

# Scheduling and Dispatch Procedure Development

Participant Response Template

Participant: Power Generation Corporation

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# 1 Context

This template is to assist stakeholders in giving feedback about the changes detailed in the scheduling and dispatch procedure development discussion paper.

## 2 Participant comments

### 2.1 Procedural evolution

**Participant Question 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.

**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 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.**

## 2.2 Pre-dispatch processes

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

**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 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.

## 2.3 First off decommitment merit order (post 1800 hours)

**Participant Question 3:** Do you have any material observations and recommendations regarding the decommitment merit order post 1800 hours?

Please provide clear rationale for your recommendations.

### Observations:

It has been consistently observed that evening 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 Jenbacher (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 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.

## 2.4 Pre-dispatch solution process

**Participant Question 4:** Do you have any material observations and recommendations regarding the scheduling / pre-dispatch process?

Please provide clear rationale for your recommendations.

### 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 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 predispach 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 predispach window, integrate detailed generator constraint envelopes, incorporate gas nomination visibility, model BESS SoC and publish predispach confidence bands. Clearer communication protocols would enhance operational certainty and alignment between market scheduling and DKES security requirements.

## 2.5 Real-time commitment and dispatch

**Participant Question 5:** Do you have any material observations and recommendations regarding the real-time scheduling and dispatch process?

Please provide clear rationale for your recommendations.

**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 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.

## 2.6 Market prices – I-NTEM

**Participant Question 6:** Do you have any material observations and recommendations regarding the market price determination process?

Please provide clear rationale for your recommendations.

### Observations:

1. **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 value of essential system services provided.
2. **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.
3. BESS participation can suppress 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.
4. **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 price setting is highly marginal and lacks smoothing.
5. **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:

1. **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.
2. **Incorporate BESS costs, Start Cost, Minimum Load Penalties and Cycling Costs:** Price determination should consider warm vs cold start costs, minimum 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.
3. **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.
4. **Locationally sensitive pricing inputs:** Pricing should recognise that commitment and dispatch at Channel Island, Katherine or Weddell nodes have materially different security and cost implications. Locational factors improve price efficiency in a constrained, islanded system like DKES.



## 2.7 Market timetable procedure

**Participant Question 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.

### 5. I-NTEM Market Timetable

The *I-NTEM* market timetable for the *DPT* process is as follows:

Period	Action
Business Day -1	<ul style="list-style-type: none"><li>The <i>Load Forecast</i> for the future 96 hours (or longer if necessary) is submitted by email no later than 0900 hours.</li></ul>
Business Day -1	<ul style="list-style-type: none"><li>The Generator Offer for the Trading Day(s) is submitted to the <i>DPT</i> by email no later than 1230 hours.</li></ul>
Business Day -1	<ul style="list-style-type: none"><li>Risk Notices for the Trading Day are submitted to the <i>DPT</i> by email no later than 1230 hours.</li></ul>
Business Day -1	<ul style="list-style-type: none"><li>The relevant pre-dispatch information is to be sent by email to the System Controller and Generators no later than 1700 hours.</li></ul>
Business day +1	<ul style="list-style-type: none"><li>The market information is to be sent by email to the Market Operator no later than 1500 hours.</li><li>The market information is published on a suitable webpage by 1700 hours.</li><li>If this time can't be achieved in any one day, the Market Operator is to publish a notice advising of the delay in accordance with clause 4.8(f) of the System Control Technical Code.</li></ul>

The principle adopted for setting the timeline is that all parties should have the ability to undertake their contribution to the process within business hours wherever possible.

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.

## 2.8 Generator forecast compliance procedure

**Participant Question 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.

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 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 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.**

## 2.9 Generator offer procedure

**Participant Question 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.

1. **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.
2. **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.
3. **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.
4. **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)
5. Introduce a **pricing framework for black start capability** provided to power system to support with reliability and system security.
6. 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.

## 2.10 Generator unit tie break procedure

**Participant Question 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.

**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 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.

## 2.11 System Control plant outage procedure

**Participant Question 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.

**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 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.

## 2.12 Dispatch and pricing procedure

**Participant Question 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.

**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:

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The consolidation 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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## Contact

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