Vector Limited
110 Carlton Gore Road
PO Box 99882
Newmarket
Auckland 1149
+64 9 978 7788 / vector.co.nz

18 August 2025

By email: fsr@ea.govt.nz

Tēnā koutou,

Future system operation in the evolving power system

Vector welcomes the opportunity to provide feedback to the Electricity Authority (the Authority) on its consultation on the future operating model in New Zealand's evolving power system[1] (the consultation paper).

As the country's largest distributor of electricity and gas, Vector is deeply engaged in managing the transformation of the distribution network, driven by the rapid uptake of consumer-owned and other distributed energy resources (collectively, DER), increasing electrification, and the transition to a low-carbon energy future.

Our submission reflects insights drawn from Vector's extensive operational experience, our prior 2024 submission to the Authority on future system operation[2], and analysis we commissioned from NERA Economic Consulting in 2022-23[3] (NERA Report).

We also integrate findings from the Electricity Networks Association's 2025 report by Baringa Partners (Baringa Report), which provides a rigorous evaluation of potential DSO models and the transition pathways suitable for New Zealand[4].

---

[1] Available online at https://www.ea.govt.nz/projects/all/future-security-and-resilience/consultation/distribution-system-operation/

[2] Available online at https://blob-static.vector.co.nz/blob/vector/media/vector-2024/vector-submission-on-the-future-operation-of-new-zealand-s-power-system.pdf

[3] NERA Economic Consulting (2023). *Promoting efficient and affordable infrastructure to enable electrified transport*. Available online at https://blob-static.vector.co.nz/blob/vector/media/vector-regulatory-disclosures/nera-report-for-vector-20230228-v1-0.pdf

[4] Available online at https://www.ena.org.nz/assets/DMSDocuments/Potential-DSO-models-for-New-Zealand.pdf

Vector's Symphony ambition is fully aligned with Government policy direction

Vector is a strong advocate for demand flexibility, and a firm believer in its role in minimising whole-system cost to consumers. Our corporate Symphony strategy is shaping a cleaner, smarter, more reliable energy future, with our customers at the heart. A core component of Symphony is making optimal use of demand flexibility to minimise network investment, thereby minimising investment and ongoing costs and maximising affordability for consumers.

As part of our strategy execution, the key actions we are taking to support the electrification of Auckland include[5]:

- Orchestrating distributed energy resources such as electric bus charging to reduce the need for additional infrastructure spending
- Developing and deploying digital systems, integration protocols, cyber security, and data platforms that support the development and operation of energy resource orchestration
- Developing strategic partnerships, which includes our strategic alliance with AWS, and partnership with X, the Moonshot Factory (formerly Google X) to enable smart electricity networks to benefit customers
- Enhancing monitoring of the low-voltage network to optimise infrastructure utilisation
- Actively engaging to influence regulatory and policy settings and standards such as regulated standards for smart electric vehicle chargers
- Actively engaging with customers to build our understanding of preferences and behaviours, and working with retailers to evolve their offerings that influence how and when customers use the network

Within this context, a key risk we need to manage is the potential inability to efficiently manage load to avoid network congestion. In a disorderly decarbonisation scenario, an absence of timely policy, regulatory and market changes results in customer peak demand increasing faster than average annual usage. Depending on network response and planning, two distinct future scenarios may emerge:

a) a highly congested network with network connection queues and reliability challenges; or
b) a strong increase in physical network investment leading to affordability challenges for customers.

Neither would be a good outcome for consumers in Auckland.

In October 2024, the Government set out its clear expectations for the role of distributors in minimising investment costs through efficient operation of networks, and the efficient use of networks by customers. We were pleased to note the strong alignment with our actions above. The key excerpt from the Government Policy Statement (GPS) is as follows[6]:

---

[5] These are taken from Vector's 2025 Climate-related Disclosures, forthcoming.

[6] Government Policy Statement on the New Zealand electricity industry, available online at https://www.beehive.govt.nz/sites/default/files/2024-10/Government%20Policy%20Statement%20on%20Electricity%20-%20October%202024.pdf

Strengthen transmission and distribution networks

13. Electrification of the economy will require significant investment in strengthening transmission and distribution network. It is critical that this investment is economically efficient, which means (among other things) that it reflects demand and optimises new capacity in a manner that avoids unnecessary cost increases for consumers, while ensuring network reliability.

14. Efficient network pricing is essential:

a) To find the lowest cost solution, which may include demand-side response and flexibility to avoid or defer the need for network capacity augmentation; and

b) For connections to enable efficient investment in new electricity consumption, including electrifying transport and process heat in industry.

15. As provided for under current arrangements:

a) The Electricity Authority is responsible for setting principles (and regulating if warranted) for transmission and distribution pricing structures.

b) The Commerce Commission is responsible for setting price and quality controls for Transpower and distribution businesses that are not classified as consumer-owned.

The aspiration that investment in new network capacity is optimised "*in a manner that avoids unnecessary cost increases for consumers, while ensuring network reliability*" is completely consistent with our corporate objectives.

We also noted references elsewhere in the GPS to:

- An expectation that demand flexibility also be used to balance intermittent renewable generation across the grid, as well as deferring network investment (para 10); and
- Household and business consumers making "*meaningful choices*" between competing suppliers, including in relation to demand-side flexibility (para 29).

Vector has long advocated for the benefits of new technology to be considered for their whole-system benefits, and for system planning and operation to be undertaken with a whole-system perspective. We were therefore pleased to see the consistency in Vector's corporate ambitions with the clear direction specified by the Government and take this as explicit endorsement our goals are consistent with national policy direction.

However, where we do not think there is consensus yet in New Zealand is *how* these goals may be achieved. For example, while we agree that potential response by consumers and aggregators to "*efficient network pricing*" is one tool in the EDB's toolkit for activating flexibility (which we could call 'uncontracted orchestration'), it cannot meet the Government's objectives by itself. As was articulated clearly in the NERA Report, potential response to network pricing (even if dynamic and highly locational) certainly cannot be relied on at the low-voltage level by EDBs to drive outcomes consistent with maintaining network security. Further, it is not clear who will be providing what services in this whole-system optimisation.

What is currently missing in the discussions in New Zealand is a sense of urgency for resolving the key areas of uncertainty on how efficient orchestration of DER will occur. Delays in providing clear direction in this area forces EDBs to continue to invest in maintaining peak load capacity headroom, for fear of 'herding events' and the risk of incurring quality breaches under the current regulatory regime. While we are aligned in the aspiration, and hear the justification for the direction of the Government and regulator, we do not feel we are yet in any position to advise our Board to reduce our capital expenditure as a response to effective orchestration.

Much of the remainder of our submission is framed around these key points. Our responses to the specific questions posed follow at the end of this cover letter.

Core building blocks need to be in place to maintain network security while enabling consumer choice

We have submitted consistently over the past two years about the increased coordination risks arising from enabling customers to choose which party (or parties) manage the devices in their homes and businesses, on their behalf.

Achieving the Government's whole-system coordination aspiration above will require those parties to respond to both national and local signals, whilst ensuring they operate <u>within the confines of the distribution network</u>, at that location and at that point in time. As the NERA Report pointed out, EDBs cannot rely on uncontracted orchestration – or response to network price signals alone – to drive outcomes consistent with maintaining network safety and security.

For example, in July 2024 we submitted to the Authority[7] (with our subsequent emphasis added):

> *We are now seeing a number of retailers on our network develop capability and products for managing consumers' hot-water and electric vehicle-charging loads. All these are positive developments in the demand-response market, building depth in the market, creating choice for consumers and helping minimise whole-system costs. …*
>
> *Parties operating DER on EDBs' networks must be compelled to* ***enter load management protocols with their hosts****, regardless of whether they are actually providing their hosts any flexibility services.* ***This applies to both retailers and non-retailers****.*
>
> *We have submitted several times to the Authority that EDBs need to be empowered to* ***direct the response to emergency situations*** *by the DER Managers on their networks – from widespread grid emergencies to local, low-voltage issues (e.g. car-versus-pole) and* ***imminent interruptions that can be avoided****. Ensuring the lights*

[7] Vector submission to the Authority on its draft *Guidance on distributor involvement in the flexibility services market*. Available online at: https://blob-static.vector.co.nz/blob/vector/media/vector-2024/202407-vector-feedback-to-draft-flexibility-guidelines.pdf

remain on, taking steps to avoid cascade or widespread failure and restoring services if they do are, ***at the very heart of the distribution services an EDB provides*** *to customers (and retailers). These powers are akin to the System Operator's ability under the Code to manage grid emergencies.*

In order to maintain quality and reliability while building more efficient networks, EDBs ***need the power to avoid emergencies*** *(referencing DDA cl 5.6 and expressed as "imminent" interruptions in the definition of System Emergency Event) by ensuring distribution-level constraints (physical and power quality) are understood and adhered to by parties managing DER on distribution networks (DER Managers). This needs:*

- *A* ***mandatory, 24/7 operating envelope*** *at each ICP that must be adhered to by DER Managers*
- *DER Managers to ensure offers into wholesale markets, and any other actions,* ***stay within their operating envelopes***

As we have previously submitted, ***enabling Code*** *is the first-best solution for these things, and should be expedited. In its absence, we are attempting to formalise the points above in a 'load management protocol' with retailer DER Managers, as per DDA cl 5.6. Our engagement with leading retailers to date has been constructive and positive.*

However, no such mechanism exists to enable safe operation ***by non-retailer DER Managers*** *(not currently industry participants to whom the Code applies) on our networks (and there is no indication that this is expected 'good electricity industry practice').*

This was consistent with the views put forward by the Northern Energy Group (NEG) in its February 2024 position piece, titled *DSO Evolution*[8], and built on the conclusions of the report we commissioned from NERA Economic Consulting, published in February 2023 (NERA Report). We were pleased to see the NEG's work acknowledged by the Authority in its consultation paper, alongside other thought pieces from the industry. We also contributed towards the Baringa Report completed for ENA.

While we continue to make good progress towards an industry-standard load management protocol, referenced above, we remain of the view that enabling Code would be the first-best solution. While negotiation does allow for flexibility and evolution while the industry is learning together, enabling Code would make more certain the need for compliance and the consequences of non-compliance, both of which are inherently unclear in the Default Distribution Agreement (DDA). We believe the "stick" requiring aggregators to manage device in accordance with "good electricity industry practice", ensuring they respect the requirements of the network, needs to be both large and credible enough to give EDBs confidence that the decentralised system will work.

[8] Available online at https://www.linkedin.com/posts/northern-energy-group-neg_neg-vision-on-the-dso-evolution-activity-7165419774091481088--VEo/

Non-retailer aggregators are still conspicuously absent from the Code.

As noted above, the uncertainty in the future operating environment does little to provide confidence to EDBs that they can begin to rely on orchestration to reduce their capital expenditure requirements. We urge the Authority to sufficiently prioritise its activity in this area.

Further, we are still exploring what physical safeguards, such as low-voltage circuit breakers, must be deployed to support decentralised control of DER (and maintain network integrity in this environment). We think the total costs of this supporting investment will be significant – and potentially cost-prohibitive. The Authority must be mindful that, despite the potentially significant costs of enabling market-led device aggregation, not all consumers will participate, and the indirect benefits may be limited and diffuse. There are significant risks of equity issues emerging between the haves and have-nots. Lower-cost solutions are available.

Evolving role definition of the EDB in the New Zealand context

We generally agree with the Authority's articulation of the evolving functions and roles of EDBs in the New Zealand context, recognising the critical importance of real-time coordination of DER, congestion management, and facilitation of flexibility services at the distribution level. The challenges outlined, including network complexity, the growing role of inverter-based resources, and the emergence of new market participants such as DER aggregators, are accurately identified.

Where we may differ with the Authority is in articulating the evolving scope of EDBs in fulfilling these functions. New Zealand has set clear precedents for the division of roles on the transmission system between the System Operator and Grid Owner, and these precedents should be relied on heavily by the Authority and Commerce Commission in determining how EDBs will perform their regulated functions going forward.

The table below summarises our views.

Role	Vector position on EDB accountability	NZ grid precedent
Network planning	This is a core role of an EDB, requiring a deep knowledge of local context, network context, and engagement with consumers, other customers, and related agencies (e.g. councils, transport agencies). It includes coordination with both the System Operator and Grid Owner.	System-wide forecasting and studies are done by the System Operator, but there is also a team in the Grid Owner responsible for long-term forecasting. Planning how to evolve and develop the grid to meet those forecasts is a core role of Grid Owner. There is now also a Future Grid division looking further ahead for the Grid Owner.
Customer connection, including	Relatedly, facilitating customer connections also requires deep local, network and customer knowledge, especially with	Connecting customers to the transmission network, including building those connections and recovering costs, is a core role of the

flexible connections	increased prevalence of flexible connections. Flexible connections are inextricably linked to customer needs, network planning and operation.	Grid Owner. Bespoke requirements (including flexibility, run-backs, etc) are also negotiated between the connecting customer and the Grid Owner. Part 8 of the Code sets out common quality requirements that apply to asset owners connecting to the grid. The System Operator will also undertake testing as part of its commissioning process.
Operating and maintaining network assets (including outage management)	This is a core role of an EDB. It includes coordination with the System Operator and Grid Owner.	These are core roles of the Grid Owner. The Grid Owner has its own National Grid Operation Centres (NGOCs), working closely with the System Operator's.
Contracting flexibility solutions (non-wires alternatives)	In the context of an EDB, these contracted services (what we could call 'contracted orchestration' will include at least: • Flexible connections (recently endorsed by the Authority as a core EDB service, in its connections workstreams) • Direct control tariffs (e.g. hot-water) • Contracted flexibility from retailers, in the form of network-wide, 'indirect' control tariffs • Non-wires alternatives for specific flexibility services in specific locations Note we assume these functions take primacy over other forms of contracted or uncontracted flexibility services, to prevent issues with 'duelling'.	While provision of transmission alternatives by third parties has been limited to date, these would be contracted by the Grid Owner. This would include specific services to manage planned outages. When contracted services are called upon, they would then be dispatched by the Grid Owner, albeit potentially through the System Operator's staff. It is expected the contractual arrangements would require these services to take primacy over services offered by the third parties to other buyers. The System Operator contracts national ancillary services, such as reserves and black start capability.
Pricing to recover regulated network revenues + signal the benefits of price-	An EDB's maximum allowable revenue is set by the Commerce Commission. How it should be recovered from customers is regulated by the Authority. As noted above, the regulators and Government view an EDB's pricing as the key tool for optimising use of	The Grid Owner designs, develops and implements the transmission cost allocation for recovering its allowable revenue from its customers, within the guidelines set by the Authority. This included making design decisions on whether a forward-looking congestion signals was

responsive (uncontracted) flexibility	the network, and ensuring investment is efficient. This includes adequately signalling and compensating the value of flexibility in posted prices, in terms of avoidable cost ('uncontracted orchestration'). This function is therefore inextricably linked to network planning, flexibility contracting, network operations and flexibility dispatch. Again, it needs detailed knowledge of local context, network context and customer contexts.	required on a transitional basis, and also covers the costs for connecting to the transmission network.
Management of system emergency events	Events requiring immediate response typically occur multiple times per day on an EDB's network, and cannot be readily separated from BAU active network management by the EDB's Control Room. Major event management is a core requirement of an EDB, again requiring considerable local knowledge and coordination with maintenance crews.	Planned and unplanned outages of transmission assets are managed by the Grid Owner, but, for planned outages, the System Operator coordinates the timing of assets being taken offline and returned to service. The System Operator has responsibility for re-dispatching and instructing emergency response by market participants for a broad set of emergency situations, except for load shedding by EDBs which is coordinated via the Grid Owner's operations centres.

In summary, all the roles above require intimate connection with both the network topology and connected customers, and would not make sense to be disaggregated to a third party.

New roles / functions required to enable value-stacking by aggregators

However, new roles will emerge that are not currently undertaken by EDBs, and may not be required evolutions of an EDB's core roles. They include, primarily, the allocation of available network headroom to aggregators seeking to use consumers' flexibility resources to:

1. Minimise their customers' time-varying *network* charges (e.g. static or dynamic TOU pricing) payable to the host EDB, or otherwise complying with the conditions of the customer's network charge
2. Minimise the cost of fulfilling their customers' *energy* needs (in an uncontracted manner)
3. Participate directly in other markets, and offer services to other parties, including national wholesale markets, such as energy dispatch or ancillary services.

The role/function of "available headroom allocator" (AHA), calculating and providing information about capacity limits to these parties and ensuring their compliance with those limits, intuitively feels more mathematical, requiring less local knowledge, and could therefore be consolidated across individual GXPs, networks or regions. It could be that these are bundled in with evolving

EDB roles, or they could be separated. However, for consistency, the rules governing the allocation of headroom, and the operation of AHAs, would presumably require standardisation nationwide. Despite standardisation, headroom allocation will vary within, and across networks. Low-voltage networks are built to different standards of after-diversity maximum demand, and will be more sensitive to any changes in low-voltage demand. This new use of EDBs' networks would also require reconsideration of EDBs' accountabilities and obligations to maintain quality standards.

As noted in the table above, we explicitly assume that the flexibility services contracted by the EDB, through whatever means, have primacy. They would therefore take precedence over the services offered to national markets, to prevent "duelling". This is due to the reasons discussed in our 2023 NERA Report, namely the limited "market" depth available to EDBs contracting locational flexibility services from flexibility providers, compared with the national needs of the System Operator, and the importance of both surety of response, and term, required to enable an EDB to defer investment. Similarly, we would assume also that network alternatives contracted by the Grid Owner would fall below an EDB's services in the hierarchy, but above any *unoffered* national services.

Over time, we would expect the AHA role to become more sophisticated, with available headroom allocated on the basis of value-based bids by aggregators. This could lead to convergence between the capacity optimisation the AHA is undertaking, and the flexibility procurement and pricing functions of the EDB, which aim to maximise network utilisation for minimum cost.

Vector's preference is for a hybrid model

We appreciate the Authority's consideration of international experiences, particularly from Australia and the United Kingdom, which offer useful lessons on governance, market design, and the separation of roles to manage conflicts of interest. New Zealand's relatively small and interconnected market means that a tailored approach balancing local agility with system-wide coordination is appropriate.

Of the proposed DSO models — Total TSO, Hybrid, and Total DSO — Vector advocates a preference for the Hybrid model. Flexibility service providers will be entering contracts with, and receiving dispatch instructions from, at least their host EDB, as per the table above. This will not change. Any party engaging in national services would also be required to engage with Transpower and the AHA for the GXP(s) on which they are operating.

The AHA could be the party clearing national offers and bids from aggregators, and issuing dispatch instructions, on the System Operator's behalf. If the AHA role were to be bundled into the core EDB roles in our table above, this would mimic the Total DSO model proposed. Equally, the AHA role could be undertaken by an iDSO, or the TSO, which would then be a form of Hybrid. In either case, the necessity of the EDB contracting for a range of local flexibility solutions, including flexible connections, rules out the Total TSO model.

The Hybrid model appropriately balances the distribution of responsibilities between transmission and distribution operators, leveraging local network knowledge and customer relationships while maintaining coordinated system operation through the TSO. It eliminates the risk of duplication of capability between the TSO and DSO/EDB, given the EDB will already be required to calculate headroom on its own network to determine its own requirements for dispatching contracted flexibility. The Hybrid model also supports incremental transition and flexibility, which is vital given the current stage of flexibility market development.

We recognise governance and transparency issues raised by the concept of an independent DSO (iDSO) and agree that independent market facilitation functions may be needed as flexibility markets mature. However, the establishment of a fully independent DSO entity is clearly premature at this time. Instead, enhanced regulatory oversight of distributors performing DSO functions, combined with robust transparency and accountability measures, provides a more practical pathway forward.

Price discovery in flexibility markets is essential to achieving efficient and secure system operation. The Hybrid model is positioned best to support coordinated market mechanisms that reflect local and system-wide conditions, helping flexibility service prices converge toward the wholesale market ideal of security-constrained economic dispatch.

Resolving uncertainty in this area is urgent. Vector urges the Authority to prioritise development of clear data standards, interoperable communication platforms, device and network visibility, and governance frameworks and accountability that enable collaborative operation between various roles in the market. Early implementation of "least-regrets" measures such as enhanced DER visibility tools, flexible connection agreements, and coordinated forecasting, will help mitigate risks and enable innovation, but more needs to be done – at pace – before EDBs can begin to rely on orchestration to reduce their capital expenditure requirements.

We thank the Authority for its continued leadership in progressing these complex reforms. Vector looks forward to working constructively with all stakeholders to support an efficient, reliable, and consumer-focused future for New Zealand's power system.

We remain available to discuss this submission and contribute to further consultation and implementation work.

Ngā mihi

[redacted]

James Tipping
GM Market Strategy / Regulation

Responses to specific questions posed

1. 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?

As discussed in our cover letter, in Vector's view the EDB role will continue to evolve to encompass pricing, contracting and dispatch of flexibility, through flexible connections and a range of other services. Our view on the evolving roles and functions of the EDB in the New Zealand context is articulated in the table in our cover letter, and should be referred to by the Authority in the context of this answer.

Critically, the Authority must recognise that different EDBs will choose different ways to fulfil each of the functions in their emerging roles. Some will choose to self-fulfil, others will collaborate and form relevant "clubs" (as is already happening for cyber security and ADMS systems), and others will outsource completely. Allowing for a diversity of approaches, albeit with standardisation where required, will create the best conditions for innovation in this area.

We recommend that the Authority further clarify the scope of DSO responsibilities relative to the transmission System Operator (TSO) to avoid role ambiguity. It is also critical to maintain flexibility in how DSO functions are allocated across one or multiple entities, allowing for evolution as market maturity and technology capabilities develop. The definition should explicitly incorporate the increasing importance of data management and transparency, as well as market facilitation, as central DSO functions.

2. 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?

Vector agrees that the current and emerging challenges primarily centre around distribution system operation, given the rapidly growing penetration of DER and the increasing complexity at the distribution network level. Focusing on enhancing operational functions at the distribution level aligns with the evolving realities of the power system and addresses the areas where coordination and innovation can most effectively support reliability and economic efficiency.

Nonetheless, Vector stresses that improvements at the distribution level must not be developed in isolation. Close integration and coordination with transmission system operation remain essential. The focus on distribution system operation should therefore be complemented by frameworks that support end-to-end visibility and planning across transmission and distribution boundaries. Further, operators of DER resources will be providing services to EDBs and to other parties (including the wholesale market), and that the primacy of the EDB's call on these resources must be recognised. This is because, as described in our NERA Report of 2023, the "market" depth available to meet the needs of the EDB is significantly less than available to the TSO to operate national markets.

Relatedly, regardless of how the EDB and DSO roles evolve, standardisation between TSO and EDB/DSO operations will be critical, as will standardisation between EDBs and DER Managers.

3. 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?

The Authority has provided a thorough summary of the key changes impacting distribution systems, including DER uptake, bi-directional power flows, and the growing role of inverter-based resources.

Vector suggests the inclusion of several additional factors that are increasingly relevant:

- The growing range of mechanisms EDBs will use to contract flexibility resources, including flexible connections. These are a clear feature of the Australian and British power systems, and were recently endorsed by the Authority in its connections workstreams.

- The impact of emerging technologies such as electric vehicles (EVs), battery storage, and demand response on operational complexity.

- The growing importance of data interoperability standards, cybersecurity and operational technology (OT) risks in system operation.

- The need for adaptive network planning approaches that leverage non-wires alternatives and flexibility services.

Incorporating these factors will provide a more comprehensive picture of the distribution system transformation.

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

Vector agrees with the framing of the problem as one requiring a more coordinated and integrated system operation framework. The increasing decentralisation and digitalisation of the power system necessitate collaboration between all system operators to optimise resource utilisation and maintain reliability.

An integrated approach must include coordinated operational planning, aligned investment decisions, and shared data platforms to enable real-time coordination. Vector emphasises that integration should not compromise competitive dynamics or innovation incentives, and regulatory frameworks should be designed to balance coordination with market-based mechanisms.

Most importantly, we still have reservations about the increased signalling from the Authority that EDBs be ring-fenced out of direct control of devices. We do not believe there has yet been a detailed cost-benefit analysis of progressing with any kind of model that includes decentralisation of control and aggregator-managed resources, as opposed to control by a single entity such as an EDB (or DSO). Across its various workstreams, the Authority appears convicted that enabling competition and choice for device control must lead to the best outcomes for consumers, long term. We are still exploring what physical safeguards, such as low-voltage circuit breakers, must be deployed to support decentralised control of DER (and maintain network integrity in this environment). We think the total costs of this supporting investment will be significant – and potentially cost-prohibitive. The Authority must be mindful that, despite the potentially significant costs of enabling market-led device aggregation, not all consumers will participate, and the indirect benefits may be limited and diffuse. There are significant risks of equity issues emerging between the haves and have-nots.

Lower-cost solutions that achieve much of the benefit will be possible, with less risk of creating equity issues. Precedents from other jurisdictions, such as Germany's recent paragraph 14a of its Energy Industry Act (EnWG)[9], must be considered as valid alternatives which strike a balance between consumer choice and network integrity. We have in-depth knowledge of the German solution and would welcome the opportunity to discuss this further with the Authority team.

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

The Australian and British experiences provide valuable lessons for New Zealand, particularly in managing the transition to more active distribution system roles. Key relevant aspects include:

- The emphasis on establishing clear roles and responsibilities to avoid conflicts of interest, especially where network owners may also act as DSOs.
- The development of market mechanisms that facilitate flexibility service procurement while promoting competition and innovation.
- The justification for, and use of, independent DSOs (iDSOs) or separation of functions to address governance and transparency concerns.
- The importance of standardised data exchange protocols and interoperability frameworks to support multi-party coordination.

However, we were disappointed that there was not more focus placed on DSO models in other jurisdictions, such as the EU, where EDBs have been bestowed with the DSO title. We think there are still significant uncertainties regarding how regulation will evolve to support DSO and decentralised control of resources, including DSO incentive structures, funding mechanisms, cost-recovery of that funding, and the evolution of quality measures.

New Zealand should adopt a pragmatic approach that balances learnings from these jurisdictions with its unique market structure and regulatory environment.

[9] See https://www.esig.energy/germanys-paragraph-14a-enwg/

6. 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?

Vector supports the ongoing research efforts by ENA, the NEG, and SIDG, which provide essential insights into the technical, economic, and regulatory challenges of evolving DSO functions. We were key contributors to NEG's position paper over 2023-24. The Baringa Report commissioned by ENA, in particular, offers a rigorous evaluation of potential DSO models and pathways.

This research highlights the importance of adopting flexible, least-regrets approaches that enable incremental capability development while maintaining system security and consumer outcomes. Vector encourages continued collaboration between industry stakeholders and research bodies to translate findings into practical implementation strategies.

7. 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?

Vector acknowledges the governance and conflict-of-interest concerns that have driven interest in independent DSOs. However, we consider that New Zealand's relatively small market size and unique regulatory context favour a more gradual approach. At this stage, Vector does not believe there is a case for establishment of a fully independent DSO. Instead, a hybrid model where EDBs' roles evolve to encompass new functions under enhanced regulatory oversight and transparency is more appropriate.

In our view, any conflict requiring separation must surely emerge between the TSO and Grid Owner first. As indicated in the Baringa Report, the appropriate course of action in New Zealand is to monitor *risks* of conflicts of interest arising first, and, as risks do manifest, put in place controls that manage those risks appropriately. Independence should be a *last* resort, not the first. The frameworks that govern the relationship between the TSO and Grid Owner provide excellent precedents.

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

Per ENA's Baringa Report, the Authority's three proposed models — Total TSO, Hybrid, and Total DSO — provide a useful framework for considering future system operation arrangements.

- **Total TSO:** While it offers centralised coordination, this model may not leverage local knowledge and innovation at the distribution level and could struggle with the operational complexity of high DER penetration. This model would not be appropriate for the New Zealand context in which EDBs' roles involve pricing and contracting for a range of flexibility services, including flexible connections and non-wires alternatives, from a range of parties.

- **Hybrid:** This model balances responsibilities between transmission and distribution operators, allowing EDBs to leverage their network knowledge and customer relationships while maintaining system-wide coordination. It aligns well with Vector's view of a phased evolution.

- **Total DSO:** Full DSO responsibility places significant operational and market facilitation burdens on EDBs. While potentially efficient, it raises governance and capability challenges that would require significant investment and oversight. Requiring EDBs/DSOs to clear local wholesale markets would place them under significant financial scrutiny. We note that recommendation 1D in Australia's recently-released NEM Review Draft Report Consultation[10], explicitly states the following in this regard:

  Do not create distribution-level wholesale energy markets. Instead, facilitate distribution-level energy resources to participate in regional markets and use dynamic operating envelopes and dynamic network tariffs to manage local constraints.

  This strongly suggests the Total DSO model should be ruled out as a viable option. It continues:

  The Panel does not see the creation of a separate distribution-level wholesale energy market as a necessary reform at this time. This approach would likely involve significant implementation costs and add complexity for participants engaging across multiple markets and regions, potentially having negative consequences for competition. The Panel considers that the NEM is already evolving to integrate CER within the existing market framework and that work on developing separate distribution-level wholesale markets would divert resources away from this. Rather than pursuing structural redesign, the Panel has focused on accelerating this evolution through targeted reforms that enable CER to participate more fully and efficiently. This includes integrating distribution-level resources into the existing regional market framework (see Recommendation 2). This would be supported by dynamic operating envelopes and network tariffs to manage local constraints efficiently. The Panel has considered other aspects of the roadmap at Recommendation 3.

  Overall, Vector prefers the Hybrid model as a pragmatic and flexible pathway that accommodates evolving market and technology developments.

9. Do you prefer one model over the others?

As noted above, Vector prefers the Hybrid model, with the evolution of the EDB role described in the table in our cover letter. It offers the benefits of distributed knowledge and operational agility while maintaining coordinated system operation through the TSO.

The Hybrid model also mitigates risks of conflicts of interest by delineating market facilitation and operational functions, and enables incremental transition as flexibility markets mature.

---

[10] Available online at https://consult.dcceew.gov.au/nem-review-draft-report-consultation

This approach aligns with the recommendations of the Baringa Report, and supports technology-neutral, least-regrets decision-making.

10. 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?

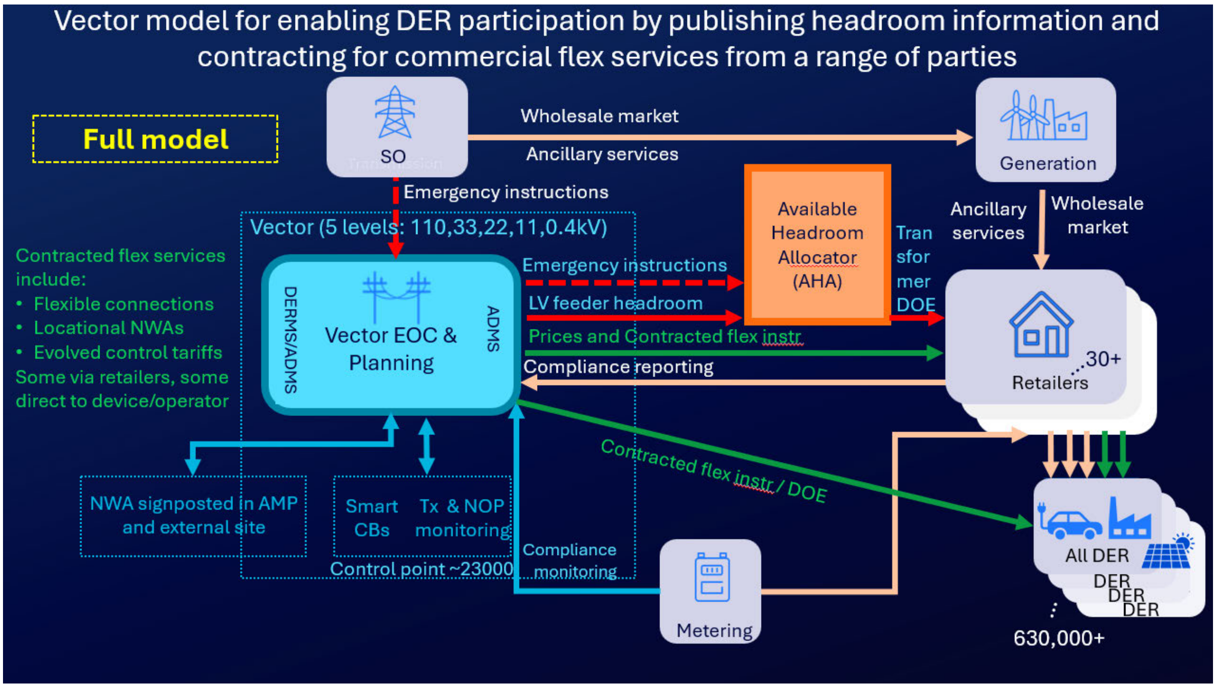
The TSO should retain responsibility for system-wide coordination, contingency management, and cross-boundary operational planning.

As discussed above, the EDB role will continue to evolve to encompass a range of contracted flexibility services, as set out in the table in our cover letter. Core roles such as planning and network operations will remain within the EDB, as part of the following list:

- Network planning
- Customer connection, including flexible connections
- Operating and maintaining network assets
- Contracting flexibility solutions (non-wires alternatives)
- Pricing to recover regulated network revenues + signal the benefits of price-responsive (uncontracted) flexibility
- Management of system emergency events

Market facilitation functions, including allocation of available headroom (the AHA role) after the EDB's flexibility services have been dispatched, could be shared or gradually transitioned depending on market maturity, with transparent frameworks to manage overlaps.

Coordination mechanisms, supported by common data platforms and governance arrangements, are essential to ensure alignment and efficiency. Our current preferred architecture is shown in brief in the diagram below:



11. 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?

From a price discovery perspective, the Total TSO model offers the most direct alignment with wholesale market principles but may be impractical in distribution systems with high complexity. Refer to the draft NEM review's recommendation above around local wholesale markets.

The Hybrid model provides a balance, enabling efficient price signals at both transmission and distribution levels through coordinated market facilitation and local flexibility procurement.

The Total DSO model could promote granular local price signals but risks fragmentation and inconsistencies without strong coordination.

Therefore, Vector ranks the models as follows:

1. Hybrid – best balance of coordination and local market responsiveness.
2. Total DSO – highest risk of fragmentation, but greatest likelihood of all three models of maintaining local network integrity, and potential for local innovation if well governed.
3. Total TSO – strongest theoretical price discovery but operationally challenging and cannot be as "total" as anticipated, due to the EDB's role encompassing contracting and dispatch of local flexibility resources, with primacy.