REPORT TO
DEPARTMENT OF INDUSTRY, TOURISM AND TRADE
26 NOVEMBER 2020

REVIEW OF ESSENTIAL SYSTEM SERVICES IN REGULATED SYSTEMS

ECONOMIC ADVICE

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EXECUTIVE SUMMARY

In 2012, the Territory Government (the Government) commenced a substantial reform of the electricity sector in the Territory. Central to the reforms was the separation of Power and Water Corporation's (PWC's) contestable retail and generation businesses from its regulated, monopoly network business and the establishment of the Interim Northern Territory Electricity Market (I-NTEM).

The current I-NTEM arrangements are now being challenged by the generation profile in the Territory, which is evolving rapidly to support the Government's 50 per cent by 2030 renewable energy target. The Government has identified a package of coordinated priority reforms to facilitate increased market participants and accommodate the emerging technologies, while ensuring an efficient, secure and reliable electricity supply and supporting the Government's renewable energy target.

One of the priority reform areas is the provision of essential system services (ESS). Territory Generation (T-Gen), the Government-owned incumbent electricity generation business, is currently the sole provider of all types of ESS. Other generators must compensate T-Gen for their share of costs in accordance with a codified price that was set in 2015.

In June 2020, the Government released an Issues Paper on the review of ESS. The objective of the review is to ensure that the delivery of ESS is economically efficient and at least cost but there is no compromise to system security.[1]

ACIL Allen Consulting (ACIL Allen) was engaged by the Department of Industry, Tourism and Trade (the Department) to review the submissions on the Issues Paper and provide economic advice and recommendations in relation to the following three matters considered in the Issues Paper:

- service provision framework
- administered pricing arrangements and market power mitigation
- cost allocation and settlement.

The economic advice draws on technical advice provided to the Department by GHD Advisory (GHD) on the categorisation and definition of services, and service requirements.[2]

Service provision framework

The Territory's current ESS framework is characterised by regulation with a mix of a regulated tariff and mandated provisions. Generators must pay an amount of $5.40 per MWh (sent out) to T-Gen for the provision of ESS in the Darwin-Katherine Interconnected System (DKIS).

Other generators may be called on by the System Controller to provide ESS, but there is no formal mechanism to compensate them for this. The current framework thereby does not facilitate private

[1] Northern Territory Government, *Review of Essential System Services in the Northern Territory's Regulated Electricity Systems, Issues Paper*, June 2020, page 4
[2] GHD Advisory, *Review of Essential System Services in the Northern Territory, Final Report*, 16 November 2020

proponents to provide potentially cheaper and more innovative ESS. To reform the lack of incentive and opportunity for private proponents to provide ESS, the Issues Paper identified three broad frameworks for the procurement of ESS:

- regulation (including regulated tariffs and mandated provision)
- bilateral contracts
- pricing and dispatch through a spot market.

ESS are most likely able to be acquired at least cost when they are acquired through some form of competitive process and there are sufficient potential providers of those services participating in the process to apply competitive tension. There are various ways to introduce competition into the provision of services such as these. Spot markets are one.

Spot markets have the advantage of (usually) being highly visible and transparent. However, the disadvantage with the spot market approach, particularly in the context of high fixed (capital) costs, is risk.

With a typical spot market approach, such as the wholesale electricity spot markets used in the National Electricity Market (NEM), acquisition is frequent and for a short period. This means that, based on spot markets *alone,* suppliers cannot be confident of being able to supply the service in question for long enough to earn a reasonable return on their investment and are thus less likely to invest.

To overcome this, renewable energy and other generation projects are invariably underpinned by power purchase agreements (PPAs). This occurs *even though* the generators in question are required to sell all of their output through the NEM spot market. In effect, the market for PPAs becomes as important, if not more so, for driving efficiencies in generation investment. The spot market is used as a guide to the current and future price of electricity and, as such, as an information input to the PPA.

New renewable energy generators will need to be developed to meet the Government's renewable energy target. These generators are likely to be accompanied by batteries (or other technologies) to meet the Generator Performance Standards, and will be able to provide some or all of the ESS that are the responsibility of the System Controller. This will require capital investment which will only be made if the investor has reasonable confidence in recovering it. For this reason, a market based around longer term bilateral contracts, rather than a short and frequent spot market, is likely to be more suitable.

Bilateral contracts can be awarded following a competitive tender or reverse auction process, which will facilitate an efficient outcome.

The structure of any bilateral contracts will be important:

- to allow different bids at different times of day to facilitate efficient provision of services while meeting required technical standards
- to provide investment certainty by matching the tenure of the contracts to the nature of the service provided
- to ensure technology neutrality by unbundling services.

Administered pricing arrangements and market power mitigation

The Territory's current I-NTEM arrangements include an administered price for ESS provided by T-Gen in the DKIS. There are no specific arrangements for pricing or recovery of ESS in the Alice Springs and Tenant Creek systems.

The deficiencies in the current administered pricing arrangement include that:

- the administered price has not been reviewed since 2015 despite substantial activity in the DKIS which has likely impacted on the provision of ESS and thus T-Gen's costs
- the single bundled price does not provide system participants with an understanding of the costs of individual or categories of ESS captured by the rate

— there is no mechanism for the administered price to change over time with changing conditions, such as the introduction of substantial new solar energy generation and emerging technologies for providing ESS.[3]

A competitive service provision framework facilitates the efficient provision of services if there are sufficient participants to apply competitive tension. As the Territory's electricity supply transitions to meet the 50 per cent renewables target by 2030, there will increasingly be additional providers of ESS to apply more competitive tension as part of any competitive process to provide ESS. However, in the short term, competition may not be effective. It will be important to consider measures to mitigate T-Gen exercising its market power in the short term.

We assessed the following four options for mitigating the exercise of market power:

— administered pricing
— limits on revenue
— constraints on offer prices
— default provider of ESS services.

Our assessment has identified that, if services are procured through bilateral contracts, the most favourable option is to place constraints on offer prices, with the prices bid through a competitive tender process and capped at the long run marginal cost (LRMC). The LRMC would be determined for each service for each system, and where applicable, for specific times of day.

The constraint that is placed on the offer prices for a particular service should be reviewed prior to the conduct of a competitive process to procure that service through bilateral contracts. For example, if the competitive process for a particular service and system is conducted every two to three years, then the LRMC for that service should be reviewed every two or three years.

If the market is competitive enough for a spot market, then a constraint on offer prices should not be required.

In addition to placing a constraint on offer prices, we also recommend that there be a default provider for each service in each system until there is an effectively competitive market for that service. In the absence of a competitive market, T-Gen, as the incumbent provider of services, would most likely be the default provider.

To facilitate the transition to more competitive arrangements over time, the default provider should only be used by exception – only for those services in those systems during those times when there is no alternative provider willing to provide services at (or below) the LRMC. The price for providing those services should be at the actual cost so the default provider does not make windfall gains or incur losses.

Cost allocation and settlement

The ESS costs are currently allocated to generators on the basis of energy sent out. The current arrangement is inequitable because it does not allocate costs between system participants on the basis of the benefits received from the ESS provided. Other system participants, such as unlicensed generators and consumers may benefit but do not pay.

The current arrangement is also inefficient as it does not provide incentives for system participants to manage their contribution to, or assist with the correction of, frequency deviations which are the primary drivers of the requirement for, and costs of, ESS.

We assessed the following four options to allocate the costs associated with ESS:

— generators pay, which is the existing approach
— causer pays similar to that in the NEM, under which generators pay for contingency raise ESS, customers pay for contingency lower ESS and voltage management / network support ESS, the

[3] Northern Territory Government, *Review of Essential System Services in the Northern Territory's Regulated Electricity Systems, Issues Paper*, June 2020, pages 21- 22

causer pays for regulation ESS, RoCoF ESS and system strength ESS, and all system participants pay for system restart ESS

- hybrid causer pays as proposed by Sun Cable in its submission to the Issues Paper, which is as per the NEM approach except for regulation ESS
- customers pay, under which customers pay for all ESS.

The option assessed most favourably is the causer pays option. While the causer pays option is more costly than the generator pays or customer pays options, it is more efficient as the costs of providing regulation ESS, RoCoF ESS and system strength ESS are paid for by the parties causing the need for those services. For this reason, it provides an incentive to parties to minimise frequency deviations, rate of change and system strength issues.

The hybrid causer pays approach proposed by Sun Cable is assessed only slightly less favourably than the causer pays approach because incentives under those contractual arrangements, and therefore the efficiencies associated with those arrangements, are dependent on the contractual arrangements between the generators and the third parties that are providing services to those generators to net out impacts on the electricity supply system. The incentives may or may not mirror the causer pays approach.

In the NEM, under the causer pays approach, the costs associated with regulation ESS are allocated to the generators and customers that contribute to frequency deviations. This provides appropriate incentives to generators and customers to minimise frequency deviations.

The costs associated with contingency raise and lower ESS and system restart ESS are allocated to generators and/or customers on the basis of energy production and consumption, as appropriate. However, the amount of contingency raise and lower ESS that is required is a function of the largest generating unit and largest load on the system, respectively. Accordingly, more appropriate bases for allocating the costs of the contingency raise and lower ESS are, in the case of generation, the size of the generating unit, and in the case of loads, the maximum demand.

The costs associated with system restart ESS are allocated in the NEM on the basis of energy production and energy consumption. However, system restart ESS are not used very frequently and there is no clear singular driver of these types of events. For that reason, there does not appear to be a more appropriate basis for allocation than the current simplistic approach.

The NEM currently does not have a Rate of Change of Frequency (RoCoF) ESS or system strength ESS, which have been recommended by GHD for the Territory. Consistent with the regulation ESS, the costs associated with the RoCoF ESS are most appropriately allocated to the party causing the service to be enabled to provide an incentive to minimise the rate of change of frequency.

Under a causer pays approach, the costs associated with the system strength ESS are most appropriately allocated to the party responsible for the system strength issue. This provides an incentive to minimise system strength issues while recognising that not all costs can be allocated in this way. Where there is not a clear party responsible for the system strength issue, there is no clear singular driver for the balance of the costs. The recovery of these costs from customers is the simplest.

As GHD has noted that the requirements for network support / voltage management services are to avoid a network investment, the allocation of the costs associated with those services would be subject to PWC's economic regulatory framework.

1 INTRODUCTION

In 2012, the Territory Government (the Government) commenced a substantial reform of the electricity sector in the Territory.

Prior to 1 July 2014, the Power and Water Corporation (PWC) was the sole supplier of electricity services in the Territory. It was a vertically integrated electricity service provider, providing generation, network and retail services.

Central to the reforms was the separation of PWC's contestable retail and generation businesses from its regulated, monopoly network business.[4] The sector was restructured into three separate Government-owned businesses:

- **Territory Generation (T-Gen)** was established as an electricity generation business.
- **PWC** continued to provide network services to customers connected to the Darwin-Katherine Interconnected System (DKIS), in Tennant Creek and Alice Springs, and to be the vertically integrated electricity service provider in numerous off grid locations in the Territory. It is also the power system controller for the DKIS, and for the electricity system in Tennant Creek and Alice Springs, and the market operator for the DKIS.
- **Jacana Energy (Jacana)** was established as an electricity retailer. The Government has introduced full retail contestability, so other retailers are able to participate in the Territory's retail electricity market, but Jacana remains the dominant retailer to residential and small business customers.

Part of the Government's electricity market reform program is to work towards a competitive wholesale electricity market in the Territory. A key step towards this was taken on 27 May 2015 with the commencement of the Interim Northern Territory Electricity Market (I-NTEM). The I-NTEM was intended to be a short-term transitional arrangement to initiate market operations in the sector and begin the process towards implementation of the full NTEM.

The I-NTEM was designed and implemented using a minimalist approach to developing systems and regulatory arrangements. It leveraged existing arrangements and utilised legacy systems and practices, to provide a vehicle for familiarisation and testing of processes, and roles and responsibilities of parties.

Another aspect of energy policy in the Territory that is relevant to the current report is the Government's Renewable Energy and Electricity Market Reform Implementation Plan 2018-20. This plan was developed in response to the Renewable Energy Expert Panel's Roadmap to Renewables Fifty per cent by 2030 report (the Roadmap), which was released in September 2017.

[4] From 1 July 2014

The Government has a target to:

- achieve an increase in the proportion of renewable energy generation in the Territory from around 4 per cent in 2017 to 50 per cent by 2030
- while maintaining secure, reliable and least-cost electricity for consumers and taxpayers.[5]

The Roadmap assumes that solar PV is the most prospective renewable energy technology for the Territory, with gas-fired generation for backup.

The 50 per cent by 2030 renewables target will be a key driver of change in the electricity sector in the Darwin-Katherine region and throughout the Territory in the short to medium term. It is intended to have a substantial impact on the sources from which Territorians obtain their electricity.

1.1 Electricity Market Priority Reform Program

The current I-NTEM arrangements are being challenged by the generation profile in the Territory, which is evolving rapidly to support the Government's renewable energy target.

The Government has identified a package of coordinated priority reforms to facilitate increased market participants and accommodate the emerging technologies, while ensuring an efficient, secure and reliable electricity supply and supporting the Government's renewable energy target.

The priority reform areas are: [6]

1. Reliability – there is currently no formal system-wide standard for reliability of supply, and thereby no objective means to appropriately trade off cost and reliability.
2. Dispatch – the current arrangements are inefficient, do not include provision to optimise the use of energy and essential system services, cannot manage a number of plausible operational situations, and will be unable to efficiently manage the increased amounts of solar generation.
3. Essential system services – T-Gen is currently the sole provider of all types of essential system services. Other generators must compensate T-Gen for their share of costs in accordance with a codified price that was set in 2015.
4. Settlement – the existing settlement arrangements will not accommodate foreseeable contractual arrangements for the sale of energy between multiple market participants.

In June 2020, the Government released an Issues Paper on the third of these areas – the review of essential system services (ESS). The objective of the review is to ensure that the delivery of ESS is economically efficient and at least cost but there is no compromise to system security.[7] The changes proposed by the Government are to:

- *[update] the quantum of the rate paid to Territory Generation for ESS by other generators*
- *[codify] the process for reviewing and updating the quantum of the rate to ensure the rate remains up to date*
- *[improve] 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.*[8]

The Issues Paper sought stakeholder comments on:

- the categorisation and definition of services
- service requirements
- service provision framework
- administered pricing arrangements and market power mitigation
- cost allocation and settlement
- the legislative and regulatory framework.

[5] https://roadmaptorenewables.nt.gov.au/implementation, accessed 16 December 2019
[6] Northern Territory Government, *Northern Territory Electricity Market Priority Reform Program, Introductory notes on scope and work program*, June 2020, pages 5-6
[7] Northern Territory Government, *Review of Essential System Services in the Northern Territory's Regulated Electricity Systems, Issues Paper*, June 2020, page 4
[8] Ibid, page 5

Submissions were received from the following five stakeholders:

1. T-Gen – which is currently remunerated for providing ESS.
2. Jacana – which is currently the dominant retailer in the Territory.
3. Eni Australia (Eni) – which is currently developing solar farms near Katherine, at Batchelor and at Manton Dam.
4. Epuron – which owns and operates solar farms in Alice Springs, Yulara, Ti Tree, Kalkarindji and Alpurrurulam, and originally developed the solar farm at Katherine before selling the project to Eni.
5. Sun Cable – which is proposing the construction of a 10 GW solar farm with approximately 26 GWh of battery storage close to Elliott, a 3 GW transmission line to Darwin and 2 GW HVDC submarine cable linking the system to Singapore.

ACIL Allen Consulting (ACIL Allen) was engaged by the Department of Industry, Tourism and Trade (the Department) to review the submissions on the Issues Paper and provide economic advice and recommendations in relation to the:

— service provision framework
— administered pricing arrangements and market power mitigation
— cost allocation and settlement.

The economic advice draws on technical advice provided to the Department by GHD Advisory (GHD) on the categorisation and definition of services, and service requirements.[9]

1.2 Structure of the report

The rest of this report is structured as follows:

— Chapter 2 provides background information as context for the rest of the report.
— Chapter 3 considers the service provision framework, which will govern how the System Controller procures the ESS required to maintain system security.
— Chapter 4 considers administered pricing for the provision of ESS by T-Gen under the current monopoly provision arrangements, and appropriate pricing and/or other market power mitigation arrangements that would be appropriate under a potential competitive market framework.
— Chapter 5 considers the allocation of the unbundled costs associated with procuring ESS on a 'causer pays' basis.
— Our responses to the issues raised in the Issues Paper on the service provision framework, administered pricing arrangements and market power mitigation, and cost allocation and settlement are summarised in Chapter 6.

[9] GHD Advisory, *Review of Essential System Services in the Northern Territory, Final Report*, 16 November 2020

2 BACKGROUND

This chapter provides background information as context for the rest of the report.

2.1 Operating and controlling the Territory's electricity system

The following sections describe PWC's role as the network operator and system controller in the Territory. As indicated in chapter 1, PWC is also the market operator for the DKIS.

2.1.1 Network operator role

As the network operator, PWC's responsibilities include delivering energy from T-Gen and other generators to its customers in a safe and reliable way. It is also responsible for connecting new generators and users to the network, and restoring power after faults and emergencies happen due to severe weather events and other causes.

PWC currently relies on generators to provide it with network support services so that it can reliably deliver energy from power generators to its customers. For example, synchronous generators in Katherine, that are less efficient than those in Darwin, provide network support services in case of loss of the transmission line between Darwin and Katherine.[10]

2.1.2 System controller role

PWC's system controller function is defined in section 38(1) of the *Electricity Reform Act 2000* as:

… monitoring and controlling the operation of the power system with a view to ensuring that the system operates reliably, safely and securely in accordance with a technical code (the System Control Technical Code) prepared by the system controller and approved by the Utilities Commission.

As the system controller, PWC is responsible for:

- operating the power system in such a way that:
  - the system transfers electricity securely and efficiently
  - the number of interruptions customers experience is minimised
  - the system can be restored as soon as reasonably practical after an interruption
- setting the target frequency of the Territory's power system and arranging for ancillary services to maintain that frequency
- establishing operating protocols for generation dispatch and to maintain power system security
- ensuring that equipment used on the network meets the applicable requirements.

[10] During a previous consultation with T-Gen, it advised that the power station at Katherine is necessary as a source of system support, but energy can be supplied more efficiently from Channel Island.

The System Controller is able to set charges for its system control and market operation activities, with the charges subject to approval by the Utilities Commission. The system control charges are recovered from electricity customers in Darwin, Katherine, Tennant Creek and Alice Springs. The market operator charges are recovered from electricity customers in the Darwin-Katherine region only.

The system control charges relate to the direct operation of the System Controller. They do not include the costs of acquiring the ancillary services (or ESS) necessary to maintain the security and reliability of the power system. Rather, the cost of the services themselves is covered by generators who, in accordance with section A6.11 of the System Control Technical Code, must pay T-Gen for these ancillary services. The amount they pay is based on the energy produced on a sent out basis and a price, which is generally $5.40 per MWh except where varied during specific events.

2.2 Essential System Services

ESS are required to support the electricity system to produce and transport energy of an acceptable quality to consumers, and maintain the balance between supply and demand in real-time during normal and abnormal conditions.

There are generally three broad categories of ESS:

- Frequency management – to maintain power frequency within acceptable standards at all times. If the demand is greater than supply then the frequency will decrease, and if the demand is less than supply then the frequency will increase.
- Voltage management – to manage voltages at different points of the network, control power flow within the networks' capacity and maintain stability following disturbances. The electricity system may need more or less reactive power to control the voltage.
- Restart services – to re-establish the power system following a significant event that has resulted in complete (or significant partial) system blackout.

2.2.1 Current provision of ESS in the Territory

The current requirements for ESS in the Territory, which are set out in the System Control Technical Code (SCTC), the Network Technical Code (NTC), and the System Secure Guidelines (SSG), are summarised in 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 Services (C-FCAS)
	– Raise – fast, slow, delayed
	– Lower – fast, slow, delayed
	Inertia Frequency Control Ancillary Services (I-FCAS)
	Spinning reserve
Voltage management	Voltage control
	Reactive power reserve
Restart services	Black start capability

SOURCE: GHD ADVISORY, REVIEW OF ESSENTIAL SYSTEM SERVICES IN THE NORTHERN TERRITORY, FINAL REPORT, 16 NOVEMBER 2020, PAGES 13-14

Electricity has traditionally been generated by synchronous generators. These synchronous generators have generally been owned and operated by T-Gen with gas-fired generators at Channel Island and Katherine to supply the DKIS, and in Alice Springs and Tennant Creek.

These generators have also provided voltage regulation services and in some cases power system stabilisation. They have been able to respond to voltage disturbances on the power system in a manner which resists the disturbance and limits its size, thereby stabilising network voltages.

Additionally, the connection of synchronous generators to the system maintained system impedances within acceptable limits. System strength is mainly about impedances – large impedances lead to larger voltage swings and more chance of power system instability.

As a result, the ESS required in the Territory have traditionally been provided by T-Gen with a payment of $5.40 per MWh made by other generators in the DKIS to T-Gen.

However, as progress is made towards the Government's 50 per cent by 2030 renewable energy target, the existing synchronous generators will be progressively displaced by non-synchronous solar generation. This has occurred in the National Electricity Market (NEM) over the last ten years or so, and has gradually reduced the overall level of system strength in the power system. Following a system black event in the South Australian region in September 2016, the National Electricity Rules (NER) were amended to include frameworks for addressing system strength issues.

The same broad challenge faces the Territory's electricity sector as the use of solar generation increases, with the Territory's Generator Performance Standards also recently amended.

A key part of the current reform program is to ensure that the necessary ESS can be provided by the most efficient combination of sources. Table 2.2 provides an indication as the existing technical capability to provide each type of ESS that is currently required in the Territory. There are multiple sources for each type of ESS, potentially other than for restart services.

TABLE 2.2 TECHNICAL CAPABILITY TO PROVIDE ESSENTIAL SYSTEM SERVICES

Service	Territory Generation – synchronous generation	Independent synchronous generation	Independent large-scale solar	Distributed generation (i.e. rooftop PV)
R-FCAS	√	√		
C-FCAS (raise)	√	√		
C-FCAS (lower)	√	√	√	√
I-FCAS	√	√		
Spinning reserve	√	√		
Restart services	√	Unknown		

SOURCE: GHD ADVISORY, REVIEW OF ESSENTIAL SYSTEM SERVICES IN THE NORTHERN TERRITORY, FINAL REPORT, 16 NOVEMBER 2020, PAGES 22-23

Notwithstanding the availability of multiple sources to provide ESS (potentially other than restart services), T-Gen continues to be the monopoly provider of all ESS as a bundled service.

2.2.2 Generator Performance Standards

Recent changes to the Territory's Generator Performance Standards (GPS) facilitate the provision of ESS by generators other than T-Gen's synchronous generators.

The GPS set conditions generators must meet for connection to the power system so that the System Controller has the levers to balance supply and demand in real time to avoid customer outages.[11] The GPS do not describe how a generator is dispatched, do not describe power system security constraints, and do not rely on the presence or absence of an energy or ancillary services market.[12]

The GPS can broadly be grouped as:

- *Capability to remain in continuous operation under prescribed system normal and abnormal conditions;*
- *Capability to support power system security during abnormal conditions; and*
- *Meeting a prescribed level of predictability and dispatchability.*[13]

[11] PowerWater, *Review of the Northern Territory Generator Performance Standards, Application to the Utilities Commission to approve amendments to the Network Technical Code and System Control Technical Code*, September 2019, page 11
[12] Ibid, page 12
[13] ibid

In March 2020, the GPS were amended. The objective of the amendments was to ensure that:

… the power system remains secure and reliable, and that those who drive risks and costs to the system face those costs, to minimise them commercially.[14]

The new GPS seek to ensure that the system can technically support a high penetration of PV generation rather than relying on synchronous generation to off-set intermittency and provide all non-energy services, and to facilitate least cost outcomes by placing the risk with those best placed to manage it.[15]

The new GPS include requirements relating to:

- inertia – all generator systems are required to provide inertia by either synchronous or non-synchronous (emulated) sources to maintain a sufficient level of system inertia in a system normal state and in the event of a credible contingency[16]
- system strength – a generating system must not have an adverse impact on system strength[17]
- voltage control – a generating unit is required to maintain a specified voltage range at the connection point during normal operation and contingency condition[18]
- frequency control – a generating system must be able to provide Frequency Control Ancillary Services (FCAS).[19]

The new GPS include grandfathering provisions that apply to generators physically connected prior to 1 April 2019. A grace period is provided for generators that physically connected between 1 April 2019 and when the amendments were approved. The new provisions apply to any generator that physically connects to the system after the amendments were approved.[20]

Under the new GPS, all generators are required to be **capable** of providing FCAS so that the System Controller can effectively manage frequency control under all possible operating conditions and dispatch scenarios, while facilitating high levels of PV generation dispatch. The principle is:

… to 'do no harm' in regards to reducing the power system's technical capability to maintain power system frequency by ensuring a sufficient level of services being available to be dispatched.[21]

However, under the I-NTEM, there is currently no mechanism to facilitate ancillary service payments to generators other than T-Gen.[22] Accordingly, generators other than T-Gen are only likely to provide FCAS under abnormal circumstances when T-Gen is unable to provide those services.[23]

2.2.3 Recommended new Essential System Services

In its advice to the Department on the technical aspects of the Issues Paper, GHD has recommended the set of ESS as set out in Table 2.3. Our advice in this report is based on this set of services.

TABLE 2.3 ESSENTIAL SYSTEM SERVICES AS RECOMMENDED BY GHD

Service definition	Purpose
Rate of change of frequency (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 under frequency load shedding for all credible contingency events.

[14] ibid, page 5
[15] Ibid, pages 14-15
[16] Network Technical Code, clause 3.3.5.15
[17] Network Technical Code, clause 3.3.5.16
[18] Network Technical Code, clause 3.3.5.13
[19] Network Technical Code, clause 3.3.5.11
[20] PowerWater, *Review of the Northern Territory Generator Performance Standards, Application to the Utilities Commission to approve amendments to the Network Technical Code and System Control Technical Code*, September 2019, pages 26-27
[21] Ibid, page 50
[22] Ibid, page 49
[23] Ibid, page 51

Service definition	Purpose
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 between dispatch intervals.
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.

SOURCE: GHD ADVISORY, REVIEW OF ESSENTIAL SYSTEM SERVICES IN THE NORTHERN TERRITORY, FINAL REPORT, 16 NOVEMBER 2020, PAGE 40

While most of the provision of most of these services will be the responsibility of System Control, GHD has identified that voltage management / network support and system strength services are only required to respond to localised issues. GHD is of the view that the process for identifying shortfalls in capacity or reactive power capability and for identifying emerging system strength issues should be identified as part of normal planning processes by the Network Operator.[24]

2.3 Principles for reviewing ESS

The Issues Paper proposed that the overarching assessment framework for the review of ESS be aligned to the National Electricity Objective (NEO) as defined under the National Electricity Law, which 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 …[25]

The following principles were proposed to frame the review:

- Required security standards must be met.
- Services should be acquired at least cost.
- ESS acquisition is to be technology neutral.
- To the extent possible, the proposed arrangements should deliver certainty to industry participants, so as to provide the confidence to invest.
- Arrangements must support the achievement of the Government's 50 per cent renewables by 2030 target and reductions to greenhouse gas emissions.
- Reforms must improve the overall efficiency of electricity supply, putting downward pressure on the combined cost of ESS, wholesale electricity and network services.

In considering three of the issues in this report, we have had regard to these principles. We have also had regard to the scale of the electricity system in the Territory – it is of a much smaller scale than the National Electricity Market (NEM) and the Western Australian Electricity Market (WEM).

[24] GHD Advisory, *Review of Essential System Services in the Northern Territory, Final Report*, 16 November 2020, page 42
[25] Section 7

2.4 Assessment criteria

This paper considers three of the issues that were discussed in the Issues Paper:

1. The service provision framework, which will govern how the System Controller procures the ESS required to maintain system security.
2. Administered pricing for the provision of ESS by T-Gen under the current monopoly provision arrangements, and appropriate pricing and/or other market power mitigation arrangements that would be appropriate under a potential competitive market framework.
3. The allocation of the unbundled costs associated with procuring ESS on a 'causer pays' basis.

We have identified options that may address the issues, by reference to the Issues Paper and stakeholder submissions to the Issues Paper. We have assessed each of these options against a set of criteria that are drawn from the NEO and the principles listed above. The assessment criteria that we have used are:

- Efficiency – the extent to which the option enables the services to be acquired at least cost and improves the overall efficiency of electricity supply.
- Administrative costs – the extent to which administrative costs are incurred in implementing and administering the option over time.
- Meeting required standards – the extent to which the option facilitates the electricity system meeting required security standards.
- Investment certainty – the extent to which the option delivers certainty to industry participants, so as to provide the confidence to invest.
- Technology neutrality – the extent to which the option facilitates ESS acquisition that is technology neutral.

We have weighted each criteria so that the options can be readily compared. We have assigned a weighting on a scale of one to five, based on the perceived relative importance of each criterion. We have assigned a weighting of five to the efficiency criterion, one to the administrative costs criterion and three to each of the remaining criteria. The choice of weightings is a subjective decision.

3 SERVICE PROVISION FRAMEWORK

This chapter considers the service provision framework, which will govern how the System Controller procures the ESS required to maintain system security. Section 3.1 summarises the issue and the relevant comments by stakeholders, section 3.2 identifies and assesses options for the service provision framework, and section 3.3 provides our response to the questions raised in the Issues Paper.

3.1 Background

The Territory's current ESS framework is characterised by regulation with a mix of a regulated tariff and mandated provisions. As discussed in section 2.1, under section A6.11(b) of the SCTC, generators must pay an amount of $5.40 per MWh (sent out) to T-Gen for the provision of ESS in the DKIS.

Other generators may be called on by the System Controller to provide ESS, but there is no formal mechanism to compensate them for this. There is also no incentive, other than through sub-contracting by T-Gen, for third parties to provide ESS voluntarily.

The current framework thereby does not facilitate private proponents to provide potentially cheaper and more innovative ESS. To reform the lack of incentive and opportunity for private proponents to provide ESS, the Issues Paper identified three broad frameworks for the procurement of ESS:

- regulation (including regulated tariffs and mandated provision)
- bilateral contracts
- pricing and dispatch through a spot market.

The Issues Paper sought comments from stakeholders on the following questions:

(a) *What types of ESS are most suitable for market provision and in which systems? Are there certain categories of ESS which would benefit from continued Territory Generation and why?*

(b) *What are the likely costs and benefits of spot market procurement of certain types of ESS in any of the Territory electricity systems?*

(c) *What service provision framework would deliver the most appropriate balance between costs and benefits for each category of ESS in each regulated electricity system?*

Stakeholder comments on each of these questions are summarised in the following sections.

3.1.1 Which types of ESS (and for which systems) are most suitable for market provision?

All stakeholders were of the view that ESS in each of the regulated systems were suitable for market (competitive) provision. However, there were some differences in view between them as to the best way to structure the market(s) in which ESS would be transacted.

T-Gen submitted that all ESS currently provided by it could be provided by other providers in all the regulated power systems, but would need to be formally recognised as suppliers of those services. Epuron had a similar view.

Jacana was of the view that frequency control services are better provided through spot markets whereas other services are better acquired through competitive tender arrangements. It noted that competition with T-Gen for the provision of ESS will increase gradually over time with the retirement of T-Gen units and increased investment by others.

Eni's response was focused on the DKIS. It was of the view that the scale of the DKIS does not justify full spot market provision. Sun Cable was similarly of the view that a spot market mechanism is not suited to any grid in the Territory.

3.1.2 Costs and benefits of a spot market

As stakeholders generally did not support the development of a spot market for the provision of ESS, many did not comment on the cost and benefits of a spot market.

Sun Cable submitted that the potential anti-competitive outcomes of a spot market in a small system, such as those in the Territory, may hinder the lowest cost procurement of ESS. It was of the view that there are not enough participants in the short to medium term to ensure the efficient operation of a spot market.

… a spot market built on a monopoly (featuring only Territory Generation) or an oligopoly (featuring, for example, Territory Generation, Sun Cable and one or two other participants) may enable the exercise of extreme market power, which would be to the detriment of both consumers and generators ..[26]

Additionally, it was of the view that large-scale capital investments, that may be required to deliver ESS, are rarely made on a spot market merchant basis.

T-Gen submitted that the costs of providing ESS through a spot market are unlikely to be lower than the current arrangements because of the need to set up a 24/7 trading desk, and because one or more services may still need to be provided by a synchronous generator, which would increase the costs associated with providing that service. It also raised the risk that there may be no generator to provide energy or ESS.

Epuron was of the view that procuring ESS through a spot market would be the lowest cost provision of ESS, however the overhead costs associated with doing so would be high.

3.1.3 Appropriate service provision framework

Stakeholder's views on the appropriate service provision framework varied.

T-Gen was of the view that all ESS should be provided centrally until all services can be supplied independently.

Eni submitted that there should be a default provider of ESS that should not be T-Gen. The private providers should be given the opportunity to bid into a competitive procurement process to provide the services over a 10 year period. It was of the view that the 10 year period would be:

… an appropriate compromise between competitive tension on the one hand and capital recovery for the proponent on the other.[27]

It was also of the view that the development of a new battery announced by the Government should be the subject of a competitive procurement process. If the battery is to be built by T-Gen to provide

[26] Sun Cable submission to the Issues Paper
[27] Eni Australia submission to the Issues Paper, page 9

ESS, then this will act as a barrier to the entry of private providers to this market, but this should not be a barrier to the development of a more competitive market for the provision of ESS.

Epuron proposed that there be a capacity market. The Network Operator (sic) would determine how much ESS each system requires. Generators would then bid for and be contracted to provide the ESS that is required.

Sun Cable submitted that frequency control essential services be procured through bilateral contracts, which could be negotiated on an individual or over-the-counter bilateral basis, or administered via a regulated market mechanism, such as a reverse auction mechanism, with a contingency ESS supplier of last resort. It proposed that system restart services be open to procurement from third parties with relatively long-term contracting to assist investment decisions.

Jacana proposed the arrangements that it considered appropriate for each type of service as set out in Table 3.1.

TABLE 3.1 SERVICE PROVISION FRAMEWORK PROPOSED BY JACANA

Type of service	Proposed arrangement
Frequency regulation and contingency services	DKIS – competitive spot market Other regulated systems – competitive tendering arrangements, with default service provision arrangements with T-Gen
Rate of Change of Frequency control service	Constrained off/on payment system
Other services such as network control services, voltage support and system restart services	Competitive tendering arrangements, with default service provision arrangements with T-Gen

SOURCE: JACANA SUBMISSION TO THE ISSUES PAPER, PAGES 5-6

3.2 Assessment of options

The Issues Paper identified the following three options for the procurement of ESS, which are assessed in this section:

- regulation (including regulated tariffs and mandated provision), which is the current approach
- bilateral contracts
- pricing and dispatch through a spot market.

3.2.1 Efficient provision of services

The principles for reviewing the ESS include that the services should be acquired at least cost, and that the reforms should improve the overall efficiency of the electricity supply, putting downward pressure on the combined cost of ESS, wholesale electricity and network services.

ESS are most likely able to be acquired at least cost when they are acquired through some form of competitive process and there are sufficient potential providers of those services participating in the process to apply competitive tension. There are various ways to introduce competition into the provision of services such as these. Spot markets are one.

Spot markets have the advantage of (usually) being highly visible and transparent. However, the disadvantage with the spot market approach, particularly in the context of high fixed (capital) costs, is risk.

With a typical spot market approach, such as the spot wholesale markets used in the NEM, acquisition is frequent and for a short period. This means that, based on spot markets *alone,* suppliers cannot be confident of being able to supply the service in question for long enough to earn a reasonable return on their investment and are thus less likely to invest.

To overcome this, renewable energy and other generation projects are invariably underpinned by power purchase agreements (PPAs). This occurs *even though* the generators in question are required to sell all of their output through the NEM spot market. In effect, the market for PPAs becomes as

important, if not more so, for driving efficiencies in generation investment. The spot market is used as a guide to the current and future price of electricity and, as such, as an information input to the PPA.

New renewable energy generators will need to be developed to meet the Government's renewable energy target. These generators are likely to be accompanied by batteries (or other technologies) to meet the GPS, and will be able to provide some or all of the ESS that are the responsibility of the System Controller. This will require capital investment which will only be made if the investor has reasonable confidence in recovering it. For this reason, a market based around longer term contracts, rather than a short and frequent spot market, is likely to be more suitable.

A spot market has the advantage of providing price discovery. Prices can be published and new entrants may choose to participate in the ESS market over time. The prices negotiated under bilateral contracts are usually not public. Thus, the incentive for entry during the contract term is reduced (prevented by contract) and information to support entry when a new competitive process is called is harder to come by, which gives the incumbent an advantage. This disadvantage of the bilateral contract approach could be addressed by requiring prices to be disclosed.

A spot market also has the potential to co-optimise the dispatch of wholesale energy and ESS. However, the two markets can only be co-optimised if there is a wholesale energy market and need only be co-optimised for synchronous generators.

T-Gen is currently the predominant provider of ESS using synchronous generators. However, as the Territory's electricity supply transitions from synchronous generators to new renewable energy generators and batteries over the period to 2030, there is the opportunity to introduce additional providers of ESS to apply more competitive tension as part of any competitive process to provide ESS – more so in the Darwin-Katherine system than in the smaller Alice Springs and Tennant Creek systems.

Given this transition over the next decade, and assuming there is a move towards more competitive provision of ESS, the timing and transition path will be important to be able to leverage the benefits of competition but not be penalised during the transition period when competition may not be effective. This is considered further in chapter 4.

The competitive processes are likely to be more competitive, and therefore result in more efficient outcomes, if the services are unbundled so that proponents can choose to offer all, some or one of the services. That is, that each of the services is separately tendered and/or negotiated in the case of bilateral contracts, but with the tenders being issued at the same time so that proponents can choose which services to offer, or separately bid and dispatched in the case of a spot market.

Under a bilateral contracts approach, the contracts could be awarded for the full volume of services required on a periodic basis, or contacts could be staggered with contracts awarded for a portion of the volume of services required on an annual basis.

If the contracts are staggered, with half or a third of services procured each year, rather than all services procured every second or third year, then the System Controller will have a portfolio of contracts with a range of prices – with potentially higher prices in one year offset by lower prices in another year. However, while this may mitigate the risk of entering into contracts for a 2-3 year period when prices are higher, there may be less competitive tension during the tender process as the value of contracts are lower, which may result in higher prices.

The current approach based on regulated prices and mandated provision is not a competitive process and therefore does not facilitate the dispatch of the least cost ESS as more potential providers enter the market.

GHD has recommended to the Department that there are seven different types of ESS, as set out in Table 2.3. Of these, GHD notes that two should be the responsibility of the Network Operator – voltage management / network support services and system strength services.

The Network Operator is subject to an incentive-based economic regulatory regime. Its revenues are determined on a five yearly basis by the Australian Energy Regulator, with prices set annually in accordance with the revenue determination. If the Network Operator is responsible for providing voltage management / network support and system strength services under the legislative and

regulatory framework, then the revenue determined and the prices set to recover the costs associated with those services will be in accordance with the economic regulatory regime.

A summary of the assessment of the efficiency of the three options for service provision is provided in Table 3.2. The assessment of the options to facilitate an efficient provision of services is made in relation to the ESS for which the System Controller is the responsible party.

TABLE 3.2 EFFICIENT PROVISION OF SERVICES – ASSESSMENT OF OPTIONS

Option	Rating	Comment
Regulation	○	Not a competitive process and therefore not necessarily an efficient provision of services
Bilateral contracts	◕	A competitive process but may not result in an efficient outcome if the market is not effectively competitive. This approach is more likely to support investment and works even if there is only competition infrequently (when bids are called)
Spot market	◕	A competitive process but may not result in an efficient outcome if the market is not effectively competitive. This approach really only works if there is a number of competitors that participate frequently. Has the potential to co-optimise the dispatch of wholesale energy and essential system services

○ Inefficient ◔ Largely inefficient ◑ Moderately inefficient ◕ Slightly inefficient ● Efficient

SOURCE: ACIL ALLEN ASSESSMENT

3.2.2 Administrative costs

Under the regulation option, there are the upfront costs associated with regulating the tariffs, mandating the required provisions, and for the System Controller to ascertain which providers are prepared to provide ESS at the regulated tariff and under what conditions. These costs would be incurred each time the regulatory process is repeated. On an ongoing basis, the System Controller would need to understand any change in the preparedness of providers to provide services and to dispatch the services as required.

Under the bilateral contracts option, there are the upfront costs associated with conducting some form of competitive process to tender for the services and award contracts to the successful tenderers. These upfront costs would be incurred each time the services are retendered, which is discussed further in section 3.2.4. The more frequently the services are retendered, the higher the administrative costs.

Once these bilateral contracts have been entered into, the System Controller would dispatch the services as required in accordance with the terms of the contract. The administrative costs associated with the bilateral contracts option are higher than the administrative costs associated with the regulation option.

Under the spot market option, there are the upfront costs to establish the rules, processes and systems for the spot market, in which processes and systems are required to be established by the System Controller and the providers of services. There are ongoing costs associated with the registration of providers, the bidding of services by providers and settling payments as well as the dispatch of services as required by the System Controller in accordance with the bids received. While the System Controller must dispatch ESS under each of the options, under this option the System Controller would need to dispatch the services under the more dynamic circumstances associated with a spot market. The administrative costs associated with the spot market option are higher than the administrative costs associated with the bilateral contracts option.

An estimate of the administrative costs under each of the options is provided in Table 3.3.

TABLE 3.3 ESTIMATED ADMINISTRATIVE COSTS FOR EACH SERVICE PROVISION OPTION

Option	Upfront costs	Ongoing costs
Regulation	$100k - $300k each time regulatory arrangements are updated plus 1 FTE through the period of establishing the arrangements	Part of 24/7 operation of the control centre
Bilateral contracts	$200k - $500k each time tender process is conducted plus 1 FTE through the tendering and contracting period	Part of 24/7 operation of the control centre, with a higher level of resourcing than the regulation option
Spot market	$2 million -$10 million to establish the rules, processes and systems	Part of 24/7 operation of the control centre, with a higher level of resourcing than the bilateral contracts option

SOURCE: ACIL ALLEN ASSESSMENT

A summary of the assessment of the administrative costs associated with each of the three options for service provision is provided in Table 3.4.

TABLE 3.4 ADMINISTRATIVE COSTS – ASSESSMENT OF OPTIONS

Option	Rating	Comment
Regulation	◕	Upfront costs to establish framework and ongoing costs to dispatch services
Bilateral contracts	◑	Higher upfront costs to conduct competitive process and enter into contracts. Higher ongoing costs to dispatch services as required in accordance with the terms of the contracts
Spot market	◔	Upfront costs higher again to establish the rules, processes and systems for the spot market. Higher ongoing costs to dispatch services as required in accordance with the bids received

○ Very high costs ◔ High costs ◑ Moderate costs ◕ Low costs ● Very low costs

SOURCE: ACIL ALLEN ASSESSMENT

3.2.3 Meet required standards

Under the regulation option, the framework can be established to ensure that the required standards are met. However, this may be achieved by dispatching inefficient ESS and potentially imposing significant costs on the Government-owned entities. If this is the case, these costs may be borne by taxpayers rather than electricity market participants.

To facilitate meeting the required standards under a bilateral contract option, the System Controller would need to enter into a range of contracts. As a minimum, there would need to be separate contracts for each service for each system. As some technologies will be better placed to provide some services at certain times of day, the contracts may need to be structured to allow prices to be tendered that vary across the day. This would enable proponents to either not bid or bid very high prices at times when the services either cannot be provided or provided at high marginal cost, and to bid low prices at times when the services can be provided at low marginal cost. The System Controller can then dispatch the lowest cost service to meet the required standard in any system based on the time of day.

The spot market would be able to respond more dynamically to the particular circumstances prevailing at the time at which the ESS are required to be dispatched. The likelihood that the required standards would be met using this approach is much greater for services for which the revenue supplements the main revenue stream and for which the services are required regularly, such as regulating frequency control. However, there is a risk that no bids would be made for services that are required on a less frequent basis, such as system restart. A revenue stream is required for providers of system restart services beyond the period in which the service is dispatched to ensure that they are able to provide those services as and when required.

A summary of the assessment of the extent to which each of the three options facilitates meeting the required standards is provided in Table 3.5.

TABLE 3.5 MEET REQUIRED STANDARDS – ASSESSMENT OF OPTIONS

Option	Rating	Comment
Regulation	●	Framework can be established to ensure required standards are met
Bilateral contracts	◕	Framework can be established to ensure required standards are met, but contracts may need to be structured to allow different prices to be bid at different times of day
Spot market	◑	Spot market will be able to respond more dynamically to the particular circumstances when services are required, but risk that bids not made for important but infrequently used services

○ Does not meet required standards ◔ Partly meets required standard ◑ Somewhat meets required standards ◕ Largely meets required standards
● Meets required standards

SOURCE: ACIL ALLEN ASSESSMENT

3.2.4 Provide investment certainty

The regulation option provides investors certainty as to the price that would be paid for services in the short-medium term, assuming that the regulated price is available to all participants that provide services, but may not provide the required investment certainty. This is because the price may be too low to incentivise investment in technology to provide the services and/or there may be too much uncertainty as to the price in the longer term.

The use of bilateral contracts to procure ESS has the potential to provide sufficient investment certainty, however that certainty is dependent on the tenure of the contracts. To provide investment certainty, contracts would need to be of a longer tenure (such as 5-10 years) for services that are provided infrequently and for which a revenue stream is required to ensure that they are available as and when required, such as system restart services. Contracts could be of a shorter tenure (say two to three years) for services which could be provided with low fixed (capital) costs, or where the fixed costs could be apportioned between the provision of ESS and energy services.

If the contracts are staggered, with half or a third of services procured each year, rather than all services procured every second or third year, then:

— the value of services procured each year will be lower, which provides a lower level of investment certainty, but

— it provides the opportunity for new players to enter into a contract to provide services each year.

The spot market provides little investment certainty and is therefore only applicable to services that are provided frequently and where the provision of ESS supplements the main revenue stream from the energy market, such as regulating frequency control.

A summary of the assessment of the extent to which each of the three options for service provision provides investment certainty is provided in Table 3.6.

TABLE 3.6 PROVIDE INVESTMENT CERTAINTY – ASSESSMENT OF OPTIONS

Option	Rating	Comment
Regulation	◑	Depends on the framework, in particular whether the price is high enough to incentivise investment and the certainty as to price in the longer term
Bilateral contracts	◕	Can provide investment certainty if the tenure of the contracts is commensurate with the type of service to be provided
Spot market	◔	Does not provide investment certainty for services that are provided less frequently, such as system restart services

○ Does not provide investment certainty ◔ Partly provides investment certainty ◑ Somewhat provides investment certainty ◕ Largely provides investment certainty ● Provides investment certainty

SOURCE: ACIL ALLEN ASSESSMENT

3.2.5 Technology neutrality

The extent to which the regulation option is technology neutral will depend on the nature of the regulatory provisions – whether or not they are specific to particular technologies.

Similarly, the extent to which the bilateral contract option is technology neutral will depend on the nature of the contracts – whether or not the way in which providers are required to tender for services is specific to particular technologies. The bilateral contract option will be more technology neutral if the services are unbundled. While some technologies may be able to bid for some services, the more the services are bundled, the more limited the range of technologies that are able to bid.

Assuming that services are unbundled, a spot market would be technology neutral.

A summary of the assessment of the extent to which each of the three options for service provision is technology neutral is provided in Table 3.7.

TABLE 3.7 TECHNOLOGY NEUTRALITY – ASSESSMENT OF OPTIONS

Option	Rating	Comment
Regulation	◑	Depends on the regulatory framework
Bilateral contracts	◑	Depends on the nature of the contracts
Spot market	●	If services are unbundled, technology neutral

○ Technology specific ◔ Partly technology neutral ◑ Somewhat technology neutral ◕ Largely technology neutral ● Technology neutral

SOURCE: ACIL ALLEN ASSESSMENT

3.2.6 Summary of the assessment of framework options for service provision

The assessment of the three service provision framework options against the criteria is summarised in Table 3.8.

Of the three service provision framework options assessed, the use of bilateral contracts was assessed the most favourably. The assessment is based on bilateral contracts being awarded following some form of competitive tender or reverse auction process, with the services being unbundled.

The competitive process facilitates the efficient provision of services if there are sufficient participants to apply competitive tension. As the Territory's electricity supply transitions to meet the 50 per cent renewables target by 2030, there will increasingly be additional providers of ESS to apply more competitive tension as part of any competitive process to provide ESS. However, in the short term, competition may not be effective. It will be important to consider measures to mitigate T-Gen exercising its market power in the short term. This is considered further in chapter 4.

The structure of any bilateral contracts will be important:

— to allow different bids at different times of day to facilitate efficient provision of services while meeting required technical standards

— to provide investment certainty by matching the tenure of the contracts to the nature of the service provided

— to ensure technology neutrality by unbundling services.

The upfront and ongoing costs will be higher than the existing regulatory approach – to conduct the competitive process and enter into bilateral contracts, and to dispatch services in accordance with the bilateral contracts.

The spot market is similarly more efficient than the regulatory approach if the market is effectively competitive. However, it is a higher cost approach than bilateral contracts, and the approach is not as well suited to services that are provided infrequently and for which a revenue stream is required to ensure they are available as and when required.

TABLE 3.8 SUMMARY OF THE ASSESSMENT OF THE FRAMEWORK OPTIONS FOR SERVICE PROVISION

Criterion	Weighting	Regulation	Bilateral contracts	Spot market
Efficient provision of services	5	○ Not efficient	◕ Efficient if process effectively competitive	◕ Efficient if effectively competitive
Administrative costs	1	◕ Upfront costs to establish framework and ongoing costs to dispatch services	◑ Higher upfront and ongoing costs	◔ Upfront and ongoing costs higher again
Meet required standards	3	● Can be established to meet standards	◕ Contracts will need to allow different bids at different times of day	◑ Risk that bids not made for infrequently required services
Investment certainty	3	◑ Depends on framework	◕ Can provide certainty with appropriate tenure of contracts	◔ Does not provide investment certainty
Technology neutrality	3	◑ Depends on framework	◑ Depends on nature of contracts	● If services unbundled, technology neutral
Weighted total (out of 60)		27	41	37

○ Does not meet assessment criterion ◔ Partly meets assessment criterion ◑ Somewhat meets assessment criterion ◕ Largely meets assessment criterion ● Meets assessment criterion

SOURCE: ACIL ALLEN ASSESSMENT

3.3 Response to questions related to service provision framework

This section responds to the questions that were raised in the Issues Paper.

What types of ESS are most suitable for market provision and in which systems? Are there certain categories of ESS which would benefit from continued Territory Generation delivery and why?

In the longer term, more competitive provision of ESS is appropriate for each of the different types of services in each of the regulated systems.

However, in the short term, there may not be effective competition for each of the services in each of the regulated systems and so T-Gen may continue to provide services. Some safeguards will be required to mitigate the exercise of market power by T-Gen.

We would recommend that an Expression of Interest process be undertaken to seek firm commitments from participants in the market as to their interest and ability in providing each of the services (other than the services which are the responsibility of the Network Operator) in each of the regulated systems. This would provide an indication of the extent to which there is likely to be effective competition for the provision of each service in each system, and the extent to which there will need to be safeguards to mitigate the exercise of market power by T-Gen.

What are the likely costs and benefits of spot market procurement of certain types of ESS in any of the Territory electricity systems?

The key benefits of spot market procurement of ESS relative to the current regulatory approach are that it:

1. Facilitates the more efficient procurement and dispatch of ESS. However, this assumes that the market is effectively competitive and that the services are unbundled. The market will become more effectively competitive over the next few years as the Territory's electricity supply system transitions to meet the Government's 50 per cent renewables target by 2030.
2. Enables the wholesale energy and essential services to be co-optimised, assuming there is a wholesale energy market.
3. Enables the procurement of ESS on a technology neutral basis.

However, the upfront and ongoing costs associated with implementing and administering a spot market are higher than the current regulatory approach, and the approach is not as well suited to services that are infrequently required and for which a revenue stream is required to ensure they are available as and when required, such as system restart services and contingency ESS. There is a higher likelihood that system security standards may not be met if participants do not bid to provide infrequently provided services and there is less certainty for investors to invest in projects that will provide these services.

What service provision framework would deliver the most appropriate balance between costs and benefits for each category of ESS in each regulated electricity system?

As discussed in section 3.2.6, the most appropriate balance between costs and benefits would be achieved by procuring ESS, that are the responsibility of the System Controller to procure, through bilateral contracts that are entered into following a competitive tender or reverse auction process. The tenure of the contracts would need to reflect the characteristics of the relevant ESS, with:

— contracts of a longer tenure (such as 5-10 years) for services that are provided infrequently and for which a revenue stream is required to ensure that they are available as and when required, such as system restart ESS

— contracts of a shorter tenure (say 2-3 years) for services that are provided frequently and where the provision of ESS supplements the main revenue stream from the energy market, such as regulation ESS.

To facilitate the development of a more effectively competitive market in the longer term, it is recommended that the prices for ESS be published in some form to facilitate price discovery.

The provision of regulation ESS is the service most suited to provision through a spot market. As the market for regulation ESS becomes more competitive, the potential to provide regulation ESS through a spot market could be reviewed.

The existing incentive-based economic regulatory framework provides the framework for the provision of ESS for which the Network Operator is responsible.

4 ADMINISTERED PRICING ARRANGEMENTS AND MARKET POWER MITIGATION

This chapter considers administered pricing for the provision of ESS by T-Gen under the current monopoly provision arrangements, and appropriate pricing and/or other market power mitigation arrangements that would be appropriate under a potential competitive market framework. Section 4.1 summarises the issue and the relevant comments by stakeholders, section 4.2 identifies and assesses options for the mitigation of market power, and section 4.3 provides our response to the questions raised in the Issues Paper.

4.1 Background

The Territory's current I-NTEM arrangements include an administered price for ESS provided by T-Gen in the DKIS. There are no specific arrangements for pricing or recovery of costs associated with the provision of ESS in the Alice Springs and Tenant Creek systems.

The deficiencies in the current administered pricing arrangement include that:

- the administered price has not been reviewed since 2015 despite substantial activity in the DKIS which has likely impacted on the provision of ESS and thus T-Gen's costs
- the single bundled price does not provide system participants with an understanding of the costs of individual or categories of ESS captured by the rate
- there is no mechanism for the administered price to change over time with changing conditions, such as the introduction of substantial new solar energy generation and emerging technologies for providing ESS.[28]

Some form of administered pricing for T-Gen and/or other form of market power mitigation measures may be required in the future. Four options were identified in the Issues Paper:

- administered prices for the provision of ESS
- limits on revenue that can be earnt from providing ESS
- constraints on offer prices in any market mechanism
- an obligation to supply required volumes of ESS, such as a default provider arrangement.

[28] Northern Territory Government, *Review of Essential System Services in the Northern Territory's Regulated Electricity Systems, Issues Paper*, June 2020, pages 21- 22

The Issues Paper sought comments from stakeholders on the following questions:

(a) *What changes should be made to the current administered pricing arrangements for the provision of ESS provided by Territory Generation?*

(1) *What methodology should be used to determine prices for each of the ESS categories?*

(2) *What process should be put in place to ensure the administered prices remain up to date?*

(b) *What market power mitigation measures would be appropriate for the provision of different ESS by Territory Generation?*

Stakeholder comments on each of these questions are summarised in the following sections.

4.1.1 What changes should be made to the current administered pricing arrangements?

Jacana submitted that, with the move to competitive arrangements, having default supplier arrangements in place (i.e. T-Gen) will ensure that services are delivered efficiently (that is, at a regulated price) if there are limited alternative suppliers of services for a particular service category or in a particular regulated network.

While Sun Cable recommended replacing the administered pricing arrangements with market mechanisms, it is of the view that the administered pricing arrangements are useful as they provide an estimated upper bound for market outcomes, and could be used either as a market cap or regulatory guide to examine whether market power is being exercised over the long term.

Eni does not support the current administered pricing arrangement. It is of the view that it is:

… the result of a monopoly that is expensive, inappropriate and a significant deterrent to private investment in the DKIS.[29]

It also does not support administered prices moving forward. Rather, it is of the view that ESS should be procured on a competitive basis over the long term (for example, ten years) to allow both investor certainty for cost recovery and competitive tension to manage the price, with all services procured at the same time so that synergies in the cost of providing multiple services at once can be realised.

Methodology for determining prices for each of the ESS categories

Epuron submitted that a base (administered) price could be developed which represents the cost to install a new generator to provide more ESS than required in each market. In effect, this is the long run marginal cost to provide additional ESS. Sun Cable similarly recommended that the administered price be calculated based on the hypothetical marginal unit of supply to the system, while noting that it is of the view that this should only be used as a market cap or regulatory guide.

T-Gen submitted that the methodology for determining prices should be as follows:

- cost reflective
- capacity charge to support installed capacity maintenance
- ESS dispatched before energy needs as ESS underpin the power system.

Processes to ensure administered prices remain up to date

Epuron submitted that the base (administered) price could be updated at set time periods (for example, annually) by the Network Operator (sic). T-Gen also suggested that the administered prices be reviewed annually, with the administered prices auditable by the Utilities Commission.

Sun Cable recommended that, under constrained competition, the prices be determined using an open tender or bilateral negotiation process. Sun Cable's preferred tender process is a reverse auction. It noted that:

In oligopolistic competition scenarios, a first-price auction is preferred, but it should be noted that such mechanisms are not strictly incentive compatible and may lead to a considerable amount of 'shadowing'

[29] Eni submission to the Issues Paper, page 10

of more expensive bids. There may be other mechanisms, such as second-price auctions, that may lead to more efficient outcomes if the market has enough bidders to produce competitive conditions.[30]

4.1.2 What market power mitigation measures would be appropriate?

As Eni is of the view that T-Gen should not be the default provider of ESS, it considered that there is no need for market power to be mitigated as T-Gen would not possess significant ESS market power. Similarly, Sun Cable is of the view that many of the more serious potential opportunities for the exercise of market power will be removed by avoiding the procurement of services through a real-time spot market with limited competition.

However, Sun Cable noted that market power could still be exercised in bilateral negotiations or under various tender processes. It submitted that regulators could utilise an administered price cap or price monitoring to ensure that prices are not pushed above expected levels in the long-term. Reduction of market power could be achieved in a reverse auction or tender process through careful application mechanism design principles and in bilateral over-the-counter contracting with rules around open sharing of prices with regulators or anonymous mechanisms.

Epuron suggested the following market power mitigation measures:

- *administered minimum and maximum prices for the provision of ESS,*
- *constraints on offer prices in any market mechanism,*
- *an obligation to supply required volumes of ESS, such as a default provider arrangement in the absence of other providers,*
- *a capacity limit to ensure extra ESS capacity is not built beyond a margin above sufficient capacity. For example no payment for new capacity if existing capacity already exceeds 130% of required capacity.*[31]

T-Gen questioned how an efficient market can be established if T-Gen is the generator of last resort and provider of ESS, and noted that a point of competition occurs with the negotiation of Wholesale Energy Supply Agreements between generators and retailers. It suggested the following market power mitigation measures:

— review by the Utilities Commission
— quasi-regulated costing
— minimisation of additional market compliance costs.

4.2 Assessment of options

In chapter 3, we have recommended that the Territory transition to a more competitive provision of ESS in each of its regulated systems. As the Territory's generation mix changes as it moves towards meeting the 50 per cent renewables target by 2030, there will be more providers of ESS than there are currently. However, early in this transition process, there may not be sufficient providers of ESS to facilitate an effectively competitive market for each of the ESS in each of the regulated systems, whether that be through tendering for bilateral contracts or a spot market.

At least in the short term for some services and for some systems, additional measures will be required to facilitate a transition to a more competitive ESS market while mitigating the potential for T-Gen to exert any market power. This section assesses the following options for mitigating market power:

— administered prices for the provision of ESS
— limits on revenue that can be earnt from providing ESS
— constraints on offer prices in any market mechanism
— an obligation to supply required volumes of ESS, such as a default provider arrangement.

[30] Sun Cable submission to the Issues Paper
[31] Epuron submission to the Issues Paper, page 4

4.2.1 Efficient provision of services

While there is the potential for T-Gen to exert some market power in the supply of ESS, there will be the potential for these services to be supplied inefficiently. The objective of introducing measures to mitigate the exercise of market power by T-Gen is to minimise the inefficiencies that would otherwise arise in the provision of ESS, both in the short term and the long term. In the long term, services will be provided efficiently if there is an effectively competitive market.

Administered prices can be set based on the actual cost of providing services or the long run marginal cost (LRMC) of providing those services. Further information on actual costs and LRMC are provided in Appendix A.

In the short term, the actual cost of providing services may be lower than the LRMC, depending on how the LRMC is calculated and whether the services are provided by older plant that has already been depreciated over a number of years. However, if the actual cost is less than the LRMC and administered prices are set based on the actual cost of providing services, competition may be stifled in the short term, which may lead to higher prices in the longer term. Competition will be facilitated in the longer term if administered prices are set based on LRMC, but customers will pay more than they would otherwise and providers may earn windfall gains.

As new technologies for providing ESS enter the market, the LRMC of providing ESS may decrease below T-Gen's actual cost of providing ESS. If T-Gen continues to provide some of those services and is paid the LRMC, it may incur losses in providing ESS with those losses ultimately paid for by the Territory's taxpayers. If it is paid the actual cost, customers will pay more than they otherwise would.

Services will be provided more efficiently if administered prices are set for each service and for each regulated system rather than setting an administered price for a bundle of services.

Similarly, if constraints are placed on offer prices based on LRMC rather than the actual costs of providing services, services will be provided more efficiently in the longer term, and will be more efficient if the constraints are placed on the price of each service in each regulated system rather than a constraint on a bundled service. However, in the case of constraints placed on offer prices, there is the potential for proponents to bid lower than the constraint price rather than to have an administered price imposed. This will lead to a more efficient outcome in the shorter term than administered pricing.

While some of the costs associated with providing ESS are fixed in nature, others are variable in nature. The revenue derived from those services for which the costs are variable in nature will be a function of the price and volume. A limit on revenue will therefore need to consider both the price and the volume of services.

The price that is factored into a revenue limit could be based on the actual cost of providing services or the LRMC, as discussed above. To facilitate competition in the longer term, and the efficient provision of services in the longer term, the price would need to be set based on LRMC rather than the actual cost of providing services. However, if the LRMC is higher than the actual cost, this could result in a revenue limit that is substantially higher than the actual cost of providing services in the short term and windfall gains for the provider.

In addition, any consideration of a revenue limit would also need to consider the volume of services, which will vary from year to year and will vary over time as the generation mix changes. If the revenue limit is based on a volume of services that is too low, it may constrain the provision of services below those required. If the revenue limit is based on a volume of services that is too high, it will have no practical effect.

Placing an obligation to supply on a default provider may not facilitate the efficient provision of services over the longer term, more so if there is one default provider for all services.

The price of ESS under a default provider arrangement could be the actual cost or LRMC. As the default provider arrangement will not facilitate a competitive market, the price need not be set at LRMC to incentivise new market entrants. If the price is set at the LRMC and the actual cost is less than the LRMC, the service providers will get a windfall gain and customers will pay more than they would otherwise. If the actual price is more than the LRMC, then no providers other than T-Gen would provide the services. T-Gen would incur losses with those losses paid for by the Territory's taxpayers.

A summary of the assessment of the efficiency of the four options for mitigating market power is provided in Table 4.1.

TABLE 4.1 EFFICIENT PROVISION OF SERVICES – ASSESSMENT OF OPTIONS

Option	Rating	Comment
Administered prices	◕	Facilitates a competitive market in the longer term if prices set for each service based on LRMC, but prices may be higher in the short term
Limits on revenue	◑	Revenue subject to decisions on price and volume, with resulting potential for inefficiencies based on each of these decisions
Constraints on offer prices	●	Facilitates a competitive market in the longer term if prices set for each service based on LRMC, and allows for efficient prices in the short term
Default provider arrangements	○	May not facilitate efficient provision of services over the longer term

○ Inefficient ◔ Largely inefficient ◑ Moderately inefficient ◕ Slightly inefficient ● Efficient

SOURCE: ACIL ALLEN ASSESSMENT

4.2.2 Administrative costs

Estimating the LRMC for each service is complex. If administered prices are set or there are constraints on offer prices, there are the upfront costs associated with determining the prices and to codify them. Similarly, if there is a default provider, there are the upfront costs to set up these arrangements.

The upfront costs associated with determining a revenue limit would be higher than for setting an administered price or constraints on offer prices because the volume of services needs to be considered in addition to the unit cost of providing services. In addition, there would be the ongoing costs to monitor the revenue earned relative to the revenue limit.

An estimate of the administrative costs under each of the options is provided in Table 4.2.

TABLE 4.2 ESTIMATED ADMINISTRATIVE COSTS FOR EACH MARKET POWER MITIGATION OPTION

Option	Estimated costs
Administered prices	Included in the estimated costs for service provision
Limits on revenue	Included in the estimated costs for service provision plus an additional 0.25 FTE
Constraints on offer prices	Included in the estimated costs for service provision
Default provider arrangements	Included in the estimated costs for service provision

SOURCE: ACIL ALLEN ASSESSMENT

A summary of the assessment of the administrative costs associated with each of the four options for mitigating market power is provided in Table 4.3.

TABLE 4.3 ADMINISTRATIVE COSTS – ASSESSMENT OF OPTIONS

Option	Rating	Comment
Administered prices	◕	Upfront cost to determine administered price (LRMC)
Limits on revenue	◑	Upfront cost to determine revenue (LRMC and volume of services) and ongoing cost to monitor revenue earned against revenue limit
Constraints on offer prices	◕	Upfront cost to determine constraint on offer price (LRMC)
Default provider arrangements	◕	Upfront cost to set up arrangements

○ Very high costs ◔ High costs ◑ Moderate costs ◕ Low costs ● Very low costs

SOURCE: ACIL ALLEN ASSESSMENT

4.2.3 Meet required standards

Setting the administered price and constraint on offer prices based on LRMC will facilitate, but not guarantee, meeting the required standards. There is a slightly higher risk of not meeting the required standard if there is a limit on revenue – if the revenue limit is exceeded, a technology may not be available to provide a service when called upon to do so.

Setting up default provider arrangements provides the highest likelihood of meeting the required standards until the market for ESS is effectively competitive.

A summary of the assessment of the extent to which each of the four options facilitates meeting the required standards is provided in Table 4.4.

TABLE 4.4 MEET REQUIRED STANDARDS – ASSESSMENT OF OPTIONS

Option	Rating	Comment
Administered prices	◑	Facilitate, but not guarantee, meeting required standard
Limits on revenue	◔	May not meet required standard, particularly if revenue limit exceeded
Constraints on offer prices	◑	Facilitate, but not guarantee, meeting required standard
Default provider arrangements	●	Highest likelihood of meeting required standard

○ Does not meet required standards ◔ Partly meets required standard ◑ Somewhat meets required standards ◕ Largely meets required standards ● Meets required standards

SOURCE: ACIL ALLEN ASSESSMENT

4.2.4 Provide investment certainty

Investment certainty will be provided if the administered price or constraint on offer price is based on the LRMC for providing services. Depending on how the volume of services is estimated when placing a limit on revenue, investment certainty may be adversely impacted.

If the default provision of ESS is exercised by exception, only when required to do so to meet the required standards, there will be minimal impact on investment certainty. However, if it is in effect, a default way in which services are provided, the impact on investment certainty will be more adversely impacted.

A summary of the assessment of the extent to which each of the four options for mitigating market power provides investment certainty is provided in Table 4.5.

TABLE 4.5 PROVIDE INVESTMENT CERTAINTY – ASSESSMENT OF OPTIONS

Option	Rating	Comment
Administered prices	●	If administered price based on LRMC, provides investment certainty
Limits on revenue	◑	Depending on how revenue limit determined, may adversely impact investment certainty
Constraints on offer prices	●	If constraint on offer price based on LRMC, provides investment certainty
Default provider arrangements	◕	If default provider arrangements only exercised by exception, minimal impact on investment certainty

○ Does not provide investment certainty ◔ Partly provides investment certainty ◑ Somewhat provides investment certainty ◕ Largely provides investment certainty ● Provides investment certainty

SOURCE: ACIL ALLEN ASSESSMENT

4.2.5 Technology neutrality

If the administered price, revenue limit and constraint on offer price are based on the LRMC for providing services, the arrangements will be technology neutral.

If there is one default provider of all services, the technologies that can be deployed by the default provider will be limited. The option is therefore unlikely to be technology neutral.

A summary of the assessment of the extent to which each of the four options for mitigating market power is technology neutral is provided in Table 4.6.

TABLE 4.6 TECHNOLOGY NEUTRALITY – ASSESSMENT OF OPTIONS

Option	Rating	Comment
Administered prices	●	If administered price based on LRMC, technology neutral
Limits on revenue	●	If revenue limit based on LRMC, technology neutral
Constraints on offer prices	●	If constraint on offer price based on LRMC, technology neutral
Default provider arrangements	◔	If one default provider for ESS, unlikely to be technology neutral

○ Technology specific ◔ Partly technology neutral ◑ Somewhat technology neutral ◕ Largely technology neutral ● Technology neutral

SOURCE: ACIL ALLEN ASSESSMENT

4.2.6 Summary of the assessment of options for mitigating market power

Until the market for ESS is effectively competitive, safeguards will be required to mitigate the exercise of market power by T-Gen. The assessment against the criteria of the four options that were identified for mitigating the exercise of market power is summarised in Table 4.7.

The option to place constraints on offer prices is assessed the most favourably. If the offer prices are constrained to be no higher than the LRMC, this will facilitate the efficient provision of services, investment certainty and technology neutrality. Placing constraints on offer prices is assessed to be marginally favourable compared to setting administered prices – placing constraints on prices puts a cap on prices at the LRMC, which is more efficient than setting administered prices at the LRMC as it facilitates parties offering prices that are below LRMC. In both cases, there will be administrative costs incurred in determining the LRMC for the provision of each ESS.

Placing a cap on prices based on the LRMC is preferable to placing a cap based on actual costs as it facilitates a more competitive market in the longer term, which facilitates more efficient outcomes.

The major disadvantage of conducting a competitive process with constraints placed on offer prices is that there is a lower level of assurance that the services will be offered and therefore that the required standards will be met. Given the importance of meeting required standards, it is proposed that, particularly in the early stages of the development of the market, there be a default provider. By

definition, a default provider is only required when there is no other provider to provide the service, and so T-Gen, as the incumbent provider of services, would most likely be the default provider of services.

To facilitate the transition to more competitive arrangements over time, the default provider should only be used by exception – only for those services in those systems during those times when there is no alternative provider willing to provide services at (or below) the LRMC. The price for providing those services should be at the actual cost so the default provider does not make windfall gains or incur losses.

TABLE 4.7 SUMMARY OF THE ASSESSMENT OF THE OPTIONS FOR MITIGATING MARKET POWER

Criterion	Weight	Administered prices	Limits on revenue	Constraints on offer prices	Default provider
Efficient provision of services	5	◕ Facilitates competitive market if prices set based on LRMC, but prices higher in short term	◑ Potentially inefficient decisions based on price and	● Facilitates competitive market if prices set based on LRMC	○ Not efficient over the longer term
Administrative costs	1	◕ Upfront cost to determine price	◑ Upfront cost to determine price and volume	◕ Upfront cost to determine price	◕ Upfront cost to set up arrangements
Meet required standards	3	◑ Not assured standard met	◔ Not assured standard met, particularly if revenue limit exceeded	◑ Not assured standard met	● Highest likelihood of meeting standard
Investment certainty	3	● Investment certainty if price set based on LRMC	◑ May adversely affect investment certainty	● Investment certainty if price set based on LRMC	◕ If exercised by exception, minimal impact
Technology neutrality	3	● Technology neutral if price set based on LRMC	● Technology neutral if revenue limit set based on LRMC	● Technology neutral if price set based on LRMC	◔ If one provider, unlikely to be technology neutral
Weighted total (out of 60)		48	33	53	27

○ Does not meet assessment criterion ◔ Partly meets assessment criterion ◑ Somewhat meets assessment criterion ◕ Largely meets assessment criterion ● Meets assessment criterion

SOURCE: ACIL ALLEN ASSESSMENT

4.3 Response to questions related to administered pricing arrangements and market power mitigation

This section responds to the questions that were raised in the Issues Paper.

What changes should be made to the current administered pricing arrangements for the provision of ESS provided by Territory Generation?

What methodology should be used to determine prices for each of the ESS categories?

In chapter 3, we have recommended that a competitive process be undertaken as the basis for entering into bilateral contracts for each ESS service. The frequency of the competitive process would depend on the characteristics of the ESS, with:

— contracts of a longer tenure (such as 5-10 years) for services that are provided infrequently and for which a revenue stream is required to ensure that they are available as and when required, such as system restart ESS

— contracts of a shorter tenure (say 2-3 years) for services that are provided frequently and where the provision of ESS supplements the main revenue stream from the energy market, such as regulation ESS.

The market for providing ESS will become more competitive as the electricity system transitions to meeting the Government's 50 per cent renewables target by 2030. However, in the short term, additional safeguards may be required to mitigate T-Gen exercising its market power. In section 4.2, we have assessed the following four options for mitigating the exercise of market power:

— administered pricing

— limits on revenue

— constraints on offer prices

— default provider of ESS services.

Our assessment has identified that the most favourable option is to place constraints on offer prices, with the prices bid through a competitive tender process or a spot market capped at the LRMC. The LRMC would be determined for each service for each system, and where applicable, for specific times of day.

Where no provider is willing to provide a service at (or below) the LRMC, a default provider will be required with the services provided at actual cost.

What process should be put in place to ensure the administered prices remain up to date?

The constraint that is placed on the offer prices for a particular service should be reviewed prior to the conduct of a competitive process to procure that service. For example, if the competitive process for a particular service and system is conducted every two or three years, then the LRMC for that service should be reviewed every two to three years.

The Utilities Commission, as the independent economic regulator, is the best placed to determine the LRMC for each service, for each system. The cost to do so is estimated to be between $100k and $300k each time the LRMCs are reviewed.

What market power mitigation measures would be appropriate for the provision of different ESS by Territory Generation?

Over time, as the market for providing ESS becomes more competitive, T-Gen will have less opportunity to exercise market power. However, until the market is effectively competitive, T-Gen will have the opportunity to exercise market power. The constraint on offer prices, as discussed above, will be a key mitigation measure, while encouraging competition in the provision of ESS in the longer term.

In addition to placing a constraint on offer prices, we also recommend that there be a default provider for each service in each system until there is an effectively competitive market for that service. In the

absence of a competitive market, T-Gen, as the incumbent provider of services, would most likely be the default provider.

To facilitate the transition to more competitive arrangements over time, the default provider should only be used by exception – only for those services in those systems during those times when there is no alternative provider willing to provide services at (or below) the LRMC. The price for providing those services should be at the actual cost so the default provider does not make windfall gains or incur losses.

Epuron has suggested there be a capacity limit to ensure extra ESS capacity is not built beyond a margin above sufficient capacity. For example, it suggested that there be no payment for new capacity if existing capacity already exceeds 130 per cent of required capacity.

No commercial entity would invest in excess ESS capacity unless it was economic to do so. We therefore assume that Epuron's suggestion is directed towards T-Gen's investments. Given T-Gen's financial position, it is ultimately dependent on Government funding to finance any new investments. T-Gen is unlikely to invest in new capacity unless funded to do so by the Government. The decision to not invest in excess ESS capacity is thereby effectively a Government decision.

5 COST ALLOCATION AND SETTLEMENT

This chapter considers the allocation of the unbundled costs associated with procuring ESS on a 'causer pays' basis. Section 5.1 summarises the issue and the relevant comments by stakeholders, section 5.2 identifies and assesses options for the allocation of the costs associated with providing ESS, and section 5.3 provides our response to the questions raised in the Issues Paper.

5.1 Background

As discussed in section 2.1, under section A6.11(b) of the SCTC, generators must pay an amount of $5.40 per MWh (sent out) to T-Gen for the provision of ancillary services (ESS) in the DKIS. Each settlement period (one calendar month), the Market Operator calculates the ESS quantity for each generator and issues a settlement statement. T-Gen then issues invoices to the other generators.

The ESS costs are currently allocated to generators on the basis of energy sent out. The current arrangement is inequitable because it does not allocate costs between system participants on the basis of the benefits received from the ESS provided. Other system participants, such as unlicensed generators and consumers may benefit but do not pay.

The current arrangement is also inefficient as it does not provide incentives for system participants to manage their contribution to, or assist with the correction of, frequency deviations which are the primary drivers of the requirement for, and costs of, ESS.

The alternative is to introduce a causer-pays approach in which the ESS costs are allocated to the parties who have deemed to have caused the need for the services and have capacity to take action to reduce the need.

A causer pays approach has been adopted in the NEM as follows:

- Contingency raise ESS, which are required to manage the loss of the largest generator on the system, are recovered from generators based on their proportion of total energy production.
- Contingency lower ESS, which are required to manage the loss of the largest load or transmission element, are recovered from customers based on their proportion of total energy consumption.
- Regulation ESS, which are required to correct frequency deviations, are recovered from generators and customers which contribute to frequency deviations. Generators whose production and customers whose consumption cause frequency deviations or who do not contribute to their correction are allocated higher contribution factors than those that do not cause or assist to correct frequency deviations.
- Network Support ESS, which are required to assist with voltage control, are recovered from customers based on their proportion of total energy consumption.

— System Restart ESS, which are required to assist with restoration of the system, and which benefit all system participants, are recovered from all system participants in proportion to their energy production and consumption.[32]

The Issues Paper sought comments from stakeholders on the following questions:

(a) What are the appropriate bases for the allocation of ESS costs?

(b) Are there alternatives to a causer pays approach for the recovery of the ESS costs?

(c) Are there any technical barriers to the adoption of a causer pays or alternative approaches to ESS cost recovery in the Territory?

(d) What issues would the transition to a causer pays or alternative basis of ESS cost allocation present for system participants?

(e) What oversight or regulatory arrangements should accompany any causer pays allocation or alternative arrangements?

Stakeholder comments on each of these questions are summarised in the following sections.

5.1.1 What are the appropriate bases for the allocation of ESS costs?

Jacana supported moving towards a causer pays model with the price of ESS unbundled and cost reflective in the short term. Jacana and T-Gen noted that a portion of ESS costs are usually fixed, reflecting the capacity required to supply services, and therefore support passing through ESS charges via a combination of fixed and variable charges.

Epuron also supports moving to a causer pays approach.

Sun Cable supports the causer pays approach as adopted in the NEM for contingency raise and lower ESS, network support ESS and system restart ESS, but has proposed an alternative approach for regulation ESS, as discussed in the next section.

By way of contrast, Eni is of the view that, given the small scale of the DKIS, the causer pays model should be simplified relative to the models in other markets, fit for purpose, while encouraging the right behaviours from market participants. Given that electricity customers fund all the costs of operating a power system, it suggests that the cost of "business as usual" ESS should be funded directly by customers, without any margins applied by parties as the costs are passed through the supply chain. Generators should only pay for ESS if they introduce a new credible contingency to the power system that requires higher levels of ESS.

5.1.2 Are there alternatives to a causer pays approach for the recovery of ESS costs?

Sun Cable recommended the following alternative approach for the recovery of regulation ESS costs:

— Generators – drawing on the existing GPS, generators contract with third parties so that their total impact on the grid (across a number of sites) is effectively non-existent. If these third party suppliers fail to provide the services required, any fees or charges resulting from the overall impact on the grid are passed on to these suppliers. Sun Cable refers to this as the hybrid causer-pays approach.

— Loads and distributed energy resources (DER) – the concept of causer pays falls on the market participant (i.e. the retailer or large industrial off-taker):
  - loads and DER above a certain threshold (100 kW) – can be used to 'net off' grid impacts via the direct-contracting causer pays system
  - loads and DER with smaller capacities – aggregated at the distribution level with grid impacts pro-rated across consumed / generated volumes across the distribution sector.

As discussed above, Eni is of the view that, given that electricity customers should fund all the costs of operating a power system, retailers (representing customers) should be charged for ESS unless there is justification to charge them to some other party. The only circumstance under which this could be

[32] Northern Territory Government, *Review of Essential System Services in the Northern Territory's Regulated Electricity Systems, Issues Paper*, June 2020, pages 24- 25; AEMO, *A Guide to Ancillary Services in the National Electricity Market*, April 2015

justified is in the case of a contingency raise service if a generator introduces a new credible contingency that is greater than is currently being used.

T-Gen proposed an alternative model to the causer pays approach which would be a continuation of the current model of centralised supply of ESS by T-Gen, with the ESS being more clearly identified and procured to enable "improved asset improvement" (sic) in the future, and payment for some of the ESS made by the Network Operator.

5.1.3 Are there any technical barriers?

T-Gen identified two technical barriers to moving to a causer pays approach – the ability to identify the causer where accumulation meters are still in use, and the ability to prioritise the service required at any point (which service is most needed, and why).

Eni identified the significant overlap between the ESS and the mandatory provisions on new generators as a technical barrier. It found it difficult to see how services that are mandated can then be remunerated and/or incentivised, and was of the view that if a legacy plant is currently providing ESS, it should continue to provide these services as if they were new plant where these provisions are mandated.

Sun Cable identified that the hybrid causer-pays approach that it proposed requires live monitoring of any participating generators or loads, with the required monitoring and management tools available off-the-shelf.

5.1.4 Are there any transitional issues?

Eni welcomed a transition to a more appropriate ESS regime as it is having difficulty funding the current ESS charge as well as meeting the forecasting accuracy requirements in the Network Technical Code.

T-Gen identified a number of transitional issues, including:

- capital investment required
- the settlement process – evidence of the need and supply of ESS
- calculation of losses to the meter / generation connection point
- ability for the centralised supply of ESS to generators under the Network Technical Code and the System Control Technical Code.

Sun Cable identified that, under the hybrid causer-pays approach it proposed, system participants over a given capacity threshold would be required to install high-frequency SCADA monitoring equipment and enter into contracts with potential ESS providers, or install equipment to ensure a 'net zero' impact on the grid.

5.1.5 What oversight or regulatory arrangements are required?

T-Gen is of the view that the causer pays allocation should be accompanied by review and approval by the Utilities Commission.

Eni noted a number of potential conflicts of interest associated with the entity that provides the System Controller functions. Give these potential conflicts of interest, it is of the view that the Utilities Commission needs to have sufficient technical resources of its own to provide effective regulation of the electricity industry. However, it noted that the Utilities Commission is heavily reliant on electricity industry consultants, many of which may face conflicting positions as they appear to also provide consultancy services to PWC.

Sun Cable has proposed that, under the hybrid causer pays approach that it proposed, any fees or charges from the operator be initially performed by ESS suppliers, with strict reporting and transparency obligations.

5.2 Assessment of options

Based on the Issues Paper and stakeholder submissions received, we have assessed the following four options to allocating the costs associated with ESS:

- generators pay, which is the existing approach
- causer pays similar to that the NEM, under which generators pay for contingency raise ESS, customers pay for contingency lower ESS and voltage management / network support ESS, the causer pays for regulation ESS and all system participants pay for network support or system restart ESS
- hybrid causer pays as proposed by Sun Cable, which is as per the NEM approach except for regulation ESS
- customers pay, under which customers pay for all ESS.

Table 5.1 summarises which party pays for which service under each of these four options. This table includes the services identified in the Issues Paper as well as two additional services that are recommended by GHD – a Rate of Change of Frequency (RoCoF) ESS and a system strength ESS.

The purpose of a RoCoF ESS is to:

… control the rate of change of frequency on the power system following contingencies.[33]

GHD recommends that the RoCoF ESS be considered for both credible contingency events and protected contingency events. A credible contingency event is defined in the System Control Technical Code as the unexpected loss of generation or a major item of transmission plant. Protected events are the loss of the 132 kV transmission line south of Channel Island, the 132 kV Channel Island nodes and the loss of multiple transmission lines due to shared towers.

Accordingly, RoCoF ESS is required on the loss of generation or the loss of transmission plant. Consistent with the regulation ESS, under a causer pays approach, the costs of the RoCoF ESS are most appropriately allocated to the party that causes the service to be enabled.

The purpose of the system strength ESS is to:

… provide sufficient system strength capability to ensure voltage stability and sufficient fault current when a shortfall is identified.[34]

GHD identified that a system strength ESS 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. Under a causer pays approach, the costs of the system strength ESS are most appropriately allocated to the party responsible for the system strength issue. Where there is not a clear party responsible for the system strength issue, the costs are most appropriately recovered from customers.

TABLE 5.1 PARTY LIABLE FOR EACH ESS

ESS	Generators pay	Causer-pays	Hybrid causer pays	Customers pay
Contingency raise ESS	Generator	Generators	Generators	Customer
Contingency lower ESS	Generator	Customers	Customers	Customer
RoCoF ESS	Generator	Party that causes the service to be enabled	Party that causes the service to be enabled	Customer
Regulation ESS	Generator	Generators and customers that cause frequency deviations Customers without SCADA – balance	Supplier of services to generators – 'net' impact of generation Large loads and DER – 'net' impact Smaller loads and DER - balance	Customer
Voltage management / network support ESS	Generator	Customers	Customers	Customer

[33] GHD Advisory, *Review of Essential System Services in the Northern Territory, Final Report*, 16 November 2020, page 24
[34] Ibid, page 2

ESS	Generators pay	Causer-pays	Hybrid causer pays	Customers pay
System restart ESS	Generator	Generators and customers	Generators and customers	Customer
System strength	Generator	Where possible, party responsible for the system strength issue Customers – balance	Where possible, party responsible for the system strength issue Customers – balance	Customer

SOURCE: ACIL ALLEN ASSESSMENT

5.2.1 Efficient provision of services

The efficient provision of ESS is facilitated when participants are incentivised to minimise the extent to which ESS are required. This occurs to the greatest extent under the causer pays approach, similar to that adopted in the NEM.

The hybrid causer pays approach proposed by Sun Cable is the same as the causer pays approach for all services other than for regulation ESS. The hybrid causer pays approach expands upon the Territory's GPS which require a generator's total impact on the grid (across a number of locations) to be effectively non-existent. Generators can contract with third parties to correct for any frequency control impacts. Under Sun Cable's model, the third party contracted by the generator would then be liable for any net frequency control impacts.

Any differences between the incentives under the two approaches are driven by the contractual arrangements between the generators and the third parties – the incentives under the hybrid causer pays approach could be aligned with the incentives under the causer pays approach or the liability could be transferred completely to the third parties as implied by Sun Cable's submission.

The existing generator pays approach and the customer pays approach are similar in terms of efficiency. Under both of these approaches the costs associated with providing regulation ESS, RoCoF ESS and system strength ESS are not paid for by the parties causing the need for those services.

A summary of the assessment of the efficiency of the four options for cost allocation is provided in Table 5.2.

TABLE 5.2 EFFICIENT PROVISION OF SERVICES – ASSESSMENT OF OPTIONS

Option	Rating	Comment
Generators pay	○	Costs of providing regulation ESS, RoCoF ESS and system strength ESS not paid for by those causing the need for those services
Causer pays	●	Most efficient approach
Hybrid causer pays	◕	Efficiency depends on contractual arrangements between generators and third parties
Customers pay	○	Costs of providing regulation ESS, RoCoF ESS and system strength ESS not paid for by those causing the need for those services

○ Inefficient ◔ Largely inefficient ◑ Moderately inefficient ◕ Slightly inefficient ● Efficient

SOURCE: ACIL ALLEN ASSESSMENT

5.2.2 Administrative costs

The administrative costs associated with the generator pays and customer pays approaches are relatively low. The total costs are either allocated to generators based on energy produced or customers based on energy consumed.

The administrative costs associated with the causer pays and hybrid causer pays approaches are higher as the equipment would need to be in place to be able to monitor the system, and the System Controller would need to use that information to allocate the costs associated with regulation ESS, RoCoF ESS and system strength ESS to the appropriate party. In the case of the hybrid causer pays

approach, the System Controller would also need to understand the contractual arrangements between the generators and third parties to assess the 'net' impacts.

Arrangements would also need to be in place to resolve any disputes that arose from the allocation of costs under the causer pays and hybrid causer pays approaches.

An estimate of the administrative costs under each of the options is provided in Table 5.3

TABLE 5.3 ESTIMATED ADMINISTRATIVE COSTS FOR EACH COST ALLOCATION OPTION

Option	Estimated costs
Generators pay	0.1 FTE
Causer pays	0.5 FTE plus $0.2m-$1.0m per annum for expert advice to resolve disputes that arise
Hybrid causer pays	0.5 FTE plus $0.2m-$1.0m per annum for expert advice to resolve disputes that arise
Customers pay	0.1 FTE

SOURCE: ACIL ALLEN ASSESSMENT

A summary of the assessment of the administrative costs associated with each of the four options for cost allocation is provided in Table 5.4.

TABLE 5.4 ADMINISTRATIVE COSTS – ASSESSMENT OF OPTIONS

Option	Rating	Comment
Generators pay	●	Allocation of costs is relatively simple
Causer pays	◑	Allocation of costs associated with regulation ESS, RoCoF ESS and system strength ESS more complex
Hybrid causer pays	◔	Allocation of costs associated with regulation ESS, RoCoF ESS and system strength ESS more complex, and requires an understanding of contractual arrangements between generators and third parties
Customers pay	●	Allocation of costs is relatively simple

○ Very high costs ◔ High costs ◑ Moderate costs ◕ Low costs ● Very low costs

SOURCE: ACIL ALLEN ASSESSMENT

5.2.3 Meet required standards

There is a higher likelihood that the required standards would be met under the causer pays and hybrid causer pays approaches to cost allocation as the party causing frequency deviations, rate of change of frequency and system strength issues is liable for paying for the relevant ESS. This provides an incentive to these parties to minimise frequency deviations, rate of change of frequency and system strength issues.

The likelihood may be higher under the causer pays approach than the hybrid causer pays approach as the incentives under the hybrid causer pays approach depend on the contractual arrangements between the generators and third parties.

By way of contrast, there is no incentive for generators and customers to minimise frequency deviations, rate of change of frequency and system strength issues under the generator pays and customers pays approaches.

A summary of the assessment of the extent to which each of the four options facilitates meeting the required standards is provided in Table 5.5.

TABLE 5.5 MEET REQUIRED STANDARDS – ASSESSMENT OF OPTIONS

Option	Rating	Comment
Generators pay	◔	No incentive to minimise frequency deviations, rate of change of frequency and system strength issues
Causer pays	●	Incentive to minimise frequency deviations, rate of change of frequency and system strength issues
Hybrid causer pays	◕	The incentive to minimise frequency deviations, rate of change of frequency and system strength issues is driven in part by the contractual arrangements between the generators and third parties
Customers pay	◔	No incentive to minimise frequency deviations, rate of change of frequency and system strength issues

○ Does not meet required standards ◔ Partly meets required standard ◑ Somewhat meets required standards ◕ Largely meets required standards ● Meets required standards

SOURCE: ACIL ALLEN ASSESSMENT

5.2.4 Provide investment certainty

The customer pays approach to cost allocation has the least impact on investment certainty as generators do not pay for ESS. The generator pays approach has the greatest adverse impact on investment certainty as the generators pay for ESS and could be paying for regulation ESS, RoCoF ESS and system strength ESS that is caused by other generators and loads.

The investment certainty under the causer pays approach and hybrid causer pays approach is slightly lower than under the customer pays approach. While the generators pay for some of the ESS under these approaches, they do not pay for regulation ESS, RoCoF ESS and system strength ESS that is caused by other generators and loads.

A summary of the assessment of the extent to which each of the four options for cost allocation provides investment certainty is provided in Table 5.6.

TABLE 5.6 PROVIDE INVESTMENT CERTAINTY – ASSESSMENT OF OPTIONS

Option	Rating	Comment
Generators pay	○	Generators pay for all ESS, including regulation ESS, RoCoF ESS and system strength ESS caused by other generators and customers
Causer pays	◕	Generators pay for some ESS, with regulation ESS, RoCoF ESS and system strength ESS paid by generators and customers that cause frequency deviations, rate of change of frequency and system strength issues
Hybrid causer pays	◕	Generators pay for some ESS, with regulation ESS, RoCoF ESS and system strength ESS paid by generators and customers that cause frequency deviations, rate of change of frequency and system strength issues
Customers pay	●	As generators do not pay for ESS, has no adverse impact on investment certainty

○ Does not provide investment certainty ◔ Partly provides investment certainty ◑ Somewhat provides investment certainty ◕ Largely provides investment certainty ● Provides investment certainty

SOURCE: ACIL ALLEN ASSESSMENT

5.2.5 Technology neutrality

The method of allocating the costs associated with providing ESS does not have a significant impact on technology choices. The generator pays and customer pays approaches to cost allocation are technology neutral because under the generator pays approach all generators pay the same for ESS regardless of technology and under the customer pays approach the generators do not pay for ESS.

The causer pays and hybrid causer pays approaches may have an influence on the technology as the generator would be required to pay for regulation ESS, RoCoF ESS and system strength ESS based on the frequency deviations, rate of change of frequency and system strength issues caused (but this may contribute to meeting the required standards).

A summary of the assessment of the extent to which each of the four options for cost allocation is technology neutral is provided in Table 5.7.

TABLE 5.7 TECHNOLOGY NEUTRALITY – ASSESSMENT OF OPTIONS

Option	Rating	Comment
Generators pay	●	As generators pay the same regardless of technology, technology neutral
Causer pays	◕	May influence technology if required to pay for regulation ESS, RoCoF ESS and system strength ESS based on frequency deviations, rate of change of frequency and system strength issues caused
Hybrid causer pays	◕	May influence technology if required to pay for regulation ESS, RoCoF ESS and system strength ESS based on frequency deviations, rate of change of frequency and system strength issues caused
Customers pay	●	As generators do not pay for ESS, technology neutral

○ Technology specific ◔ Partly technology neutral ◑ Somewhat technology neutral ◕ Largely technology neutral ● Technology neutral

SOURCE: ACIL ALLEN ASSESSMENT

5.2.6 Summary of the assessment of the cost allocation options

The assessment of the four options for allocating the costs associated with providing ESS against the criteria is summarised in Table 5.8.

Of the four options assessed, the option assessed most favourably is the causer pays option. While the causer pays option is more costly than the generator pays or customer pays options, it is more efficient as the costs of providing regulation ESS, RoCoF ESS and system strength ESS are paid for by the parties causing the need for those services. For this reason, it provides an incentive to parties to minimise frequency deviations, rate of change of frequency and system strength issues.

However, it may also have a slightly adverse impact on investment certainty and technology neutrality because of the requirement to pay for frequency deviations, rate of change of frequency and system strength issues.

The hybrid causer pays approach proposed by Sun Cable is assessed only slightly less favourably than the causer pays approach because the assessment of most of the criteria is dependent on the contractual arrangements between the generators and the third parties that are providing services to those generators to net out impacts on the electricity supply system. The incentives under those contractual arrangements, and therefore the efficiencies associated with those arrangements, may or may not mirror the causer pays approach.

The customer pays approach proposed by Eni is similar to the current generator pays approach. However, the certainty for investors is greater under the customer pays approach than the generator pays approach because the generators do not pay for ESS.

TABLE 5.8 SUMMARY OF THE ASSESSMENT OF THE COST ALLOCATION OPTIONS

Criterion	Weight	Generator pays	Causer pays	Hybrid causer pays	Customer pays
Efficient provision of services	5	○ Causer of regulation, RoCoF and system strength ESS does not pay	● Most efficient	◕ Depends on contractual arrangements	○ Causer of regulation, RoCoF and system strength ESS does not pay
Administrative costs	1	● Relatively simple	◑ More complex	◔ More complex and requires understanding of contracts	● Relatively simple
Meet required standards	3	◔ No incentive to minimise issues on system	● Incentive to minimise issues on system	◕ Incentive to minimise issues driven partly by contracts	◔ No incentive to minimise issues on system
Investment certainty	3	○ Generators pay for all ESS	◕ Generators pay for some ESS	◕ Generators pay for some ESS	● Generators don't pay for ESS
Technology neutrality	3	● Technology neutral	◕ May influence technology choices	◕ May influence technology choices	● Technology neutral
Weighted total (out of 60)		19	52	43	31

○ Does not meet assessment criterion ◔ Partly meets assessment criterion ◑ Somewhat meets assessment criterion ◕ Largely meets assessment criterion ● Meets assessment criterion

SOURCE: ACIL ALLEN ASSESSMENT

5.3 Response to questions related to cost allocation and settlement

This section responds to the questions that were raised in the Issues Paper.

What are the appropriate bases for the allocation of ESS costs?

In considering the appropriate bases for the allocation of ESS costs, we have considered:

— the parties to which ESS costs are allocated

— whether the costs be allocated on the basis of energy produced or consumed, or some other basis

— the nature of the costs, whether they are fixed or variable.

The parties to which ESS costs are allocated

As set out in the Issues Paper, ESS costs are typically allocated to parties who are determined to have caused the need for the services and have capacity to take action. In the NEM this has resulted in the allocation as set out in section 5.1. This approach is generally well accepted.

GHD has identified two additional services to be provided in the Territory – the RoCoF ESS and system strength ESS.

RoCoF ESS is required on the loss of generation or the loss of transmission plant. Consistent with the regulation ESS, the costs are most appropriately allocated to the party that causes the service to be enabled.

GHD identified that a system strength ESS 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. Under a causer pays approach, the costs of the system strength ESS are most appropriately allocated to the party responsible for the system strength issue. Where there is not a clear party responsible for the system strength issue, the costs are most appropriately recovered from customers.

Only Sun Cable suggested a different basis for the allocation of regulation ESS. Rather than allocating the costs associated with regulation ESS to generators and customers that contribute to frequency deviations, it suggested the following alternative approach:

- Generators – drawing on the existing GPS, generators contract with third parties so that their total impact on the grid (across a number of sites) is effectively non-existent. If these third party suppliers fail to provide the services required, any fees or charges resulting from the overall impact on the grid are passed on to these suppliers. Sun Cable refers to this as the hybrid causer-pays approach.
- Loads and distributed energy resources (DER) – the concept of causer pays falls on the market participant (i.e. the retailer or large industrial off-taker):
  - loads and DER above a certain threshold (100 kW) – can be used to 'net off' grid impacts via the direct-contacting causer pays system
  - loads and DER with smaller capacities – aggregated at the distribution level with grid impacts pro-rated across consumed / generated volumes across the distribution sector.

The approach proposed by Sun Cable is similar to the approach adopted in the NEM, with the outcomes dependent on the contractual arrangements between the generators and the third parties that are providing services to those generators to net out impacts on the electricity supply system.

Should costs be allocated on the basis of energy produced or consumed?

In the NEM, under the causer pays approach, the costs associated with regulation ESS are allocated to the generators and customers that contribute to frequency deviations. This provides appropriate incentives to generators and customers to minimise frequency deviations.

The costs associated with contingency raise and lower ESS and system restart ESS are allocated to generators and/or customers on the basis of energy production and consumption, as appropriate. However, the amount of contingency raise and lower ESS that is required is a function of the largest generating unit and largest load on the system, respectively. Accordingly, more appropriate bases for allocating the costs of the contingency raise and lower ESS are, in the case of generation, the size of the generating unit, and in the case of loads, the maximum demand.

The costs associated with system restart ESS are also allocated in the NEM on the basis of energy production and energy consumption. However, system restart ESS are not used very frequently and there is no clear singular driver of these types of events. For that reason, there does not appear to be a more appropriate basis for allocation than the current simplistic approach.

The NEM currently does not have a RoCoF ESS. Consistent with the regulation ESS, the costs are most appropriately allocated to the party that causes the service to be enabled. This provides appropriate incentives to parties to minimise the rate of change of frequency.

The NEM also does not currently have a system strength ESS. We have suggested that, under a causer pays approach, the costs are most appropriately allocated to the party responsible for the system strength issue. This provides an incentive to minimise system strength issues while recognising that not all costs can be allocated in this way. Where there is not a clear party responsible for the system strength issue, there is no clear singular driver for the balance of the costs. The recovery of these costs from customers is the simplest.

As GHD has noted that the requirements for network support / voltage management services are to avoid a network investment, the allocation of the costs associated with those services would be subject to PWC's economic regulatory framework.

The nature of the costs to be allocated

As identified by T-Gen and Jacana in their submissions to the Issues Paper, there are variable and fixed costs associated with the provision of ESS.

In the NEM, the Australian Energy Market Operator (AEMO) operates a spot market for two regulation ESS, three contingency raise ESS and three contingency lower ESS. Participants bid for each of these services on the basis of an amount per MW per hour. AEMO dispatches the services needed in merit order of cost.[35] The costs allocated are therefore variable.

In the WEM, AEMO enters into contracts for Load Following Ancillary Services, which are similar to regulation ESS. In 2020-21, AEMO has entered into contracts for:

- +/- 85 MW between 5.30 am and 7.30 pm
- +/- 50 MW between 7.30 pm and 5.30 am.[36]

AEMO has also entered into contracts for the following:

- Spinning Reserve Services, which is similar to contingency raise ESS, for 42 MW supplied by long interruptible load contract and 21 MW sourced from a short-term interruptible load contract[37]
- Load Rejection Reserve service, which is similar to contingency lower ESS, for 90 MW.

While these contracts are based on capacity, it is unclear whether the prices bid are fixed or variable.

In both the NEM and the WEM, AEMO contracts for system restart services. In the NEM, AEMO enters into long term contracts with payments for:

- availability – made for every trading interval the service is available, which is a fixed charge
- testing – made for costs incurred for annual testing of service, which is a fixed charge
- usage – made for every trading interval when the service is used, which is a variable charge.[38]

Assuming that the Territory's System Controller enters into bilateral contracts for each type of ESS, we recommend that the appropriate bases for the allocation of ESS costs, based on the approaches adopted in the NEM and WEM, are as set out in Table 5.9.

These bases ensure that costs are allocated in a way that is consistent with the driver for those costs, and take into account the frequency with which the services will be required and/or the extent to which they are allocated to parties who are deemed to have caused the need for the services and have capacity to take action. For example, it is recommended that services that are used less frequently, and are allocated broadly across generators and/or customers, such as contingency ESS and system restart ESS, have a fixed and variable cost component, while services that are used more frequently and/or are allocated to the party that causes the need for the services, such as regulation ESS and RoCoF ESS, have a unit cost comprising a fixed and variable component.

TABLE 5.9 APPROPRIATE BASIS FOR THE ALLOCATION OF COSTS

Service	Party costs allocated to	Basis for the allocation of costs
Contingency raise ESS	Generators on the basis of capacity	Fixed cost – availability of service Variable cost – usage of service
Contingency lower ESS	Customers on the basis of maximum demand	Fixed cost – availability of service Variable cost – usage of service
RoCoF ESS	Party that causes the service to be enabled	Unit cost incorporating fixed and variable costs
Regulation ESS	Generators and customers that contribute to frequency deviations, with balance recovered from customers	Unit cost incorporating fixed and variable costs

[35] Australian Energy Market Operator, *Guide to Ancillary Services in the National Electricity Market*, April 2015, page 9
[36] Economic Regulation Authority, *Decision on the Australian Energy Market Operator's 2020/2021 Ancillary Services requirements*, 7 July 2020, page 5
[37] Ibid, page 7
[38] Australian Energy Market Operator, *Guide to Ancillary Services in the National Electricity Market*, April 2015, page 14

Service	Party costs allocated to	Basis for the allocation of costs
Voltage management / network support ESS	Customers through network charges	Consistent with economic regulatory regime
System restart ESS	All participants on the proportion of total energy production and consumption	Fixed cost – availability of service and annual testing Variable cost – usage of service
System strength ESS	Where possible, party responsible for the system strength issue, with balance recovered from customers	Unit cost incorporating fixed and variable costs

SOURCE: ACIL ALLEN ASSESSMENT

Are there alternatives to a causer pays approach for the recovery of the ESS costs?

In section 5.2, we have identified and assessed three alternatives to a causer pays approach for the recovery of ESS costs:

- generator pays, which is the current approach
- customer pays, as proposed by Eni
- hybrid causer pays approach, as proposed by Sun Cable.

These options, as well as the causer pays approach, were assessed against five criteria:

- efficient provision of services
- administrative costs
- meet required standards
- investment certainty
- technology neutrality.

As discussed in section 5.2.6, the causer pays approach was assessed to be the most favourable approach. While the causer pays option is more costly than the generator pays or customer pays options, it is more efficient as the costs of providing regulation ESS, RoCoF ESS and system strength ESS are paid for by the parties causing the need for those services. For this reason, it provides an incentive to parties to minimise frequency deviations, rate of change of frequency and system strength issues, respectively.

However, it may also have a slightly adverse impact on investment certainty and technology neutrality because of the requirement to pay for frequency deviations, rate of change of frequency and system strength issues.

The hybrid causer pays approach was assessed as being slightly less favourable than the causer pays approach because the incentives under the hybrid causer pays approach are dependent on the contractual arrangements between the generators and third parties.

Are there any technical barriers to the adoption of a causer pays or alternative approaches to ESS cost recovery in the Territory?

The key technical barrier to the adoption of a causer pays approach that was identified by stakeholders in submissions to the Issues Paper is metering. However, we note that PWC is well advanced in 'rolling out' interval (or smart) meters to its customers. Table 5.10 shows the progress that had been made with the roll out as at 30 June 2018, with an expectation by PWC that by 1 July 2019, most customers consuming more than 40 MWh per annum would have a smart meter installed.

PWC estimates that by the end of June 2024, approximately 16,000 interval meters will be converted to smart meters by adding communication facilities, and an additional 35,000 smart meters will be installed. That is, more than half of the electricity customers in the Territory will have had a smart meter installed by the end of June 2024.

TABLE 5.10 REGULATED NETWORKS – CUSTOMER NUMBERS BY GROUP AND METER TYPE, AS AT 30 JUNE 2018

Customer group	Darwin-Katherine	Alice Springs	Tennant Creek
Using more than 750 MWh per annum			
With interval meters	172	22	3
Without interval meters	-	-	-
Using between 40 and 750 MWh per annum			
With interval meters	8,739	1,844	17
Without interval meters	1,052	82	278
Using less than 40 MWh per annum			
With interval meters	4,920	928	65
Without interval meters	56,173	9,536	1,231

SOURCE: PWC, UPDATED 14 MARCH 2019

Accordingly, we would expect that any customer that may cause a frequency deviation requiring regulation ESS to be provided would have the required metering installed.

That said, the System Controller may not have the processes and systems in place to be able to allocate costs in accordance with the causer pays methodology. These would need to be developed before implementing such an approach.

What issues would the transition to a causer pays or alternative basis of ESS cost allocation present for system participants?

There are a number of issues that would need to be considered and resolved prior to transitioning to a causer pays basis of ESS cost allocation. These include:

— Procedures for allocating costs – the System Controller would need to develop the procedures for allocating costs under the causer pays approach. The procedures for the dispatch of ESS and the allocation of costs should be published to provide transparency.

— Settlement – decisions would need to be made as to whether the ESS market is settled through net payments directly between the beneficiaries of services and the providers of those services or through the System Controller. If the market is settled through the System Controller, decisions would need to be as to the appropriate prudential requirements.

— Amendments to the relevant Codes and Guidelines – the Codes and Guidelines would need to be amended to replace the current approach to paying for ESS with the causer pays approach. Decisions would need to be made as to whether any of the existing mandatory requirements in the GPS could be relaxed with the transition to the causer pays approach, in particular, the balance of services to be provided by new connecting generators *vis a vis* the ESS dispatched via the System Controller.

— Amendments to the Wholesale Electricity Supply Agreement (WESA) – the WESA would need to be amended to provide for a change in costs incurred by T-Gen with the change in the approach to recovering the costs associated with ESS.

Eni has welcomed the move to a "more appropriate ESS regime" as it has difficulty funding the existing charge. That said, the cost impacts of the new regime would need to be quantified to determine the impact on existing contractual arrangements between retailers and generators.

What oversight or regulatory arrangements should accompany any causer pays allocation or alternative arrangements?

In case of dispute between the System Controller and participants in relation to the dispatch of ESS and the settlement of the costs for those ESS, particularly the regulation ESS, RoCoF ESS and system strength ESS, which are allocated on a causer pays basis.

The independent economic regulator, the Utilities Commission, is best placed to be the arbiter of such disputes, but may need additional resources to do so.

6 SUMMARY OF RECOMMENDATIONS

Table 6.1 summarises our responses to the questions raised in the Issues Paper on Essential System Services in relation to:

- the service provision framework
- administered pricing arrangements and market power mitigation
- cost allocation and settlement.

TABLE 6.1 SUMMARY OF RECOMMENDATIONS

Question	Response
Service provision framework	
What types of ESS are most suitable for market provision and in which systems? Are there certain categories of ESS which would benefit from continued Territory Generation and why?	In the longer term, market provision of ESS is appropriate for all services and in all systems. However, in the short term, there may not be effective competition for each of the services in each of the systems, so T-Gen may need to continue to provide some services as the default provider.
What are the likely costs and benefits of spot market procurement of certain types of ESS in any of the Territory electricity systems?	The key benefits of a spot market are that it facilitates the more efficient procurement and dispatch of ESS, enables the co-optimisation of the wholesale energy and essential services markets, and enables the procurement of ESS on a technology neutral basis. However, the upfront and ongoing costs associated with implementing and administering a spot market are high, and the approach is not as well suited to services that are required infrequently and for which a revenue stream is required to ensure they are available as and when required.
What service provision framework would deliver the most appropriate balance between costs and benefits for each category of ESS in each regulated electricity system?	The most appropriate balance between costs and benefits would be achieved by procuring ESS, which are the responsibility of the System Controller to procure, through bilateral contracts that are entered into following a competitive tender or reverse auction process. The tenure of the contracts would need to reflect the characteristics of the relevant ESS. The existing incentive-based economic regulatory framework provides the framework for the provision of ESS for the services for which the Network Operator is responsible.

Question	Response
Administered pricing arrangements and market power mitigation	
What changes should be made to the current administered pricing arrangements for the provision of ESS provided by Territory Generation? What methodology should be used to determine prices for each of the ESS categories?	Constraints should be placed on prices that are offered through the competitive process, with the offer prices capped at the LRMC for the particular service.
What process should be put in place to ensure the administered prices remain up to date?	The LRMC for each service should be reviewed prior to the conduct of a competitive process to procure that service. The Utilities Commission, as the independent economic regulator, is best placed to determine the LRMC for each service, for each system.
What market power mitigation measures would be appropriate for the provision of different ESS by Territory Generation?	Until there is an effectively competitive market for each service and each system, there should be a default provider for each service and each system to ensure that the required standards can be met. The default provider should be used on a by exception basis only so as to facilitate competition with prices set based on actual costs to avoid the provider earning windfall gains or incurring losses.
Cost allocation and settlement	
What are the appropriate bases for the allocation of ESS costs?	The appropriate bases for the allocation of ESS costs are: – Contingency raise ESS – generators on the basis of capacity – Contingency lower ESS – loads on the basis of maximum demand – RoCoF ESS – party that causes the service to be enabled – Regulation ESS – generators and customers that contribute to frequency deviations, with balance recovered from customers – Network support ESS – customers – System restart ESS – generators and consumers on the basis of energy produced / consumed – System strength ESS – party that causes the system strength issue, with balance recovered from customers
Are there alternatives to a causer pays approach for the recovery of the ESS costs?	Three alternative options to a causer pays approach were assessed – a generator pays approach, a customer pays approach, and a hybrid causer pays approach as proposed by Sun Cable. The causer pays approach was assessed more favourably than the other approaches. While it is more costly, it facilitates more efficient outcomes.
Are there any technical barriers to the adoption of a causer pays or alternative approaches to ESS cost recovery in the Territory?	The key technical barrier to the adoption of a causer pays approach is the processes and systems required by the System Controller to allocate costs in accordance with the causer pays methodology.
What issues would the transition to a causer pays or alternative basis of ESS cost allocation present for system participants?	The issues that would need to be resolved in the transition to a causer pays approach include: – developing procedures for allocating costs – determining how the ESS market would be settled – amending the relevant Codes and Guidelines – amending the Wholesale Electricity Supply Agreement.

Question	Response
What oversight or regulatory arrangements should accompany any causer pays allocation or alternative arrangements?	A dispute resolution mechanism should accompany a causer pays allocation. The Utilities Commission, as the independent economic regulator, is best placed to be the arbiter of such disputes.

APPENDICES

A ACTUAL COST AND LRMC

A.1 Actual cost

The total actual costs for providing a service would typically be estimated using a building block approach which comprises:

- the return of capital, that is, depreciation
- the return on capital
- fixed operating and maintenance costs
- variable costs over the life of the plant (including fuel)
- tax costs (if using a post-tax rate of return).
- In the case of generators, the variable costs include the cost of fuel and in the case of batteries, includes the cost of charging the battery.

If the plant providing a service could produce energy as well as provide ESS, the fixed costs (the capital costs and the fixed operating and maintenance costs) could be recovered through the sale of energy and in providing ESS. The actual costs associated with the provision of ESS could be determined on a marginal basis or on a fully absorbed cost basis.

If the actual costs associated with the provision of ESS are determined on a marginal basis, the fixed costs would be fully recovered through the sale of energy. Any incremental fixed costs and the variable costs associated with the provision of ESS would be recovered through the provision of ESS.

If the actual costs associated with the provision of ESS are determined on a fully absorbed cost basis, the fixed costs would be allocated between the two services – the sale of energy and the provision of ESS. The actual costs for providing ESS would be the allocation of the fixed costs and variable costs incurred in providing ESS.

A unit cost would be calculated by dividing the total costs by the volume of services forecast to be provided.

A.2 Long run marginal cost

The marginal cost is the cost of producing a particular unit of output.

The marginal cost of the first unit of output is all the fixed cost and the variable cost of the first unit.

The marginal cost can be different in the short term, where some costs are fixed, and in the long term, where no costs are fixed.

When determining the long run marginal cost to provide a service at a point in time, the period over which no costs are fixed (that is, all costs are considered to be variable) is the life of the plant that provides that service.

The long run marginal cost (LRMC) is therefore defined as the cost of an incremental unit of capacity, spread across each unit of service provided over the life of the plant.

When calculating the LRMC for new plant, the costs considered include all costs relevant to the investment decision. These costs are:

- the capital cost (including connection and other infrastructure)
- other costs, including legal and project management costs
- fixed operating and maintenance costs
- variable costs over the life of the plant (including fuel)
- tax costs (if using a post-tax discount rate).

The LRMC is the average cost over the long term of supplying incremental service requirements.

There are two approaches to estimating the LRMC:

- A **standalone** or **greenfield** approach, which assumes that there is currently no plant to provide the required service. The approach theoretically builds, and prices, a whole new system that is least-cost. In effect, it re-prices all existing plant at efficient levels and includes the capital costs of new plant in the LRMC estimate.
- An **incremental** approach, which assumes that the existing mix of plant in the system is in place and that the required service can be provided using both existing plant and new plant. This approach prices services on the basis of the least-cost way of adding to the existing stock of plant and does not factor in the capital costs of existing plant as this is assumed to be sunk.

The standalone or greenfield approach is generally used for estimating the LRMC for regulatory purposes. The incremental approach results in a very low LRMC (more related to the short run marginal cost) unless new plant is immediately required.

In a competitive market, the price outcomes will align with the LRMC over the *long-term*. If the price outcomes were lower than the LRMC over the long term, service providers would not be viable. If the market is competitive then the price outcomes will not be higher than the LRMC values over the long term.

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