INDEPENDENT ELECTRICITY GENERATORS ASSOCIATION

Chairman: Warren McNabb, warren.mcnabb@altimarloch.com
Secretary: David Inch, david@nzenergy.co.nz

24 February 2017

Submissions
Electricity Authority
P O Box 10 041
Wellington 6145

By email: submissions@ea.govt.nz

Dear Carl,

RE: Transmission Pricing Methodology: Second issues paper: Supplementary consultation

The Independent Electricity Generators Association (IEGA) welcomes the opportunity to make this submission on the Supplementary consultation paper published by the Electricity Authority (Authority) on 13 December 2016. The IEGA comprises about 40 members who are either directly or indirectly associated with predominantly small scale power schemes connected to local networks throughout New Zealand for the purpose of commercial electricity production. [1]

If the TPM Guidelines are to change, the IEGA supports the Authority's decision to make the TPM Guidelines less prescriptive and more principles based. However, it is our preference that the Authority adopts Transpower's simplified transmission pricing methodology and staged approach outlined in their submission on the 2nd Issues Paper. It is important that the Authority has confidence in Transpower to propose a robust and durable transmission pricing methodology based on any Guidelines at the next step in the process without lengthy debate with the Authority.

The proposed TPM is directly relevant to the IEGA given the:

1. adjustments made in the modelling of the published indicative-only charges for proposed new distributed generation and co-generation
2. flexibility provided to Transpower in determining the allocator for the residual charge
3. opportunity for Transpower to design and implement a long-run marginal cost (LRMC) change
4. our concerns about the Authority's inconsistent approach to electricity prices for end consumers and wealth transfers

This submission addresses each of the above points.

1. Adjustments made in modelling for proposed new distributed generation and co-generation

The Authority has arbitrarily reduced the Gross Anytime Maximum Demand volumes to take into account yet to be committed distributed generation (DG) investment by a distribution company and

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

estimated demand side management (DSM) by direct connect industrials. The details of these arbitrary amendments to Gross AMD[2] are:

Top Energy: reduced Gross AMD from 72.3MW to 48.6MW; 25MW removed from demand based on the 25MW Ngawha expansion, due to an assumed permanent change in demand

Norske Skog: reduced Gross AMD from 114MW to 93MW: A change to gross AMD to reflect netting of onsite generation

NZ Steel: reduced Gross AMD from 170MW to 136.8MW; A change to gross AMD to reflect netting of onsite generation. Paragraph 3.135 of the Supplementary consultation paper also states that *"An adjustment has been made to improve modelling of demand response at NZ Steel's Glenbrook site."*

The Authority's modelling finally recognises that DG and DSM reduces the use of the transmission grid, transmission costs and charges. This has been the IEGA's argument throughout the review of the DGPP. The Authority's modelling of indicative transmission charges for these customers is summarised in the following table.

Designated Transmission Customer	Reduction in Gross AMD	2nd Issues Paper estimate of TX charges ($m)	Latest estimate of TX charges ($m)		Change AFTER Cap ($m)
			BEFORE Cap	AFTER Cap	
Top Energy (including Jukon)	25MW	10.3	6.1	6.1	-4.2
Norske Skog	21MW	6.8	5.2	1.3	-5.5
NZ Steel	33.2MW	16.6	15.3	7.8	-8.8
Total	**78.2MW**	**$33.7m**	**$26.6m**	**$15.2m**	**-$18.5m**

Source: Results_20161221_updated_on_2Feb2017.xls: Residential Cap sheet columns BA and BB and Charges as $M per year sheet column E

While the IEGA supports these adjustments being made in principle, we have three concerns about how this adjustment has been applied, in that:

- designated transmission customers can avoid proposed transmission charges (ACOT) by owning DG and using DSM, whereas the TPM Guidelines prevent Transpower from making similar adjustments to other networks with similar connected assets; and
- the Authority has used a different test for this DG compared with the new test for existing DG under the revised DGPP Code (namely, that the DG is necessary to meet the Grid Reliability Standards); and
- these adjustments have resulted in lower transmission charges for these transmission customers that are similar to current RCPD prices. Indicative charges BEFORE the cap are reduced by $90,793 per MW (cf. current ACOT RCPD payments at ~$114,000 per MW).

The IEGA questions how the Authority can deem these TPM transmission cost adjustments, at about the same cost per MW of current RCPD ACOT payments, to be efficient when in its DGPP problem definition and final decision the Authority deemed the current ACOT payment levels as being too high and a subsidy?

[2] See Appendix 1 – Electricity Authority letter to Pioneer Energy 15 February 2017, page 9

In January the IEGA wrote[3] to the Authority about these concerns and we appreciate the Authority's efforts to address the questions we asked. Our letter, attached as Appendix 2, raised concerns about what these arbitrary adjustments to the allocation of residual charges. The Authority's reply (also in Appendix 2) clearly states;

> *"It is important to re-emphasise that the charges are indicative and the approach taken in the modelling will not bind Transpower."*[4]

Whilst the modelled charges are indicative only and the Authority's approach does not bind Transpower, we are concerned that the published lower charges for some transmission customers relative to the 2nd Issues Paper, using this indicative modelling, will influence their responses to the Supplementary consultation paper. Further, these relatively minor adjustments to the modelling assumptions have resulted in significant redistribution of transmission costs to designated transmission customers.

The purely indicative nature of the charges published by the Authority, and the sensitivity to assumptions, makes it very difficult for owners or investors in generation and load to make decisions about investment in long-life assets for the next 3-4 years until any revised TPM is implemented. At the same time the Authority is relying on ongoing economically efficient investment in generation, load or transmission to achieve its statutory objective.

2. Flexibility provided to Transpower in determining the residual charge allocator

The IEGA does not agree with the use of Anytime Maximum Demand as an allocator of the residual as it is not an accurate indicator of actual use of the transmission grid interconnected assets. We note that the proposed Guidelines provide Transpower with flexibility to determine the method by which to allocate the residual charge subject to weighing up the criteria in clause 32. The IEGA supports this flexibility in the draft Guidelines.

We expect that there will be transparency about the method chosen and request the Guidelines include a provision that the method will be consistently applied across all types of transmission customers (and not include arbitrary adjustments for particular customers). For example, the impact of distributed generation, co-generation, demand side management and demand response on any designated transmission customer will be treated consistently in any adjustment to the allocation methodology, whether the transmission customer has made the investment or a third party has contributed to a change in the customer allocation.

The IEGA does not agree with including a process for optimisation of transmission assets in the TPM Guidelines. A lower residual charge for one transmission customer due to optimisation of assets will increase the residual charges for all other customers. The process of identifying and valuing the assets that might be optimised will likely increase Transpower's required revenue. The Commerce Commission is responsible for ensuring, on a regular basis, that the valuation of transmission assets is fit for purpose and to make any adjustments to reflect any change in volumes or usage in its determination of Transpower's revenue requirement.

3. LRMC charge

The IEGA strongly supports the option for Transpower to design and implement an LRMC charge in the TPM to be effective in 2020. IEGA, and many other submitters, agree that peak demand drives transmission investment. The proposed AoB charge is fixed once a transmission investment is made. The Authority expects electricity users will make themselves aware of the potential for this charge if a

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[3] See Appendix 2 – IEGA letter to Electricity Authority 18 January 2017

[4] See Appendix 2 - Electricity Authority letter to IEGA 14 February 2017, in response to Q3 on page 8

new investment happens. However, as presented in submissions on the 2nd Issues Paper, there are a number of reasons why individual customers potentially facing an AoB charge will not change their behaviour to influence the need for future investment[5]. The allocation of residual transmission costs is not designed to influence efficient behaviour to defer or avoid future transmission investment.

An LRMC charge is a visible tangible cost that a customer can avoid if they change their immediate behaviour which can defer or reduce the cost of future transmission investment. The Authority confirms this view in its 14 February letter to the IEGA:

> *"ACOT payments may therefore be appropriate if DG can, by operating, efficiently defer or reduce the cost of future transmission investment. ACOT payments could, for example, be paid by a distributor subject to an LRMC charge where operation of the DG allows the distributor to avoid paying the LRMC charge. This is appropriate as the operation of the DG in this case would efficiently defer the transmission investment at which the LRMC charge is targeted."* [6]

It is difficult to predict demand and this is compounded by the lengthy regulatory process and planning requirements before commissioning an investment. There must be an economic price, an LMRC charge, which signals potential future need for transmission investment that anyone can respond to. This response will defer or avoid the need for transmission investment.

An LRMC charge would be complimentary to other methods Transpower has of efficiently deferring investment. Any LRMC charge developed by Transpower will be transparent and publicised, reducing the barriers for transmission customers or third parties to provide services that defer or avoid transmission investment (such as distributed generation). In contrast, Grid Support Contracts are bespoke bilateral contracts. The demand response programme is much more tactical and applicable for short term management of system security in real time.

4. Inconsistent approach to changes in prices for consumers

The Authority has consistently said it cannot take into account the impact of the TPM proposal (or the DGPP decision) on the level of electricity prices paid by end consumers – as these are wealth transfers.

However, the Authority is promoting the TPM (and DGPP) decisions by claiming major savings for some end users. We query whether the Authority is consistent in the way it looks at the change in prices for end consumers for consumers' long term benefit. For example:

- The modelling of Top Energy's yet to be committed new distributed generation reduces their charges, and increases charges for other transmission customers, by $5.5 million per annum relative to the 2nd Issues Paper. Noting that this charge is 'indicative' the assumption that this DG is efficient and permanently reduces demand (as other DG does) has an NPV of $55 million – well in excess of the benefits the Authority estimated from its proposal to remove the DGPPs of $21.7 million. This is a transfer of wealth to Top Energy unless the same methodology is applied equally to all Network and Direct Connect customers paying the Residual charge.

- The Authority has not taken into account any possible increase in electricity prices for consumers from the removal of a peak demand price signal – because this is a wealth transfer. But publicity about the DGPP and TPM decisions emphasis the Authority's expected reduction in electricity prices. While these two opposite impacts on end prices may not be directly comparable in a CBA or economic analysis, the economic constrict is being used to avoid analysis of any possible upward force on prices.

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[5] Electricity Authority Summary of Submissions line 334 https://www.ea.govt.nz/dmsdocument/21368

[6] See Appendix 2 - Electricity Authority letter to IEGA 14 February 2017, in response to Q1 on page 4

- There are two significant factors driving the final indicative prices that Transpower will have no control over when they announce the actual charges in 2020. Namely:

    - the cap on the overall bill for end consumers of 3.5% requires Transpower to have accurate information about energy charges by retailers as well as all other components of an end users bill. That is, the transmission charge for individual customers is a balancing item after taking into account other components of the bill.

    - the assumption that the WACC for Transpower (and distribution companies) will be lower in 2020 – Transpower, or the Authority, has no control over the global macroeconomic drivers of New Zealand's monetary policy.

The cap clearly impacts the allocation of Transpower's total allowable revenue so that some end consumers must be paying more if other consumer's bills are capped – we understand this transfer of wealth between electricity consumers is $34 million per annum. These may be the exact same electricity consumers that the Authority has promised will benefit from lower payments to distributed generation.

We note that the Authority's interpretation of its statutory objective[7] states that *"if wealth transfers seriously undermine confidence in the pricing process or in the electricity industry more generally then that can inhibit efficient entry and investment decisions and these dynamic efficiency effects should be taken into account when evaluating proposals"*. We suggest the Authority should consider in its final decision on the TPM Guidelines the dynamic efficiency effects of a loss of confidence.

In summary, we suggest it is misleading for the Authority to claim lower charges for some customers under this proposal when these estimates are "indicative" only and in many instances are unlikely to be realised.

We would welcome the opportunity to discuss this submission with you.

Yours sincerely

Warren McNabb
Chairman

Attachments:
Appendix 1
– IEGA letter to Electricity Authority 23 December 2016
– Electricity Authority response to IEGA 30 January 2017

Appendix 2
– IEGA letter to Electricity Authority 18 January 2017
– Electricity Authority response to IEGA 14 February 2017

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[7] Source: http://www.ea.govt.nz/dmsdocument/9495

INDEPENDENT ELECTRICITY GENERATORS ASSOCIATION

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Secretary: David Inch, david@nzenergy.co.nz

23 December 2016

Dr Brent Layton
Chair
Electricity Authority
P O Box 10041
Wellington 6143

By email: brent.layton@ea.govt.nz

Dear Brent

RE: Review of the Distributed Generation Pricing Principles

The Independent Electricity Generators Association appreciated having your staff presenting and discussing the Electricity Authority's (Authority) decisions relating to its review of the Distributed Generation Pricing Principles at our recent meeting.

While there was a robust question and answer session, there was confusion, contradiction and unanswered questions from the Authority staff during the discussion and we are writing to seek clarity on the following questions:

1. Will Transpower consult as it develops its methodology to identify distributed generation that is required for Transpower to meet the grid reliability standards (undertaking the work required on clause 2A of the amended Code)?

2. It is our strong expectation that the methodology adopted and applied by Transpower for the Lower South Island by 15 March 2017 will be the same methodology as is applied to all distributed generation in New Zealand. Can you please confirm this? If not, why not?

3. What criteria will the Authority use when it is reviewing and approving Transpower's report in relation to distributed generation (under clause 2B of the amended Code)?

4. Will the Authority publish its reasons for declining Transpower's report and / or its directions to Transpower as to how it should amend its report (under clause 2B(2) of the amended Code)?

5. How many times can the Authority decline Transpower's report or direct Transpower as to how to amend its report?

6. Will the Authority consult on its review and opinion of Transpower's report?
    a. If yes, why is this step not included in the amended Code?

b. If no, on what grounds did the Authority decide that a consultation process was not necessary?
c. Who will the Authority consult with?

7. The timeframes for Transpower's report and the Authority's decision have no regard to the Capacity Measurement Period for RCPD calculations or the fact that network payments to distributed generation are paid twelve months in arrears. Is the Authority prepared to reconsider these timeframes to align with the construction timeframe of transmission charges?

8. The DGPP discussion also fails to adequately address two key principles:

   a) Why has the Authority overlooked the obvious competition issue? Distributed generation competes with and is a substitute for transmission investment. Electricity from distributed generation does not use the transmission grid. Transpower is being asked to identify ex post distributed generation that competes with their investment in transmission infrastructure. Transpower's recommendations and the Authority's decisions could potentially be anti-competitive.

   b) Why has the Authority decided the current playing field is not level? The field was level before the Authority amended the DGPPs. Network companies continue to get paid for avoiding transmission charges by using load and hot water ripple control – DG provides the same service as load control. The latest TPM proposal appears to acknowledge the benefits of industrial co-gen behind the meter – placing co-generation behind the meter at a competitive advantage to DG. Grid connected generation relies on transmission to be able to sell its electricity to load and does not pay transmission charges – even under the proposed new TPM it does not pay for transmission in proportion to its reliance on this infrastructure.

9. We note the analysis in the Concept report on Winter Supply Margin for the TPM and DGPP decisions estimates that "the average nodal price during the 100 peak hours would increase from around $100/MWh to approximately $230/MWh. The time weighted average nodal price over the year would increase by approximately $1.5/MWh"[1]. Where does this cost appear in the Authority's CBA for the DGPP decision?

We appreciate your timely attention to these questions, especially as about 30% of existing distributed generation is to be subject to this new regime within the next three months.

Yours sincerely

Warren McNabb
Chairman

[1] Source: page 34 of Concept Consulting report

ELECTRICITY AUTHORITY
TE MANA HIKO

30 January 2017

Warren McNabb
Chairman
Independent Electricity Generators Association

Review of the Distributed Generation Pricing Principles

Thank you for your letter of 23 December 2016 asking questions about the recent amendment to the Electricity Industry Participation Code (Code) relating to the Distributed Generation Pricing Principles (DGPP).

Staff from the Electricity Authority (Authority) welcomed the opportunity to present to, and discuss with, the Independent Electricity Generators Association (IEGA) the decisions made in regards to the DGPP. We do not agree with your characterisation that there was confusion and contradiction from Authority staff at the meeting. As they clearly indicated at the meeting there are still further matters to be dealt with in the implementation stage, and accordingly they were not able to clarify some matters because those matters are still to be addressed.

Your letter asks nine questions (set out below in italics). An answer to each is provided below.

1. *Will Transpower consult as it develops its methodology to identify distributed generation that is required for Transpower to meet the grid reliability standards (undertaking the work required on clause 2A of the amended Code)?*

That is a decision for Transpower to make. At this stage I am not aware whether Transpower plans to consult. Note that the Authority intends to consult with affected parties before publishing any list of the distributed generation in each region that should receive ACOT payments.

2. *It is our strong expectation that the methodology adopted and applied by Transpower for the Lower South Island by 15 March 2017 will be the same methodology as is applied to all distributed generation in New Zealand. Can you please confirm this? If not, why not?*

I am not in a position to confirm this one way or the other. Transpower is responsible for determining the methodology required to advise the Authority about which existing distributed generation is required for Transpower to meet the Grid Reliability Standards. I expect Transpower will use the most appropriate methodology in meeting its Code obligations in respect of each region.

3. *What criteria will the Authority use when it is reviewing and approving Transpower's report in relation to distributed generation (under clause 2B of the amended Code)?*

The Authority will consider whether Transpower has met its obligations under the Code. With respect to Transpower's first report, the Authority will consider whether the report is likely to correctly identify which (if any) distributed generation located in the Lower South Island is required for Transpower to meet the Grid Reliability Standards in the period from 1 April 2017 to 31 March 2020. The Authority will give particular consideration to the assumptions Transpower has made and to any discretionary judgement exercised by Transpower in preparing its report.

In reviewing Transpower's report in relation to distributed generation, the Authority will be guided by its objective to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

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4. *Will the Authority publish its reasons for declining Transpower's report and / or its directions to Transpower as to how it should amend its report (under clause 2B(2) of the amended Code)?*

The Authority seeks to be as transparent as possible regarding all of its decisions providing doing so is in the long-term interests of consumers. However, the Authority's standard practice is to make decisions about publishing any matters, including the matters you refer to, only once it has all of the facts at hand.

5. *How many times can the Authority decline Transpower's report or direct Transpower as to how to amend its report?*

The Code does not limit the number of times the Authority may decline to approve a report from Transpower or direct Transpower as to how to amend its report.

6. *Will the Authority consult on its review and opinion of Transpower's report?*
    a. *If yes, why is this step not included in the amended Code?*
    b. *If no, on what grounds did the Authority decide that a consultation process was not necessary?*
    c. *Who will the Authority consult with?*

The Authority intends to consult with affected parties before finalising any list of the distributed generation in each region that should receive ACOT payments. As part of that consultation, I expect we will release Transpower's report and advise affected parties of the Authority's preliminary (ie, prior to consultation) opinion of Transpower's report.

This step was not included in the amended Code as to do so was considered unnecessary to achieve the purpose of the Code amendment.

According to its consultation charter, the Authority may seek feedback from interested parties on matters it considers material. The Authority Board will decide which parties to consult. I expect that, at least, we will consult owners of distributed generation in the relevant region.

7. *The timeframes for Transpower's report and the Authority's decision have no regard to the Capacity Measurement Period for RCPD calculations or the fact that network payments to distributed generation are paid twelve months in arrears. Is the Authority prepared to reconsider these timeframes to align with the construction timeframe of transmission charges?*

The Authority is not prepared to reconsider the timeframes for Transpower's report and our decision, which are set out in the Code. By reducing the inefficient incentives caused by ACOT, the Code amendment will create significant long-term net benefits to consumers. Delay to the implementation of the Code amendment would reduce these benefits.

I recognise that owners of distributed generation in the Lower South Island and Lower North Island regions will need to make operation decisions during the current capacity measurement period in the absence of complete information about whether they will receive ACOT payments for that operation.

However, owners of distributed generation are aware of the test that will be applied to determine whether they are eligible for ACOT payments. They can therefore form their own view about the likelihood that they will continue to qualify. Where the operation of distributed generation is required for Transpower to meet the Grid Reliability Standards, parties should expect this to be recognised.

8. *The DGPP discussion also fails to adequately address two key principles:*

    a. *Why has the Authority overlooked the obvious competition issue? Distributed generation competes with and is a substitute for transmission investment. Electricity from distributed generation does not use the transmission grid. Transpower is being asked to identify ex post distributed generation that competes with their investment in transmission infrastructure. Transpower's recommendations and the Authority's decisions could potentially be anti-competitive.*

The Authority has considered these issues and recognised in its decision paper that Transpower may not have the right incentives in this area, particularly in the case of existing distributed generation that provides a transmission benefit. To address these issues, the Authority decided:

- to introduce a test that Transpower must apply, based on the Grid Reliability Standards
- to have the Authority make the final decision on which existing distributed generators will be paid ACOT (based on Transpower's advice).

The Authority considers that introducing a test for Transpower to apply and introducing oversight from the Authority ensures the efficiency benefits of the Code amendment will be realised in respect of existing distributed generation.

These measures do not apply in respect of new distributed generation. Nevertheless, the Authority expects that Transpower will enter into agreements with owners of new distributed generation whose operation could efficiently reduce or defer transmission network costs, as:

- the framework for investment decisions established by the Commerce Commission provides incentives for Transpower to procure new distributed generation as a substitute for transmission investment where that is the efficient investment option
- Transpower's incentives are changing, due to emerging technologies (which raise the possibility that new transmission assets will be stranded some time in their life, and so give Transpower an incentive to favour non-transmission solutions).

I would also note that prospective investors in new distributed generation have other options available for their investment. Unlike for some existing distributed generation, prospective investments are not sunk investments and so Transpower cannot force them to accept uncompetitive terms and conditions.

    b. *Why has the Authority decided the current playing field is not level? The field was level before the Authority amended the DGPPs. Network companies continue to get paid for avoiding transmission charges by using load and hot water ripple control – DG provides the same service as load control. The latest TPM proposal appears to acknowledge the benefits of industrial co-gen behind the meter – placing co-generation behind the meter at a competitive advantage to DG. Grid connected generation relies on transmission to be able to sell its electricity to load and does not pay transmission charges – even under the proposed new TPM it does not pay for transmission in proportion to its reliance on this infrastructure.*

The Authority has decided the current playing field is not level because ACOT payments that are made to distributed generators that do not avoid transmission costs are an artificial advantage for that generator over competitors (eg, a grid-connected generator that is similar in other respects). So the decision does remove a barrier to competitive neutrality.

However, the decision does not purport to make the playing field perfectly level in all respects. We recognise that the regulatory arrangements in this area may not result in competitive neutrality, even after the Code amendment. For example, the regulated price ceiling (which the decision leaves untouched) may provide distributed generators with an artificial competitive advantage over grid-connected generators and also over other technologies that could compete with distributed generation in providing various services. For this reason, the Authority intends to revisit this issue and resolve it in a way that will promote efficiency and competitive neutrality between distributed generators, grid-connected generators and other technologies.

More broadly, the Authority has not made any final decisions about the TPM. The Authority's proposed TPM guidelines state the Authority is seeking competitive neutrality for different forms of generation and the Authority is keen to hear stakeholders' views on these matters. Accordingly, we look forward to receiving your submission on our TPM consultation on or before the due date for submissions (24 February 2017).

9. *We note the analysis in the Concept report on Winter Supply Margin for the TPM and DGPP decisions estimates that "the average nodal price during the 100 peak hours would increase from around $100/MWh to approximately $230/MWh. The time weighted average nodal price over the year would increase by approximately $1.5/MWh". Where does this cost appear in the Authority's CBA for the DGPP decision?*

The effect of this modelled increase in the nodal price is a wealth transfer between different parties. The Authority doesn't include wealth transfers in its CBAs unless they have efficiency effects. No efficiency impacts have been identified as a result of this price change. Accordingly, it does not appear in the Authority's CBA.

As you are no doubt aware the Concept report identifies the modelled increase in nodal prices as a transitional effect only. Concept states that "the long term drivers of nodal prices will remain unchanged, and so we would not expect any long-term change to average nodal prices." The fact that the modelled nodal price change is only temporary makes it less likely that it would result in any efficiency impacts.

The Authority also wishes to respond to the IEGA's comment that "about 30% of existing distributed generation is to be subject to this regime within the next three months". The Authority presumes that this refers to Transpower's obligation to provide its report on distributed generation in the Lower South Island by 15 March 2017 (or such later date as the Authority may allow). However, distributed generators located in the Lower South Island are still entitled to receive ACOT payments under the current regime until the Code amendment takes effect in respect of that region on 1 April 2018. That is, the current regime will continue until 1 April 2018, despite the fact that the Code amendment came into force generally on 9 January 2017, and Transpower's obligation to provide its report by 15 March 2017 (or such later date as the Authority may allow).

Thank you again for your letter.

Yours sincerely

Carl Hansen

Carl Hansen
Chief Executive

IEGA
INDEPENDENT ELECTRICITY GENERATORS ASSOCIATION

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18 January 2017

Carl Hansen
Chief Executive
Electricity Authority
P O Box 10041
Wellington 6143

By email: carl.hansen@ea.govt.nz

Dear Carl

RE: Transmission pricing proposal in relation to distributed generation

The Electricity Authority's proposed refinements to the transmission pricing methodology (TPM), outlined in the "Transmission Pricing Methodology: Second issues paper Supplementary consultation" paper, include a number of new assumptions relating to distributed generation (DG) and demand side management (DSM).

The purpose of this letter is to seek clarity about:

a) these assumptions, which have been made in relation to allocating transmission costs; and
b) whether these assumptions are consistent with the Authority's decision on its Review of the Distributed Generation Pricing Principles (DGPPs) – a decision that was made at the same time as the 'refinements' to the TPM where being developed.

We would appreciate your timely consideration of our questions so that the clarity provided can be reflected in our submission.

a) New assumptions in relation to allocating transmission costs

Change from Gross AMD to allocate residual charges

IEGA **seeks confirmation** that the Authority has revised its approach to the allocator for the residual charge. Gross AMD appeared to be the preferred approach in the 2nd Issues Paper. The Supplementary consultation paper states:

> *3.111 "The proposed guidelines provide that the residual charge should be calculated according to historical AMD or another method."*

Our confusion arises because para 5.24 then states

> *"The proposal permits Transpower to use a method related to* ***gross*** *load other than AMD to calculate the residual ..."* [emphasis added]

Q1. Please clarify that the derivation of the AMD allocators will reflect your definition of a cost reflective charge, ie maximum use of the grid at any time.

i. Does Transpower have the flexibility to use an allocator for the residual charge that may or may not add on load supplied by DG and DSM to the load at a GXP?
ii. Why does aggregation of historic GXP metered loads result in a decline in the AMD allocator? This is noted in para 3.133 and in the results spreadsheet, eg the assumptions for Northpower at Bream Bay where the Bream Bay GXP AMD has been notionally adjusted with the AMD at Mangatapure but should be directly additive.

We are surprised that one of the principles in the guidelines for the design of an efficient residual by Transpower (para 3.123(b)) relates to how a distributor might pay or credit DG with transmission charges avoided by the distributor.

Q2. Please explain the rationale for this principle.

i. Is this principle stating that Transpower cannot add generation volumes supplied by the DG to the load of the network/customer to determine the allocation for that network/customer of the total residual charge?
ii. Does this principle mean that DG that has resulted in a transmission customer being charged a lower residual (and transmission capacity that is or would be lower capacity (para3.120(c))) should not be compensated for this benefit?
iii. The DGPP decision states that DG approved by the Authority is entitled to payments by a network company for avoided transmission charges indefinitely. Does this principle contradict the DGPP decision?
iv. Is this principle related to the DGPP decision that a network company can charge DG only incremental costs (and therefore can not pass on to a DG any AoB or Residual transmission charge that reflects the existence of this DG)?
v. Where a net AMD is applied discretionarily by Transpower, can we then assume that this DG is deemed to be on the 'approved list' under the grid reliability standard test and thus entitled to an ACOT payment under the DGPP?

Avoid double counting and other anomalies

IEGA is surprised that 'addressing anomalies' has resulted in significant changes to the indicative charges for affected parties (with a flow on to all transmission customers). In our view, this demonstrates that the proposed methodology is not stable or durable.[1]

The following table summarises the changes that the Authority has made that directly reflect distributed generation (on-site or embedded) and demand-side management.

DG / DSM related changes to TPM charges	Description of new assumptions	2nd Issues Paper estimate of TX charges ($m)	Latest estimate of TX charges ($m)		Change AFTER Cap ($m)
			AFTER Cap[2]	BEFORE Cap[3]	
Norske Skog	Co-gen output netted off against load and improved modelling on demand response[4]	6.8	1.3	5.8	-5.5

[1] The Authority acknowledges the sensitivity of charges to AMD in para 3.138
[2] From Authority results spreadsheet – sheet called Geographic sort_trans
[3] From Authority results spreadsheet – sheet called Charges as $M per year
[4] This is our assumption as we could not find a detailed explanation of the reasons for the change in charges for Norske Skog in the Authority's papers

Refining NZ	Reflects generation exported by Top Energy's Ngawha expansion	4.8	~3.2	n/a	-1.6
NZ Steel	Co-gen output netted off against load + improved modelling of demand response at Glenbrook	16.6	7.8	14.6	-8.8
Top Energy	New 25MW capacity at Ngawha geothermal site included as a reduction in demand	10.3	4.8	4.7	-5.5
Orion	New 25MW generation site included as a reduction in demand	47.6	45.8	44.7	-1.8
Total		**86.1**	**62.9**		**-23.2**

We commend the Authority for publishing the detailed results spreadsheet. The above numbers are our best attempt at interpreting the indicative charges from this information. We note that the proposed cap appears to replace the prudent discount uneconomic exit proposal.

Q3. The commentary in the supplementary consultation paper implies that the 2nd issues paper assumed net load (after generation and demand response) for industrials. Our understanding was that the allocator in the 2nd issues paper for direct connects was 'load + co-generation + demand response'. Please confirm if the proposed allocator for **all** load (networks and direct connects) is now 'net load', ie load recorded at the GXP.

The allocation must be consistent across all load otherwise it appears the prudent discount inefficient exit proposal has been replaced with a rebate of avoided transmission costs (ACOT) for selected loads.

One of the main assumption changes has been to take into account the generation volumes from the "well signalled" expansion at Ngawha – assumed to be 25MW[5]. Schedule 1 (attached) lists all the consented and "well signalled" new generation that can be commissioned within the same timeframe as the Authority assumes for the new Ngawha expansion.

Q4. Why has the Authority included a future local generation upgrade at Ngawha but omitted to make more major adjustments to larger generation that has also been "well signalled" , for example the decommissioning of Huntly and Nova's large gas peaker project at Otarahonga?

Q5. We would appreciate the Authority explaining why the 500MW Huntly exit is not as material to AoB allocators as the 25MW Ngawha expansion now seems to be?

Q6. Why have no other new generation or DSM adjustments been made in other regions that would similarly reduce AoB and/or Residual charges to those loads?

b) whether these assumptions are consistent with the Authority's decision on its Review of the Distributed Generation Pricing Principles

The DGPP decision has established the principles to apply to DG and payments for avoiding transmission costs and charges. The Authority has states its proposed TPM guidelines are now less prescriptive and more principles based. However, the changes to the calculation of the allocator for selected transmission customers discussed above moves away from a principles based approach.

[5] An exemption application lodged with the Authority by Top Energy indicates the expansion is 32MW http://www.ea.govt.nz/dmsdocument/21586

The combination of DG and DSM input changes (in the table above) results in material changes to charges of $17.3m per annum. These changes clearly show that the Authority agrees that DG and DSM continue to reduce transmission customer's exposure to transmission charges. These customers benefit from avoiding transmission costs.

The Authority's position in the proposed TPM is therefore inconsistent with its decision on its Review of the Distributed Generation Pricing Principles. The DGPP decision claims that distributed generation does not reduce transmission costs and provides no benefits unless Transpower can identify that the distributed generation is required to meet its Grid Reliability Standards.

The reduction in charges for the group of customers in the table above is $23.2m per annum – well in excess of the Authority's estimate of the benefit of changing the DGPPs to eliminate ACOT payments of up to an **NPV** of $21.7m.

Q7. We seek further clarification as to why the Authority has identified selected DG providers as private beneficiaries of avoiding transmission charges, when the Authority clearly deemed these as "economically inefficient investments" in its recent DGPP decision.

We believe the Authority is now applying different criteria for the allocation of transmission costs in the TPM compared with the DGPP decision. There is also a conflict between the processes and methodology that Transpower will use to allocate transmission costs – using GXP load net of DG and DSM - and to determine the value of DG in avoiding transmission costs for transmission customers – using the Grid Reliability Standards.

Q8. Please explain how the Authority reconciles these differences. For example, a new industrial customer might install co-generation which will reduce their transmission charges, while a new DG plant will have to negotiate with Transpower to identify any benefit from the DG in reducing transmission costs.

A clear focus of the DGPP decision was to ensure a level playing field.

Q9. The Authority has adjusted the transmission charges for a network company based on information the network company provided about its own generation assets. A number of IEGA members own generation assets independently. Can the Authority please confirm that network companies with independently owned generation supplying their network are being treated the same in its analysis as network companies that own generation? This question applies equally for DSM as direct connects now benefit from their demand management activities – how do third party providers of DSM benefit?

We believe these are serious issues relating to the Authority's analysis and decision processes and would appreciate responses to our questions as soon as possible given that time is now of the essence for the TPM consultation process.

Yours sincerely

WBMcNabb

Warren McNabb
Chairman

Attachment: Schedule 1: New Consented and Well Signalled Generation Data

Schedule 1: New Consented and Well Signalled Generation Data

October 2016

Generation type	Region	ransmission Regio	Location / Name of Projec	Owned by	Capacity (MW)	Earliest commission date	Status	Notes
	Taranaki	LNI	Junction Road	Nova Energy	100	2018-2020	Consented	
Geothermal	Bay of Plenty	LNI	Te Ahi O Maui	Eastland Group	20	2018-2020	Consented	
	Bay of Plenty	LNI	Rotoma	Rotoma No. 1 Corporation	35	2017-2020	Applied for consent	
Hydro	Hawkes Bay	LNI	Ruataniwha Plains	Hawkes Bay Regional InvCo	6.5	2017-2020	Consent under appeal	
Wind	Hawkes Bay	LNI	Waitahora	Contact Energy			Consent lapsed	
	Hawkes Bay	LNI	Maungaharuru	Meridian Energy	270	2017-2020	Consented	
	Manawatu	LNI	Central Wind (Moawhango)	Meridian Energy	125	2017-2020	Consented	
	Manawatu	LNI	Turitea	Mighty River Power	303	2017-2020	Consented	
	Taranaki	LNI	Waverley	Trustpower	135	2017-2020	Applied for consent	
	Wellington	LNI	Castle Hill	Genesis Energy	860	2017-2020	Consented	
	Wellington	LNI	Puketoi	Mighty River Power	159	2017-2020	Consented	
	Wellington	LNI	Long Gully	Windflow Technologies	12.5	2017-2020	Consented	
Subtotal LNI					2026			
Hydro	Canterbury	LSI	Rakaia River	Ashburton Com. Water Trust	16	2017-2020	Consented	
	Canterbury	LSI	Lake Pukaki	Meridian Energy	35	2017-2020	Consented	
	Canterbury	LSI	North Bank Tunnel	Meridian Energy	240	2017-2020	Applied for consent	
	Canterbury	LSI	Balmoral Hydro	Meridian Energy	15	2017-2020	Applied for consent	
	Otago	LSI	Hawea Control Gate Retrofit	Contact Energy	17	2017-2020	Consented	
	Otago	LSI	Upper Fraser	Pioneer Generation	6.5	2020	Consented	
Wind	Otago	LSI	Mahinerangi Stage 2	TrustPower	164	2017-2020	Consented	
	Southland	LSI	Kaiwera Downs	TrustPower	240	2017-2020	Consented	
Subtotals LSI					733.5			
Gas	Auckland	UNI	Otahuhu C	Contact Energy			Consented	Otahuhu plant is closed down
	Auckland	UNI	Rodney	Genesis Energy			Consented	Genesis Energy will not progress the project
	Waikato	UNI	Waikato Power Plant	Nova Energy	360	2021-2022	Applied for consent	
Geothermal	Northland	UNI	Ngawha expansion	Top Energy	50	2017-2020	Consented	
	Waikato	UNI	Tauhara II	Contact Energy	250	2020	Consented	
Marine	Northland	UNI	Kaipara Harbour pilot	Crest Energy	200	2017-2020	Consented	
Wind	Auckland	UNI	Awhitu	TrustPower	18	2018-2020	Consented	
	Waikato	UNI	Hauāuru mā raki	Contact Energy			Consented	Contact Energy will not progress the project
	Waikato	UNI	Taharoa	Taharoa	54	2017-2020	Consented	
	Waikato	UNI	Taumatatorara	Ventus	44	2017-2020	Consented	
Subtotal UNI					976			
Diesel	Canterbury	USI	Bromley	Orion	11.5	2017-2020	Consented	
	Canterbury	USI	Belfast	Orion	11.5	2017-2020	Consented	
Hydro	Marlborough	USI	Wairau	TrustPower	70.5	2017-2020	Consented	
	West Coast	USI	Stockton Plateau	Hydro Developments Ltd	25	2017-2020	Consented	
	West Coast	USI	Stockton Mine	Solid Energy	35	2017-2020	Consented	
	West Coast	USI	Arnold (Dobson)	TrustPower	46	2017-2020	Consented	
Wind	Canterbury	USI	Mt Cass	MainPower	55	2017-2020	Consented	
	Canterbury	USI	Hurunui	Meridian Energy	76	2017-2020	Consented	
Subtotal USI					330.5		Peak Demand by Region	Load Share

ELECTRICITY AUTHORITY
TE MANA HIKO

14 February 2017

Mr Warren McNabb
Chair
Independent Electricity Generators Association

Dear Mr McNabb

RE: Transmission pricing proposal in relation to distributed generation

Thank you for your letter dated 18 January 2017 seeking clarification on the impact of the Authority's transmission pricing methodology (TPM) proposal outlined in the TPM second issues paper: supplementary consultation, in relation to distributed generation.

Given the technical nature of some of the questions and responses, we have opted to set out our responses (in red) under your questions.

Yours sincerely

Carl Hansen

Carl Hansen
Chief Executive

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Authority response to IEGA questions on 18 January 2017

Authority responses included in red below.

RE: Transmission pricing proposal in relation to distributed generation

The Electricity Authority's proposed refinements to the transmission pricing methodology (TPM), outlined in the "Transmission Pricing Methodology: Second issues paper Supplementary consultation" paper, include a number of new assumptions relating to distributed generation (DG) and demand side management (DSM).

The purpose of this letter is to seek clarity about:
A. these assumptions, which have been made in relation to allocating transmission costs; and
B. whether these assumptions are consistent with the Authority's decision on its Review of the Distributed Generation Pricing Principles (DGPPs) – a decision that was made at the same time as the 'refinements' to the TPM where being developed.

We would appreciate your timely consideration of our questions so that the clarity provided can be reflected in our submission.

A. New assumptions in relation to allocating transmission costs
IEGA **seeks confirmation** that the Authority has revised its approach to the allocator for the residual charge. Gross AMD appeared to be the preferred approach in the 2nd Issues Paper.

After considering submissions on the second issues paper, the Authority amended the draft guidelines to provide additional discretion to Transpower in its design of the TPM. The draft guidelines in the second issues paper required the residual charge allocator to be a proxy for physical capacity, being either transformer capacity, line capacity or gross anytime maximum demand (gross AMD)[1]. However, the draft guidelines in the supplementary consultation paper (draft guidelines) allow Transpower the flexibility to develop the residual charge subject to certain criteria. Namely, the residual charge must (among other things):

- apply to load
- correct for double counting and other anomalies
- result in broadly equivalent charges for customers in broadly equivalent circumstances
- be difficult to avoid
- be related to the size of a customer's load.[2]

The proposed guidelines do not specify whether the residual charge must be anytime maximum demand (AMD) or, if it is, whether it should be net or gross. However, in order to calculate indicative charges, to assist parties to understand how the TPM might impact them, the Authority modelled the residual charge with gross AMD as the allocator. It is important to note that Transpower may propose a different allocator and that the charges are indicative only. Actual charges under a revised TPM may differ significantly from those modelled.

We emphasise that the Authority's TPM proposal is set out in the draft guidelines and not in the modelling. Accordingly, the assumptions used in the modelling should not be read as implying an Authority position on treatment of DG or demand response (DR). For those aspects of TPM

1 Draft TPM guidelines, second issues paper, Clause 24.

2 Draft TPM guidelines, supplementary consultation paper; Clauses 32(a), 32(b), 32(c), 32(d), respectively.

design not specified in detail in the guidelines, Transpower would have discretion to propose the approach that best met the requirements of the guidelines and the Code and best promoted the Authority's statutory objective. We would therefore encourage you to focus your submission on whether the guidelines proposed in the supplementary consultation paper would promote the Authority's statutory objective.

Q1. Please clarify that the derivation of the AMD allocators will reflect your definition of a cost reflective charge, ie maximum use of the grid at any time.

i) Does Transpower have the flexibility to use an allocator for the residual charge that may or may not add on load supplied by DG and DSM to the load at a GXP?

Please refer above.

ii) Why does aggregation of historic GXP metered loads result in a decline in the AMD allocator? This is noted in para 3.133 and in the results spreadsheet, eg the assumptions for Northpower at Bream Bay where the Bream Bay GXP AMD has been notionally adjusted with the AMD at Mangatapure but should be directly additive.

Paragraph 3.133 of the supplementary consultation paper describes the adjustment of some parties' residual charges (in the indicative modelling of charges) to reflect the aggregation of some loads. Should the Authority publish revised guidelines, Transpower would be required to consider whether such 'aggregation' would avoid anomalous charges and would be consistent with the requirements for the residual charge.

In the indicative modelling, aggregation was undertaken to reflect the proposal in the draft guidelines that the residual allocator must correct for 'double counting',[3] which was an issue identified in submissions on the second issues paper. It is important to note that the draft guidelines do not specify aggregation in a general sense but just specify that the residual charge allocator must correct for double counting.[4]

We are surprised that one of the principles in the guidelines for the design of an efficient residual by Transpower (para 3.123(b)) relates to how a distributor might pay or credit DG with transmission charges avoided by the distributor.

Paragraph 3.123(b) of the supplementary consultation paper describes the workings of clause 32(f) of the draft guidelines, which states that the method for calculating the residual charge must:

> "*be designed so that any distributed generator that is paid or credited for transmission charges avoided by the relevant distributor would not receive such payment or credit in respect of the residual charge component of the relevant distributor's transmission charges (for example, by adding back a value representing the load supplied by the distributed generator for the purpose of calculating the residual charge).*"

The clause was included to clarify that if, under a revised TPM, distributed generation (DG) injection volumes would otherwise reduce a distributor's share of the residual charge (eg, if net AMD or a similar "net" allocator was applied for calculating residual charges) and this results in

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3 Clause 32(b) of the draft guidelines.

4 *ibid.*

avoided cost of transmission (ACOT) payments or the equivalent, an approach to calculating the residual charge should be applied such that no ACOT payment would be made, eg, by subtracting the injection in calculation of the charge.

The residual charge recovers a fixed cost. Thus, if under a revised TPM, DG injection volumes reduced a party's share of the residual, this would not defer or reduce transmission costs or the size of the residual, but would just shift the avoided charge onto other parties, which would not promote efficiency. Accordingly, the criteria for the design of the residual charge are intended to counteract incentives for operation of DG to avoid it.

This is consistent with the Authority's distributed generation pricing principles (DGPPs) decision in which the Authority determined that ACOT payments should only continue to the extent that a DG efficiently defers or reduces transmission costs. ACOT payments may therefore be appropriate if DG can, by operating, efficiently defer or reduce the cost of future transmission investment. ACOT payments could, for example, be paid by a distributor subject to an LRMC charge where operation of the DG allows the distributor to avoid paying the LRMC charge. This is appropriate as the operation of the DG in this case would efficiently defer the transmission investment at which the LRMC charge is targeted.

Q2. Please explain the rationale for this principle.

i) Is this principle stating that Transpower cannot add generation volumes supplied by the DG to the load of the network/customer to determine the allocation for that network/customer of the total residual charge?

As stated above, the draft guidelines do not specify whether the residual charge should be gross or net of DG. The criterion related to payment of ACOT is intended to ensure that the residual charge is calculated in a way that does not promote investment in, or operation of, DG to avoid the residual charge, as this would be inefficient.

ii) Does this principle mean that DG that has resulted in a transmission customer being charged a lower residual (and transmission capacity that is or would be lower capacity (para3.120(c))) should not be compensated for this benefit?

As stated above (and as set out in clause 32 of the draft guidelines) the residual charge should be designed---to the extent that it can be economically achieved---to not create incentives or opportunities for designated transmission customers to inefficiently avoid the charge; and that the design must ensure that ACOT payments would not be made for operation of DG to reduce the residual charge.

Paragraph 3.120 of the supplementary consultation paper provides an example of an approach for allocating residual charges. This was termed "adjusted AMD".

The approach means that, unless recent DG (ie, commissioned within the last 10 years) would have reduced actual transmission capacity requirements at a grid connection point, there is unlikely to be any material difference between adjusted AMD and gross AMD. The approach does, however, mean customers are not penalised because of material changes in demand etc that have happened or are forecast to happen on the basis of information prior to the release of the policy, provided they would reduce capacity requirements.

Note that the approach has not been tested in any detail. If the Authority confirms the draft guidelines, and should Transpower propose an "Adjusted AMD" approach, or a variation, the Authority will consider that proposal.

If such an approach were applied, it would need to be designed in a way to meet the criterion that ACOT payments would not result from operation of DG that would otherwise reduce the residual charge. However, the guidelines are silent on the issue of ACOT payments for DG that led to a lower initial residual charge if the adjusted AMD approach was applied.

iii) The DGPP decision states that DG approved by the Authority is entitled to payments by a network company for avoided transmission charges indefinitely. Does this principle contradict the DGPP decision?

The DGPP decision does not state that DG approved by the Authority is entitled to payments indefinitely. Rather, it is clearly stated in the Authority's Decisions and Reasons Paper on its Review of Distributed Generation Pricing Principles that further refinement of the ACOT arrangements is expected over time – especially to ensure that the rate of ACOT payments does not exceed transmission benefits.

In that Decision Paper the Authority noted that in future, nodal prices in the wholesale electricity market may be sufficient to encourage the operating and investment responses required for efficient management of transmission network constraints. To the extent nodal prices do not provide a sufficient signal, a long-run marginal cost (LRMC) charge may be desirable. The proposed new TPM would allow Transpower to introduce an LRMC charge. If either of these changes occurs, the new ACOT arrangements might no longer be needed, or could require refinement.

The Authority also said in the Decision Paper that if the TPM guidelines change, then in parallel with submitting a new TPM to the Authority for approval, Transpower should also recommend to the Authority further adjustments to the DGPPs that will promote efficiency and competitive neutrality between demand response, distributed generation and grid-connected generation.

The Authority also said that if the current TPM remains in force then we will review the new ACOT arrangements for each region by no later than five years after the new arrangements have commenced for each region. In either case, the review will make sure that the pricing arrangements in place will provide ongoing incentives for efficient investment and operation of distributed generation.

Accordingly, under the DGPP decision, avoided cost of transmission (ACOT) payments should be made for deferred or reduced grid costs and not avoided transmission charges. The nature of ACOT payments could change if there were a new TPM. ACOT payments would only be appropriate if the operation of the relevant DG resulted in deferring or reducing transmission investment. This would suggest that if the transmission investment is made, there would be no reason for ACOT payments to DG built to defer the investment to continue, unless this would defer or reduce other transmission investment.

iv) Is this principle related to the DGPP decision that a network company can charge DG only incremental costs (and therefore cannot pass on to a DG any AoB or Residual transmission charge that reflects the existence of this DG)?

Clause 4(d) of the draft guidelines provides for competitive neutrality, as far as is practicable, between grid-connected generation, distributed generation, and demand response. The purpose of this clause is described in paragraphs 3.174 to 3.178 of the supplementary consultation paper.

This clause was included in the draft guidelines partly to ensure that DG is treated, as much as possible, in the same way for transmission charging purposes as grid connected generation and demand response. Accordingly, it is not intended that DG would be allocated a portion of the residual charge in Transpower's calculation of the residual charge to distributors, as grid-connected generators would not face the residual charge. This would promote competitive neutrality between grid-connected generation and DG. Given that the Authority decided not to remove the provision under the DGPPs whereby distributors can charge DG no more than incremental cost (at this stage), distributors should only pass on to DG transmission charges that result from connection of the DG to their network. Accordingly, if connection of DG results in injection at a GXP and results in the distributor incurring an AoB charge, it would be appropriate for the distributor to pass on to the DG that proportion of the AoB charge resulting from the connection of the DG.

To answer the question specifically, as stated above, clause 32(f) of the draft guidelines relates to the calculation of the residual charge to a transmission customer, and requires that the residual charge be designed so that transmission customers cannot avoid it by incentivising operation of DG through ACOT payments. Clause 32(f) does not, however, address the calculation of transmission charges in relation to DG. To the extent that the proposed guidelines address the DGPP decision that DG can be charged no more than incremental cost, this is addressed by clause 4(d)'s requirement that the TPM must as far as practicable facilitate competitive neutrality between DG, grid-connected generation, and demand response.

v) Where a net AMD is applied discretionarily by Transpower, can we then assume that this DG is deemed to be on the 'approved list' under the grid reliability standard test and thus entitled to an ACOT payment under the DGPP?

As discussed above, this level of guidance is not provided in the draft guidelines. Further, it is important to note that the TPM is not the regulatory mechanism that addresses the eligibility of DG for ACOT payments. However, were an adjusted AMD approach applied, DG that reduces transmission capacity would not be penalised in the calculation of residual charges. This is not to say, however, that this means such DG is automatically eligible for ACOT payments: that would be determined by the DGPP regime. Specifically, as set out in the Authority's Decisions and Reasons Paper on its Review of Distributed Generation Pricing Principles, Transpower will assess which DG in each region are required for Transpower to meet the Grid Reliability Standards, and will advise the Authority of its findings. The Authority will decide, based on Transpower's advice, which existing DG will be entitled to receive ACOT payments under the regulated terms.

Avoid double counting and other anomalies

IEGA is surprised that 'addressing anomalies' has resulted in significant changes to the indicative charges for affected parties (with a flow on to all transmission customers). In our view, this demonstrates that the proposed methodology is not stable or durable.

The following table summarises the changes that the Authority has made that directly reflect distributed generation (on-site or embedded) and demand-side management.

DG / DSM related changes to TPM charges	Description of new assumptions	2nd Issues Paper estimate of TX charges ($m)	Latest estimate of TX charges ($m)		Change AFTER Cap ($m)
			AFTER Cap.[2]	BEFORE Cap.[3]	
Norske Skog	Co-gen output netted off against load and improved modelling on demand response.[4]	6.8	1.3	5.8	-5.5

Refining NZ	Reflects generation exported by Top Energy's Ngawha expansion	4.8	~3.2	n/a	-1.6
NZ Steel	Co-gen output netted off against load + improved modelling of demand response at Glenbrook	16.6	7.8	14.6	-8.8
Top Energy	New 25MW capacity at Ngawha geothermal site included as a reduction in demand	10.3	4.8	4.7	-5.5
Orion	New 25MW generation site included as a reduction in demand	47.6	45.8	44.7	-1.8
Total		**86.1**	**62.9**		**-23.2**

We commend the Authority for publishing the detailed results spreadsheet. The above numbers are our best attempt at interpreting the indicative charges from this information. We note that the proposed cap appears to replace the prudent discount uneconomic exit proposal.

Q3. The commentary in the supplementary consultation paper implies that the 2nd issues paper assumed net load (after generation and demand response) for industrials. Our understanding was that the allocator in the 2nd issues paper for direct connects was 'load + co-generation + demand response'. Please confirm if the proposed allocator for **all** load (networks and direct connects) is now 'net load', ie load recorded at the GXP.

As stated above, the draft guidelines do not prescribe an approach. However, indicative charges were calculated based on gross AMD with some adjustments. For example, co-generation was netted off for direct consumers, and some anomalies were addressed. Further, Top Energy's gross AMD was reduced by 25MW to account for the 25MW Ngawha expansion which has been announced, consistent with the "adjusted AMD" approach discussed in paragraph 3.120 of the paper. As noted above, it is the guidelines that Transpower must follow in developing its proposed TPM and not the assumptions used in the indicative modelling.

The allocation must be consistent across all load otherwise it appears the prudent discount inefficient exit proposal has been replaced with a rebate of avoided transmission costs (ACOT) for selected loads.

As noted above, the modelling approach does not determine how the proposed guidelines would be applied; rather Transpower must just follow the guidelines (and the Code) in developing its proposed TPM. To the extent that the inefficient exit prudent discount proposal has been replaced, it has been replaced by the proposal to cap increases in transmission charges. There is no proposal to rebate ACOT for selected loads.

One of the main assumption changes has been to take into account the generation volumes from the "well signalled" expansion at Ngawha – assumed to be 25MW4F4F S Schedule 1 (attached) lists all the consented and "well signalled" new generation that can be commissioned within the same timeframe as the Authority assumes for the new Ngawha expansion.

The Authority decided to adjust its modelling of indicative charges to account for the possible impact of the Ngawha expansion because parties in the Far North requested this information. The Authority recognises that other regions may be in a similar situation as the Far North as per your Schedule 1.

The Authority's approach for adjusting Top Energy's gross AMD downwards by 25MW was developed after balancing the criteria for the residual charge provided in the draft guidelines. Specifically, the modelling reflects clause 32(e) where the residual allocation must be related to the size of a customer's load, and it also reflects the "adjusted AMD" approach. The Ngawha expansion would presumably reduce Top Energy's reliance on the transmission grid, ie, it would be a permanent change in demand. However, in designing the residual charge, Transpower must, to the extent that it can be economically achieved, design the charge so as to not create incentives or opportunities for designated transmission customers to inefficiently avoid the charge. The Authority has not come to a decision as to how that design should be achieved in practice. The requirement that the residual charge must reflect the size of a customer's load, while also, to the extent that it can be economically achieved, be designed so as to not create incentives or opportunities for designated transmission customers to inefficiently avoid the charge, is a complex trade-off. This is a matter for Transpower to consider should the Authority confirm the draft guidelines.

It is important to re-emphasise that the charges are indicative and the approach taken in the modelling will not bind Transpower.

Q4. Why has the Authority included a future local generation upgrade at Ngawha but omitted to make more major adjustments to larger generation that has also been "well signalled" , for example the decommissioning of Huntly and Nova's large gas peaker project at Otarahonga?

Refer above.

Q5. We would appreciate the Authority explaining why the 500MW Huntly exit is not as material to AoB allocators as the 25MW Ngawha expansion now seems to be?

Refer above. Further, note that indicative charges are for the 2020 calendar year only. Genesis Energy announced in 2016 that the 500MW at Huntly will still be in operation by the end of 2020.

Q6. Why have no other new generation or DSM adjustments been made in other regions that would similarly reduce AoB and/or Residual charges to those loads?

Refer above.

B. whether these assumptions are consistent with the Authority's decision on its Review of the Distributed Generation Pricing Principles

The DGPP decision has established the principles to apply to DG and payments for avoiding transmission costs and charges. The Authority has states its proposed TPM guidelines are now less prescriptive and more principles based. However, the changes to the calculation of the allocator for selected transmission customers discussed above moves away from a principles based approach.

As noted above, the guidelines do not prescribe the method for calculating charges but rather set out criteria that Transpower must apply in designing the charges, such as those discussed above for the residual charge. The Authority's modelling of charges is indicative only, and as with all modelling, is based on simplifying assumptions. However, the Authority's modelling of the residual charge using gross AMD, with adjustments in certain circumstances, is as described above. Transpower's design of charges must take into account (and comply with) the criteria set out in the guidelines.

The combination of DG and DSM input changes (in the table above) results in material changes to charges of $17.3m per annum. These changes clearly show that the Authority agrees that DG and DSM continue to reduce transmission customer's exposure to transmission charges. These customers benefit from avoiding transmission costs.

As stated above, the choice of allocator for the residual charge is not intended to convey that DG or demand response avoids transmission costs. The residual is a fixed cost that must be recovered and cannot be avoided by the subsequent actions of DG or DR. Clause 32(f) of the draft guidelines confirms this position. However, it is important to note that both DG and DR may be able to avoid future transmission investment, and if that is the case payments to owners of DG or DR may be appropriate to encourage the investment in, and operation of, DG or DR that would defer or avoid transmission investment. As noted above, the Authority's approach to determining eligibility for ACOT payments, as set out in the Authority's Decisions and Reasons Paper on its Review of Distributed Generation Pricing Principles, is that Transpower will assess which DG in each region are required for Transpower to meet the Grid Reliability Standards, and advise the Authority of its findings. The Authority will decide, based on Transpower's advice, which existing DG will be entitled to receive ACOT payments under the regulated terms. Further, Transpower will be responsible for assessing the need for additional grid support from new distributed generation where that would be the cheapest way to achieve the required level of transmission service.

The Authority's position in the proposed TPM is therefore inconsistent with its decision on its Review of the Distributed Generation Pricing Principles. The DGPP decision claims that distributed generation does not reduce transmission costs and provides no benefits unless Transpower can identify that the distributed generation is required to meet its Grid Reliability Standards.

The Authority disagrees. The Authority's TPM position is entirely consistent with its DGPP decision. In particular, under both the TPM proposal and the DGPP decision, DG would only receive an ACOT payment where the DG is able to efficiently defer or reduce future transmission investment. As noted above, the Authority's approach to determining eligibility for ACOT payments, as set out in the Authority's Decisions and Reasons Paper on its Review of Distributed Generation Pricing Principles, is that Transpower will assess which DG in each region are required for Transpower to meet the Grid Reliability Standards, and will advise the Authority of its findings. The Authority will decide, based on Transpower's advice, which existing DG will be entitled to receive ACOT payments under the regulated terms.

Further, it is incorrect to say that the DGPP decision claims that distributed generation provides no benefits unless Transpower can identify that the distributed generation is required to meet its Grid Reliability Standards. To the contrary, the DGPP decision recognises a number of benefits or services that distributed generation can provide. These benefits (including for example the provision of energy and ancillary services) are set out in Tables 3 and 4 in section 3 of the Authority's Decisions and Reasons Paper on its Review of Distributed Generation Pricing Principles. For the reasons set out in section 3 of the paper, the Authority's view is that DG could still be paid for the benefits they provide (and pay for the costs they create), even if they do not receive ACOT payments from distributors (in cases where the distributed generator does not efficiently defer or reduce transmission costs).

The reduction in charges for the group of customers in the table above is $23.2m per annum – well in excess of the Authority's estimate of the benefit of changing the DGPPs to eliminate ACOT payments of up to an **NPV** of $21.7m.

These two figures are unrelated. The first relates to reduced estimated charges as a result of modelling changes since the second issues paper. The second relates to the net economic benefits of the Authority's DGPP changes. There is no economic reason to link the former to the latter.

Q7. We seek further clarification as to why the Authority has identified selected DG providers as private beneficiaries of avoiding transmission charges, when the Authority clearly deemed these as "economically inefficient investments" in its recent DGPP decision.

The Authority has not determined which existing DG avoids transmission costs and to what extent. The approach used to model indicative transmission charges should not be used to infer the Authority's position on which DG avoids transmission costs and which may therefore be eligible to receive ACOT payments.

Further, the Authority's recent DGPP decision did not determine whether particular investments in DG were efficient or inefficient. As noted in the paper, some generators, by operating at times of peak network demand, allow Transpower to reduce its grid costs. Other generators do not. However, the decision did not identify which DG fell into which category. As detailed above, the Authority will make a decision about which DG in each region will be entitled to receive ACOT payments after receiving advice from Transpower, in accordance with Schedule 6.4 of the Code.

We believe the Authority is now applying different criteria for the allocation of transmission costs in the TPM compared with the DGPP decision. There is also a conflict between the processes and methodology that Transpower will use to allocate transmission costs – using GXP load net of DG and DSM - and to determine the value of DG in avoiding transmission costs for transmission customers – using the Grid Reliability Standards.

As stated above, the method by which the residual charge is allocated to parties has no bearing on whether DG or demand response avoids transmission costs. Further, as stated above, it is the draft guidelines that set out the Authority's proposed treatment of DG with respect to the TPM, not the approach used for modelling indicative charges.

Q8. Please explain how the Authority reconciles these differences. For example, a new industrial customer might install co-generation which will reduce their transmission charges, while a new DG plant will have to negotiate with Transpower to identify any benefit from the DG in reducing transmission costs.

A clear focus of the DGPP decision was to ensure a level playing field.

The draft guidelines do not prescribe whether co-generation should reduce parties' residual charge allocations. The modelling is indicative only. The treatment of co-generation in the calculation of the residual charge is a matter for Transpower to consider, should the Authority confirm the draft guidelines.

We would also note that even after the DGPP decision, the DGPP arrangements may not ensure a level playing field. For example, the regulated price ceiling mandated in the DGPPs may provide distributed generators with an artificial competitive advantage over grid-connected generators and also over other technologies that could compete with distributed generation in providing various services. The Authority has stated in its Decisions and Reasons Paper on its Review of Distributed Generation Pricing Principles that it intends to revisit the DGPP arrangements and resolve this issue in a way that will promote efficiency and competitive neutrality between distributed generators, grid-connected generators and other technologies.

Q9. The Authority has adjusted the transmission charges for a network company based on information the network company provided about its own generation assets. A number of IEGA members own generation assets independently. Can the Authority please confirm that network companies with independently owned generation supplying their network are being treated the same in its analysis as network companies that own generation? This question applies equally for DSM as direct connects now benefit from their demand management activities – how do third party providers of DSM benefit?

As stated above, clause 4(d) of the draft guidelines provides for competitive neutrality between grid-connected generation, DG, and demand response, as far as is practicable. The matter of practicability is a matter for Transpower to consider.

However, to expand on the question of practicability, it may be necessary or efficient to apply thresholds. For example, if the residual allocator was gross AMD, should Transpower adjust for energy efficient lightbulbs so as to achieve competitive neutrality between energy efficient lightbulbs and highly measurable forms of demand response? These are matters for Transpower to consider.

We believe these are serious issues relating to the Authority's analysis and decision processes and would appreciate responses to our questions as soon as possible given that time is now of the essence for the TPM consultation process.

Thank you for your letter.