NTESMO

Scheduling and Dispatch Procedure Development

Stakeholder Responses and Draft Documentation
May 2026

Introduction

Power and Water Corporation (**Power and Water**), in its capacity as the Power System Controller, is seeking to update and amend the suite of procedures governing scheduling and dispatch of generators and dispatchable supply side resources in the Darwin Katherine Power System (DKPS).

The System Control Technical Code[1] prescribes obligations on the Power System Controller in relation to the development of, and consultation on, guidelines and procedures governing the scheduling and dispatch of generators in various locations. The System Control Technical Code requires consultation with System Participants prior to publishing such documents.

The paper has been prepared to provide responses to the written submission invited by the Northern Territory Electricity System and Market Operator (**NTESMO**) prior to developing the Draft Scheduling and Dispatch Guideline and Draft Plant Outage Procedure. A discussion paper was published on 3 November 2025 and submission were invited by Monday 1 December 2025 as per a standard consultation (NER (NT) Chapter 8.9.2). The submission timeframe was extended by 5 business days post cyclone Fina to Monday 8 December 2025. Written submissions were received by EDL, Territory Generation, ENI and Rimfire.

NTESMO thanks EDL, Territory Generation, ENI and Rimfire for responding to the Scheduling and Dispatch procedure development consultation. NTESMO has reviewed the clarifications and matters raised and provided responses to the stakeholder comments within this document.

Rationale for amendments

The amendments to the existing scheduling and dispatch suite of procedures aim to improve clarity, streamline processes, and better align the guideline with current operational practices while maintaining consistency with the transitional nature of the Interim Northern Territory Electricity Market (**I-NTEM**). Six separate procedures were considered in the scope of the Scheduling and Dispatch Guideline, as detailed in

Table 1.

The key drivers behind the proposed amendments are as follows:

- **Improved operational clarity and usability:** The consolidated Scheduling and Dispatch guideline, consisting of 4 previously separate procedures, and the revised Plant Outage Procedure enhances the effectiveness of application by NTESMO and provides clearer, more consistent guidance for market participants, supporting improved understanding and operational outcomes. Targeted updates have been applied across all relevant documents to align with current operational practices and streamline process diagrams.

- **Alignment with evolving market conditions:** The amendments from the consultation process reflect changes in the generation mix, including the integration of new and emerging technologies, ensuring alignment with current system operating conditions and practices. This will improve the efficiency of system dispatch through automated management of transmission line constraints and optimisation of renewable generation, while maintaining system security.

[1] System Control Technical Code

- **Consolidation of existing procedures:** A significant number of procedures are beyond their review date. Consolidation into a single guideline reduces duplication, addresses overlapping themes, and improves efficiency through a more streamlined and consistent structure.

- **Closure of outstanding consultation processes:** The inclusion of the I-NTEM Dispatch and Pricing Procedure within the consolidated Scheduling and Dispatch Guideline finalises the consultation process initiated in 2020, ensuring completeness and integration within the current framework.

- **Modernisation of the tie-break framework:** The existing tie-break procedure was no longer fit for purpose and has been updated to reflect the implementation of Proportional Energy Dispatch (**PED**), providing a more equitable, transparent, economically efficient and operationally relevant approach. This will provide updates on real-time system operations to maximise renewable energy dispatch through the PED tool.

- **Foundation for future reforms:** Collectively, these amendments address existing gaps and inefficiencies, improve operational efficiency through consolidation, introduce targeted enhancements, strengthen accountability and repeatability of system operations, and establish a structured and adaptable framework to support ongoing developments under the Territory Electricity Market Reform Program.

The general summary of the stakeholder feedback was support for the consolidation of the suite of scheduling and dispatch procedures and that the Scheduling and Dispatch Guideline should align with current practices. Feedback from Territory Generation and ENI recommended that the following two procedures remain separate:

- Generator Forecast Compliance Procedure; and
- System Control Plant Outage Procedure.

NTESMO agrees with this feedback and has not incorporated the content from the before mentioned procedures into the Scheduling and Dispatch Guideline.

Some stakeholder feedback—particularly those pertaining to broader market-design related implications—are outside the scope of this guideline update. The Northern Territory Government is currently progressing reforms to the Territory Electricity Market (**TEM**). The Scheduling and Dispatch Guideline specifically makes no references to the development or timing of the TEM Rules however there is a requirement to update the Scheduling and Dispatch Guideline once the rules are published.

It shall be noted, the Generator Forecast Compliance Procedure has not been included within the current suite of procedural changes. The Generator Forecast Compliance Procedure is currently addressed under the Network Technical Code (NTC), specifically Clause 3.3.5.17 relating to Capacity Forecasting. This area will instead be considered as part of a future reform activity, informed by the operational experience and learnings NTESMO has progressively developed in the forecasting domain.

In addition, the proposed amendments to the Plant Outage Procedure include the introduction of provisions for compliance testing, as well as new generator and load testing activities. This is followed by updates to references within the guideline and the removal of Outage and Testing Requests and Return to Service instructions. Collectively, these changes are intended to enhance clarity, streamline processes, and ensure alignment with current operational practices.

Table 1: Scheduling and Dispatch suite of procedures

Procedure	Version	Date Effective	Review Period	Consolidated into the Guideline or Standalone
Market Timetable Procedure	1.0	July 2016	Subject to System Control Technical Code changes	Consolidated
Generator Forecast Compliance Procedure	1.1	July 2020	Subject to Network Technical Code and System Control Technical Code changes	Stand-alone
Generator Offer Procedure	2.0	September 2020	Subject to System Control Technical Code changes	Consolidated
Generator Unit Tie Break Procedure	2.0	September 2020	Subject to System Control Technical Code changes	Consolidated
System Control Plant Outage Procedure	1.0	October 2020	Subject to System Control Technical Code changes	Stand-alone
Dispatch and Pricing Procedure	Draft	Not yet released	To be determined	Consolidated

Summary of proposed amendments

The high-level summary of the Scheduling and Dispatch amendment that were incorporated into the Draft Scheduling and Dispatch Guideline are:

- **Consolidation of Existing Procedures:** Four existing procedures have been consolidated into a single, unified Scheduling and Dispatch Guideline. This consolidation reduces duplication, supports consistent interpretation, and provides a centralised reference for Market Participants.
- **Adoption of Proportional Energy Dispatch:** The guideline formally adopts Proportional Energy Dispatch, replacing the previous 5 MW block tie-break method. The revised Proportional Energy Dispatch provides a fairer, economically efficient and more transparent approach to resolving equal-price dispatch scenarios.
- **Treatment of Self-Committed Units:** The guideline now allows Generators to nominate their self-committed units as tied for the purposes of Proportional Energy Dispatch. This enhancement supports consistent application of Proportional Energy Dispatch and simplifies dispatch outcomes where multiple units of the same participant are offered at equal prices.
- **Flexibility for Operational Adjustments:** New flexibility provisions allow the System Controller to make real-time adjustments to dispatch order, provided these adjustments do not affect other Market Participants. This reflects the virtual nature of the current market, where the total dispatch quantity for each Generator must be preserved
- **Removal of Outdated or redundant provision**: The following elements have been removed to ensure the guideline reflects current operational practice:

- References to overnight generating units, now implicitly captured within the pre-dispatch processes.
- Explicit references to Frame 6 units, which are instead captured through Long-Term Risk Notices (LTRNs).
- First-on and first-off provisions that are inconsistent with the intent and design of the I-NTEM.

Consultation and implementation timetable

NTESMO are conducting a standard consultation aligned with clause 8.9.2 of the National Electricity Rules (NER) (NT). NTESMO encourages stakeholders to submit responses to the Draft Scheduling and Dispatch Guideline no later than 08 June 2026 so that proposed amendments can be developed, reviewed, updated, finalised and published in accordance with the indicative schedule below in Table 2.

Table 2 - Scheduling and Dispatch standard consultation timetable

Stage	Commence	Complete	Explanation
Release of consultation pack	3 November 2025	8 December 2025	Provides stakeholders at least 20 business days as per clause 8.9.2(a) of the NER (NT)
Review and consolidation of responses	8 December 2025	02 January 2026	50 business days to draft amendments to
Develop and review amended procedure/s	05 January 2026	04 May 2026	Sufficient time to review and draft amendments taking into consideration stakeholder's first round submissions
Publish responses and commentary **Publish amended procedure**	11 May 2026	15 June 2026	Amended schedule Publication of response to stakeholder's first round submissions and amendments via notification on NTESMO's website
Review and draft response to submissions by System Participants	15 June 2026	14 August 2026	Sufficient time to update proposed amendments taking into consideration stakeholder's second round submissions
Publish responses and commentary **Publish final amended procedure**	21 August 2026	21 August 2026	Final publication, including notification of date of effect
Date of effect of amended Procedure	TBC 2026	TBC 2026	Date of effect may be brought forward contingent upon outcomes of stakeholder consultation

NTESMO proposes that on finalisation of this current consultation and successful consolidation of the procedures (following the consultation timeline in Table 2), a minimum of two revisions of the guidelines will be required.

In preparation for TEM reform, NTESMO propose a consultation on the guidelines to identify incremental I-NTEM changes such as trial generator offers for essential system services, generating unit start costs, and other inputs to improve security constrained unit commitment and security constrained economic dispatch functionality through a fit for purpose techno-economic engine to be delivered as part of the in-flight Territory Dispatch Engine Stage 1 project.

A subsequent consultation on the guidelines to move from I-NTEM arrangements to TEM will be scheduled once the TEM design is finalised. This consultation will include implementation of the new TEM arrangements for energy and essential system service cost parameters, as well as market pricing arrangements for market clearing. NTESMO's will seek funding approval to implement a market participant interface for exchange of market and performance data with Market Participants (future Territory Dispatch Engine Stage 2 project).

Consultation questions

The following questions were provided as a prompt for stakeholders and interested parties through the Scheduling and Dispatch procedure development discussion paper regarding areas that are of particular interest to NTESMO. Table 3 represents a summary of the stakeholder feedback and the approach and response NTESMO has applied in the development of the Scheduling and Dispatch Guideline and revision of the Plant Outage Procedure:

1. What are your views on consolidating some or all of the existing procedures into a single procedure / reference guide governing the scheduling and dispatch of System Participant Facilities? Which procedures should be consolidated into a single procedure, and which (if any) should not? Please provide clear rationale for not including any of the existing procedures into a single consolidated procedure.

2. Do you support amending the Generating Unit Tie Break Procedure to more accurately reflect the current operational practice of proportional energy dispatch process?

3. Do you have any material observations and recommendations regarding the decommitment merit order post 1800 hours? Please provide clear rationale for your recommendations.

4. Do you have any material observations and recommendations regarding the scheduling / pre-dispatch process? Please provide clear rationale for your recommendations.

5. Do you have any material observations and recommendations regarding the real-time scheduling and dispatch process? Please provide clear rationale for your recommendations.

6. Do you have any material observations and recommendations regarding the market price determination process? Please provide clear rationale for your recommendations

7. What amendments would you recommend to the existing market timetable as described in the Market Timetable Procedure? Please provide clear rationale for recommending such changes.

8. What amendments would you recommend to the existing generator forecast compliance procedure based upon current negotiated access? Please provide clear rationale for recommending such changes.

Do you support consolidation of the generator forecast compliance procedure into the proposed scheduling and dispatch procedure? If not, please provide a clear rationale for an alternative approach.

9. What amendments would you recommend to the existing generator offer procedure based upon prevailing market conditions? Please provide clear rationale for recommending such changes.

10. What amendments would you recommend to the generator unit tie break procedure based upon prevailing market conditions? Please provide clear rationale for requiring such changes. Do you support centralised dispatch of all generating units to afford incremental proportioning of dispatch? Can you recommend any alternative methods to be considered? Please present clear rationale for such.

11. What amendments, if any, would you recommend to the existing System Control plant outage procedure based upon prevailing market conditions? Please provide clear rationale for recommending such changes.

12. Do you support the consolidation of the draft dispatch and pricing procedure into the proposed scheduling and dispatch procedure? Please provide clear rationale for any alternative approaches proposed.

NTESMO welcomes any broader feedback from stakeholders on the Scheduling and Dispatch Guideline, revision of the Plant Outage Procedure and the content outlined in this consultation paper. Such input is highly valued, as it can provide insights beyond the scope of the consultation questions and support the ongoing refinement and continuous improvement of the framework.

Table 3 – Summary of responses from participants

Question #	Consultation Question	EDL	Territory Generation	ENI	Rimfire Energy	NTESMO
1	**What are your views on consolidating some or all of the existing procedures into a single procedure / reference guide governing the scheduling and dispatch of System Participant Facilities? Which procedures should be consolidated into a single procedure, and which (if any) should not?** **Please provide clear rationale for not including any of the existing procedures into a single consolidated procedure.**	EDL support consolidating most, if not all System Control Technical Code (SCTC)-based procedures into a single Scheduling and Dispatch Procedure. EDL expects this matter, along with other items outlined in the discussion paper, to be addressed as part of the broader market reforms currently underway. As a member of the Industry Reference Group, EDL intends to work through this issue with other members during reference group meetings throughout 2026.	TGen supports the consolidation of the draft dispatch and pricing procedure into the proposed scheduling and dispatch procedure. The rationale is a consolidated document will include a single set of definitions, timing obligations and a single source of reference for all market participants, reducing ambiguity and simplifying compliance, where possible. In the DKES system, scheduling, dispatch and pricing are tightly coupled because: • Reserve shortfalls drive commitment decisions • Unit constraints impact pricing outcomes • Interaction of BESS and thermal units affect start-stop decisions Note that Q2.1 and Q2.12 are the same. The consolidation of the existing procedure	As a participant, Eni sees merit in consolidating some of the existing procedures into a single procedure/reference guide governing the scheduling and dispatch of System Participant Facilities. The following could be consolidated into a single procedure: • Market Timetable Procedure • Generator Offer Procedure • Generator Unit Tie Break Procedure • Dispatch and Pricing Procedure Draft The following should not be consolidated into a single procedure and should remain separate: • Generator Forecast Compliance Procedure • System Control Plant Outage Procedure	Rimfire is supportive of the procedures being consolidated into a single guide, provided there is clear process such that individual procedures can be updated (without loss of productivity for the market and its participants) in the future based on adequate notice and consultation with industry.	NTESMO supports stakeholders' views that consolidation of the relevant procedures is appropriate. The Generator Forecast Compliance Procedure and the System Control Plant Outage Procedure will remain as standalone documents due to their distinct scope and functional requirements. Additionally, NTESMO has chosen not to amend or revise the Generator Forecast Compliance Procedure at this time. Generator Forecast Compliance is currently addressed under NTC Clause 3.3.5.17 relating to Capacity Forecasting. This matter will instead be addressed as part of a future reform program.

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			documents reduces duplication, improves clarity and better aligns with the operational and market realities of the DKES. It strengthens transparency, simplifies compliance and supports integration of new technologies such as BESS. However, consolidation must retain strong segmentation, clearly defined operational triggers and a transition table for participants to track changes. Any substantive changes to obligations should remain subject to full consultation.	Procedure Consolidation: • Generator Forecast Compliance Procedure: does not apply to all generators. Eni would like to understand if this will be replaced with SFURM methodology/procedure. If so, will the Network Technical Code be revised accordingly? System Control Plant Outage Procedure: plant outage procedure includes both generators and transmission network assets (transmission lines, substations, transformers).		
2	**Do you support amending the Generating Unit Tie Break Procedure to more accurately reflect the current operational practice of proportional energy dispatch process?**	Given proportional energy dispatch (PED) is the current method used in practice, EDL supports amending the Generating Unit Tie Break Procedure to reflect PED as the standard method. PED should, however, continue to respect the minimum stable loads (Band 1) and ramp constraints of the generator itself to allow	TGen supports centralised dispatch of all generating units within the DKES including thermal, renewable and storage assets to enable incremental and proportional dispatch across the whole fleet. One suggestion to NTESMO is to explicitly distinguish interparticipant vs intraparticipant tie breaks. There's often no clear	Eni is supportive of a proportional dispatch in tie break situations, mostly because it is a much simpler methodology while retaining fairness. Proportionality should be based on capacity being offered by the generators with the same offered price. Therefore, Eni supports amending the procedure to reflect this principle.	Rimfire supports changing the tie break procedure to align with current practice of proportional energy dispatch.	• NTESMO notes that fast-start and self-commitment tie-break processes have historically applied between participants, and this remains unchanged. Energy-based tie-breaks were also previously inter-participant, as participants could not submit tied prices for self-committed units.

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		the most efficient and cost-effective generation.	difference or limited clarity between tiebreaks between different generators and tie-breaks between units owned by the same participant. Note that Q2.2 and Q2.10 are the same. The introduction of inter participant tie breaks using the current system centric criteria which is security > efficiency > flexibility > emissions and intra participant tie breaks which allows the market participant to nominate a unit priority order multiple times in a day as required to reflect maintenance strategy, optimise commercial/fuel considerations and run hour management will result in a fair and transparent treatment between different market participants, empowering generators to retain flexibility to optimise their own fleet internally as long as system outcomes are met.			• With the updated framework allowing tied offers for self-committed units, proportional energy dispatch is now participant-agnostic. • The proportional energy dispatch methodology has been designed to respect all relevant generating unit constraints. • Additional provisions have been introduced to allow real-time operational deviations from merit order where this does not adversely impact other participants. This enables generators to optimise their fleets while maintaining system-wide fairness.
3	**Do you have any material observations and recommendations regarding the decommitment merit**	EDL does not have any material observations to note	**Observations:** • It has been consistently observed that evening	The decommitment merit order post 1800 hours predominantly considers dispatch of thermal generating units, referencing	While it is recognised that a decommitment merit order submission provides flexibility to some	NTESMO notes the recommendations provided by Territory Generation:

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	order post 1800 hours? **Please provide clear rationale for your recommendations.**		load generally drops after the early evening peak (around 16:00 hours – 21:00 hours). This naturally reduces unit commitment requirement, opening a window to decommit higher cost or lower efficiency machines. • High efficiency gas units remain preferred such as LM6000s (DKES) and Jenbachers (ASPS) because of lower $/MWh compared with older units. • Inertia requirements continue to drive commitment where even as load reduces, inertia floors require at least one to two Frame6B machines online. **Recommendations:** 1. Update the decommitment process to consider BESS discharge capability to reduce conservative over commitment. 2. Prioritize decommitment based on variable cost	fast start generating units and self-committed unit operating at minimum load, and does not appear to take into consideration the application of Battery Energy Storage Systems (BESS) as generating units forming part of the decommitment merit order post 1800 hours. Recommendation is for BESS to be included, and clarification provided as to whether BESS are classified as a fast start generating unit. It is not clear how System Control would intend to use a fully charged BESS as part of the decommitment merit order post 1800 hours.	generators (principally Territory Generation), it is also recognised that the TEM is small and hence there is a need to reduce unnecessary regulatory burden and the associated costs. Further consideration should therefore be given to whether this procedure actually adds more benefit than costs; and a preference to minimise unnecessary procedures may result in this being removed. Section 4.8.2 – Frame 6 units. The Secure System Guidelines ("SSG") v5 specifies the system requirements, rather than specific units like Territory Generation's Frame 6 units. Specific unit requirements are dealt with in the Risk Notices ("RNs"). Rimfire supports this approach and suggests this section is therefore no longer relevant to this consultation. Section 4.9 – Pre dispatch solution process – Minimum stable loads. Setting of minimum stable loads for Generators is a significant	• Recommendation 1 falls within the System Controller's operational discretion. • Recommendations 2 and 3 are expected to be supported through enhanced operational flexibility provisions in the revised guideline. • The merit order principles identified will be further considered as part of the in-flight Territory Dispatch Engine Stage 1 project, which aims to enable dynamic, real-time optimisation and efficiency improvements. In response to stakeholder feedback, NTESMO has incorporated the following updates into the Scheduling and Dispatch Guideline (SDG): • Acknowledgement of stakeholder preferences to minimise procedural complexity, while retaining the "first-off" decommitment order due to its operational importance.

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			and restart cost to avoid situations where cheaper unit is turned off but must be restated at higher cost. 3. Treat diesel units as 'security only' unless gas curtailment is imminent. **Merit Order Principles:** 1. Security First: Maintain minimum inertia + fault level + SR before decommitment. 2. Costs: Prioritize keeping low heat rate gas units and decommitting high heat rate/diesel units. 3. Location: The physical position of each generator determines its impact on stability and regional support, making location a critical factor in merit order. Where a unit sits on the network impacting voltage support, line loading and contingency coverage, decommitment decisions must consider geography of system strength.		factor in the operation of the Darwin-Katherine Electricity System ("DKES"). Lower specified minimum stable loads would allow greater flexibility and more sustainable generation. There should be consideration of some form of incentive and/or regulation for Generators to set their lowest possible minimum stable load. Related, the period of stability should be defined, and a sensible time limit set such as stable for the trading day (24 hours). Without conditions on setting of minimum stable load this could lead to a misuse of market power and potential crowding out of more economic sources of generation. Section 4.9 – Pre dispatch solution process. The statement "With the foreshadowed introduction of the PPM, this situation will not occur" requires further explanation, noting Rimfire's prior comments in relation to the PPM.	• Removal of references to specific generating units (e.g. Frame 6 units), replaced with a risk-notice-based approach. • Confirmation that minimum stable load settings remain technical parameters and are unchanged. • Removal of references to the PPM in the draft SDG.

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4	**Do you have any material observations and recommendations regarding the scheduling / pre-dispatch process?** **Please provide clear rationale for your recommendations.**	EDL does not have any material observations to note. EDL expects this matter, along with other items outlined in the discussion paper, to be addressed as part of the broader market reforms currently underway. As a member of the Industry Reference Group, EDL intends to work through this issue with other members during reference group meetings throughout 2026.	**Observations:** • Lack of visibility on other market participants: TGen operational decisions are affected by independent generators whose pre dispatched behaviours is unpredictable or under signalled. This impacts unit commitment planning and scheduling. **Recommendations:** 1. Establish a more binding pre dispatch period, especially for peak periods. This will result in reduction of late recall of TGen units resulting in consistent steam cycle operations, minimised starts/stops and improved thermal efficiency. 2. Publish BESS SoC and duration-based dispatch limits in pre-dispatch where NTESMO should model usable BESS energy separately from SR commitments. 3. Introduce guidelines advising market	Long Term Risk Notices and non-reliability notices are not regularly taken into account in the pre-dispatch instruction. It is recommended that the pre-dispatch schedule account for any long-term network constraints and any planned outages of the generator itself. Otherwise, the generator receives a pre-dispatch schedule that can't align with the actual dispatch instructions issued in real time. For instance, if the generator is not allowed output above a set level due to existing network constraints, this should be reflected in the schedule.	The NT DKES is a relatively small market (<400 MW) and hence the amount of regulation should be kept to an absolute minimum to reduce the cost to NTESMO, NT electricity consumers and the NT economy. In this context, Rimfire makes the following comments: i. Self-committed does not apply to embedded generation under 2 MVA, as these units do not participate in the market. This category is relevant to large generators, which are typically dispatched by the Power System Controller. Further consideration should be given to whether this category can be eliminated to reduce regulatory burden. ii. Fast start classification is useful, however the System Control Technical Code ("SCTC") lacks a clear definition here and should be addressed. For example, defining fast start as a generator that can ramp from cold to full output	NTESMO notes that several items raised for improvements of pre-dispatch scheduling relate to scope that the in-flight Territory Dispatch Engine Stage 1 project will address and are therefore outside the scope of the current guideline. The Draft SDG incorporates additional flexibility to address near-term operational challenges. Further: • NTESMO recognises that while the DKES is a relatively small system, it remains operationally complex. Work is underway to formalise reserve requirements using appropriate technical methodologies and supporting tools. • Definitions within the System Control Technical Code fall outside the scope of this consultation. • The term "unreliable" is intentionally not prescriptively defined to preserve System Controller discretion

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			participants with BESS on how much capacity is forecast to be required to offset the Spinning Reserve for thermal generation. Consider including fault current support as a distinct category for effective utilisation of other available BESS services. 4. Strengthen communication and recall protocols with a clear rule set as to when NTESMO can vary pre-dispatch commitments which would support with operational planning, minimise inefficient cycling of units and improve reliability of weekend rosters and outage windows. The current DKES pre dispatch process often diverges from real time operational realities for TGen due to limited visibility of technical constraints in the power system. To improve reliability, NTESMO should establish a more binding pre-dispatch window, integrate detailed generator constraint envelopes, incorporate gas		in 10 minutes. Clear definitions will assist generation proponents when assessing and deploying investment in DKES connected generation. iii. Section 5.2.1 – The term 'unreliable' in the statement "Therefore, in the event that a unit has recently been unreliable when starting, the next unit in the merit order may be dispatched first" is undefined and subjective. Clearly defining 'unreliable' would offer guidance and ensure procedural fairness.	during real-time operations, particularly under critical conditions. • NTESMO agrees with EDL that broader market reform programs are the appropriate forum to address several of these matters. References to the PPM will be removed in the final document. • NTESMO agrees with ENI that pre-dispatch outcomes should reflect known long-term network constraints and planned outages.

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			nomination visibility, model BESS SoC and publish pre-dispatch confidence bands. Clearer communication protocols would enhance operational certainty and alignment between market scheduling and DKES security requirements.			
5	**Do you have any material observations and recommendations regarding the real-time scheduling and dispatch process?** **Please provide clear rationale for your recommendations.**	EDL generally receive phone calls from System control to change dispatch / scheduling. Written communication / confirmation is not always provided after the fact. **Recommendations:** EDL would recommend Improvements in transparency and communication: 1. Provide real-time updates on why deviations occur (e.g., security constraints, outages). 2. Provide digital / automated confirmation of real time dispatch and scheduling changes with a method to view	**Observations:** • Insufficient visibility of system level constraints for participants: TGen often receives dispatch instructions without the full context of binding constraints, Fast Raise/ Spinning Reserve dependencies or voltage considerations. This limits the ability to respond proactively and support power system objectives efficiently. • Contingency and security behaviours are unpredictable: Real-time schedules do not consistently incorporate changing system strength conditions, load pockets or unit specific fault level contributions, especially during	The real-time scheduling and dispatch process highlights "Priority 1 – Security Constraints" and "Priority 2 - Economic Commitment and Dispatch Arrangements" however it is not clear or transparent to system participants at which load level does Priority 2 - Economic Commitment and Dispatch Arrangements commence. For example, for a network load of 120 MW, generators supplying system security and essential system service requirements could be generating 90 MW, leaving only 30 MW demand to be served by remaining generators under economic dispatch. If this information was made available, remaining generators would understand they are being curtailed or ramped down	In general, the above comments (Rimfire response to question 4) on pre-dispatch, should also be considered for real time dispatch, and hence are not repeated here.	• The matters raised by TGen fall outside the scope of the Draft SDG amendments. The Territory Dispatch Engine is expected to address the issues raised regarding real-time constraint transparency and improved operational visibility. • Security-derived constraints vary significantly in real time, and the provided example from ENI is noted. The in-flight Territory Dispatch Engine Stage 1 project will provide enhanced visibility of decision drivers for deviations and applicable thresholds. • A fit for purpose participant interface module to support Market Participant data exchange and digital confirmation of

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		and receive historical real time deviations in the past. 3. Publish post-event reports Include explanations for major deviations from pre-dispatch to build confidence in the process.	morning/evening peak transitions. **Recommendations:** • Provide real-time constraint transparency to market generator participants: A live view of binding constraints, shadow prices and system security drivers would allow generators to prepare for upcoming changes, optimise fuel burn and provide more effective operational support to the system operator.	to zero, assuming no other network events have taken place. To improve transparency, it is recommended to specify what capacity, and which generators fall into Priority 1, and which fall into Priority 2 Further, current operating practices don't address concerns regarding transparency in curtailment, including allocation of such curtailment. Lastly, NTESMO should adopt a suitable tool or platform to better support renewable integration allowing their maximum dispatch, thereby reducing electricity costs for Territorians.		real time dispatch and scheduling changes is planned as part of NTESMO's systemisation of TEM implementation in the future Territory Dispatch Engine Stage 2 project. • Tools such as proportional energy dispatch (PED) and the SFURM framework are being adopted (pipeline) to support renewable integration.
6	**Do you have any material observations and recommendations regarding the market price determination process?** **Please provide clear rationale for your recommendations.**	EDL does not have any material observations to note. EDL expects this matter, along with other items outlined in the discussion paper, to be addressed as part of the broader market reforms currently underway.	**Observations:** • Current price signals do not fully reflect security-driven commitments: When System Control commits units out of merit, prices do not reflect the true system cost distorting the true	Eni has no comment on Question 6.	No material objections at this time to the market price determination process.	• The I-NTEM is a virtual market and is not subject to short-term forecast–driven price volatility characteristic of other real-time markets. • Operational flexibility provisions have been incorporated to address operational challenges to

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		As a member of the Industry Reference Group, EDL intends to work through this issue with other members during reference group meetings throughout 2026.	value of essential system services provided. • Fast start and minimum load characteristics: The price determination framework does not explicitly recognise warm/cold start costs or minimum stable load inefficiencies. This contributes to distorted price outcomes during low load periods and transitional ramping windows. • BESS participation can supress price signals without reflecting duration limits. Prices may remain artificially low during periods when thermal units must stay online for system strength/inertia but receive no uplift for their mandatory presence. • Price formation is highly sensitive to short term forecast errors: Small deviations between real time dispatch and forecasts can produce significant price swings, not because of genuine changes in the power system cost but because			bring efficiency where applicable. • NTESMO propose the Territory Dispatch Engine Stage 1 consultation will consult in more detail on incremental I-NTEM pricing changes to align to TEM design and the more substantial pricing issues raised.

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			price setting is highly marginal and lacks smoothing. • Limited transparency on constraint shadow prices: Participants cannot identify which constraints are actively influencing price, limiting their ability to interpret market outcomes or plan operationally. **Recommendations:** • Introduce an essential system services price uplift mechanism: When units are committed for inertia, voltage support or contingency coverage, a structured uplift should feed into price determination. This ensures price outcomes reflect the true marginal cost of meeting both energy and essential system service requirements. • Incorporate BESS costs, Start Cost, Minimum Load Penalties and Cycling Costs: Price determination should consider warm vs cold start costs, minimum			

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			up/down times, minimum stable load inefficiencies and cycling penalties, where applicable. Prices should incorporate both BESS energy limits and time to empty constraints, preventing prices from being anchored to BESS bids during periods when thermal units are required regardless of BESS availability. • Improve shadow price transparency for constraints: Publish a simple real time or near real time view of binding constraints, shadow prices and the drivers (inertia shortfall, shortfall, voltage limit, line capacity). This supports participants with understanding price movements and improves operational decision making. • Locationally sensitive pricing inputs: Pricing should recognise that commitment and dispatch at Channel Island, Katherine or Weddell nodes have materially different			

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			security and cost implications. • Locational factors improve price efficiency in a constrained, islanded system like DKES.			
7	**What amendments would you recommend to the existing market timetable as described in the Market Timetable Procedure?** **Please provide clear rationale for recommending such changes.**	EDL does not have any material recommendations to note. EDL expects this matter, along with other items outlined in the discussion paper, to be addressed as part of the broader market reforms currently underway. As a member of the Industry Reference Group, EDL intends to work through this issue with other members during reference group meetings throughout 2026.	Consider review of the procedure and enabling the data published on NTESMO website to be user friendly compatible with API use to support integration of the published data into use by existing systems and software in use.	For transparency and ease of reference, the Market Timetable Procedure could include the period for publication of the preliminary, final and 13-week settlement statements to generators.	No comments.	• A participant-centric interface is planned as part of the future Territory Dispatch Engine Stage 2 project to implement TEM reforms. • The Generator Forecast Compliance Procedure will not be incorporated into the Scheduling and Dispatch Guideline. Issues raised are noted.
8	**What amendments would you recommend to the existing generator forecast compliance procedure based upon current negotiated access? Please provide clear rationale for recommending such changes. Do you support consolidation of the generator forecast**	EDL does not have any material recommendations to note. EDL expects this matter, along with other items outlined in the discussion paper, to be addressed as part of the broader market	Expand on 'material forecast deviation' criteria re Generator Forecast Compliance for DKES Specific Conditions: • Material forecast deviation defined as a forecast error big enough such that it matters for system	In Eni's view the requirements of clause 3.3.5.17 of the NTC, to which the generator compliance procedure refers, are impossible to implement in a commercially sound way, also due to the unavailability of technologies with the accuracy that such clause requires. A	This section is very brief on the Forecast Compliance Procedure. In addition, it is noted that the Network Technical Code ("NTC") v4 is currently undergoing review, which includes section 3.3.5.17 which underpins this procedure.	• The Generator Forecast Compliance Procedure will not be incorporated into the Scheduling and Dispatch Guideline. Issues raised are noted. • NTESMO acknowledges stakeholders feedback and confirms that this procedure will remain

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	compliance procedure into the proposed scheduling and dispatch procedure? **If not, please provide a clear rationale for an alternative approach.**	reforms currently underway. As a member of the Industry Reference Group, EDL intends to work through this issue with other members during reference group meetings throughout 2026.	security, dispatch efficiency or market outcomes. It is not just any difference between forecast and actual output but rather, a significant difference large enough to cause incorrect unit commitment, insufficient reserves, inaccurate DR margin, incorrect fuel nominations, unexpected BESS charge/discharge and potentially impact power quality or frequency stability issues. • The existing 'forecast deviation' definition is too rigid and not suited to small, sensitive grids. Consider low risk (solar midday) plus/minus 5 MW tolerance; medium risk (morning/shoulder periods) plus/minus 5 MW tolerance and high risk (evening ramps) at plus/minus 5 MW. • Apply higher tolerance for inherently volatile generation (solar) and lower tolerance for controllable thermal	negotiated access has not yet been achieved but it is expected to deviate significantly from the automatic access. Eni understands that NTESMO is considering a different approach (SFURM), and Eni has provided its feedback to the proposal (and supports efforts in this direction). It follows that the compliance procedures will need to be significantly amended once a new forecasting and firming policy is defined, however it is premature to do so. As per feedback provided to the SFURM team, in Eni's view NTESMO should configure the network so that renewable generators are allowed to export at their full potential, which should ultimately result in a lowering of the cost of electricity on the I-NTEM. **Do you support consolidation of the generator forecast compliance procedure into the proposed scheduling and dispatch procedure?** No, since there will likely be substantial changes to the	This review process should be undertaken first, and then NTESMO's views on changes to this procedure should be provided for consultation.	separate, particularly given anticipated future changes to underlying code requirements.

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			units. This will reduce unnecessary non-compliance events and reflects a better system risk profile. • Introduce clear rules on Forecast Performance Reporting as in the current system, market participants are unable to demonstrate improvement or recognise the need of corrective actions. By introducing a requirement of quarterly forecast performance reports from NTESMO which taken into consideration mean absolute errors, peak period forecast deviation, correction cycles triggered, and annual forecast • improvement plans for underperforming assets supplying power to the grid, it would lead to continuous • improvement and consistent expectations across all generators.	underlying code requirements in the future.		

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9	**What amendments would you recommend to the existing generator offer procedure based upon prevailing market conditions?** **Please provide clear rationale for recommending such changes.**	EDL have no recommendations for changes at this time. EDL expects this matter, along with other items outlined in the discussion paper, to be addressed as part of the broader market reforms currently underway. As a member of the Industry Reference Group, EDL intends to work through this issue with other members during reference group meetings throughout 2026.	• Introduce Offer Granularity to reflect fast changing solar and load conditions: Current daily offer windows assume stable conditions but given that DKES see rapid changes in PV and load especially during evening peaks, there is value in adding sub-hourly offer refresh capability during high variability periods. Allow conditional offer adjustments based on forecast PV error thresholds. This will reduce unnecessary starts, improve BESS coordination and lower dispatch inefficiency. • Formalise BESS - specific offer structures: Existing offer formats were written for thermal units and do not suit BESS characteristics. Structured BESS offer components could include Charge bids, Discharge bids, Reserve (FR/SR) enablement bids and SOC reservation bands. This will result in transparent SOC/reserve interactions.	The generator offer procedure and template should be updated for inverter-based solar generators and BESS generators as current instructions consider thermal generation only.	Limited changes should be made now to the Generator Offer Procedure, but further changes should be proposed for consultation once the details of the TEM and Territory Dispatch Engine ("TDE") are known.	• The updated guideline introduces limited flexibility while ensuring no adverse impacts on other generators or real-time operational requirements. • Improvements relating to BESS coordination will be explored through the Territory Dispatch Engine and are out of scope for this guideline. • Minor amendments have been introduced, including allowing self-committed units to submit offers at the same price. • Solar units may now be tied when self-committed, supporting integration of inverter-based resources.

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			• Add diesel risk and gas supply availability disclosure requirements, noting that market efficiency and system security are impacted when gas shortages or diesel exposure are not communicated early. System Control should also take into perspective the impacts from exposure to directional gas flows which have direct price impacts to electricity consumers in the Northern Territory. • Introduce a dynamic reserve pricing offer component: Reserve requirements vary significantly based on BESS SOC, weather and grid conditions. Allow generators to submit reserve enabled offers with price for SR, price for FR, price for capacity available and time dependent conditions ('after 17:00 only", "SOC > 40%", etc) • Introduce a pricing framework for black start capability provided to power system to			

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			support with reliability and system security. • Generator market participants incur higher costs to maintain liquid capability of the fleet in comparison to running thermal generation units on gas. When a dual fuel capable unit is required to run on diesel instead of gas, there is a higher wear and tear of the machine, resulting in direct impacts to maintenance intervals, outage scheduling and cost of delivery of electricity at wholesale rates. Consider template revision to account for pricing bands when units are run on gas or diesel fuel.			
10	**What amendments would you recommend to the generator unit tie break procedure based upon prevailing market conditions? Please provide clear rationale for requiring such changes.** **Do you support centralised dispatch of all generating**	EDL supports amending the tie-break procedure to formalize PED, as long as this continues to take a generators incremental capacity and minimum stable loads into account. EDL supports centralised dispatch however would raise concern over the cost of	TGen supports centralised dispatch of all generating units within the DKES including thermal, renewable and storage assets to enable incremental and proportional dispatch across the whole fleet.	Eni doesn't have specific recommendations on how to draft the amendments, noting only that Eni favours simplicity. As per the response to Question 2; Eni supports amending the Generating Unit Tie Break Procedure to reflect the current operational practice of	Rimfire is supportive of the proportional energy dispatch approach which will bring the TEM in line with other Australian markets.	• As outlined previously, the updated procedure incorporates proportional energy dispatch and provides clarification on relevant distinctions within tie-break processes.

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	units to afford incremental proportioning of dispatch? **Can you recommend any alternative methods to be considered?** **Please present clear rationale for such.**	implementation and who bears this cost if it is to be implemented. EDL expects this matter, along with other items outlined in the discussion paper, to be addressed as part of the broader market reforms currently underway. As a member of the Industry Reference Group, EDL intends to work through this issue with other members during reference group meetings throughout 2026.	One suggestion to NTESMO is to explicitly distinguish interparticipant vs intraparticipant tie breaks. There's often no clear difference or limited clarity between tiebreaks between different generators and tie-breaks between units owned by the same participant. The introduction of inter participant tie breaks using the current system centric criteria which is security > efficiency > flexibility > emissions and intra participant tie breaks which allows the market participant to nominate a unit priority order multiple times in a day as required to reflect maintenance strategy, optimise commercial/fuel considerations and run hour management will result in a fair and transparent treatment between different market participants, empowering generators to retain flexibility to optimise their own fleet internally as long as system outcomes are met.	proportional energy dispatch process **Do you support centralised dispatch of all generating units to afford incremental proportioning of dispatch?** Yes, if done so transparently when generating units have an equal offered price. As stated above, Eni favours the simple proportional approach. NTESMO may also wish to consider and evaluate, if it hasn't already, the approaches currently being implemented in the Wholesale Electricity Market (WEM) in Western Australia. The WEM reforms have placed strong emphasis on system security while reducing unnecessary and higher cost commitments, and some of these design features may offer useful insights.		

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11	**What amendments, if any, would you recommend to the existing System Control plant outage procedure based upon prevailing market conditions?** **Please provide clear rationale for recommending such changes.**	EDL have no recommendations for changes at this time. EDL expects this matter, along with other items outlined in the discussion paper, to be addressed as part of the broader market reforms currently underway. As a member of the Industry Reference Group, EDL intends to work through this issue with other members during reference group meetings throughout 2026.	Electricity markets are dynamic with increasingly high uptake of renewables and variable demand. Traditional outage procedures focus on system security (generation/network availability, N-1/N-2 and less on market/economic risks. Incorporating market-condition awareness (price signals, reserve margins and renewables penetration) will support with reduction of risk on adverse market outcomes (price spikes/shortages), improves maintenance planning across the system as a whole and optimises asset availability. 1. Develop a single window portal for market participants and maintain a record of OTR/RTS/RFA/RN copies with relevant related documentation. 2. Define 'no go' window for overlapping outages when market conditions forecast poor availability. 3. Report outage window costs/risks metrics by	In Eni's view, the current version of the System Control plant outage procedure is effective, and Eni appreciates the current timely flow of information.	The System Control Plant Outage Procedure ("SCPOO") requires Outage and Test Requests ("OTRs") at least 10 business days in advance, however this is often impractical and represents a significant opportunity for improvement, especially for R2 testing where scheduling depends on PWC & PSC reviews. This causes delays and inefficiencies. R2 Testing should have separate criteria and processes, decided through additional consultation.	• The System Control Plant Outage Procedure is considered outside the scope of the Scheduling and Dispatch Guideline. • Improvements to outage planning information sharing, including enhanced participant interfaces, will be explored through the future Territory Dispatch Engine Stage 2 project and are subject to a separate consultation to implement TEM arrangements.

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			addition of obligation on System Controller to capture metrics post outage such as incremental cost to market, price impacts, lost revenue, additional ancillary services cost and use these metrics as a basis for continuous improvement of outage planning across the power system. Tracking how outage timing correlates with market outcomes supports with refinement of future scheduling between market participants.			
12	**Do you support the consolidation of the draft dispatch and pricing procedure into the proposed scheduling and dispatch procedure?** **Please provide clear rationale for any alternative approaches proposed.**	EDL supports consolidation of the draft Dispatch and Pricing Procedure into the proposed Scheduling and Dispatch Procedure. EDL expects this matter, along with other items outlined in the discussion paper, to be addressed as part of the broader market reforms currently underway. As a member of the Industry Reference Group, EDL intends to work through this issue with other members during reference group meetings throughout 2026.	TGen supports the consolidation of the draft dispatch and pricing procedure into the proposed scheduling and dispatch procedure. The rationale is a consolidated document will include a single set of definitions, timing obligations and a single source of reference for all market participants, reducing ambiguity and simplifying compliance, where possible. In the DKES system, scheduling, dispatch and	Eni remains neutral on this topic.	As per previous responses above (Rimfire response to question 11).	NTESMO supports consolidation, consistent with stakeholder feedback.

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			pricing are tightly coupled because: • Reserve shortfalls drive commitment decisions • Unit constraints impact pricing outcomes • Interaction of BESS and thermal units start-stop decisions The consolation of the existing procedure documents reduces duplication, improves clarity and better aligns with the operational and market realities of the DKES. It strengthens transparency, simplifies compliance and supports integration of new technologies such as BESS., However, consolidation must retain strong segmentation, clearly defined operational triggers and a transition table for participants to track changes. Any substantive changes to obligations should remain subject to full consultation.			

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