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New Zealand

Manawa Energy Submission: Proposed ACOT Code change

Executive Summary

Manawa Energy (**Manawa**) supports the Electricity Authority (**Authority**) adopting a phased transition for the removal of Avoided Cost of Transmission (**ACOT**) payments.

The proposed removal of ACOT payments represents a fundamental change to the arrangements for renumerating distributed generation (**DG**) and will require a reliance of nodal prices and/or contractual arrangements, the effects of which are not yet fully understood.

Manawa's view is that the proposed Code change creates a material risk to reliability, particularly at the local GXP level. This view is supported by expert advice from The Lantau Group and Calderwood Advisory.

We have closely examined the tools the Authority considers can be used to manage this risk and are concerned that while each tool has its place, collectively these tools will fall short of the mark. This has led the Authority to under-estimate the potential reliability benefits of a transition for consumers. We think a phased transition over a longer period would best address these risks, but Option 2 is better than no transition.

Finally, we note the Authority has made a significant commitment to benefit-based pricing in its new TPM. It follows that it should encourage (not discourage) all forms of coalition that transmission counterparties – including distributors might wish to enter as alternatives to transmission service. This is essential for it achieving the broader reform objectives.

Introduction

Manawa Energy (**Manawa**) thanks the Electricity Authority (**Authority)** for the opportunity to submit on its September 2022 "Avoided Cost of Transmission (**ACOT**) – proposed TPM related amendments" consultation paper (**Consultation Paper**).

The Authority is consulting on a proposal to amend the default pricing principles in Schedule 6.4 of the Code to remove an obligation on each distributor to consider the extent to which eligible pre 2017 distributed generation (**DG)** lowers its transmission costs when setting DG's connection costs.

The Authority is also seeking feedback on its preference to make this Code change without any transitional arrangements for pre-2017 DG owners[1].

The Authority sees this Code change proposal as consequential on its earlier decision to adopt a new transmission pricing methodology (**TPM**) which, amongst other changes, removed the interconnection charge based on regional coincident peak demand (**RCPD**) usage.

Manawa's submission on this Code change proposal comprises this cover letter and expert reports from:

- The Lantau Group, titled Response to the Authority's Consultation Paper on ACOT; and
- Calderwood Advisory, titled Case Study – Kaimai Generation Grid Support,

which are attached as Appendix 1 and 2 respectively.

Manawa's interest in this proposal

Manawa is New Zealand's largest independent[2] electricity generator and developer, currently responsible for around five percent of Aotearoa New Zealand's existing generation capacity. We have a clear strategy to grow this further by building a diverse portfolio of development and further optimising our existing assets.

Manawa is also currently the largest owner of DG in New Zealand[3] and has been providing flexibility services to network businesses from our DG since the late 1990s.

The basis for payment for these flexibility services is set out in a variety of bilateral contracts with distributors. Most of these contracts predate the pricing principles in Schedule 6.4 of the Code. These contracts record the counterparties' longstanding agreement as to how the "benefits and burdens" of DG on particular networks will be allocated and paid for.

Manawa acknowledges the Authority's confirmation that it does not intend to reopen or override these relational contracts. We think our contracts represent an early manifestation of the type of coalition arrangement that benefit-based charging is designed to encourage. The main difference being that benefit-based charges only operates to moderate activity which triggers new investment whereas the RCPD based interconnection charge influenced both usage and investment decisions.

If benefit-based charging is to be successful, t the Authority must support distributors seeking to reduce their exposure to the costs of upgrading those parts of the grid that benefit them as well as generators seeking to invest to the same effect.

[1] There is currently ~975MW of DG with an installed capacity of >1MW that is potentially eligible for ACOT payments.
[2] By independent we mean without an integrated mass market retail business.
[3] With ~180 MW of eligible DG, based on installed capacity.

It follows these costs should be recoverable for price-quality regulated distributors.

Current Code provisions

The Consultation Paper correctly identifies that the Code requires distributors to pay DG the full value of any costs they avoid because of DG's operation in relation to the distribution network **(ACOD)** and, for eligible DG, transmission **(ACOT)**.

As outlined in previous submissions historically very little ACOD has been paid as DG has regarded the ACOT arrangements as a proxy for both ACOD and ACOT.

This issue is likely to be revisited with the proposed Code change. DG will no longer be as willing to provide cover without payment as it was in the past. This is relevant to the Authority's assessment of the overall benefits of its proposal.

Impact of new TPM on ACOT payments

Manawa agrees with the Authority that the removal of the interconnection charge also removes the benefits that DG previously provided distributors by operating to reduce the distributors' regional coincident peak demand.

It follows that payments for this operation no longer need to be made under the new TPM. Manawa also agrees with the Authority that the presence or absence of DG on a network is not relevant to the calculation of the residual charge as this is payable on a network's 'grossed up' or underlying demand.

However, we consider the presence or absence of DG is still relevant to transmission investment decisions including the allocation of costs of existing transmission assets subject to benefit-based charges. If the presence of DG in particular networks has led to a lower benefits allocation to distributors, and the parties have previously contracted to share that benefit, we do not see anything unorthodox in allowing those arrangements to continue.

Put simply, the presence of DG providing an alternative transmission service has meant the distributor has needed less grid services. It should be noted that these payments would not be of the same order of magnitude as the current ACOT payments as they are related to the benefits of particular investments not annual grid usage.

We think it would be a poor outcome for consumers if there were no incentives on distributors to seek to lower the costs of transmission investments. There should be no prohibition on sharing this benefit or in price-quality regulated distributors recovering the costs of this alternative transmission service.

Maintaining reliability in the new environment

As the energy transition accelerates it must be acknowledged that peak demand charging has suppressed network and generation investment and offtake for decades. These effects have been largely unseen by the market. The contribution of DG is particularly relevant at the local GXP level which is often overlooked by policymakers in favour of national assessments.

The removal of TPM usage charges creates uncertainty as to the level of demand that will now come forward and the embedded demand response that will drop out. Problematically this is occurring at a time when we are already in tight supply conditions.

Over the medium term, the Authority has advised it plans to investigate new arrangements for flexibility services which are technology neutral. We support this work as well as a number of other initiatives which are underway to improve supply conditions and demand side response.

However, while these new arrangements are being developed, and the associated new investments made, there is a short-term risk that the removal of the RCPD charge will exacerbate existing capacity issues. In particular, we understand that a number of distributors are no longer operating load control so as to avoid peak usage. In addition, we also confirm that Manawa has already changed the operation of some of our plant given the removal of the RCPD charge, so it no longer operates to assist distributors reduce their peak usage.

Consequentially it is not surprising that there are already signs of peak demand increasing at higher-than-expected levels. Transpower's data shows that there has been an upward trend in peak load over the last few years. The 10 highest system peak demands in the last decade have all occurred since mid-June 2021. In the first half of 2022 it noted that there were five days with peak loads higher than 6500MW and that it was seeing "the continued effects of load growth combined with the removal of the RCPD putting upward pressure on peak load values".[4]

Consultation on need for a transition arrangement for this proposal

Manawa understands the Authority considers that a combination of:

(a) the price signalling provided by high or volatile nodal prices;
(b) the prospect of service contracts with the grid owner (such as demand response and network support contracts);
(c) the possibility of introducing a new transitional congestion charge; and
(d) the tools available to the system operator (such as issuing various warning/shortfall notices and administrative load control)

should be sufficient to ensure the reliable supply of electricity over the medium term.

Consequently, the Authority does not favour an option to continue to pay DG an allowance based on previous RCPD charge allocations for a two-year transition period as an insurance against Transpower's ability to continue to meet the Grid Reliability standards (**GRS**) across its network.

Manawa urges caution on this element of the proposal for the following reasons:

Existing ACOT lists show the size of the contribution of DG

The range of DG including in the existing lists of DG eligible for ACOT payments show the extent of the DG that has been assessed as having the potential to maintain GRS. If this list was refreshed in the light of current demand/supply conditions, we expect that some of Manawa's DG which is currently not on the list {eg Wheo/Flaxy] would need to be added to the list.

Nodal pricing may not provide the desired price signals

The Authority's analysis appears to assume that nodal prices will rise to a level which adequately signals transmission congestion and that these prices will be sustained for a sufficient period to encourage the required DG output in the relevant region.

The Consultation Paper notes that "*if distributed generation is downstream of a congested part of the transmission network, it can access elevated prices for energy it produces at that time. This means*

[4] Source: System Operator analysis of peak demand, 26 June 2022 https://www.transpower.co.nz/sites/default/files/bulk-upload/documents/Market%20Operations%20-%20Weekly%20Market%20Movements%20-%2026%20June%202022.pdf

distributed generators can set a price that should ensure they recover their operating costs whenever they are required to alleviate a transmission constraint."[5]

The Consultation Paper does not examine how the new trading conduct rules impact on its assumption that elevated prices will sufficiently reward DG for operating at times of congestion. Our view is that these rules operate to restrict DG from pricing at levels which would enable DG to recover their operating costs in meeting transmission constraints. This is because of the high risk that any elevated prices would subsequently be assessed as being above those that would be offered in a competitive market.

This means that we are unlikely to see the high pricing needed to cover the costs for DG to operate at times of transmission congestion at local GXPs.

Network support contracts and demand response

We agree that network support contracts and demand response can be helpful in providing network alternatives where congestion is known in advance. The importance of having these contracts in the reliability eco-system is likely to grow over time.

However, the track record for these contracts suggests that there may be barriers for their deployment which the Authority should examine. The Consultation Paper acknowledges that "contracting for grid support from distributed generation is not a well-established, routine process"[6] and that "payments to generators (or other flexibility providers) as a substitute for distribution network investment is also uncommon"[7].

We agree with the Authority that this is likely to be the result of a combination of factors. These include issues of comparing alternative services, effectiveness of incentives, and other impediments including contract challenges and regulatory barriers.

In addition, we note that while network support contracts may be a useful tool for planned outage or upgrade work, they are unlikely to provide a workable solution where reliability is adversely affected by an unforeseen combination of factors – including weather related events, unexpected consumption changes and/or outages.

This is where insurance, or a reasonable safety margin, can be invaluable.

Transitional congestion charge has a problematic threshold

We do not believe the Authority can realistically rely on a transitional congestion charge as a mechanism to manage grid use. This is because the threshold for its deployment in the TPM Guideline sets the bar too high for the charge to serve any practical value. We refer the Authority to its previous correspondence with Transpower on this issue[8]. As far as we are aware nothing has changed.

System operator tools

As a result of these factors, there is likely to be increasing use of the system operator tools of "warning" and load shedding. Both are problematic. We already have a media primed to report on

[5] Page 9
[6] Page 14
[7] Page 38
[8] See Transpower's January 2021 TPM Development Checkpoint 1 submission: Transitional Congestion charge (sections 2 and 3)

system security at every forecast adverse weather event. This is not the environment to encourage the uptake of new electricity technologies.

We are also troubled by the notion that load shedding, rather than an insurance product, is considered an acceptable solution for addressing unexpected changes in demand or transmission/generation availability. The last 18 months has demonstrated there is little appetite for the lights going out.

Preferred transition

For these reasons the Code change should provide a transition option as we move from a TPM which has a peak or capacity charge as a core component to an environment where conduct-regulated nodal pricing is intended to be the sole signal to manage grid use.

As explained in previous submissions our preferred option would be a phased transition from the RCPD charge over a five-year time period. This would give time for the behavioural and market adjustments the Authority is seeking. However, Option 2 is preferable to no transition.

TLG Report

TLG question the Authority's assumptions that

- there is unlikely to be a change in the behaviour of DG that risks grid reliability as nodal prices can fulfil this role sufficiently in isolation;
- that other tools are sufficient to manage unexpected network congestion risks; and
- a transitional phase out of ACOT payments is not worth the cost.

Amongst other matters the TLG report notes that there is no guarantee that the wider ecosystem in which nodal prices sits is ready to support the removal of ACOT payments, that replacement arrangements could be problematic due to information and bargaining power asymmetries between parties, and that the Authority's alternative mechanisms will not deliver the reliable supply consumers seek.

This all suggests that a transition is needed to provide time to manage uncertainty and provide valuable information about behavioural changes and market needs.

Report from Calderwood Advisory

Calderwood Advisory have analysed the contribution that our power scheme at Kaimai provides to ensuring N-1 security. Their report indicates that in 2021 there were 474 periods when some Kaimai generation was required to maintain N-1 security.

Under the current TPM, Kaimai has operated in the high demand months to maximise generation at peaks. The Calderwood Advisory report queries how this operation will be secured under the new TPM.

Manawa observes it needs time (and ongoing commitment) for meaningful discussions with Transpower and/or PowerCo about how this generation can be secured under the new TPM.

We are not even sure how their regulatory regimes would accommodate the outcomes of such discussions and consider there is a risk that a network solution will be inefficiently brought forward.