

# NTEM Priority Reform Program: Priority changes to dispatch and settlement

Policy Position Paper

January 2021

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## Executive Summary

The Northern Territory Government is undertaking the Northern Territory Electricity Market Priority Reform Program (NTEM Priority Reform Program), which is a package of coordinated priority reforms to existing market arrangements in the Darwin-Katherine Interconnected System (DKIS). The DKIS is undergoing significant transition and the priority reforms are required to facilitate market entrants and emerging technologies that will support the government’s target of 50 per cent renewable energy by 2030, while maintaining secure, reliable and least-cost electricity for consumers and taxpayers.

On 12 June 2020, the Territory Government published the *Northern Territory Electricity Market Priority Reform Program: Introductory notes on scope and work program* (the Introductory Notes), which provided an overview of the NTEM Priority Reform Program. The Territory Government, in the Introductory Notes, sought nominations for a Stakeholder Working Group that was established to consult on the reforms.

This policy position paper relates to the dispatch and settlement components of the NTEM Priority Reform Program, reflecting that the Introductory Notes identified these components as two of the immediate priority changes to be implemented as quickly as possible, see Table 1, below. The policy positions set out in this paper have been informed by consultation with the Stakeholder Working Group.

Table 1- Need for immediate priority reforms – re-cap from the Introductory Notes

Dispatch	Settlement
<p>Priority changes are needed to improve the efficiency of dispatch of generation.</p> <p>Existing arrangements were commenced in 2015 and were designed to trial a competitive arrangement with the existing two generation businesses for a limited time.</p> <p>The arrangements will not efficiently accommodate increased intermittent generation.</p>	<p>Priority changes to settlement arrangements are needed because the current ‘virtual market’ (no financial flows) does not accommodate foreseeable contractual arrangements for sale of energy between generators and retailers.</p> <p>Settlement arrangements must also support the priority dispatch changes.</p>

## Summary of immediate priority dispatch and settlement changes

The immediate priority dispatch and settlement changes are an important step in the transition to a fit-for-purpose long term market design for the DKIS, building on the existing arrangements established in May 2015, termed the Interim Northern Territory Electricity Market (I-NTEM).

The I-NTEM was the first step (or a precursor) to transitioning to long term market arrangements that will reduce barriers to entry and improve the efficiency of the DKIS system. The long term arrangements will allow competitive entry to the generation and retail sectors of the DKIS, by providing arrangements for buying and selling electricity with enhanced cost transparency, while maintaining reliability and security. The I-NTEM was designed and implemented using a minimalist approach to developing systems and regulatory arrangements. It leveraged existing arrangements and utilised legacy systems and practices. This was appropriate at the time because the purpose of the I-NTEM was to provide a vehicle for familiarisation and testing of processes, and roles and responsibilities of parties.

Since the introduction of the I-NTEM, interest and activity in the DKIS has increased and the existing I-NTEM arrangements are not sufficient to meet the rapidly evolving generation profile in the DKIS with increased amounts of solar energy generation and other emerging technologies. The Territory Government’s policy positions on the priority changes to existing I-NTEM arrangements in respect to dispatch and settlement, are outlined in the tables below.

## Priority dispatch changes

Table 2, below, summarises the priority dispatch changes to be made, compared to the current I-NTEM arrangements, and outlines the policy rationale for each change.

Table 2 – Need for immediate priority reforms

I-NTEM arrangement	Priority change	Policy rationale	More information
<ul style="list-style-type: none"> <li>Scheduling decisions are made looking ahead at 30-minute Trading Intervals.</li> </ul>	<ul style="list-style-type: none"> <li>Intertemporal optimisation will be introduced.</li> <li>Scheduling decisions will look ahead over an appropriate scheduling horizon that will be a sufficiently long period to assess the trade-offs between start up and operating costs.</li> </ul>	<ul style="list-style-type: none"> <li>Increased intermittent generation is likely to see more frequent stops and starts of thermal generation plant. Optimising startup and operating costs will lead to more efficient dispatch.</li> <li>In the absence of this priority change, the existing I-NTEM arrangement would result in less efficient stopping and starting of generators, which would increase costs.</li> </ul>	Section 5.1
<ul style="list-style-type: none"> <li>A static merit order (order for dispatch) is used.</li> <li>The merit order is set by prices submitted by generators a day-ahead of actual dispatch, which are not updated as circumstances change.</li> </ul>	<ul style="list-style-type: none"> <li>Centralised unit commitment and dispatch will be introduced.</li> <li>The System Controller will make all scheduling decisions.</li> <li>The System Controller will make scheduling decisions at any time, and over any time period, within the scheduling horizon.</li> <li>The System Controller's decisions will be informed by cost data submitted by generators and other information available to it.</li> </ul>	<ul style="list-style-type: none"> <li>The priority change removes the need for a static merit order and will support more efficient scheduling based on the most up-to-date information.</li> <li>Generators will not need to determine a price a day-ahead based on assumptions about their run time the next day, ensuring generators do not apply 'risk premiums' due to uncertain assumptions.</li> </ul>	Section 5.1
<ul style="list-style-type: none"> <li>The Market Operator publishes some market information.</li> </ul>	<ul style="list-style-type: none"> <li>The System Controller must publish a record of the basis for its scheduling decisions for participants to review.</li> <li>While there will be different timeframes for publishing information, all information (except if it is commercially sensitive) will be published.</li> </ul>	<ul style="list-style-type: none"> <li>The System Controller will be making more decisions, in particular around unit commitment. The priority changes will enhance transparency of decision making to increase accountability.</li> </ul>	Section 5.2

I-NTEM arrangement	Priority change	Policy rationale	More information
<ul style="list-style-type: none"> <li>The Market Price for out-of-balance 'virtual' settlement is \$65/MWh.</li> <li>This approach reflected the I-NTEM was a short term arrangement to trial new concepts, with existing generators.</li> </ul>	<ul style="list-style-type: none"> <li>The Market Price for setting out-of-balance energy will be set by the price band of the marginal, unconstrained generator.</li> </ul>	<ul style="list-style-type: none"> <li>The approach to setting Market Price reflects the basic principle that price will reflect the marginal or incremental cost of a small change in demand as this is an economic signal to both generators and retailers of the value in changes in generation and demand.</li> </ul>	Section 5.3

## Priority settlement changes

Table 3 below summarises the priority settlement changes to be made, compared to the current I-NTEM arrangements, and outlines the policy rationale for each change.

Table 3 – Need for immediate priority reforms

I-NTEM arrangement	Priority change	Policy rationale	More information
<ul style="list-style-type: none"> <li>No financial settlement of out-of-balance energy by the Market Operator</li> <li>All settlement is through bilateral contracts.</li> </ul>	<ul style="list-style-type: none"> <li>Financial settlement of out-of-balance energy by the Market Operator will be introduced.</li> </ul>	<ul style="list-style-type: none"> <li>The priority change will ensure market settlement can accommodate a range of foreseeable contractual arrangements between market participants.</li> </ul>	Section 3.2
<ul style="list-style-type: none"> <li>Location of settlement is at each generator's sent out point.</li> </ul>	<ul style="list-style-type: none"> <li>Settlement will be deemed to occur at two Reference Nodes, being 'common points' in the system.</li> <li>The Reference Nodes will be located north and south of Channel Island.</li> </ul>	<ul style="list-style-type: none"> <li>Settling at every generator's sent out point will become increasingly complex, and eventually unworkable.</li> <li>The two Reference Nodes have been chosen to balance price accuracy and contracting complexity.</li> </ul>	Section 6.2

I-NTEM arrangement	Priority change	Policy rationale	More information
<ul style="list-style-type: none"> <li>A generator's startup costs are recovered through bilateral contract settlement.</li> </ul>	<ul style="list-style-type: none"> <li>Startup costs will be a component of the Settlement Amount that is settled by the Market Operator.</li> <li>The cost that will be recoverable will be for a complete successful startup and shutdown cycle for the generator.</li> </ul>	<ul style="list-style-type: none"> <li>Generators will not control the number of startups and shutdowns as the System Controller will make all scheduling decisions.</li> <li>The settlement design will ensure cost recovery of generators' successful starts/shutdown cycles.</li> <li>Options for settlement of startup costs that were considered but did not align with the broader market design are discussed in the paper.</li> </ul>	Section 6.3
<ul style="list-style-type: none"> <li>No prudential arrangements reflecting that the I-NTEM is a virtual market.</li> </ul>	<ul style="list-style-type: none"> <li>Prudential arrangements are to be introduced that are proportionate to the expected level of risk in the early stages of the market.</li> </ul>	<ul style="list-style-type: none"> <li>Prudential arrangements are needed to ensure the financial integrity for market settlement via the Market Operator.</li> <li>The prudential arrangements have been designed for the low level of risk expected in the net settlement market where most energy is likely to be settled through bilateral contracts, at least in the short term.</li> </ul>	Section 6.4
<ul style="list-style-type: none"> <li>Settlement is a simple statement of energy consumed or dispatched.</li> </ul>	<ul style="list-style-type: none"> <li>The settlement covers the cost of out-of-balance energy plus the costs of a startup and shutdown cycle.</li> <li>Provision is made for losses to and from the Reference Nodes</li> <li>The Settlement Amount can include additional elements if required in the future.</li> </ul>	<ul style="list-style-type: none"> <li>The settlement needs to accurately recover and pay for the market operations of participants.</li> <li>Evolving contractual and other market arrangements will need to be settled.</li> </ul>	Section 6.5

## Next steps

This policy position paper will guide implementation of the priority dispatch and settlement reforms, including the development of detailed market rules.

The detailed market rules are expected to be primarily contained in the System Controller's System Control Technical Code, which is the current location of such rules. The Northern Territory Government is considering options to ensure suitable governance to support implementation while ensuring the dispatch and settlement reforms are implemented as a priority.

Further information will be provided to stakeholders on implementation and next steps, including on consultation opportunities for stakeholders to ensure that they can provide feedback on the draft detailed market rule changes.

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## 1. Purpose

The purpose of this paper is to inform stakeholders of the Northern Territory Government's policy position in respect to priority reforms to dispatch and settlement arrangements in the Darwin-Katherine Interconnected System (DKIS), which form part of the Northern Territory Electricity Market Priority Reform Program (NTEM Priority Reform Program).

The policy positions set out in this paper have been informed by stakeholder consultation via a Stakeholder Working Group. This paper will guide development and implementation of amendments to market rules, primarily through the System Controller's System Control Technical Code (SCTC), that are consistent with government's policy intent.

## 2. NTEM Priority Reform Program

The Northern Territory Government's NTEM Priority Reform Program is a package of coordinated priority reforms to existing market arrangements in the DKIS to facilitate greater levels of competition and adoption of emerging technologies, including to support government's renewable energy target. The reforms will ensure efficient, secure and reliable electricity for consumers and taxpayers.

Delivery of the NTEM Priority Reform Program is being overseen by the Design Development Team which is a working group comprising officers of the Economic Policy unit of the Department of Treasury and Finance (DTF) and the Office of Sustainable Energy within the Department of Industry, Tourism and Trade (DITT).<sup>1</sup> The Design Development Team is responsible for preparation of consultation papers, engaging with the Stakeholder Working Group, providing policy advice to government and project management.

The priority reforms relate to reliability, dispatch, essential system services and settlement arrangements. Table 1 sets out a high level description of each component of the priority electricity market reforms and a summary of the need for change. For further information in respect to other components of the NTEM Priority Reform Program refer to the *Northern Territory Electricity Market Priority Reform Program: Introductory notes on scope and work program* (the Introductory Notes) which was released on 12 June 2020. The Introductory Notes is available on the [DITT's website](#)<sup>2</sup>.

Table 4 Summary of priority reforms

Component	Need for change
Dispatch	The current I-NTEM dispatch arrangements commenced in 2015 and were designed to trial competitive arrangements with the existing two generation business for a limited time. The arrangements are inefficient and cannot manage a number of plausible operational situations and will be unable to efficiently manage the increased amounts of intermittent generation.
Settlement	The I-NTEM is a virtual market, and existing out-of-balance energy settlement arrangements will not accommodate foreseeable contractual arrangements for sale of energy between multiple market participants. Changes are required to ensure energy settlement arrangements can accommodate foreseeable contractual arrangements.

<sup>1</sup> DITT was formally the Department of Trade, Business and Innovation

<sup>2</sup> <https://industry.nt.gov.au/projects-and-initiatives/business/northern-territory-electricity-market-priority-reform-program>



Component	Need for change
Reliability	<p>There is currently no formal system-wide standard for reliability of supply to ensure electricity costs are as low as possible for consumers while ensuring electricity is continuously supplied to consumers with minimal (or an 'acceptable' level of) power outages.</p> <p>An existing requirement on generators mandates that they must have sufficient capacity to meet their customers' (retailers) demand. This is an inefficient approach to ensuring reliability, and incompatible with a generation fleet comprising different technologies. Further, it does not establish a standard taking into account an appropriate cost-reliability trade off. An overarching system-wide standard is needed.</p>
Essential system services	<p>Essential system services are a growing proportion of system cost in the DKIS. There are a number of factors that can materially impact essential system service requirements, including the changing generation mix. Current arrangements assume Territory Generation is the sole provider of all types of essential system services. Other generators must compensate Territory Generation for their share of costs in accordance with a codified price.</p> <p>The codified price requires review as there has been substantial activity in the DKIS since it was set in 2015. The price review will also provide greater transparency to government and industry on the cost of providing these services.</p> <p>In addition to the implementation of reforms to the provision of essential system services by Territory Generation, potential arrangements for the market provision of essential system services in the Territory's regulated electricity systems are being reviewed.</p>

The focus of this policy position paper is the priority dispatch and settlement reforms. The Introductory Notes identified that dispatch and settlement priority changes must be implemented as quickly as possible and the scope of changes and work program outlined in the Introductory Notes was designed with this urgent need for reform in mind.

It is noted that priority changes to reliability and essential system services are in the process of being developed and consulted on, and are subject to government's consideration.<sup>3</sup> While it is possible that, pending their final design, there may be a need for some consequential amendments to dispatch and settlement arrangements, the priority dispatch and settlement reforms outlined in this paper are to be progressed as the highest priority as they are required to accommodate new entrants.

The remainder of this paper:

- outlines the need for priority dispatch and settlement changes (recapping information in the Introductory Notes)
- summarises stakeholder consultation undertaken via the Stakeholder Working Group
- sets out government's policy position on dispatch and settlement priority reforms; and
- outlines next steps in progressing the dispatch and settlement priority reforms.

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<sup>3</sup> Consultation papers on reliability and essential system services can be found at: <https://industry.nt.gov.au/electricityreforms>

## 3. Need for priority dispatch and settlement reforms

### 3.1. Dispatch and unit commitment

Unit commitment is the process by which generating (or other schedulable) units are synchronised to and de-synchronised from the power system (or started and stopped). Dispatch is the process for providing instructions about the level of output each unit must produce, once it is synchronised.

The System Controller must ensure generation (and other schedulable) units are started (and stopped) and energy is dispatched to meet system demand, taking into account security constraints. Decisions should be based on the principle of security-constrained economic dispatch, meaning that in addition to taking security constraints into account, the System Controller must dispatch at the lowest cost possible. This supports the interests of consumers and taxpayers.

However, changes to the current I-NTEM arrangements are required to ensure that unit commitment and dispatch decisions result in the most efficient outcomes. The current arrangements were intended to be transitional and will not result in appropriate efficient outcomes if continued on a long term basis. Under the current arrangements, two factors impact the overall efficiency of dispatch:

- There is a lack of intertemporal (that is, more than the next 30-minute period) consideration of unit commitment and dispatch decisions. This limits the ability for the most efficient decisions to be made because the short term outlook period means it is difficult to optimise start-up and operating costs
- Generators make 'one shot' submissions on price and availability to the System Controller a day ahead of actual dispatch, each weekday. A generator's price incorporates an amortisation of start-up costs requiring the generator to forecast when, and for how long, its generation unit(s) will run, and the price is not updated as circumstances change. This results in a static merit order that is not informed by the most up-to-date information, including the System Controller's information (such as knowledge of demand, the state of the system on that day and the availability of other generators).

These factors impact efficient unit commitment and dispatch and both will become more significant as large-scale intermittent generators connect to the power system and the level of behind-the-meter solar PV grows. The behind-the-meter PV systems will increase the volatility of demand impacting the demand profile, while, on the supply side, the availability of large-scale intermittent generation may be more variable.

As a result, the System Controller will need to turn gas generation units on and off more frequently. Generators' ability to accurately forecast run times will be reduced if current dispatch arrangements continue.<sup>4</sup> The way in which unit commitment and dispatch decisions are made needs to change to accommodate the intermittent nature of new generation and to ensure efficient outcomes for consumers and taxpayers.

Accordingly, the Northern Territory Government identified that priority reforms to dispatch arrangements are required and outlined these in the Introductory Notes, which are presented below.

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<sup>4</sup> It is noted that the PWC's generator performance standards include forecasting requirements that will provide a greater understanding of the availability of large-scale solar PV generators. This may assist in understanding demand volatility, but it will not remove the volatility. Further, it will not assist in understanding demand volatility from behind-the-meter solar PV.

The priority dispatch changes identified by the Territory Government include:

- the introduction of an intertemporal requirement to ensure the System Controller must consider scheduling requirements over an appropriate scheduling horizon, not just for isolated short periods. This will ensure decisions are informed by expected demand and power system conditions over a period that allows for efficient scheduling decisions, including consideration of the trade-offs between start-up and operating costs of generation units
- adoption of a centralised unit commitment and dispatch process, which will require:
  - generators (or other schedulable units) to provide cost information (such as start-up and operating costs) but will not require them to make assumptions regarding run times
  - the System Controller to use the cost information provided, as well as a broad range of whole-of-system information available, to make decisions about which units to commit (or decommit), when and for how long, on an intertemporal basis.

## 3.2. Settlement

Settlement refers to the after the fact, centralised, reconciliation of market operation for energy and essential system services to determine the financial payments required to and from the Market Operator and generators and retailers. In the DKIS, net settlement is to be used for energy and as a result the centralised settlement process only applies in respect to out-of-balance energy (being energy that is more or less than contracted amounts between generators and retailers). Bilateral contracts including Power Purchase Agreements between retailers and generators will affect the level of out-of-balance settled by the Market Operator. Bilateral contracts will be settled between the contracting parties.

The I-NTEM is a virtual market. All commercial transactions continue to occur through bilateral contracts between generators and retailers. A market operator function, established within System Control (referred to as the Market Operator in this paper), prepares virtual net settlement statements for out-of-balance energy and essential system services. Currently no financial transactions occur via the Market Operator.

While this current arrangement is compatible with the current form of bilateral contracts used by market participants, this is unlikely to be the case in the future. The existing out-of-balance settlement arrangements, including virtual settlement, are not sufficiently flexible to accommodate foreseeable circumstances, such as market participants seeking to adopt certain types of contract forms that are common in other markets. With increasing numbers of participants, it is necessary to either mandate the type of contractual arrangements that market participants must have (to remove the possibility of there being energy out-of-balance) or ensure energy out-of-balance settlement arrangements are sufficiently flexible to accommodate a range of contract forms that market participants may foreseeably utilise. The Territory Government recognises that the former will not be satisfactory to market participants nor result in efficient outcomes for consumers and taxpayers. Therefore, changes to out-of-balance arrangements for energy are required to introduce financial settlement.

The DKIS must also move away from the current approach of settling at each generators' sent-out point (known as pool price points) as this will become increasingly complex and eventually unworkable as more participants enter the market. The priority changes for settlement include introduction of reference node(s), which is a physical location within a power system at which settlement is deemed to occur.

Financial settlement for energy out-of-balance means that the risk of participant default on payments to the Market Operator needs to be managed to ensure financial integrity of the market. At least in the short term, this risk is not expected to be substantial (relative to other markets such as the Australian National

Electricity Market (NEM) gross settlement market) given most energy will continue to be settled through contractual arrangements. Prudential arrangements should be proportionate to the risk associated with the DKIS net energy settlement arrangements.

The priority reforms for settlement identified by the Northern Territory Government were outlined in the Introductory Notes and are presented below.

The priority settlement changes identified by the Territory Government include:

- changes to out-of-balance arrangements for energy, including to:
  - accommodate a foreseeable range of types of contractual arrangements
  - introduce financial settlement of an energy out-of-balance pool by the Market Operator
  - introduction of reference node arrangements
  - implementation of appropriate arrangements for management of participant default risk that are proportionate to the level of risk for the net energy settlement market

## 4. Stakeholder Working Group consultation

A Stakeholder Working Group was established to inform the detailed design of the priority electricity market reforms, with nominations for the Group sought through the Introductory Notes. The Terms of Reference for the Stakeholder Working Group can be found at Appendix F.

There was strong interest in the Stakeholder Working Group with 24 organisations nominating to be members of the Group, which included current and intending (and prospective) industry participants, businesses with industry-related interests and community interest groups.

Reflecting the high priority of dispatch and settlement reforms, consultation was undertaken via Stakeholder Working Group workshops in mid-July 2020. The purpose of the workshops was to consult stakeholders to gain their input into the design of the dispatch and settlement changes. The responses from the stakeholder informed the Territory Government's policy position in respect to dispatch and settlement.

Two Stakeholder Working Group workshops were held, one each for dispatch and settlement, with the option of stakeholders attending in person or via video conference. The workshops provided an opportunity to 'walk-through' proposed draft design papers on dispatch and settlement to seek feedback from stakeholders. Follow up feedback after the workshops was also invited.

Feedback from stakeholders was highly constructive and views expressed were generally positive. Consultation summaries outlining comments and questions from the workshops and the Design Development Teams' responses were prepared and provided to stakeholders. A summary of the stakeholder feedback is also included at Appendix E. This summary has been updated for any feedback provided subsequent to the workshops.

Given the positive feedback provided by the Stakeholder Working Group, the Design Development Team has not identified a need to make wide ranging changes to policy proposals outlined in the draft design papers that were discussed at the stakeholder workshops. However, stakeholder feedback has been valuable in refining aspects of the draft design which is reflected in government's policy positions set out in sections 5 and 6 of this paper.

## 5. Policy position on dispatch: priority changes

This section outlines the Territory Government's policy position in respect to the design of priority dispatch changes to implement centralised unit commitment and dispatch and intertemporal optimisation.

The priority reforms for dispatch focus on the wholesale market, regulatory and economic principles for dispatch and unit commitment which at all times will be subject to requirements to maintain a secure, safe and reliable power system in accordance with instruction of the System Controller.

Real time operation also involves technical and logistical processes and procedures especially for ensuring security of operation, integration with network operation and operation of automatic dispatch systems (e.g. Automatic Generation Control (AGC)), load shedding and operational communication protocols. While current technical and power system security standards in the Territory are not the subject of government's NTEM Priority Reform Program, considerable care has been taken to integrate the design of priority dispatch (and other market arrangement) changes with these processes and technical requirements.

The unit commitment and dispatch design outlined in this paper is technology neutral consistent with the broader electricity regulatory framework in the Territory.

### 5.1. Scheduling objectives and mechanisms

Scheduling (unit commitment and dispatch) is to be undertaken in accordance with industry standard security-constrained economic dispatch principles to ensure customer demand is met securely and at least cost consistent with the current I-NTEM requirement.<sup>5</sup> This should be clearly stated in the market rules.

#### 5.1.1. Timeframe and logistics of scheduling

While a simple relatively static merit order of generating sets has provided an adequate basis for decisions about unit commitment in the past, a more dynamic and forward looking arrangement is required to improve efficiency, particularly as the generation mix evolves.

##### 5.1.1.1. Scheduling horizon

In line with government's decision to introduce intertemporal optimisation, the System Controller's decisions about unit commitment will be made over a scheduling horizon that will allow the System Controller to make unit commitment decisions for a sufficiently long period to adequately assess the trade-off between start-up and operating costs for supply of energy and essential system services.

The scheduling horizon should always extend to a period of low load, notwithstanding that the shape of system load is changing and at some times of the year the low point may be in the middle of the day.

A scheduling horizon that runs from the current time to 0400 two days later, is an example of a scheduling horizon that meets these policy requirements. This arrangement would create a horizon that varies between 25 hours and up to 47 hours into the future.

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<sup>5</sup> This design of dispatch assumes that the ESS will be provided through least cost dispatch schedules that meet all related security constraints. It is noted that a review of ESS provision is undergoing consultation and the outcome of that review may result in a need for consequential changes to the dispatch arrangements if a competitive market for ESS is chosen.

Box 1 – Detailed design to be determined through stakeholder consultation on market rules

### **Scheduling horizon**

The scheduling horizon suggested in the paper of the current time to 0400 two days later may be refined taking into account stakeholder feedback through the stakeholder consultation process, providing that the scheduling horizon set out in the market rules meets the policy intent.

#### **5.1.1.2. Scheduling logistics**

The System Controller will make all scheduling decisions consistent with government's decision to introduce centralised unit commitment and dispatch.

To perform this role, the System Controller will require information, including costs and times related to starting and running each schedulable unit and expected capacity. This information is set out at section 5.1.3 of this paper. The System Controller will combine this information with its own estimates of aggregate customer demand across the scheduling horizon and its assessment of the requirements for essential system services and operating constraints to ensure secure and efficient operation of the power system.

The System Controller will make decisions about which generation units and schedulable load blocks (if any) should be committed, or decommitted, and the level at which each unit should be dispatched at. By reassessing the information available to it, the System Controller may make these scheduling decisions at any time, and over any time period, within the scheduling horizon.

It is noted that the approach of the System Controller making scheduling decisions at any time differs from many other markets such as the NEM and the Western Australian Electricity Market (WEM). These markets use a scheduling model where generators are given a dispatch target that they must meet by the end of an interval (e.g. 30 or 5 minute interval) and regulating frequency control services are dispatched under Automatic Generation Control (AGC) for supply and demand fluctuations (from levels assumed at the beginning of the interval). This model reflects that energy demand is typically the primary driver of scheduling decisions in these larger power systems.

The NTEM Priority Reform Program does not adopt the scheduling model of larger systems, reflecting that in a smaller power system like the DKIS, the need to maintain sufficient regulating and contingency reserve has a more dominant influence on scheduling decisions. The scheduling model for the NTEM Priority Reform Program will minimise the level of regulating reserve requirement (relative to if the NEM and WEM model was used) and aligns with the long standing arrangements in the DKIS for real time dispatch to be continuously determined by the System Controller's automatic dispatch systems (e.g. AGC) (which is discussed at section 5.1.5).

#### **5.1.1.3. System Controller may use algorithm or procedural assessment**

Depending on the available resources, the System Controller's unit commitment decisions may be informed by an algorithm which accounts for the costs for start-up and operation over the full horizon. Among other matters this algorithm will observe minimum run time restrictions advised in generator submissions. Alternatively, a procedural assessment over a shortened horizon may be used providing that consideration is given to the full horizon by other means such as (documented) operating practices, which also account for minimum run times or shutdown times.

Regardless of the means used by the System Controller to perform this role, the objective of the overall scheduling process will remain unchanged. At least in the short term a procedural assessment as described above may be a cost effective means for the System Controller to carry out its role noting that it may wish to develop more complex algorithmic approaches for the longer term. The rules will not limit the System Controller's discretion as to how it performs its role providing it does so in an efficient manner and

complies with the scheduling process, the principles of security-constrained economic dispatch and unit commitment and the broader market rules.

### 5.1.2. Scheduling of demand

The immediate focus of the NTEM Priority Reform Program in respect to dispatch and settlement is to ensure market arrangements can accommodate imminent new participants that plan to trade energy, most notably, new large scale solar generators. There is currently no known schedulable demand seeking to participate to be scheduled within the energy dispatch process and receive payment.

The NTEM Priority Reform Program therefore does not include arrangements for *both*:

- the scheduling of demand by the System Controller (that is allowing the System Controller to instruct reductions in demand within the dispatch process on the basis of prices submitted by retailers); and
- providing an associated payment arrangement through the settlement arrangements.

Notwithstanding this, the ongoing market reforms will include consideration of a payment arrangement for schedulable demand seeking to participate in the energy dispatch process as this is currently a barrier to entry. Payment for participation of controllable demand to be scheduled within the energy dispatch process as an alternative to dispatch of generation is complex and will require time to develop.

While the settlement design in this policy paper does not include a payment mechanism for the reasons outlined above, in recognition that schedulable demand should be accommodated, the dispatch design outlined in this paper includes arrangements to be able to dispatch schedulable demand. The System Controller should implement these arrangements noting that they are unlikely to be used until the associated payment mechanism is introduced.

For the avoidance of doubt, the policy set out in this paper is that arrangements for allowing schedulable demand to participate in the energy dispatch process should be established. This will ensure that the dispatch arrangements are ready for when an associated payment mechanism is introduced in the future. The payment mechanism will be developed as part of government's ongoing reform program.

It is also noted there are two other ways that any demand, that is controllable, is likely to be able to participate in the NTEM Priority Reform Program and receive payment:<sup>6</sup>

- Under the proposed reliability priority reforms, a retailer can directly contract with customers in order to reduce its obligation to hold capacity
- Under the proposed market provision of essential system services arrangements, controllable demand may participate in the provision of essential system services.

### 5.1.3. Commitment and dispatch decisions

The System Controller will require information about the availability, costs and operating limits of schedulable units as an input into its scheduling decisions as described in section 5.1.1.2.

The design of commitment and dispatch submission information aims to cover the broad range of generating technologies including dispatchable gas fired generators, solar and storage. Not all information requirements will be relevant for all technologies. Participants will only be required to submit information pertinent to them.

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<sup>6</sup> Consultation papers on reliability and essential system services can be found at: <https://industry.nt.gov.au/electricityreforms>

The dispatch arrangements, including submission information requirements, should accommodate participation of schedulable load and all combined cycle gas turbine plant, noting that specific submission information requirements for these are not set out in section 5.1.3.1. Refer to Box 2 for why these detailed information requirements are not set out in this policy position paper and how they will be determined.

Box 2 *Detailed design to be determined through stakeholder consultation on market rules*

**Submission requirements**

*Submission information requirements will need to support schedulable load*

Government recognises that schedulable load could exist in the Territory in the future and that submission information requirements should be ready for schedulable load participating in the market and not be a barrier to its entry.

The specific submission requirements for schedulable load are not listed in section 5.1.3.1 because they need to be determined with regard to the System Controller's design of its dispatch algorithm (or procedural assessment). These submission information requirements will be set out in the market rules and will be informed by consultation.

*Multiple minimum run times will be allowed to accommodate different technology*

Multiple minimum run times to accommodate combined cycle gas turbine plant with different modes of operating and run times is accommodated. The specific submission information requirement for multiple minimum run times for combined cycle gas turbine plant will be set out in the market rules after consultation with stakeholders.

### 5.1.3.1. Submission information requirements

Subject to Box 2, the submission requirements will include:

- Minimum stable load level
- Run time limitations (if any)
- Time to synchronise from when called by the System Controller
- Time to reach minimum stable load once synchronised.
- One-off cost for start-up and shut-down cycle covering gas use and any maintenance cost related to a cycle as distinct from variable operating cost which is proportional to hours of operation - (\$/startup/shutdown cycle)
- Capacity per band
- Operating cost per band - \$/MWh operating cost in three parts
  - Part 1: The cost to operate at minimum stable load
  - Part 2: A variable operating band between minimum stable load and 'normal' maximum.
  - Part 3: A variable operating band above normal maximum and allows for overload capability and sprint.

The overall design presumes that costs submitted will be bona fide operating costs rather than prices. For example, the only opportunity to amend a submission is because of a physical change to plant or fuel supply. Accordingly, the rules will require that costs submitted will be genuine costs. Dollar amounts must be equal to the actual change in cost due to operation. This requirement will support economic efficiency and prevent the emergence of anti-competitive behaviour, noting at some stage in the future as competitive market structures evolve, consideration may be given to the merits of relaxing this requirement. Although market-oriented mechanisms would be preferable for when it is appropriate to



relax these arrangements in the future, this cost-based approach is seen as a low cost way to manage actual and perceived risk of market power while current market structures exist.

Recognising that there may be a range of possible costs, for example due to variations in plant condition, a 'safe harbour' regimen (set out at section 5.1.3.2) will be established in order to reduce the burden of compliance monitoring for market participants and regulatory authorities. Section 5.1.3.4 provides further information on a requirement to keep auditable records in relation to costs outside 'safe harbour' cost ranges. For further discussion on audit and compliance monitoring arrangements, refer to section 5.2.

The cost in each variable operating cost band must be higher than the previous band. Costs are to be the incremental costs within the band and not averaged from zero.

Revisions to submissions will be required for changes to physical capability promptly after a market participant becomes aware of the change. Noting that all submissions are to be related to costs, any changes during a day will need to be justified as relating to changes in physical capability of plant. This is often termed a bona fide rebid requirement. Commercially motivated rebidding will not be required nor permitted.

### 5.1.3.2. 'Safe harbour' cost ranges

During day to day operation the System Controller will assume all information in submissions provided to it complies with regulatory requirements (for example, that costs in submissions are based on actual costs).

The System Controller will not assess compliance. This will be the responsibility of the Utilities Commission, consistent with its role as independent regulator responsible for enforcement of the SCTC under Regulation 3D of the Electricity Reform (Administration) Regulations 2000, and for the industry more broadly.

The 'safe harbour' cost range regime will be administered by the Utilities Commission to reduce compliance and enforcement overhead costs for the Commission and participants.<sup>7</sup> The Commission will set 'safe harbour' cost ranges for each participating generator (or schedulable load blocks) to assist with development of submissions. Under this regime:

- Submission of costs *within* the relevant 'safe harbour' cost range will be deemed to be compliant with the requirement for cost based submissions
- Submission of costs *outside* the relevant 'safe harbour' cost range will be permitted providing that participant is able to provide justification (which must be documented in a submission) and auditable information is retained in accordance with the requirements at section 5.1.3.4.

To be clear, the 'safe harbour' cost range regime will have no impact on costs that can be submitted by participants on a day to day basis (which is the case in some markets) or how the System Controller will use data in submissions in making scheduling decisions. Safe harbour cost ranges will only reduce the need to undertake ex-post compliance monitoring discussed in section 5.2.2.

The alternative option is not to have 'safe harbour' cost ranges which would mean that every submission would be subject to compliance monitoring by the Utilities Commission. This approach would have a higher regulatory burden on the Commission and participants. Participants would have to keep auditable records to support every submission they make to the System Controller.

#### Setting 'safe harbour' cost ranges by the Utilities Commission

As costs vary by technology and possibly other factors, 'safe harbour' cost ranges set by the Commission will need to be plant specific. For each plant, a 'safe harbour' cost range will be determined for the

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<sup>7</sup> The rules to introduce the 'safe harbour' cost range regime will be introduced in the System Control Technical Code subject to legal and drafting considerations.

startup/shutdown cycle cost and the highest operating cost band. The mid-point of a 'safe harbour' range would be the median cost submitted for a plant.

To provide for transparency and ensure a consistent methodology for setting 'safe harbour' cost ranges for all plant, the Utilities Commission will be required to publish its overarching methodology for setting 'safe harbour' cost ranges. However, the 'safe harbour' cost ranges of each plant will only be shared with the relevant participant and the System Controller and must be treated as confidential by those parties. This is consistent with the requirement of submissions to be confidential (refer to section 5.1.3.7).

The Utilities Commission will be required to review the 'safe harbour' cost ranges every two years, or more frequently at its discretion. A participant may notify the Commission and the System Controller to request an earlier review of its safe harbour range because its costs have been impacted by technology changes or other factors. The Utilities Commission may commence an earlier review in response to a request at its discretion. Because a 'safe harbour' cost range is a pre-qualification range, a review to determine 'safe harbour' cost ranges would be similar to an ex-post review if there was suspicion of non-cost based (non-compliant) submissions. The Commission may seek information from market participants and the System Controller (such as cost and performance information) as inputs into its review and will be required to reference costs for similar plant elsewhere.

#### 5.1.3.3. General cap

In addition to 'safe harbour' cost ranges, there will also be a single system wide general cap to apply to all participants set at a level determined by the Utilities Commission above the highest plausible level of the highest operating cost band. The introduction of a general cap is a market power mitigation measure that can be reviewed in the future.

The Commission will determine the general cap as part of its two yearly reviews, or more frequently at its discretion. Submissions will not be accepted above the general cap. If a submission is made above the general cap, it will be adjusted to the cap. The general cap will be published.

#### 5.1.3.4. Retention of auditable records

Generators (and schedulable load blocks, if any) will be required to keep auditable information and records relating to costs in submissions *outside* a 'safe harbour' cost range (as discussed in section 5.1.3.2).

Information and records to substantiate costs and availability must be kept for seven years. This time period is proposed as it represents a reasonable time period in which disputes or investigations in respect to potential non-compliance may arise.<sup>8</sup> Examples of information and records include, but are not limited to, information from the manufacturer of equipment, records of testing of plant including in respect to efficiency, and data on plant gas use.

#### 5.1.3.5. Submission timelines

Submissions for all generation units (and schedulable load blocks, if any) are to be provided each day. Participants will have the option to set up default submissions where the content of submissions is not expected to change.

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<sup>8</sup> Time periods for retaining records are typically linked to allowable periods for raising disputes or non-compliance concerns. The Territory's dispute resolution mechanisms and the Utilities Commissions' powers in respect to monitoring non-compliance are not limited. However, seven years is proposed as a reasonable time period for retaining records for these purposes.

Box 3 – Detailed design to be determined through stakeholder consultation on the market rules

**Time of day for submitting submissions**

The time of day for provision of submissions is not specified in this policy position paper. The time will need to be determined as part of consultation on the market rule changes as it will be strongly influenced by logistical considerations best assessed in detailed consultation with market participants.

### 5.1.3.6. Capacity

The Generator Performance Standards (GPS) in the Network Technical Code require that forecasting is provided to the System Controller every five minutes. GPS forecasting will be assumed to be the actual capability of a generation unit. This will be overlaid on the generator submission for each interval and be used to set a maximum actual quantity available to dispatch.

### 5.1.3.7. Form of submissions and confidentiality

All the information requirements to be included in submissions will be set out in the market rules, noting that not all information requirements will be applicable to all technology types. However, the format in which participants submit data to the dispatch process, including the detailed design of submission template(s) is an operational matter and not prescribed as a government policy position in this paper.

Submissions will be confidential and will not be published. This reflects that they are cost based (rather than 'price') submissions. This is a similar arrangement to cost based markets elsewhere and reflects that that cost information is commercially sensitive, whereas price based markets typically release submitted prices after a delay.

Box 4 – Detailed design to be determined through stakeholder consultation on market rules

**Form of submissions**

The form in which participants submit data to the dispatch process, including the detailed design of submission template(s) will be determined as part of consultation on the market rule changes.

The consultation process could consider a revised form of the submission template described in the current SCTC or a standardised electronic form. Consideration could also be given to submission templates specific to each technology or a common template that requires each participant to complete only the parts relevant to its technology.

### 5.1.4. Pre-dispatch

Pre-dispatch information will be published by the System Controller for periods commencing 0400 hours for 48 hours ahead.

The pre-dispatch information will include a combination of private information (to be provided to the relevant individual participant) and public information (to be published on the System Controller's website).

Private information will include the relevant participant's expected average output of each generation (or other schedulable) unit in MW on a 30-minute basis and amounts of different essential system services required. Public information will include forecasts for underlying demand and behind the meter solar energy, flow on the 132kV line and prices per 30-minute interval.<sup>9</sup>

Publication requirements for information are discussed at section 5.2.1.

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<sup>9</sup> These are not intended to be exhaustive lists of private information and public information.

### 5.1.5. Real time dispatch

Second by second physical dispatch after a generating unit has reached minimum stable load will continue to be based on incremental cost curves, noting they will now be multiplied by the Marginal Loss Factor assigned to the generator connection point for the purposes of determining dispatch order. The cost curves are based on incremental heat rates combined with fuel cost (including delivery) in the System Controller's automatic dispatch systems (e.g. AGC). Ideally these cost curves should align with the cost data from generators but may introduce minor approximations. As settlement will be on the basis of 30-minute data, misalignment will be assumed to be immaterial. Refer to Appendix C for further detail on loss factors.

### 5.1.6. Tie-break decisions

Where two or more generators could equally be eligible for dispatch based on effective cost and security concerns, the System Controller will where feasible pro rata dispatch. Where this is not practicable, the System Controller will add a small random number of (e.g. \$0.0001/MWh) to the cost of a unit so that when rounded, the two decimal market price will not be impacted. The System Controller will be required under the market rules to establish and publish a procedure for managing tie breaks. The market rules will require consultation on development of the procedure with market participants.

### 5.1.7. Derivation of security constraints

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

Based on that advice, the System Controller will determine network operating limits and constraints on the commitment and dispatch of generators needed to ensure secure operation of the power system. The System Controller will also determine the level of essential system services and related system security constraints it will require to ensure the power system operates securely in accordance with principles in the SCTC and detailed procedures in the System Operating Procedures.

The System Controller will be required to retain a record of any constraints that it applies so that they are transparent and able to be understood and reviewed by market participants. This information will constitute public information and will be published on the System Controller's website in accordance with timing in section 5.2.1.

### 5.1.8. Commitment and dispatch instructions

The System Controller is to determine the mode for issuing instructions in accordance with protocols established between it and market participants under the market rules. For example, this may include logged telephone calls for commitment and AGC for dispatch instructions.

## 5.2. Ex-post arrangements to ensure transparency and accountability

### 5.2.1. Documentation of scheduling decisions

Inevitably the System Controller's decisions about unit commitment may not be optimal when analysed after the event (for example, because a generating unit failed or demand or solar capability was materially different from forecast). The System Controller should only be accountable for factors within its control.

To ensure transparency and enhance accountability the System Controller will be required to publish sufficient information for participants to review decisions about unit commitment and dispatch. Publishable records of the basis for unit commitment decisions may be in the form of a note of expected

run time and how the operating cost and startup cost of the selected unit will be the lowest cost option. Reference to pre-dispatch information may be the most pragmatic means to create this record.

Before the time of dispatch, pre-dispatch information will include both private and public information as noted in section 5.1.4. At the time of pre-dispatch, public information will be published, however, private information will only be provided to the generator (or schedulable load block) it relates to.

Seven days after the time of dispatch, all private information from pre-dispatch will also be published on the System Controller's website. At this time, the System Controller's record of the basis for unit commitment, actual dispatch of each generating unit and flow on major transmission lines, will also be published. Only commercially sensitive information should remain confidential on an ongoing basis (with only the relevant participant, System Controller and Utilities Commission entitled to access it).

#### 5.2.1.1. Compensation for dispatch errors

Arrangements for compensation for a range of types of dispatch 'errors' (such as human error, incorrect SCADA inputs, among other things) will not be introduced as part of the Priority Reform Program. It is noted that in most markets where such arrangements are in place, dispatch errors do not occur frequently and rarely have material financial impacts on market participants. The implementation and administration of compensation arrangements would result in increased costs that would ultimately impact consumers and taxpayers and are not expected to outweigh the benefits. The enhanced transparency requirements outlined above are considered to be a more cost-effective means to increase the System Controller's accountability.

#### 5.2.2. Suspected non-compliance and audits

The Utilities Commission will have the power to investigate submissions outside 'safe harbour' cost ranges for suspected non-compliance by participants in respect to the requirement for cost-based submissions to be provided to the System Controller. It may carry out investigations consistent with the Commission's powers under the *Utilities Commission Act 2000*, licence conditions and the broader regulatory framework.

The options available to the Utilities Commission to investigate suspected non-compliance include its current power imposed through licence conditions to appoint an external auditor. This power may be used to audit information and records to assess whether a participant is complying with the requirement for submitted cost information to be equal to auditable operation costs.<sup>10</sup> Under the current external audit arrangements, the licensee pays for an audit, which creates an incentive for licensees to use all reasonable endeavours to remain within their 'safe harbour' cost ranges, but also highlights the importance of reviewing the guidelines two yearly or earlier as required.

The market rules will require that the System Controller provide a report to the Utilities Commission documenting all instances where participants have made submissions outside their 'safe harbour' cost ranges. The report must include the justification for the non-compliance provided by a participant in its submission. The report must be provided on a six monthly basis and will not be published reflecting that cost submissions and 'safe harbour' cost ranges will be confidential. The report will ensure the Commission is informed of submissions outside of 'safe harbour' cost ranges so that it may investigate these at its discretion, consistent with its role as independent regulator.

Should the Commission investigate submissions outside of a 'safe harbour' cost range (for example, by undertaking an audit) and form a view that the submissions are non-complaint, the Commission has the discretion to take appropriate action to enforce the market rules under its powers available to it as part of the Territory's broader regulatory framework.

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<sup>10</sup> Rebidding restrictions in the NEM require similar records. Use of existing audit powers in the Territory (rather than establishing a new powers) will minimise additional costs.

### 5.3. Market Price and relationship with settlement arrangements

The Market Price will be used to determine the cost of trading out-of-balance energy (being energy that is in surplus or deficit to contracted amounts between generators and retailers). Energy production and consumption that is covered by contracts will be priced in accordance with contractual arrangements between market participants. It is understood that many contracts currently used by market participants in DKIS will not result in out-of-balance energy.

Calculation of the Market Price will be undertaken by the System Controller as it relies on knowledge of the way the power system is operated and is generally considered the last step of the dispatch process.

The price band of the marginal, unconstrained generator (or possibly schedulable demand in the future) offer will determine the Market Price for each 30-minute Trading Interval. Unconstrained, in this sense, refers to a generator that would be dispatched to a higher level if demand increases but is not otherwise constrained (for example, due to network or system limitations or to provide certain essential system services). This reflects the basic principle that price will reflect the marginal or incremental cost of a small change in demand as this is an economic signal to both generators and retailers of the value in changes in generation and demand. This principle is used to set prices in most competitive electricity markets around the world. Use of the price of highest unconstrained generator is a pragmatic approximation to a more complex derivation of marginal cost that could show multiple generators and multiple essential system service providers may be at the margin.

Due to the high degree of interrelationship with the priority settlement changes, further information on the Market Price and the method for calculating it, is set out in section 6 and Appendix B.

## 6. Policy position on settlement priority changes

This section outlines the Territory Government's policy position in respect to the design of priority settlement changes.

The dispatch and settlement priority changes have been designed, and consulted on, in a coordinated manner to ensure they complement each other and will result in aligned outcomes.

The design of the settlement arrangements has involved making appropriate trade-offs aimed at providing an efficient design that provides the best outcome for customers. It is preferable to deal with complex issues through the design of less time sensitive issues, like settlement, rather than in the design of real time activities, like dispatch. This approach is reflected in the design of the priority changes for settlement in this paper. In acknowledgement of this, section 6 discusses various policy options and the trade-offs that were considered in reaching government's policy positions for the design of priority changes for settlement.

There are many aspects to settlement. The information box below breaks settlement components into three main categories and provides a guide for where policy for each component is discussed in this paper.

#### Box 5 - Overview

##### **Overview of priority settlement arrangements**

The policy design on settlement priority arrangements comprises the following three main components:

- **The settlement process and timetable.** This includes the number of days to be included in a single settlement (the Settlement Period), the number of days before the settlement statement is produced and the number of days before payment is required and energy sellers are paid. See section 6.1.

The settlement process will include an ability to dispute settlement. See section 6.1.2.2.

- **Calculation of the Settlement Amount.** This is the calculation of the amounts to be collected from nett purchasers of services and the amounts to be paid to the nett providers of those services. This includes six related issues:
  - Metering and the calculation of energy sent out or consumed which is regulated under Chapter 7A of the National Electricity Rules
  - The number and locations of the settlement points (Reference Nodes) (see section 6.2 and Appendix B)
  - The treatment of startup and shutdown costs (see sections 6.3 and 6.5.2).
  - The treatment of losses (see Appendix C)
  - Calculation of out-of-balance energy payment (see section 6.5 and Appendix B)
  - The management of settlement residues (see section 6.2.2.1)
- **Management of the risk of participant default.** These are the measures employed to mitigate default risk where possible and to ensure that the financial integrity of the market can be maintained in the unlikely event that a failure of a participant occurs. See section 6.4 and Appendix D.

As noted in section 2, given the need to implement the priority dispatch and settlement as quickly as possible, and that design of essential system services and reliability components of the NTEM Priority Reform Program are ongoing, the current approach to settlement of essential system services is assumed in this paper.

In respect to essential system services, currently, settlement statements are prepared by the Market Operator but settlement occurs directly between market participants and Territory Generation as the primary service provider. The design development and consultation process for priority dispatch and settlement changes (undertaken during the second half of 2020) did not seek to design alternative settlement arrangements for essential system services as this would have pre-empted the outcomes of the review of potential market provision of these services. For similar reasons, the design in the paper does not contemplate potential settlement arrangements associated with reliability reforms that are still under development and subject to government's consideration.

In addition, no changes are proposed to the current arrangements for cost recovery for the System Controller. System Control (and Market Operator) tariffs will continue to be determined in accordance with section 39 of the *Electricity Reform Act 2000*.

## 6.1. Settlement timetable

For an electricity system with privately owned participants, the timetable will need to balance the needs of market participants and the Market Operator for:

- an administratively simple process
- a steady flow of cash to efficiently fund their operations
- a manageable limit to their market exposure in the case of default.

Factors to consider when making the decision are:

- the size and variability of the of the settlement transactions in the market
- the riskiness of the participants, which can be measured by their credit rating.

For the initial stages of the market under the Priority Reform Program:

- the size of the balancing market amounts will be relatively low, in the event there is energy out-of-balance.
- there will be no financial settlement of essential system services via the Market Operator, with all financial transaction to continue to occur between Territory Generation and market participants.

### 6.1.1. Alternatives

An analysis of different markets shows a range of approaches to the settlement timetable. Table 5 shows parameters for the current I-NTEM in place in the DKIS, the NEM and the WEM.

Table 5 Settlement timetables for the current I-NTEM, NEM and WEM

Option	Current I-NTEM	NEM	WEM
Settlement Period (SP)	One Calendar month	7 days	7 days
Draft invoice	5 business days after SP	5 business days after SP	-
Settlement statement (transaction details)	5 business days after SP	5 business days after SP	1 business days after SP
Final invoice	15 business days after SP	15 business days after SP	1 business days after SP
Settlement day	20 business days after SP	20 business days after SP	2 business days after SP
Dispute notification	Not stated	After receipt of the draft invoice and before the final invoice.	Before 21 business days after settlement statement

The current I-NTEM approach allows one month of trading to accrue followed by 20 business days before settlement occurs. The WEM has a Settlement Period of seven days and settles two business days later. The NEM is between these two options with a settlement week of seven days and final settlement 20 business days after the end of the week.

The WEM provides for a fast flow of cash through the settlement system but at the cost of potential clawbacks as disputes over trading amounts are handled after settlement has occurred. While it is not stated in the current I-NTEM it is likely that a participant would dispute a draft invoice, like in the NEM and any errors in the invoice could be corrected before settlement occurs. This is administratively simpler.

When considering the potential for default, the current I-NTEM has the longest period for a participant to accrue debt, between 56 and 59 days, while the WEM has the shortest of 11 days. The NEM, which has the highest Settlement Amounts of the three markets, allows 37 days.

### 6.1.2. Policy position

Taking into account the policy considerations and factors discussed above, it is considered appropriate to adopt a Settlement Period of seven days with other items remaining the same as for the current I-NTEM. This approach should be administratively simpler and reduce the risk of default. It may also have some benefits due to its similarity with the NEM by providing some degree of familiarity for new or prospective new entrant market participants with knowledge of the NEM.



The settlement timetable will comprise:

- a Settlement Period of seven days
- a settlement statement and a draft settlement invoice to be provided to each market participant five business days after the end of the Settlement Period
- a final invoice to be provided to each market participant fifteen business days after the end of the Settlement Period
- a requirement on market participants to provide the Market Operator any funds due twenty business days after the end of the Settlement Period<sup>11</sup>
- a requirement on the Market Operator to pay participants any funds due twenty business days after the end of the Settlement Period

The Market Operator will publish and maintain a settlement procedure and timetable.

#### 6.1.2.1. Transitional timetable

A transitional settlement timeline is required before moving to the Settlement Period of seven days.

The Power and Water Corporation (PWC) is currently in the process of procuring a new Meter Data Management System (MDSM) which it needs to improve its management of metering data as the Territory's metering service provider. Improved meter data management capability will also support the new settlement timetable. Accordingly, the current I-NTEM settlement timetable, with a Settlement Period of one calendar month, will need to continue until the MDMS is in place.<sup>12</sup>

If this transitional arrangement is not provided, to accommodate the new settlement timetable with a seven day Settlement Period, PWC would need to upgrade systems and other (manual) capability on a temporary basis prior to the commissioning of its MDMS. There would not be a net benefit to consumers associated with this as a short term measure.

#### 6.1.2.2. Settlement disputes

The inclusion of third parties in the market will require the development of an effective method for handling settlement disputes. An efficient disputes mechanism will include:

- a clear, transparent process
- effective communication processes with appropriate documentation
- strategies that are:
  - fair and proportionate to the matters in dispute
  - lead to early resolution at minimal cost
- genuine engagement between the parties in dispute and potentially impacted parties
- collaboration in developing the solutions and approaches to resolution
- appropriate escalation of the issue when required.

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<sup>11</sup> In the NEM, parties owing settlement amounts lodge cleared funds with AEMO via Austraclear in the morning of the settlement day and AEMO pays cleared funds via Austraclear to parties owed settlement amounts in the afternoon.

<sup>12</sup> Chapter 11A of the National Electricity Rules requires that the MDMS be in place on 1 January 2022.

Currently, relevant dispute resolution processes are set out in SCTC clause 1.5 which requires negotiation of mutually acceptable outcomes between a market participant and the System Controller or Market Operator, but not between two market participants. The *Electricity Reform Act 2000* also provides a mechanism for the Utilities Commission to investigate complaints relating to whether an electricity entities conduct is contrary to licence conditions(s) or the objectives of the *Electricity Reform Act 2000* or the *Utilities Commission Act 2000*.

A comprehensive review of all disputes process and frameworks for the Territory's electricity sector is not contemplated as a priority change required as part of this work program. However, amendments will be made to the existing dispute resolution arrangements at SCTC clause 1.5 to support the priority changes including for settlement.<sup>13</sup> This will include improvements to the dispute resolution arrangements for disputes between parties (including two market participants) in respect to payment of moneys, or the performance of an obligation, under the SCTC.

Relevantly to the settlement timetable, this will include a requirement to raise any dispute in relation to the Settlement Amount when a draft invoice is issued and prior to the final invoice being issued.

The premise of improved dispute resolution arrangements for the SCTC will continue to be that disputing parties should seek to resolve disputes themselves and only escalate disputes (e.g. to the Utilities Commission, or an independent body agreed between the disputing parties) if this fails.

## 6.2. The number and location of nodes

The market arrangements to be introduced in the Priority Reform Program will ensure outcomes in respect to settlement are accurate in relation to both the balancing and the contract markets in the face of network constraints that limit the physical dispatch of energy.

### 6.2.1. Background

To assist the trading in energy, when there are multiple buyers and sellers there is a need for a common point to value the energy that they trade, which is termed the Reference Node. Currently, there is no common point to trade energy in the DKIS which will become increasingly complex and eventually unworkable with the increasing number of participants to be settled.

In electricity markets, all transactions are typically considered to have been made at one or more Reference Nodes and the common price for trading is the price(s) at the Reference Nodes (the Market Price(s)). The issue for generators is therefore to get their energy to the Reference Node and for retailers to be able to access energy from the Reference Node. Due to network constraints, some markets contain more than one Reference Node to correctly value the energy traded. The decision on whether to use a single or multiple Reference Nodes is a trade-off between market complexity and market efficiency (pricing accuracy).

For example, in the current design of the WEM, based on an unconstrained network, there is one Reference Node used by customers. Generators that are constrained away from the Reference Node suffer a reduction in the price of their energy and are paid an uplift so that they receive the Market Price. Customers incur the cost of the uplift. The WEM design is currently being modified to a constrained model where constraints that are economically justified can result in dispatch of affected generators being constrained. No decision about uplift has been taken for the new design. The WEM approach with one Reference Node and a common price reduces contracting complexity but means that the generators and

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<sup>13</sup> An appropriate dispute framework that should be used as a model for improvements to the SCTC dispute resolution arrangements is the Western Australian Wholesale Electricity Market Rules, sections 2.18–2.20.

retailers may not see the true economic price for the energy sold and consumed. This reflects how accuracy, complexity and cost are balanced in the WEM design.

The NEM design uses a different approach with five Reference Nodes (Regional Reference Nodes or RRN). This provides for more accurate energy pricing for market participants (compared with a uniform market wide price) but increases the complexity of contracts since they need to be valued against their local RRN. Contracting between regions requires acceptance of a price risk as contracts are settled against the local RRN. For the NEM, this risk is mitigated somewhat by the sale of settlement residues<sup>14</sup> to offset this risk<sup>15</sup>. The NEM design is also being reviewed through the Coordination of Generation and Transmission Investment (COGATI) review being run by the Australian Energy Market Commission (AEMC). Additional financial access contracts are being discussed in this process.

Markets elsewhere, for example New Zealand and many United States, markets use a nodal approach where a separate price is determined for each connection point. This approach is known as Locational Marginal Pricing (LMP).

### 6.2.2. Comparison of the options

Under the market design for the Priority Reform Program, the marginal, unconstrained, dispatched generator will set the price. Unconstrained, in this sense, refers to a generator that would be dispatched to a higher level if demand increases but is not otherwise constrained (for example, due to network or system limitations or to provide certain essential system services).<sup>16</sup>

If the DKIS is considered as a whole, when there are constraints on generation south of Channel Island<sup>17</sup> due to a significant flow of energy from the south to the north, only a generator in the north can be the marginal, unconstrained generator for the entire DKIS.

There will be a marginal generator south of Channel Island which will meet the local supply but as it is constrained away from the entire load, it cannot set an overall price. It does, however, indicate the value of supply for connected parties south of Channel Island during the constrained operation.

If only one Reference Node is used all out-of-balance bought or purchased by generators and retailers in any location in the DKIS would be transacted at the same price, being that of the marginal generator north of Channel Island in this example.<sup>18</sup> This would have the effect of overvaluing out-of-balance energy in the south. This would benefit suppliers of out-of-balance energy but disadvantage purchasers. Depending on why the out-of-balance occurred this will result in windfall gains and losses to either generators or retailers.

This situation can be contrasted to a gross settlement market (such as the NEM) where market settlement relates only to metered generation and consumption and does not consider contracts. In the example above, generators would receive a windfall gain and retailers would pay more than the economic value of their consumption. In a net settlement market, as is to be in place for the DKIS, the exposure to market

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<sup>14</sup> Settlement residues are the differences between the amounts collected and the amounts paid out during a settlement process. The expected settlement residues are discussed at 6.2.2.1.

<sup>15</sup> The sale of the settlement right is a "Flowgate Right", that is a right to the value across a constraint. In effect, the price at the local RRN plus the Flowgate Right should equal the price of the RRN on the other side of the constraint, in the long run.

<sup>16</sup> This is a common approximation to an algorithmic calculation of what the change in cost across the power system would be for a small increase in demand which may involve more than one generator and reallocation of essential system services.

<sup>17</sup> This example assumes the constraint is due to flows from the south, but the same analysis would apply for flows from the north. As each plant is dispatched to its maximum for a band the next more expensive plant/band is always chosen next. Therefore, when the line becomes constrained, the next plant chosen, which is on the load side of the constraint, must be at a higher price.

<sup>18</sup> This is due to the rule for setting the Market Price based on the marginal, unconstrained generator. Other price setting rules could be developed but this would create a complication for settlement.

price depends on differences between metered quantities and contracts which can be positive or negative for generators and retailers, and any windfall from settlement using a single reference point has a less certain outcome.

Using two Reference Nodes would allow two prices during periods when there are constraints either side of Channel Island. The price against each node would be set by the relevant marginal, unconstrained generator<sup>19</sup>. The two node approach therefore ensures that the value of energy exchanged between retailers and generators is a more accurate reflection of the true value of the energy exchanged. The cost of out-of-balance energy settlement will be lower in aggregate compared to if only one Reference Node was used. This will result in lower and more accurate customer charges under a two Reference Node model. Accordingly, a two Reference Node model is in the best long-term interests of consumers.

It should be noted that under a two Reference Node approach, when a constraint occurs other than at Channel Island, the result will still create winners and losers and pricing inaccuracy but on a smaller scale. This could be addressed by adding additional Reference Nodes, but this is not likely to be cost effective or reflect the most appropriate trade-off between accuracy and complexity.

An additional benefit of more accurately valuing energy under two Reference Nodes is that it would create locational signalling. Noting that there may be many factors considered by a connecting party when deciding where to locate, under two Reference Nodes there would be an incentive for new generators to locate near the highest value loads. Similarly, to the extent customers have locational flexibility (noting many customers would not), they would be incentivised to locate in regions with lower prices.

The two Reference Node option is therefore preferable and reflected in the proposal in section 6.2.3.  
Policy position

The policy position on Reference Nodes has been determined to ensure simplicity in contracting and to recognise the likely key constraint in the DKIS is of flow on the 132kV line south of Channel Island. Noting that the Market Operator will only settle out-of-balance energy, not gross amounts like in the NEM, the design is:

- To introduce two Reference Nodes, being Channel Island North and Channel Island South, located either side of Channel Island linked via a virtual inter-connection with no loss
- If flow on the 132kV line between Channel Island and Katherine is not constrained in a particular half hour, there will be no difference in Market Price between the two Reference Nodes
- Losses for all participants are to be calculated with reference to the Channel Island Reference Nodes, noting that the location of the nodes has been chosen such that there will be no loss in between the two nodes
- All other constraints will be ignored for settlement purposes (but will nevertheless affect dispatch volumes and the out-of-balance Market Price)
- The two Reference Nodes will result in the creation of two regions in the DKIS for the purposes of settlement. Each region will include all connection points connected to either Channel Island North or Channel Island South
- The settlement process will take into account the allocation of participants' contract volumes north and south of Channel Island (within either the northern or southern region). Market participants will be able to nominate their allocation of contract volumes if desired to accurately reflect true

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<sup>19</sup> If there is no constraint, the two prices will converge as any generator in the DKIS can be the marginal unconstrained generator for either node.

conditions. In the absence of a notice from contracting parties, the settlement process will assume contract volumes are aligned with retailer's load in each region.

This approach — of two Reference Nodes and a lossless link — will simplify the contracting process. Generators and retailers may continue to contract on the basis of a single system (i.e. separate contractual arrangements will not be required for north and south of Channel Island). However, as noted, participants can advise that contracts are to be treated as split between the regions at their discretion and this can be accommodated within the design. The practical application of this approach is described in more detail in Appendix B.

An additional benefit of the lossless link between the two Reference Nodes, is that at times when there is no constraint at Channel Island, or if the constraint permanently ceases, DKIS would effectively act in the same way as a single region, rather than two regions. Effectively, there would be a common price for the DKIS.

It is understood that at present, contracts entered into by market participants are in a whole of meter form where no energy out-of-balance will occur.

#### 6.2.2.1. Settlement residues

The use of two Reference Nodes and Marginal Loss Factors will lead to a variance between the amounts paid to the Market Operator and the amounts paid out by the Market Operator. This is termed a Settlement Residue.

In the event that contracts create out-of-balance energy conditions, the Market Price differs between the two Reference Nodes and there is a power flow between the two regions, a Constraint Settlement Residue will occur, where the Market Operator will collect more or less revenue from participants than it pays to participants. This Constraint Settlement Residue can be positive or negative (as discussed further in Appendix B). Appendix B notes that it is highly likely there will be more instances of positive residue than negative residue, where the Market Operator collects more from participants than it pays out and is left with surplus funds.

The use of Marginal Loss Factors to determine the Market Price is discussed in Appendix C, which notes that positive settlement residues will result.

Any nett settlement surpluses (positive residue), whether due to constraints or loss factors, will be returned to customers. This will be implemented by offsetting the Market Operator component of the System Control tariff approved by the Utilities Commission<sup>20</sup>. A calculation of any reduction of the Market Operator component of the tariff to take into account nett settlement surplus may be calculated annually.

### 6.3. Startup and shutdown cycle costs

It is important to ensure the coordinated consideration of unit commitment and dispatch and settlement arrangements (and all market arrangements more broadly) given their high degree of interrelationship. The processes for cost (or price band) submissions by generators (of schedulable demand blocks), unit commitment, dispatch, determination of Market Price and settlement must be individually and collectively robust and support least cost delivery of a secure and reliable power system. Arrangements for payment for providing essential system services and for participating in the central dispatch process (for example, where decisions to start each generating unit are made by the System Controller) should align and be internally consistent with other elements of the design.

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<sup>20</sup> Regulations under the *Electricity Reform Act 2000* may be made to clarify this policy intent.

The treatment of startup/shutdown cycle costs must align with other design elements of the Priority Reform Program, and this was a key consideration in assessing the options for treatment of startup/shutdown costs below.

### 6.3.1. Options

As discussed in section 5, under centralised unit commitment, the System Controller will determine when a unit will startup and shutdown by taking into account the trade-off between startup and shutdown cycle costs and operating costs. Therefore, startup and shutdown expenditures are outside the control of generators.

There are a number of options to ensure generators can recover a startup and shutdown cycle, which are set out in Table 6, below.

Table 6 Summary of options for treatment of startup and shutdown cycle costs in settlement

Option	Commentary
<p>Amortising costs for startup/shutdown cycles in the price for energy:</p> <ul style="list-style-type: none"> <li>• based on <i>expected</i> run time at the time of startup; or</li> <li>• after the event based on <i>actual</i> energy</li> </ul>	<p>Both of these options will create discrepancies with the process for dispatch to be introduced as part of the Priority Reform Program, which is based on dispatch on incremental cost<sup>21</sup> in the current System Controller’s AGC (or similar) system<sup>22</sup>.</p> <p>In some circumstances when congestion is present and out-of-balance energy is settled at a prices for Channel Island North and Channel Island South, both of these options could result in ‘reverse price flows’ where flow from north to south is in the economically correct direction but inconsistent with market price.</p> <p>Additionally, in the absence of contracts that create energy out-of-balance conditions (as is currently the case), generators would not be able to recover startup/shutdown costs if this approach was used.</p>
<p>Assuming generators will recover an allowance for startup/shutdown cycles in contracts.</p>	<p>The advantage of this approach is that it is simple. However, it is also opaque and exposes generators to a risk of costs that they had not expected (in terms of the number of cycles) as they are out of their control.</p> <p>In these circumstances, it is typical for generators to include a conservative allowance (risk premium) in their contracts and day ahead pricing to address this risk. This allowance is likely to increase cost to customers and represents a deadweight loss to the market.</p> <p>This may reduce the benefits of introducing centralised unit commitment.</p>

<sup>21</sup> The incremental cost is based on incremental heat rates combined with fuel cost (including delivery)

<sup>22</sup> Market designs such as the NEM use this option but also use the amortised price in dispatch and hence dispatch and price are aligned. Further the NEM is an energy only design where pool prices are expected to rise above the cost of fuel and participant estimated amortised startup cost in order to recover fixed costs that are embedded in contract prices in the NT under current arrangements (or in the future, possibly capacity prices).

Option	Commentary
Separately charging for startup/shutdown cycles	<p>The key advantage of this option is that generators are paid for the actual number of startup/shutdown cycles instructed by the System Controller. The market rules would limit payments to successful starts as an incentive to generators to improve reliability of starting.</p> <p>Disadvantages of this option are that:</p> <ul style="list-style-type: none"> <li>• current generator to retailer contracts would need to be adjusted to remove startup/shutdown cycle costs</li> <li>• additional monies would be transacted through the Market Operator settlement system; and</li> <li>• there would be additional record keeping.</li> </ul> <p>The payment would be based on the full cost of the startup/shutdown cycle for a generator (i.e. all costs incurred except the running cost while dispatched).</p>

It is noted that the draft NTEM Functional Specification, which was consulted on in February 2019, canvassed the first option in this table where the cost of startup would be amortised across the day and added to the variable cost.

However, with two Reference Nodes to be introduced in the Priority Reform Program (as discussed in section 6.2 of this paper), this approach could, in some circumstances, result in perverse, reverse power flows. This would occur where the correct flow from lower to higher variable priced regions becomes a flow from higher to lower priced regions after the addition of startup cost to the ex-post Market Price in the settlement process.

For example, in a situation where the 132kV line is constrained south of Channel Island:

- the variable cost in the south is \$50/MWh and in the north is \$60/MWh; and
- the flow would be correctly scheduled to flow from the lower to higher variable priced region, being a flow south to north.

However, if the Market Price (determined ex-post) including amortisation of startup cost where:

- the amortised startup component in the south is \$15/MWh and in the north is \$2/MWh,
- the ex-post Market Prices would be \$65/MWh in the south and \$62/MWh in the north; and
- the correctly dispatched flow would be from the higher to lower variable priced region.

Further, if startups were to be charged as an amortised component of Market Price in a situation where there was no energy out-of-of balance – and therefore no energy out-of-balance payment – generators would be forced to incorporate an estimate of the number of startups in contract prices, despite having no direct control over how often their units were started. This would effectively result in the second option in the table above which is likely to increase the costs to consumers.

The third option in the table to separately charge for startup costs would avoid the counter-price flows issue, the need for generators to estimate startups for their generation units and the associated incentive to make conservative estimates. Therefore, the third option is the most efficient.

### 6.3.2. Policy position

The approach to be introduced as part of the Priority Reform Program is to separately charge and pay for startup/shutdown cycle.

- Each generator will be paid for the sum of its startup/shutdown cycles at the end of each week. This is the total of the costs attributable to starts and stops in the week.<sup>23</sup>
- Each retailer will pay for a share of the total weekly cost of startup/shutdown cycles of all generators. The share will be calculated based on each retailer's share of total energy.

The approach will ensure that there is no likelihood of 'reverse price flows' and the cost recovery for startup/shutdown cycle costs is efficient and serves the best interests of consumers.

To be clear, startup/shutdown cycle costs of a generator will only be recoverable through this mechanism when the startup and/or shutdown is successful and at the direction of the System Controller. For a successful startup/shutdown cycle at the direction of the System Controller, a generator will be entitled to recover all costs associated with the startup/shutdown cycle except for the cost of running while dispatched.

The separate charge for startup/shutdown cycles will not be used:

- to recover costs for a generator's unsuccessful startup (e.g. if a unit fails to synchronise or once synchronised fails to reach minimum stable load. A detail definition will be developed)
- startups and shutdowns that are not in accordance with unit commitment instructions of the System Controller; or
- startups and shutdowns that are for a generator's maintenance and testing purposes.

In the case of unsuccessful startups, not providing cost recovery through this mechanism reflects that a generator should not be compensated if it does not provide the required service. This also provides an incentive for generators to ensure that their plant is capable of reliably starting when required.

In the case of startups/shutdowns for maintenance and testing, these costs are part of the cost of doing business and equivalent to fixed costs and likely to be recovered through contracts.

This approach will introduce variability into retailers' settlement amounts outside of contracts. However, the aggregate startup/shutdown cycle amount will be far less than amounts expected to be settled under contracts covering energy and capacity and also essential system service charges.

## 6.4. Participant default

A potential exists for market participants to exit the market under a range of scenarios, including leaving a debt to the Market Operator. This is a common issue for all open access markets that requires consideration of prudential arrangements. A useful discussion of prudential approaches can be found in a paper by a CIGRE working group<sup>24</sup> and relevant considerations are canvassed in Appendix D.

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<sup>23</sup> Where a generation has started but not stopped in the settlement week, the full cost of the startup and shutdown would be charged in that week and not when the generator is shutdown.

<sup>24</sup> Ford et al, "Default Management in Electricity Markets", 2016. CIGRE Technical Brochure 648, [www.e-cigre.org](http://www.e-cigre.org).



### 6.4.1. Approaches used in other markets

Other markets use a set of common approaches to manage the risk of participant default:

- Participant fitness. Almost all markets require a participant to show that they are financially and operationally fit to perform their market roles at the time of registration. In some markets, like the NEM, this is not retested unless there is a default event. Other markets, like Colombia and PJM<sup>25</sup>, have an ongoing fitness test for financial fitness.
- Limiting trading. All markets limit the ability of participants to trade based on:
  - their investment grade or backing
  - lodged cash or prudential instruments; and
  - variability of the market.

For example, in the NEM, each participant is required to lodge cash or prudential instruments to a level determined by the Australian Energy Market Operator (AEMO) based on their expected Settlement Amount and the volatility of the Market Price.

- ‘Step in’ rights. In some markets, notably Colombia, where a participant is failing, the Market Operator has the right to take over its operations to prevent default and to manage or sell the operation.

The approach to be taken depends on:

- the nature of participant entering the market. Large, investment grade entities are lower risk than small startup companies
- the design of the market, in particular how large the potential outstanding amount for each participant can be; and
- the consequence of default. In the Territory, and most markets, it is impossible to disconnect customers if their retailer fails. Therefore, the billing process and flow of cash to energy providers must be maintained to protect against cascading failures of market participants

Currently in the Territory, the amounts expected to be settled in the early stages of the Priority Reform Program are low and therefore the consequences of participant default are low. The settlement requirements to manage the risk of participant default should be proportionate to the risk and can therefore be set at a low level, subject to review if the amounts settled by the Market Operator become significant.

### 6.4.2. Policy position

It is proposed that the Priority Reform Program adopt:

- A fitness test for new entrants. Under the *Electricity Reform Act 2000*, a person must not carry on operations without being granted a licence by the Utilities Commission and the Commission must consider the suitability of the licence applicant in accordance with the requirements of the Act. This is consistent with the approach in other markets and includes:
  - the applicant’s previous commercial and other dealings and the standard of honesty and integrity shown in those dealings

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<sup>25</sup> PJM Interconnection is a transmission level network and energy exchange operated for a number of states, including Pennsylvania, New Jersey and Maryland in the US. It is a balancing market like that in the DKIS but with a capacity overlay.

- the financial, technical and human resources available to the applicant; and
- the officers and if applicable, major shareholders of the applicant and their previous commercial and other dealings and the standard of honesty and integrity shown in those dealings.

The licence should include a specific requirement for the participant to notify the Commission should any of the factors considered by the Commission in granting the licence change<sup>26</sup>

- An unlimited trading limit, subject to review by the Utilities Commission two years after these reforms commence, noting the rule will also allow the Market Operator to propose (and outline its reasoning for the proposal) that a review be undertaken earlier, which the Commission may consider
- An obligation on the Market Operator to manage counterparty risk in market settlement. This will be a statutory function on the Market Operator and include a requirement for it to make payments to market participants owed in the event of a default
- The discretion for the Market Operator to impose additional prudential requirements on a Market Participant that is likely to pose a material default risk. Under this arrangement:
  - the 'trigger' for when a participant is likely to pose a material risk will be clearly defined. The additional prudential requirements will only be permitted to be imposed by the Market Operator if:
    - a market participant's Settlement Amount averaged across four Settlement Periods exceeds 10 per cent of the total of the Settlement Amounts<sup>27</sup> of all market participants; and
    - the market participant has a credit rating<sup>28</sup> that is less than BBB+
  - if this trigger is met, the Market Operator may require the market participant to lodge bonds, guarantees or cash up to the amount that is equal to the two most recent Settlement Amounts. The participant will then be required to maintain the required level of lodged bonds, guarantees or cash
  - where the Market Operator notifies a participant that an increased amount is required (due to the amount of the two most recent Settlement Amounts changing), the market participant must lodge bonds, guarantees or cash to satisfy the requirement within two days of the notification of the increased amount
  - In the event that a market participant, subject to these requirements, defaults on all or part of a required payment to the Market Operator, the Market Operator will use all or part of any lodged bonds, guarantees or cash from that participant to satisfy the debt of the market participant. If a debt remains, the Market Operator will pay the other market participants as part of its statutory function, described above.

Failure to pay a Settlement Amount, or lodge bonds guarantees or cash if required, will constitute a Default Event.

Appendix D provides further detail on the prudential arrangements to be introduced as part of the Priority Reform Program, as well as a summary of other options which were considered.

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<sup>26</sup> Regulations may be made under the *Electricity Reform Act 2000* to clarify this policy intent.

<sup>27</sup> Set at a level that indicated a material risk of default

<sup>28</sup> Standard and Poors or equivalent. The exact rating could be varied but should be around 'investment grade' where counterparty risk is considered low.

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## 6.5. Settlement Amount

The Settlement Amount is the nett payments amount due to or to be collected from a participant (via the Market Operator) as a result of the operation of the market during a Settlement Period. The Settlement Period will initially be one month as a transitional arrangement, and then seven days (see section 6.1).

### 6.5.1. The nature of contracts and market settlement

Contracts are arranged bilaterally between generators and retailers under the current I-NTEM and under the arrangements to be introduced by the Priority Reform Program. The risk management and settlement of the bilateral contracts is a matter for market participants to agree and resolve.

Under the design for the Priority Reform Program set out in this paper, financial settlement of amounts by the Market Operator will only be for out-of-balance energy and settlement of startup/shutdown cycle costs.<sup>29</sup>

Each participant will be required to provide the Market Operator with the MW value of contracts held for each Trading Interval. Note only the MW value will be required, not the value or prices in the contracts. The energy out-of-balance value is the variation between the actual MW value of energy sent out or used at a connection point during a Trading Interval and the MW value of notified contracts in relation to that connection point.

As there are to be two Reference Nodes, there will be two energy out-of-balance values, one for the northern region and one for the southern region. Similarly, there may be two Market Prices, one for each Reference Node. As a result, the Settlement Amount will be the sum of the variance values against each Reference Node.

### 6.5.2. Calculation of settlement amounts

Out-of-balance energy settlement amounts are to be calculated for each participant and advised to participants after the Settlement Period according to the settlement cycle.

The Market Operator is responsible for calculating the Settlement Amounts and invoicing the participants.

The calculation of the Settlement Amounts through the settlements process will result in a:

- positive number where the amount is due to the market participant; and
- negative number where payment is due from the market participant.

The Settlement Amount is calculated differently for generators and retailers, as shown below. Retailers pay the generator start costs based on their share of energy purchased during the week.

$$\text{Generator Settlement Amount } (SA_g) = OOBV_n + OOBV_s + GSP$$

$$\text{Retailer Settlement Amount } (SA_r) = OOBV_n + OOBV_s + GSC$$

Where:

OOBV *Out of Balance Value*, is the sum, across the Settlement Period, of the energy out-of-balance values for each half hourly period for each of the northern and southern regions. This may be a positive or a negative number.

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<sup>29</sup> As noted at the beginning of section 6, this paper assumes no changes to essential system services and reliability arrangements. However, additional settlement could occur via the Market Operator pending the outcomes of the ongoing reforms.

- GSC** *Generator Start Costs*, is the share of Generator Start Payments to be recovered from retailers across the Settlement Period, allocated based on market energy share.
- GSP** *Generator Start Payments*, is the sum of costs for the generator for all starts during the period. Note that the Generator Start Payment is levied based on starts but includes all generator costs for starting, running up to minimum load and shutdown of the generator.

These are calculated as:

$$OOBV_n (\$/MWh) = \sum_1^{336} (0.5 \times MP_n \times OOBQ_n \times L)_1, \dots, (0.5 \times MP_n \times OOBQ_n \times L)_{336}$$

$$OOBV_s (\$/MWh) = \sum_1^{336} (0.5 \times MP_s \times OOBQ_s \times L)_1, \dots, (0.5 \times MP_s \times OOBQ_s \times L)_{336}$$

$$GSC = \left( \sum_1^n GSP_1, \dots, GSP_n \right) \times \frac{\text{retailer MWh}}{\sum \text{retailers MWh}}$$

$$GSP = \sum \text{Generator Start costs (for the week)}$$

Where:

- MP** *Market Price*, is the price for each half hourly period calculated in accordance with the method shown in Appendix B for each of the northern and southern regions.
- OOBQ** *Out of Balance Quantity*, is the amount of out-of-balance energy for each half hourly period for each of the northern and southern regions, calculated in accordance with the method shown in Appendix B.
- L** *Loss*, is the Marginal Loss Factor for each market participant, calculated in accordance with a methodology approved by the Utilities Commission. Arrangements for losses are described in Appendix C.

### 6.5.2.1. Inclusion of additional items in the Settlement Amount

The design for settlement is focused on the energy out-of-balance but other items could be included in the future, such as for essential system services and reliability, if current review in relation to these matters determines that it would be appropriate and cost effective.

## Appendix A: Terms introduced in this paper

Terms introduced or relied on in this paper are explained in this table. Generic abbreviations or terms, such as NT for the Northern Territory are not included.

Table A1 Terms

Term	Abbreviation	Explanation
Commit, commitment		A plant commits or is committed when it is connected to the power system, starts and is available to the System Controller for dispatch.
Default Event		When a participant fails to pay a required Settlement Amount to the Market Operator within a specified timeframe or lodge cash, bonds or guarantees when required within a specified timeframe
Dispatch		The requirement for a market participant to operate at a specific output or demand level. <i>Also</i> , the level of output of a plant as a result of dispatch.
Fitness test		Verifying that a participant has the necessary financial strength and operational experience to be licenced or registered.
Loss Factor, Marginal Loss Factor	LF, MLF	The factor applied in settlements to all connection points to account for physical losses in the network in accordance with Appendix C.
Market Operator		A function of the System Controller related to operation of a wholesale market in the DKIS.
Market Price, Price	MP	The price of the marginal unconstrained, dispatched generation that is used to calculate the value of the out-of-balance energy to be included in the Settlement Amount.
Out of Balance Payment	OOBP	The amount to be paid to or by a Market Participant as a result of their OOBQ during a Trading Interval.
Out of Balance Quantity	OOBQ	The amount a participant is out of balance during a Trading Interval.
Out of Balance Value	OOBV	The amount that a participant is due to pay or be paid in respect of energy out-of-balance during a Trading Interval.
Reference Node (Settlement Point)	RN	The location where losses and settlements are referenced to provide a single point for pricing. There are two Reference Nodes; Channel Island North and Channel Island South.
Region, Settlement Region	-	The area encompassing all generators and customers connected to a specific Reference Node.
Scheduling		The operation of the System Controller in managing participant dispatch to ensure that the system remains stable and meets the demand.
Scheduling horizon		The period that the System Controller can look ahead to optimise the commitment and dispatch.
Settlement	-	The calculation and transfers of amounts owed or owing to the Market Operator and market participants.

Term	Abbreviation	Explanation
Settlement Amount	SA	The amount to be paid by or paid to a Market Participant. This is calculated in accordance with section 6.5. This amount only relates to out-of-balance energy and startup/shutdown cycle costs in this policy position paper, noting that it could be adapted in the future to include other settlement items.
Settlement Period	SP	The number of days or Trading Intervals to be included in the calculation of a settlement invoice for participants, as described in section 6.1.
Settlement Residue	SR	Amounts that arise due to differences in collections and payments by the Market Operator. Nett settlement surpluses will be applied to the benefit of customers.
Settlement Timetable		The schedule of events and actions in the settlement process.
Trading Interval		The time period for the calculation of a single dispatch solution and market price. In the DKIS it is 30-minutes.

## Appendix B: Settlement – Out-of-balance energy settlement

### B.1. Introduction

Section 5 of this paper describes the dispatch arrangements under the NTEM Priority Reform Program including that:

- market scheduling is to follow security constrained dispatch principles to ensure customer demand is met at least cost and all security constraints are observed
- the System Controller dispatches plant by making unit commitment decisions (to starting and stop plant) as required to meet security needs and energy demand
- to meet second by second demand, physical dispatch will continue to be based on incremental cost curves (or heat rate curves) in the System Controller's automatic dispatch systems (e.g. AGC); and
- the price band of the marginal, unconstrained generator offer will determine the Market Price (MP) for each Trading Interval.

In relation to settlement, section 6 of this paper provides that:

- out-of-balance energy will be settled at two Reference Nodes, Channel Island North and Channel Island South, located either side of Channel Island linked by a virtual inter-connection with no loss
- there will be two Market Prices, one for Channel Island North and the other for Channel Island South
- if flow on the 132kV line between Channel Island and Katherine is not constrained in a particular half hour there will be no material difference between price at the two nodes; and
- generators and customers connected to the Channel Island North Node will be in the northern Settlement Region. Generators and customers connected to the Channel Island South Node will be in the southern Settlement Region.

### B.2. Calculating the Market Price

A market or balancing price can be determined in a number of ways (for example, before the event or after the event, accounting for operating constraints or unconstrained with additional payments to true up the effect of constraints).

The objective of a Market Price is to, as accurately as practicable, set a price for the trading of variances from the contracted amounts between generators and retailers. The price is to reflect the incremental cost of balancing supply and demand, and will be calculated by the System Controller as it relies on knowledge of the way the power system was operated. Energy production and consumption that is covered by contracts will be priced in accordance with contractual arrangements between market participants.

The price determination process to be implemented as part of the Priority Reform Program is designed to be internally consistent with other elements of the design and is described below.

Market Price will be determined by the System Controller after the event based on SCADA meter readings of generation output, knowledge of generator submissions and operating constraints. The price will be the

highest of the operating generators that are not constrained<sup>30</sup> (i.e. the price of the generation source that supplied the last MW of demand).<sup>31</sup>

$$\text{Market Price } (\$/MWh) = \max \left\{ \left( \frac{\text{UD Generator band price}}{\text{Generator Loss factor}} \right)_1, \dots, \left( \frac{\text{UD Generator band price}}{\text{Generator Loss factor}} \right)_n \right\}$$

Where:

*UD Generator* is an unconstrained, dispatched generator during the relevant trading interval. Only unconstrained generators can set the Market Price.

*UD Generator band price* is the price of the band in which the relevant generator is being dispatched in the half hour.

*n* is the total number of the price bands offered into the market by unconstrained generators that are being dispatched during the relevant half hour.

*Generator Loss factor* is the loss factor assigned to the generator.

Market prices are to be determined ex-post on the basis of records of actual operation with some automated preparatory calculations.

The equation above assumes only generators are participating in the market and would need to be generalised to accommodate schedulable demand being traded in the energy as an alternative to generators providing energy. This generalisation will be undertaken in the future as part of government's ongoing reform program. Refer to section 5.1.2 for further discussion.

### B.3. Calculating the out-of-balance quantity for settlement

For each half hourly Trading Interval, the dispatch solution will show the difference between a participant's contracted energy and the amount sent out or consumed at each Reference Node, which is the out-of-balance quantity (OOBQ) for use in settlement for that participant. The amount may be positive or negative for any participant.

To allow the Market Operator to calculate the OOBQ, each participant will be required to provide the Market Operator with the MW value of contracts held for each trading interval. Only the MW value will be required, not the value or prices in the contracts.

The out-of-balance value is the variation between the actual MW value of energy sent out or used at a connection point during a trading interval and the MW value of notified contracts in relation to that connection point.

### B.4. Out-of-balance settlement for two Reference Nodes

For settlement of out-of-balance values, generator and retailer contracts will be assigned to the Reference Nodes. This explanation of the assignment process assumes that each retailer will have customers in each settlement region and will not be contracting separately in the two settlement regions. Similarly, it assumes that retailers will contract with generators who will be physically located in one settlement region

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<sup>30</sup> The test for whether a generating unit is constrained is if the demand increased by 1 MW whether the System Controller would increase the output of that unit. If the answer is no, then the unit is constrained for example because it is providing spinning reserve.

<sup>31</sup> Although this is a common method of determining market price it is an approximation to the marginal value of supply and also presumes no change to dispatch of ancillary services.



and that contracts with retailers will be to supply the demand of the retailer regardless of which settlement region the demand sits.

The contracts will be assigned:

- **For retailers**, the proportionate share of each contract with a generator will be in direct proportion to their loads in the respective settlement region. For example:
  - Retailer A has contracts with Generator A for 100MW and Generator B for 50MW.
  - for settlement, Retailer A loads are split 70 per cent in the northern settlement region and 30 per cent in the southern settlement region.
  - as a result, for settlement, the Retailer A contracts are assigned as:

$$\text{Retailer Contracts (North)} = (100 \times 0.7) + (50 \times 0.7) = 105MW$$

$$\text{Retailer Contracts (South)} = (100 \times 0.3) + (50 \times 0.3) = 45MW$$

- **For generators**, the values of OOBQ(n) and OOBQ(s) will be determined based on the proportion of the loads in the two settlement regions that are attributable to the retailers that are the counterparties to their contracts. For example:
  - Generator A has contracts with Retailer A for 100MW and Retailer B for 50MW for a total of 150MW.
  - as a result, for settlement, 70 per cent of the load of Retailer A and 80 per cent of the load of Retailer B are in the northern Settlement Region
  - during those trading intervals, the generator contract position is

$$\text{Generator Contracts (North)} = (100 \times 0.7) + (50 \times 0.8) = 110MW$$

$$\text{Generator Contracts (South)} = (100 \times 0.3) + (50 \times 0.2) = 40MW$$

## B.5. Settlement Residues due to constraints

When there is a constraint on the 132kV line between Katherine and Channel Island, the settlement process will not completely balance due to the difference in prices at the Reference Nodes. The amount of the imbalance is termed a Settlement Residue, and more specifically is a Constraint Settlement Residue. Constraint Settlement Residues can be positive or negative.

Empirical analysis shows that the Constraint Settlement Residues are:

- always positive if the flow on the network is southward (i.e. the dispatched generation in the north exceeds the load in the north). This outcome is a consequence of the proportion of both demand and generation and the relative cost of generators in the two regions; and
- may in some circumstances be negative when the flow on the network is northwards (i.e. dispatched generation in the south exceeds the load in the south).

The analysis indicates that the balance of Constraint Settlement Residues for a full Settlement Period will be positive for likely scenarios.

## Appendix C: Settlement – Treatment of losses

### C.1. Issue

Energy is used (lost) when electricity is transported across networks. Therefore, more energy must be injected into the network from generators in total than is taken out (consumed) by customers. The difference<sup>32</sup> between the amount of energy that enters the grid and the amount that leaves the grid via exit points is termed “losses”. The two key drivers for losses at any given time are the technical characteristics of the network and the demand of consumers which is matched by injections from generators.

Where there are multiple generators connected at different locations on the network and also multiple customers connected to different locations on the network, the location of generators and customers is also a factor that affects losses. Settlement must always reflect losses that have occurred. However, settlement can also be used to create incentives for connecting parties to locate in parts of the network with lower losses and for demand to occur at times with lower loss. These incentives can result in more efficient outcomes.

One way to categorise a market is by the way the network is represented. The two most common approaches are a nodal representation and a zonal representation. In a nodal representation every transmission point is considered in the settlement process. In a zonal design the full network is approximated by a reduced number of points (for example, the NEM network is represented by one point (node) in each state and the WEM has one node). If nodal representation is used the technical characteristics of the network are represented directly. In a zonal design the technical characteristics are amalgamated and losses are represented by loss factors between the node(s) and generators and customers.

As discussed in section 6, the Priority Reform Program will introduce a bespoke two Reference Node approach. It is bespoke in that the two Reference Nodes will be electrically closely coupled with zero loss between them.

### C.2. Options to account for losses

The simplest way to account for losses is to calculate the difference between injection and consumption at any given time and allocate the loss to customers according to their location by increasing the amount of energy they are deemed to purchase. This approach results in losses being paid by customers and generators being paid for their sent out energy. More complex versions can allocate a share of the calculated loss to generators, effectively splitting responsibility for losses between generators and customers. This is an average loss allocation process and assumes that all injection from a generation site and all consumption by a customer has the same impact on the amount of losses. This is a big approximation. The approach offers only a muted, or average, signal about the more beneficial locations for future generation and demand.

Alternatively, where the intention is to create incentives for improved performance and more efficient consumption, the allocation of losses to generators and customers can be on the basis of marginal (as opposed to average) impact. This approach creates a more accurate incentive for location and also provides better information to the System Controller about the order in which generators should be dispatched. As noted, if the market design uses a nodal approach the representation of losses is moot as the network characteristics are represented directly.

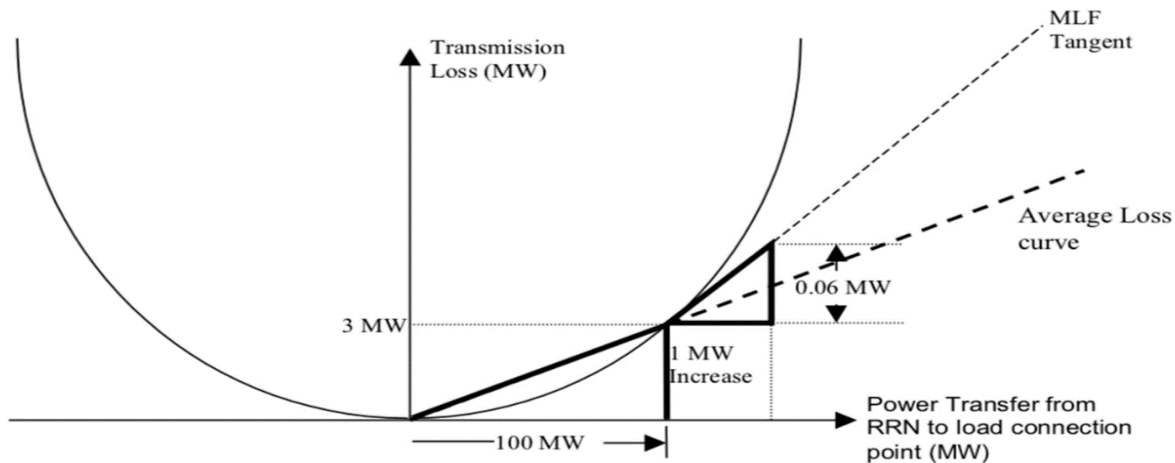
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<sup>32</sup> In this document non-technical losses, which can be due to theft or unmetered and unbilled supplies, are not accounted for.

Marginal and average losses are related. Average losses consider the total input and output across a network element whereas marginal losses consider the impact of a small increment of demand added to the connection point for which that factor is being determined, including for the connection point for a generation unit.

The relationship between marginal and average losses is shown in Figure C1 which plots losses against power flow in the network. The figure shows how actual losses increase more rapidly the higher the power flow. As a good approximation of the relationship, the actual losses increase proportionately to the square of power flow, which can be represented by a quadratic equation<sup>33</sup>.

Figure C1 Relationship between marginal and average losses



As the flow of energy across the system increases and decreases, the actual losses will follow the arc shown in Figure C1<sup>34</sup>.

The average loss factor value of loss at any particular time is represented by the slope of the line between the origin and the point on the arc for a particular flow. When the amount of energy flowing across the system changes, the plotted average loss point moves along the arc to a new value on the loss characteristic and a new average loss can be calculated.

As noted above, another perspective is to assess the impact of small (marginal) change in flow and its associated Marginal Loss Factor. This value is the tangent to the arc. The Marginal Loss Factor is a more accurate reflection of the impact of change in losses due to change in flow, compared to the average factor. As power flow is determined by generation and demand conditions, marginal losses more accurately represent the impact of supply and demand changes. Settlement based on average losses is more intuitive but gives less accurate economic incentives.

<sup>33</sup> This diagram is drawn from a presentation by Julian Eggleston from the AEMC, “Masterclass – marginal loss factors in the NEM”, available from <https://www.aemc.gov.au/news-centre/videos/julian-eggleston-masterclass-marginal-loss-factors-nem>. The AEMC also has a simplified explanation fact sheet “Transmission Loss Factors” available at: <https://www.aemc.gov.au/sites/default/files/2019-11/Fact%20sheet%20different%20ways%20to%20calculate%20transmission%20loss%20factors%20FINAL.PDF>

<sup>34</sup> This would happen automatically in a nodal design

The Marginal Loss Factor represents the ratio of the change in losses for a small (marginal) change in supply or demand. Algebraically Marginal Loss Factor (or MLF) can be calculated as follows:

$$\textit{Marginal loss factor} = \frac{\textit{Change in losses}}{\textit{Marginal change in energy transferred}}$$

### C.3. Other considerations

Under both approaches, the System Controller must have knowledge of demand and actual losses to dispatch sufficient aggregate generation irrespective of the treatment of losses in settlement. However, the settlement loss factors should be used to inform the order of dispatch of generation to maintain consistency between dispatch and settlement. This will also support efficiency of dispatch.

Marginal Loss Factors are the approach used in the NEM and WEM and many markets elsewhere for dispatch and settlement between generation connections and Reference Nodes (as discussed in section 6), which reflects that they provide the most accurate economic signal. However, Marginal Loss Factors result in a gap in the settlement amounts charged to retailers and paid to generators, which is termed Settlement Residue (and discussed further in C.5.). Markets differ in how they treat residue resulting from the use of Marginal Loss Factors.

It should be noted that markets, including the NEM and the WEM, use an average loss approach to (assumed) radial connections from transmission connection points to customer connection points, which are called Distribution Losses Factors (or DLF). Under this approach, inaccuracies are smeared (or shared) across all affected retailers. As a result, the settlement value for customers is the sum of the two loss factors, the Marginal Loss Factor and the Distribution Loss Factor.

Marginal Loss Factors are applied to the price paid to generators (for energy set out) and by retailers (for energy consumed by their customers). Loss factors for generators are generally less than one and are lower the further away from the Reference Node the generator is located.<sup>35</sup> Similarly, customer loss factors are higher the further away from the Reference Node to which they relate. All loss factors, including Marginal Loss Factors are specific to the location of the generator or customer and the location of the Reference Node to which they relate.

### C.4. Marginal Loss Factors

Taking into account the considerations discussed above, Marginal Loss Factors will be used to account for losses between a generator and Reference Node, under the NTEM Priority Reform Program. Loss factors determined by the Network Service Provider using a methodology approved by the Utilities Commission will be published on PWC's website.

### C.5. Settlement Residues from the use of Marginal Loss Factors

As noted above, one impact of using Marginal Loss Factors rather than average loss factors is that the Market Operator receives slightly more income from retailers than is paid to generators. This is known as Settlement Residue due to losses, and is different to residue due to Constraint Settlement Residues that accrue during out-of-balance settlement as discussed in section 6.2.2.1.

This loss residue is an expected outcome as Marginal Loss Factors are greater than average loss factors. The Market Price at the Reference Node is used to calculate the charges to out-of-balance energy users

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<sup>35</sup> For completeness note that in a meshed network in some circumstances the location of a generator may mean it is allocated an MLF greater than 1. For example, if additional generation reduces flow to a remote section of network.

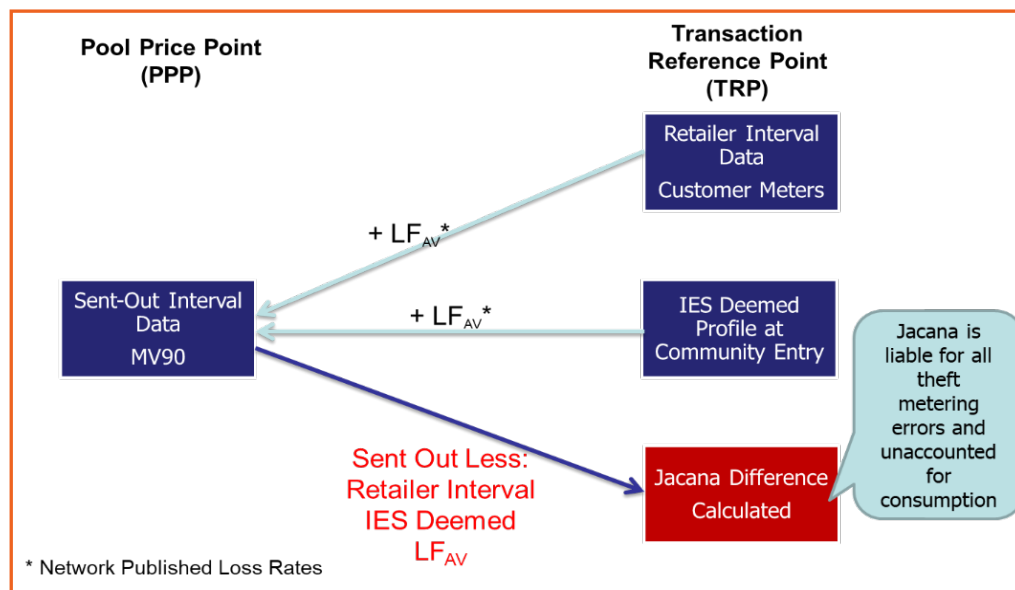
and the payments to out-of-balance energy suppliers. As a result the market design must include a provision for what happens to the residue. This is discussed further in section 6.2.2.1.

Note that only out-of-balance energy amounts are to be settled by the Market Operator and the accounting for losses in energy settled through contracts is a matter for the contracting parties.

## C.6. Application of loss factors

The current market arrangements for the I-NTEM use average loss factors. These are calculated from the Pool Price Point (PPP) to the Transaction Reference Point (TRP) for retailers with customers that have interval meters. The remaining losses (and unaccountable settlement errors) are charged to Jacana Energy. This arrangement is shown in Figure C2<sup>36</sup>.

Figure C2 Current NT loss model



Two changes are to be implemented as part of the Priority Reform Program.

- The use of Marginal Loss Factors (MLF)
- The use of Reference Nodes for settlement.

These changes, in particular the use of Reference Nodes, necessitates a different application of losses. As show in Figure C3:

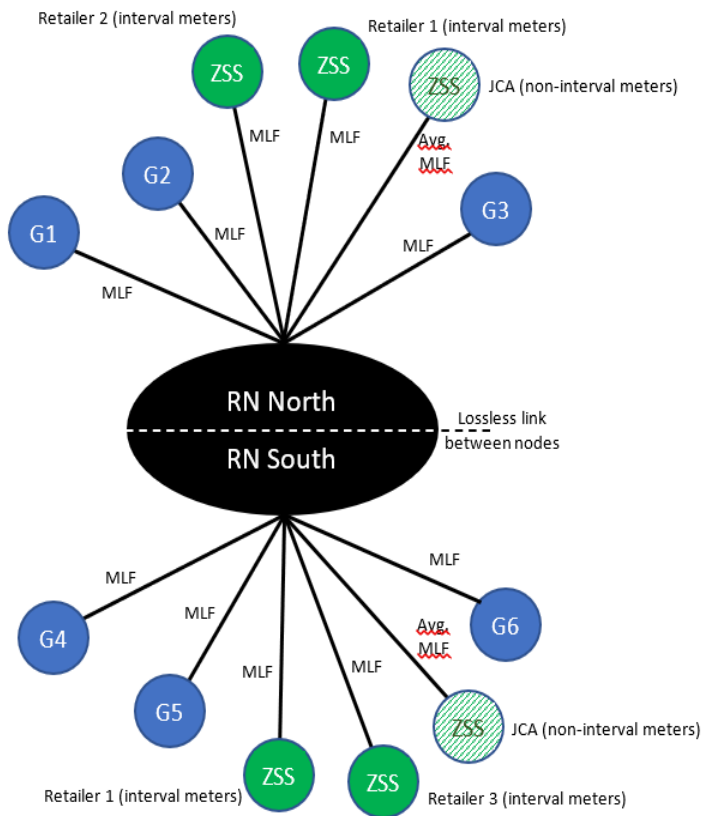
- Marginal Loss Factors will be published with reference to the Reference Nodes
- There will be two Reference Nodes, Channel Island North and the other for Channel Island South
- There will be no losses between the Reference Nodes.
- Losses for generation and loads in the northern and southern regions will be calculated in relation to the Reference Node in their region (as there will be a lossless link between Channel Island North and Channel Island South, as noted above)

<sup>36</sup> Provided by the Power and Water Corporation

- Marginal Loss Factors will be applied to generators from their point of connection to the relevant Reference Node
- Marginal Loss Factors for retailers with interval meters will be calculated from the relevant Reference Node to the Zone Substation (ZSS)
- An average of the Marginal Loss Factors for the relevant ZSS will be used for Jacana Energy.

Any Settlement Residues will be used by the Market Operator for the benefit of customers as outlined in section 6.2.2.1.

Figure C3 Marginal loss factors with two nodes



## Appendix D: Settlement – Participant default and prudential obligations

### D.1. Background

In all markets, including electricity markets, there is a risk that participants in the market will default, where one party fails to make payments to other participants that are owed money via the market. Where the counterparty is known, and contracts are established directly with the counterparty, an entity can assess the risk and take appropriate steps.

In a markets like in the DKIS (and the NEM and the WEM) the dispatch process is interposed between the parties to the market and it is not possible for an entity to fully manage the risk of participant default. However, in a net settlement market like in the DKIS, the risk of participant default associated with settlement administered by the Market Operator is significantly lower than in gross settlement markets like in the NEM. The bulk of the risk of participant default will be managed in bilateral contracts (where the counterparty is known). Most energy is expected to continue to be settled through bilateral contracting, at least in the early stages of the market.

As under the NTEM Priority Reform Program, where the Market Operator will only settle the energy out-of-balance amounts (in the event out-of-balance exists) and the startup/shutdown cycle costs, the requirements for managing associated default risk are relatively low. Prudential requirements introduced as part of the Priority Reform Program must be proportionate.

### D.2. Issue to be managed

There are two key issues to be managed if a participant defaults:

- **Maintenance of supply.** While a participant may default, the financial responsibility for the ongoing supply of energy to medium and small customers, in particular, needs to be maintained<sup>37</sup>. In addition, the responsibility for billing and managing customers' needs to be efficiently transferred to another party.
- **Financial management of the market.** There is a need to maintain cash flows to participants to cover the amounts owed in the event of a default to minimise the risk of cascading failure. This is the subject of this appendix.

### D.3. Factors to be considered in the financial management of market

The approach to be used should be based on four factors:

1. **The size of the market.** Nett markets, like current and proposed arrangements for DKIS, only trade balancing amounts with the bulk of the energy value being directly settled between the participants. This means that the value at risk during a participant default is likely to be low.

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<sup>37</sup> In practical terms, current meters and connection arrangements do not allow a customer to be interrupted due to a financial default.

2. **Risk of default.** Many markets contain only large or asset linked participants. In these markets the actual risk of default is low. For example, in PJM<sup>38</sup>, parties with investment grade financial ratings are not required to lodge any guarantees.
3. **Sign of the outstanding amounts.** In balancing markets, like the out-of-balance energy market proposed, it is possible for participants to owe money for a period and be owed money for another period. This differs from the NEM, where participants are generally either owed or owe Settlement Amounts. Where the sign of the outstanding amounts can vary, fixed prudential arrangements are less efficient.
4. **Length of the settlement cycle.** The level of default risk in a market is dependent on the size of debt that can accrue before the default occurs and can be managed.

For example, in the NEM, settlement occurs weekly and payment is required 20 business days after the end of the settlement week. This means that the defaulting party will have accrued 35 days of electricity usage debt before the default is discovered. Adding a week of activities before the default can be managed and closed out leads to the requirement that the prudential instruments lodged must meet the expected maximum debt that will occur in a 42 day period. Participants can reduce the level of expected debt by reducing the length of the settlement cycle.

#### D.4. Approach to be adopted in the NTEM Priority Reform Program

A prudential arrangement should be sufficiently robust to protect the participants in the market and no more complex than necessary. Any financial costs on market participants, and additional resources or administrative burden on the Market Operator that are higher than necessary to assure financial integrity will give rise to more costly operation of the DKIS than necessary.

As discussed in section 6.4 of this paper it is proposed that as part of the Priority Reform Program the following be adopted:

- A reporting requirement for participants so that the Market Operator and the Utilities Commission are assured that the participant can meet its obligations
- An unlimited trading limit, subject to review by the Utilities Commission two years after these reforms commence
- An obligation on the Market Operator to manage counterparty risk in market settlement. This will be a statutory function on the Market Operator and include a requirement for it to make payments to market participants owed in the event of a default; and
- The ability for the Market Operator to require that any Market Participant that poses a material risk to settlement be required to lodge bonds, guarantees or cash to offset that risk.

These arrangements are considered most suitable because:

- of the low level of default risk associated with net settlement, and particularly as most participants are likely to be fully contracted with no energy out-of-balance when the Priority Reform Program commences; and
- the costs of establishing other options considered would not be proportionate to the expected level of risk and would not present a net benefit to consumers.

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<sup>38</sup> PJM is a transmission level market from North Eastern USA, centred around Pennsylvania, New Jersey and Maryland. It is a net market, like the DKIS under NTEM Priority Reform Program.



In the longer term, changes in load, generation and contract positions may result in misalignments between the contracted volumes and actual volumes leading to material out-of-balance energy amounts.

As the market matures, it follows the prudential arrangements may require a review should the settlement risk become so significant that the identified prudential arrangements are no longer proportionate.

## D.5. Summary of options considered

A summary of options that were considered for managing the risk of participant default, including the preferred option of introducing a statutory function on the Market Operator to manage counterparty risk in market settlement is provided below.

### 1. No prudential arrangement

Designate a single party, likely to be Territory Generation, to provide a balancing service on an ongoing basis so that other parties are not obligated to make out-of-balance payments. This approach would use the size of Territory Generation to spread the cost of default across all Territory Generation customers, removing the potential risk.

However, the advantage of the simplicity of this option is outweighed by the disadvantages.

This option would reduce the efficiency of the market as the optimal out-of-balance source cannot be guaranteed given the designated provider does not have access to all resources. In the long run, the inefficient cost would be borne by customers and this approach may also inhibit market development.

#### *Short payment*

In the NEM, as a last resort, AEMO is allowed to short pay participants under National Electricity Rule 3.15.22. This option is to ensure that AEMO is not required to pay NEM participants from its own funds. It is understood that this provision has never been used in the NEM.

This is acceptable in the NEM because the parties that are short paid would be generators, who have asset backing and the relative amounts would be low after AEMO has collected the amounts lodged by the defaulting parties under the prudential obligations in the NEM.

In this design, the shortfall could be for payments to either generators or retailers on a relatively random basis for any specific Settlement Period. The amount may be relatively significant if applied to a single, small retailer.

For these reasons, this approach is considered inappropriate for the Priority Reform Program.

### 2. Market operator function to manage risk (included in policy position on design)

As part of its role in operating the wholesale market and settling the market, a statutory function could be introduced requiring the Market Operator to manage risk of default occurring in markets that it settles.

This would require the Market Operator to pay market participants who have amounts owing in the event of a participant default.

At the commencement of the Priority Reform Program where there is a low default risk, the provision of this risk management service by the Market Operator as part of settling the market would ensure the financial integrity in the market in a simple and efficient manner.

The Market Operator would be authorised to recover costs associated with exercising its statutory function, as part of operating the wholesale market, in accordance with section 39 of the *Electricity Reform Act 2000*. This could be via a simple pass through of costs associated with a default event after a default event or by maintaining self-insurance arrangements.

This approach would be the lowest cost prudential arrangement.

### 3. Participant Prudential obligation

Participants could be required to provide the Market Operator with sufficient securities, either cash or some other form of guarantee that would ensure that any out-of-balance obligation can be met<sup>39</sup>.

Two variations were considered:

#### a. Progress payments

In this option, participants are required to lodge cash or other instruments on a regular basis. Under this option, more regular 'progress payment' would reduce risk by reducing the amount of time for debt to accrue. For example, a participant could lodge instruments at the start of a week as a surety against the out-of-balance payment for that week. The payment amount would be agreed in advance based on historical out-of-balance information and adjusted if the Market Operator is of the view that the historical amount is not likely to reflect the payment for that participant for the week.

In addition to the progress payment, this option should also require a market participant to pay a deposit for covering its credit risk during the reaction period. (This is assumed to be one week as in the case for the NEM but may need to be reviewed in the event it is implemented.)

Hence, a market participant's total balance of deposit (for protecting the prudential integrity market settlement via the Market Operator) would consist of up to two weeks of credit risk exposure<sup>40</sup>. That is: (a) one week for covering the current week out-of-balance risk exposure; and (b) one week for covering the out-of-balance credit risk for the reaction period.

The advantages of this option are that there would be no need to amend the current monthly settlement cycle and participants would have a reduced amount of cash tied up (compared option 3b) and would not need to use bank guarantees.

The disadvantages of this option, like 3b, are that it would increase administrative burden. There would be increased administration costs for the Market Operator including to estimate the weekly risk for each participant and the advance payments requirements would impose additional financial and administrative burden on market participants. There would also need to be an adjustment if the out-of-balance amount nears the deposited amount.

#### b. Prudential instruments

This approach would require that participants maintain a level of cash or other instruments with the Market Operator so that their expected maximum obligation can be met. The amount would be determined quarterly, and the participant would be required to maintain the cash or instruments at the required level.

This option is similar to arrangements in the NEM and the WEM. The only exception is that monitoring of the actual credit risk exposure would be carried out at the end of the four-week settlement cycle rather than regular monitoring as in the case of the NEM and WEM. This is because there will be no timely load consumption data available for such regular monitoring in the Territory for the foreseeable future.

In terms of the parameters of a prudential arrangement design, they would comprise:

- Form of payment surety – either deposit or bank guarantee (like the NEM and WEM)

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<sup>39</sup> It is noted that participants have only one means to practically reduce their risk – to take on more contracts. Where an out-of-balance market is used, this simply transfers the market Settlement Amount from retailers to generators, and does not reduce the risk for the Market Operator.

<sup>40</sup> In the extreme case, participants could lodge cash each day, limiting their exposure to the reaction period or 7 days.

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- Amount of surety payment – estimate is based on the period of settlement cycle (28 days), one week of billing period (7 days) and one week of reaction period (7 days). This would make the calculation of the estimated amount of surety to be based on 42 days credit exposure
- Monitoring of exposure – during the out-of-balance week, the total exposure of the participant would not be allowed to exceed 80 per cent of the lodged instruments. If the exposure exceeded this amount the participant would be required to adjust their instruments or lodge cash.

The advantages of this option is that it offers wider choice in the form of credit support provision by market participants compared to option 3a, and the similarities of this option to the NEM and the WEM may increase familiarity for market participants.

However, like option 3a, this option is a complex approach and would require significant administration and management by the Market Operator. It would also impose significant financial and administrative burden on participants and tie up greater amounts of working capital compared to other options.

Overall, both of these options (3a and 3b) are considered to be too complex with high levels of administrative and financial cost than necessary for the expected level of default risk. As the market matures, there may be merit in reconsidering prudential arrangements and these options may become more appropriate if the level of risk becomes more significant.

#### **4. Prudential obligation for individual participant that presents a material risk (included in policy position on design)**

Under this approach, a participant that is likely to pose a material default risk, could be required to provide the Market Operator with sufficient securities, either cash or some other form of guarantee that would ensure that any out-of-balance obligation can be met<sup>41</sup>. This would protect the market from the risk posed by an individual participant.

The ‘trigger’ for when a participant is likely to pose a material risk will be clearly defined<sup>42</sup>. The additional prudential requirements will only be permitted to be imposed in the event that:

- a market participant’s Settlement Amount, averaged across four Settlement Periods, exceeds 10 per cent of the total of the Settlement Amounts of all participants; and
- the market participant has a credit rating of less than BBB+.

If this trigger is met, the Market Operator would be permitted to require the participant to lodge bonds, guarantees or cash to meet two weeks of settlements.

It is not anticipated that this prudential obligation for an individual participant that presents a material risk will need to be utilised on commencement of the NTEM Priority Reforms, but it provides some level of ‘future proofing’ of the prudential arrangements. Inclusion of this prudential arrangement will not remove the need to consider changes to prudential arrangements over time as the level of risk in the market (and the design of the market) evolves. However, this supplementary design element may delay a possible need

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<sup>41</sup> It is noted that participants have only one means to practically reduce their risk – to take on more contracts. Where an out-of-balance market is used, this simply transfers the market Settlement Amount from retailers to generators, and does not reduce the risk for the Market Operator.

<sup>42</sup> The wording of this definition may differ as part of the drafting process as part of implementation. This definition is provided to explain the policy intent.

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to reform the prudential arrangements by protecting the financial integrity of the market in the event that a single participant poses a material risk.

This proposed 'future proofing' option is also considered to be a cost effective approach as it would allow the Market Operator to assess the level of risk but only develop systems to define and manage prudential obligations when it becomes necessary. Similarly, it will only result in additional obligations on a participant if they are warranted. This contrasts with option 3b which was not considered proportionate to the level of expected risk.

## D.6. Process for when a Default Event occurs

A 'default event' will occur when a participant fails to:

- pay a required Settlement Amount to the Market Operator within a specified timeframe; or
- lodge cash, bonds or guarantees when required by the Market Operator within a specified timeframe (if the participant poses a material risk to the market as discussed in sections 6.4.2 and D.5).<sup>43</sup>

The process that should be followed when a Default Event occurs is largely in line with existing arrangements in place in the Territory's electricity regulatory framework.

In respect to a retailer default, the relevant process is largely contained in the Utilities Commission's Electricity Retail Supply Code (ERSC) which sets out ROLR arrangements, and section 36 of the *Electricity Reform Act 2000* which provides the Utilities Commission the power to suspend or cancel an electricity entity's licence.

The potential for a generator to default is low given a generator is a net recipient of funds. The amounts to be paid by a generator are lower compared to the income it would receive (primarily from bilateral contracts), and it is expected that a generator, even under administration, would continue to trade as long as it has a net income. Additionally, unlike a retailer, a generator can manage its operating losses by declaring itself unavailable for dispatch, noting a generator would need to consider any possible energy out-of-balance payments that may accrue if it took this path.

In the unlikely event a generator defaulted, and the default could not be rectified, the Utilities Commission would have the power to suspend the generator's licence under section 36 of the *Electricity Reform Act 2000*.

The table below sets out the process to be followed in relation to a market participant that defaults. The process to be followed for a generator that defaults would only be steps 1 and 4. All steps would be followed for a retailer that defaults.

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<sup>43</sup> The wording of this definition may differ as part of the drafting process as part of implementation. This definition is provided to explain the policy intent.

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Table D1 Process for when a Default Event occurs

Step	Process	Legislation/ Rules
1	<p>If the Market Operator identifies that a Default Event has occurred, the Market Operator must notify the Utilities Commission immediately.</p> <p>The Market Operator must then:</p> <ul style="list-style-type: none"> <li>• request that the participant rectify the issue (e.g. provide payment) within 72 hours; and</li> <li>• if the Market Operator has not already, call on cash, bonds or guarantees lodged by the market participant (if any) with 72 hours</li> </ul> <p>If, following these steps, resolution is not possible, the Market Operator must notify the:</p> <ul style="list-style-type: none"> <li>• Utilities Commission that the Default Event was not able to be rectified within 72 hours</li> <li>• market participant that the matter has been referred to the Utilities Commission.</li> </ul>	<p>No current provisions.</p> <p>This process will need to be implemented in the market rules in the SCTC.</p>
2	<p><b>Step 2 is relevant to a retailer default only</b></p> <p>When the Utilities Commission receives notification from the Market Operator that a Default Event was not able to be rectified within 72 hours, it is proposed that the Commission commences its ROLR process for a retailer.</p> <p>A declaration of a ROLR event will trigger the transfer of the relevant customers to Jacana Energy as the designated ROLR, and will trigger the process to suspend the licence of the retailer that has defaulted (see ERSC section 9.2 and 9.3).</p>	<p>ERSC – Section 9</p> <p>Only minor changes to the existing ROLR arrangements are likely to be necessary. The definition of a ROLR event at section 9.1.2 of the ERSC will need to be amended. For example, a ROLR event should be added for when ‘a default event occurs that is not resolved in the timeframe specified under the SCTC market rules’ could be added.<sup>44</sup></p>
3	<p><b>Step 3 is relevant to a retailer default only</b></p> <p>If the Commission declares a ROLR event, the Market Operator will suspend the retailer from trading in the Market Operator administered market settlement arrangements (e.g. for out-of-balance energy).</p>	<p>No current provisions.</p> <p>These market rules should provide the power to suspend a participant from trading in the Market Operator administered Market Settlement arrangement if the Commission declared a ROLR event. (The rules should not provide the Market Operator a broader power to suspend participants from trading due to any other circumstances, or to suspend participants from carrying out other activities permitted under their licence.<sup>45</sup>)</p>

<sup>44</sup> The Commission would ultimately have discretion as to how to ensure ROLR arrangements are appropriate to support the NTEM Priority Reform Program given the ERSC is administered by the Commission.

<sup>45</sup> The power for the Market Operator to *only* suspend a participant from trading in Market Operator administered market settlement *after* a ROLR event is declared. It is appropriate that only the Utilities Commission, as the regulator responsible for enforcement of the SCTC (and of the industry more broadly), and the broader power to suspend a market participant’s ability to carry out other activities permitted in its licence, through licencing. This is reflected in the next step in the process.

NTEM Priority Reform Program: Priority changes to dispatch and settlement

Step	Process	Legislation/ Rules
4	<p>The Commission may formally proceed with the process of suspending or cancelling the market participant's licence. If the Commission proceeds with this, it must notify the market participant in writing and provide its reasons and allow the participant at least 14 days to make a submission before acting on its intent to suspend or cancel a licence.</p>	<p><i>Electricity Reform Act 2000</i> – Section 36                      No changes necessary.</p>

## Appendix E: Summary of Stakeholder Working Group feedback

The table below summaries feedback provided by the Stakeholder Working Group at workshops and in follow up to the workshops. The Development Design Team's (DDT) response are also provided.

### On the draft dispatch design (Workshop 17 July 2020)

Table E1 Stakeholder feedback

Category	Question/comment	DDT response
<b>General</b>	<p>Comments in support of the proposed priority changes to dispatch arrangements.</p> <p>It was noted that the proposed design was in line with the Roadmap to Renewables Report.</p>	<p>The Priority Reform Program is being undertaken to provide a workable framework to facilitate increased market participants in the DKIS including new renewable energy generation entrants.</p> <p>The Priority Reform Program will ensure efficient, secure and reliable electricity supply and support government's renewable energy target.</p>
	<p>Question regarding the independence of the System Controller and whether there are plans to structurally separate the System Controller from PWC.</p>	<p>The System Controller currently operates under a specific System Control licence and in accordance with statutory functions under the <i>Electricity Reform Act 2000</i>. It is also subject to regulatory 'ring-fencing' provisions.</p> <p>The Priority Reform Program is to occur within the current structure. Where possible the rules will be amended to enhance transparency and accountability for the System Controller and industry participants.</p> <p>Appropriate industry governance is an important component of the ongoing reforms to transition to a long term fit-for-purpose regulatory framework.</p> <p>The proposed priority reforms, including changes to the dispatch arrangements, will not restrict options for future industry governance arrangements.</p>
<b>Scheduling submission information</b>	<p>Question regarding minimum run time and whether the design is able to accommodate multiple minimum run times for generators with different modes of running combined cycle gas turbine plant.</p>	<p>Multiple minimum run times to accommodate combined cycle gas turbine plant with different modes of operating and run times was not included in the design presented to the Stakeholder Working Group.</p> <p>However, in response to stakeholder feedback, this policy position included at section 5.1.3 of this paper is that combined cycle gas turbine plant should be accommodated through multiple minimum run times.</p>

Category	Question/comment	DDT response
	<p>Comment regarding startup costs: A stakeholder commented that if a generator loses control of startup, the decisions made by the System Controller on startup may impact them and make 'bidding' more complex because startup costs can vary as a function of previous run time and time since shutdown.</p>	<p>The design allows for provision of information (to inform the System Controller's decision making) on both startup cost and minimum run time, which together should protect a generator from loss.</p> <p>A benefit of centralised unit commitment and dispatch is that it does not require generators to undertake complex 'bidding' including by making assumptions (or guesses) about how often the System Controller will make unit commitment decisions requiring a generator's units to start up, as is currently the case. Rather the dispatch and settlement arrangements will reduce risk for generators in respect to recovery of startup costs.</p> <p>The design does not rule out the ability for revisions to submissions during the day as long as they are justified as relating to changes in physical capability of plant. Only commercially motivated changes will not be required or permitted.</p>
	<p>Question regarding whether the scheduling process can accommodate demand side response and small-scale generation.</p>	<p>The scheduling process can accommodate anything that can be scheduled to ensure that the dispatch process is in place for when an associated payment arrangement is established (refer to section 5.1.2). This can include a large load that is schedulable for energy or an essential system service subject to outcomes of the review of essential system services in the Territory's regulated electricity systems being undertaken. Stakeholders are encouraged to contribute to this review.</p>
	<p>Comment regarding whether the submission template appropriately accommodates solar energy generation. Concerns were raised regarding the 'optics' of the proposed information requirements.</p>	<p>The submission information requirements, and the broader dispatch design, are technology neutral and seek to accommodate imminent new entrant solar generators and any other new entrants (of any technology).</p> <p>In response to stakeholder feedback, the design has been refined in this policy position paper to clarify that solar energy generators (or generators of any particular technology) will only need to provide information that is pertinent to them.</p> <p>More broadly, the policy position paper has been written to ensure the policy intent is clear that the dispatch design should accommodate generators of any technology, and schedulable load, in as technology neutral manner as practicable.</p>



Category	Question/comment	DDT response
	Question regarding incentives for generators to reduce minimum stable load level.	<p>Although this is a valid point, the way to create incentives for generators to reduce minimum stable load level is through increased exposure to the out-of-balance Market Price. Initially it is expected that the majority of energy will be settled through contractual arrangements rather than at the Market Price for out-of-balance energy. It is noted that generators with high minimum load tend to have higher costs which can be less attractive to retailers.</p> <p>Regulatory oversight is an option as noted by the stakeholder. The design of the priority changes to dispatch arrangement will not prevent consideration of regulatory arrangements (or other options to improve incentives) in the future, noting that the costs of increased regulation will need to be understood and weighed against the benefits.</p>
<b>Scheduling process and mechanisms</b>	Comment regarding what happens in the event of out of merit dispatch.	The centralised unit commitment and dispatch process does not result in the System Controller creating a static day ahead merit order. Rather it identifies the optimum loading which may move between units as demand changes. In effect the merit order is recalculated throughout the day as circumstances change. To be clear this can mean that a unit with higher incremental cost but low startup cost is run for a short time ahead of a unit with low(er) operating cost but high(er) startup cost.
	Comment regarding misalignment between real time dispatch and settlement. A stakeholder considered that that there is more to operating cost than heat rates in the Automatic Generation Control.	The DDT considers that the misalignment will be immaterial. However, in response to this comment at the Stakeholder Working Group workshop, DDT indicated that it was open to a discussion with any concerned stakeholders regarding this matter. No further feedback was provided by stakeholders.
	Question regarding who will develop a dispatch algorithm and whether energy or essential system services will be dispatched first.	<p>It is understood that the System Controller will develop the dispatch algorithm, noting that the design will not specify the means in which the System Controller performs its role so long as it does so efficiently, and complies with the scheduling process, the principles of security-constrained economic dispatch and unit commitment and broader market rules.</p> <p>Dispatch algorithms that provide for optimisation of energy and essential system services to provide a least cost combination are commonly used in markets around the world. Optimisation does not require a choice to be made about whether to make energy or essential system services decisions first. Optimisation of energy and essential system services is being considered through the review of essential system services in the Territory's regulated electricity systems. Stakeholders were, and continue to be, encouraged to contribute to this review.</p>

NTEM Priority Reform Program: Priority changes to dispatch and settlement

Category	Question/comment	DDT response
	<p>Comments regarding provision of essential system services, including in respect to generators that can generate or absorb reactive power (MVar) and opportunities for batteries to smooth solar energy generation.</p>	<p>The dispatch priority changes will not restrict the ability for essential system services arrangements to be established that utilise these forms of provision of essential system services, pending the outcomes of the review being undertaken of essential system services in the Territory's regulated electricity systems. Stakeholders were, and continue to be, encouraged to contribute to this review.</p>
	<p>Question regarding whether all thermal plant will be controlled by the Automatic Generation Control.</p>	<p>All thermal plant should be controlled by an automatic generation control system. If there are reasons why a particular plant cannot be, this may require bespoke design. In response to this question at the Stakeholder Working Group workshop, the DDT indicated that it was open to a discussion with any concerned stakeholders regarding this matter. No further feedback was provided by stakeholders.</p>
	<p>Question regarding whether there will be an ongoing requirement for two Frame Six units.</p>	<p>This is currently a security constraint. The priority changes relate to the unit commitment and dispatch process. The process deals with how inputs (including what security constraints the System Controller considers are needed in the system) are taken into account when making decisions about unit commitment and dispatch.</p> <p>However, it is important to note that the System Controller is accountable for security constraints it applies. This is why the dispatch design enhances transparency by requiring the System Controller to retain a record of any constraints which will be public information. Please refer to sections 5.1.7 and 5.2.1 of this paper regarding transparency and publication requirements.</p>
	<p>Question on whether consideration has been given to five minute dispatch and settlement (rather than the proposed 30-minute)?</p>	<p>This is not contemplated as part of the Priority Reform Program which is designed to make priority changes needed to be put in place quickly to provide a workable and efficient framework that can accommodate new entrants.</p> <p>A move to five minutes would add considerable complexity and cost. Should this be considered in the future, careful consideration would need to be given to whether the benefits outweigh the costs and complexity.</p>

Category	Question/comment	DDT response
<b>Safe harbour cost ranges and general cap</b>	Question about what would happen if a thermal plant 'bid' in at higher than the general cap. Would they be dispatched?	<p>The system wide general cap will be set at a level determined by the Utilities Commission above the highest plausible level for any plant. Accordingly the Utilities Commission would be able to consider potential emergency gas supply in determining the highest plausible level for the cap.</p> <p>If a submission is made above the general cap, it will be adjusted to the cap rather than being removed from consideration for dispatch. A generator would still receive payment through any contractual arrangements for energy dispatched.</p>
<b>Publication requirements</b>	<p>Question regarding when demand forecasting is to be undertaken in the scheduling process.</p> <p>Will forecast demand be provided to generators for them to improve operation?</p> <p>Will accuracy of forecasting be transparent through ex-post provision of information?</p>	<p>The System Controller will undertake demand forecasting as regularly as it requires as conditions change.</p> <p>Before the time of dispatch, pre-dispatch information will be published including forecasts of demand as public information. At the time of pre-dispatch, public information will also include demand forecasts.</p> <p>The general policy position regarding transparency is that the only information that should not be published is cost sensitive information.</p> <p>It is noted that the System Controller could consider accuracy of forecasting as a key performance indicator (KPI). This is not included as part of the Priority Reform Program, however, there is nothing to prevent the System Controller treating this as a KPI or it being considered as part of ongoing reforms.</p>

Category	Question/comment	DDT response
<p><b>Additional feedback received post-workshop (where not addressed above)</b></p>	<p>Further to a stakeholder feedback on the role of PWC as System Controller (see above), the stakeholder provided follow up feedback:</p> <ul style="list-style-type: none"> <li>○ supporting the transparency obligations on the System Controller including in the dispatch design. The stakeholder also supported metrics on forecasting accuracy</li> <li>○ advising that it is important to clearly establish which aspects of the design are decisions of government that the System Controller should reflect in the drafting of changes to the SCTC, compared to what aspects of the design they System Controller should have discretion over in drafting and consulting on SCTC changes.</li> <li>○ advising the System Controller decisions in developing SCTC changes should be accompanied by detailed justification to provide confidence to stakeholders</li> </ul>	<p>The introduction of increased transparency requirements as a cost effective way to enhance accountability of the System Controller was a key element of the design of the dispatch priority changes. Although forecasting or other performance metrics could be used for the System Controller, there is not a clear net benefit to mandating such metrics at this time. This policy position paper is intended to clearly set out government policy. All amendments to the SCTC should be drafted to be consistent with the policy set out in this paper.</p> <p>Detailed operational and technical matters that will need to be considered as part of development of the detailed market rules will be consulted on. Examples of such matters that should be determined through market rules consultation are flagged in this policy position paper, noting that matters flagged in this paper do not represent an exhaustive list. Refer to the boxes labelled ‘Detailed design to be determined through stakeholder consultation on market rules’.</p> <p>Comments by the stakeholder are supported on the need for justification for the design of detailed market rules changes. The rule change process should include an open and transparent stakeholder consultation process.</p>
	<p>A stakeholder noted that the Draft Design Paper for Dispatch was a technical paper, and that it was important that there be a clear focus on customers.</p>	<p>Key to all policy decisions on the design of wholesale market reforms is the best interests of customers and taxpayers.</p> <p>As the stakeholder notes, the Draft Design Paper was a very technical document for the Stakeholder Working Group and this key objective may have unintentionally not been communicated as clearly as it should have been. In this policy position paper, the explanation of policy positions includes consideration of efficiency, minimising overhead costs, appropriate trade-offs between complexity and accuracy, and so on. These are key considerations aimed at ensuring the dispatch (and all) priority changes meet the best interests of consumers and taxpayers.</p>
	<p>Stakeholder commented that there needs to be a clear timetable for review of parts of the design where initial changes may evolve in the future depending on the market evolution</p>	<p>Where appropriate the policy position paper notes the possibility of review and further development of the market as has been the case for many markets including the NEM and WEM. While the market design may require changes over time as the market evolves, it is impractical to set a timetable.</p>

Category	Question/comment	DDT response
	Stakeholder commented that it was not clear how the proposed position on sustained minimum stable load (and two tiered minimum stable load) was reached	The position paper clarifies the policy reasoning for why only a sustained minimum stable load has been including in the design at this time.
	Stakeholder commented that essential system services needs are proportionately higher in a smaller system like DKIS, compared to the larger NEM. The stakeholder sought clarification on the merit of dispatch (of energy) reforms in light of this.	<p>The proportionally higher costs of essential system services have influenced a number of the policy positions as described within the policy position paper for coordination of unit commitment, energy dispatch and enablement of essential services which are even more important than in a larger system.</p> <p>There is a net benefit to consumers and taxpayer of the identified reforms to dispatch arrangements because they will result in more efficient unit commitment and dispatch decisions. Current arrangements for making scheduling decisions only looking 30-minute ahead is not efficient as the trade-offs between start up and operating costs cannot be considered. Similarly, introduction of centralised scheduling will also lead to more efficient outcomes because it will avoid the need for generators to make price submissions based on estimates of startups and run times a day ahead of actual dispatch. Section 3.1 provided further detail on the need for priority dispatch changes.</p>

## On the draft settlement design (Workshop 23 July 2020)

Table E2 Stakeholder feedback

Category	Question/comment	DDT response
<b>General</b>	Comment from stakeholder expressing the view that no rules are perfect as trade-offs need to be made, and that there needs to be evolution over time as the market changes. Further comments expressing the need for nimbleness so that the market is able to evolve as required.	<p>The DDT agrees with these observations.</p> <p>A common theme of discussion throughout the workshop was that the design of a market is a series of trade-offs aimed at providing efficient design that provides the best outcome for customers in terms of reliable and secure supply at reasonable cost.</p> <p>As was discussed at the opening of the workshop, where there are complex issues, it is preferable to reduce their impact on real time (dispatch) activities and instead deal with them through less time sensitive activities, such as the settlement process.</p>

Category	Question/comment	DDT response
	<p>Stakeholder question on whether the design accommodates retail customers that generate electricity behind the meter (through distributed energy resources) including virtual power plants.</p>	<p>The settlement design accommodates these arrangements. The use of rooftop solar energy generation, demand response or other distributed generation will be reflected in the metered values at connection points. By using Marginal Loss Factors in settlement, a more accurate value of these activities to the out-of-balance market will be visible to retailers, who are best placed to provide the correct valuation and signal to customers.</p> <p>It is noted that depending on the activities of customers and/or operators of virtual power plants, any relevant requirements of the <i>Electricity Reform Act 2000</i> and subordinate regulations in respect to licencing would need to be complied with.</p>
<p><b>Settlement timetable</b></p>	<p>Question regarding whether the seven day Settlement Period is designed to reduce exposure.</p>	<p>Yes, this is a reason for the seven day Settlement Period.</p> <p>It is also noted that the transitional arrangement of a monthly Settlement Period is appropriate for the short term given the size and riskiness of the out-of-balance market is expected to be small and low respectively in the initial stages of the market.</p>
	<p>Question regarding the costs of moving to seven day settlement.</p>	<p>The cost of undertaking settlement day-to-day (e.g. calculating Settlement Amounts, producing settlement statements and so on) is minimal. Therefore, there would be no material difference in cost between monthly and seven day settlement.</p> <p>Given the Market Operator advises that its current settlement system will not be able to handle increasing numbers of market participants (which was raised in discussion at the workshop), it intends to replace/upgrade its existing settlement system. These system changes will result in costs, however, the driver of the changes is increased market participants not the proposed settlement timetable. Providing certainty to the Market Operator about the settlement timetable will enable the Market Operator to design its system to the requirements.</p>

Category	Question/comment	DDT response
<p><b>Prudential arrangements</b></p>	<p>Comment from stakeholder that it was uncomfortable with the Market Operator carrying prudential risk because PWC's balance sheet may be used to cover the risk which may prevent possible structural separation of the System Controller and Market Operator in the future (from PWC). Stakeholder also commented that it was not correct to assume the Market Operator bears no risk under the proposal.</p>	<p>The prudential arrangements would be equally fit-for-purpose for a structurally separated (standalone) Market Operator as for the current arrangements whereby the System Controller and Market Operator form a business unit of PWC.</p> <p>The Market Operator statutory function to manage counterparty settlement risk would require the Market Operator to pay creditor market participants in the event of default and also enable it to recover the costs of providing this service through the System Controller (and Market Operator) tariffs. Given it would be able to recover its costs, the Market Operator would bear little to no risk.</p> <p>However, in the event this risk was realised (i.e. the Market Operator incurs costs performing its statutory function that it does not recover) this would be a cost to the Market Operator and not a cost to another business unit of PWC. This is consistent with the Utilities Commission's revised Ring-Fencing Code (to commence in August 2020) and the System Control tariff arrangements.</p> <p>More broadly, the DDT notes that the Market Operator statutory function to manage counterparty risk will provide a prudential arrangement that is proportionate to the expected level of risk. It is the lowest cost option to market participants, and ultimately to customers.</p> <p>The alternative options summarised in Appendix D are generally more administratively complex and require each market participant to hold deposits or bank guarantees which would increase their operating costs, and as a result increase costs to customers.</p>
	<p>Stakeholders expressed concern with the proposal for the Market Operator to recover costs associated with managing prudential risks but that compensation for dispatch errors is not proposed in the Priority Reform Program.</p>	<p>The approach of the Market Operator recovering costs associated with the statutory function to manage counterparty risk is consistent with the System Controller (and Market Operator) remuneration arrangements at section 39 of the <i>Electricity Reform Act 2000</i>. This is because the Market Operator would be recovering the cost of providing a service as part of operating the market.</p> <p>Arrangements for compensation for dispatch errors have not been included as part of the Priority Reform Program given that in most markets where such arrangements are in place, dispatch errors do not occur frequently and rarely have material financial impacts on market participants. Introduction of such arrangements would result in increased costs that would ultimately impact customers. A more cost effective means to enhance the accountability of the System Controller in regard to its dispatch decisions is through increased transparency requirements. These are to be introduced as set out in section 6.2.1 of this paper.</p>

Category	Question/comment	DDT response
Reference nodes	Question regarding how settlement arrangements would work for a generator in the southern region that has a contract with a retailer with only customers in the northern region.	<p>Where there are different Market Prices in the southern and northern nodes/regions (when there is a constraint), market participants could have positive or negative outcomes. Participants may elect to trade against a specific Reference Node if they prefer to reduce this form of risk providing this is consistent with their contractual arrangements and participants submit notice to the Market Operator to this effect for the purposes of settlement calculations. This is a decision that can be left to participants to manage in their assessment of counterparty risk.</p> <p>It is noted that as only out-of-balance will be settled through the market at the Market Prices, it is expected that the majority of energy will be settled in accordance with contractual arrangements. This will reduce any risk associated with out-of-balance settlement.</p>
	Question regarding relationship with, or consideration given to, work in the NEM to move away from Regional Reference Nodes. (i.e. Coordination of Generation and Transmission Investment (COGATI review by the AEMC).	<p>In considering the number of common points to value energy traded (i.e. number of Reference Nodes), consideration needs to be given to an appropriate trade-off between market (and contracting) complexity and market efficiency.</p> <p>Two Reference Nodes have been identified as the most appropriate trade-off for the DKIS given that this:</p> <ul style="list-style-type: none"> <li>- improves market efficiency (in comparison to one Reference Node) in respect to the most significant/commonly occurring constraint in the DKIS south of Channel Island</li> <li>- does not significantly increase complexity by ensuring the design does not result in market participants having to move away from whole-of-system contracting (noting they could do so at their discretion).</li> </ul> <p>Nodal pricing as contemplated by COGATI for the NEM is considered to be a level of complexity not warranted for the DKIS. The complexity and associated cost would outweigh the benefits of market efficiency.</p> <p>In discussion at the workshop, a stakeholder noted that other constraints in the DKIS exist (in addition to that south of Channel Island) and two Reference Nodes may not result in optimal market efficiency in respect to those. This was discussed in the draft design paper and is included at section 6.2.2 of this policy position paper. An option would be to introduce further Reference Nodes (e.g. a third node), however, this would add market (and contracting) complexity. Two Reference Nodes are proposed as representing the most appropriate trade-off between complexity and efficiency for the DKIS, and consequently, is considered to be the option that best serves the long term interests of customers.</p>



Category	Question/comment	DDT response
	Question about whether two Reference Nodes give rise to gaming of the price differential between Market Prices.	The cost based submission requirements in the design for dispatch will protect against the potential for gaming. Minimising the risk of gaming is one of the reasons that cost based submissions for the unit commitment and dispatch process are to be required.
	Question regarding settlement for when islanding occurs between generator and load locations.	<p>The settlement arrangements would accommodate this with zero flow on that network element. The Market Price would continue to be based on the marginal, unconstrained generator for the relevant Reference Node.</p> <p>Noting this may result in inaccurate pricing (reduced market efficiency), the design with two Reference Nodes is considered the most appropriate trade-off between market (and contracting) complexity and market efficiency that best reflects the long term interests of customers.</p>
<b>Loss factors</b>	Question regarding loss factors including the risk of inaccurate loss factors if they are calculated as an annual average, and governance associated with determining loss factors.	<p>An annual average calculation does not represent a change from current calculation of loss factors. The management of tidal (or other large variations) in losses would introduce increased complexity, which may not result in a net benefit. As is the case for many settlement design choices, this reflects consideration of the trade-off between complexity (and pragmatism) and accuracy.</p> <p>The Utilities Commission will have oversight of calculation of loss factors by approving the methodology used to calculate loss factors.</p>
<b>Calculating Settlement Amount</b>	Question regarding what occurs when there are multiple generators setting the Market Price.	<p>The terminology used in the draft design paper and this policy position paper refers to <b>the</b> marginal, unconstrained generator and is a simplification.</p> <p>Noting it is proposed that the Market Price be calculated ex-post, if the Market Price is determined manually it will need to be based on a single price band for practical reasons. While it may be possible to calculate a composite price using an algorithm (that could include an optimisation approach) the manual approach of identifying the actual marginal price band should produce a sufficiently accurate price.</p> <p>If at some stage in the future there is a move to ex ante price setting, it may be more practical to use an optimisation routine for dispatch and price setting which would accommodate more complex price setting rules.</p>

Category	Question/comment	DDT response
	<p>Question regarding how security constraints will affect Market Price and a further question regarding what would occur if a generator was constrained on to provide essential system services.</p>	<p>The Market Price for out-of-balance energy is set by the marginal, unconstrained generator. This is the generator that would be dispatched at a higher level to meet a (hypothetical) increase in energy demand. If a generator is constrained on to provide essential system services it would not contribute to setting the Market Price to the extent it is operating to provide essential system services and it would not increase to meet additional energy demand so would be regarded as constrained.</p> <p>Current arrangements for compensation of generation constrained on to meet essential system services requirements (provided almost exclusively by Territory Generation at present) are through contractual arrangements and the codified price in the System Control Technical Code, noting that a review is underway of essential system services arrangements in the Territory's regulated electricity systems. Stakeholders were, and continue to be, encouraged to contribute to this review.</p>
	<p>Question on the definition of the cost of startup and a subsequent question regarding whether there will be multiple startup costs if required (such as for a combined cycle gas turbine unit).</p>	<p>The draft design paper provided some high-level guidance, and in response to this stakeholder question, the policy intent for cost recovery of startup costs has been further clarified in this policy position paper.</p> <p>However as part of implementation, a definition of startup/shutdown cycle costs that are recoverable through the settlement mechanism will need to be developed through consultation, providing it meets the policy intent set out in this paper.</p> <p>A core principle is that the definition will need to ensure that a generator is kept whole. Therefore, the definition should consider all costs that a generator would incur for starting, that it would not have incurred if it did not. Section 6.3.2 of this paper clarifies that a generator will be entitled to recover all costs associated with the startup/shutdown cycle except for the cost of running while dispatched.</p> <p>The definition should include consideration of multiple startup costs if required to ensure a generator (such as a combined cycle gas turbine unit) is kept whole.</p>
	<p>Question on relationship between startup cost recovery arrangements and contracting.</p>	<p>Participants may amend their bilateral contracts if current contractual arrangements include startup/shutdown cycle costs. This is an implementation issue. In response to this question at the Stakeholder Working Group workshop, the DDT indicated that it is open to a discussion with any concerned stakeholders regarding the need for transitional arrangements. No further feedback was provided by stakeholders.</p>

Category	Question/comment	DDT response
<b>Other questions</b>	Question regarding whether the System Controller will publish long term demand forecasts (one to five years) to inform dispatch and planning for generators.	<p>There needs to be appropriate division of responsibility in respect to planning. Ultimately it is most appropriate for generators to undertake planning in regard to understanding the utilisation of their plant and maintenance requirements and to accept some risk. This is the case currently for fast start machines under the current dispatch arrangements.</p> <p>A role for the System Controller to undertake or contribute to long term whole-of-system demand forecasting is not part of the dispatch (or settlement) priority reforms. However, a proposal for a long term demand forecasting role for a Reliability Manager is proposed as part of the reliability (capacity) mechanism, which is to be the subject of a consultation paper also released in January 2021.</p>
	Question regarding relationship between the proposed dispatch and settlement arrangements, and the generator performance standard (GPS) at section 3.3.5.17 of PWC's Network Technical Code (NTC).	<p>The DDT advised at the workshop that it was not aware of any conflict between the GPS requirement and the proposed priority reforms for dispatch and settlement but committed to reviewing the relevant section of the NTC.</p> <p>On review of the NTC, the DDT confirms that there is no misalignment between the GPS capacity forecasting requirement and the proposed priority reforms.</p> <p>The GPS requirement relates to forecasting of capacity (which can be thought of as 'availability' or 'capability' to produce energy, but not as a dispatch instruction or required actual output).</p> <p>To explain this distinction, when a generator forecasts capacity in accordance with the GPS requirement, it is not automatically required to produce energy in accordance with its forecast. Forecasts of capacity are distinct from instructions of the System Controller regarding unit commitment and dispatch, and the generator is only required to produce energy in response to a unit commitment or dispatch instruction of the System Controller in accordance with the dispatch rules.</p> <p>For clarity, if the System Controller dispatches a generator at a lower level than its capacity forecast, this is within the rules and does not constitute non-compliance by either the generator or the System Controller. It reflects that the capacity forecast is only an information input to inform the dispatch process.</p>

Category	Question/comment	DDT response
<p><b>Additional feedback received post-workshop (where not addressed above)</b></p>	<p>A stakeholder expressed concern about PWC Networks' ability to implement its Metering Data Management System within expected timeframes and suggested that this be considered in transitional arrangements for the interim settlement timetable</p>	<p>The transitional settlement timetable is intended to remain in effect until the Meter Data Management System is in place (i.e. rather than a specified date).</p>
	<p>A stakeholder expressed concerns about the proposed prudential arrangements, including that:</p> <ul style="list-style-type: none"> <li>○ the settlement risk should be managed by market participants, as this will incentivise participants to take on efficient levels of risk</li> <li>○ the further measures are required to reduce the prudential risk</li> <li>○ the Market Operator may risk not being able to fully recover its costs associated with the Market Operator statutory function to manage counterparty risk</li> </ul>	<p>Participants face a range of risks and manage those risks to maximise their profit. This is the optimum level of risk for each participant. The settlement regime, per se, does not change options available to market participants to manage their risk.</p> <p>A key reason for the prudential design including the Market Operator function to manage counterparty risk is because this prudential arrangement is proportionate to the expected level of risk. The settlement risk has to be considered in the context of the overall market design, including that it is expected that there will be a high level of bilateral contracting, at least in the early stages of the market. This is discussed in Appendix D.</p> <p>The design provides for the Market Operator to recover its efficient costs as part of operating a wholesale market. The Utilities Commission have flagged, in their System Control Charges determination, pass through arrangements for changes of the System Controller (Market Operator) functions.</p>
	<p>A stakeholder noted that they understood the rationale behind that two Reference Nodes but felt that this would add a level of complexity that may not be required long term (e.g. if the constraint ceases)</p>	<p>This was considered in the design of the two Reference Node arrangements. Further explanation in respect to that has been added to this policy position paper. Section 6.2.3 notes that additional benefit of the lossless link between the two Reference Nodes, is that at times when there is no constraint at Channel Island, or if the constraint permanently ceases, DKIS would effectively act in the same way as a single region, rather than two regions.</p>
	<p>A stakeholder questioned the need for startup/shutdown cycle costs to be treated separately</p>	<p>It is necessary for startup/shutdown cycle costs to be treated separately to avoid the occurrence of 'reverse price flows' and to ensure the most efficient design for customers and taxpayers. The reasons for this are outlined in more detail in section 6.3.1 of this paper, which also included an example of the 'reverse price flows' issue that could occur if startup/shutdown cycle costs were amortised in the Market Price.</p>

Category	Question/comment	DDT response
	<p>A stakeholder advocates for the creation of a (competitive) essential system services market and encourages consideration of options for this as part of the essential system services program of work.</p>	<p>The merits of a competitive essential system services framework are being considered as part of the NTEM Priority Reform Program. Stakeholders are encouraged to contribute to this review.</p>
<p><b>Additional feedback (supplementary draft design paper on prudential arrangements circulated to settlement workshop participants)</b></p>	<p>The majority of feedback received was broadly supportive of the proposed supplementary design.</p> <p>One stakeholder commented that the proposal appears to provide a good balance between the level of risk and the cost to participants.</p>	<p>The supplementary draft design paper on prudential arrangements proposed the inclusion of the prudential obligation for individual participant that presents a material risk. It also clarified the arrangements to be followed in the event of a default.</p> <p>In light of the positive feedback received, the supplementary design elements for prudential arrangements have been incorporated into this policy position paper.</p>
	<p>One stakeholder advocated for:</p> <ul style="list-style-type: none"> <li>○ prudential and default event arrangements for market participants that fail to make payments under a generator's bilateral contract; and</li> <li>○ the prudential obligation for an individual participant to be triggered when a participant has a credit rating higher than BBB+.</li> </ul> <p>The stakeholder also commented that consideration should be given to the administrative burden associated with moving to monthly Settlement Periods for participants that have monthly settlement under bilateral contracts.</p>	<p>The purpose of the prudential arrangements are to manage settlement risk associated with centralised settlement via the Market Operator, where participants cannot 'know' their counterparty.</p> <p>Where the counterparty is known, such as when bilateral contracts are established directly with the counterparty, an entity can assess the risk and take appropriate steps to manage settlement risk.</p> <p>Accordingly, the NTEM Priority Reform Program prudential arrangements are not designed to manage risk associated with bilateral contracts.</p> <p>The BBB+ requirement is consistent with existing codes and networks. Accordingly, BBB+ is considered appropriate level and will ensure that retailers that do not present a high credit risk are not unnecessarily required to comply with the additional individual prudential obligation.</p> <p>A key consideration in transitioning to monthly settlement periods is to reduce settlement risk by reducing the exposure period. The change to the Settlement Period for Market Operator settlement does not necessarily impact on bilateral contracts, however, it is noted that the transition from weekly to monthly settlement should provide time to make any small adjustments required.</p>

## Appendix F: Stakeholder Working Group Terms of Reference

The Terms of Reference was provided to stakeholders that nominated to be included on the Stakeholder Working Group, in advance of the workshops that were held in July 2020.

Box F1 - Terms of Reference

### Stakeholder Working Group – Terms of Reference

#### Objective of Working Group

The objective of the Stakeholder Working Group is to consider proposed detailed and technical design proposals for components of the Northern Territory Electricity Market Priority Reform Program and provide constructive feedback on the proposals.

The Stakeholder Working Group is not a decision making body. Feedback received from the Stakeholder Working Group will be used to inform the Design Development Team's development of the proposed design of each component of the Priority Reform Program.

#### Scope

The Stakeholder Working Group's scope is to provide feedback in relation to the proposed draft design of the reforms outlined in the *Northern Territory Electricity Market Priority Reform Program: Introductory notes on scope and work program* paper released on 12 June 2020.

The scope of a workshop of the Stakeholder Working Group relates to the reform or design component(s) outlined in the agenda for that workshop provided to the Stakeholder Working Group.

#### Providing feedback

To ensure the Stakeholder Working Group can effectively work together to meet its objective, all members of the Stakeholder Working Group should have regard to the scope in forming and providing feedback.

Feedback should be provided in a constructive manner. In providing feedback, the Stakeholder Working Group should have regard to the objectives of the Territory's electricity supply industry regulatory framework as set out in the *Electricity Reform Act 2000* rather than solely representing individual organisational interests. The objectives set out in the 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.

Feedback may include the identification of costs and benefits of the proposed design, alternative approaches that could be considered or any other practical/functional concerns or questions.

The Stakeholder Working Group should recognise that feedback provided and views expressed at a workshop will constitute feedback that will be used by the Design Development Team to inform the finalisation of the proposed design of each component of the Priority Reform Program. However, views expressed or an agreement reached at a Stakeholder Working Group on proposed design elements will not constitute 'final' policy positions. This reflects that the Stakeholder Working Group is not a decision making body and the Design Development Team is responsible for provision of policy advice and for overseeing the delivery of the market reforms.

Formal consultation will be undertaken separately as required for amendments to the System Control Technical Code. Consultation as part of the Stakeholder Working Group is designed to provide stakeholders an early opportunity to comment on the draft design.

### Timing of feedback

Stakeholders are encouraged to provide written feedback in advance of Stakeholder Working Group workshops and verbal feedback at workshops. Written feedback may also be provided within one week after the relevant workshop to enable consideration by the Design Development Team.

## Workshops

### Registration and attendance

Registration for attendance at each workshop of the Stakeholder Working Group will be sought to ensure appropriate facilities and arrangements can be put in place for the workshop. Stakeholders will have one week to register.

Continuity in attendance of workshops is strongly encouraged given the interrelated nature of components of the Priority Reform Program. A member of the Stakeholder Working Group may propose to register one additional participant from its organisation to attend a workshop (i.e. maximum of two participants per organisation). As a guide, two participants from an organisation may have a technical and commercial focus respectively with a suitable level of knowledge and experience to be able to engage in the workshops on detailed design of components of the Priority Reform Program.

### Administration of workshops

At least one week prior to a workshop, the Design Development Team will circulate an agenda for to the Stakeholder Working Group to members that register their intention to attend the relevant workshop. Other materials (such as the relevant draft design paper) will also be provided.

Workshops will be chaired by the Design Development Team (and its expert advisor) and run in accordance with the agenda. All participants in workshops are expected to be open and transparent in their provision of feedback and their consideration of the views of other participants.

All efforts should be made by the Stakeholder Working Group and the Design Development Team to consider and respond to feedback and questions at the workshop, however, there may be occasions when the Development Design Team will take questions on notice.