Local Electricity Market Guidance

For the transport sector

Waka Kotahi NZ Transport Agency

August 2023

WAKA KOTAHI NZ TRANSPORT AGENCY

Te Kāwanatanga o Aotearoa New Zealand Government

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1. Introduction

1.1. Purpose of this guide

The purpose of this guide is to provide an easy-to-understand guide for Public Transport Authorities (PTAs), bus operators, and owners of other heavy commercial fleets on the issues and options associated with electrifying vehicle depots. The guide is intended to assist these parties to have informed discussions and negotiations with electricity sector participants on the provision of electricity infrastructure and power supply for charging heavy commercial fleets.

1.2. The role of electric heavy commercial fleets

The deployment of low or zero emission heavy commercial vehicles (including buses) in place of diesel vehicles reduces carbon emissions as well as air and noise pollution.

In particular, electrifying buses can make a significant contribution to decarbonising New Zealand's transport system. Public transport buses tend to run many hours a day compared to other vehicles and typically return to a depot at the end of the day, which allows for overnight charging. In addition, Auckland trials indicate that operating costs of an electric bus fleet can be 70-85% lower than equivalent diesel bus services on the same route.

PTAs have begun encouraging the use of lower emission buses as part of their bus contracts. Battery electric buses have already been implemented on numerous routes in Auckland, Tauranga, Wellington, and Christchurch, with many PTAs looking to accelerate their roll out. The government has announced a target of decarbonising the public transport fleet by 2035. Furthermore, the government has mandated that all new buses procured after 01 July 2025 must have zero emissions at the exhaust pipe[1].

Key benefits of battery electric buses for residents, public transport users, and bus operators compared to diesel buses are listed in Table 1.

Table 1: Key benefits of battery electric buses compared to diesel buses

Greenhouse gas emissions	Battery electric buses have zero tailpipe emissions and will help New Zealand in the journey to be carbon neutral.
Air pollution	Diesel buses emit pollutants including nitrogen and particulate matter which has been linked to respiratory and cardiovascular conditions. Buses tend to operate in concentrated areas (such as town and city centres) which exacerbates the air pollution issue.
Reduced noise[2]	Battery electric buses generate less noise and vibrations than diesel buses, making for a more pleasant journey for passengers and reduces noise pollution for residents and pedestrians along public transport routes.
Lower maintenance costs	Battery electric buses have fewer regular serviceable parts than those with internal combustion engines. Therefore, battery electric buses have lower maintenance costs than diesel buses.
Lower fuel costs	Battery electric buses have lower driving costs because, per kilometre, electricity is cheaper than diesel. Furthermore, battery electric buses are more energy efficient then internal combustion engines.
Improved energy independence and diversification	Electric buses contribute to reducing dependence on fossil fuels for public transportation. By utilising electricity from renewable energy, electric buses offer opportunities for energy diversification and reduced reliance on imported fossil fuels. This diversification improves

[1] https://www.transport.govt.nz/area-of-interest/environment-and-climate-change/public-transport-decarbonisation/

[2] The quietness of electric buses can pose a safety issue for those in the street environment who have visual impairments so Vehicle Alerting Systems should be considered. Note that parts of Australia are already planning to mandate this type of system.

	energy security and helps transition towards a more sustainable energy system. This is particularly relevant for New Zealand.

1.3. What this guide covers

This guide starts by setting out what is involved in obtaining the electricity infrastructure (including connection to the electricity distribution network) and power supply required for an electrified bus depot.

A depot owner/operator will face several choices when electrifying a bus depot, which are crucial for managing electricity infrastructure and power supply costs, minimising the cost of future depot upgrades, and ensuring that the bus fleet is resilient to power outages. Guidance on these choices is provided in Chapter 3.

To arrange the electricity infrastructure and power supply the depot owner/operator will need to engage with the local electricity distribution business (EDB). Chapter 4 provides guidance on how to ensure that engagement between depot owners/operators and the EDB is productive.

The guide also includes background information on the New Zealand electricity sector (Chapter 5) and the regulatory environment governing electricity distribution and supply (Chapter 6). It is recommended that readers who have minimal familiarity with the electricity sector read Chapter 5 before reading the remainder of this guide.

This guide focuses on the electrification of bus fleets but is also applicable to other owners of heavy commercial fleets looking to electrify depots or implement other large demands for electrical power such as hydrogen electrolysers.

This guide is not intended to provide engineering, costing, or funding advice. Depot owners/operators should seek independent advice from suitably qualified advisors when considering depot design and electrification options.

1.4. Guide should be read in conjunction with other guidance and requirements

This guide should be read in conjunction with:

- Waka Kotahi's *Battery Electric Bus Charging: Public Transport Design Guidance:* https://www.nzta.govt.nz/assets/Walking-Cycling-and-Public-Transport/docs/public-transport-design-guidance/battery-electric-bus-charging/public-transport-design-guidance-battery-electric-bus-charging.pdf – of particular relevance is section 3.1 on depot charging
- *Requirements for Urban Buses*: Requirements for urban buses in New Zealand (the 'RUB') | Waka Kotahi NZ Transport Agency (nzta.govt.nz)
- Standards New Zealand Publicly Available Specification: Electric Vehicle (EV) Chargers for Commercial Applications: SNZ PAS 6010:2021 :: Standards New Zealand. [It is noted that, at the time of writing, a new version of the PAS is being developed which is expected to be published by mid-2023.]

2. What's involved in electrifying a bus depot—a summary

When a depot owner/operator decides to electrify a bus depot, they will:

- need to consider the interdependencies between route scheduling, optimised power demand, optimised power supply and the consequent infrastructure and operations selection decisions
- need to install charging equipment (chargers, distribution boards, and cabling)
- probably need upgrades to the electricity distribution network, including:
    - a larger electricity connection to meet higher power capacity demand at the bus depot
    - potentially need additional capacity upgrades further 'upstream' in the distribution network.

These charger and network upgrade costs can be substantial, and upgrade timeframes are usually longer than the time required to procure electric buses. The choices a depot owner/operator makes around electrifying a bus depot are crucial for:

- managing these charger and network upgrade connection costs and timeframes
- minimising electricity costs
- minimising the cost of future depot upgrades
- ensuring that the bus fleet is resilient to power outages
- operational efficiencies.

If bus operators and PTAs are aware of these issues and options at the start of the electrification process and engage early and effectively with their local electricity distribution business (EDB), they can achieve faster and lower cost electrification outcomes.

2.1. Depot characteristics and use of depot

Before getting an electricity connection (or upgrading an electricity connection) a depot owner/operator will need to make choices about the bus depot characteristics and how the depot is to be used. These choices include:

- depot characteristics
    - if a new depot, the location of the depot, including proximity to power availability and distance to key power exit point
    - whether the depot includes on-site electricity generation and/or battery storage
    - how the depot is laid out and consideration for space optimisation
    - the specifications of chargers and transformers
- use of the depot chargers
    - how and when buses are charged, including the use of smart charging
    - whether data about electricity consumption at an individual bus level is needed (such data can help to identify higher consuming buses, which may be due to specific bus equipment issues or potentially driver behaviour, so that appropriate interventions can be applied)
    - whether other heavy vehicle operators should be able to use the chargers and the associated access arrangements.

The choices that a depot owner/operator makes can affect the cost of connection, ongoing costs, the cost of future upgrades, and resiliency to power outages. A depot owner/operator can use 'smart' technology to reduce their connection capacity needs and allow for the remote control of charging, including by power companies, to shift electricity consumption away from peak network demand periods, which can reduce the upfront and ongoing costs of electricity supply. If a depot owner/operator can be flexible (for example, on where the bus depot is located and/or whether the fleet can be spread over several sites) the upfront and ongoing costs of electricity supply can be reduced further.

When making these choices, the depot owner/operator should also be cognisant of the likely growth in the electric bus fleet so that the depot's capacity and physical layout either allows for this growth or can be easily upgraded (at least cost) when required.

Chapter 3 provides guidance on how choices around depot characteristics and the use of the depot can affect the cost of connection, ongoing costs, the cost of future upgrades, and resiliency to power outages.

2.2. Engagement with the local electricity distribution business (EDB)

A depot owner wanting to electrify a bus depot will need to engage with the local EDB to determine whether an upgrade to the electricity distribution network is required and, if so, the extent (and cost) of the upgrade.

If the bus depot is owned by a bus operator, it will be the bus operator's responsibility to engage with the local EDB. However, the PTA may assist the bus operator in this engagement—how involved the PTA will be depends on the PTA.

If the bus depot is owned by the PTA, it will be the PTA's responsibility to engage with the local EDB. However, the PTA needs to ensure that the bus depot's connection will meet the needs of the bus operator (or bus operators) that will use the depot.

To ensure that the depot's connection gets upgraded in a timely manner, the depot owner should engage with the local EDB as early as possible. The depot owner should also make sure that it sets out clearly the depot's electricity needs when first engaging with the EDB.

Chapter 4 provides guidance on the role of different parties in getting an upgraded connection to the electricity distribution network (or to get a new connection) and how to engage with the local EDB.

3. Depot characteristics and use decisions

When electrifying a bus fleet, the depot owner/operator will need to make choices and trade-offs in relation to depot characteristics—location, design, operations, component specification, on-site generation, and/or battery storage. These choices will have an impact on the cost of connecting the depot (or upgrading the existing electricity connection), ongoing electricity costs, the costs of future depot upgrades, and the resiliency of the electric bus fleet to power outages on the distribution network. Understanding these choices will enable bus operators and PTAs to make the best decisions for their situation.

The rest of this chapter sets out these different choices and how these choices can affect cost and resiliency. Also included are three scenarios that illustrate the potential benefits of some of these choices:

- Scenario 1: smart charging
- Scenario 2: installing battery storage
- Scenario 3: getting smart charging or charging infrastructure as a service.

3.1. Depot characteristics

3.1.1. Depot location

If a bus operator or PTA has a choice of depot location, then the following factors should be considered when deciding on the preferred location:

- impact of location choice on cost of electricity connection, cost of servicing bus routes, and land cost
- electricity network resiliency at each location (and cost of improving resiliency if needed)
- potential to split bus fleet across multiple depot sites.

The work required to connect and electrify a bus depot will vary depending on the location of the bus depot. If a bus depot is located on a capacity-constrained part of the electricity network more work is likely to be required to upgrade the network to the required capacity than if the bus depot is located on a part of the electricity network that is less constrained, subject to any pending planned upgrades by the EDB.[3] Therefore, the cost of connection it is likely to be less if the bus depot is located on a less constrained part of the electricity network. In addition, the cost of connection will likely be lower the closer the bus depot is to a zone substation.

If the bus operator or PTA has a choice about where to locate the electrified bus depot, then choosing a location that is optimal for the electricity network could reduce the cost of getting connected substantially. For example, one EDB noted that trenching costs for installing new feeder cable (between the depot site and the zone substation) can cost up to $1000 per metre in inner city areas—therefore, locating a depot closer to a zone substation could save hundreds of thousands of dollars.[4]

Another possibility for very large electrified bus depots is direct connection to the transmission grid[5]—this may be possible for depots that have 3 Megawatts (MW) or more of electricity demand and who are close to a grid exit point (GXP), but is unlikely to be suitable for most depots.[6] Depending on situation specifics, it is possible that connecting to the transmission network may be lower cost than connecting to the

[3] An EDB may have network upgrade(s) planned for capacity-constrained parts of the network. However, these upgrades may be scheduled for later than when the depot operator wishes to start operating the electrified bus depot.

[4] This assumes that new feeder cable needs to be installed – a depot site further away from a zone substation could be cheaper to connect than a depot site closer to a zone substation if no new feeder cable is required at the further-away depot site.

[5] Sections 5.1.2 and 5.1.3 explain the difference between the transmission grid and distribution networks.

[6] A grid exit point (GXP) is a point of connection to the transmission grid where electricity flows out of the transmission grid.

distribution network. A bus operator or PTA who considers direct connection to the transmission grid is a possibility should contact Transpower's connection team to investigate the possibility.[7]

However, a bus depot location that is optimal for the electricity network may not be optimal for the bus operator's bus routes. When considering where to locate an electrified bus depot the bus operator or PTA will need to consider the trade-offs between the cost of electricity connection and the cost of servicing bus routes (for example, if the bus depot is located far away from the end of the bus operator's bus routes there will be costs of having to drive further (labour and electricity costs) and it could increase the number of buses required to service routes). The bus operator or PTA will also need to weigh these costs against the cost of land at different locations—often, particularly in urban areas, the bus operator or PTA will have little choice on where to locate a bus depot as there is often limited land available.

Another factor to consider is the electricity network's resiliency at a potential depot location. It is preferable to locate an electrified bus depot on a 'meshed' part of the local electricity network – on a meshed part of the network there will be multiple network lines that could serve the depot, so if there is a failure on one of those network lines, electricity may be able to be rerouted along another network line. This reduces the likelihood that a failure somewhere on the distribution network will cause a power outage at the depot and if there is a power outage at the depot (due to a network failure) it could reduce the duration of the outage. The depot owner/operator should ask their EDB whether a potential depot location is located on a meshed part of the distribution network, and if not, whether the EDB considers there is a heightened risk of power outages (due to network failures) at that site.[8]

The cost to the bus operator of a power outage could be significant if the outage occurs when buses are normally being charged and the outage is for an extended period (that is to say for multiple hours or more)—this could result in buses not being sufficiently charged to operate their usual routes.

For context, the average length of time electricity consumers in urban networks suffer an outage is approximately one hour per year, varying by about +/- 30 minutes across different networks. However, there is significant variation within a network, with some consumers enjoying relatively uninterrupted supply, while others may suffer longer periods of outage.

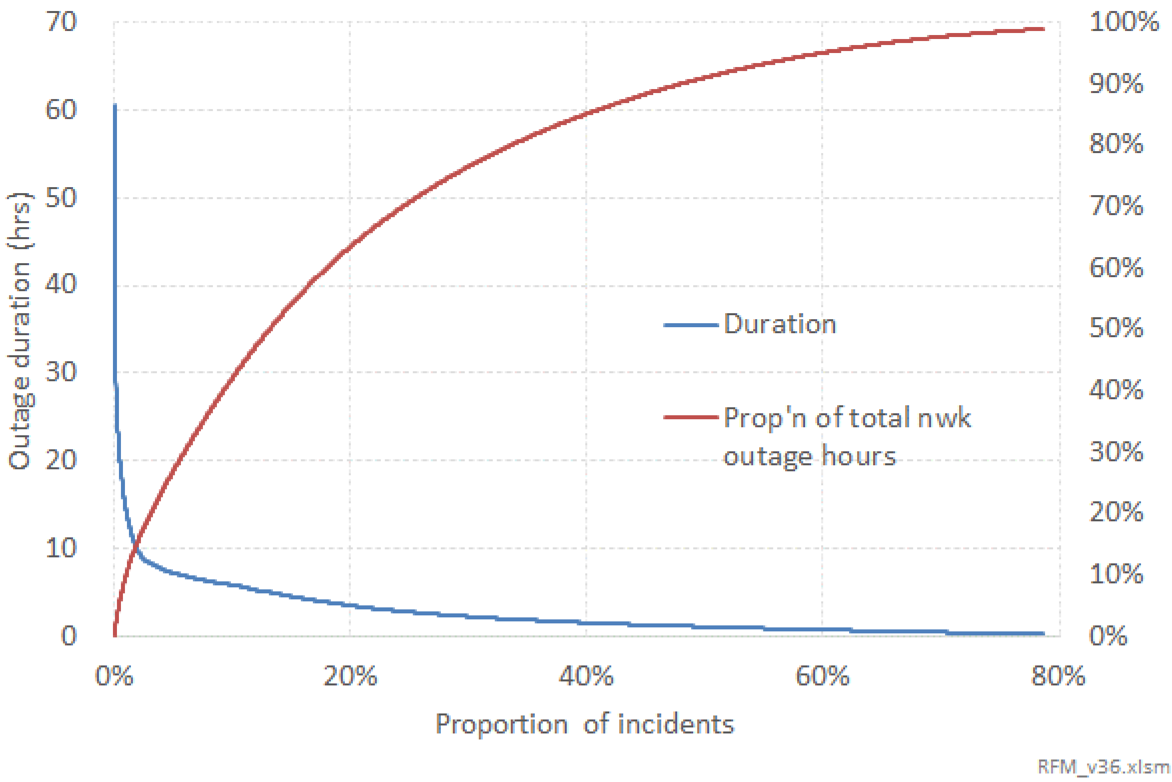
Similarly, one hour of outages per year on average could be experienced as longer but less frequent outages (for example, a six-hour outage once every six years).

This latter point is illustrated by Figure 1 which shows the distribution of outage durations for a hypothetical NZ network – based on typical values for networks.

[7] Information on Transpower's connection process can be found here: https://www.transpower.co.nz/connect-grid/our-connection-process.

[8] Suggested questions to ask the EDB are included in section 4.2.5.

Figure 1: Distribution of network outage durations



Source: Concept Consulting analysis of EDB outage data.

As can be seen, there are a few very long outages, but the majority of outages are relatively shorter in duration. The median duration is approximately one hour. The 20th percentile is 3.5 hours, and the 5th percentile is seven hours.

When this is factored by the typical frequency of outages occurring on a network, a customer located on such a network could expect to incur an outage of four hours or longer once every 6.5 years, and ten hours or longer once every 70 years. Further, this reliability is for all consumers, including domestic consumers located on a low-voltage network. A bus depot would typically be located on a higher-voltage part of the network, where reliability is typically better.

Subject to increased investment by EDBs in making networks more resilient, there is also the potential for the frequency and length of outages to increase in the future because of more frequent climate-change-related extreme weather events.

If network resiliency is poor at a chosen location, the bus operator or PTA could consider asking the EDB for a network upgrade to improve resiliency (which could be costly) or installing battery storage (with or without on-site generation) as backup if there is a power outage. Installation of battery storage is considered further in section 3.1.2 below. The bus operator and PTA could also ask the local EDB if they can be placed on the priority list for reconnection so that normal operation of bus services can resume as soon as possible following a power outage.[9]

A bus operator or PTA could reduce the cost of connecting a bus depot and improve electricity supply resiliency by splitting a depot across multiple locations. This would reduce the capacity needed at each

[9] A bus operator should also have plans in place for electricity supply disruptions, so they know in advance which reduced timetables to operate in different scenarios (eg, no overnight charging, partial overnight charging etc.). This is discussed in more detail on pp34-35, Waka Kotahi NZ Transport Agency, Battery Electric Bus Charging: Public Transport Design Guidance (2023), version 13. Available online: https://www.nzta.govt.nz/assets/Walking-Cycling-and-Public-Transport/docs/public-transport-design-guidance/battery-electric-bus-charging/public-transport-design-guidance-battery-electric-bus-charging.pdf.

site, which may remove or limit the need for electricity network upgrades. In addition, spreading the depot across multiple locations will reduce the risk of a power outage affecting all the bus operator's electric bus fleet (particularly if the depots are connected to different zone substations). Any benefits of splitting the depot across multiple locations will need to be assessed against any additional costs of the splitting the depot—these costs could include extra labour costs (for example, to manage charging at each location) and the costs of needing to provide facilities for staff at each location (for example, kitchen, bathroom, and office space).

What to consider when contemplating depot location:

- Is it feasible, from a bus route perspective, to split the depot across multiple sites?
- Are there other sites where the depot could be located (other than the preferred site) if changing the site reduces electricity costs?
- What impact would locating the depot at an alternative site have on the cost of servicing bus routes? (for example, if the bus depot is located far away from the end of the bus operator's bus routes there will be costs of having to drive further (labour and electricity costs) and it could increase the number of buses required to service routes)
- How important is it to avoid power outages? Would you consider having the depot at another site if it reduced the likelihood of power outages?

3.1.2. On-site generation and/or battery storage

A depot owner/operator could install on-site generation and/or battery storage to manage electricity use. However, the depot owner/operator needs to consider carefully whether there would be a net benefit of installing both or either.

The most viable type of on-site generation is solar generation. Solar generation is most feasible at depots where there is roof space or land area available (that isn't better utilised for another purpose[10]). Solar generation will be more beneficial if the depot's electricity usage is highest during the day rather than overnight (during the hours when solar panels will generate if the sun is shining). A depot with many electric buses will need to have substantial roof space or 'spare' land for on-site solar generation to be able to make a significant reduction on the electricity that the depot operator needs to purchase. For context, installing solar panels on an area the size of a typical rugby pitch would generate enough power, on average, to power just over nine battery electric 40-seater buses. However, solar generation may be beneficial for reducing ongoing electricity costs at some depot sites. There are now companies that offer industrial rooftop solar—this can be at no capital cost to the customer and with the offer of lower ongoing electricity charges.

If solar panels are generating, and on-site demand is less than the amount generated, the excess power can either be stored in batteries for overnight charging or be exported onto the grid. A bus depot will need to have an arrangement with its retailer to purchase this excess power. The price received for such exported power will generally be significantly less than the retail tariff. This is because a significant amount of the retail tariff includes pass-through of lines charges. However, lines costs are not avoided by on-site generation. Furthermore, while energy market spot prices are currently very high, it is likely that the large amounts of solar generation that is projected to be built over the next decade will significantly lower energy prices – particularly at times when it is sunny. Accordingly, the price that consumer-owned solar power could expect to receive for export today is likely to be significantly higher than in five to ten years' time.

The technical configuration of solar panels (or indeed any type of generation installed by a consumer) will also need to be approved by the local lines companies who will specify technical requirements in their connection code.

[10] Some depots may have land that has limited uses (eg, because it was previously a landfill) that can be used to install solar PV.

Battery storage can be installed independent of on-site generation and would allow the depot to charge a battery (or batteries) from the grid when electricity is cheapest (principally during the night and, to a lesser extent, during the middle of the day) and discharge when electricity prices are higher and there are electric buses that need charging. Installing battery storage is likely to be most beneficial when:

- the depot owner/operator has access to a cheap battery (or batteries) (one source could be batteries that were previously installed in electric buses but have come to the end of their life (in terms of use in an electric bus))
- there is sufficient land space at the depot available to install a battery or batteries — a typical 6 metre (20 foot) length container could house a 1.5 MWh battery, which is enough energy to power nine 40-seater buses for typical urban operation (200 km/day)
- the depot's electricity usage is highest during the electricity network's peak periods, which are typically 7 am to 11 am and 5 pm to 9 pm (as shown in Figure 2) (although this varies between EDBs).[11]

Figure 2: Example of network peak, shoulder, and off-peak periods

When considering whether installing battery storage will be economically beneficial, the depot owner/operator needs to ensure it accounts for degradation of the battery over time and other impacts such as space requirements for the battery.

Installing on-site battery storage could also help improve the depot's electricity supply resiliency. If power is lost on the distribution or transmission network, then having battery storage may allow the depot to continue to charge some buses.

Some batteries also have the advantage of being reasonably portable, so a battery could be moved from one site to another (or to a different part of the same site) if required.

If a depot installs on-site generation and/or battery storage then the depot owner/operator needs to ensure it informs the local EDB as it will change the depot's use of the electricity network.

Section 3.2.3 includes a scenario setting out the potential benefits of installing battery storage at a bus depot.

What to consider when assessing whether to install on-site generation:

- Does the depot have roof space or land area suitable for installing solar panels? If yes, are there other uses of the roof space or land area that could be more economically beneficial? Is the depot likely to need any excess land space for an expanded electric bus fleet in the future?
- Is the depot's electricity usage highest when the on-site generation is likely to be generating?
- Will installing on-site generation reduce the depot's electricity usage off the network at peak times?
- Will installing on-site generation improve electricity supply resiliency significantly?
- Would it be beneficial to install battery storage along with on-site generation?

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[11] Of the EDBs that have time-of-use (TOU) tariffs:

- some EDBs just have day (7am – 11pm) and night rates (11pm – 7am)
- other EDBs have two peak periods (usually 7am – 9:30am or 11am, circa 5pm – 8pm or 9 pm), an off peak period (usually 11pm – 7am), and shoulder periods for the remainder of the day (middle of the day and late evening)
- some EDBs have different TOU tariffs in summer (Oct-Apr) than in winter (May-Sep).

What to consider when assessing whether to install battery storage:

- Will battery storage reduce the capacity of the network upgrade needed (for example, by reducing the peak electricity demand for the depot) and consequently network upgrade costs?
- Does the depot have sufficient and suitable land for installing battery storage and any associated infrastructure? If yes, are there other uses of the land area that could be more economically beneficial? Is the depot likely to need any excess land space for an expanded electric bus fleet?
- Is the depot's electricity usage highest during peak periods?
- Can the bus operator use electric bus batteries that have come to their end of life (in terms of use in an electric bus) for battery storage?
- How much will the battery or batteries degrade over time?
- Will installing battery storage improve electricity supply resiliency significantly?
- Would it be beneficial to install on-site generation along with battery storage?

3.1.3. Depot layout and specifications

How an electrified bus depot is laid out, and the specifications of chargers and transformers, can have a significant impact on upfront costs associated with electrifying the depot, ongoing electricity costs, and the cost of upgrading the depot in the future (as the fleet of electric buses expands). These choices will also affect how efficiently the depot can be used and potentially the resiliency of the depot to power outages and equipment failures. Therefore, it is important to consider the appropriate layout of an electrified bus depot and equipment specifications in detail before the depot is connected.

Key components of the depot layout are the chargers, transformers, and the cabling to connect chargers to transformers and the distribution network.[12] Table 2 sets out the impact of depot component choices on costs, resiliency, and efficient use of the depot. Often there will be trade-offs when making depot component choices (for example, installing multiple smaller transformers rather than one large transformer may reduce cabling costs (if fewer metres of cabling are required) and can provide resilience if one transformer fails or catches fire, but will likely increase transformer cost), so the depot owner/operator will need to determine the likely magnitude of trade-offs to determine the best choice for the depot. The depot owner/operator should engage a suitably qualified electrical engineer to assist in electrical design decisions (such as cabling choices).

Table 2: Impact of charger, transformer, and cabling choices on costs, resiliency, and efficiency

		Component:		
		Chargers	Transformer(s)	Cabling
Impact on:	**Upfront costs**	Choosing whether to install alternating current (AC), direct current (DC), or high-power DC chargers will have an impact on cost[13], along with whether chargers are	Total capacity of the transformer(s) will affect upfront cost. Choosing whether to install one large transformer or multiple smaller transformers could also impact	Upfront cost will be higher the more cabling is required, so to the extent possible, cabling length should be minimised. While cabling costs are not too significant if

[12] Distribution boards are also required, but the choice of distribution board will have little impact on costs, resiliency, and efficiency so they are not considered here.

[13] There are some buses that can only accept DC charging, while others can accept both AC and DC charging. Further discussion of AC and DC chargers, including the pros and cons of each, can be found in sections 3.1.5 and 3.1.6 of the Waka Kotahi's *Battery Electric Bus Charging: Public Transport Design Guidance:* https://www.nzta.govt.nz/assets/Walking-Cycling-and-Public-Transport/docs/public-transport-design-guidance/battery-electric-bus-charging/public-transport-design-guidance-battery-electric-bus-charging.pdf.

		Component:		
		Chargers	Transformer(s)	Cabling
		single dispenser (plug) or multiple dispenser (typically 2-4). Location of chargers will affect the length (and therefore cost) of cabling required.	upfront cost—multiple smaller transformers may be more expensive than one larger transformer, but having multiple smaller transformers may reduce length of cabling required (from transformer(s) to chargers).	aluminium cabling can be used, the cost of trenching and making good can be significant.
	Ongoing electricity costs	Will have an impact to the extent that charger choice limits or allows optimal smart charging choices (see discussion on smart charging in section 3.2.1).[14] The power factor of the chargers could also affect ongoing electricity costs if the EDB has a power factor charge (see discussion on power factor in Box 1 below).	EDB may require the depot to pay a capacity charge, so the total capacity of the transformer(s) will affect ongoing electricity costs. When deciding on the size of the transformer(s), the depot owner/operator will need consider what their charging needs are and what ability they have to spread bus charging over the day. This is discussed in more detail in section 3.2.1. Some EDBs also have 'break-points' in their capacity charges which means there can be big jumps (and occasionally falls)[15] in the capacity charge for a small increase in capacity—these break-points should be taken into account when considering transformer size. The power factor of the transformer(s) could	There will be voltage drop in cabling, which will affect ongoing electricity costs (if voltage drop is higher, it will increase the electricity consumption required to charge the buses). Voltage drop of a cable depends on cable length, the current to be carried, and the electrical resistance of the cable. The depot owner/operator should engage a suitably qualified electrical engineer to assist in cabling decisions.

[14] Note that buses also have different charge acceptance rates, and a bus will only charge at its maximum rate even if the charger installed is higher power. However, DC charge acceptance rates are tending to increase with new bus models as battery technology develops.

[15] This can occur if an EDB changes the method for charging customers above a certain capacity – this is currently the case for Wellington Electricity as shown in Figure 3 below.

		Component:		
		Chargers	Transformer(s)	Cabling
			also affect ongoing electricity costs if the EDB has a power factor charge (see discussion on power factor in Box 1 below).	
	Cost of future upgrades	Probably not cost effective to install extra chargers at onset to allow for future growth in electric bus fleet (although this will depend on how fast the fleet is expected to grow). However, if possible, the depot should be laid out to allow for additional chargers to be installed later. In addition, the depot owner/operator should consider installing cabling (or trenching/ducting for cabling) for any additional chargers likely to be required in the future (see last column).	May not be cost effective to install extra transformer capacity at onset to allow for future growth in electric bus fleet (especially if depot must pay a capacity charge)[16], but depot should be designed to allow for additional transformers to be installed later if possible.	Likely to be cost effective to install future cabling requirements such as trenching / ducting (for both power and communications) at onset—installing cabling requires significant earthworks (which is costly) and could significantly disrupt efficient use of the depot if left until later.[17]
	Resiliency	Choice of chargers (eg, high power DC chargers versus AC or lower power DC chargers) could affect how quickly the depot can get electric buses back on the road following a power outage. Depots may have one or two high power DC chargers for ultra-fast charging if needed, with	Having multiple transformers rather than one transformer will mean that some buses can still be charged even if a transformer fails.	N/A

[16] However, the bus depot owner/operator could consider adding a small buffer in capacity to give the bus depot operator time to sort out initial inefficiencies—this will also allow for some growth in the electric bus fleet without requiring additional capacity.

[17] Before pre-installing any ducting, the depot owner/operator needs to ensure that it is possible to add cabling later (this may not be possible, for example, if there are corners in the ducting). An alternative approach is to dig trenches with removable covers at onset so that ducting and cabling can easily be added later.

		Component:		
		Chargers	Transformer(s)	Cabling
		most chargers being lower power DC or AC for overnight charging.		
	Efficient use of depot	Chargers, transformer(s), and cabling should be located to ensure efficient use of depot both now and in the future. This includes ensuring that fully charged buses can depart when needed without having to move other buses out of the way.		

When electrifying a bus depot, the depot owner/operator should consider what their future electrification plans are and what can be done now to ensure that the depot has the necessary electricity supply and infrastructure to meet those plans. For example, a depot owner/operator could upscale infrastructure installation so that it allows for planned growth in the electric bus fleet. Alternatively, a depot owner/operator could make decisions on how it lays out its depot with future growth in mind (for example, designing the depot so that additional cabling can be laid later without disrupting existing charging facilities). An approach that strikes a balance (such as installing some future cabling requirements now to prevent having to dig trenches twice but waiting to install additional chargers and transformers until they're needed) may be the least costly approach.

Bus operators and PTAs should discuss their future electrification plans with their local EDB when discussing their initial connection. This will allow the EDB to advise on whether the network connection needs to be sized to allow for this future growth and to factor in these increased electricity supply requirements into their planning. How and when bus operators and PTAs should engage with their local EDB is discussed in chapter 4.

What to consider when contemplating charger specifications and layout:

The reader should refer to Waka Kotahi's *Battery Electric Bus Charging: Public Transport Design Guidance* (https://www.nzta.govt.nz/assets/Walking-Cycling-and-Public-Transport/docs/public-transport-design-guidance/battery-electric-bus-charging/public-transport-design-guidance-battery-electric-bus-charging.pdf) for what to consider when contemplating charger specifications and layout.

What to consider when contemplating transformer specifications and layout:

- Where should transformer(s) be located?
- Is it better to have one large transformer or two or more smaller transformers?
- What should the total capacity be? What does this total capacity mean for the depot's capacity charge? (for example, is the capacity around a 'break-point' in capacity charges, meaning that a small change in capacity could lead to big jump (or some in cases even a decline)[18] in the capacity charge)

[18] *This can occur if an EDB changes the method for charging customers above a certain capacity – this is currently the case for Wellington Electricity as shown in*

- Should additional capacity be installed to allow for growth in the electric bus fleet?[19] Or should the depot operator/owner ensure there is space and enabling infrastructure (ducting) in the depot to install additional transformers in the future when required?

What to consider when contemplating cabling layout:

- What are the implications of charger and transformer location for electrical cabling? (Electrical cabling can be expensive, so limiting the length of cabling required may lead to cost savings.)
- Should extra cabling be laid now for additional chargers and transformers that may be needed in the future? Or should the depot owner/operator ensure that further cabling (for power and communications) can be installed in the future without interrupting existing use of the depot by installing ducting?

What to consider when contemplating general bus depot layout:

- Does the layout of the bus depot allow space for the electric bus fleet to expand in the future?
- Does the depot layout allow fully charged buses to depart when required without having to move other buses?

Section 3.1 of NZTA's [Battery Electric Bus Charging: Public Transport Design Guidance (2023)] provides more guidance on depot layout considerations and charger specifications and location.

3.2. Use of depot

3.2.1. Smart charging

Smart charging involves being deliberate about when and how electric buses are charged to avoid (or limit) charging during the electricity network's peak periods, to reduce the bus depot's peak electricity consumption, and/or to manage charging of buses to ensure each bus is sufficiently charged when required. This is done by providing remote access to the charging, including potentially by power companies or third parties. Smart charging should save the bus operator money by reducing the amount they pay in retail electricity tariffs and reduce the size of network connection. How much the bus operator can save will depend on the structure of these tariffs (which can vary significantly). Smart charging can also be used to optimise battery life in accordance with different manufacturers' charging recommendations.

Smart charging can also provide electricity consumption data for individual buses to help manage bus electricity consumption. This will require individual vehicle ID (such as an RFID tag) and connection to an appropriate back-end data system. Some smart chargers are smarter than others, so it is important to look at what version of the Open Charge Point Protocol (OCPP) a smart charger uses to ensure it is capable of the functionality your bus depot needs. The OCPP allows communication and data exchanges between electric vehicle charging points and central control systems. Chargers should be verified as compatible with OCPP 1.6 or above and connected to a back-end central control system which can be set up and readily altered at the bus operator's request. Smart charging will also require the depot site to have at least a 4G mobile signal to allow communication with the chargers via the internet.

Box 1: Retail electricity tariffs

Electricity users are billed by their electricity retailer (usually monthly) for their electricity consumption. This bill will be made up of an energy charge (generation, retail, and metering) and a lines charge (distribution and transmission).

Figure 3 below.

[19] Note that the electricity lines charges may include a capacity charge, which could be based on the size of the transformer installed (even if the bus depot is not using all of the capacity). Lines charges are discussed below in Box 1.

Energy charges

The customer's energy retailer will bill the customer for the following energy charges:

- Generation: the cost of procuring electricity from generators. As set out in more detail in section 5, retailers will purchase power from generators – either via the spot market, or via bilateral contracts – and then on-sell the power to end consumers.
- Retail: the retailer's operating costs for billing, customer service, and so on.
- Metering: the cost of reading and maintaining the customer's electricity meter
- Market governance and services: a levy to fund the organisations that regulate and operate the electricity market
- Goods and services tax (GST).

For a large load such as a bus depot, the generation component will be by far the biggest component of the energy charge.

A retailer will typically offer a large commercial and industrial customer a choice of retail plans for the energy charge, with such plans varying in how the risk of generation spot price volatility is shared between the retailer and the consumer. Such plan types include[20]:

- a fixed energy rate ($/kWh), which may vary by time of day (ie, be a time-of-use (TOU) rate) and could be on a fixed term contract,
- a spot market linked plan where the price ($/kWh) is linked to wholesale electricity market spot prices,
- a mixed plan – some electricity use charged at a fixed energy rate and some spot market linked, or
- a custom plan.

The retail plan will typically also include a daily fixed charge.

Lines charge

As well as charging for the consumption of electricity, the customer's electricity retailer will also charge the customer for electricity distribution and transmission costs (the lines charge). This lines charge covers costs that the EDB will charge to the retailer (the distribution tariff). The retailer may directly pass through the distribution tariff to its customers, or it may re-structure the distribution tariff and/or bundle it with other retail charges (see energy charges above).

Each EDB is required to publish distribution tariffs once a year (and these are available on the EDB's website). Distribution tariff structures may change from one year to the next.

kW or kVA – what's the difference?

Some lines charges are quoted in $/kW, while others are quoted in $/kVA. They are both a measure of capacity and can be considered broadly equivalent—that is, 1 kW is roughly equal to (although generally a bit less than) 1 kVA.

The difference relates to the power factor (pf) which is a measure of the efficiency of the equipment in turning 'apparent' power (measured in kVA) into useful output as 'actual' power (measured in kW). The relationship is kVA x pf = kW. Typical power factors range between 0.8 and 1.

Some EDBs have a "power factor charge" (see discussion on lines charges later in Box 1).

[20] Note that the examples of retail plans are just a selection of plans available at the time of writing. There are a variety of other plans from different retailers and the depot owner/operator should "shop around" to get the best deal for their situation (which is discussed further at the end of Box 1).

In the context of an electric bus depot, the power factor will depend largely on the transformer, but buses and chargers can also affect the power factor. When purchasing buses and chargers, the depot owner/operator should look at the power factor of the buses and chargers – some chargers have power factor correction to over 0.99.[21]

The structure of distribution tariffs varies by EDB and can include some combination of the following charges:[22]

- Daily fixed charge: $/day (charged by most EDBs)
- Connection capacity charge: $/kVA/day (charged by about half of EDBs)
  - an EDB may also charge a higher capacity charge for any measured demand above an agreed capacity limit
- Consumption charge: $/kWh (charged by most EDBs)
  - flat rate, or
  - time-of-use (TOU) rate, with higher rates during peak periods (usually morning and evening on weekdays, sometimes also differentiating between summer and winter)
- Measured peak capacity charge: $/kW/day (charged by about 40 percent of EDBs) – this could take various forms:
  - Anytime Maximum Demand (AMD) – the maximum demand of the customer during any half-hour period during the year
  - On-peak demand (summer or winter) – the customer's maximum demand in summer/winter during peak hours (for example, 7am to 11am and 5pm to 9pm)[23]
  - Coincident peak demand[24] (CPD) – the customer's average demand during periods when the EDB is experiencing peak demand.
- Distance charge: $/kVA-km/day, with distance being from the customer's premises to the nearest major substation (only one EDB currently has this charge)
- Dedicated asset charge: $/kVA/month – this is for the recovery of transformer assets which are dedicated to a consumer (charged by around 20 percent of EDBs)
- Power factor charge: $/kVAr/month – this charge type is intended to incentivise consumers with poor power factors to take measures to improve them (charged by around 25 percent of EDBs).

Some distribution pricing structures have capacity 'break-points' with step-changes in the connection capacity charge. For example, Figure 3 shows the distribution tariffs for five example EDBs for different installed capacities.[25] EDB2 and EDB4 networks have significant 'break-points' in their connection capacity charges—for the EDB2 network this means there is a significant jump up in the distribution

[21] While an EDB may not currently have a power factor charge (see discussion on lines charges in Box 1), they could add a power factor charge in the future. Therefore, it is recommended that all depot owner/operators consider power factor when purchasing equipment.

[22] Note that the number of EDBs that have various charges will change over time.

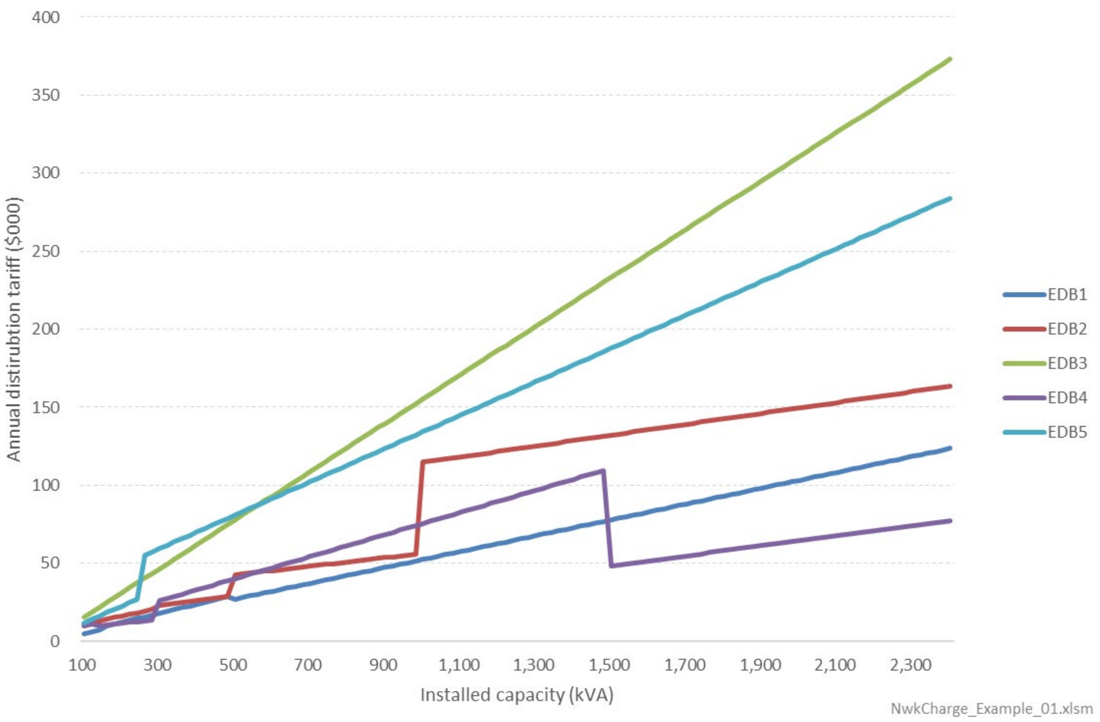
[23] Peak hours can vary by EDB – for example, Wellington Electricity has peak periods of 7:30am – 9:30am and 5:30 pm – 7:30pm for its on-peak demand charge (but does not differentiate between summer and winter).

[24] Coincident peak demand is sometimes referred to as 'control period demand' and applies when the EDB is controlling/managing demand during its period of system peak.

[25] The distribution tariffs have been modelled on an example bus operator that does 80% of charging during the electricity network's off-peak period, and 10% during each of the network's peak and shoulder periods.

tariff when the installed capacity increases to 1,000 kVA, while for EDB4 the distribution tariff *falls* substantially when the installed capacity increases to 1,500 kVA.[26]

Figure 3: Illustrative distribution tariffs for different installed capacities[27]



Distribution tariff structures may change for some EDBs in the future due to ongoing reform of distribution pricing by the Electricity Authority to make it more cost reflective. This should reduce distribution tariffs in the long term, but also means that the structure of distribution tariffs could change over time.

For example, in a 2022 Electricity Authority letter to EDBs, the Electricity Authority said it expected "distributors to reduce their use of charges based on a customer's own AMD as soon as possible" as it considered AMD over-signalled distribution network costs.[28]

How to choose a retail plan and retailer

Which type of retail plan a bus operator chooses will depend somewhat on their appetite for risk. Wholesale electricity spot prices can vary significantly both within-day and over the course of the year due to changes in electricity supply and demand. For example, electricity supply can fall if there is little wind to power wind turbines or if inflows into hydro catchments are low, which will push electricity prices up. In addition, if demand for electricity increases because cold weather increases the use of heating, this will also push prices up.

Figure 8 in Section 5.1.1 shows that spot prices typically sat anywhere between $0.01 and $500 per MWh over 2021 and 2022. However, prices sometimes spiked much higher due to low electricity supply, high electricity demand, or a combination of both. Figure 4, below, shows that even on relatively benign days, spot prices can change substantially within a day, particularly in winter.

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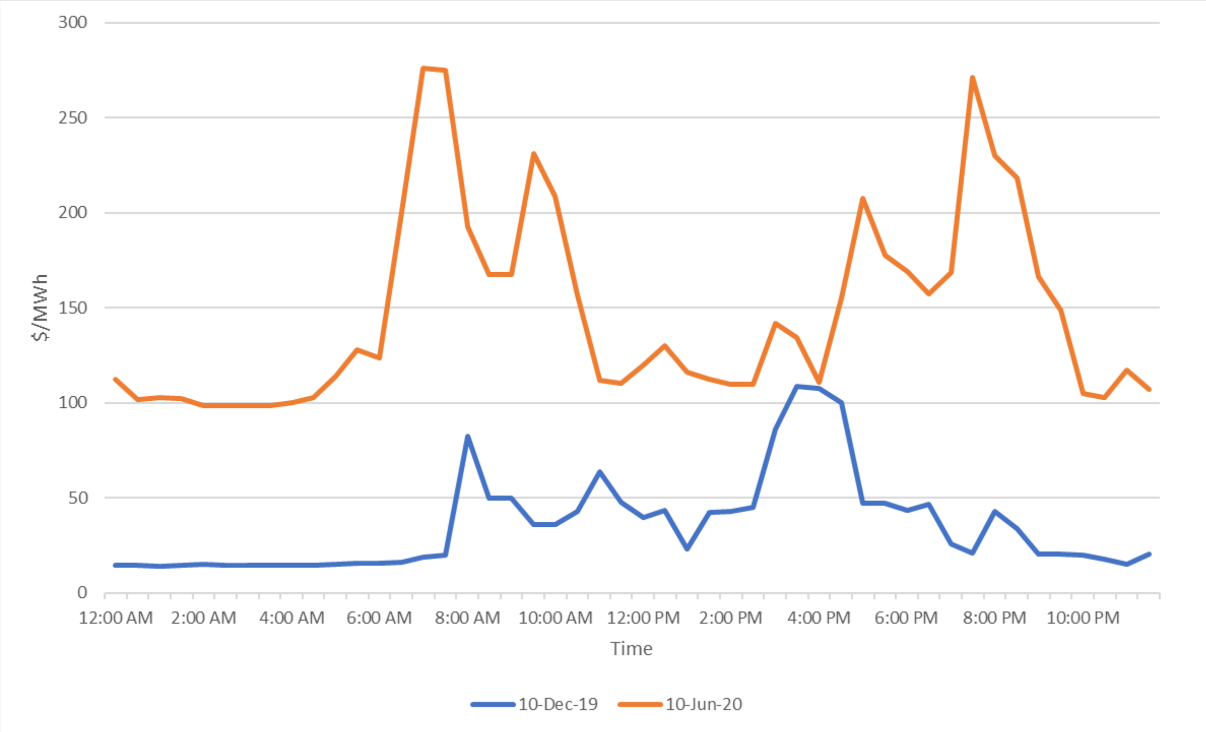
[26] This counter-intuitive outcome for ED4 is due to consumers above a certain capacity being charged on a CPD basis, whereas smaller consumers are charged on an AMD basis. The CPD basis rewards consumers for being smart and avoiding charging outside of the EDB's peak periods, which for this example all bus companies are assumed to do, whereas an AMD charging approach provides much less opportunity to avoid charges by being smart.

[27] Distribution tariffs are for the 12 months starting April 2023.

[28] p6, https://www.ea.govt.nz/documents/1878/Letter-to-distributors-re-pricing-September-2022.pdf.

Figure 4: Illustrative winter and summer wholesale electricity spot prices



If a bus operator goes on a spot market linked plan, they may enjoy very low prices if electricity supply conditions are favourable (for example, hydro inflows are high), but also risk getting a very high electricity bill if New Zealand experiences a dry-year event. In some months, a customer on a spot market linked plan could easily face an electricity bill that is five times their usual bill.

The bus operator could manage this pricing risk by limiting electricity use when spot electricity prices are high, but there may be little or no warning of high spot prices. Even if there is warning of high spot prices, a bus operator is unlikely to have much flexibility to move its electricity use to lower-priced periods (because buses need to be sufficiently charged to service their routes). Electricity price risk can also be managed by purchasing electricity hedges[29] (either directly or through a third party).

If the bus depot goes on a fixed energy rate then the retailer will need to manage the spot market price risk, which will be factored into the fixed energy rate (that is to say, it will be higher than the expected average price on a spot market linked plan).

Consumers have a choice of retailers. A bus operator should consider going to tender to get offers from multiple retailers as the size of their demand means they are likely to get better deals than standard posted tariffs. For operators with buses in different cities around New Zealand, these tenders could be for aggregated demand across multiple depots across different parts of the country.

In some cases, it may make sense for the PTA to arrange a retailer and negotiate pricing. For example, if the PTA owns the depot and there are multiple bus operators operating from the depot, the PTA may deal with the retailer and then on-charge the bus operators for their usage. The PTA may also be in a better position than a bus operator to negotiate a better retail deal (particularly if they can aggregate their demand across other parts of the PTA's/regional council's business).

A bus operator or PTA can get an idea of what retailers offer commercial electricity plans in their area by looking at: [Electricity Authority - EMI (market statistics and tools) (ea.govt.nz)]() and selecting the relevant region.

[29] An electricity hedge is a financial contract between two parties that can be used to manage future electricity price risk. Hedges can be purchased directly from another party or on the Futures and Options Exchange on the ASX.

Some examples of how a depot owner/operator could reduce electricity costs using smart charging are:

- if the depot has a TOU charge, or a CPD charge, then it will be cheaper to charge buses overnight than during peak electricity periods (which are usually in the morning and evening)
- if the depot has an AMD distribution capacity charge, then the depot's distribution charge will depend on the depot's maximum demand during any half hour period during the year (or sometimes the previous month), so the depot owner/operator will save if it reduces the bus depot's peak electricity consumption by spreading demand (charging) across a wider span of hours[30]
- if the depot is on a spot price linked retail plan, then it will be cheaper to charge buses when electricity spot prices are lower (although this may be difficult to predict in advance)[31]
- if the depot intends to use smart charging at the planning stage of bus depot electrification, and is confident about its ability to reduce the bus depot's peak electricity consumption, it could reduce the capacity of the connection that is required (including the size of the transformer needed) and therefore reduce its connection charges
- if the smart charger provides individual bus electricity consumption data, this data can be used to identify buses that are consuming more electricity than expected (which could be due to technical issues or driver behaviour), and the bus operator can then identify interventions to remedy the situation.

Smart charging can vary in its level of 'smartness'. For example, if the bus depot is just wanting to manage its charging to avoid higher priced periods on a TOU plan, then the charging plan could be relatively simple and could be completely manual (for example, the depot could start charging buses as soon as the lower night-time rate starts). Managing spot price movements, limiting demand during control periods (where there is a CPD capacity charge), or managing buses with different range limits and charging rates (for example, due to battery degradation) will likely require smarter automated systems. Some manufacturers offer depot management applications which facilitate smart charging to optimise energy use, as well as managing charging rates and duration of charge for electric bus fleets.

Section 3.2.2 illustrates the potential annual lines charge cost savings from using a reasonably simple smart charging plan.

When using smart charging, the depot owner/operator needs to ensure that the charging plan still allows each bus to be sufficiently charged to meet its required range (that each bus is sufficiently charged before it starts its routes in the morning) and needs to allow for degradation of batteries over time.

Smart charging may also need to manage any restrictions that the local EDB puts on how much electricity a bus depot can use at certain times of the day. For example, for a depot that has a 2 MVA capacity, the EDB may limit the bus operator to using 1 MVA during daytime hours.

A bus operator could decide to get someone else to manage their smart charging for them. Section 3.2.5 considers opportunities to get a specialist to manage smart charging for the bus operator or even to provide all charging infrastructure as a service.

What to consider when developing a charging plan:

- Should internal capability in specifying, managing, and maintaining charging infrastructure be developed? Should internal capability in managing smart charging be developed? Or should all (or some) of this be outsourced?
- Do buses need to be charged during peak electricity periods or can they be charged off peak? Do buses need to be fast-charged or can be charged more slowly overnight to limit peak electricity demand?
- Are you willing to have electricity usage capped? If yes, are you willing to have it capped at all times or only during certain periods? (For example, when the electricity network is at peak usage).

[30] However, if the depot also has a TOU charge, spreading demand by moving some (or more) charging into a peak electricity period may not reduce electricity costs.

[31] Spot prices are usually lower overnight than during the day, but this is not always the case.

- How can you design a charging plan to reduce distribution and retail tariffs?
- Can the charging plan be simple (for example, slow charge all buses from start of network's off-peak period) or is a more complex and reactive charging plan needed?
- How can the charging plan be designed to limit peak demand and still meet the needs of the bus fleet and timetabled route requirements?
- What information is needed from the smart charging system to help manage the operator's bus fleet and drivers?

3.2.2. Scenario 1: potential benefits of smarter charging

As discussed above in section 3.2.1, if a bus operator uses smart charging, they could save money by reducing the amount they pay in retail tariffs (both energy and lines charges). The extent of these savings will depend on various factors, including the structure of the EDB's distribution tariffs and whether the retailer passes through the EDB's distribution tariffs directly to the bus operator or bundles them with energy charges.

Figure 5, below, shows how much a hypothetical bus operator will pay in retail tariffs in each of the five example EDB networks[32] under two alternative charging regimes. This illustrative example is intended to show the potential magnitude of savings that a bus operator could make if it uses "smarter" charging.

This illustrative example is for a depot of 50 electric buses that each consume approximately 160 kWh/day of electricity.[33] The example assumes that retailer directly passes through the EDB's distribution tariffs to the customer and has a TOU-based energy charge.[34]

Under the first charging regime 'fast-charge during evening', the bus operator fast charges each bus as it comes into the depot in the evening—this means that most of the bus charging occurs during the electricity network evening peak and also requires the bus depot to have a larger connection capacity to allow many buses to be fast charged at the same time.[35]

Under the second charging regime 'optimised during night', the bus operator waits to charge buses overnight during the electricity network's off-peak and spreads the charging over the entirety of the off-peak period—this means that the bus depot can have a smaller connection capacity as the charging is spread over a greater number of hours.[36]

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[32] These five example networks were chosen as they represent a range of distribution tariff structures.

[33] This is based on a typical 40-seater bus travelling 200 km per day on average and an efficiency of 0.8 kWh/km.

[34] Where the TOU charge is based on a peak, shoulder, and off-peak periods.

[35] In the 'fast-charge during evening' charging regime, 60% of charging is during the electricity network's peak period, 20% during its shoulder period, and 20% during its off-peak period. The bus depot has a 2,000 kVA capacity (capacity is set to allow for 25% of daily consumption to occur in one hour).

[36] In the 'optimised during night' charging regime, 10% of charging is during the electricity network's peak period, 10% during its shoulder period, and 80% during its off-peak period. The bus depot has a 1,000 kVA capacity (capacity is set to allow for 12.5% of daily consumption to occur in one hour).

Figure 5: Illustrative retail electricity cost for two different charging regimes[37]

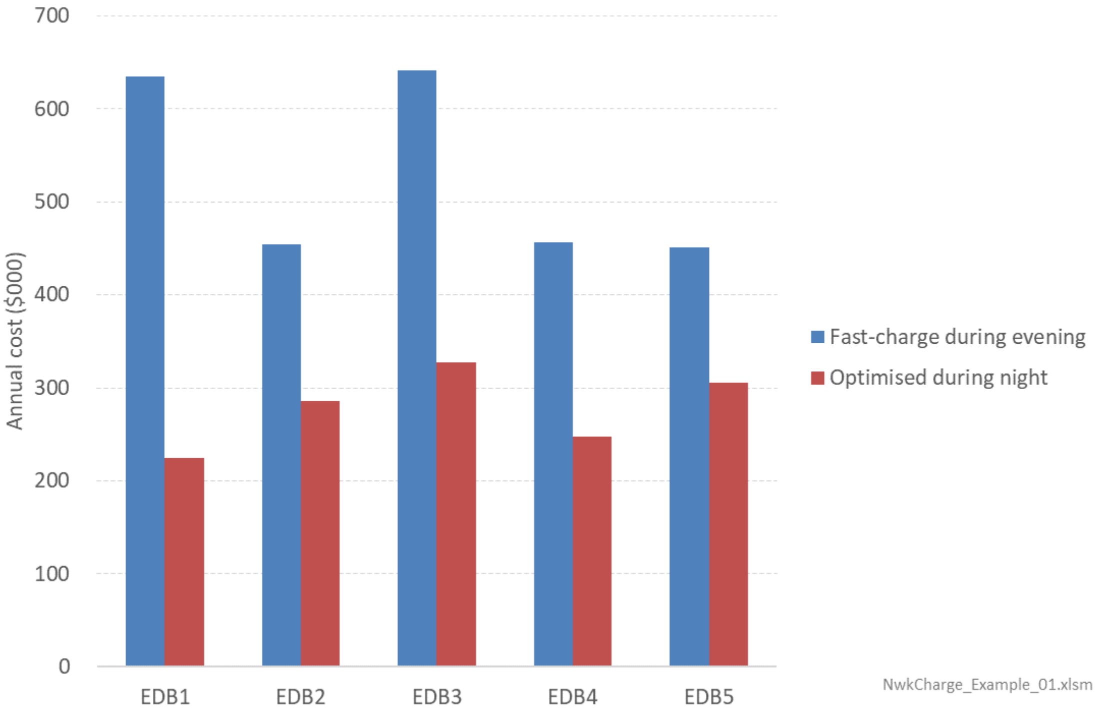

Figure 5 shows that for each EDB, the annual retail charge (which covers both energy and lines charges) is lower if the bus operator optimises its charging during the night (the red bars) rather than fast-charging during the evening (the blue bars). This is because:

- a TOU-based energy charge is assumed (which charges more for consumption during peak periods (including the evening) than shoulder or off-peak)
- two of the EDBs have a TOU-based lines charge (EDB2 and EDB3)
- two other EDBs have a capacity charge (EDB1 and EDB4) – this means that the greater capacity required for the 'fast-charge during evening' charging regime costs more than the lower capacity required for the 'optimised during night' charging regime.

The difference in retail electricity cost between the two charging regimes is lowest for a customer on EDB5's network because EDB5's distribution tariff includes a consumption charge that doesn't differentiate between peak, shoulder, and off-peak periods and doesn't have a capacity charge. The difference in cost between the red and blue bars for a customer on EDB5's network is due entirely to the TOU-based energy charge.

As set out above, it is likely that EDBs will progressively move towards more cost-reflective tariffs. Any changes to tariff structures will alter the lines costs for depots regardless of the type of charging regime they use. However, in general, moves to more cost-reflective tariffs will tend to increase the benefit for 'smarter' charging regimes (such as optimised charging overnight).

3.2.3. Scenario 2: potential benefits of installing battery storage

Installing a battery can enable a lower connection capacity (and therefore lower upfront capital costs for network upgrades) and should enable lower ongoing energy and lines costs.[38]

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[37] Costs are based on distribution tariffs for the 12 months starting April 2023.

[38] There may be some ongoing costs associated with installing a battery (for example, maintenance), but these are likely to be insignificant.

The extent of benefit will strongly depend on network circumstance, particularly the level and structure[39] of lines charges, and how much connection cost will vary with connection capacity.

To illustrate, a worked example has been developed for a hypothetical 1.5 MWh battery with a four-hour storage capability (resulting in a 0.375 MW peak capacity), and with an assumed 1 percent per annum degradation in storage capacity, that delivers the following benefits:

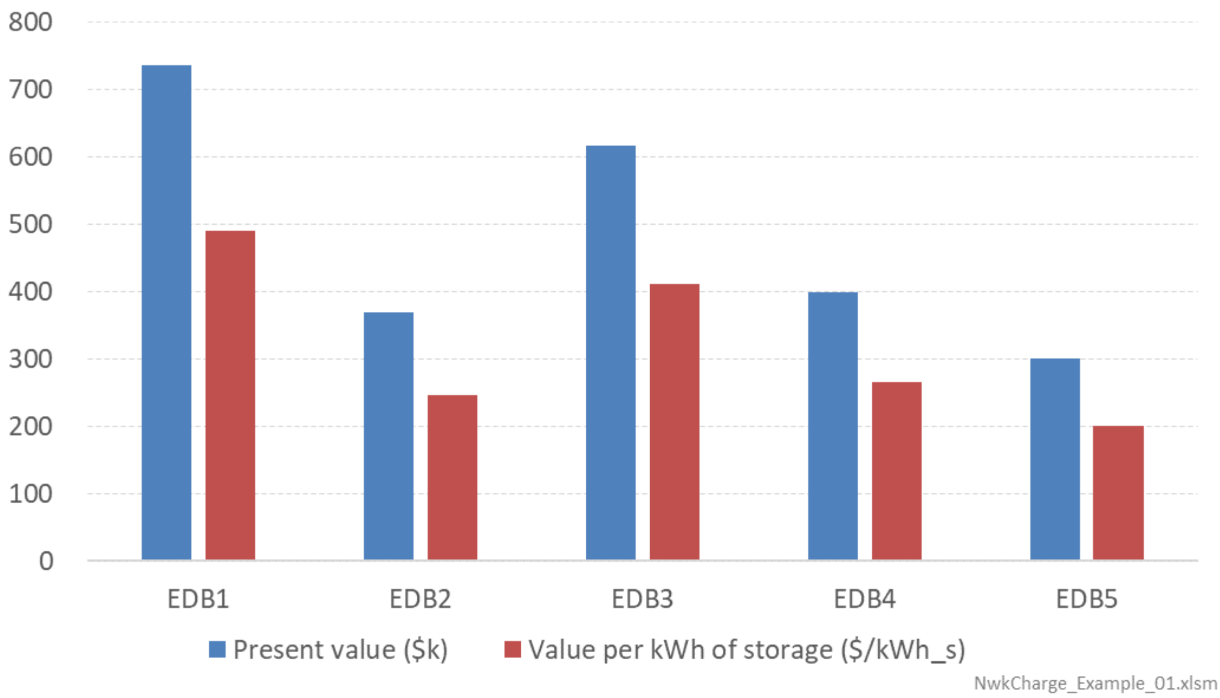
- Lines charge benefits:
  - Reducing a depot's consumption in network peak periods by 1.5 MWh, but leading to an increase in off-peak periods by 1.5 MWh x (1+15%), with the 15% representing the energy lost when charging and discharging the battery[40]
  - Reducing the capacity of the depot connection by 0.19 MW. (This is on the assumption that the battery could be reliably called to discharge over an 8-hour period, hence 1.5 MWh ÷ 8 hr ≈ 0.19 MW)
  - Reducing the measured anytime peak capacity of the depot by the same amount
  - Reducing the depot's measured contribution to the network's peak demand by 0.25 MW (based on the assumption that 2/3 of the battery's peak capacity can reliably be called upon during network peak periods)
- Energy charge benefits:
  - Arbitraging energy prices in the wholesale market in terms of purchasing power during off-peak periods (at an assumed average price of 5 c/kWh) and discharging during peak periods (at an assumed average price of 15 c/kWh).

Figure 6 shows the results of the analysis for the five example EDB network areas, with the benefit expressed in terms of the present value of ten years' worth of battery benefits (the blue bars) as well as also expressing this value in terms of dollars of benefit per kWh of storage capacity (the red bars) – this latter metric being useful to compare with the cost of installing a battery which is typically quoted in $/kWh of storage.

[39] The structure of lines charges refers to whether a network has TOU pricing, capacity charges, measured peak charges, etc, as set out in more detail in Box 1 on page 15.

[40] This energy loss is often referred to as the round-trip loss efficiency.

Figure 6: Value of battery in different networks



As can be seen, the value varies significantly depending on the lines charges in the different networks.

A projection from the International Energy Agency[41] suggests that by 2025, new utility-scale batteries could cost approximately NZ$450/kWh_s.[42] If a battery could be installed that cheaply, it would be cost-effective in the EDB1 network, but none of the other networks considered.

However, if the smaller size of the battery also reduces the scale of an up-front connection cost, it is possible that the installation of battery capacity in the EDB3 network could become cost-effective (although only if a considerable up-front cost could be avoided).

Further, over time, bus operators should have access to cheaper batteries, in the form of bus batteries that have reached the end of their economic life for transport purposes but could still be usefully used to shift electricity use from network peak periods to off-peak periods.

When evaluating potential battery investments to lower their electricity costs, bus companies should also be mindful of the potential for lines companies to change both the level and structure of their lines charges. In part this will be driven by the Electricity Authority which has indicated that networks need to introduce progressively more cost-reflective lines charges.

In part, this will also be driven by the changing economics of batteries themselves which are likely to alter future energy and network costs:

- as batteries are installed and respond to within-day energy prices, the within-day differentials between peak and off-peak prices should reduce until they reach a level which will just reward the marginal new battery scheme
- as utility-scale batteries become cost-effective alternatives to networks building additional lines capacity, the cost of installing utility batteries should become the price of capacity signalled in cost-reflective lines charges.

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[41] https://www.iea.org/data-and-statistics/charts/capital-cost-of-utility-scale-battery-storage-systems-in-the-new-policies-scenario-2017-2040.

[42] IEA value factored by US$/NZ$ exchange rate and correcting for inflation since 2017.

Thus, as energy and lines charges change, battery investments may only become cost-effective if they can be installed more cheaply than the utility-scale batteries that will tend to be the marginal source of within-day energy flexibility.

However, in the short-term, installing batteries may be cost-effective if networks are slow to reform their tariffs or the market is slow to install batteries.

3.2.4. Multiple users of chargers

There may be other electric heavy vehicles that could utilise the chargers installed at an electrified bus depot. Allowing these other vehicles to use the depot's chargers could provide an opportunity for other heavy vehicle operators to contribute to the capital and operating costs associated with electrifying. The benefit of allowing other heavy vehicle operators to use the chargers is likely to be highest if the other operators can charge their vehicles when the bus fleet is not usually fully utilising the chargers. However, this may not be the case if these times coincide with peak periods on the distribution network (and distribution tariffs are higher at that time).

If the depot operator allows other heavy vehicle operators to use chargers at the depot and charges them for electricity use, the depot operator could be classified as an electricity retailer, which would put additional obligations on the depot operator (for example, compliance with the Electricity Industry Participation Code 2010 (Code) administered by the Electricity Authority[43]). Charging other heavy vehicle operators for electricity use would also introduce on-billing requirements—the depot operator may want to consider engaging a Mobility Service Provider (MSP) to provide this service rather than doing it in-house.

What to consider if contemplating allowing other operators to use chargers:

- If other operators are allowed to use chargers, does this increase the risk that buses won't be able to be charged when needed? How can this risk be minimised?
- What constraints should there be on other operators' use of the chargers? (for example, limited time of day that other operators can use chargers, and/or maximum number of chargers that an operator can use at once)
- If there are multiple users of the chargers, what happens if there is a power outage? How do you decide who gets priority when power is restored?
- Will allowing other operators to use chargers reduce electricity costs? How can a charger-use agreement be structured to minimise the bus depot operator's electricity charges?
- If other operators are allowed to use chargers, how will their charger and/or electricity use be tracked, and how will other operators be billed? Should an MSP be engaged to provide on-billing services?

3.2.5. Scenario 3: potential benefits of getting smart charging or charging infrastructure as a service

There are companies that will provide smart charging and infrastructure services to bus operators. These services can range from just providing smart charging software, through to providing and owning charging infrastructure and batteries. A specialist company that provides smart charging services may be better able to design and employ smart charging to minimise ongoing electricity costs (and possibly connection costs) than a bus operator. They can also prioritise which buses get charged first, so that buses used on routes with earlier timetabled starts are fully charged ahead of buses with later starts.

For example, a specialist company may be able to design more sophisticated charging software that increases how much charging is done during the electricity network's off-peak by 10 percentage points (for example, from 70% to 80%). For a depot of 50 buses this could save tens of thousands of dollars per year in retail electricity charges.[44]

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[43] Section 6.2 provides more information on the Code.

[44] For the five EDBs in scenario 1 (in section 3.2.2), the annual savings would be $20,000 - $30,000 depending on the EDB (under certain assumptions).

If a bus operator engaged a specialist company to provide and own charging infrastructure and batteries this would shift risks associated with infrastructure or battery failure from the bus operator to the specialist company.

A bus operator will need to consider whether engaging a specialist company to provide any of these services will provide net savings.

3.3. Summary of depot characteristics and use choices and their impact on costs and resiliency

Table 3 provides a summary of the impact that choices around depot characteristics and the use of the depot can have on costs and resilience.

Table 3: Summary of depot characteristics and use choices and their impact on costs and resiliency

	Potential impact on:				
	Electricity connection cost	**Other upfront costs**	**Ongoing electricity costs**	**Cost of future depot upgrades**	**Resiliency**
Depot location	Connection costs could be reduced by locating a depot: • where the distribution network is not constrained • near a zone substation, and/or • across multiple sites.			Cost of future depot upgrades could be reduced by locating a depot: • where the distribution network is not constrained, and/or • where the EDB is already planning network upgrades.	Resiliency could be improved by locating a depot: • on a meshed part of the distribution network, and/or • across multiple sites (that are connected to different zone substations).
On-site generation	Installing on-site generation may reduce the electricity connection cost if it means a smaller connection capacity is needed.	Installing on-site generation may increase upfront costs because of: • the cost of purchasing and installing generation equipment, and/or • potentially the need for a bigger depot to allow space for generation equipment. However, there are emerging options where solar generation can be installed by a third party	Installing on-site generation should reduce ongoing electricity costs because: • once solar (or wind) generation is installed it can be run at a very low cost, and • if the on-site generation means a smaller connection capacity is needed and the depot operator is charged a capacity charge, then the capacity charge will be lower.		Installing on-site generation could improve resiliency to power outages by providing an alternative electricity source.

	Electricity connection cost	Potential impact on: Other upfront costs	Ongoing electricity costs	Cost of future depot upgrades	Resiliency
		with no upfront capital costs.			
Battery storage	Installing battery storage may reduce the electricity connection cost if it means a smaller connection capacity is needed.	Installing battery storage may increase upfront costs because of: • the cost of purchasing and installing a battery[45], and/or • potentially the need for a bigger depot to allow space for the battery. However, there may be options to lease battery storage (with minimal or no upfront cost).	Installing battery storage could reduce ongoing electricity costs if: • buses need to be charged during the electricity network's peak, and/or • the storage means a smaller connection capacity is needed and the depot operator is charged a capacity charge, then the capacity charge will be lower. Installing battery storage will have little or no impact on ongoing electricity costs if buses can be charged during electricity network off-peak (for instance, overnight).		Installing battery storage could improve resiliency to power outages by providing a short-term alternative electricity source.
Depot layout and specs		Depot layout can increase or decrease upfront costs. For example, changing the depot layout could reduce the length of electric cabling (and	Charger choice could affect ongoing electricity costs if charger choice limits optimal smart charging choices. If the depot owner/operator is required to pay a capacity charge, then the total capacity	Ensuring that depot layout allows for future growth in electric bus numbers (for instance, by installing cabling for future depot upgrades)	Resiliency could be improved by: • installing at least some high-power DC chargers so that buses needing to go out first

[45] The purchase cost could be avoided if the depot owner/operator uses batteries that was previously installed in a bus.

	Electricity connection cost	Potential impact on: Other upfront costs	Ongoing electricity costs	Cost of future depot upgrades	Resiliency
		associated trenching) needed. Specifications chosen for chargers and transformers will also affect upfront costs.	of the transformer(s) will affect ongoing electricity costs.	will minimise the cost of future upgrades.	can be charged quickly following a power outage[46] • having multiple transformers rather than one (so that some buses can still be charged even if a transformer fails)[47].
Smart charging	If smart charging is used to reduce the bus depot's peak electricity consumption this may reduce the connection capacity required (including size of transformer needed), potentially making connection cheaper.	Could be the cost of acquiring automated smart charging equipment.	If smart charging is used to limit charging during the electricity network's peak periods, this will likely reduce the depot operator's electricity bill (depending on tariff structure). Additional income may be gained by reducing demand or supplying electricity back to the grid (if electric buses are V2G[48] configured) at certain times through participation in demand management programmes. There may be an ongoing charge for using a smart charging system (however,		

[46] However, the depot operator may be limited by how quickly it can charge buses following a power outage by the depot's connection capacity and/or any electricity use agreement it has with the EDB (eg, to limit electricity use during daytime hours).

[47] Generally, transformers are reasonably reliable, so the risk of transformer failure is quite low. However, if a transformer at a bus depot does fail and the bus operator is therefore unable to charge buses, the cost to the bus operator of transformer failure could be significant.

[48] Vehicle-to-Grid (V2G) technology allows an electric vehicle to supply energy back to the electricity network from its battery.

	Potential impact on:				
	Electricity connection cost	**Other upfront costs**	**Ongoing electricity costs**	**Cost of future depot upgrades**	**Resiliency**
			this should be offset by savings in electricity charges).		
Multiple users of chargers			Could reduce ongoing electricity costs payable by the depot operator depending on how it charges other operators for using the chargers.		Resiliency to power outages could be reduced if depot operator not given priority use of chargers following a power outage.

4. Engagement with local EDB

4.1. The roles of the local EDB, bus operator, and PTA in depot electrification

There are 29 EDBS in New Zealand that own the electricity distribution networks that take electricity from the national grid to electricity consumers. To get a new or upgraded electricity connection, a depot owner needs to engage with their local EDB to arrange the connection. More information on EDBs including which EDB owns the network in each part of the country can be found in section 5.1.3.

If a bus depot that is getting electrified is owned by a bus operator, then it will be the responsibility of the bus operator to arrange the new or upgraded connection with the local EDB. However, the PTA may have some involvement—what this involvement looks like will depend on the PTA and the commercial arrangements between the PTA and bus operator. Some PTAs may choose to take a leading role engaging with the local EDB (at least initially, for example see Box 2 below on Auckland Transport (AT)'s engagement with Vector), while other PTAs may choose to have little involvement at all. A bus operator needing to get a new or upgraded connection for electrifying a bus depot should talk to their PTA at the start of the process to ascertain what the PTA's involvement will (or can) be.

Box 2: Auckland Transport's engagement with Vector

Auckland Transport (AT) and Vector signed a Memorandum of Understanding (MoU) in 2020. This MoU was signed to look at ways to reduce the cost of electrifying Auckland's bus fleet. In 2022, Vector completed a study into what it would take to electrify all of Auckland's bus fleet with high-capacity charging infrastructure at each of AT's 21 bus depots.[49] AT has identified which depots will be electrified in the next few years and have engaged with Vector to determine what power supply is available now and what will be available in the future. When a bus operator is looking at electrifying an Auckland bus depot, AT will engage with Vector to get a high-level costing and charging scheme for the bus depot. AT will then take this information to the bus operator who then engages directly with Vector. It then becomes the bus operator's responsibility to work towards signing a commercial agreement with Vector, although AT can still help the bus operator if requested.

If the PTA owns a bus depot that is getting electrified, then the PTA will be responsible for arranging the new or upgraded connection.

There may be benefits in PTAs, and local government authorities more generally, being pro-active in working with their local EDB to help coordinate the electrification of bus depots with electrification of other parts of the local economy (for example, other public transport (such as rail or ferries), truck depots, and industrial boilers). This is because there may be opportunities for lower cost outcomes if EDBs can anticipate broader electrification-driven upgrade requirements across their networks, with consumers sharing the costs of better-optimised network upgrades.

4.2. What is needed for productive EDB engagement?

4.2.1. Timing for EDB engagement

It is critical that a bus operator or PTA wanting to electrify a bus depot engage early with the local EDB – getting or upgrading a connection to the local electricity network is a lengthy process that can be delayed by supply chain issues (for instance, in some cases it has taken 18 months for a transformer to be installed). One EDB spoken to as part of preparing this guide said that if a large depot is getting electrified, then the depot owner should be talking to them about three years before the connection is needed. In

[49] https://www.vector.co.nz/articles/vector-electrifies-auckland-bus-depots.

most cases, a smaller depot will take less time (as it is less likely that major upgrades will be needed). In addition to engaging with the local EDB early, the earlier the depot owner can commit to getting the new or upgraded connection, the earlier the EDB will be able to procure the transformers and other associated equipment, and get the depot connected.

4.2.2. Preparation for first engagement with the local EDB

Engagement with the local EDB is likely to be more productive if the bus operator and/or PTA comes prepared. The bus operator and/or PTA should have the following information prepared when first meeting with the local EDB:

- Precise location of depot to be electrified. Alternatively, if there is more than one possible depot location, the depot owner should provide the location of each of these sites.
- Proposed charging plan (or possible charging plans). A charging plan should include:
    - What will the depot's peak electricity demand be?
    - What time of the day will peak electricity demand be?
    - What's the electricity load shape likely to be? (what will the depot's electricity demand look like over a 24-hour period)
    - How will the depot be charging buses? (for instance, how many chargers and buses will there be, how many buses will be charged at once, will the buses be fast-charged (using high power DC chargers), slow-charged, or a mix)
- How much flexibility there is for charging plan to be changed or for how capacity is used.
- Willingness to have electricity usage capped (this could be in general or only at certain times of the day).
- What connection capacity will the bus depot need initially and what is it likely to need in two, three, five and 10 years, as electrification of the bus fleet progresses.
- How the bus depot will be laid out (for instance, where chargers will be – this will have implications in terms of how many transformers are needed and how large each of them are).

To aid in this preparation of this information the depot owner should consider engaging an electrical engineer. If the bus operator and/or PTA is unsure of what information they need to provide, then the local EDB should be willing to provide some guidance on what they require.

4.2.3. Business studies

The EDB may require a business study to be completed so they can determine what works and equipment will be required to upgrade or install the connection. What the business study covers will vary by EDB.

The EDB is likely to charge the depot owner/operator for the business study. If the depot owner/operator wants the EDB to consider different connection sizes in the business study this may cost more or require multiple studies.

The depot owner/operator will need to engage with the EDB to understand the EDB's approach to business studies.

4.2.4. Contracting for physical works

Some EDBs allow customers requesting a large connection to choose which contractor does the physical works of the network upgrade. For example, customers on the Aurora Energy (Aurora) network (the EDB serving Dunedin, Central Otago, and Queenstown Lakes) can get quotes from any number of Aurora's approved service providers and choose which provider they would like to do the work. However, on some other networks, the customer has no choice of contractor and must use the EDB's nominated contractor.

4.2.5. Questions that the bus operator or PTA could ask the EDB

The bus operator and/or PTA should come prepared with questions for the EDB to help ensure that the depot gets the right connection for their circumstances.

Some examples of questions that the bus operator and/or PTA may want to ask the EDB include:

General:

- What's required to get our site connected?

Timeframes for connection:

- How long will it take to get connected?
- What has the longest lead time?
- What is the transformer lead time?

Connection upgrade at proposed depot location:

- Is there enough network capacity available where we're thinking of situating the bus depot? If so, how much available capacity is there?
- How much electricity network investment will be required to get a new or upgraded connection at our proposed depot location? How long will it take to get the connection?
- Does the EDB have any planned upgrades for this part of the network? If so, when will these upgrades take place?
- If there is a choice of depot locations, what locations have most spare capacity on the network? What locations will cost the least to get an upgraded connection?
- Will the cost of connection be lower if the bus depot is split over multiple sites on different parts of the electricity network?
- How much of the connection cost will the depot owner/operator need to pay? What is the EDB's capital contribution and reapportionment policy?[50]
- What is the resiliency of the network where we're wanting to locate the electrified bus depot? Is the proposed site on a meshed part of the distribution network?
- What's the likelihood of a power outage at the proposed site? If there's a power outage, what's the likelihood that the power outage will last for more than two hours?
- How costly would it be to make the electricity network more resilient at the proposed depot locations?
- Can the bus depot be placed on the priority list for reconnection so that normal operation of bus services can resume as soon as possible following a power outage?

Business studies:

- How much will it cost to get a business study done by the EDB?
- What is included in a business study?
- How long will it take for the business study to be completed?
- Do we need to pay for multiple studies for different connection sizes?

Smart charging/charging plan:

- Are there changes we can make to our charging plan to access greater cost savings?
- Can we reduce our costs by smart charging? If so, what are the options?

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[50] Capital contribution policies (including reapportionment) are discussed in section 4.3 below.

- Will there be limits in how much we can charge at different times of the day?

Physical works:

- What is the process for determining who does the physical works of the network upgrade?
- Do I get any choice who does the physical works of the network upgrade?
- How can I ensure that I am getting value for money for the network upgrade?

Transformers

- Is it better to install one large transformer or multiple smaller transformers? What is the cost difference between getting one large transformer and multiple smaller transformers?
- Can we choose where our transformer is purchased from? If so, what requirements does the transformer need to meet?

Future upgrades:

- How can we minimise the cost of future upgrades needed for growth in the electric bus fleet?
- How can we minimise the time taken for future connection upgrades to be completed?

On-site generation and battery storage:

- Is there anything we need to be aware of if we decide to install on-site generation and/or battery storage?

4.3. Cost of getting a new or upgraded connection

The cost of getting a new or upgraded connection for an electrified bus depot will vary depending on who the local EDB is and where on the network the connection is. As discussed above in section 3.1.1, a bus depot owner/operator may be able to reduce connection costs by locating the depot where the distribution network is not constrained, near a zone substation, and/or across multiple sites.

However, one of the largest drivers of the variation in cost will be the local EDB's capital contribution policy. The Commerce Commission requires each EDB to have a capital contributions policy.[51] This policy will set out when a customer seeking to get or upgrade a connection will need to contribute to the costs of the connection and how that contribution will be calculated. An EDB does not need to require a capital contribution—it can bring the asset under its regulated asset base (RAB) instead. The RAB is explained in more detail in section 6.3. However, capital contributions can mitigate prudential risk for EDBs. If a customer exits and the EDB's assets become stranded, then the distributor risks not recovering the full cost of those assets if it does not charge a capital contribution.[52]

Some capital contribution policies set out when a capital contribution will or won't be required—for example, Marlborough Lines says it generally won't require a capital contribution for a distribution transformer (the equipment cost only) as it is an asset that Marlborough Lines can reuse elsewhere if no longer needed in that location.[53]

Regardless of who pays the cost of getting a new or upgraded connection, the EDB will own the connection assets (including the transformer).

When a capital contribution is required, EDBs do vary significantly in how much of a contribution is required. However, there are four common methods for determining how much the contribution should be - the first two (100% contribution and maximum investment value) are the most common:

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[51] Links to each of the capital contributions policies are included in the References. Commerce Commission regulation of EDBs is discussed more in section 6.3.

[52] This risk is less acute for reusable assets (such as transformers).

[53] https://www.marlboroughlines.co.nz/s/20220601-_Capital-Contributions-Policy_FINAL.pdf (section 6.1).

- **100% contribution** – the connecting party (the depot owner) pays full cost of connection up front.
- **maximum investment value** – the EDB sets a limit on the costs it will cover, above which a capital contribution is required by the connecting party.
- **standard charges** – the EDB sets a fixed charge for common types of connection. Standard charges are typically used for routine, high-volume connection types (such as a standard house connection). Standard charges may also apply for connections under a certain capacity.
- **formula-driven** – the distributor sets capital contributions case-by-case using a prescribed calculation methodology. Calculations will usually consider upfront and ongoing costs, then offset these with forecast use of system charges.

Some EDBs will require a reapportionment charge to be paid when a customer applies to connect to an asset that another customer has already paid for (entirely or partially) through a capital contribution. Reapportionment ensures that future users of network assets pay for their share of the cost of providing those assets. Whether reapportionment is charged is at the discretion of the EDB. Some capital contribution policies set out a formula for calculating the value of the reapportionment charge, while other capital contribution policies leave it entirely to the discretion of the EDB. Reapportionment will only apply for some limited timeframe after the asset is installed – under Alpine Energy's current capital contributions policy, reapportionment can only apply if there has been a capital contribution for that asset within the previous ten years, while under Network Waitaki's capital contributions policy the timeframe is five years.[54] Some capital contribution policies do not state a timeframe for which reapportionment may apply.

A depot owner/operator should ensure they have read and understood their local EDB's capital contribution policy before getting an upgraded or new connection so that they are aware of what level of capital contribution they will be liable for and can ensure the policy is applied correctly.

[54] See Alpine Energy's New Connections and Extensions Policy (last amended November 2021) and Network Waitaki's Capital Contributions Policy | Network Waitaki (last revised August 2021).

5. Structure of the New Zealand electricity sector

5.1. Electricity industry structure

The electricity supply chain can be divided into four main segments: generation, transmission, distribution, and retail sales. This is shown diagrammatically in Figure 7 below.

Figure 7: Overview of electricity industry structure (Source: Ministry of Business, Innovation and Employment)

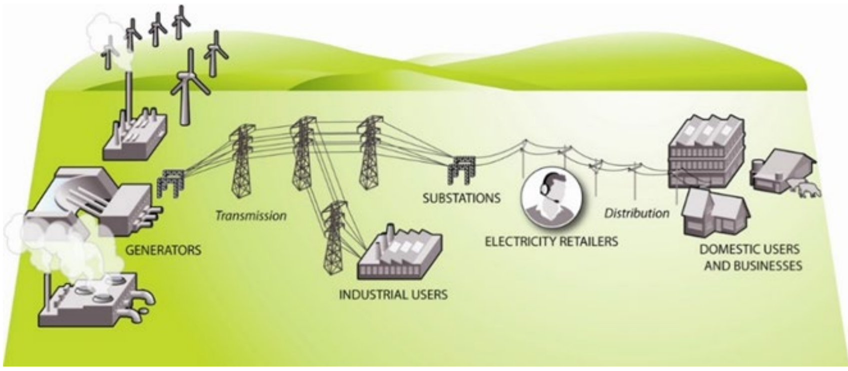


Figure 7 depicts a 'traditional' form of the electricity industry. However, evolving technologies and innovation are starting to allow mass participation in the electricity industry which will have some impact on the electricity industry's structure. For example, a consumer that installs solar panels in combination with a battery can generate when it's sunny and then store the electricity to use when they need it later. This consumer could either be off-grid (they're not connected to the distribution network and they generate enough electricity for their own consumption) or they could be on-grid (purchasing any extra electricity they need from a retailer and/or selling any excess generation from their solar panels to a retailer).

Peer-to-peer (P2P) trading is another innovation that may affect the workings of the electricity industry. P2P platforms allow electricity to be bought and sold in a market. For example, a household or business with solar panels could sell any surplus electricity to other local households or businesses rather than selling it back to their retailer.

5.1.1. Generation

In Aotearoa New Zealand, electricity is generated using water, wind, geothermal, gas, coal, solar, and steam resources. Generation is spread through the country ranging from large generating stations that generate enough to power hundreds of thousands of households through to small scale generation such as solar PV panels on a small business or consumer's roof space.

Over the past decade, over 80 percent of electricity generation has been renewable (hydro, geothermal, wind, and solar).[55] The proportion of generation that is renewable has been increasing over time and is expected to continue to increase as New Zealand moves towards 100 percent renewable electricity generation. However, the proportion of generation that is renewable can vary significantly from year to year due to weather conditions (especially how much rain or snow melt there is in the hydro catchment areas)—for example, 87.1 percent of electricity generated was from renewable sources in 2022, but in 2021 only 82.1 percent of electricity generation was renewable due largely to lower hydro generation.

Large generating stations are connected to the transmission grid, but smaller generators are generally connected to a distribution network (distributed generation). The transmission and distribution networks are explained below (in sections 5.1.2 and 5.1.3, respectively).

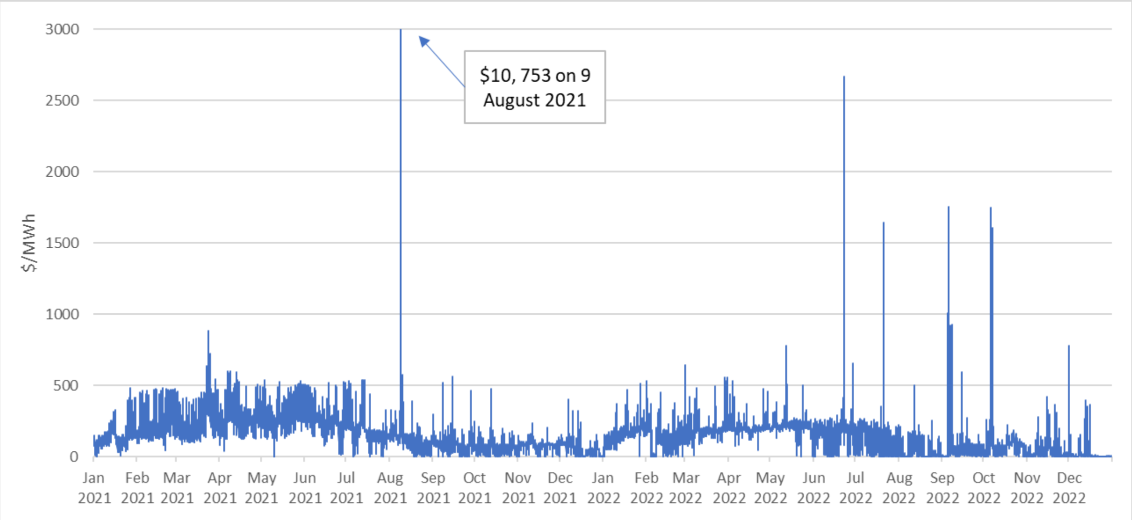
Large generating stations connected to the transmission grid are required to participate in the wholesale electricity spot market. In this market, electricity is sold in a half-hourly auction process. Supply

[55] In the ten years to 2022, 82.1% of electricity generation was renewable. Source: https://www.mbie.govt.nz/assets/Data-Files/Energy/nz-energy-quarterly-and-energy-in-nz/electricity.xlsx.

(generation) and demand (consumption) of electricity can vary substantially within a day and across the year and need to be balanced at all times. This leads to price variations over time. Some of these price variations are reasonably predictable (demand is generally higher in winter than in summer with greater use of heating), while some price variations are less predictable (for instance, a prolonged calm weather period which reduces wind generation). Spot prices are also usually higher in 'dry years' when inflows into hydro catchments are below average.

Figure 8 plots the average half hourly wholesale electricity spot prices for New Zealand over 2021 and 2022. It shows that over the two-year period, spot prices were between $0.01 and $500 per MWh most of the time. However, spot prices occasionally spiked much higher (including to over $10,000/MWh on 9 August 2021)[56].

Figure 8: Half hourly wholesale spot prices over 2021 and 2022



There is competition in the generation segment of the electricity industry.

5.1.2. Transmission

The transmission network (also known as the national grid) transports electricity from generators directly to distribution networks and some large electricity users. Transpower (a state-owned enterprise) owns and operates New Zealand's national grid.

The national grid is mostly High Voltage Alternating Current (HVAC) (66 kV, 110 kV, and 220 kV) with a 350 kV High Voltage Direct Current (HVDC) cable between Benmore in South Canterbury and Haywards in Wellington.

The transmission segment of the electricity industry is not subject to competition because it is generally uneconomic to replicate electricity networks. Transpower's transmission business is regulated under Part 4 of the Commerce Act 1986. Details of this regulation are provided in section 6 below.

5.1.3. Distribution

Twenty-nine electricity distribution businesses (EDBs) (also known as lines companies or distribution companies) own distribution networks that transport electricity from the national grid to businesses and households.

EDBs use substations to reduce the voltage from the national grid, providing high voltage supply to large commercial and industrial users and low voltage supply to households and small business customers.

[56] On the evening of 9 August 2021 there was a grid emergency due to record-high electricity demand.

EDBs are monopolies as there is only one EDB in each area of the country that owns distribution lines. EDBs are also regulated under Part 4 of the Commerce Act 1986. Details of this regulation are provided in section 6 below.

This map (https://www.ena.org.nz/lines-company-map/) shows where each EDB operates. The largest EDBs (by numbers of connections) are Vector (in Auckland), Powerco (Tauranga, the Coromandel, Taranaki, Manawatū, and Wairarapa), Orion (Central Canterbury), and Wellington Electricity. A full list of the EDBs in provided in Table 4 below.

5.1.4. Retail

Electricity retailers purchase electricity from generators and on-sell it to consumers. Retailers also pay lines charges, arrange metering, and perform billing and payment services. These costs are all passed on to the consumer.

Consumers can choose which retailer they buy their electricity from (although not all retailers are available in all parts of New Zealand). In main urban centres there are usually twenty or more retailers for commercial customers to choose from.[57] Retailers have different retail charges for different consumer groups (residential, business, industrial and commercial).

[57] The choice of retailers is more limited on smaller electricity networks, but a commercial customer will still have a choice of at least ten retailers.

6. The regulatory environment governing electricity distribution and supply

6.1. Regulatory agencies

There are two key agencies that regulate electricity supply and distribution in New Zealand - the Electricity Authority and the Commerce Commission.

The Electricity Authority is New Zealand's electricity market regulator. Its main objective is to promote competition, reliability and efficiency for the long-term benefit of consumers.

The Commerce Commission is the economic regulator for monopolies, including EDBs and Transpower. All EDBs are subject to information disclosure requirements with some EDBs also subject to revenue and cost recovery requirements.[58]

Both regulators are Independent Crown Entities, which means their decision making is independent of ministers and government departments. However, both agencies interact with government regarding their funding and wider policy matters.

The Utilities Disputes Limited (UDL) is another organisation that has a role in electricity sector. UDL operates the approved Energy Complaints Scheme under the Electricity Industry Act 2010 and the Gas Act 1992.

Sections 6.2 and 6.3 explain in more detail the roles of the Electricity Authority and Commerce Commission in regulating electricity supply and distribution. Section 6.4 explains UDL's Energy Complaints Scheme.

6.2. Electricity Authority regulation

As the electricity market regulator, the Electricity Authority oversees the wholesale market, system operation, the retail market, small consumer protection, and aspects of network regulation not covered by the Commerce Commission.

The Electricity Authority's main objective is to promote competition, reliability and efficiency for the long-term benefit of consumers, with an additional objective to protect the interests of domestic consumers and small business consumers in relation to the supply of electricity to those consumers.[59] One of the ways that the Electricity Authority does this is through developing, administering, and enforcing the Electricity Industry Participation Code 2010 (Code). The Code sets out rules that govern New Zealand's electricity industry, including some rules that regulate EDBs.

The areas of EDB regulation that the Electricity Authority oversees include:

- pricing – while the Commerce Commission regulates how much revenue EDBs can earn,[60] the Electricity Authority oversees how target revenue is allocated between consumer groups and how prices are structured (for example, between capital contributions, fixed charges, and usage charges)
- network access – for example, rules governing connection processes and commercial terms for access seekers or retailers.

The Electricity Authority provides information on EDB's obligations here: https://www.ea.govt.nz/industry/distribution/obligations/

The Electricity Authority is also responsible for rules related to the retail electricity market and metering, including rules around switching retailers and metering standards and requirements. However, the

[58] Some consumer-owned distributors are exempt from revenue and cost recovery requirements. This is explained in section 6.3.

[59] The Authority's objectives are set out in section 15 of the Electricity Industry Act 2010.

[60] For non-exempt EDBs.

Electricity Authority does not regulate retailers' prices and does not investigate complaints into retailers (or distributors)[61].

The Electricity Authority has also developed Consumer Care Guidelines to encourage retailers to adopt behaviours and processes that support positive relationships with their customers. The Consumer Care Guidelines are available here: https://www.ea.govt.nz/documents/2093/Consumer-Care-Guidelines.pdf.

More information on retailers' obligations can be found here: https://www.ea.govt.nz/industry/retail/obligations/.

6.3. Commerce Commission regulation of EDBs

Under Part 4 of the Commerce Act, the Commerce Commission has a role regulating electricity distribution (and transmission) businesses. Its regulation of EDBs includes:

- revenue caps—these aim to ensure EDBs recover no more than their efficient investment and operating costs
- efficiency incentives—these encourage EDBs to out-perform regulatory allowances, and also share cost overrun risk with consumers
- associated network quality standards—these aim to ensure efficiency gains are not at the expense of compromised reliability
- annual information disclosures—these require expenditure, profitability, and asset management information to be made publicly available in a standardised form.

Certain consumer-owned distributors are exempt from the first three items, and only subject to information disclosure. The rationale is that owner and end user incentives should be well aligned for those businesses.

The following subsections set out:

- which EDBs are subject to revenue controls and which EDBs are exempt
- the role of revenue caps
- what the regulated asset base (RAB) and capital contributions are
- the potential for distribution sector input methodologies (IMs) to change and what impact this may have.

6.3.1. Non-exempt and exempt EDBs

Table 4, below, lists which EDBs are subject to revenue controls and information disclosure requirements (non-exempt EDBs) and which EDBs are only subject to information disclosure requirements (exempt EDBs).

Exempt EDBs are consumer-owned distributors that meet certain criteria set out in section 54D of the Commerce Act 1986.[62] These EDBs are exempt from revenue controls because their consumers are considered to have input into how the business is run.

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[61] See section 6.4 for information about UDL's Energy Complaints Scheme.

[62] These criteria include that all the control rights in the distributor are held by one or more customer or community trusts, the trustees are elected by persons who are consumers, at least 90% of the persons who are consumers benefit from income distribution, and the distributor has fewer than 150,000 ICPs.

Table 4: Non-exempt and exempt EDBs

Revenue controlled EDBs (non-exempt EDBs)	Information disclosure only EDBs (exempt EDBs)
Alpine Energy	Buller Electricity
Aurora Energy	Centralines
Electricity Ashburton	Counties Energy
Firstlight Network*	Electra
Horizon Energy	Mainpower NZ
Nelson Electricity	Marlborough Lines
Network Tasman	Network Waitaki
Orion NZ	Northpower
Powerco	Scanpower
The Lines Company	The Power Company
Top Energy	Waipa Networks
Unison Networks	WEL Networks
Vector Lines**	Westpower
Wellington Electricity	

* Was previously known as Eastland Network.
** Vector is only partly community owned, so is not exempt.

6.3.2. Non-exempt EDBs are revenue capped

The Commerce Commission caps the revenue that non-exempt EDBs (listed in Table 4 above) can recover. The revenue cap is fixed every five years for a five-year regulatory period, with the cap based on each EDB's forecast investment (capex) and the Commerce Commission's forecast of their operation costs (opex). The current regulatory period runs until March 2025. The revenue cap enables the EDB to recover their forecast costs, including related tax and financing costs (which include profits that enable a return on equity).

6.3.3. The role of the regulated asset base (RAB) and capital contributions

Financing costs for an EDB's revenue cap are assessed based on the value of the EDB's assets – their regulated asset base (RAB). Investment costs are added to the RAB net of capital contributions. For example, a $5,000 transformer that had a $2,000 capital contribution would add $3,000 to the RAB.

The Commerce Commission has a balance to strike—it needs to make sure the return on the RAB is generous enough to support ongoing investment by EDBs, while also encouraging EDBs to efficiently control their costs.

One way it does this is with expenditure incentives. These reward an EDB for out-performing (that is under-spending) forecast capital and/or operating expenditure or penalise the EDB for under-performance. This incentive rate is currently 24% so that, for example, if an EDB can reduce its costs by $100[63] then it will get a one-off $24 (before tax) improvement in its profit. [64] This can reward distributors for shifting cost recovery toward capital contributions (and away from their regulated expenditure).

[63] For example, by increasing the share of a project's costs that are recovered through capital contributions.

[64] Distributors vary in their preferences regarding this outcome (effectively a higher return against smaller investment) versus gaining a lower (but stable) return on a bigger asset base.

Capital contributions can also mitigate prudential risk for EDBs. If a customer exits and the EDB's assets become stranded, then the distributor risks not recovering the full cost of those assets.[65] Payment of a capital contribution also provides an EDB with comfort that the customer is committed and has a stake in seeing their project through to completion.

Note that the Commerce Commission regularly reviews its regulatory settings, so incentives for EDBs to use capital contributions could weaken in the future.

Exempt EDBs have more flexibility to adjust their target revenue, so cost recovery and prudential risks are less of a driver. However, exempt EDBs will usually set revenues with reference to the methodologies used by controlled distributors.

6.4. Utility Dispute Limited's Energy Complaints Scheme

Transpower and all electricity retailers and distributors are required to be part of UDL's Energy Complaints Scheme.[66] The purpose of the Energy Complaints Scheme is to ensure that any person (including electricity consumers) who has a complaint about a retailer, distributor, or Transpower has access to a scheme to resolve that complaint.[67]

When a consumer has a complaint about their retailer or distributor (or Transpower) they need to complain to retailer or distributor first. If the retailer or distributor does not resolve the complaint within a reasonable period, then UDL will work with both parties to resolve the complaint. UDL can only deal with complaints where the value of the complaint is less than $50,000. It is free to make a complaint to UDL.[68]

The rules governing the Energy Complaints Scheme can be found here: https://www.udl.co.nz/our-publications-and-schemes/scheme-rules/.

[65] This risk is less acute for reusable assets (such as transformers).

[66] Gas distributors and retailers are also required to be part of the Energy Complaints Scheme.

[67] Schedule 4 of the Electricity Industry Act.

[68] UDL's Energy Complaints Scheme is funded through levies on retailers, distributors, and Transpower.

7. Glossary of terms

Alternating current (AC): an electric current that reverses its direction many times a second and the type of electricity supply provided by the national grid

Anytime Maximum Demand (AMD): the maximum electricity demand of a customer during any half hour period during the year

Capacity charge: a $/kVA/day charge for an electricity connection (can be part of the customer's lines charge)

Capital contribution: the amount that an EDB requires a customer to contribute to the cost of a new or upgraded connection

Code: Electricity Industry Participation Code 2010 administered by the Electricity Authority

Coincident Peak Demand (CPD)): a customer's average demand during periods when the EDB is experiencing peak deamand

Commerce Commission: New Zealand's economic regulator for monopolies, including EDBs and Transpower

Consumption charge: a $/kWh charge charged by a retailer as part of the energy charge and/or lines charge, which can be a flat rate or a TOU rate

Daily fixed charge: a $/day charge charged by a retailer as part of the energy charge and/or lines charge

Dedicated asset charge: a $/kVA/month charge for the recovery of transformer costs (can be part of the customer's lines charge)

Direct current (DC): an electric current flowing in one direction only and the type of electricity supply provided by batteries

Distance charge: a $/kVA-km/day charge, with distance being from the customer's premises to the nearest major substation (can be part of the customer's lines charge)

Distribution network: network that transports electricity from the national grid to businesses and households

EDB: electricity distribution business, also known as a distributor or lines company

Electricity Authority: New Zealand's electricity market regulator

Energy charge: charge by a retailer that covers costs associated with generation, retail, metering, and market governance and services

Kilovolt amperes (kVA): a unit of power measurement equal

Kilowatt (kW): a unit of how much power is used

Kilowatt-hour (kWh): a measure of how much energy is used per hour, with 1 kWh equal to 1 kW of power consumed over one hour

Lines charge: charge by a retailer that covers costs associated with distribution and transmission

Measured peak capacity charge: a $/kW/day charge based on the customer's maximum demand, which could take the form of AMD, on-peak demand, or CPD (can be part of the customer's lines charge)

National grid: owned and operated by Transpower (a state-owned enterprise), the network that transports electricity directly to distribution networks and some large electricity users (also known as the transmission network)

Network peak: the period when electricity demand is highest on the distribution network (usually in the morning and evening on weekdays)

Off-peak period: used to help define TOU charges, is usually overnight (eg, 11pm – 7am), and is the period when the TOU rate is the lowest

On-peak demand: the customer's maximum demand during peak hours (eg, 7am – 11am and 5pm – 9pm), sometimes measured separately over summer (Oct – Apr) and winter (May – Sep)

Open Charge Point Protocol (OCPP): protocol used for communication and data exchange between electric vehicle charging points and central control systems

Peak period: used to help define TOU charges, is usually in the morning and evening (eg, 7am – 11am and 5pm – 9pm), and is the period when the TOU rate is the highest

Power factor (PF): measure of the efficiency of the equipment turning 'apparent' power (measured in kVA) into useful output as 'actual' power (measured in kW), PF = kW/kVA

Power factor charge: a $/kVAr/month charge intended to incentivise consumers with poor power factors to take measures to improve them

PTA: Public Transport Authority

Range: The distance which a battery electric vehicle can travel before needing to be recharged

Reapportionment charge: an EDB may require a customer to pay a reapportionment charge when the customer applies to connect to an asset that another customer has already paid for (entirely or partially) through a capital contribution

Regulated Asset Base (RAB): the value of an EDB's assets, used to calculate the EDB's revenue cap

RUB: Requirement for Urban Buses

Shoulder period: used to help define TOU charges, is usually in the middle of the day and late-evening (eg, 11am – 5pm and 9pm – 11pm), and will have a TOU rate that is higher than the off-peak rate but lower than the peak rate

Time-of-use (TOU): a consumption charge where the rate ($/kWh) is highest during peak periods, lowest during off-peak periods, and somewhere in between during shoulder periods

Transformer: a piece of equipment that reduces or increase the voltage of an alternating current (AC)

Transpower: a state-owned enterprise that owns and operates the national grid

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