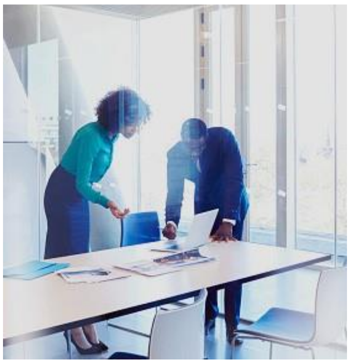

Review of Essential System Services in the Northern Territory

Final Report

Department of Industry, Tourism and Trade

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Executive summary

Essential system services refer to a range of services relied upon by electricity network and system operators to help deliver a secure power system. GHD has been commissioned to prepare a report that identifies, and provides guidance on, appropriate definitions, categories and specifications for essential system services required in the each of the three regulated power systems in the Northern Territory (NT).

The purpose of GHD's report is to inform the development of policy reforms that will enable essential system services to be provided in a manner that:

- aligns with the National Electricity Objective[1]; and
- accommodates the changing requirements of the regulated power systems (e.g. new technologies).

The case for reform of essential system services

A framework for essential system services is required to support the NT's regulated power systems to continue operating securely and reliably, ensuring adequate power quality for customers connected to those systems. The framework must also be capable of providing appropriate price signals to NT regulated power system stakeholders to allow efficient investment decisions. The reforms will pave an opportunity for a more efficient dispatch arrangement, with essential system services and energy needs considered holistically.

In this context, the essential system service definitions, categories, and specifications should therefore be capable of delivering:

- Disaggregated, clearly defined essential system services for black start, frequency, system strength and voltage management;
- Technology-neutral terminology and specifications, allowing flexibility towards any potential future arrangements for essential system services, to accommodate changing technologies or market conditions;
- Flexibility for the System Controller / appropriate head of power to procure additional services if required to retain system security or power quality;
- Technical specifications that do not unfairly disadvantage existing market participants, but allow new participants to compete to provide services;
- Alignment between the essential-system-service arrangements in each of the NT regulated power systems, where possible and practicable;
- Compatibility with reformed dispatch and market arrangements and the NT's new generator performance standards;
- Flexibility for volumes of essential system services required to be optimised for different system dispatch conditions; and
- Alignment with the NT Government's 50 per cent renewable energy by 2030 target.

[1] The National Electricity Objective is defined in schedule 1, section 7 of the National Electricity Law and is "“… to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to — (a) price, quality, safety, reliability and security of supply of electricity …”.

Recommendations

GHD's recommendations are divided into: (i) Definitions; and (ii) Reform implementation and next steps.

Definitions

GHD recommends a revised set of essential system services as per the table below.

Essential system service recommended definitions

Essential system service definition	Purpose
RoCoF control	• Control maximum rate of change of frequency (RoCoF) on power systems. • Ensure system security for credible contingency events and "protected events".
Contingency frequency control (raise)	• Stabilise frequency within "emergency" defined operating band after a credible contingency resulting in the net disconnection of generation. • Ensure system security without under frequency load shedding (UFLS) for all credible contingency events.
Contingency frequency control (lower)	• Stabilise frequency within "emergency" defined operating band after a credible contingency resulting in the net disconnection of load. • Ensure system security without over frequency generator tripping for all credible contingency events.
Regulating frequency control	• Regulate power system frequency within normal defined frequency operating band.
Voltage management / network support	• Management of network voltage control issues where required. • Management of network capacity shortfall issues where required.
System restart	• Enable the restart of the regulated power systems from a "black system" event.
System strength	• Provide sufficient system strength capability to ensure voltage stability and sufficient fault current when a shortfall is identified.

Reform implementation and next steps

GHD recommends a codified process for review of the suitability of essential-system-service volumes being procured is established, following the example of the current arrangements in the WEM. This will ensure the levels remain appropriate given the changing needs of the power systems', and interactions with wider reforms which may interact with essential system service requirements. The development of a codified review process and publication of the service level requirements will provide transparency and clarity to existing and future service providers. In addition, the framework for essential system services should allow for the freedom to not procure services for regulated systems where it is identified that these services are not required.

Where a shortfall in power system capability is identified resulting in a system security issue that cannot be managed through the planning timescales, the framework should allow the flexibility to define and procure additional essential system services where required. The implementation of the new essential systems services framework will likely require time for gradual reform and can be done in concert with a number of other measures to ensure power system security.

Finally, it is recognised that implementing the new technical requirements will likely be carried out in stages, and in parallel with the Northern Territory Energy Market (NTEM) Priority Reform Program. This may result in a temporary misalignment between the NT regulated systems with regards to their frameworks, as the reforms are implemented. Going forward, however, an aligned set of services in a consistent technical framework should be the desired outcome of the reforms.

Disclaimer

This report has been prepared by GHD for the Department of Industry, Tourism and Trade (DITT) in the Northern Territory, and may only be used and relied on by DITT for the purpose agreed between GHD and DITT, as set out in this report.

GHD otherwise disclaims responsibility to any person other than DITT arising in connection with this report. GHD also excludes implied warranties and conditions, to the extent legally permissible.

The services undertaken by GHD in connection with preparing this report were limited to those specifically detailed in the report and are subject to the scope limitations set out in the report.

The opinions, conclusions and any recommendations in this report are based on conditions encountered and information reviewed at the date of preparation of the report. GHD has no responsibility or obligation to update this report to account for events or changes occurring subsequent to the date that the report was prepared.

The opinions, conclusions and any recommendations in this report are based on assumptions made by GHD described in this report. GHD disclaims liability arising from any of the assumptions being incorrect.

GHD has prepared this report on the basis of information provided by DITT and others who provided information to GHD (including Government authorities), which GHD has not independently verified or checked beyond the agreed scope of work. GHD does not accept liability in connection with such unverified information, including errors and omissions in the report which were caused by errors or omissions in that information.

Glossary of terms

Term	Description
BESS	Battery Energy Storage System
C-FCAS	Contingency Frequency Control Ancillary Services
DITT	Department of Industry, Tourism & Trade
DTBI	Department of Trade, Business and Innovation. Now DITT
ESS	Essential System Services
FCAS	Frequency Control Ancillary Services
GPS	Generator Performance Standards
I-FCAS	Inertia Frequency Control Ancillary Services
I-NTEM	Interim Northern Territory Electricity Market
MW	Megawatt
NEM	National Electricity Market
NT	Northern Territory
NTC	Network Technical Code
NTEM	Northern Territory Electricity Market
OFGS	Over Frequency Generator Shedding
PV	Photovoltaic
PWC	Power and Water Corporation
R-FCAS	Regulating Frequency Control Ancillary Services
RoCoF	Rate of Change of Frequency
SCTC	System Control Technical Code
SSG	Secure System Guidelines
STATCOM	Static Synchronous Compensator
SVC	Static VAR Compensator
UFLS	Under Frequency Load Shedding
WA	Western Australia

Term	Description
WEM	Wholesale Electricity Market (WA)

1. Background and context

Electricity consumers supplied by the Northern Territory's regulated power systems expect a reliable and secure power system. Achieving this requires that the power system is operated such that the voltage and frequency remain within specified limits and that the system is robust enough to ride through a reasonable range of contingency events with little or no supply interruption. However, there is a trade-off between increasing security and costs imposed to the system, which must be considered when taking measures to improve security of supply.

Essential system services refer to range of services relied upon by network and system operators to help deliver a secure power system. Essential system services could include each of the following:

- Frequency control services;
- Services that limit the rate of change of frequency (RoCoF);
- System strength services;
- Voltage and reactive power control services; and
- System restart services.

Some of these services such as frequency control provide system wide benefits while others provide a more localised benefit such as reactive power or voltage control. The scope of the benefits, as well as the potential pool of participants capable of providing a service can influence the appropriate means for procuring a service, and the party that is best placed to manage the procurement and dispatch of the service. The Department of Industry, Tourism and Trade (DITT) has engaged GHD (us) to prepare a report to provide advice on these matters.

This GHD report explores appropriate categories, definitions and specification for essential system services required in the each of the Northern Territory's regulated electricity systems (Darwin-Katherine, Alice Springs, and Tennant Creek). The purpose of the report is to inform the development of policy reforms that will enable these services to be provided in a manner that aligns to the National Electricity Objective[2] going forward as the power systems, technologies and their requirements change over time.

In this chapter, GHD briefly outlines the reform process to date and summarises messages from the Government's Issues Paper, as well as further issues identified in stakeholder submissions responding to the Issues Paper that are relevant to GHD engagement.

1.1 Reform process to date

The Northern Territory Government is reviewing the arrangements for the provision of essential system services that support the Territory's power systems. The reforms coming out of the review will be implemented as part of the Northern Territory Electricity Market Priority Reform Program.

[2] The National Electricity Objective is defined in schedule 1, section 7 of the National Electricity Law and is ""… to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to — (a) price, quality, safety, reliability and security of supply of electricity …".

In June 2020, the Government published the initial scoping and work program for the broader reform program[3] and an Issues Paper on the review of essential system services[4]. The Issues Paper identified issues with the current arrangements, setting out a framework for reform, and inviting feedback and input from stakeholders. Specifically, the Government identified the scope of the Issues Paper to be:

- updating the quantum of the rate paid to Territory Generation for essential system services by other generators.
- codifying the process for reviewing and updating the quantum of the rate to ensure the rate remains up to date.
- improving the transparency of costs for individual and categories of services captured in the rate, such as by defining and separately costing each essential system service required.

In addition, in reviewing essential system services, the Design Development Team will review the merit of potential arrangements for the competitive provision of essential system services in the Territory's regulated electricity systems.

1.2 GHD's scope and assumptions

GHD was engaged by the Northern Territory Government to identify and provide guidance on appropriate categories, definitions and specification for essential system services required in the each of the Territory's regulated power systems. The purpose of GHD's report is to inform the development of policy reforms that will enable these services to be provided in a manner that aligns with the National Electricity Objective[5] going forward as the power systems, technologies and their requirements change over time.

In preparing analysis and this report, GHD has been guided by the Government's Issues Paper, submissions from stakeholders responding to the Issues Paper and discussions with representatives from the Government.

GHD has also considered:

- The effect the Northern Territory Government's 50% renewable energy by 2030 target policy will have on the future requirements for essential system services.
- The Priority Reform Program, including changes to implement a Northern Territory Electricity Market (NTEM).
- Work done by the system controller on disaggregation of essential system services in version 4.2 of the Secure System Guidelines.
- The capability of NT service providers to deliver essential system services.
- Developments in other power systems regarding essential system service reform.

In developing this report, GHD undertook desktop-based research considering the information outlined above. GHD has not independently verified the information provided, nor has it conducted power system modelling to specify volumes of essential system services that may be required.

[3] Northern Territory Government, *Northern Territory Electricity Market Priority Reform Program – Introductory notes on scope and work program*, June 2020.

[4] Northern Territory Government, *Review of Essential System Services in the Northern Territory– Issues Paper*, June 2020

[5] The National Electricity Objective is defined in schedule 1, section 7 of the National Electricity Law and is ""… to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to — (a) price, quality, safety, reliability and security of supply of electricity …".

To inform its analysis, GHD has drawn on its experience assisting with regulatory reform of essential system services in other jurisdictions, including in Western Australia (WA).

GHD understands that the Northern Territory Government may elect to publish this report to inform its review of essential system services and to support any subsequent changes to legislation and regulatory documents as required.

1.3 NT regulated system background

The three regulated power systems in the Northern Territory are, by size, Darwin-Katherine, Alice Springs, and Tennant Creek. The Network Operator and Power System Controller Role for each regulated system is undertaken by Power and Water Corporation, a government owned entity in the Northern Territory.

The electricity industry in the Territory, like elsewhere in Australia, is experiencing a rapid transformation, primarily driven by large growth in distributed solar PV systems as well as the connection of large-scale solar PV systems. This transformation is a key component of the future requirements of the power system and the need for essential system services to maintain system security.

The Darwin-Katherine power system is the largest in the NT, with maximum system demand steady at around 300 MW. This trend is forecast to continue, with modest growth of 0.76% per annum predicted for maximum demand. Minimum demand is close to 100 MW, and forecast to decline significantly due to the high uptake of rooftop PV systems, with a decline of 4.11% per annum predicted.

The Alice Springs power system has a maximum system demand of around 50 MW, with modest growth of 0.45% per annum predicted. Minimum demand is close to 11 MW and forecast to decline at 3.05% per annum between 2022/23-2028/29. However, the connection of a new facility is expected to boost demand on the power system, therefore the projected minimum demand is not expected to decline below current levels in the foreseeable future.

The Tennant Creek power system has a maximum system demand of around 7 MW, with modest growth of 0.45 MW expected to come from pipeline operators in the near future. Minimum demand has been close to 1.5 MW and forecast to be effectively flat.[6]

The majority of generation capacity connected to the Northern Territory regulated systems is thermal synchronous gas fired generation. However, the increasing uptake of solar PV has already required curtailment of renewable generation on the Alice Springs power system to maintain adequate synchronous generation to provide essential system services. The essential system services on the NT regulated systems, currently referred to as ancillary services are currently provided as a monopoly arrangement by synchronous generation owned by Territory Generation.

The current trends on the Northern Territory regulated systems, with declining levels of minimum demand forcing off generators, are likely to see further curtailment of renewable generation. This curtailment is required under the existing framework, to retain adequate ancillary service provision and system security requirements.

A change to the existing framework is therefore required, to meet system security needs, while allowing these to be met by the alternative technologies connecting to the NT regulated systems.

[6] 2018/19 NT Electricity Outlook Report

1.4 Essential system service concepts

Essential system services are required to assist with the secure and stable operation of the power system, ensuring adequate power quality for generators and loads.

1.4.1 Frequency management

Frequency regulation

In the Northern Territory, frequency is managed to a level of 50 Hz under normal operating conditions. Power system frequency reflects the balance between supply and demand. Maintaining frequency at 50 Hz therefore requires continuous balancing of generation and load. As generators are not redispatched continuously to adjust for every change in demand, frequency management services are required in power systems to maintain the balance, via constant frequency regulation. The purpose of maintaining a regulated frequency at 50 Hz, is to ensure power quality for connected generators and loads to the system. Failure to regulate frequency close to 50 Hz, leads to increased "wear and tear" on synchronous generators, and loads, especially motors.

Rate of change of frequency (RoCoF)

RoCoF is controlled on power systems by a combination of synchronous inertia, the store of kinetic energy provided by the aggregate rotating mass of all machines directly coupled to the grid, and the size of a contingency, causing a mismatch in power supply and demand and the resultant frequency change.

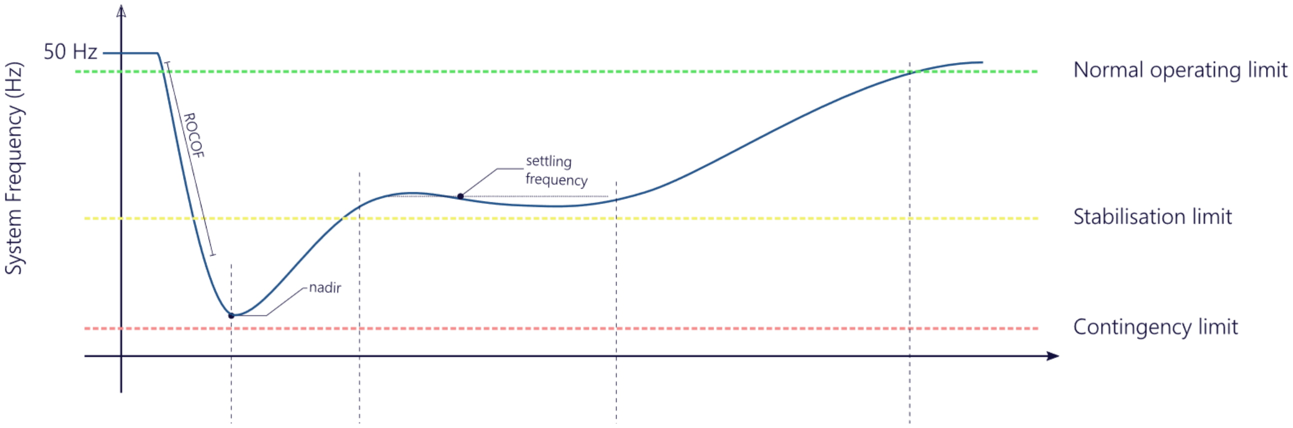
High RoCoF is undesirable and potentially threatening secure system operation, due to:

- Pole slip – High RoCoF can cause pole slip. Pole slip is a loss of synchronisation between a synchronous generating unit and the power system resulting in significant damage to the generating unit. Failure to arrest high RoCoF on a power system will lead to synchronous generators tripping to protect themselves from pole slip, or alternatively sustaining severe damage as they lose synchronisation. The automatic access standard in the Network Technical Code (NTC) allows generators to disconnect from the NT power systems if the RoCoF exceeds 4 Hz/s.
- Under frequency load shedding (UFLS) operation – UFLS relays operate at distinct frequency levels below 50 Hz and are set with a time delay for operation. A RoCoF level that is too high can cause a system frequency nadir below an acceptable level for system generation before UFLS relays have time to operate. Under these circumstances, generators will disconnect to protect themselves from the rapid decline in frequency. The automatic access standard defined in the NTC allows generators to disconnect at frequencies below 47 Hz after 2 s, or immediately once the frequency falls below 45 Hz.
- Contingency frequency or spinning reserve response time – A high RoCoF event requires a faster acting contingency frequency response to avoid the frequency nadir breaching the limits specified in the NTC. In this scenario frequency response providers need to quickly sense the frequency change and adjust their power output to arrest the frequency change.
- Anti-islanding protection – Many power systems use protection set on RoCoF to detect islanding or "loss of mains" on a network for embedded generation. This results in a straightforward method to trip embedded generation after islanding, thereby de-energising the islanded power system and allowing for technicians to complete works safely to re-energise. However, if RoCoF settings are set too low, this can exacerbate a response to generator contingency events, with embedded generation tripping under high RoCoF events.

Contingency frequency control

Figure 1 shows the response of a power system to a contingency event involving the trip of a generator. The chart shows a frequency response characterised by the initial RoCoF, the nadir or lowest frequency reached before the frequency settles to a stable point. The frequency then gradually recovers back to 50 Hz. A similar response can be drawn for a load contingency with the frequency increasing beyond 50 Hz, reaching a maximum point before the settling frequency is reached.

Figure 1: Frequency response of a power system to a contingency



Source: GHD Advisory, Essential System Service Framework review, report prepared for the Energy Transformation Implementation Unit (WA), July 2019

Contingency frequency control is required to arrest the change in frequency following generator and load contingencies and to restore the frequency to 50 Hz. Failure to arrest the change in frequency will lead to frequency operation outside of a defined contingency limit[7]. This can, depending on severity of the event, result in either under frequency load shedding, or generators disconnecting to protect themselves. An active power response must therefore be provided to arrest frequency change and restore frequency to 50 Hz following a contingency.

1.4.2 Voltage management

Voltage management and regulation is a universal concept required by power systems. Keeping voltages regulated between defined technical limits is required to allow voltage quality to be maintained for connected loads, which may suffer from mal-operation or failure due to lack of adequate voltage regulation. Historical studies of power quality requirements on systems have found a limited tolerance for operation below or above design voltages for loads. Low voltage may cause overheating, reduced torque and a shortened lifespan for a motor connected to the power system. Inverter connected equipment such as computers may also suffer from low or high voltages beyond design, with potential for damage and data loss.

Voltage regulation in steady state operation and under a contingency requires sufficient reactive power reserve to respond to the changing needs of the power system. Reactive power, which can be provided by equipment such as capacitor banks, static VAR compensators (SVCs), static synchronous compensators (STATCOMs), or by generators is required to compensate for the inherent inductive and capacitive elements of a power system, which otherwise could raise or lower voltage beyond defined limits.

Voltage management services may sometimes be required to maintain system voltages within bounds set in the NTC. Unlike frequency management, which is universal and power system-wide, in many areas of the

[7] The frequency limits applicable in the NT regulated power systems are specified in the NTC.

power system voltage management via essential system services will not be required because generators are inherently capable of producing adequate reactive power to keep voltages within acceptable levels and will provide this system support when dispatched.

However, in some areas of the network, ancillary equipment, such as reactors, capacitor banks, SVCs, STATCOMs and synchronous condensers may be required to control voltages, or voltage control could be provided through dispatch of a generator (where the generator is not already providing power).

1.4.3 System restart

Restart services are required to restart the system from a total power outage on the network. While not relevant to day-to-day system operation, a restart essential system service is required to ensure the system can recover in a timely manner following a blackout event.

1.4.4 System strength

System strength is an emerging issue on many power systems, particularly where inverter connected generation utilising grid following inverters, forms an increasing proportion of the generation mix. The three-phase fault level at a point in the power system is often used as a high-level indicator of system strength. Declining fault current contribution from inverter connected generation technologies, compared with conventional synchronous generators, leads to declining system strength and issues with protection operation, and extreme voltage variations including a higher rate of change of voltage. In addition, grid following inverters can be susceptible to unstable operation when connected to areas of the power system with low system strength.

Grid following inverters rely on tracking the voltage angle to control their output. In areas of poor system strength, the voltage waveform is less robust and significant changes in voltage magnitude and phase can occur, which can result in disconnection of inverter connected generation or activation of fault ride through response. In areas of low system strength, the action of generation connected via grid following inverters can significantly influence the voltage waveform. The interaction of these generators can lead to poorly damped or unstable power system oscillations.

System strength can be defined as the ability of the power system to maintain and control voltages and the voltage waveform at any given location on the power system, both during steady state operation and after a disturbance. System strength is distinct as an issue from voltage management, due to its cause, which is primarily due to an inability to maintain a robust voltage waveform and contribute sufficient fault current for reliable protection operation.

1.5 Structure of this report

The remainder of our report is structured as follows:

- **Chapter 2 Current arrangements** expands on the Government's description of the current arrangements for essential system services as codified in the NTC, SCTC and SSG.
- **Chapter 3 Case for reform** summarises the limitations of the existing framework for essential system services in the Northern Territory. To do this we draw on observations made independently by GHD as well as observations made by the Government and stakeholders responding to the Government's Issues Paper. The section makes a clear case for change.
- **Chapter 4 Future requirements** presents a recommended set of revised essential system service arrangements. The recommendations seek to align with the planned reforms to the electricity market,

support changing technology mix available on the power systems and allow the System Controller to continue to manage the power system securely and efficiently. Consideration has also been given to the ability for the revised service arrangements to send appropriate price signals to the market, including current and future service providers, and the Network Operator.

This section includes recommendations for the future work required to operationalise the recommended essential system service framework.

- **Chapter 5 Recommendations** presents a summary of the key recommendations and next steps.

2. Current arrangements

In the issues paper, the Government outlined the current essential system services arrangements. The current services and provisions related to their delivery are set out in various codes and guidelines, meaning there is no single point of reference for these services, which are currently referred to in all codes as "ancillary services".

The Network Technical Code (NTC) defines "ancillary services" as *"voltage control, reactive power control, frequency control, control system services, spinning reserve and post-trip management"*, however the System Control Technical Code (SCTC) has an alternative definition, of *"voltage control, reactive power control, frequency control, and black start capability".* In practice, the requirements for ancillary services and what they must accomplish in terms of power quality, system security and reliability are set out in the SCTC Chapter 5, while further guidance on how these services are specified and procured by the System Controller is given in the System Secure Guidelines (SSG) [8].

Territory Generation is currently the monopoly provider of all essential system services. The price for services is codified in Attachment 6.11 of SCTC and set at $5.40 per MWh. The price was established in 2014 and intended as a temporary arrangement, along with the implementation of the temporary interim market design expected to last for 6 months. This price does not distinguish between the services envisioned in the SCTC and SSG, nor has it been adjusted since being set. Generators pay Territory Generation this set price for the provision of services per MWh generated by each independent (non-Territory Generation) generator.

In this chapter, we expand on the Government's description of the current arrangements as outlined in their Issues Paper. We discuss the current frequency management, voltage management and restart services as well as identified services gaps in the subsequent sections.

The current arrangements for services, as defined in the SSG are outlined Table 2-1.

Table 2-1: Current defined essential system services

Type of service	Service
Frequency management	Regulating Frequency Control Ancillary Services (R-FCAS)
	Contingency Frequency Control Ancillary Service (C-FCAS) • Raise – fast, slow, delayed • Lower – fast, slow, delayed
	Inertia Frequency Control Ancillary Services (I-FCAS)
	Spinning reserve
Voltage management	Voltage control

[8] Northern Territory Government, *Review of Essential System Services in the Northern Territory– Issues Paper*, June 2020, p. 9

Type of service	Service
	Reactive power reserve
System restart	Black start capability

While the SSG makes provisions for the procurement of a variety of different essential system services, in practice the majority of these services are not currently enacted. The SCTC does not codify precisely how essential system services should be procured, instead giving guidance on the outcomes expected of essential system services. Therefore, there is significant scope available for guidance in the SSG to change in line with new technologies or to meet new system requirements. For example, we note that Contingency Frequency Control Ancillary Service (C-FCAS) and Inertia Frequency Control Ancillary Service (I-FCAS), provisions have been made in the SSG, without being enacted. Rather, the technical requirements of these services are provided for via the existing spinning reserve requirement, which is also defined in the SSG.

2.1 Frequency management services

The current ancillary service arrangements as defined in the SSG recognise the need for separated services to manage frequency regulation, frequency under contingencies and RoCoF. However, in practice the actual services procured are not entirely separated. While a separate “R-FCAS” regulating service (also referred to as “regulating reserve”) is currently procured, the SSG also lays out guidelines for the procurement of C-FCAS to control frequency under contingencies and I-FCAS to control RoCoF, however these are not currently enacted. The current “spinning reserve” ancillary service instead provides a frequency response under contingencies, and inherently provides inertia to control RoCoF as a by-product of synchronous generators holding the spinning reserve. The end of the spinning reserve arrangement, with its replacement by the separated I-FCAS and C-FCAS has yet to be implemented.

The minimum requirements and the current use of provision is summarised for each of the regulated power systems in Table 2-2, Table 2-3 and Table 2-4.

Table 2-2: Current and proposed provisions and operational use - Darwin-Katherine Power System

Service	Codified requirements[9]	Operational use of service
R-FCAS / regulating reserve	The greater of 5 MW or anticipated change in system load over 30 minutes.	In use
C-FCAS	SSG provides guidance as to how each C-FCAS service provider’s contribution to the overall C-FCAS requirement can be assessed by the Power System Controller. The SSG provides that the C-FCAS requirements are to be assessed by and approved at the discretion of the Power System Controller. The System Controller is yet to procure this service and yet to specify to the market the overall requirement for the system.	Implementation date not set
I-FCAS	Principles for determining a minimum requirement is set out in the SSG.	Implementation date not set

[9] All services are outlined in the SSG however some do not have an implementation date, and are not in practice enacted.

Service	Codified requirements[9]	Operational use of service
	SSG also provides that all inertia contributions (whether synchronous or emulated) towards the I-FCAS are only accredited by the Power System Controller. Minimum requirements and implementation date are yet to be determined.	
Spinning reserve	25 MW at all times, including a minimum of two Frame 6 machines that are: • on different nodes • loaded to 26 MW or below • not restricted in capacity or response	In use

As identified in the Government's Issues Paper: "In practice, the System Controller maintains higher combined levels of R-FCAS and Spinning Reserve in the Darwin-Katherine system than specified due to the size of the generators in the system and their minimum safe loadings (and other constraints on operation). The system is actually generally operated with a higher level of reserve capacity — at an average level of around 40 MW"[10].

Table 2-3: Current and proposed provisions and operational use – Alice Springs

Service	Codified requirements	Operational use of service
R-FCAS / regulating reserve	The greater of 2 MW or anticipated change in system load over 10 minutes.	In use
C-FCAS	SSG provides guidance as to how each C-FCAS service provider's contribution to the overall C-FCAS requirement can be assessed by the Power System Controller. The SSG provides that the C-FCAS requirements are to be assessed by and approved at the discretion of the Power System Controller. The System Controller is yet to procure this service and yet to specify to the market the overall requirement for the system.	Implementation date not set
I-FCAS	Principles for determining a minimum requirement is set out the SSG. SSG also provides that all inertia contributions (whether synchronous or emulated) towards the I-FCAS are only accredited by the Power System Controller. Minimum requirements and implementation date are yet to be determined.	Implementation date not set
Spinning reserve	The larger of either: • 8 MW during the day • 5 MW at night, or • the largest machine's output in MW.	In use^

^ Stakeholder submission from independent Alice Springs generator (Epuron) alleged that spinning reserve was commonly over procured on the Alice Springs system.

[10] Northern Territory Government, *Review of Essential System Services in the Northern Territory– Issues Paper*, June 2020, p. 16

Table 2-4: Current and proposed provisions and operational use – Tennant Creek System

Service	Codified requirements	Operational use of service
R-FCAS / regulating reserve	The greater of 0.5 MW or anticipated change in system load over 10 minutes.	In use
C-FCAS	SSG provides guidance as to how each C-FCAS service provider's contribution to the overall C-FCAS requirement can be assessed by the Power System Controller. The SSG provides that the C-FCAS requirements are to be assessed by and approved at the discretion of the Power System Controller. The System Controller is yet to procure this service and yet to specify to the market the overall requirement for the system.	Implementation date not set
I-FCAS	Principles for determining a minimum requirement is set out the SSG. SSG also provides that all inertia contributions (whether synchronous or emulated) towards the I-FCAS are only accredited by the Power System Controller. Minimum requirements and implementation date are yet to be determined.	Implementation date not set
Spinning reserve	0.8 MW at all times.	In use

In practice there is a discrepancy between the current codified requirements for spinning reserve and the way they are procured. For example, the Alice Springs system currently has an operational battery energy storage system (BESS) which is used to provide a C-FCAS response (rather than the officially enacted spinning reserve response), however as the requirements are written it is not clear whether this is considered to contribute to the spinning reserve total or not.

2.2 Voltage management services

In the Northern Territory, under the current framework, voltage control requirements are defined in the SCTC and NTC. There is currently no formalised ancillary service for voltage control in the NT regulated power systems defined in the SSG, although there is provision for an ancillary service in the SCTC. In practice, voltage control mandates applied by the System Controller can be used to require the provision of voltage control services by system participants.

Voltage management services on the NT Transmission power systems are provided by switching of reactive network devices, tapping of transformers and generators. The Generator Performance Standards currently enacted in the Network Technical Code clause require all generators to provide reactive power capability and control systems that ensure reactive power is provided as and when required to control voltage on the network (clauses 3.3.5.1 & 3.3.5.13).In current operational practice, existing synchronous generators are instructed to manage network constraints by being constrained on or off to provide localised active and reactive power support, particularly after contingencies where network capacity may be limited.

2.3 Restart services

The SCTC references a black system procedure in its ancillary services section, however in practice the capability for black start is currently provided by Territory Generation generators, consistent with the monopoly provision of other ancillary services. The Power System Controller is held responsible for black start procedure, is required to have a single restart procedure for each regulated power system, and is required to review arrangements for the procedure annually.

2.4 System strength

There is currently no essential system service for system strength defined on any of the NT regulated power systems.

Clause 3.3.5.16 of the NTC presents a framework for addressing adverse system strength impacts created by the connection of new generators or by modifying existing generating systems. The framework was introduced in March 2020 and requires the Network Operator to develop system strength impact assessment guidelines that describe how adverse system strength impacts will be assessed. Any generator that creates an adverse system strength impact is required to fund the investments required to mitigate those impacts.

The framework in the NTC provides a suitable means of assessing whether a new generation development or modification of an existing generating system is likely to cause an adverse system strength impact and if necessary provides a mechanism for the applicant to fund any necessary mitigations measures. However, the system strength framework in the NTC as currently implemented may not be able to address all system strength issues that could arise in the NT regulated power systems.

Retirement of existing synchronous generators may reduce system strength creating adverse impacts. If those retirements are not linked explicitly to the connection of a new generator then the framework in the NTC may not provide a mechanism to address the adverse system strength impact.

2.5 Mandatory requirements

Mandatory requirements for generators connected to the NT regulated power systems are not essential system services, however have been considered as part of the scope of this work because of their direct impact on essential system service procurement, especially with regards to frequency regulation.

There are currently mandatory requirements for frequency response applied to generators on the NT regulated power systems. The generator performance standards specified in the NTC require a frequency response capability with a deadband settable within the range of 0 ± 1.0 Hz and a droop[11] of between 1% and 6%. The deadband and droop settings are to be agreed with the System Controller. The SSG specifies deadband settings shown in Figure 2. The governor deadband is the maximum frequency change that can occur before the generator adjusts its active power output. The “active frequency control” deadband is the frequency deviation that will occur before the AGC system move the generator dispatch targets to correct frequency. Those generators capable of supplying R-FCAS are controlled by the AGC. Both deadbands are set inside the normal operating frequency bands for the NT regulated power systems.

[11] ‘Droop’ control is a type of primary control that regulates the frequency by adjusting the output active power (commonly) of a controlled asset (usually a generator).

Figure 2: Current normal frequency operating bands and generator mandatory requirements in the SSG

Normal Operating Frequency Band is:	DEFINED BY REGION.
Governor Deadband is:	50.00 +/- 0.025 hz.
Active Frequency Control Deadband is:	50.00 +/- 0.05 hz.
Emergency Operating Frequency Band is:	50.00 +/- 0.5 hz.
Regional Application	
Darwin/Katherine	
Normal Operating Frequency Band is:	50.00 +/- 0.2 hz.
Tennant Creek	
Normal Operating Frequency Band is:	50.00 +/- 0.4 hz.
Alice Springs	
Normal Operating Frequency Band is:	50.00 +/- 0.2 hz.

A move in the NEM away from this mandatory approach when ancillary services markets were first implemented, allowed generators to switch off their governors when not contracted to provide FCAS and to implement deadbands set to the limits of the normal frequency band. This led to a significant decline in the quality of frequency regulation around 50 Hz, with an increased burden on the providers of the AGC frequency regulation ancillary service. Changes have recently be introduced in the NER that require all generators to implement changes to their control systems to provide primary frequency response meeting primary frequency response requirements developed by AEMO[12] These changes require generators to implement narrow deadbands set well within the normal frequency band and to provide a 5% droop. Generators are required to provide frequency response (subject to energy source limitations) whenever they are synchronised.

Another measure taken by Power and Water Corporation and the Utilities Commission to assist with the regulation of frequency was the introduction of updated Generator Performance Standards (GPS) through revisions to the Network Technical Code (NTC). The new GPS approved in March 2020 require that all new licenced generators, which exceed the materiality threshold specified in the NTC, are predictable and controllable. As a result, new large-scale solar PV systems, for example, should not substantially add to the requirement for additional volumes of essential system services in terms of frequency regulation. Under the revised GPS, new generation systems should be capable of meeting their dispatch targets each half hour. The revised GPS also requires that all generators, that exceed the materiality threshold specified in the NTC, contribute to responding to frequency deviations recognising that this response will be subject to energy source limitations. In addition, the GPS places obligations on generating systems to ride through a RoCoF of up to ± 4 Hz/s.

The current reformed generator performance standards will reduce the burden on frequency regulation that would otherwise be imposed by the connection of non-dispatchable generation. This approach is consistent with a causer pays mechanism for frequency regulation because the capacity forecasting GPS ensure that generators that might otherwise contribute to an increased requirement for R-FCAS are instead responsible for mitigating their own contributions.

[12] https://aemo.com.au/-/media/files/initiatives/primary-frequency-response/2020/interim-pfrr.pdf?la=en

3. Case for reform

The Northern Territory Government outlined the case for reform in its Issues Paper published in June 2020. Further issues were identified by stakeholders in submissions to the Issues Paper and GHD has independently identified further issues.

This Chapter summarises the issues with the current arrangements, and the case for reform to better meet the NT regulated power systems' security and stability requirements as the systems change. We also identified guiding principles underpinning our recommendations and reform process.

3.1 Principles for change

An essential system services framework is required that will support the regulated power systems in the Northern Territory to operate securely and reliably, and to ensure adequate power quality for customers connected to those systems. The framework must also be capable of providing adequate price signals to NT regulated power system stakeholders to allow efficient investment decisions. The reforms also represent a greater opportunity to move towards a more efficient dispatch arrangement, with essential system services and energy needs considered together.

The principles for essential system services definitions, categories, and specifications should therefore be capable of delivering:

- Disaggregated, clearly defined essential system services for black start, frequency, system strength and voltage management.
- Technology neutral terminology and specifications, which allows flexibility towards any potential future arrangements for essential system services, whether these arrangements are changing technologies or market conditions
- Flexibility for the System Controller / appropriate head of power to procure additional services if required to retain system security or power quality.
- Technical specifications which do not unfairly disadvantage existing market participants but allow new participants to compete to provide services.
- Alignment between the essential system services arrangements in each of the NT regulated power systems where possible and practicable.
- Compatibility with reformed dispatch & market arrangements and new generator performance standards in the Northern Territory.
- Flexibility for volumes of essential system services required to be optimised for different system dispatch conditions.
- Alignment with the Northern Territory government's 50% renewable energy target by 2030.
- Transparency around determination, procurement, and dispatch of required essential system services volumes.

Specific issues with the existing essential system services definitions in terms of meeting the above targets are explored in Section 3.2.

3.2 Issues with current arrangements

3.2.1 Frequency management issues

The existing frequency management needs of the NT regulated systems are met by the existing spinning reserve and regulating frequency management services. However, the current needs of the system do not reflect its future requirements due to significant changes in the mix of technologies connecting to the regulated systems. As such, issues to be resolved with the current arrangements have been identified.

- The Northern Territory has a 50% renewable energy target by 2030, which requires a higher penetration of non-synchronous solar PV. As this target is met, it will inherently displace synchronous generators, the only generators capable of providing “spinning reserve”.
- Continuing to procure “spinning reserve” as the only essential system service controlling frequency following contingencies will result in the substantial curtailment of non-synchronous generation as this arrangement will require the constraining on of synchronous generators to provide the service.
- “Spinning reserve” inherently requires generators to be dispatched at less efficient output levels.
- A displacement of synchronous generators will cause a reduction in inertia on the systems in the Northern Territory, making the systems more likely to experience potentially damaging high RoCoF events. There will be a need for other methods of controlling RoCoF in the future.
- The current monopoly provision of frequency management services by synchronous generation isn’t feasible as new technologies connect to the NT regulated power systems i.e. inverter connected PV solar generation, without constraining off these new technologies. This arrangement is incompatible with a functioning competitive market for electricity on the Northern Territory regulated power systems and therefore is not aligned with the National Electricity Objective. The arrangement is also likely to inhibit achieving the existing 50% renewable energy target for the NT regulated power systems.
- Frequency management essential system services can be provided by other technologies, including BESS, loads capable of reducing/increasing power output and in some cases, non-synchronous generators. The current arrangements for frequency management services are not technology agnostic, and prevent alternative technologies providing essential system services.
- There are inconsistencies between frequency management services as defined and as procured i.e. the Alice Springs BESS is used for a spinning reserve function. This inconsistency should be addressed if essential system services are to be open to competitive procurement arrangements.
- The current arrangements for recovering the costs of providing essential system services do not recognise any differences in the need for services created by different generators and loads. Developing appropriate causer pays mechanisms for recovering the costs of providing essential system services may help drive more optimal power system developments as those parties that invest in equipment that require less essential system services would be rewarded by attracting lower essential system services costs.

3.2.2 Voltage management / network support issues

The existing generator performance standards mandating the provision of adequate reactive power from generators are fair and equitable, as all generators participate equally in providing investments necessary to support voltage control on the NT regulated systems. There are therefore limited circumstances under which a voltage control service would require procurement. However, an outage of a network element may require a generator to provide an active power response to support a load due to a network constraint. The current arrangements for provision of these network support services are not adequate for the system going forward. Mandatory provision of network support services by system participants can lead to generation dispatched out of merit order to maintain voltage control, contributing to inefficient system operation.

- Where generators are required to provide reactive capability when producing no active power e.g. solar farms at night, this falls outside the generator performance standards and should be considered as an essential system service if required to operate the system.
- Mandatory provision of network support services by system participants under the current monopoly framework will not be tenable for localised issues going forward. Where Territory Generation is not capable of providing a solution to a localised issue, provision of a voltage control service from an independent generator will be without any explicit compensation.
- Lack of unbundling of pricing of network support or voltage management services means there is no signalling or incentive for the network operator to resolve issues.
- Under a clear and transparent framework, shortfalls identified in reactive power reserve or network capacity could be met by a broader range of providers including both generators and loads, despite geographical limitation for providers of each service.

3.2.3 Restart service issues

- Current black start arrangements as defined are not open to be provided by “grid forming” inverters, or other future technologies which are technically capable of providing such a service. This will become more important as inverter connected generation increases its presence on the system.

3.2.4 Other issues

- Currently there are no specified essential system services for system strength. This may be a necessary requirement for future reliable operation of the power system. This essential system service may be required to manage adverse system strength impacts resulting from the retirement of synchronous generation rather than those effects directly attributable to the connection of new non-synchronous generation utilising grid following inverters. The essential system service would complement the system strength framework recently added to the NTC[13].

3.3 Service providers’ capabilities

The current spinning reserve regime can inherently only be provided by synchronous generators. The current SSG specifies specific generators “Frame 6 machines” to hold spinning reserve on the Darwin-Katherine Interconnected System – wholly owned by Territory Generation. While in practice network constraints may require provision of essential system services by generators or other technologies located in specific areas on the system, the codification of specific generators is not appropriate for provision of services by multiple technologies. If this codification is temporarily required due to existing network constraints i.e. minimum inertia requirements, this reasoning should be clearly defined in the SSG.

Implementation of separate I-FCAS and C-FCAS arrangements as outlined in the SSG would allow more technologies to participate in the provision of essential system services.

- The I-FCAS defined in the SSG allows for “emulated inertia” technologies to be given an inertial response accreditation by the System Controller. This in theory widens the potential I-FCAS service

[13] Clause 3.3.5.16 of the NTC defines the system strength framework for managing any adverse impacts caused by generator connections or the modification of existing generators.

providers from rotating synchronous machines providing inertia to include BESS or other fast responding inverter connected technologies. Flywheel technology can also be deployed to provide I-FCAS. ElectraNet is currently installing synchronous generators fitted with flywheels in South Australia to provide I-FCAS. However, the current definition of “emulated inertia” in the SSG may be inappropriate, as it raises performance characteristics including “measuring” time. Technologies capable of providing an inertial service should be capable of an instantaneous power response without the need for measurement of frequency.

- C-FCAS (raise) can be provided by synchronous generators and BESS. While in theory inverter connected renewable generation without any integrated BESS could provide a C-FCAS raise response, in practice to do so they would need to operate below their maximum power output consistently, suffering a very significant efficiency penalty, which is undesirable for generators with zero marginal cost for production. To meet their obligation consistently, with no disruptions from weather events, energy storage would also be required. Therefore, inverter connected generators without an integrated BESS do not typically seek to provide C-FCAS raise services.
- C-FCAS (lower) can be provided by synchronous generators, inverter connected generators and BESS. The discrepancy in provision of C-FCAS (lower) and (raise) provides justification to differentiate these services, to facilitate a greater degree of participation in the competitive provision of C-FCAS lower services.

  Embedded PV systems utilising inverters that adhere to the latest Australian Standard (AS 4777) should provide a response that reduces their output following a load contingency that increases system frequency. While the embedded generation response could present a meaningful aggregate level of service, it may not be cost effective for a customer with embedded systems to invest in the metering infrastructure and testing regime necessary to provide ongoing validation of their ability to provide a lower C-FCAS service.
- R-FCAS can be provided by synchronous generators and BESS. In practice, R-FCAS is not typically provided by inverter connected generation that does not incorporate BESS due to the efficiency penalty required to provide a bi-directional regulation service. Inverter connected renewable generators that do not incorporate a BESS could provide a unidirectional service, providing an R-FCAS service that only operated to correct over-frequencies.
- Black start services can be provided by both synchronous generators and by “grid forming” inverter connected generation and BESS. However, in practice, the majority of inverter connected generators are not capable of “grid forming” unless their control system is specifically designed to be so. In each case the black start service provided needs sufficient capacity to not only restart themselves but to also support the re-energisation of transmission corridors to allow reconnection of loads and other generators. Hence the technology deployed, its capacity and location of a facility are all factors that need to be considered when assessing whether it can act as a viable black start service provider.

Table 3-1: Existing technical capability for essential system services provision (SSG defined services)

Service	Territory Generation – synchronous generation	Independent synchronous generation	Independent large-scale solar	Distributed generation (i.e. rooftop PV)
Spinning reserve	✓	✓		
I-FCAS	✓	✓		

Service	Territory Generation – synchronous generation	Independent synchronous generation	Independent large-scale solar	Distributed generation (i.e. rooftop PV)
C-FCAS (raise)	✓	✓		
C-FCAS (lower)	✓	✓	✓	✓
R-FCAS	✓	✓		
Black start	✓	Unknown		

Source: GHD Advisory analysis based on Utilities Commission data [2018-19 NT Electricity Outlook Report], 2020

The capability of existing system participants to provide essential system services is more limited, however the revisions to the existing Generator Performance Standards, approved by the Utilities Commission in March 2020, require connecting generators to meet a capacity forecasting obligation. Meeting this obligation can be done through a variety of measures, but one outcome of this obligation is likely to result in renewable generators installing or contracting with energy storage systems, likely in the form of BESS.

New renewable generators should therefore be capable of providing and competing for a wider range of essential system services, although in practice the C-FCAS (raise) service may see less competition from this generation, due to battery capacity being required to maintain capacity forecasting requirements. However, new BESS coupled with renewable generators should be capable of providing an I-FCAS equivalent service, C-FCAS (lower) and R-FCAS. Provided adequate incentives are provided to establish a framework for compensation for installation of such equipment and provision of such services, there is also no barrier for “grid forming” renewable generation to provide black start services.

4. Future requirements

The following requirements need to be met to ensure the power system will have the right mix of resources in real time, and at the lowest overall cost to consumers:

- Establishing robust techniques to forecast the requirement for essential system services under different dispatch scenarios
- Establish efficient processes for procuring essential system services that values services available from all providers and ensures sufficient services are procured to meet the power system requirements.
- Incorporating a mechanism in the pre-dispatch and dispatch process that provides visibility and enables efficient use of the diverse set of resources ahead of time to ensure all necessary system services will be available, without costly and distortionary interventions.
- Establishing an appropriate and fair means of allocating essential systems services costs across system participants.

4.1 Frequency management

There are three forms of frequency management which together are required to give the Northern Territory power systems a flexible, suitable approach to managing frequency going forward. As identified in the sections below, there is overlap in the requirements suggested for the future and the existing provisions in the SSG. We discuss the need for the following services in turn:

- RoCoF control service
- Contingency frequency control service
- Regulating frequency control service

4.1.1 RoCoF control service

The purpose of a RoCoF control service is to control the rate of change of frequency on the power system following contingencies.

The Inertia Frequency Control Ancillary Service (I-FCAS) specified in the SSG, if enacted, is a technical equivalent to a RoCoF control essential system service. We suggest that this service is defined as a RoCoF control service – this provides a technology-neutral description of the required services, whereas inertia (and therefore I-FCAS) is a characteristic of synchronous machines. This is likely to become more important going forward as more technologies become capable of providing RoCoF control and avoids the description of such technologies as “emulated inertia” where this may not be appropriate.

RoCoF control has previously been provided on Northern Territory power systems as an inherent by-product of spinning synchronous generators, which provide inertia, limiting the total RoCoF which occurs after contingencies[14]. This has not previously required a specific service, due to the inherent capabilities of synchronous generators. Increasing penetration of photovoltaic solar generation, which provides no inherent inertia, will increase the need for a RoCoF control service to be explicitly defined and procured to ensure secure and stable operation of the regulated systems.

[14] Note there is an inversely proportional relationship between inertia and RoCoF, hence when more inertia is inherently provided, RoCoF reduces.

The purpose of a RoCoF control service is therefore to prevent a high RoCoF causing damage to equipment or the system, resulting in at the extremes, a black system event. The following subsections discuss the requirement for RoCoF control to cover credible contingencies and protected events, the technology provisions, and the procurement arrangements in turn.

Credible contingencies and Protected Events

Due to the system security implications for a high RoCoF event outlined above, a RoCoF control service must be specified to cater for both credible contingency events and “protected” contingency events. UFLS or over frequency generator shedding (OFGS) will not be able to affect RoCoF, and therefore will not prevent any of the severe consequences to equipment or the system caused by a high rate of change of frequency. The current definitions for credible contingency events and protected contingency events are outlined in Box 1 below.

Box 1: Credible contingency events and protected contingency events

In the Northern Territory, credible contingency event is defined in the NTC for planning purposes and in the SCTC for operational purposes.

In the SCTC, credible contingency event is defined as “A *contingency event*[15], the occurrence of which the *Power System Controller* considers to be reasonably possible as defined in Clause 3.2.7 [of the SCTC]”. Examples provided in section 3.2.7 of the SCTC include:

- the unexpected automatic or manual disconnection of, or the unplanned reduction in capacity of, one operating generating unit; or
- the unexpected disconnection of one major item of transmission plant (e.g. transmission line, transformer, or reactive plant) other than as a result of a three-phase electrical fault anywhere on a power system.

Protected events are contemplated in the SSG. In accordance with section 3 of the SSG, under normal conditions, the following contingencies are classified as protected:

- Loss of the 132 kV Transmission line south of Channel Island– Only to the extent that the southern region may go black, impact to the remainder of the Darwin-Katherine System is managed as a credible contingency and should not result in UFLS.
- 132 kV Channel Island Nodes are operated as protected events. Outage planning and dispatch is managed to prevent System Black, however UFLS may occur.
- Loss of multiple transmission lines due to shared towers.

The definition of “protected” contingency against credible contingency is not part of the scope of this review. However, due to load shedding not ameliorating severe consequences as a result of an unacceptably high RoCoF, a wider range of contingency events must be inherently be catered for when specifying this service. Agreement on protection against particular contingency events must be considered within a wider framework, accounting for the costs of RoCoF control against implications for system security, system planning criteria and other measures to manage contingency sizes.

Specification of a secure RoCoF limit

Procurement of a RoCoF control service requires the study and assessment of a secure RoCoF limit for each regulated system in the Northern Territory.

[15] A *contingency event* is defined in the SCTC as “An event affecting a *power system* which the *Power System Controller* expects would be likely to involve the failure or removal from operational service of a *generating unit* or *network element* as defined in clause 3.2.7.”

Factors that must be weighted and considered when setting a secure RoCoF limit include:

- Maximum credible or "protected" contingency size – RoCoF on a power system is a function of system inertia and contingency size, therefore the maximum possible contingency size required to be secured will define the volume of service required to set RoCoF to an acceptable limit.
- Generation ride through capability – The ability of existing synchronous generators to ride through high RoCoF events is often a limiting factor for allowable RoCoF on a power system.
- UFLS / OFGS operating times – This must be aligned with the secure RoCoF limit to allow for operation in enough time to prevent a severe frequency nadir / peak.
- Contingency frequency operating band – The allowed RoCoF will define the time available for frequency control actions to take effect before the frequency reaches the edge of the contingency operating band. The contingency frequency control band describes the extent of frequency deviation allowed following a contingency. Clause 2.2.2(b) specifies that frequency must remain between 47 Hz and 52 Hz under abnormal conditions.
- RoCoF protection – These protection settings are used as "loss of mains" protection for embedded generators in many power systems (and are currently allowed by clause 3.4.10 of the NT Generator Performance Standards). These settings must be aligned with a secure RoCoF limit to prevent the tripping of embedded generation exacerbating contingency events.
- Contingency frequency response time – This must be aligned with a secure RoCoF limit for credible contingency events (where load shedding is not expected) to ensure a contingency frequency essential system service is able to respond in time to prevent a frequency nadir / peak that falls outside of the contingency frequency operating band.

Currently the secure RoCoF limit has been defined on the NT regulated systems as 4 Hz/s. Aligning with this, the new automatic access standard for generators defined in the revised NT Generator Performance Standards clause 3.3.5.3 requires that all new generators connecting be capable of riding through a 4 Hz/s RoCoF. Under a review of the existing generator performance standards, PWC advised that generators connected to the NT regulated systems had demonstrated capability of riding through 4 Hz/s RoCoF events.

Although the 4 Hz/s limit is defined in the NTC, the SSG state that the figure is "preliminary only and further assessment is required". Further works to establish confidence in its specification will require, at minimum;

- certification / evidence of existing generation ride through capabilities,
- assessment of UFLS relay operating times and their effectiveness under a 4 Hz/s contingency event,
- assessment and/or changeover of current RoCoF protection settings on the NT regulated systems for embedded generation, including rooftop PV solar, to ensure that a 4 Hz/s contingency event will not result in significant nuisance tripping which could exacerbate RoCoF problems.

The current RoCoF limit does not have to remain a static requirement going forward. It may be more cost effective for the regulated NT systems to relax contingency frequency operating bands or change the speed of response required from Contingency FCAS service providers, change UFLS relay settings to faster times, change RoCoF protection settings and require higher RoCoF ride through standards for connected synchronous generators. In practice many power system operators, in Australia and Europe facing greater penetration of non-synchronous generators are transitioning to gradually higher allowable RoCoF limits, through the imposition of more onerous ride through requirements in Generator Performance Standards, programs to change RoCoF protection settings, retirement of legacy generation unable to tolerate high

RoCoF levels and procurement of faster acting contingency frequency control equivalent services, such as Fast Frequency Response.

The costs of implementing such standards, services and programs must be considered against the cost of procurement for a RoCoF control service, which will be more expensive to procure as the allowable limit is set to a slower RoCoF. A move to a faster RoCoF limit than 4 Hz/s is not desirable on any of the NT regulated systems until the suitability of the current limit is defined and established. Additionally, certain requirements such as contingency frequency operating bands are already significantly relaxed in the NT compared to other power systems, and further relaxation is undesirable from a power quality perspective.

Technologies capable of providing the service

Keeping power system RoCoF controllable under a contingency currently utilises post-contingent synchronous inertia, which inherently instantaneously controls RoCoF as a physical consequence of the rotating mass connected to the power system by a synchronous machine.

"Zero-inertia" power systems, with no synchronous plant, and a BESS providing "grid forming" RoCoF control capability are technically possible and practicable, but in practice they have only been implemented on small islanded microgrids and stand-alone power systems, where control systems implementing grid forming algorithms can be co-ordinated. Implementation on larger power systems, which require integration with synchronous plant control schemes or interactions between multiple inverter control systems to retain a stable frequency following contingencies is still an area of development and it is therefore unlikely that the Alice Springs or Darwin Katherine power systems will be capable of zero inertia operation in the short to medium term. However, developments in technologies are likely to improve the performance and potentially the capability of alternative technologies to provide a RoCoF control service equivalent to synchronous inertia. Synchronous inertia differs from "fast frequency response" provided by grid following inverters, in that it is instantaneous, and does not require measurement, giving an immediate energy response.

Procurement arrangements

To control RoCoF to within a maximum defined limit, other power systems facing similar constraints due to penetration of non-synchronous generation have set "inertia floors", or a minimum level of inertia required to securely operate the power system. This approach has been considered by AEMO in South Australia[16] (also resolving system strength issues) and EirGrid in Ireland.[17]

Larger interconnected power systems such as the NEM, do not have an inertia floor requirement, primarily due to a large level of synchronous inertia inherently dispatched as baseload. This approach will not be suitable for an NT regulated power system requiring penetration of non-synchronous generation in excess of 50% to meet the current NT renewable generation target for 2030. The NT regulated systems have characteristics similar to a smaller islanded power system, such as the disconnected South Australia, or Ireland. It is therefore suggested that approaches adopted to control RoCoF in those smaller isolated systems are followed as examples for defining a solution to the issue in the NT regulated systems.

Defining a requirement for inertia to control RoCoF is not inherently technologically neutral and potentially a barrier to entry for future technologies which, when developed may be capable of providing an equivalent energy response. A RoCoF control service requirement in defined in MWs (the normal unit used to measure

[16] https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2020/2020-notice-of-south-australia-inertia-requirements-and-shortfall.pdf?la=en&hash=673E32C8547A8170C9F4FA34323F3A8F#:~:text=In%20current%20and%20forecast%20power,14%2C390%20MWs%20in%202021%2D22.

[17] http://www.eirgridgroup.com/site-files/library/EirGrid/RoCoF-Alternative-Solutions-Project-Phase-2-Report-Final.pdf

the synchronous inertial energy response of a machine) or megajoules (the equivalent energy unit), with an instantaneous response required will currently restrict provision of such a service to synchronous machines, either generators or condensers. However, this requirement will not preclude alternative technologies, such as a gird forming BESS acting as virtual synchronous machine and providing such a service in the future. The key technology development that remains it to demonstrated that a number of virtual machines can operate successfully on a power system which includes solar farms connected via grid following inverters and synchronous generators. A RoCoF control requirement specified as an equivalent energy response rather than an inertia floor appears to be an appropriate approach for the NT regulated systems going forward. The requirements for this service should therefore be:

An energy response that is;

- instantaneous;
- not reliant of frequency measurement;
- sufficient to control RoCoF below a defined limit for the largest contingency required to be survived by the power system.

Cost recovery arrangements

A simple mechanism to implement pricing for this service could be set by the cost required to deviate from a least cost energy dispatch, although this is not consistent with the current security constrained economic dispatch approach. Alternatively, the minimum requirement could be independently and directly contracted from providers. As generators and loads both benefit from a RoCoF service through prevention of damage and safeguarding system security, it may be appropriate to recover costs from both generators and loads. Either of these approaches would provide price signals to participants which could trigger investment in equipment such as grid forming inverters or synchronous condensers.

4.1.2 Contingency frequency control service

The purpose of a contingency frequency control service is to arrest a change in frequency following a contingency event. The service operates to prevent under frequency load shedding or over frequency generation tripping, thereby stabilising the power system frequency such that it remains within safe limits until a redispatch can return the system to 50 Hz.

The following subsections discuss the merit of differentiating between contingency frequency control raise and lower, adoption of dynamic requirements, and the technology capabilities available to provide the service, and the procurement arrangements in turn.

Contingency raise & lower

The separation of contingency frequency control services into raise and lower contingency control services is already contemplated in the SSG, although the C-FCAS provisions are not currently used by the System Controller in operating the power system.

Separation of contingency frequency control into two distinct services allows for a clear price signalling where a trade-off between the costs of managing generator contingencies can be made using either:

- Generator curtailment, or
- Procuring greater volumes of contingency frequency control raise.

Another advantage of this approach is to encourage market participation from participants who may be unwilling (or unable) to provide both services. For example, renewable generators may not want to participate in a “contingency raise” service which requires them to constantly operate below their maximum output, and to install greater backup storage capacity to ensure they are capable of providing the service when called. This is likely to be a more significant issue for renewable generators, which have no marginal cost of production and therefore typically have more to gain from every kWh generated. However, these generators may still wish to provide a “contingency lower” service that requires them to turn down for a dispatch period. The same argument may hold for a synchronous generator that is operating at minimum output during the middle of the day to accommodate generation from solar farms. While the synchronous generator would be able to provide a contingency raise service it would not be capable of providing a contingency lower service.

Finally, separation of the two types of contingency frequency control services has the advantage of allowing different volumes to be specified for “raise” and “lower” capacity, as required by the system. This would allow the extent of service dispatched at any time to meet the needs of the actual power system at that time.

Fast / slow / delayed contingency control

“Fast” contingency frequency control is required to arrest a change in frequency following a contingency event, and prevent frequencies falling outside of the frequency operating standards applied in the NTC for contingency events, in this case between 47-52 Hz. As higher RoCoF becomes standard on the system following contingencies, this increases the requirement for a faster responding contingency frequency control service.

An efficient approach to procurement of this service would determine the fastest possible response time required to cater for the most onerous credible contingency event (protected events can violate the 47-52 Hz frequency operating standards and undergo load shedding). For example, a contingency event resulting in a 2 Hz/s RoCoF, would require a response within 1.5 s to prevent a frequency nadir below 47 Hz, or a response within 1s to prevent an over frequency event exceeding 52 Hz.

The requirement to procure a “slow” or “delayed” service, as currently specified in the SSG is to establish a new settled frequency close to 50 Hz, inside the normal frequency operating band. This requirement is unnecessary if sufficient “fast” response can be procured to accomplish this requirement. The rationale behind procuring separated contingency services by speed has historically been to do with the technologies capable of providing a contingency response. Providers with slower responding equipment may form a more competitive market for the slower services. For example, batteries or modern gas plant governors may be the only equipment capable of providing a “fast” active power response, older coal fired generators governors may be capable of providing a slower response, but cannot sustain this level of output for long, hence AGC control of generators may be required to provide a “delayed” response to return to 50 Hz or within the normal frequency operating band. Slower response may also be provided by contracted demand response whereby a load agrees to reduce consumption to correct an under-frequency event.

Differentiating contingency frequency control into services with different response time and ability to sustain the service is necessary where sufficient “fast” contingency control service cannot be procured to return the frequency to the normal frequency operating band, or where “fast” providers are incapable of sustaining their output for a dispatch interval. The technical requirement of contingency frequency control can be met by a single “fast” service, provided this can be sustained, however a competitive procurement process may find value in a further degree of specification.

Dynamic requirements

Contingency frequency control raise and lower services should cater for the largest "credible" contingency event. As outlined in Box 1, credible contingency events are currently defined in the SSG. Credible contingency events are typically events such as the loss of the largest generator, loss of a transmission element that also disconnects generation, or the loss of the largest load.

The dispatch and load conditions of each the Territory's systems varies, as does the credible contingency events that need to be considered. Securing against larger contingency events without load shedding will be more onerous and costly. A mechanism used in other power systems limits the maximum loss of a single infeed to the system, to manage the impacts on required essential system services for both RoCoF and contingency response.[18] Even where a transmission contingency sets the largest contingency event, as is the case on the Darwin-Katherine Power System, a similar approach could be used to limit the aggregate dispatch across a number of generators to limit the transmission line flow and hence the size of the contingency.

The most onerous system conditions and events will change over time as the system develops. Similarly, the appropriate volume of contingency frequency control raise and lower should be dynamically specified in line with system dispatch and load conditions. For example, where the most onerous single contingency event on a system is the loss of multiple solar power stations connected to a single transmission line, contingency response service will be required to secure against the loss of the line during the day. However, the MW loss from a fault on the transmission line will vary throughout the day as the output of the connected solar farms change. The essential system service volume required to secure against the loss of the line will therefore also change across the day. Therefore, a dynamic requirement will be able to avoid the over procurement of the raise and lower services.

Technologies capable of providing the service

There are no technical barriers to a contingency frequency control service being provided by alternative technologies to the existing synchronous generators on the Northern Territory regulated systems. BESS and inverter connected renewable generation can both provide contingency frequency control lower services, often with response times below that of synchronous generation. BESS can also provide contingency raise services. Interruptible loads may also be capable of providing demand side response to contingency events, through tripping. However, as explained above, inverter connected renewable generation may find it uneconomic to provide contingency frequency control raise services.

BESS are proven providers of contingency frequency services in other markets. This service is provided in South Australia by the Hornsdale Power Reserve, and in the United Kingdom where distributed battery systems participate in frequency response markets. A BESS is also currently installed in Alice Springs, where it is used to provide a C-FCAS response, despite this arrangement not currently being formally enacted in the Secure System Guidelines.

Given the faster response times achievable from non-synchronous technologies, a move towards a technology neutral specification is vital for efficient procurement of this service going forward.

Contracted load interruption can also be an effective option for providing contingency frequency control raise services. This could either take the form of individual large loads agreeing to be disconnected in response to an under-frequency event or for an equivalent response to be provided by aggregated facilities.

[18] UK National Grid Electricity System Operator – Security and Quality of Supply Standard "normal & infrequent infeed loss risk"

Procurement arrangements

The speed of a frequency control response following a contingency will become more valuable as systems operate with a higher RoCoF (likely in the Northern Territory due to the increasing penetration of non-synchronous generation).This will likely happen despite the specification of a RoCoF service, which is only required to keep RoCoF within a maximum limit, unless set conservatively. The higher speed of response is desirable for prevention of a frequency nadir (or peak) that causes load shedding or over frequency generation tripping.

Dynamic power system studies are required to determine the volumes of contingency raise and lower frequency control required to stabilise each of the Northern Territory power systems within their respective “emergency” frequency operating bands. By conducting these studies, the System Controller will also be able to determine the response times required for the new services to be effective under high RoCoF scenarios and allow the System Controller to specify response times required accordingly. For example, if sufficient contingency raise service cannot be procured in a timeframe required for a 4 Hz/s under frequency event to prevent a frequency nadir below the system frequency operating standard, a slower RoCoF limit may be preferred.

Requirements for a contingency frequency control raise or lower service can be published as a dynamic MW amount, as a fixed percentage of the largest contingency, to cover the largest credible contingency on the system, and allow for a frequency recovery post contingency.

Cost recovery arrangements

Separating the contingency frequency control services between raise and lower services allows the costs of these services to be recovered from those parties that contribute to the need for the service. For instance, because under frequency events may be anticipated to primarily arise due to generator contingency it may therefore be appropriate to recover the costs of the contingency frequency raise services from generators. Applying similar arguments, a case could be made for recovering the cost of the contingency frequency lower services from loads.

To further align with a causer pays principle the amount recovered from different loads and generators could be varied in proportion to their size on the basis that the size of the generator or load can set the largest contingency and hence the required amount of contingency frequency response service.

4.1.3 Regulating frequency control service

Regulating frequency control is required to maintain frequency at close to 50 Hz, within the normal frequency operating band specified in the SSG. While demand and supply are matched with every redispatch of generation, small changes in system load and output variation from unregulated generation occurring between dispatch instructions taking effect must be managed by a regulating frequency control service.

The following subsections discuss the interactions between regulating frequency control services and dispatch, the technology capabilities to provide this service and the procurement arrangements in turn.

Dispatch period interaction

In relatively small power systems such as the NT regulated systems, the amount of regulation service available at any time needs to be sufficient to provide the regulation requirement over the period it would take to bring another regulation service online. The regulation requirement is therefore set by the time expected to bring additional services online and the extent of variation in demand expected across that time. The requirement is therefore unlikely to change significantly unless the technology relied on to provide the service changes. Technology change could reduce the average time taken for service providers to come online and hence allow a lower R-FCAS requirement. The current approach to scheduling and dispatch, allows the System Controller to redispatch the system on an as-required basis. This process allows redispatch to be used when necessary to replenish the available regulation services. Sufficient service is however required to allow time for the redispatch to take effect.

Technology capabilities to provide services

The updated GPS, approved by the Utilities Commission in March 2020, require all generators connecting to the Northern Territory regulated systems to be capable of meeting their half hour ahead dispatch target. For renewable generation, this will require the installation of or contracting with BESS or other energy storage technologies to cater for variations in output. BESS that is allowing renewable generators to comply with their capacity forecasting requirements may also be technically capable of providing a regulating frequency control service in addition to this compliance. It is therefore likely that there will be a wider pool of potential providers for a regulating control frequency service, including both synchronous generators and BESS.

It is noted that while BESS may be capable of meeting capacity forecasting requirements and providing a regulating frequency control service, they will not be capable of providing other services while meeting capacity forecasting requirements unless significantly oversized. While providing a contingency response or RoCoF control service would typically deplete the energy stored in a battery system, a regulating frequency control service typically has a lower energy requirement, instead requiring constant charging and discharging cycles, or adjustments to output for a generator.

Procurement arrangements

Allowing other technologies such as BESS or other energy storage systems to participate as providers of a frequency regulating service, should increase the number of eligible participants capable of providing a regulating service. The significant rate of increase in uncontrolled generation connecting to the NT regulated systems, such as rooftop PV solar, will lead to greater variation in output between dispatch periods than has historically occurred. It is therefore likely that the current volumes of regulating service procured are likely to be insufficient as cloud cover events causing a change in output become a more significant factor on the regulated systems.

While an increase in rooftop PV solar may be a driver for procurement of increased volumes of regulating frequency essential system service, this also may promote efficiencies in procuring a dynamic level of service across a 24-hour period. At a minimum, procurement of a different lower volume for frequency regulation for an 8 hour “night” period may be appropriate, as a lack of rooftop PV should promote lower variations between dispatch periods.

Procurement of appropriate volumes of frequency regulating service will require analysis of past system load changes, but can be further informed by forecasting exercises to determine the potential impact of cloud cover events compounded with a “normal” change in system load. This analysis will allow for the specification for a dynamic day / night MW value for regulating frequency service to be procured.

Cost recovery arrangements

The introduction of the capacity forecasting GPS means that new renewable generators connecting to the Northern Territory power systems should not require any increase in the amount of frequency regulation service required. It is therefore appropriate that the cost for regulations services be recovered from loads.

4.2 Voltage management / Network support

Transmission level voltages on a power system are typically managed through a combination of reactive power control from connected generation, and ancillary reactive compensation equipment, including capacitor banks, Static Volt Ampere Reactance (“VAR”) Compensators (SVCs) and Static Synchronous Compensators (STATCOMs).

Most voltage issues are resolved at a planning stage by the network operator through specification of sufficient reactive compensation equipment or through the existing Generator Performance Standards in connection agreements. Network capacity constraints are typically also resolved at a planning stage, but may become more significant issues due to temporary equipment outages.

Freedom to procure a voltage management service from a generator producing no active power, or a network support service by constraining on a generator may therefore have key advantages for the system, namely the opportunity to appropriately optimise between procurement of essential system services and alternative system reinforcement solutions.

Where an essential system service for voltage management or network support is not defined, the network operator will be forced to manage voltage or capacity issues through reinforcement, which may result in the requirement for procurement of more expensive solutions such as installation of SVCs and STATCOMs for reactive power support, or through conventional capacity reinforcements such as larger cables / overhead lines. A holistic approach that considers all technical solutions would result in overall lowered costs for the consumer in the Northern Territory by avoiding reinforcement costs where a lower cost solution is available.

The following subsections discuss the technology capabilities to provide this service and the procurement arrangements in turn.

Technology capabilities to provide services

A voltage management or network support service should be open to provision from any technology capable of providing reactive and active power support. This can include inverter connected technologies such as BESS and PV solar, as well as conventional synchronous generators. Where network capacity is a temporary issue, for example only occurring at peak demand some loads may be willing to provide demand side response for limited periods of time to resolve this issue. Therefore any definition and specification of a service that is technology neutral is likely to result in more competitive options for provision and ultimately the least cost service being procured.

Procurement arrangements

Unlike frequency management, voltage or capacity issues on a network are localised. This will inherently restrict the number of participants capable of providing such a service. However, the system should consider the provision of such a service from loads where this is thought to be practicable for a network capacity issue.

Cost recovery arrangements

As a voltage control service can avoid a network investment it is recommended that the costs of those services be recovered in the same fashion as would the costs of an alternative network investment such as the installation of a reactor to control over voltages during periods of low demand.

4.3 Restart services

Restart or black start services and associated procedures are a function of every power system. While not part of normal system operation, these services are essential for restoring power as soon as reasonably achievable after a system black event. Reforms should not change the fundamental nature of the current black start ancillary services. However, the service and associated procedures defined in the SCTC and SSG require updating to reflect the changing conditions on the Northern Territory regulated power systems. In particular, the ability for new large-scale solar to provide the service should be considered.

The following subsections discuss the technology capabilities to provide this service and the procurement arrangements in turn.

Technology capabilities to provide services

Restart services can be provided by either synchronous generators, or by large-scale inverter connected generation and energy storage systems with “grid forming” capabilities. Given the greater role of inverter connected technologies in the generation mix on the Northern Territory regulated systems going forward, any specification of the reformed system restart service should include the opportunity for these technologies to provide the service in order for the restart procedure to continue to work.

Regardless of the technology utilised, a back start service provided needs sufficient capacity to not only restart themselves but to also support the re-energisation of transmission corridors to allow reconnection of loads and other generators. Hence the technology deployed, its capacity and location of a facility are all factors that need to be considered when assessing whether it can act as a viable black start service provider.

Procurement arrangements

In the short term, restart services are likely to continue being provided by Territory Generation due to the lack of alternatives currently available.

A reformed system restart service could be defined to allow the service to be provided from a range of providers as alternatives become available. Such a reform will provide an incentive for participants other than Territory Generation to install the control systems or equipment capable of providing a restart service, which will eventually create alternative providers for the service.

Cost recovery arrangements

Both generators and loads benefit from the system being restarted in a time efficient manner, and it is therefore suggested that a simple and cost-effective method of cost recovery for this service is to recover costs for the provision of this service from both generators and loads, split 50% to each.

4.4 System strength

The definition of an essential system service requirement for system strength may be desirable to manage issues that cannot be resolved in a cost effective manner through system reinforcement, or where issues arise that are not resolvable in planning timescales, such as unexpected generator breakdown or retirement. System strength shortfalls are likely to become an emerging issue on the NT regulated power systems as grid following inverter connected generation forms an increasing proportion of the generation mix, and the definition of an system strength essential system service will help manage this issue.

The specification of a system strength essential system service may be a preferable option to manage these issues. Detailed electromagnetic transient studies are required to investigate system strength issues and identify optimal mitigation measures. The NTC requires that the Network Operator undertake those studies with provisions in the NTC ensuring that the Network Operator has access to the detailed models required. It is therefore appropriate that the Network Operator assess any requirement for a system strength essential system service.

Technology capabilities to provide services

System strength can be provided by technologies capable of contributing sufficient fault current. Rotating plant in the form of either synchronous generators or synchronous condensers are most suited to providing system strength support, however other technologies are capable of providing a fault current contribution, and procurement requirements should not exclude any technology unnecessarily. Other mitigation measures that can be effective in addressing system strength issues include:

- Contracting with Generators with synchronous generating systems for the provision of system strength services
- Network augmentation to reduce the impedance between inverter connected generators and synchronous generators providing system strength
- Retuning the controls on grid following inverter to reduce the likelihood of unstable behaviour
- Replacing grid following with grid forming inverters that are less susceptible to system strength performance issues
- Implementing post-contingent control schemes that can disconnect part or all of an inverter-based generator to avoid unstable operation

Some of the above solutions would require network investments while others could be delivered through contracts with service providers. This means that the Network Operator is well placed to assess the optimal system strength mitigation measure to address a particular system strength issue.

Procurement arrangements

The system strength GPS provisions in the NTC should be capable of identifying system strength issues associated with new or modified generators and addressing them as part of the generator connection or modification approval process.

Provided sufficient notice is provided of the proposed decommissioning of a synchronous generator, the Network Operator should be able to implement an appropriate mitigation measure including the procurement of any system strength essential system service. Appropriate revisions would be needed to the regulations in the Northern Territory to provide the Network Operator with the ability to procure system strength essential system services.

Cost recovery arrangements

Cost recovery for the system strength essential system service can be implemented in a similar manner to the “causer pays” arrangement for system reinforcement under the system strength impact assessment guidelines. Namely, where a connection is identified as responsible for causing a system strength issue, i.e. a deterioration of system performance to voltage instability, the connecting generator will pay for either system reinforcement or for the essential system service to be procured to resolve the issue.

For other system strength issues that arise as a result of generators retirements of the unexpected temporary removal of a synchronous generator, there is not a clear causer from which costs incurred in addressing the system strength issue could be recovered. In this instance the costs should be recovered from all system participants as the services are being provided to maintain a secure and stable power system, which all participants benefit from.

4.5 Mandatory requirements

Mandatory requirements for generators will have a direct impact on the burden placed upon essential system services on the NT regulated systems going forward. It is not anticipated that changes to the existing large-scale generator mandatory requirements will be required in the short term to adapt to the new essential system service definitions. However, in addition to growth in large-scale renewable generation, the Northern Territory regulated systems are experiencing significant growth of “behind the meter” rooftop photovoltaic solar generation. The requirements for these generators were not addressed in the updated GPS review in the NTC.

The current mandatory requirements for these rooftop PV solar in the NTC are likely to be inappropriate for the system going forward, as this generation becomes an increasing presence on the system. Issues noted are as follows:

- There is no specific RoCoF ride through requirement for small inverter systems, this should be made consistent with the maximum RoCoF limit set by the RoCoF control service. A low RoCoF ride through requirement on small generators has previously caused unexpected load shedding on large, interconnected power systems (the GB National Grid).[19]
- The references to AS 4777 made in the NTC in clause 3.5.2 are outdated, referring to the 2005 version of the standard. Several changes have been made between the 2005 standard and the updated 2016 standard, including a mandatory requirement for a droop response to over frequency events. Updating the reference to this standard could significantly reduce the burden on contingency frequency control service, specifically over frequency events in the future.
- Current “frequency limits” set for small inverter systems are inconsistent with the frequency limits applied to larger generators, under frequency values are 47.5 Hz compared to 47 Hz. This inconsistency should be rectified.

A failure to apply these updated standards to future embedded photovoltaic solar generation, and an increased requirement for frequency regulation under normal operation, with a greater burden falling on the essential system service's framework for frequency regulation. The lack of a specified requirement for RoCoF ride through for small inverter systems must also be rectified as part of establishing a maximum frequency limit for a RoCoF control service.

4.6 Additional services

As a general principle, where a need for an additional essential service is identified through a transparent and open framework, the framework should leave open the possibility to define additional essential system services as required to retain security of supply on the power systems. Additional services may be required going forward if they are considered to be an efficient and cost-effective approach to retain power system security and power quality compared to alternatives. Issues that could arise on the power system requiring a defined essential system service include:

[19] https://www.ofgem.gov.uk/system/files/docs/2020/01/9_august_2019_power_outage_report.pdf

- Failure of installed generation ramping capability to meet a “duck curve” (rapid increase in system load from midday to evening caused by increased penetration of rooftop PV solar generation). While such an issue is not expected to present as an issue on the Northern Territory regulated systems in the short term, freedom to procure a “ramping service” may be an efficient way to manage this issue if it arises.
- Generation exceeding load on the Alice Springs system solely due to the penetration of increased rooftop PV solar generation is possible within seven years. A “load / demand management” service i.e. paying loads to consume power at times of minimum demand, may be a cost-effective way to manage this outcome in the short term.

4.7 Other considerations

In forming the requirements for essential system services on the regulated Northern Territory power systems, there was a need to consider the context of ongoing power system market reforms and other requirements, including co-optimisation to ensure an efficient outcome. These are discussed in the section below.

4.7.1 Co-optimising dispatch of energy and essential system services

> *“The trade-off between optimal energy and ancillary service dispatch is quite complex, and changes dynamically and unpredictably, for all kinds of reasons. So a sequential approach, in which ancillary service dispatch is determined either before or after energy dispatch, may be expected to consistently yield sub-optimal outcomes.”*[20]

The Northern Territory Government through the Priority Reform Program is looking to implement the NTEM, which will replace the I-NTEM.

The NTEM will apply in the Darwin-Katherine Interconnected System only. It will be a capacity plus energy market, where generators are dispatched in accordance with their market bids. Expected outcomes of the proposed reforms include:

- Transition from the existing “virtual” market, where the market operator oversees transactions between generators and retailers, to a system with actual financial transfers.
- Unbundling of wholesale charges (essential system services, capacity, and energy) to provide clearer price signals.
- Moving away from a contract only system to a balancing market approach that overlays the bilateral contracts – for the energy market, and potentially essential system services.

Ideally, the NTEM will be optimised after consideration of essential system services required for secure system operation. The NEM and future WEM arrangements involve the simultaneous co-optimisation of energy and selected essential system services, however essential system services in the Darwin-Katherine Interconnected System of greater importance given the relative size of the system.

Detail on the NTEM is yet to be finalised; however, the following should be considered in the dispatch design to allow for delivery of optimised energy and essential system services.

Dispatch alignment

- Adopting fixed duration dispatch intervals can influence the amount of frequency regulation required. Shorter fixed duration dispatch intervals have been shown to be effective in assisting to reduce the frequency regulation requirement. Elsewhere in Australia:

[20] Rebennack, S., Pardalos, P, Pereira, M, Iliadis, N (editors), *Handbook of Power Systems*, 2010, p. 308.

  - The NEM features 5-minute dispatch interval.
  - The WEM is currently in the process of moving from a 30 minute dispatch interval to a 5 minute dispatch interval.[21]

  If fixed duration dispatch intervals were to be adopted in the NT power systems, they should be as small as possible to reduce frequency regulation requirements.

  Maintaining the current approach, which allows for redispatch on an as-required basis, may be more effective as this allows redispatch flexibility.

- As mentioned in section 4.1.3, in small power systems such as those in the NT, the ability to redispatch on an as-required basis can be effective for restoring the amount of essential system service that are available at any time. This may be more effective than adopting fixed duration dispatch intervals.

Co-optimisation

- Judging the most cost-effective trade-off between energy market dispatch and adjustments to minimise frequency control costs is managed in some markets via the co-optimisation of frequency control services and energy market dispatch through a dispatch algorithm.
- Further work is required to define co-optimisation of energy and any essential system services in the Northern Territory and is more likely to be feasible for the Darwin-Katherine Interconnected System, given the NTEM reforms compared with the other Northern Territory power systems, which will not have a market arrangement which lend themselves to co-optimisation.
- Use of a competitive contract procurement arrangement does not facilitate co-optimisation as compared to an essential system services spot market. However, the merits of co-optimisation in the Northern Territory power systems must be considered with the counterfactual cost of setting up a spot market for the procurement of essential system services if this arrangement is not considered.
- Where BESS provide essential system services, co-optimisation with dispatch is not required. A move to focus solely on co-optimising dispatch and essential system services could miss efficiencies of procurement of essential system services from new technologies, which are not capable of co-optimising with dispatch.

4.7.2 Use of common requirements across the Territory's power systems

In redefining the essential system services there is an opportunity to either develop different definitions, services, and specification methods for each of the Territory's power systems or to adopt a common set of provisions across the power systems.

While the three regulated systems vary significantly in size, as well as in terms of numbers and type of connected generators and equipment, a unified framework for essential system services across the three systems is desirable as maintaining three sets of rules (including definitions) is likely to create extra administration and unnecessary complexity. Further, provisions can be crafted to allow the System Controller flexibility in procuring the specified services and the level of service that it procures.

While governance arrangements, service definitions and method or principles applied to determine service level requirements can be considered "common" between systems, practical requirements and implementation will differ due to each system's unique characteristics. For implementation in each system to be suitable, detailed specification of the level of services, alignment with market dispatch where this applies,

[21] https://www.wa.gov.au/sites/default/files/2020-09/TDOWG%20Meeting%205%20-%20Slides%20.pdf

and sections of the procedures used to manage the services must be unique to the requirements of each system.

The Government's Issues Paper contemplated the relative merit of developing and maintaining three system specific sets of rules and procedures. In responses to the issues paper stakeholders generally agreed with the principle of all systems having the same definition of essential system services, which could reduce administrative overhead for the systems. However, the submissions also recognised that specific procurement arrangements may have to reflect the particular system characteristics, and be more specific to each individual system.

5. Recommendations

5.1 Definitions

GHD recommends a revised set of essential system services as per Table 5-1. The services, definitions and responsibilities chosen have been selected to be technologically neutral, and to apply across the three regulated power systems in the Northern Territory.

Table 5-1: Essential system service recommended definitions

Essential system service definition	Purpose
RoCoF control	• Control maximum RoCoF on power systems. • Ensure system security for credible contingency events and “protected events”.
Contingency frequency control (raise)	• Stabilise frequency within “emergency” defined operating band after a credible contingency resulting in the net disconnection of generation. • Ensure system security without UFLS for all credible contingency events.
Contingency frequency control (lower)	• Stabilise frequency within “emergency” defined operating band after a credible contingency resulting in the net disconnection of load. • Ensure system security without over frequency generator tripping for all credible contingency events.
Regulating frequency control	• Regulate power system frequency within normal defined frequency operating band.
Voltage management / network support	• Management of network voltage control issues where required. • Management of network capacity shortfall issues where required.
System restart	• Enable the restart of the regulated power systems from a “black system” event.
System strength	• Procurement of sufficient system strength capability to ensure voltage stability and sufficient fault current when a shortfall is identified.

5.2 Implementation

GHD recommends that a common set of essential system services be defined that apply across the three regulated power systems in the Northern Territory. Aligned definitions will create clarity about services and their requirements.

Regardless of the shared definitions, the implementation of the new framework will necessarily result in a different set of services and level of service being procured in each of the regulated systems. Procurement of essential system services will reflect the unique mix of generation and set of potential service providers on each power system.

Requirements for services are likely to change based on system constraints, generation mix, load growth and other factors. An ongoing review process is likely to be required to ensure the specified volume requirements for essential system services continue to be appropriate for the system going forward.

GHD recommends a codified process for review of the suitability of essential-system-service volumes being procured to ensure the levels remain appropriate given the changing power systems’ needs is established. In the WEM, the quantities of essential system services are reviewed annually by the Economic Regulation

Authority. In the NEM, AEMO reports on the adequacy of frequency control services to remain within the limits specified in the frequency operating standard. The development of a codified review process and publication of the service level requirements will provide transparency and clarity to existing and future service providers.

While the current practice of publishing the methodology for calculating an essential system services contribution from a generator in the SSG is appropriate in principle for transparency (although this is not applied to any enacted service), other practices, including defining essential system services categories with reference to specific synchronous generators are inappropriate for the revised framework.

The essential system services framework should allow for the freedom to not procure services for regulated systems where it is identified that these services are not required. For example, the Tennant Creek regulated system may not require a specific paid RoCoF control service to be procured, if sufficient RoCoF control is inherently provided either by existing synchronous generators, or in future by “grid forming” BESS inverters. Small-scale power systems similar to the size of the Tennant Creek system have proven capable of operating in “hydrocarbon off” modes, with no inherent synchronous inertia.

Finally, where a shortfall in power system capability is identified resulting in a system security issue that cannot be managed through the planning timescales, the framework should allow the flexibility to define and procure additional essential system services where required.

The implementation of the new essential systems services framework will likely require time for a gradual reform and can be done in concert with a number of other measures to ensure power system security. In the WEM and on the NEM, a gradual process for reform has been undertaken, with a range of projects and initiatives undertaken by the AEMC, AEMO and other organisations to implement changes to requirements for RoCoF[22], system strength[23], and others when required. It is suggested that a focus on the most immediate concerns for the power systems should be a priority for the NT regulated systems, which is likely to be on RoCoF control and contingency frequency control.

5.3 Next steps

This document is focused on the technical requirements for the new essential systems framework for the Northern Territory regulated systems. It is recognised that this work is part of the wider reform package, which includes consideration of the merits of a reformed competitive procurement process. The next steps for the implementation of the essential systems service requirements in this document focuses solely work required to complete the detailed specification of the technical requirements for each of the regulated systems in the Northern Territory. It is recognised that the implementation of the new technical requirements will likely be carried out in stages, and in parallel with the wider reform program. This may result in a temporary misalignment between the NT regulated systems with regards to their framework, as the reforms are implemented. Going forward however, an aligned set of services in a consistent technical framework will be the desired outcome of these reforms.

5.3.1 RoCoF control – specification of a maximum tolerable RoCoF limit for each regulated system, and definition of minimum level required to achieve this (if applicable).

Specification of a maximum RoCoF limit (in Hz/s) and definition of a minimum energy level (defined either in MWs or MJ) required to be stored on each system for an instantaneous response will require, at minimum,

[22] https://www.aemc.gov.au/rule-changes/managing-the-rate-of-change-of-power-system-freque

[23] https://www.aemc.gov.au/rule-changes/managing-power-system-fault-levels

consideration of each of the factors addressed in section 4.1.1. Dynamic power system studies using power system analysis software will be required to determine the minimum energy level required to secure RoCoF below its maximum limit for the largest contingencies on the regulated power systems. Operation below the minimum limit could be permitted without breaching the RoCoF limit if a BESS is used to provide fast frequency response or constraints are applied to reduce the largest contingency size.

5.3.2 Contingency frequency control (raise) and (lower)

Specification of contingency frequency control volumes (in MW), as well as separation into "timed" responses will depend on the capabilities of service providers as explained in section 4.1.2. "Fast" contingency control must be aligned with the RoCoF limit, however separation of the service further into "slow" and "delayed" services as well as appropriate times for these should be considered. Value from this separation will only be achieved if this separation of times is aligned with technological limitations and performance. Dynamic power system studies will be required to determine the amount of separated service volumes required (if separated by time). It is recommended that the "time" requirements for contingency frequency response are conducted in parallel with the definition of the secure RoCoF limit on each regulated power system, as this is directly relevant to the time requirements for contingency frequency response.

5.3.3 Regulating frequency control – specification of dynamic volume requirements considering system dispatch arrangements for each regulated system

Specification of this service requirement (in MW) will not change significantly, assuming the current approach allowing redispatch on an as-required basis is retained as part of the NT reform program. The requirement for this service can be established by spreadsheet analysis of historical data and forecasting the variability in generation / load over a period necessary for redispatch instructions to take effect.

5.3.4 System restart – specification of performance requirements for synchronous generators and other technologies

Specification of this service requirement (no. of units) will not change significantly but can be redefined to allow participation from alternative technology providers. The viability of these providers will still require assessment on a case by case basis.

5.3.5 Requirements for "system strength" or "network support / voltage management" services

Detailed definition of requirements for "system strength" or "network support / voltage management" services are not required, as these solutions will require procurement only in response to localised issues, which by definition will have unique requirements, and cannot be strictly defined in advance of the issue

The process for identifying shortfalls in capacity or reactive power capability should be identified during normal planning processes already undertaken as a normal course of business by the Network Operator in the Northern Territory.

The process for identification of an emerging system strength issues is likely to require additional analysis aside from the existing "do no harm" impact assessment guidelines implemented for generator connections in the Northern Territory. Processes developed around identification of these issues for determining "fault level shortfalls" by AEMO[24], can be a suitable guide to the assessment process required, which will require detailed fault level studies to be undertaken for the NT regulated systems. This work could be incorporated into the normal planning processes regularly undertaken by the Network Operator.

[24] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf

Appendices

Level 7 24 Mitchell Street Darwin NT 0800 Australia
PO Box 351 Darwin NT 0801 Australia

61 8 8982 0100
drwmail@ghd.com

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