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20 October 2022

Submissions
Electricity Authority
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By email: network.pricing@ea.govt.nz

Dear Electricity Authority Board Members,

RE: Consultation Paper – consultation on ACOT payments to distributed generation

The Independent Electricity Generators Association Incorporated (IEGA) welcomes the opportunity to submit on the proposal to amend Part 6.4 of the Code. [1]

This consultation is of significant importance to IEGA members and we are disappointed the Authority is rushing through a decision[2].

It is critical to differentiate between two key aspects of the current arrangements: a **payment** is required to be made to distributed generation for the **service** provided by distributed generation of avoiding, or potentially avoiding (deferring)[3], investment in transmission infrastructure. That is, because distributed generation is supplying electricity to end consumers the transmission grid has less capacity than would otherwise be required if the distributed generation did not exist.[4]

The IEGA acknowledges that the new TPM means the construct of the current **payments** (ie based on RCPD charge) ceases to exist. The new TPM does **not** change the **service** provided by distributed generation.

The Authority "*required Transpower to identify which distributed generation was required for Transpower to meet its Grid Reliability Standards*"[5]. The Transpower commissioned Mitton ElectroNet

[1] The Committee has signed off this submission on behalf of members.

[2] That is, only 5 weeks consultation period (closing 20 October) and a Board meeting on 13 December when distributors are expecting to finalise their pricing plans in December.

[3] Code refers to avoided and avoidable investment.

[4] IEGA's preference is to introduce a new name for this payment for transmission benefits provided by distributed generation.

[5] Source: Paragraph A.10(a)(ii) of the Authority's consultation paper.

analysis[6] investigated whether the National Grid can reasonably be expected to meet (n-1) security requirements[7] without distributed generation that existed in December 2016 supplying part of end consumer demand. Distributed generation that was needed to ensure n-1 supply security was defined as 'eligible' for payment for this service, as a legitimate alternative to transmission investment – a "*transmission benefit provided by distributed generation*"[8]. This is the **service** that continues to be provided by existing distributed generation[9] (and can be provided by new distributed generation[10]).[11] The IEGA is focused on the 627.6MW[12] of distributed generation nationwide ensures Transpower is able to meet its n-1 Grid Reliability Standard.

This submission discusses in more detail the increasing importance of the service being provided by distributed generation. The IEGA strongly submits that the Authority's focus must now be on designing a new payment mechanism for this service.

Our recommendations are that the Authority **retain the status quo** until the following work has been completed:

a) commission independent analysis that redoes the analysis Transpower commissioned Mitton ElectroNet undertake that demonstrated at least 627.6MW of December 2016 existing distributed generation is a substitute for transmission capacity; that is, without the distributed generation the transmission capacity at individual GXPs could not supply / is less than is required to supply 100% of the load at the GXP; and

b) require Transpower to sign Grid Support Contracts with each of the distributed generation that is required so that Transpower can reliably meet demand identified in this new analysis; and

c) implement a standard payment for this service provided by distributed generation[13].

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6 This is the only system modelling analysis that has been completed during the entire debate (since 2013) about whether ACOT payments are 'efficient'.

7 Part 12 of the Code requires Transpower to produce "a Grid Reliability Report (GRR) setting out 10-year forecasts of demand at grid exit points, generation at grid injection points, and whether the National Grid can reasonably be expected to meet (n-1) security requirements, and proposals for assessing identified issues". This obligation is fulfilled by the Transmission Planning Report. Source Page 3 of Transpower's 2022 Transmission Planning Report.

8 Source: Paragraph A.11 of the Authority's consultation paper.

9 It is economically efficient that payment to existing distributed generation continue even if subsequent transmission investment increases capacity at a particular GXP.

10 New distributed generation can be contracted by Transpower as a non-transmission solution and the regulatory regime already includes the requirement to pay for this service (although no payments have been made).

11 This transmission service can be provided to assist during peak demand as well as network congestion (due, for example, because of an outage).

12 This differs from the Authority's sum of eligible distributed generation of 1,033MW as we ignore capacity for personal use as well as capacity owned by utility scale generators.

13 This could be the LRMC for recent and proposed transmission investment as there are currently a number of 'live' projects. This standard payment system would be standard across any technology that provided transmission benefits. The Authority's October 2022 Distribution Pricing: Practice Note describes the effective level of a price signal "Price signals should not normally exceed the forecasted cost-reflective level of the future network investment required to respond to current and forecast demand. A price signal up to this level can be an efficient means of avoiding or deferring that future investment." Paragraph 46 https://www.ea.govt.nz/assets/dms-assets/30/Distribution-Pricing-Practice-Note-v-2.2-October-20221376845.1.pdf

It may be that the Commerce Commission is the correct regulatory agency to undertake this work as it is responsible for authorising transmission / non-transmission investment and the recovery of investment costs incurred by Transpower.

The Authority's proposed transition already establishes a method for retaining the status quo – without applying any discount.

Transmission service provided by distributed generation (avoiding or deferring transmission investment)

Recap of Transpower commissioned Mitton ElectroNet analysis

The Authority's 2016 Code amendment required Transpower to identify which distributed generation was required for Transpower to meet its Grid Reliability Standards.

The IEGA notes 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**[14]. This analysis was relied on to determine distributed generation eligible to continue to receive payment for the transmission service of avoiding or deferring transmission costs since 2017.

The Authority's consultation paper does not elaborate on why it considers this assessment identified "*locations where the DG potentially contributes to grid reliability – is, the lists are not confirmation that any given DG is essential to reliability …*"[15]. [emphasis added] The analysis was all DG behind a GXP ON or OFF – thus it relied on all the DG capacity behind the GXP to meet the n-1 Grid Reliability Standard taking into account all of the local, regional and grid backbone performance.

Transpower amended the analysis as it progressed looking at different regions. One change was the introduction of an effectiveness hurdle "*to ensure that reliability benefits from distributed generators were genuine*"[16]. [emphasis added]

Mitton ElectroNet noted "*If the DG was not available to meet the load, then Transpower would have to invest in the substation, by upgrading the transformer capacity, or engage in load shedding (or ask the distribution utility to shift load, if possible) during a transformer outage, at peak times*."[17]

The analysis was based on both winter and summer peak demand.

If there are shortcomings in this analysis the Authority must elaborate on these. Further, 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.

The Authority's consultation paper acknowledges reliability risks if ACOT payments are terminated, saying "*By grid reliability risk, we mean Transpower's ability to continue to meet the Grid Reliability*

[14] We are also disappointed the Authority continues to frame ACOT payments as an avoidance of charges. This analysis identified transmission investment and costs that have not occurred and had nothing to do with any avoidance of transmission charges.

[15] Source: Paragraph 2.6 of consultation paper

[16] Source: Page 1 https://www.ea.govt.nz/assets/dms-assets/23/23436Appendix-C-Explanatory-note-from-Transpower.pdf

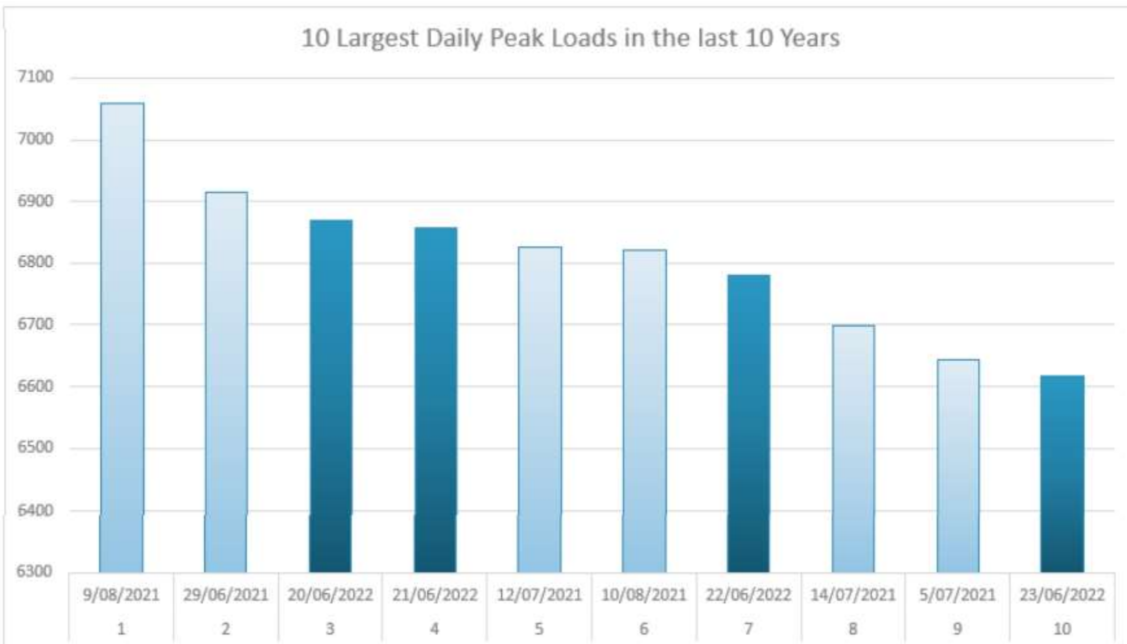
[17] Source : Page https://www.ea.govt.nz/assets/dms-assets/23/23432Appendix-B-Mitton-ElectroNet-report.pdf

Standards (GRS) across its network. Distributed generation may provide support to Transpower in meeting the GRS at points on its network, as an alternative to further transmission investment."[18]

Grid reliability is at risk

Peak demand has increased

Transpower has reported national peak demand increased 3.4% in calendar 2021[19]. August 9, 2021 was a new record national gross demand for electricity with a near record peak for grid offtake. By mid-July, 2022 there had been a further 4 of the 10 highest national peaks ever recorded and the 10 largest daily peak loads since 2012 have occurred in the period since mid-June 2021.[20]



Transpower's analysis of the 20 highest daily peak loads from each year since 2012 is below. "*The chart shows that nationally the lower end of the spread has risen. This increase is against a warming environment, with 2022 the warmest winter on record, pushing 2021 to second, and 2020 to third."*[21] To mid-June 2022 there were five days with peak loads higher than 6,500 MW - more days with a peak load of greater than 6,500 MW than any year before 2021. [22] Transpower concludes "*we do see a clear*

[18] Source: Footnote 21 of consultation paper

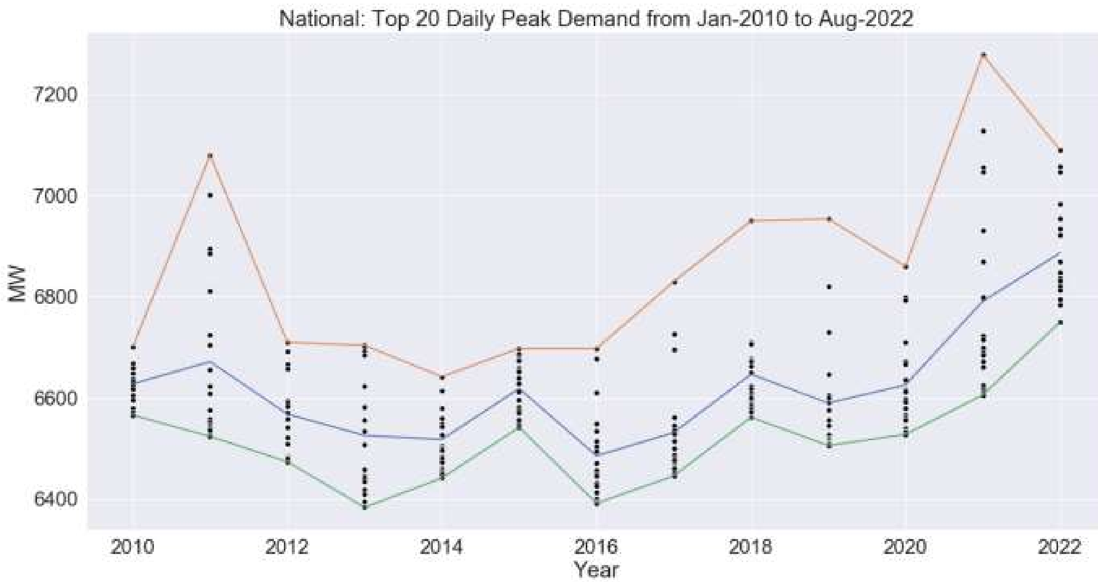
[19] Source: Page 9 2022 Transmission Planning Report.
This national non-coincident GXP peak demand increase is highly relevant given the transmission grid is built for demand levels at each GXP.

[20] Comments and graph from System Operator analysis of peak demand, 26 June 2022 https://tpow-corp-production.s3.ap-southeast-2.amazonaws.com/public/bulk-upload/documents/Market%20Operations%20-%20Weekly%20Market%20Movements%20-%2026%20June%202022.pdf?VersionId=QqVWyY77Dx.8mvmPHu_w4cSfArip3sk4

[21] Source: System Operator analysis of peak demand, 16 October 2022 https://tpow-corp-production.s3.ap-southeast-2.amazonaws.com/public/bulk-upload/documents/MO%20Latest%20Daily%20Update.pdf?VersionId=NFrHbjwkWvIvFPjPxX_83APjEU4yt6Kn

[22] Source: System Operator analysis of peak demand, 26 June 2022

increase in peak demand following the removal of the Regional Coincident Peak Demand (RCPD) charge as a result of changes in the transmission pricing methodology". [23]



As well as an increase in actual electricity demand, distributors have been specific that the value of their ripple control investment to control demand has declined with the removal of RCPD charges – meaning this equipment may no longer be maintained or used. Transpower highlight this in their 2022 Transmission Planning Report "*Some of our customers have chosen to reduce their use of demand management during system peaks which is creating higher peaks. This has not been included in this year's forecast but we expect it to be in future forecasts*." [24]

Transpower's GEN Notice on 7 October 2022 specifically requested increased output from distributed generation to decrease demand for electricity from the transmission grid.[25]

Incentives for distributed generation to provide the transmission service of avoiding or deferring transmission investment

Distributed generation has been incentivised to generate during peak demand periods when the transmission grid is most likely to be constrained and the ability of the transmission grid to deliver 100% of peak demand is at its weakest. This is the **service** that eligible distributed generation are currently being paid for.[26]

The Authority claims nodal spot prices will replace this payment and be sufficient to incentivise distributed generation to generate in peak demand periods. We suggest the following charts demonstrate limited correlation between peak demand periods and high spot prices. That is, spot

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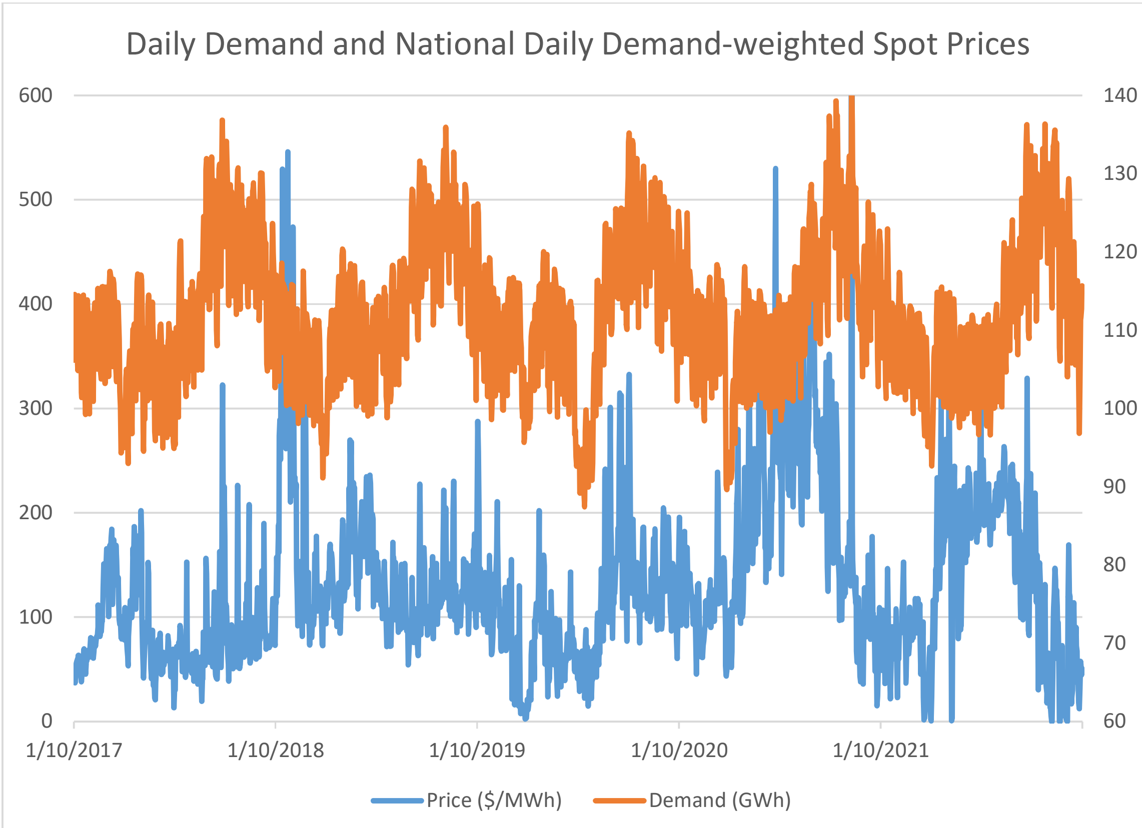
[23] Source: System Operator analysis of peak demand, 16 October 2022

[24] Page 32 https://tpow-corp-production.s3.ap-southeast-2.amazonaws.com/public/publications/resources/2022%20Transmission%20Planning%20Report.pdf?VersionId=UQKqI20NFpbEf1WECSGnY42Dhii2.H87

[25] https://tpow-corp-production.s3.ap-southeast-2.amazonaws.com/public/interfaces/gen/GEN%20Insufficient%20Generation%20offers%20North%20Island%204497985737.pdf?VersionId=7uRDZXrj6b65t9GQoghUpDTsfxDcIWmV

[26] The spot price is irrelevant if distributed generation is contracted to supply electricity.

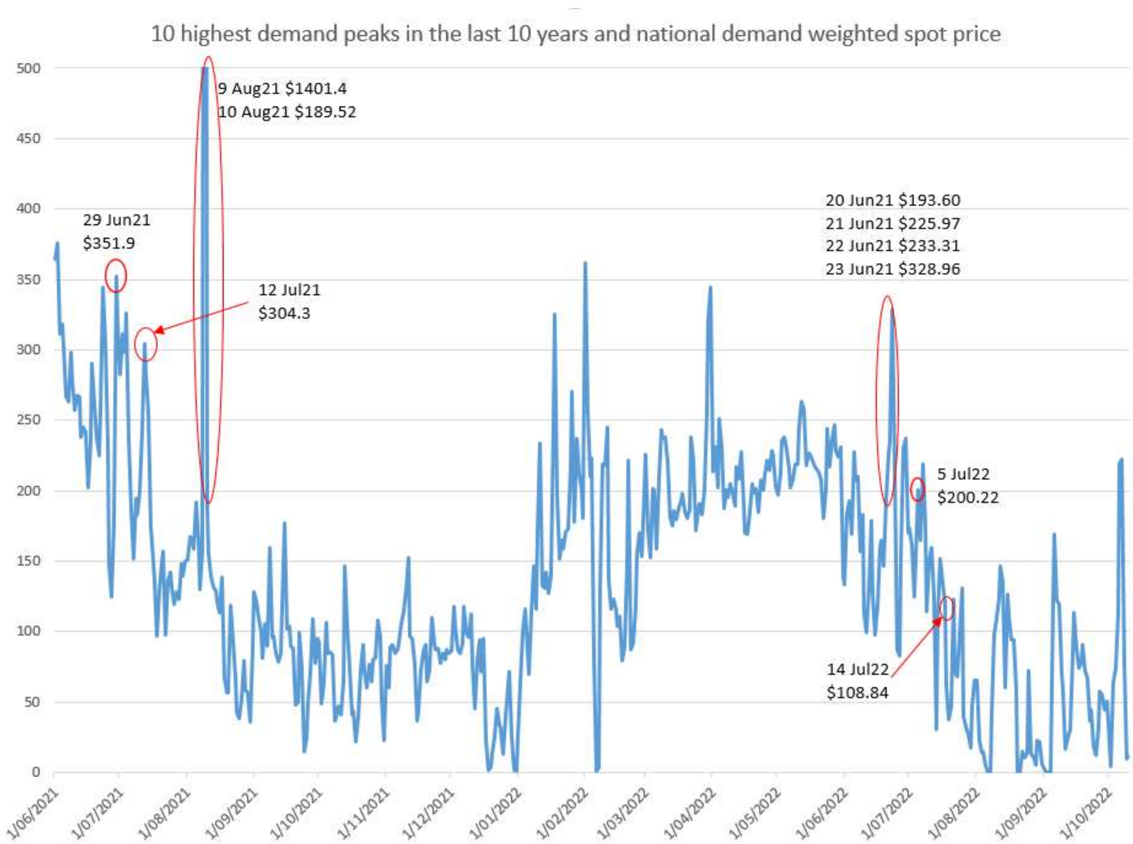
prices are driven by other factors such as fuel storage, gas and coal prices, carbon prices etc. The Authority's own analysis confirms this[27].



As mentioned above Transpower has published that the 10 highest demand peaks over the last 10 years have occurred since June 2021. The following graph of daily demand-weighted spot price highlights these 10 highest peak demand periods. Over the graphed time period, 1 June 2021 to 10 October 2022, there were 127 days with daily spot prices greater than $200/MWh but only 7 of the highest 10 peak demand days had prices greater than $200/MWh.[28] The price were less than $200/MWh for 3 of the highest peak demand periods in the last 10 years, including for the day of the 3rd highest peak demand.

[27] For example, the Authority's regression analysis price models https://www.ea.govt.nz/assets/dms-assets/29/Appendix-A-Regression-Analysis.pdf

[28] Maybe this means that peak demand contributed to prices greater than $200/MWh for 5% of the time (7/127).



This raises the question about whether spot prices are high enough / consistent / predictable enough to incentivise distributed generation to operate to reduce volumes through the transmission grid when the grid is congested.

As well as nodal pricing the Authority is relying on "*administrative load control associated with scarcity pricing*" to be efficient methods to manage grid demand.[29] In our view, the public and political perceptions of the industry will be severely negatively impacted if there are increasing incidents of 'administrative load control associated with scarcity pricing' given the experience of 9 August 2021.

Payment for transmission service provided by distributed generation

Transitional Congestion Charge

The Authority has allowed for a Transitional Congestion Charge (TCC) in the new TPM and claims in its consultation paper that this is could be a mechanism to solve payment to distributed generation for avoiding or deferring transmission investment. The IEGA strongly supported implementation of a Transitional Congestion Charge.

[29] Paragraph 3, Chapter 15, Transpower's TPM Proposal Reasons Paper 20 June 2021 https://tpow-corp-production.s3.ap-southeast-2.amazonaws.com/public/plain-page/attachments/TPM%20Proposal%20Reasons%20Paper%2030%20June%202021.pdf?VersionId=zoTI0_VwumBrPUw5v._U.Basr2ZPACTa

However, the Authority also knows that after careful consideration Transpower advised the Authority that it could not design a TCC that would met the criteria or thresholds the Authority determined for this TCC charge: "*We are unable to satisfy ourselves that we could demonstrate the criteria the Authority intends for a TCC could be met*."[30]

Thus, it is irrelevant to refer to or rely on a TCC to provide any payment to distributed generation for avoiding or deferring transmission investment. We suggest the Authority revisit the criteria for a TCC before relying on this charge to incentivise distributed generation to generate at peak demand and periods of transmission congestion.

Benefit-based charges

The Authority's TPM Guidelines are based on the premise that beneficiaries must pay for transmission services. Reiterating our position in numerous prior submissions, distributed generation competes with transmission to deliver electricity to end consumers – it is a substitute for transmission capacity. If distributed generation was not connected to the distribution network, investment in the transmission grid would be required to increase capacity at the GXP to reliably supply electricity from the grid to end consumers. Transpower is therefore a beneficiary of distributed generation investment, or using the Authority's description – there are "*transmission benefits being provided by distributed generation*"[31].

The value of transmission grid infrastructure is therefore the value of Transpower's investment in traditional poles and wires plus a value for the investment that has not been required because distributed generation has delivered the electricity and not the transmission grid.

The amount distributors pay in benefit-based charges for transmission services is the value of Transpower's investment. 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).

LRMC of transmission investment

Until relatively recently estimating an LRMC of transmission investment had been theoretical. We suggest costings and estimated benefits relating to recent projects (CUWLP, WUNIVMI) and proposed projects (HVDC, CNI and WR) could provide a basis for estimating a standard payment amount for transmission investment avoided and deferred by distributed generation.

The IEGA's feedback on the Authority's questions is in Appendix 1.

[30] Ibid, Paragraph 15.6, Chapter 15

[31] Source: Paragraph A.11 of the consultation paper

Concluding remarks

We note that the reasons given in the consultation paper[32] for why the Authority did not change the DGPPs in 2016 still apply, namely: there continues to be no other constraint on distributors using "*their monopoly power to overcharge distributed generation for connection services*"; and "*exacerbate[ing] the risk that distributors underpay avoided costs of distribution (ACOD)*".

The IEGA's position is that distributed generation is (and has been for many years) providing transmission benefits and must be compensated for this (consistent with the Authority's beneficiaries pay approach for transmission costs).

Robust analysis was undertaken to identify 'eligible' distributed generation. This analysis has not been disproven or reviewed. Any change to payments to distributed generation for transmission services must be based on robust analysis (and not assertions).

We reiterate our recommendation - that the Authority **retain the status quo** until the following work has been completed:

a) commission independent analysis that redoes the analysis Transpower commissioned Mitton ElectroNet undertake that demonstrated at least 627.6MW of December 2016 existing distributed generation is a substitute for transmission capacity; that is, without the distributed generation the transmission capacity at individual GXPs could not supply / is less than is required to supply 100% of the load at the GXP; and

b) require Transpower to sign Grid Support Contracts with each of the distributed generation that is required so that Transpower can reliably meet demand identified in this new analysis; and

c) implement a standard payment for this service provided by distributed generation[33].

We suggest a discussion about this submission is appropriate given our strongly and long held views differ from those of the Authority.

Yours sincerely

Warren McNabb

Chair

Attached - Appendix 1: IEGA responses to consultation questions

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[32] Source: Paragraph A.9 of consultation paper

[33] This could be the LRMC for recent and proposed transmission investment as there are currently a number of 'live' projects.

Appendix 1: IEGA responses to consultation questions

Chapter 2

Do you have any comments on the background and context material in this chapter or Appendix A?

We provide the following comments about Appendix A:

- Para A.2: states the regulations were intended to "encourage" distributed generation. This overstates the intent which was clearly to 'facilitate' distributed generation.

- Para A.4(a)(i): The regulations were developed in 2007 before "batteries or other flexibility providers" existed. We suggest it is the Authority's role to ensure the Code is up to date with technology or technology agnostic. Batteries are now known as generators so maybe this solves part of the issue raised by the Authority.

- Para A.9: As noted in our cover letter (page 9) the reasons given for the Authority pulling back from its initial 2016 proposal still exist. There has been no regulatory change that limits distributors from using their monopoly powers to overcharge distributed generation for connection services or the risk that distributors underpay avoided costs of distribution.

The Authority's focus in this section is on transmission <u>charges distributors didn't have to pay because</u> distributed generation generated during regional coincident peak demand periods. It is important the focus is on transmission <u>costs</u> that have been / are being avoided or deferred; that is, what is being 'avoided' is costs not charges. The avoided transmission <u>costs</u> were identified and legitimised in the Transpower commissioned Mitton ElectroNet analysis of Transpower's ability to meet its Grid Reliability Standard without distributed generation.

Chapter 3

Do you agree with the Authority's preferred approach of clarifying that ACOT payments are no longer required?

The IEGA strongly disagrees with the Authority's analysis and conclusions that ACOT payments are inefficient and not required. Therefore we also disagree with the Authority's preferred approach to amend the Code outlined in paragraph 3.5 of the consultation paper.

Do you have any comments on the alternative approaches that could be used to justify ACOT payments?

As discussed already, the Authority's analysis in paragraphs 3.12 – 3.17 is flawed as it does not take into account that distributed generation has provided transmission benefits and the transmission grid is smaller (and costs lower) than it would otherwise be if there was no distributed generation energy. Distributors benefit from this because the allocation of transmission costs to distributors with distributed generation is lower. Under a beneficiaries pay approach it is the distributed generator (and not the distributor) that has provided this benefit of lower transmission costs.

The crux is that the total cost of delivering electricity to end consumers is the cost of current transmission infrastructure plus the transmission service benefits provided by distributed generation.

This reality is confirmed by the Mitton ElectraNet power system analysis which proved that distributed generation is required for Transpower to meet its Grid Reliability Standards.[34] We are happy to discuss this in more detail to aid the Authority's understanding.

Pricing neutrality between grid connected and distributed generation is irrelevant (para 3.14(b)(i). Grid connected generation – by definition – is wholly reliant on the transmission grid, otherwise it is impossible to get electricity to end consumers. 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.

Do you have any comments on the Authority's proposed amendments to the Code?

The IEGA agrees with the proposed amendment to remove the works "with connection services".

We are unsure of the value of adding reasonable "additional" costs given incremental costs is a well stablished economic term and distributors have been applying the concept of incremental costs in their distribution pricing for many years (as it is used in the Distribution Pricing Principles[35]).

As discussed above, the IEGA disagrees with the proposed Code amendment to delete clauses 2(a)(i) and (ii), 2A, 2B and 2C. Our strong recommendation is to retain the status quo until robust analysis is undertaken to reveal if the current payments are, as the Authority asserts, inefficient.

The new clause 2D provides a methodology for calculating a payment amount that supports retaining the status quo.

Chapter 4

Do you agree with the transition risks we have identified, and our assessment of them?

Our cover letter addresses the risks of system reliability and the high cost of supply interruptions. We also highlight that nodal prices do not provide the equivalent signal to ACOT payments. In our view the Authority's assessment understates the transition risks.

Our strongly held view is that the status quo must be retained – please read our cover letter.

Do you think there are any other transition risks we should consider?

Please read our cover letter

Do you have any information that would allow the Authority and Transpower to better assess the risk that removing the requirement to make ACOT payments could lead to changes in distributed generation behaviour that could impact reliability?

Transpower is already experiencing higher peak demand on its network and attributing this to the removal of the RCPD charge.

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[34] From our understanding of the Mitton ElectroNet conclusions, it is the entire distributed generation fleet in the Upper North Island area that is needed in order for Transpower to meet its Grid Reliability Standard.

[35] The 2019 review changed incremental to avoidable and the Authority's explanation was that the terms are interchangeable.

Do you have any comments on the design of the phase-out option?

No comment – our focus is to retain the status quo.

Do you agree with our preference that ACOT payment obligations cease from April 2023 with no phase out?

No – the IEGA does not agree with the Authority's preference that ACOT payment obligations cease from April 2023.[36]

Chapter 5

Do you have any comments on the distributed generation pricing context material provided in Appendix C?

The IEGA suggests the comments reflect a perception that distributed generation does not provide any transmission benefits despite the fact that robust analysis to prove the Authority's conclusion has not been undertaken or presented.

Do you have any comments on the Authority's plans for further work on whether there is a future role for additional price signals for grid support technologies?

We query whether the Authority's work on considering a "future role for additional price signals" is the same as recognising that entities providing grid support services / technologies should be paid for that service. The IEGA notes the industry-led FlexForum appears to support payment for (flexibility) services offered by grid support technologies. Establishing a payment mechanism for transmission benefit services (including to distributed generation) and distribution flexibility services must be a priority.

In our view, the Authority's commentary in this chapter 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"[37]. Distributed generation does / can provide the exact same services as demand response.

Chapter 7

Do you agree with the objectives of the proposed amendments? If not, why not?

Please read our cover letter and the answer to the next question.

Do you agree the benefits of the proposed amendments outweigh their costs?

In our view, the Authority can not claim the benefits of the proposed amendments outweigh the costs because the Authority has not undertaken any robust analysis of the transmission benefits provided by distributed generation that is currently eligible to receive payments. Until the Authority updates or replaces the Transpower commissioned Mitton ElectraNet power system analysis that identified

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[36] Any change to ACOT payments should coincide with the date the new TPM is effective – this may or may not be 1 April 2023.

[37] Table 1, Page v https://www.ea.govt.nz/assets/4-Monitoring/Issues-Paper-Promoting-competition-in-the-wholesale-electricity-market-in-the-transition-toward-100-renewable-electricity.pdf

distributed generation that is required for Transpower to meet its Grid Reliability Standards any claim by the Authority that ACOT payments are inefficient is self-serving and unsubstantiated.

Do you agree that alternative means of meeting the objective are not as effective in meeting the Authority's statutory objective? If you disagree, please explain your preferred alternative option in terms consistent with the Authority's statutory objective.

No, the IEGA does not support the Authority's alternative means of meeting the statutory objective. The alternative also relies on a view that ACOT payments are inefficient. The IEGA's submission strongly argues payments for transmission benefits provided by distributed generation are efficient and the status quo must be retained until robust power system analysis is undertaken which proves otherwise.

Do you agree the Authority's proposed amendment complies with section 32(1) of the Act?

The IEGA does not agree the proposed amendment complies with section 32(1) of the Act. As discussed in this entire submission, the IEGA's view is that 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.

Do you have any other comments on this chapter?

No comments in addition to the balance of this submission.

Do you have any other feedback on any other aspect of this consultation paper?

There are a number of comments in the consultation paper that are assertions without any detail about why the Authority has come to that conclusion/assertion.[38] The underlying problem with the Authority's proposals and consultation paper is that there has been no robust network system modelling to underpin the assertions that such as:

- ACOT payments are inefficient
- distributed generation is "*reasonably unlikely*" to be needed to sustain grid reliability (para 4.7)

We note that Appendix B on 'ACOT consultation as part of TPM reform' quotes a number of industry participants – but not the IEGA or (then) Trustpower who are the parties with the most at stake. Maybe the Authority could advise us on how to make our submissions more effective or worthwhile from your point of view.

[38] There are also factual errors. For example, IEGA members' are not exposed to nodal prices in the same way as grid-connected generators (para 3.8) as they are price-takers and do not offer / influence nodal prices (or exert market power) like grid connected generators.