TRANSPOWER

TPM Operational Review

Briefing session and Q&A

9 March 2026

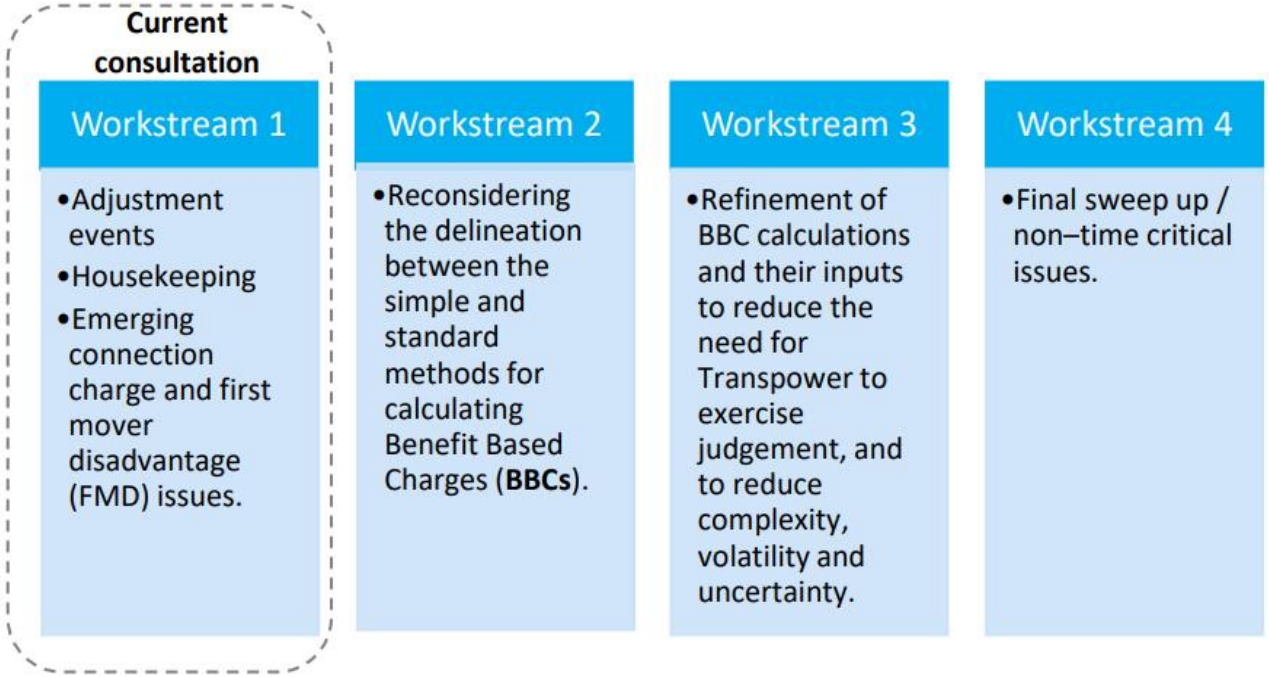
Agenda

- Introduction to the Operational Review
- Purpose of this Workstream 1 consultation
  - Adjustment events
  - Housekeeping (focus on simple method)
  - Emerging issues – early feedback
- Questions

Introduction to the Operational Review

Purpose

- Ensure the TPM continues to meet its intended objectives and customers can easily understand and manage their transmission charges.
- Since we introduced the Authority's new TPM in 2023, we've listened to feedback from customers and investors about how it could work better, particularly around reducing uncertainty, volatility, and complexity.
- The Operational Review aims to improve the TPM's implementation, addressing potential issues identified by stakeholders and Transpower since its introduction.
- We are undertaking the Operational Review under an initial four 'workstreams'. At the end of each workstream, Transpower will form its final views on any issues identified
- This consultation is focused on workstream 1.



Consultation focus

- These are operational, not policy changes
- Stakeholder views sought on options, preferences, and impacts

Purpose of this consultation

We are seeking feedback on the first set of amendments to the TPM we think could be introduced for the pricing year commencing 1 April 2027 as part of workstream 1:

1. Adjustment events
    - Timing
    - Triggers
    - Workability

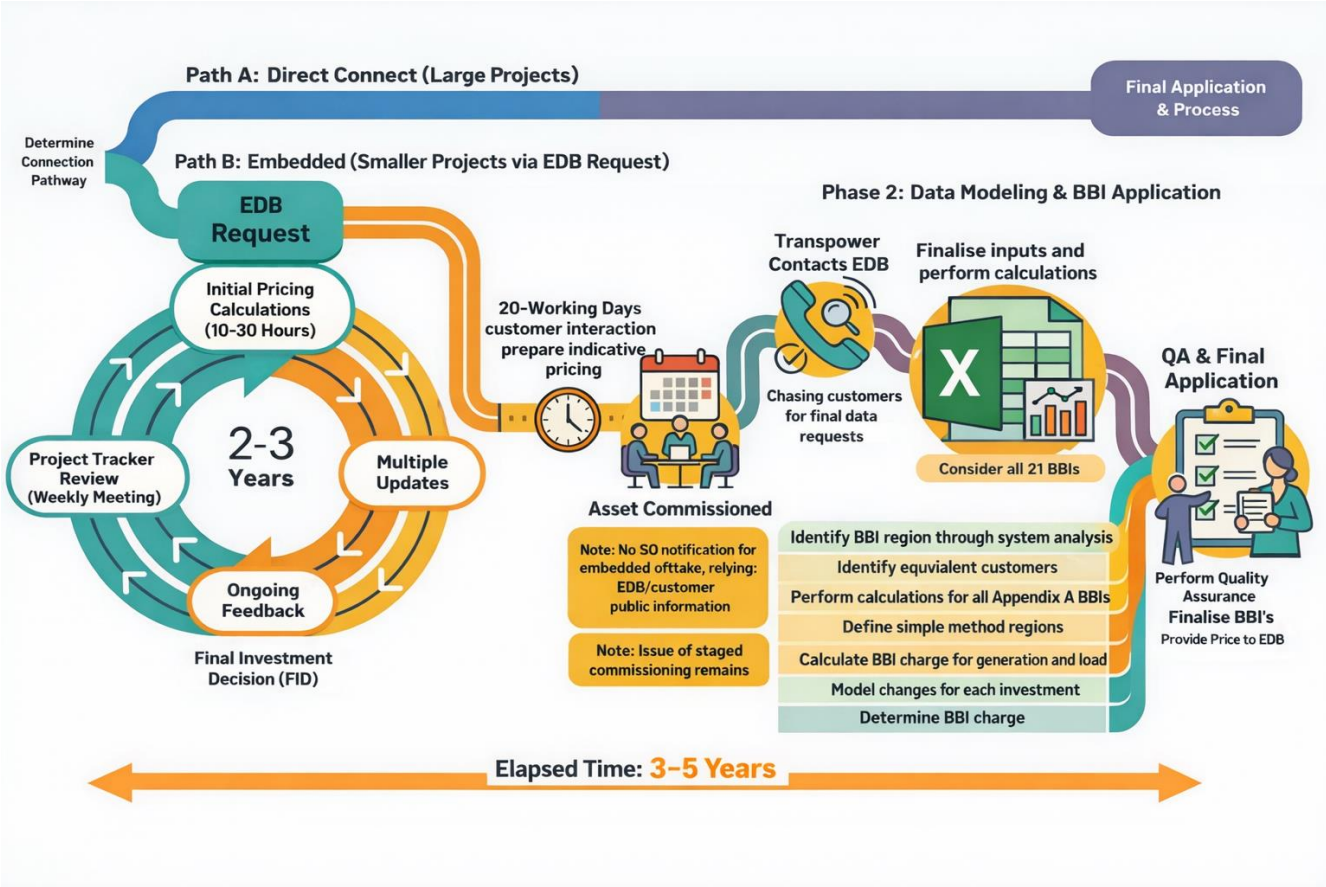
2. Housekeeping
    - Pause work on next simple method period pending outcome of Operational Review
    - General TPM drafting clean up

3. Emerging issues: early feedback whether and how certain issues with connection charges and FMD should be addressed
    - Disconnection from shared connection locations
    - Anticipatory investment and First Mover Disadvantage (FMD Type 2)
    - FMD Type 1 issues for embedded large plant

Adjustment events

Simplified view of adjustment process

- ~20 adjustment events expected in Pricing Year 2025-26, not including indicative pricing requests for future projects. Similar or larger numbers are expected for future years.
- Each adjustment event triggers a recalculation to customer charges (creating volatility) and highly complex nuanced calculations (creating administrative burden).



Adjustment events problem assessment

We are consulting on three problems with adjustment events:

1. **Timing (processing within-year changes):** adjustment events are processed during the pricing year; this:

- Results in mid-year charge changes and wash-ups
- Is misaligned with distributors' and retailers' pricing cycles
- Creates inefficiency, uncertainty and avoidable complexity

2. **Threshold (volume of adjustment events):** "large plant" >10MW deemed large enough to connect to the grid; this:

- Doesn't reflect true minimum scale needed for grid connection, which more likely is >25MW
- Results in a large volume of events (~50% of all adjustments), and growing as small-mid scale DG increases, this contributes to:
  - Volatility in charge
  - Significant administrative cost for Transpower and our customers (and their customers)

3. **Workability (SSI adjustment events)**

- Substantial Sustained Increase (SSI) events are difficult to implement
- Reliance on:
  - Incomplete or lagged data
  - Customer self-reporting
  - Transpower judgement
- Creates uncertainty and inconsistency in application

Adjustment events: options and consultation intent

We are consulting on a range of solutions for the adjustment event issues, including:

1. Process all adjustments for a pricing year at one time :

- Perform any adjustments within a pricing year at a pre-defined date each year and run pricing calculations for all adjustments as of that date.
- This is akin to the 'pricing grid' used to set connection charges.
- This option would reduce calculation complexity and administrative load for Transpower and simplify pricing for EDBs and other customers.
- It would not materially affect customer/EDB/embedded party interaction required to gather information to perform adjustment calculations.

2. Raise the threshold trigger for adjustment events:

- There appears to be a strong case for adjusting the threshold, to at least 25MW for large connected plant and potentially higher for offtake.
- This would better reflect the minimum viable grid connection size. This change would significantly reduce the number of adjustments, simplifying calculations and materially reducing customer/EDB/embedded part interaction required to gather information to perform adjustment calculations. It would reduce exposure to BBI charges to just plant that could viably connect to the grid.

3. Replace adjustment events with an Annual Intra-regional allocator update:

- Instead of multiple in-year charge changes, customers would see one update each year, with charges based on how the grid is actually being used.
- It significantly reduces charge volatility, administrative effort, and reliance on judgement, while still reflecting how the grid is actually being used overall.
- This means one predictable annual update, rather than reacting to individual connections, disconnections, or upgrades as they occur.

Worked example 1: Batching

Basic Solar Farm with a capacity of 50MW was connected to its new connection location on 1 October 2025. The solar farm was commissioned on 1 February 2026.

Commencement/adjustment of transmission charges		
Party affected	Status quo TPM	With proposed batching
Basic Solar Farm • Connection Charges • Benefit-based Charges	 1 October 2025 1 February 2026	 1 April 2027 1 April 2027
Other Customers • Benefit-based Charges	 1 April 2027	 1 April 2027
Wash-up of benefit-based charges for all customers	31 March 2027	Not needed

Worked example 2: Threshold

1. Hurricane Wind Farm embeds its 20MW plant to EDB Networks and no upgrade is required to connection assets
   - **Status quo TPM:** triggers BBC adjustment event and EDB Networks' BBCs are adjusted.
   - **Threshold Increase to 25 MW for 'large' embedded plant:** does not trigger BBC adjustment event.
2. Cyclone Wind Farms connects its 20MW plant to the grid
   - **Status quo TPM:** triggers BBC adjustment event and Cyclone Wind Farms will pay benefit-based charges (and connection charges).
   - **Threshold Increase to 25 MW for 'large' embedded plant:** no change (as proposed threshold increase does not apply to grid-connected plants).

Worked example 3: Annual Intra-Regional Allocator update

- Simplified assumption:
  - A BBI has a covered cost of $1M (for simplicity it does not change YoY)
  - There are 2 beneficiary regions Western SI and Northern SI. Western SI Load has a RNPB of 30%, Northern SI Gen has a RNPB of 70%, so Western SI Load has total BBC of $300k and Northern SI Gen, $700k
  - There are 3 beneficiaries in Western SI Load (Energo, LightOn and Powerly)

1 September 2021 to 31 August 2026 – PY2027/28		1 September 2022 to 31 August 2027 – PY2028/29
Energo 5 year average annual net offtake = 100k kWh (29% of Total IRA) Assigned Cost= 29%*30%*$1M= $87k	**No change** →	**Energo** 5 year average annual net offtake = 100k kWh (28% of Total) Assigned Cost= 28%*30%*$1M= $84k
LightOn 5 year average annual net offtake = 50k kWh (14% of Total) Assigned Cost= 14%*30%*$1M= $42k	**Gen plant connected 10k kWh** →	**LightOn** 5 year average annual net offtake = (50k kWh – 10k kWh/5) = 48k kWh (13% of Total) Assigned Cost= 13%*30%*$1M= $39k
Powerly 5 year average annual net offtake = 200k kWh (57% of Total) Assigned Cost= 57%*30%*$1M= $171k	**Load plant connected 50k kWh** →	**Powerly** 5 year average annual net offtake = (200k kWh + 50k kWh/5) = 210k kWh (59% of Total) Assigned Cost= 59%*30%*$1M= $177k
Total IRA in Western SI Load = 350k kWh		**Total IRA in Western SI Load = 358k kWh**

Workability issues of some adjustment events

1. Substantial Sustained Increase (SSI) – triggered when an embedded large plant or customer increase its IRA by at least 25%.
    - Transpower does not have access to meter data for large consuming plant and would rely from EDBs to report.
    - Transpower does not have access to adequate information to decide whether the increase is sustainable or not.
2. Definition of large plant includes a discretion for Transpower to classify multiple units or projects as single large plant or event. When treated as one event, customers pay for full capacity from the first commissioning date, which may not accurately represent their true grid usage or benefit.

Preliminary proposal:

- Remove the SSI adjustment events
- Clarify how Transpower should treat staged projects by adding time and certainty constraints
- Remove all embedded adjustment events; and/or
- Switch to annual review of IRAs

Housekeeping

Housekeeping

Second simple benefit-based investment (BBI) method period

- The second simple method period is currently scheduled to begin on 1 April 2028, drawing on data collected from 1 September 2021 to 31 August 2025. The simple method allocation setting typically requires six months, and system changes can take 6 months to 18 months, depending on complexity.
- The task of updating simple method draws on many of the same staff working on this Operational Review and there are likely to be interdependencies between the outcomes of the Operational Review and requirements for the second simple period setting.
- We think it pragmatic to extend the current simple method period and defer preparations for the start of the second period until the operational process is complete (and the Authority has had sufficient time to consider, consult and decide on any changes to the simple method). Required changes to the simple method BBI would then be managed through the TPM Operational Review Work Packages 2 (simple method BBCs) or 3 (standard method BBCs) as needed.

Drafting tidy up

- In addition to extending the period, we are suggesting a general clean up of the TPM's legal text to remove redundant and outdated clauses, especially those relating to "pre-commencement events", which applied only prior to TPM's go-live and now create unnecessary complexity and interpretive noise.

Emerging issues

Emerging issues

- We want to test early with stakeholders whether and how certain issues with connection charges and FMD should be addressed through the Operational Review
- Future workstreams? Or better be addressed by the Authority?
- We welcome your views on how these issues should be addressed

Consultation questions: Q16
Q17
Q18

Disconnection from substation

Problem

- When a customer(s) disconnects from a shared connection location, the entire charge for the connection location is reallocated to the remaining customer(s) at that location.
- We do not think this is intentional, rather it is an artefact of drafting in the ‘original’ TPM (this was not altered by the new TPM)
- Our view is this is inequitable and could trigger further disconnection and functional stranding.
- Charging connected parties for assets that are significantly larger (and more expensive) than the customer contracted for or requires may lead:
    - that party to disconnect from the location, resulting in function stranding of Transpower and customer plant (and loss of economic activity)
    - place that customer at a competitive disadvantage, affecting competition in downstream markets

Consultation questions: Q19
Q20
Q21

Anticipatory investment - interconnection

Problem:

- FMD Type 2 mechanism spreads the cost of anticipatory investment in connection assets across a wider customer base.
- There are no similar provisions for investment in interconnection assets. This means that existing customers fund the cost of upgrades until new customers connect.
- Our view that anticipatory investment protections for existing customers in the TPM could go further, and that the costs of anticipatory investment in interconnection assets should be more widely socialised until the future beneficiaries connect.

Consultation questions: Q22
Q23
Q24
Q25

First mover disadvantage (FMD) Type 1

Financial risk is second mover doesn't connect

- Under FMD Type 1, the first mover funds connection assets via a Transpower Works Agreement. The second mover is expected to reimburse part of these costs through the funded asset component (FAC) and rebate mechanism.
- The first mover bears the financial risk if a subsequent customer either does not connect or delays connection.
- Question raised: which is best placed to bear this risk – the first mover (for whom it would increase risk and therefore investment cost of capital), consumers or another party?

FAC application to Embedded Large Plant

- Concerns have been raised that the FMD Type 1 mechanism is not functioning as intended for connection assets that benefit embedded large plants. For example,

  Where a generator funds an upgrade at a grid exit point already shared with a distributor, future embedded generators (not Transpower customers) do not pay the FAC despite benefiting from the funded asset.

Wrap up

- Question
- Q+A on website
- Submissions
- We expect to submit proposals to the EA in April