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The future operation of New Zealand's power system

Transpower welcomes the opportunity to submit on the Electricity Authority's (the Authority's) consultation *The future operation of New Zealand's power system,* published 24 June 2025. This submission is from Transpower as the System Operator for the transmission system of New Zealand.

We support the Authority's consideration of "*a coordinated approach to the evolution of power system operation over the coming decades*" having regard to relevant international developments. The increased penetration of more variable, renewable generation means investment in more firm, flexible resources including battery energy storage systems, demand side flexibility and peaking generation, will be essential for the power system to remain balanced and deliver the reliable, affordable service that consumers expect.

New renewable electricity resources will become more decentralised and connected at the distribution level as the Aotearoa New Zealand electrification transition progresses. The power system will increasingly coordinate two-way electricity flows between transmission and distribution, within distribution networks, and at individual ICPs. The primary role of Transpower, in its role as the transmission System Operator, is to keep the power system secure at all times. To do so into the more decentralised future the System Operator must have adequate visibility of, and interoperability with, distributed and consumer energy resources (DER and CER).

Distribution System Operators (DSO) will, first and foremost, need to be focussed on coordinating activity on distribution networks to ensure power system security is maintained, including across the impacts distribution level activity has for real-time security of the transmission system. This is the first and foremost role of a system operator and the physical enabler to any products or services that consumers will want to consume from, or offer to, the market.

In our view, this means prioritising near-term activity and resources to those investments and initiatives needed to operationally resolve real-time power system challenges such as localised constraints or power system health issues. We expect these types of physical power system issues to typically (at least in the shorter term) be contained to just a few very localised parts of distribution networks and/or time periods across the year. As electrification momentum builds over time the potential for further benefits to consumers to be achieved by distribution-level markets can follow. But the benefits of such markets can only be achieved if the power system is secure and reliable first. This remains true regardless of which DSO model is progressed.

Short-term the priority is to progress foundational, no-regrets actions needed for all future system operation pathways

We recommend the Authority progress its future operation of the power system workstream in two timeframes:

(i) in the short term there are several foundational, no regrets actions which enable all future system operation pathways: these should be progressed now (see our answer to Question 2), and

(ii) over the medium to long term work should continue to further explore and refine thinking on roles and responsibilities including the choice of the most appropriate DSO model for Aotearoa New Zealand's future power system.

For both timeframes there is the opportunity to be a fast follower from experience in Australia, and developing thinking being progressed there in parallel to the Authority's work.

The Authority's preferred option (Hybrid model) is pragmatic and keeps options open

For the short term we support the Authority's preferred, hybrid model because it retains existing capabilities and functions of the System Operator dispatch across the transmission system while enabling each distributor to develop visibility and dynamic dispatch capability across their networks at the pace appropriate for its needs and customers.

More broadly, our view is that there is time yet to decide on which of the three DSO models explored in the consultation paper (or where on the spectrum between them) is the ultimate 'right' set of roles and responsibilities for our future power system. We consider the Authority's short-term focus should continue its policy development work on data visibility and sharing arrangements, and increased visibility of distribution networks. These are foundational, no regrets initiatives regardless of the DSO model that is chosen over the medium to long term.

Transpower is willing and able to perform the role of Total-TSO if it was found to be the best solution for New Zealand and was appropriately funded and resourced to do so. Any organisation tasked with implementing a DSO function will need to invest in new capabilities across people, processes and technology. It may be the case that there are efficiencies to be gained by leveraging the existing System Operators capabilities alongside developing distributor capabilities.

Standardisation will be needed across DSO terminology, interfaces, data exchange and operational processes

Regardless of the end point of TSO/ DSO arrangements, to deliver a digital future for consumers with more choices, standards, and data sharing all requires standardised terminology, interfaces, data exchange and operational processes across all distribution networks and DSO providers.

In the United Kingdom, NESO will take forward initial development of a data sharing infrastructure, first through a pilot, and then through developing a minimum viable product. [1] The initial focus is on establishing a cyber- secure and interoperable framework that enables the seamless exchange of energy system data.

Our responses to the Authority's consultation questions follow in the attached Appendix.

Yours sincerely,

Rebecca Osborne

Head of Market Services

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[1] Department for Energy Security and Net Zero, Digital Spine feasibility study

Appendix A Consultation question responses

Q1. Do you agree with the explanation of the distribution system operator (DSO) role/ entity, and the explanation of the distribution system operation (DSO) functions that one or more DSO entities would be required to perform?

We broadly agree with the Authority's characterisation of the issues. We note, appropriately given the 'step-in-the-process', details on exactly how some of the roles and functions would be performed under each model, and how they would interact with existing/enduring roles and functions are unavailable to comment on. Any final decision on the most appropriate model for our future power system will need a more detailed exploration to inform an assessment (quantitative and qualitative) of the relative costs, benefits and consequences of each model.

Further, we note 'operational need' is the key driver for a DSO function. For those parts of distribution networks where there is currently the absence of real or emerging physical distribution network issues requiring coordination there is currently no need for an active DSO function. However, there is the need to be developing foundational capability ahead of time so that emerging needs are identified early and future DSO capability can be ready in time.

Irrespective of the need for an active DSO function there is a need for passive DSO functions and capabilities such as:

- LV network monitoring to determine when active DSO functions will be needed, and
- facilitating data and information exchange to the TSO to enable improved power system modelling, load forecasting, assessments of planned transmission asset outages, and real time operations (including restoration activities).

Q2. Do you think we are correct that the themes we identified in submissions to the initial consultation paper mean we should focus mostly on system operation at the distribution level, and on the new functions required for effective distribution system operation?

Yes, we agree with the themes extracted from prior submissions by the Authority. However, we also believe it is premature to decide now which DSO model will be most appropriate for the future power system.

There are foundational investments, including the passive DSO functions and capabilities noted in our response to Q1, that are requirements common to each of the models. The Authority's current focus should be on those.

As we recently submitted to the Authority:[2]

> *In a recent discussion with representatives from Australian Energy Market Operator (AEMO) covering their lived experiences of CER/DER and DSO models a clear*

[2] Transpower submission to the Authority, Our Future is Digital, transforming to a smarter, more connected and data-driven electricity system, July 2025

recommendation made was to start the data exchange journey as soon as you can. It was also noted there will be some data exchange which is common across all possible future operational arrangements, consequently no regrets choices can be made once this data is identified. This is a point System Operator staff have made to Authority staff in relation to the Authority's Future System Operation consultation. Finally, an observation we made following the discussion is while there is a cost to data exchange, there is also a cost to not sharing data; in the absence of access to Consumer and Distributed Energy Resource (CER/DER) data, [AEMO filled the gap in their data needs by using] publicly available data and built forecasting tools to get 'visibility' of CER/DER within distribution networks.

Essentially, AEMO incurred costs to reengineer data which existed but was not available to them. There is a window of opportunity open now for New Zealand to avoid this kind of inefficiency by learning from the Australian experience.

Australia has significantly more CER/DER than New Zealand and much more lived experience of the impacts of it on the power system. It also has a very clear opportunity to leverage widespread uptake of rooftop solar and BESS installations to avoid and defer the need for other investments including in the transmission infrastructure that will otherwise be needed to unlock utility scale solar and wind generation potential. Unlike New Zealand its existing transmission infrastructure is often not located to do so. We strongly encourage the Authority to leverage the learnings, thinking and expertise rapidly developing in Australia to inform its decisions on priorities, market settings and next steps.

The Australian Department of Climate Change, Energy, the Environment and Water (DCCEEW) is currently consulting, under its National Consumer Energy Resources (CER) Roadmap workstream[3], on redefining roles for market and power system operations[4] through its Consumer Energy Resources Taskforce (CER Taskforce). The consultation paper is supported by analysis from a report by Cambridge Economic Policy Associates (CEPA) on Distributed System Operator (DSO) market design. [5] This report was commissioned by the Australian Energy Market Commission (AEMC) to "*develop a set of future-focused market designs for a wholesale electricity market at the distribution level, and to examine how the roles and responsibilities of a distribution system operator (DSO) or distribution market operator (DMO) could be allocated under each design*."[6]

The CER Taskforce's consultation paper concludes *that the majority of activities required to operate the power system and market with high levels of CER are being performed by existing actors – at least to a level that allows current levels of CER to be managed to deliver secure system outcomes. But there are some gaps particularly when considering how to support the higher levels of CER expected in the future*.[7] We consider this conclusion is likely to apply also to New Zealand, including because currently our level of uptake of CER is much lower than in Australia.

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[3] National Consumer Energy Resources (CER) Roadmap - Redefine roles for market and power system operations – M3/P5 - Department of Climate Change, Energy, Environment and Water

[4] Consumer Energy Resources (CER) Taskforce DMSO consultation paper

[5] CEPA DSO Market Design Final Report.pdf page 12

[6] CEPA DSO Market Design Final Report.pdf Executive Summary

[7] Ditto

The paper seeks feedback on the Taskforce's conclusion that *the immediate priority is to clarify, formalise and standardise roles, expectations and accountabilities in six key areas (contributing to three major outcomes)*. These areas are:

Outcome 1: CER is **visible and predictable** and can be used effectively as part of power system operations. To support this [DCCEEW] propose actions to clarify, formalise and standardise the roles, expectations and accountabilities for all parties involved in:

i. defining, collecting, updating, maintaining quality, and sharing **device-level data and information**
ii. defining, collecting, aggregating, updating, maintaining quality, using and sharing **CER monitoring data**.

Outcome 2: CER is **orchestrated effectively** to deliver value for consumers and the power system. To support this [DCCEEW] propose actions to clarify, formalise and standardise the roles, expectations and accountabilities for all parties involved in:

iii. establishing and **using off-market mechanisms** (flexibility services, dynamic operating envelopes (DOEs), dynamic network prices (DNPs)) and communicating relevant information to enable widespread adoption of these.
iv. **monitoring and compliance** of non-conforming CER, that is, CER or aggregated CER portfolios, that do not respond as agreed when participating in off market mechanisms.

Outcome 3: CER plays a central role in **system security and emergency management** frameworks and processes. To support this we propose actions to clarify, formalise and standardise the roles, expectations and accountabilities for all parties involved in:

v. accounting for, using or controlling CER as part of **system security** and emergency management frameworks
vi. **monitoring and compliance** of CER within security frameworks.

Submissions to this consultation are due 20th August 2025.

In our view the Authority's decisions about next steps should be informed by close consideration of work by and findings of the CER Taskforce and recognising the opportunity to be a fast follower from the Australian experience. We think this means prioritising focus now on the following foundational steps, which will enable all future possible future system operation pathways and DSO models.

- **System security** – as the power system and industry transitions to a more distributed energy focus, maintaining system security for consumers is critical. Regulated operating rules need not be draconian or overly conservative but the effects of a shift to more DER on system security must be considered at every decision point.
- **Data exchange** – there is a significant amount of data which is not shared with/available to all parties who would benefit from it. We reiterate our position the Authority needs to have a digital strategy for the industry and should undertake a robust assessment of data gaps within the industry. Consideration should be given to mandated exchange of data under 'cost plus' arrangements – ultimately every dollar in the industry comes from the pockets of New Zealanders. Leaving data exchange arrangements between parties on a commercial basis may not have worked well for New Zealand, particularly when the

value of data to one party can differ significantly to the costs of provision for the holder of the data.

- **Low Voltage Network visibility** – an active DSO function is only needed if there are LV network issues requiring management. To identify the need for a DSO therefore requires sufficient LV Network visibility to determine if there are, or are impending, network issues which require management. A key component of LV network visibility is monitoring/metering equipment. The Authority should consider access to Network Operational Data (NOD) as part of their digital strategy. It may be the case it is more efficient for distributors to install their own network monitoring equipment but this needs to be tested on behalf of their consumers via an alternative of access to NOD information from (retailer controlled) smart meters.
- **Standardisation** – all three DSO models require elements of standardisation to function efficiently (or even to be viable in the case of Total-DSO). The Authority should undertake investigations to identify common practices across all three DSO models and assess which require standardisation. Industry working groups in conjunction with the Authority could undertake to decide 'the standard' for each process or practice identified.
- **Aggregators/flex traders** – are currently absent from the Code and therefore not subject to any common quality/shared good obligations. For example, an aggregator may vary consumer demand but is not required to notify anyone, no matter how large the change to the power system results from their actions. The Authority should progress the addition of aggregators/flex traders to the Code and place common quality/shared good obligations on them.

Q3. Do you think we have accurately covered the main changes to the distribution system in this section? If not, what have we missed or where have we gone wrong?

In addition to the main changes to the distribution system the Authority has identified we would add:

- As above, the absence of any recognition in the Code of aggregators and flex providers, with the consequence that the Authority and participants (including the System Operator) cannot compel these parties to provide information or to behave in ways that support system security and benefits to consumers more broadly.
- The general increase in unpredictability of consumer behaviour arising from retailer tariffs, aggregator activities etc.

Q4. Do you agree with how we have defined the problem, as the need for a more coordinated framework of integrated system operation?

Broadly, we note that absent distribution network issues requiring management, demand side flexibility (DSF) can be achieved via retailers, aggregators, price signals, and tariffs without the need for a DSO function to be in place. To optimise operation of the power system, including expansion to more active operation on distribution networks, under these arrangements would still require significant increases in data sharing and the creation of an aggregator participant class to place obligations on aggregators.

We agree with the Authority statement "*Distributors, the TSO, and aggregators must be sure that their functions and interactions with each other are consistent and complementary…*" We are less sure of the statement "…*and that there will be no regulatory prohibition once they have already committed resources to improving the coordination of DER.*" Regulation almost always follows need, consequently there is always some commercial risk to be balanced by participants of subsequent regulation impacting on prior unregulated decisions.

Further, we note there are no-regret investments and steps which could be taken by distributors to develop DSO capabilities through investment in LV network visibility and access to data. Progress is not contingent on the Authority deciding on the DSO model it believes is best for New Zealand, especially given that when a decision is made there will be a material lead time (likely years) before the consequent rule changes have been developed, confirmed and implemented to affect the decision.

While it is unclear exactly how much effort will be required to implement whichever DSO model is chosen, what is clear is that learning-by-doing opportunities and making incremental progress to coordinate the future operation of the power system should continue while that decision is made and implemented in the Code.

From the CEPA report [page 79]:

> *"Non-market mechanisms such as dynamic operating envelopes (DOEs), dynamic network pricing (DNPs) and flexibility services, if materially improved, have the potential to manage congestion adequately. They can ensure constraints do not bind and maintain system security and reliability, while also enabling better utilisation of the network. However, without the price signals and behavioural information revealed through a market, these tools rely on forecasts of expected behaviour rather than real-time system conditions or the actual value of access. By contrast, markets can enable efficient congestion management by using real-time offers and bids to reveal how the network is used and where value lies. This information allows the system to respond dynamically, pricing constraints accurately and making the most efficient use of available network capacity."*

And:

> *"It is difficult to quantify the unrealised benefits between adequate and efficient integration of CER. This is because the size of this gap depends on a series of unknowns including how sophisticated off-market mechanisms can and will become, the uptake of CER, how price-responsive they become and how many will choose to participate in the market. This uncertainty makes a conventional quantitative CBA challenging. While further work could explore the options in more detail, and should be undertaken, a quantitative CBA is unlikely to provide a definitive answer. Ultimately, it is likely to be a strategic decision that must be made to decide to capture these efficiency benefits, taking into account the costs involved."*[8]

[8] CEPA DSO Market Design Final Report.pdf page 79

Q5. In your view, what aspects of the Australian and British deliberations around DSO models are relevant to New Zealand?

In our view the most pertinent fact is that, while both Australia and Great Britain are further advanced in their DER and DSO journey, neither have completely landed the 'answer'.

Secondly, we should learn from their journeys to date. As well as studying their decisions and progress we should seek to engage with the parties involved and ask, "*what would they do differently if they had their time again*?" Such conversations are likely to highlight no-regret steps which could be undertaken to progress CER integration with the power system while we gather a body of lived experience of increased CER in New Zealand, certainty of the challenges and opportunities that raises, and mix relevant overseas experience with our own to decide what is best.

We also need to be mindful of the differences between New Zealand and other jurisdictions when learning from their experiences. Our fully nodal real-time energy only market, geographic isolation, power system size, and our diverse distributor networks are unique. We shouldn't seek to reinvent the wheel, but we need to ensure the wheel is the 'right fit' for us. The differences between our respective countries also needs to extend to the wider policy drivers related to CER such as decarbonisation. Therefore, we consider the best next step for our system is to pursue no-regrets investments and initiatives such as those discussed in our responses to Q1 and Q2.

Q6. What do you think about the direction of research conducted in New Zealand by bodies such as the ENA, NEG and SIDG on the challenges of preparing to perform DSO functions?

The work undertaken to date by bodies in New Zealand has greatly increased the awareness of the topic within the industry. Some excellent work has been produced which unsurprisingly reflects the primary concerns of the authors or commissioners of the report. All the work is mostly conceptual in nature focussing on 'who', 'what', and 'why' with little consideration of 'how'. Delving in to the 'how' will be necessary to fully understand the consequences of choices in front of the Authority and industry.

For example, it is simple to posit the DSO will solve local markets and integrate with the wholesale market and TSO but what does that mean in practice? Particularly when our wholesale market is fully nodal energy-only real-time in design and the "2-tier" market will iterate and influence each other's outcomes.

We recommend before any final decision is made by the Authority 'how' each model would be implemented in practice is sufficiently scoped to enable a thorough robust consideration, if not costing, of each of the three DSO models to be performed – including implementation approaches, timelines and transition plans. In our view this should include consideration of incremental changes to the status quo over time that can be a least regrets approach and more easily adjusted as information becomes available through learned experience.

Q7. What is your view about the need for an independent DSO (iDSO)? Should we consider an iDSO now as an option to perform all DSO functions, or a subset of functions related to market facilitation? Or can that decision wait until the market for flexibility services is more developed?

This approach might be needed if the Authority chooses to implement DSO functions via a service provider model and the DSO services multiple distributor networks.

We note there are existing regulatory requirements for the transmission System Operator that deliver an impartial service without the need for structural separation or arms-length arrangements. If the risks between a DSO and a distributor are the same as those between the System Operator and Transpower it would be appropriate for similar arrangements to be applied to ensure a DSO delivers an impartial service.

Q8. What do you think about the three DSO models proposed by the Authority?

The three DSO models presented by the Authority span the range of possibilities which exist. As the Authority notes the allocation of roles in the hybrid model can move it closer to the bookend models of Total-TSO and Total-DSO. Under all models, operators, whether TSO or DSO, require sufficient certainty in the resources they are dispatching to perform their operational roles.

We observe there are what appear to be implicit assumptions around differences between the models, rather than policy or design decisions. In theory, given the same information and optimisation goals the results should be the same no matter who is running the optimisation, or if they are optimising the distribution networks or the whole system including distribution networks. The exception would be if distribution networks were optimised solely with assets connected to them without reference to wholesale market resources. Solving in such a manner could see prices (or at least costs) rise on distribution networks as more expensive local assets are cleared before the 'overs-and-unders' are offered to the wholesale market.

Q9. Do you prefer one model over the others?

For the immediate future we support the Authority's preferred hybrid model as the model that retains existing capabilities and functions of transmission System Operator wholesale market dispatch across the power system. We think this strikes the right balance by also enabling those distributors that want or need to, to develop expertise in dynamic dispatch across their networks.

The hybrid model has the most utility to meet New Zealand's evolving needs, as they are revealed, and the most scope for agility to adapt to those needs based on learned experience over time.

Transpower is willing and able to perform the role of Total-TSO if it was found to be the best solution for New Zealand and was appropriately funded and resourced to do so. Any organisation tasked with implementing a DSO function will need to invest in new capabilities across people, processes and technology. It may be the case that there are efficiencies to be gained by leveraging the existing System Operators capabilities alongside developing distributor capabilities.

Q10. Given the hybrid model can take several forms, what do you think would be the best allocation of DSO functions between the TSO and one or more distributors as DSOs?

To begin with, the roles should remain as they are split between the (T)SO and distributor. As the evolution of the New Zealand power system becomes clearer, informed discussions can take place about roles and responsibilities for dispatch of DER, and planning activities for distribution networks. Note the current grid owner and distributor planning process is already a collaborative one – to some extent it is already a hybrid model.

Conversely, some activities such as wholesale market energy dispatch and the procurement of ancillary services should only ever sit with the TSO[9]. Equally, connection studies and connection agreements for the distribution network should only ever sit with the distributor/DSO.

The flexibility afforded by a hybrid model lends itself to enabling a level of customisation reflective of the nature of New Zealand's 29 distributors. Those with a greater DER penetration and operational capability may take on additional roles and functions if that is efficient and delivers benefits for end consumers. Note as previously stated and described in the Authority's paper, any customisation would be within a standardised operating model for each 'level' of DSO function performed.

Q11. How would you rank the DSO models in terms of enabling the process of price discovery in the market for flexibility services to approach the wholesale market ideal of security-constrained economic dispatch?

The CER Taskforce has been considering this question in depth, and we encourage the Authority to review its work. The Taskforce is currently consulting on its consideration of advice received from CEPA across different design options for integrating CER through a real-time energy market in the future. It asks its stakeholders to consider:

- *whether off-market mechanisms will remain an effective way of leveraging CER opportunities in the future, or whether there will come a time where the benefits of real-time market arrangements will be sufficient to offset their costs and complexity*

[9] There is only one system frequency to manage, and it is most efficiently managed centrally through the procurement of frequency keeping, instantaneous reserve, and over-frequency reserve. Given the redundancy built into transmission and distribution networks any form of 'reserve' at the distribution network would be covering for a network failure not generation.

Black start services could exist on distribution networks. However, they would be to liven an electrical island within a distribution network rather than livening the Grid. It is also likely the most efficient livening of distribution networks is achieved by reconnection to the live Grid or live parts of the distribution network. Especially, given outages on the distribution are more likely to arise from a network asset failure than collapse of the system.

- *what conditions might indicate that the benefits of introducing real time market arrangements for CER outweigh the cost and complexity of implementing what would be significant reforms*.[10]

In our view similar questions apply in New Zealand's context but with more time available before a decision needs to be made, or before it can be possible to quantify/qualify the potential costs and benefits of investing in the very considerable resources that would be needed to explore this topic further, develop rules and implement them in practice.

Theoretically, as noted previously, if the same information and data, the same network model, and the same goals are used under all three DSO models they will deliver the same outcome. However, the overhead on industry to attempt to replicate security constrained economic dispatch (SCED) on the distribution networks would be prohibitive on many levels. There is also very considerable uncertainty about what benefits could be achieved by chasing that goal. At the wholesale market level where SCED price signals are currently sent, responding to those signals is only a part of an asset owner's or asset developer's decision-making process. Generation gets built primarily where resources and transmission are available. It is important to note SCED price signals do not include the cost of transmission, only the impact of transmission limits on energy prices. The transmission grid is made of relatively few large centrally located assets, while local distribution networks comprise many more much smaller assets that are necessarily more widely dispersed. We consider it is uncertain what benefit would be achieved when by creating such signals on distribution networks including because it is unlikely many consumers will be exposed directly to SCED price signals and will instead be responding to simplified retail tariff models that are less locationally-granular.

There are several ways signals can be sent which will orchestrate DER efficiently, such as dynamic operating envelopes (DOE), dispatch instructions, retail tariffs etc These can equally be achieved under each of the Authority's three DSO models.

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[10] Consumer Energy Resources (CER) Taskforce DMSO consultation paper Executive Summary