Transmission pricing methodology: 2019 Issues paper

Supplementary consultation

Consultation paper

Submissions close: 5pm 3 March 2020

11 February 2020

Executive summary

The Electricity Authority (Authority) is proposing a new approach to transmission pricing, through its review of the guidelines that Transpower must follow in developing the transmission pricing methodology (TPM).

The Authority set out its proposed new TPM guidelines in the 2019 Issues paper in July 2019. In response, we received 93 submissions, 18 cross-submissions and 25 oral submissions.

The Authority's TPM review is ongoing and its decision on the proposed TPM guidelines has not yet been made. This supplementary consultation is part of that ongoing process. The content of this consultation paper does not preclude further changes or stakeholder engagement, such as on the cost benefit analysis or peak charging, in response to the Authority's consideration of submissions on the 2019 Issues paper which the Authority has been undertaking.

In considering submissions, we identified some possible refinements to the proposal that in our view may better promote the Authority's statutory objective. Submissions are available on the Authority's website.[1]

The Authority is now proposing that:

- annual benefit-based charges for post-2019 grid investment be set according to the depreciated historical cost (DHC) method, instead of the indexed historical cost (IHC) approach that was proposed for post-2019 investments in the 2019 Issues paper
- if a direct connect or generation customer closes down one of its plants, its liability for associated benefit-based charges would cease ten years after the commissioning of the relevant grid investments, instead of continuing indefinitely as was proposed in the 2019 Issues paper
- the initial allocation of the residual charge (which is based on historical gross anytime maximum demand) is to be adjusted annually based on changes in the four-year rolling average of gross annual energy usage, lagged by seven years
- a customer may apply for a prudent discount if its transmission charges would exceed the standalone cost of the transmission services it receives.

This consultation paper is supplementary to the 2019 Issues paper. Its purpose is to consult on the above proposed refinements to the proposal set out in the 2019 Issues paper. Further discussion of the refinements is set out in sections 3 to 6 of this consultation paper. We welcome submissions on the refinements. Submissions close on Tuesday, 3 March 2020, at 5pm.

The Authority is currently planning on announcing its decision on the transmission pricing guidelines in the second quarter of 2020. However, this timeframe does depend on the issues raised in submissions and in any further engagement with stakeholders. We will take the time we require to consider the issues raised.

1 https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c18138

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1 What you need to know to make a submission

What this consultation paper is about

1.1 The purpose of this paper is to consult with interested parties on proposed amendments to the Authority's proposal set out in the 2019 Transmission Pricing Methodology (TPM) Issues paper.

1.2 This supplementary consultation document contains four specific proposed changes to the 2019 proposal, following the Authority's consideration of submissions made by stakeholders on the 2019 Issues paper. These proposed changes are sufficiently substantive or different to options set out in the 2019 Issues paper to warrant consultation with stakeholders.

1.3 The Authority's TPM review is ongoing and its decision on the proposed TPM guidelines has not yet been made. This supplementary consultation is part of this ongoing process. The content of this consultation paper does not preclude further changes or stakeholder consultation.

How to make a submission

1.4 The Authority prefers to receive submissions in electronic format (Microsoft Word). Submissions in electronic form should be emailed to tpm@ea.govt.nz with "Consultation Paper—proposed changes" in the subject line.

1.5 If you cannot send your submission electronically, post one hard copy to either of the addresses below, or fax it to 04 460 8879.

Postal address	Physical address
Submissions Electricity Authority PO Box 10041 Wellington 6143	Submissions Electricity Authority Level 7, Harbour Tower 2 Hunter Street Wellington

1.6 Please note the Authority wants to publish all submissions it receives. If you consider that we should not publish any part of your submission, please:

(a) indicate which part should not be published

(b) explain why you consider we should not publish that part

(c) provide a version of your submission that we can publish (if we agree not to publish your full submission).

1.7 If you indicate there is part of your submission that should not be published, we will discuss with you before deciding whether to not publish that part of your submission.

1.8 However, please note that all submissions we receive, including any parts that we do not publish, can be requested under the Official Information Act 1982. This means we would be required to release material that we did not publish unless good reason existed under the Official Information Act 1982 to withhold it. We would normally consult with you before releasing any material that you said should not be published.

When to make a submission

1.9 Please deliver your submissions by **5pm** on Tuesday **3 March 2020**.

1.10 This deadline allows three weeks for submissions. This timeframe reflects the small number and specific, narrow nature of the proposed changes to the proposal in the 2019 Issues paper, and the familiarity of stakeholders with the issues.

1.11 We will acknowledge receipt of all submissions electronically. Please contact the Authority at tpm@ea.govt.nz or 04 460 8878 if you don't receive electronic acknowledgement of your submission within two business days.

2 Background

The Authority's objectives

2.1 The Authority's intention is to improve the TPM so that it better meets the Authority's statutory objective as set out in section 15 of the Electricity Industry Act 2010 (Act):

> "to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers".

2.2 The Authority discussed its statutory objective in the context of transmission pricing in the 2019 Issues paper in Chapter 4 (from paragraph 4.223) and in Appendix D and it continues to consider the proposed guidelines in light of its statutory objectives.

Issues with the current TPM

2.3 The current TPM has three main charges:

(a) connection charge to recover connection asset costs from connecting parties

(b) high voltage direct current (HVDC) charge to recover the costs of the HVDC link from South Island generators

(c) interconnection charge to recover other transmission costs from load customers.

2.4 In the 2019 Issues paper the Authority identified significant flaws in the current TPM that it considered are leading to inefficient investment and electricity consumption outcomes. These include:

(a) The interconnection charge spreads the costs of regional grid investments across all New Zealand. This makes such investments look cheaper than they are at the local level, compared to local alternatives, while other regions pay for assets they do not benefit from.

(b) Interconnection charges are allocated based on consumption during just 100 regional peak trading periods in a year (the regional coincident peak demand or RCPD charge). This creates a very strong price signal to consumers, which:

   (i) inefficiently discourages electricity use at times consumers most value it, even when there are no grid congestion issues

   (ii) encourages unnecessary investments in technologies such as batteries and distributed generation to avoid paying transmission charges, shifting charges to others without reducing Transpower's costs

(c) South Island generators pay for all the costs of the high voltage direct current (HVDC) line that transports electricity between the South and North Islands, while North Island generation does not face equivalent charges. This 'tax' on South Island generation encourages investment in North Island generation that would otherwise be more expensive.

2.5 In the 2019 Issues paper we noted that these problems increase the cost of electricity to consumers. They are likely to get worse as more grid investments are made to support growing regions and to transition to a low-emissions economy, and as distributed generation resources, such as solar panels and batteries, become more affordable.

The proposal in the 2019 Issues paper

2.6 The TPM guidelines proposed in the 2019 Issues paper were designed to address these problems. The proposal is to replace the RCPD and HVDC charges in the current TPM with two new core charges:

(a) a benefit-based charge to recover costs of new grid investments and depreciated costs of seven major existing investments based on their benefits to transmission customers

(b) a residual charge to recover any remaining transmission costs in a manner which does not unnecessarily distort incentives to invest or use the grid.

2.7 These proposed new charges, together with nodal pricing in the wholesale market, are intended to send better signals to consumers on the economic cost of using the grid, while minimising distortions to grid use and to investment in generation and transmission alternatives.

2.8 Other core components of the proposal in the 2019 Issues paper include:

(a) a connection charge (largely unchanged)

(b) a prudent discount policy (PDP) with minor modifications

(c) a price cap that limits transmission charge increases on load customers.

2.9 The proposal also provides for seven additional (not mandatory) components. This includes the option for Transpower to introduce a transitional peak charge, to operate alongside nodal prices, at specific points in the grid that would otherwise experience congestion.

This supplementary consultation paper

2.10 The Authority's TPM review is on-going and its decision on the proposed TPM guidelines has not yet been made.

2.11 This supplementary consultation is part of that ongoing process. The content of this consultation paper does not preclude further changes or stakeholder engagement in response to the Authority's consideration of submissions on the 2019 Issues paper which the Authority has been undertaking.

3 Recovery profile for future benefit-based investments

3.1 The Authority proposes that annual benefit-based charges for post-2019 grid investment be set according to the time profile specified by the Commerce Commission under Transpower's individual price-quality path (depreciated historical cost (DHC)), instead of the indexed historical cost (IHC) approach proposed in the 2019 Issues paper.

Background: the proposal in the 2019 Issues paper

3.2 The total benefit-based charge for a grid investment needs to be converted to annual charges. The present value of those charges must equal the total benefit-based charge for the investment.

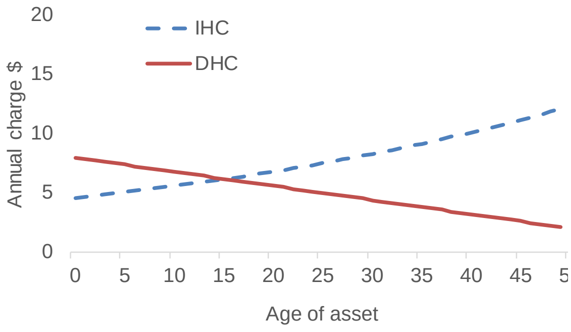
3.3 Under the IHC approach, Transpower would set the annual benefit-based charges for post-2019 investments as equal annual amounts over the benefit-based investment's expected life (a flat recovery profile). This would then be adjusted by a price index (to account for inflation).

3.4 The 2019 Issues paper proposed the IHC approach for post-2019 grid investments because that recovery profile was viewed to reflect the real flow of services from a grid investment over time. This would be consistent with the pricing that would be expected in a workably competitive market. It would also have some efficiency advantages – for example, it could avoid distorting decisions on replacement investments. (It was also proposed that Transpower could propose a different method than IHC if it considered this would better meet the Authority's statutory objective).

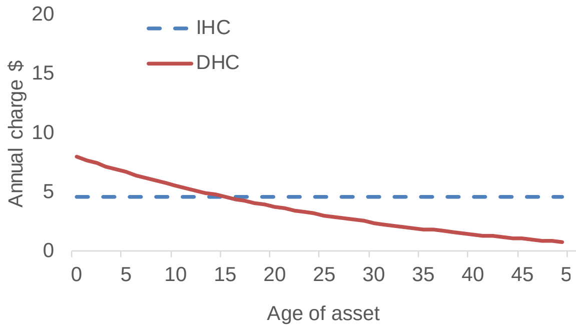
3.5 A different method was proposed for pre-2019 (historical) investments. Charges for these investments would be recovered using the DHC method, as specified by the Commerce Commission for Transpower's individual price-quality path. This was for practicality reasons and because the efficiency benefits of IHC would be smaller for historical investments.

3.6 The DHC method results in a front-loaded recovery profile. That is, more of the costs are recovered early in the investment's life. This difference is illustrated in the following charts, which show the annual charges (depreciation and capital cost) for a $100 investment under the different recovery profiles in nominal and real (ie inflation adjusted) terms.

Nominal



Real



Note: assumes investment of $100, real cost of capital (or discount rate) of 4%, inflation of 2% pa

Revised proposal: all recovery on depreciated historical cost

3.7 After considering submissions, we now propose for efficiency reasons that the TPM guidelines require annual benefit-based charges for post-2019 grid investment to be set according to the time profile specified by the Commerce Commission for Transpower's individual price-quality path (DHC).

3.8 This would mean the same approach applies to both pre-2019 and post-2019 investments. It would also mean the amount recovered through benefit-based charges in respect of an investment in any given year is the same as the costs the Commerce Commission decides Transpower can recover in respect of that investment for that year (unless Transpower makes adjustments permitted in the guidelines).

Issue and submissions

3.9 The issues include the following:

(a) the IHC method requires adjustments to the residual charge that may result in economic inefficiencies (as previously identified)

(b) compared to DHC, IHC recovers more costs later in an asset's life and this may:

(i) heighten the risk of any future disputes over allocations (a potential problem raised in submissions by various submitters)

(ii) distort grid use and investment decisions.

3.10 Meridian and Rio Tinto submitted the annual benefit-based charges for post-2019 transmission investments should be set in a way that is consistent with the Commerce Commission's approach, citing various reasons including the economic inefficiencies resulting from adjustments.

3.11 NERA submitted (for Meridian) that it is not necessarily correct that prices would be uniform over time in workably competitive markets, and that applying the IHC increases complexity as it would result in a different time profile of cost recovery to that underlying the Commission's calculation of Transpower's maximum allowable revenue (p.55).

3.12 The Distribution Group supported the IHC approach in principle, unless it materially impacted the residual charge. Axiom submitted (for Transpower) that IHC should be used for all assets subject to the benefit-based charge – including existing assets (p.68).

Assessment

3.13 We still consider that IHC has the efficiency benefits discussed in paragraph 3.4. However, we now consider these are outweighed by its efficiency costs.

3.14 A key efficiency cost of IHC is that it may cause future disputes over allocations. Some submitters (for example Transpower, p.5) were concerned the benefit-based charge for an investment could become increasingly misaligned with customer benefits, due to changes in grid use patterns over time. Submitters were concerned this could lead to disputes and lobbying, reducing the durability of the proposed new TPM guidelines.

3.15 Compared to IHC, DHC recovers more costs early in the life of an asset, when it is more likely there would be a better match between the allocation of charges and actual benefits and beneficiaries than later in the life of the investment. Further, under DHC the charges later in an asset's life are lower, reducing incentives to dispute allocations.

3.16 IHC may distort customers' grid use and investment decisions, because, compared to DHC, IHC recovers more costs later in an investment's life. This puts more at stake in any future reallocation of sunk investment costs (for example, in the event of a substantial and sustained change in grid use). This could increase a customer's incentive to (inefficiently) alter its grid use to reduce its future charges.

3.17 Other reasons to prefer DHC for future investments (over IHC) are that it:

(a) avoids efficiency losses that could be caused by a higher residual charge early in the life of the investment[2] under an IHC approach (Rio Tinto pp.18, 20)

(b) is consistent with the cost recovery profile used by the Commerce Commission in its decisions on Transpower's Input methodologies (IMs). The use of IHC would alter that profile and could undermine the intent of IM decisions (Rio Tinto, p.23).

3.18 The above reasons to prefer DHC over IHC also suggest that a requirement to use DHC should be preferred over allowing Transpower to propose an alternative method.

3.19 DHC could inefficiently discourage replacement investment (as an investment would result in a significant increase in annual charges in the first year). However, we consider this is unlikely, because customers will typically receive substantial private benefits from an investment and because it does not change the present value of the charges.

3.20 In the Authority's view the proposed refinement would increase the net efficiency benefits of the proposal and is pragmatic. The proposal is at a level of detail that would not materially affect the quantified level of expected net benefits of the TPM proposal. Accordingly, we rely on the qualitative analysis of costs and benefits set out above.

Indicative impact on customer transmission charges

3.21 This revised proposal would have only limited impacts on indicative transmission charges for the first year of any new TPM, as the change only affects post-2019 investments. The change to DHC would affect the timing of charges, but not their present value. Compared to the proposal in the 2019 Issues paper:

(a) customers benefitting from a post-2019 investment would see higher charges in the early years of a new investment and lower charges later

(b) there would be no need to recover costs from all load customers through residual charges in the early years of a new investment (see footnote 2).

3.22 For example, a rough estimate is that Vector's annual charge for Waikato and Upper North Island (WUNI) investment would rise by $2.7m in 2030 ($2 per household) when the majority of WUNI costs are expended.[3] But by 2043 the impact reverses and by 2054 Vector's annual charges would be $2.8m lower under DHC.

Q1. Should the annual benefit-based charges that recover the costs of post-2019 investments be set using DHC, IHC or some other approach?

Q2. Should Transpower be required to use the DHC as proposed, or should it be able to propose a different method if that better met the Authority's statutory objective?

[2] Under an IHC approach the residual charge would adjust over time to allow for the difference between actual charges and Transpower's recoverable revenue attributable to the investment.

[3] A similarly rough estimate is that Northpower's charges would initially be +$300k ($1.70/ household) higher, and Top Energy's +$60k (90c/household) before reversing in later years.

4 Adjusting benefit-based charges when a plant closes

4.1 The Authority proposes that if a customer closes one of its plants, its liability for associated benefit-based charges would cease after ten years of the commissioning date of the relevant grid investment (instead of continuing indefinitely, as was proposed in the 2019 Issues paper).

Background: the proposal in the 2019 Issues paper

4.2 In the 2019 Issues paper the Authority proposed that benefit-based allocators would be fixed when a grid investment was decided and not revised, other than in specific circumstances (such as a substantial and sustained change in grid use). This meant that where a transmission customer shut down one of its generation facilities or industrial plants, but remained a transmission customer, it would continue to be liable for the same level of charges. This was intended both to ensure the customer properly scrutinises grid investment proposals during the investment approval process and to avoid creating an inefficient incentive to shut down a plant in order to avoid the benefit-based charge.

4.3 The 2019 Issues paper also proposed that if a transmission customer opens a new plant, that plant would be subject to similar transmission charges as a similar (but perhaps hypothetical) customer at the same location. This was intended to avoid creating a competition problem, as otherwise two similar competitors could be required to pay different levels of transmission charges.

Revised proposal: adjust when customer closes one of its plants

4.4 After considering submissions, we now propose that liability for benefit-based charges in respect of a given grid investment would continue when a generation or load customer closes one of its plants (but still remains a transmission customer) until ten years after the commissioning date of that grid investment and would then cease.[4]

4.5 If a plant closes more than ten years after the commissioning date of the grid investment, liability for the benefit-based charge for that plant is proposed to cease immediately.

4.6 When the plant owner's liability for the benefit-based charge in respect of the closed plant ceases, the charges it was paying are reallocated to the other beneficiaries of the relevant investments. This is the same as what happens if the customer closes all of its plants and ceases to be a transmission customer. See box on the next page.

Issue and submissions

4.7 The provisions proposed in 2019 regarding a customer's liability for benefit-based charges may inefficiently discourage a customer from adjusting its portfolio by closing one plant and opening another.

4.8 Contact submitted (p.1) that when a generation customer shuts down one of its generation assets, the customer should no longer be charged ongoing transmission charges following closure of that asset. A number of submitters (for example, Powerco, p.2) argued that the allocation of all benefit-based charges should be updated regularly, so that the allocation continues to reflect customers' benefits as they shift over time.

[4] For load customers' plant, by closure, we mean that the plant has permanently ceased to operate the equipment that previously consumed the bulk of its energy needs and is not intending to replace it. Any residual energy use would be negligible compared to the prior energy use. For generation, we mean that the plant has permanently ceased energy production. Later installation of new plant at the site would be considered the entry of a new customer.

Box: Illustration

Consider Transpower had commissioned a grid upgrade in 2025, but a large industrial customer then closed one of its grid-connected plants in 2030 that benefited from that upgrade. Under the proposal, the industrial customer would continue to pay the benefit-based charges associated with that grid upgrade until 2035, that is 10 years after the upgrade had been commissioned. The charges would then cease.

The benefit-based charges for other beneficiaries of the upgrade would be adjusted so that the cost of the upgrade continued to be recovered (unless reassignment conditions were met).

If instead the industrial customer's plant was embedded in a distributor's network, then the distributor's transmission charges would not change as a consequence of the plant's shut-down. (Whether the industrial customer continues to bear transmission charges would be a contractual matter between it and the distributor.)

However, the distributor's charges may be reduced if:

(a) Transpower determines that the shutdown meets the test of a substantial and sustained change in grid use

(b) the shut-down and consequent reduction in load means that the conditions for a reassignment of the cost of the grid upgrade are met.

Assessment

4.9 We continue to hold the view that the provisions proposed in 2019 have the advantages noted above at paragraphs 4.2 and 4.3. However, we also acknowledge these provisions have some significant potential disadvantages, which in our view warrant an adjustment to our proposal.

4.10 A key disadvantage is that a customer may be discouraged from adjusting its portfolio. For example, a business considering closing one of its fossil-fuel generators and starting up a new wind farm might decide not to do so because of the resulting net increase in transmission charges (as it would be liable for transmission charges for both the closing plant and the new plant, for the life of each relevant grid investment). This may be the case even where the change would have been efficient (for example, where the new generator has lower costs and requires no additional transmission).

4.11 One potential solution could be to stipulate that if a transmission customer opens a new plant, that plant would not be subject to benefit-based charges if it does not cause the need for additional transmission infrastructure. This potential solution is not proposed, because it could create the competition problem noted at paragraph 4.3 above.

4.12 For these reasons, we now consider that the benefit-based charge should not continue indefinitely when a generator or a load customer closes one of its plants.[5]

4.13 That said, the benefit-based charge should not always be removed *immediately* upon closure. This might weaken the customer's incentive to reveal relevant information during the investment approval process. This would be inefficient where long-term grid investments are made in the wrong expectation of long-term demand from a customer.

5 If a designated transmission customer completely disconnected from the grid, its liability for transmission charges would cease.

4.14 For example, a customer might withhold information concerning a shut-down of one of its plants that it privately expects to occur two years after a new grid investment is commissioned. This can lead to a situation where a new grid investment is approved (but would not have been approved had the private information been revealed) – the customer would benefit from the grid investment for two years, then stop paying for it as soon as the plant closes at the expense of other transmission customers post-closure.

4.15 To balance the competing considerations, the Authority proposes liability for benefit-based charges should continue but cease after a ten-year period following the commissioning of the grid investment. We see this as equivalent to the risk-sharing arrangements that would likely be part of long-term contracting arrangements in a workably competitive market. It could be considered comparable to a long-term take-or-pay contract (which are used to share risk in the oil and gas sector).

4.16 We considered a range of potential lengths for the proposed "take-or-pay period":

(a) at the upper end, 20 years would be consistent with the typical duration of long-term contracts in the oil and gas sector. A long-term commitment would support the scrutiny objective but may be a barrier to efficient closures. If the proposed DHC method were to be taken up, the front-loaded recovery of the costs of grid investments further suggests a long period is not required.

(b) at the lower end, a five-year period would give the closing-down customer more flexibility to efficiently adjust its portfolio of plants. However, this shorter period does not reflect the long-term nature of a typical grid investment.

(c) on balance ten years seems appropriate – indicative modelling indicates it would result in a relatively even sharing of risk between the closing-down customer and other customers.

4.17 It is not proposed that liability in respect of the *residual* charge should cease after ten years. That's because the proposal provides separately for updates to the residual charge: through a Transpower operational review (as proposed in the 2019 Issues paper) or instead through a regular annual update (as proposed in this paper).

4.18 In the Authority's view the proposed refinement would likely increase the net efficiency benefits of the proposal. The proposed change is not material enough to affect the quantified level of expected net benefits of the proposed TPM guidelines. As such we rely on the qualitative analysis of costs and benefits set out above.

Indicative impact on customer transmission charges

4.19 When liability for benefit-based charges does cease (after the expiry of the ten year period, if relevant) the revised proposal would reduce the charges payable by a customer whose plant has closed down, and increase pro-rata the charges of all other beneficiaries of each investment relevant to the closed-down plant.

4.20 The revised proposal is not expected to have a major impact on charges for transmission customers, since:

(a) it would only have an effect when a customer shut down a plant

(b) it would only have an effect after the expiry of the ten-year period from the commissioning of the relevant grid investment(s)

(c) after the expiry of the ten-year period, the customer's charges would be spread across other transmission customers who benefited from the same investments (and possibly across all customers through the reassignment provisions).

Q3. If a transmission customer closes one of its plants, should its liability for associated benefit-based charges continue indefinitely, cease immediately or cease after a specified period of time has elapsed since the commissioning dates of the relevant grid investments? If the latter, should that period be 5, 10 or 20 years? Should the relevant period be expressed relative to the commissioning date of the investment or some other period?

5 Regular updates of the residual charge allocation

5.1 Having considered submissions, the Authority proposes the initial allocation of the residual charge (which is based on historical gross anytime maximum demand) is to be adjusted annually based on changes in the four-year rolling average of gross annual energy usage, lagged by seven years.

Background: the proposal in the 2019 Issues paper

5.2 The function of the residual charge is to recover Transpower's remaining allowable revenues that are not recovered through the benefit-based charge or any other transmission charges. It is intended to be allocated among customers in the least distortionary way and is allocated based on a proxy for ability to pay.

5.3 As such it was proposed that the residual charge would be a fixed-like charge and based on a historic gross measure of demand. This was to avoid creating incentives for customers to inefficiently change their grid use or investment to avoid the charge.

5.4 Gross anytime maximum demand (AMD) was proposed in the 2019 Issues paper as the relevant measure of demand. Energy consumption (MWh) was also considered, but this was judged likely to have a material adverse impact on some industrial load customers, which could potentially lead to inefficient disconnection.

5.5 The 2019 Issues paper did not prescribe a regular adjustment process for the residual charge. Instead it proposed that Transpower could update the residual allocator from time to time through an operational review of the TPM, using gross AMD lagged by ten years (to weaken customers' incentives to inefficiently change their behaviour).

Revised proposal: method for regular updating

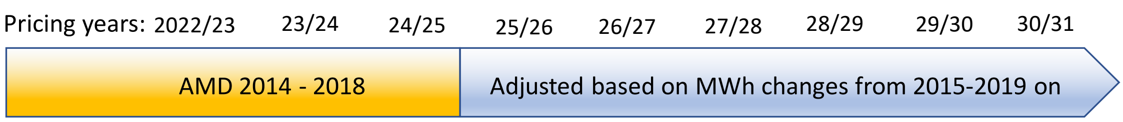
5.6 Having considered submissions, we now propose that the guidelines specify that, for the residual charge:

(a) the initial allocation is based on the four-year average annual value of gross AMD for the 2014-2018 period, as was proposed in the 2019 Issues paper

(b) that initial AMD-based allocation is then adjusted annually based on changes in a four-year rolling average of customers' gross annual energy usage (measured in MWh), lagged by seven years.

5.7 The effect of the lag is that the initial allocation applies until the end of the 2024/25 pricing year. Annual adjustments are made to the allocation from the 2025/26 pricing year onwards (as illustrated in the figure below). In that year, the initial allocation is adjusted by the percent change in average annual usage for the four-year period 1 July 2015 to 30 June 2019 compared to average annual usage for 1 July 2014 to 30 June 2018. Each year after 2025/26, the four-year average rolls forward by one year.

Figure: Annual adjustments to the residual allocation begin in 2025/26



5.8 These provisions would replace the current provisions that allow updates to the residual charge through a Transpower operational review.

Issue and submissions

5.9 There are two issues:

(a) regular updating of the allocation of the residual charge based on changes to AMD risks creating relatively strong incentives for a customer to inefficiently change its grid use (perhaps by investing in alternatives) in order to reduce its allocation of the residual charge at the next update. Some submitters have argued that these incentives would be stronger in the case of AMD than for other potential allocators, as it is easier for a customer to adjust its AMD than say its energy use.[6]

(b) if the allocation is not updated regularly, customer charges could become increasingly misaligned with customers' size and ability to pay. Some submitters (including Buller Electricity, Contact Energy, Winstone Pulp, Unison and Centralines) have argued the residual charge allocation should be revised on a regular basis. Trustpower said the residual charge must be capable of evolving with changing circumstances, rather than only in extreme circumstances (p.57).

Assessment

5.10 We agree with submitters that using gross AMD to update the residual allocation could be distortionary, even with a lag. This is because AMD is a measure of peak demand that a customer could adjust at low cost relative to other measures (such as total usage). AMD is also easier for a customer to predict and control, compared to regional coincident peak demand, as AMD is based on a customer's own peak usage rather than the regional coincident peak.

5.11 These issues do not arise if AMD is used to set the initial allocation. Moreover, the reasons for using AMD to set the initial residual allocation remain: AMD is a proxy for the customer's size and ability to pay and would reduce the likelihood of disconnection of some industrial loads that would be adversely impacted if the initial allocation was based on energy consumption (MWh).

5.12 The approach we are now proposing addresses both issues, because gross AMD is used to set the initial allocation but is not used to update that allocation subsequently.

5.13 We also agree with submissions it would be appropriate to update the residual charge regularly to reflect relative changes in size (as a proxy for ability-to-pay).[7] If the allocation was not updated for some time, this could mean that a shrinking region ends up making a disproportionately large contribution to the residual charge (and a growing region making a disproportionately small contribution). This diverging burden could distort customers' decision-making and is unlikely to be durable. A regular revision would account for changes in customers' size (and thus their ability to pay) over time.

5.14 If there were to be a regular revision, it would be desirable that this process is transparent, is mechanical (that is, does not require the exercise of judgement) and does not lead to incentives for inefficient customer decision-making.

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6 See, for example, Creative Energy Consulting for Trustpower.

7 Here we make a distinction between the residual charge and the benefit-based charge. It is appropriate to update the residual charge regularly to reflect relative changes in size, as a proxy for ability-to-pay, because the residual charge is essentially similar to a tax, and should be allocated in a way that least distorts decision-making. By contrast, the benefit-based charge is an access charge for the grid. Revising the allocation of the benefit-based charge regularly would distort incentives to properly scrutinise grid investment proposals and to reveal information to the Commerce Commission during the investment approval process.

5.15 In our view the proposed approach to updating the allocation meets these objectives. Annual gross energy usage is an easy-to-observe indicator of relative size/ability to pay, so the update would be a transparent, mechanical process.

5.16 Using a gross energy usage (MWh) allocator for updating the allocation could create opportunities for customers to seek to avoid charges. However, the incentive is relatively muted compared to using an AMD allocator, since the party seeking to avoid the charge would have to alter its total energy use to do so. It is more difficult or more costly for a customer to change its annual usage than its AMD (which occurs in a single period).

5.17 The risk of distorting customers' decision-making would be further mitigated through providing for a lag. A ten-year lag period was proposed in the 2019 Issues paper for updates to the residual allocation. As noted in that paper, we considered that a ten-year lag should in large part mitigate inefficient incentives for avoiding the charge and for inefficient investment in, or operation of, distributed generation (as it reduces the NPV of a customer's benefits from any changes to its behaviour). Further, charge avoidance is likely to be less of a concern after ten years as the residual charge would reduce over time as existing investments depreciate, and as an increasing share of transmission charges is recovered via the benefit-based charge.

5.18 However, a ten-year lag may be regarded as too long in a context of potentially rapid and substantial changes in, for example, regional economies and populations. However, having no lag or even a short lag of a few years would risk promoting inefficient cost-avoidance and cost-shifting. The Authority proposes a lag of seven years to balance these competing considerations. It would mean allocators start to adjust from 2025/26.

5.19 We considered using alternative allocators for updating distributors' residual charge; in particular, changes in the annual number of ICPs or households.[8] This allocator would not need to be lagged as it is unlikely to be altered to avoid charges. But it would not work for direct-connect industrials. So even if ICPs were used for distributors, a different allocator (such as MWh) would need to be used for direct-connects. The chief disadvantage of a mixed approach is that it would create a risk of commercial consumers re-arranging their affairs (for example, embedding) to minimise their charges (though that risk might be mitigated to a degree through the prudent discount policy).

5.20 Given that the updating procedure is a mechanical process and – if a lag is used – relatively free of distortion, it is reasonable to stipulate that it occur frequently (annually). Use of a rolling average updated annually has the advantage of smoothing out price changes over time.[9] A four-year rolling average is proposed for consistency with the length of the period used to set the initial allocation (1 July 2014 - 30 June 2018).

5.21 In the Authority's view, this proposed change would reduce potential for distorted decisions and support durability of the proposal. This would not result in a material change to the quantified level of expected net benefits of the proposed TPM guidelines. Accordingly, we rely on the qualitative analysis of costs and benefits set out above.

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8 Unison and Centralines suggested using the annual number of ICPs or households as an allocator.

9 Buller Electricity and Winstone Pulp discussed a rolling average approach in their submissions. Trustpower submitted that solutions such as a rolling average over multiple years may assist with providing a cost allocation mechanism that evolves with changing circumstances, while lessening the likelihood to distortionary responses (p.57).

Box: Stylised example for Boomtown

Boomtown is a transmission customer with a fast-growing economy and population, reflected in growing annual electricity usage (MWh). Its usage was growing at 1% per year and later (from 2021-22) at 5% per year. Other customers' annual electricity usage is not changing.

Initially, Boomtown had been allocated 10% of the residual charge based on its historic AMD. This does not change until the end of pricing year 2024-25.

From pricing year 2025-26 onwards, Boomtown's allocation of the residual charge increases by the percent change in average annual usage for the four-year period ending June 2019 compared to average annual usage for the four-year period ending June 2018.

The following year, the allocation increases by the percent change in average annual usage for the four-year period ending June 2020, compared to the four-year period ending June 2019. The allocation for other customers is not changing, and thus Boomtown's share of the residual charge rises.

By pricing year 2030-31, Boomtown's allocation of the residual charge (as illustrated in the table below) has increased to 11.1%.

Table: Boom-town's allocation of the residual charge

Pricing year:	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31
Boom-town	10%	10%	10%	10%	10.1%	10.2%	10.3%	10.5%	10.7%	11.1%
Other	90.0%	90.0%	90.0%	90.0%	89.9%	89.8%	89.7%	89.5%	89.3%	88.9%

Indicative impact on customer transmission charges

5.22 The total amount recovered via the residual charge is intended to reduce over time.

5.23 The revised proposal would not affect indicative transmission charges for the first years of any new TPM, as it only affects future updates to the residual charge (beginning in the 2025-2026 pricing year, assuming a seven-year lag). From that date, residual charges would be relatively higher or lower (with a lag) compared to the track implied by the proposal in the 2019 Issues paper, based on whether a customer's total energy use (ie number of consumers or electricity used per consumer) grows faster or slower than average.

5.24 Based on recent patterns of growth in MWh, the absolute distributional impacts are small.

Q4. Should the guidelines stipulate for regular updates to the residual charge allocation?

Q5. If so, is the revised proposal an appropriate way to provide for such updates?

6 Prudent discount for charges above standalone cost

6.1 The Authority's revised proposal is to allow a customer to apply for a prudent discount if its transmission charges would exceed the standalone cost of the transmission services it receives.

Background: Proposal in 2019 Issues paper & 2nd Issues paper

6.2 The prudent discount policy (PDP) addresses the risk of uneconomic disconnection from the grid. Avoiding a disconnection by providing a prudent discount can avoid inefficient outcomes. It can also be better for all transmission customers that an applicant pays discounted transmission charges if the alternative is that the applicant would disconnect from the grid and pay no transmission charges (provided the customer receiving the prudent discount was paying at least its incremental cost).

6.3 In the 2016 2nd Issues paper the Authority proposed extending the PDP to make discounts available where charges would exceed the standalone costs of delivering electricity to the customer and to situations where transmission charges might cause the customer to close down its New Zealand plant. The latter was withdrawn later in 2016 on the basis that it could be gamed (given information asymmetry is likely).

6.4 Under the 2019 proposal a prudent discount is available to a transmission customer if it can show that it would be "technically and operationally feasible, and commercially beneficial" for it to by-pass the grid and source an alternative supply of energy, where it is not efficient to do so. In the 2019 Issues paper we did not propose to make discounts available where charges would exceed standalone cost, on the basis that the approach based on a viable business case for disconnection would generally reach a similar outcome.

Revised proposal: limit transmission charges to standalone cost

6.5 After considering submissions, we now propose that the guidelines also allow a customer to apply for a prudent discount that would reduce its transmission charges to the efficient standalone cost of supplying it with the transmission services it receives.

6.6 The standalone cost of supplying a transmission customer is the cost required to provide transmission services to that customer alone.[10] For a load customer, it is equivalent to the cost the customer would incur today to provide it with independent greenfield access to load on essentially similar terms to that which it currently gets from the grid. Likewise, for a generator with respect to access to load.

6.7 We propose that any new TPM should include a method for determining the efficient standalone cost of supply. This method would need to adequately define the transmission services received by the customer, taking into account all relevant dimensions of service including grid reliability, energy security and price considerations.

6.8 This proposed limb of the prudent discount policy would be in addition to the avenue proposed in the 2019 Issues paper, under which a customer shows a viable business case for disconnection.

[10] It is possible to calculate the standalone cost of supplying a single service, or alternatively, the standalone cost of supplying a single customer. We refer here to the standalone cost of supplying a single customer.

Issue and submissions

6.9 The current policy and that proposed in the 2019 Issues paper do not explicitly cover the situation where bypass of the existing network would be a financially viable option in theory, but other considerations stand in the way.

6.10 For example, Rio Tinto submitted that it would be impossible to obtain a resource consent for construction of a duplicate transmission link through pristine wilderness. In such a situation, the cost estimated using a real-world business case for bypass of the network could be prohibitive. It suggested an alternative is to place an upper limit on transmission charges at the standalone cost of supply. By implication, under such an approach it would be assumed that it was possible for a customer to obtain the required greenfield resource consents, after incurring all the costs that it might reasonably expect to incur in seeking to obtain the consent. The submission argues that this approach would be consistent with the way prices are set in workably competitive markets.

6.11 Contact submitted that direct consumers should be able to apply for a prudent discount if their transmission charges were creating a material risk that would lead to closure.[11]

6.12 A number of submissions in response to the 2016 2nd Issues paper argued against extending the PDP to situations where charges might cause the customer to close down its New Zealand plant. Submitters typically either did not specifically address the proposal to make discounts available where charges would exceed standalone cost or supported it. For example, Genesis submitted: “Although we agree with the Authority that a discount should be available in situations where allocated cost exceeds stand-alone cost, we caution against allowing a business to apply for a PDP based on insufficient available revenue or risk of exit.”[12]

Assessment

6.13 The main objective of the prudent discount policy is to discourage inefficient disconnection from the grid.

6.14 In our view, prudent discounts based on a real-world business case for bypass of the grid would effectively discourage inefficient disconnection in circumstances where the customer’s alternative is to disconnect in favour of alternative supply. This approach is consistent with the approach to prudent discounts that is followed in Australia.

6.15 However, such an approach is not effective where a customer has no real alternative but to exit the country. The risk that transmission charges could lead to inefficient exit is a key justification for including “safety valves” like the PDP in the TPM, according to Professor Hogan.[13] Prudent discounts could be allowed where a customer can demonstrate that transmission charges are creating a material risk that would lead to closure of New Zealand plant, as Contact has proposed. However, we do not propose to adopt this approach: it risks being gamed due to the asymmetry of information between Transpower and the customer – as the evidence relates to the customer’s industry.

6.16 In these circumstances the standalone cost approach can be a useful, objective standard. Assessing the standalone cost of supplying transmission services to a transmission customer is likely to be within Transpower’s domain of expertise. Pricing below efficient standalone cost is recognised in the economics literature as consistent

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11 Contact cross-submission page 1

12 Genesis submission in response to 2016 2nd Issues paper, p.10

13 Filenote: Electricity Authority Teleconference with Professor William Hogan, 17 May 2018

with efficient "subsidy-free" prices and pricing above this level is inefficient.[14] There are precedents for the use of standalone cost in regulatory proceedings to establish price ceilings.[15] The standalone cost test is an objective measure that can be used to assess whether or not a customer is being overcharged.

6.17 The standalone cost approach would mitigate a limitation of the proposal in the 2019 Issues paper that could mean some customers are charged above standalone cost. If the costs of all transmission investments were recovered from customers in proportion to the benefits they receive from those investments, then all customers would likely be charged below the standalone cost of supply. But this is not the case. Initially at least, the majority of the costs of pre-2019 investments are proposed to be recovered through the residual charge, which is not based on the benefits customers receive from the grid.[16] So customers that receive below-average benefits from the grid (perhaps because they are located close to generation) may nevertheless pay a large residual charge, and as a result be charged above standalone cost.

6.18 A larger number of PDP applications might be expected under this approach, as the scope for applications is less restricted. However, standalone cost should present a high hurdle that would limit the number of successful applications. This is because economies of scale and scope are very significant in transmission, and the hypothetical supplier of a single customer does not benefit from Transpower's scale economies. Further, the requirement to take into account all relevant dimensions of the transmission service received by the customer (including grid reliability, energy security and price considerations) means that the standalone cost may be significantly greater than just the cost of a single transmission link to the nearest generation source. For these reasons, we expect only a very small number of additional prudent discount applications would be successful under the standalone cost approach.

6.19 The standalone cost approach could involve higher transactions costs than the current approach to the PDP, as it would likely lead to arguments over the definition of the transmission service received by the customer and other conceptual issues – and because it could lead to a larger number of applications. However, the number of applications will be constrained naturally by the cost and effort customers would face in preparing applications, and Transpower's own resourcing considerations.

6.20 Under the proposal any new TPM would need to include a method for determining standalone cost so that the Authority can assess the method in advance of it being used. The method would need to allow the assumption that duplication of any part of the existing transmission grid is possible. (We are not advocating that transmission links ought to be constructed through "pristine wilderness" or that such prohibitions are unreasonable. Our approach is based on the economic principles around standalone cost.) One approach would be to require a hypothetical business case for grid bypass in favour of alternative supply in which this assumption is made. An alternative approach might be to calculate the replacement cost of the transmission network of a hypothetical efficient grid owner that provides transmission services to the customer making the

14 Faulhaber (1975), Baumol, Panzar & Willig (1982)

15 Ofcom has used a standard it calls the distributed stand-alone cost (DSAC) of a service to establish a ceiling on telecommunications service prices charged by suppliers with significant market power. Ofcom, *Cost orientation: Review*, 5 June 2013 https://www.ofcom.org.uk/__data/assets/pdf_file/0018/63261/cost_orientation.pdf

16 Transpower may propose, under additional component E, that all pre-2019 investments are recovered through the benefit-based charge. However, this may not prove to be feasible or cost-effective.

application and to no other customers. Other regulators have calculated similar hypothetical costings.[17]

6.21 The Authority has considered the incremental efficiency effects of the revised proposal on the PDP. (These would be in addition to the 2019 Issues paper which estimated the incremental benefits and costs of the proposed changes to the PDP separately from the rest of the proposal.)

6.22 The Authority considers the net benefits of this proposal to be small but positive. This is because our assessment is that the proposal would extend the prudent discount provision to only a very narrow range of situations. For example, it is unlikely to change the business case for distributors or most direct-connect customers. If a prudent discount application under this provision were successful, then by definition it would be net beneficial, subject to transaction costs (para 6.19), as it would avoid an inefficient disconnection. Net benefits would likely be greater if there were more successful applications.

Indicative impact on customer transmission charges

6.23 The bespoke nature of prudent discounts means it is not possible to undertake general modelling of the impact of the revised proposal with respect to the PDP.

6.24 However, as a hypothetical case study, consider an example where a prudent discount reduces a load customer's current charges of $10m per annum by $5 million per annum.

6.25 The prudent discount would be recovered through the residual charge, spread across all load customers. If the customer disconnected because they did not receive a prudent discount, this exit would require reallocation of $10m in charges, which would be spread across all other customers through their benefit-based and residual charges.

Q6. Should a load customer be eligible for a prudent discount if it can establish that its transmission charges exceed the efficient greenfield standalone cost of supply?

7 Next steps

7.1 All of the refinements proposed in this paper would require corresponding changes to the TPM guidelines proposed with the 2019 Issues paper.

7.2 Once we have considered submissions that we receive in response to this consultation paper and settled on policy positions on these issues (and on any other outstanding issues), we intend to redraft any affected elements of the TPM guidelines accordingly to reflect these decisions.

17 For example, in 2015 the Commerce Commission calculated the replacement cost of the telecommunication network of a hypothetical efficient supplier of telecommunication services, in order to determine regulated prices for other providers accessing Chorus' unbundled copper local loop (UCLL) and unbundled bitstream access (UBA) services. See Final Pricing Review Determinations [2015] NZCC 37 and [2015] NZCC 38 at https://comcom.govt.nz