Submission to the Electricity Authority

On the discussion paper Updating the Regulatory Settings for Distribution Networks: Improving competition and supporting a low emissions economy

28 September 2021

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Introduction

Transpower supports the Electricity Authority's proactive endeavours to develop a future-proof electricity market that will benefit New Zealand.

In Whakamana i Te Mauri Hiko, we highlighted a future where Distributed Energy Resources (DER) play an important role in achieving New Zealand's decarbonisation ambitions. This is aligned with the view of the Electricity Authority presented in the consultation document, and it is consistent with the international evidence and other examples that we will be highlighting in our responses.

This body of work illustrates that a well-designed, competitive market is key to maximising consumer benefits, and the integration and efficiency of the electricity system. If done well, Sapere's study shows that the potential benefits to New Zealand are in the order of billions of dollars.

At Transpower, in both our roles as Grid Owner and System Operator, we believe that unlocking these consumer benefits is something worth pursuing. Anticipating the needs of New Zealand's future electricity market will get us ahead of the curve to enable the entire electricity industry to deliver benefits to New Zealand.

In this spirit, although this consultation is centred on the distribution sector, we have taken the initiative to highlight areas where regulatory changes would positively impact the overall system (e.g. greater visibility of DER connected to the networks), or where those changes could also facilitate the connection of DER on the transmission network (e.g. where Part 6 of the code is applicable).

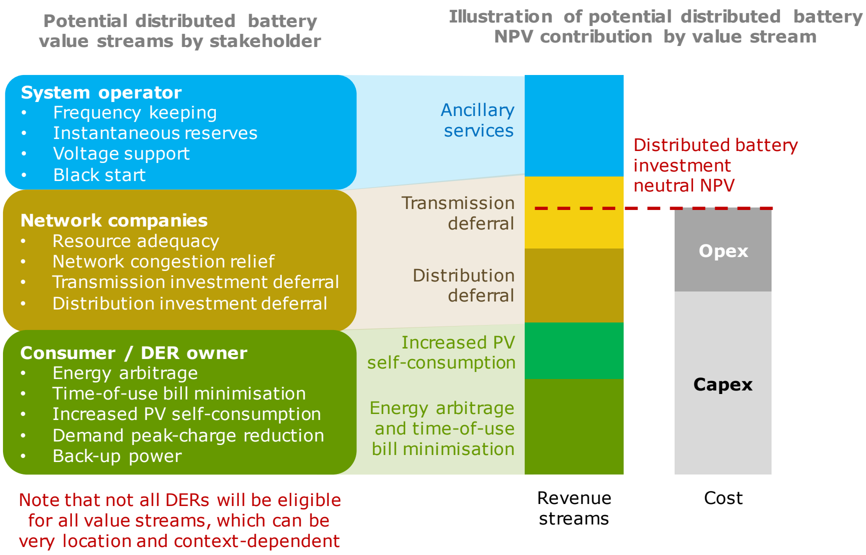
We have also attached a copy of our July 2021 submission to Wellington Electricity's EV Connect project as an Appendix. It contains more insights of our investigations into flexibility operating models used internationally.

Flexibility markets are an effective way to unlock the value offered by DER to consumers and the electricity system as a whole.

Whakamana i Te Mauri Hiko also highlighted that demand-side management was a key area of change necessary to efficiently meet our energy needs. This outlined the importance of the value stack for providing consumers with the economic benefit that could be realised by providing valued services to the electricity system. Since then we have learnt from other countries how these value stacks can be unlocked. This is illustrated in figure 1, adapted from the work previously published by the Rocky Mountain Institute, which outlines the full value that DER can deliver in a well-designed market.

Sapere's analysis, published alongside this consultation document, reinforces this principle, and values the entire stack at several billions of dollars out to 2050.

Figure 1: Illustration of the DER Value stack



The attached Wellington Electricity's EV connect project submission provides further insights into the value stack and how it can best be enabled.

Delivering the value stack requires a team effort. Different stakeholders need to enable flexibility traders to access different markets.

The value stack cannot be fully realised without the involvement of several stakeholders. In Table 1 below, we want to start the discussion about who the potential value stream enablers could be in the New Zealand context. Value stream enablers in this context are the parties who enable access to a flexibility market. This table reflects some examples of the flexible services we have procured (listed in our response to question 10) and our observations:

- As a Grid Owner, we continue to proactively look for non-network alternatives to support grid investment deferral (item #3 in Table 1).
- As a System Operator, we procure flexibility through ancillary services such as frequency keeping (item #2 in Table 1).
- In the distribution sector, Aurora has entered a contract with a flexibility trader to realise distribution deferral, while Powerco has run several competitive tenders to procure flexibility (item #6 in Table 1).

It is essential to ensure that stakeholders do not lock consumers from accessing other parts of the value stack. Contractual arrangements with flexibility traders, or connection constraints to the electricity network should not become a barrier to value realisation.

Table 1: Value streams enablers

Value Stream	#	Accessible through[1]	Value Stream Enabler
Ancillary services	1	Reserves market	EA / System Operator
	2	Frequency keeping market	EA / System Operator
Transmission deferral and congestion management	3	Grid Owner flexibility procurement	Grid Owner
	4	Nodal pricing	EA / System Operator
	5	Transmission pricing	EA / Grid Owner
Distribution deferral and congestion management	6	Distribution Network Owner flexibility procurement	Distribution Network Owner
	7	Distribution tariffs	EA / Distribution Network Owner
Energy services	8	Direct wholesale participation	EA / System Operator
	9	Indirect wholesale participation	EA / System Operator[2]
	10	Self consumption	Retail provider[3]

1. Value streams can be accessed via different markets through direct participation or via a flexibility trader who can value stack on the consumers' behalf.
2. Indirect wholesale participation can occur when a DER is used for either demand response or generation but is not bid into the market. This can be achieved via a flexibility trader who can value stack on the consumers' behalf. The EA and the System Operator still enable the value stream as it is the wholesale market price signal that is being responded to.
3. Where a consumer uses self-consumption, it is often to avoid retail charges. The Retail provider is considered the value stream enabler due to their tariff acting as the price signal which a direct participant or flexibility trader would respond to on the consumers' behalf. When this occurs, it can lead to access to components of the value stack beyond energy services (i.e. avoiding volumetric network charges).

We have the opportunity to harness latent DER already installed to accelerate the impact and adoption of flexibility services.

One of the keys to successful flexibility markets will be having enough available DER to supply the flexibility service required and be competitive against traditional energy, ancillary service or network solutions. In the context of network solutions, this was one key learning of our Demand Response programme and recommendation #10 of the Innovation and Participation Advisory Group (IPAG) review of the programme for the Electricity Authority.

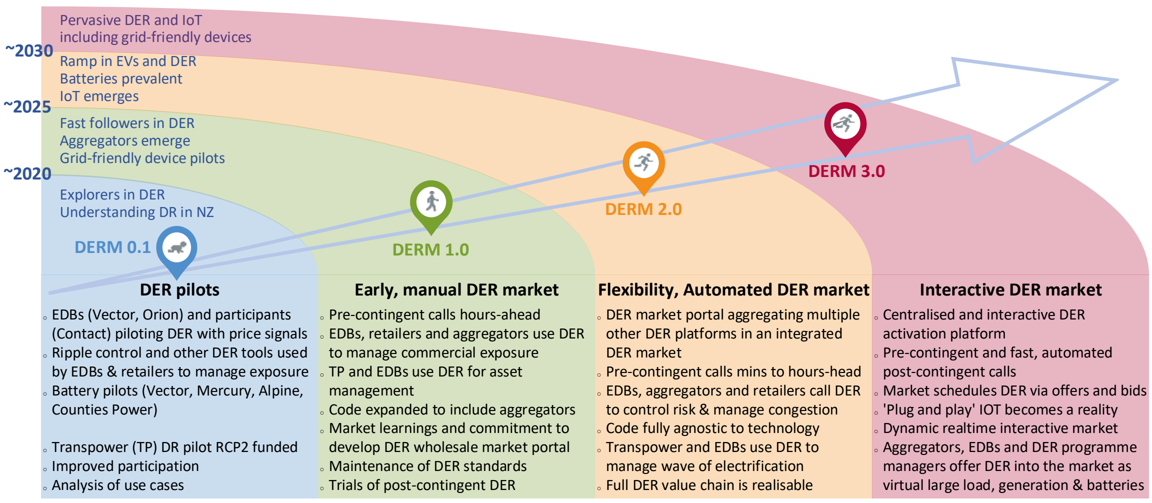
We believe that there is a large number of devices already connected to electricity networks that could offer flexibility services if the right markets and arrangements are in place. For example, if existing residential heat pumps are retrofitted with smart controllers adjusting the temperature, this could quickly unlock more than ~1m devices capable of demand response across the country. This would represent over 1 GW of flexibility (1 kw per unit) that could be provided without any perceptible difference to consumer service as it would not require having to turn off any heat pumps.

In the United Kingdom, we have seen Electricity Distribution Businesses (EDBs) using flexibility to defer capital investment. As of July 2021, more than 1.5GW of flexibility services were contracted by network companies, ultimately reducing the costs to consumers. We believe this use case is also applicable to New Zealand.

To incentivise the uptake of DER and the progressive enablement of the value stack, the flexibility market will need to evolve through time.

The task at hand to create an optimised flexibility market is significant, but we do not need to wait to commence its development. Figure 2 below illustrates how a DER market could grow and mature as DER become mainstream technology. Each phase is an opportunity to increase the capability of the market and unlock more layers of the value stack.

Figure 2: Maturity evolution of flexibility markets



Experimentation and collaboration between industry and both market and economic regulators will be key to defining what's right for New Zealand.

Flexibility markets are still relatively new. In our review of examples from other jurisdictions, the common key success factor for establishing flexibility markets that meet the needs of customers and industry was the establishment of industry working groups that brought together industry players, market participants and regulators and adopted a "learning by doing" approach. Without a coordinated, cross-sector approach, like a flexibility industry working group, it is unlikely that both consumers and industry will be able to realise the value that flexibility markets can offer.

If as an Industry, we believe that the billions of dollars of value are worth chasing, we need to work together to coordinate and optimise the entire supply chain. Transpower is up for the challenge of working collaboratively with the sector to make this happen.

We welcome the opportunity to share our insights. If you would like to know more, please get in touch.

Transpower continues to present the learnings from both its practical experience and research on flexibility markets in different forums (including the Industry Participation Advisory Group), or through publicly available submissions like this one or the attached Wellington Electricity's EV connect project submission. If you have any questions about our submission, please contact Nicolas Vessiot (Nicolas.vessiot@transpower.co.nz) in the first instance.

Yours Sincerely,

Richard Hobbs, General Manager Strategy and Customer

Response to consultation questions

Section 4: Information on power flows and hosting capacity

Question 1: Access to information

Have you experienced issues relating to a lack of information or uneven access to information?

No response

Question 2: Information for informed decision making

What information do you need to make more informed investment and operation decisions?

Information sharing between EDBs and flexibility traders needs to be extended to the industry. If the question focused on flexibility traders needing to understand EDBs constraints and operational envelopes to develop their services, there is a need for EDBs in their network manager role, and flexibility purchasers (including EDBs) to have information on the volume and nature of DER on the distribution networks.

This information is important for decision making from both of Transpower's role as Grid Owner and System Operator.

As Grid Owner, we use demand forecasts from distribution businesses to feed into Transmission Pricing Methodology (TPM) calculations and to inform required grid investments. Accurate demand forecasts will require distribution businesses to have a level of understanding of the volume and nature of existing and anticipated new DER on their networks.

As System Operator, we require an understanding of the aggregate level of DER on the electricity network to maintain security and operate the grid 24/7. We discuss the impact high levels of DER can have on power quality, system stability and security later in this response.

Having more visibility on DER can help to quickly and efficiently assess the potential for procuring flexibility services as energy and ancillary services (as System Operator) or as non-network alternatives (as Grid Owner).

Sourcing this information directly from EDBs is one solution. Accessing this data through flexibility traders, retailers, or a centralised DER register are other options worth exploring. This is the model chosen by Australia Energy Market Operator (AEMO).

Question 3: Options for improving access to information

What options do you think should be considered to help improve access to information?

No response

Section 5: Electricity supply standards

Question 4: Network issues from connecting or operating DER

Have networks experienced issues from the connection or operation of DER?

Yes. Whilst these technical issues are still emerging, we can already see that some of the controls set up to prevent them are not always easy to enforce.

We also have the benefit of hindsight from international jurisdictions where a high level of DER penetration has compromised system security. For example in March 2021, in South Australia, where rooftop PV has a high penetration rate, authorities had to switch off almost 10,000 rooftop solar systems during a period of record low demand to maintain system security. Similarly in May 2020, National Grid ESO was granted emergency powers to instruct distribution network operators to curtail generation connected to the distribution network in response to significant drops in demand associated with the effects of the COVID-19 lockdown

This shows the importance of having the right tools in place for ensuring growing DER volumes can be achieved while supporting system stability, security and power quality. We have listed the main challenges we have identified below. We also note that the Electricity Authority's Future Security and Resilience project will provide a more detailed view of those challenges.

The displacement of synchronous generation may reduce the amount of system support offered by generators

Currently, large generation stations support the System Operator in areas of voltage and frequency management. They also offer visibility with SCADA indications allowing better management of the system.

As DER uptake increases, the share of generation from large stations will decrease, and the system support they provide will not necessarily be picked up by smaller DER as these assets are not required to provide the same level of support under the obligations set up in current arrangements. One possible solution to this issue would be to review the thresholds for asset owner obligations.

The speed at which DER can operate will impact frequency and voltage

By their low inertia, fast reacting nature, DER will have impacts on frequency and voltage. This will impact the System Operator's ability to maintain system security while operating the system 24/7, and distribution businesses' requirements to meet obligations under the Benchmark Agreement.

Having standards in place for DER that limit the effect they have on system security can help to mitigate this issue. A lack of standards could lead to the distribution networks having to invest in networks to manage DER, the cost of which would fall on their consumers.

The management of contingent events and protection coordination is growing in complexity

With contingent events, if smaller units do not remain connected and sustain pre-event output, the additional risk to frequency management may require additional reserves to be carried.

Alternatively, the prescription of equipment standards with settings compliant with the Code could be considered.

Post contingent event, when restoring or protecting the wider system, considerations are needed to protect DER assets from damage and to coordinate DERs with the network. The issue has not been prevalent with current low levels of DER but could arise more frequently as the volume of DER increases.

Protection coordination is also an existing and growing issue with increasing penetration of DER leading to an increase in two way flows between distribution and transmission networks. Parts of the network have more basic protection systems that were not designed to accommodate two-way flows. This has already required some significant protection upgrades and we expect this trend to continue.

Having increased visibility of real-time generation and DER capability across the system will be key for the System Operator to deliver an efficient service.

We have identified at least three challenges that DER will bring to the efficient operation of the System Operator function without sufficient visibility:

- To efficiently dispatch generation, System Operator needs to know DER volume, location and status.
- To accurately forecast load, System Operator needs to know how DERs are operating in the system.
- To maintain security of circuits and avoid overloading transmission assets, System Operator needs to be able to see and manage generation exporting power into the grid.

Currently, under Part 8, generation of >1MW are required to notify System Operator when seeking to connect to a distribution network. The distributor also has an obligation to advise the System Operator in their Asset Capability Statement. Transpower has found that even with these obligations in place, Transpower is not made aware of all embedded generation of >1MW. Transpower has worked to make this requirement more widely known through updating its website contents and engaging with industry. Here, a centralised DER register could be useful.

Although 1MW in isolation seems insignificant for the System Operator, it is important that information on these smaller DER are available: several small DER geographically close to each other could have the same aggregate effect on the system compared to a single larger DER. Transpower is already experiencing system challenges from DER sized 10-30MW and is working with the Electricity Authority and the wider industry to understand what would be required for large DER to be operable on the network

Question 5: Electrical Safety Regulations

Do the Electrical (Safety) Regulations require review? If so, what changes do you think are needed (a) in the near term and (b) in the longer term?

To create clarity and consistency, we support a review of the Electrical (Safety) Regulations. We acknowledge that the regulations are sitting across several areas (Worksafe, MBIE and the Electricity Authority) and recommend that a focus is applied to clearly delineate areas of regulation, and that any requirements to connect to a network refer to the appropriate regulation instead of specifying its own standards.

For example, under Part 6 provisions, many distribution connection agreements will specify frequency standards for DER that do not align with AS/NZ4777 (for DER <1MW) or Part 8 (for DER >1MW). Rather than specifying a frequency standard, the connection agreement should refer to AS/NZ4777 or Part 8.

Separately, under current regulation DER operators may also fall under the Civil Defence and Emergency Management Act as a lifeline utility. Under Schedule 1, Part B – A lifeline utility is defined as "An entity that generates electricity for distribution through a network or distributes electricity through a network." Any DER that injects power into the network could fall under this classification but many DER operators are unlikely to be aware of the obligation. Although this is unlikely to be an issue in the near term, it could become an issue in the future if the penetration of DER is high enough that it makes up a material proportion of New Zealand's generation mix. This could create a challenge for Transpower in the future when working with the electricity industry at times of emergency. DER operators may also have obligations under Part 8, Tech Code B, Emergencies.

Question 6: Part 6 fit for purpose

Does Part 6 remain fit for purpose? If not, what changes do you think are needed (a) in the near term and (b) in the longer term?

There are areas where Part 6 could be improved to ensure it is fit for purpose. Part 6 was written with smaller DER in mind, and not the larger tens of MW individually or amalgamated that networks are starting to see.

When treating DER enquiries under Part 6, there are scenarios where distributors find themselves in a position of not being able to meet the required turnaround times because the enquiry is sufficiently large that the distributer requires input from Transpower, within a timeframe that is unachievable for Transpower. An option for mitigating this issue is having a separate process for larger scale DER that recognises the additional investigation efforts required.

There are other inconsistency issues within the Part 6 connection standards. For example, many distribution connection agreements will specify frequency standards for DER that do not align with AS/NZ4777 (for DER <1MW) or Part 8 (for DER >1MW).

To help overcome these challenges, we recommend that the industry develops and adopts a standard approach to DER connection that creates consistency across the industry and ensures other parts of the Code are referred to when appropriate. This could be achieved via an EEA technical guideline. Transpower would be open to collaborating with industry to developing this standard approach.

Question 7: Minimum mandatory equipment standards for DER

Is there a case to be made for minimum mandatory equipment standards for DER equipment, specifically inverter connected DER?

We agree that there is a case for minimum mandatory equipment standards for DER equipment. International examples, including Australia, have shown how the lack of equipment standards for DER can cause large issues for the power system.

At a minimum, standards should be in place where they are important for maintaining power quality and electrical safety. For example, standards could cover fault ride-through capabilities, interoperability, automatic anti-islanding, protocols and communication interfaces, cybersecurity, inverter performance, or demand response capabilities. Currently, there is already a need for grid scale inverter standards due to operating challenges. Standards should be sufficiently generic such that interoperability between DER and the system is enabled but new technologies are not restricted from entering the market.

Standards for smarter technology (e.g. smart EV charging, household appliances (water heaters, air con, dryers, etc) smart solar inverters) should be in place for the same reasons as above and should be enabled to adapt with the evolving technology.

In New Zealand, this role may fall on to the EEA.

Question 8: Standards for reliability and connectivity

What standards should be considered to help address reliability and connectivity issues?

No response

Question 9: Connection and operation standards under Part 6

Is there a case to look at connection and operation standards under Part 6 with a view to mandating aspects of these standards?

We support a review of the connection and operation standards under Part 6, with the view of ensuring all parts of the Code work consistently with each other and are up to date and fit for purpose.

For example, Part 6 (distribution connection standards) and Part 12 (transmission connection standards) should be designed to work in harmony. Both Parts 6 and 12 also need to correctly reference Part 8 of the Code when referring to performance standards rather than repeating performance standards and risking inconsistency. Similarly, trading aspects of generation should refer to Parts 8 and 13.

Question 10: Flexibility services being pursued

What flexibility services are you pursuing?

Transpower considers flexibility services as both Grid Owner and System Operator.

As Grid Owner, we actively consider flexibility services as non-network alternatives for grid investment. This is part of the guidelines set by the Commission. Non-network solutions are close to becoming economic compared to traditional grid investment. For example, in 2020, Transpower went out for tender for Waikato-Upper North Island Voltage Management (WUNIVM). A potential solution was to contract with a generator to use their own generation plant as synthetic inertia.

As System Operator, we also consider flexibility services can be procured for ancillary services whilst our Grid Owner function can use the same resources for outage management. This enable us to maximise the value DERs deliver. We currently procure these flexibility services from large generators, distributors, industrial loads, and an aggregator, for ancillary services.

Looking ahead, System Operator is working with the Electricity Authority on the Real-Time Pricing work programme which will help to enable participation of flexibility services in the wholesale electricity market.

Question 11: Flexibility services through a competitive process

Are flexibility services being pursued through a competitive process?

Transpower always pursues flexibility services through a competitive process (for example, the WUNIVM tender). These services are defined by a Grid Support Contract (GSC). Transpower does not seek to directly own or interact with the individual resources themselves.

Question 12: Options for incentivising non-network solutions

What options should be considered to incentivise non-network solutions?

There are several mechanisms being used overseas to incentivise non-network solutions. There may be merit in the Electricity Authority and the Commerce Commission working with industry to explore whether any of these solutions could be adapted for the New Zealand context. Currently, there is insufficient understanding of how these could be applied in New Zealand and therefore Transpower neither supports nor opposes these mechanisms.

These mechanisms are listed below:

- Great Britain's (GB's) Office of Gas and Electricity Markets (Ofgem), the energy regulator, developed the total expenditure (totex) incentive mechanism (TIM) to equalise the incentive between opex and capex and over time. In this scheme and under certain conditions, some opex occurred can be added to the Regulatory Asset Base.
- Alternative funding allowances, for example, the demand management incentives scheme (DMIS) in Australia where the Australia Energy Regulator allows distribution network service providers to seek better recovery for the procurement of non-traditional network solutions during their revenue control period.

- Ofgem's most recent iteration of RIIO (Revenue = Incentives + Innovation + Outputs), RIIO-2, has increased the scope for networks to engage with customers/ consumers to identify outputs that they value and are willing to pay for. These outputs are over and above the networks' core quality of service requirements.
- A regulatory sandbox approach to enable "learning by doing". A regulatory sandbox can allow companies to avoid specific regulatory requirements, or receive support from the regulator, to test innovative solutions or provision of new services.

Question 13: Options to encourage competitive procurement processes

What options would encourage competitive procurement processes for flexibility services?

For flexibility buyers to procure flexibility services, they need to have visibility on the capability of DERs present on the system. To discover these capabilities, in the absence of a central DER or flexibility register, competitive processes play an important role.

These competitive processes are also essential for ensuring that value stacking opportunities available to flexibility owners are fully realised, and for incentivising the optimal investment in DER.

Competitive processes are becoming more common in New Zealand. We would like to highlight Aurora Energy and SolarZero's partnership that was the result of an extensive ROI/RFP process in 2019. Similarly, as Grid Owner, Transpower follows a tendering process for non-network alternatives to grid investments, the most recent being the WUNI Stage 1b Non-transmission solutions.

We agree that education can play a large role in encouraging competitive procurement. Education can raise awareness of the value and potential of DER and awareness of how to run competitive procurement processes. GB's Energy Networks Association (ENA) and its members have worked with Ofgem to promote competitive procurement with the publication of Flexibility Services Procurement Statements.

Another dimension of education is about learning from others in the industry. In GB, by sharing their experiences, participants of the ENA's Open Network project who have procured or offered flexibility services can allow the rest of the industry to learn about flexibility services.

While there has been engagement between Transpower and the IPAG to capitalise on the learnings of our initiatives, we believe that going a step further and having an industry working group, including industry participants, regulators and policy makers is a good avenue to adopt a "learning by doing" approach, generate learnings and to develop best-practice guidelines.

Section 7: Operating agreements

Question 14: Difficulties with negotiating operating agreements

Have you experienced difficulties with negotiating operating agreements for flexibility services?

As our maturity has increased, we have developed a better understanding, required contractual structure and balanced view of the agreements between ourselves and flexibility traders.

We look forward to reviewing the feedback that the Electricity Authority receives which can help us to improve our processes to minimise barriers to flexibility agreements.

Question 15: Transaction costs of developing contracts

Are the transaction costs of developing contracts a barrier to entering the market for flexibility services?

We look forward to reviewing the feedback that the Electricity Authority receives which can help us to improve our processes to minimise barriers to flexibility agreements.

Question 16: Operating agreements to lower costs and level negotiating positions

Would an operating agreement help lower transaction costs and level negotiating positions?

We look forward to reviewing the feedback that the Electricity Authority receives which can help us to improve our processes to minimise barriers to flexibility agreements.

In Transpower's work with IPAG, we proposed that a standard contract should be developed with other parties that have procured flexibility services. Transpower is open to working constructively with the Electricity Authority and other parties to deliver this.

Question 17: Options for operating agreements

What kind of operating agreement would address the issues described in this Section?

We look forward to reviewing the feedback that the Electricity Authority receives which can help us to improve our processes to minimise barriers to flexibility agreements.

Section 8: Capability and capacity

Question 18: Efficient and effective transformation of distribution networks

What are distributors doing to ensure their network can efficiently and effectively manage the transformation of networks?

No response

Question 19: Achieving better outcomes for consumers

How are distributors currently working together to achieve better outcomes for consumers?

An example of distributors currently working together and, importantly, with the wider industry is in the South Island. The South Island EDBs, EECA, Transpower and DETA Consulting are currently collaborating to understand the current state of coal boiler use in the South Island, assessing what the future demand of process heat fuels could be and developing a pathway to converting coal boilers to renewable fuels.

This distribution, transmission and wider industry collaboration has the potential to achieve better outcomes for consumers as it brings a diverse range of expertise to problem solving which can enable a more optimal and balanced decarbonisation solution for the process heat users. In turn, this could provide a lower cost solution to the user while also ensuring the local networks are able to play an enabling role.

The UK and Australian examples show how this can be achieved in the context of developing flexibility markets. It is important to note that the involvement of regulators and policy makers was key to the success of these groups.

Transpower continues to be open to other opportunities to collaborate with distribution businesses, regulators and policy makers to deliver good outcomes for consumers.

Question 20: Coordination between distributors

Could more coordination between distributors improve the efficiency of distribution?

No response

TRANSPOWER

Submission to Wellington Electricity

On their EV Connect draft roadmap consultation

15 July 2021

Transpower submission on Wellington Electricity's EV Connect

We thank Wellington Electricity for the opportunity to provide feedback on their EV Connect draft roadmap and commend them for their contribution to the ongoing discussion about how the electricity sector can best enable electric vehicle uptake and empower New Zealand's decarbonisation.

The role of DER in enabling New Zealand's decarbonisation

We agree that Distributed Energy Resources (DER), including smart chargers for electric vehicles, will play a vital role in ensuring that New Zealand's energy transition is made at the lowest possible cost, and with the highest benefit to consumers. We elaborate on this position in Whakamana i Te Mauri Hiko, in which we estimated that for every GW of avoided peak demand, consumers would save approximately $1.5B leading to potential savings of over $3B by 2050.

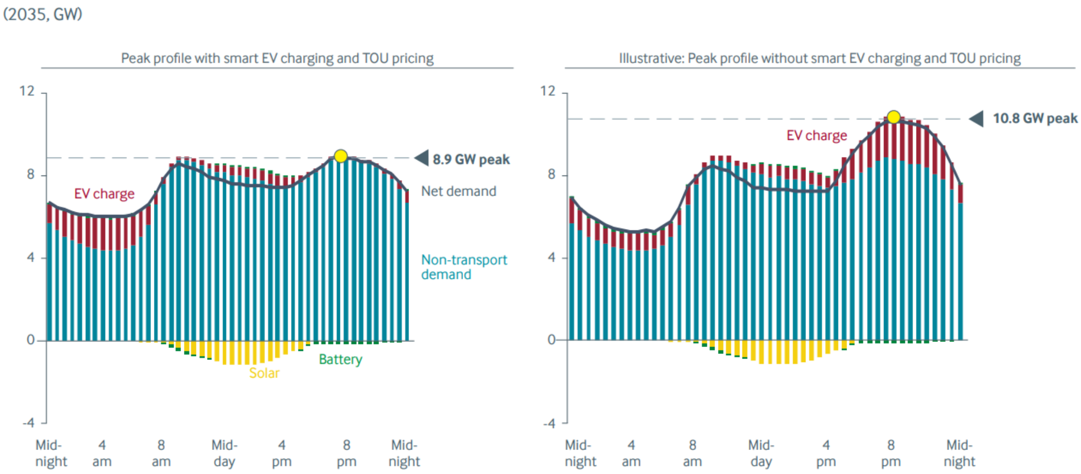


Figure 3: Peak profile loads with and without smart EV charging[1]

These findings were supported by an independent report commissioned by the System Operator - Distributed energy resources: Understanding the potential. The majority of these benefits are derived from DERs' contribution to resource adequacy, both as virtual peaking generation and as a means to manage constraints on networks.

In addition to this desktop analysis, Transpower has gained hands on insight and experience in DER management through our Demand Response Pilot Programme which ran from 2010 to 2020. We have worked with the Electricity Authority's Innovation and Participation Advisory Group (IPAG) to share our learnings and to support their investigations into how future DER markets (or flexibility markets) might function. All materials from our work with IPAG is available in the IPAG's meeting papers, beginning from June 2020 through to May 2021.

[1] Section 5 of Whakamana i Te Mauri Hiko – "Demand side management of peaks" pp 61 - 70

Value stacking is vital to DER uptake

In order to enable the benefits of DER it is essential that DER owners are able to offer services to, and capture value from a number of different value streams - a concept known as value stacking. Through value stacking, DER owners are properly compensated for the full potential of their assets and are therefore better incentivised to adopt new technologies that can then be used to optimise the power system for the benefit of all parties involved.

New Zealand stands to gain the most when flexibility services are able to dynamically allocate their services to the highest value use through transparent commercial processes. Whether this is a tender process for planned network support services, or a real time market for dynamic energy market dispatch, it is essential that consumers and their agents are given real value stacking opportunities to optimise the uptake, and allocation of DER in New Zealand. Transparent commercial processes which encourage value stacking are essential to maximising the incentives for new DER to be installed and for their benefits to be made available across the electricity sector.

In order to discuss the measures that are effective in unlocking the value stack, it is helpful to first identify and discuss each of its constituent components. The contributions that DER assets make to the power system vary based on how they are dispatched, and the how benefits of these contributions accrue to different parties:

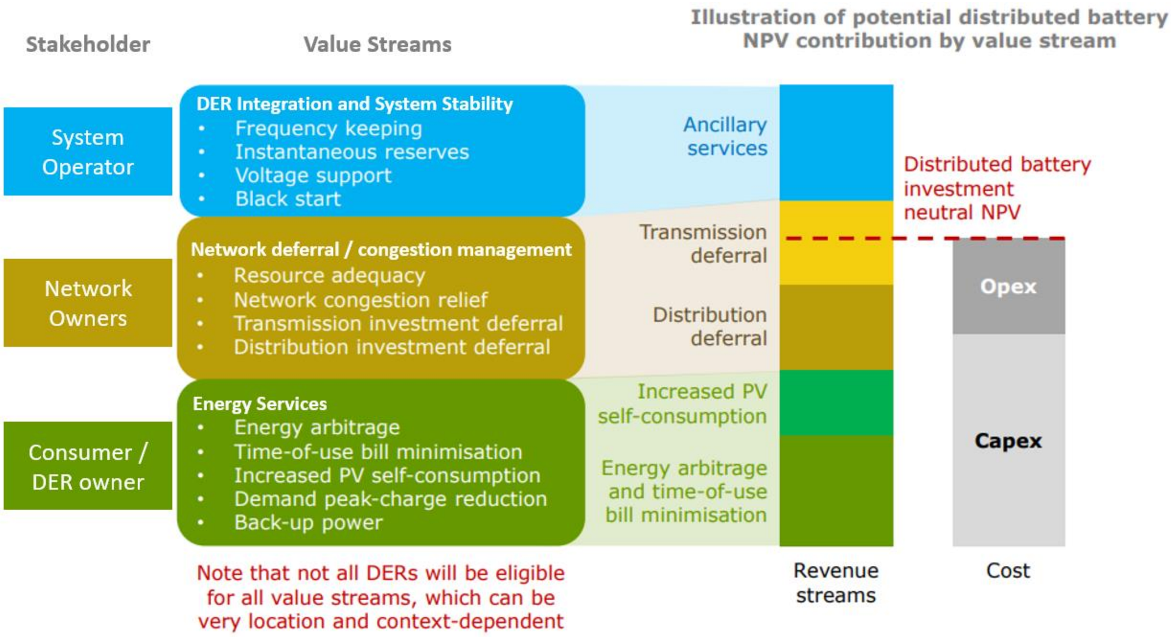


Figure 4: Value stacking provides consumers with the best opportunities to install smart chargers, batteries, and other DER[2]

Unlocking the value stack

There are two main aspects that need to be achieved to unlock the full value stack. Firstly, each value stream across DER Integration and System Stability, Energy Services, and Network Deferral and Congestion Management needs to enable access to new or existing markets to provide economic benefit for the valued services that DER can provide. Secondly, it will be important that these markets can 'value stack' with each other to provide additive benefit to incentivise DER uptake and market participation.

DER integration and system stability

A proliferation of distributed energy resources has the potential to disrupt the power system if the deployment is not coordinated. The mechanics of this disruption, and the solutions that are most appropriate are different depending on whether the deployed resources are more likely to draw from the grid or inject into it. For example, the proliferation of rooftop solar in Australia means that it is becoming necessary to constrain generation during high production periods to maintain security. Because a large portion of this generation is embedded in the distribution system, Australia has been considering how a Distribution System Operator (DSO) might better coordinate this generation. However, in situations where changes in network usage are caused by concurrently charging electric vehicles for example, demand response may be a more appropriate method of managing the system to protect security. These scenarios require different services to be procured, and would require different flexibility market designs to enable them. Some system needs may

[2] Slide 20 - Transpower DERM briefing to IPAG – December 2020

necessitate new markets for more responsive demand, whereas other system needs may only necessitate wider access to existing ancillary services markets.

An important aspect of realising this portion of the value stack will be ensuring that DER owners and their agents can access these ancillary services markets to derive economic benefit for the valuable services that they could provide to the system. This could be via individual DER participation or via aggregated DER participation – for example, in the form of a Virtual Power Plant (VPP).

Energy Services

In addition to the services that DER owners can provide to ensure ongoing system security, DER owners are also able to directly benefit through participation in energy markets. For example, self-consumption of energy produced by solar panels and energy arbitrage offer opportunities for owners to profit from their investments. It is important that self-consumption and personal load shifting opportunities are preserved when designing flexibility markets to serve other system needs, to ensure that incentives for potential owners of DER are maintained to incentivise investments.

An important aspect of realising this portion of the value stack will be ensuring that DER owners and their agents can access energy markets to derive economic benefit for the energy that they could provide to the system. This could be via individual DER participation or via aggregated DER participation – for example, in the form of a VPP.

Network deferral and congestion management

There may be circumstances in which it is more economically efficient for network companies to procure services from DER owners to manage flows on their networks than it is to invest in new built assets. Both transmission and distribution network owners should consider non-built solutions when they are making investment decisions to accommodate changes in network usage. While network companies, through their function as asset owners, benefit from flexibility through network deferral, their operations function also stand to gain from flexibility services for congestion management.

An important aspect of realising this portion of the value stack will be ensuring that network owners can provide DER owners and their agents access to transmission and distribution deferral flexibility markets.

International examples demonstrate different potential models

To maximise the opportunities to consumers and to the power system, actors across the electricity sector will need to work collaboratively to introduce opportunities for DER owners to offer services into existing and new markets. The mechanisms that are introduced to enable this will need to be tailored to the problems that are trying to be solved, and international experience provides us with examples of models which provide DER owners opportunities to contribute to resolving different system needs. Mechanisms that enable, rather than preclude, value stacking of DER services are preferable.

California DRAM: Network deferral / congestion

Since 2014, California's network companies have had access to a panel of DER aggregators through their Demand Resource Auction Mechanism. This model has proven to be successful in balancing the network utility's need for assurance of future DER performance with the need for DER owners to be able to access a range of value streams to make their investment in new equipment viable.

By maintaining a panel of providers, network operators can be confident in the capability and availability of DER owners to respond in grid emergencies and to manage constraints. DER owners gain access to the value stream associated with managing network constraints, and are able to participate in other markets during trading periods in which the networks do not require them, and in the energy market during periods where they are dispatched for network management purposes. This arrangement both maximises the economic opportunities for DER owners through value stacking and improves the availability and price at which flexibility services are provided to network companies.

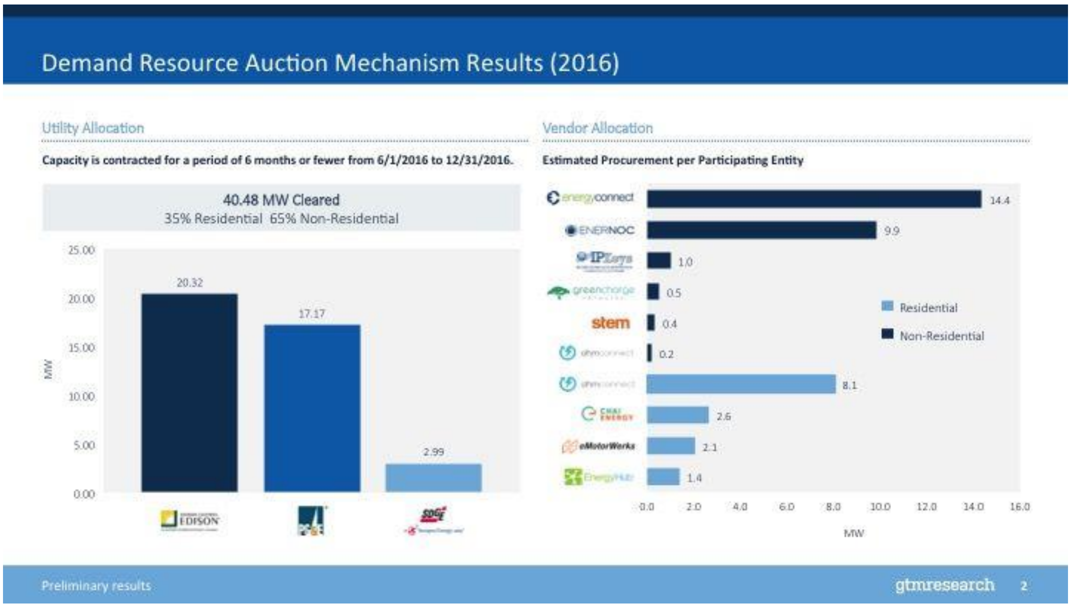
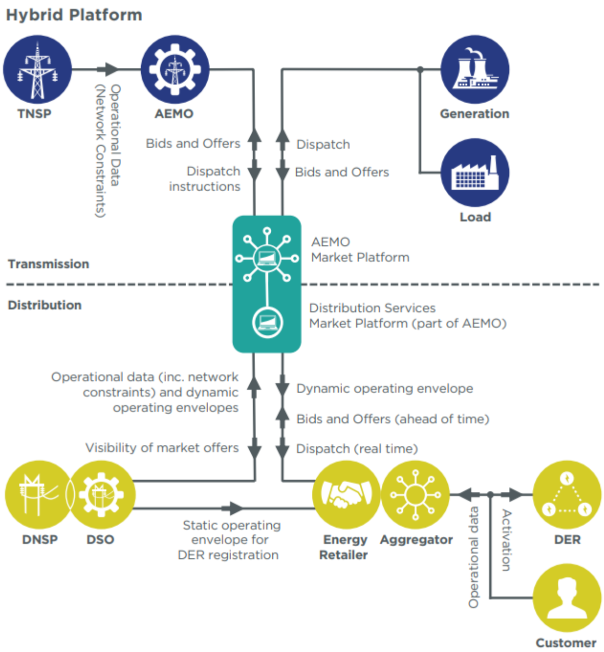


Figure 5: Competitively tendered panels of aggregators have provided California's network companies with flexibility services since 2014

Western Australia DERP: DER Integration and system stability

In addition services provided to network companies, wholesale market participation offers additional value stacking opportunities to DER owners. While network companies may require high confidence that DER will respond to calls during periods of network need, and may even structure contracts to provide obligations during these periods, during other periods DER owners may wish to participate in other markets. This offers them additional incentive to install new DER, and effectively decreases the cost at which flexibility services can be made available to network companies.

This dynamic is recognised in Australia's Energy Transformation Taskforce's DER roadmap which was adopted in AEMO's ensuing Project Symphony pilot for the WA Distributed Energy Resources Program. In this, they propose that to best enable value stacking, the roles of Aggregators, Distribution System Operators (DSOs), and Distribution Market Operators (DMOs) must be designed to maximise these opportunities:



Key characteristics	
Market arrangments	» There is a two-sided market platform, comprised of wholesale and ancillary services that is organised and operated by AEMO » Market participants, including DER via aggregators/retailers, submit bids and offers for system services to the market platform which in turn makes them available to AEMO for whole system optimisation
AEMO	» AEMO organises the operates the market » AEMO assesses all bids and offers and optimises the dispatch of energy resources considering T-network and D-network constraints » AEMO sends out dispatch instructions to energy resources, including DER via their respective Aggregator/Retailer
DSO	» DSO provided DER with static operating envelopes based upon the technical capability forecast of the D-network to accommodate DER dispatch » The DSO assesses market bids and D-network constraints to generate dynamic operating envelopes for DER which respect distribution network constraints and inform their technical and commercial offering to the markets
Aggregator / Retailer	» Aggregator/Retailer combines different DER and offer their aggregated output as system services to the market platform

Figure 6: Possible DSO / DMO model proposed in the Energy Transformation Taskforce's DER Roadmap

Under this model, DSOs work with the Transmission System Operator to co-optimise market dispatch and manage network constraints. DSOs provide information to both flexibility owners (energy retailers and aggregators) and to the Transmission System Operator via the Distribution Services Market Platform. Market systems then co-optimise transmission connected and distribution connected dispatch and provide participants with instructions. This model is well suited to the Australian context, which is a power system that is being disrupted by distributed generation that is increasing the need for flexibility services being offered into the wholesale market.

UK Flexibility Markets: DER integration, system stability, and congestion management

The paradigm of large fossil fuelled generation is also being disrupted in the UK. However, in the UK the compact nature of the grid and concentration of renewable resources in the northeast of the country provides a different context and a presents a slightly different system need than the Australian example. The UK is adopting a wide range of flexibility markets to unlock access to network management and system security services and using centralised tendering programmes to coordinate the various measures. As a recent example, in April this year SP Energy Networks released a tender for 1.4GW of flexibility services across their networks via a single platform that has been adopted by all distributors.

Industry collaboration essential

Introducing distributed flexibility markets into the electricity sector will require changes that span the breadth of the industry.

The emerging market designs described above demonstrate that there are a variety of ways that DER can be enabled and coordinated to minimise overall system costs for the benefit of consumers. These markets provide us with a valuable resource to inform the decisions we make as an industry about the future of flexibility markets in New Zealand. Alongside market architecture and high level design as we discussed above, there are lessons in the need for information sharing, standards, and market settings that enable open access for DER owners.

Processes followed in both Australia and the United Kingdom provide examples of how an industry working group, comprised of regulators, the System Operator, grid owner, and representatives of the distribution sector provide the perspectives and expertise that are required to successfully enable DER to realise its full potential. Transpower looks forward to participating in future flexibility market developments, in both our role as the owner and operator of the transmission network, and as the System Operator.

Conclusions

Transpower would once again like to thank Wellington Electricity for continuing the conversation around the future of EVs and the discussion on how they might fit into broader flexibility markets in New Zealand.

While the impact of EV charging will be felt most acutely in the distribution networks they will also be felt in the transmission network and in the wholesale market. A truly successful solution to the challenges presented by EV charging must include co-ordination and integration with the operation of the transmission network, wholesale electricity market, and System Operator. To assist in achieving this collective goal Transpower looks forward to continued engagement in future industry discussions. We appreciate the opportunity to provide feedback to Wellington Electricity's roadmap and look forward to the results of the consultation.

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