ELECTRICITY AUTHORITY
TE MANA HIKO

Avoided Cost of Transmission (ACOT) – TPM-related amendments

Decision paper

20 December 2022

Executive summary

The Electricity Authority (Authority) has decided to amend the Electricity Industry Participation Code 2010 (Code) to make it clear that payments by distributors to eligible distributed generation for avoided cost of transmission (ACOT) are no longer required. Previously, distributors had a Code obligation to net off these amounts from connection charges for those distributed generators. The total ACOT payments effectively being made to distributed generators have been in the order of $35 million per year,[1] with the cost recovered from distribution customers (and ultimately from consumers) through lines charges.

This change is prompted by the introduction of a new transmission pricing methodology (TPM) from April 2023. Under the prior TPM, most ACOT payments have been based on avoided interconnection charges (rather than underlying transmission costs) and this basis for payments will no longer exist. Amending the Code removes the risk of uncertainty or dispute regarding payments under the new TPM.

Having carefully considered submissions, the Authority remains of the view that the current ACOT regime, based on transmission charge avoidance and resulting in other customers paying more, does not represent an efficient payment for any grid support value provided by distributed generation.

The Authority has decided ACOT obligations will end with the new TPM

In our October 2022 consultation paper, we sought views on whether to phase ACOT payment obligations out over two years to mitigate potential transition risks. The Authority has decided not to provide a phase out period.

Transpower, in its role as system operator, submitted in favour of phasing out ACOT obligations due to its view that capacity margins will remain tight in coming years and ACOT payments may contribute to security of supply by encouraging generation capacity availability during peak demand periods. Transpower notes that ACOT payments were not intended for this purpose. The Authority considers that ACOT payments are not an efficient or effective tool for managing security of supply.

Several submitters argued that a phase out would support grid reliability by preserving incentives for distributed generators to operate at times of regional peak demand. The Authority considers that nodal prices provide a more accurate signal of where and when generation is of value for grid reliability, which is more to do with local congestion than regional demand. Where nodal prices are not effective, we are reassured that Transpower as system operator has tools to manage near-term risks, and Transpower as grid owner has obligations to plan for investment solutions.

The Authority acknowledges that there is some uncertainty in transition, with distributed generators recalibrating to different incentives. We expect Transpower, distributors and distributed generators to prioritise responding to any actual or potential grid reliability issues arising during this ACOT transition period, noting the range of tools available to Transpower, and that in any given circumstances a transmission investment response (traditional or alternative) may not be warranted under the grid reliability standards.

1 This figure is the aggregate distributed generation allowance paid by distributors. As well as ACOT payments, it includes two prudent discount agreements and one notional embedding contract – like ACOT, payments under these three agreements are also underpinned by charges under the current TPM.

The Authority will review arrangements for transmission alternatives

The Authority accepts that the incentives and funding mechanisms for transmission alternatives – including distributed generation and other flexibility services – may be able to be enhanced. The Authority intends to initiate a new workstream considering the wider set of incentives for investment in distributed generation to determine whether their efficiency can be improved.

The Authority notes that its aim is to ensure least cost solutions are developed for the benefit of end consumers. This means regulatory price signals to distributed generation or other flexibility providers (ie, other than nodal price and other revenue) should, if used at all, be set in such a way as to minimise any adverse impact on end consumers.

Code Amendments promote the Authority's statutory objective

The Code amendments set out in this decision paper promote the Authority's statutory objective by removing the impetus for inefficient payments and providing a more level playing field as between pre-2017 distributed generation, other generation (whether distribution or grid connected) and other transmission alternatives.

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1. Introduction

1.1. Under the Code, distributors may only charge distributed generation their incremental costs of providing connection services. For some pre-2017 distributed generation, this means making payments to distributed generation for avoided costs of transmission. Historically, most ACOT payments have been made based on avoided interconnection charges. However, the new Transmission Pricing Methodology (TPM) has been designed without usage-based charges such as the interconnection charge, instead replacing them with fixed-like charges. As such, distributors' ACOT payment obligations need to be clarified.

1.2. The Authority published a consultation paper on its proposal to clarify that ACOT payments will not be required under the new TPM. The consultation period closed on 20 October 2022 and 20 submissions were received. The cross-submission period closed on 3 November 2022 and 7 cross-submissions were received. Finally, the Authority also published and sought feedback on correspondence between itself and Transpower on the issue of grid reliability. It received 5 further submissions on this correspondence.

1.3. Following consultation, the Authority has decided to amend the Code to remove provisions that required distributors to make ACOT payments to certain pre-2017 distributed generators. It has also decided not to adopt the alternative option of phasing out ACOT payments.

1.4. The Code amendment is consistent with the Authority's statutory objective because it will deliver long-term benefits to consumers by promoting the efficiency and competition limbs of our statutory objective. Specifically, the amendment will:

(a) promote efficiency by removing inefficient payments to certain pre-2017 distributed generation that does not necessarily reduce transmission costs

(b) promote competition by creating a level playing field between certain pre-2017 distributed generation and other generation services (ie, grid-connected or ineligible distributed generation), flexibility services (ie, other dispatchable generation, energy storage or demand response technologies) and transmission services (ie, poles and wires, demand response or other transmission alternatives).

1.5. This paper sets out the Authority's decision to remove the requirement on distributors to make ACOT payments (including its decision not to phase-out ACOT payments) and addresses points raised in submissions.

1.6. The paper also confirms the Authority's intention to initiate further work on considering the wider set of incentives for investment in distributed generation to determine whether their efficiency can be improved.

2. Removing ACOT payments

Our decision

2.1. The Authority has decided to amend the Code to remove provisions that required distributors to make ACOT payments to certain pre-2017 distributed generators.[2]

What we proposed

2.2. The October 2022 consultation paper proposed amending the Code to clarify that ACOT payments will no longer be required following implementation of a new transmission pricing methodology (TPM) from April 2023.

2.3. Previously, ACOT payments were typically based on the contribution that distributed generators make to reducing a distributor's interconnection charges.[3] The new TPM replaces interconnection charges with fixed-like charges designed to avoid inefficiently influencing usage of already-built grid assets. As such, the current basis on which ACOT payments are typically made will be gone from 1 April 2023 with no clear replacement. The Code amendment clarifies that distributors are not required to make payments based on, for example:

(a) the limited charge avoidance opportunities that remain under the new TPM (primarily through allocator updates), or

(b) forward-looking assessment of future transmission charges.

2.4. The effect of this change is to clarify that price-quality regulated distributors cannot build ACOT payments into their target revenue via the "distributed generation allowance" component of recoverable costs.[4]

Submitters' views and our assessment

2.5. We received 18 submissions[5] relating to whether the Code should be amended to clarify that ACOT payments will no longer be required.

2.6. Nine submitters agreed the Code should be amended to clarify that ACOT payments are not required under the new TPM.[6] These submissions generally agreed with the Authority's reasoning set out in the consultation paper, specifically that:

(a) Previous ACOT arrangements have supported inefficient payments for charge avoidance – ie, unless transmission investment is avoided, any reduction in a distributor's interconnection charges is fully offset by ACOT payments (hence local

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2 The specific Code amendment amends clause 1.1 and Schedule 6.4 of the Code to remove the obligation on distributors to net off the transmission costs that an efficient distributor would be able to avoid by connecting certain distributed generation (avoided cost of transmission) when calculating the maximum connection charges that may be applied to that generation under the regulated terms.

3 Commonly referred to as regional coincident peak demand, or RCPD charges.

4 See clause 3.1.3(1)(f) of the Electricity Distribution Services input Methodologies Determination 2012 (Consolidated 20 May 2020) at https://comcom.govt.nz/__data/assets/pdf_file/0017/60542/Electricity-distribution-services-input-methodologies-determination-2012-consolidated-20-May-2020-20-May-2020.pdf

5 EA Networks and Vector's submissions did not express a firm view on this.

6 Aurora submission, para 3; Horizon submission, at para 3; Meridian submission, page 1; MEUG submission, para 5; Network Tasman submission, page 1; Northpower submission, page 2; The Lines Company submission, page 2; Unison/Centralines submission, page 1; WEL Networks submission, page 1.

consumers don't benefit) and increases in interconnection charges for other transmission customers (hence other consumers pay more).[7]

(b) Continuing ACOT payments does not fit with the structure of the new TPM, which only includes fixed-like (rather than usage-based) charges – including because ACOT payments would not be offset by transmission charge reductions, so local consumers would pay more.[8]

(c) Continuing ACOT payments would perpetuate an uneven playing field between eligible distributed generation and other transmission alternatives – including grid-connected generation and newer distributed generation.[9]

2.7. Powerco agreed with the rationale for removing ACOT payments but considered that a more targeted transition regime for currently eligible distributed generation could be appropriate.

2.8. Ngāwhā and Top Energy agreed in principle that the Code should be amended to reflect changes to the TPM but did not support removing ACOT in its entirety. They argued that ACOT payments should be retained for distributed generation that is genuinely deferring transmission investment, at least until other support mechanisms are in place.

2.9. Other submitters also argued that ACOT payments should be retained until a suitable replacement is in place[10] or that payments should at least be phased out as per the alternative option the Authority presented in the consultation paper.[11] [12]

2.10. Key themes arising from submissions against removing ACOT payments were:

(a) distributed generation is providing a valuable service, so ACOT payments are efficient

(b) nodal prices are not sufficient to ensure grid reliability, both in terms of investment and operational signals

(c) there are gaps in regulatory arrangements and/or supplier incentives that stymie efficient funding of transmission alternatives, and ACOT is needed to remedy this problem.

2.11. We address each of these themes below.

Does ACOT provide efficient payments for a valuable service?

2.12. Many parties submitted that distributed generation provides a valuable service by reducing the amount of grid investment that would otherwise be needed – ie, by delaying transmission investment or allowing for lower transmission capacity (or less redundancy).[13] Submitters noted that these benefits exist independently from the TPM,

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7 Aurora submission, page 6; Meridian submission, page 1; Northpower submission, page 1; WEL Networks submission, page 1.

8 Aurora submission, para 3; Horizon submission, page 3; The Lines Company submission, page 2; Unison/Centralines submission, page 3.

9 Meridian submission, page 2; Northpower submission, page 2.

10 Electra submission, page 1; IEGA submission, page 2; King Country Energy submission, page 2.

11 Manawa submission, page 1; Transpower submission, page 1.

12 For discussion of the Authority's decision on phase out, refer to Part 3 of this paper.

13 IEGA submission, page 1; King Country Energy submission, page 1; Manawa submission, page 3; Ngāwhā submission, page 3; The Lantau Group report (on behalf of Manawa), page 9; Top Energy submission, page 1.

as while the new TPM removes the basis for current ACOT payments, it "does not change the service provided by distributed generation."[14]

2.13. Some submitters argued that distributed generation should be compensated for the services they provide. For example:

(a) Ngāwhā argued that "the providers of these services should be compensated to ensure the service continues to be supplied at the lowest cost to consumers, and the cost should reflect the actual benefit provided"

(b) Top Energy was concerned that the Authority "assumes that participants will provide a service for free".

2.14. Some submitters also linked the case for payments to the use of benefit-based charges under the new TPM. For example:

(a) The Lantau Group (on behalf of Manawa) noted that the service provided by distributed generators will result in lower benefit-based charges (under the new TPM) and argue that "clearly if BB charges are lower than they would otherwise be, then an ACOT style payment is merited by the resources that contribute to those savings. The services cannot just suddenly be assumed to be provided without compensation."

(b) the IEGA noted that "the benefit-based charges modelling identifies the amount distributors have not had to pay because distributed generation supplies some of their total load. The IEGA strongly believes it is equitable for distributors, or Transpower, to be required to pay this amount to distributed generation. This is a payment for services provided (and not for an avoided charge)."

2.15. The Authority agrees that distributed generation can reduce the need for transmission investment, and hence provide a benefit in terms of reducing transmission investment costs or, alternatively, enabling a given level of transmission investment to provide a better reliability outcome for local consumers.

2.16. However, the Authority is concerned to ensure that costs for consumers are not unnecessarily high relative to the benefits obtained. To this end, costs for consumers are increased if ACOT payments are:

(a) made to distributed generation that is not providing transmission benefits. The Mitton ElectroNet analysis enabled ACOT eligibility to be narrowed by providing a high-level assessment of which pre-2017 distributed generation is potentially contributing to grid reliability, but this does not mean all currently eligible distributed generation is needed to support grid reliability. We discuss the Mitton ElectroNet report further at paragraph 2.18 below

(b) higher than the value of the associated transmission benefits. As previously discussed, ACOT payments have been linked to avoided interconnection charges rather than the actual value of any transmission benefits provided. As such, there is no safeguard to prevent the cost of the payments exceeding the benefits

(c) made to distributed generation that would have provided transmission benefits anyway, or in return for smaller payments. In many cases, investment and operation would occur without ACOT payments – typically supported primarily by

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14 IEGA submission, page 1. The Lantau Group report at page 10, Manawa's submission at page 3 and Powerco's submission at page 1 made similar points.

revenue from energy sales. This is already the case for ineligible distributed generation (including any plant commissioned since 2017) and for grid-connected generation. Horizon, for example, considered that "any economically rational generator will continue to operate based on its wholesale market position regardless of the availability of ACOT payments." [15] In other cases, the operation of distributed generation could be influenced with much smaller payments.[16]

(d) contributing to an uneven playing field, such that the best solutions are not developed. This contributes to higher costs of supply, which flows to consumers over time. Under current settings, ACOT payments favour eligible distributed generation relative to non-eligible distributed generation (which includes all new distributed generation), local grid-connected generation, and other sources of flexibility (such as batteries or demand response).[17] Meridian agreed that "continuation of ACOT payments would create an uneven playing field between pre-2017 distributed generation and distributed generation built after that date as well as grid connected generation." [18]

2.17. The Authority does not agree that the interaction between distributed generation and benefit-based transmission charges (BBC) provides a basis for ACOT payments. As with the points made above, the Authority is concerned to ensure that costs for consumers are not unnecessarily high. In particular:

(a) The suggested approach would often be complex and subjective, requiring counterfactual analyses to test what BBC allocations would have been without distributed generation, and then making payments to distributed generators based on the assessed savings.[19] The analysis would be repeated for each connection location with distributed generation, and each analysis could involve reallocation of transmission costs or construction of different, hypothetical, transmission assets. Consumers would in aggregate be paying more than the actual cost of actual transmission assets, with the amount of the excess "savings" not linked to the benefits actually provided by distributed generation.

(b) Assuming the above process did produce a robust view of the cost savings delivered by distributed generation, it would leave consumers paying for 100% of those savings, including in cases where the payment is not necessary to achieve the outcome (eg, because energy sales would have provided sufficient revenue to support the distributed generation).

(c) Local grid-connected generators do not receive payments when their presence reduces the local benefit provided by a given transmission investment (and hence reduces the benefit-based charge at a connection location). Requiring consumers to pay distributed generators in a similar situation would contribute to an uneven

15 Meridian's submission at page 2 and WEL Networks' submission at page 3 made similar points.

16 For context, the 2022/23 interconnection rate of $96.89 per kW is equivalent to nearly $2,000 per MWh for a distributed generator who perfectly targets the 100 peak trading periods, or nearly $1,300 per MWh in a more realistic scenario where they target 150 periods (due to uncertainty).

17 In the extreme, it is plausible for generous subsidies to transmission alternatives to result in under-build of transmission that could have provided greater benefits.

18 Northpower's submission at page 2 made a similar point.

19 Northpower's submission at page 2 expressed the view that "It will be virtually impossible for distributors to calculate ACOT on BBI charges, as Transpower uses specialised software that is not available to its customers".

playing field. Competitive distortions cost consumers in the long-run and are contrary to the Authority's statutory objective to promote competition in the electricity industry for the long-term benefit of consumers.

2.18. Finally, we note that some submitters referred to the Mitton ElectroNet analysis that was used to identify the pre-2017 distributed generation currently eligible for ACOT payments.[20] For example:

(a) the IEGA noted that "the Mitton ElectroNet analysis is the only public analysis since the ACOT debate started in 2013 of the impact of distributed generation on reducing transmission costs" and "robust system analysis must be undertaken before making any change to the current arrangements, otherwise the Authority's claim that ACOT payments are inefficient is self-serving and unsubstantiated"

(b) Powerco noted that "for DG on our network, the starting point is the 2018 Mitton report used to derive a list of generators eligible to receive ACOT."

(c) in its cross-submission, Manawa expressed concern that the Authority's comments on the Mitton report may have been misleading, as "the Mitton ElectroNet analysis was designed to assess DG that was "required" to help Transpower meet its grid reliability standards not "potentially" required."

2.19. We acknowledge that the Mitton ElectroNet analysis was an important screening tool for identifying what distributed generation potentially contributes to grid reliability. However, it is not a definitive determination of what distributed generation provides transmission benefits. The assessment uses a binary test of either assuming all distributed generation is on or all is off, which does not distinguish how much of the installed distributed generation is needed (or its merit order).[21] Also, the analysis applies the N-1 screening step of the grid reliability testing process, but not the more analytically demanding economic testing step (which we would expect to further narrow eligibility).[22] [23]

2.20. On this basis we do not accept that our previous characterisation of Mitton ElectroNet's reports is in any way misleading, and do not consider that Mitton ElectroNet's analysis is the right starting point for the immediate question in front us, ie, how to respond, in terms of the provisions of the Code that drive ACOT payments, to the end of the TPM RCPD charge from 1 April 2023.

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20 Mitton ElectroNet completed four reports for Transpower during 2017 and 2018, covering the Upper and Lower halves of each island. https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/acot-code-change-implementation/consultations/#c17580

21 For more information see (for example) page 11 of Mitton ElectroNet, "Lower North Island Distributed Generation Impact Study", December 2017 (23432Appendix-B-Mitton-ElectroNet-report.pdf (ea.govt.nz)).

22 The distinction between GRS screening and economic testing is discussed further in paragraphs 3.19(e) and 3.23(c).

23 We also acknowledge the IEGA's point at page 3 of its submission that Transpower amended the Mitton analysis "to ensure that reliability benefits from distributed generators were genuine". Transpower introduced an "effectiveness hurdle" of 0.1% per MW injected for LNI and USI assessments. Transpower's explanation is that "the hurdle is needed because interactions between regional and grid backbone power flows can show DG improving transmission issues by percentages within the margin of modelling accuracy." (see 23944Appendix-A-Transpower-report-Distributed-Generation-to-meet-GRS-in-Upper-North-Island-31-May-2018.PDF (ea.govt.nz), p11). This does not alter the methodology, which still applies a binary test using N-1 only.

Are nodal prices effective at supporting grid reliability?

2.21. Some submitters disputed the Authority's argument that nodal prices can provide an efficient and effective signal for coordinating distributed generation investment and operation to support grid reliability and argue that ACOT payments therefore need to be retained. Submitters argued that:

(a) nodal prices do not provide sufficient signals to invest in distributed generation, as they may be:

(i) too weak to ensure that new investment will be commercially viable, including because they may collapse when significant distributed generation comes on stream[24]

(ii) too inconsistent to convert to a bankable investment case[25]

(b) nodal prices do not provide sufficient signals to operate distributed generation at times of peak demand, as they may be:

(i) too unpredictable and volatile to ensure that the distributed generation operates at times of peak demand (for example, scheduling outages for outside these periods)[26]

(ii) "irrelevant if distributed generation is contracted to supply electricity"[27]

(c) offering distributed generation at a sufficiently high price to recover costs risks breaking trading conduct rules.[28] Manawa's view was that these rules would "restrict DG from pricing at levels which would enable DG to recover their operating costs in meeting transmission constraints."

2.22. The Authority agrees that nodal prices may not always provide a fully efficient or effective signal to support investment decisions or operational coordination – including because:

(a) price discovery can be imperfect, particularly at grid exit points where there is thin (or zero) participation by generators

(b) nodal price signals can be relatively unpredictable and volatile, which can make them difficult to convert into a bankable investment case or simple operating procedures

(c) contractual arrangements may insulate a generator from nodal prices, although contracts can be structured to preserve an incentive to maximise generation when prices are high, and this form of contract would be desirable in areas where grid reliability is constrained.

2.23. However, the Authority is satisfied that nodal prices produce a significantly better signal of grid reliability needs than ACOT payments based on charge avoidance. For example:

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24 ETNZ submission, page 3; Ngāwhā submission, pages 2-4.

25 The Lantau Group report, footnote 2 and pages 6, 8.

26 IEGA submission, page 5; King Country Energy submission, page 2; The Lantau Group report, page 4. Vector at para 5 also expressed general concern that there would be "limitations to relying solely on the nodal price to manage peak demand in the transmission grid".

27 IEGA submission, footnote 26.

28 Calderwood Advisory Limited, page 4 of the case studies appended to King Country Energy and Manawa's submissions; Manawa at page 5.

(a) The strength of the signal provided by interconnection charge avoidance is a function of Transpower's allowable interconnection revenue, which bears no relation to the actual value of distributed generation at any given location.

(b) It is not the case that the value of distributed generation is always at its highest during RCPD periods. Nodal prices are more granular – reflecting conditions node-by-node – and reflect both demand and supply conditions. For example, nodal prices may be low at a node during an RCPD period due to low demand at that node, or high availability of low-cost supply (for example, because it is windy, or river flows are high). Conversely, the value of distributed generation can be high outside of RCPD periods due to high local demand or low supply (including when transmission constraints restrict imports).

(c) Nodal signals are volatile in large part because they accurately reflect the value of energy production in a capacity-constrained system with limited storage. Coordinating operations to anticipate or respond to nodal price signals may be more difficult for distributed generators, but is also more useful in terms of optimising supply to align with times of greatest value.[29] The Authority also notes that the "real time pricing" changes implemented in November this year have made nodal price signals significantly more actionable and accurate for generators and load parties alike.

(d) Generation that may be large enough to cause nodal prices to collapse would typically offer in tranches, participate in ancillary services markets, and/or seek some combination of spot and contract revenue[30] to create a bankable investment case for a right-sized and well-configured (in terms of flexibility) project. In other words, there are avenues for distributed generators to pursue to convert nodal price signals into investment revenue without relying on regulated payments.

2.24. The Authority also notes that:

(a) Market conduct rules are not intended to, and should not in practice, prevent recovery of actual costs. Rather, they require offers to be "consistent with the offer that the generator, acting rationally, would have made if no generator could exercise significant market power at the point of connection to the grid and in the trading period to which the offer relates."[31] This does not imply that offers must be below the price at which a generator would be willing to operate, or able to recover all associated costs (including opportunity cost if applicable). We acknowledge that market conduct rules are relatively new and encourage generators to discuss them with the Authority if they are unsure as to their effect.

(b) Nodal price signals are technology-agnostic, applying across old and new distributed generation, batteries, demand response and other flexibility

29 Notwithstanding this point, generators who prefer to retain a simple operational approach that has worked for them in terms of maximising ACOT revenue should be able to successfully adopt a relatively unsophisticated approach to targeting nodal prices. The system operator's dispatch notification process will enhance small generators' ability to do this.

30 The Authority acknowledges the important role offtake or power purchase agreements have played in new entrant investment in electricity generation. This role was considered as part of the Authority's October 2022 Issues paper "Promoting competition in the wholesale electricity market in the transition toward 100% renewable electricity" (Long-form report (ea.govt.nz)). The Authority has committed to keeping "progress on investment under review, through regular monitoring of progress on generation investments and an annual update of the investment pipeline and impediments".

31 See clause 13.5A(2)(a) of the Code.

technologies. They also apply equally across distributed, embedded and grid-connected generation. We disagree with the IEGA's implication that different treatment is warranted here because their members "are not exposed to nodal prices in the same way as grid-connected generators … as they are price-takers and do not offer / influence nodal prices (or exert market power) like grid connected generators".[32] We also disagree with the IEGA's implication that pricing neutrality is irrelevant because "Grid connected generation creates the need for investment in transmission. Distributed generation reduces the need for transmission investment by being located within the local network close to load."[33]

(c) From April 2023, the new "dispatch notification generation" option will expand opportunities for small-scale distributed generation to participate in price discovery and dispatch processes. Opting into this process can improve system operator awareness of distributed resources, improve price discovery, improve locational signalling in nodal prices and provide enhanced notification to a generator when conditions are forecast to be tight. This can both improve grid reliability and enhance revenue for distributed generation and other flexibility resources – making it less likely that nodal prices will provide insufficient incentive for distributed generators to operate at times of greatest need.

2.25. In other words, the Authority considers that although nodal prices may be imperfect, they are preferable to transmission charge based ACOT payments in terms of efficiency and effectiveness. Furthermore, for the reasons set out above we are satisfied that there is not a case for retaining the current inefficient ACOT payments permanently as a complement to nodal prices. This view is reinforced by observing the significant investment in distributed generation since 2017 (see paragraph 3.12 below), with no ACOT payments available to this new generation. We consider whether there are any grounds for retaining ACOT payments temporarily in the next chapter.

Are ACOT payments needed to address a regulatory gap?

2.26. Various submitters pointed to regulatory gaps and/or problems with commercial incentives that stymie investment in transmission alternatives.

2.27. For example, in relation to a lack of constraints on distributors' monopoly powers:

(a) The IEGA and The Lantau Group noted that the Authority's rationale for not changing the Distributed Generation Pricing Principles in 2016 still apply, specifically "the asymmetric buying power of distributors and how this could lead to overcharging distributed generation for connection services and under-remunerating them for avoided costs of distribution."

(b) The Lantau Group submitted that ACOT payments have "served as a proxy for the kind of contractual relationship between a generation or demand resource and loads in a network region for services (costs) that might otherwise take the form of network costs". They submitted that this proxy is necessary because network owners are monopolies, so voluntary contract negotiations are unlikely to achieve

32 Whether generation actively participates in offer and dispatch processes, and whether its offers are ever at the margin, is not a function of whether it is grid or distribution connected. For example, grid-connected wind generation typically offers at low prices, and could also be considered a "price taker".

33 We don't agree with this characterisation, including because any connected generation (whether grid-connected or distributed) can increase or decrease the need for transmission, and because many generators have a choice as to whether they connect to the transmission network or a distribution network.

efficient outcomes. They also noted that "the availability of alternative contractual instruments or mechanisms is not yet well established".

2.28. In relation to the issue of distributors being unable to recover the cost of incentivising distributed generation themselves:

(a) Manawa noted the Authority's emphasis on benefit-based pricing in the new TPM and emphasised that the Authority should be encouraging distributors to facilitate transmission alternatives. It considers that "it would be a poor outcome for consumers if there were no incentives on distributors to seek to lower the costs of transmission investments. There should be no prohibition on sharing this benefit or in price-quality regulated distributors recovering the costs of this alternative transmission service"

(b) Top Energy expressed concern that "the complete removal of ACOT removes our options to act in the long-term best interests of consumers by incentivising DG to continue to operate to avoid these costs"

(c) Aurora and Manawa commented on distributors' ability to recover the costs of procuring transmission alternatives.[34]

2.29. The Authority does not agree with the IEGA and The Lantau Group that there is no constraint on distributors overcharging distributed generation for connection services and under-remunerating them for avoided costs of distribution. On the contrary, the distributed generation pricing principles retain a requirement for distributors to charge no more than incremental costs. This means that, unlike other classes of distribution network customer, charges for distributed generators must be set at the low end of the subsidy-free range (meaning distributed generators make no contribution to the cost of shared network assets and operations from which they undoubtedly derive some benefit). This also places distributed generators in a favourable position relative to grid-connected generation that, under the new TPM, will start making benefit-based contributions to shared transmission network assets and operations. The change in TPM materially alters the circumstances in which the Authority is weighing up the merits of retaining ACOT payments, hence the Authority reaches a different view now to its position in 2016. The likelihood that circumstances would change, and that this could impact arrangements for ACOT payments, was known and signalled in 2016.

2.30. The Authority is conscious that there may be other gaps in regulatory arrangements that could be addressed to improve prospects for efficient incentives for transmission alternatives. One potential gap that comes through in submissions[35] is that (price-quality regulated) distributors can pass on the costs of transmission, but not the cost of procuring transmission alternatives directly. However, we note that:

(a) if there are gaps, they already exist with respect to transmission alternatives not listed as eligible for ACOT payments. This includes all post-2017 distributed generation, local grid-connected generation, and non-generation sources of flexibility. As such, in most cases removing existing ACOT provisions won't alter the prospects for new transmission alternative investments

(b) whether these features are truly a gap that needs addressing should be considered in light of wider arrangements and, if relevant, alternative means of

34 Aurora submission, para 7; Manawa submission, page 3.

35 Aurora submission, para 7; Manawa submission, page 3; Top Energy, page 1, 2.

addressing any underlying problems. For example, in the case of recoverable payments by distributors, an alternative approach could be to bolster or otherwise refine Transpower's obligations

(c) even if some kind of recoverable payment by distributors were to be introduced in future, any such payments would need to operate differently from existing arrangements by being better targeted, linked to future transmission costs (not charges) and designed to ensure savings are shared with consumers.

2.31. These questions are best considered as part of longer-term work that examines matters such as network and technology neutrality, the effectiveness of network pricing signals for distributed generation, and the balance between Transpower's role and the role of distributors.

2.32. As such, the Authority does not agree that any such regulatory gaps are a reason to retain inefficient ACOT arrangements. Nor does it accept submissions that this current ACOT decision making process is too narrow (ie, should be put on hold until the Authority's future distributed generation incentives work is complete) or has been 'rushed' in a way that reduces the quality or effectiveness of the decision.[36] On the contrary, the Authority is satisfied that it can and should reach a decision now as:

(a) it has heard and properly assessed all the relevant evidence available and views offered about the current ACOT arrangements in the Code[37]

(b) a longer decision-making process would not, under any foreseeable scenario, have led to it making a different decision in terms of the need to clarify the current ACOT arrangements in the Code

(c) the current decision process would only be too narrow if it led to an interim period where the Authority's statutory objective was being met less well than by the current arrangements. Having thoroughly considered the arguments made to it about grid reliability, security of supply, and distributed generator incentives outside of ACOT payments, the Authority considers that this is not the case

(d) the current ACOT arrangements come at a significant ongoing cost to New Zealand electricity consumers.

2.33. Having considered all submissions, the Authority agrees with submissions in favour of clarifying that ACOT payments are no longer required. We consider that:

(a) the new TPM removes usage-based charges, so that, absent clarification, there may be dispute as to the need for, and basis of, ongoing ACOT payments

(b) if some distributors were to continue making ACOT payments, these would likely be less efficient than payments that Transpower can make on a more targeted

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36 Ngāwhā Generation submission, pages 5, 6; Electra submission, pages 2, 3; IEGA submission, page 2. We note that there is a suggestion in Electra's submission that the Authority's ACOT decision timeline is being driven inappropriately by the implementation of the new TPM on 1 April 2023. While the removal of the RCPD signal is undoubtedly relevant to this ACOT decision, the Authority's priority is making the right decision, regardless of time pressure. As IEGA notes at page 3 of their submission, if the Authority considered that continuing with ACOT payments for a further period was the best outcome, "[t]he Authority's proposed transition already establishes a method for retaining the status quo".

37 Noting that the arguments for and against the current ACOT arrangements are already well understood from the Authority's earlier DGPP decision making process that concluded in 2016, and that no submitter has suggested that they have further factual or expert evidence, or lines of argument, that have not been able to be made because of timing constraints.

basis for specific grid support needs. They would also continue to harm competition, because they are only available to certain pre-2017 distributed generators and not newer distributed generation, grid-connected generation, or other sources of flexibility[38]

(c) nodal prices provide a more efficient and competitively neutral signal for coordinating resource operation and investment. Also, scope for participating in nodal price discovery and dispatch processes is expanding with introduction of the system operator's dispatch notification product

(d) if there are regulatory gaps that stymie investment in flexibility resources for transmission support purposes, these would exist already, and their solution would not necessarily involve regulated payments by distributors. This matter is better considered as part of the Authority's wider work programme.

Code amendment

2.34. We have attached a copy of the relevant provisions from the Code amendment instrument (with changes from the amendment proposed in the consultation paper marked-up) at Appendix B.

2.35. Several submitters raised specific points regarding our proposed drafting of the definition of "incremental cost":

(a) Parties submitted in favour[39] and in opposition[40] to deletion of the words "with connection services" in the definition of incremental costs. On balance, the Authority considers that deletion improves clarity by removing redundant words.

(b) EA Networks submitted, and the IEGA agreed,[41] that the definition of incremental costs should be clearer that the "reasonable additional costs that an efficient distributor would incur in providing electricity distribution services to distributed generation" can include both transmission and distribution costs. The Authority agrees and has added the words "which include any reasonable additional transmission costs" to improve clarity.

(c) Manawa and Electra submitted that treatment of transmission costs in the incremental cost definition should be symmetrical – ie, that incremental costs should lower if distributed generation enables a distributor to avoid transmission costs. The Authority does not agree and has added the words "which do not include any transmission costs" to clarify that incremental costs are net of distribution costs only.

(d) Aurora submitted, and the IEGA agreed, that "if the Code amendment made it clear that a distributor's avoided costs excluded charges from the transmission provider, then concerns about making ACOT payments based on allocator updates and diminished future investments would largely disappear". [42] The Authority

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38 The Authority is concerned that continuing to effectively grand-parent favourable terms for selected pre-2017 distributed generation privileges the status quo, and dampens incentives to innovate through new flexibility services and investments (at the very point when such innovation is critical to New Zealand making a cost-effective transition to a low emissions economy).

39 IEGA submission, page 11; Manawa cross-submission, page 4.

40 Northpower submission, page 4; Electra submission, page 3.

41 EA Networks, pages 1, 2; IEGA cross-submission, page 6.

42 Aurora submission, page 7; IEGA cross-submission, page 6.

agrees and notes that the change referred to in paragraph (c) above will have this effect.

2.36. The Authority notes that incremental costs (as defined in the Code) set an upper limit on charges. As such, the Code does not prevent a distributor, at their discretion (and with reasonable conditions if appropriate), from further discounting their charges if distributed generation will help them avoid transmission costs. However, if a price-quality regulated distributor were to discount to below zero (ie, to pay distributed generators) then they would not be able to treat such payments as a recoverable cost. As discussed above, this issue will be considered within the wider future programme of work on distributed generation incentives.

2.37. EA Networks raised queries in their submission as to how, in practice, distributors should assess the "reasonable additional transmission costs" component of incremental costs. In particular:

(a) whether additional costs should include transmission charge allocation increases and, if so

(b) whether they should be net of offsetting allocation reductions.

2.38. The Authority has not altered the Code further to prescribe such matters, because they are more suited to distributor assessment on a case-by-case basis and, if needed, Authority guidance. However, we note our expectations are:

(a) it is not practical to conduct exhaustive "with and without" analysis, so adopting a materiality threshold is a reasonable approach. This applies to transmission costs as much as to any other cost. In the case of transmission costs, adopting a reasonable materiality threshold should eliminate most (if not all) routine allocation-driven changes in transmission charges

(b) in cases where a distributor identifies material additional transmission costs,[43] it would be reasonable for such costs to be assessed on a net basis (ie, material increases less material reductions).

43 For example, because grid connection assets require reconfiguration, or because the distributor becomes a net grid injector and picks up material additional benefit-based cost allocations.

3. Phasing out payments

Our decision

3.1. The Authority has decided not to adopt the alternative of phasing out ACOT payments.

What we proposed

3.2. Our October 2022 consultation paper discussed an alternative option of phasing out ACOT payments for the purpose of mitigating transition risk, specifically regarding investor confidence and grid reliability.

3.3. We described a phase-out option in which the Authority would:

(a) identify RCPD periods for each region for each year based on publicly available demand data[44]

(b) determine the ACOT payment rate that distributors would apply against an eligible distributed generator's output (averaged across the RCPD periods)

(c) ramp the payment rate down each year – to 50% of the current interconnection rate for 2023/24 payments and then 25% for 2024/25.

3.4. We considered that investor confidence risk did not justify a phase-out of ACOT payments, as the removal of ACOT payments has been well signalled and eligible distributed generation has benefited from up to six years of further ACOT payments since the Authority's 2016 decision to restrict eligibility.

3.5. We also considered whether a phase out could be justified on the basis that it would provide time for Transpower (as grid owner) to form contracts with distributed generation where needed to support grid reliability. However, we were confident that removing the obligation to make ACOT payments is unlikely to prompt any heightening of reliability risks, including because:

(a) existing distributed generation is unlikely to cease operation when ACOT payments cease given ongoing revenue streams linked to nodal prices

(b) nodal prices provide a more efficient signal than ACOT payments for coordinating the operation of distributed generation (and other resources) – and the Authority is improving the effectiveness of nodal pricing through its real-time pricing project, which includes measures to remove barriers to distributed generation offering into the market (and therefore potentially setting prices)

(c) Transpower can contract with distributed generation directly if situations arise where this is an efficient alternative to grid investment

(d) as a fall back, Transpower has options available including demand response, administrative load control, and revisiting its decision to not include a transitional congestion charge in the TPM.

Submitters' views and our assessment

3.6. Submitters expressed strong views for and against a phase out.

[44] RCPD periods are measured during the capacity measurement period, or CMP. The CMP for transmission charges that will apply from April 2023 ended on 31 August 2022.

3.7. Many submitters agreed that phase-out was not preferred.[45] Some submitters supported the Authority's key argument in the consultation paper that the phase-out option "would involve consumers paying on the order of $20 million for insurance that appears to be of questionable value".[46] For example, Horizon noted that it "relies on speculative benefits while placing a material additional cost on consumers."[47]

3.8. Other arguments that were raised in favour of no phase-out included that:

(a) there is no practical basis for phasing out ACOT payments (ie, they are not linked to avoided transmission costs or charges under the new TPM and would be inefficient to calculate separately)[48]

(b) some end consumers would end up with a "double hit" of transmission charge increases where TPM charges have increased as RCPD charges are removed but the increase is not offset by the full removal of ACOT payments[49]

(c) the first year of phase-out payments would be based on RCPD periods that have already occurred, so they provide no additional incentive to distributed generation to alter behaviour[50]

(d) phasing out ACOT payments would undermine the spot market by sending an additional signal on top of nodal price signals.[51]

3.9. We have decided not to implement a phase out predominantly based on the costs that this option would impose on consumers, for likely minimal benefit. However, for completeness we note that:

(a) we do not agree that there is no practical basis for phase-out payments, as they would be designed to mimic the status quo (from a distributed generator's perspective)

(b) we agree phase-out payments would mean some end consumers would pay more – in this case due to TPM charges no longer offsetting ACOT payments – however, consumers paying more has always been a feature of ACOT payments. The difference under phase-out is that consumers in the same region as the distributed generation pay twice, whereas historically costs have been spread to other consumers. The Authority acknowledges the impact this option would have on consumers, particularly in low-income regions, and notes that the decision to fully remove ACOT payments will result in some degree of offset to transmission charge increases for some consumers

(c) we agree that making payments against RCPD periods that have already occurred would provide no incentive and would therefore be unnecessary. Accordingly, when deciding whether to provide a phase out we considered a profile with no

45 Aurora submission, para 4; Horizon submission, para 5; Meridian submission, pages 1, 2; MEUG submission, para 5; Northpower submission, page 3; The Lines Company submission, section 3; Unison/Centralines submission, page 1; WEL Networks submission, page 1.

46 See page ii of the October 2022 consultation paper.

47 Horizon submission, para 5.. See also WEL Networks submission, page 1.

48 Aurora submission, para 4 and pages 7-8; The Lines Company submission, section 2; Unison/Centralines submission, page 1.

49 The Lines Company, section 3; Unison/Centralines, page 1.

50 Northpower submission, page 4.

51 Northpower submission, page 3; The Lines Company submission, section 2.

payments during 2023/24 and resumption of payments from 2024/25[52]. This would have reduced the cost of phase out option, and provided more time for implementation, without reducing effectiveness

(d) we do not think phase-out would undermine the spot market any more than existing arrangements. We agree that an effect of ACOT payments is to encourage out-of-merit-order generation, which does impact the cost of supply and can impact nodal prices. Without an ACOT revenue stream, generators have less incentive to make below-cost offers. This should have a beneficial impact on price discovery.

3.10. Submitters that supported phase-out cited three reasons – investor confidence, grid reliability and security of supply.[53] We address these reasons below.

Investor confidence

3.11. While several submitters noted that the removal of ACOT payments in their entirety from April 2023 had been well signalled,[54] other submitters considered investor confidence would be at risk. Some submitted that the full removal of ACOT was never signalled, especially considering the controversial nature of the TPM amendment and the materiality of the proposed ACOT change.[55] Electra submitted that the "reactive feel to this Code amendment will erode investor confidence" and Ngāwhā and Top Energy expressed concerns that the promise of future work regarding potential incentives for distributed generation would not provide investors with the certainty they need.

3.12. The Authority does not agree that full removal of ACOT was never signalled, or that it would be efficiency enhancing to encourage investors to expect manifestly inefficient payments to endure. As discussed at paragraph 2.31, we also consider that the possibility of regulatory gaps does not justify retaining inefficient ACOT payments. Finally, we note that parties have continued to invest in new distributed generation since 2017,[56] which is not eligible for ACOT payments, and there is evidence of a large development pipeline.[57]

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52 We originally considered a phase out profile of 100%;50%;25%. Following submissions, we considered a profile 100%;0%;25% - ie, no payments during the 2023/24 pricing year. This reduces the direct cost to consumers of phase out from around $26 million to around $9 million.

53 By grid reliability, we mean distributed generation providing support to ensure each link in the transmission system has sufficient capacity to meet downstream demand. For some parts of the grid, there must also be sufficient spare capacity to cover failure of any individual grid asset (referred to as "N-1"). In contrast, by security of supply we mean distributed generation providing support to ensure available generation can, in aggregate, meet demand and provide adequate reserves to cover loss of any single generator (or part of the HVDC link). Security of supply is typically assessed at an island-wide level.

54 Horizon submission, para 4; Meridian submission, page 2; Northpower submission, page 3; WEL Networks submission, page 3.

55 The Lantau Group report, sections 2.12-2.13; Ngāwhā submission, page 6.

56 Installed capacity of distributed generation increased by over 360 MW from 31 December 2016 to 30 June 2022 (an increase of 25%). Examples include the Southern Generation Limited Partnership's Upper Fraser Hydro Power Scheme and Ngawha's OEC4 geothermal plant near Kaikohe commissioned in 2020. See Electricity Authority - EMI (market statistics and tools) (ea.govt.nz)

57 For example, Powerco's 2022 Asset Management Plan update observes "of particular interest is the large volume of applications we are receiving for grid connected generation" and "small-scale distributed generation (mainly rooftop solar PV units) are also being installed at unprecedented numbers" and "Powerco is not alone in seeing these unprecedented levels of customer activity on its network". See: 2022-electricity-asset-management-plan.pdf (powerco.co.nz), One of many examples in the distributed generation pipeline is Lodestone Energy's Lodestone 2 solar plant, near Kaitaia, which is intended to deliver 62GWh/year from mid-2023.

3.13. Having considered all submissions, the Authority retains the view that investor confidence risks do not justify phasing out ACOT payments.

Grid reliability

3.14. Transpower, in its response to a request for information from the Authority, provided a useful articulation of the meaning of grid reliability. It stated that "we understand "grid reliability" in the Authority's question to mean the ability of the grid to transport sufficient electricity to meet demand. It is important to distinguish that from the need for there to be sufficient offered generation to meet demand." In the context of ACOT, the Authority agrees with this interpretation of grid reliability, as distinct from security of supply.

3.15. Submitters that favoured no phase-out argued that it would be unlikely to materially impact grid reliability.[58] For example, Meridian considered that "the change has been well signalled and it was widely expected in the industry that the 2016 lists of distributed generation eligible for ACOT payments would only be an interim step." Aurora submitted that "should those risks emerge, then Transpower is best placed to understand the impact of DG operation on grid reliability."[59]

3.16. Other submitters argued that the Authority had underestimated the reliability risk of removing ACOT.[60] They considered that a phase-out of ACOT payments (or in some cases, retaining the status quo) was necessary to comply with grid reliability standards and maintain N-1 reliability at various points of connection.

3.17. Submitter concerns about transitional grid reliability risk included that:

(a) nodal prices are an insufficient incentive for distributed generation operation and investment[61] (see paragraph 2.21 above)

(b) there are multiple barriers preventing Transpower from entering into grid support contracts, including "comparing alternative services, effectiveness of incentives, and other impediments including contract challenges and regulatory barriers"[62]

(c) the timeframe is too tight to enter these contracts before ACOT payments are removed[63]

(d) Transpower may not be able to recover the costs of entering grid support contracts, and has a policy of not offering grid support contracts unless it can recover the costs[64]

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58 Aurora submission, page 7; Horizon, para 11; Meridian submission, page 1; Northpower submission, page 3; Unison/Centralines submission, page 1. WEL Networks noted on pages 1-2 of its submission that "grid reliability is the greater short-term risk identified", but still favoured no phase-out on the basis that other mechanisms could sufficiently mitigate this risk.

59 Aurora submission, page 7. Unison/Centralines' submission at page 1 made a similar point.

60 For example, Manawa submission, page 1; Ngāwhā submission, page 5; Top Energy submission, pages 2, 3.

61 ETNZ submission, page 3; King Country Energy submission, page 2; Manawa submission, pages 4, 5; Ngāwhā submission, page 4; Vector submission, para 5.

62 Manawa submission, page 5.

63 Top Energy submission, page 2.

64 Calderwood Advisory Limited, page 4 of the case studies appended to King Country Energy and Manawa's submissions.

(e) Transpower's other tools to manage grid congestion (ie, shortfall warnings and administrative load control) will not be preferable to ACOT payments.[65]

3.18. Several submitters provided information about specific examples of generation that supports the ability of the grid to meet an N-1 standard:

(a) King Country Energy noted that "Transpower's latest Transmission Planning Report highlights the need for generation support from [the Mangahao hydroelectric power scheme] to support N-1 security for load at [Mangahao substation] both for transformer capacity and voltage". Electra supported this submission. King Country Energy also submitted that without ACOT payments, "the potential difference in nodal prices created will be too small to justify cancelling our arrangements for planned outages with contractors" and that nodal price signals are "unknowable far enough in advance for us to adjust our behaviour."

(b) Manawa noted that "The present GRS defines the 110 kV lines connecting to TGA as core grid and therefore must meet N-1 security." Analysis in Appendix 2 shows that to meet N-1, generation from Manawa's Kaimai station was required for 474 trading periods in 2021. Manawa submitted that without ACOT payments or a grid support contract from Transpower, "there is no incentive for KMI to operate at peak periods, other than to maximise spot revenue", which Manawa does not believe is sufficient because it offers its generation at $0/MWh to avoid potentially breaching trading conduct rules.

(c) Ngāwhā noted that the Transmission Planning Report shows that "we provide grid reliability services north of Auckland and help Transpower meet its N-1 grid reliability standard in the Far North". It also submitted that as refurbishment decisions approach, "we now find ourselves in the position of having to ascertain if it is commercially viable to continue to operate OEC 1-3 without ACOT"

3.19. Following submissions and cross-submissions, we sought further comment from Transpower on its views, in its capacity as grid owner, on grid reliability issues and on the specific examples put forward in submissions. Transpower's response[66] included:

(a) reiterating its earlier view from the TPM reform process that, although it does not know how distributed generators would respond to removal of ACOT payments, it considers that Transpower "primarily as system operator, has sufficient tools available to it to manage grid reliability in the near term without needing the additional support of a transitional congestion charge" and adding that "we consider the same applies to ACOT."[67]

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65 The Lantau Group report, section 2.10.

66 Transpower response to grid reliability questions, 10 November 2022 (ACOT-Transpower-response-grid-reliability.pdf (ea.govt.nz))

67 We note that Transpower was similarly clear about the sufficiency of its options for managing congestion in its January 2021 TPM Development Checkpoint 1 resubmission to the Authority regarding a potential transitional congestion charge under the new TPM (TPM Transpower Checkpoint 1 Resubmission TCC (amazonaws.com), paras 33, 35 and 38):

"Our assessment concludes that, should the incidence of congestion materially increase the frequency or extent to which the system operator must shed load – potentially in places we have not anticipated above – the controls available to the system operator will limit load shedding and ensure the grid is secure, and the grid owner controls can respond quickly enough to limit the impact on consumers efficiently.

(b) confirming that Transpower "will invest in the grid and transmission alternatives to manage grid reliability issues as and when required, regardless of the ACOT outcome" and "these investments may include grid support contracts with distributed generators."

(c) with respect to connection assets, stating that "our role is to provide information about options" and "the relevant customers are ultimately responsible [for] making the price-quality decision" and "in some cases we expect it will be more appropriate and/or efficient for the customers to enter into support contracts with distributed generators than Transpower."

(d) noting that Transpower "do not have any major concerns about the processes under our Part 4 Commerce Act regulation by which we may receive expenditure allowances for grid support contracts (baseline or for major projects)."

(e) clarifying that "the n-1 criterion is not the same thing as the grid reliability standard" and "investments for n-1 reliability in respect of non-core grid assets, which includes most connection assets, are not required under the Code."

(f) confirming that Transpower has recently, in preparing its 2022 Transmission Planning report, explicitly considered the contribution of Kaimai, Mangahao and Ngāwhā to meeting N-1 criterion at Tauranga, Mangahao and Kaikohe grid exit points – observing that "generation from the Kaimai, Mangahao and Ngawha generating stations, respectively, helps meet the n-1 criterion at those GXPs" – and considered investment plans for those locations, which, at this stage, do not include entering into grid support contracts.

3.20. To ensure we had all relevant views available, we published Transpower's response and invited feedback. We received feedback from five parties.[68]

3.21. Top Energy provided feedback that maintaining N-1 reliability is "critical to Top Energy and the 33,000 customers we serve as losing our grid connection means the entire Far North is without power" and that "if Top Energy must incur grid support costs to maintain N-1 grid reliability it may not be able to recover these costs" and therefore "Transpower should be more strongly incentivised to consider and pursue transmission alternatives". The Authority notes that:

(a) falling short of N-1 reliability does not mean customers will lose power. In practice, the range of outcomes include:

…

"We consider the grid owner and system operator and tools summarised above are sufficient to mitigate and manage near-term congestion risk arising from the removal of RCPD. In our view, relying on these tools can provide short-term mitigation of any unanticipated and relatively frequent congestion. We think this approach can, if it proves necessary, provide time to develop and propose a pragmatic TCC later when it can be informed by better information about the congestion risk it is needed to address.

...

"having considered the Authority's feedback and clarification of its intent for any TCC, we have not been able to reasonably conclude that we can propose a TCC at this time on the basis of the Guidelines' requirements that:

- there are geographic areas, circuits or other circumstances where there is a significant likelihood of congestion occurring without a TCC, and
- we could not efficiently control grid demand using other means, and
- consequently, that including a TCC would better meet the Authority's statutory objective."

68 Top Energy, Horizon, Northpower, Manawa Energy, IEGA.

(i) during most periods, supply will be at N-1 with no intervention – ie, because net demand is sufficiently below its peak level

(ii) if capacity is tight and there is downstream generation (or dispatchable demand) that offers (bids) into the market, the system operator will typically apply a transmission constraint[69] such that downstream generation (or dispatchable demand) is dispatched. In this scenario, a locational price signal is produced reflecting the marginal offer (or bid) price of any constrained on generation (or demand)[70], and N-1 is maintained

(iii) as part of the outage planning process, Transpower would also request in advance that plant makes itself available

(iv) failing all of the above, supply would operate without full redundancy and the risk of interruption would temporarily be higher than usual

(b) the benchmark agreement sets out a process for Transpower and Top Energy to engage on reliability levels and investment options should N-1 become at risk and includes various tie-breaker provisions that may apply if parties cannot agree.

3.22. Other points raised in feedback were:

(a) Top Energy stated "we fear that the Authority and Transpower are conflating Top Energy and Ngawha Generation Limited (NGL) when assessing grid reliability risks of ACOT reform" and "if NGL were a separately owned business, there would be no question that some form of grid support incentive would be necessary (either from Top Energy or Transpower) to maintain reliability at Kaikohe in the absence of ACOT."[71] The Authority's decision-making on this matter is not influenced by the ownership of Top Energy and Ngāwhā, and the Authority expects Top Energy and Ngāwhā to continue to comply with their arms' length requirements

(b) Horizon and Northpower considered that Transpower's response supported their view that no phase out was required

(c) Manawa noted its view that its Kaimai generation station is required to ensure N-1 for several lines sections that are core grid (and therefore must meet the N-1 limb of the GRS). The Authority expects Transpower to be aware of its Code and transmission agreement obligations regarding core grid reliability, and to monitor its planning assumptions regarding the contribution of distributed generation

(d) IEGA reiterated its view that "the Authority designed the scope of the [Mitton ElectroNet] analysis to identify efficient distributed generation" and that similarly robust analysis is required before any change can be made. As discussed from paragraph 2.16, the Authority does not accept this view

69 In some instances where generation is required for voltage support, the system operator may constrain on generation directly using a market node constraint. Market node constraints do not result in a locational price signal and so will only be used where transmission constraints are not sufficient for maintaining security.

70 Constrained on payments ensure that constrained on generation are paid at least what they were willing to accept according to their dispatched offer prices. This is particularly important where market node constraints are used as the nodal price in a dispatch schedule doesn't reflect their cleared generation, but may also apply where transmission constraints are used and the nodal price in the dispatch schedule is higher than the final nodal price.

71 Top Energy feedback on Transpower grid reliability response, page 3.

(e) IEGA noted that "Transpower makes it clear that GRS and n-1 security are essentially one and the same". On the contrary, Transpower clearly states that "the n-1 criterion is not the same thing as the GRS".[72]

3.23. The Authority agrees that:

(a) security of supply is distinct from grid reliability. We address issues raised by submitters in relation to security of supply concerns separately from paragraph 3.31 below

(b) to the extent nodal prices are not fully effective at ensuring distributed generation will operate in a way that supports grid reliability, the system operator has tools available to manage near-term pressures

(c) the N-1 criterion is not the same as the grid reliability standards and, outside of transmission links that make up the core grid, an economic standard applies and will often correspond to less than full redundancy.[73] This reflects that full redundancy can be costly to build, and in many cases very high levels of reliability can still be achieved without full (N-1) redundancy. In other words, failing to meet an N-1 planning standard is a prompt for investigation, but is not necessarily a sign of imminent or severe grid reliability concerns.

3.24. The Authority also notes that:

(a) several other factors, including contractual commitments, asset owner obligations[74] and reputational considerations all complement nodal price signals and system operator tools in discouraging generators from withdrawing capacity at times when grid reliability would be at risk

(b) Transpower has an obligation to refresh its grid reliability assessment ahead of the normal cycle if it becomes aware of a material change in forecast demand at a grid exit point.[75] This requirement could be triggered if Transpower observes a significant change in a distributed generator's behaviour or plans for ongoing operation

(c) Transpower has timebound obligations to address grid reliability shortfalls for transmission links that are both defined as interconnection assets and are part of the core grid.[76]

(d) for connection assets, Transpower also has various obligations to work quickly to address grid reliability shortfalls. The precise obligations depend on whether connection assets are part of the core grid, and whether they are shared by more than one transmission customer. In any case, the obligations include steps where

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72 Transpower grid reliability response to Authority, question 9(a), 10 November 2022.

73 The economic standard is the level of grid reliability that would be achieved if every transmission investment that would pass the applicable economic test is made. This is more difficult to apply than the simpler, deterministic N-1 screening criteria, and can imply grid reliability that is lower or higher than N-1.

74 For example, clause 14 of Schedule 6.2 of the Code requires that, in respect of generation above 10kW, distributed generators must coordinate planned outages with their distributor and make reasonable endeavours to minimise the impact of interruptions.

75 Refer clause 12.76(3) of the Code.

76 See clause 12.114(1)(c) and (d) of the Code.

Transpower must propose solutions and may be obliged to engage with end consumers and/or the Authority and the Commerce Commission.[77]

3.25. The Authority agrees with Transpower that it could be beneficial to review Transpower's grid reliability obligations, including those contained in the Benchmark Agreement, to make them clearer and more coherent with current Commerce Commission arrangements. However, the Authority considers that this does not present a reason to retain ACOT arrangements. We are satisfied that, as system operator, Transpower has tools to manage grid reliability within operational timeframes, and, as grid owner, Transpower has obligations to find solutions for grid reliability shortfalls within investment timeframes. In addition, asset owners have obligations to manage risks within outage planning timeframes.

3.26. The Authority acknowledges the doubts some submitters have expressed regarding Transpower's willingness to entertain contracts with distributed generators for grid support. We understand submitters' concerns regarding Transpower's published guidance on design features of grid support contracts which states "Transpower as a commercial company will not offer GSCs unless it can recover the costs, which requires that they are included in its regulated revenue".[78] We note that Transpower's revenue recovery preferences would not justify it breaching any obligations regarding grid reliability shortfalls. Transpower's more recent expressions of comfort with its Part 4 regulatory arrangements are more consistent with the Authority's understanding and expectations.[79]

3.27. Notwithstanding the above, we note that absence of grid support contracts is not necessarily evidence of a problem with Transpower's regulatory arrangements or commercial conduct. We acknowledge that:

(a) in some cases, relatively low-cost "tactical" transmission solutions such as special protection schemes or variable line rating may provide cost effective options that out-compete the option of paying distributed generators for grid support

(b) in some cases, transmission investments deliver a set of benefits that are larger and longer-lived than could be provided through grid support contracts

(c) to ensure it acts as a prudent grid owner, Transpower may face very real challenges when contracting with existing distributed generation in determining that it is not over-paying, eg, for services that would have been provided anyway.

3.28. The Authority expects to further consider Transpower's procurement of distributed generation as a transmission alternative, as described in chapter 5 of our consultation paper.

3.29. The Authority agrees with The Lantau Group that the system operator having to resort to tools such as shortfall warnings and load control is not desirable but does not accept that the Authority faces a binary choice between ACOT payments and use of these tools – ie, that we are in effect choosing between these two options. Rather, we are balancing the certain cost of ACOT payments against the uncertain risk of incrementally exacerbating

77 See, for example, clause 40.2 of the Benchmark Agreement and clause 12.40 of the Code.

78 See para 4.2 of Transpower's Grid Support Contracts: GSC Design Features document (Grid Support Contracts (amazonaws.com)), referred to by Calderwood Advisory Limited at page 4 of the case studies appended to King Country Energy and Manawa submissions.

79 Transpower grid reliability response to Authority, question 9(c), 10 November 2022

grid reliability pressures, and acknowledging the various other tools available to Transpower to manage reliability.

3.30. Having considered all submissions, the Authority retains the view that grid reliability risks do not justify phasing out ACOT payments.[80]

Security of supply

3.31. Transpower, in its capacity as the System Operator, favoured the phase-out option on the basis of security of supply.[81] Transpower expressed concern that capacity margins are expected to be tight over the next few years until more generation can be built, and that this issue could be exacerbated if a financial incentive to generate at peak times such as ACOT is removed. Although Transpower accepted that “ACOT payments were not intended to assist with system security”, it argued that “to phase out ACOT would help mitigate the risk of an impact on peak demand from the immediate removal of ACOT”.[82]

3.32. The Lantau Group also (broadly) raised security of supply concerns,[83] while two other submitters expressed concern about rising peak demand.[84] Some cross-submitters specifically agreed with Transpower’s argument.[85]

3.33. By contrast, two cross-submitters disagreed with Transpower’s security of supply reasoning, arguing that ACOT payments were poorly suited to managing security of supply risks.[86]

3.34. The Authority does not consider that a phase out is justified based on security of supply issues. Transpower’s submission amounts to an asserted view that ACOT payments might help, in an undefined way, in an environment of tight margins. In our view that is not enough to justify continuing ACOT payments because:

(a) they were not designed to assist with security of supply, so are not sufficiently targeted (leading to low security of supply benefits relative to the cost of making the payments)

(b) the system operator has better tools at its disposal to manage security of supply, such as instructing discretionary load management to operate.

3.35. It is possible ACOT payments sometimes provide a useful additional incentive to a subset of distributed generation to operate during the relatively rare trading periods when the System Operator needs all available generation in the market for security of

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80 The Authority notes the submission from Unison and Centralines (page 2) regarding the practicability of implementing an ACOT phase out for the pricing year commencing 1 April 2023 if that decision was only communicated to distributors in December 2022. We also note Northpower’s feedback on Transpower’s grid reliability response, where it commented that it is “legally required under the DDA to communicate our pricing changes to retailers by 30 January at the latest.” While the Authority has ultimately decided not to pursue a phase out, for completeness we note that we consider a phase out would have been implementable in that timeframe, and this concern therefore did not play any part in our decision.

81 In this paper we use the term “security of supply” to refer to there being a sufficient margin of generation over demand at an island-wide level.

82 Transpower submission, pages 1, 4.

83 The Lantau Group report, pages 16, 17.

84 IEGA submission, pages 4, 5; Manawa Energy submission, page 4

85 Manawa Energy cross-submission, page 3; IEGA cross-submission, page 1. Electra cross-submission, page 6, also appeared to support Transpower’s view.

86 MEUG cross-submission, page 2; Horizon cross-submission, page 2.

supply reasons. However, this is not by design but is a by-product of the blanket coverage of ACOT payments across 100 peak demand periods and up to 7,590 generation installations. This poor targeting with respect to security of supply means:

(a) ACOT peak periods can coincide with comfortable capacity margins, for example when there is strong wind, hydro and thermal production, and

(b) conversely, capacity margins can be tight outside of the ACOT peak periods, for example when margins are tight due to generation outages or low output.

3.36. The Authority appreciates that security of supply is an important issue for the sector and for New Zealand consumers at present, with Transpower forecasting tight winter capacity margins and uncertainty about peak demand trends. Security of supply has been and remains a significant focus for the Authority, as evidenced by our recently released paper on options to reduce operational co-ordination risk for winter 2023.[87] However, we consider that retaining ACOT payments would not be a particularly effective, let alone efficient, method of addressing this issue.

3.37. For these reasons the Authority considers that continuing ACOT payments for security of supply reasons represents an even poorer insurance policy than continuing ACOT payments for transitional grid reliability risk. They would at best be an expensive and untargeted 'hope'.[88] In the circumstances, the Authority prefers to focus on competitively neutral[89] policy and operational interventions specifically targeted at security of supply.

Authority expectations

3.38. For the reasons set out above the Authority considers that a phase-out of ACOT payments is not justified.

3.39. The Authority acknowledges that, in the process of moving away from the current ACOT regime, with distributed generation potentially adjusting their operating behaviour more specifically towards nodal pricing incentives, there remains some level of transitional uncertainty.

3.40. New Zealanders expect a high degree of reliability from their electricity system in all parts of the country. Consistent with that, the Authority:

(a) expects that distributed generators and Transpower will communicate openly about any known or prospective grid reliability risks, with Transpower taking the leadership role expected of it by the sector and New Zealand consumers, ie, to respond proactively to any current or projected breach of the grid reliability standards with the tools available to it.[90] [91] We acknowledge for example the concerns expressed by some submitters in their feedback on Transpower's 10

87 Driving efficient solutions to promote consumer interests through winter 2023 (ea.govt.nz)

88 In considering this issue the Authority is also mindful of submissions that emphasised the customer affordability of energy, eg, The Lines Company submission, section 4.

89 The Authority maintains that there is no good justification for paying distributed generation a security of supply-driven subsidy, but not considering applying the same logic to other parts of the system that support security of supply, eg, grid-connected generation or demand response.

90 Acknowledging that for the non-core grid there is not an absolute requirement to maintain or get back to an N-1 level of grid reliability.

91 We acknowledge Manawa's submission that it "needs time (and ongoing commitment) for meaningful discussions with Transpower and/or Powerco about how [Kaimai] generation can be secured under the new TPM" and we expect Transpower to engage with Manawa in a timely way or explain to Manawa why it disagrees that such discussions are needed.

November 2022 response to the Authority on grid reliability, and expect that Transpower will work through those concerns with those submitters as a matter of urgency to ensure that there is a shared understanding between them (regardless of the outcome)[92]

(b) will closely consider the behaviour of relevant distributed generation in the event that any regional constraints arise, especially in the event that there is any evidence of economic withholding of any generation.

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92 For example, in feedback on 24 November 2022:

- Manawa Energy states that: "Our view is that the impact of Kaimai generation is on the core grid, and not just at the GXP where Manawa injects."
- Top Energy states that: "In our view, Transpower has a responsibility to maintain N-1 reliability at Kaikohe under the GRS either through grid investments or alternative transmission arrangements ... However, Transpower acknowledges it has no intention to enter into a GSC with Ngāwhā if ACOT is removed."

In each case we would expect Transpower to work with the relevant transmission customer (and distributed generator) to ensure a shared understanding of which part of the GRS applies to the relevant circuits, where responsibility sits for investment decisions if the TPR or subsequent circumstances suggest the N-1 screening test is likely to be breached, and what the transmission customer's options are if it disagrees with Transpower's view/approach.

4. Further work on network pricing for distributed generation

4.1. As set out in the consultation paper, the Authority intends to provide guidance on the pass-through of transmission charges to distributed generation in 2023.

4.2. The Authority also intends to initiate a new workstream considering the wider set of incentives for investment in distributed generation to determine whether their efficiency can be improved.[93]

4.3. That work will include considering whether additional price signals could be efficient, and how best to provide additional signals if warranted – noting that recoverable payments are not the only option.

4.4. Most submitters that commented on this further work supported the Authority undertaking it.[94] However, Transpower, as Grid Owner, was opposed to the work.[95] While Transpower agreed that using transmission alternatives can lead to more efficient consumer outcomes, it submitted that regulation under Part 4 of the Commerce Act already incentivised it to make efficient decisions between transmission investments and transmission alternatives, essentially suggesting that the Authority had no further role to play in considering any incentives relating to grid support.

4.5. By contrast, having reviewed Transpower's submission, Vector reiterated its view that "the role of network support contracts in supporting reliability will likely grow in importance over time and that it is worth the Authority examining barriers to Transpower entering these contracts".[96]

4.6. The Authority appreciates the role of the Commerce Commission in regulating Transpower under Part 4, and particularly the efficiency incentives contained within the individual price-quality path set for Transpower by the Commission. We also note that the Code may not purport to do or regulate anything the Commission can do or regulate under Part 4. However, an exception to this rule is that the Authority may put in place a regulatory solution in the Code in the form of a pricing methodology or a quality or information requirement for Transpower or one or more distributors in relation to access to transmission or distribution networks.[97] The Authority may also monitor Transpower's

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93 As set out in the consultation paper, this workstream includes considering nodal price signals; Transpower's procurement of transmission alternatives; the 'incremental cost rule' in the DGPPs; and neutrality between the various options for grid support.

94 For example: Horizon Networks submission, page 5 (supporting a review of the DGPPs in Part 6 of the Code); Manawa Energy submission, pages 3, 5; The Lantau Group report, page 13; MEUG submission, para 6; Vector submission, para 7 and cross-submission, para 10. In addition, while not expressing an overall view, Aurora was the only party to comment on the Authority's 'starting view' principles for potential additional price signals for grid support technologies - para 5.7(b) the consultation paper - which it supported (Aurora submission, page 8).

95 Transpower submission, pages 2, 3.

96 Vector cross-submission, para 10. The Lantau Group report at page 11 also raises concerns regarding Transpower's negotiating power, as a monopoly, on the formation of grid support contracts: "This contractual proxy avoids the problems of the inherently asymmetrical positioning and negotiating power that exists between, on one hand, the stakeholders who compete to provide generation and demand resources and the monopoly grid entities to whom they are beholden when offering transmission alternatives."

97 Section 32 of the Electricity Industry Act 2010. We note also IEGA's submission at page 2 where it suggests that the Commerce Commission is the correct regulatory agency to undertake further work on incentives relating to grid support provided by distributed generation. For the reasons set out in the main text above, we disagree.

performance, within the context of the Authority's wider monitoring functions,[98] because that is outside of the Code. More generally, the Authority is not prevented from looking holistically at distributed generation investment incentives.

4.7. The Authority will confirm early in 2023 when it intends to start reviewing the wider set of incentives for investment in distributed generation to determine whether their efficiency can be improved. The Authority will work closely with the Commission on this matter to ensure that any specific jurisdictional questions that arise are resolved early and transparently. The Authority also remains open to any views on the scope of this work.[99]

98 Section 16(1)(c), (f) and (g) of the Electricity Industry Act 2010.

99 We note for example, Aurora's submission at page 5, which raises the importance of considering support provided to connection assets, as well as to interconnection assets, when assessing incentives for investment in distributed generation; Aurora's submission at page 8, which suggests a merit order of nodal pricing, then additional pricing signals and "as a last resort, grid support contracts"; Electra's submission at page 3, which says "the sector has consistently called upon the Authority to undertake a thorough review of Part 6"; IEGA's submission at page 12, which notes "the industry-led FlexForum appear to support payment for (flexibility) services offered by grid support technologies"; The Lantau Group report in support of Manawa's submission at page 2, which states that "ACOT payments have historically facilitated a default, regulated 'proxy' contractual arrangement between DG resources and the transmission provider, something that left to a free market may be sub-optimal due to the informational and bargaining power asymmetries between parties"; Ngawha's submission at page 5, which states that "it would be possible for Transpower to identify DG that provides grid support by applying the benefits measurement approach used in the TPM for new investments" and at page 6, which observes that "EDBs may however be best placed to assess the trade-offs between grid supply and transmission alternatives" and notes that "ACOT payments associated with avoided transmission 'connection assets' could be managed by EDBs as they are responsible for contracting Transpower to provide connection services" such that "it may be best to clarify this in the definition of avoided costs of distribution"; Top Energy's submission at page 3, which notes that "we are a potential participant in the proposed REZ and instead of this amendment to Part 6 clearing up some of the issues needing to be resolved, it adds to them"; Manawa's cross-submission at page 3 that "under the new TPM [distributors] are expected to understand the modelling that sits behind the allocation of benefits and enter arrangements to lower their allocation of charges where it is efficient to do so"; IEGA's feedback on Transpower's response to grid reliability questions at page 4, that "the most important aspect, and one that a regulator can be expected to assist with as per the genesis of Part 6 of the Code, is that asymmetry of information and grossly unbalanced bargaining power means an individual distributed generation investor will always struggle to negotiate with a monopoly like Transpower"; and Top Energy's feedback on Transpower's response to grid reliability questions at page 3, which submits that "Part 6 should allow EDBs to recover grid support costs paid to distributed generation through a reformed ACOT definition".

5. Other matters

5.1. Several submitters raised additional points that do not fit neatly under the topics discussed above.[100] For completeness, we set these out below:

(a) Powerco suggested that "one solution [to the transitional risk issue] could be to transfer the existing EDB-DG arrangements to Transpower for them to refine and renegotiate as value is assessed and in a timeframe that works for them and the generator". We disagree as we consider that this would reverse the onus from distributed generators needing to demonstrate how a specific payment arrangement is efficient, to Transpower having to demonstrate that it is not. This would be a significant workload for Transpower and would likely result in inefficient payments persisting.

(b) Horizon submitted that the impact modelling for its network is incorrect, as it takes into account a prudent discount arrangement "which is not ACOT and is not related to distributed generation so is not covered by Part 6 of the Code". The Authority acknowledges that the Commerce Commission disclosures on which these impact analyses were based do not separate such payments from ACOT payments, so these figures may not be completely accurate for all networks. However, these impact analyses were produced for indicative purposes only and we do not consider any such discrepancies to be material enough to affect our decision.[101]

(c) Northpower's submission highlighted that due a simplifying assumption used in the household bill impact assessment, the estimated bill impacts for households in the Northpower region are under-estimated. We note that simplifying assumptions could also affect estimates for other networks, but as noted above these impact analyses are for indicative purposes only.[102]

(d) IEGA submitted in relation to chapter 5 of the consultation paper, that "the Authority's commentary ... about grid support technologies and flexibility contradicts a conclusion from the Authority's latest paper on the Wholesale Market Competition Review that the Authority would "investigate mechanisms to accelerate the development of the demand response market".[103] We disagree. In our view there is nothing inconsistent between the Authority's approach to ACOT, and the options referred to in its Issues paper on promoting wholesale market

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[100] While the Authority has sought to be thorough in its response to submissions, it has not responded or referenced all points made by submitters. In some cases, we have instead addressed points directly with submitters, eg, Network Tasman's comments in relation to Cobb on page 2 of its submission.

[101] ETNZ (submission, page 2) and The Lantau Group (expert advice appended to Manawa submission, page 3) raise broader questions about the household bill impact analysis in the consultation document. In our view these submissions misunderstand the household bill impact analysis. It is simply a day 1 snapshot of average bill changes, assuming full pass through to consumers, on 1 April 2023 based on the new TPM and the Authority's preferred ACOT clarification. The consultation document explicitly noted that the household bill impact assessment was not seeking to set out the full costs and benefits of the proposal, though for the avoidance of doubt the Authority does not agree with the assessment of costs implicit in ETNZ's and The Lantau Group's submissions.

[102] The Authority has not updated its bill impact analysis to reflect actual transmission charges under the new TPM (published on 7 December 2022) or more recent information on ACOT. Actual consumer bills may vary across consumers for a variety of reasons including distribution and retailer pricing decisions. With transmission pricing finalised and a final decision on ACOT, we consider that retailers, working with distributors, are best placed to provided clarity to consumers on the bill impacts of regulatory changes (eg, new TPM and ACOT) and non-regulatory drivers (eg, wholesale electricity costs).

[103] IEGA submission, page 12.

competition, eg, enabling small load to participate in the market as dispatchable demand as part of the real-time pricing changes; removing regulatory barriers relating to distribution networks; and promoting efficient distribution pricing.

(e) ETNZ submitted that distributed generation fulfils the purpose of section 54Q of the Commerce Act 1986 and that, if the Authority removes the ACOT provisions from the Code, it should "recognise the clear instructions provided in that section of the Commerce Act and move at once to put an effective alternative is in place [sic]".[104] Ultimately it is for the Commission, not the Authority, to consider how best to apply section 54Q. The regime put in place by the Commission under Part 4 of the Commerce Act 1986 has a range of incentives in place already, and the Commission continues to consider whether to make any changes/improvements to that regime through either information disclosure requirements or price-quality path settings (currently through its targeted information disclosure review, the input methodologies review, and its price-quality path resets for Transpower and electricity distributors). As noted above, we intend to continue engaging with the Commission as we review the wider set of incentives for investment in distributed generation to ensure they are efficient.

(f) Network Tasman and Unison/Centralines both raised questions in relation to legacy contracts, ie, contracts for ACOT payments from distributors to distributed generation where the contractual obligations may survive the removal of any obligation under the Code. As previously noted in the context of its July 2022 decision on notional embedding contracts under the new TPM,[105] the Authority is conscious of the importance of respecting contractual bargains and risk allocations entered into by sector participants. While the Authority's broader view of the existing ACOT arrangements has been clearly set out, we consider that it is not appropriate to comment further on any legacy contracts, but rather to recognise any pre-existing regulatory change mechanisms in those contracts and leave it to the parties to those contracts to negotiate further if necessary.

(g) The Authority's statement in the consultation paper that "Transpower also retains the option to revisit the need for a transitional congestion charge if needed" received responses from Transpower, IEGA and Manawa.[106] This ACOT decision does not ultimately depend on whether or not Transpower proposes a transitional congestion charge (TCC). The Authority simply notes in response that:

(i) in our view the TCC potentially remains another useful tool for Transpower's management of grid reliability

(ii) we remain open to further discussion with Transpower at any point regarding a potential TCC

(iii) we appreciate though that any TCC would not be in place on 1 April 2023, when ACOT payments end.

104 ETNZ submission, page 2.

105 [Notional embedding contracts decision paper (ea.govt.nz)]

106 Transpower submission, page 2; IEGA submission, page 7,8; Manawa submission, page 5.

6. Regulatory statement

6.1. The October 2022 consultation paper included (in Chapter 7) a regulatory statement in accordance with section 39(1) and (2) of the Act.

6.2. The regulatory statement included in the October 2022 consultation paper:

(a) noted that the objective of the proposed Code amendment is to mitigate risks of unnecessary administrative costs and inefficient payments

(b) provided an evaluation of the costs and benefits of the proposed Code amendment, finding that the benefits were expected to outweigh the costs

(c) explained that the Authority had identified a viable alternative means of addressing the proposed Code amendment's objectives, involving a phase-out period, but concluded that this option was not likely to be as effective in meeting the Authority's statutory objective as the proposed Code amendment

(d) summarised how the proposed Code amendment complied with section 32(1) of the Act

(e) documented the Authority's consideration of the Code amendment principles.

Submitters' views and our assessment

6.3. Only a few submissions engaged directly with the Authority's regulatory statement or the issues it addresses.[107] The key points raised were:

(a) Horizon submitted that our two options (with or without phase-out) address separate issues, so are not true alternatives to each other.[108] We recognise phase-out addresses a narrower issue (transition risk) than the Code clarification (efficiency and competition), but that narrower issue arises directly from the proposed clarification. We consider it is appropriate for the regulatory statement to assess the counterfactual (no amendment) to the two options as framed.

(b) IEGA submitted that the amendment does not comply with section 32(1) of the Act because "the Authority has not provided robust evidence that its proposed changes will improve efficiency or the reliability of the supply of electricity to the consumer."[109] Ngāwhā submitted that the amendments do not comply because they "put at risk the reliability of grid supply (particularly for Top Energy where Ngāwhā is not incentivised to generate) and the efficiency of Transpower's investment decisions."[110] We disagree with these views. Having considered submissions (as described in this paper) we are satisfied with the assessment of section 32(1) compliance in the regulatory statement.

(c) Transpower submits (referring to our assessment of compliance with section 32(1) of the Act) that "we consider it is not certain that *"The proposed amendments are not expected to have a material impact on the reliable supply of electricity consumers.""*[111] We note that this comment in the regulatory statement is

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107 Aurora submission, page 8-9; Horizon submission, pages 5-7; IEGA submission, pages 12-13; Top Energy, page 3; Transpower submission, page 5; Unison/Centralines, page 4; WEL Networks, pages 3-4.

108 Horizon submission, page 6.

109 IEGA submission, page 13.

110 Ngāwhā submission, page 5.

111 Transpower submission, page 5.

comparing clarification (without phase-out) against a counterfactual of no clarification and no phase out. As explained in the consultation paper, our view is that, in the absence of clarification, any continued ACOT payments would likely not be well targeted to reliability needs. As such, we are satisfied with the assessment in the regulatory statement.

(d) Top Energy submits that our cost benefit analysis at paragraph 4.14 of the consultation paper "has not considered any change in behaviour from participants and assumes that participants would provide a service for free."[112] We note that the information referred to is not a cost-benefit analysis. Rather, it is provided as context on the relative values of ACOT payments and unserved energy costs. The consultation paper provided analysis of the drivers of behaviour change and we have considered submissions on expected behaviours as discussed in this paper. We remain satisfied with the assessment of cost and benefits in the regulatory statement.

6.4. Overall, the Authority considers the regulatory statement in the October 2022 consultation paper is fit for purpose.

Impact of changes to the Code amendment

6.5. As noted above, while the Authority has largely adopted the Code amendment that was proposed in the October 2022 consultation paper, we have made some minor changes. Specifically, the Authority decided to:

(a) clarify that the 'reasonable additional costs' that a distributor may charge a distributed generator may include transmission costs

(b) clarify that avoidable distribution costs do not include transmission costs.

6.6. The Authority has considered whether any of these amendments may have impacted on the assessment provided in the regulatory statement set out in the consultation paper. In our view, these amendments do not impact the assessment as they provide clarification only.

Conclusion

6.7. Overall, the Authority is satisfied that it has met the requirements of a regulatory statement in section 39(2) of the Electricity Industry Act 2010, and that it has had proper regard for the Code amendment principles as required by the Authority's Consultation Charter.

6.8. After carefully considering all submissions on the proposed Code amendment, the Authority considers the final Code amendment will deliver long-term benefits to consumers by promoting the efficiency and competition limbs of our statutory objective.

6.9. Specifically, the amendment will promote the efficient operation of the electricity industry and promote competition by removing inefficient payments that favour pre-2017 distributed generation over other transmission alternatives.

112 Top Energy submission, page 3.

Appendix A Submissions received

A.1 The Authority received 20 submissions on its October 2022 consultation paper and seven cross-submissions. We also received feedback from five parties on Transpower's response to our request for information regarding grid reliability.

A.2 Parties who made submissions and provided feedback are listed in Table 1. Submissions and feedback are available on the Authority's website.[113]

Table 1: List of submitters

Submitter	***Category***	***Round^***
Aurora Energy	Electricity distribution	1
EA Networks	Electricity distribution	1
Electra	Electricity distribution	1, 2
Energy Trusts of New Zealand Inc (ETNZ)	Electricity distribution	1
Horizon Networks	Electricity distribution	1, 2, 3
Independent Electricity Generators Association (IEGA)	Electricity generation representation	1, 2, 3
King Country Energy	Electricity generation	1
Manawa Energy	Electricity generation	1, 2, 3
Meridian Energy	Electricity generation and retailing	1
Major Electricity Users' Group (MEUG)	Electricity consumer representation	1, 2
Network Tasman	Electricity distribution	1
Ngāwhā Generation	Electricity generation	1
Northpower	Electricity distribution	1, 3
Powerco	Electricity distribution	1

113 https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c19173

Submitter	*Category*	*Round^*
The Lines Company	Electricity distribution	1
Top Energy	Electricity distribution	1, 3
Transpower	Electricity transmission	1, 2
Unison and Centralines	Electricity distribution	1
Vector	Electricity distribution	1, 2
WEL Networks	Electricity distribution	1

^ 1 = submission on consultation paper; 2 = cross-submission; 3 = feedback on Transpower's response to grid reliability questions

Appendix B Code amendment

B.1 The below text shows the key sections of the Code amendment instrument, with changes compared to our October consultation marked-up in red.

4 Clause 1.1 amended (Interpretation)

In clause 1.1(1), replace the definition of **incremental costs** with:

"**incremental costs**, for the purpose of Part 6, means:

"(a) the reasonable additional costs (which include any reasonable additional transmission costs) that an efficient **distributor** would incur in providing **electricity** distribution services to **distributed generation**; minus

"(b) the **distribution** costs (which do not include any transmission costs) that an efficient **distributor** would be able to avoid as a result of the **electrical connection** of the **distributed generation**."

5 Schedule 6.4 amended (Pricing principles)

(1) In Schedule 6.4, clause 2, replace the words "to connect" with "as a result of connecting".

(2) In Schedule 6.4, replace clauses 2(a) and (b) with:

"(a) subject to paragraph (i), connection charges in respect of **distributed generation** must not exceed the **incremental costs** of providing connection services to the **distributed generation**.

"(b) when calculating **incremental costs**, any costs that cannot be calculated must be estimated with reference to reasonable estimates of how the **distributor's** capital investment decisions and operating costs would differ, in the future, with and without the generation:"

(3) In Schedule 6.4, revoke clauses 2A, 2B, 2C and 4.