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Tēnā koutou,

Consultation on TSO–DSO coordination – Operational requirements

Unison Networks Limited and Centralines Limited are consumer-owned electricity distribution businesses serving communities in Hawke's Bay, Taupō, Rotorua, and Central Hawke's Bay. We welcome the opportunity to comment on Transpower's discussion paper, TSO–DSO coordination: Operational requirements (14 October 2026), which proposes five foundational, no-regret operational requirements to support coordination between the System Operator and distribution-level operations.

As consumer-owned entities, we operate in the best interests of the communities we serve. Guided by our vision, and values, we strive to deliver economic benefits to both our customers and community shareholders, while championing a sustainable energy future. We are committed to maintaining the right balance between keeping electricity affordable and making strategic investments that secure the long-term reliability and resilience of our network. In all aspects of our operations, we place strong emphasis on meeting industry compliance requirements, ensuring we uphold all relevant standards. This approach not only supports New Zealand's transition to new energy solutions but also enables our communities to access cleaner, smarter, and more flexible energy options, now and for generations to come.

Executive summary

Unison and Centralines support the direction set out in the discussion paper. The five proposed requirements are broadly sound and principle-based and provide a sensible no-regret foundation for coordination between the System Operator and distributors. However, coordination needs to be proportionate, avoid duplication and preserve clear accountability for who does what and who pays.

Our comments draw on input from our network operations and control room team and focus on five points:

1. **Use existing authoritative information sources and avoid duplicate reporting.** Information on installed distributed generation and batteries should come from the Electricity Registry, asset information from the Connected Asset Commissioning, Testing and Information Standard (CACTIS), and other information from arrangements already in place, such as the annual Demand Forecast template we complete for Transpower, rather than through new distributor-to-System Operator reporting.
2. **Allocate responsibilities to the party best placed to perform them.** This includes GXP forecasting, where the System Operator is better placed than distributors, using registry data, weather information, outage notices and its own forecasting tools. Asset owners, retailers and aggregators are best placed to provide information on the resources they control.

3. **Preserve distributor operational authority, with clear primacy and escalation arrangements.** Distributors must remain able to act quickly to protect their networks, and agreed protocols should set out how conflicting transmission and distribution actions are resolved.
4. **Ensure information exchange is two-way, automated and appropriately governed, particularly for commercially sensitive flexibility data.** Distributors need timely information from the System Operator, exchanges should use low-effort automated channels rather than email, and flexibility a distributor has contracted for its own network should not be treated as available to the System Operator without procurement and compensation.
5. **Avoid new distributor capability or cost unless there is a demonstrated system benefit and appropriate regulatory and funding treatment.** New data, systems and telemetry obligations should follow a clear operational case and cost-benefit assessment and be recognised in regulatory and funding settings.

We support the proposed working group and would welcome the opportunity to participate. Our suggested priorities for early definition or trial are set out under Question 6.

Question 1 — The five operational requirements

What should be changed, added or removed from the five operational requirements?

We support all five requirements and do not propose removing any. Our suggested changes are set out below.

Requirement 1: Clear operational accountabilities

We agree that existing divisions of operational responsibility can remain in place initially. The arrangements should focus on decision rights where the two domains meet. For example, our control room may need to shed or transfer load quickly to relieve an overloading asset or change how load is shared between grid exit points, and that action may affect a GXP or wider transmission security. In other cases, the System Operator may be unable to support, or may prefer to avoid, an action we need to take. These situations can develop quickly, so the agreed protocols should:

- define how primacy is established when transmission and distribution actions conflict, while preserving a distributor's ability to act immediately where public safety or the integrity of network assets is at risk;
- provide for early notification of developing situations through an agreed channel where time allows; and
- set out escalation and fallback arrangements where agreement cannot be reached in the time available.

Primacy rules for flexibility contracted to more than one party should be developed alongside the Authority's flexibility work (DSO roadmap, paragraph 3.37), and emergency demand management should be consistent with the Common Load Management Protocol.

Requirement 2: Minimum static information

The Electricity Registry should be identified as the authoritative source of installed distributed generation and battery information. Distributors already record this information as part of the connection process and it is subject to audit, so the System Operator should obtain it from the registry rather than through separate reporting. This is consistent with the paper's own preference for a shared, governed source of information rather than repeated bilateral collection.

The requirement should also focus on resources that can change grid conditions. Established large loads generally behave predictably and are already reflected in GXP metering, so detailed operating characteristics should be limited to new or atypical loads such as data centres. For controllable demand, what matters is what can be dispatched: knowing how many megawatts of hot water load sit behind load control equipment is of limited value compared with knowing how much is available at a point in time. We already provide network models, typically in PowerFactory, when Transpower requests them. Formats and level of detail should be agreed for each study use, as distributors use different modelling tools and providing models in a different form could involve significant work.

Requirement 3: Minimum dynamic information
We support the principle that timing should be derived from the decision it supports and that not every item needs real-time telemetry. Actual MW and MVAr at GXPs is already measured by Transpower, so distributor obligations should be limited to information the System Operator cannot observe or derive itself. Information on DER state, such as battery state of charge, should come from the party that controls the resource.

The item on available and activated controllable demand or flexibility should distinguish controllable load from contracted flexibility. Flexibility a distributor contracts, for example through Unison's local flexibility market platform, is procured for a specific network constraint and priced against the value of deferring investment. Reporting it should not imply that it is offered for transmission purposes, and any System Operator access should be through procurement, compensation and agreed primacy rules. Data on contracted flexibility is also commercially sensitive and needs clear rules on access and use.

Requirements 4 and 5: Interoperable exchange and predictable technical performance
We support a small, governed set of interfaces and the reuse of existing channels, such as the registry and the Electricity Information Exchange Protocols (EIEPs), before new ones are built. Event-triggered exchanges should be automated: during significant events, control room staff should not have to rely on email to send or receive notifications. For technical performance, we support an outcome-based approach built on CACTIS and existing inverter standards rather than a parallel set of requirements.

Question 2 — Sources of information

For each information item listed, is the proposed source best placed to create and maintain an authoritative value?

Our general principle is that the party with operational control of a resource, or the party that holds the authoritative record, is best placed to provide information about it. Where information about resources connected to a distributor's network is provided directly to the System Operator by asset owners, retailers or aggregators, the distributor should be kept informed so that all parties in the chain share a consistent view. Our views on each item are set out in Tables 1 and 2 (see below).

Table 1: Static information (Requirement 2)

Information item	Our view
Installed embedded generation and batteries, including capability and import/export limits	The Electricity Registry should be the authoritative source, with no new distributor reporting beyond the connection notifications and Demand Forecast information we already provide (see Question 4). Where battery operating characteristics are needed, the asset owner or the party controlling the battery is best placed to provide them.
Large loads and data centres, including capacity and expected operating characteristics	We already notify Transpower when loads over 1 MW are connected, and report future step increases in demand, such as data centres, through the annual Demand Forecast template (see Question 4). Connection capacity could also be added to the registry. Only the asset owner can reliably provide operating characteristics and planned outages, and distributors should be kept informed.
Controllable demand and known flexibility, including operational control and response characteristics	The party with operational control. We already report load control at peak through the annual Demand Forecast template (see Question 4). Distributors can report load they control and flexibility they have contracted and can verify but have no visibility of what retailers and aggregators can dispatch.
Network equivalents, impedances, topology boundaries and constraints	Agree. When Transpower requests them, we already provide network models, typically in PowerFactory (see Question 4). Formats, level of detail and update frequency should be agreed for each study use.
Technical performance and protection information	Agree. Asset owners are best placed for their own equipment, and distributors for distribution protection. We already provide this information when Transpower requests it (see Question 4).

Table 2: Dynamic information (Requirement 3)

Information item	Our view
Aggregate actual and forecast MW and MVAr at the agreed boundary	Actuals at GXPs are already measured by Transpower. The System Operator is well placed to produce forecasts, with distributors notifying material planned outages and switching that affect GXP demand.
Available and activated controllable demand or flexibility	The party with operational control. Distributors should report only resources they control or have contracted and can verify, without implying that those resources are available to the System Operator.
Material DER availability, constraint or state information	The asset owner or aggregator that controls the resource. Distributors only where they hold an agreement that provides this information.
Material distribution faults, outages, constraints or loss of control capability	Agree, subject to clearly defined materiality thresholds and automated, low-effort notification channels.

We agree that the System Operator is the appropriate source of the information it provides to distributors.

Question 3 — Aggregation and timing

Is the proposed level of aggregation and timing proportionate to the operational use?

Generally, yes. GXP-level aggregation will be adequate for most System Operator purposes, with finer detail only where a defined use requires it, such as restoration planning or a high concentration of DER behind one GXP.

As DER grows, weather-driven changes in solar and wind output are likely to be the main driver of short-term change at GXPs. The System Operator is better placed to track this than distributors are to report it, for example by extending the weather-based approaches it uses for grid-scale generation, and centralised forecasting avoids each of the 27 distributors developing its own methodology. Real-time exchange from distributors should therefore be limited to material events, outages and changes. For the dispatch of embedded generation, day-ahead schedules with notification of material changes would meet most of our needs.

Question 4 — Requirements that can already be met

Which requirements can already be met through existing information, systems or processes?

Several requirements can already be met, wholly or partly, through existing arrangements. These include the Electricity Registry for installed distributed generation and batteries, asset capability statements and CACTIS for larger generation, batteries and loads, Transpower's own GXP metering and demand forecasting, AUFLS and rolling outage arrangements, and the Common Load Management Protocol for trader-controlled load during system emergencies.

In addition, Unison and Centralines already provide Transpower with much of the static information proposed under Requirement 2, either routinely or on request. Our commercial team notifies Transpower each time a load or generation over 1 MW is connected, including, for generation, the type of generation, installed capacity (MW) and energy forecast (MWh). Each year, our network constraints team completes Transpower's Demand Forecast template where data is available. The template has included embedded generation, load control at peak (which communicates controllable demand) and future step increases in demand (which would capture large new loads such as data centres). When Transpower requests them, we also provide network models, typically in PowerFactory, and technical performance and protection information, including for specific projects.

Where these existing arrangements are fit for purpose, they should be relied on and changed through their own governance processes rather than duplicated. For example, the Demand Forecast template already changes from year to year and could be extended to capture any additional static information the System Operator needs, avoiding the need for a new reporting channel. There is, however, currently no process for exchanging information

on planned or unplanned outages with the System Operator, in either direction. This is a gap rather than something that can already be met and is reflected in our priorities under Question 6.

Question 5 — Information, quality, access and capability gaps

Where are the material information, quality, access or capability gaps?

The main gaps in the information the System Operator seeks are:

- The Electricity Registry may not capture all resources. Standby generation installed behind the meter for customers' own use may never be notified to the distributor. The registry also does not record the capacity of load connections at ICP level.
- Distributors lack the tools to require customers to provide information. Our engineers have had difficulty obtaining specifications such as reactive power capability for customer-owned generators, and large customers have no obligation to share operating profiles or planned outages. If this information is needed for system security, the obligation should sit with the asset owner, with appropriate regulatory backing.
- Distributors have limited visibility of load controlled by retailers and aggregators, whose control schedules are increasingly dynamic.

There are also gaps in what distributors receive from the System Operator:

- As noted under Question 4, there is no process for exchanging outage information with the System Operator. The limited grid outage information we do receive comes through manual channels, and we do not receive restoration status.
- GXP constraint information, which directly affects how we operate our networks, should be provided routinely.
- Where market-scale generation is embedded in our network, such as in the Taupō area, we have no visibility of the System Operator's arrangements with it or how it is expected to respond when a GXP is constrained. The working group should consider what information on material embedded assets the System Operator shares with host distributors.

Finally, many of the exchanges described are aspirational relative to current distributor systems, which were not designed for automated data exchange with third parties. Requirements should be phased, and their cost recognised in regulatory and funding settings.

Question 6 — Priority information exchanges

Which initial information exchange(s) should be prioritised for early definition or trial?

We recommend prioritising the following information exchanges:

- Defining how the System Operator accesses static DER and CER information from the Electricity Registry, and any registry enhancements needed.
- A GXP forecasting trial that models DER and CER behaviour. For example, after a cloudy afternoon, household batteries may enter the evening peak with limited charge, so net demand may rise earlier in the peak than expected. Unison and Centralines would be interested in participating using GXPs on our networks.
- An automated package of System Operator information for distributors, covering material grid outages, restoration status, GXP constraints and the dispatch of material embedded generation.
- Event-triggered notification of material distribution events, with clear materiality thresholds.

The primacy and escalation protocols under Requirement 1 can be progressed in parallel, as they do not depend on new data exchanges.

Question 7 — Alignment with other initiatives and standards

Are there relevant initiatives or standards we should align with to avoid duplication?

Yes. The most significant overlap is with CACTIS, which already specifies asset capability information, commissioning, modelling, testing and operational communications for generation, batteries and loads. The requirements should build on CACTIS and its review cycle rather than create parallel obligations.

We also recommend alignment with:

- the revised Common Load Management Protocol published by ENA and the Electricity Retailers' and Generators' Association of New Zealand (ERGANZ) in October 2026, whose 12-month review is a natural point to align information exchange and communications;
- the Authority's DSO roadmap workstreams on registry enhancements, network visibility and device standards, and the data hub option in its Market Operation Service Provider roadmap;
- the EIEPs, where existing exchanges could be extended;
- industry work on dynamic export limits and flexible connections for distributed generation; and
- the Emergency Reserve arrangements, so that controllable load and flexibility are treated consistently.

Question 8 — Priority use cases

Do you agree with the priority use cases that we have identified? If not, which would you consider are higher priority?

We agree with the five use cases, which are realistic starting points, and do not propose others at this stage:

- GXP forecasting should be the highest priority. It underpins most other uses and can largely be delivered from registry data, weather information and the System Operator's own tools.
- Controllable load during an event needs more guidance before it is progressed, particularly on what information distributors can meaningfully supply. Much controllable load is now controlled by retailers and other parties, and the revised Common Load Management Protocol recognises that technical, contractual and customer factors may constrain the load available. The use case should distinguish controllable load under the Code from contracted flexibility.
- Material distribution events are a sensible use case, provided thresholds are clear and notification is automated. The planned shutdown of a large industrial plant is a useful example.
- Relevant System Operator information should be progressed alongside the GXP forecast, including GXP constraints, restoration status and dispatch information for material embedded generation.
- DER behaviour during disturbances should build on CACTIS and existing inverter standards and focus on aggregate behaviour that is material to system security.

Conclusion

Unison and Centralines support the direction set out in the discussion paper. Coordination between the System Operator and distributors needs to be proportionate, avoid duplication and preserve clear accountability for who does what and who pays.

Nā māua noa, nā

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