

Submission by Transpower as System Operator dated 31 August 2026

To: Electricity Authority

By email: compliance@ea.govt.nz

Submission on draft determination of causer: 23 October 2025 under-frequency event (UFE)

1. This is the system operator's submission on the Electricity Authority's draft determination that the system operator was the causer of the under-frequency event that occurred at approximately 5.42pm on 23 October 2025.
2. The system operator does not agree with the Authority's draft determination, for the reasons set out below.
3. The system operator does not consider any part of this submission to be confidential.

The Authority appears to have made its draft determination without input from a protection system expert.

4. The causer determination in this case turns on the internal workings of complex protection systems at time scales measured in milliseconds. Despite this, the Authority appears not to have obtained any advice from a protection system expert about the normal operation of the types of protection system involved or how they operated in this event.
5. The system operator considers this to be a flaw in the Authority's process for this causer determination. The Authority should have tested its views with a protection system expert and shared that expert's opinion with stakeholders for comment.
6. To inform this submission, the system operator commissioned protection system experts Gutteridge Haskins & Davey Limited (**GHD**) to review the performance of the generator protection for TAB G1 and TAC G1 in this event. GHD's report to the system operator is attached and referred to below.

The Authority has not established that the system operator should have known that Contact's protection would trip TAB G1 or TAC G1 when CB662 was closed.

The differential protection for TAB G1 should not have operated.

7. The system operator does not agree with the Authority's assertion that "the trip of TAB G1 on differential protection was a foreseeable response to the conditions created by the closure" (paragraph 5.37 of the draft determination). As set out

below, the differential protection for TAB G1 should not have operated in the conditions that arose, and the system operator had no reason to anticipate that it would.

8. Differential protection is designed to protect generation plant against internal faults within the plant. It is not designed to trip on transient current arising from a network switching operation.
9. GHD has confirmed that there is no evidence of an internal fault in TAB G1, whether caused by the transient current or otherwise, and that only one of the two CTs measured the current as expected. GHD's conclusion is:

TAB (Tauhara): One of the two current transformers (CTs) feeding the generator differential element measured the current as expected, while the other did not i.e. the CT measurements diverged, consistent with current transformer saturation. This difference between the two CT measurements is the primary cause of the event: it produced a false differential current on phase 3. The operation of the 87G differential protection was an effect of that CT measurement difference, and not a response to a true internal fault. GHD found no other protection pick-up, unrelated to the differential protection, that would have tripped the TAB unit.

It was the CT behaviour that caused the TAB unit to trip: the protection operation resulted from the false current reading and not from an internal fault, and therefore the under-frequency event would not have happened without the false current reading.

10. The CT that appears to have saturated should not have done so. A voltage angle difference across a closing three-phase circuit breaker produces a transient current that differs in magnitude across the three phases. System events such as faults or three-phase switching always introduce such inter-phase imbalances, including DC offsets in one or more phases. CTs measuring such currents must be specified to handle the theoretical maximum fault currents and either avoid saturation or correct for DC offsets, so as to prevent mis-operation of differential protection.
11. CTs are designed not to saturate under worst-case fault currents, which for TAB G1 exceed three times nominal current. In this event, the transient current was approximately two times nominal current — well within the expected tolerance of the CTs and the overall differential protection system.
12. GHD's conclusions indicate either a deficiency in the CT that saturated or a shortcoming in the protection design that did not account for such saturation. Recognition of this issue with CTs used for current differential protection and the necessity of applying mitigation at the design stage are dealt with in detail in the relevant standards - e.g. C37.110-2023 (IEEE Guide for the Application of Current Transformers Used for Protective Relaying Purposes). The system operator

understands from information provided by Contact during the system operator's investigation that Contact has been investigating potential deficiencies in the TAB G1 protection system.

13. The transient occurred immediately upon closure of the circuit breaker and was momentary. The differential protection tripped TAB G1 after the transient had passed, at a point when the machine was operating at rated currents. This is further evidence that the differential protection operated incorrectly.

The protection for TAC G1 may have incorrectly operated due to the tripping of TAB G1

14. GHD has confirmed that the operation of the protection for TAC G1 may have been a consequence of the incorrect operation of the differential protection for TAB G1:

TAC (Te Huka): Contrary to the initial understanding (reflected in the Electricity Authority's draft determination, section 3.15) that TAC tripped on rate-of-change-of-frequency (RoCoF), the relay record shows that the 51V (voltage-restrained overcurrent) element picked up on the circuit-breaker closure but did not itself trip, and that the 81RXT (RoCoF) element subsequently picked up during the disturbance. GHD is not able to provide definitive evidence of which element issued the TAC trip, owing to the missing data set out in Section 6; Section 5 presents GHD's assessment based on the recorded events.

GHD further notes that the relay internal timestamps are not a reliable common reference (the two TAC relays differ by approximately three seconds for the same event). Using the circuit-breaker closure as a common zero-origin reference, TAB picks up at approximately 200 ms and trips at approximately 250 ms after closure, and the TAC 81RXT pick-up coincides with the TAB trip consistent with a working hypothesis that the loss of TAB drove the subsequent behaviour at TAC. This causation cannot be established conclusively for the reasons set out in Section 5.

15. In making a causer determination, the Authority should be concerned only with what actually happened, not with theories about what might have happened in different circumstances.

The system operator is not resourced or expected to investigate the details of asset owners' protection systems.

16. It is not part of the system operator's connection approval process to conduct a detailed review of an asset owner's transducers and protection design, and the system operator is not resourced to do so.
17. The system operator's connection studies are designed to check compliance with asset owner performance obligations (AOPOs). The system operator's power system models do not include CTs or differential protection, and reproducing this type of event would require specialist electromagnetic transient (PSCAD) modelling.

18. Protection co-ordination is agreed between the asset owner and the grid owner, and the co-ordination report is provided to the system operator on that basis. If the Authority considers that the system operator should assume this function, the Authority would need to fund the significant cost of establishing a service agreement with a specialist protection consultancy.
19. The system operator's outage planning procedure (PR-OC-203) does include a check for "phase angle issues" (see page 26 of the attached procedure). However, that check relates to angles during the outage (for automatic reclose operation in the event of a subsequent fault), not to the angle across the restoring circuit breaker at the conclusion of the outage.
20. In the 12-month outage planning timeframe, the system operator tests voltage and thermal limits relative to forecast load. The voltage angle that eventuated on 23 October 2025 was a function of real-time dispatch conditions (including wind and solar output), not of load, and would not have been identified by the system operator's outage planning analysis or the tools used for that purpose.
21. The system operator has benchmarked its practices against those of its international counterparts, and in particular their approach to phase angle considerations associated with switching operations and circuit breaker closing. The responses received from AEMO (Australia) and EirGrid (Ireland) confirm the following:
 - a. System operators internationally do not maintain in-house protection expertise.
 - b. It is normal practice for system operators to rely on grid owners to agree connection details, protection settings, and co-ordination arrangements with generators. This includes the setting of auto-reclose angle limits and whether manual reclose angle limits are enabled.
 - c. Where grid owners have established design limits for maximum phase angles across open points, those limits are significantly higher than 23 degrees (35 degrees in Australia, 40 degrees in Ireland, and, at least historically, higher in the United Kingdom).
 - d. Issues with phase angles on outage restoration are uncommon, and system operators internationally do not routinely check for this as part of outage planning.
 - e. Where potential phase angle issues have been identified by grid owners, those issues are incorporated into operational procedures, and system operators manage the resulting restrictions within their outage planning processes.

From a process perspective, the Authority has not explained why the grid owner is not the causer, despite the grid owner being “another participant” under paragraph (a) of the definition “causer”, and a more proximate one than the system operator.

22. The system operator’s causer investigation had identified Contact as the causer and not the grid owner. However, the Authority’s process in focusing on the system operator’s role instead of Contact and the grid owner creates a gap. The grid owner closed circuit breaker CB662 and is the most proximate participant to this event, other than Contact. The system operator’s role was limited to giving the grid owner permission to proceed with returning the circuit to service.
23. The circuit was equipped with synchronisation check facilities that would have enabled the grid owner to verify the voltage angle before manually closing the circuit breaker. Had the grid owner performed that check and considered the voltage angle to be too high, it could have chosen not to close the circuit breaker, despite the system operator’s permission to proceed.
24. At the design stage, it is the grid owner that determines auto-reclose angle settings and approves the grid interface design. That approval process would — or at least should, in the system operator’s view — include a review of the protection design for connected generation, including assessment of the conditions under which protection might operate. The [Generation Connection Guide](#) (GL-SD-1343) makes it clear that protection is part of design and the system operator is just checking that a protection co-ordination report has been agreed between the generator and the grid owner (section C.3.3).
25. As noted above, international practice is that system operators rely on grid owners to agree connection details, protection settings, and co-ordination with generators. The draft determination does not engage with this allocation of responsibility, nor does it explain why the grid owner — the participant that closed the circuit breaker and that, together with Contact, bears responsibility for protection design and co-ordination — should not be considered the causer.
26. Paragraph 4.2 of the draft determination records that, in December 2025, Contact and the grid owner agreed to reduce the relevant sync check from 20 to 10 degrees and to require TAB G1 to be ramped down to 0 MW before any manual reclose action. Notably, these are arrangements between the grid owner and Contact, not the system operator and Contact, reflecting where responsibility for protection settings and co-ordination most appropriately lies. Despite that, the Authority goes on in paragraph 4.3 of the draft determination to treat these arrangements as evidence — perhaps even an admission — of wrongdoing by the system operator. That is not a leap the Authority should make on the evidence.

27. It is not apparent from the draft determination that the Authority even considered the possibility that the grid owner was the causer. The draft determination simply says that “the grid owner’s practice in this area may warrant separate Authority attention” and that “the Authority will follow up with the grid owner separately to this event” (paragraph 5.32). In the system operator’s view, this is another flaw in the Authority’s process for this causer determination.

The system operator did not breach the Code, and in any event the event charge regime is not the appropriate mechanism for enforcing compliance with the Code.

28. The principal performance objective (PPO) the Authority has relied on as the basis for both alleged breaches is clause 7.2A(1) of the Code, which relates to cascade failure. This under-frequency event was corrected within approximately 10 seconds by the automatic response of instantaneous reserve, and there is no suggestion that cascade failure was even a remote possibility. Further, clause 7.2A(1) concerns “dispatch”, and it is not clear that any relevant dispatch was deficient in this case. The only relevant dispatch was the system operator’s dispatch of instantaneous reserve, which was clearly sufficient and functioned as intended. The Authority notes in the draft determination that the under-frequency event was resolved without widespread impact (paragraph 3.6).

29. The Authority’s interpretation of “outage” in clause 3 of Technical Code D — as including a return to service — is highly questionable. The definition of “outage” for the purposes of Technical Code D in Part 1 of the Code refers three times to assets being “not available” and does not expressly extend to those assets having been returned to service. In any event, the system operator assessed the outage within the normal scope of its role and in accordance with its established procedures and PPOs and therefore complied with that clause.

30. Clause 8.25(1) of the Code relates to the grid owner’s assets. The system operator’s obligation under that clause is to have regard to the design and configuration of “those assets or associated protection systems” — meaning the grid owner’s assets and protection systems. The Authority’s case is that the system operator is the causer because it did not have regard to the design and configuration of Contact’s (not the grid owner’s) assets and associated protection systems, specifically their tolerance for voltage angles across the circuit breaker and resulting transient currents. That cannot be a breach of clause 8.25(1).

31. More broadly, the Authority is using the event charge regime as a de facto Code enforcement tool against the system operator. If the Authority considers that the system operator has breached the Code, the appropriate course is to follow the regulated process for Code breach allegations under the Act and Enforcement Regulations, which includes potential Rulings Panel scrutiny of alleged but denied

Code breaches. That process also includes a per-event liability limit for the system operator that is lower than the event charge in this case. While every event should be treated as a learning experience, the Authority's approach circumvents those protections and is not appropriate.