Batteries and residual transmission charges

Options for ensuring efficient cost recovery

May 2021

SENSE PARTNERS
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1. Purpose and scope

This report recommends a method for calculating residual transmission charges for battery energy storage systems (batteries).

Under the Electricity Authority's transmission pricing methodology guidelines (TPM guidelines)[1], residual transmission charges are to be used to recover Transpower's required revenue not recovered through benefit-based charges.[2]

The objective of residual charges is to ensure revenue recovery while minimising distortions to designated transmission customers' and consumers' behaviour.

Residual charges are to be allocated to load (electricity consumers). They are not allocated to generation because this could cause unnecessary and costly distortions to generation investment or operation decisions.

Electricity storage is both load, when charging, and generation, when discharging. It is possible then that, in this type of situation, levying residual charges on load could cause unnecessary and costly distortions to investment in or use of storage.[3]

This report discusses the extent of potential distortions and considers options for minimising those distortions.

Options are assessed against the Authority's statutory objective "to promote competition in, reliable supply by and the efficient operation of, the electricity industry for the long-term benefit of consumers" and a recommendation is made to exempt batteries from residual charges.

First, for context, the next section summarises:

- transmission pricing principles
- the design of the residual charge and how it is expected to be applied under the transmission guidelines
- the characteristics of and services provided by battery energy storage systems
- treatment of storage, for transmission pricing purpose, elsewhere in the world.

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[1] https://www.ea.govt.nz/assets/dms-assets/26/26850TPM-2020-guidelines-10-June-2020.pdf

[2] The charges are expected to recover around 70% of interconnection charges in the first few years of the new TPM, declining to around 40% of interconnection charges in the late 2020s. See Figure 6 on page 59 of the Authority's (2020) decision paper at https://www.ea.govt.nz/assets/dms-assets/26/26851TPM-Decision-paper-10-June-2020.pdf

[3] This issue was raised by Contact Energy Limited in a letter to the Authority on 16 November 2020 (https://www.ea.govt.nz/assets/dms-assets/27/Contact-Energy-letter-to-the-Authority.pdf).

2. Context

2.1. Principles for pricing of transmission services

The Authority has derived principles for the pricing of transmission services to give effect to the Authority's statutory objective.[4] Relevant principles that are reflected in the overall approach to residual charges in the 2020 guidelines are:

a) charges for access to transmission services should recover the total cost of providing transmission services[5]

b) charges for a transmission user should be similar to those for other competing users after adjusting for their size[6]

c) any additional costs should be recovered by a charge on load customers designed to affect their behaviour as little as practicable.

2.2. Design of the residual charge

The residual charge in the 2020 TPM Guidelines has been designed to minimise distortions[7] to producer and consumer behaviour by:

1) applying a flat rate at all locations, to avoid distorting locational investment decisions

2) applying charges on demand (load customers), not generation, to avoid negative impacts on generation investment[8]

3) allocating charges by historical demand[9], to reduce incentives to alter demand to avoid charges

4) allocating charges by final consumption demand, rather grid offtake, as this:

    a) reduces incentives to invest in embedded generation to avoid charges

    b) best reflects customer size and customer ability to pay for charges.

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[4] Refer paragraph D.86 of the Authority's 2019 issues paper (https://www.ea.govt.nz/assets/dms-assets/25/25466TPM-Issues-Paper-30-July-2019-full-document.pdf).

[5] In its original form this principle refers to recovering the costs of "a transmission investment" (paragraph D.86 (c) in the Authority's 2019 issues paper) but it applies more generally in the sense that charges must recover all of the grid-owner's regulated revenue.

[6] The more general version of this principle in paragraph D.86 (b) of the Authority's 2019 issues paper includes that charges should be similar after adjusting for location. Locational differences are not relevant for residual charges.

[7] When people invest resources to avoid residual charges those resources are wasted, from a system- or society-wide perspective, because the costs still need to be recovered from somewhere.

[8] Charges applied to generation are likely to cause delays in investment in generation and higher energy prices and thus, ultimately, charges on generation would largely be passed into load via higher energy prices (see paragraph 10.17 of the Authority's 2020 decision paper).

[9] Initial allocations to be based on peak energy use in the four-year period between 1 July 2014 and 30 June 2018 (see paragraph 30 of the 2020 transmission pricing methodology guidelines).

The objective is to minimise rather than eliminate distortions because it is inevitable that a residual charge will distort behaviour to some extent.

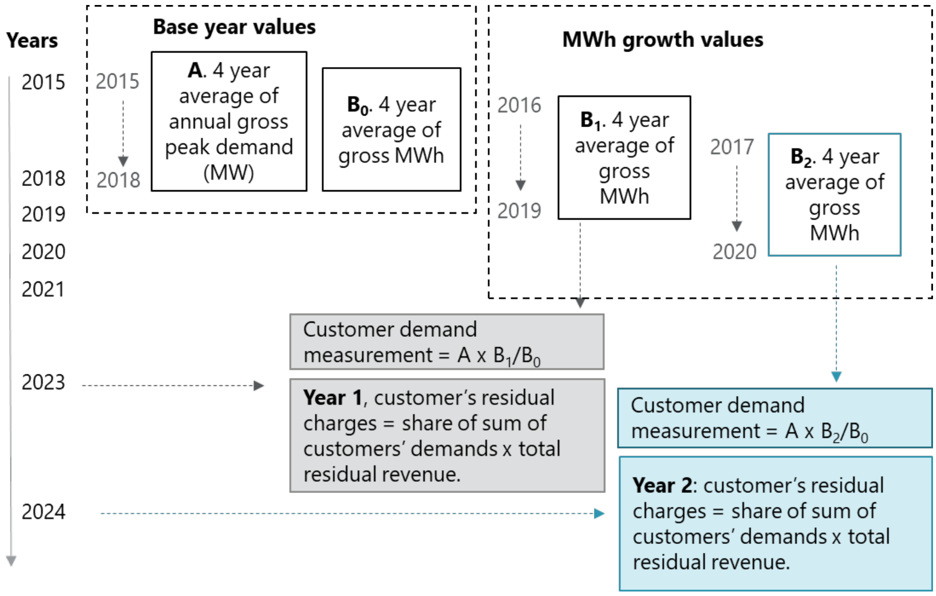
2.2.1. Allocation of residual charges for existing customers

Residual charges will be paid by designated transmission customers that have equipment that draws electricity from the grid or draws electricity from generation behind their point of connection to the grid.

Charges will be allocated in proportion to shares of electricity demand. For existing customers, demand is measured by (see Figure 1):

- a base period value of average anytime maximum gross demand (MW) over the period 2014 to 2018
- an adjustment reflecting four yearly average historical growth in gross consumption (MWh) four years prior relative to a base period of average gross consumption over the years 2014 to 2018
- gross demand and gross consumption defined as the net quantity of electricity flow from the grid plus concurrent generation behind the designated transmission customer's point of connection.

FIGURE 1: RESIDUAL CHARGE CALCULATIONS[10]



[10] Note that pricing years (2023 and 2024) are years ended March 31. Demand measurement years are years ended June 30.

2.2.2. New transmission customers

For new designated transmission customers, demand is to be estimated as if the customer is fully operational when connected. This lends itself to an assessment of demand based on assuming anytime maximum gross demand equal to the capacity of a newly connected customer's assets.

Adjustments for growth in consumption apply to new customers after eight years of operation based on the growth calculation set out above and in Figure 1.[11]

2.3. Batteries

2.3.1. Definition

The term battery is used here as a shorthand for any equipment functioning together as a single entity that is both able to store electricity from a network and provide injection.[12]

This definition is used here to cover all systems where electricity is the key input and output and hence can be said to store electricity.[13]

It is a deliberately broad definition and includes a range of methods and equipment for storing electricity, including (Guney and Tepe, 2017):

- electro-chemical e.g.
  - lithium-ion
  - redox flow batteries
- electrical e.g. capacitors
- mechanical e.g.
  - compressed air energy storage
  - flywheels
  - pumped hydro storage systems
- chemical e.g. hydrogen.

Pumped hydro storage is the most widely used of these technologies globally (over 95% of capacity) while electro-chemical batteries are by far the fastest growing form of battery energy storage.

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[11] Charges are to be applied as if the plant was operational on 1 July 2014. As such, the base years for the consumption charge adjustment will be the average consumption over the first four years of operation.

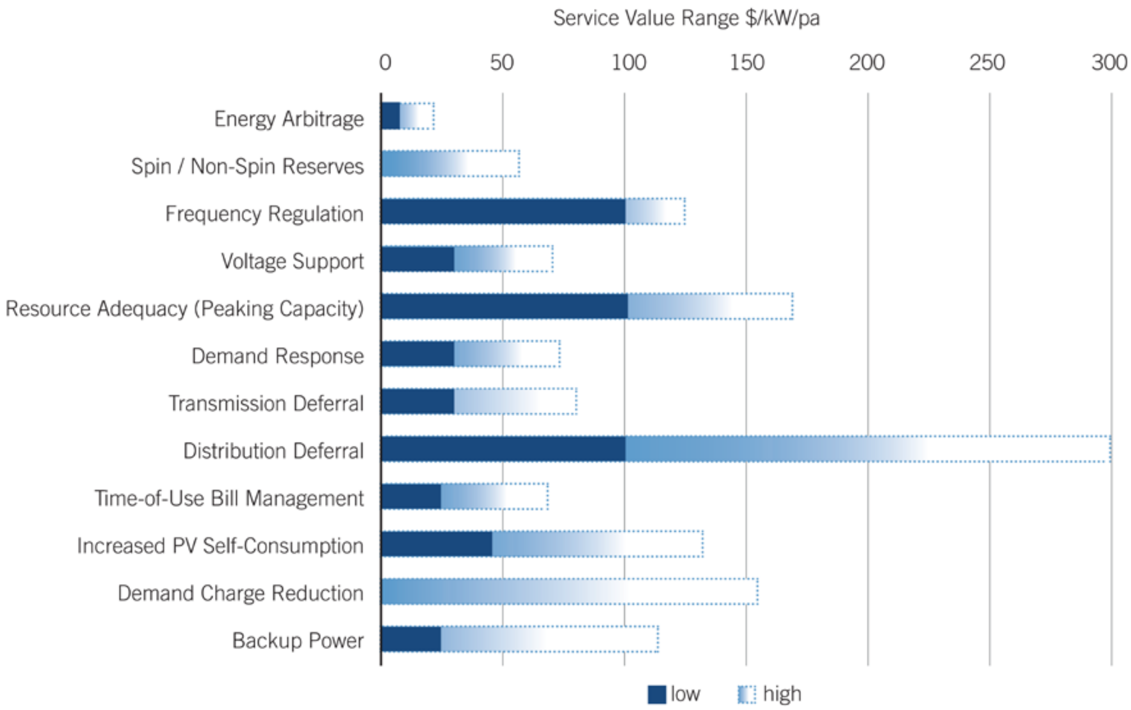
[12] This definition comes from a group working on a Code amendment to enable the participation of battery energy storage systems in the reserves market, where technologies capable of participating in the reserves market are listed in the code. In this definition: injection means the flow of electricity into a network; electricity means electrical energy measured in kilowatt-hours (kWh); network means the grid, a local network or an embedded network.

[13] The definition excludes storage of energy that does not involve electricity as an input and output such as conventional hydro storage, gas storage, coal stock-piles.

2.3.2. Functions and value

Transpower (2017) assessed the potential value of batteries in the New Zealand economy[14] and noted the range of services that can be provided by batteries. Figure 2 summarises Transpower's high-level assessment of the relative value of services provided by batteries.

FIGURE 2 TRANSPOWER'S 2017 ASSESSMENT OF THE VALUE OF BATTERY FUNCTIONS



Storage can provide a range of services. These include:

- load smoothing, more traditionally associated with demand response
- reserve energy, hydro
- voltage support, transmission equipment, power stations
- frequency keeping, transmission equipment and power stations.

Batteries have some advantages over other resources e.g.

- almost zero ramp rates, meaning that a MW of batteries can operate more cost-effectively than a MW of generation[15]

[14] This report is a useful and thoughtful assessment of the potential uses of batteries in the New Zealand context. It's main findings around the relative value of batteries in different uses remains valuable even if they are somewhat dated in light of rapid declines in costs of batteries and rapid increases in knowledge about the deployment and operation.
[15] Although this advantage is offset by lower durations of response. See e.g. https://kleinmanenergy.upenn.edu/wp-content/uploads/2020/08/Energy-Storage-in-PJM_0-1.pdf

- operating as both generation and load for reserve purposes
- can produce reactive power for voltage support, which not all generating plant can do.

The potential for batteries to enter the market and offer energy services such as reserves also has the potential to increase competition, whether for services offered directly by battery owners, such reserves or frequency keeping, and for related services such as energy production where the ability to store energy from intermittent generation has the potential to increase capacity offered to the energy market.

The Authority recently estimated that allowing batteries to offer instantaneous reserve could produce benefits of $44 million dollars (present value).[16]

In South Australia the Hornsdale battery installation has been associated with an approximate 25% reduction in the costs of frequency control ancillary services.[17]

2.4. International experience

Electricity industry rules are in a state of flux internationally as regulators and market participants try to determine how best to accommodate energy storage within rules that have traditionally defined market participants as either load or generation.

Storage is exempt from transmission charges in several other jurisdictions, to avoid distorting investment decisions. These exemptions typically consist of grouping storage with similar service providers and designating all providers of those services as exempt from charges.

2.4.1. Australia considering rules to exempt storage from transmission charges

Australian regulators are currently reviewing market rules with a view to introducing a new class of industry participant for energy storage assets – in order to clarify the treatment of energy storage in market rules and for the purposes of determining if they are eligible for transmission charges.

In Australia generators do not pay directly regulated (interconnection/shared costs) transmission or distribution charges, however they do pay negotiated charges for costs directly associated with establishing and maintaining their connection to a transmission or distribution network.

Currently storage that takes in electricity and exports electricity must register as both a load participant and a generation participant and, in the absence of bespoke arrangements, transmission-connected energy storage systems are liable to pay transmission use of system (TUOS) charges.

In practice, owners of batteries have sought bespoke exemptions from TUOS charges. For example, the Australian Energy Regulator (AER) approved an exemption from TUOS charges for a 30 MW-8 MWh battery owned by ElectraNet in South Australia and operated by AGL. The exemption was on the basis that the battery was providing network support services and thus akin to a transmission

[16] https://www.ea.govt.nz/development/work-programme/evolving-tech-business/batteries-as-instantaneous-reserve/consultations/

[17] https://www.aurecongroup.com/-/media/files/downloads-library/thought-leadership/aurecon-hornsdale-power-reserve-impact-study-2020.pdf

investment.[18] Although the AER considered that this exemption did not create a general precedent for other projects.

The lack of clarity around treatment of batteries for the purposes of TUOS charges caused concerns that

> *"If this is not clarified different arrangements may be implemented across the NEM, potentially creating perverse incentives for locating ESS in some regions or to configure facilities for the purpose of defeating any charging requirements rather than in a way that reflects efficient outcomes".* (AEMO, 2019, p. 20)[19]

The Australian Energy Market Operator (AEMO, 2019) has proposed introducing a 'Bi-directional Resource Provider' participant category and that Transmission use of system (TUOS) charges should not be charged for bi-directional assets, but that distribution use of system (DUOS) charges should be levied on the load component of bi-directional assets. The Australian Energy Market Commission (AEMC) has been consulting on this and other rule changes for integrating energy storage systems into the electricity market. A draft determination on rule changes is expected in July 2021.[20]

2.4.2. Treatment of storage varies widely across the European Union

DG Energy (March 2020)[21] reviewed the treatment of energy storage in member states' electricity markets, including with respect to transmission charges. The review noted that several member states are in the process of implementing changes to transmission pricing to avoid problems of double-charging of storage that is treated as both generator and load for the purposes of transmission pricing.

Transmission pricing practices vary considerably in the EU. Several member states charge generators and load for transmission interconnection costs. This has the effect that storage, including pumped hydro, faces both demand charges and generation charges in some member states. Other member states recover transmission interconnection costs solely from load, though this leads to charges being levied twice on energy that is stored and then consumed and creating an uneven playing field with respect to other providers of services such as reserves and voltage support.[22]

2.4.3. United Kingdom has decided not to levy residual charges on storage

In the United Kingdom recent changes to transmission charging mean that from next year generators will no longer face residual charges (or receive payments for embedded generation). In October 2020 Ofgem further decided that, in line with earlier decisions, "residual charges should be paid by final

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[18] See p.115 of https://www.aemc.gov.au/sites/default/files/2018-12/Final%20report_0.pdf.

[19] https://aemo.com.au/-/media/files/electricity/nem/initiatives/emerging-generation/23-august-2019--integrating-ess-rule-change-proposal-final.pdf?la=en&hash=F500525F8539D6BA070629AA3E0ACEDD

[20] https://www.aemc.gov.au/rule-changes/integrating-energy-storage-systems-nem

[21] https://op.europa.eu/en/publication-detail/-/publication/a6eba083-932e-11ea-aac4-01aa75ed71a1/language-en

[22] See 'ACER Practice report on transmission tariff methodologies in Europe' by the European Agency for the Cooperation of Energy Regulators (2019) available at https://acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Practice%20report%20on%20transmission%20tariff%20methodologies%20in%20Europe.pdf

demand only, thereby excluding all types of generation (including stand-alone storage) from residual network charges".[23]

2.4.4. United States exempts storage from charges where it provides market services

In the United States, rules that distinguish storage assets from generation or load are well-developed compared to other jurisdictions but only in the case of storage assets being used for ancillary or network support services. The treatment of storage in other instances is less clear.

The Federal Energy Regulatory Commission (FERC) has ruled that energy storage must not be charged use-of-system charges if it is providing scheduled network support services (including frequency keeping, reliability/reserves and voltage support).[24] This is intended to ensure even-handed treatment of energy storage in the market for network support services.

For other services provided by energy storage, including load shifting, FERC has said that it will make decisions about the treatment of these services or assets on a case-by-case basis depending on the both the specific services being provided by energy storage assets and the context in which they are provided including prevailing transmission tariffs. Thus the treatment of storage assets remains a matter for the judgement of regional transmission and independent system operation organisations. FERC has said that where energy storage is exempted from transmission charges the system operator must show that the exemption is reasonable given the existing rate structure for transmission charges.

The Californian system operator (CAISO) does not levy residual transmission charges on energy storage, which it views as consistent with its practice of not levying residual charges on generators. CAISO created a separate customer category of 'non-generator resource' for energy storage and when these resources are batteries and are charging the charging energy is treated as negative generation so is not subject to transmission charges which are levied only on load.[25]

The independent system operator in Pennsylvania, New Jersey and Maryland (PJM) treats large Pumped Hydro Storage Units as generators and does not assess transmission charges to them. However it does treat some charging of other forms of storage as load, for the purposes of transmission charges:

- energy export is exempt from transmission charges if it is for reinjection and to provide ancillary services
- otherwise energy export attracts transmission charges (charges which are wholly charged on load in the PJM region).

Other operators have attempted to exempt all storage from transmission charges, but have been rebuffed by FERC. FERC has said that where energy storage is exempted from transmission charges

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[23] Ofgem's "Decision on clarifying the regulatory framework for electricity storage: changes to the electricity generation licence" (2 October 2020, p.3), https://www.ofgem.gov.uk/ofgem-publications/166793
[24] See e.g. FERC's 2019 rehearing and clarification on FERC Order 841, available at https://www.federalregister.gov/documents/2019/05/23/2019-10742/electric-storage-participation-in-markets-operated-by-regional-transmission-organizations-and
[25] See para 137 of 169 FERC, 61,126 https://www.ferc.gov/sites/default/files/2020-05/E-3_74.pdf.

the system operator must show that the exemption is reasonable given the existing rate structure for transmission charges.

For example, in 2019 the New York Independent System Operator (NYISO) proposed to treat the charging of storage as negative generation that does not attract any transmission service charges, to the extent that withdrawal is for later injection to the grid. This was consistent with its long-standing practice of not charging pumped hydro stations demand-side transmission charges. However, NYISO's approach was rejected by FERC on the grounds that it treated storage differently to other load. In response to arguments made by NYISO, FERC said

> *"We do not find the assessment of transmission charges twice in this instance to be unjust and unreasonable because the electric storage resource uses the transmission system once in withdrawing energy for later injection and wholesale load again uses the transmission system when withdrawing that same energy for resale to end-use customers. Accordingly, two different transactions occur: one that entails the electric storage resource purchasing charging energy at wholesale from the RTO/ISO market and another that entails wholesale load purchasing energy from the electric storage resource via the RTO/ISO energy market. As such, we find that it is reasonable to apply transmission charges to both the electric storage resource and the loads associated with those separate transactions, and for load to ultimately pay the two transmission charges."* (172 FERC ¶ 61,119, para 22, August 2020)

FERC has rejected similar applications from the New England ISO to exempt storage from transmission charges, on the grounds that the ISO had failed to demonstrate that complete exemption, for all charging energy, was justified.[26]

[26] 172 FERC 61,125 4 August 2020, https://www.iso-ne.com/static-assets/documents/2020/08/er19-0470-004_8-4-20_order_accept_compliance_further_compliance_req_order_841.pdf.

3. Problem definition

Battery storage presents a unique problem for the application of residual charges. While batteries make use of electricity, the primary purpose of a battery is to provide a service. Batteries compete with other service providers and generation technologies.

Levying residual charges based on metered electricity demand raises the cost of investing in batteries that are not levied on comparable service providers. This is inconsistent with the intent of the transmission pricing guidelines and may not best promote the Authority's statutory objective.

3.1. Illustrative impacts of residual charges

To illustrate the implications of residual charges for investors and operators of batteries we consider single hypothetical 10 MW battery investment, a range of connection options and a range of battery uses.

The results of this analysis are summarised in Table 1. This demonstrates two main results:

- residual charges would create a **barrier to entry** for new designated transmission customers, thereby impeding competition because e.g. residual charges for a new customer installing a battery would be approximately 75% of the cost of investment in the battery while for existing customers that figure would be 3.75%.
- residual charges create a **technology bias**, whereby the costs of investment in batteries are higher than competing technologies, such as would be the case for an industrial load customer choosing between investing in a battery for back-up supply versus investing in a diesel generator.

Because residual charges are allocated based on demand there is no impact whatsoever of residual charges on costs of investment in embedded generation, unless that generation uses electricity. If embedded generation is used to serve new load, there will be an increase in residual charges. But if there is no increase in load then residual charges are unchanged.

Table 1 includes an example of a new hydro generation plant where the plant is expected to provide tailwater depressed reserve and electricity is consumed to keep turbines spinning. Under that scenario residual charges would have a small but non-zero effect on the costs of the project, raising costs by 0.10%.

TABLE 1: IMPACT OF RESIDUAL CHARGES ON COST OF INVESTMENT FOR ELECTRICITY PRODUCERS AND SERVICE PROVIDERS

Investment	Co-located with…	New transmission customer?	Connection	Functions e.g.	Present value cost per MW ($m)	% impact on investment cost
10 MW battery	None	Yes	Grid	Load shifting, reserve, voltage support, frequency keeping	0.60	75.0%
	None	No	Grid	Load shifting, reserve, voltage support, frequency keeping	0.03	3.75%
	Industrial load	No	Grid	Energy cost management, back-up supply	0.03	3.75%
	Renewable generation	Yes	Grid	Peaking capacity, frequency regulation	0.60	75.0%
	Renewable generation	No	Grid	Peaking capacity, frequency regulation	0.03	3.75%
1 MW battery	Embedded load	No	Local network	Load shifting, voltage support, network cost deferral	0.03	3.75%
	Embedded load and generation	No	Local network	Load shifting, voltage support, network cost deferral	0.03	3.75%
100 MW Hydro generator	None	Yes	Grid	Energy, reserve (tail-water depressed), frequency regulation	1.40	0.10%
	None	No	Grid	Energy, reserve (tail-water depressed), frequency regulation	0.50	0.07%
1 MW Hydro generator	Embedded load	No	Local network	Energy	Nil	Nil
10 MW cogeneration plant	Industrial load	No	Grid	Energy cost management, back-up supply	Nil	Nil
10 MW diesel generator	None	No	Grid	Peaking capacity	Nil	Nil
	Industrial load	No	Grid	Energy cost management, back-up supply	Nil	Nil
	Embedded load	No	Local network	Network cost deferral, back-up supply	Nil	Nil

The examples in Table 1 relate to investment costs for a single simplified battery project for a battery with an energy to power ratio (MWh:MW) of 1. In practice, residual charges would incentivise new transmission customers to invest in batteries with low power to output ratios because lower MW of maximum demand would mean lower residual charges. While lower MW would constrain battery operation and earnings, this could be partially compensated for by having higher MWh of storage. Existing transmission customers would be incentivised to favour higher power to output ratios and thus fewer MWh per MW and lower residual charges although this incentive would be small given the comparatively small size of residual charges for existing customers. These potential distortions are not captured in Table 1, where we consider only a single type of battery to simplify comparisons.

Another distortion not illustrated in Table 1 is the incentive on new designated transmission customers to first enter the market and to subsequently install batteries, so that the battery load is not captured in the initial assessment of maximum demand.

3.2. Inconsistency with intent of guidelines

Residual charges are allocated in proportion to demand so that they account for consumers relative size and ability to pay those charges. This is intended to minimise economic costs.

Using demand as a proxy for ability to pay is imperfect but obviously a reasonable approximation when one considers the difference between Nelson Electricity's 7 MW maximum demand and Vector's 1,000 MW of maximum demand.[27]

Battery demand does not compare well with final consumption demand in terms of ability to pay because a battery is primarily an extension to equipment that manages supply of electricity. It is not demand in and of itself.

Consider two identical factories, both directly connected to the grid and both with a maximum demand of 40 MW but one of the factory's has invested in a 10 MW battery. The demand of the factory with the battery is no larger than the load of the factory without the battery but it will be assessed as such under the residual charging method in the guidelines.

It may be that the ability to invest in a 10 MW battery indicates a greater ability to pay residual charges, especially if the battery is used to inject energy into the grid and earn income. However, if a factory owner chose to invest in standby generation instead of a battery it's residual charges would not change (other things being equal).

Levying residual charges on batteries would thus distort generation investment decisions and provide a substantial incentive for people to adapt their investment behaviour to avoid residual charges. This is precisely the sort of distortion that was intended to be avoided by not levying residual charges on generation.

Similarly, the economics of intermittent renewables combined with battery storage would be undermined by residual charges levied on battery load. This has the potential to substantially increase the costs of generation in future, to the extent that it means an overbuild of generation.

[27] Values used in assessing the incidence of transmission charges in the 2020 TPM Decision paper.

3.3. Inconsistency with the Authority's statutory objective

As currently envisaged, residual charges on batteries risk:

1) **impeding competition** in the supply of electricity and related services by
   a) creating a barrier to entry not faced by incumbent providers or other potential market entrants
   b) preventing efficient investment in low or least cost electricity supply technologies
2) **promoting inefficient investment and operation** by
   a) encouraging investment in smaller scale batteries embedded in local networks, even where these might not be the most cost-effective configurations
   b) incentivising battery owners not to use the full operational range of their batteries
3) **undermining reliability** of electricity supply by
   a) reducing investment in batteries which promise a highly flexible and potentially cost-effective source of system balancing services
   b) limiting the operation of batteries so that they provide only a limited subset of system balancing services
   c) impeding investment in batteries as a private source of back-up electricity supply for large electricity consumers.

The above risks are not equally likely or equally material. And actual impacts will vary depending on how residual charges are implemented and on developments in the cost and operation of battery storage technologies. The key issue is to ensure that residual charges are collected in a way that minimises these distortions.

4. Options

Six options for adapting the residual charge to reduce the effects of residual charges on battery investment are set out below. Retention of the status quo is also an option but discussion here is limited to alternative options.

4.1. Option 1: phased introduction of charges for new transmission customers

This option is intended to address the problem that residual charges are much higher for new entrants investing in batteries relative to existing transmission customers investing in batteries.

Equivalent treatment of battery investments, whether they are installed by existing designated transmission customers or new transmission customers, means either:

- increasing the allocation of residual charges for existing customers who install new assets e.g. by reassessing their AMD and applying an immediate step-change in allocation of residual charges or
- modifying the calculation of residual charges for new transmission customers so that they face only a gradual implementation of residual charges, as would be faced by existing transmission customers who increase their use of electricity (whether through installation of assets or otherwise).

This option takes the latter approach and in doing so it presents a derogation from clause 33(c) in the guidelines because the new transmission customer would not face charges "an annual residual charge equivalent to the charge that would, in Transpower's reasonable opinion, have been payable had the large offtake plant, large generating station or designated transmission customer been fully operational from 1 July 2014".

This option could involve adding an additional term to the adjustment mechanism in clause 30 of the guidelines when constructing the transmission pricing methodology. This additional term, N_t for a new customer at time t, would be:

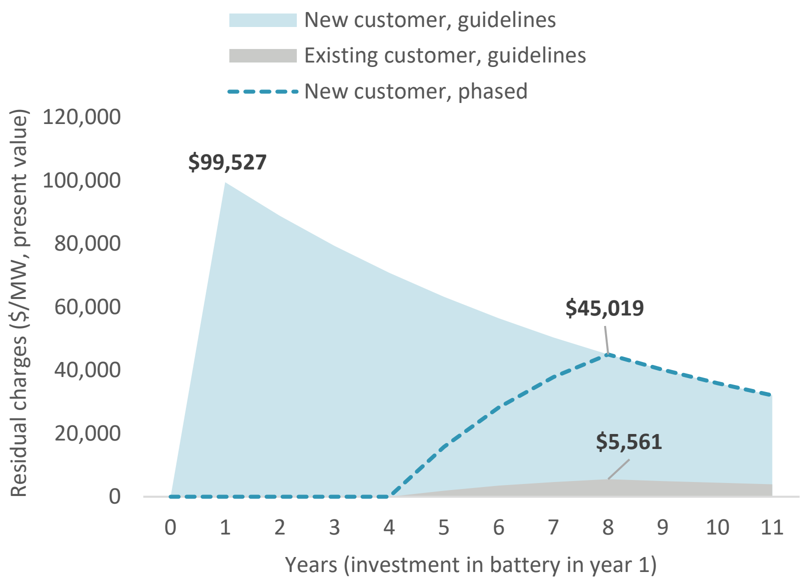
- $N_t=0$, for the first and subsequent 3 pricing years (i.e. years 1 to 4 inclusive) that the new transmission customer's is a designated transmission customer
- then rise in equal steps until it equals 1 in the 8^{th} year that the new transmission customer is a designated transmission customer i.e. $N_5=0.25$ in year 5, $N_6=0.50$, $N_7=0.75$, $N_8=1$
- N_t would remain equal to 1 for all years beyond the seventh year that the new transmission customer's is a designated transmission customer.

Transpower would assess the anytime maximum demand of the new transmission customer, just as it would also do under the status quo. This would set a value for $HAMD_0$ as set out in clause 30 of the guidelines.

Transpower would also have to determine growth in gross MWh of energy consumption to calculate the adjustment terms U_0 and U_t under clause 30 of the guidelines.

In principle it would be reasonable to deem the adjustment terms U_0 and U_t as both equal to 1 until such time as sufficient data is available to calculate lagged growth in gross MWh based entirely on actual observed consumption. That is, until year 10 of the new transmission customer's operation.

FIGURE 3 PHASED INTRODUCTION OF CHARGES FOR NEW CUSTOMERS



It makes sense to calculate growth in gross MWh based only on actual data because of potentially significant distortions in behaviour due to:

- deemed values for gross MWh having a non-trivial effect on marginal operating decisions i.e. if Transpower deemed a value of 100MWh, but a new investment could operate at 200MWh, there would be a significant incentive on the new transmission customer not to operate at 200MWh
- an alternative of using only a few years observations could unduly impact costs for investments that take time to rise to full operation and thus significantly affect the operation of a new investment or investment decisions.

Phasing-in of charges for new designated transmission customers would not result in perfectly comparable residual charges for new transmission customers and existing customers investing in the same assets. This is because changes to existing customers' residual charges would be determined by gross MWh and charges for new transmission customers would be based on AMD. The effect of this is ambiguous in the sense that there are three possible outcomes, depending on the utilisation of a new asset:

- charges are perfectly comparable, as between new and existing customers, if the percentage change in asset capacity (MW) is equal to the percentage change in energy use (MWh)

- new transmission customers will face higher residual charges than existing customers if the percentage change in the existing customer's asset capacity is larger than the percentage change in gross energy use (MWh)
- existing transmission customers will face higher residual charges than existing customers if the percentage change in the existing customer's asset capacity is smaller than the percentage change in gross energy use (MWh).

Thus, there would remain some incentive for new and existing transmission customers to structure the legal form of their investments (whether as new transmission customers or through existing customers) to minimise exposure to transmission charges.[28]

Further, this adjustment mechanism would not resolve incentives to invest in batteries that have high energy to power ratios (i.e. high MWh stored relative to MW of capacity). As such, the transmission pricing methodology would provide an inefficient incentive for new designated transmission customers to favour investing in batteries with high energy to power ratios.

This option would partially address technological bias that results from higher regulatory costs faced by investors in storage as opposed to other technologies such as cogeneration. Albeit that electricity using technologies would still face residual charges while other technologies do not, so some technological bias would remain.

Two subsidiary options under option 1 are:

- option 1a: phasing is applied to all new designated transmission customers with load
- option 1b: phasing is applied only to batteries installed by new designated transmission customers.

Option 1a has the advantage of simplicity in the sense that there is no need to identify whether the new customer has installed a battery. It may also have benefits beyond the scope of this note. However, because option 1a has much wider implications than simply battery storage it is inconsistent with the scope of the issue to be addressed. That being so, for the rest of this document we consider only option 1b.

4.2. Option 2: reassessment of residual charges for substantial changes in use

An alternative method for ensuring equivalence as between existing and new transmission customers' residual charges, as mentioned above in option 1, would be to reassess the AMD basis for existing customers if there is a substantial change in demand, including connection of large new offtake plant.

[28] This effect could be further moderated adjusting new customer's charges to account for battery diversity factors (i.e. expected MWh per MW of maximum demand), alongside phasing of new transmission customers' charges. This would further close if not eliminate the gap between new and existing customers' charges. However, this option would strike non-trivial information problems as there is no standard operating profile for batteries.

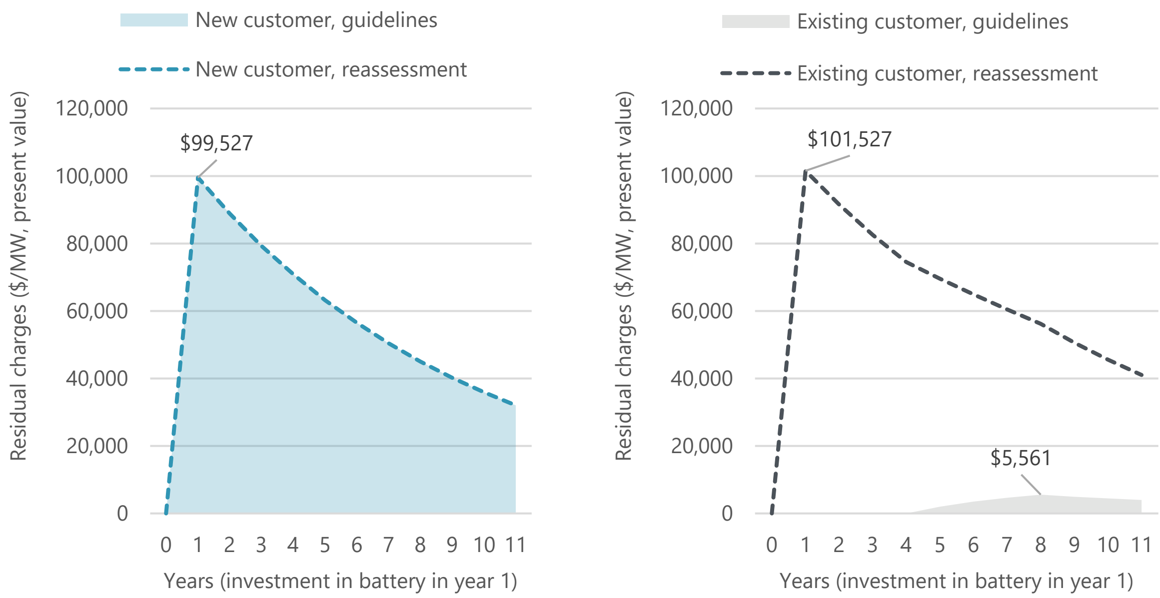
This option would see a step change in the AMD basis for allocating existing customers' residual charges - one that would be equivalent to the AMD basis for allocating charges for new designated transmission customers.

The effect of this option would be to increase the charges of an existing transmission customer that invested in a battery. This contrasts with option 1 where the intent is to reduce residual charges or new designated transmission customers. That is, under this option the present valued residual charges shown for a new designated transmission customer in Figure 1, without phased adjustment, would apply for existing transmission customers too.

This option would eliminate a potential barrier to entry and eliminate incentives for a battery investor to channel their investment through an existing designated transmission customer. In this regard this option (option 2) has an advantage over option 1 which only partially addresses the potential barriers to entry.

In fact, this option would see existing customers paying slightly higher residual charges than new customers, unless additional adjustments were made to the calculation of customers' shares of adjusted anytime maximum demand. This is because growth in gross energy consumption would be applied to the higher reassessed maximum demand. This can be seen in the example in Figure 2 where the initial charge faced by an existing customer is $101,527 per MW (present value) and $99,527 for the new customer – the difference being two years of growth in rolling average gross MWh at an illustrative 1% growth per annum.

FIGURE 4 RESIDUAL CHARGES WITH A REASSESSMENT OF MAXIMUM DEMAND



This option would require defining a threshold that triggers a readjustment of residual charges for existing designated transmission customers such as:

- a percentage change in demand and measured by either AMD or MWh and/or

- an absolute change in the size of assets connected directly or indirectly to the grid.[29]

Step changes to residual charges could be applied to any substantial change in demand or only to the installation of batteries. For the purposes of this assessment and the focus on batteries, this distinction is of no consequence. Batteries and load are complements in the sense that no one would ever choose to invest in a battery instead of load. Thus a charge on batteries but not on load would not cause an inefficient incentive to invest in load instead batteries purely for the purpose of avoiding an increase in residual charges. Although additional costs associated with battery investment could deter load investments if it reduced an investor's options for procuring back-up supply or managing exposure to price risk.

Regardless of scope of application, whether to batteries or any substantial change in demand, this option would be a derogation from the guidelines in so far as it explicitly moves away from the core intent of the residual charge: a fixed charge where any adjustments are very gradual and occur far enough into the future as to minimise incentives to change demand to avoid residual charges.

The guidelines do not explicitly provide for an adjustment to <u>existing</u> designated transmission customers' residual charges except through a four-year rolling annual average of gross annual energy consumption (MWh) lagged by approximately four years – such that a change in demand today only has an effect on residual charges eight years into the future. This gradual adjustment, combined with an expected gradual decline in the amount revenue recovered from the residual charge, significantly reduces incentives to adapt behaviour to avoid the residual charge.

This option would have the following significant disadvantages relative to option 1:

- defining thresholds for substantial change would be likely to create a significant incentive for investment in assets fractionally below the threshold
- it would likely result in substantially smaller charges for investment in distributed energy storage and thus bias investment in favour of smaller scale distributed options even where this was not efficient
- it would be more costly to administer, requiring additional information gathering and scrutiny of assets in order to determine the applicable size of a new investment
- it would exacerbate technological bias caused by residual charges in the sense that, for example, a large load customer investing in back-up energy supply would face a substantially higher residual cost from investing in a battery over other technologies, at least relative to both the status quo and option 1.

This option also significantly undermines the core intent that the residual charge be very similar to a fixed charge, to limit distortions.

[29] A natural starting point for defining this sort of threshold would the one set out in clause adjustment envisaged in clause 33 (e) of the guidelines, based on whether new plant could feasibly be connected to the grid.

4.3. Option 3: allocate residual charges based on final demand

Neither option 1 nor option 2 addresses technological bias in the application of the residual charges, where batteries face charges that similar technologies do not.

This option would partially address this technology bias by defining gross energy as gross final demand – thereby excluding from residual charges any electricity (MW or MWh) that is imported (used for charging) for subsequent resale in the electricity market.

Provisions in the proposed TPM would not need to be much more complicated for allocating residual charges on gross final demand than they are for allocating charges based on gross load as currently expressed in the TPM guidelines. They would only require the addition of the term 'final demand'.

Final demand could be specified as either final consumption, which includes use of energy for the direct support of production of energy or electricity services and excludes losses during transformation or transportation, or it could be taken to include final consumption plus losses in transformation or transportation.

In this option, we define final demand as including losses. Below we consider the case for excluding losses, which has the effect of exempting batteries from residual charges.

Given this, gross final demand could be estimated as the sum of[30]:

- a customer's off-take from the grid, plus
- concurrent generation behind the designated transmission customer's point of connection, <u>excluding injection from batteries</u> *less*
- <u>generation from battery energy storage systems</u>.

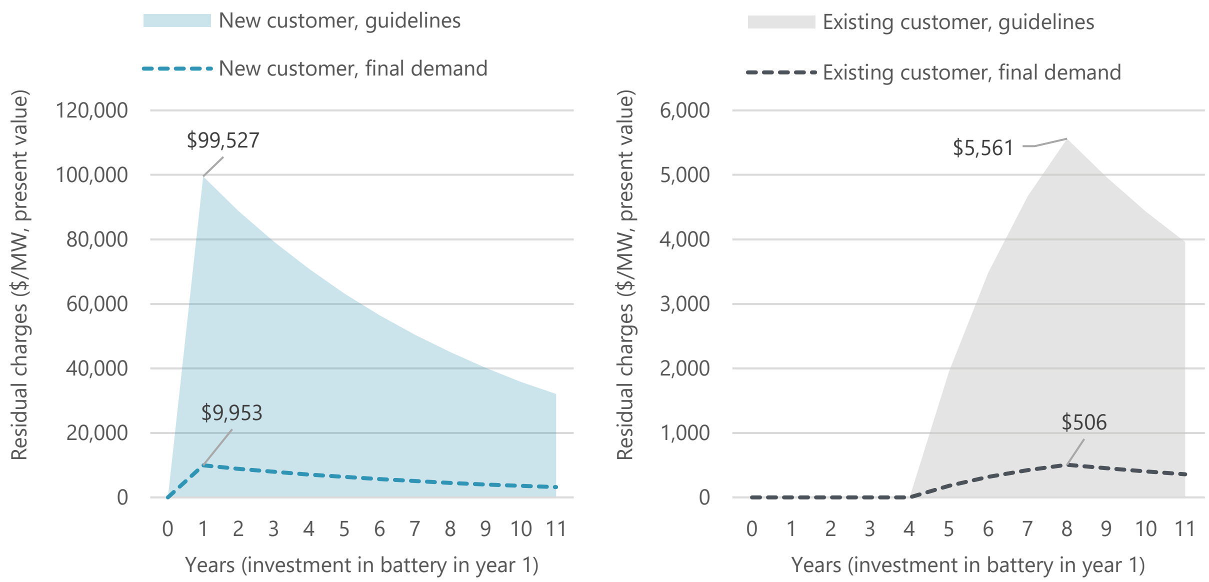
The impact of this option on residual charges faced by investor's in batteries is summarised in Figure 2. Note that there is a substantial reduction in residual charges for both existing designed transmission customers and new designated transmission customers. Although residual charges for new customers would be substantially higher than for existing customers because batteries are likely to represent a larger proportion of MW of anytime maximum demand than MWh of energy consumption.

The difference in residual charges between existing and new customers need not be as extreme as is shown in Figure 2. This is only one example based on a battery that discharges 1100 MWh for every MW of capacity. In practice, the effect could be both more or less pronounced depending on the purpose of the battery.

FIGURE 5 RESIDUAL CHARGES BASED ON FINAL DEMAND

[30] The first two elements of this calculation are from the guidelines. The intent in this example is to suggest demand measurement methods for the purposes of both initial residual allocation and for rolling updates of the residual allocations over time.

Charges for new and existing customers are charted on different scales



For new designated transmission customers investing in grid-connected batteries estimating gross final demand would be reasonably straight forward, with an efficiency factor applied to the batteries' capacity (maximum potential demand) to account for the share of maximum demand that would be recycled to the grid. For example, if the round-trip efficiency loss of a battery is 10% and the battery is 10 MW, the AMD for the purposes of residual charges would be 1 MW.

For existing transmission customers gross final demand (MWh) could be calculated by deducting grid injection by batteries from the existing customer's gross energy.

Estimating gross final demand for networks with embedded storage would also be straight forward:

- no adjustment is needed for small batteries because their net load is automatically captured in grid offtake or concurrent generation[31]
- generation from larger batteries, with visible concurrent generation, would need to be deducted from the gross energy (MWh) calculation.

Advantages of this option are:

- both barriers to entry and technology bias are significantly reduced
- transaction or administrative costs are relatively low because they rely on

[31] This assumes that Transpower cannot see and does not measure battery discharge and thus does not include battery discharge in its measure of concurrent generation.

- there are no negative effects in terms of distortions to optimal scale of investment because batteries have the same effect on residual charges whether they are small or large or grid-connected or embedded in local networks.

Disadvantages of this option are:

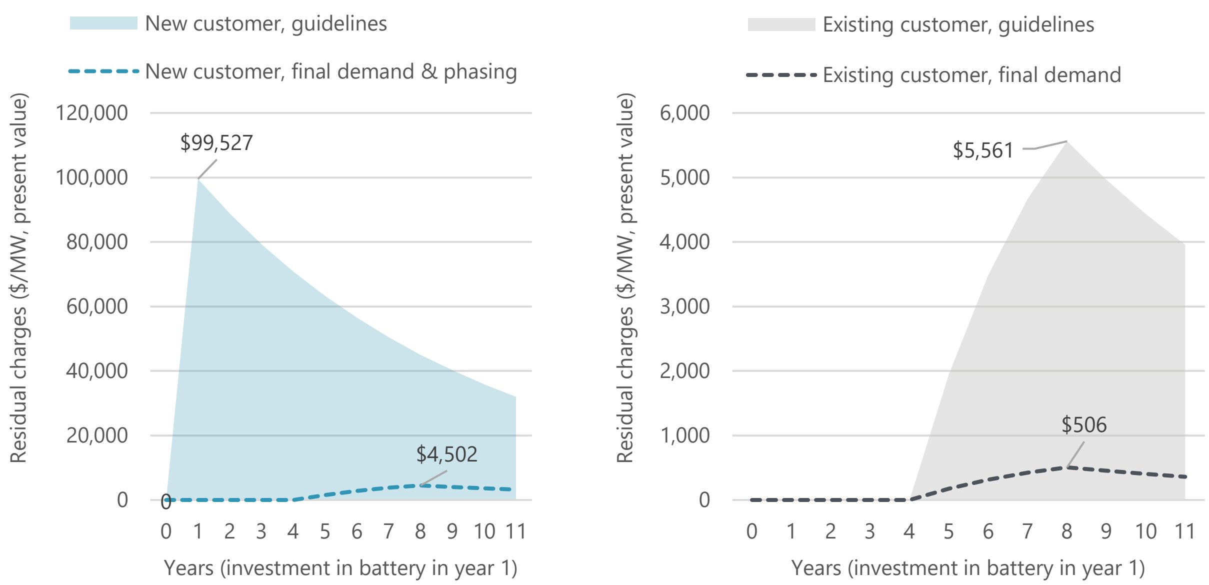
- technology bias is not eliminated it is only reduced because batteries still face residual charges while similar technologies do not
- barriers to entry for new designated transmission customers are not eliminated.

4.4. Option 4: phased charges for new customers plus charges based on final demand

Option 3 could be combined with option 1, with the intent of option1 to reduce distortions as between existing and designated transmission customers and option 3 aimed at reducing disincentives to invest in batteries over other substitute technologies.

Option 1 and option 3 resolve quite different issues, so the two options are complements rather than substitute and they can be combined to provide a more complete solution to the identified problems.

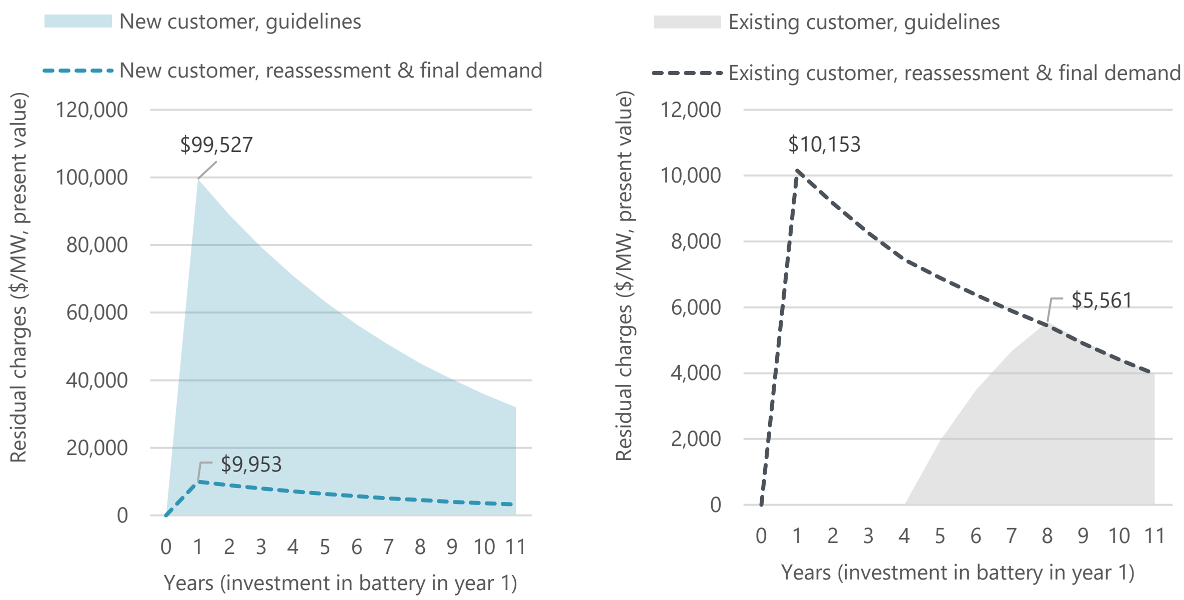
FIGURE 6 RESIDUAL CHARGES BASED ON FINAL DEMAND AND PHASING FOR NEW CUSTOMERS
Charges for new and existing customers are charted on different scales



4.5. Option 5: reassessment of residual charges and charges allocated on final demand

Reassessment of residual charges when there are substantial changes in use could be coupled with the option 3 approach of allocating residual charges based on final demand. This would have the effect of significantly reducing the technology bias in the residual charge while also largely addressing barriers to entry, albeit with new customers facing slightly lower charges than existing charges due to, as discussed in the case of option 2, rolling average growth in gross MWh being applied immediately to the higher reassessed basis for anytime maximum demand.

FIGURE 7 RESIDUAL CHARGES BASED ON FINAL DEMAND AND PHASING FOR NEW CUSTOMERS
Charges for new and existing customers are charted on different scales



4.6. Option 6: exempt batteries from residual charges

This option is the same as option 3 in that it adapts the definition of gross energy demand to be gross energy demand for final consumption but it differs from option 3 by excluding losses incurred during transformation and this has the effect of exempting batteries from residual charges.

This option would involve calculating gross energy demand as the sum of:

- a customer's off-take from the grid, plus
- concurrent generation behind the designated transmission customer's point of connection, less
- battery energy storage system demand.

The above calculation assumes that injection by batteries is measured in concurrent generation. If it is not, the deduction of battery energy storage demand will reduce measured gross energy demand below what it would otherwise be without a battery and the exemption would incentivise installation of batteries to reduce residual charges.

Measuring generation from batteries would not be onerous in the sense that it would not require half-hourly metering. For example, if half hourly data on battery generation and investment is not available then the value of load to be exempted could be calculated based on adding annual battery generation and deducting annual battery demand.

Batteries installed behind ICPs, such as in commercial or residential buildings, would not receive this exemption unless steps were taken to identify energy consumed in the process of charging and discharging batteries. This would create a distortion, in principle, from treating batteries differently depending on their location and, implicitly, size. But this distortion is not likely to be significant e.g. because the load of batteries installed behind ICPs would be treated on the basis of final demand, by default, and residual charges would only be affected by growth in MWh due to battery losses during charging and discharging.

This option has the advantage that it would almost eliminate technology bias and barriers to entry imposed on new designated transmission customers that install batteries. The only exception is the case of new investment in hydro generation that supplies tail-water depressed spinning reserve, which would not be exempted, given that the definition used above applies only to battery energy storage systems. Thus, some degree of technology bias and barrier to entry would remain, however it would be small.

Another key advantage of this option is that it is the only option that resolves non-trivial distortions to the use of batteries co-located with grid-connected generation. Under all the above options and under the guidelines adjustments to residual charges using growth in gross MWh has the potential to create additional distortions to battery investment or use if a battery is co-located with grid-connected generation.

This practical problem arises because the definition of gross energy is net <u>off-take</u> from the grid plus a reasonable estimate of concurrent generation.

Generation plant with a co-located battery is likely to draw very little energy from the grid. If the operator of the plant ever decides to increase use of grid-supplied electricity to charge the battery this could easily cause a substantial change in MWh of offtake and a non-trivial increase in residual charges. Even if that change in residual charges occurs with a lag the plant's operator would likely be constrained in making best use of the battery. This could prevent efficient use of generation assets, including batteries, and impose costs on new investments that reduce competition between generators.

An additional related complication is that gross energy includes "Transpower's reasonable estimate of concurrent generation behind the designated transmission customer's point of connection". Strictly speaking, all generation or consumption occurs <u>behind</u> a designed transmission customer's point of connection. That being so, the gross energy of a battery co-located with generation would include the energy used to charge the battery plus the energy generated to charge the battery. This implies that an investor in grid-connected connection who decided to install a battery would, perversely, face twice the residual charges of any other battery investor.

Double counting of battery charging and co-located generation, when measuring gross demand, is clearly not intended, being that the guidelines envisage that load embedded with generation would be treated as if it was grid connected. Thus, it might simply be resolved in the drafting of the transmission pricing methodology, without requiring a derogation from the guidelines.

5. Assessment

Table 2 shows that exempting batteries from residual charges is the only option that can eliminate cost increases, avoid distortions to battery investment and eliminate technology bias and barriers to entry. This suggests that exemption is the best option.

TABLE 2: IMPACT OF ALTERNATIVE OPTIONS ON BATTERY INVESTMENT COSTS

	New customer		Existing customer	
Options	**PV cost per MW ($m)**	**% impact on investment cost**	**PV cost per MW ($m)**	**% impact on investment cost**
No change	0.60	75.0%	0.03	3.75%
1. phasing	0.20	25.0%	0.02	2.50%
2. reassessment	0.60	75.0%	0.70	87.50%
3. final demand	0.10	12.5%	0.002	0.25%
4. final demand and phasing	0.02	2.5%	0.002	0.25%
5. reassessment and final demand	0.06	7.5%	0.069	8.63%
6. exemption	Nil	Nil	Nil	Nil

There are two caveats to this assessment. First, small, distributed batteries would, indirectly, face residual charges on a final demand basis, thus creating a modest bias towards larger scale battery investments due to a 0.25% increase in investment costs for small batteries (i.e. the impact measured for option 4).[32]

Second, average residual charges will be higher than they would be under the other options, assuming that battery investments proceed under the other options. In general, it is preferable to spread residual charges as widely as possible because it reduces unit charges and reduces distortions. However, this effect was considered by the Authority alongside potential negative effects of residual charges on the efficiency of production and as such, it is consistent with the guidelines to ignore this cost.

[32] The new designated transmission customer cost for option 3 does not apply for small distributed batteries because by definition they will not be designated transmission customers (i.e. not grid-connected).

6. Appendix: assumptions behind modelled residual charges

In the modelling of residual charges, to assess effects of the guidelines and of alternative options, we assume that:

- a battery is considered for connection in 2023, the first year of new transmission prices under the new transmission pricing methodology guidelines
- the cost of the battery is $8 million[33]
- revenue to be recovered from residual charges are expected to be $450 million in 2023, declining at a rate of 2.6% per year[34]
- total MW demand nationally, for the purposes of residual allocation is 4,000 MW[35]
- national gross consumption grows at a rate of 1% per annum
- a discount rate of 8%.[36]

A single type of battery is modelled – one with an energy to power (MWh:MW) ratio of 1.

To examine the effects of residual charges on hydro generators offering tailwater depressed spinning reserve we assume:

- a long run marginal cost of $84 per MWh
- each MW of reserve dispatched consumes .015 MWh of energy
- an average energy cost of $70 per MWh
- maximum reserve offer is 20.4 percent of plant capacity[37]
- a project life of 40 years (in contrast to our battery investment examples where project life is assumed to be 10 years).

[33] Based on projected 2023 costs of $800/kW inclusive of connection and maintenance and capital costs, consistent with the projected battery storage costs for a 1MW:1MWh battery used in the TPM CBA (refer paragraphs 2.217 to 2.225 of the June 2020 technical paper on CBA approach, methods and assumptions for the TPM decision paper at https://www.ea.govt.nz/assets/dms-assets/26/26849Technical-paper-CBA-approach-method-and-assumptions.pdf). Clearly this number would be larger for smaller projects but we use a single number for simplicity.

[34] Consistent with the residual charges reported in Table 4 of the TPM decision paper (2020) and with expected growth in benefit based and residual charges for 2022 to 2049 in Table 5 of the TPM CBA technical paper (2020).

[35] Based on the values used to calculate indicative TPM charges in the TPM decision paper.

[36] This rate is the same one used to calculate battery investment costs.

[37] Based on observed maximum ratio of fast instantaneous reserve capacity offered relative to energy offered.

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