19 April 2024

Northern Energy Group submission to the Electricity Authority consultation on the Future Operation of New Zealand's Power System

Introduction

The Northern Energy Group (NEG) welcomes the opportunity to provide feedback to the Electricity Authority (Authority) on its consultation paper *the Future Operation of New Zealand's Power System* (Consultation Paper).

Our feedback is structured in two sections:

1. Core messages

2. Specific responses to questions from the Consultation Paper.

Several NEG members are submitting individually on this consultation. This submission is intended to provide a high-level and shared perspective on the issues and areas that are most pressing for NEG.

About the Northern Energy Group

NEG was formed in 2019 around a common belief that consumer voices needed to be stronger in industry and government decision-making. NEG consists of Counties Energy, Northpower, The Lines Company, Top Energy, Waipā Networks, Vector and Electra.

All our networks are **entirely or majority-owned by customer trusts**. We believe customers' interests belong at the heart of our energy sector. Together, nearly 50% of New Zealand's consumer power connections (ICPs) are located on our networks and the majority of demand growth is forecast to be within our network areas. Our goal as consumer-owned entities is to lift consumers up together.

NEG members provide a trusted, local perspective. We should be a priority stakeholder for the Authority for future engagement on power system operations. We have feet on the ground locally and our members' networks are already experiencing some of the most rapid growth in Consumer Energy Resources (CER)[1] around Aotearoa – this is only set to grow.

[1] While the consultation paper refers to Distributed Energy Resources (DER), in this submission we refer to Consumer Energy Resources (CER), recognising that these assets belong to consumers and it is consumers who will choose how they want to use them.

Core messages

We agree that the future operation of New Zealand's power system is changing

The energy sector in Aotearoa is on the brink of significant change and opportunity. The economy's electrification means demand on our networks will double. De-carbonising the sector is crucial to climate action in Aotearoa.

Electricity Distribution Businesses (EDBs) have a critical role to play in supporting innovation and enabling greater consumer choice. Together, NEG members have developed a vision document that sets out some of the shifts in context shaping the future of the sector and how our roles will evolve to ensure we continue to deliver for our communities. We have attached this document – NEG Distribution System Operator Evolution – as Annex One to this submission.

Among other things, this vision document sets out:

- Our view on the emerging phases of DSO operation
- The principles adopted by NEG to guide our involvement
- Our view of the priorities for regulators and decision makers to enable the transition.

We will refer to the relevant aspects of the vision document throughout this submission.

NEG is committed to leading a new energy future with the voices and interests of our communities at the centre. We welcome the Authority's focus in this area. The release of this Consultation Paper is an important milestone and reflects several of the shifts and directions we have identified.

As power system operations change, the role of EDBs will evolve

EDBs in Aotearoa have a critical role to play to support innovation and enable greater consumer choice. In today's world, EDBs are Distribution Network Operators (DNO) responsible for the safe, secure and reliable distribution of electricity to our connected customers. At relatively low levels of penetration, the use of distributed consumer-owned resources can happen (and is happening) relatively independently of the EDBs that host them. This is because the swings in output and/or demand are unlikely to be large enough to impact network operation, violate network constraints or ultimately impact other consumers' supply.

Tomorrow, as CER continues to grow, along with our traditional DNO responsibilities, EDBs' roles will naturally evolve to include more active distribution system operations. Use of flexible resources by CER Managers[2] and increases in distributed generation cannot happen independently of the EDB. We will evolve to play the role of 'energy orchestrators', being the primary entry point into the

[2] CER Managers is the term we use to refer to aggregators as managing CER for consumer owners is their primary role.

dynamic distribution system for new actors such as prosumers, EV charging and demand-side managers, and other aggregators. As Distribution System Operators (DSOs), we will foster engagement and interaction with stakeholders, unlocking a flexible system that creates new opportunities for innovative energy services and shared value.

We see the evolution of this DSO function occurring in two phases:

- Phase 1: DSOs **enable** safe CER management and 'value stacking' by emerging CER Managers
- Phase 2: DSOs begin to **procure** dedicated services and solutions from CER Managers.

Further details on how we see the evolution of inter-relationships during each of these two phases are set out in Table 1 below.

Table 1: Evolving System Inter-relationships in the DSO Evolution

	Status Quo	Phase 1 – Enabling	Phase 2 – Procurement
Phase of CER market development	**Limited relationship** and **interaction** between CER Managers and EDB	DSO **enables** safe CER management and 'value stacking' by emerging CER Managers	DSO begins to **procure** dedicated services and solutions from CER Managers
Active CER Managers in this phase	EDBs (hot water, network batteries, other DER) C&I consumer process managers DG owners (e.g., hydro, wind, solar)	As per status quo, plus: Retailers and other aggregators (smart hot water, smart EV charging, e-buses, home batteries, etc)	As per phase 1, but in even greater numbers and with a wider range of business models
Main CER management activities	EDBs utilising DER for network management (i.e., *utility-led* mode) DG owners optimising wholesale market revenues – either *passive* response to spot prices or *active* participation in the market ('active' = offered to, and dispatched by, the TSO)	As per status quo, plus: New CER Managers are responding to wholesale prices and TOU distribution prices (i.e., *price-led* mode), either actively (offered) and/or passively (non-offered). New CER Managers managing 'flexible' network connections (e.g. bus charging)	As per phase 1, plus: CER Managers operating under a market-procured contract to the DSO (EDB) for specific services, including investment deferral (i.e. *market-led* / *contract-led* mode)
Main DSO activities: • local capacity management • CER orchestration	EDB and non-EDB CER Managers operate independently of each other Limited active relationship between DSOs and CER Managers; EDBs may have little awareness of CER Manager presence CER Managers have little, if any, awareness of network capacity constraints	DSO will enable safe CER Management and value-stacking by providing static or dynamic operating envelopes to CER Managers DSO will orchestrate CER response to network and grid emergencies Over time, more sophisticated time-varying distribution pricing could emerge	As per phase 1, plus: The DSO will procure (via contract) specific services and specific responses from CER Managers, including investment deferral (non-wired alternatives) and ancillary (network support) services. Over time, more sophisticated market and pricing mechanisms for networks could emerge

We have identified several principles that will guide our role in the transition

Consumers and communities belong at the heart of our energy sector. NEG has developed and adopted the following principles to guide how each of our member networks are considering and pursuing DSO functions:

- Start with consumers. Our future energy system offers the potential for greater consumer choice and value. Continuing to meet the needs of our consumers and other customers will require flexibility for the role of EDBs to evolve as technologies and consumer preferences also evolve. This includes the role of EDBs in managing CER directly and engaging with CER Managers to help them meet consumers' needs. EDBs will need to consider different international models and pathways. The Authority's scoping of international examples of developments in power system operation is a helpful contribution to this discussion.

- Reliability and safety are fundamental. Ensuring whole system reliability is fundamental to delivering sustainable consumer choice. Networks need to be able to manage load to the extent they can protect system security and reliability. EDBs must have the ability to orchestrate CER to manage emergencies on their networks and insulate necessary operations from CER Managers who don't have the same obligations to keep the lights on. Obligations on EDBs must remain fit-for-purpose in this future world. Similarly, prioritising safety is a fundamental value in the energy sector and needs to remain a focus as CER continues to be adopted at the household and local levels.

- Standardisation across the system. This system-to-system integration – i.e., between the DSO, CER Managers and the System Operator – will be enabled by the right standards. EDBs will need to be outward-looking, with a focus on pricing and purchasing, new business models, and enabling the simplest interface with consumers and other market participants. We will need to decide what will require human interaction and what can be left to monitor and automate through Artificial Intelligence (AI). EDBs will need to establish and consistently adhere to legitimate standards between their DSO and DNO functions.

- Enabling system transition and enabling new market growth. Along with regulatory alignment, the role of EDBs will evolve. We have a leading role in the transition to and operation of DSOs. EDBs will have an enhanced function in addition to ever-improving DNOs. Evolving the role of the EDB will, in turn, enable the emergence of new markets and a more complex and valuable ecosystem.

- Regulatory collaboration and progress. We bring extensive network experience and an unwavering commitment to doing right by our consumers. Regulatory leadership is needed regarding standards for CER technology and communications protocols, opt in/out mechanisms for consumers, minimums, contracts, safety measures, consumer expectations, EV charging, dynamic metering and access to operational data.

- No-regrets capabilities. We want to move quickly at the right time, acknowledging that there are significant differences among our networks, including the rate of consumer uptake of these technologies. This requires an approach of leveraging and sharing capabilities efficiently to respond to the unique challenges and opportunities on each EDBs' network.

Our priorities: Regulators and decision-makers have a key role to play in supporting and driving the transition

NEG members have established a vision for their role in this transition. At the same time, there will be policy settings and regulatory levers that will need to be in place to ensure that the transition occurs in an orderly and coordinated manner and in a way that maximises consumer benefits. The Authority has identified several challenges and opportunities for the sector as we transition to a new mode of system operations. We consider that critical areas of focus for regulators and decision-makers will include:

1. Ensuring statutory regulations for EDBs (e.g. quality and reliability) remain fit-for-purpose in a world with market-based CER management
2. Establishing minimum technology and communication standards to enable smart system management and interaction, and provide the allowances to invest in this capability (and the data required)
3. Developing – potentially through 'sandboxing' – a framework for the implementation and operationalisation of dynamic capacity management on distribution networks, including principles for how capacity is allocated between system users and the requisite communication protocols
4. Ensuring that all parties managing CER on behalf of consumers and investors (the CER Managers) have agreed operational protocols with their host networks, formalising the requirement on the CER Manager to manage within the operational limits of the network and maintain power system quality
5. Clarifying the ability of DSOs to orchestrate the response of CER Managers to system emergencies – from the very local (e.g. car vs pole) to nationwide
6. Amending distribution pricing rules to ensure parties who benefit commercially from network capacity fund it
7. Enabling commercial access to network operational data and ensuring the minimum level of metering capability necessary to deliver it

We encourage the Authority to consider fully each of these areas as it progresses its work on the future of system operations. We cover a number of these issues in further detail in our response to the Authority's individual consultation questions below.

Specific responses to questions from the consultation document

1. Do you consider section 3 to be an accurate summary of the existing arrangements for power system operation in New Zealand?

We broadly agree with the Authority's summary.

For completeness, we consider that the summary should also note existing mechanisms and processes that contribute to system security – for example, Automatic Under-Frequency Load Shedding (AUFLS) and Transpower's grid outage planning and grid emergency processes.

We note that the Authority's description in Appendix A of the regulatory arrangements for power system operation highlights that the Electricity Industry Participation Code has limited provisions for the operation and management of distribution networks. This emphasises the need for the Authority to carefully consider how the regulatory settings for EDBs will need to be updated in the context of the wider changes described in the Consultation Paper and our DSO vision document.

2. Do you agree that we have captured the key drivers of change in New Zealand's power system operation?

We note the Authority's description of drivers of change focuses primarily on the development of new technologies and sectoral trends. NEG takes a more fundamental view of the drivers of change. We see the underlying drivers as a shift towards energy independence and resilience, New Zealand's decarbonisation goals, and the need to maintain energy affordability for consumers, particularly in light of increasing asset renewal and the infrastructure required to support Aotearoa's decarbonisation goals. These dimensions of the 'energy trilemma' will underpin the landscape of the evolution of system operations in New Zealand over the coming years and decades. A further driver in the New Zealand context could be 'equity', i.e., ensuring that electricity access is available (and affordable) to all, particularly in a context of increased electrification (and decreasing gas use).[3]

In contrast, we view the matters described by the Authority – particularly those relating to technology change – as *enablers* of change in response to these underlying drivers. Maintaining a focus on the *fundamental drivers* of change will help ensure that regulatory settings and system operations evolve in a way that best meets these challenges.

3. Do you have any feedback on our description of each key driver?

Notwithstanding our comments above, we broadly agree with the description of key drivers while noting the following:

[3] For example, one NEG member has been approached by local iwi to consider options for connecting customers who are currently off grid due to the prohibitive (but cost-reflective) cost of connection. The concern of iwi is that, with a single source of energy moving forward, customers without electricity connections will be denied access to any energy services. This may, for example, highlight a need for establishment of an Energy Poverty Fund focussed on new connection subsidies.

- The description of Dispatch Notification (in paragraph 4.27) should distinguish between 'active' (dispatchable) and 'passive' (price responsive) market participation by demand-side resources. For example, large industrial consumers or load aggregators bidding demand response into the wholesale market can be considered 'active' demand-side participants – which entails a particular set of responsibilities and rewards. We consider that the example provided in the Consultation Paper of Contact's '3 hours of power' plan is better described as a 'passive' market response by consumers, i.e., it represents a price offering from a retailer that a consumer is free to respond to or not, without any binding commitment or direct payment being made (only the cost savings of a lower price on energy consumed). This distinction becomes increasingly important in a future scenario where the System Operator is relying on prosumer generation and demand to manage system constraints.
- The Authority notes that advanced operational tools like AI and machine learning will likely need to be employed across the power system to realise the potential of CER (in paragraph 4.34). While such tools may be useful in the future, we consider it is important not to rely on the 'magic wand' of AI to solve future problems but to take real, tangible steps today. Data will be critical in future decision making, whether it is to inform AI and machine learning or to enable automation. We should now consider what data we need to collect, how we will collect it, and how it will be managed and accessed. We need to ensure this is done in a way that is cost-efficient and promotes competition while also supporting ongoing investment and evolution of service offerings by data providers. We encourage the Authority to give appropriate consideration and priority to these initial steps to support and enable future system operations.

4. What do you consider will be most helpful to increase coordination in system operation?

We agree with the Authority's statement on the need for **common standards and/or protocols** to facilitate interoperability (in paragraph 5.7). As noted above, a major expected change in the electricity sector is the extension of power system operations to distribution networks and CER. There will be a greater need for consistency and alignment in that context.

The Authority notes that its work programme on **updating the regulatory settings for distribution networks** is tackling these issues. We consider that the Authority's planned work in this area may address some of the 'low-hanging fruit' but that this work needs to be expanded to include operating protocols and data flows between CER Managers and their host EDBs. The Consultation Paper is relatively light on the focus it gives this critical emerging issue.

We note the Authority's discussion on the **need for DSOs** in the future (in paragraph 5.9). As set out in our DSO Evolution document, we believe as CER continues to grow there will be a need for local system operations to be managed at the local level to ensure power flows operate within network constraints and system security is maintained. EDBs, as the local network owner and operator, will be best placed to undertake this role.[4] Initially, we see EDBs' existing roles expanding to include interaction with CER Managers to manage constraints and allocate available network capacity to ensure both system security and maximisation of the value of CER. In some cases, this interaction will also be required to manage emergency events, from local outages to national grid emergencies. In time, DSOs will also need to develop portfolio management and network optimisation capabilities with a focus on procurement, coordination, and dispatch of CER Managers' flexible resources. Further details on our vision for the DSO transition are included in Annex One.

We agree with the Authority's statement that initial steps in this transition will need to include greater communication between the System Operator, EDBs, and parties operating on networks such as aggregators and flexibility traders (in paragraph 5.11). In addition, we recommend the Authority consider the following matters:

- Given their differing characteristics and impact on the system, different approaches may be necessary to managing distributed generation versus managing flexible load. As such, the Authority may at times need to consider the future obligations of these two technologies separately rather than grouping them together.
- A threshold at which point EDBs would be required to notify the System Operator about the penetration of DER on their network may need to be established so that the potential impact of these resources is accounted for in system management.
- As new industry participants, it will be important to set clear expectations for the performance of CER Managers given their actions will increasingly impact system balancing and local security. This could occur, for example, through a comprehensive 'onboarding' process.
- Establishing a publicly available register of CER to provide visibility to all market participants of its location and scale may be beneficial. Such a register has been adopted in Australia and is understood to assist network owners planning and managing their networks. Network operators will certainly need visibility into who is managing each CER installation and how.
- Establishing a centralised and shared platform for managing real-time and forecast data on supply and demand may be beneficial. This recognises the more sophisticated functions required of EDBs as they transition to DSOs and the wide variability of EDBs in Aotearoa in terms of scale and resources. A centralised data platform could help create efficiencies and ensure adequate capabilities, particularly if more complex arrangements such as 5-minute pricing are pursued.
- We consider that EDBs, as DSOs, may need the ability to coordinate the response of CER Managers and their portfolios of flexible resources in grid emergencies, especially as flexible loads need to be gradually brought back

[4] Either themselves or through contracting this function to a third party (such as another EDB) if it is more efficient.

online following a period of control (which can take some hours to achieve safely while maintaining system stability).

- The Authority notes that EDBs have called for greater visibility of distribution network users, e.g., compelling flexibility traders and CER Managers to negotiate with EDBs via a default distributor agreement over the use of distribution networks and to establish operating protocols. We note that, in general, coordination at the distribution level (between EDBs and aggregators) has not been given as much attention as coordination between the System Operator and EDBs. Coordination at this level has largely been left to EDBs and aggregators to reach agreement with little input from regulators. However, the boundary between commercial solutions and system security can be difficult to draw. We anticipate that regulatory intervention will be needed in this area and recommend the Authority initiate thinking and analysis of these issues now.

5. Looking at overseas jurisdictions, what developments in future system operation are relevant and useful for New Zealand?

We agree with the Authority on the value of learning lessons from reviewing developments and approaches in other jurisdictions. In particular, we consider that lessons relevant for New Zealand can be drawn from:

- Several EDBs in Australia have implemented Dynamic Operating Envelopes (DOEs) and dynamic pricing in concert with CER Managers and retailers.[5] For example, SA Power Networks has achieved almost double the load flow on its network than it had previously estimated due to smarter management, dynamic line ratings, and access to data.
- Ofgem's decision **not** to separate DNO and DSO functions within EDBs. Ofgem found that DNOs are best placed to retain responsibility for real-time operations, having the required expertise and capabilities to deliver a safe and reliable network while growing their DSO capabilities. In contrast, it concluded that mandated separation would be costly and time-consuming, taking up significant industry, government, and regulator resources for little tangible benefit.[6]
- Australia's adoption of vertically integrated trials to incorporate CER into market operations.[7] We note that there are a range of CER projects happening across the sector in Aotearoa, but these have tended to involve a subset of industry players. Given the benefits and impacts of CER will ultimately affect a broad set of market participants, we consider there would be value in working together across the sector – including the System Operator, DSOs, retailers, CER Managers and the regulator – to undertake a vertically-integrated trial to ensure cooperation and alignment in the further integration of CER. Our view is that this is needed not just to show the technical viability (which has already been proven in trials overseas) but also

[5] https://arena.gov.au/assets/2022/03/dynamic-operating-envelope-working-group-outcomes-report.pdf
[6] https://www.ofgem.gov.uk/sites/default/files/2023-11/Future%20of%20local%20energy%20institutions%20and%20governance%20decision.pdf
[7] https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge/project-edge-reports

to demonstrate commercial viability and to inform the necessary regulatory changes required to support Aotearoa's overall ambition to decarbonise and become more sustainable.

- Experiences in South Australia with high penetration of solar PV. With regulatory support, SA Power Networks has introduced flexible export limits for rooftop solar. Customers can choose a standard export of 1.5 kW or install a smart inverter and install up to 10 kW. The network dials back the export when the network is congested but 95% of the time full export is enabled. This gives customers flexibility and increases the amount of solar exported overall.

6. Do you consider existing power system obligations are compatible with the uptake of DER and IBR-based generation?

We expect power system obligations will need to be updated as CER and IBR-based generation increases. One example of this is the availability of real-time supply and demand data on local networks. As the managers of consumption and operational data, Metering Equipment Providers (MEPs) will play a critical role in enabling the provision of such data. It will be important for MEPs to have clear obligations ensuring that the infrastructure and platforms are available to collect and provide access to data cost-effectively and efficiently and that they are appropriately incentivised to continue to invest and evolve their service offerings, including expanding communications networks to those currently unserved with a communicating smart meter so they do not miss out on the benefits that accrue.

As a market with limited competition, there may need to be greater oversight in how MEPs are delivering on this need and potentially a review of the adequacy of current regulatory arrangements. The development of an 'MEP roadmap' to guide the development of MEP technical and product capability could provide useful direction-setting to MEPs and other market participants. There may also be a need to encourage greater transparency in MEP pricing to ensure any additional services are provided cost-effectively and that consumers are not paying twice for this asset and service.

Secondly, we agree with the Authority that there are increasing expectations that industry participants and consumers can seamlessly access and share their data (in paragraph 5.26). This includes network operational data (e.g., current and voltage) as well as consumption data. In our submission to the Authority on 'Updating the Regulatory Settings for Distribution Networks' we noted (emphasis added):

> *"The focus of smart metering deployment to date has been on enabling the collection and provision of consumption data for retailers.* ***This is not necessarily the data we need to operate the network****, nor to implement some of the cost-reflective pricing advocated for by the Authority. Regulatory direction is needed to establish a standardised approach to smart meter data including the type, frequency and costs of information provided (and to ensure the equipment installed has the technical capability required)."*

We reiterate these points in the context of this consultation and stress the urgency of action required to address these issues.

7. Do you consider we need an increased level of coordination of network planning, investment and operations across the New Zealand power system?

We agree that network planning, investment and operations across the power system will need to be coordinated more effectively. This will include coordination within distribution networks as well as between distributors, and between distributors and Transpower. For example, greater coordination will be needed between CER Managers and their host EDBs to ensure the network's safety and stability.

In the future, we view the role of DSO as being increasingly similar to that of the System Operator. This will be a significant change and it will be important to ensure that the regulatory settings governing these arrangements are developed in a timely manner and in a way that maximises the benefits to consumers. This will include consideration of a range of interconnected issues, such as:

- Developing principles and rules for static and dynamic capacity allocation on distribution networks, and consequently for investment to unlock constraints that are limiting consumers' (or their agents') access to upstream markets.
- Ensuring that the pricing of network investments reflects who benefits (noting that Part 6 currently precludes the recovery of the cost of anticipatory network upgrades from distributed generation owners who would benefit from them).
- Developing a data governance framework to help facilitate efficient data handling and storage (as noted by the Authority in paragraph 5.33). This should cover sharing data with external parties (e.g., consultants seeking access to GIS and other data) as well as between Transpower and EDBs.
- Increasing integration of network planning processes. We note that, while other jurisdictions have adopted integrated systems planning, these have tended to focus on transmission planning. In New Zealand, the regulator and industry have a vision for greater integration and upstream market participation of resources on distribution networks to enable greater system efficiency and deepen competitive pressure, yet this is often implicit (at best) in system planning.
- Considering the need for – and potential approach to – future arrangements for managing congestion and allocating headroom within local networks, noting that distribution networks lack the dynamic price signals used on transmission networks to efficiently and dynamically manage and allocate network capacity. This will need careful consideration if we are to avoid underutilisation of networks (e.g., from only using conservative static limits like South Australia's export limit of 1.5 kW as mentioned above) or overbuilding of networks to accommodate increasing quantities of CER. However, there are also complexity and efficiency trade-offs to be made when considering the sophistication of signalling and the dynamism required.

While we agree overall with the need for greater coordination among network operators in the future, it is the view of NEG members that this should not entail full structural integration of transmission and distribution. We note that Transpower, as the Grid Owner, and New Zealand's 29 EDBs operate infrastructure of a significantly different scope and scale. For example, Transpower's role requires balancing demand and supply across around 280 different "nodes", whereas our low-voltage networks have at least 100 times as many nodes. Resources connected to the national system are broadly fungible from Transpower's perspective but for our network operators, location really matters. As such, we consider that there will continue to be clear and distinct roles for the Grid Owner and EDBs.

One of the first steps that the EA and industry could work on together, and learn from overseas, is getting very clear on what the new and evolving functions of the DNO and DSO are, what is needed to enable them, and what kind of co-ordination is required.

Lastly, NEG would like to note that EDBs are already contributing to effective coordination of power system operations in situations where this is needed. For example, eight upper South Island EDBs have been working together to effectively manage the peak loads on Transpower's grid in this region. This mechanism allows both the management of transmission network constraints and the rapid shedding of load in the case of a grid emergency. It means that, generally, Transpower only needs to communicate with a single EDB when managing this constraint. This scheme has been operating successfully for many years and is a practical demonstration of EDBs' willingness and capability to cooperate in the interests of wider system security.

8. Do you think there are significant conflicts of interests for industry participants with concurrent roles in network ownership, network operation and network planning?

We acknowledge the risks of conflict of interest in the sector's evolving roles. At this stage, however, we consider most conflicts of interest remain theoretical rather than having a clear and immediate impact on incentives or competition.

We note that management of the potential conflict between the roles of Grid Owner and System Operator has evolved progressively with time and as our understanding of these functions has deepened. Similarly, it is appropriate to adopt a 'watch closely' approach to managing emerging conflicts in local system operations. This might involve, for example, the Authority tracking the evolving roles and responsibilities in the sector, assessing whether conflicts are impacting consumer benefits, and responding as and when these impacts reach a threshold. This would ensure that conflicts with a tangible impact are managed while the development of new services and the delivery of other functions are not curtailed.

We note also that the same entity can undertake some network and system operations functions without giving rise to conflict-of-interest concerns. For example, EDBs in New Zealand have successfully operated ripple control for decades for the benefit of system security and their customers. This reinforces that a cautious approach to changing the regulatory settings for existing arrangements is required.

While some jurisdictions such as Australia have adopted ring-fencing provisions to deal with network owners undertaking both regulated and commercial activities, we consider the context and structure of the New Zealand market to mean that ring-fencing would not be an appropriate approach here. Many EDBs in Australia are owned by state governments and have comparatively large customer bases (and operate as monopolies). Arguably, they have disproportionate market power relative to other players in the Australian market. In Aotearoa, EDBs are a mixture of trust-owned, council-owned, and private equity-owned and generally have much smaller local customer bases. Introducing ring-fencing provisions to New Zealand EDBs would be disproportionate to those entities' market power. It would likely add a level of administrative burden that, for most, would preclude investment in anything other than core business. This could stifle innovation and hold back the transition to a lower-cost, more dynamic and more reliable electricity system.

A further key issue to consider is the current treatment of capital expenditure versus operational expenditure for price-quality regulated businesses under the Commerce Commission's Part 4 regulatory framework. Our view remains that the regulatory framework incentivises capex spending over opex. Given that the major advantage of a DSO comes from its ability to access latent capacity within the network, it is an operational optimisation rather than a physical building out or a replacement of existing network assets. This approach is stifling investment in developing the required infrastructure, capability, processes, commercial models, and operational frameworks, which are all required tools that allow a DSO to be successful. The comfort provided by these tools can then accommodate EDBs to consider a "flexibility first" approach instead of the status quo, i.e., more poles, wires, cables, etc. These regulations are currently at odds with Aotearoa's broader aspirations to decarbonise and build a resilient and sustainable electricity system. We recommend that the Authority engage with the Commerce Commission on this issue to ensure both regulatory regimes are aligned with our overall sector ambitions.

Lastly, as consumer-owned organisations, NEG members have the interests of our customers at the core of all that we do. We are committed to doing what we can to build our networks efficiently, implement the most effective solutions and keep costs down for our customers. Many of our members have demonstrated a willingness to adopt innovative approaches to supporting their customers. Consumer-owned networks are well-placed to drive forward the evolution in system operations. As such, we believe that maintaining the optionality for EDBs to participate in and lead this change will ultimately serve the interests of the sector and consumers.

9. Do you have any further views on whether this is a good time for the Authority to assess future system operation in New Zealand, and whether there are other challenges or opportunities that we have not covered adequately in this paper?

We consider the Authority's assessment of these issues timely and recommend that this work be prioritised and key foundational aspects undertaken with urgency. The sector is undergoing rapid change. Having a clear view of the drivers, challenges, and solutions will be critical to ensuring this change occurs optimally and maximises consumer benefits.

A further challenge for the Authority to consider is future responsibilities around system reliability. At present, EDBs are responsible for maintaining system reliability on their network via price-quality regulation (i.e., SAIDI and SAIFI targets). In the future, there will be a range of other market participants that will increasingly influence network reliability (e.g., CER Managers and large flexibility traders), and some may be relied on to contribute towards it. As the impact of these market participants increases, there may be a need to consider how responsibility for system reliability obligations is shared. We recommend that the Authority engages with the Commerce Commission on this issue to ensure that future regulatory settings for system reliability are fit-for-purpose, fair and in the interests of consumers.

Finally, we refer the Authority again to our DSO Evolution vision document, attached as Annex One. This sets out our vision for the evolving changes in sector roles and responsibilities and, importantly, our view on the overarching actions required of regulators and decision-makers. We would be happy to engage with the Authority further on this to ensure alignment and cooperation in supporting these exciting industry changes to deliver further benefits to Aotearoa's electricity consumers.

Please contact me if you would like to discuss this or any other aspect of our submission further.

Andrew McLeod

Chair of the Northern Energy Group

Annex One: NEG DSO Evolution

NEG

Northern Energy Group
DSO Evolution

February 2024

Electra EMPOWERING YOUR FUTURE | Northpower | the lines company keeping you connected | WAIPĀ NETWORKS | TOP ENERGY Te Puna Hihiko | vector | Counties Energy

Contents

Glossary:

C&I – Commercial and Industrial

DER – Distributed Energy Resources

DERM – DER Manager, also referred to as a flexibility provider or DER Aggregator

DG – Distributed Generation

DNO – Distribution Network Operator

DNx – Dispatch Notification

DSO – Distribution System Operator

EDB – Electricity Distribution Business

GXP – Grid-Exit Point

HW – Hot Water

ICP – Connection Point

LMP – Locational Marginal Pricing

NEG – Northern Energy Group

Prosumer – someone who produces and consumers electricity

SPD – Scheduling, Pricing, and Dispatch

SO – System Operator

TSO – Transmission System Operator

NEG Background

The Northern Energy Group (NEG) formed in 2019 around a shared belief that consumer voices need to be stronger in industry and government decision-making, and that their interests belong at the heart of our energy sector. We want to be a leading voice for change which benefits energy consumers.

The NEG is made up of seven consumer-trust owned EDBs in the North Island (Top Energy, Northpower, Vector, Counties Energy, Waipā Networks, The Lines Company, and Electra). The NEG consists of companies with a track record of taking action and being willing to give things a go. Across our group you'll see the very best in consumer engagement, generation development, future thinking, systems deployment, field operations, and engaging in practical ways with grass roots communities. Collectively we're all companies who have grown and evolved over the years.

The energy sector in Aotearoa is on the brink of enormous change and opportunity. Electrification of the economy means demand on our networks will double. De-carbonisation of the sector is crucial to climate action in Aotearoa.

Together, **nearly 40% of connections** in Aotearoa are on our networks. The majority of demand growth will also be on our networks.

Regulation has a critical leadership role to play to enable and direct the energy transition. As a collection of community trust-owned EDBs we are directly connected to our consumers and are always available to share our perspectives and expertise.

NEG
NORTHERN ENERGY GROUP

Northpower · the lines company keeping you connected · vector · Electra EMPOWERING YOUR FUTURE · WAIPĀ NETWORKS · TOP ENERGY Te Puna Hihiko · Counties Energy

DSO Evolution One Pager

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Introduction

EDBs have a critical role to play to support innovation and enable greater consumer choice. The range of ways our consumers' and other customers' expectations can be met in future will be huge. Consumers will be wanting to do new things on our networks, as will investors, aggregators, and retailers. We will too.

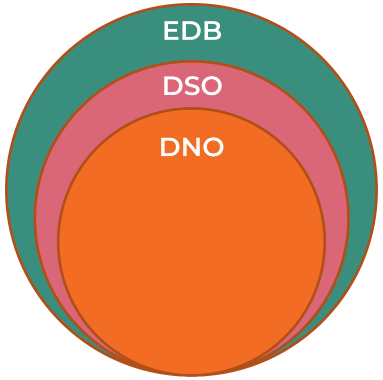
Active DER, if orchestrated well, can play a key role in minimising our network costs, including network integration and connection costs.

Increasing tension between proposed market solutions, the certainty EDBs require for network planning, EDBs' legislated requirements for power quality and reliability, and the physics of running our networks and keeping the system in balance, poses significant risks to the overall operation of the network and keeping the lights on for our consumers. We have seen this play out on the grid at times during grid emergencies. We consider EDBs will need additional controls, similar to those Transpower currently has for the national grid, to mitigate this risk.

What is a Distribution System Operator (DSO)?

Today, EDBs are the DNO with responsibilities for the safe, secure and reliable distribution of electricity to our connected customers.

Tomorrow, along with our traditional distribution network operator (DNO) responsibilities, as DSOs we will play the role of 'energy orchestrators' – operating an open and inclusive participatory service.



Activities requiring EDB collaboration with regulators and Government decision makers:

1. Ensure regulations for EDBs remain fit-for-purpose in a world with market-based DER aggregation
2. Establish minimum technology and communication standards
3. Develop a framework for the implementation and operationalisation of dynamic capacity management on distribution networks
4. Ensure all DER Managers have agreed operational protocols with their host networks
5. Clarify the ability of DSOs to orchestrate response of DER Managers to system emergencies (national and local)
6. Amend distribution pricing rules to ensure parties who benefit commercially from network capacity fund it
7. Enable commercial access to network operational data

NEG DSO Principles

Consumers and communities belong at the heart of our energy sector. We have developed and adopted the following principles to guide how each of our member networks are pursuing and considering DSO functions:

- Start with consumers
- Reliability is fundamental
- Standardisation across the system
- Enabling system transition – enabling new market growth
- Regulatory collaboration and progress
- No-regrets capabilities

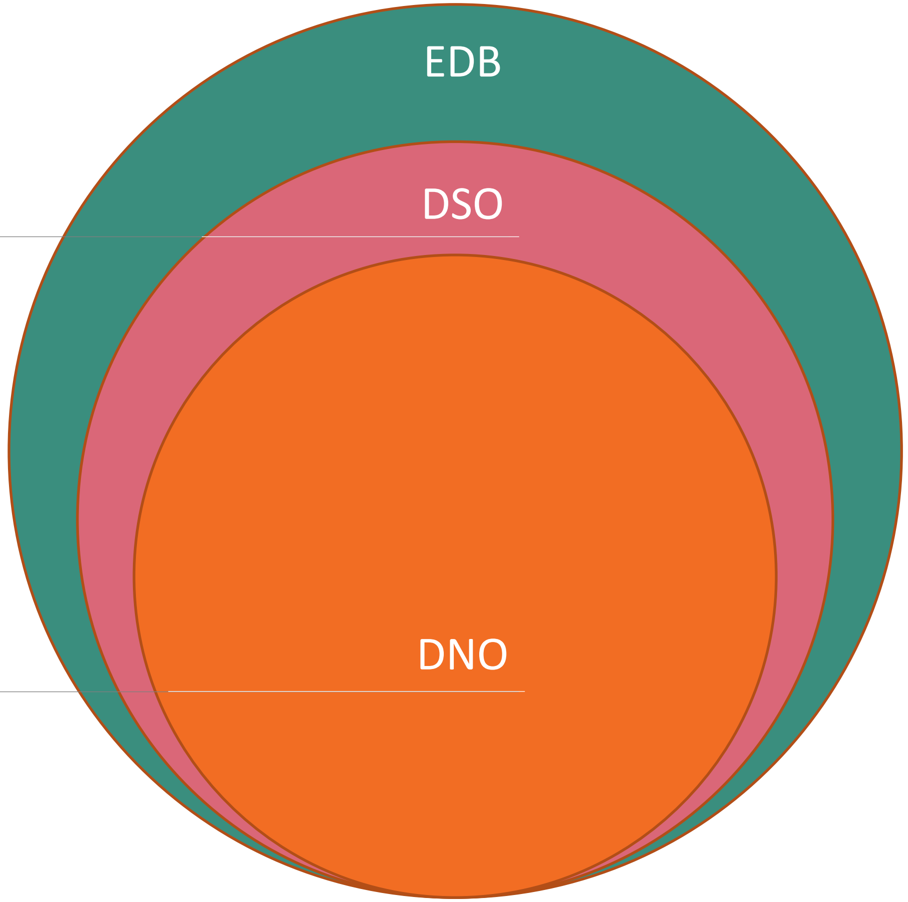
Phase of DER market development	Status Quo	Phase 1 – Enabling	Phase 2 – Procurement
	Limited relationship and **interaction** between DER Managers and EDB	DSO **enables** safe DER management and 'value stacking' by emerging DER Managers	DSO begins to **procure** dedicated services and solutions from DER Managers

What is a Distribution System Operator (DSO)?

Tomorrow, along with our traditional distribution network operator (DNO) responsibilities, as DSOs we will play the role of 'energy orchestrators' – operating an open and inclusive participatory service, being the primary entry point into the dynamic distribution system for new actors such as prosumers, EV charging and demand-side managers and aggregators

The DSO will foster engagement and interaction with stakeholders, unlocking a new flexible system that creates new opportunities for innovative energy services and shared value

Today, EDBs are the DNO with responsibilities for the safe, secure, and reliable distribution of electricity to our connect customers. As New Zealand electrifies, this role will become more important than ever.



Key notes

The DSO will support safe, secure, and reliable operation of the network, orchestrating resources at the local distribution level.

Evolving functions will include:

- managing and coordinating local demand and distributed generation
- acting as a neutral facilitator – providing a local capacity allocation and management service for the parties managing DER on their networks
- enabling easy and flexible access to the distribution network

While advanced DSO functions are a logical evolution of EDBs' existing operations, different EDBs will likely choose different ways of meeting these needs. We imagine larger EDBs will develop and provide DSO functionality themselves, and potentially share these capabilities with smaller EDBs.

Context and assumptions

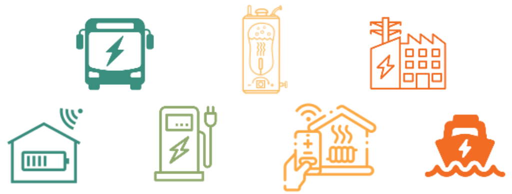
1. EDBs have a critical role to play to support innovation and enable greater consumer choice. The range of ways our consumers' and other customers' expectations can be met in future will be huge. Consumers will be wanting to do new things on our networks, as will investors, aggregators, and retailers. We will too.

2. If orchestrated appropriately, active DER (also known as "flexibility" resources), such as smart EV chargers or smart HW control, and other remotely-manageable devices, can play a key role in minimising our network costs, including network integration and connection costs.

3. For the near term at least, many aggregators (whom we refer to as "DER Managers", as their core role is managing consumers' DER) will be primarily focussed on meeting consumers' needs, first and foremost. They will also build portfolios of active DER, including smart chargers, industrial loads, home batteries, and smart HW, to provide services to Aotearoa's wholesale markets – accruing value to those DER assets and their owners.

4. This includes larger-scale DG – e.g. hydro, wind, solar. Their business cases are focused primarily on wholesale market revenues, but they still rely on our networks as their channel to market – from the local connection point to the point of connection with the national grid.

5. Some consumers, and other parties, will be able to provide EDBs with services to help us manage constraints on our networks. Along with flexible connection management for large consumers like bus-charging depots, local flex procurement is beginning to be pursued to manage specific constraints on EDBs' networks (e.g. Warkworth, upper Clutha, Whangamatā). In these cases, the EDB works with and contracts directly with DER Managers for a service – potentially just for a defined period, or permanently.



6. This is all aligned with the market regulator's stated objective to unlock or "stack" as much value from DER as possible, from as many sources, in order to minimise whole-of-system costs to consumers.

7. Increasing tension between proposed market solutions, the certainty EDBs require for network planning, EDBs' legislated requirements for power quality and reliability, and the physics of running our networks and keeping the system in balance, poses significant risks to the overall operation of the network and keeping the lights on for our consumers. We have seen this play out on the grid at times during grid emergencies, and consider EDBs will need additional controls, similar to those Transpower (as TSO) currently has for the national grid, to mitigate this risk.

8. We think we can leverage our deep experience and capability to play a key role in enabling great outcomes for consumers. EDBs already play the leading role in managing DER on their networks (e.g. ripple control, network batteries). Some EDBs will want to continue to playing this role, potentially evolving to become the "default (or backstop) DER Manager" on the network. This can ensure that consumers who choose to have their devices managed can find at least one party equipped to do so.

9. While reliability will become even more critical, it will not be efficient or cost-minimising for EDBs to build networks large enough to enable *all* possible future flow scenarios. The DSO and TSO will become increasingly reliant on the actions of DER to keep the lights on. Enabling that will help to minimise network build and greater affordability for consumers.

Context and assumptions

10. On the transmission system, in emergency situations the TSO has significant powers to manage resources and maintain the safety of the network. As our reliance on DER increases, we will need a similar remit.

11. Day-to-day, however, the TSO's flow/constraint management role is played by the security-constrained, economic dispatch in the spot market, via the Scheduling, Pricing and Dispatch (SPD) optimisation platform. SPD ensures generation volumes and flows stay within transmission constraints. Signals are provided to all users by the locational marginal pricing (LMP) that results. Dispatch is overseen and augmented by the TSO, as and when required (e.g. constraining "on", grid emergency management).

12. Many of the DER Managers on our networks will be primarily responding to those wholesale signals. In April 2023, the EA introduced the "dispatch notification" (DNx) product within real-time pricing, to enable more demand response and other DER from aggregators to offer directly into the wholesale markets and be dispatched by the TSO, at the GXP.

13. However, in dispatching resources and responding to SPD and the LMPs, the TSO, and DER Managers, currently pay little, if any, attention to the local constraints and conditions on distribution networks – nor do they have any visibility of these. Average loss factors on distribution networks, used for financial settlement, are unlikely to accurately reflect actual losses at any location or point in time. Local thermal and voltage constraints, in particular, could significantly limit what actions DER Managers can take safely, and when. Response to signals could create un-manageable secondary peaks.

14. Increasingly, EDBs will therefore need to coordinate the dispatch by the TSO with our own network needs. Initially this will be focused on ensuring the TSO's dispatch instructions, and other DER operations, stay within our network constraints, but in time will also include dispatching some DER ourselves. In the absence of dynamic, granular LMP pushing deeply onto our distribution networks, the DSO role will need to be more active.

15. DER Managers providing wholesale services will therefore need to understand any constraints on our networks between their connection point (ICP) and the GXP. DER Managers may need to limit their offers to the TSO at times, as dispatch by the TSO at their full, nameplate capacity may not be physically possible, given the conditions on the local network. Reliance by the TSO on actions by DER Managers that are not technically feasible could create major issues for system security.

16. This will necessitate the need for EDBs to have a platform to communicate the feasible operating ranges available to each DER, either directly to the DER at the ICP, or to the DER Manager responsible (which could be the EDB). Each DER's operating 'envelope' could either be static, or could change dynamically, based on network conditions – hence the 'dynamic' operating envelope(DOE) concept.

17. In the NZ context, initially the EDB's existing core, primary roles will expand and evolve, requiring active interaction with DER Managers to:

A. actively manage constraints and allocate available capacity on the distribution network, in light of:
  - consumers' desire to have the lights stay on, and
  - DER Managers' desire to maximise value from "stacking" service delivery across local and national markets

B. respond to system emergency events (from the very local, such as storms and car vs pole, to nationwide)

18. In time, DSOs will also need to develop portfolio management and network optimisation capability, with a focus on procurement, coordination and dispatch of DER Managers' flexible resources – who will be providing services to the EDB, thereby helping to manage constraints on the network.

NEG DSO Principles

Consumers and communities should be at the center

Start with consumers

Our future energy system offers the potential for greater consumer choice and value. Continuing to meet the needs of our consumers and other customers will require flexibility for the role of EDBs to evolve over time as technologies and consumer preferences also evolve. This includes the role of EDBs in managing DERs directly and engaging with DER Managers to help them meet consumers' needs. EDBs will need to consider different international models and pathways.

Reliability is fundamental

Ensuring whole system reliability is fundamental to delivering sustainable consumer choice. Networks need to be able to manage load to the extent they can protect system security and reliability. EDBs must have the ability to orchestrate DERs to manage emergencies on their networks and insulate necessary operations from DER Managers who don't have the same obligations to keep the lights on. Obligations on EDBs must remain fit for purpose in this future world.

Standardisation across the system

This system-to-system integration – i.e., between the DSO, DER Managers and the SO – will be enabled by the right standards. EDBs will need to be outward-looking, with a focus on pricing and purchasing, new business models, and enabling the simplest interface with consumers and other market participants. We will need to decide what will require human interaction and what can be left to monitor and automate through AI. EDBs will need to establish and consistently adhere to legitimate standards between their DSO and DNO functions.

Enabling system transition – enabling new market growth

Along with regulatory alignment, the role of EDBs will evolve. We have a leading role in the transition to, and operation of, a DSO. EDBs will have an enhanced function in addition to ever-improving DNOs. We support the ENA Network Transformation roadmap, and the work of the Future Networks Forum, and see this NEG DSO value-stream as both building on these and providing critical input to future direction. Evolving the role of the EDB will in turn enable the emergence of new markets and a more complex and valuable ecosystem.

Regulatory collaboration and progress

We bring extensive network experience and an unwavering commitment to do right by our consumers. We need regulatory leadership regarding standards for DER technology and communications protocols, opt in/out mechanisms for consumers, minimums, contracts, safety measures, consumer expectations, EV charging, dynamic metering and access to operational data. We encourage this strategic direction at a high level – to be incorporated into our direction and KPIs.

No-regrets capabilities

We want to be able to move quickly at the right time, acknowledging that there are significant differences among our networks. This requires an approach of leveraging and sharing capabilities efficiently, to respond to the unique challenges and opportunities on each EDBs' network.

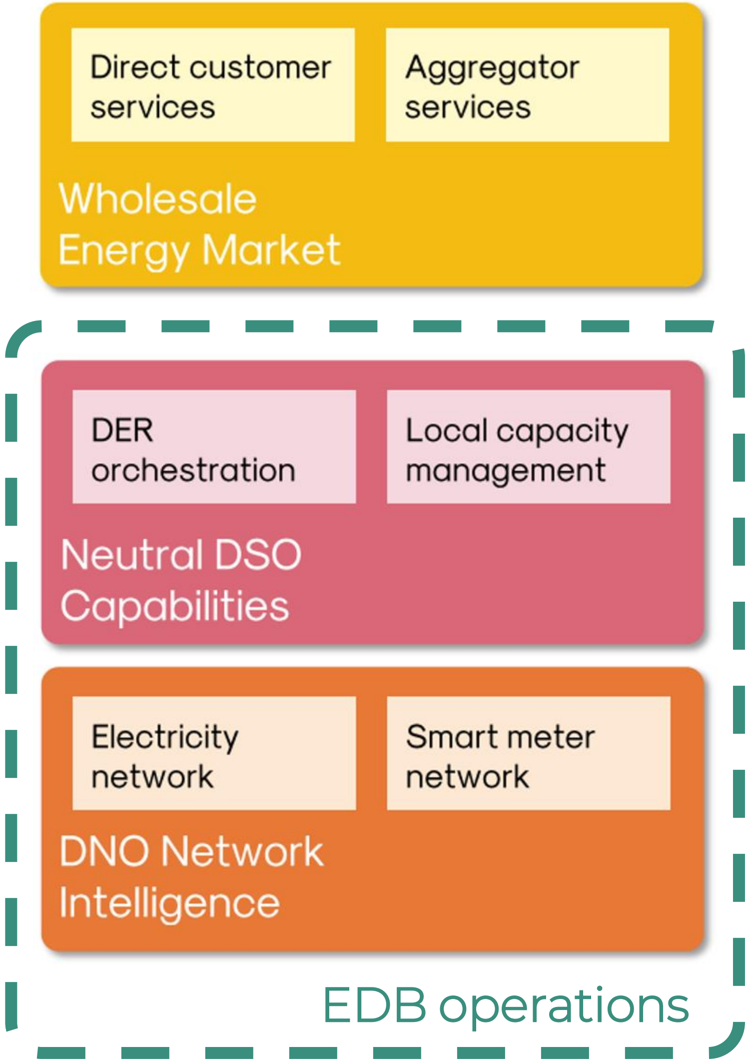
DSO Operating Model

DSO sits between the network and the national wholesale markets

Detailed diagrams of the relationships and functions of the different actors within the electricity system during the DSO Evolution are provided as an appendix.

The primary function of the layer between the market and DNO is **dynamic management of capacity and orchestration of DERs (and DER Managers)**.

The market and network functions rely on this layer for safe and secure DER management.



Eventually both core functions in this layer will be carried out by the DSO.

However, during the first phase of the transition (which we call "enabling") the DSO will be responsible largely for local capacity management to guide DER Managers. This will be an essential role for **all** EDBs in Aotearoa.

From the second phase of the transition onwards ("procurement")* the DSO will begin to procure services directly from DER Managers, enabling DER orchestration.

Management of local and national emergencies via DER Managers will be a critical enduring capability requirement of the DSO.

*Some networks will have different use cases – timing of procurement and enabling capability development will vary for different networks, and could be reversed.

Evolving System Inter-relationships

The DSO will safely unlock and enable whole-of-system value from de-centralised resources

	Status Quo	Phase 1 – Enabling	Phase 2 – Procurement
Phase of DER market development	**Limited relationship** and **interaction** between DER Managers and EDB	DSO **enables** safe DER management and 'value stacking' by emerging DER Managers	DSO begins to **procure** dedicated services and solutions from DER Managers
Active DER Managers in this phase	• EDBs (hot water, network batteries, other DER) • C&I consumer process managers • DG owners (e.g. hydro, wind, solar)	• As per status quo, plus: • Retailers and other aggregators (smart hot water, smart EV charging, e-buses, home batteries, etc)	• As per phase 1, but in even greater numbers and with a wider range of business models
Main DER management activities	• EDBs utilising DER for network management (i.e. *utility-led* mode) • DG owners optimising wholesale market revenues – either *passive* response to spot prices, or *active* participation in the market ('active' = offered to, and dispatched by, the TSO)	• As per status quo, plus: • New DER Managers responding to wholesale prices and TOU distribution prices (i.e. *price-led* mode). Either active (offered) and/or passive (non-offered). • New DER Managers managing 'flexible' network connections (e.g. bus charging)	• As per phase 1, plus: • DER Managers operating under market-procured contract to the DSO (EDB) for specific services, including investment deferral (i.e. *market-led / contract-led* mode)
Main DSO activities: • **local capacity management** • **DER orchestration**	• EDB and non-EDB DER Managers operate independently of each other • Limited active relationship between DSOs and DER Managers; EDBs may have little awareness of DER Manager presence • DER Managers have little, if any, awareness of network capacity constraints	• DSO will enable safe DER Management and value-stacking by providing static or dynamic operating envelopes to DER Managers • DSO will orchestrate DER response to network and grid emergencies • Over time, more sophisticated time-varying distribution pricing could emerge	• As per phase 1, plus: • The DSO will procure (via contract) specific services and specific responses from DER Managers, including investment deferral (non-wired alternatives) and ancillary (network support) services. • Over time, more sophisticated market and pricing mechanisms for networks could emerge

See Appendix for more detailed relationship diagrams

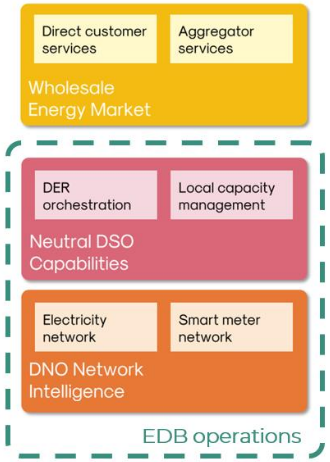
Simplified relationship diagram: 'Phase 2 – Procurement – DSO procures from DER Managers'

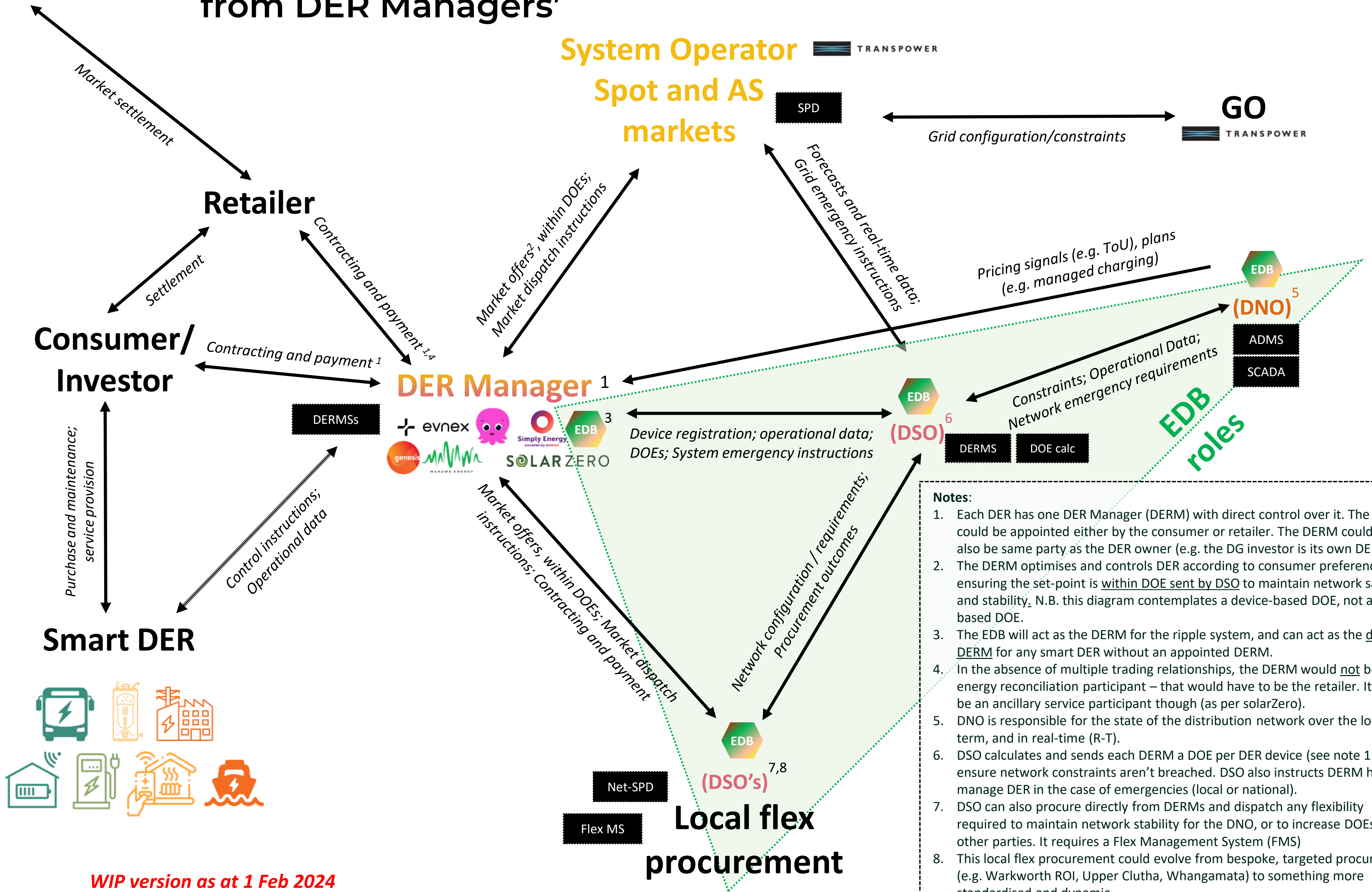
The colours from the DSO Operating Model (slide 9 and below) have been used as a key.

DNO is orange

DSO is pink

Wholesale market is yellow





Notes:

1. Each DER has one DER Manager (DERM) with direct control over it. The DERM could be appointed either by the consumer or retailer. The DERM could also be same party as the DER owner (e.g. the DG investor is its own DERM)
2. The DERM optimises and controls DER according to consumer preferences – ensuring the set-point is within DOE sent by DSO to maintain network safety and stability. N.B. this diagram contemplates a device-based DOE, not an ICP-based DOE.
3. The EDB will act as the DERM for the ripple system, and can act as the default DERM for any smart DER without an appointed DERM.
4. In the absence of multiple trading relationships, the DERM would not be an energy reconciliation participant – that would have to be the retailer. It could be an ancillary service participant though (as per solarZero).
5. DNO is responsible for the state of the distribution network over the long term, and in real-time (R-T).
6. DSO calculates and sends each DERM a DOE per DER device (see note 1), to ensure network constraints aren't breached. DSO also instructs DERM how to manage DER in the case of emergencies (local or national).
7. DSO can also procure directly from DERMs and dispatch any flexibility required to maintain network stability for the DNO, or to increase DOEs for other parties. It requires a Flex Management System (FMS)
8. This local flex procurement could evolve from bespoke, targeted procurement (e.g. Warkworth ROI, Upper Clutha, Whangamata) to something more standardised and dynamic.

WIP version as at 1 Feb 2024

Success Criteria

What we're doing and where Government collaboration is required

Each of our member networks needs a clear pathway for necessary functions that is standardised and transparent but allows each EDB to move at the appropriate time. Across our networks we will have significantly different DERs/EV uptake, rate and timing of population growth, network realities, and equity considerations.

These are the core DSO functions NEG members are pursuing:

- Whole system orchestration
- Capacity allocation and management
- Asset and operations management
- Flexible systems and flexible network connections
- Digitalised operations and communications interfaces and standards

We are also participating in the corresponding workstreams of ENA's Future Networks Forum, which are aiming to deliver nationally-aligned solutions.

Activities requiring EDB collaboration with regulators and Government decision makers:

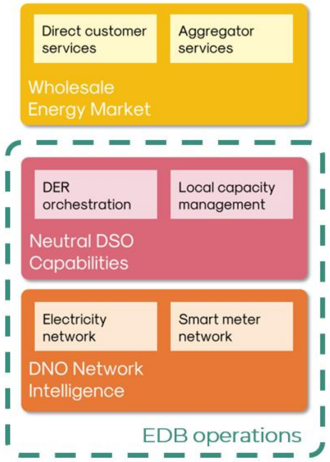
1. Ensure statutory regulations for EDBs (e.g. quality and reliability) remain fit-for-purpose in a world with market-based DER management
2. Establish minimum technology and communication standards to enable smart system management and interaction, and provide the allowances to invest in this capability (and the data required)
3. Develop – potentially through 'sandboxing' – a framework for the implementation and operationalisation of dynamic capacity management on distribution networks, including principles for how capacity is allocated between system users and the requisite communication protocols
4. Ensure that all parties managing DER on behalf of consumers and investors (DER Managers) have agreed operational protocols with their host networks, formalising the requirement on the DER Manager to manage within the operational limits of the network
5. Clarify the ability of DSOs to orchestrate the response of DER Managers to system emergencies – from the very local (e.g. car vs pole) to nationwide
6. Amend distribution pricing rules to ensure parties who benefit commercially from network capacity fund it
7. Enable commercial access to network operational data and ensure the minimum level of metering capability necessary to deliver it

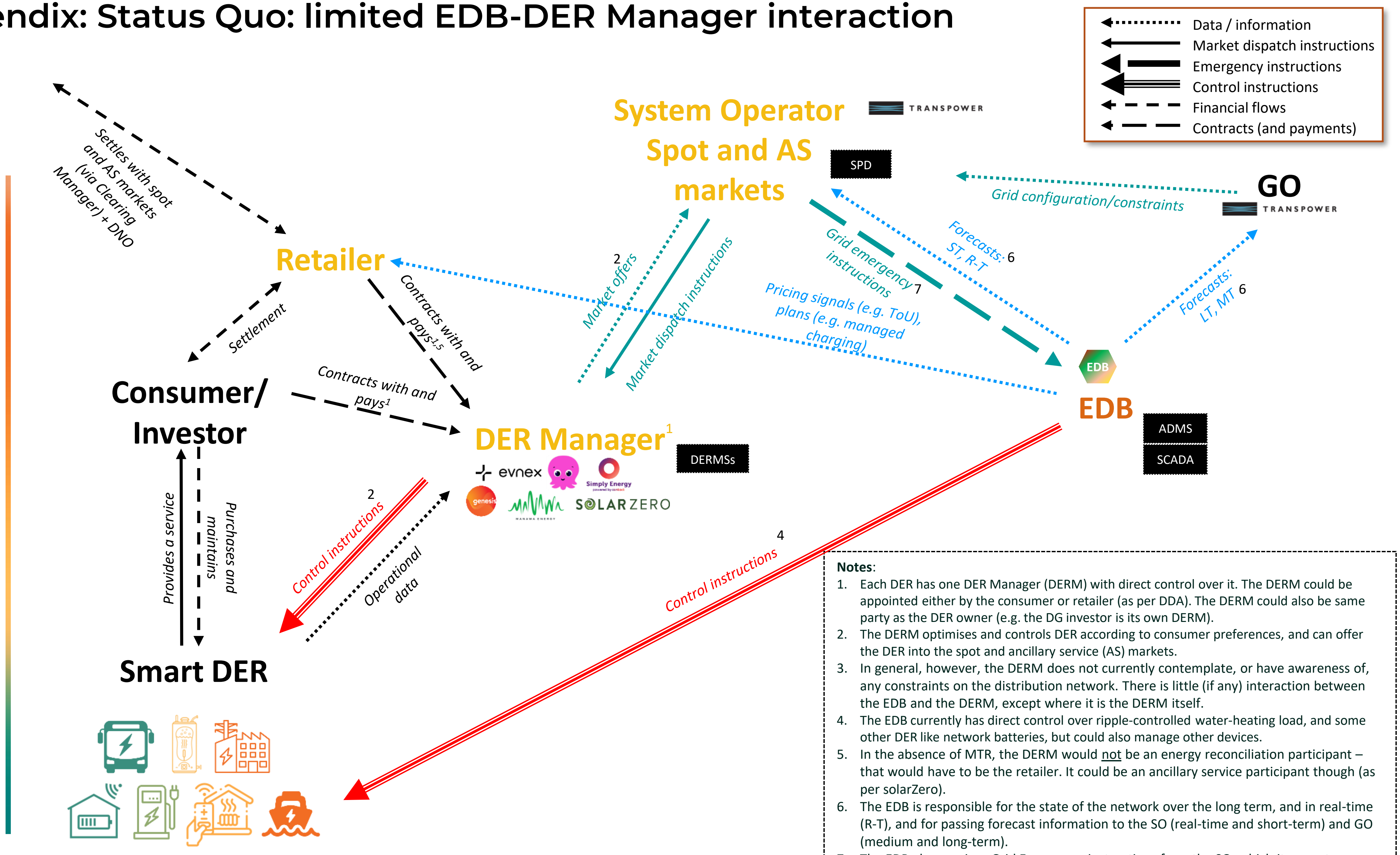
Appendix: Status Quo: limited EDB-DER Manager interaction

The colours from the DSO Operating Model (slide 9 and below) have been used as a key.

DNO is orange

Wholesale market is yellow





Notes:

1. Each DER has one DER Manager (DERM) with direct control over it. The DERM could be appointed either by the consumer or retailer (as per DDA). The DERM could also be same party as the DER owner (e.g. the DG investor is its own DERM).
2. The DERM optimises and controls DER according to consumer preferences, and can offer the DER into the spot and ancillary service (AS) markets.
3. In general, however, the DERM does not currently contemplate, or have awareness of, any constraints on the distribution network. There is little (if any) interaction between the EDB and the DERM, except where it is the DERM itself.
4. The EDB currently has direct control over ripple-controlled water-heating load, and some other DER like network batteries, but could also manage other devices.
5. In the absence of MTR, the DERM would not be an energy reconciliation participant – that would have to be the retailer. It could be an ancillary service participant though (as per solarZero).
6. The EDB is responsible for the state of the network over the long term, and in real-time (R-T), and for passing forecast information to the SO (real-time and short-term) and GO (medium and long-term).
7. The EDB also receives Grid Emergency instructions from the SO, which it can act upon with Control instructions to DER and feeders. There is currently no mechanism for EDBs to coordinate with DERMs in emergencies.

WIP version as at 1 Feb 2024

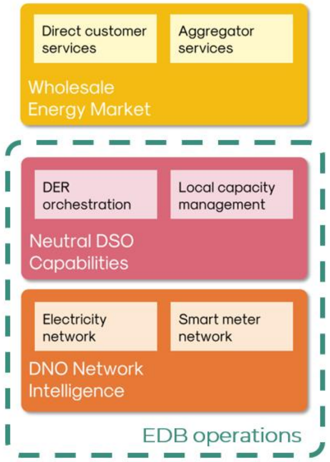
Appendix: Phase 1 – Enabling: DSO enables safe DER management via DOE

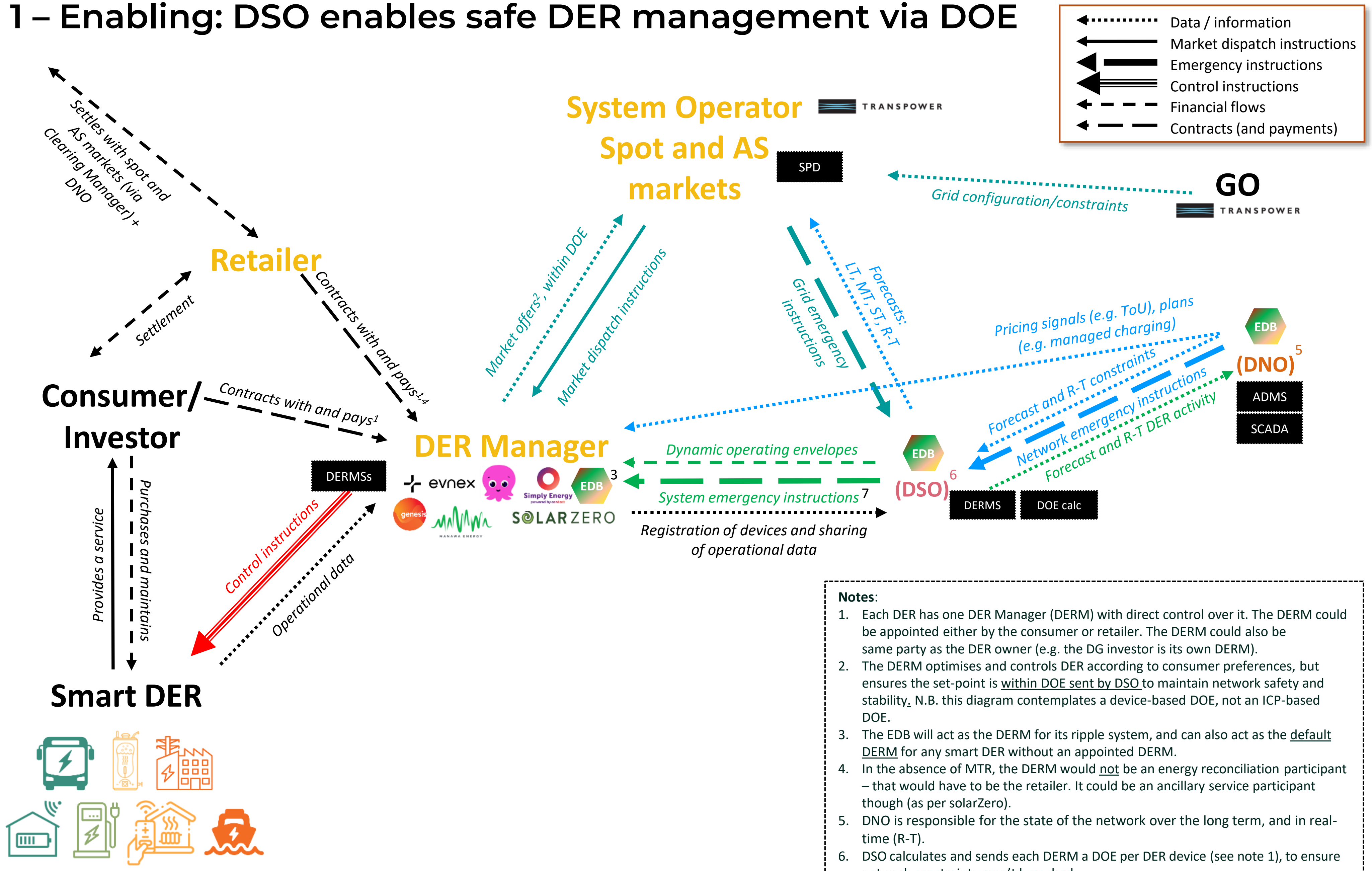
The colours from the DSO Operating Model (slide 9 and below) have been used as a key.

DNO is orange

DSO is pink

Wholesale market is yellow





Notes:

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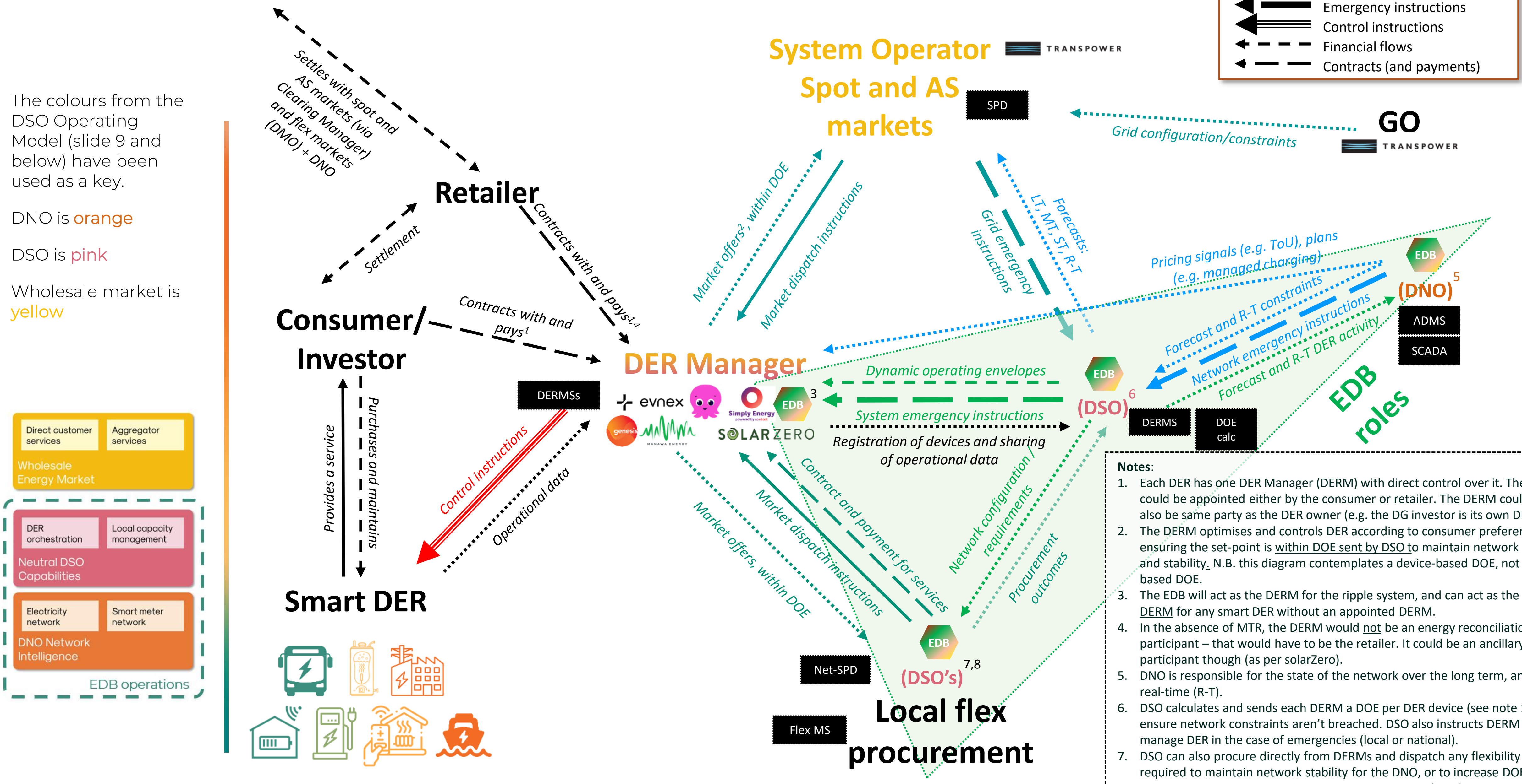
2. The DERM optimises and controls DER according to consumer preferences, but ensures the set-point is within DOE sent by DSO to maintain network safety and stability. N.B. this diagram contemplates a device-based DOE, not an ICP-based DOE.
3. The EDB will act as the DERM for its ripple system, and can also act as the default DERM for any smart DER without an appointed DERM.
4. In the absence of MTR, the DERM would not be an energy reconciliation participant – that would have to be the retailer. It could be an ancillary service participant though (as per solarZero).
5. DNO is responsible for the state of the network over the long term, and in real-time (R-T).
6. DSO calculates and sends each DERM a DOE per DER device (see note 1), to ensure network constraints aren't breached.
7. **DSO also instructs DERM** how to manage DER **in the case of emergencies** (both local and/or national events).

WIP version as at 1 Feb 2024

Appendix: Phase 2 – Procurement: DSO procures from DER Managers



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1. Each DER has one DER Manager (DERM) with direct control over it. The DERM could be appointed either by the consumer or retailer. The DERM could also be same party as the DER owner (e.g. the DG investor is its own DERM)
2. The DERM optimises and controls DER according to consumer preferences – ensuring the set-point is within DOE sent by DSO to maintain network safety and stability. N.B. this diagram contemplates a device-based DOE, not an ICP-based DOE.
3. The EDB will act as the DERM for the ripple system, and can act as the default DERM for any smart DER without an appointed DERM.
4. In the absence of MTR, the DERM would not be an energy reconciliation participant – that would have to be the retailer. It could be an ancillary service participant though (as per solarZero).
5. DNO is responsible for the state of the network over the long term, and in real-time (R-T).
6. DSO calculates and sends each DERM a DOE per DER device (see note 1), to ensure network constraints aren't breached. DSO also instructs DERM how to manage DER in the case of emergencies (local or national).
7. DSO can also procure directly from DERMs and dispatch any flexibility required to maintain network stability for the DNO, or to increase DOEs for other parties. It requires a Flex Management System (FMS)
8. This local flex procurement could evolve from bespoke, targeted procurement (e.g. Warkworth ROI, Upper Clutha, Whangamata) to something more standardised and dynamic.

WIP version as at 1 Feb 2024