

Northern Territory Electricity Market Consultation Draft Functional Specification

Consultation Notes

Submissions due 8 March 2019 to
DTF.UtilitiesReform@nt.gov.au

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Attachment A – NTEM Consultation Draft Functional Specification

1. Consultation notes

The Northern Territory Government is undertaking reform of the electricity sector in the Territory. The objectives of electricity reform in the Territory as currently set out in the *Electricity Reform Act* are to:

- promote efficiency and competition in the electricity supply industry
- promote the safe and efficient generation, transmission, distribution and selling of electricity
- establish and enforce proper standards of safety, reliability and quality in the electricity supply industry
- establish and enforce proper safety and technical standards for electrical installations
- facilitate the maintenance of a financially viable electricity supply industry
- protect the interests of consumers of electricity.

Inherent in these objectives is that competition in the electricity industry serves as the primary means of achieving efficiency in the production, transport and consumption of electricity for the long term benefit of consumers and the economy.

On 8 October 2018, the Northern Territory Government announced that a Northern Territory Electricity Market (NTEM), tailored to the Territory's circumstances, will be developed. The NTEM is to ensure that the growing interest in renewable energy can be facilitated in the Darwin-Katherine power system in a way which will deliver lower cost generation and reliable power to Territorians. Government has committed to working closely with stakeholders on the NTEM design and implementation.

The Department of Treasury and Finance (DTF) and its technical advisers Oakley Greenwood, have developed the NTEM Consultation Draft Functional Specification at Attachment A. The NTEM Functional Specification will outline how each of the functional components of the proposed market arrangements will operate and interact with each other. The Functional Specification is planned to be the primary reference document for the detailed design and implementation of arrangements to manage reliability and security of supply, trading and dispatch activities, metering and settlement and how the NTEM is to support the Territory Government's renewable energy target.

The purpose of this consultation is to invite comment from stakeholders on the NTEM Consultation Draft Functional Specification. DTF also welcomes comments on any other matters related to the design, implementation or operation of NTEM that are beyond the scope of the Consultation Draft Functional Specification.

Specific matters that DTF considers stakeholders may wish to comment on but which are beyond the scope of the Consultation Draft include some governance arrangements (market bodies and rule makers) and transition timelines. However, DTF welcomes and will consider comments on any matters related to NTEM raised by stakeholders in submissions.

Market governance

The governance arrangements for the NTEM, including legislative and institutional frameworks, will be critical for supporting investment and competition in the Darwin-Katherine system. Potential new entrants and investors will require confidence that all market participants will be able to compete on a level playing field.

The development of the legislative and regulatory framework and market design for NTEM, including initial Market Rules, will be the responsibility of government in consultation with stakeholders. However, the impartiality of the process for amending the Market Rules will be important to support investor confidence. A process for changes to the Market Rules will be required and a set of NTEM objectives enshrined in the Market Rules will be developed to guide the development of the Market Rules over time.

Further, the institutional arrangements to support the operation and development of the NTEM will be a key concern for stakeholders. Initially, the Utilities Commission, Power and Water Corporation (as System Controller and Market Operator) and DTF, will fulfil key regulatory, operational and policy roles. However, in the long term the institutional framework which will best support future development of the NTEM taking into account the small size of the market and the need to keep overheads low, will be established by government.

Stakeholders may have views on the rule change process, the construction of market objectives and the institutional arrangements to support NTEM operation and development.

Transition timelines

There is an imperative for the NTEM to commence in 2019 to permit the entry of prospective new entrant generators in the Darwin-Katherine system. The short timeframe for commencement of the NTEM will require the Territory to develop transitional arrangements to apply from 1 July 2019 ahead of the implementation of the full market design at a later date. Key transitional arrangements are proposed for Ancillary Services, the Reliability Standard and the Capacity Mechanism.

DTF intends for the transition to the full market design to be undertaken in a staged manner, however, is yet to determine a timeline. If the NTEM is operating successfully under transitional arrangements, consideration may be given to deferring the implementation of the full market design. Stakeholders may have views on an appropriate timeline or conditions for the transition of particular elements of the NTEM from the transitional to full arrangements.

The remainder of these consultation notes provide background to the Territory Government's electricity sector reforms and context for the NTEM Draft Consultation Functional Specification.

2. Background

2.1. Legal structure

From the 1980s until 2000 the Power and Water Corporation (PWC) (and its predecessors) was the Territory's monopoly provider of utilities services and operated as a vertically and horizontally integrated multi-utilities business. In theory, the single-company model offered economies of scale and scope, however, the single-company model lacked financial and operational transparency, did not incentivise PWC to operate efficiently given its monopoly position and enabled cross-subsidisation between business units. Combined with an outdated regulatory environment, this led to sub-optimal operational and financial outcomes and significant inefficiencies in the Territory's utilities sector.

While an open access regime was introduced in 2000, PWC's vertical integration deterred competition emerging in the Territory's electricity supply industry, resulting in PWC, and consequently Government, being the primary investor in new generation, and bearing all associated risks.

In 2013 the Territory commenced an electricity market reform program to deliver financial transparency, improved quality and efficiency of service delivery, and to promote competition in the generation and retail sectors.

Key to the reform program was structurally separating the contestable retail and generation businesses out of PWC in 2014 to create two new government owned corporations (GOCs), Jacana Energy, the electricity retailer; and Territory Generation, the electricity generator. PWC retained responsibility for electricity networks, gas services, water and sewerage, as well as Indigenous Essential Services.¹

¹ The structural separation of PWC was achieved through amendments to the *Government Owned Corporations Act* and the introduction and passage of the *Power Retail Corporation Act* and *Power Generation Corporation Act*. This legislation commenced on 29 May 2014, with operational commencement from 1 July 2014. Additional regulations were also required, under the *Government Owned Corporations Act*, to transfer appropriate assets, liabilities, instruments, proceedings and other parts of the PWC business to Territory Generation and Jacana Energy.

Structural separation is now complete. Each business is undertaking separate financial reporting and publishes an annual Statement of Corporate Intent in accordance with the *Government Owned Corporations Act*.

Structural separation has allowed the three businesses to specialise in, and focus on, their specific core business, cost drivers and financial performance and has facilitated greater transparency to government of the performance of each business.

In its 2015-16 Power System Review, the Utilities Commission observed that structural separation has resulted in improvements in focus and accountability in the separated entities, which has resulted in improved performance and increased reliability experienced by customers.

Further, structural separation has assisted the emergence of competition in the Territory's electricity supply industry, as evidenced by Rimfire Energy's and Next Business Energy's entry into the retail sector, EDL's retail licence, and the recent generation licences provided to two new solar farms (Batchelor and Katherine) intending to connect to the Darwin-Katherine electricity system. Three further generation licences are expected to be issued imminently and increased market interest and activity has also been observed more generally.

2.2. Open access and rules

Open access to shared facilities is central to the use of competitive forces to manage the efficient operation of any industry. The provision of electricity infrastructure used to transport electricity is a natural monopoly service and cannot be economically duplicated – it is a shared service. PWC, as the owner and operator of the Territory's electricity networks holds a strategic position in the electricity supply industry, given generators and retailers can only carry on operations if they can transport the electricity they buy and sell via PWC's electricity networks. As such, the existing third party "open access" regime for electricity networks is an essential requirement for competitive generation and retail markets.

Under an open access regime, generators (and customers) have the right to connect to the network on a non-discriminatory basis subject to meeting certain technical obligations or conditions related to maintenance of power system security.

An open access regime for the Territory's electricity networks was implemented in 2000 with the introduction of the *Electricity Reform Act*, the *Electricity Networks (Third Party Access) Act* and the *Utilities Commission Act* which:

- abolished the statutory monopoly over electricity supply in the urban systems held by the (then) Power and Water Authority
- established a third-party access regime for specified electricity networks
- put in place a timeframe for the phased introduction of retail competition
- established an independent economic regulator, the Utilities Commission (the Commission) to regulate monopoly electricity services, licence market participants and enforce regulatory standards for market conduct and service quality.

This new model facilitated the Territory meeting its national competition policy obligations to reform publicly owned monopolies and comply with competitive neutrality principles for government owned businesses.

However, the Utilities Commission lacked the powers, resources and multi-jurisdictional experience to ensure that PWC met its obligations regarding the efficient and reliable operation of its electricity networks. Further, Territory-specific regulatory arrangements were a deterrent to electricity businesses that operate in the eastern states from entering the Territory market given their relative unfamiliarity with the bespoke arrangements. To address these limitations and better align the Territory's regulatory arrangements to the greatest extent appropriate and practicable with those in NEM, further legislative changes were introduced.

In 2015, the *National Electricity (Northern Territory) (National Uniform Legislation) Act* transferred the economic regulation of the Territory's regulated electricity networks (Darwin-Katherine, Alice Springs and Tennant Creek) from the Commission to the Australian Energy Regulator (AER), which is a better resourced and more experienced regulator with greater powers. Currently the AER is regulating PWC's network business under the Territory's existing electricity legislative framework until 2019.

In 2016, the National Electricity Law and Rules (NER) were adopted in the Territory. While the NER has been adopted fully under the Act, the Territory has effectively 'switched off' various aspects through Territory regulations. This allows the Territory, through a series of reform packages, to progressively 'switch on' aspects of the NER as required by the AER and PWC to inform the preparation of PWC's 2019-24 Network Price Determination. The Territory is exercising its ability to seek derogations and transitional arrangements where it considers NER arrangements are not appropriate for the Territory.

Two packages of regulations implementing modified chapters of the NER commenced on 1 July 2016 and 1 July 2017, and the AER and PWC are in the final stages of the process to determine PWC's revenue requirement for the 2019–24 regulatory period.

Work is underway on the third package of regulations to be in place by 1 July 2019. This package will include further metering obligations and a framework for connections to the network, noting the current Territory connections framework under the *Electricity Networks (Third Party Access) Act* is legislated for repeal on 1 July 2019.

Compared to the current Territory arrangements, the NER is a more formal and prescriptive compliance and reporting framework. However, it is these prescriptive requirements that will provide the AER insight into PWC's operational and financial performance and provide a sound basis to determine PWC's efficient costs.

Some aspects of the NER are not expected to be adopted and will remain switched off for the foreseeable future, particularly those related to NEM wholesale electricity market arrangements, given the Territory will require its own market rules for the NTEM.

2.3. Trade of electricity

Once generators or retailers have exercised their rights to connect to a network under an open access regime they need a mechanism to buy and sell electricity on a competitive basis – a market. The Territory's current market structure comprises bilateral contracting arrangements of a form carried over from the previous closed-access arrangements when PWC controlled who could connect, where and when. Rather than being able to sell into a wholesale market (as in the National Electricity Market (NEM) or in the Western Australian South West Interconnected System), a new entrant generator company in the Territory is currently required to secure customer contracts upfront through a licenced retailer. Although the previous restriction requiring physical load following has been removed, the current arrangements are overly restrictive.

The bilateral contracting arrangement also lacks pricing transparency and this is perceived as a significant barrier to private investment in the Territory's generation sector.

In September 2013, the Utilities Commission was tasked with undertaking a review into appropriate wholesale market arrangements for the Territory and to recommend a wholesale market design and rules suitable for the Territory's circumstances. The Commission's report recommended a market design, termed the Northern Territory Electricity Market or NTEM, comprising an energy trading mechanism and a capacity (investment) mechanism.

The former Territory Government endorsed the strategic direction outlined in the Commission's report and approved the development and implementation of the NTEM and an interim energy trading arrangement as a precursor to the NTEM for the Darwin-Katherine system. It is not expected to be cost effective to extend NTEM arrangements to the Tennant Creek and Alice Springs power systems.

The Interim NTEM or I-NTEM, commenced operations in May 2015 and was implemented using a minimalist approach to development of systems and regulatory arrangements with the design premised on 'piggy backing' off existing arrangements and accommodating legacy infrastructure, systems and operational practices. This approach was designed to minimise cost and resource effort but provide a base for familiarisation and testing of processes and roles and responsibilities of the parties.

The I-NTEM is a virtual market in that all commercial transactions occur through bilateral contracts between generation and retailing entities. These contracts continue the practice of bundling electricity in a single tariff that includes energy, capacity and ancillary services, with network charges separate. I-NTEM applies only to the Darwin-Katherine Interconnected System and was implemented through amendments to the existing System Control Technical Code under the *Electricity Networks (Third Party Access) Act*. However, the interim systems and process cannot accommodate multiple new entrant generators and require further development to provide a fully functional market mechanism.

The proposed NTEM market design is intended to facilitate cost-effective and sure short-term dispatch of electricity while providing a closely managed investment regime affording certainty to industry participants. It also provides a transparent and competitive framework to allow for participation by multiple players (government and privately owned) and does not preclude or favour the participation of one generation technology over another and can readily accommodate the Government's renewable energy policy. The proposed NTEM design is from the broad family of capacity plus energy markets which are characterised by generators receiving (or being entitled to) separate, centrally administered, revenue streams for energy and capacity (in addition to revenue from optional external bilateral contracts). Capacity plus energy markets are used in many countries and also in the Western Australian South West Interconnected System. The detailed design of markets in different countries and regions often varies to accommodate local conditions and circumstances.

3. How to make a submission

DTF seeks submissions on the NTEM Consultation Draft Functional Specification by **8 March 2019**.

Submissions should be provided in Adobe Acrobat or Microsoft Word format by email to DTF's Utilities Reform unit, email DTF.UtilitiesReform@nt.gov.au. On receipt of a submission a confirmation of receipt will be provided, however, it is the submitter's responsibility to ensure successful delivery of their submission.

Any questions regarding the consultation should be directed to DTF's Utilities Reform unit by email DTF.UtilitiesReform@nt.gov.au.

Confidentiality

DTF will make submissions publicly available on its website, with the exclusion of confidential information. Submissions must clearly identify any confidential information and a version suitable for publication with the confidential information removed should be provided to DTF.

DTF may also exercise its discretion not to publish any submission based on content, such as submissions containing material that is offensive or defamatory.

Next steps

Following receipt of submissions, DTF will review the submissions and prepare a final NTEM Functional Specification for consideration by the Territory Government.

Once the NTEM Functional Specification has been approved by government, DTF will undertake further work and consultation to implement the NTEM.



Oakley Greenwood

Northern Territory Electricity Market (NTEM)

Functional Specification

prepared for:
Department of Treasury and Finance,
Northern Territory

DRAFT VERSION ONLY.

SUBJECT TO CONSULTATION AND SUBSEQUENT CHANGE

DISCLAIMER

This document presents a Consultation Draft Functional Specification for a Northern Territory Electricity Market (NTEM) as part of a broader package of industry reform.

This Consultation Draft Functional Specification has been prepared in consultation with, and advice from, the Department of Treasury and Finance, in particular in respect of policy direction.

Oakley Greenwood has prepared this Consultation Draft Functional Specification with reasonable care and expertise but makes no representation that it is a complete or fully formed specification.

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ACRONYMS AND ABBREVIATIONS

AEMC	Australian Energy Market Operator
AER	Australian Energy Regulator
AFSL	Australian Financial Services Licence
AGC	Automatic Generation Control
DKIS	Darwin-Katherine Interconnected System
DSR	Demand Side Response
EMS	Energy Management System
FFR	Fast Frequency Response
GOC	Government-Owned Corporation
GPS	Generator Performance (Access) Standard
I-NTEM	Interim Northern Territory Electricity Market
MDP	Metering Data Provider
NEM	National Electricity Market
NER	National Electricity Rules
NER(NT)	National Electricity Rules (Northern Territory)
NTC	Network Technical Code
NTEM	Northern Territory Electricity Market
PWC	Power and Water Corporation
POE	Point of Exceedance
SCTC	System Control Technical Code
Territory	Northern Territory
T-Gen	Territory Generation

1. Background

The Northern Territory (Territory) Government is seeking to increase the opportunity for competitive forces to influence the investment in, and operation of, the electricity supply industry in the Territory. The objective of facilitating greater levels of competition is to reduce the cost of electricity supply for consumers in the Territory and facilitate the effective entry of renewable power.

Territory legislation has provided for Open Access (or Third Party Access) to the regulated electricity networks in the Territory since 2001 under the *Electricity Networks (Third Party Access) Act*¹. However, until now, these arrangements have not been complemented by workable mechanisms for operation of generators who choose to connect.

In 2014, to support competition, the Territory Government structurally separated the then-existing vertically-integrated, government-owned utility entity, Power and Water Corporation, into separate businesses. They are now: Jacana Energy (Jacana) for electricity retailing, Territory Generation (T-Gen) for electricity generation, and Power and Water Corporation (PWC) for Networks and System Control (which retained the original business name and also continues to deliver water and sewerage services).

On 8 October 2018, the Territory Government announced electricity market reforms to deliver lower cost and reliable power, and meet its Renewable Energy Strategy aimed at achieving its target of 50 per cent renewable energy² across the Territory by 2030³. This includes the introduction of a Northern Territory Electricity Market (NTEM) to facilitate the introduction of renewable energy sources in the Darwin-Katherine Interconnected System (DKIS).

The Australian Energy Regulator (AER) commenced regulation of the Territory's electricity networks in 2015 under existing jurisdictional legislation and will commence full regulation under the National Electricity Rules (Northern Territory)⁴ from 1 July 2019.

The National Electricity Rules (Northern Territory) are a modified version of the National Electricity Rules (NER), which govern the National Electricity Market (NEM) on the East Coast of Australia. The NER are progressively being applied in the Territory, where appropriate and modified where the cost of adopting the NER in full outweighs the benefits, or where an alternative approach is required to reflect the characteristics of the Territory's electricity systems.

Arrangements for connection (access), planning, economic regulation and metering activities are being transferred from local Territory regulatory instruments to the NER(NT) for the AER's 2019 to 2024 Network Price Determination.

Arrangements for the management of system reliability, security of supply and related dispatch, and metering and settlement for the DKIS will form part of the NTEM.

1 <https://legislation.nt.gov.au/Legislation/ELECTRICITY-NETWORKS-THIRD-PARTY-ACCESS-ACT>

2 This will be provided from grid connected generation installations, including behind-the-meter generation, and all Aboriginal communities supplied by Indigenous Essential Services, but excluding self-generating enterprises that generate electricity for their own use in their primary business.

3 <http://newsroom.nt.gov.au/mediaRelease/27210>

4 <https://www.aemc.gov.au/regulation/energy-rules/national-electricity-rules-northern-territory>

An interim form of the NTEM, known as the I-NTEM, commenced operation in the DKIS in 2015 and the System Control Technical Code⁵ (SCTC) was updated accordingly.

This document specifies how each of the functional components of the NTEM will operate. It is intended to be the primary reference document for detailed design of arrangements to manage system reliability, security of supply, trading and dispatch activities, metering and settlement, and how the NTEM is to support the government's Renewable Energy Strategy.

To manage the transition from the existing arrangements (I-NTEM), a number of critical policy and regulatory mechanisms overlay the detailed design of the NTEM. These include the management of the dominant market positions of the government-owned corporations (T-Gen and Jacana), facilitating the implementation of the government's Renewable Energy Strategy, and coordinating the progressive introduction of competitive mechanisms. These transitional arrangements have been designed to allow them to fall away as the NTEM matures and government policy evolves.

Governance arrangements are referred to, where appropriate, and will be developed in detail following the finalisation of the Functional Specification.

1.1. The NTEM and I-NTEM

By design, the I-NTEM was a short-term, fit-for-purpose, interim market arrangement with virtual settlement, to initiate market-based operations within the electricity sector by building on pre-existing processes and infrastructure.

Under the NTEM, virtual settlement in the I-NTEM will be replaced with actual financial transfers.

In the NTEM, Ancillary Services will be provided by a separate regime for competitive acquisition of services run by System Control. This arrangement will replace the I-NTEM arrangement whereby T-Gen is the sole provider of Ancillary Services and is compensated within its energy tariff or via a fixed fee paid by other generators when appropriate. (Note: transition arrangements will apply - see Ancillary Services sections)

The NTEM is to take the form of a 'Capacity plus Energy' market, whereby separate mechanisms exist to manage long-term infrastructure investment and day-to-day operation of the power system respectively. The concept of a Capacity Mechanism was envisaged, but not activated, in the I-NTEM description.

In the NTEM, the Capacity Mechanism will be managed by a Reliability Manager who will calculate the aggregate level of generating Capacity (and controllable demand) that is required in the system to ensure system-wide reliability. The Reliability Manager will allocate responsibility to purchase and pay for a share of the required capacity to Retailers. A price for Capacity will be determined as part of the Capacity Mechanism, which will allow market participants to benchmark the price for Capacity and will also be used when (and if) the Reliability Manager purchases Capacity. The rules for the Capacity Mechanism will define how responsibility for Capacity will be allocated to retailers on behalf of end-use customers. Capacity may also be able to be traded bilaterally to meet a retailer's obligation.

⁵

Section 38 of the *Electricity Reform Act* requires the power system controller to prepare a System Control Technical Code and submit it for approval to the Utilities Commission of the Northern Territory. This code sets out the controller's competitively neutral operating protocols, arrangements for system security and system dispatch, as well as arrangements for the interruption of supply.

2. NTEM Functional Specification - Overview

2.1. Introduction

This Functional Specification is a “living document” in that it describes the expectations for the ultimate market design, but in a number of areas there are transitional arrangements. A number of the elements of the design described here are yet to be commented on by stakeholders and amendments may flow from these consultations. The Functional Specification will also be amended over time as the market matures, with changes and approvals to be handled by way of detailed governance arrangements.

Many of the components of the NTEM are already in place, although amendments will be required to the way a number of the components operate.

2.2. Industry context

Following is a list of the main components of the broader industry arrangements within which the NTEM sits and their relationship to each other. They are illustrated in Figure 1 following:

- Statutory, legal and regulatory instruments - including relevant Acts and Market Rules to mandate and authorise market operation and to register participants, including confirmation that participants meet required commercial and technical standards;
- Customer participants - Retailers and Wholesale Customers who purchase energy through the wholesale market. This group includes all retailers and any individual large customers who choose to purchase directly from the wholesale market;
- Generation participants - the suppliers of energy into the wholesale market. This group includes the market generators considered by System Control in making dispatch decisions which affect the Balancing Price;
- Network Service Provider - delivers a regulated network service and acts as the metering services provider;
- Trading and Dispatch - undertaken by the System Control function which manages the security of the power system operation, acquires Ancillary Services, manages Security Constrained Economic Dispatch and determines the Balancing Price;
- Metering and Settlement - Market Operator receives metering data from the Network Service Provider, and calculates market settlement positions and manages associated payments;
- Market oversight and information - managed by the Utilities Commission and Department of Treasury and Finance; and
- A Capacity Mechanism - including a Reliability Manager function which assesses Capacity requirements and manages payments and where appropriate charges for Capacity. This is a new function in the NT and is an independent role responsible for management of whole-of-system reliability. The Reliability Manager will be responsible for calculating the aggregate level of Capacity needed in the system to meet the Reliability Standard, and ensuring that the market responds to meet this requirement.
- The Reliability Standard will define the level of reliability of supply that can be expected from generation after accounting for scheduled Demand Side Response resources.
- For the avoidance of doubt, arrangements will be made to confirm and ensure that participation in the NTEM will not require an Australian Financial Services Licence (AFSL).

Supplementary note: The Reliability Manager will allocate responsibility for meeting the aggregate Capacity requirement to Retailers, who will be responsible for contracting for their allocated share or alternatively paying the Reliability Manager who will acquire any amount not sourced by Retailers. This form of design of a 'Capacity plus Energy market' is often referred to as a Retailer Obligation form of market and is similar to the concept currently being discussed for the NEM for reliability guarantees. In consultation with government, the Reliability Manager may also require that a specified amount of Capacity be sourced from renewable energy generation and therefore provide an additional policy lever for government to implement its Renewable Energy Strategy.

2.3. NTEM features

Operating within the broader framework outlined above, the key features of the NTEM are:

- **Capacity Mechanism:** Retailers and, if necessary, the Reliability Manager will be responsible for entering into contracts to bring generation Capacity to market. The minimum amount of Capacity in aggregate required across the network will be calculated by the Reliability Manager as the amount needed to meet a mandated Reliability Standard.

Each year the Reliability Manager will also determine and publish a Capacity Price. This price will be the price the Reliability Manager expects to pay if it is required to contract for Capacity. It will also be available as a benchmark price for Retailers and Generators to refer to in their negotiations.

The Capacity Price will form the basis for incentives or penalties related to the timing of reductions in Capacity during a year; for example, to incentivise maintenance activity at times of high reserve Capacity.

- **Daily Nominations:** Generators must submit a day ahead forecast of their available Capacity for dispatch to System Control on a daily basis, with details of the short run cost of operation. In the event there are material and bona fide changes to availability or cost, the generators will be expected to make an amended submission.
- **System Control** will assess the requirements for Ancillary Services and other operating constraints to ensure the secure operation of the power system on a continuous basis.
- **System Control** will call on available Capacity and Ancillary Services and the power system according to Security Constrained Economic Dispatch principles to meet demand at least cost (without regard for contracts between market participants - see Out Of Balance below).

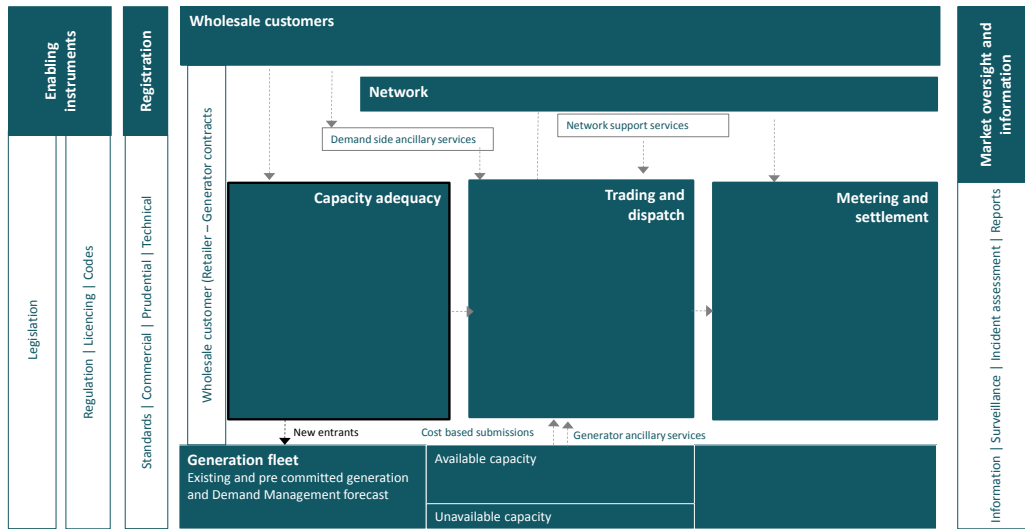
Transitional arrangements apply to the procurement and provision of Ancillary Services - see later section in this document.

- **Out Of Balance:** The Market Operator will assess the amount by which the dispatch of each Generator and consumption of each Retailer is 'Out Of Balance' with its contracted position. Out Of Balance can occur as the result of inaccurate forecasts or plant failure, or it can result as a consequence of dispatch being designed to occur at minimum cost across the system as a whole.

The amount of Out Of Balance volume of each party will be deemed to be traded through an Out Of Balance pool at the Balancing Price.

- **Balancing Price:** After the event (ex post), System Control will determine a Balancing Price for the energy produced or consumed based on the highest unconstrained variable cost of generation or scheduled demand needed to meet the total system demand.

Figure 1: Overview



2.3.1. Managed transition using contracts

At the start of competitive arrangements in many power systems, such as the introduction of the NTEM, management of the risks created by incumbents with dominant market power is often a significant issue. The NTEM will initially be dominated by T-Gen on the generator side and Jacana on the retail side. Both have a dominant market share with an associated level of market power.

At the start of market arrangements it is common practice for dominant parties to be allocated administered contracts - often called vesting contracts. In the NTEM, T-Gen and Jacana are currently negotiating contracts to support a transition from the current arrangements to a competitive environment. There is scope for these contracts to be adopted as NTEM vesting contracts⁶.

Transition contracts are a means to:

- Balance the impact of market dominance of GOC generation and retail entities in the emerging market;
- Provide financial stability and certainty to incumbent GOC generators and retailers as they adapt to market conditions including, for example, the retirement of ageing and surplus Capacity, and the unbundling of the costs of energy, Ancillary Services and Network Support Services.

2.3.2. Summary of Long-term Design and Short-term Transitional Arrangements

To facilitate the introduction of the NTEM in alignment with government policy and available resources, there are a number of transitional arrangements. Where applicable, transitional

6 At the most basic level, vesting contracts involve the imposition of an obligation on electricity generators to sell a specified amount of electricity at a specified price, and a corresponding obligation on retailers to purchase the specified volume of electricity at the specified price. The obligation is 'vested' in the generators and retailers rather than being entered into voluntarily, and the price and volume for the exchange may not reflect the market price or volumes the parties would have otherwise agreed to. Vesting contracts have been used in many markets including in all jurisdictions of the NEM and in the WEM in WA to facilitate the launch of market arrangements.

arrangements are described in this document in association with the detail of the design of associated components.

Supplementary note: Power System Reviews published by the Utilities Commission suggest that T-Gen’s current Capacity will exceed the Capacity likely to be needed to meet the NTEM Reliability Standard. However, T-Gen’s portfolio includes a number of ageing plants that will either need refurbishment or will be retired in the next 5-10 years. Retirement of T-Gen Capacity will afford a window of opportunity for investment in renewable resources without increasing the surplus Capacity. An increase in surplus Capacity would increase the costs of providing electricity and require tariffs and/or the Community Service Obligation⁷ (CSO) to be increased.

A number of parties are in the process of negotiating short-term (up to 12 month term) contracts. Subject to review for alignment with government policy and consideration of the commercial risk (to government) and cost to consumers and impact on the CSO, these contracts may be endorsed as transitional contracts.

Separately, government may instruct T-Gen and Jacana in respect of if and how each may be involved in future contracting for renewable resources. Any instruction in this regard will be outside the design of the NTEM as it will be an instruction from the owner to one (or more) of its business entities.

Table 1 summarises the proposed design of long term and transitional arrangements, further details are presented in the body of the document.

Table 1 Long term and short-term design characteristics

Market Component	Long-term Design	Short-term Transitional Arrangements
Management of Reliability	<p>Government sets Reliability Standard</p> <p>Reliability Manager role established</p> <p>Reliability Manager:</p> <ul style="list-style-type: none"> calculates Capacity Obligation calculates and publishes reference Capacity Price allocates proportional responsibility for Capacity Obligation to Retailers confirms Retailers’ contracted Capacity arrangements Reliability Manager contracts for balance of Capacity if necessary 	<p>Government sets transitional Reliability Standard</p> <p>T-Gen Asset Retirement Schedule is established</p> <p>Reliability Manager role undertaken by DTF</p> <p>Reliability Manager:</p> <ul style="list-style-type: none"> calculates transitional Capacity Obligation calculates and publishes reference Capacity Price allocates proportional responsibility for Capacity Obligation to Retailers confirms Retailers’ contracted Capacity arrangements

⁷ The CSO is a subsidy provided by the Territory Government to minimise the gap between the revenue received by electricity retailers under the regulated electricity retail tariffs in the Electricity Pricing Order and the actual cost of providing this service.

	True-up process: Retailers adjust Capacity holding with secondary trading, overseen by Reliability Manager	Retailers must contract for their forecast Capacity Obligation, no purchases by Reliability Manager. No Capacity Out Of Balance Annual true-up process between Retailers, facilitated by Reliability Manager
Compatibility with Renewable Energy Strategy	Market Rules reduce barriers to entry (technology neutral)	Market Rules reduce barriers to entry (technology neutral)
Real-time Operation (Scheduling and Dispatch)	Security Constrained Economic Dispatch: unit commitment by System Control	Security constrained Economic Dispatch: unit commitment by System Control (manual processes as required)
Ancillary Services	Competitive procurement process run by System Control Costs allocated on a broadly 'causer pays' basis	T-Gen supplies all Ancillary Services, except EDL and solar plant in excess of GPS, and when 132kV line is interrupted
Balancing Price	Marginal variable cost of generation plus amortised start-up cost	Marginal variable cost of generation plus amortised start-up cost
Capacity Price	Marginal cost of Capacity based on detailed economic modelling	Marginal cost of Capacity (where applicable), based on industry estimates
Dispatch Support Service	A new ancillary service to be introduced to enhance economic efficiency of dispatch, where security and reliability are not under threat but dispatch limits would need to be applied, reducing efficiency	Not available
Network Support Service	Network Service Provider will be responsible for procuring the availability of the service	Ring fenced T-Gen cost (no Network Support Services contracted by the Network Service Provider)
Settlement	By Market Operator for: <ul style="list-style-type: none"> Capacity (annual) Capacity OOB Energy OOB (per Trading Interval) 	By Market Operator including: <ul style="list-style-type: none"> Energy OOB (per Trading Interval) Ancillary Services at defined annual rates No Dispatch Support

	<ul style="list-style-type: none"> Ancillary Services contracts of System Control Dispatch Support <p>By Network Service Provider</p> <ul style="list-style-type: none"> Network Support Contracts (if economically efficient) 	<ul style="list-style-type: none"> Ring fenced accounts within T-Gen for Network Support
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The governance arrangements for the NTEM, including legislative and institutional frameworks will be critical for supporting investment and competition in the DKIS. Table 2 highlights the key entities, and their responsibilities, in the NTEM for both the short term transitional arrangements as well as the longer term design of NTEM.

Table 2 Key entities/Governance Bodies in the Northern Territory Electricity Market

Entity	Long Term	Short Term
Power and Water Corporation Networks		
Operates the Northern Territory’s regulated networks in accordance with the <i>Electricity Networks (Third Party Access) Act</i> (and subordinate Network Technical Code and Network Planning Criteria) and <i>National Electricity (Northern Territory) (National Uniform Legislation) Act</i> . Currently regulated by the Australian Energy Regulator (from 1 July 2015 onwards) under a regulatory revenue determination. Metering services provider.	✓	✓
System Control		
Maintains the security of the Northern Territory’s regulated power systems. This function is performed by the Power and Water Corporation System Control unit. Assess requirements for Ancillary Services.	✓	✓
Market Operator		
This function is currently performed by the Power and Water Corporation under its System Control licence. Receives metering data from the Network Service Provider, and calculates market settlement positions and manages associated payments such as energy and capacity out of balance.	✓	✓

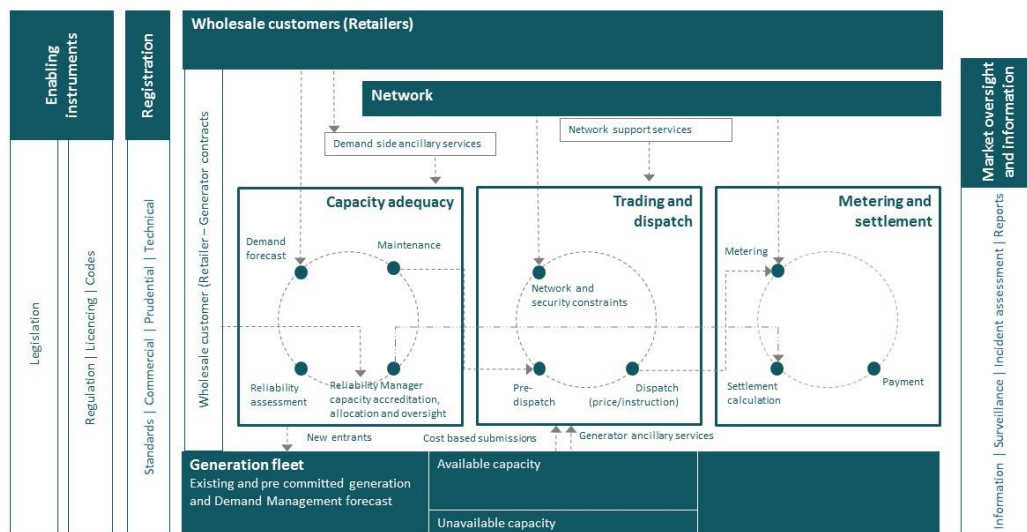
Reliability Manager		
<p>New body responsible for calculating the amount of capacity needed in aggregate to meet the defined Reliability Standard.</p> <p>Responsible for entering contracts to bring generation Capacity to market.</p> <p>Determine and publish a Capacity Price.</p>	New body to be established	Performed by DTF
Utilities Commission of the Northern Territory		
<p>The independent economic regulator for the Northern Territory that is established under its own enabling legislation (the <i>Utilities Commission Act</i>). Monitors (and if necessary, enforces) compliance with the Territory electricity industry's regulatory framework.</p> <p>Responsible for granting of licenses.</p> <p>Independent Market monitor and oversight of cost data provided to system controller.</p>	✓	✓
Market Rule Maker		
<p>New independent body (independent of PWC - given its roles as System Controller and Market Operator) to be established to make the NTEM rules.</p>	Rule change panel	Oversight by DTF, PWC and UC
Department of Treasury and Finance		
<p>Responsible for the development of Territory Government policy for electricity reform and the market design for the NTEM in consultation with industry.</p>	✓	✓

3. Functional Specification - Conceptual Design

3.1. Introduction

Figure 2 shows more detail of the functionality within each of the arrangements for Capacity Adequacy, Trading and Dispatch, and Metering and Settlement components of the NTEM, and is the basis for the conceptual design which is outlined in this section, and the detailed design for the final version along with transitional arrangements which is outlined the following section.

Figure 2: Operational Detail



3.2. Capacity Adequacy

A reliable power system requires that there be sufficient Capacity installed and available for operation when needed by customers.⁸ Competitive, open access markets use different combinations of standards and commercial incentives to ensure sufficient Capacity is available and operational. The NTEM design is from the broad family of ‘Capacity plus Energy’ markets in that Capacity and Energy (and Ancillary Services) are separately administered and accounted for.

In the NTEM, a Reliability Standard will be established that sets the minimum level of reliability of supply for customers. The Reliability Manager will administer a number of processes to ensure that there is sufficient Capacity present in the system to meet the Reliability Standard.

Supplementary note: For the avoidance of doubt, it is crucial to note that reference to risk of interruption of supply discussed in the context of the level of investment is a trade-off between increasing costs by constructing more plant in order to hold higher reserve and accepting the risk of interruption. This is a trade-off made in the NEM and the WA WEM and international power systems and in other industries. Further, interruptions to supply due to insufficient investment can always be controlled and will only be for a small fraction of the demand at any one time and is quite different to the widespread or complete system-wide blackouts

⁸ Customers receive continuous supply when a power system has sufficient generating Capacity and that Capacity is operated securely so that it can withstand the impact of disturbances such as the sudden shutdown of generation or disconnection of blocks of customer demand for any reason.

experienced in Darwin (and Alice Springs) in previous years due to unstable operating conditions due to sudden disturbances on the power system.

Retailer Obligation: Retailers will be allocated accountability by the Reliability Manager for their share of the required Capacity. The Retailer may contract directly with accredited scheduled generation, Demand Side Response and storage sources (e.g. batteries) for their Accredited Capacity volume, or alternatively rely on the Reliability Manager to acquire Capacity on their behalf and pay the Reliability Manager accordingly.⁹

The Reliability Manager will:

- Calculate how much effective Capacity will be needed to satisfy the Reliability Standard for a given year. Detailed work will need to be undertaken to establish an appropriate capacity procurement timeline to ensure that contracting for capacity occurs well ahead of time to reduce the risks of a potential shortfall in capacity. In other markets this often occurs on a rolling 3 or 4 year cycle;
- Manage an accreditation process for each facility (scheduled generating unit, storage facility or Demand Side Response resource) that applies to be capable of supplying Capacity to the market;
- Determine how much each accredited facility (generating unit, storage facility or demand side response resource) can reliably contribute to meeting the required amount of system Capacity. This will be the Accredited Capacity of the facility. The Accredited Capacity determination will account for failure rate, fuel certainty (including solar variability) and any network constraints that affect the effective Capacity of a facility;
- Allocate to Retailers a share of the required effective Capacity Obligation in proportion to their expected customer demand;
- Monitor whether enough Accredited Capacity is in the market and, if not, seek to enter into contracts in its own right and pass the cost through to those parties who fall short in procuring their share of Capacity;
- Calculate a Capacity Price. This will be the price at which the Reliability Manager will pay for Capacity it purchases, and charge to Retailers who fall short in their Capacity Obligation. Key considerations for designing the operation of the capacity price include whether it will be responsive to the supply-demand balance and once declared for a capacity year, will there be scope to adjust the capacity price or volume. The need for such adjustments have arisen in a number of capacity markets, including in the WA WEM, and will need to be taken into account in the NTEM. The Capacity Price will be published as a benchmark price for bilateral contracts for Capacity. The Capacity Price will be a key input to calculations for 'Capacity Out Of Balance'; and
- The Capacity Mechanism will include provision for government to consult with the Reliability Manager to set that a minimum amount of the Capacity required to meet the Reliability Standard must be sourced from a particular energy type or technology, for example, renewable energy or storage technology.

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Alternative approaches include: a) to centralise pricing and acquisition of capacity, for example with the Reliability Manager, where a Capacity Price is set that would be paid to all capacity that responds to invitations to enter the market with the Capacity Price automatically increasing or decreasing with the level of deficit and surplus respectively; or b) a regular (possibly annual) auction to find the price and or volume. There are advantages and disadvantages with all approaches however, the Retailer Obligation concept is closer to the current contracting regime, provides retailers and generators more flexibility over duration of contract and can more readily accommodate policy and other government initiatives such as the Renewable Energy Strategy and retirement of T-Gen plant. It is however, a more managed or administered mechanism which is an advantage in the context of the NT.

3.2.1. Transitional arrangement for Capacity Adequacy

In the first instance, the existing contract arrangements will mean T-Gen meets much of Jacana's initial obligation. A balance will need to be struck between managing the impact of the transition on T-Gen's capacity, which will underpin its commercial viability, and creating opportunity for new entrants when ageing T-Gen plant is retired or exposed to the risk of displacement from new entrant competitors.

A pragmatic transitional arrangement is proposed to create a basis for entry of new renewable resources in 2019 before more complete implementation of the Capacity Mechanism can be put in place. The transitional arrangement will be based on simplifications of the Reliability Standard and be designed to integrate with analysis being undertaken of options for entry of renewable energy.

3.3. Capacity Out Of Balance

From time to time generators may suffer outages and may also not have the Capacity or performance available that they expected. Generators will also need to undertake planned outages. These situations may result in Capacity Out Of Balance.

In the NTEM, failure by a generator to provide Capacity for which they are accredited, and in accordance with the requirements to meet the Reliability Standard, will be deemed to be a Capacity Out Of Balance and charged at the Capacity Price (see section 4.7.2), multiplied by a Scaling Factor depending on the prevailing level of Reserve Capacity available.

If the Reserve Capacity available is high, the Scaling Factor will be zero meaning no financial impact. If the Reserve Capacity available is low the Scaling Factor will be greater than 1. The Scaling Factor for generators undertaking maintenance planned and approved well in advance will be zero but for unplanned outages at a time when low Reserve Capacity is available the Scaling Factor will be greater than 1.

The Capacity Out Of Balance arrangements will therefore create incentives to manage the timing of outages to avoid times when there is low Reserve Capacity available, and to plan and coordinate maintenance. These incentives will complement System Control's management of planned maintenance. It will also be important to avoid a situation where poor performing generation plant can become exempt from penalties by obtaining a long term planned outage approval.

3.3.1. Transitional arrangements

To avoid unnecessary commercial disruption within the industry, in the short term it will be necessary to recognise contractual arrangements that have been entered into by Retailers and Generators or at least to provide for a phased transition to a new regime.

Supplementary note: T-Gen has entered into a number of contracts which provide for it to supply any requirements not supplied by other generators, including when those other generators experience a breakdown, through a load following contract. In part this situation has been driven by the need for contracts that avoid the Out Of Balance arrangements in place in the I-NTEM which were not designed for long term operation or for multiple market participants. The load following nature of the contracts results in no Out Of Balance (for Capacity or Energy) but shifts all the risk to T-Gen as it is contractually committed to provide Capacity and Energy without limit.

This arrangement is a practical, short term arrangement but is unsustainable in the long-term in a disaggregated industry. One way to visualise the unsuitability of the arrangements in the long term is to consider the situation where multiple generators are offering multiple Retailers load-

following arrangements of this nature. Generators will not be able to discern which party to invoice.

The proposed Capacity Out Of Balance arrangements are designed to create a central clearing mechanism for Capacity Out Of Balance.

As a transitional arrangement, retailers will be obligated to demonstrate they have contracted for Capacity to cover their allocated share of total system requirements as a condition of participation, but no Capacity Out Of Balance charges or payments will be included in the initial transitional NTEM. The incentives to arrange maintenance and manage the timing of higher and lower availability and to recognise the Capacity contribution to cover for outages of plant will sit with the enforcement regime and contracts. This will result in a more structured and administered instrument to manage availability than the longer-term design.

3.4. Trading & Dispatch

Dispatch in the NTEM will be based on Security Constrained Economic Dispatch unit commitment and dispatch principles, where System Control determines both the unit commitment and dispatch level of generating units on the basis of requirements to maintain system security and minimise the overall cost of supply.¹⁰ After the event, settlement calculations will reconcile any variations between the level dispatched and contracted volume between generators and retailers (Out Of Balance volume). Contracted volume and price will not be considered by System Control in determining dispatch levels.

Supplementary note: Systems for dispatch can be one of the longer lead time components in implementing market design (the other being for settlement and metering). However, suitable arrangements can be introduced progressively using manual decision making by experienced System Control staff based on the same principles as automated systems. These principles will be documented in the Market Rules. When manual decision making is used the liability of System Control and commercial implications of participants needs to be carefully balanced.

The main steps System Control will follow in the dispatch process are as follows:

- Forecast demand in the system;
- Define operating constraints and Ancillary Service requirements for the day;
- Receive cost-based submissions (updated as needed for bona fide and verifiable changes in circumstances occurring within the Trading Day) from generation participants including availability, variable cost and start-up costs.

The information provided in the submissions will enable System Control to optimise unit commitment to meet Energy and Ancillary Service requirements (Ancillary Service requirements are often central to unit commitment decisions in the DKIS);

- Prepare short-term operating plans;
- Issue instructions to individual generation, Demand Side Response and storage facilities; and

¹⁰ Shifting the unit commitment decision to System Control is a significant change from the I-NTEM in the mechanism for day to day operation of the market. It is designed to reduce overhead costs within market participant businesses (avoids the need for trading rooms) and in System Control systems. It also recognises that increased amounts of intermittent resources will make the unit commitment decision more complex and reduce the accuracy of any pre-dispatch forecasts that participants would have needed to rely on if they were to make unit commitment decisions. Arrangements for the Balancing Price are also modified from I-NTEM as a result of this change.

- Prepare price forecasts and determine the Balancing Price post-event, based on the cost-based submissions.

3.5. Balancing Price

The Balancing price will be set after the event (ex post) for each 30 minute period at the highest marginal cost of operation of unconstrained generating units producing energy in the 30 minute period. This price will be used for settlement of Energy Out of Balance volumes.

Further details of the settlement process are described in section 4.7.5.

3.6. Ancillary Services

3.6.1. Background

Security of a power system is the result of the interaction between the technical characteristics of generators, customer loads, the network and deployment of Ancillary Services. The standard to which security must be maintained is set out in regulatory instruments; in the Northern Territory it is currently in the System Control Technical Code and Secure System Guidelines, and is planned to be incorporated in later versions of the NER (NT).

All connected equipment (generators and customer load) are required to meet technical conditions laid down at the time of connection and described in the Generator Performance (Access) Standard.

Ancillary Services are used by System Control to complement the technical characteristics of the plant and equipment connected to the system.

A major design consideration is how to strike the balance between obligatory technical characteristics required of individual connected plant (paid for by individual developers) and Ancillary Services (which are sourced from the most cost-effective providers across the system), and paid for by System Control, who then recover the cost incurred as an allocated charge to market participants.

Supplementary note: The balance between mandatory provision and system-wide Ancillary Services is affected by factors such as overhead cost for System Control to administer a system-wide regime, the potential for competition to allow multiple competing parties and technologies to offer services and for innovation to result in more efficient and lower cost services are typically considered in setting the boundary.

The long-term arrangements described in this paper presume that Ancillary Services (and implied payment to T-Gen for the provision of certain Network Support associated with operation of the Darwin to Katherine interconnection - see section 3.7.1) have been separated or unbundled from the T-Gen tariff and are to be paid for by separate mechanisms to suppliers who may or may not be T-Gen. A prerequisite to commence separate Ancillary Service arrangements is that corresponding adjustments to energy tariffs are also made. A transitional measure described below starts with the separation of T-Gen's Energy and Ancillary Services from its current bundled price.

A further presumption is that responsibility for technical characteristics of inertia and system strength will be assigned to network service providers in a similar manner and for similar reasons to that in the NEM through the NER as applied in the Territory.

System Control will be responsible for acquiring services to manage power system frequency and system restart (also known as Black System Services).

While the standards for system security, for connection, and the mechanisms for System Control to acquire Ancillary Services, are defined in regulatory instruments, the volume and detailed design of Ancillary Services is a responsibility of System Control based on its assessment of the performance of the power system.

These Ancillary Services will operate alongside Generator Performance (Access) Standards that will include a requirement for actual or equivalent governor response. While synchronous generation will exhibit this capability, providing their governors are enabled (not 'gagged'), asynchronous inverter-based technologies such as solar PV (and any associated batteries) will require suitably configured inverter controls and operation below maximum Capacity. See also Dispatch Support Services in section 3.7.3.

The cost for each Ancillary Service acquired by System Control will be allocated to generators and customers, as appropriate, according to the principle of 'causer pays'.

For Regulating Services, System Control's monthly costs will be apportioned between generation and demand based on variability during the month, calculated using data from within System Control's Energy Management System (EMS) system. Generators, when running on System Control's Automatic Generation Control (AGC) system and providing a frequency sensitive regulating response, will be excluded from the calculation for any times they are in that mode. A contribution factor for other generators will be developed based on the difference between records of actual output and the output expected by the AGC after allowance for scheduled ramping due to changes in demand but not generator availability.

Contingency Services are provided by facilities with the capability to rapidly respond in the event of a significant disturbance to power system frequency, for example, due to sudden disconnection (or trip) of a generator or block of load due to transmission interruption. Costs for Raise Contingency Service (that is where frequency has fallen) likely will be allocated to generators and Lower Contingency Services to customers, while standards within the network regulatory regime also often include incentives based on how well the effect of disturbances within the network are handled.

3.6.2. Transitional arrangements

Supplementary note: Full implementation of a competitive Ancillary Services regime will involve the resolution of technical, commercial and regulatory issues and arrangements and involve System Control, PWC as Market Operator and T-Gen, who currently operate under a single, full cost recovery, energy-based tariff.

Further, as a matter of practicality, T-Gen will be the default supplier of most Ancillary Services until further notice. However, the entry of storage associated with solar PV and the current role of EDL's plant at Pine Creek create unavoidable exceptions to T-Gen providing all services. T-Gen can, however, be the dominant supplier of Regulating Services pending opening up of these services to other players and technologies. It will be necessary to determine separate prices for different services that will progressively be provided by batteries associated with solar PV in order to meet their GPS requirements and, as a result, reduce the need for T-Gen to provide Contingency Services. In addition, it will be necessary to set a price to recognise the inherent service provided by any other thermal generators.

In respect of Ancillary Services provided by T-Gen it is proposed to adopt a feature of the Western Australian Wholesale Electricity Market (WEM) with appropriate adjustments for the DKIS. When the WEM opened, Verve (predecessor to Synergy's generation arm) was the sole provider of most Ancillary Services. Payments, known as the Margin Peak and Margin Off-Peak, were included in the design of the WEM to compensate Verve for providing these services and accounted for the cost of running, energy production foregone (priced at the market's Balancing Price) and inefficient operation. The arrangement continues today with allowance for other generators to provide Regulating Services (aka Load Following Ancillary Services, LFAS), if they can do so at lower cost. The result is similar to the situation in the DKIS in that T-Gen is to be the dominant provider but, as noted, some services will unavoidably be provided by other generators.

In respect of Ancillary Services provided by T-Gen it is proposed to adopt a feature of the West Australian Wholesale Electricity Market (WEM) with appropriate adjustments for the DKIS. For the NTEM, the key features of the WEM Margin Peak and Margin Off-Peak arrangement will be adapted to set a rate of payment to T-Gen for regulating, voltage control and the contingency services it provides during a transitional period.

In respect of Contingency Services provided by other parties, in particular batteries, as noted earlier, GPS requirements will obligate solar PV facilities to provide contingency FCAS as part of their connection agreement at no charge. This requirement will apply while the facility is generating - that is, during daylight hours.

Allocation of the cost of Ancillary Services

Supplementary note: Who pays, or how the costs incurred in providing Ancillary Services is distributed, is often a contentious issue. Costs are typically allocated to parties who are deemed to be the causers of the need for the services and can act to reduce the need. For this reason, mature market arrangements typically allocate Frequency Raise Contingency Services to generators and Frequency Lower Contingency Services to customers. Regulating Services are allocated to identifiable causers of the need for regulation, such as generators that have short term variable output that needs to be offset by regulating response and, where it can be measured, demand blocks. Residual frequency regulating costs are typically allocated to customers. Arrangements for system restart and voltage control vary. Costs for voltage control are borne by the Network Service Provider and are subject to regulatory oversight and recovered through network charges. Separate services specific to inertia are relatively new and allocation of cost varies.

As T-Gen will be the dominant provider of Ancillary Services, at least initially, it will be difficult to create competitive pressure on T-Gen to lower the cost of Ancillary Services. It will also add unnecessary complication and cost to pay T-Gen for the majority of Ancillary Services and then charge it to them. Further, it will be assumed that the GPS obligations on solar PV installations to provide a contingency capability and also smoothing of variability in output (for example due to changing cloud cover) will substantially mitigate the increase in regulating duty expected with increasing levels of solar (note: this obligation only applies to solar PV above the cut-off where the GPS applies and does not cover small behind-the-meter installations).

The NTEM arrangements will replace the current provision in I-NTEM (see A6.11(b) of the SCTC), whereby T-Gen is assumed to be the sole provider and generators make payments to T-Gen related to contracted demand. The practice of exempting EDL from the requirement to pay T-Gen when the 132kV line is out of service will no longer be needed.

All Ancillary Service costs will be recovered from customers on a per kWh of consumption basis. These charges will be managed by the Market Operator and charged to Retailers.

The intention to move to a broader ‘causer pays’ approach will be included in the Market Rules and can be achieved by including a requirement that the Ancillary Service arrangements be reviewed within a specified time including considering the introduction of ‘causer pays’ principles for cost recovery.

Once the NTEM arrangements are established and other technologies, especially in Demand Side Response, and possibly batteries, providing Regulating Services can participate in providing Ancillary Services it will be appropriate to review the arrangements described. This review should include consideration of a more targeted allocation of costs, including to generators. To support this review the impact of utility-scale solar and batteries should be recorded and published from the date of commissioning.

3.7. Other services

3.7.1. Network Support Services

Especially at the edge of a network, reliability of supply to localised parts of a network can be determined by a combination of generation, short-term Demand Side Response facilities and network facilities. Standards of reliability to these locations can be set either in a system-wide Reliability Standard or in local network reliability/performance standards. In the NTEM, the system-wide Reliability Standard will be the instrument that governs the overall level of generation (and, where appropriate, Demand Side Response) and local network reliability/performance standards will be set for specific connection points, local areas or electricity networks, as necessary.

A local network reliability/performance standard is appropriate for the Katherine area (and possibly other areas). Katherine is connected to the Darwin region via a single transmission line which will be out of service at times, for example, for maintenance or as the result of storm activity.

The Network Service Provider will be responsible for deciding whether the resultant reliability of supply to Katherine meets the standard and whether it is appropriate to:

- augment the transmission line or transmission equipment for voltage control (subject to economic justification within the regulatory framework);
- to arrange for generation near Katherine to operate when the line is out of service; or
- for customers to reduce demand under a contracted Demand Side Response.

The efficient cost of the Network Support Services will be recoverable by the Network Service Provider as regulated revenue.

Note 1: The introduction of a Network Support Service will shift much of the cost of operation of Katherine generating units from a system Ancillary Service to a Network Support Service. Under a Network Support Service arrangement, the Network Service Provider will be responsible for procuring the availability of the service, but dispatch remains a matter for System Control.

Note 2: Generators may choose to locate at Katherine or close by and their presence may reduce the need for Network Support Services in the area. Over time, development of solar PV generation sources in the south of the DKIS may enhance reliability of supply to the south and reduce the need for Network Support Service there but increase the potential that generation around Darwin will be withdrawn from service and increase the potential need for Network Support Services around Darwin.

3.7.2. Spinning Reserve and Inertia

System Control has determined that for current conditions the minimum level of physical inertia requires that two 'frame' units should be synchronised at all times¹¹. In the future, the technical implementation of the Frequency Control Ancillary Services will allow the current requirement for two frame units to be restated as the required quantities of inertia and contingency FCAS irrespective of unit type. With a significant number of batteries, contingency FCAS quantities provided through the fast frequency raise capability may see the requirement for two frame units to be relaxed. System Control also requires a minimum level of contingency reserve in order to ensure frequency recovers after a contingency event that disturbs the power system frequency.

A minimum amount of physical inertia is needed because, although it can respond very rapidly, synthetic inertia¹² provided by batteries takes time to respond after a disturbance whereas physical inertia is present simply as a result of being connected and has zero response time. As a result, a minimum amount of physical inertia is currently required to control the impact of a large disturbance.

Supplementary note: Spinning Reserve and inertia are currently provided by T-Gen's generation plant and paid for within the bundled tariff charged to Retailers. In the future, ensuring there is sufficient inertia capability installed in the system will be the responsibility of the Network Service Provider, and requirements specified in the proposed GPS (under consultation at the time of writing) would require new generators provide a level of inertia or FFR or combination of both. This arrangement is consistent with recent changes introduced into the NEM and incorporated in the NER, with some important differences. The GPS proposed for the NT recognises that to some extent there is an opportunity to trade off fast-acting frequency response (synthetic inertia) that can be provided by batteries and physical inertia, however there is a minimum amount of physical inertia that must be provided by the rotating mass of synchronous generators or synchronous condensers or other non-traditional devices such as flywheels.

In summary:

- The level of Contingency Reserve required reduces as the level of inertia available increases; and
- The level of physical inertia required also reduces as the level of synthetic inertia/Fast Frequency Response (FFR) rises but only to the point where the requirement for a minimum level of physical inertia is met.

Supplementary note: A generator with physical inertia will assist the management of contingencies simply and unavoidably by being synchronised. The arrangements in the NEM recognise that as asynchronous generation enters the market the level of physical inertia will fall to potentially dangerous levels and have assigned responsibility for ensuring a minimum level of system strength and inertia to Network Service Providers. In the longer term, these arrangements are proposed to be adopted in the Territory.

¹¹ Frame units have more inertia than the lighter aero-derivative units of the (currently) all gas generation portfolio in the DKIS.

¹² Synthetic Inertia is a relatively new term within the industry. In this paper it is used in the sense that it has a similar effect on the management of frequency disturbances as physical inertia that is inherent in synchronous generating plant. Both physical and synthetic inertia impact the rate of change of power system frequency (RoCoF) that is a critical measure of the ability of a power system to withstand disturbances. Other slightly slower acting reserves, generally categorised as contingency frequency ancillary services, act to restore frequency whereas as physical and synthetic inertia slow down the change in frequency to allow time for contingency services to act. Although the jargon is still evolving synthetic inertia is also very closely related to another term, Fast Frequency Response (FFR).

Additionally, the proposed GPS (under consultation at the time of writing) would require new generator users provide a level of inertia and FFR, or a combination of both.

Under the NEM rules new connections will be required to redress any negative impacts (harm) to system strength that will result from their connection. The NTEM requirement however is subtly different in that it is a uniform minimum obligation regardless of impact or location, but less costly to implement. In the longer term, the NER arrangement will be considered for adoption in the Territory.

It is notable that the Australian Energy Market Commission (AEMC) considered a proposal for an inertia market for Capacity in excess of requirements for connection, but did not accept the proposal noting more work is needed.

Note: AGL Rule Change proposal ERC 0208 and SA Minister for Energy proposal ERC 0211. The proposal by the SA Minister was partially adopted by putting the obligation on TNSPs to ensure their connection agreements included a requirement to do no harm but did not adopt the proposal that the proponent would be required to provide support as part of the connection agreement.

It is understood that in the short term it is likely that System Control will still require two frame units to be online in order to ensure that the minimum physical inertia is provided and also that network flow (north into Channel Island) will not reach a point where there are economic benefits of the nature referred to by AEMC for the NEM. However, where new connecting parties choose to meet their obligatory connection obligations by providing FFR which brings both synthetic inertia and Contingency Reserve there will be some saving in gas use due to reduced requirement for gas units to provide Contingency Reserve (but as noted still with a requirement for two frame units to be synchronised).

Two principles underpin the GPS requirements:

- Each connecting facility must 'do no harm' to the security of operation of the power system in relation to system strength; and
- The synthetic inertia/FFR obligation is designed to be competitively neutral relative to generators with physical inertia.

The NTEM assumes the GPS will require new entrants to have a minimum level of a combination of FFR and inertia to satisfy the 'do no harm' principle and potentially exceed it.

As the connection requirements are obligatory, there will be no market payment for provision of the capability as costs are expected to be embedded in Energy and Capacity charges to Retailers or other charges to Networks, as appropriate.

When a facility, in particular a synchronous generator, is called on to provide inertia at a time when it would not have been connected to the system and, as a result, generates electricity, it will sell energy as Out Of Balance volume at the Balancing Price. The service may be called upon at any time, including when the attendant generation facility is not producing.

The Balancing Price may be less than the generator's costs and, if this is the case, the generator concerned will be kept whole by a payment that will be funded at an annual rate assessed through a forward-looking simulation based on the concepts underpinning the WA Margin Peak Margin Off Peak algorithm.

The market settlement process will track the volume per Trading Interval as an indicator of the accuracy of the simulation for future determination of the rate.

If there is no impact on energy production (which may often be the case with batteries called on to provide FFR) there will be no market payment as it will be delivering a service that is mandated under the GPS.

Future arrangements may be developed to distinguish between provision of service that enhances system-wide economic benefit and occasions when associated generation facilities are not operating.

A second possible transitional step, to be considered in the medium term but before there are sufficient players to run competitive tenders, is the value of any services provided by batteries over and above the requirements of GPS can be recognised in an administratively determined price. For example the price might balance (i) the benefit of an incentive for the installation of additional batteries in order to further reduce gas use and (ii) the cost of Contingency Services provided by T-Gen at: the minimum of 125% of the opportunity cost to the owner of the battery and 90% of the cost of providing the service from T-Gen gas portfolio to discourage inefficient construction or use of batteries for this role. This possible second transitional step is noted here only to illustrate the potential direction of development.

3.7.3. Dispatch Support Services

A new form of service is to be introduced to enhance economic efficiency of dispatch where security and reliability are not under threat but constraints on operation of generation might need to be applied forcing higher cost generation to be dispatched. The new service will incentivise parties to act in ways that enable the constraint to be relieved and allow a lower cost of system-wide generation. This type of service is to be known as Dispatch Support Services.

The first Dispatch Support Service in the NTEM is designed to reduce or avoid the need to curtail output of solar PV plant installed along the single Darwin to Katherine 132kV transmission line at times of high solar generation which would be replaced with gas if the solar generation is curtailed. This will be achieved by creating an incentive for developers to install the batteries that they are required to provide under the GPS in the Darwin area, instead of co-locating them with the solar plant.

The settlement calculation will also recognise the contribution to Dispatch Support from stand-alone batteries, i.e. batteries not associated with solar generation.

3.8. Metering/Settlement/Payment/Prudential management

NTEM settlements will provide for net settlement of contract and balancing transactions in that the generators and retailers must provide details of contract volumes (not prices) to the Market Operator and market settlement will net out contract volumes and settle only uncontracted components. Draft statements will be issued for review by the parties, followed by a final statement.

The Market Operator will not be required to bear any financial risk in carrying out its role in facilitating market settlements. As such, participants may be required to provide prudential arrangements to ensure the Market Operator's position is protected.

3.9. Reporting/ Information/ Oversight

Successful operation of any market relies on participants making informed decisions in response to price incentives and, where necessary, working within specified processes. Central market entities must also perform their roles in line with Market Rules.

Market participants can only respond to price if there is sufficient and timely information available and the incentives created by the prices are well designed. Reports and information about the operation of the market and relevant forecasts of future conditions are therefore essential.

A list of market information to be released will be developed. Market oversight may also require access to additional data that may not be public - for example around costs of generation. Details will be developed progressively.

4. Functional Specification - Detailed Design

This section describes:

- Individual processes of the NTEM in more detail;
- Data and information flows between organisations; and
- Processes for the Capacity Adequacy arrangements, Trading and Dispatch, and for Metering and Settlement.

This section is intended to inform the development of detailed rules, processes and other arrangements. The proposed long-term arrangements and transitional arrangements for the Reliability Mechanism, Ancillary Services and related aspects of settlement (in particular for Energy Out Of Balance) are described below.

4.1. Capacity Adequacy

4.1.1. System-wide Reliability Standard

For the NTEM, the Reliability Standard form is proposed to be expressed as the number of hours at risk or Loss of Load Hours (LoLH) e.g. this could translate to 3 hours of supply per year at risk. The form and level of the Reliability Standard is subject to a separate consultation process by DTF.

The form and level for the NTEM Reliability Standard will be reviewed every four years by an independent party.

The system Reliability Standard will assume all network elements are in service and a local network reliability/performance standard is created for the Katherine area (and potentially others) which is at the end of the single 132kV line between Darwin (Channel Island) and Katherine.

To the extent needed, additional generating Capacity to provide Spinning Reserve (Raise Contingency Service) would add to the requirement for Capacity needed to meet the Reliability Standard.

4.1.2. Translation of Reliability Standard to physical Capacity and Energy capability.

A key step in the management of reliability of supply is for the Reliability Manager to determine the amount of Capacity that is needed to meet the minimum level required by the Reliability Standard. This will involve detailed economic modelling of the power system.

This modelling is to be carried out by the Reliability Manager at least annually and will use well-established industry techniques.

Supplementary note: It is likely the Reliability Manager will wish to outsource this work. However, the Reliability Manager could choose to establish in-house capability (expertise and software tools) as it will be valuable for other studies such as advice to government about retirement of assets or assessments of proposals for change to the market arrangements in the future.

The analysis will be similar to that undertaken by AEMO and the NEM Reliability Panel for assessment of NEM reliability settings and also by the Utilities Commission for aspects of the Power System Review. There are a number of providers of software for this task.

Key inputs for capacity adequacy include:

- Forecast system-wide demand;
- Forecast available Capacity of existing and planned generating units;

- Fuel cost, heat-rate, fixed and variable operating costs for existing and planned generating units;
- Potential new entrant generating plant including capital cost, fuel cost, heat-rate, fixed and variable operating costs;
- Transmission network details including transfer limits and losses; and
- Investment and operating policies - e.g. Reliability Standard, Spinning Reserve/Ancillary Service constraints, emissions limits, renewable energy targets.

4.1.3. Accredited Capacity

In general, different technologies and facilities in different locations make different contributions to ensuring reliability of supply. For example, a solar PV installation cannot contribute to reliability after the sun sets and its contribution is reduced due to cloud cover but, coupled with battery storage or other 'firming' arrangements, it will contribute more, depending on the size of the battery. On the other hand, a gas fired generating unit can contribute throughout the day, but the contribution is dependent on fuel supply and risk of breakdown.

Any analysis of reliability must take these plant specific characteristics into account. Where different businesses own generating facilities and are paid on the basis of performance it is also important to be clear about what each unit is being paid for. Different commercial arrangements do this in different ways ranging from claw back provisions of PPAs through to Capacity Price adjustments in capacity markets such as the NTEM and variable market prices within a day in energy only markets such as the NEM.

In the NTEM the Accredited Capacity will be the reference point for assessing performance and for calculating the aggregate of all units.

The Accredited Capacity for each plant will be a critical factor in the assessment of the business case of the plant for developers, and will also be important to purchasers (i.e. the Reliability Manager or a Retailer) as the lower the plant's contribution to system reliability, the lower the Capacity value the plant will have.

The Market Rules will include the principles by which accreditation is to be assessed, and a requirement for the Reliability Manager to establish details of the analysis and undertake the calculations. The conceptual principle is that the total of accredited capacity of individual generation plant required to meet the Reliability Standard, is the generation capacity that can be relied on with a high probability at a time of minimum reserve, after accounting for forced and planned outages, and fuel limitations (including, in the case of solar PV plant, the likely solar radiation).

Consideration will be given to issues around how to deal with surplus capacity, i.e. whether the amount of accredited capacity will be limited to just the level of capacity required to meet the Reliability Standard, or whether surplus capacity above the level needed to meet the Reliability Standard will be accredited. As noted in Section 4.1.1, consultation on the form and level of a Reliability Standard for the Territory is currently being undertaken by DTF.

In the first instance, it is expected DTF with technical assistance will act as the Reliability Manager and prepare the first analysis.

4.1.4. Allocation of Capacity Obligation

In the NTEM, retailers are to be accountable for providing their share of the total Capacity Obligation. Retailers will have the choice to contract directly with owners of Accredited Capacity or to rely on the Reliability Manager to purchase Capacity at the Capacity Price and then charge the retailer for their share of the Capacity Obligation at the Capacity Price. In principle, there will

be no difference in cost to retailers unless they are able to negotiate better pricing than the Capacity Price offered by the Reliability Manager.

The allocated portion of the total Capacity Obligation that each retailer will be accountable for will depend on the retailer's demand load. Methodologies to establish the allocation of Accredited Capacity Obligation will be required. In the first instance, this work will be undertaken by DTF and a transitional arrangement is described below.¹³

4.1.5. Transitional Arrangements

Currently there is a surplus of Capacity in the DKIS on a nameplate basis, although some of this Capacity has reduced capability or high outage rates. The long-term arrangements described above will take some time to establish and in the short-term government is expected to manage the level of T-Gen Capacity that remains in service.

The key features of the transitional arrangements are as follows:

- In parallel with work to establish a robust long-term customer-focused Reliability Standard, a relatively simple n-3 transitional generator-focused¹⁴ Reliability Standard will be introduced as advised by System Control.
- This will deliver a required system-wide generating Capacity =
 - + The expected 10 point of exceedance (POE) peak demand for the year sourced from AEMO forecasts for the Utilities Commission
 - + FCAS requirements from generating Capacity as determined by System Control (*note: batteries may provide increasing amounts of FCAS reducing System Control's requirement for FCAS from generators*)
 - + the expected Capacity of the 3 largest generating units
- The Reliability Manager will publish a forecast of the required system-wide Capacity for the next 3 years to inform contracting activity between participants
- The Reliability Manager will allocate accountability to each retailer for their share of the system-wide Capacity Obligation to meet the Reliability Standard. Each retailer's share will be based on a forecast of the average of the highest 10 half hour demands for each retailer on peak system day (10 POE peak i.e. the forecast of demand expected to be exceeded only 1 in 10 years) for the next year.
- Retailers will be required to hold contracts with generators for a minimum of their allocated share. In the transitional arrangement there will be no option for Retailers to contract for less than this share and rely on the Reliability Manager to undertake contracting on their behalf as proposed in the longer term design.
- This obligation will require retailers to provide a forecast of expected demands, however, the post-event reconciliation against actual demands will provide a means to recognise customer switching and forecasting errors as well as any attempts to game the original forecast and under contract.

13 Typical allocations in other markets are based on a measure of peak demand (e.g. top 20 half hour readings) of each retailer, or retailer demand at time of minimum reserve which is intended to account for increasing levels of solar generation which may mean the lowest reserve occurs after sunset, although storage Capacity will influence this timing.

14 A generator-focused Reliability Standard bases the reliability of supply on the level of generation Capacity available rather than on impact on customers. The longer-term standard is expected to be customer-focused or related to customer experience of interruptions, but is more sophisticated than a generator-focused Reliability Standard and requires time to establish. Note: common network standards such as SAIDI are customer-focused Reliability Standards and, accordingly, there is benefit in aligning the approach to network and generation standards.

- To meet their Capacity Obligation, Retailers may include (on the advice of System Control):
 - For customers on the Darwin load side of Channel Island, 5 percent of nameplate rating of solar generation Capacity (data analysis is required to inform this value) between 0900 and 1900 hours and 0 percent outside these hours, unless supported by longer-term storage; and
 - For customers on the Katherine side of Channel Island 5 percent of nameplate of solar generation Capacity (data analysis is required to inform this value) between 0900 and 1900 hours and 0 percent outside these hours, unless supported by longer-term storage.
- After the end of each financial year, a reconciliation between contracts held based on forecast demand and actual demand will be undertaken. Retailers holding excess Capacity must make their surplus Capacity available for purchase by Retailers in deficit. Subsequently, generators (including T-Gen) with uncontracted Capacity may then also offer this amount for sale.

Supplementary note: This reconciliation provision is about reallocation of existing Capacity and therefore reserve which, by definition, was deemed adequate at the start of the year. If demand is generally below expectations, then all parties may be in surplus and no trades are likely or needed.

Retailers in deficit must purchase from surplus Capacity offered. Market participants may choose to trade between themselves prior to the end of the financial year to redress any deficit and in practice it is likely the peak demand period will occur in the wet season leaving a number of months for bilateral adjustments.

- A transitional reference Capacity Price will be set at the industry estimate of the capital cost of replacement OCGT in the first instance and this will provide certainty of pricing. The principles for determining the reference technology and methodology to calculate the Capacity Price will be included in the Market Rules, including a requirement for regular re-evaluation of the price.

4.2. Unit Commitment and Dispatch

4.2.1. Introduction

Dispatch in the NTEM will be based on Security Constrained Economic Dispatch unit commitment principles whereby System Control determines both the unit commitment and dispatch level of generating units on the basis of requirements to maintain system security and minimise the overall cost of supply. It will differ from the I-NTEM arrangement only in the approach taken to the selection of which units are brought online.

4.2.2. Scheduling Logistics

In order to make decisions about which generating units should be called online, System Control will require information, including:

- For units not online at the time, details of time to start-up and the costs that will be incurred in starting, and any requirements for minimum run time;
- Availability (Capacity) over the horizon over which decisions will be made;
- Minimum loading levels; and
- Details about the cost to operate (dispatch) each unit at different loading levels.

Supplementary note: These arrangements are based on the following assumptions:

- For the duration of the period of the transitional arrangements, to manage reliability, the contribution of solar generation to the Capacity Obligation will be small because peak requirements will coincide with heavy cloud cover, reducing the contribution to reliability that can be made from solar both south of Channel Island and in the Darwin area north of Channel Island; and
- A local network reliability/performance standard is in place for Katherine and will result in contracts for the existing generating Capacity at Katherine remaining in service. As a result, assessment of the Capacity Obligation can be undertaken on a system-wide (i.e. DKIS wide) basis and need not necessarily consider locational factors, however, account will need to be taken of location to the extent credible contingencies may result in the Reliability Standard not being met.

System Control's decisions about unit commitment will be made over the scheduling horizon which will run from the current time to 0400 two days later. This arrangement will create a horizon that varies between 25 hours up to 47 hours in the future. The longer horizon is designed to allow System Control to make unit commitment decisions for a sufficiently long period to adequately assess the trade-off between start-up and operating costs.

System Control will combine this information with its own estimates of aggregate customer demand across the horizon and its assessment of the requirements for Ancillary Services and operating constraints needed to ensure secure and efficient operation of the power system.

System Control can use the information received to reassess the requirement for units to be online (or to go offline) at any point in the day, for example if weather conditions change or a generator suffers a breakdown and must be replaced.

Example: In a situation where additional production is needed as overall system demand approaches a peak for the day that is forecast to last for 3 hours, System Control has two viable options - call on sprint water injection to boost the output of one or more units already online or bring an additional unit on for the 3 hour period and incur the start-up cost of the additional unit (noting that the additional unit may have a minimum loading which will mean the output of other units online will need to be reduced and operate less efficiently). All else being equal, sprint should be used if the increased cost of less efficient production at higher output with sprint in service is less than the cost of the start-up cost of an additional unit, the net change in the cost of operating an additional unit and saving of gas on units operated at (less efficient) reduced output.

The Balancing Price will reflect the choice made. If the sprint option is adopted the variable cost of sprint will likely be the highest cost source of generation for the period it is used. On the other hand if an additional unit is started the Balancing Price will be formed from the variable cost of operating the additional unit plus its start-up cost divided by the energy produced during the 3 hours of operation, correctly conveying the cost of the peak in demand.

The unit commitment and dispatch process will involve a more dynamic assessment of future conditions than a single, simple merit order prepared in advance, in particular to determine whether sprint (water injection) can be used to avoid the short term start-up/shutdown cycle of units. In the short term, System Control is to develop procedures. These procedures will need to be made as procedures under the SCTC and their use logged to provide transparency and consistency. It is also likely that over time System Control will develop software support for its unit commitment decisions.

Second by second physical dispatch will continue to be based on heat rate curves in System Control's AGC system which, all else being equal, will dispatch units with equal cost pro-rata to

available Capacity. Minimum levels of synchronous plant may need to be retained online at these times.

4.2.3. Commitment and Dispatch Submissions

Generators and schedulable load blocks (if any) will be required to submit details of:

- Available Capacity
- Variable operating costs (exclusive of start-up costs) at different loading levels
- Start-up costs
- Time for start-up
- Run time limitations (if any)

4.2.4. Derivation of Security Constraints

The Network Service Provider will provide details of the capability of network assets to System Control.

Based on that advice System Control will determine network operating limits or constraints on the dispatch of generators needed to ensure secure operation of the power system.

System Control also determines the level of Ancillary Services (Spinning Reserve) it will require to ensure the power system operates securely, in particular so it can maintain stable operation following a credible contingency event such as the sudden breakdown and disconnection of generation or transmission. Technical standards define the maximum size of a credible event that System Control is expected to arrange Ancillary Services against, as provision of Ancillary Services adds cost.

Table 2 summarises the Central scheduling approach.

Table 2: Components of Central Scheduling

Component	Description
Dispatch (scheduling) horizon	Minimum one day dispatch horizon.
Day ahead scheduling	System Control forecast day ahead scheduling for the Trading Day, including a runtime estimate which is not known but is informed by Generators as to what their start-up cost and operating costs are.
Basis of dispatch	Cost-based.
Real-time dispatch	System Control uses Generator start-up and operating costs to decide which units to commit. System Control manages Ancillary Services/Spinning Reserve due to its high influence on dispatch.
Data from Generators	Generators submit, availability, start-up cost data and operating costs to System Control. And provide updates if necessary. System Control inputs data to algorithm to decide commitment and Security Constrained Economic Dispatch order at each 30 minute Trading Interval.

Component	Description
Resubmissions	Only required from Generators where there is a material and bona fide change in availability.

4.3. Ancillary Services

The background and conceptual design of Ancillary Services was presented in sections 3.6.1 and 3.6.2. This section focuses on the detailed design.

4.3.1. Ancillary Services Procurement

System Control is responsible for acquiring and dispatching as much Ancillary Service as is required to meet the standard for system security prescribed in the SCTC. For events that are bigger than the prescribed standard for a credible contingency, a controlled level of involuntary interruption of customer load may be required. This is technically unavoidable and is standard international practice.

The NTEM payments for Ancillary Services to manage power system frequency will be designed to leave providers in a position where they are commercially indifferent as to whether they provide energy or Ancillary Services.¹⁵ Section 4.7.6 discusses the interaction between Out Of Balance and Ancillary Service volumes.

Procurement of Ancillary Services requires System Control to assess how much of each type of service may be needed in order to ensure there will be sufficient available for dispatch at any time and under plausible conditions. (System Control will retain the authority to recruit from non-contracted services in the event there is a shortfall).

System Control will issue tenders for the different services it defines.

Regulating Services. Contracts for Regulating Services could provide for payment for:

- Availability - This payment is intended to cover the costs incurred in maintaining the capability to receive and respond to electronic control signals from System Control's AGC system. Tenders will be sought from all potential providers including from controllable demand such as both large Commercial & Industrial customers and distributed air-conditioning facilities and emerging levels of storage.
- Dispatch Efficiency - The traditional source of supply of regulation in the DKIS is thermal generation, often operating at a level below maximum efficiency. The Dispatch Efficiency payment is designed to cover the increased cost of fuel. Energy contract or Balancing Price payments are expected to pay for the energy produced and hence the loss of efficiency and loss of opportunity to generate would recompense Ancillary Service providers. Generators constrained-on to provide Ancillary Services which have costs in excess of the Balancing Price will receive payment calculated across each day.

Initially, the costs of operating at lower efficiency will be recompensed by a factor that will be assessed each month from System Control's records, comparing actual output and potential output. This will be an approximation that in future could, in principle, be replaced with a more detailed calculation each Trading Interval.

¹⁵ In price based markets such as the NEM where this principle also applies, the real-time price for Ancillary Services can rise to very high levels reflecting loss of revenue from energy markets. NTEM Ancillary Service pricing will be based on operating cost and thus will not rise to high levels. Further, NTEM Ancillary Service pricing will be calculated for each Trading Day rather than each Trading Interval.

The revised Ancillary Services contracting arrangements will allow for frequency control services to be sourced from a wider range of technologies than currently available and aim to lower the total cost.

Contingency Services. These services are only called upon in the event of a significant disturbance to power system frequency and can readily be provided by generation, Demand Side Response and storage resources. Costs can vary markedly depending on technology and include the cost of facilities to detect falls in frequency and accommodate the impact of rapid change in output or consumption.

Payments for these services will be made as follows:

- Availability - This payment is designed to cover the costs of facilities to detect changes in frequency or receive control signals from System Control that are over and above those required by technical standards for connection. It applies regardless of whether the service is enabled.
- Enablement - This payment is designed to cover any opportunity cost of being enabled. It will include payment for being constrained on or down to provide headroom;
- Dispatch - This payment would cover costs not otherwise recovered from availability, enablement and balancing. Demand Side Response providers may seek a payment per event, for example, but generators may receive an Energy Out Of Balance payment for additional energy produced and not require additional payment.

Note: in the event Frequency Standards are set for occasions where part of the DKIS is islanded (e.g. during storm activity leading to interruption of the transmission line to Katherine), separate amounts of Ancillary Services would need to be recruited to manage each identified situation.

System Restart. Contracts will be relevant only to facilities able to assist restart of generation in the event of widespread shutdown of generators in the power system which at the time of writing is understood to be limited to synchronous generation plant.¹⁶

4.3.2. Transitional Arrangements

In the long-term design, Ancillary Services will be acquired under contract. During the transitional period, providers will be paid under static payment arrangements (as opposed to dynamic payments such as in the NEM where the price for the service is set for each Trading Interval)¹⁷.

4.4. Network Support Services

Network Support Services will replace the use of system-wide Ancillary Services in situations where generation (or in the future Demand Side Response or storage facilities) are dispatched for the benefit of the network or local part of the network.

In the NTEM local network reliability/performance standards will be set where necessary, including for Katherine, and responsibility for ensuring network reliability/performance standards are met will become a responsibility of the Network Service Provider. In respect to Katherine, the Network Service Provider may (in principle) meet this responsibility by augmenting the network

¹⁶ See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power-system-requirements.pdf

¹⁷ Subject to a cost benefit assessment, dynamic payments could be introduced in the future.

to Katherine, or establishing voltage control facilities in the Katherine area, or contract with local generation or Demand Side Response facilities.¹⁸

Dispatch of contracted Network Support Services will be undertaken by System Control. The Network Service Provider's costs for Network Support Services is expected to be fully recoverable within the network tariff as the requirement to meet the network standards will be a regulatory obligation.

Facilities contracted for Network Support Services may also be dispatched for other reasons, including to meet energy requirements (for example, if system-wide reserves are low), therefore it will be necessary to settle dispatch of contracted facilities according to the reason for dispatch. This will require careful logging of the reason(s) for dispatch by System Control and calculations within the settlement process to allocate payments and costs to the appropriate parties.

4.5. Dispatch Support Services

A new form of Ancillary Service is to be introduced to enhance economic efficiency of dispatch, where security and reliability are not under threat but dispatch limits would need to be applied, reducing efficiency - to be known as a Dispatch Support Service.

Supplementary note: As the amount of solar PV grows, System Control anticipates that solar production will need to be curtailed because transfer into the Darwin region will grow to the point where it exceeds the level that can be accommodated within the standards for system security in the event of interruption of the single 132kV line. At present, System Control considers that the ability to transfer power into the Darwin area is increased by the presence of batteries connected in the Darwin area thereby reducing the risk of the need to curtail the output of generation connecting south of Channel Island. This will mean higher levels of low-cost solar production can be maintained and output of gas fired generation reduced, thereby reducing overall system cost.

A Dispatch Support Service will be created to reward the owner or contracted beneficiary of batteries installed in the Darwin area in proportion to the economic saving due to the increased Capacity in each Trading Interval.

System Control will monitor the Capacity of the batteries in the Darwin area and increase the transfer limit accordingly and allow dispatch of solar generation up to the (higher) limit. If necessary, System Control will curtail generation to limit transfer into the Darwin area to within the higher limit without regard to the ownership of batteries.

Post-event settlement calculations will identify the respective beneficiaries (purchasers) and sources (sellers) of the Dispatch Support at a price *related to* the prevailing marginal cost of production in the market or Balancing Price. Further details are to be developed.

4.6. Transitional arrangements for Ancillary Services, Network Support Services and Dispatch Support Services

4.6.1. Ancillary Services and Network Support Services

Section 3.6.2 presented the conceptual design for a transitional Ancillary Service regime that is intended to be compatible with the longer term design but also recognises the need for a pragmatic short term arrangement.

The GPS will obligate facilities to have capabilities for, amongst other matters, a minimum combination of Fast Frequency Response (which also brings synthetic inertia characteristics) and

¹⁸ Similar arrangements apply in the NEM, for example for supply to Port Lincoln in South Australia where ElectraNet has contracted with a generator located there.

physical inertia. In the short term at least, when these facilities are called on by the System Controller, any impact on energy production will be compensated for, in order to keep the provider whole.

Initially, payments to keep parties whole in the energy market will be through the Market Operator at an annual rate. In the long-term, payments relating to frequency control will be part of contract (or other) arrangements organised by the System Operator as part of the competitive procurement of Ancillary Services. Any payments related to operation as a result of requirements under the GPS will be made by the Network Service Provider, but this is impractical until regulatory arrangements under the NER are in place to allow the Network Service Provider to recover these costs.

The transitional payments will be determined as follows, utilising a similar concept of the WA Margin Peak/Margin Off Peak methodology¹⁹:

- Regulating Services provided by T-Gen: at cost and as determined by a calculation adapted from the WA Margin Peak/Margin Off Peak methodology.
- Contingency Services supplied by T-Gen's thermal plant: the impact on dispatch of energy will be at cost and determined by a calculation adapted from the WA Margin Peak/Margin Off Peak methodology.
- In the event Contingency and Regulating Services (if required) supplied by thermal plant (i.e. not from batteries operating under GPS obligations) other than those owned by T-Gen (e.g. by EDL plant when the 132kV line is out of service) where there may be similar operating efficiency losses: at cost and as determined by a calculation adapted from the WA Margin Peak/Margin Off Peak.
- Voltage Control Services provided by T-Gen: at cost and as determined by a calculation adapted from the WA Margin Peak/Margin Off Peak methodology
- Black Start Services: at cost. Provided by T-Gen in keeping with T-Gen being the default provider of Ancillary Services (where practicable).

Voltage Control Services, for example for the Katherine area, that are provided by T-Gen will be provided at cost with a separate accounting of the cost in preparation for transfer of responsibility to networks.

Only operational impact on energy production is to be compensated for.

Separate rates and accounts are to be kept for:

- Regulating Services;
- Contingency Raise;
- Contingency Lower;
- Voltage Control; and
- Black Start.

Accounts for T-Gen will need to be kept for each category while T-Gen is the default provider. Contingency services need to be recorded for other participants but subdivided into periods when the 132kV line to Katherine is in service and when it is not.

¹⁹ For the avoidance of doubt, this need not be the same calculation as used in WA but will be conceptually similar and suitable for the NT.

4.6.2. Cost allocation

Section 3.6.2 noted that, while T-Gen is the dominant provider of Ancillary Services, NTEM is to recover all costs of each Ancillary Service from the customer via Retailers on a per kWh basis. The Market Operator will administer the settlement based on the pre-determined rates to be paid to the different suppliers.

As noted in Section 2.3.2, there are a number of parties in the process of negotiating short-term (up to 12 month term) contracts as well as existing contracts for electricity supply currently in place. In order to mitigate the commercial risk for industry players and any associated impact on consumers, consideration will be given to manage the impact of the transition to the NTEM framework for existing contracts.

In the case of T-Gen, the rate for contingency services will vary with the entry of solar PV/battery facilities which will result in a drop in the volume of services provided by T-Gen. The revised rate will necessitate a recalculation. In the long-term, payment would be expected to be on a \$/MW basis rather than \$/MWh basis and recalculation should not be necessary.

Each Retailer will be charged for Ancillary Services and make payment to the Market Operator. *(This will remove the current arrangement where EDL makes payments to T-Gen for the demand of its customers and is exempted from payment when the 132kV line to Katherine is out of service.)*

4.6.3. Dispatch Support Services - Transitional Arrangements

Dispatch Support Services will only be implemented when constraints on the output of solar PV installed south of Channel Island are expected. The Dispatch Support Service is implemented in settlement, and dispatch is a straightforward pro-rata scaling back of affected solar (assuming equal costs). Settlement calculations can be adjusted in parallel with the installation of any additional generation south of Channel Island.

4.7. Capacity and Energy Pricing

4.7.1. Introduction

Section 3 presented the conceptual role of Capacity and Energy Pricing. In summary, these prices are important features of arrangements for disaggregated and competitive electricity sectors where efficient, separate prices are set for different components of the sector in place of a single averaged total cost of, for example, a utility. Separate pricing enhances incentives for efficient responses from the parties who are able to manage the costs of each component. It also creates transparency and facilitates accountability.

In the NTEM, there will be three primary types of pricing: for Capacity, Energy and Ancillary Services. Further prices will be calculated for networks and for market fees outside of the wholesale trading NTEM arrangements.²⁰ This section provides the specification for three NTEM wholesale trading prices.

4.7.2. Capacity Price - Long-term design

Objective: A Capacity Price will be set for each year. A Capacity Price is part of a regime that creates incentives to ensure the overall level of investment in generation is adequate and available for service when needed. The Capacity Price will be:

²⁰ Small customers typically do not wish to deal with multiple prices and services and a key role of Retailers is to bundle each of the prices into a tariff for them. However, the availability of information about the price for separate services allows large customers, wholesale participants and authorities to monitor the separate costs and also allows targeted allocation of costs to different stakeholders to signal when and how costs can be mitigated.

- The price the Reliability Manager will pay for any Capacity it must acquire (i.e. where retailers fail to contract to meet their Capacity Obligations);
- Published as a benchmark price to inform negotiations between generators and retailers;
- An input to Capacity Out Of Balance settlement; and
- An incentive for timing of maintenance activities.

The level of Capacity required and the impact of transitional contracts will determine the level of Capacity present in the system. The Capacity Price will, therefore, not be a prime driver of investment in the near term.

In the long-term, the Capacity Price will be derived from market studies of forecast demand compared to the forecast availability of generating Capacity. This will be done by examining the change in cost to deliver the same level of reliability under the Reliability Standard if forecast demand was 1 MW different to the prevailing forecast - i.e. what is the extra (or lesser) cost likely to be if demand was marginally more (or less). In the analysis, consideration will need to be given to the impact of the diurnal change in output from solar plant as the lowest reserve may occur after dark. Other key considerations include whether the Capacity Price will be responsive to the supply demand balance and once declared for a capacity year, will there be scope to adjust the capacity price or volume. The need for such adjustments have arisen in a number of capacity markets including in the WA WEM and will need to be taken into account in the NTEM.

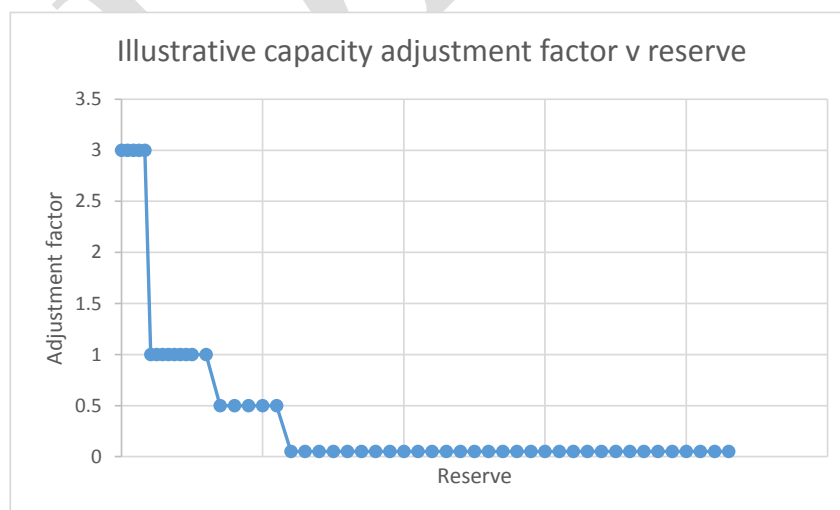
Typically, Capacity Prices are in the order of \$10/MW/hour/per year, however a final value will only be available from detailed analysis²¹.

4.7.3. Capacity Out Of Balance

Generators will pay or receive payment if they present less or more Capacity than they have undertaken to present as part of contractual arrangements with retailers or directly with the Reliability Manager, but not more than each unit's Accredited Capacity.

The \$/MW values for peak and off-peak periods are shown in Figure 3 where the price is found by scaling a declared Capacity Price by a Scaling Factor. The shape of the profile, the Scaling Factor and the Capacity Price are the key variables to be selected along with the frequency of calculation. The following presents illustrative examples and the starting point for detailed design.

Figure 3: Capacity unders/overs: Price vs Reserve



²¹ \$1.2 million/MW capital cost amortised over 25 years results in a Capacity price of \$128,000/MW/year or approx. \$14/MW/hour. Discounted to \$10/MW/hour in this example reflecting current surplus of Capacity.

Applying the illustrative values in Figure 3 and a declared Capacity Price of \$10/MW/hour, capacity contracted as part of a Retailer's Capacity Obligation is not available:

- at times when reserve is at a minimum. The Scaling Factor would be 3 and these generators would incur a charge of $3 * \$10/\text{MW}/\text{hour}$ or \$30/MWh, meaning a 40MW unit that was unavailable at these times would be charged \$1200/hour during peak times;
- at times when reserve is moderate. The Scaling Factor would be 1 and these generators would incur a charge of $1 * \$10/\text{MW}/\text{hour}$, or \$400/hour for a 40MW shortfall; and
- at times when reserve is high, which is likely to apply off peak and during dry season periods. The Scaling Factor would be zero, reflecting the low value of additional Capacity under those conditions. However, these periods may also be times of significant scheduled maintenance which may reduce the reserve and may lead to a factor between 0 and 1 which would correctly reflect the resulting higher level of risk.

The Scaling Factor is applied to each Trading Interval of the energy trading mechanism.

4.7.4. Planned outages

For approved planned outages, generators must provide System Control with a minimum 10 working days notice and advise the expected duration²².

Planned Outages

If a generator, for example: G1, is performing an approved planned outage and hence has declared itself unavailable in its daily bid AND given 10 days' notice to System Control, the Scaling Factor for that generator will be set to 0.

If, after approval of G1's outage, G2 then requests an outage compliant with the notice period, planned reserve limits will be known. System Control will assess the reserve requirements and approve or postpone the planned outage. G1 and G2 Scaling Factors will both be zero, providing the planned outage is carried out during the period approved by System Control.

Short-notice Planned Outages

If a request for a planned outage is made (and approved) with more than the 10 days' notice period before the Trading Day, the generator's maximum Scaling Factor will be SFX 0.

If a request for a planned outage is made (and approved) with between 1 and 10 days' notice period before the Trading Day, the generator's maximum Scaling Factor will be the SFX minus 1 (minimum 0), where SFX is the prevailing Scaling Factor determined for that Trading Interval.

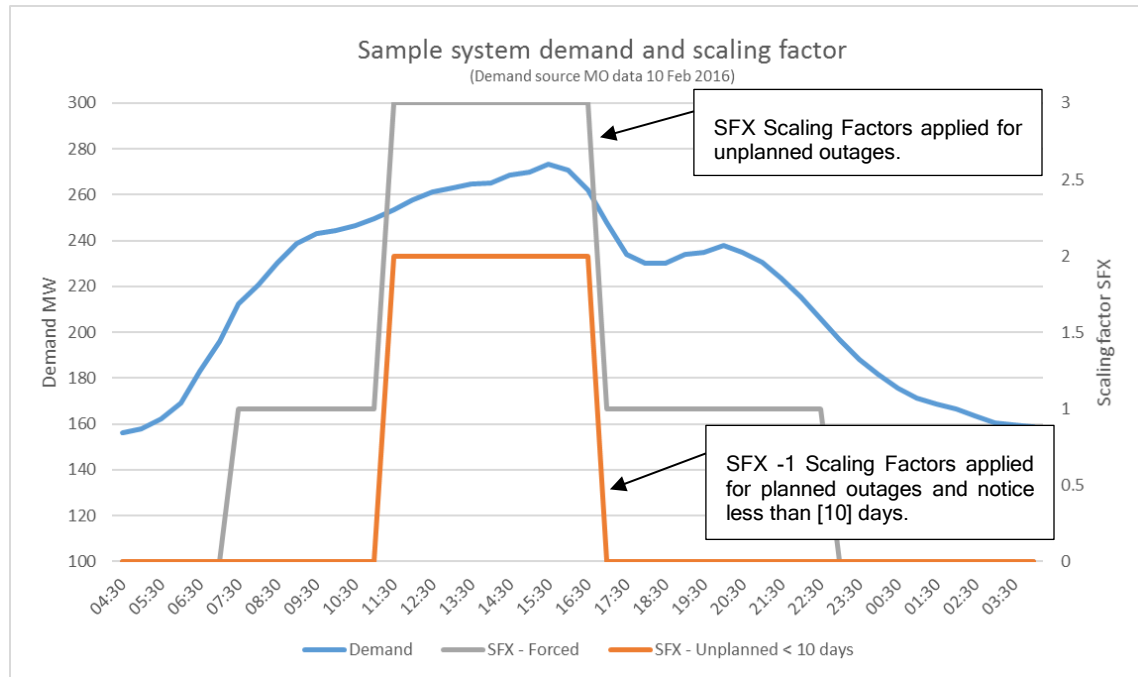
If an outage is taken with less than 1 days' notice period before the Trading Day, the generator's maximum Scaling Factor will be the SFX, where SFX is the prevailing Scaling Factor determined for that Trading Interval.

This provision provides an incentive for planning outages ahead of time.

22

System Control Technical Code Clause 6.5.

Figure 4: Sample Scaling Factor calculation for unplanned and planned with notice less than requirement



In principle, there should be a disincentive to plan outages during low reserve periods (which would make a generator’s Scaling Factor greater than one because the prevailing Balancing Price should be relatively high and all generators are incentivised to make themselves available. There should also be the incentive to discourage declaration of planned outages in less than the specified notice period without compromising the incentive to provide in compliance with the specified notice period. It will also be important to avoid a situation where poor performing generation plant can become exempt from penalties by obtaining a long term planned outage approval.

Table 3: Summary of Scaling Factor scenarios - planned and unplanned outages (subject to change)

Scenario	Scaling Factor
Unplanned outage low reserve	3
Unplanned outage moderate reserve	1
Unplanned outage high reserve	0 to 1
Approved planned outage notice period compliant	0
Approved planned outage notice period non-compliant	SFX ²³ - 1 (minimum 0)

Note:

- Any generator meeting its contracted obligation will be in balance and not exposed to the Capacity Out Of Balance arrangements.
- Energy Out Of Balance and Capacity Out Of Balance are separate and independent calculations.

23 SFX = the prevailing Scaling Factor.

Transitional arrangements.

As discussed in section 3.3.1 no transitional Capacity Out Of Balance will be accounted for.

4.7.5. Energy Out Of Balance and Balancing Price

An Energy Balancing Price will be set after the post-event for each 30 minute Trading Interval at the highest marginal cost of operation of unconstrained generating units producing energy in that 30 minute period.

The bulk of energy transactions are expected to be on the basis of bilateral contracts agreed between buyers and sellers. An Out Of Balance arrangement will operate to settle occasions when generation of a contracted party differs from the contract and also when consumption differs from the contract.

Transacting only the volumes Out Of Balance with a contracted position is often termed a net settlement as opposed to a gross settlement where all energy produced and consumed is bought and sold through a central pool.²⁴ In a net settlement arrangement, market participants must advise the Market Operator of their contracted volumes with other market participants, but not price.

Balancing Price

The Balancing Price is the price applied to Energy Out Of Balance volume to calculate the net settlement amount for each market participant in each 30 minute Trading Interval. The Balancing Price is to be determined in a manner that reflects the cost of a small change in production or consumption (marginal cost) and only includes unconstrained generating units.

The marginal cost of operation of an unconstrained unit in a 30-minute Trading Interval is the sum of:

- The variable cost to produce energy at the metered output; and
- Where relevant, for each contiguous block of 30 minute periods of operation from the half hour beginning at 0430 in the current day to the half hour beginning at 0400 the following day, and where the generating unit is operating in that block because of an instruction to start by System Control:
 - the start-up cost; divided by
 - the energy produced in that contiguous block of 30 minute periods.

4.7.6. Volume of Energy Out Of Balance

Energy Out Of Balance volumes may occur for a number of reasons:

- A small volume of Energy Out Of Balance is unavoidable even when generators are attempting to run to a specified contract volume and retailers accurately forecast their demand.
- Larger volumes of Out Of Balance may occur if generators are out of service and other generators are called upon to supply the contracted demand.
- Out Of Balance may also result from the Security Constrained Economic Dispatch arrangements, which do not consider contract arrangements, and a contracted generating unit is dispatched below full Capacity or not dispatched because there are lower cost sources of energy available. The Dispatch and Out Of Balance settlement processes will allow generators to meet their contract commitments from the lowest cost source of

24 Which is the default position in the NEM.

generation available at the time by either generating from their own resources or buying from the Out Of Balance regime while still receiving payment at the contracted rate.

Supplementary note: In the NTEM it is likely that Energy Out Of Balance volumes under some contracts will be zero as it is understood some contracts are being written with a variable, rather than specified, volume based on the output of the generator or the demand of the Retailer - these are often termed load-following contracts. These arrangements can be recognised in the NTEM settlement process by a statement from the parties that a load-following contract is in place.

The volume of Energy Out Of Balance will also be affected by whether or not a generating unit(s) is providing Ancillary Services which results in the unit(s) being reduced or increased in output, for example to provide Contingency Reserve capability. When a unit is backed down to provide an Ancillary Service, the Energy Out Of Balance will be increased by the amount the unit(s) is backed down by, as advised by System Control. The generator providing the Ancillary Service will therefore be buying energy through the Energy Out Of Balance arrangements to meet part of its contractual obligations, or will be receiving a lower Out Of Balance payment. It is crucial, therefore, that the payment for Ancillary Services recognises this situation and recompenses the generator.²⁵

The arrangement described here allows for Out Of Balance to be calculated separately to payment and charges for Ancillary Services - see Sections 3.6.2 and 4.6.

4.7.7. Energy Out Of Balance Payment

The Energy Out Of Balance Payment for each market participant will be calculated by the Market Operator as follows:

Energy Out Of Balance Payment (OOBP) = OOB x Balancing Price

Where OOB is the volume of Energy Out Of Balance in each Trading Interval in MWh.

OOB for each participant will be found from the following calculations:

Generators: $OOB = (SO \times MLF) - \sum CQ$
 $OOBP = OOB \times BalP$

Retailers: $OOB = SL \times MLF - \sum CQ$
 $OOBP = OOB \times BalP$
 $SL = \sum CSL \times DLF$

Where:

- A function of the declared Capacity Price (DCP) which is calculated by the Reliability Manager and is the value of System Capacity per MW (\$/MW).
- SO (Sent Out energy) is the quantity of energy measured at the generator connection point.
- SL (Served Load) is the sum of the quantities of energy served by the retailer at its customer sites (CSL) as measured by the site meters and adjusted for losses (DLF).
- CSL (Customer Served load) is the energy supplied to a customer at its connection point.

²⁵ In the NEM the price for FCAS is calculated at the same time as the price for energy and leaves the provider of Ancillary Service commercially indifferent as to whether it provided energy or Ancillary Service. This is a far more complex arrangement than is contemplated for the NTEM.

- CQ (Contract Quantity) is the value of energy contracted between a generator and a retailer. Each party is expected to have multiple contracts and the sum of the contracts determines their net contracted quantity for OOB calculations.
- OOB (Out Of Balance) is the quantity of the mismatch between the contracted energy and the actual load or dispatched energy.
- OOBP (Out of Balance Payment) is the amount to be paid to or received from the market for Out Of Balance volume at the Balancing Price.
- BalP (Balancing Price) is the value of the Out Of Balance energy. This represents the price of the marginal generator in which the Out Of Balance occurs, calculated at the Reference Node.
- MLF (Marginal Transmission Loss Factor) is the specific loss factor for each generator connection point or each transmission connection point to represent the marginal loss to the Regional Reference Node.
- DLF (Distribution Loss Factor) is the loss factor assigned to customers to represent their share of technical energy lost in the network to the transmission connection point.

Note: until all Ancillary Services are open to a competitive tender process, and while the transition arrangements described at section 3.6.2 are in place, T-Gen will be compensated for energy foregone through an NT adaption of the WEM Margin Peak and Margin Off Peak approach.

4.7.8. Capacity Out Of Balance Charge

The NTEM Capacity Mechanism will oblige Retailers to contract for their share of the level of Capacity determined by the Reliability Manager as sufficient to meet the Reliability Standard.

In the long term (not in the transition), if actual Capacity available is less than the minimum level required, there will need to be some form of financial adjustment. Detailed arrangements will include allowances for planned outages for maintenance and incentives to be available at times when there are conditions of system stress. Capacity out of balance will be paid to or by the Market Operator who will be cost neutral for this activity.

Section 4.7.3 summarises the approach proposed as part of the Capacity Mechanism and presents a proposal for a Capacity Out Of Balance Charge.

The Capacity Out of Balance Charge will be:

- A function of the declared Capacity Price (DCP) which is calculated by the Reliability Manager and is the value of System Capacity per MW (\$/MW).
- Subject to a Scaling Factor (SFX) which is relative to the amount of reserve available in the system in each Trading Interval and is determined 1 day ahead by System Control.

$$\text{Capacity Out Of Balance Charge} = \text{DCP} \times \text{SFX} \times \text{QC}$$

Where:

- DCP is the declared Capacity Price (\$/MW).
- SFX is the Scaling Factor and is defined in Section 4.7.3.
- QC is the volume of Capacity Out Of Balance in each trading interval (MW).

4.7.9. Metering and losses

Metering in the DKIS is a combination of interval and accumulation meters at customer premises plus some metering of exit feeders from transmission.

NTEM will use Marginal Transmission Loss Factors and average Distribution Loss Factors for the purposes of settlement.

Settlement Residue will occur and is the inherent difference between collections from customers and payments to generators in a Marginal Loss Factor approach to settlement, as well as errors in metering. Consideration will need to be given to where the Settlement Residue value resides.

4.7.10. Loss factors

Supplementary note: Currently, the Network Service Provider is required to advise loss factors under the SCTC.

Four technical (or actual) loss factors are provided for the entire DKIS (Darwin high voltage, Darwin low voltage, Katherine high voltage and Katherine low voltage). These factors are designed to approximate the actual or technical losses in supplying customers. This form of loss factor is consistent with settlement at customer connection point where all supply is from a single generation entity.

In the NTEM, Channel Island will be the Reference Node for settlement of Balancing Energy and Capacity²⁶. Generators are to be assigned Marginal Loss Factors to link them to the Reference Node. Customers will be assigned average Distribution Loss Factors to their local transmission connection point, and then each transmission connection point will be linked to the Reference Node by a Marginal Loss Factor.

4.7.11. Settlements by the Market Operator

The Market Operator will be required to calculate and make settlement payments to participants as outlined above including:

- Receiving meter data from interval meters at entry and exit points to the system;
- Calculating the balance of energy supplied through non-interval meters, assuming the system is in balance;
- Calculating and making Ancillary Service payments to providers taking into consideration System Control contracts, records of dispatch and corresponding charges to recover those costs;
- Calculating, making and receiving payments and charges relating to capacity market purchases made by the Reliability Manager and Capacity Out Of Balance payments and charges; and
- Performing settlement calculations in accordance with the Market Rules.

The market will be dispatched around a 24 hour Trading Day from the half hour beginning 0400 on one day to the end of the half hour beginning 0330 the next day.

The Trading Day is divided into 48 Trading Intervals of 30 minutes each.

The NTEM will settle on a monthly basis. The Market Operator will provide settlement statements to the respective parties on a monthly basis and arrange relevant payments and collections.

²⁶ Hudson Creek is potentially closer to the electrical centre of the DKIS but congestion on the 132kV line south of Channel Island is anticipated if significant amounts of solar PV is established along the 132kV line to Katherine and, under conditions of high flow north, exceed the limit into the Darwin region. If this situation occurs, calculation of market price may need to be amended for flows either side of Channel Island and making it the Reference Node will facilitate settlement in this instance. The choice of Reference Node will impact the loss factors but these are self-adjusting in that there is no impact on the final payment to generators or charge to customers.

4.8. Data publication

The System Operator will prepare and publish key daily information including the Balancing Price and Total System Demand in each Dispatch Period for the previous day.

The Market Operator will publish market-relevant data on a publicly accessible platform.

The published data will include but not be limited to:

- System demand in each Trading Interval;
- Balancing Price in each Trading Interval;
- Daily volume of generation (MWh);
- Daily peak demand (MW);
- Daily average demand (MW);
- Day ahead demand forecasts (MW per Dispatch Period); and
- Incident reports.

4.9. Legislation/Regulation

Legislation and Regulatory Instruments create the legal framework for the sector.

The electricity sector is generally of sufficient significance to the economy that legislation is established to grant force of law to the primary institutions as well as regulatory and subsidiary instruments.

Laws and regulations may establish obligations in respect of safety, rights and obligations of parties to access, construct and operate networks and generation, to connect and supply electricity to individual customers, authority to set a market price (which may otherwise be in breach of competition law), to operate a monopoly network, and to charge consumers a tariff.

It is expected that additional regulatory instruments may be needed for the NTEM which will be considered once the Territory Government has considered and endorsed the market model as described in this Functional Specification.

4.10. Licensing

Licensing is the step where the commercial and technical credentials of potential participants in the NTEM are validated.

Legislation and regulations have established standards for parties to be market participants; for example, generators must meet technical standards and retailers must be financially sound. The licensing phase is therefore a safety measure designed to ensure all participants meet those minimum standards as a protection for all other participants and the credibility of the market.

4.11. Registration

Market Registration works in parallel with licensing. Together, they ensure compliance with technical and possible prudential standards. Although there is scope for some issues to be dealt with either as a licence provision or on registration, there are generally some matters, such as contact details and nomination of participation in the different parts of a market (e.g. energy transactions and Ancillary Services) that require a market registration.

The Market Operator will establish and maintain relevant details for the NTEM.