NERA
ECONOMIC CONSULTING

PROMOTING EFFICIENT AND AFFORDABLE INFRASTRUCTURE TO ENABLE ELECTRIFIED TRANSPORT

PREPARED FOR VECTOR

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Introduction

- Alongside government programmes to increase EV uptake, the NZ electricity industry, including the market regulator (the Electricity Authority) is considering options for a framework for EVs and EV charging to provide flexibility services. According to a recent study by the Boston Consulting Group (BCG) on behalf of several parties in the NZ energy industry, load flexibility could yield $10 billion in NPV savings to 2050 (across generation, transmission, and distribution). These savings would be passed onto to consumers through market competition and various regulatory mechanisms.[1]

- The EA states that flexibility services "should be procured competitively with all providers competing on a level playing field", and is currently considering the competition impacts of network operators directly controlling DER (including EV charging) through their work programme to update the regulatory settings for distribution networks.[2]

- Flexibility services can provide value to the whole system through (a) avoided dispatch of expensive generators; (b) avoided investment in peaking capacity; and (c) avoided investment in transmission and distribution capacity. This value will be felt by consumers through lower network revenue allowances and lower wholesale energy prices.

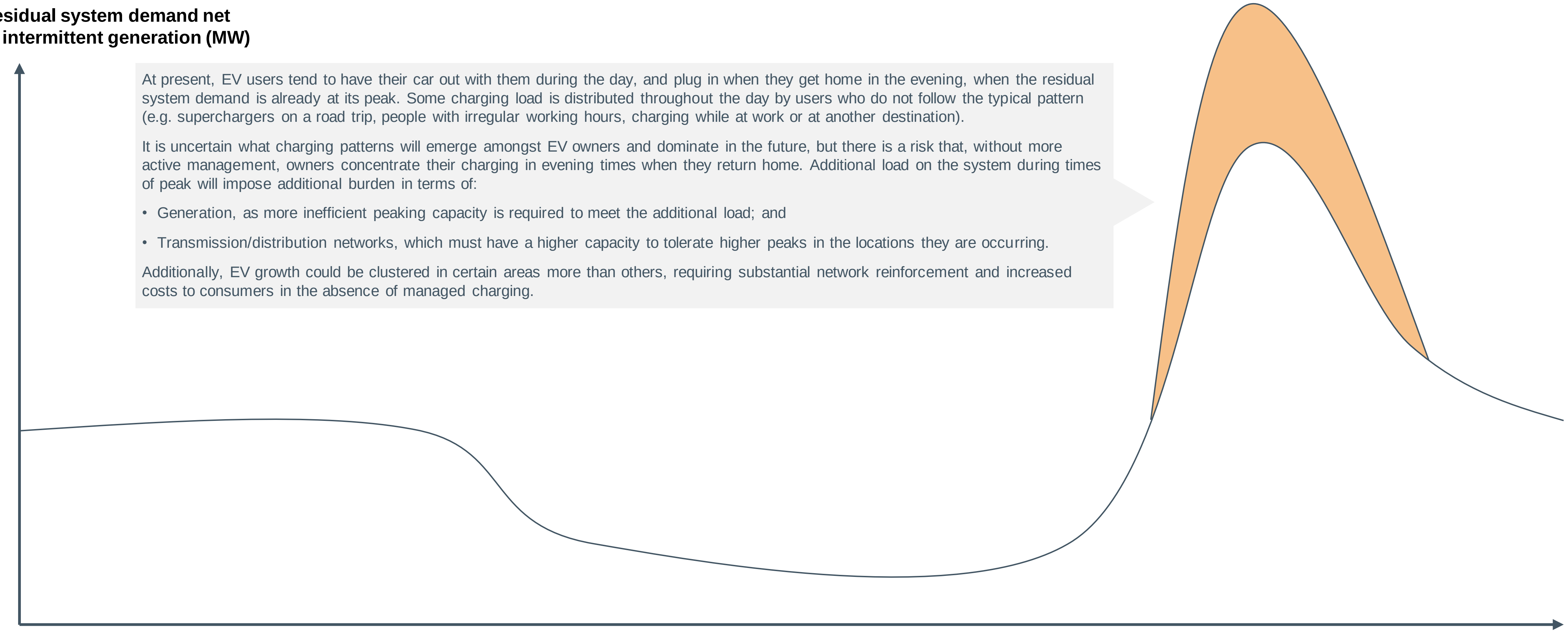
- As we demonstrate through these slides, competitive provision of flexibility services may realise the value of **(a)**, but is unlikely to be *immediately* effective in realising **(c)**, particularly the distribution component (or **(b)** but that doesn't have as much to do with distribution networks). While this report focusses on EV charging, the same principles would deliver savings from any DER with a degree of flexibility and dispatchability.

- A framework that provides EDBs with a high degree of certainty over EV charging behaviour and outcomes is the only way to avoid network solutions during the initial stages of the EV rollout in the next few years. The key objective of such a framework should be to provide the certainty EDBs need while not getting in the way of flexibility markets developing.

1. BCG (November 2022), The Future is Electric – A Decarbonisation Roadmap for New Zealand's Electricity Sector
2. EA (July 2021), Updating the Regulatory Settings for Distribution Networks, Improving competition and supporting a low emissions economy, para. 6.3.

Unmanaged EV charging could impose large costs on society

In the absence of managed EV charging, the EV roll-out may exacerbate system peak demand



At present, EV users tend to have their car out with them during the day, and plug in when they get home in the evening, when the residual system demand is already at its peak. Some charging load is distributed throughout the day by users who do not follow the typical pattern (e.g. superchargers on a road trip, people with irregular working hours, charging while at work or at another destination).

It is uncertain what charging patterns will emerge amongst EV owners and dominate in the future, but there is a risk that, without more active management, owners concentrate their charging in evening times when they return home. Additional load on the system during times of peak will impose additional burden in terms of:

- Generation, as more inefficient peaking capacity is required to meet the additional load; and
- Transmission/distribution networks, which must have a higher capacity to tolerate higher peaks in the locations they are occurring.

Additionally, EV growth could be clustered in certain areas more than others, requiring substantial network reinforcement and increased costs to consumers in the absence of managed charging.

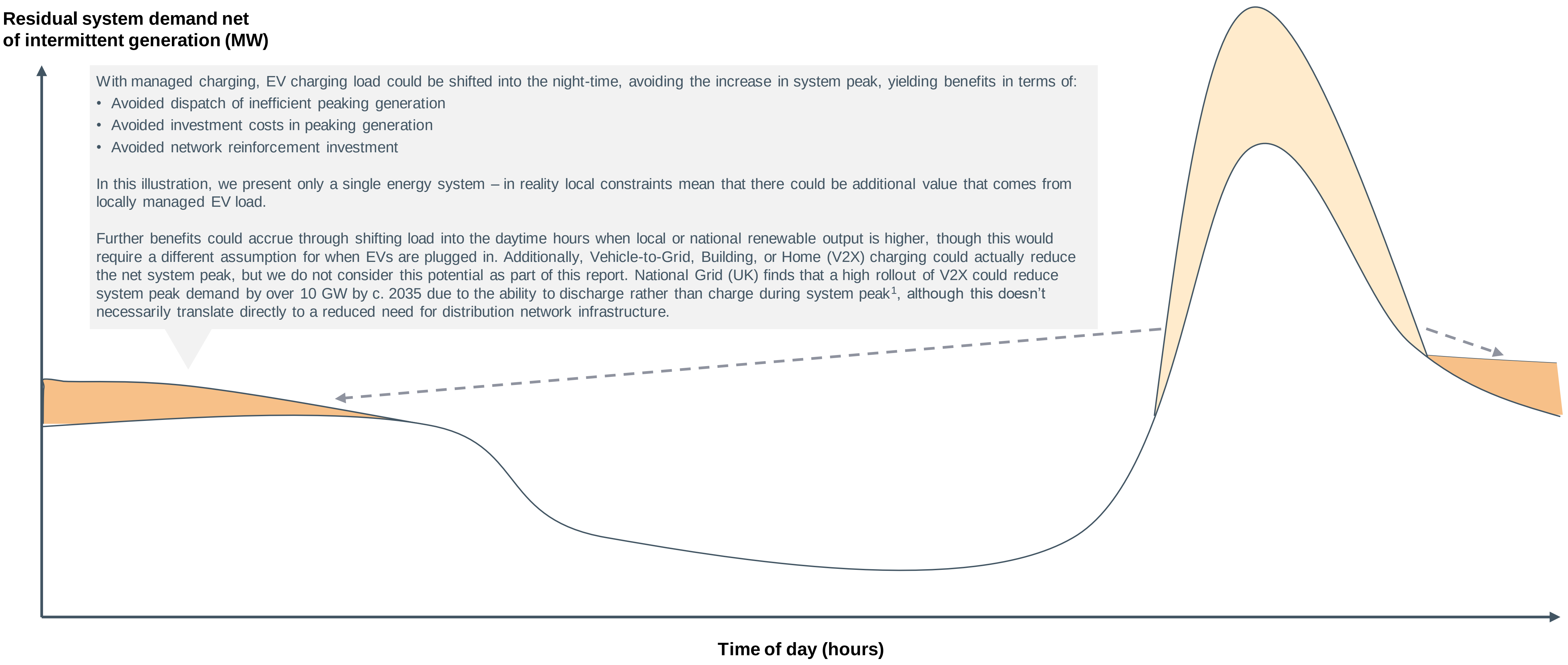
Many social benefits could arise from flexible charging

With managed charging, EV charging load could be shifted into the night-time, avoiding the increase in system peak, yielding benefits in terms of:

- Avoided dispatch of inefficient peaking generation
- Avoided investment costs in peaking generation
- Avoided network reinforcement investment

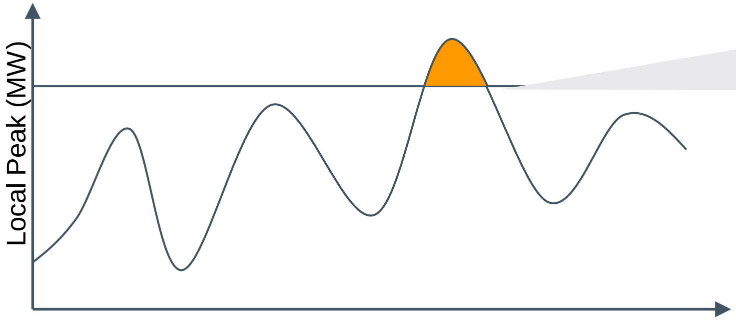
In this illustration, we present only a single energy system – in reality local constraints mean that there could be additional value that comes from locally managed EV load.

Further benefits could accrue through shifting load into the daytime hours when local or national renewable output is higher, though this would require a different assumption for when EVs are plugged in. Additionally, Vehicle-to-Grid, Building, or Home (V2X) charging could actually reduce the net system peak, but we do not consider this potential as part of this report. National Grid (UK) finds that a high rollout of V2X could reduce system peak demand by over 10 GW by c. 2035 due to the ability to discharge rather than charge during system peak[1], although this doesn't necessarily translate directly to a reduced need for distribution network infrastructure.

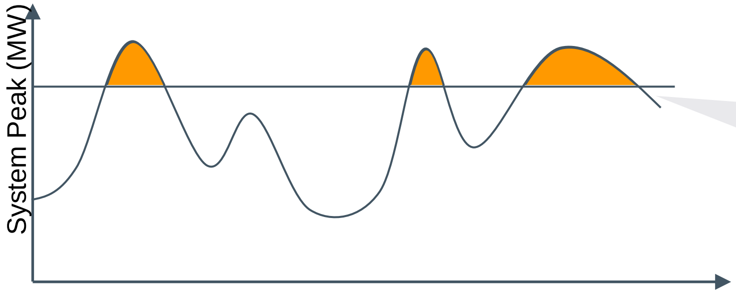


1. National Grid (2021), Future Energy Scenarios, p. 273

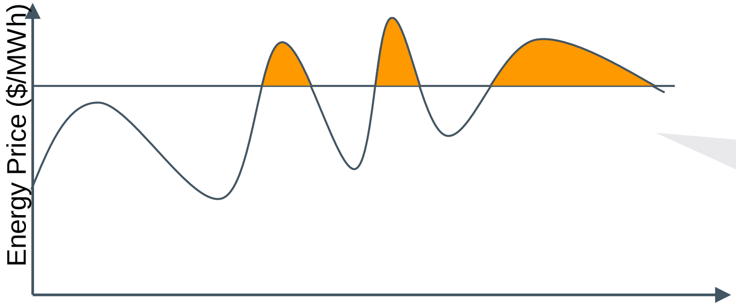
The value to the system from orchestrated EV charging, in terms of generation and network savings, are partially overlapping



Benefits to distribution networks are driven by local peaks, which may be very granular and not visible to anyone but the EDB. Owners of EVs or flexibility traders could access this value by shifting their charging out of periods of congestion, which would mean EDBs avoid the capex required to accommodate higher local peaks. At low voltages, individual EVs may represent a significant portion of a local peak, due to limited diversity on smaller sub-networks.



Benefits to the transmission network and investments in peaking capacity are driven by system peaks. Owners of EVs or flexibility traders could access this value by selling flexibility to Transpower which could avoid the capex required to accommodate higher peaks and impact forecasts of system peak demand.



Benefits to the system from avoided dispatch of expensive generation comes from arbitraging wholesale energy prices and providing ancillary services (i.e. charge when RE output is high and discharge when demand is at its peak, or interrupt charging when system frequency falls). Owners of EVs, or flexibility traders operating on their behalf, could access this value by directly participating in wholesale or ancillary markets.

For the remainder of this report, we focus on the societal benefits which could be provided in terms of avoided investment in distribution networks

System benefits are ultimately passed through as consumer savings

While system cost savings may benefit many parties in the short term, the forces of competition and regulation mean that electricity consumers are the ultimate beneficiary through reduced prices.

Wholesale energy costs

- In the short run, EV owners will tend to arbitrage peak and off-peak wholesale energy prices, reducing price volatility and reducing prices at the system peak.
- In the long run, a less volatile and more flexible total consumption profile means that capacity requirements can be better met through efficient baseload capacity and cheap renewable energy resources.
- EV owners and flexibility traders will bring more competitive discipline to the wholesale market. Further, competitive forces will push energy retailers to procure the cheapest energy they can and pass those savings on to consumers.
- At all times, however, the actions taken by those managing EV charging and other DER to reduce wholesale costs must remain within the physical and power quality limits of the network.

Network costs

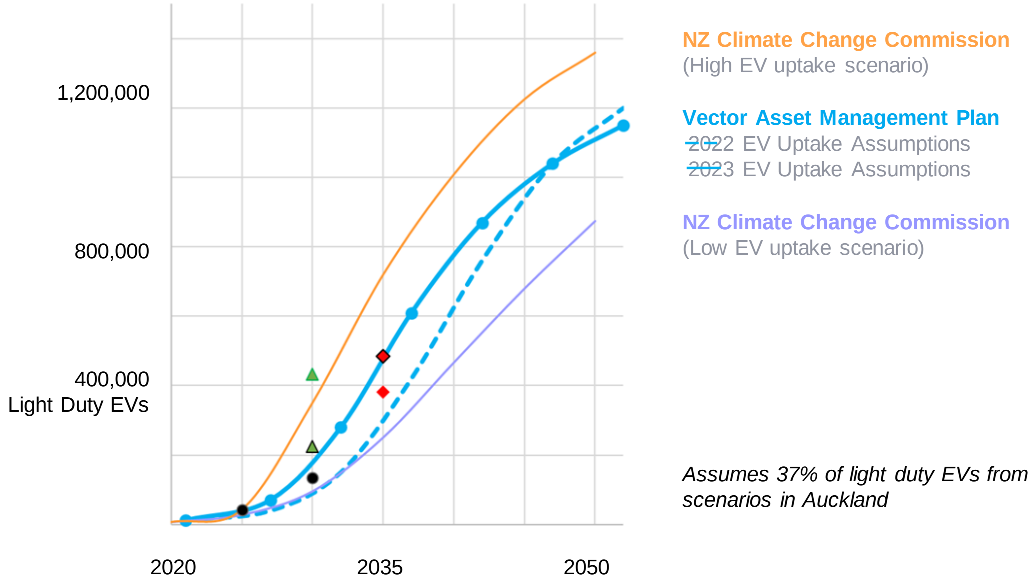
- “Steel in the ground” network investments lock in a specific peak management solution, and a resulting cost, for decades. This increases the potential for assets to be stranded as technology (e.g. V2X) and new solutions develop.
- Additionally, due to the forecast uncertainties for long-lived assets, costs of deployment, and the sizing options for standard equipment, investments may be oversized relative to what is ultimately required. Flexibility delivered from EVs is shorter-term, more adaptable, and better able to meet the precise needs of the system without oversizing.
- This would require the ability to either use short-term opex in place of long-term capex to benefit consumers through reduced regulated revenue for network companies, or to incentivise off-peak charging through sharper TOU signals for distribution charges.

Throughout this document, benefits to the system can be extended to ultimately benefit consumers.

Vector forecasts rapid EV uptake in Auckland

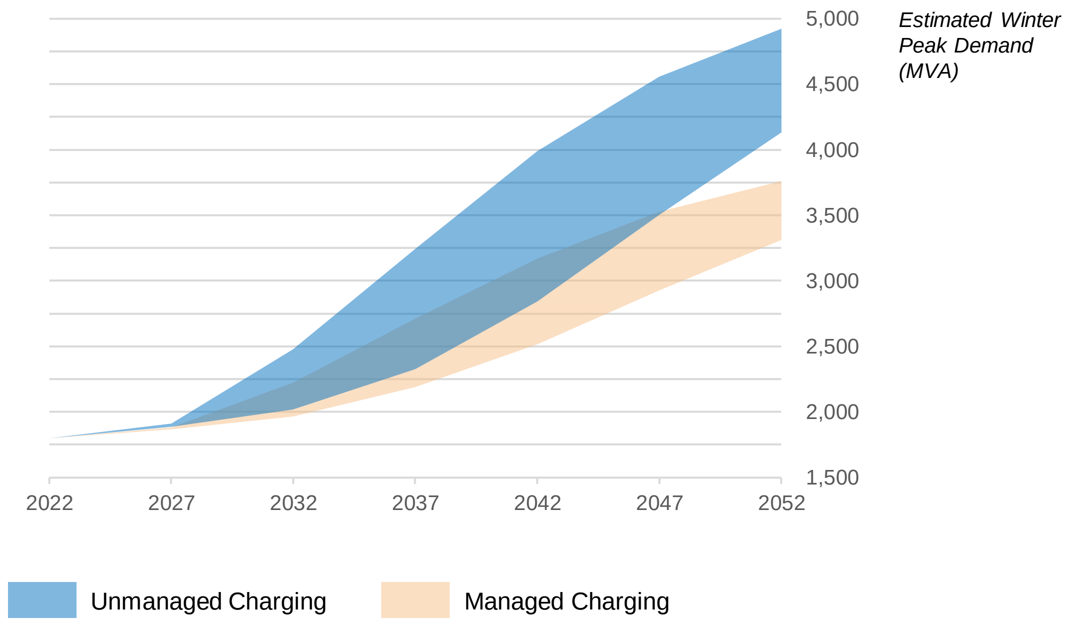
Vector has run scenarios studying the impacts of EVs, finding that unmanaged EV charging results in significantly higher winter peak demands and wider ranges of potential outcomes than with managed EV charging, and this will start impacting network investment planning for the next regulatory cycle.

There could be up to 1.4m Evs in Auckland by 2050



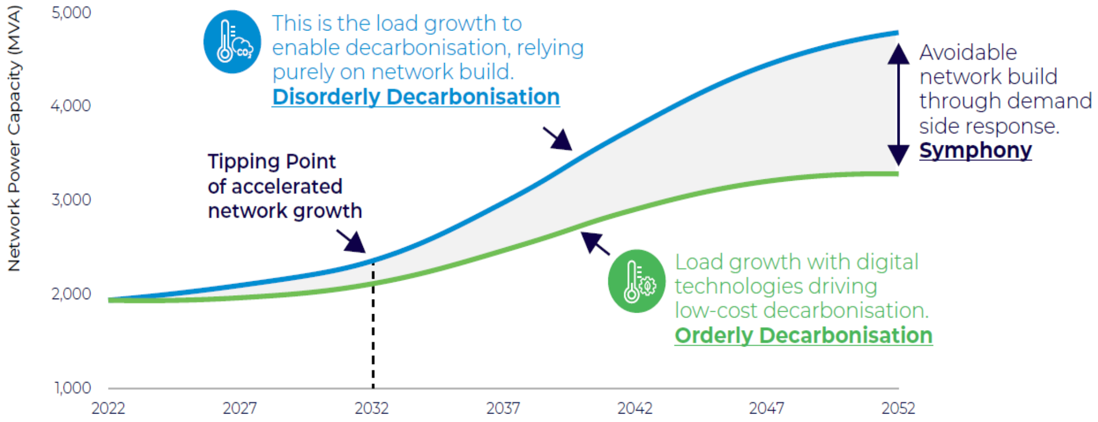
Assumes 37% of light duty EVs from CCC scenarios in Auckland

Vector Winter Peak Demand Estimates with Managed and Unmanaged Residential EV Charging



Rapid EV uptake in Auckland could precipitate the need for significant network reinforcement if charging is unmanaged

If charging is inflexible or unmanaged, Vector's network capacity is expected to more than double to accommodate charging load[1]



Vector's 2022 TCFD Report

Potential consumer savings of ~$150 MM per annum in 2050s

- Investment decisions made during the coming regulatory cycles could make some of the full potential value unavailable in the future
- Based on Sapere's estimated peak cost of $96/kW per annum for distribution.[2]
- BCG estimates total savings from EV smart charging could reach $3 bn by 2035 in aggregate, including generation and transmission savings.[3]

By comparison, the Climate Change Commission finds that EV-driven peak demand growth could increase network costs by $1.7 BN nationally.[4]

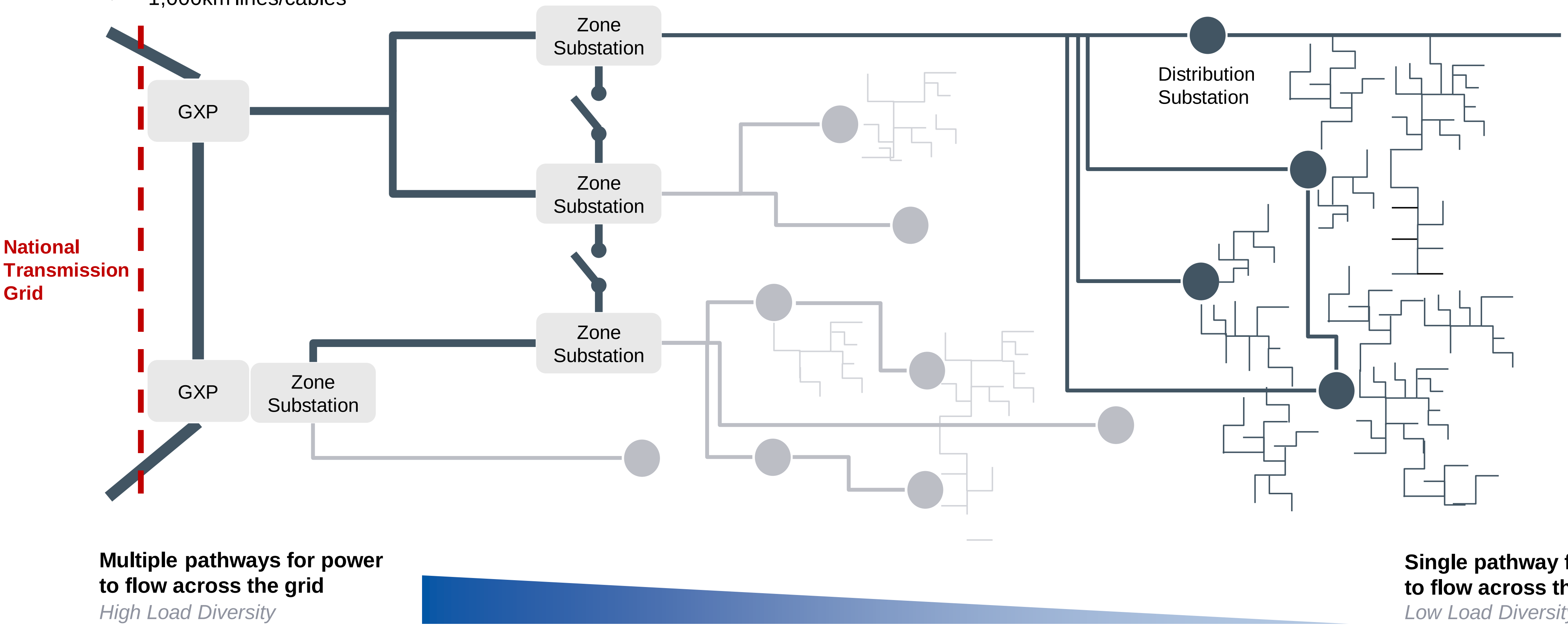
1. Vector (August 2022), 2022 TCFD Report, p.17.
2. Sapere (30 August 2021), Explaining the Cost Benefit Analysis performed on the potential of Distributed Energy Resources, slide 12.
3. BCG (November 2022), The Future is Electric – A Decarbonisation Roadmap for New Zealand's Electricity Sector, p. 92.
4. EECA (8 August 2022), Improving the performance of electric vehicle chargers, p.9.

Basic Structure of the Distribution Network

Sub-Transmission
- 15 GXPs connecting Auckland's network to the national grid
- ~200 circuits
- ~1,000km lines/cables

High Voltage Distribution
- 113 Zone Substations
- ~1,000 feeders
- ~7,500km lines/cables

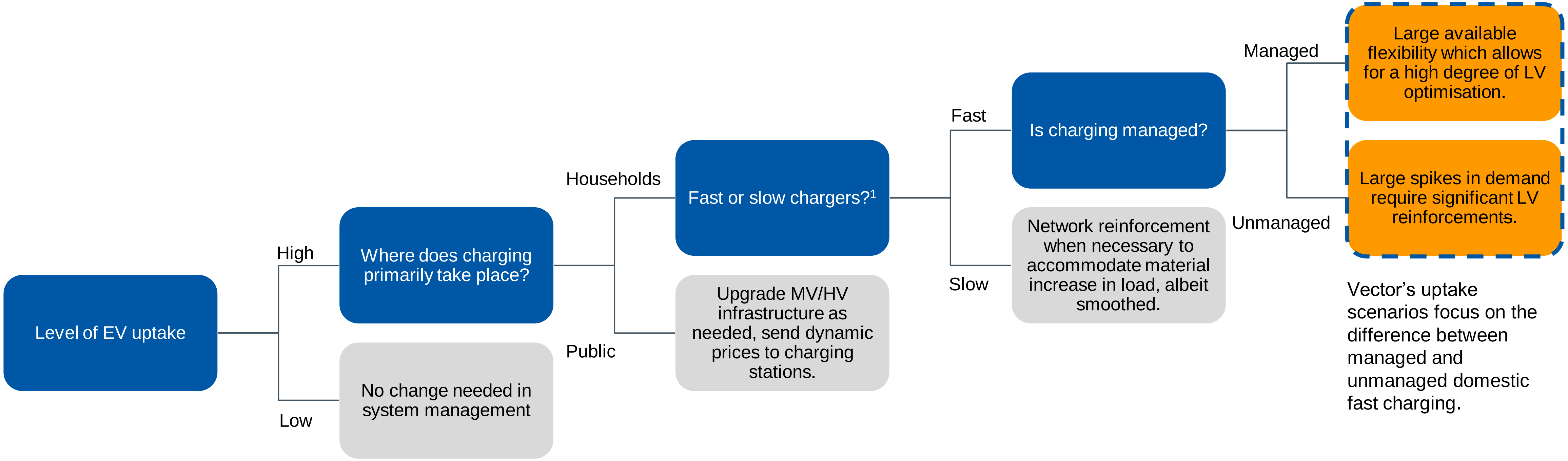
Low Voltage Distribution
- ~22,000 Distribution Substations
- ~35,000 feeders
- ~11,200km lines/cables



Multiple pathways for power to flow across the grid
High Load Diversity

Single pathway for power to flow across the grid
Low Load Diversity

The exact increase in network demand will depend not only on the level of EV uptake, but how they are charged



The ultimate value of flexibility on EDB investment depends on (a) level EV uptake; (b) whether charging occurs at home or in public; and (c) whether homes have managed charging

1. Fast charger: Dedicated wall charger for EV; Slow charger: 3-pin outlet.

The challenges presented by, and the solutions for, public charging and private charging differ

Public charging points

- If EV rollout is focussed towards public chargers, the additional load profile will likely be more dispersed, e.g. drivers may time their charging with their lunch break or shopping trips, rather than in the evening.
- Public charging stations are likely to be connected at higher voltages than household charging, which would avoid localised congestion on parts of the low-voltage network.
- Because drivers will actively choose to charge their vehicle at a public charging point, these could be dynamically priced in the same way that a petrol station is.
- Sending dynamic pricing signals to smaller numbers of public charging stations is likely to be more practicable than to a much larger number of individual homeowners, at least in the near term.

VS.

Residential charging points

- If EV rollout is focussed towards private, domestic use, then charging patterns are more likely to be centred on evening peaks and at low voltages.
- In a world with many private chargers, management of charging output is more important, because:
  - Chargers are connected to small, localised LV networks, where just a few chargers could be a substantial burden on the local network.
  - Charging is likely to be concentrated in the evening times, across most users which coincides with historical network peaks on winter evenings.
  - End users are domestic electricity customers with limited active engagement with the energy system, rather than charging businesses that are motivated to receive, manage and pass on price signals in real time.
  - Where reinforcement is required, the benefits are very local but the costs are socialised across many consumers in that EDB pricing zone, introducing affordability and equity concerns.

For the purposes of this presentation, we address the challenges presented by domestic charging points, even in scenarios where public charging is widespread.

In order to achieve most of these potential savings, a high degree of managed charging is required across the localized LV networks

A high degree of coverage is needed to achieve reinforcement benefits

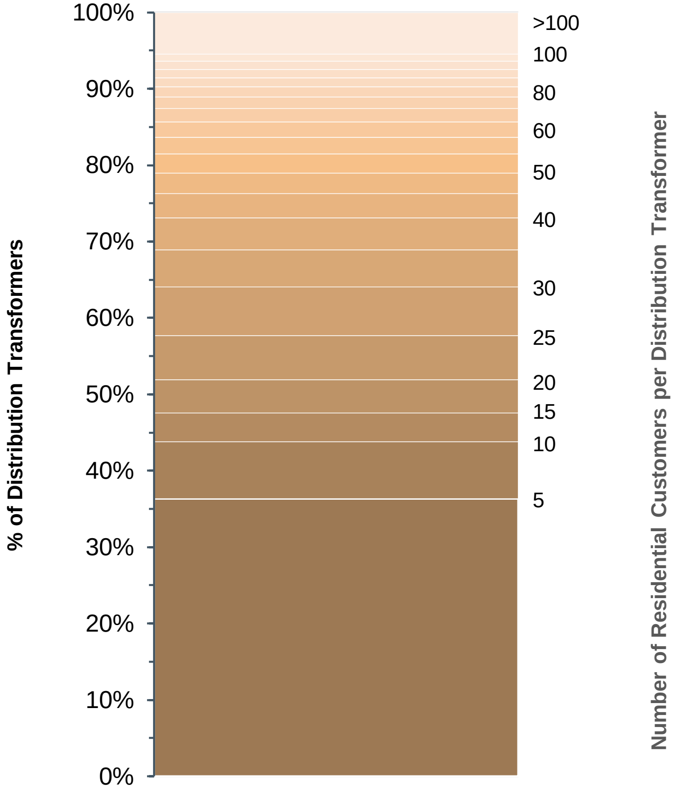
- Distribution reinforcement can be lumpy, and so a large amount of flexible charging capacity could be needed to avoid a particular reinforcement project. Once the reinforcement is made, flexibility in the vicinity becomes less valuable, because it no longer defers investment in localised network capacity.
- Where reinforcements are small/incremental, EDBs must make decisions based on assumptions, in the absence of having visibility of, e.g., exactly which houses on a particular street have a smart charger.
- If EV owners have the option to opt out of managed charging in any given period, some diversification and a degree of overbuild (or over-procurement) is needed to maintain reliability and confidence in sufficient capacity.
- The ability to manage each vehicle may be limited (e.g. at some point the vehicle has to actually charge). Having access to many vehicles provides more options to EDBs to manage a long-duration requirement. However in the early stages of the EV roll-out, geographical concentrations are unlikely to be high enough, or targeted in the right areas, to harness them as specific solutions.

EV managed charging must be available across a wide swathe of area

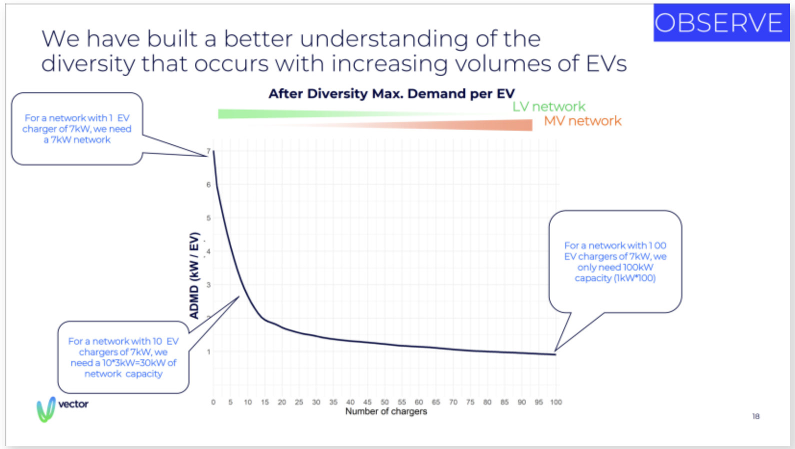
- Vector's network could be viewed as the aggregation of the smaller, localised networks connected to the 22,000 distribution substations across the region.
- Network reinforcement activity is conducted to:
  - ensure that *each of the smaller, localised networks* is capable of meeting local peaks, and
  - ensure the network up to the GXP is capable of meeting the network-wide peaks.
- Thus, EV charging must be visible and available at the connection level which enables an EDB to maximise the opportunities to avoid or defer network reinforcement at all levels of voltage – from LV to sub-transmission.

Due to limited diversification of charging with smaller numbers of consumers, the greatest impacts of rapid EV uptake will be at low voltages[1]

~80% of Distribution Transformers in Auckland have fewer than 50 Residential ICPs



- Many distribution network assets only serve a small number of consumers. With each distribution transformer potentially only **providing power to a handful of EVs**, there is a reasonable probability that most or all of them will at least sometimes charge at the same time. Thus, EDBs will need to consider LV reinforcement needs at a granular scale to accommodate the potential for simultaneous charging.
- However, as the geographical range considered increases, it becomes increasingly unlikely that most or all EV owners will independently charge simultaneously just by chance. **Thus, EDBs can benefit from diversification when considering higher voltage assets.**
- Additionally, limited market depth and liquidity at a local level means that there may be no alternative source when one participant declines to behave optimally, or changes its behaviour at short notice.
- **In order to mitigate extensive and expensive LV reinforcement at a local level, EDBs will require the certainty that peak charging profiles can be managed and guaranteed at a similarly local level.**



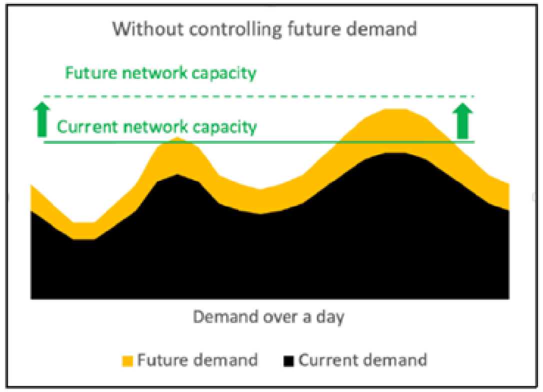
1. See Vector's previous study on diversity effects on its network: https://www.vector.co.nz/articles/ev-smart-charging-trial

Wellington Electricity (WE) has come to similar conclusions in its EV Connect Roadmap

Identified Problems

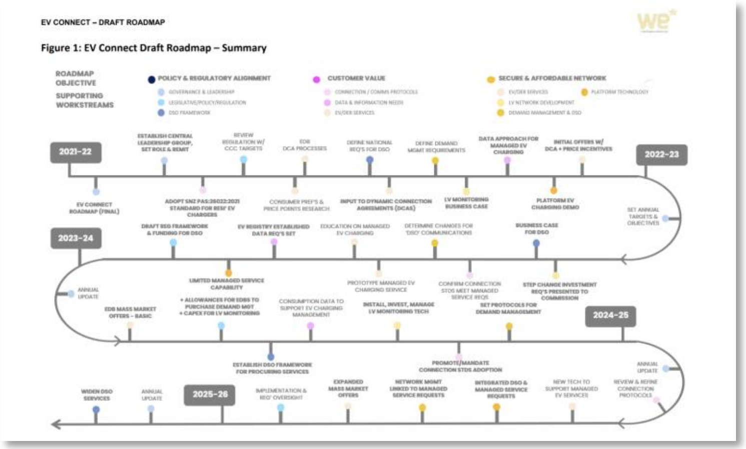
- WE estimates that uncontrolled EV charging could result in an 80% increase in energy use, at a cost to WE of up to $1 billion.
- Just to upgrade 3,000 residential transformers, WE estimates that it would have to double its workforce and it would still take 20 years to do so.

Figure 4: Network capacity without ability to control demand



Proposed Solutions

- WE proposes a detailed 5+ year roadmap for adapting to high EV growth, with focuses on (i) policy & regulatory alignment (e.g. DNO vs DSO arrangements); (ii) customer value; and (iii) secure & affordable network.
- A key component of providing a secure and affordable network is the development of a Dynamic Connection Agreement (DCA), which would provide a "dynamic ability for the network to manage an asset, with owner permissions, during times of network congestion", in return for a payment to the asset owner.
- The DCA is equivalent to the Dynamic Operating Envelope (DOE) we discuss further below.



1. Wellington Electricity (May 2021), EV Connect Consultation, Draft Roadmap

Two main approaches are being considered towards optimal orchestration and management of flexibility

The value from EV flexibility could be achieved with both direct load management and market-based solutions

Managed load	Market-based flexibility
• With ICP-addressable technology an EDB could manage when and where load is reduced in order to avoid the need to build additional peak capacity. • This could either be through a simple rule, e.g. no charging between 4-9 pm, or dynamic charging limits that reflect real-time network conditions. • This system would provide certainty for EDBs to defer investment at all levels of voltage, benefiting consumers through lower distribution charges. • However, it may limit co-optimisation with other sources of value for flexibility, such as wholesale market arbitrage, in some circumstances.	• Parties that manage demand (flex traders) are able to seek out the highest value for that service, optimising across the system over the short-term and creating value to EV owners. • Long-term commitments (e.g. to EDBs) may limit the ability to pursue all short-term market opportunities, and thus will be a part of a portfolio of options to maximise returns from the assets under their control. However, long-term commitments can help to underwrite investment in DER or capability, and may be a necessary part of the overall package. • On the other hand, if flexibility traders target short-term market opportunities, EDBs may be unable to acquire demand reductions at affordable / economical terms to the extent necessary to influence long-term planning, leading to increased infrastructure investments, under sub-optimal timeframes. • Dynamic pricing that balances the benefits of long-term commitments to short-term market opportunities is necessary to ensure co-optimisation on a local level.

If possible, the ideal end state would allow for the dynamic value provided by a market-based solution, while also providing enough certainty to limit unnecessary peak investment in distribution grids. Given this is not yet possible, a framework for smart, managed load in the meantime is necessary.

A Smart EV Charger roll-out underpins all potential solutions

With simple 3-pin chargers in place, managing EV load becomes significantly more challenging, relying on vehicle manufacturer integrations or the owner physically unplugging the car. The Energy Efficiency & Conservation Authority is currently consulting on smart charger roll out.[1]

EECA's approach will seek to strike a balance between the following objectives

- Minimise energy emissions and encourage EV uptake
- Alleviate the costs of decarbonisation on NZ households
- Reduce electricity disruptions for consumers
- Maximise security of supply, reliability and stability
- Minimise network investment using demand management

Smart chargers, connected to smart systems, are critical to unlocking the benefits of demand flexibility to all parts of the electricity system.

1. EECA (8 August 2022), Improving the performance of electric vehicle chargers, p.11.

Flexibility Markets are *Currently* Insufficient to Provide Alternatives for Capex Solutions

Problem: Challenging to determine who should pay for network reinforcement due to EV charging

In the absence of a mechanism to manage load, network reinforcement is likely, but who is it equitable to allocate the costs to?

Reinforcement costs included in EDBs' revenue allowance and charged to generality of customers according to existing distribution charging scheme

This charging mechanism would be the simplest because it would fit within the existing frameworks for revenue allowances and distribution charging.

However, customers that do not own EVs would see an increase in their network-related energy bill, even though they did not do anything to contribute to those additional costs. Presently, EV owners may be more affluent on average than non-EV owners, so it does not seem equitable to require non-EV owners to pay for costs driven by EV owners.

Additional cost-reflective charge by EV owners payable to EDB associated with installing a fast charger, designed to pay for reinforcement costs

This charging mechanism would be more equitable and cost-reflective, but would likely be seen as discouraging EV rollout, contrary to national objectives.

More cost-reflective distribution pricing would help, but in the absence of fully dynamic, locational distribution charging, it would be difficult to send the *right* signal to each fast charge installation point, and so may still not be completely equitable and cost-reflective.

Dynamic, locational distribution charging could resolve this challenge, but would be complex to implement and may further penalise customers who cannot afford the up-front capital required to purchase energy-efficient appliances or choose when to consume electricity.

Additionally, a pricing mechanism should ensure that a single customer that triggers a reinforcement is not responsible for all of the costs.

This problem is solved by introducing mechanisms which prevent the need for EV-related reinforcement

Problem: There is no market price signal to provide granular distribution-level EV response

Wholesale market price signals will not always coincide with when the distribution network benefits from curtailment

Currently the only widespread price signal available to flexibility traders is the wholesale energy spot price, and so benefits can only be delivered to transmission and distribution reinforcement savings if peak congestion on the network coincides with high wholesale prices.

Generally speaking:

- Wholesale prices are high when system-wide demand is **high,** and when renewable output is **low**.
- Wholesale market prices do not account for any distribution-level constraints – the market is blind beyond the GXP
- Distribution capacity constraints are far more complex and localised. They may happen at the same time as system peaks, but not with enough certainty that the wholesale price signal is effective on the distribution level.
- Wholesale prices are likely to be impacted by national renewable output, while distribution costs will continue to be driven by local demand peaks, meaning that wholesale prices will weaken as a proxy for distribution system requirements.

Thus, going forward, wholesale energy prices are **highly unlikely to signal EV response when and where it can help the distribution network defer the need to reinforce** (which would then result in savings for consumers)**.** Even when wholesale and distribution requirements do align, the signal delivered by the wholesale price alone **will fail to adequately reflect the full value that managed EV charging could provide** at that time.

Distribution locational marginal pricing (D-LMP) for distribution charges could signal efficient EV charging, but this is complex to implement

EDBs recover their revenue requirement through a distribution charge, which is levied on retailers and then passed onto customers through retail rates.

In Vector's footprint, customers' distribution charges vary based on whether they are: (i) controlled or uncontrolled load participants; (ii) low or normal users; and (iii) on time-of-use (TOU) or flat tariffs. TOU customers, which are the majority, pay the most granular rates, with a flat daily charge and different volumetric rates for peak (weekdays 7-11 am and 5-9 pm, April-September only) and off-peak (all other periods) consumption. There is now also a separate tariff specifically for manageable DER.

Thus, distribution charges currently only signal reinforcement costs very bluntly in the TOU tariff, **assuming that the need to reinforce the network is driven uniformly by consumption during all peak hours and across the entire network.**

An effective distribution charge for this purpose would need to **dynamically signal the value of congestion on a very short time scale and narrow geographic region**, which would require Vector to move away from charging fixed, published distribution rates, which is likely to be unpopular. Additionally, Sapere (2017) found that D-LMP would be technically very challenging because "the DC approximation of the electrical system [is unlikely to] provide a reliable basis to produce DLMPs".[1]

Even with an effective D-LMP, relying on retailer and/or consumer response to price signals will not necessarily provide long-term certainty that matches the certainty provided by network reinforcement, or the certainty required to defer investment at the local level, where diversity benefits are low.

1. Sapere (2017), An exploration of locational marginal pricing at the distribution level in the New Zealand context, p.ix

Problem: Transaction and coordination costs may be prohibitive for customers and flexibility traders, and will require EDBs to enhance their capability

Customers and flexibility traders must find and coordinate with each other

At present, the only realistic way to sell flexibility services is to the wholesale market (including ancillary services) or to arbitrage the time-of-use distribution charges. While broader flexibility markets will ideally develop, each residential EV customer currently provides only limited value to the flexibility trader. Until deeper, markets exist, the **search and onboarding costs** associated with each additional customer may be a significant proportion of the potential value that a flexibility trader can achieve.

Residential customers generally do not buy EVs with the intention of providing flexibility services, which will be increasingly true as EV ownership spreads to wider populations. In other words, it's an old problem in a new world: disengaged retail customers are now disengaged EV owners. **Thus, in a world where EV owners have to choose to participate, there is a real risk that they do not, and minimum scale is not reached**.

By relying on customers and flexibility traders to seek out and find each other, there is very likely to be inefficiently low participation in selling flexibility services, providing little certainty to EDBs.

Commercial arrangements between EDBs and flexibility traders will require time to establish

In order to engage freely with flexibility traders, EDBs would need to enter into complex contractual arrangements with flexibility traders, where the money paid to the flexibility trader reflects the value delivered to the EDB. This will require more flexibility in the EDBs' funding regime than currently exists – a regime which does not currently incentivise the avoidance of capex in the long run.

While EDBs are well-placed to understand what the requirements of the system are at any given time, they do not generally procure services like these, nor do they have established methods to assess the value received from these types of services.

EDBs will likely need to develop new procurement, contracting and trading capabilities to ensure that the flexibility procured matches the system requirements. **This will entail substantial set-up and ongoing transaction costs, which EDBs are not funded for in the short run.** These capabilities will benefit society in the long run and so should and will be developed by EDBs, but are not readily available unlike capex solutions. This transition will be more challenging for smaller EDBs, for whom network solutions are much simpler and more affordable than engaging in flexibility markets.

Until the necessary relationships between customers, flexibility traders and EDBs are established, direct load management is necessary to ensure efficient use of distribution networks.

Problem: Networks have a long-term commitment to customers and regulators, and thus seek long-term solutions to security of supply

Network reinforcement is a long-term investment, so any non-network solutions must provide the same level of long-term certainty in order to replace it

Where a distribution network is locally constrained, the EDB could reinforce the network to increase its capacity. The reinforcement would last decades with virtual certainty, and would be paid for by consumers over the duration of the asset.

By contrast, flex contracts with EVs would only last for as long as a counterparty is willing to contract for, likely no more than a few years. It would be challenging for flexibility traders to sign a contract for as long as the life of the asset it replaces, and ensure that they will retain that consumer as well its contracted load. A shorter contract would not itself be a problem if each contract could be renewed or replaced (by a different user with a similar profile) upon expiry, but it is difficult for an EDB to have confidence that this will happen.

If a contract ends without replacement and the EDB was insufficiently diversified, it may need to carry out network reinforcement to replace the contract, or risk jeopardising the security of supply. A network solution cannot simply be implemented overnight and cost the same as if it were planned in advance.

Given the lead time required to carry out network reinforcement (e.g. a few years, depending on the project), an EDB may carry out the network reinforcement anyway, to protect against the risk that a contract ends without replacement and the reinforcement is needed. Lead times are even longer for Transpower, which may require up to 10 years to plan an investment.

Network industries tend to prefer capex over opex solutions

In regulatory regimes globally, capex plans tend to receive lighter scrutiny than opex. Additionally, networks can benefit by outperforming not only the expenditure allowance but also the allowed rate of return. Combined, there is a tendency for network companies' commercially-focussed shareholders to prefer building the asset base and earning low risk returns were possible.

Network (capex) solutions are more familiar to the normal operating practices of network industries, in comparison to contracting with flexibility traders, auctioning capacity, etc. Additionally, as discussed on the following slide, at a small scale with only a few participants, there would be limited liquidity which EDBs could use to respond to network constraints.

In jurisdictions with explicit programmes to promote non-network solutions, uptake has been slow even when they do not rely on market dynamics. For example, California's Distribution Investment Deferral Framework had only commissioned 38 MW of non-network capacity in its first three annual solicitation rounds, due in part to the onerous solicitation process.[1]

Until flexibility markets are mature and liquid at a low voltage level, they will not be able to fully substitute or defer capex solutions in the majority of circumstances.

1. California Public Utilities Commission (2 March 2021), Demand-side alternatives to traditional supply-side investments: Updated and new approaches in California

Problem: In planning for very local network requirements, there is effectively no market depth or liquidity

Market dynamics on a national level

In a national market (like the wholesale spot market or transmission networks), there are hundreds or thousands of traditional and non-traditional resources, owned by a large number of individual operators who compete with each other.

These resources are relatively fungible, i.e. they each provide MW of capacity and/or MWh of energy, plus maybe a small number of ancillary attributes.

If one player changes its behaviour or fails to deliver, it can be replaced by any number of alternatives, albeit perhaps at a slightly higher cost to the system. Ultimately, the lights will stay on.

Market dynamics on a local level

On a local level, a resource that can be provided to the distribution network will only provide value to network infrastructure upstream of it, e.g. local LV infrastructure on its street, but not on a neighbouring street.

If the “market” for a particular service consists of just five houses (or five EV chargers) connected to a distribution asset, there is a high correlated risk that multiple resources become unavailable at once. For example, a retailer managing two or three EVs on that street decides today to give its capacity to the wholesale market rather than providing services to the distribution network, or those vehicle owners decide to charge during peak times.

In this case, there is no alternative provider that could step in and fill that gap to that market, even for an increased price, and no short-notice alternative solution to the EDB.

It is unclear whether markets would thus ever be sufficient at an LV level, even once DER are ubiquitous. In the transition to that state, DER deployment is not likely to occur uniformly or in the areas they are most needed.

Even a market-based solution must have a mechanism to ensure that the physical limits of the network are reflected in EV owners’ ability to deploy their flexibility.

Comparator Models from Other Jurisdictions or Industries

The UK 2021 UK Regulation on Smart Charge Points

Regulation parameters[1]

- Each new Smart Charge Point (CP) must have a **smart functionality**.
- The default option of those CP is to **shift EV charge off peak time** (peak time defined as weekdays 8AM-11AM and 4PM-10PM).
- **Charging start randomly delayed** by up to 10 minutes in order to protect the grid stability, avoiding creating a new peak demand and "gradually ramping up the demand."
- Only **private** CP are concerned.
- Leaves the option for the consumer to **override time constraints** and **change default options,** which is especially attractive given general consumer preferences for smart charging.
- Regulation is focused on Smart Chargers only – does not apply to non-smart chargers.

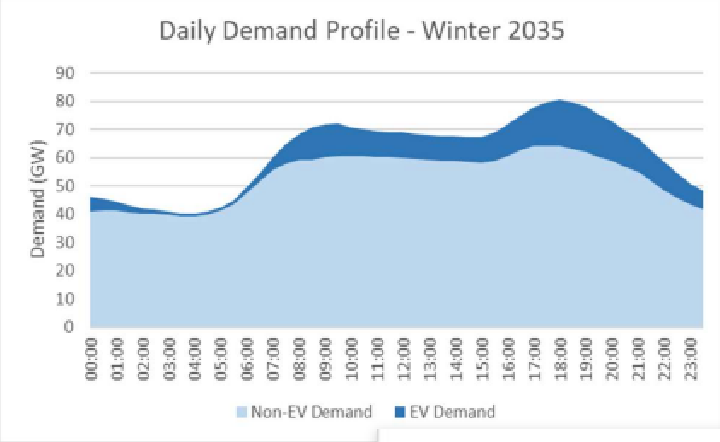
The motivation[2]

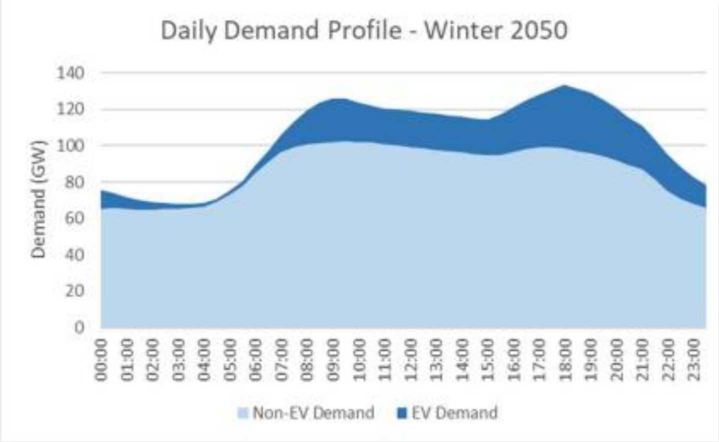
- Shifting EV charging time could **reduce the peak by 11% by 2030 and 9% by 2050** (the impact might be lower if more CP are constructed in workplace, increasing the morning consumption peak).
- **Reducing the risks and costs of instability** due to overcharging the grid if too many EV start charging at the same time.
- Saving from **£300m to £1100m in power system cost** by 2050 at effectively just the of introducing the programme.
- Eventually, could help filling the power gap in the grid using **bidirectional charging** (V2G and V2X).

1. Office for Product Safety and Standards (May 2022), Complying with the Electric Vehicles (Smart Charge Points) Regulations 2021
2. Department for Business Energy and Industrial Strategy (14 July 2021), Impact Assessment: The Electric Vehicles (Smart Charge Points) Regulations 2021

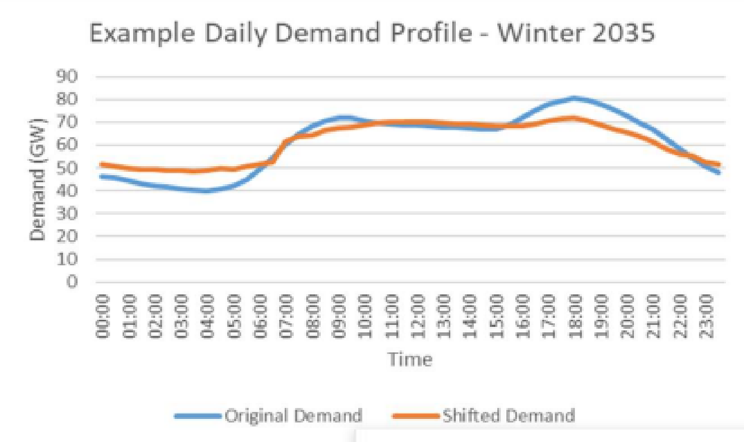
The UK charging regulations are driven particularly by the potential to shift demand away from peaks

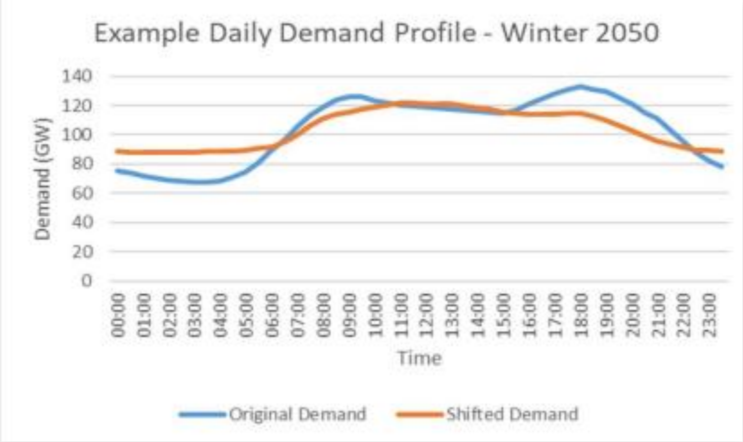
“Unshifted” EV demand is expected to be a significant contributor (20-30%) to system peak demand in coming decades





Peaks can be completely flattened if EVs shift towards off-peak periods





1. Department for Business Energy and Industrial Strategy (14 July 2021), Impact Assessment: The Electric Vehicles (Smart Charge Points) Regulations 2021

Physical limits of the network can be maintained through either a static or dynamic "operating envelope"

An "operating envelope" is a limit on the amount of energy that can be imported from or exported to the network at any time, in order to maintain network stability. This envelope could be either static or dynamic.

Static Operating Envelope

- Traditionally operating envelopes have been set conservatively and statically (by necessity), to ensure that the network can tolerate the "worst case scenario" in terms of import or export. For example, the new UK EV charging rules, for those who don't opt out, are effectively a static operating envelope that reduces to 0 during peak hours.
- A static envelope does not make full use of the network, because it does not account for periods when there *is* spare capacity locally due to underuse of available capacity. Thus it does not enable optimal allocation of capacity and will be unnecessarily restrictive on DER.

Dynamic Operating Envelope (DOE)

- In order to make better use of distributed solar and storage, the Australian Renewable Energy Agency (ARENA) launched Project Evolve, to test the feasibility of a DOE**.** The goal is to maximise the use of DER, while limiting the risk of breaching the physical and operational limits of the network. Different forms of DOE are being trialed and implemented around Australia.
- Under a DOE, the DNSP can release the static operating envelope by computing dynamically upper and lower bounds on the import and export of power in real time for each customer connection point using algorithms. These bounds are computed as function of the network properties, time, weather, customer energy consumption and generation, etc, and can be set on up to a 5-minute basis, forecasted for the next day or so. The bounds can also be used to manage the ramp-up of load after a period of reduced capacity.
- The Australian Energy Regulator has recently released guidance on estimating the Customer Export Curtailment Value (CECV), and on how these values can inform cost benefit analyses to expand the network and allow for wider envelopes (i.e. because the value of curtailed export is potentially greater than the cost of network expansion).[1]
- New Zealand's FlexForum recently released an insights paper introducing DOEs, noting that they will be an essential tool for enabling the safe and secure participation of DER in national wholesale markets.[2] There are already some early applications of DOEs in New Zealand, for example at Auckland Transport's new e-bus charging depot in Panmure.

Under either type of envelope, an investment trigger is necessary to ensure that operating envelopes are not a perpetual tool to avoid network reinforcement where that is the economically efficient choice. A minimum standard envelope could be maintained, or EDBs could estimate an equivalent to CECV which feeds into its reinforcement plans. Alternatively, EDBs could procure load flexibility from those same EVs to keep the DOE wide for EVs which do not participate, with a commensurate cost allocation and payment.

1. AER (June 2022), CECV Final Methodology, Explanatory Statement
2. FlexForum (August 2022), A Flexibility Plan 1.0: what we need to do and how we can do it

Transpower and EDBs have explicit powers in case of an emergency, which could be extended to allow for DER response

The Electricity Industry Participation Code 2010 obligates the SO to take action in a grid emergency[1]

- The SO must ensure in advance that it has the physical ability to disconnect load or generation if it becomes necessary.
- The SO must notify participants if conditions arise where it is likely to take an emergency action.
- If an emergency occurs due to insufficient generation or other mismatches in generation/demand/frequency, the SO may request that generators or demand users adjust their output/demand accordingly to ensure stability.
- If an emergency occurs due to the transmission constraints, the SO may request that generators and/or demand on either side of the transmission constraint increase/decrease their output/demand accordingly to relieve the constraint.

The Default Distributor Agreement gives load management abilities to EDBs[2]

- The DDA covers the relationship between EDBs and energy retailers, but not with non-retailer aggregators, specific consumers, EVs, etc.
- EDBs must provide SO with capability to disconnect load when requested for transmission system capabilities.
- Load shedding, and the restoration of power, by the EDB must follow the following list of priorities:
  - Safety
  - Network stability and security
  - Maintaining power to critical infrastructure
  - Maintaining power to high voltage infrastructure
  - Maintaining power high priority customer groups

While load management powers exist in some circumstances, EDBs do not currently have the power to manage EV charging and other DER in emergency situations. These powers could be broadened, with care to ensure that they do not become so broad as to discourage development of flexibility markets.

1. Electricity Industry Participation Code 2010, Schedule 8.3, Technical Code B
2. Default Distributor Agreement, Schedule 4

Assessment of Potential Interim Solutions

We develop and appraise a range of frameworks which EDBs could follow to manage EV load until flexibility markets are mature

- Given the obstacles which currently exist in relying on market signals and flexibility markets to deliver distribution system benefits at the low-voltage level, a framework is necessary to ensure that EDBs can still manage and avoid local system peaks which would otherwise be imposed by EVs.

- This will minimise the need for network investment to be made to accommodate EV charging in peak periods – investment that could one day be stranded as flexibility markets, or other technologies (e.g. V2X), develop

- Based on precedents which exist in other jurisdictions and contexts, we develop a range of different frameworks which could apply in this context. We assess these against a range of criteria covering each framework's short-term practicality and contribution to the long-term goal of a deep and liquid flexibility market.

- The different options are not mutually exclusive, and could be further sequenced to aid in the progression towards a liquid flexibility market.

Assessment criteria

Provides long-term certainty, enabling EDBs to defer investment	Provides granular certainty, enabling EDBs to efficiently manage constraints	Implementable in the near future	Consumer centric	Allows for transition to full flexibility markets
• In order to avoid distribution reinforcement, any solution must reliably reduce EV charging load at local system peaks. • The solution must be sustainable over a long period of time, such that the EDB can reliably avoid implementing capex solutions.	• Much of distribution network reinforcement happens at LV levels, where each individual end user has a sizeable effect on local network demand and has the potential to exacerbate local network constraints. • In order to manage peaks and constraints at a very granular LV network level, coverage of the solution must be widespread (i.e. high penetration and certainty of behaviour at very localized level).	• EV uptake is increasing rapidly, and planning for local network solutions will begin soon to accommodate potential load growth. Such investments are likely to be chunky compared to the demand they accommodate. • Thus, to avoid investment, a framework must emerge shortly, so that it is in place once network reinforcements would be required to accommodate EV-driven load growth.	• First and foremost, EVs are a mode of transport. Some consumers are likely to feel strongly that they are able to charge their vehicle when they need to, and that their vehicle should be charged in the event of an emergency. • Solutions should be equitable in that costumers which do not purchase an EV aren't held responsible for the cost of a network or non-network solution.	• The ideal efficient steady state of the market would be to procure flexibility from traders on a local, liquid basis, while allowing traders to identify the revenue sources of greatest value in real time. • Thus, while the steady state is likely not realistic in the near future, any interim solution should not prevent or slow down the steady state from emerging. • Not all customers will be engaged in the steady state, so framework should also maximise value provided by disengaged customers.

Options will cover both physical mechanisms for ensuring charging is managed effectively, and contractual mechanisms to ensure that consumers receive value for the flexibility they provide

Some arrangements could be easily implemented in the short term because the tools already exist, but they may impede progress towards a fully liquid end state.

Some arrangements fit more closely with the end state of a fully liquid flexibility market, but may not be possible to implement in the timescales required to avoid network reinforcement.

Physical mgmt. arrangements

- Default off-peak charging or static operating envelope
- Dynamic operating envelope

Within a DOE widening or narrowing, consumers could receive value either through avoiding high prices, DER payments or the trade of their services with other market participants.

Contractual mgmt. arrangements

- Static TOU charge already present in status quo
- TOU distribution charges
- Managed charging regime via registered DER manager[1]
- Tradable charging rights

These options could be treated as a progression, moving from left to right over time as the relationship between EDBs and flexibility traders becomes more formalised

1. The EDB would be the default DER manager, focusing exclusively on use for distribution investment deferral, until customer selects a different DER manager that can access all value sources.

Options vary in terms of the access rights for EDBs and customers

Each model presents a spectrum of rights for EDBs and customers.

Customer generally has full control of charging; EDB can't circumvent this.

EDB can override customer preferences in emergency circumstances.

EDB is able to determine allowable charging levels, in all circumstances.

Default off-peak charging

- Option 1: No penalty for opting out; mechanism acts as simply a nudge to encourage users to think about their use of charging infrastructure.
- Option 2a: Customer is required to be on a cost-reflective time-of-use tariff if they install a fast charger.
- Option 2b: Customers can opt out for a one-off fee every time they charge during peak hours, based on contribution to reinforcement cost. Alternatively, customer foregoes payment/discount for participating in scheme.
- Option 3: Customers simply cannot charge at peak – there is no ability to opt out.

Dynamic operating envelope

- Option 1: Customer can decline to be subject to DOE, but may be subject to emergency control of charging if local distribution capacity is constrained. A high fee may be charged to opt out of DOE in any period, reflecting the narrower DOE which would apply to other customers.
- Option 2a: Customer can decline to be subject to DOE, and instead receive a static, profiled envelope or static limit.
- Option 2b: DOE is fully at the behest of EDB. EDB can decline application to connect a fast charger for a customer which declines DOE.

Managed charging regime via registered DER provider

- Option 1: Customer can opt out of scheme with no penalty or additional charge to do so.
- Option 2a: Customers who participate in scheme have a lower tariff overall.
- Option 2b: Customers who participate in scheme can opt out of individual events, following advance notification by the EDB. A fee is charged for doing so, or incentive payment for participation is forgone.
- Option 3: Mandatory participation in scheme, but customer can switch DER providers, which would be responsible for coordinating charging with the EDB.

Tradeable charging rights

- Option 1: Customers are given the option to charge or not on an event-specific basis, given price signal provided by EDBs. Correct payment is necessary to ensure that customers respond optimally and sufficient response is procured.
- Option 2: EDB can turn down EV charging and determine payment later, based on estimated cost to user of not charging vehicle. Correct payment is necessary to create the conditions for flexibility traders to emerge.

Default off-peak charging for smart EV chargers (static envelope)

Option description	Option assessment
• Inspired by mechanism implemented in the UK, applicable to all smart EV chargers (which we assume will be widespread). • Unless the user opts out of it, charging would occur only during designated off-peak periods, with a random delay of up to 10 minutes to ensure that there is no surge in demand right on the hour. In practice, customers could plug into a 3-pin wall charger to avoid the effects of the mechanism, but they may still not do so if it is inconvenient. • Opt out condition (one-off or sustained) could involve some disincentive so that it is only selected by users who genuinely desire it. In the absence of complex distribution charging, opt-out customers could pay a surcharge for distribution costs, or be required to be on a cost-reflective time of use tariff. However, these signals would likely be too blunt to reflect the true cost of opting out on an unpredictable granular time and geographical basis. This uncertainty would necessitate EDBs building a "buffer" into their load forecasts and investment. • Alternatively, as in the UK, it may simply be a "nudge" to change behaviour and helps disengaged consumers avoid on-peak charging. • If the user opts out, they could engage with a flexibility trader to have their charging managed, participate in other markets, or not participate.	• **Provides long-term certainty to EDBs**: **Medium**. Depends on the strength of the signal to not opt out (e.g. is there an additional charge or is it just a "nudge"). If many users opt out (and do not engage with other mechanisms), then it may not be effective, particularly at local low-voltage levels of the network. Does not address three-pin charging, which is indistinguishable from other uses of electricity. • **Provides granular certainty to EDBs**: **Medium.** Strong performance so long as LV-level peaks remain within pre-defined peak hours, but this may not always be the case. • **Implementable in the near future**: **Strong**. Has already been achieved in the UK. • **Consumer centric**: **Medium.** Depends on strength of signal to not opt out. If consumers can opt out immediately with no charge, then they retain full flexibility, but other users may have to pay more if an upgrade is required. If a user has to pay extra to opt out in an individual instance, then they lose some flexibility and autonomy. Regime is a 'blunt instrument', managing charging in many periods in which it would not otherwise have been required, effectively "over-controlling" load and unnecessarily restricting flexibility. • **Transition to full flexibility market**: **Medium/Poor.** Flexibility traders and EDBs would have limited opportunity to develop necessary capabilities, because a customer that only charges off-peak has a reduced opportunity for using flexibility for other reasons, such as arbitraging wholesale prices. Score depends on the counterfactual for customers who don't opt out. If they wouldn't have engaged in flexibility services anyway, then default off-peak does not stand in the way of a flexibility market developing and banks some cost-savings in the near-term; Alternatively, the default option may provide some inertia, preventing some EV owners from engaging with flexibility traders in the first place, when they may have otherwise. • **Other implementation challenges/risks**: Like all options, reliant on a mandate to install smart chargers. Time of local EDB peak need may fall outside of pre-defined peak periods. One-off opt-out charges must be high enough that consumers do not use it systematically. • **Overall assessment: Medium.** Option will almost certainly achieve the near-term objective of avoiding network solutions, but may hinder the development of a full flexibility market.

Dynamic operating envelope

Option description	Option assessment
• Inspired by DOE mechanism being developed and rolled out in Australia. • EDB would send import (and export) limits to each charging point for the day ahead, which would provide bounds around the amount they could charge during intervals through the day that are reflective of the real-time physical limits of the network. Bounds may also reflect maximum allowable rates of change of charging load. • The alternative to a DOE would need to be a static operating limit, set conservatively to ensure that the bounds are never triggered. Thus, **DOE is set based on the physical limits constraining the network**, and it is not possible to opt out, unless a market exists to trade for a share of the DOE of a neighbour (i.e. someone facing the same binding network constraints). These limits would be sent to each charge point in advance. • Customers could engage with flexibility traders, though the traders themselves would have to operate within the bounds of the DOE (unless the customer has opted for a static envelope). Traders could manage the EV owner's charging according to their preferences and ensure charging remains within the DOE at all times. • DOEs also enable the ability to manage export limits, which is increasingly relevant as Vehicle to Grid (V2G) becomes more prominent. • Some reporting by EDBs necessary to demonstrate that DOEs are not being overused to the detriment of customers.	• **Provides long-term certainty to EDBs**: **Strong.** EDBs would retain the ability to curtail demand, if (and only if) physical limits risk being breached, ensuring that their primary objective of security of supply will always be met first. • **Provides granular certainty to EDBs**: **Strong.** A different DOE can be assigned at whichever granularity it is needed. • **Implementable in the near future**: **Medium.** Process is still experimental in Australia, and would need to be translated to NZ context to ensure signals are accurate and feed appropriately into network reinforcement. Early tests are underway in NZ. • **Consumer centricity**: **Medium.** Consumers could only opt out to a static envelope, but a DOE is likely preferable from a consumer's perspective to being given the static envelope as the only alternative. • **Transition to full flexibility market**: **Strong.** Flexibility traders may require more sophistication to forecast and react to changes in the DOE, but this should be feasible. Once flexibility markets are liquid, EDBs could send dynamic *prices* in addition to the envelopes (potentially including D-LMP), allowing traders to include distribution as part of its value stacking. • **Other implementation challenges/risks**: Additional IT investment may be necessary to calculate DOEs and communicate them to end users. Further understanding and monitoring necessary to ensure that efficient reinforcement does still happen (i.e. cost of curtailment vs cost of reinforcement). Further understanding necessary to ensure that efficient reinforcement does happen. Could be complicated and subjected to ensure that available capacity is allocated in a principled fashion. • **Overall assessment**: **Strong.** If it can be rolled out quickly, DOE acts as a good balance between short-term feasibility and ease of transition to full flexibility market, and would remain even with a full flexibility market. DOEs will become increasingly necessary to enable DER participation in wholesale markets.

Note: a DOE is a physical arrangement representing constraints on the network, which could underpin the different contractual arrangements discussed below.

Managed charging regime via registered DER manager

Option description	Option assessment
• Inspired by "ripple control", already in place to manage hot water heaters. Would provide a means for managing the charging of disengaged customers while allowing engaged customers to opt-out and contract with other DER managers. • In the default, EDB would be the DER manager for EV chargers (and other DER), and would deploy flexibility in ways to benefit EDB, and customer would receive a preferred rate for engagement (e.g. a lower distribution charge). The EDB would be able to manage DER in a way that aligns with local network conditions, and manage the return of the load when charging recommences. • If customers opt out of the default arrangement and select a different DER manager (e.g. their retailer), then that DER manager would be given the same incentive or rate for engaging with the EDB (e.g. reduced distribution charges). However, they would also be able to value stack and sell flexibility services into different markets where it is more valuable. By design, the EDB leaving part of the value stack on the table gives flex traders and retailers a competitive advantage against the default EDB DER manager. • In either case, EDB would have the ability to send out a signal to manage the rate at which a customer can charge in order to meet the local requirements of the EDB.	• **Provides long-term certainty to EDBs**: **Strong.** With a sufficient surcharge for opting out of managed charging, most participants would likely only opt out if they are able to offset that surcharge by selling flexibility services through other means, which may also achieve the type of long-term certainty that EDBs require. Additionally, operating limits would still bind. • **Provides granular certainty to EDBs**: **Strong.** With a sufficient surcharge for opting out of managed charging, most participants would likely only opt out if they are able to offset that surcharge by selling flexibility services through other means, and geographic coverage would be near complete. • **Implementable in the near future**: **Strong**. Has already been achieved through hot water ripple control, and alternative providers to the EDB are not immediately necessary. • **Consumer centricity**: **Medium.** Consumers have the ability to opt out or choose a different provider in general, but cannot opt out of the default on a case-by-case basis. • **Transition to full flexibility market**: **Strong.** More opportunity for flexibility traders to engage with engaged customers during peak periods (who have opted out of the default regime). • **Other implementation challenges/risks**: Sticky customers may not wish to switch away from simplicity offered by EDB as default manager, but inability of EDB to value stack creates incentive for other traders to market to the customer. Could be mitigated by having a sunset clause to the arrangement, after which customers on the default option are allocated to a different party. A procedure would need to be developed to ensure that smart EV chargers are enrolled with a DER manager, default or otherwise, e.g. through the terms of connection. • **Overall assessment: Medium/strong**. Effective in the near-term objective. Could hinder but not completely prevent the introduction of a liquid flexibility market.

Flexibility traders are given firm access rights to the charging capacity of the EV

Option description	Option assessment
• Much like access rights a transmission-connected generator could receive, an EV owner (and by extension a flexibility trader it contracts with) would have firm access rights to charge an EV or sell its full charging capacity of an EV to wholesale energy markets, and/or to Transpower/EDBs. • EDBs would have the ability to curtail an EV's charging beyond the level of the DOE if desired (e.g. to widen the DOE for other customers), but would need to reimburse the owner/flexibility trader for having done so. The value to be reimbursed would need to consider (possibly the maximum of): ➢ The opportunity cost of not having a charged vehicle to drive, and the need to charge it at a different time. ➢ The wholesale revenues that the flexibility trader could have earned by selling power from the charged vehicle. • Clear limits or strong disincentives would be necessary to ensure that EDBs do not often curtail load.	• **Provides long-term certainty to EDBs**: **Medium.** EDBs would have a price to pay to avoid network reinforcement, and will continue to pay it as long as it is more cost efficient to do so. However, that price required to change behaviour isn't guaranteed, and could prove to be less economical than network reinforcement. • **Provides granular certainty to EDBs**: **Medium**, as above. • **Implementable in the near future**: **Medium/poor**. Challenging to determine what the correct value to pay for curtailment would be, considering the dynamic opportunity cost of selling into the wholesale market. Likely to lead to disputes if cannot easily be measured objectively. • **Consumer centricity**: **Poor**. More challenging to determine the true value of curtailed charging for an EV owner (who values having a car to drive) than for curtailing a generator which operates as a business. Additionally, curtailment costs would ultimately be paid by all customers, including those which do not own an EV. • **Transition to full flexibility market** : **Medium/strong.** EDBs paying for flexibility services fits neatly into existing wholesale market framework, making it easy for flexibility traders to enter and eventually sell to EDBs as well as the wholesale energy market. However, an incorrect price signal may shut out the emergence of a flexibility market. • **Other implementation challenges/risks**: Ongoing modelling required to ensure curtailment price is an accurate reflection of the opportunity cost. • **Overall assessment**: **Medium/poor.** May not be immediately practical given the sophistication required to price firm access. However, it could be a useful further step near the end state of full flexibility.

Pricing of opt-out mechanisms could be complicated

Free / "nudge"

- Customers could opt out of a mechanism (e.g. default off-peak charging) for free, where the benefit of the mechanism is to nudge customers to think about the value that EV charging can provide to the system. Customers could opt out on a long-term or a case-by-case basis. EDB would need to cater for this behaviour, increasing its investment, thereby increasing costs.
- However, customers who are indifferent may opt out for no particular reason, limiting the benefits which can be provided to the system and possibly increasing costs borne by all other consumers.
- Backstop system could be established which ensures that customers only opt out if they *opt in* to a different system, e.g. they contract with a flexibility trader or enter a different form of arrangement with the EDB.

Simple opt out charge

- Customers could pay a daily fee to opt out (or forego receiving a daily incentive payment), which reflects the long-run marginal cost associated with each unit of capacity which is or is not participating. That fee (or forgone reward) could be an attribute of the commercial proposition offered by retailers to consumers.
- However, this LRMC would need to be an average over time and space. In any one instance, a local network which has no network constraints could allow more users to opt out without incurring any additional costs, while another local network may be close to its limit and may value participation more greatly.
- A simple signal thus is likely to be inaccurate in many places and times, thus signalling inefficient use or disuse of EV charging.

Dynamic opt out charge

- Like a DOE, a dynamic opt out charge would reflect the real-time and locally-granular constraints on the network, and would therefore signal the most efficient use of the network. This would end up being equivalent to D-LMP.
- It is technically complex to determine and communicate the price that would be charged, and may not be immediately feasible. In addition, the retailer would need to pass this charge on in some form for it to be effective.
- Before dynamic pricing can be introduced, a physical limit (like a DOE) must be established and underpin the framework. Dynamic charges would then allow owners to respond within the bounds of that limit.

Assessment against criteria (1/2): Physical arrangements

	Provides long-term certainty to EDBs	Provides granular certainty to EDBs	Implementable in the near future	Consumer centricity	Transition to full flexibility markets	Other implementation challenges/risks	Overall assessment
Default off-peak charging for smart chargers (static envelope)	Medium. Depends on the strength of the signal to not opt out (e.g. is there an additional charge or is it just a "nudge"). Does not address three-pin charging, which is indistinguishable from other uses of electricity.	Medium. Strong performance so long as LV-level peak is always during peak hours, but this may not always be the case.	Strong. Has already been achieved in the UK.	Medium. Depends on strength of signal to not opt out. If consumers can opt out immediately with no charge, then they retain full flexibility, but other users may have to pay more if an upgrade is required. If a user has to pay extra to opt out in an individual instance, then they lose some flexibility and autonomy. Regime is a 'blunt instrument', managing charging in many periods in which it would not otherwise have been required, effectively "over-controlling" load and unnecessarily restricting flexibility.	Medium/Poor. Flexibility traders and EDBs would have limited opportunity to develop necessary capabilities, because a customer that only charges off-peak is effectively unavailable to provide any useful services, or to sell their flexibility when wholesale prices are high. If disengaged customers wouldn't have engaged anyway, then option does not stand in the way of a flexibility market developing; However, option may introduce inertia, preventing some EV owners from engaging with flexibility traders in the first place, when they may have otherwise.	: Like all options, reliant on a mandate to install smart chargers. Time of local EDB peak need may fall outside of pre-defined peak periods. One-off opt-out charges must be high enough that consumers do not use it systematically.	Medium. Option will almost certainly achieve the near-term objective of avoiding network solutions, but will hinder the development of a full flexibility market.
Dynamic operating envelopes	Strong. EDBs would retain the ability to curtail demand, if (and only if) physical limits risk being breached, ensuring that their primary objective of security of supply will always be met first.	Strong. A different DOE can be assigned at whichever granularity it is needed.	Medium. Process is still experimental in Australia, and would need to be translated to NZ context to ensure signals are accurate and feed appropriately into network reinforcement. Early tests are underway in NZ.	Medium. Consumers could only opt out to a static envelope, but this is likely preferable from a consumer's perspective to simply being given the static envelope as the only alternative.	Strong. Flexibility traders may require more sophistication to forecast and react to changes in the DOE, but this should be feasible. Once flexibility markets are liquid, EDBs could send dynamic *prices* in addition to the envelopes (potentially including D-LMP), allowing traders to include distribution as part of its value stacking.	Some investment in IT may be necessary to allow for signalling fully dynamic envelopes. Further understanding and monitoring necessary to ensure that efficient reinforcement does still happen. Could be complicated and subjected to ensure that available capacity is allocated in a principled fashion.	Strong. If it can be rolled out quickly, DOE acts as a good balance between short-term feasibility and ease of transition to full flexibility market, and would remain even with a full flexibility market. DOEs will become increasingly necessary to enable DER participation in wholesale markets.

Assessment against criteria (2/2): Contractual arrangements

	Provides long-term certainty to EDBs	Provides granular certainty to EDBs	Implementable in the near future	Consumer centricity	Transition to full flexibility markets	Other implementation challenges/risks	Overall assessment
Managed charging regime via registered DER manager	Strong. With a sufficient surcharge for opting out of managed charging, most participants would likely only opt out if they are able to offset that surcharge by selling flexibility services through other means, which may also achieve the type of long-term certainty that EDBs require. Additionally, operating limits would still bind.	Strong. With a sufficient surcharge for opting out of managed charging, most participants would likely only opt out if they are able to offset that surcharge by selling flexibility services through other means, and geographic coverage would be near complete.	Strong. Has already been achieved through hot water ripple control, and alternative providers to the EDB are not immediately necessary.	Medium. Consumers have the ability to opt out or choose a different provider in general, but cannot opt out of the default on a case-by-case basis.	Strong. More opportunity for flexibility traders to engage with engaged customers during peak periods (who have opted out of the default regime).	Sticky customers may not wish to switch away from simplicity offered by EDB as default DER manager, but inability of EDB to value stack creates incentive for other traders to market to the customer. Could be mitigated by having a sunset clause to the arrangement, after which customers on the default option are allocated to a different party. A procedure would need to be developed to ensure that smart EV chargers are enrolled with a DER manager, e.g. through the terms of connection.	Medium/Strong. Effective in the near-term objective. Could hinder but not completely prevent the introduction of a liquid flexibility market.
Tradeable charging access rights	Medium. EDBs would have a price to pay to avoid network reinforcement, and will continue to pay it as long as it is more cost efficient to do so. However, that price required to change behaviour isn't guaranteed, and could prove to be less economical than network reinforcement.	Medium. EDBs would have a price to pay to avoid network reinforcement, and will continue to pay it as long as it is more cost efficient to do so. However, that price required to change behaviour isn't guaranteed at a locally-specific level.	Medium/poor. Challenging to determine what the correct value to pay for curtailment would be, considering the dynamic opportunity cost of selling into the wholesale market. Likely to lead to disputes if cannot easily be measured objectively.	Poor. More challenging to determine the true value of curtailed charging for an EV owner (who values having a car to drive) than for curtailing a generator which operates as a business. Additionally, curtailment costs would ultimately be paid by all customers, including those which do not own an EV.	Medium/strong. EDBs paying for flexibility services fits neatly into existing wholesale market framework, making it easy for flexibility traders to enter and eventually sell to EDBs as well as the wholesale energy market. However, an incorrect price signal may shut out the emergence of a flexibility market.	Ongoing modelling required to ensure curtailment price is an accurate reflection of the opportunity cost.	Medium/poor. May not be immediately practical given the sophistication required to price firm access. However, it could be a useful further step near the end state of full flexibility.

Conclusions

- EV rollout in the coming decades will place significant burdens on distribution networks, especially at the low voltage level. The cost of reinforcements, if carried out, will be costly if allocated to EV owners, and unequitable if allocated to all customers.
- However, EVs can also provide significant value to the whole electricity system, if their charging (and battery) capacity is used flexibly.
- In the near term, distribution pricing is unlikely to be as dynamic, locationally-granular or cost-reflective to provide the signals needed to manage EV loads, in a way that enables the EDB to defer investment in the majority of low-voltage assets.
- In the future, flexibility markets *may* be able to signal and coordinate the highly-localised load management necessary to avoid distribution network reinforcement, assuming that sufficient market depth and liquidity emerges at a local level. At present, this is not possible, and future development of market-based solutions to address highly-localised LV constraints, with limited market 'participants', appears challenging.
- As these markets are being developed and tested, various measures should be put in place that allow charging of EVs to be managed to minimise network reinforcement requirements, thereby maximising affordability.
- We have described and evaluated four such options, which are not mutually exclusive.
  - Default off-peak charging and the EDB as default DER manager can be implemented immediately. Users who opt out of off-peak charging could possibly be enrolled with the EDB (if not another DER Manager) to manage charging separately.
  - A dynamic operating envelope and tradeable charging rights will require technical and regulatory development, but are closer to the end state where flexibility traders maximise the value of services that can be provided at any given time, within the physical and power quality limits of the network.
  - In any event, some mechanism for signalling the physical capability of the local network at a given time is necessary to ensure that EVs do not create emergency situations. This can either take the form of a static operating limit or a dynamic operating limit, where the latter would allow EV owners to charge faster when realtime system needs allow it. EDBs may require additional emergency powers that allow them to manage DER during emergency situations.
- A framework should be developed which allows for the progression from the less mature to the more mature operating models.

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