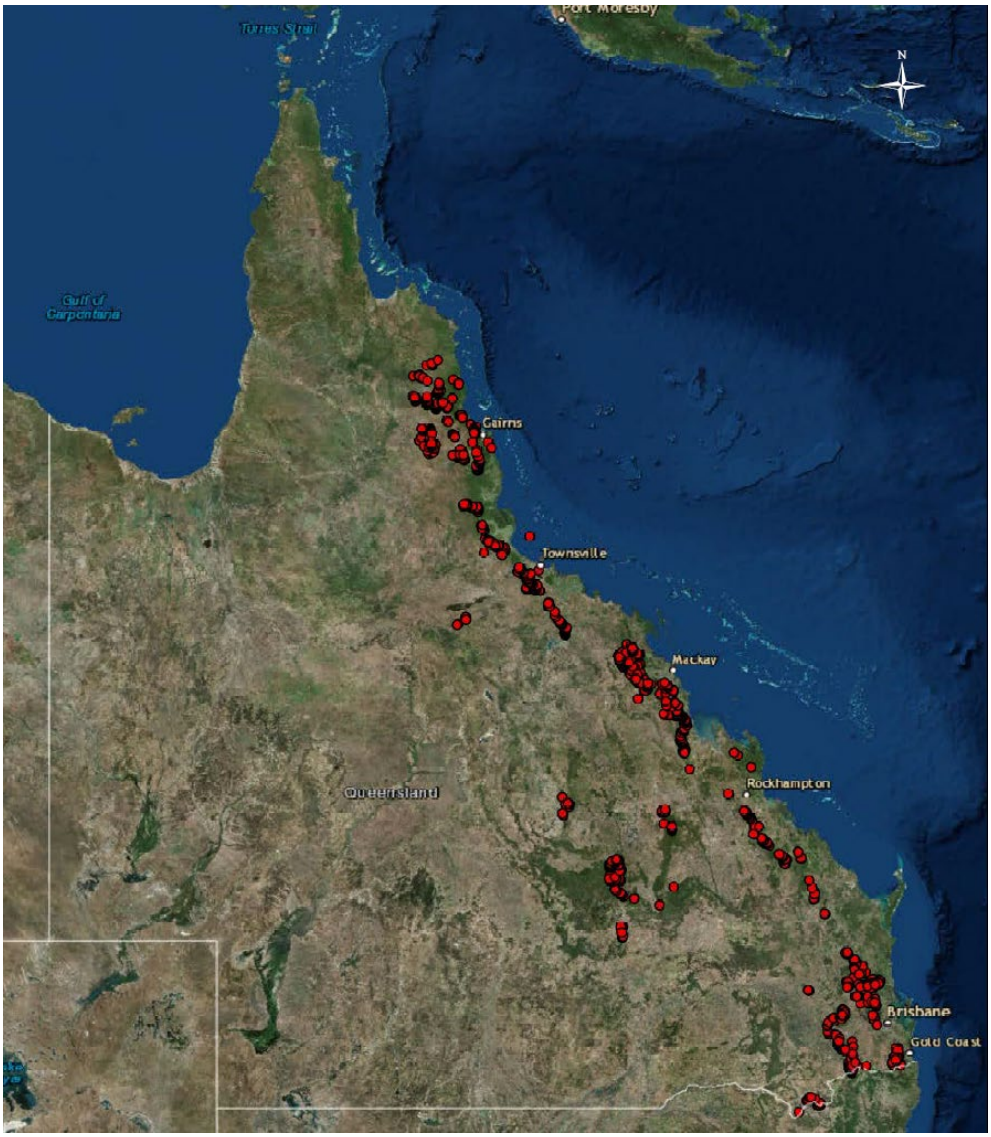

Figure 8 – Potential Pumped Hydro Sites in QLD

Source: ANU, An atlas of pumped hydro energy storage, September 2017

In addition to using naturally occurring landforms, it may also be possible to re-use the pits leftover from open-cut mining operations as long as appropriate regard is given to any potential hazards (e.g. geological structure). There could be synergies in identifying the conversion to pumped hydro energy storage while the mine is still operating and gradually working towards this final configuration e.g. if the overburden could be strategically deposited in a manner which forms both reservoirs.

There is some trade-off from using synchronous pumped hydro (compared to variable speed drives). For example, a synchronous motor is either on or off (i.e. binary), whereas a variable speed drive is continuously variable. The use of synchronous motors limits the ability of the pump to closely 'follow' the output of a variable renewable generator. In a larger scheme with multiple pumps, it may be possible to stagger the operation of the synchronous pumps to provide some degree of load following and/or to have a combination of synchronous pumps and a variable speed drive. These options, including the impact upon system strength, need to be considered on a case-by-case basis.

3.4.2 Practical considerations

Given all of the case-by-case considerations for a pumped hydro development, project development is likely to be more complicated and may require early ground-work from specialist disciplines (e.g. drilling cores to assess geotechnical conditions).

An extended development timeframe may also be required to satisfy regulatory, environmental and community approvals. Estimates for the regulatory approval and design process, for a short duration scheme, take 2 years with construction lasting another 2.5-5 years[17].

To date, pumped hydro has largely been implemented at significant scale – typically necessitating a role for government. Experience with smaller-scale schemes, including those envisaged by ANU's work, is limited in Australia.

As already mentioned, the significant lead-time, complexity and capital requirements mean that synchronous storage is unlikely to be practical for individual project developers. However such an asset could be a very effective foundation for a REZ, supporting a cluster of nearby renewable developments.

3.4.3 Cost

Capital costs are site-dependent but as a guide range between $1,000,000 per MW to $1,400,000 per MW with fixed operating costs at $6000 per MW per annum[18, 19]. Pumped hydro energy storage has a long lifespan and can operate, with upgrades, from between 50 and 100 years with significant upgrades usually needed after 30 years of operation.

Pumped hydro energy storage developments are therefore likely to involve substantial capital cost. It is only likely to be viable in situations where there is a simultaneous requirement for a large amount of energy storage as well as system strength in a favourable geographic location, suitably proximate to transmission networks and VRE generation. Where there is a requirement for deep energy storage, pumped hydro energy storage represents the lowest cost means of providing this, and is significantly less expensive, and more practicable, than batteries for high-energy storage applications. Because of its lower cost, pumped hydro energy storage is the most widely used form of electricity storage, accounting for 97% of worldwide capacity[20]. However, given that pumped hydro energy storage is a mature technology, its future-cost trajectory is mostly flat, compared to batteries which are rapidly declining in cost. It is unclear whether the cost effectiveness of battery will ever become less than a well-sited pumped hydro energy storage installation, although there is a range of other considerations for and against each technology (including asset life, round-trip efficiency, responsiveness, capital cost etc.). An holistic comparison of batteries versus pumped hydro for energy storage is beyond the scope of this report.

Incorporating significant energy storage into a project will boost the revenue that the generator earns from the spot market (assuming that energy will be stored during low-price times and sold during peak

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[17] GHD estimate

[18] GHD, *AEMO costs and technical parameter review*, September 2018. Available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/9110715-REP-A-Cost-and-Technical-Parameter-Review---Rev-4-Final.pdf

[19] GHD in-house cost data drawn from supporting feasibility studies on multiple pumped storage hydroelectric projects over recent years.

[20] ANU, *An atlas of pumped hydro energy storage*, September 2017. Available at: https://energystoragealliance.com.au/site/wp-content/uploads/2017/08/170803-PHES-Atlas.pdf

pricing). The modified generating pattern will also impact upon the MLF applied to the generator, most likely in a favourable way (assuming that the times when the generator outputs align with times of higher local demand – so the electricity doesn't need to travel as far through the grid to reach a load). The energy storage may also allow the generator to earn additional revenue participating in the Frequency Control Ancillary Services (FCAS).

There are ongoing costs in the form of maintenance and energy-losses. The round-trip efficiency is strongly dependent upon the characteristics of the system and how it is operated, but typically in the order of 75 to 80 per cent for a well-sited installation.[21]

3.5 Synchronous condensers

A synchronous condenser is essentially a synchronous generator that doesn't produce any real power and has been specifically optimised for supporting system strength through provision of a high level of reactive power (volt-amps reactive or VAr) almost instantaneously following a system disturbance but for a relatively short (250 ms) duration. A small motor (called a pony motor) is used to spin up the synchronous condenser so that it can synchronise to the grid. This motor then disconnects and the synchronous condenser's electro-magnetic coupling with the grid will cause the rotor of the synchronous condenser to keep spinning (drawing a small amount of power from the grid to offset the mechanical and electrical losses (from the stator excitation current and current flowing in the rotor windings)).

The main advantage is that, whilst other solutions may be possible in a limited set of circumstances, an appropriately specified synchronous condenser is currently the most likely to work across a wider range of circumstances.

However, it is possible to run into stability issues with synchronous condensers (and synchronous generators for that matter), related to fault-ride through and small perturbations without a predefined contingency event occurring (oscillatory/small-signal stability) – which are longstanding issues in the Australian power system. Therefore, specific detailed analysis is still required to ascertain the stability, effectiveness, and scale of the synchronous condenser to address the particular issues with each connection. The potential for a synchronous condenser to become unstable is reduced if its inertia is increased. This can be achieved by installing a flywheel with the synchronous condenser – which adds additional mass, thus enabling the synchronous generator to have greater momentum with which it can resist the impact of any disturbances. This, in turn, enables the synchronous condenser to help maintain power system frequency stability. This dual role of synchronous condensers, simultaneously providing both system strength and inertia, is being leveraged by the synchronous condensers being installed in South Australia (as discussed in section 2.3.2). The complexity in realising this value is one of the key issues identified in the AEMC's system strength frameworks review (discussed in section 5)

For a range of economic and practical reasons, there may be value in a centralised model in which scale-efficient synchronous condenser/s service several nearby renewable projects. The main issues with the use of large, centralised synchronous condensers is the rate at which the system strength diminishes as you move away (electrically) from the location of the synchronous condenser, and the commercial and regulatory complexity that exists with the current regulatory frameworks. We explore these issues in more detail in sections 4 and 5.

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[21] Entura, *Batteries vs. Pumped Hydro – Are they sustainable?* Available at: https://www.entura.com.au/batteries-vs-pumped-storage-hydropower-are-they-sustainable/

3.5.1 Effectiveness

Synchronous condensers are a mature technology and have proved reliable at providing system strength support in a range of circumstances. Synchronous condensers are built to order, and thus can be custom designed to the needs of each particular situation.

The units generally have a long economic life of 30 years (lower if integrated with a flywheel)[22], and with refurbishments may last as long as 70 - 80 years. Synchronous condensers can outlast the renewable generation projects they are designed to support. Thus there may be an option for them to continue to provide system strength (and inertia) post decommissioning of the renewable generation project, or supporting the redevelopment of the renewable generation.

3.5.2 Practical considerations

The overall footprint of a synchronous condenser comprises of the core synchronous condenser device, plus balance of plant to connect it to the grid. The size of this footprint is relatively small (see Figure 9) and the space taken up is unlikely to be an issue in the rural locations where renewable generators are typically built.

Source: GE Budget Letter, 2019

Figure 9 – 225 MVAr synchronous condenser

The noise produced by a synchronous condenser operation is also something which should be considered if using close to an urban setting, but may be able to be managed through design (with sound-walls etc.)

Enclosing the synchronous condenser in a building (as in the image above) may be advantageous to manage environmental issues such as noise, salt/pollution-related corrosion, and heat.

The size and weight of synchronous condenser components may restrict the locations to which they can be transported. The components are manufactured overseas and are typically transported via

[22] GHD Advisory, *Economic life for ElectraNet synchronous condensers,* 28 June 2019. Available at: https://www.aer.gov.au/system/files/GHD%20Advisory%20-%20MGSS%20Contingent%20Project%20-%20Economic%20Life%20Advice%20-%2028%20June%202019.pdf

ship, but after arriving at a major port, the ability for road infrastructure to accommodate the size and weight of synchronous condenser components may restrict locations. Alternatively, additional time and cost could be incurred (e.g. to strengthen bridges), with the cost borne by the proponent.

A synchronous condenser is a specialised piece of hardware, and limited production slots are available. Therefore, there is the potential for substantial lead times (e.g. 12-24 months). Synchronous condensers require very different competencies to the renewable generation projects which need them to be installed. Generation operators will need to think carefully about how to undertake asset management (including monitoring, maintenance, spares holding etc.) over the long term.

Where VRE generators are dependent upon a synchronous condenser to meet the terms of their grid connection, an outage of the synchronous condenser may require the renewable generator to come offline. There is, also, a limit to the amount of generation which can be secured with a single synchronous generator before the sudden loss of this generation would present a threat to the power system. The implications of this are further explored in section 4.2. Although synchronous condensers are a mature technology, they are nevertheless large and complex mechanical devices. Generator proponents should, therefore, consider the potential impact of an unplanned extended outage of the device.

The inclusion of a synchronous condenser as part of a renewable generation project will increase the fault level experienced by the project (especially if the synchronous condenser was connected onto the low voltage side of the grid-connection transformer). It may therefore be prudent to consider the possible implications of a synchronous condenser when specifying the electrical design of the renewable project (e.g. ensuring the switchgear is rated appropriately). The impact of the additional fault level on the nearby transmission and distribution network would also need to be assessed. The cost of any remediation would be borne by the developer of the synchronous condenser.

3.5.3 Cost

Synchronous condensers have significant upfront and ongoing costs.

The preliminary capital costs, including installation costs, of a 70 MVAr unit is of the order of $28.5 million.[23] (equivalent to $400,000/MVAr.). There is potential for significant economies of scale achievable by the use of higher capacity units – an effect which is explored further in section 4.2. To understand how this arises it is constructive to break down the component costs into two categories:

- The core synchronous condenser components are: frame, stator, rotor and pony motor. For a modestly scaled device (e.g. that may be required to support an individual renewable generator), these components account for approximately one-third of the overall cost. The cost increases largely in proportion with the scale of the device, perhaps with some price steps where there is a change in the underlying platform (the point of which can vary between manufacturers).
- Supporting infrastructure: civil works, control systems, cooling, and the grid connection make up the bulk of the remainder of the costs. For a modestly scaled device, these costs make up approximately two-thirds of the overall cost. However, these costs are largely fixed, with only modest incremental costs as the scale of the synchronous condenser is increased.

Costs depend on a number of factors, such as supply capacity of manufacturers versus demand, commodity prices at the time of tender receipt (copper, steel, iron), transport logistics, site

[23] GE, *Budget letter,* 2019

characteristics etc. So whilst there is a substantial fixed cost to overcome to implement a synchronous condenser, the incremental cost of making it larger is relatively low.

The ongoing operating costs can also be broken down into two categories:

- The operating costs constitute a large component of the total life cycle costs due to the electrical power consumption to excite the stator called the "no-load losses". The no-load losses consume more than 12 times the electrical power than the main transformer[24].
- Maintenance of the unit is frequent, occurring every year, but is usually non-disruptive and at a low cost of $300 per MVAr per year[25]. However, taking a system wide approach, multiple proponents owning and operating multiple different types and sizes of synchronous condensers from differing manufactures will inevitably lead to higher spares holding costs and maintenance costs than would be the case for a smaller number of larger sized synchronous condensers.

3.6 Upgrade network connection

The propagation of system strength from synchronous devices (generators, condensers, and loads) depends upon the impedance of the network. Inverter-connected VRE solar PV generators and WTG often employ multiple inverters at relatively low voltage levels (33 kV or below). Therefore, the impedance of the electrical infrastructure (including cables, transformers, switchgear and overhead lines) which interconnect the different inverters to the grid, impacts upon the level of system strength experienced by each inverter. The thoughtful design of the network connection can minimise its impedance so that more system strength is able to propagate through to the inverter's terminals.

Depending on the nature of the issues which are being encountered (noting the low system strength is a pre-condition in which a variety of issues can arise), there can sometimes be merit in the installation of harmonic filters and dynamic reactive compensation to either provide or absorb reactive power (such as a STATCOM or other 'Flexible AC Transmission System' (FACTS) devices).

3.6.1 Effectiveness

This is potentially an effective solution in situations where:

- A higher voltage (and likely higher system strength) connection option is available nearby, or
- Sufficient system strength is available at the point of connection and the use of a low-impedance network connection can maximise the amount of system strength that propagates to the actual inverters (e.g. thoughtful specification of the transformers, and heavier conductor or multi-conductor bundles on any lines which need to be built).

Paradoxically a lower impedance connection can also make the inverter electrically closer to other inverters and in certain circumstances can lead to adverse impacts due to uncontrolled and un-damped interactions between these inverters. Therefore, detailed PSCAD assessment is recommended to verify the effectiveness of this measure.

3.6.2 Practical considerations

Changes to one aspect of the network connection can have a cascading impact on other aspects of the network connection. Therefore, this mitigation strategy is likely to be most effective when it is

[24] GE, *Budget letter,* 2019

[25] Confidential supplier information

identified early in the project design process. However, this does somewhat conflict with the requirement for all of the details of the network connection to be provided upfront to enable the detailed connection assessment to take place.

A pragmatic middle ground may be to minimise the impedance of the connection from the inverters to the transmission network as one of the up-front design objectives (amongst other considerations, including cost), pursuing design choices that involve modest additional costs. To the extent that this is partially effective, it may reduce the scale and cost of any other remedial measures.

3.6.3 Cost

Given that the costs depend on a variety of factors and are project specific, it is not possible to provide generally-applicable advice.

3.7 Reconfigure upstream network

Another option to increase the level of system strength experienced by an inverter is to reduce the impedance of the upstream network. This doesn't necessarily involve significant new network infrastructure (e.g. new transmission lines or transformers), as relatively modest changes to the configuration of the network can sometimes yield significant improvements. A common example of this is explained below. Reconfiguring the upstream network can work effectively in concert with other remediation options.

3.7.1 Effectiveness

The effectiveness of this approach depends on particular circumstances. It is potentially a very effective solution in situations where there is a particularly onerous network contingency that can be mitigated.

A connecting generator must be capable of operating stably when the network is fully-intact, and when any single network element is out of service (i.e. a partially degraded state). It is not uncommon for there to be one or two network contingencies which is particularly onerous.

A common situation in which this can occur is where a generator is proposed to be connected to the network by 'cutting into' a single circuit of a double circuit transmission line. A photo of an actual instance is shown in the photo below.

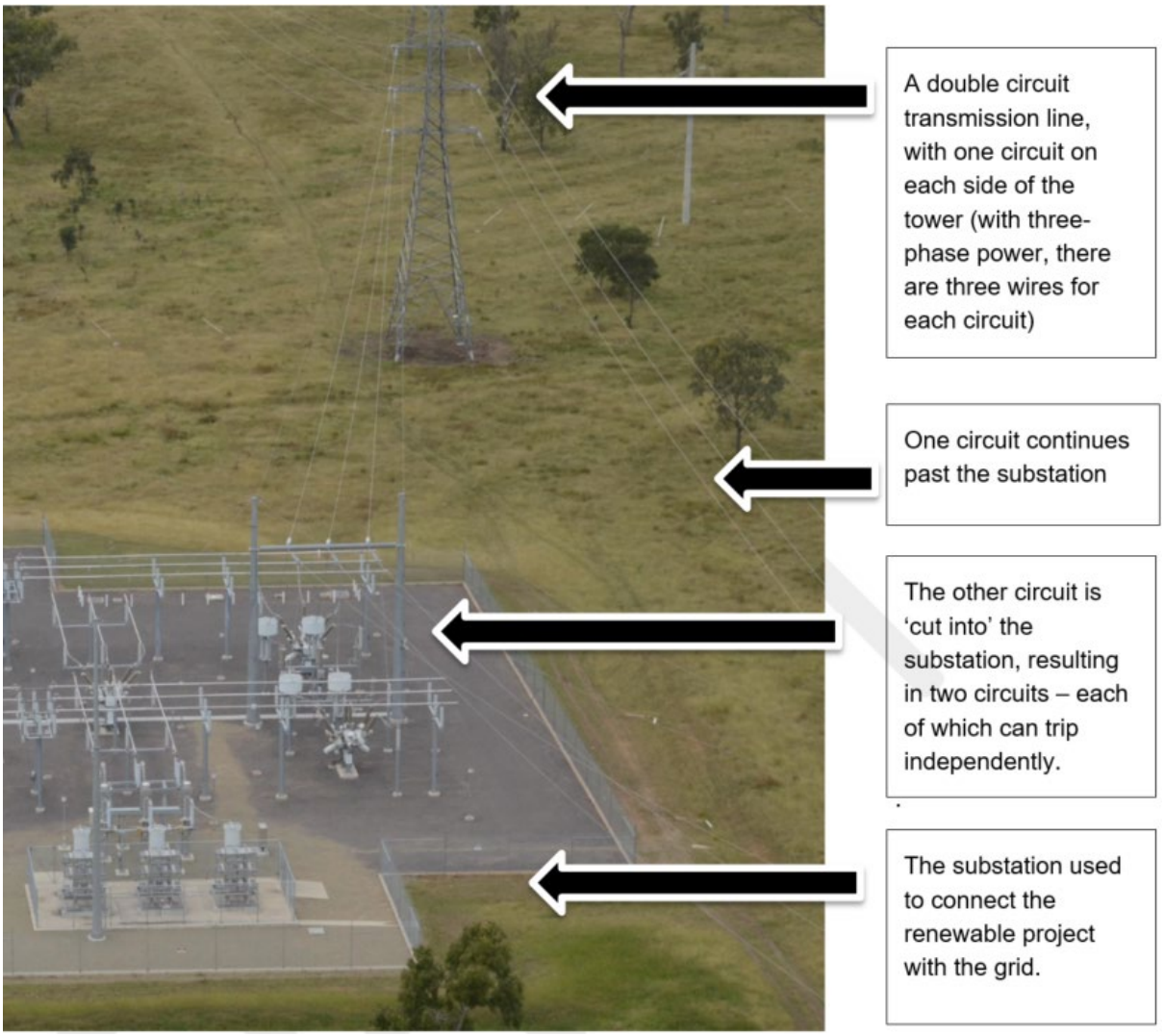


Figure 10 – Example of double circuit transmission line where only one line is connected to a substation

This situation is also shown diagrammatically in the sequence of images below (commencing with Figure 11), in which blue lines denote a simplified network, and the green arrows represent the flow of system strength from the source to the renewable inverter (with the size of the arrow denoting the amount of system strength that flows). It represents a double circuit line connecting two substations, and an intermediate substation used to connect a renewable generator which has been 'cut into' only one of the circuits.

When the network is intact, the short length of the circuit between the system strength source and the renewable inverter provides a low impedance path that allows a lot of system strength to flow. A much lesser amount of system strength also reaches the renewable inverter via the alternative path.

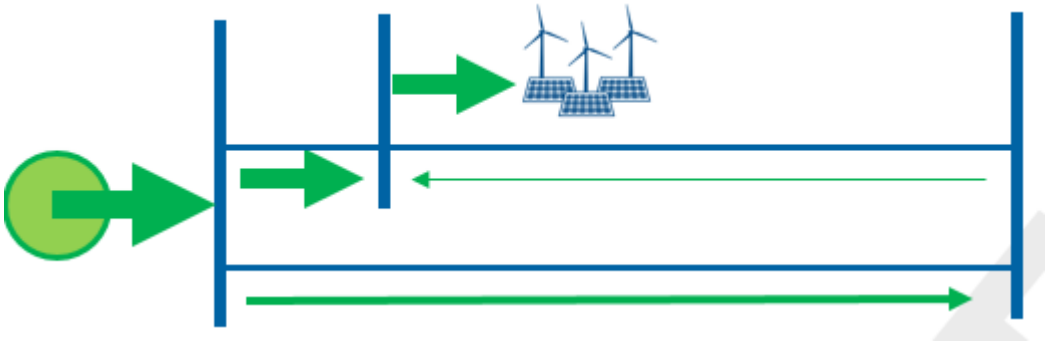


Figure 11 – System intact

However, during the outage of this short link, the only remaining path from system strength to flow is via the remote substation. The length of this route means that the impedance is much higher, and consequently, a relatively small amount of system strength makes it to the inverter. The inverter is still required to operate stably in this condition unless it was mutually agreed that the inverter could be tripped during this system condition using special protection. For the inverter, this would likely be the most-onerous system condition, and thus could necessitate more system strength remediation than would otherwise be required.

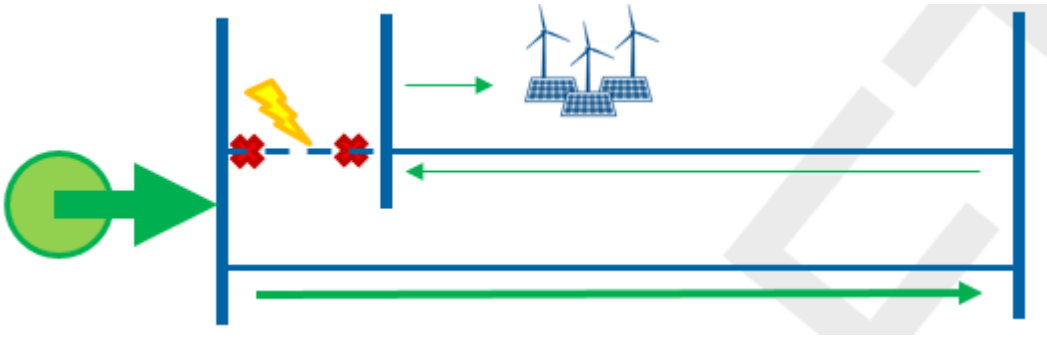


Figure 12 – N-1 contingency

If the other circuit (which presently runs past the substation) was also 'cut into' into the substation, it would effectively side-step the critical contingency, since even with one circuit out of service there remains a short low-impedance connection through to the source of system strength.

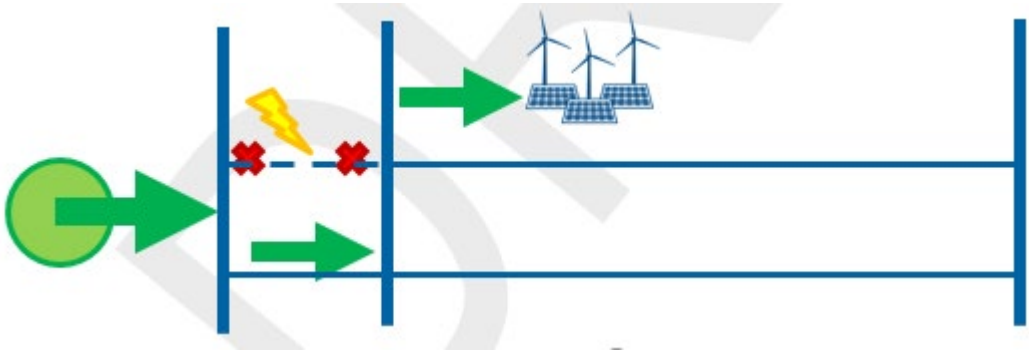


Figure 13 – Network upgrade, N-1

Having the additional circuit cut into the substation would also increase the level of system strength that is available during system intact conditions (i.e. most of the time) by reducing the impedance between the inverters and the source of system strength.

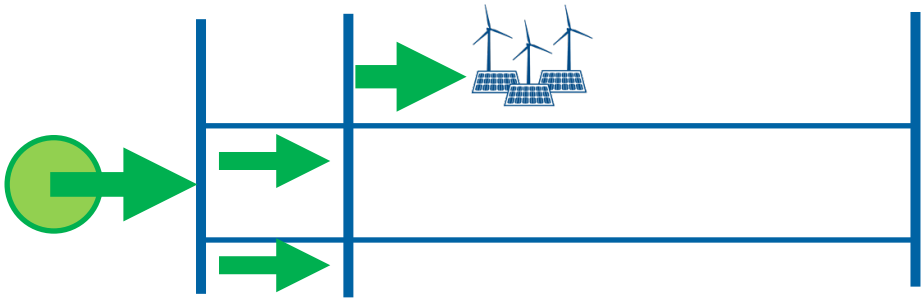


Figure 14 – Network upgrade, system intact

Whilst this situation is a common scenario, this same effect in which a single contingency adds significant impedance between the inverter and the source of system strength, can occur in a variety of different network situations. The effectiveness of network modifications needs to be investigated on a case by case basis.

Another scenario may involve modifying the control system of any active network devices in the area such as static VAR compensators (SVCs) or Statcoms. The effectiveness of this approach will depend on the particular details of the situation.

3.7.2 Practical considerations

This approach can work effectively in tandem with other mitigation responses such as modifying the network to deal with any particularly problematic contingency and thus reducing the amount of other mitigation which might be required. The main alternative to this approach would be to use special protection to detect the particularly problematic circumstances and tripping it – thus removing the requirement for it to operate stably.

There may be circumstances in which a network is not able to implement a particular change, such as if it would adversely impact other customers.

3.7.3 Cost

The cost of implementing changes to the upstream regulated network is borne by the party whom requests it. The level of expenditure is dependent on particular circumstances, and thus it is not possible to provide generic guidance.

3.8 Advanced inverter controls

Inverter manufacturers have been implementing refinements to their generator's control systems to reduce their susceptibility to unfavourable interactions with other inverters.

3.8.1 Effectiveness

The effectiveness of this measure can only be verified through detailed PSCAD analysis. However experience has found that it can provide a material improvement to the stability of inverters in an area of low system strength. A recent example is where upgraded firmware was applied to five solar farm inverter control systems in the West Murray zone. This allowed AEMO to relax generator operating constraints. However, whilst this measure may increase a transmission network area's hosting

capacity for inverter based generation (all other factors being equal), the potential for instability and other system-strength related issues remain.

3.8.2 Practical considerations

Increasingly these enhancements may be already included as part of the supplier's default product offering.

Any changes to the controller design may require the connection assessment process to be re-started, so it may be advantageous to specify the use of any available advanced inverter controls up front.

It is possible that some controller improvements could be retrospectively applied to existing inverters, yielding benefits to the power system although presently, this would require bilateral agreement between developers and there is presently no regime to coordinate or require this. Aside from the time delays, cost and general inconvenience of needing to repeat the connection assessment process (to update system models and ensure there are no unintended consequences), existing generators may be naturally incentivised to resist improvements that would help to facilitate the development of additional generation that might compete for market access, suppress electricity prices and adversely impact marginal loss factors. Therefore, at present, retrospective improvements are most likely to be practical in situations where the renewable energy project owners implementing the change will derive the most benefit from the change. This was the case for the five solar farms in West Murray which had been constrained to half-output for seven months. This particular situation benefited from having a common inverter vendor for all of the affected solar farms, making the changes to the control systems consistent and management of intellectual property relatively easy[26].

Presently there is no requirement on generator developers to implement advanced controls beyond what is required to operate stably themselves and to "do no harm" to other existing inverters (i.e. where such controls could nevertheless be helpful to maximise the power system's hosting capacity for the future). The issue of minimum standards is complicated by the rapid evolution in technology and differences between inverter vendors (in the sophistication of their products and approaches used to implement advanced controls).

3.8.3 Cost

Advanced controls may take the form of a control setting or firmware upgrade. In any case, the cost will determined by the inverter supplier.

3.9 Synchronous generator emulating / Grid-forming inverters

3.9.1 Review summary

Synchronous generator emulating (SGE) (sometimes also called grid forming[27]) inverters are a new type of inverter that aims to replicate the function of a synchronous generator. They involve additional inverter capacity, a source of stored energy (i.e. a battery), and a different control philosophy to

[26] https://aemo.com.au/news/constraints-lifted-for-west-murray-solar-farms last accessed 27 April 2020

[27] The term grid forming inverters is also used for inverters designed for islanded ((i.e. non-interconnected) micro grids that use an internal voltage and frequency reference to set the voltage and frequency of the micro-grid. Hence our preference to use the term Synchronous generator emulating inverter in which the control systems are designed to mimic the synchronous generator controls of excitation and automatic generator control (AGC) and in which the power electronic bridge is designed to be capable of providing, at the time of writing, two times operating current during system disturbance events. The term grid forming in itself does not convey how the inverter will perform in an interconnected transmission grid arrangement.

conventional VRE generator inverters. In contrast to SGE inverters, conventional inverters are described as being “grid following”.

SGE inverters are sometimes called “grid forming inverters”, however, these should not be confused with the grid forming inverters that have predominantly been used in islanded applications i.e. where the inverter uses its own voltage and frequency reference to ‘form and stabilise an isolated (non-interconnected grid) and where the inverter is not required to operate in tandem with a broader power system.

To avoid confusion with such ‘isolated’ grid forming inverters, we recommend the use of the term Synchronous Generator Emulating (SGE) inverters. The effectiveness of SGE inverters providing system strength support has yet to be proven, although various investigations and pilot projects are underway – including an ARENA supported investigation that Powerlink is undertaking, which will be published in a separate and subsequent report.

3.10 Overall conclusions

There are a range of approaches which can assist with the issues that can arise from low system strength, however the applicability and effectiveness of each approach can vary between situations.

Synchronous condensers are most likely to be effective across a wide range of situations and issues. This is the main reason that this solution has become the de facto ‘standard’ solution, and that an increasing proportion of developers are making up front allowance for a synchronous condenser as part of their project.

Nevertheless, in certain circumstances it may be possible and advantageous to use another approach, or more commonly the optimal solution may involve a synchronous condenser in combination with other responses such as reconfiguration of the upstream network, or the use of special protection.

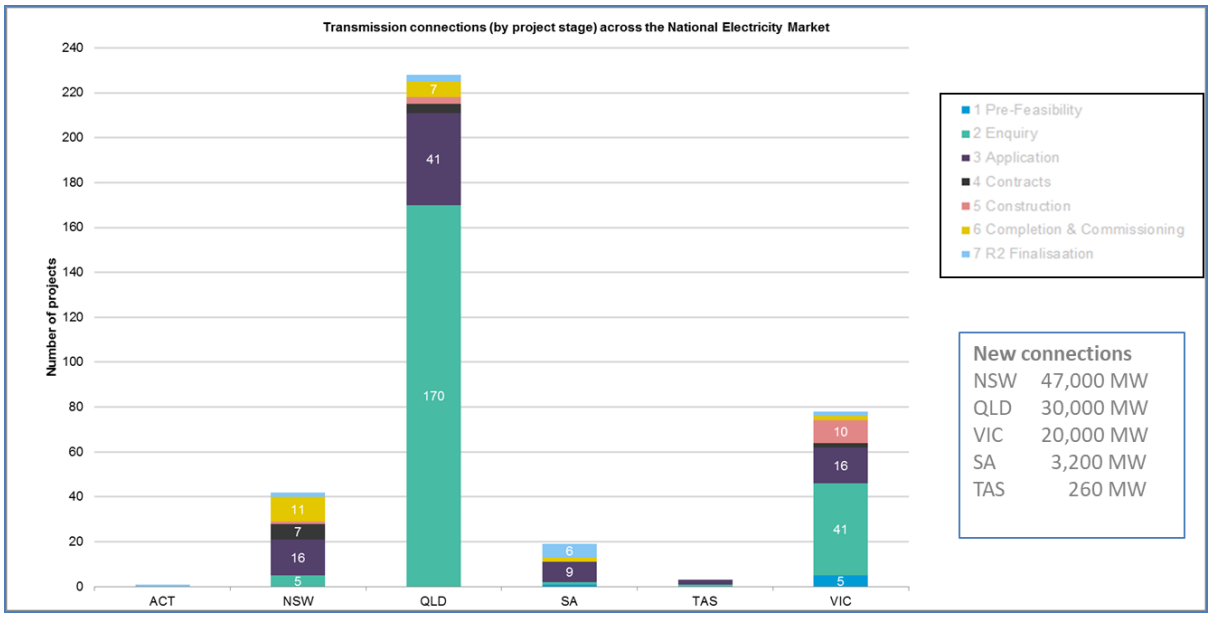
In the rest of this report, we evaluate the merits of a centralised approach to providing system strength with synchronous condensers constructed at key locations on the transmission system compared to a distributed approach using multiple, smaller synchronous condensers located at VRE generation sites.

4. Centralised versus distributed synchronous condensers for system strength

This section assesses the economic merit of installing shared synchronous condensers (with a larger capacity to support multiple generators), as compared with current practice, whereby VRE generator proponents are installing synchronous condensers on a site by site basis to provide system strength support to meet their requirements under the NER and enable them to connect to the power network.

4.1 Background

There has been an upsurge of transmission-connected renewable generation across the NEM (see Figure 15) and, as detailed in Section 2.3. Connecting generators are required to offset adverse system strength impacts by carrying out remediation measures, in compliance with the 'do no harm' provisions set out in the NER.



Source: AEMO

Figure 15 – Transmission connections by project stage across the NEM[28]

If every VRE generator were to install its own synchronous condenser (as part of a remediation arrangement), then synchronous condensers would be both numerous and highly scattered. This is not necessarily the most economically efficient outcome, and may not optimally support the national electricity objectives (NEO) of the provision of a safe, secure and efficient power system. Nor is it necessarily the most ideal arrangement from a network planning perspective. Hence there is value in evaluating the cost-effectiveness of shared models in which a smaller number of larger synchronous condensers are installed at key nodes in the system. The proactive and centralised provision of

[28] AEMO presentation, 'Is bigger really better? The outlook for utility-batteries in Australia, Australian Clean Energy Summit, 1 August 2018.

system strength to support clusters of renewable generation development should also be assessed against agreed longer term planning outcomes, represented by initiatives such as AEMO's Integrated System Plan[29].

However, while a shared approach could help reduce costs (by leveraging economies of scale), synchronous condensers become less effective at providing system strength as electrical distance increases (being a function of transmission line length, impedance and, to a lesser extent, other connecting generators and loads). In this section we also explore the relationship between synchronous condenser sizes, the electrical distance between itself and the VRE generator connection point, and the amount of system strength it is able to provide. In order to undertake this, we have conducted steady state power network modelling of the effectiveness of different configurations of synchronous condensers in different network topologies. We present the results of this analysis in Section 4.3.

4.1.1 Current issues with a decentralised approach to system strength in the NEM

Low system strength is increasing the cost, time and complexity for new generators, particularly VRE generators, to connect to the power system. These costs include power system modelling, preparation, and agreement of system strength remediation arrangements and time delays associated with these tasks, in addition to the costs of installing, operating and maintaining synchronous condensers to support their connection. Whilst a centralised solution would not avoid the need for system modelling (for instance, to assess the dependency of a generator connection upon the centralised solution to inform the cost recovery) it would potentially help to: transfer some of the technical complexity away from the developers, reduce the number of design iterations, reduce the lead time for implementing rectification, and enable individual projects to benefit from economies of scale and/or partial-redundancy.

These costs are material during the development and implementation stages of VRE generator projects and create unnecessary barriers to entry for prospective generators, further limiting competition in energy services. These costs ultimately flow through to consumers, in the form of increased transmission use of system (TUoS) costs and increased wholesale electricity costs.

4.2 Economies of scale

Economies of scale refer to cost reductions and/or advantages that are obtained as scale (e.g. units, size) increases. We conducted a present value life-cycle cost analysis based upon information supplied by synchronous condenser manufacturers. We found there are compelling cost reductions and advantages that are obtained as the size of a synchronous condenser configuration increases.

4.2.1 Synchronous condenser costs

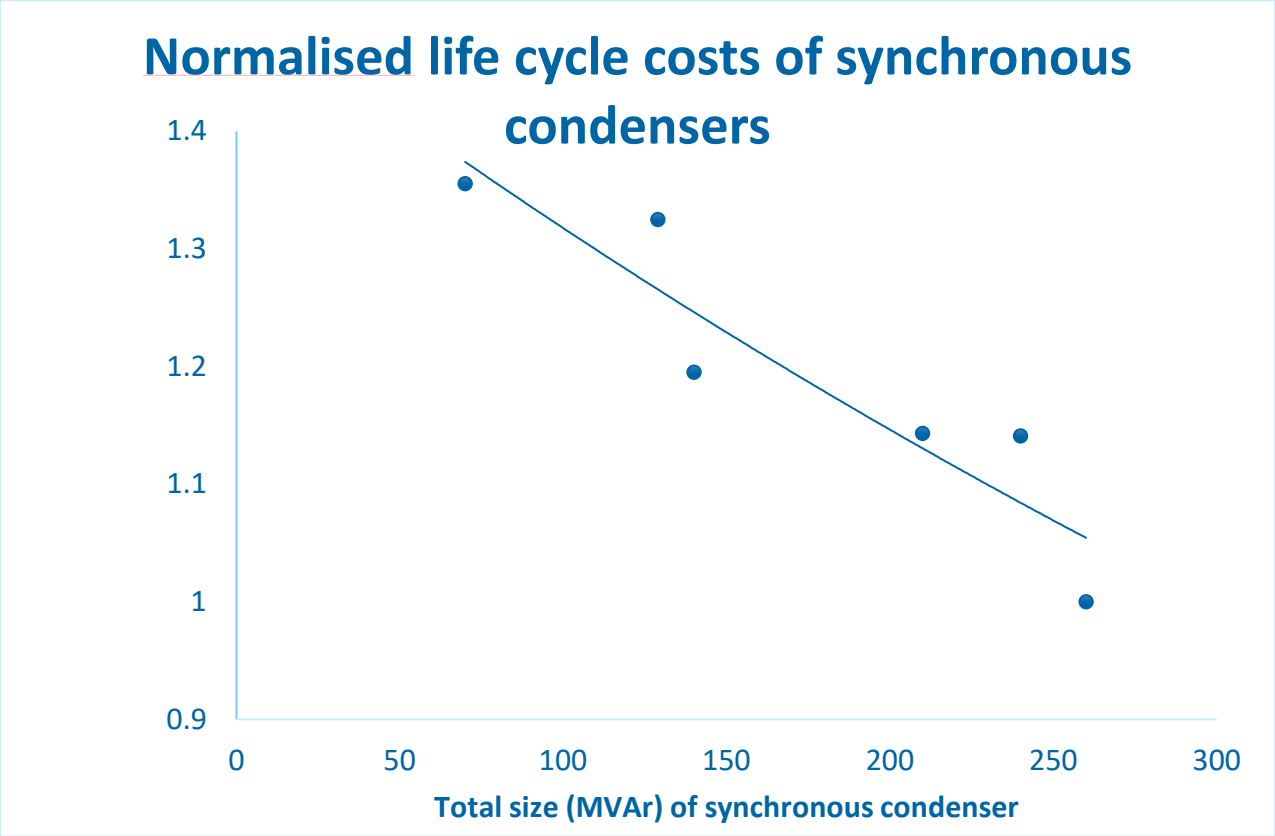
There are a range of benefits that could flow from a centralised approach to integration of synchronous condensers into the power network (reduced project lead time, reduced complexity for VRE generation developers/operators, the possibility of cost-effective redundancy, lower spares and maintenance costs etc.) – but the main benefit relates to scale efficiencies. For a typical project scale device, approximately two-thirds of the overall cost relate to components which are largely fixed costs (civils, control systems, cooling systems and grid connection), and it is predominantly the remaining

[29] https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp (last accessed 24 April 2020)

portion (stator, rotor, and pony motor) that scales with the size of the device. Thus there are potentially significant efficiencies that could be realised by a centralised model.

We used a life cycle cost analysis (LCCA) to determine total costs of a synchronous condenser. The methodology for the LCCA is documented in Appendix C. The results of an LCCA, are also known as a total cost of ownership in that the LCCA determines the economic cost of a synchronous condenser over its entire life. We assessed a variety of different sizes and configurations of synchronous condensers. Our results, shown below in Figure 16, reveal that synchronous condensers exhibit material economies of scale. As the size (MVAr) of a synchronous condenser increase, lifetime costs on a relative cost basis fall.

Our analysis also indicates that as size increases by 10 MVAr, the lifetime costs per MVAr decrease by approximately $7,000 (declining slightly as higher unit sizes are reached). The difference in life cycle cost ratios between the smaller synchronous condenser (1 x 70 MVAr) and larger synchronous condenser (1 x 260 MVAr) analysed is 0.35. This is equivalent to a 35% increase in life cycle costs, per MVAr, if a 70 MVAr synchronous condenser compared to a 260 MVAr synchronous condenser.



GHD developed, 2020. Note that this is drawn on commercially sensitive information provided by synchronous condenser manufactures to GHD for this work and from other project data to which we have access. It is not intended to portray the potential range of sizes available. Also, the intent of the plot is to show relative changes in cost with size rather than absolute costs available through firm tender responses.

Figure 16 – Life cycle costs of synchronous condenser

This does not necessarily mean the best solution is to build the largest synchronous condenser possible. As a synchronous condenser is a manufactured item there are eventually diminishing marginal economies of scale. Furthermore, transport restrictions such as bridge weight limits may restrict the physical size of a synchronous condenser. There may also be a restriction on the amount

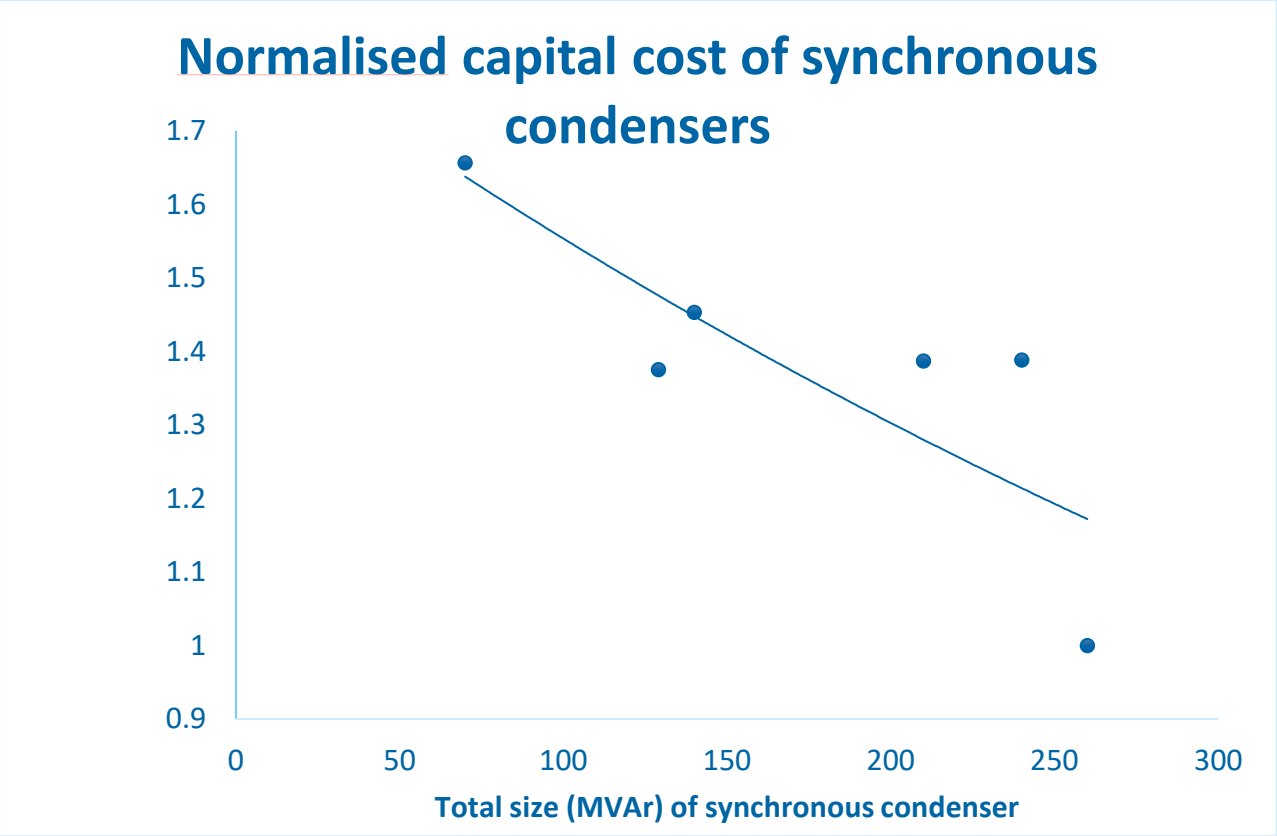
of generation which can be enabled by a single synchronous condenser (based on the power system's ability to withstand all of this generation being tripped if the synchronous condenser were to trip) which may effectively limit the size of a synchronous generator. In these instances, multiple smaller units may be used to form one larger configuration.

From our analysis of information received from suppliers and from our in-house evaluation of connection costs for differing sizes and connection voltages, we have determined that there are two major factors that determine the life-cycle costs of synchronous condensers:

- Capital costs
- No-load losses

4.2.2 Capital costs

Capital costs include all the equipment, engineering and installation services, testing and commissioning. As shown in Figure 17, capital costs demonstrate economies of scale and decline on a relative cost basis. The economies of scale are equivalent to a 0.023 decrease in $/MVAr, in relative capital costs, as size increases by 10 MVAr.



Source: *GHD developed, 2020. Note that this is drawn on commercially sensitive information provided by synchronous condenser manufactures to GHD for this work and from other project data to which we have access. It is not intended to portray the potential range of sizes available. Also, the intent of the plot is to show relative changes in cost with size rather than absolute costs available through firm tender responses*

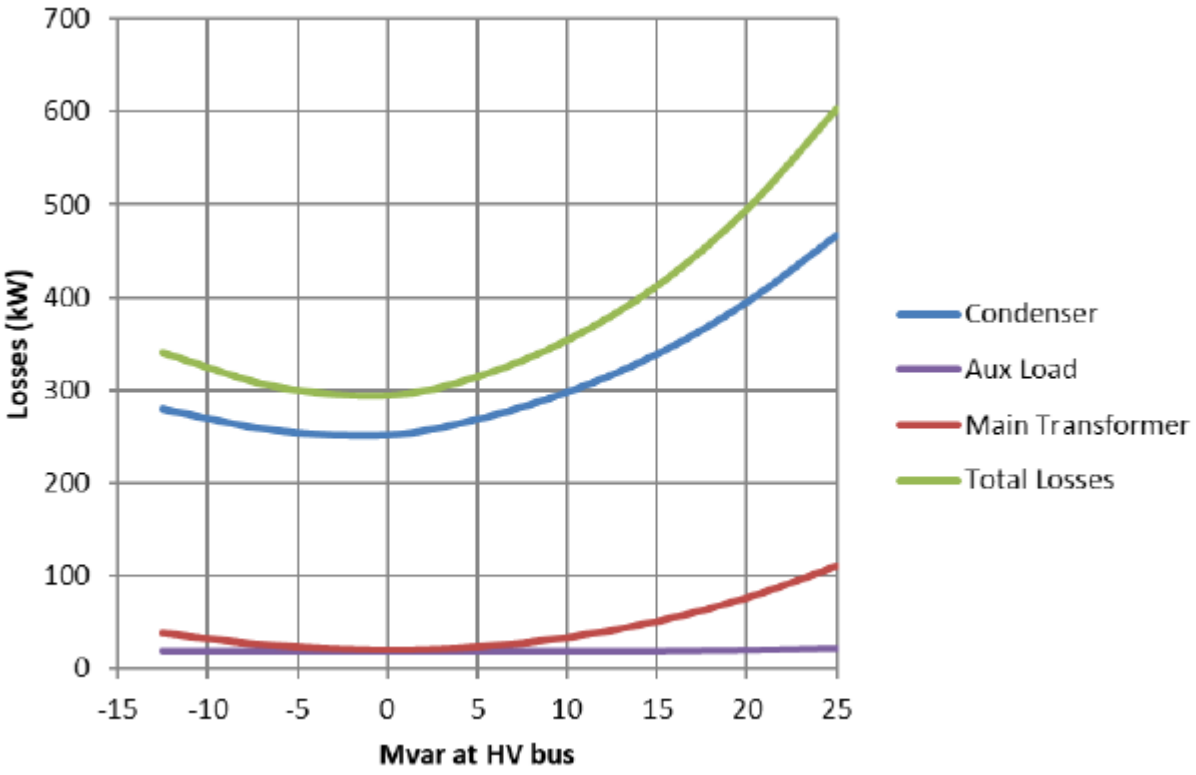
Figure 17 – Capital costs of different synchronous condenser

Capital costs represent the largest cost of the analysis and account for between 60% - 73% of the total lifetime costs. Furthermore, it is an upfront cost that must be incurred before any cash flows are realised from the VRE generation project.

It may be possible to smooth the capital costs for staged developments by employing a configuration of multiple synchronous condensers. This will allow lower initial upfront costs and economies of scale will still be realised if a contract, for set deliveries of synchronous condensers of the same size from the same manufacturer is created. The contra to this option is the need for a high degree of certainty on future system strength needs as the VRE generation project expands.

4.2.3 No-load losses

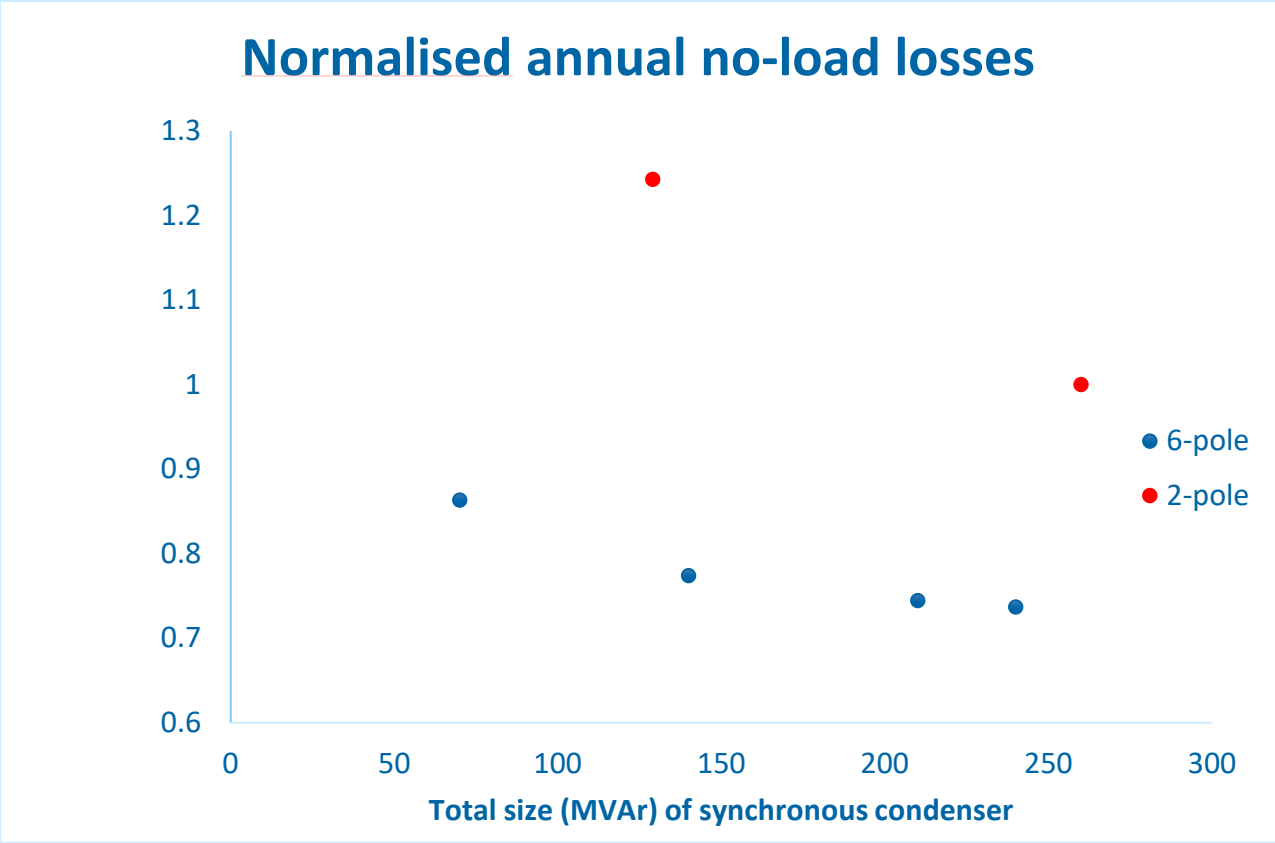
The no-load losses refer to the electricity required to power a synchronous condenser, overcoming the friction which would otherwise slow it down, and keep it spinning in synchronism with the grid. The no-load losses form the majority of the annual operating costs in the form of electricity costs. Figure 18 shows the total losses of a synchronous condenser as a function of the reactive power output of the machine. Across all output states the no-load losses (condenser losses) constitute the bulk, contributing more than 12 times the losses compared to the main transformer.



Source: GE budget letter, 2019

Figure 18 – Total losses in a 60 MVAr synchronous condenser

Figure 19 indicates no uniform trend towards energy efficiency as configurations increase in size. This is because efficiency is largely a function of the design of the machines as to their number of poles and, to a lesser extent, the quality of the components (e.g. bearings, stator and rotor winding conductor) used.



Source GHD, 2020. Note the key take out from this figure is the relative cost of annual no-load losses between different synchronous condenser sizes, not the absolute amounts as these will depend on a number of factors, and not least electricity costs.

Figure 19 – Annual no-load loss of condensers

The configurations with the highest losses are 2-pole designs and the configurations with the smaller losses are 6-pole designs. A pole (N-S) alternator is used to rotate the synchronous condenser. The greater the number of poles, the slower the synchronous condenser spins to remain in synchronism with the grid, leading to a reduction in friction and hence losses. Once this is accounted for both the 2-pole and 6-pole designs show reduced no-load losses per MVAr as the scale of the machine is increased.

Whilst a 6-pole machine is preferred from a loss perspective, proponents may opt for a 2-pole design due to the provision of greater fault current and availability in larger sizes.

4.2.4 Maintenance and operational implications

Planned maintenance costs comprise a very small proportion of total life-cycle costs, approximately 1%. The most important factor to consider in regards to maintenance and operation costs are unplanned outages. As without system strength remediation to ensure that the generator 'does no harm', AEMO will not allow generators to operate.

Table 1 shows the distinct maintenance requirements of a synchronous condenser.

Table 1 - Different maintenance levels for a synchronous condenser

Maintenance level	Frequency (whichever occurs first)	Total hours offline
L1	10,000 hours of operation or annually	8
L2	20,000 hours of operation or 3 years	32
L3	40,000 hours of operation or 6 years	104
L4	80,000 hours of operation or 12 years	224

Source: Confidential supplier information

Planned maintenance is conducted yearly with low-level maintenance (L1) being conducted overnight with minimum disturbance to solar PV based VRE generation output. L1 maintenance includes the replacement of:

- Bearing shells or liners
- Shaft seals
- Airlock filter
- Control pulse unit
- Thyristors
- Diodes

L2 maintenance includes all maintenance conducted during an L1 service and also includes:

- Diagnostic insulation test of the stator winding
- Silicon tape replacement

An L3 maintenance is a more major service, requiring greater hours offline, approximately 5 days, but is only required every 6 or 12 years. L3 maintenance includes all maintenance conducted during an L2 service and also includes:

- Water cooler replacement
- Bearing replacement
- Rectifier replacement
- Rectifier test equipment with potential rectifier kit replacement
- Impedance measurement of rotor coils

L4 maintenance is the most extensive servicing program required for a synchronous condenser with an expected downtime of approximately 10 days. L4 maintenance includes all maintenance conducted during an L3 service and also includes:

- Rotor removal and rotor kit replacement

Higher levels of maintenance (L3 and L4) requires more hours offline but this is only required once or twice a decade. This maintenance can also be scheduled during periods of expected low output and/or during scheduled maintenance of the VRE generator plant to further reduce losses.

Unplanned maintenance and outages pose the greatest potential risk to VRE generators as without meeting the 'do no harm' obligation they will either be runback or disconnected by AEMO. There are a wide range of possible failures which could result in an unexpected outage. The simplest taking a matter of days as parts are either existing spares or readily sourced. The longest, however, can take several months as bespoke parts will need to be made overseas and transported to the site.

If a single centralised synchronous condenser was supporting multiple renewable projects, then the outage of that synchronous condenser could impact the operation of multiple generators. The outage of that synchronous condenser could hence become a significant 'common mode failure', and the maximum scale of the synchronous condenser could be limited by the power system's ability to contend with a reduction in generation.

A centralised solution could help generators de-risk this liability by having a portfolio of multiple synchronous condensers. Such an approach might enable a renewable generator to continue operation, albeit at some reduced level of output, during the outage of a synchronous condenser. Such centralised solutions could involve having one central site hosting multiple condensers or having dispersed installations that are electrically close-enough to provide partial redundancy. A decision about whether to pursue such redundancy would need to be informed by whether renewable project developers would value and pay for this, or whether they could better manage their risk through other mechanisms. It would also need to be informed by the overall needs of the power system, and the impact of an aggregate reduction in generation availability. A centralised solution may also reduce the time taken to fix short outages due to better management of spare parts.

A centralised solution can also reduce project lead times and complexity for developers and operators. A synchronous condenser's total lead time and development lasts, on average, 18 months and this figure excludes the time required to complete a connection assessment process. By gaining access to an existing, centralised synchronous condenser not only will lead times be significantly reduced but so will the complexity of operation and system control the synchronous condensers.

4.3 Distance penalty

A synchronous condenser is most effective in improving system strength at the point at which in connects onto the network. At this location, there will be a step-increase in the level of system strength whenever the synchronous condenser is online. However, the level of additional system strength diminishes as you move away from the synchronous condenser due to two effects.

- ***System impedance***: Impedance is a characteristic of the network that resists the flow of system strength. The lower the impedance is, the further system strength will spread from the synchronous condenser. Generally speaking, the bigger (higher voltage) the transmission line, the lower its impedance will be. Additionally the shorter the route length is, the lower the impedance will be. So taken together the bigger the network and more direct the route is, the lower the impedance will be. It is somewhat akin to measuring the distance between two locations in terms of travel time. Two locations may be physically quite remote, but if they are directly connected by a highway the travel time may be relatively short. Conversely, two locations may be physically close, but if the only connection is by a slow and winding track, the travel time could be significant.

- ***Network contingencies***: The NER require that the power system is always operated in a secure state, which means that it must always be able to withstand the loss of the most significant single element in the network (known as N-1). Accordingly, generators must be capable of operating stably for all possible N-1 events (unless it has been mutually agreed that the generator can disconnect during some conditions, and systems have been implemented to realise this). With an element tripped, the impedance between two locations is likely to increase. Therefore, system strength will generally flow less well during an "N-1" system state, compared to the "system intact" state. How much lower the system strength is during N-1 depends on the connectivity of the network. If there are a number of major connections between two locations, the loss of one of the connections may be relatively modest. If however there is only a single major connection, and the alternative route is a minor and/or long-distance route, then the reduction in system strength may be significant.

How these issues play out very much depend on the configuration of the network. To illustrate these effects, North Queensland has been used as a worked example, which we will then examine to extrapolate general principles which may also be applied to other contexts.

4.3.1 Method to visualise system strength flow and yield general principles

We have used a fault level study to illustrate how system strength flows throughout the network. This method of analysis may significantly understate the effectiveness of synchronous condensers in dealing with situations in which multiple inverters are interacting with each other. This is the dominant form of instability within North Queensland and several other parts of the NEM. This is because the improvement in system strength may not have to cover all of the impacted inverters to be effective – it may be sufficient to settle the response of a subset of the inverters. Thus the region of "effectiveness" may extend beyond the region of system strength increase. This effect is further described in section 4.3.3.

Nevertheless, this form of analysis helps to visualise effects that can otherwise be difficult to understand, and yields principles which are generally true. Additionally, this analysis is directly applicable to other issues which can result from low system strength, including fault-ride-through. As with all aspects of this report, detailed analysis is required to yield definitive conclusions about a specific situation.

The modelling approach used is based on:

1 Simulating the impact of connecting a synchronous condenser at various locations throughout North Queensland using Siemens power network modelling tool PSS SINCAL®.

2 Observing the increase in fault level at the point at which synchronous condenser is connected, and at locations all around this. Results are expressed on a normalised basis, to show how quickly the additional fault level falls away.

3 Studying the increase in fault level both on a system intact basis (i.e. with all of the network in service), and also on an 'N-1' basis [30] (i.e. with a single network element out of service). For the N-1 results, the results shown are based on the most-onerous network contingency for each result. Both the intact and 'N-1' conditions are relevant to the connection of a new generator. Intact conditions are representative of the conditions a generator will normally experience, but

[30] All types of contingencies specified in NER S5.2.5.5, including 'circuit breaker fail'.

the NER require that they must be capable of operating stably in any credible single contingency. In practice, 'N-1' will almost always be more onerous than system intact.

This approach of modelling single synchronous condensers is not intended to preclude consideration of multiple synchronous condensers. The rationale for studying single synchronous condensers is two-fold:

- Visualising how system strength propagates across the network is clearest when there is only a single source of additional system strength at a given time.
- The effect of multiple synchronous condensers can readily be visualised by stacking the effect of two or more individual synchronous condensers. Therefore, by understanding the system strength contributed by a synchronous condenser at each location, a building-block approach can then be used to combine multiple synchronous condensers to provide the desired overall pattern of coverage (noting the previous caveats about the limitations of this method of analysis).

Nevertheless, a couple of examples with multiple synchronous condensers have been produced to illustrate how this could look. The results have been represented graphically in a heat map, with colours representing the normalised increase in system strength, with 100% reflecting the impact at the connection point for the synchronous condenser:

Table 2 - Improvement colour band

High	$\Delta X > 20$ %
Significant	$15\% < \Delta X < 20$ %
Moderate	$10\% < \Delta X < 15$ %
Low	$5\% < \Delta X < 10$ %
Negligible	$\Delta X < 5$ %

A number of examples of the heat map are provided below:

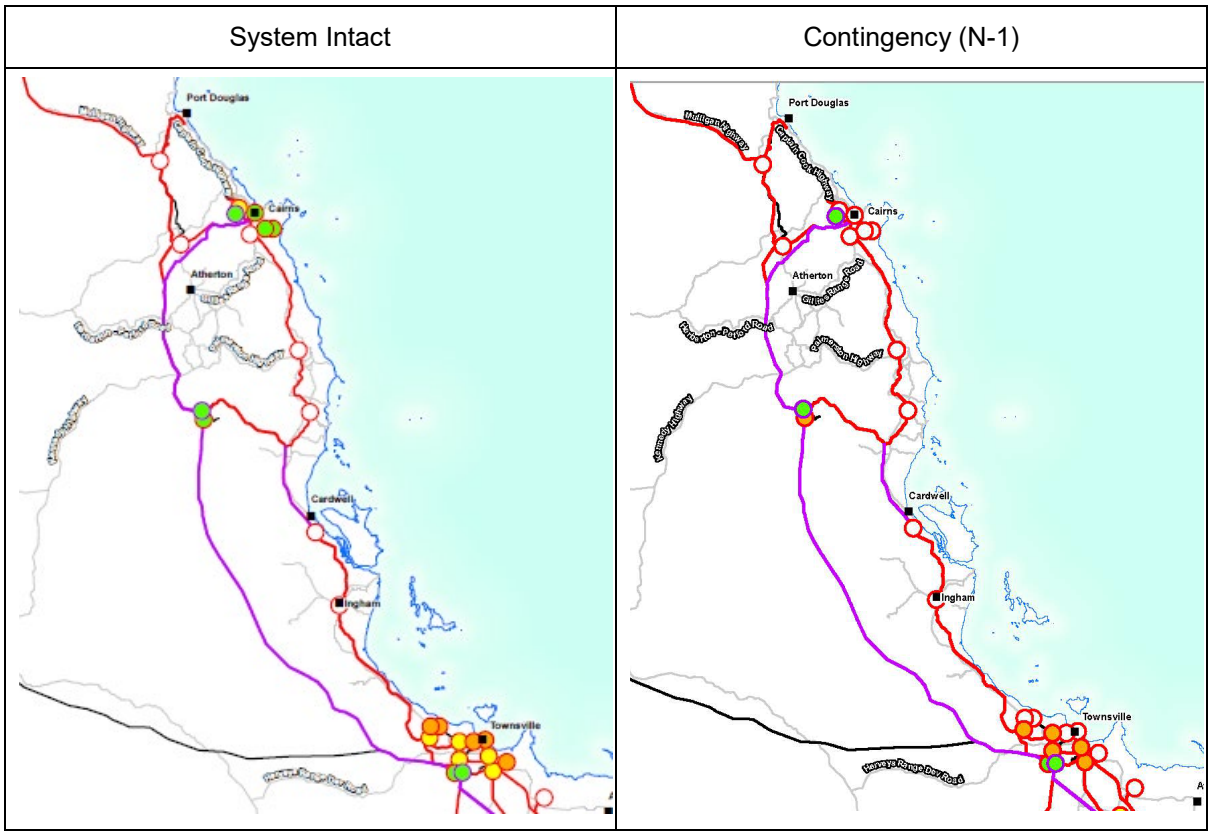


Figure 20 – Example results of modelling effect of N-1 contingency on system strength provision

Table 3 - Study legend

Study ID	Description
Study A	Low system impedance, Good N-1 - System normal, 1 unit
Study A'	Low system impedance, Good N-1 - Contingency, 1 unit
Study B1	Low system impedance, Poor N-1 - System normal, 1 unit
Study B1'	Low system impedance, Poor N-1 - Contingency, 1 unit
Study B2	Low system impedance, Poor N-1 - System normal, 2 x 0.5 units
Study B2'	Low system impedance, Poor N-1 - Contingency, 2 x 0.5 units
Study B3	Low system impedance, Poor N-1 - System normal, 4 x 0.25 units
Study B3'	Low system impedance, Poor N-1 - Contingency, 4 x 0.25 units
Study C1	High system impedance - System normal, 1 units
Study C1'	High system impedance - Contingency, 1 units
Study C2	High system impedance - System normal, 8 x 0.125 units
Study C2'	High system impedance - Contingency, 8 x 0.125 units

The full set of results are included in Appendix D. In the following discussion, we focus in on specific details to extract principles that can apply across contexts, and to identify the locations in which a shared model is most-likely and least-likely to be cost-effective.

4.3.2 Investigation outcomes

The following general observations can be made from the results obtained by the analysis described above.

4.3.2.1 Impact of different voltage levels

The impact of network voltage level can be observed by contrasting the reduction in system strength across two long predominantly-radial transmission lines:

- The Ross to Chalumbin 275 kV double circuit transmission line, with a synchronous condenser at the Ross 275 kV bus
- The Chalumbin to Turkinje 132 kV double circuit transmission line with a synchronous condenser at the Chalumbin 132 kV bus

As can be seen in the table below, the reduction in system strength, per unit of length, is over 2.5 times greater in the 132 kV line compared to the 275 kV line. This ratio holds true for both system intact, and the situation where one of the circuits (of the double circuit line) is out of service. One of the main drivers for this effect is the use of higher capacity conductors on higher voltage lines, which provide a lower impedance connection.

Table 4 - Comparison of system strength propagation through 275 kV and 132 kV circuits

	275 kV	**132 kV**
Synchronous condenser location	Ross 275 kV	Chalumbin 132 kV
Remote location	Chalumbin 275 kV	Turkinje 132 kV
Line construction & conductor	Double circuit	Double circuit
Conductor	Twin sulphur	Single oxygen
Distance	244 km	100 km
System intact: Incremental system strength at remote end	15%	11%
System intact: Reduction in system strength per unit of line length (%/km)	**0.35%/km**	**0.89%/km**
N-1: Incremental system strength at remote end	7%	4%
N-1: Reduction in system strength per unit of line length (%/km)	**0.38%/km**	**0.96%/km**

➔ **Implication 1:** The lower impedance of the 275 kV network means that system strength propagates much better and further, compared to the 132 kV network and lower voltage levels

4.3.2.2 Impact of centralised transmission backbone vs. diffuse sub-transmission network

With transmission, it is not uncommon for there to be a core transmission backbone comprising multiple circuits in parallel. In Queensland's context, this is a core 275 kV network running vertically down the state which gets progressively more circuits in parallel as you move from north to south. Additionally, at regular intervals there are substations which tie all of the network together. A consequence of this configuration is that the decrease in system strength that occurs when a single network element is out of service is relatively contained.

This contrasts with the 132 kV 'sub-transmission' network, which is more like a spider-web in configuration, and has a much greater number of substations which are cut-into a single circuit. This configuration makes them susceptible to single credible contingencies which significantly decrease the propagation of system strength.

This difference is readily apparent in the system diagram below showing the network around Strathmore substation, with the 275 kV backbone shown in purple, and the 132 kV network in red. The transmission backbone is a highly interconnected grid, while the 132 kV network is full of single-circuit connections.

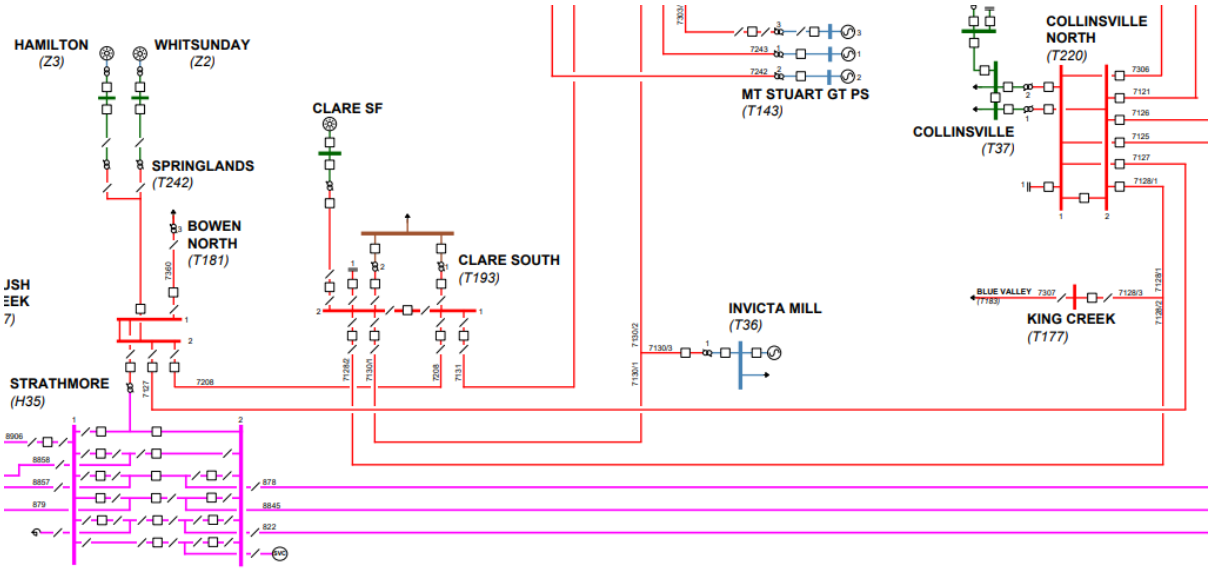


Figure 21 – 275 kV and 132 kV network around Strathmore

The effect of this configuration is shown in the table below which shows how well system strength propagates from Strathmore to all of its immediate neighbours.

Table 5 - Propagation of system strength away from Strathmore

Voltage level	275 kV		132 kV		
Synchronous condenser location	Strathmore 275 kV		Strathmore 132 kV		
Remote End	Nebo 275 kV	Ross 275 kV	Bowen North 132 kV	Collinsville North 132 kV	Clare South 132 kV
Distance	162 km	168 km	70 km	6 km	36 km
System intact: Incremental system strength at remote end	54%	39%	19%	60%	11%
System intact: Reduction in system strength per unit of line length (%/km)	0.28% /km	0.36% /km	1.16% /km	6.67% /km	2.47% /km
N-1: Incremental system strength at remote end	41%	21%	5%	2%	6%
Ratio of incremental system strength for N-1 compared to system Intact	76%	54%	26%	3%	55%

It is interesting to note:

1 How poorly system strength flows through the 132 kV network compared to the 275 kV network, even during system intact conditions. The reason the 132 kV results are different to (and worse than) the previous example is because the type of conductor used on the transmission lines, and the way in which they are interconnected.

2 On the 132 kV network, the sharp reduction in system strength between system intact and N-1 cases. This is most acute at Collinsville North where the level of system strength falls from 60% for system intact to only 2% for N-1. This is because the Collinsville North – Strathmore 132 kV circuit provided a relatively low impedance path to the synchronous condenser when it was online, but with it out of service the only alternative path to the synchronous condenser is via Clare South, which is a much longer and higher-impedance route. This same effect applies to the other locations, albeit not as severely.

3 On the 275 kV network, the propagation of system strength is still reduced during N-1 conditions, but the impact is much more modest. In all cases, a meaningful level of system strength is still able to propagate.

4 Whilst the N-1 results shown relate to the most-onerous single contingency, each result is nevertheless associated with a number of contingencies which will result in some reduction in system strength. The number and diversity of significant contingency events on the 132 kV network is much greater than on the 275 kV network. This has a detrimental impact on the practicality of using special protection (as described in section 3.2), to manage the impact of outages on the 132 kV network:

– The cost of implementing a special protection scheme is related to the number of conditions needing to be monitored. The deeper a connection is within the 132 kV, the number of problematic system conditions increases, driving increased scheme cost and complexity to the point that this would not be accepted by the TNSP and AEMO as viable.

– Special protection schemes involve agreeing to trip the inverter during known problematic conditions. The act of tripping the inverter will obviously impact on renewable generator's ability to earn revenue. If the number of problematic conditions is very low, this may be an economic trade-off. However, as the number of conditions increases, so too does the amount of time that the generator can expect to be offline.

5 In contrast, the straightforward configuration of the 275 kV network limits the number of conditions needing to be monitored. A special protection scheme is more likely to be practical and economic, compared to the 132 kV network, although the viability will always depend on the particular circumstances and will need to be investigated on a case-by-case basis.

➔ **Implication 2:** The configuration of the main 275 kV transmission backbone makes the propagation of system strength far less sensitive to network outages, compared to the 132 kV network.

➔ **Implication 3:** The configuration of the main 275 kV transmission backbone is more conducive to the use of special protection to manage the impact of contingency events, compared to the 132 kV network. However, the viability of special protection depends on particular circumstances, and each instance needs to be investigated.

4.3.2.3 275/132 kV transformation

Transformers are used to convert (or 'transform') electricity from one voltage level to another. They have a significant impedance which can restrict the propagation of system strength, and are another network element which can trip and create problematic conditions with very low system strength. The flow of system strength at three locations in North Queensland is shown in the table below.

Table 6 - Propagation of system strength through 275/132 kV transformers

Synchronous condenser location	Nebo 275 kV	Ross 275 kV	Strathmore 275 kV
Remote End	Nebo 132 kV	Ross 132 kV	Strathmore 132 kV
Number of 275/132 kV transformers at this location	3	3	1
System intact: Incremental system strength at remote end	36%	39%	19%
N-1: Incremental system strength at remote end	24%	27%	1%
Ratio of incremental system strength for N-1 compared to system Intact	67%	69%	5%

The results vary between locations due to the different specification of transformers. Nevertheless, it is the case that a significant reduction in system strength is incurred when moving between voltage levels. The reduction in system strength is equivalent to ~150 km of 275 kV transmission line.

Additionally, in situations like Strathmore where there is only a single transformer, the outage of this transformer is a particularly onerous contingency. When the transformer is in service the local 132 kV network is directly connected to the 275 kV. However, with the transformer offline, the 132 kV network is entirely disconnected from the 275 kV, with the next-closest 275 kV connection points approximately 200 km to the north and to the south.

- ➔ **Implication 4:** Because transformers significantly impede the propagation of system strength, it may be advantageous for generators to be directly connected to the high-voltage backbone.
- ➔ **Implication 5**: Be particularly alert to network configurations in which a single network element (in this case it's a transformer, but in other cases could be a single-circuit transmission line) connects the local network to the dominant source of system strength.

4.3.3 Potential over-reach in effectiveness with inverter interactions

The prior discussion in this section relates to the extent to which the additional system strength created by the synchronous condenser diminishes with distance. However, this is not necessarily the same as the distance for which the synchronous condenser will be effective. In certain cases, the effectiveness of the synchronous condenser may extend well beyond this range.

Controller interactions involve two (or more) inverters interacting with each other. In some cases, it may be possible to stop this interaction with only one of the participating inverters covered by an increase in system strength. Thus the range over which the synchronous condenser enhances stability can extend beyond the range over which it increases system strength. This effect is illustrated in Figure 22 below, in which a single synchronous condenser improves the stability of three inverters – two of which are outside the area which receives a significant increase in system strength.

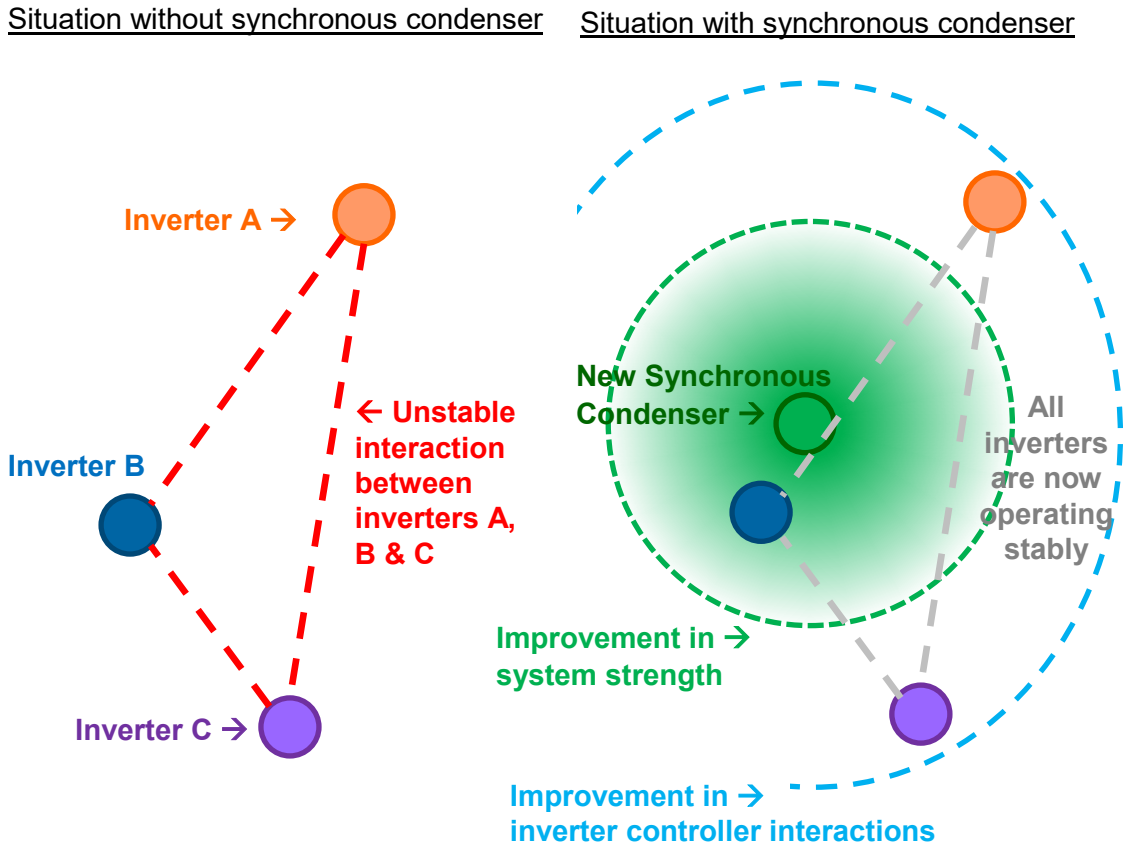


Figure 22 - Illustration of how the effectiveness of a synchronous condenser can extend beyond the area where system strength is increased

The materiality of this effect depends on the details of each situation and can only be assessed using detailed PSCAD analysis. Powerlink is in the process of conducting such analysis for North Queensland to quantify this effect, which will be the subject of another separate report.

The effectiveness of a synchronous condenser will still diminish with distance, and the general principles established in the prior analysis still apply as a 'general rule of thumb'. However, readers should be aware that fault level based analysis of system strength does not reveal the full picture of what is taking place, nor the potential effectiveness of a synchronous condenser.

4.3.4 Worked example

We undertook a worked example into the potential for a shared synchronous condenser to provide a common solution to a couple of renewable projects in North Queensland:

- Sun Metals' solar farm, which is connected to the 132 kV network on the eastern outskirts of Townsville.
- Pacific Hydro's Haughton solar farm, which is connected into the 275 kV network about 50 km south of Townsville.

Given that both projects exist in relatively close proximity to each other, it is reasonable to anticipate that a shared model could be a cost-effective common solution.

An upfront caveat is that Powerlink expect that the “effectiveness overreach” issue described in section 4.3.3 applies in this area, although PSCAD analysis is required to quantify this effect. But while this worked example cannot yield any definitive conclusions, it is nevertheless illustrative of some of the issues which may apply when considering a shared solution.

This worked example compares the effectiveness of three different models of supplying system strength:

A. having a separate synchronous condenser at both locations (essentially the ‘bring your own’ model),

B. oversizing the synchronous condenser at one location to benefit the other, and

C. having a synchronous condenser at third location, in between both projects and servicing both of their needs. The effectiveness of four possible ‘central’ locations were assessed: Townsville South 132 kV, Ross 132 kV, Ross 275 kV and Strathmore 275 kV.

The results of six different network contingencies have been presented in addition to ‘system intact’, to demonstrate their impact. All of the contingencies increase the impedance (electrical distance) between the two key locations and/or the central locations. However, it is constructive to draw out some of the nuances:

1. **Loss of a single 132 kV feeder between Sun Metals and Townsville South (feeders 7236 or 7237):** Although each feeder is only short, because they each include a 132/33 kV transformer, losing one of these circuits add significant additional impedance between Sun Metals and the rest of the grid.

2. **The loss of a single 132 kV feeder (7156 or 7249) between Townsville South and Ross:** Because of the configuration of the 132 kV network, the loss of either circuit increases the electrical distance between Sun Metals and Ross 132 kV, and hence also increases the impedance to all 275 kV locations which are accessed through Ross.

3. **The loss of a 275/132 kV transformer at Ross:** As noted in the previous section, the impedance of these transformers add significant impedance between the 275 kV and 132 kV networks even during system intact, and this effect is exacerbated during an outage of one of the three transformers.

4. **The loss of feeder 8911 between Haughton and Ross:** Because Haughton has been only cut into a single circuit, this contingency significantly increases the electrical distance between Haughton and Ross (which is a location in between Haughton and Sun Metals).

5. **The loss of feeder 879 between Haughton and Strathmore:** This is the portion of the circuit that Haughton has been cut into, and increases the impedance between Haughton and Strathmore. It is mostly just applicable to the option where the synchronous condenser is located at Strathmore

6. **The loss of either one of the two feeders which travel directly between Ross and Strathmore (feeders 8857 and 8858):** Although this is similar to the previous two contingencies, the impact is slightly different because of the line construction and the connection of Haughton. It also serves to point out that there are multiple contingencies which can increase the impedance between Strathmore and Ross – which an important consideration if contemplating the use of special protection.

In addition to these key contingencies, there are a range of additional contingencies which may have some impact, although this will be less.

The key locations and network contingencies have been highlighted on the diagram of the network, shown below.

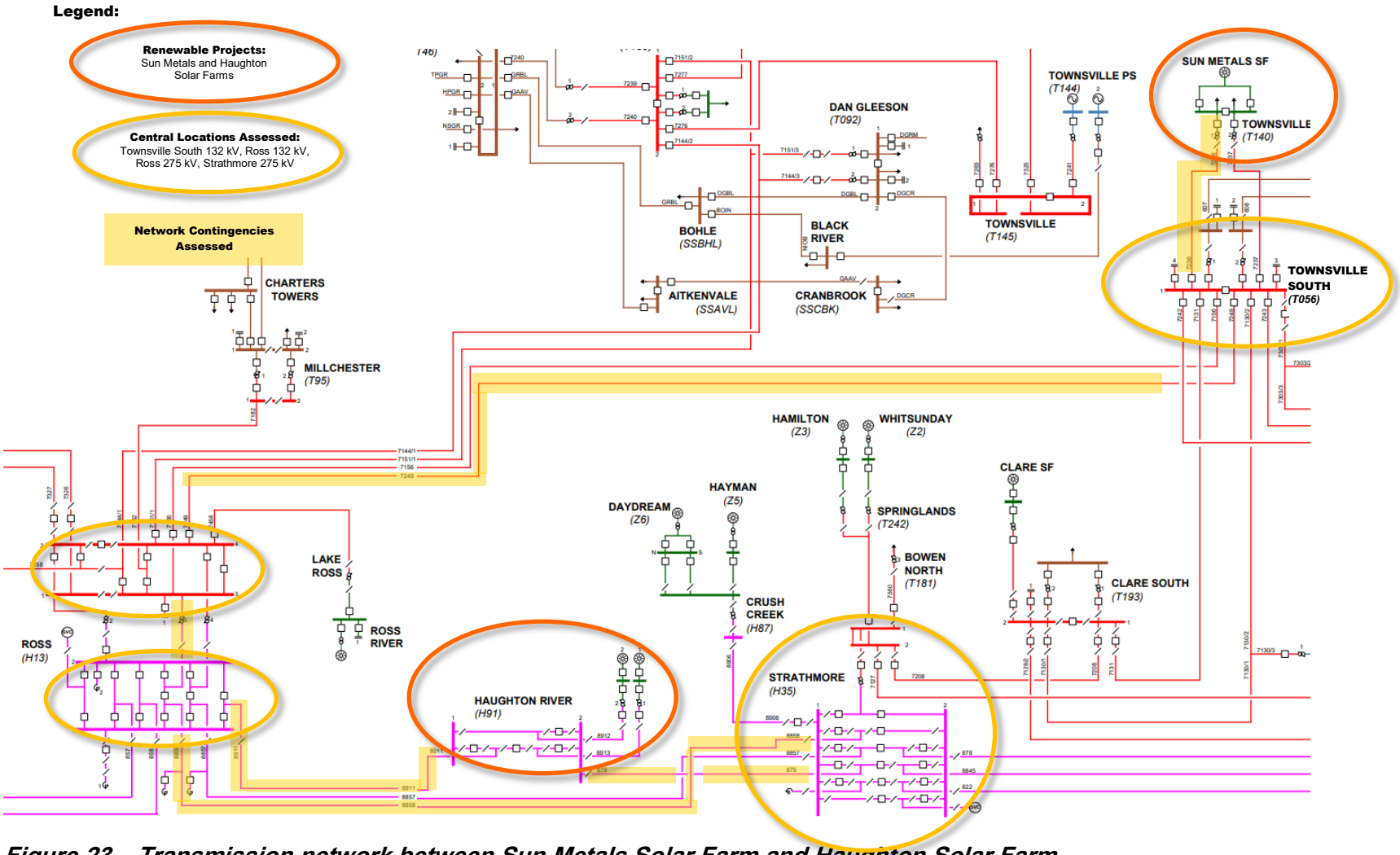


Figure 23 – Transmission network between Sun Metals Solar Farm and Haughton Solar Farm

Note: This system diagram is laid out diagrammatically. Geographically Sun Metals is located much closer to Ross than Strathmore.

Table 7 - Effectiveness of different shared synchronous condenser options[31]

Location of SynCon	Network Condition	Effectiveness at Creating Additional System Stength At					
		Sun Metals 132kV	Townsville South 132kV	Ross 132kV	Ross 275kV	Strathmore 275kV	Haughton 275kV
Sun Metals 132kV	System Intact	100%	85%	65%	45%	34%	29%
	Loss of Ross 132 - Townsville South 132	100%	85%	55%	40%	31%	26%
	Loss of Ross 275 - Haughton 275	100%	85%	65%	43%	28%	9%
	Loss of Haughton 275 - Strathmore 275	100%	85%	65%	43%	27%	22%
	Loss of Ross 275 - Strathmore 275	100%	85%	65%	44%	30%	30%
	Loss of Townsville South 132 - Sun Metals 132	100%	16%	13%	10%	8%	7%
	Loss of Ross 275 - Ross 132	100%	85%	65%	39%	31%	26%
Townsville South 132kV	System Intact	65%	100%	74%	49%	37%	32%
	Loss of Ross 132 - Townsville South 132	66%	100%	62%	44%	34%	29%
	Loss of Ross 275 - Haughton 275	65%	100%	73%	48%	31%	10%
	Loss of Haughton 275 - Strathmore 275	65%	100%	73%	48%	30%	24%
	Loss of Ross 275 - Strathmore 275	65%	100%	73%	48%	33%	33%
	Loss of Townsville South 132 - Sun Metals 132	2%	100%	74%	50%	38%	32%
	Loss of Ross 275 - Ross 132	66%	100%	73%	43%	34%	28%
Ross 132kV	System Intact	40%	58%	100%	60%	43%	38%
	Loss of Ross 132 - Townsville South 132	30%	42%	100%	61%	43%	38%
	Loss of Ross 275 - Haughton 275	41%	59%	100%	59%	35%	11%
	Loss of Haughton 275 - Strathmore 275	41%	59%	100%	59%	33%	29%
	Loss of Ross 275 - Strathmore 275	40%	58%	100%	60%	37%	39%
	Loss of Townsville South 132 - Sun Metals 132	1%	58%	100%	61%	43%	38%
	Loss of Ross 275 - Ross 132	42%	59%	100%	51%	38%	33%
Ross 275kV	System Intact	21%	29%	44%	100%	61%	58%
	Loss of Ross 132 - Townsville South 132	17%	22%	44%	100%	61%	58%
	Loss of Ross 275 - Haughton 275	23%	32%	47%	100%	47%	15%
	Loss of Haughton 275 - Strathmore 275	22%	31%	47%	100%	45%	46%
	Loss of Ross 275 - Strathmore 275	21%	30%	45%	100%	52%	59%
	Loss of Townsville South 132 - Sun Metals 132	1%	29%	44%	100%	62%	58%
	Loss of Ross 275 - Ross 132	17%	23%	34%	100%	62%	59%
Strathmore 275kV	System Intact	12%	17%	24%	45%	100%	44%
	Loss of Ross 132 - Townsville South 132	10%	13%	23%	45%	100%	44%
	Loss of Ross 275 - Haughton 275	10%	13%	18%	29%	100%	29%
	Loss of Haughton 275 - Strathmore 275	10%	13%	18%	30%	100%	16%
	Loss of Ross 275 - Strathmore 275	11%	14%	20%	35%	100%	41%
	Loss of Townsville South 132 - Sun Metals 132	0%	17%	24%	45%	100%	44%
	Loss of Ross 275 - Ross 132	10%	14%	19%	45%	100%	44%
Haughton 275kV	System Intact	16%	22%	32%	66%	68%	100%
	Loss of Ross 132 - Townsville South 132	13%	17%	32%	66%	68%	100%
	Loss of Ross 275 - Haughton 275	7%	10%	13%	21%	70%	100%
	Loss of Haughton 275 - Strathmore 275	18%	25%	37%	75%	37%	100%
	Loss of Ross 275 - Strathmore 275	15%	21%	31%	61%	62%	100%
	Loss of Townsville South 132 - Sun Metals 132	1%	22%	32%	66%	68%	100%
	Loss of Ross 275 - Ross 132	13%	18%	25%	66%	68%	100%

The implications of these results are:

- The impedance of the transformers at Ross significant limits the flow of system strength from any synchronous condenser connected to the 275 kV network through to Sun Metals. This penalty factor is then compounded by the additional effect of local network contingency events. The impact of losing one of the circuits connecting Sun Metals and Townsville South is particularly onerous, since it also involves tripping one of Sun Metal's 132/33 kV transformers. These effects could be reduced through network or connection upgrades, such as the installation of additional 275/132 kV transformers at Ross, the construction of a 132 kV

[31] Results in Table 7 were developed from PSS/E simulations of the Queensland power system performed by Powerlink

busbar at Sun Metals and/or the construction of an additional transmission line between Townsville South and Sun Metals. However, in this particular instance, the cost of implementing these measures would far exceed the benefit.

- Under most network conditions, Haughton will experience a significant increase in system strength from a 275 kV-connected synchronous condenser. The increase is greatest for a synchronous condenser located at Ross, but locating at Strathmore would also provide substantial benefit. The one exception to this is during the outage of the single transmission circuit which the substation has been cut into. Achieving a meaningful increase in system strength in this network condition would require the synchronous condenser to be significantly oversized, which is unlikely to be economic. This is a situation in which the use of special protection and/or modifying the connection to cut it into a second circuit could be highly complementary (although in this specific situation, the latter option would incur substantial cost as the second circuit does not run immediately past Haughton). The special protection scheme would be relatively straightforward and inexpensive compared to schemes that would need to take inputs from a range of remote locations.
- Without the use of special protection to manage Haughton's critical network outage, Strathmore is a slightly more effective location for Haughton. This may initially seem counter-intuitive as Haughton is much closer to Ross than to Strathmore. However, during the most onerous N-1 contingency events, Haughton is electrically closer to Strathmore than Ross.

Relating these findings back to the different models of system strength:

A. If customers bring their own system strength, this avoids any issues related to how well system strength propagates through the network.

B. There is a significant performance penalty for either Haughton or Sun Metals to be able to supply system strength to each other. Although they are geographically close, the impedance of the 275/132 kV transformers make them quite distant electrically.

C. Haughton has the greatest potential to benefit from a shared synchronous condenser connected to the 275 kV network. This benefit would be maximised if accompanied by a special protection scheme to deal with the critical contingency. Sun Metals could potentially benefit from a shared synchronous condenser connected to the 132 kV network, but as found previously, this would increase the system strength over a much more limited area (limiting the pool of potential beneficiaries), and any special protection schemes to handle contingency events would be more expensive and intrusive.

None of this analysis rules out the possibility that Sun Metals and Haughton could benefit from an improvement in inverter control interaction stability from a synchronous condenser located elsewhere through the "over-reach" effect.

4.4 Overall implications

The purpose of the economic and power modelling has been to explore the relationship between economies of scale of a centralised approach to a decrease in system strength with electrical distance.

In Section 4.2 we have set out the relative economies of scale in the total life time costs of a synchronous condenser as well as operational advantages as the total MVA increases. Applying the results of our economic modelling to estimate a life time cost curve of the different centralised and

decentralised synchronous condenser configurations were investigated. We find there are significant economies of scale produced from a centralised approach.

In Section 4.3 we have shown that the configuration of the transmission network has a significant bearing on how well system strength propagates. Different voltage levels and network connectivity can strongly impact upon system strength during both system intact and N-1 conditions.

The more widely system strength can propagate, the greater it's potential to benefit a number of projects, and thus function as a shared solution. Therefore, based upon this analysis, it is possible to think about the network in four categories, with implications for the viability of system strength.

Table 8 - Viability of a shared solution to system strength in different contexts

Context	Viability of a shared solution to provide system strength	Likelihood of needing to rely on special protection to make a shared solution viable
A strongly interconnected node on the main transmission backbone.	Highest	Unlikely to be necessary
A connection into a circuit on the main transmission backbone	↑	Possible, with relatively modest complexity and cost
A connection to the lower voltage sub-transmission network, but electrically close to the main transmission backbone	↓	Probable, with moderate complexity and cost
A connection to deep within the sub-transmission network, remote from the main transmission backbone	Lowest	Very likely, with the potential for significant cost and complexity

Unfortunately it is not possible to be entirely definitive about the viability of shared synchronous condensers, especially where the issue needing to be mitigated involves multiple inverters interacting with each other. This must be investigated on a case by case basis using PSCAD.

We hope that this information is helpful to renewable project developers and their consultants, to frame their expectations about the likelihood of different locations being able to benefit from a shared solution.

This conclusion may also have implications for the Renewable Energy Zone (REZ) concept, where the centralised provision of system strength may be a mechanism to help stimulate the development of renewable generation in an area.

5. System Strength Frameworks Review

The current regulatory arrangements for managing system strength were established in 2017 to address the immediate system strength issues and concerns. Two frameworks were established:

1 The “do no harm” framework: new connecting generators are required to deliver system strength commensurate to their 'harm' to the operation of any other generators (existing or committed) as a consequence of their connection.

2 The minimum system strength framework: addresses declining levels of system strength as synchronous generators retire or reduce their output. AEMO identify shortfalls of system strength, with TNSPs then working to address these expected shortfalls.

These frameworks underpin the process to assess connection applications, the process and accountabilities for implementing system strength remediation, and the complexities of implementing a scale-efficient solution.

In April 2019, the Australian Energy Market Commission (AEMC) initiated a review of these arrangements, in recognition of the very fast pace of change in the industry and connection of a large number of inverter-connected generators. Stakeholder feedback identified the following key issues with the existing framework[32]:

1 With respect to the ‘do no harm’ framework:

- Concern that the existing framework is “exacerbating barriers to connection for new entrants”, adding “substantial uncertainties in the forms of delays and costs”
- That the framework is resulting in “many individual and discrete system strength assets (mostly synchronous condensers) being installed”. Having so many small remedial assets “increases complexity of power system models, and increases the complexity of power system operation”, leading to “flow on effects for the connection processes of new entrants and TNSP and AEMO operations”.
- That whilst there are “potential cost, time and operational efficiencies in coordination of remediation assets such as synchronous condensers”, that “commercial realities make coordination of remediation work impractical under the framework”.

2 With respect to the minimum system strength framework:

- That the framework is “based on fault current only as a proxy measurement for system strength” and that “other parameters of system strength could also be more explicitly considered”. Additionally, there is no “margin for power system resilience when setting minimum levels”.
- That the framework is reactive in nature. Declaring already existing shortfalls has required “very costly and operationally complex interventions by AEMO” and also “limits the ability of

[32] Source: AEMC System Strength Investigation Briefing on Discussion Paper, 9 April 2020

TNSPs to provide least cost solutions." The ability of AEMO to forecast emerging shortfalls "is limited both by computational capability and the volatile development of the NEM"

- That in addition to system normal conditions, "AEMO and TNSPs have to account for unplanned outages. Practical realities mean this may result in greater costs being incurred by consumers."

3 With respect to the separation of the current frameworks (from each other and from other regulatory frameworks):

- The two frameworks interact with each other but are not linked:
  - "New entrant remediation under the 'do no harm' framework has flow on effects to the minimum strength framework… which can cause inefficient outcomes in both frameworks, such as unexpected shortfalls or constraints"
  - "System strength procurement cannot be coordinated effectively across both frameworks. E.g. New entrant needs are not considered fully when addressing a shortfall, even if a solution to one could be scaled to solve both."
- Both frameworks are based on preserving "the minimum level of system strength required to operate the power system securely" and "do not recognise the potential value of additional system strength that may alleviate constraints on generation or accelerate the connection of new plant".
- "The frameworks are not coordinated with the frameworks for other system services… such as inertia" and "do not provide for co-optimisation… unless other, non-system strength frameworks are activated simultaneously".

The AEMC's notes that "The pace of the power transition means the time has now come to adjust and expand the system strength frameworks given the rapid connection of large numbers of new non-synchronous generation. These frameworks need to evolve and be agile and flexible given the transition underway." The AEMC's review is wide-ranging, including how system strength can be planned, procured, priced and paid for. The table below outlines the spectrum of the range of options being considered[33].

Table 9 – Options considered as part of AEMC's system strength frameworks review

Structure	Description	Spectrum of Options
Plan	Determination of how much system strength is needed for and provided into the system over both short and long timeframes.	Centralised to Decentralised
Procure	Sourcing the necessary volumes of system strength - which has implications for how the service is priced.	Mandated to Competitive
Price	How system strength is valued and priced.	Regulated to Spot Market
Pay	Which parties should bear the cost of providing the service?	Public/Consumers to Private/Generators

[33] AEMC System Strength Investigation Briefing on Discussion Paper, 9 April 2020

The AEMC has described four high level models (outlined in the images below) for how system strength might be improved, and for which they are seeking stakeholder feedback. They note that these models are not mutually exclusive, and that various combinations may be appropriate to deliver system strength in the long term interest of consumers.

Centrally Coordinated Model

This model describes a centrally co-ordinated and planned approach. Such an approach would aim to coordinate and plan the grid into the future as to where system strength assets are required in the medium to long term.

Table 10 - Centrally coordinated model

Plan	This model could build on existing planning processes, such as the ISP and transmission planning frameworks, as well as other system security planning frameworks, including network support and control ancillary services (NSCAS), as well as the minimum inertia and system strength frameworks.
Procure	Under this model, a central buyer, such as TNSPs or AEMO, would be responsible for procuring necessary volumes of system strength to meet a central plan, through either contracting with third parties to provide the service or building regulated network assets to provide system strength services.
Price	Pricing of these services could be subject to a regulated approach, and could be determined through the least cost of these procurement opportunities.
Pay	There are a number of ways that these services could be paid for, including by consumers through network charges, and/or by generators through a pre-determined fee at the time of connection.

Market Based Decentralised Model

This model describes a decentralised approach that utilises dynamic procurement of system strength over a shorter timeframe, but where the price signals sent in this market could support longer term investment decisions in the provision of system strength. This model requires that system strength be co-optimised into dispatch in some manner.

Table 11 – Market based decentralised model

Plan	"Planning", or coordination, would be decentralised, with individual parties deciding to participate in the system strength market.
Procure	Procurement of the service would be done at dispatch with system strength assets being dispatched according to their bids to provide system strength to the market, with the least cost combination of assets dispatched.
Price	The price would be set by the marginal provider of service or may be subject to some form of price regulation, if a market price is a concern in this market due to a lack of competition.
Pay	The service would be paid for by consumers through wholesale market costs, and/or by generators through a causer-pays style approach who have a negative effect on system strength.

Mandatory Service Model

This option would impose direct "active" system strength provision obligations on generators — this model describes a centralised approach, utilising a generator obligation for the active provision of a given level of system strength.

Table 12 – Mandatory services model

Plan	Planning of this model would be similar to that already undertaken for generators, including the ISP and connection agreement processes.
Procure	The service would be provided by each generator, as part of its generator performance standards negotiated with its connection agreement. As such, "procurement" of the service would be the sole responsibility of each generator as a connection obligation.
Price	The price will be the costs incurred by connecting generators. It is assumed each generator would choose the lowest cost option for their situation to meet their obligation.
Pay	Generators would bear the direct costs of this model, with consumers indirectly bearing costs through higher wholesale prices, as generators seek to recoup their increased capital costs.

Access Standard Model

This model describes an obligation on generators to be able to operate stably in low system strength environments. Generators would only be able to connect to the grid if their equipment enables them to operate stably in low system strength environments. However, in contrast to the "active", mandatory service model, generators would not be required to contribute to the provision of fault current.

Table 13 Access standard model

Plan	Planning of this model would be similar to that already undertaken for generators, including the ISP and connection agreement processes.
Procure	The service is effectively "procured" through imposing an obligation on generators to install equipment, such as inverters and control systems that is capable of operating stably down to low levels of system strength.
Price	As in the mandatory service model, generators would need to procure equipment that meets the standard with the price set by the cost of doing so.
Pay	Generators would bear the direct costs of this model, with consumers indirectly bearing costs through higher wholesale prices, as generators seek to recoup any increased capital costs.

The AEMC has also included a provisional assessment of the extent to which the four conceptual models address the issues identified with the existing frameworks:

Table 14 - AEMC indicative assessment of high level models

Issue to address	Centrally Coordinated	Market Based Decentralised	Mandatory Service	Access Standard
Minimum System Strength	✓	-	✗	✗
"Do no harm"	✓	-	✗	-
Separation of frameworks	✓	✓	✓	✓

The AEMC's discussion paper[34] contains significantly more detail than this brief summary, and readers are referred to the AEMC's consultation webpage[35] for this document along with other fact-sheets, and consultation responses. The authors hope that this document will support the AEMC's review process by promoting a deeper understanding of the underlying issues among a broader range of stakeholders.

[34] https://www.aemc.gov.au/sites/default/files/documents/system_strength_investigation_-_discussion_paper.pdf

[35] https://www.aemc.gov.au/market-reviews-advice/investigation-system-strength-frameworks-nem

6. Conclusions

Our review of system strength and its application in the NEM has identified that as the generation mix shifts towards more inverter-connected VRE generation, the power system's ability to accommodate increasing numbers (and capacity) of VRE generation projects without system strength remediation is reducing. Therefore, it may be pragmatic for renewable generation developers to go into the network connection process assuming that some form of system strength remediation may be required.

There is no one "best" form of system strength remediation. The applicability and effectiveness of several options is dependent upon the particular circumstances of the network connection. Additionally, many of the options are mutually compatible, and the optimal solution may involve a combination of responses based upon the generator's needs. Therefore, individualised power systems analysis (likely using PSCAD) is required to determine the requirement for system strength provision and, potentially, the scale and cost-effectiveness of different solutions.

While there are a range of technologies and approaches that could be deployed to help manage low system strength, the technology with the broadest applicability, and likely suited to meet the needs of many generators in the near term is the synchronous condenser. By increasing the level of system strength, a synchronous condenser is acting upon the underlying condition that gives rise to the variety of specific issues which can result. The potential of grid forming inverters is presently being assessed by a number of different initiatives, including an ARENA supported investigation that Powerlink is undertaking, which will be published in a subsequent report.

From our lifecycle cost analysis we have found that synchronous condenser exhibit significant economies of scale, predominantly as a consequence of the largely-fixed capital costs related to civil works, network connection, and cooling a control systems, and the largely fixed operating cost from "no load" energy losses. Thus there is economic merit in exploring the possibility of a shared solution to system strength that supports multiple projects. A centralised approach to developing and operating this shared solution could also simplify, accelerate and de-risk the connection process for developers, as well as streamlining the ongoing operation of the synchronous condenser. There are different types and configurations of synchronous condensers and again detailed economic analysis is needed to determine the economic performance for each individual situation.

Our network modelling (using Northern Queensland as an example) reveals that the viability of a shared solution is likely to be greatest where both the synchronous condenser and the renewable projects it supports are directly connected to the main transmission backbone. The further a connection moves away from the backbone, the greater the risk that the impedance of the network and credible contingency events will hamper the propagation of system strength. If an inverter based VRE generator is built on the sub-transmission or distribution network, a shared model is less likely to be cost-effective, and more likely that each generator will need to implement their own system strength remediation. The current regulatory frameworks pose challenges to the development of coordinated or scale-efficient synchronous condensers.

The AEMC's system strength frameworks review will be an important reform to ensure that regulatory arrangements are flexible to accommodate the range of issues and options covered in this report, including the use of shared solutions in situations where this would yield practical benefits and economic efficiencies.

GHD Advisory

Appendices

Appendix A Glossary of terms and abbreviations

Abbreviation	Meaning
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFL	Available Frequency Level
AGC	Automatic Generation Control
ARENA	Australian Renewable Energy Agency
AREMI	Australian Renewable Energy Mapping Infrastructure Project
BESS	Battery Energy Storage System
CEC	California Energy Commission
DR	Demand Response
EMT	Electromagnetic Transients
FACTS	Flexible AC Transmission Systems
FCAS	Frequency Control Ancillary Devices
FIA	Final Impact Assessment
FFR	Fast Frequency Response
H-SC	Hybrid Synchronous Condenser
HSF	Haughton Solar Farm
HV	High Voltage
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
ISO	International Organisation for Standardization
ISP	Integrated System Plan
LCCA	Life Cycle Cost Analysis
LCRI	Location Constrained Resource Interconnection
LMPs	Locational Marginal Prices
MVA	Mega Volt Amp
MW	Megawatt

Abbreviation	Meaning
NEM	National Electricity Market
NER	National Electricity Rules
NLAS	Network Loading Ancillary Services
NTNDP	National Transmission Network Development Plan
NSCAS	Network Support and Control Ancillary Services
NSP	Network Service Provider
OEM	Original Equipment Manufacturer
Ofgem	Office of Gas and Electricity Markets
REZ	Renewable Energy Zones
PIA	Preliminary Assessment
PHES	Pumped Hydro Energy Storage
PSCAD	Power Systems CAD
PSS	Power System Stabiliser
PSSE	Power System Simulator for Engineering
PPC	Power Plant Controller
PV	Photovoltaic
RAB	Regulated Asset Base
RIT-T	Regulatory Investment Test
RoCoF	Rate of Change of Frequency
RUG	Releasable User Guide
SANI	South Australia-New South Wales Interconnector
SCR	Short Circuit Ratio
SENE	Scale Efficient Network Expansion
SF	Solar Farm
SGE	Synchronous Generator Emulating
SINAMICS	Modular Frequency Converter
SINCAL	Siemens Network Calculation
SMIB	Single Machine Infinite Bus
SSSPs	System Strength Service Providers
STATCOM	Static Condenser
TNSP	Transmission Network Service Provider

Abbreviation	Meaning
TOSAS	Transient and Oscillatory Stability Ancillary Service
TRR	Transmission Revenue Requirement
VAR	Volt-Ampere Reactive
VCAS	Voltage Control Ancillary Services
VRE	Variable Renewable Energy
X/R	Ratio of System Reactance to System Resistance

Appendix B Connection process

Main Parties in Connection Process

The following are the main parties involved in the network connection process.

1 AEMO is the Australian Energy Market Operator. AEMO's function is to operate the Australian National Electricity Market (NEM). This includes day-to-day market trading, as well as managing the overall power system. As a component of the latter requirement, AEMO must ensure that any new generator connecting to the power system is compliant with the National Electricity Rules (NER).

2 The Network Service Provider (NSP) is the owner and operator of the network to which the generator will connect. The NSP will work in conjunction with AEMO to confirm the generator is compliant with the NER. The NSP will also engage with the proponent to determine the assets and configuration required for the generator to connect to the power system.

3 The proponent is the owner or developer of the generation project.

4 Consultants are generally used by the proponent throughout the connection process to carry out specialised tasks such as generator and system modelling, registration, assisting the proponent in negotiations with AEMO and/or the NSP.

Connection Process

The process to secure a connection to the NEM is governed by the requirements under the NER. The NSPs have a statutory obligation to follow this NER process. The following is an explanation of this process at an overview level. Proponents should be aware that each NSP may have slight nuances on this process.

Generally, the process is as follows:

Submit Connection Enquiry

The Connection Enquiry is the first formal stage of the process. Before submission of the Connection Enquiry, the proponent may engage with the NSP to determine the optimum connection arrangement. The NSP will charge a fee to process the Connection Enquiry. The fee charged depends on each NSP, but could in the range from $10,000 to $50,000. During the Connection Enquiry assessment, the NSP will consult with AEMO and undertake a Preliminary Impact Assessment (PIA).

This PIA is a requirement that commenced on 1 July 2018 and is driven by the increase in non-synchronous generation connecting to the network. In summary, inverter based non-synchronous generators are not rotating machines and therefore do not provide 'inertia' on the system[36]. Excessive

[36] This document does not attempt to detail the complex technical issues associated with asynchronous generation.

non-synchronous generation on a power system can lead to low ‘system strength’ or a ‘weak’ system. Therefore the PIA is carried out at this early stage to determine if the non-synchronous generation will have a negative impact on the system strength at the proposed connection location.

There are two outcomes of the PIA:

1 The proposed generator does not impact on the system strength and the available fault level is positive. In this case, the use of conventional simulation tools will be adequate.

2 If the generator will impact the system strength, a Final Impact Assessment (FIA) will be required to determine the impact and the required remediation. If PIA finds a negative available fault level, then the use of electromagnetic transient (EMT) models will be required.

Application to Connect

When submitting the Application to Connect, the proponent should have completed all technical studies and requirements to demonstrate that the generator can connect to the system without impacting the power system or other connected entities. To achieve this, the proponent must carry out an extensive range of studies and network modelling and provide supporting documentation and models.

This information is provided with the Application to Connect and the connection fee. As the NSP and AEMO carry out a significant amount of work at this stage, the application fee could be around $300,000.

These are complex studies need to be undertaken. They can take a significant amount of time to carry out. When submitting the final technical package with the Application to Connect to the NSP, the proponent and its consultants should ensure that all the information required and/or requested by both the NSP and AEMO are complete and accurate. Any inaccuracies or poor data will delay the NSP and AEMO’s assessment and result in project delivery delays.

In summary, the technical requirements are as follows:

- Proposed Generator Performance Standards. The requirements are provided in Schedule 5.3 of the NER.
- A “Connection Studies Report” that details and demonstrates how the generator will meet each of the generator performance standards.
- If determined through the Connection Enquiry process, a Final Impact Assessment for system strength impacts and remediation.
- For inverter-based generators, the minimum Short Circuit Ratio (SCR) and X/R ratio at which the plant can operate, and at which PSSE/PSCAD models are validated.
- A complete set of PSSE software simulation models representing the generating system. For a non-synchronous generator, the Power Plant Controller (PPC) must be modelled as a controller.
- A PSSE Model Acceptance Report
- A Releasable User Guide (RUG), incorporating details on how to use all PSSE simulation models including, but not limited to load flow setup, generator voltage control scheme, model control modes, et al. The RUG is used to provide information on the generator to other potential connection applicants.

- A complete set of PSCAD software simulation models including user guides.
- A PSSE/PSCAD model benchmarking report based on a Single Machine Infinite Bus (SMIB) case set taking into account the lowest SCR condition at the Point of Connection.
- A Voltage Control Strategy.
  - Single Line Diagrams, showing all components of the generating system, including the Point of Connection and location of the Metering Installation.
  - Power System Design and Setting Data Sheet. At this stage, this sheet will contain the R1 data.
  - Generating system capability curve during steady state conditions and transients.
  - Protection and Control scheme details
  - Model source code associated with all PSSE user written simulation models.
  - Functional block diagrams, including all functions between feedback signals and generator output.

The NSP and AEMO will use this information provided with the Application to Connect to carry out due diligence on the impact of the generator on the network.

The technical assessment is based on the principle of “do no harm”. This means that the proposed generator will not impact the network or any other entity connected onto the network.

There are two levels that a specific technical requirement may meet.

- Automatic; and
- Minimum.

The ‘automatic’ standard means that AEMO or the NSP cannot refuse connection of the generator on the ground of technical capability. The ‘minimum’ standard is the lowest technical level that AEMO or the NSP will allow the generator to connect. Between these two levels, the requirement may be negotiated. However, AEMO advises that all technical requirements should meet the automatic standard, with any negotiation to be down from the automatic level. This is different in the past where many proponents proposed technical requirements at the minimum level and negotiated up.

The NSP assess the majority of the technical requirements with AEMO assessing some matters. Once the assessment has been completed, AEMO will issue a letter to the NSP under clause 5.3.4A of the NER stating that the technical requirements are satisfied. If an FIA is required, AEMO will also issue a letter under 5.3.4B of the NER advising of the FIA and the remediation actions that will need to be undertaken.

During this stage, the NSP and the proponent will also determine the optimum arrangement for connection to the network. There are a number of possibilities for the design, construction and ownership for the assets used for connection; such as:

- Contestable – build, own, operate by the proponent.
- Non-contestable – can only be built, owned, operated by the NSP.
- Design-build by the proponent then transfer to the NSP.
- Other arrangements, as negotiated with the NSP

Offer to Connect and Acceptance

Once the technical assessment has been completed to the satisfaction of both the NSP and AEMO, the NSP will make an Offer to Connect.

This will include all the agreed technical standards, as well as the technical and commercial aspects of the connection assets.

Once the NSP has provided the Offer to Connect, acceptance of the offer is generally by the execution of the Connection Agreement. Some NSPs incorporate the construction of connection assets into the Connection Agreement, while others may have the commercial requirements for the construction in a separate agreement.

While the technical assessment is being carried out, the proponent should engage with the NSP on the negotiation of the Connection Agreement. By agreeing on the majority of the terms and conditions prior to the offer being made will expedite acceptance of the offer.

Registration

Under the National Electricity Rules, it is illegal to connect a generator to the network without being registered as a generator with AEMO. The registration process can be a long as AEMO needs to confirm that the proponent is a fit and proper entity, the project is technically sound and that all other aspects of the proponent operating in the market are in place.

Most state jurisdictions require the proponent to also have a generation licence to operate within the state. This is more a regulatory process than technical, with most state regulators relying on the AEMO process for the technical aspects.

The AEMO registration process generally commences after the connection agreement is executed, and the project obtains a ‘committed’ status with AEMO and the NSP.

A further technical review is undertaken at this stage. This stage is referred to as the R1 Data Due Diligence. This usually requires further substantial modelling and can be time-consuming as the final technical requirements need to be negotiated with AEMO and the NSP.

Before granting registration AEMO requires that the final design complies with the modelling. The final design used in the modelling should include all other ancillary devices such as harmonic filters, synchronous condensers, inverter models, batteries, etc.

As the inverter models are usually propriety intellectual property owned by the inverters’ supplier, these may be provided as a ‘black box’ model. Or the inverter supplier may enter into a confidentiality agreement with AEMO to provide the model to AEMO only.

Other components required for AEMO registration are matters like prudential requirements, metering, operating arrangements, trading arrangements, etc.

Commissioning

Once registration has been obtained with AEMO, the generator can commence commissioning.

The commissioning requires a detailed commissioning plan that is developed between the proponent, the NSP and AEMO. As the plan can be quite complex, negotiations should be commenced a least three months before the proposed commissioning date.

Commissioning is also referred to as “R2 and Hold Point Testing”.

The commissioning process will include a number of 'hold points'. The MW output of the generator is increased to a specified level where data[37] is downloaded, analysed and compared to the modelled information. Once AEMO and the NSP are satisfied the generator is operating in accordance with the modelled performance, approval is given to move the generator's output to the next hold point.

This commissioning process may take some time as there may be a requirement to hold the generator's output at a specified level will the data is gathered. This can be problematic for solar farms and wind farms due to the variability of the energy source.

For a 100 MW generator, there may be four 'hold points' in the commissioning process.

Once the full output of the generator has been approved by AEMO and the NSP, the generator is considered commissioned and commercially operational.

[37] R2 data

1. Pre-feasibility

Applicants consider the feasibility of their project and begin discussions with the connecting Network Service Provider (NSP), landowners and relevant government authorities. NSPs generally refer to this phase as preliminary enquiry or pre-feasibility.
Applicants have considered factors such as the location, size, network constraints, infrastructure requirements, loss factors, competing or dependent projects.

Inputs
- Engagement between NSP and Applicant.
- NSP and AEMO information (e.g. Annual Planning Report, Integrated System Plan etc.).

Process
- Applicants commence preliminary discussions with NSP.
- NSP manages the connection process and provides information as requested.
- For complex connections or novel configurations, optionally the NSP or Proponent may consult AEMO.

Outputs
- Preparation of a connection Enquiry.

2. Enquiry

The Applicant submits a connection enquiry to the connecting NSP to:
- Help determine the most suitable point of connection;
- Confirm the information required to be submitted with the connection application.
- Establish the scope and estimate of any required connection assets.

Inputs
- NSP receipt of connection enquiry from Applicant, including description of the proposed installation (5.3.2 or 5.3A.5).

Process
- NSP reviews information submitted with the connection enquiry
- NSP undertakes a Preliminary Impact Assessment (PIA) and consults AEMO.
- Commence engagement with other asset owners or affected parties (including joint-planning with other NSPs, non-contestable service providers).

Outputs
- NSP provides preliminary enquiry response / detailed enquiry response to the Applicant.
- Provision of transmission network data from AEMO (upon request) if the Applicant has a participant status of "intending" or "generator".

3. Application

The Applicant submits an application to connect to the NSP, inclusive of information stipulated in the enquiry response. Technical performance and grid integration requirements are established in this phase. The timeframe can vary depending on the quality and completeness of the application. During this phase (and at least 3 months prior to planned commissioning) the Applicant commences the Market Registration process.

Inputs
- Completed connection application (5.3.1A, 5.3.4) including performance standards and supporting information.
- Description of the proposed installation, including associated computer model and other information.

Process
- NSP receives and reviews application and supporting information and undertakes technical studies (including full assessment if required).
- NSP consults AEMO in relation to any negotiated standards which are AEMO advisory matters.
- NSP consults AEMO in relation to any proposed system strength remediation (if applicable).
- Following provision of updated information from detailed design, confirm the ability to meet performance requirements (2.2.1(e)(3)) for registration purposes.

Outputs
- AEMO responds to the NSP according to 5.3.4A and 5.3.4B, and the NSP responds to the Applicant.
- Following completion of this phase – finalised connection agreement and 5.3.7(g) notification to AEMO.

Additional note
A revised assessment may be required following detailed design if there are changes to proposed plant, performance standards, network, committed projects or Rules requirements.

4. Completion

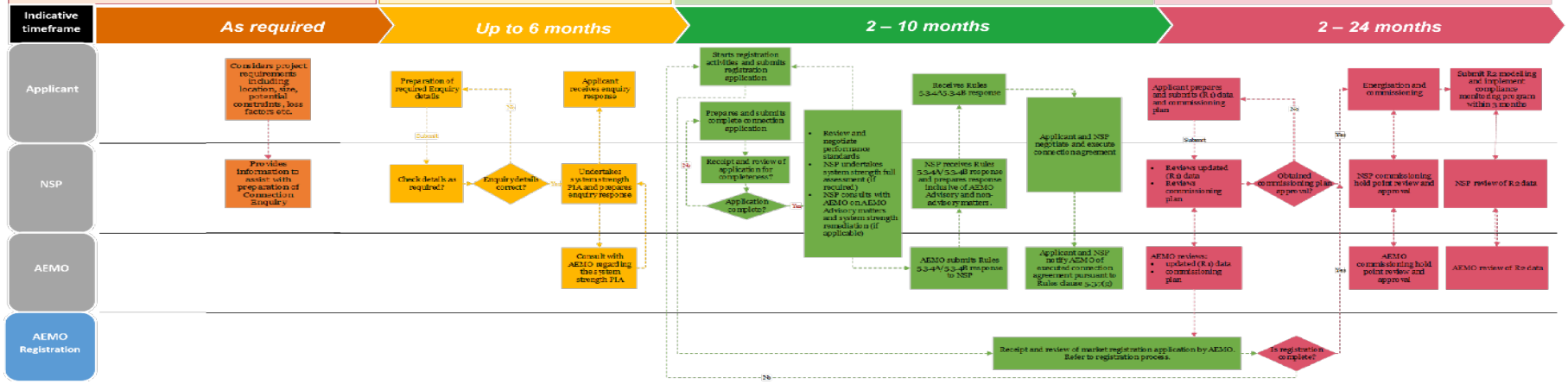
This phase involves finalisation of market registration and commissioning of the facility, involving both AEMO and the NSP. The purpose of the commissioning phase is to confirm the ability to meet the proposed performance standards and validate model information used for planning and operational performance.

Inputs
- Completion of construction.
- Market Registration complete.
- Commissioning test procedure and commissioning test schedule.

Process
- The NSP and AEMO review commissioning test results at successive hold points to confirm alignment between modelled and tested performance and successful commissioning of the facility.

Outputs
- Hold point approvals, approval for commercial operation
- Post-commissioning, acceptance of updated (R2) data and models.

Additional note
Post commissioning the proponent should provide validated models and R2 data, as well as develop and implement a compliance monitoring program. Other ongoing obligations include informing AEMO of availability and maintaining business and operational contact information.



Appendix C LCCA method

The Life-Cycle Cost Analysis (LCCA) evaluated the initial and future costs of various GE synchronous condenser configurations. The configurations we investigated are:

Configuration (MVAr)	Total fault current (MVAr)
1 x 70	70
2 x 70	140
1 x 129	129
3 x 70	210
3 x 80	240
1 x 260	260

The LCCA is an exploratory analysis and as such assumptions were made to ensure the main characteristics of economies of scale remained without conducting complete control, system and design studies. These assumptions include but are not exclusive:

- No Aux load losses
- No main transformer losses
- Fixed ($/MVAr) maintenance costs
- No lost revenue due to maintenance
- No decommissioning costs
- Residual value is assumed to be $0
- Site preparation is provided
- The capital cost of connection to the transmission network
- All equipment beyond the HV terminals of the step-up transformer is provided
- Excludes financing costs
- All items are inflated at 2% p.a.

For the LCCA, technical life is assumed to be 30 years. We decided upon this as this figure based upon our advice to ElectraNet[38] and our experience with synchronous condenser operators. Electricity usage charges are based on the owner of the synchronous condenser being a commercial 66 kV customer with Ergon

[38]GHD Advisory, *Economic life for ElectraNet synchronous condensers,* 28 June 2019. Available at: https://www.aer.gov.au/system/files/GHD%20Advisory%20-%20MGSS%20Contingent%20Project%20-%20Economic%20Life%20Advice%20-%2028%20June%202019.pdf

Energy and on the synchronous condenser constantly operating. Demand and supply charges are based off average hourly no-load losses.

The analysis was conducted by first applying cost assumptions. This was done by each cost being inflated over the technical life of the synchronous condenser. Costs were separated to see each individual cost flow. A base cash flow was established by grouping individual cost cash flows.

Total annual costs were then established for each year. These were then discounted backwards to FY2020 to form the LCCA. LCCA, and other previous costs, were then divided by the rated MVAr of each synchronous condenser to create per unit measurements for analysis.

Appendix D Results of system studies

The results of the system studies investigating the effectiveness of the various synchronous condenser configurations when applied to the different network types are contained in this Appendix.

Table 15 - Study legend

Study ID	Description
Study A	Low system impedance, Good N-1 - System normal, 1 unit
Study A'	Low system impedance, Good N-1 - Contingency, 1 unit
Study B1	Low system impedance, Poor N-1 - System normal, 1 unit
Study B1'	Low system impedance, Poor N-1 - Contingency, 1 unit
Study B2	Low system impedance, Poor N-1 - System normal, 2 x 0.5 units
Study B2'	Low system impedance, Poor N-1 - Contingency, 2 x 0.5 units
Study B3	Low system impedance, Poor N-1 - System normal, 4 x 0.25 units
Study B3'	Low system impedance, Poor N-1 - Contingency, 4 x 0.25 units
Study C1	High system impedance - System normal, 1 units
Study C1'	High system impedance - Contingency, 1 units
Study C2	High system impedance - System normal, 8 x 0.125 units
Study C2'	High system impedance - Contingency, 8 x 0.125 units

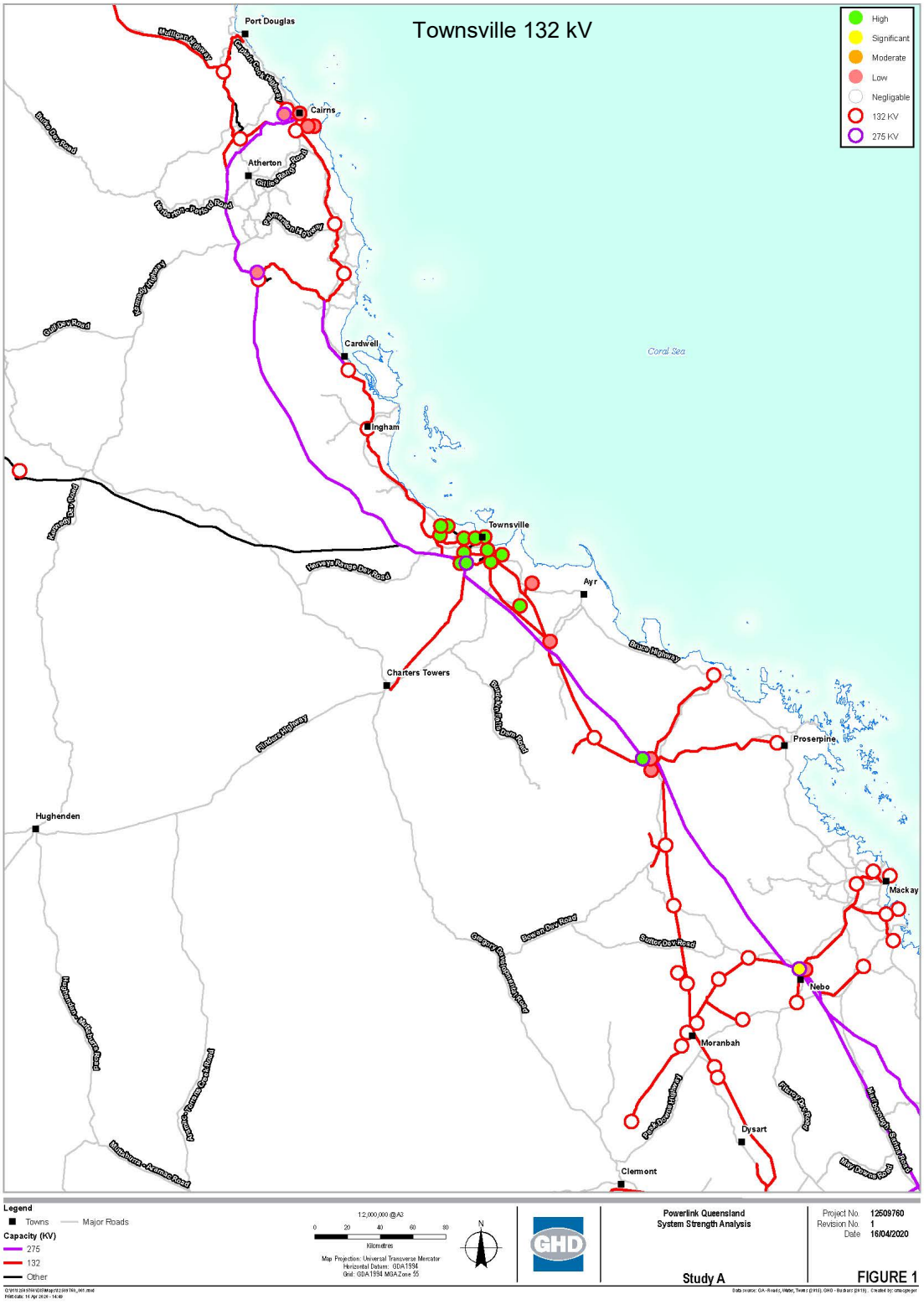
The B2/B2' and B3/B3' studies allow for a comparison of the multiple synchronous condenser centralised solutions with the larger scale single centralised solution in B1/B1'.

Table 16 - Improvement colour band

High	$\Delta X > 20\ \%$
Significant	$15\% < \Delta X < 20\ \%$
Moderate	$10\% < \Delta X < 15\ \%$
Low	$5\% < \Delta X < 10\ \%$
Negligible	$\Delta X < 5\ \%$

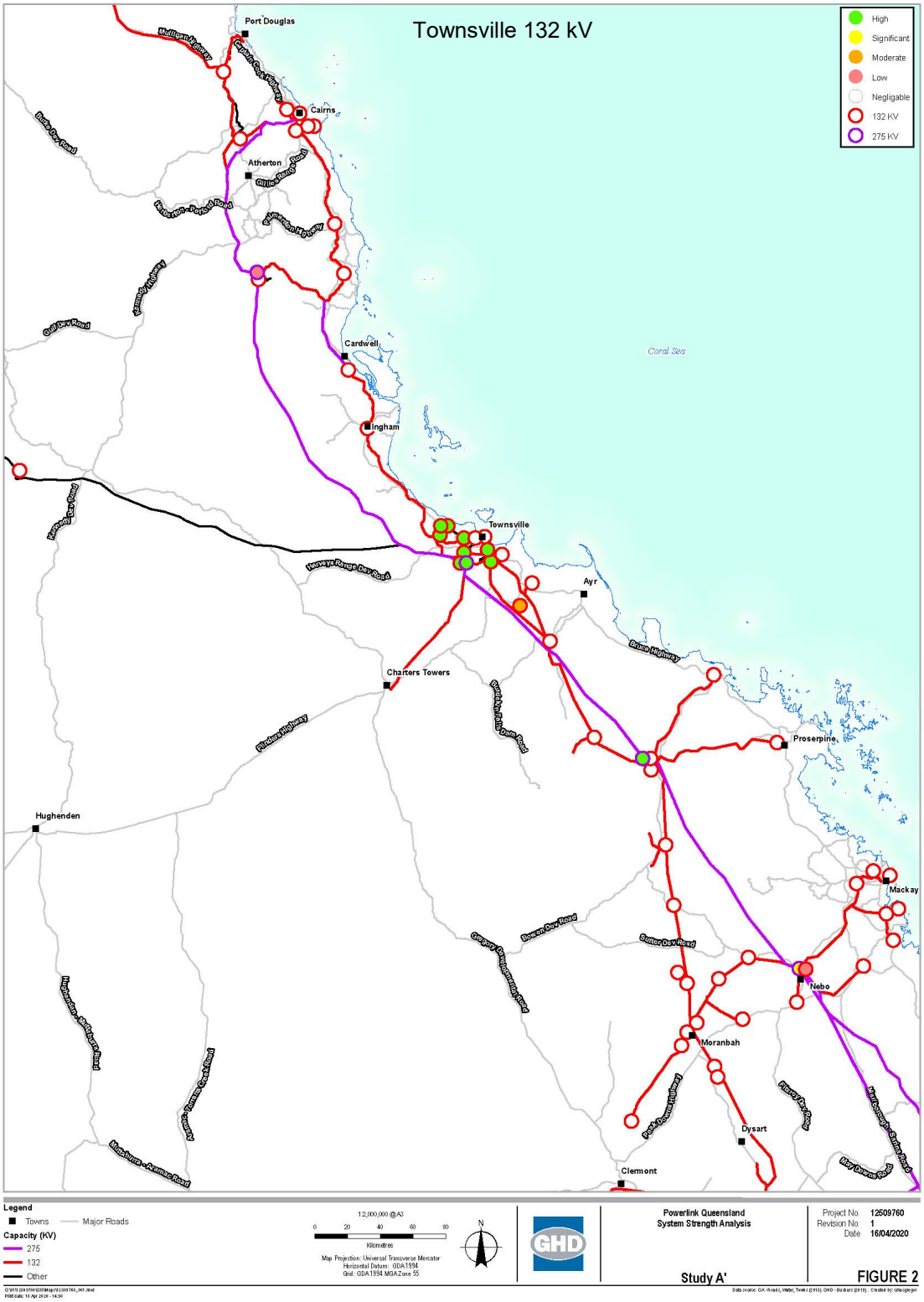
Study A

Low system impedance network, Good N-1 network configuration - System normal, 1 unit of synchronous condenser capacity installed.



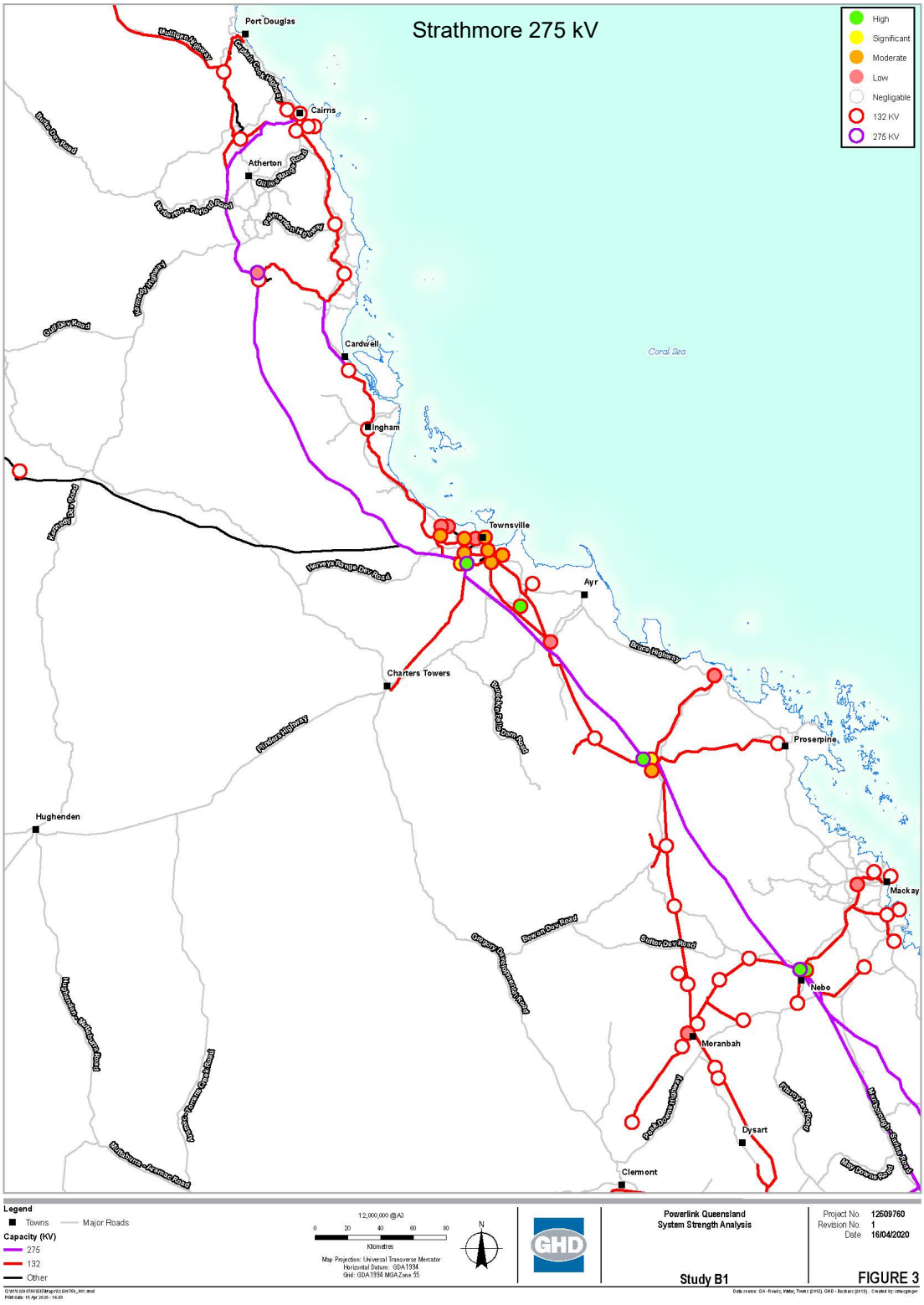
Study A’

Low system impedance network, Good N-1 network configuration - Contingency, 1 unit of synchronous condenser capacity installed.



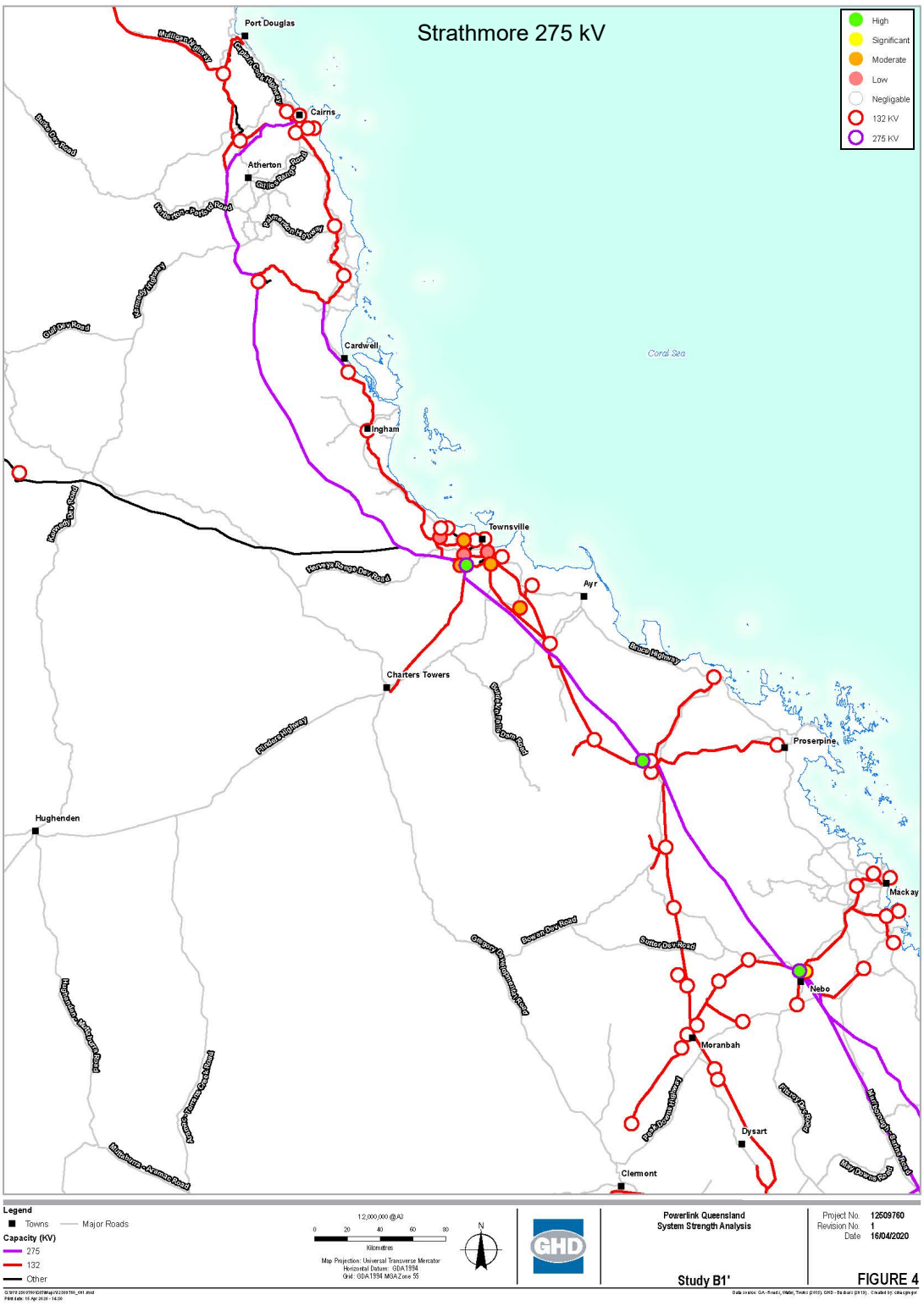
Study B1

Low system impedance network, Poor N-1 network configuration - System normal, 1 unit of synchronous condenser capacity installed.



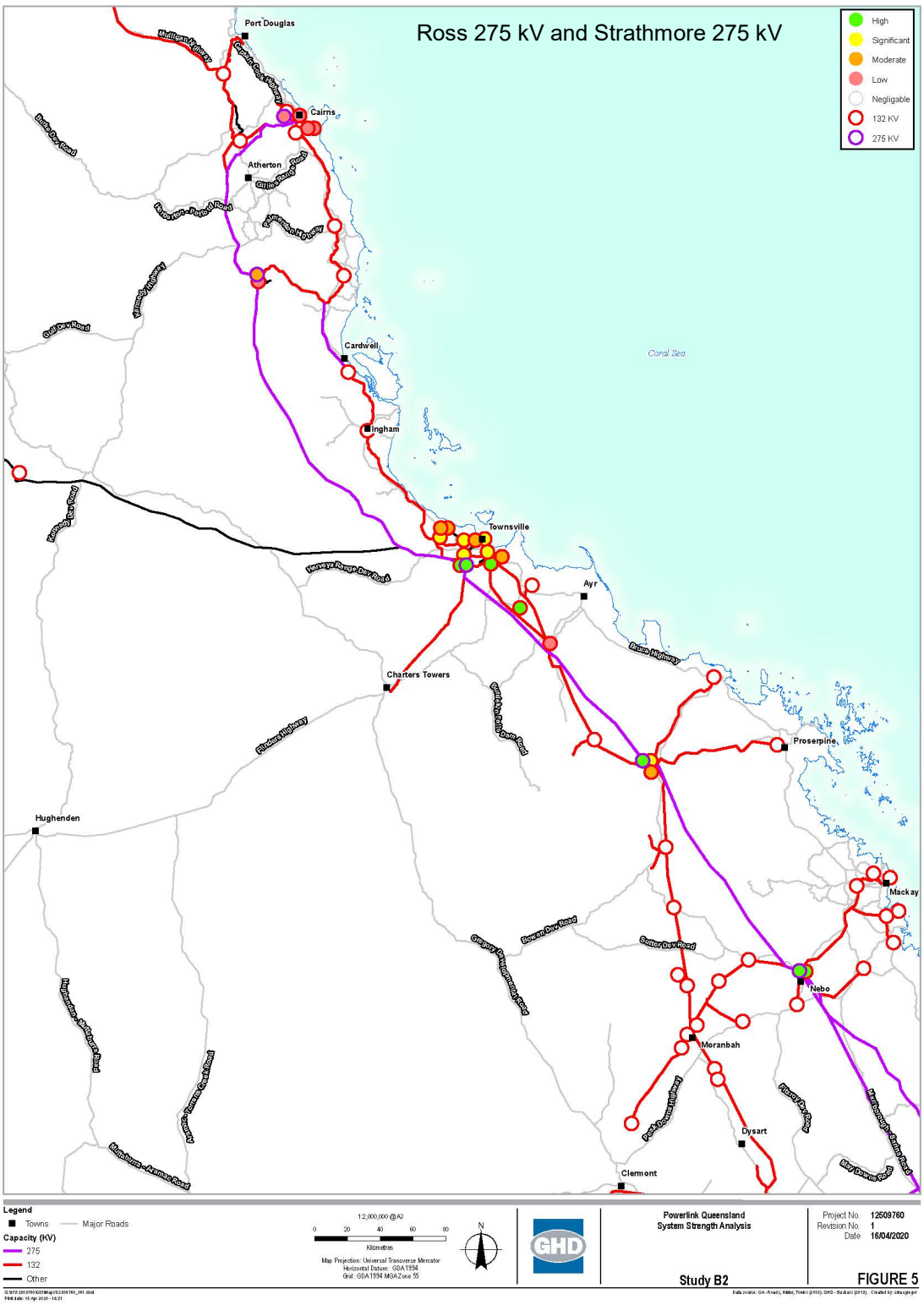
Study B1’

Low system impedance network, Poor N-1 network configuration - Contingency, 1 unit of synchronous condenser capacity installed.



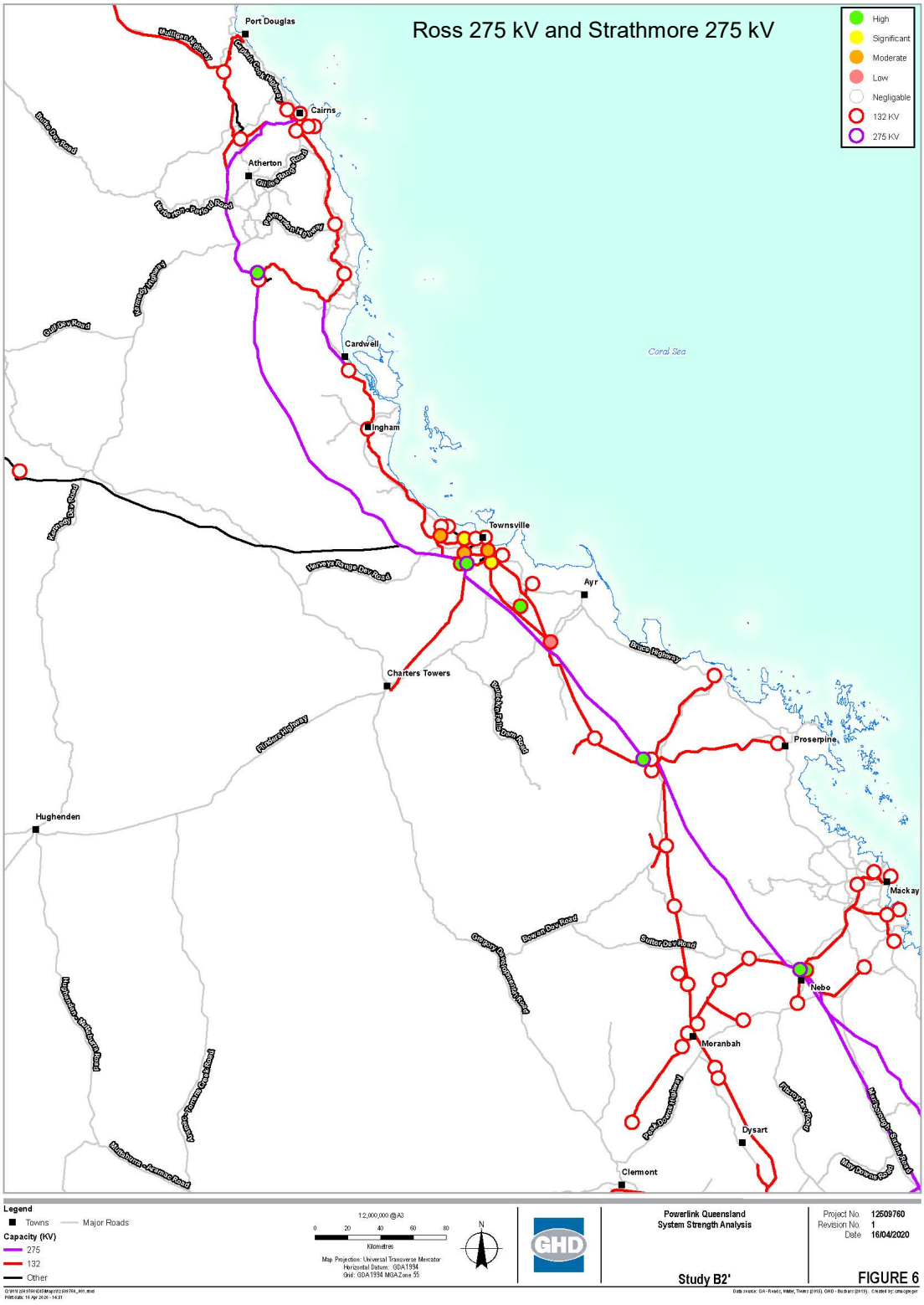
Study B2

Low system impedance network, Poor N-1 network configuration - System normal, 2 x 0.5 units of synchronous condenser capacity installed.



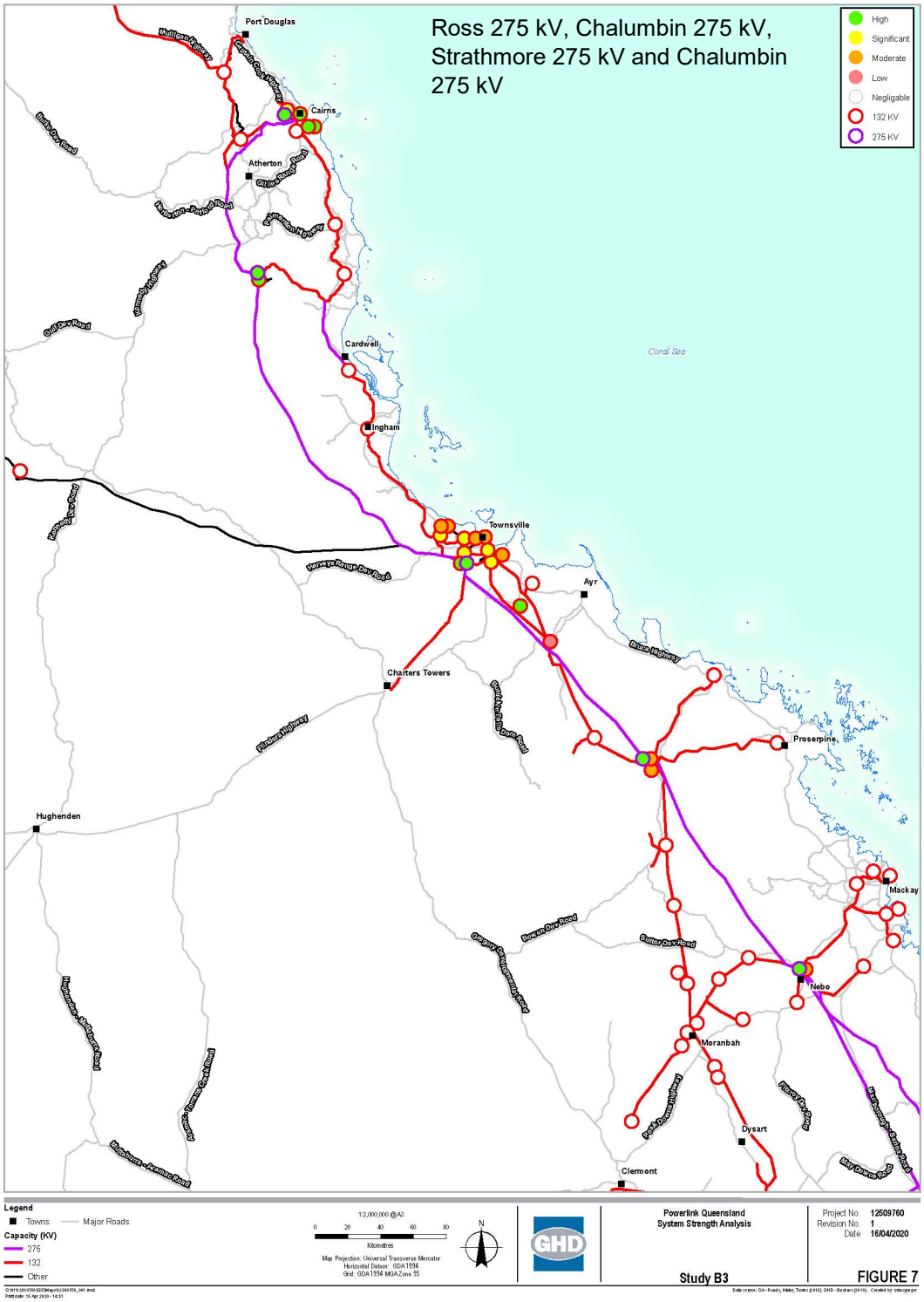
Study B2’

Low system impedance network, Poor N-1 network configuration - Contingency, 2 x 0.5 units of synchronous condenser capacity installed.



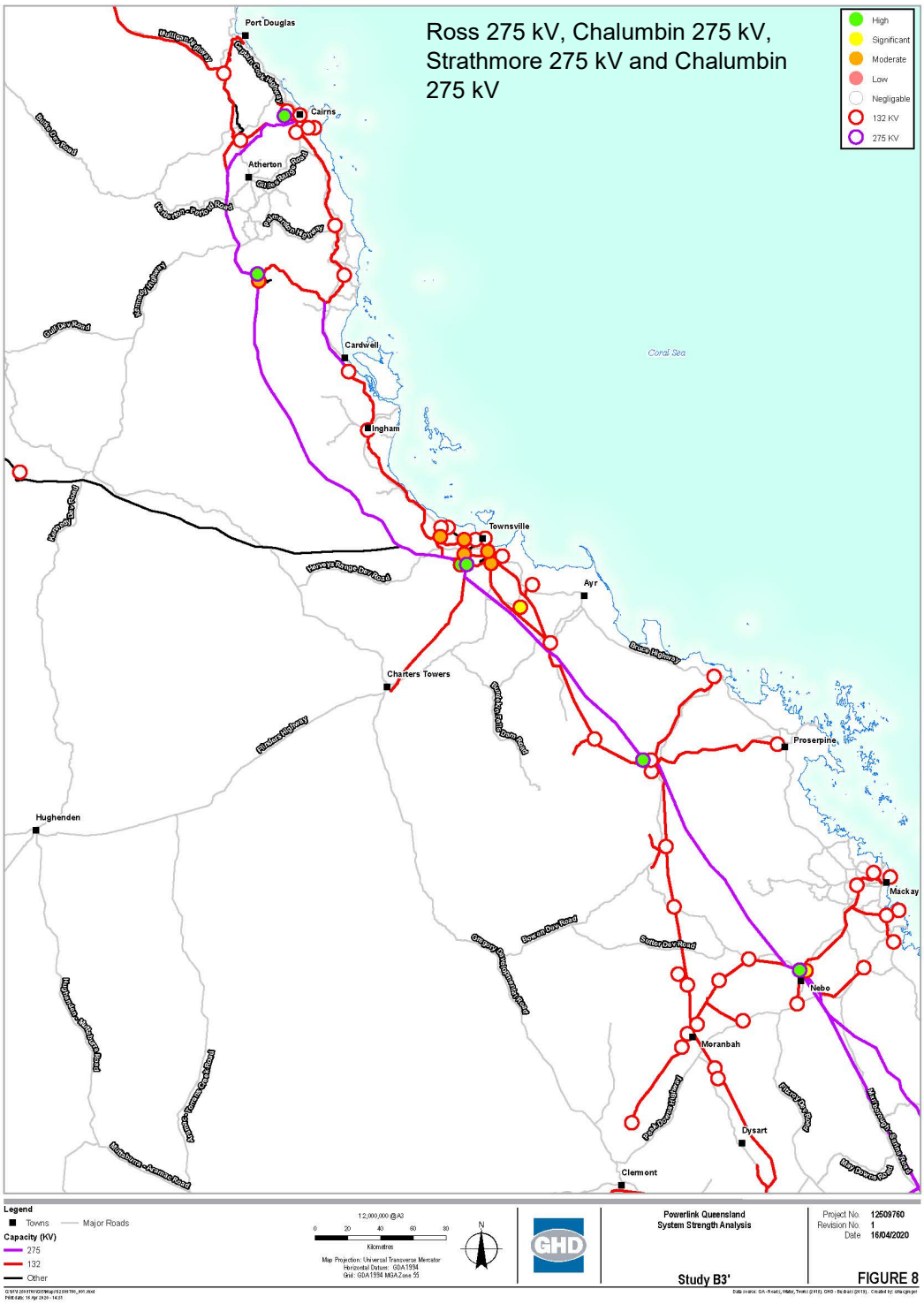
Study B3

Low system impedance network, Poor N-1 network configuration - System normal, 4 x 0.25 units of synchronous condenser capacity installed.



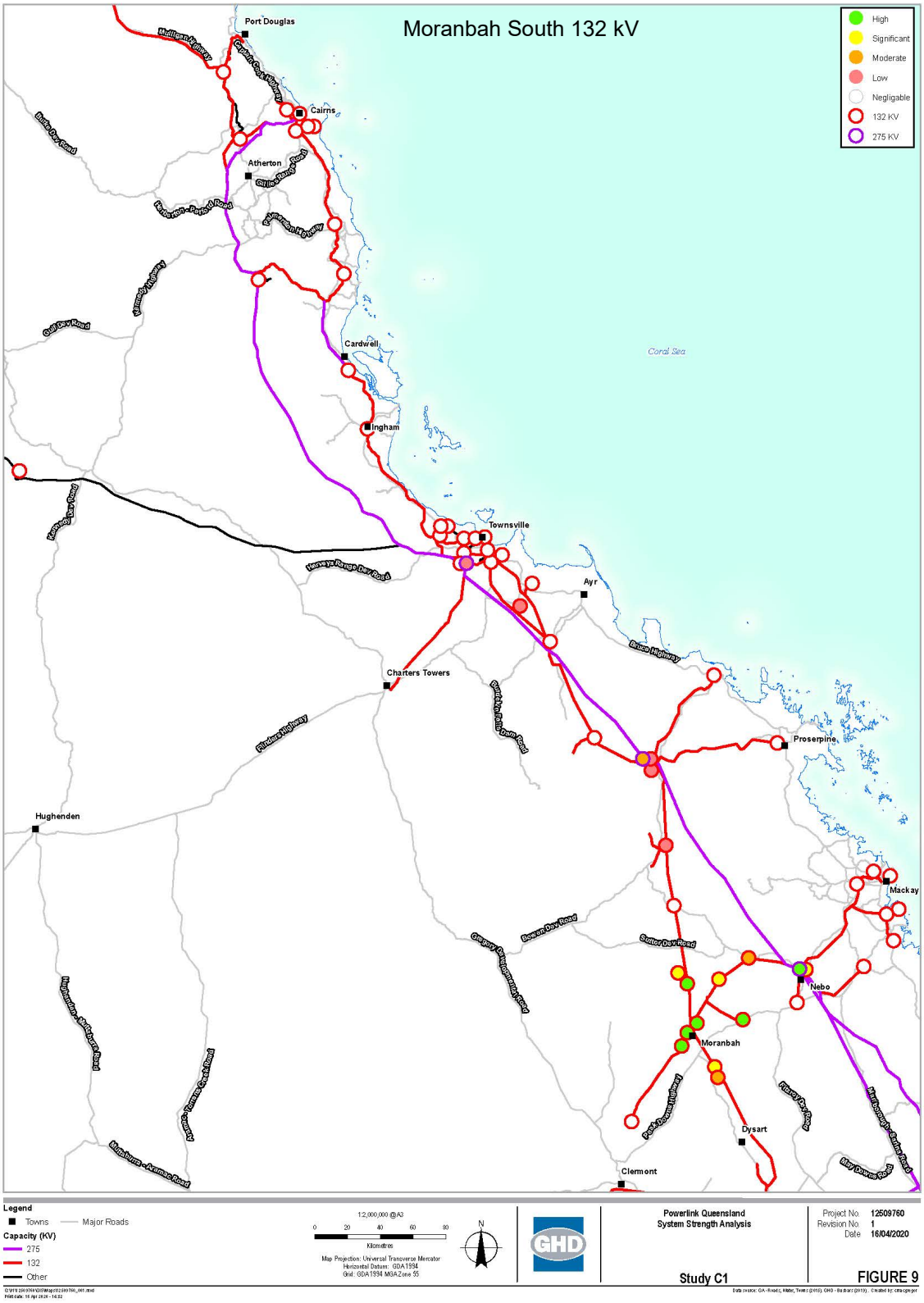
Study B3'

Low system impedance network, Poor N-1 network configuration - Contingency, 4 x 0.25 units of synchronous condenser capacity installed.



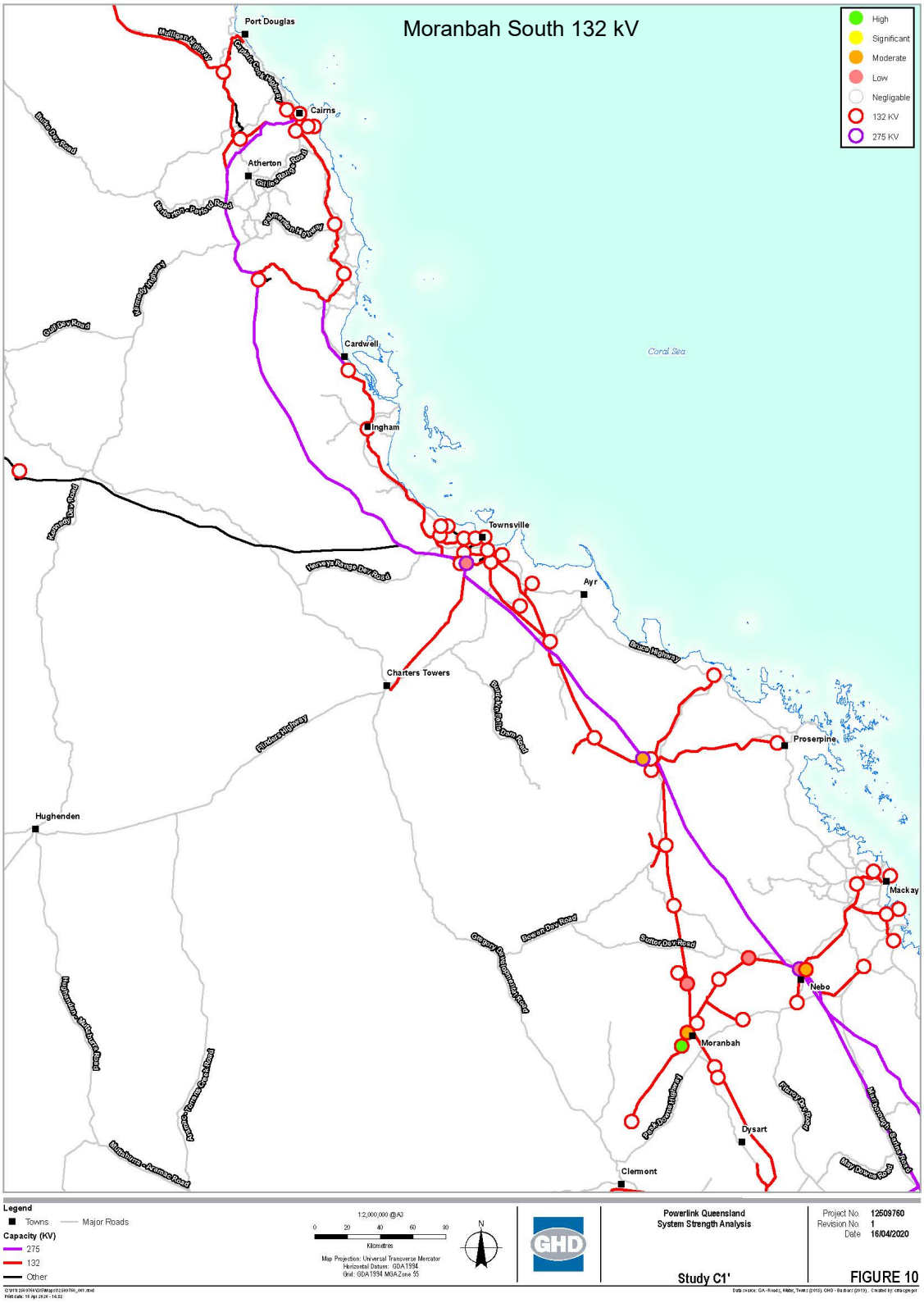
Study C1

High system impedance network - System normal, 1 unit of synchronous condenser capacity installed.



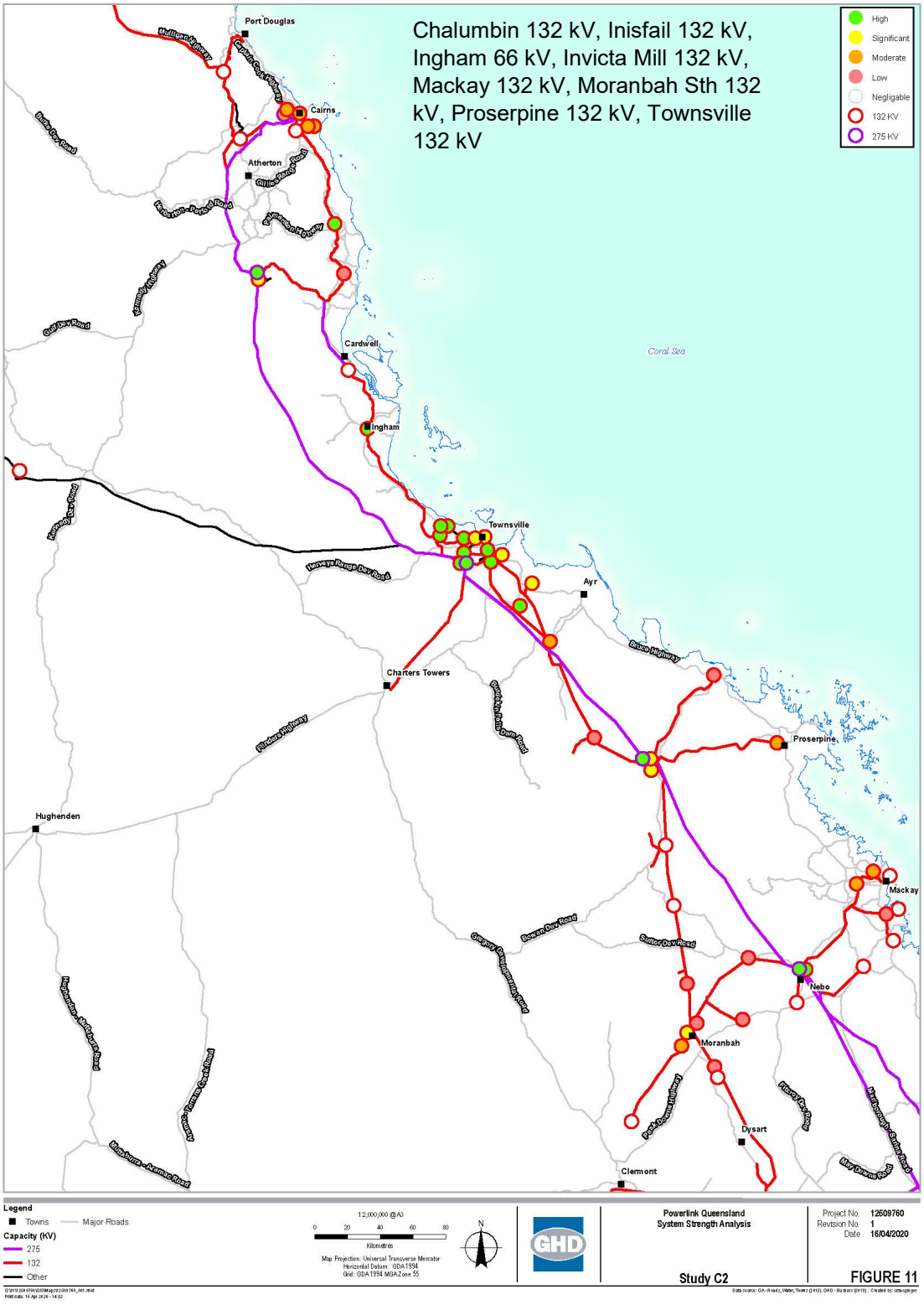
Study C1'

High system impedance network - Contingency, 1 unit of synchronous condenser capacity installed.



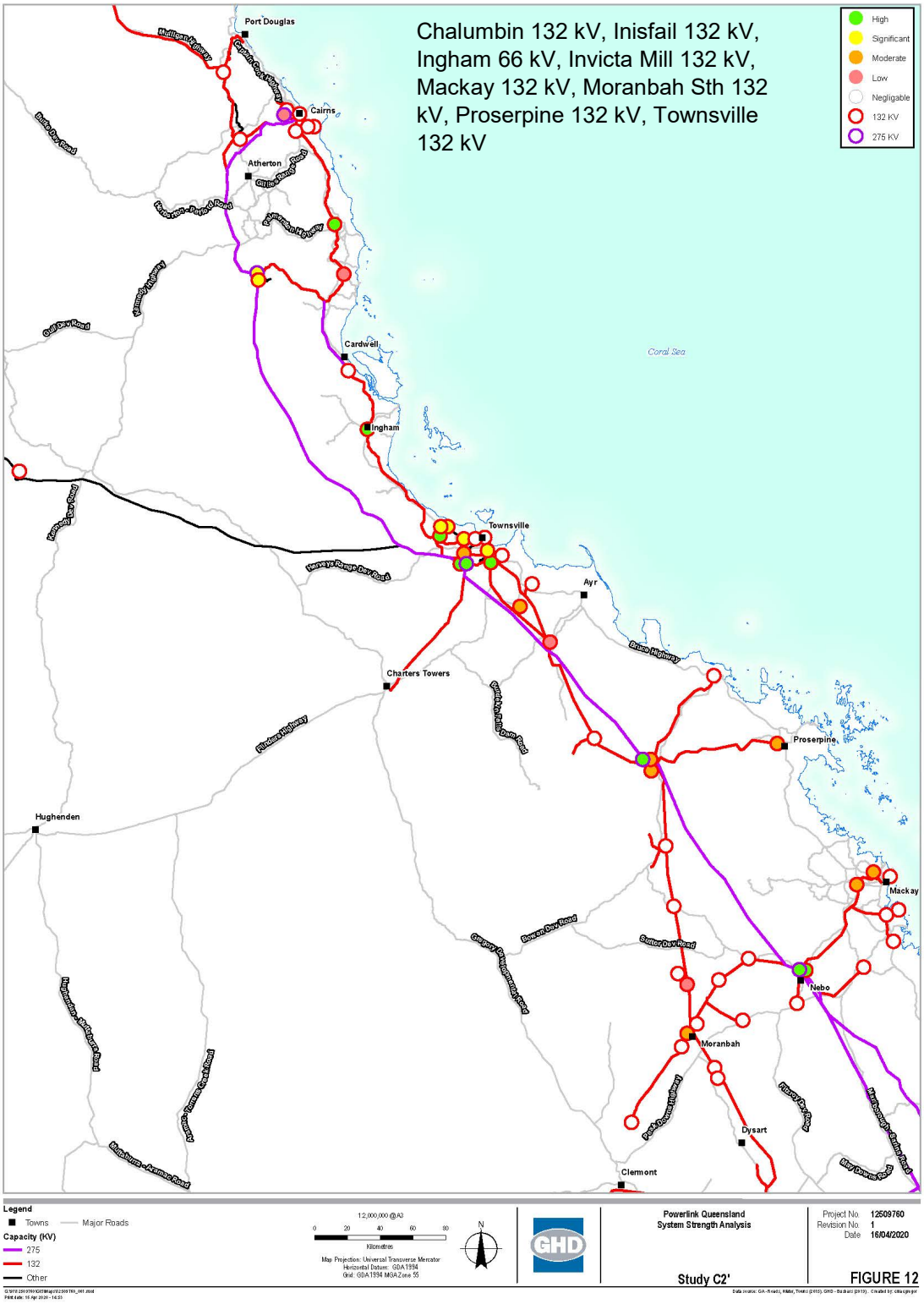
Study C2

High system impedance network - System normal, 8 x 0.125 units of synchronous condenser capacity installed.



Study C2'

High system impedance network - Contingency, 8 x 0.125 units of synchronous condenser capacity installed.



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In addition to the primary author and reviewers listed below, we would like to acknowledge the input from Peter Mangan, Craig Owens, Richard Hickling, Sefanit Birku and Helen He from GHD in preparing this report together with the invaluable support from Powerlink, Sun Metals and Pacific Hydro.

Rev.No.	Author	Reviewer		Approved for Issue		
		Name	Signature	Name	Signature	Date
3 Final	Jack O'Brien	Stephen Hinchliffe			David Bones	29/04/2020

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