Submission to the Electricity Authority

Transmission Pricing Methodology (2nd Issues Paper) and Distributed Generation Pricing Principles

26th July 2016

Contents

1 Summary

Eastland Generation Limited ("Eastland") appreciates the opportunity to respond to the Consultation papers: Review of Distributed Generation Pricing Principles and Transmission Pricing Methodology: issues and proposal, published by the Electricity Authority ("Authority") on 17th May 2016.

Eastland also supports the submissions of the Electricity Networks Association and PWC on behalf of 18 Electricity Distribution Businesses.

Eastland does not agree with the Authority's proposal to remove the DGPP from the Code in its entirety. Eastland believes that the DGPP should be retained with appropriate changes to address the economic inefficiencies identified by the Authority.

Eastland Generation believes that it would be far more productive to address the issues that the EA has raised with the DGPP's by making the following changes to them:

- Improved alignment with the EA distribution pricing principals,
- Expansion of the parties covered by Part 6 of the Code to include all connected parties above a de-minimis of 1MW,
- Changes to the meaning of incremental cost of connection to separate as a different line item, the cost of connection that parties would pay as a result of their connection and the benefits that would be paid to them for services provided to the distributor, and
- Introduction of new Code provisions to give clarity that common costs would be borne by both Generation and Load to the extent they purchase electricity over distribution networks.

Further, the Authority should introduce a RCPD based LRMC charge as proposed in this submission.

The changes should be introduced with enough prescription to allow clarity of the intent of the expected outcomes while not being so prescriptive that there is only one approach or methodology that is available to distributors to follow. Doing this will provide a durable outcome.

2 Introduction

Eastland Generation Ltd is 100% owned by the Eastland Group which also incorporates Eastland Network Limited (a regulated electricity distribution provider) as another wholly owned subsidiary. Eastland Group is owned by the Eastland Community Trust with the Gisborne District Council as the capital beneficiary of the trust.

Eastland Generation owns and operates a number of electricity generation plants comprising a 9 MW geothermal power station sited in the Kawerau region, a 5MW hydro power plant near the township of Wairoa and 6 x 1MW diesel generators that are strategically placed throughout Eastland network to provide network support. Together these power stations generated 71 GWh of electricity during the year to 31 March 2016.

The generators embedded in Eastland Network are able to operate 'islanded' from grid supply, hence can provide an alternative to grid supplied electricity.

Eastland believes that changes to the TPM and DGPP have the opportunity to fundamentally improve the efficiency of the Electricity Market and provide enduring regulatory certainty to allow efficient investment across all aspects of the market. Eastland has in the past listened to the price signals from the current TPM and the DGPP and has invested to take commercial advantage of those price signals. Some of those investments will be impacted by the proposed changes, which brings into sharp focus for Eastland the necessity for regulatory durability as an outcome of the proposed changes.

Eastland Generation does not believe that the Authority has presented a compelling case for the removal of the Distributed Generation Pricing Principles ("DGPP") from the Code. The Cost Benefit Analysis ("CBA") for the DGPP's has a large number of unquantified assumptions that could easily make the cost benefit negative. There is significant uncertainty in the design elements of the proposed Transmission Pricing Methodology ("TPM") which could lead to large unexpected outcomes.

This submission will concentrate on the DGPP changes and only comments on the TPM to the extent that Eastland believes that there is a need for a LRMC charge within the TPM regulatory settings.

Eastland have prepared this submission in response to the Consultation Papers "Review of distributed generation pricing principles" and "Transmission pricing methodology: issues and proposal (Second issues paper)" dated 17 May 2016. If you have any questions regarding this submission please contact

Brent Stewart
General Manager – Network
Ph: (06) 869-0701, 021 760 034
PO Box 1048
Gisborne 4040
brent.stewart@Eastland.nz

3 Why do we have the DGPP's as a Regulatory Setting?

3.1 Purpose of the DGPP's

As the Authority is aware the DGPPs are in essence a default or bench mark connection agreement between distributors and distributed generators (DG). As such, unlike the Authority's voluntary distribution pricing principals they are binding on both parties if they cannot agree commercial terms on a connection contract.

The first question that needs to be asked is, why was it necessary to implement the regulations in 2007 i.e. why couldn't DG and distribution companies agree connection contracts on commercial terms?

This comes down to the hold out position that a monopoly can take when negotiating with a commercially driven entity. The hold out position has the ability to cause contracts to be one sided, with the majority of benefits falling to the monopoly. In that sense the DGPPs are no different to Transpower's bench mark connections contracts that the Electricity Commission developed[1]. All of the reasons that drive the need for the Transpower bench mark agreements also apply to the industry need for DGPP's.

3.2 Has that Purpose Changed?

Eastland is of the opinion that nothing has changed in the regulatory setting for the management of monopolies that would drive them to negotiate any different today than they have in the past. Therefore the need for bench mark connection contracts that balance the costs and benefits of connection is still as strong today as it has been in the past.

4 The Connection Issue

The EA has concerns that DG does not pay for the common costs of the network they connect to. Eastland provides an example below that draws a parallel between the cost recovery processes for grid connected generation and DG in this regard.

Commonality between Grid Connected and Distributed Generation Charges

[1] Other than the fact that the DGPP presently only deal with one type of connecting parties, DG.

If you separate the cost and benefits of the service provided by the distributor[2] and the connecting party then the incremental cost of connection for DG would cover the full costs that the distributor faces as the result of the DG connection to its network. In principal this is the same connection cost recovery as grid connected generation faces from the connection charge when connecting to Transpower's network. If a grid connected generator needs in addition to connection assets, augmentation of the transmission system, such as a new line or an upgraded line where they would be the sole beneficiaries then they pay for that investment as a connection charge. The Rangipo to Tangiwai circuit is an example of this where the line was needed by the connecting asset while the circuit is part of the interconnected transmission system. As a result Genesis Energy faces the full cost of the circuit as connection costs. If a DG connects to a network and the incremental cost to the network include upgrades in other parts of the network or new lines to be built past the point of connection then those costs should be passed onto the new connecting DG.

While the recovery of interconnected costs within the transmission system is still being debated under the TPM, Eastland notes that none of the approaches that are under consideration require a grid connected generator to pay interconnected charges based on its generation output or name plate rating. Grid connected Generators do pay the present interconnection charge when they consume electricity to provide local services to their site or when generators are providing reserves while running in synchronous condenser mode. Importantly, that interconnection charge is as a result of acting as a purchaser not as a generator.

Bringing that parallel of interconnected cost recovery to the DG environment then yes, DG should be required to pay for the common costs of the network to the extent that they cause them, not as a generator nor based on their generation output as those costs are recovered via the connection fee. It is DG's use of the network via it's consumption of electricity that should drive the recovery of common cost.

To take it to its simplest form, if we have a network with one consumer then the total cost of the network are borne by that party. If a DG connects and pays the full incremental cost of their connection and does not consume any electricity off the network, then the cost to the first consumer have not changed. They are still the only one consuming electricity on the network and therefore should continue to pay the full cost. If the DG actually only runs 50% of the time and consumes some electricity the other 50% of the time then they should rightly pay some proportion of the networks costs. Importantly that charge should be in proportion to the other consumers on the network i.e. if the DG was 1% of total annual volume traded on the network then they should only pay 1 % of the common cost of the network.

In reality we have many consumers on networks who all use different levels of electricity and charges tend to be built around bands or brackets of consumers depending on their individual levels of consumption. A DG's consumption of electricity should be treated in the same way. Find its level of consumption, match it to the appropriate network tariff and charge the DG when it consumes electricity.

For a charge to be service based the parties of the contract need to identify the services provided to each other, then value and pay each other appropriately for those services. This approach would allow service based charges to be created for the recovery of common cost from DG i.e. DG would pay for the consumption services they require from the network when they consume electricity, while the network would pay the DG for the generation services they provide to the network.

Considering the rather small amount of electricity that all DG would consume in a year in comparison with the total electricity traded over all networks Eastland concluded that the complete removal of the DGPP and all of the benefits that accrue from having bench mark agreements is a disproportionate response to the issue that the EA has raised.

5 The ACOT Issue

While Eastland acknowledges that the present level of price signal in ACOT payments is above the forecast LRMC of transmission and that this could potentially lead to inefficient investments in DG. If this is the real issue then the Authority should address that issue in its TPM and DGPP amendments rather than simply remove the DGPP's from the Code.

[2] As Eastland has suggested.

Eastland is strongly of the opinion that DG has had a presence and impact on the sizing of transmission investments meaning that transmission costs have been avoided. As a real world example, Eastland Network Ltd faced for many years the prospect of needing a new 110KV circuit from Tuai to Gisborne to meet forecasted and actual increases in the demand in the Gisborne area. Eastland Generation Ltd invested in DG to provide peak load reduction services to Eastland Network Ltd, thereby allowing them to avoid the need for transmission investment. The Long Run Marginal Cost (LRMC) of the DG was lower than the LRMC of transmission making this outcome an efficient investment for all consumers on Eastland Network Ltd's network.

Simply put without the 1000MW of DG that is connected to the distributed networks in New Zealand, Transpower's investments in the interconnected grid would have needed to be larger. These impacts are enduring not one shot i.e. the removal of DG from an interconnected region will impact on the sizing of the next transmission investment.

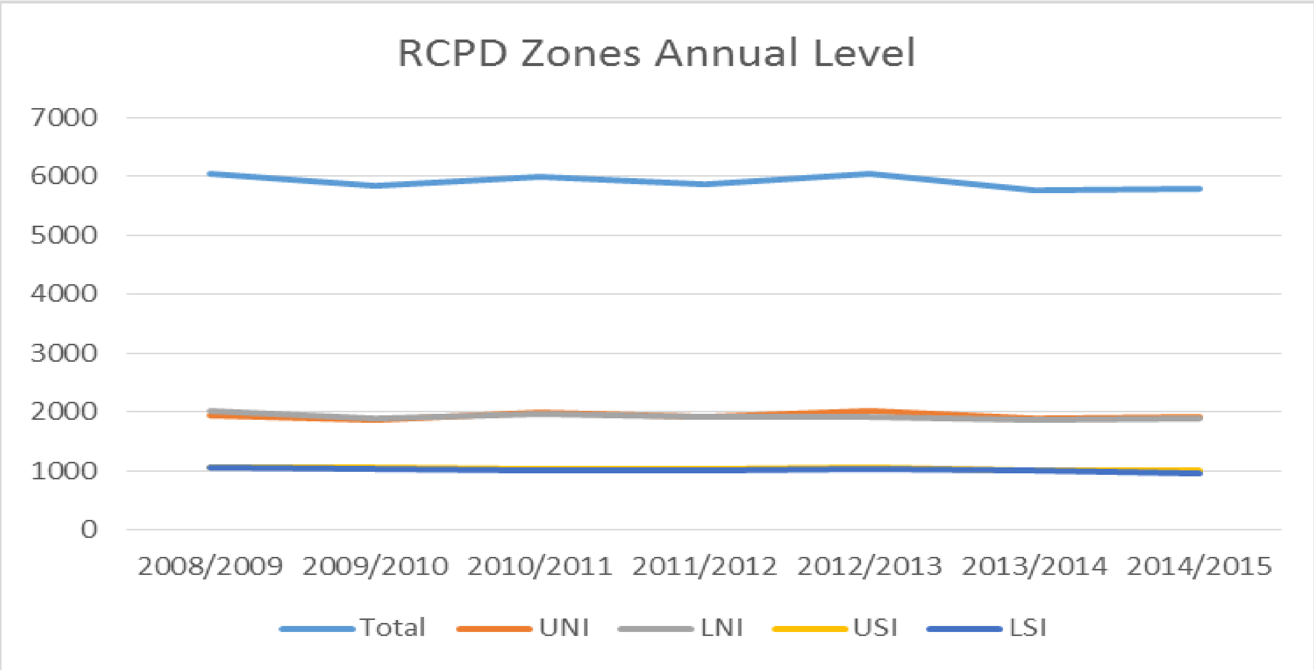
6 Removal of RCPD

Eastland believes that there is nothing wrong with an RCPD signal as it promotes the efficient use of the grid assets that are not connection assets and helps defer investment in the interconnected grid.

At the time of setting the present Electricity Commission developed TPM charges, the economic impact and benefits that were expected to flow from the use of RCPD rather than AMD to allocate the interconnection charges were well debated by the industry. The expected level of investment in alternatives and the price signals available to them were also well discussed by the industry. It is also clear when you look at the reducing level of demand in each RCPD zone over the time that the signal has been present, that RCPD has reduced load at peak times[3].

It is the level of price signal within the RCPD charge in recent years that has become distorted by the level of investment in the interconnected grid since 2004. Therefore it is very disappointing that the EA has not seen to address the issue of the size of the price signal and continued to promote a RCPD charge which would provide some level of regulatory durability from the price setting of current TPM to the proposed TPM

6.1 Graph 1 RCPD Zone Annual Demand[4]



[3] Graph 1 below
[4] Extracted from Transpower's document titled 2015 Year Specific Data with flow diagram.pdf

Doing away with the RCPD will have an impact on peak grid demands in different regions. While peaks are unlikely to reduce, it is unclear what the grid impacts (and costs) will be, which could lead to unexpected cost outcomes to the industry as a whole.

The other matter of concern with removing the current RCPD charge is whether nodal pricing is an adequate locational signal of grid congestion to the market, or whether RCPD does in fact have a regional peak signalling benefit and should be retained. To some extent this may also depend on how an AoB charge is implemented and how the whole market/transmission system evolves under a new TPM. This will likely remain a material uncertainty.

7 Use of a LRMC Charge

The use of a LRMC charge has been allowed for if Transpower believe it will:

- Promote the efficient use of grid assets that are not connection assets and help defer investment in the interconnected grid,
- Compliment or augment but not duplicate the price signals from nodal prices and other charges under the TPM.

Presently the RCPD charge is used to recover all of Transpower's revenues from the interconnected grid. Under the proposed TPM the AoB charge is the main element for collection of Transpower's revenue from the interconnected grid[5] with the residual collecting any shortfall. Therefore if a LRMC charge was introduced it would not be trying to recover all of the interconnected costs. It simply would be sending a price signal about the value of new investment. While its use would offset the residual charge, the residual charge would still ensure that Transpower's revenues were completely recovered. Therefore the need for accuracy of the LRMC price signal is somewhat diminished. It doesn't need to be perfect as long as it does not over signal and cause inefficient investment in DG or Demand response (DR) to be brought forward.

As the Authority has pointed out in the second issues paper[6] in a number of places, nodal prices by themselves cannot signal or recover the full cost of transmission investment and if they could even come close we would have a very different regulatory frame work for the TPM.

When transmission runs out of capacity existing generation cannot help as it will already be economically dispatched. New generation cannot capture the nodal pricing congestion signal as part of their investment revenue, because as soon as they connect the congestion pricing disappears. This means transmission cannot have a competitive alternative as neither DR nor DG can capture the full LRMC of transmission as revenue streams while providing a creditable and lower cost alternative to grid investment.

Load needs to be exposed to and DG[7] needs to be able to capture the full LRMC of new transmission to ensure the grid users value the investment in the present grid correctly. For these reasons Eastland Generation would support a LRMC charge being introduced to complete the pricing signals.

Eastland Generation, understands the EA concerns about over signalling the LRMC of TX and therefore the need to ensure that the combination of nodal spot prices and the LRMC charge are not greater in total than the forecast LRMC for the RCPD region. In order not to duplicate nodal prices signals they would need to be considered in the formulation of the charge.

Eastland Generation proposes that at a high level the formula could be:

LRMC charge by zone = Forecast LRMC[8] for the zone - average nodal prices at peak within the zone.

[5] Eastland Generation Ltd agrees with the introduction of the AoB charge.
[6] Section 5.75 and 5.83 of the second issues paper
[7] Or generation alternatives like Demand Response

If the measure of allocation of the charge was the MW demand at the top 100 RCPD periods then the average of the nodal prices would be calculated on those dates and trading periods.

To calculate the annual charge, Transpower needs to calculate the LRIC of the regulatory control period per RCPD zone and calculate the average price within the zone for the last years RCPD periods.

As the simplified LRIC approach to the calculation of LRMC prices produced a flat price it is ideal to use in combination with nodal prices. The effect of combining the two elements would be a LRMC charge which was:

Highest when the nodal prices did not reflect any congestion prices at peak times i.e. just after a Tx investment which has removed the congestion, and

Was lowest when nodal prices congestion price signal at peak times was highest i.e. just before the next increment in TX investment.

While this may seem a little counter intuitive i.e. the LRMC charges is lowest just before the requirement for new investment, it's the combination of nodal prices at peak and the LRMC charge that need to be looked at. This combination of the two prices would provide an enduring and consistent price signal about the LRMC of new investment in the interconnected grid.

Using the present RCPD zones, LRMC calculated via the LRIC[9] approach and the average peak nodal price by RCPD zone during the top 100 demand peaks in 2015, Eastland Generation has calculated the results in table 2 below.

7.1 Table 1 Impact of Simple LRMC charge

Region	LRMC RIC ($/MW)	AVG Nodal $ @ RCPD times	LRMC charge	RCPD Demand MW	Transpower revenue
UNI	$60,171	$110.27	$60,060	1904	$114,354,950
LNI	$38,745	$116.12	$38,629	1890	$73,008,036
USI	$27,090	$115.90	$26,974	966	$26,056,711
LSI	$71,200	$88.44	$71,111	968	$68,835,852
				Tot Recovered	$282,255,549

Like the EA's cost allocation information provided in the consultation pack, while these numbers are approximate, they are also illustrative of the level of recovery that could be achieved from a simple LRMC price signal. At this level of recovery the residual charge would be reduced to circa $218M or 22% of the total revenue requirements of Transpower. Which in Eastland Generation Ltd opinion is starting to approach what a reasonable person would call residual.

This level of charge is likely to:

- Not distort grid use;
- Not encourage inefficient investment in avoidance as even the most expensive charge at $71,200 is only 53% of OWG's estimated cost of Diesel at $132,447 which is their cheapest TX alternative;
- Reflect the combination of both nodal spot price at peak and LRMC costs to load of the next investment in the interconnected transmission grid within each RCPD zone.

This will promote efficient use of the grid assets that are not connection assets and help defer investment in the interconnected grid. While at the same time reducing the residual charge by circa $282m.

[8] Eastland Generation Ltd promotes the simple LRIC approach as outlined in the 6.23 and 6.24 of the Transmission pricing methodology review: LRMC charges working paper.

[9] The inputs to this calculation where taken from OWG's CBA input file

8 ACOT Payments

If Eastland proposed changes to separate the cost and benefits of DG connection as outlined in the front of this submission were followed and a LRMC signal was introduced then any cost reduction that a distributor received due to the connected DG should flow to the DG and the distributor should be able to pass that cost on.

If there is no avoided cost then no payment should be made.

9 Regulatory Durability

Both the TPM and the proposed changes to the DGPP are forward looking i.e. they set out a path for how DG will be treated in the future. Presently there is no process for Transpower to recognise the impact that DG has had on the sizing of recent[10] past transmission investments. The presence of DG within the interconnected regions where transmission investment has occurred has clearly been included in the design and sizing of those transmission investments by Transpower. If that is the case, how under the proposed changes is DG able to be rewarded for the reduction in transmission costs that they have and continue to provided?

It is Eastland's understanding that unless the Authority ask the Commerce Commission to consider a 52P determination, there is not a process within Transpower's Commerce Commission input methodology to allow them to recover costs other than their investment costs. This appears to preclude any grandfathering of the benefits of reduced transmission investment cost that DG has provided unless the Authority ask for a review. At the time of those investments DG received ACOT payments and there was no expectation within the industry that those payments would change. There was no driver for DG to contract directly with Transpower nor an incentive[11] for Transpower to contract with DG even if the regulatory framework allowed for such contracts to be put in place.

This effectively means that Transpower has captured that benefit as a reduction in its cost against its price path and therefore increased it profit at the determent of DG. Nor has the industry been exposed to the true cost of those transmission investments.

10 Appendix 1 - Authority Questions

	Question	Answer
Q1.	Do you consider that the proposed Code amendment described in section 4.1 is preferable to the status quo and the alternatives described in section 4.6? If not, please explain your preferred option(s) in terms consistent with the Authority's statutory objective.	No, please body of the submission

[10] Post 2004 investments

[11] If Transpower had contracted directly with a DG this would have been seen as double dipping i.e. they would of received a contracted payment form Transpower while also receiving ACOT payments from the distribution company they were connected to.

Q2.	Do you consider that the proposed Code amendment described in section 4.1 complies with section 32(1) of the Act, and with the Code amendment principles, and should therefore proceed?	No
Q3.	Do you have any comments on the drafting of the proposed Code amendment described in section 4.1? (The drafting is included in Appendix B.)	Eastland Generation Ltd does not believe that removing the DGPP from part 6 of the Code is the correct approach as outlined in the body of our submission.
Q4.	Do you consider that the proposed Code amendment should come into force at a single date, or should it be phased in?	If the code changes was to go ahead Eastland Generation Ltd believes that there should be a phased approach.
Q5.	Is the proposed phasing for the Code amendment appropriate? (The phasing is discussed in section 4.3.) If not, what alternative phasing or dates would you propose and why?	If the code changes was to go ahead Eastland Generation Ltd believes that the transition period would need to be longer to enable DG to contract effectively with Transpower
Q6.	If the proposal were to proceed, do you consider that there would be barriers that might prevent agreements being reached between Transpower and distributed generation owners to efficiently reduce or defer transmission network costs? If so, what are these barriers? Please consider both existing and proposed new distributed generation.	Monopoly hold out is of very real concern to Eastland Generation Ltd. We have no confidence that we would be able to come to commercial terms with Transpower.
Q7.	If the proposal were to proceed, do you consider that there would be barriers that might prevent agreements being reached between distributors and distributed generation owners to efficiently reduce or defer distribution network costs? If so, what are these barriers? Please consider both existing and proposed new distributed generation.	Without a fall back bench mark agreement yes Eastland Generation Ltd believes that negotiating ACOD could be problematic with some distributors.
Q8.	If the proposal were to proceed, do you consider that those distributors that were no longer able to recover the cost of making ACOT payments would cease making such payments?	Yes, clearly if distributors cannot recover cost from their customers they are unlikely to pay DG for the services they provide to them. They are not a charity.

End of document

This document is uncontrolled once downloaded or printed.

Printed: 8 August 2016

Eastland

Eastland Generation Ltd,
95 Commerce Street Whakatane 3120, New Zealand

Tel 07 308 2574 | Fax 06 867 8563 | info@Eastland.nz | Eastland.nz