Electricity Authority
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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.

# Response to the Authority's Consultation Paper on Avoided Cost of Transmission (ACOT)

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# 1. OVERVIEW

The Authority has invited views on its proposal to remove avoided costs of transmission (ACOT) payments with immediate effect from April 2023, i.e., without a transitional 'phase out' period. The Authority presents the option of a two-year phase out of ACOT payments, but reaches the view that an immediate removal of ACOT payments is preferable on the grounds that (as per Section 4.13 of the Authority's consultation paper):

- stopping ACOT payments is unlikely to change distributed generator (DG) availability or behaviour in a way that would worsen grid reliability, particularly given nodal prices will still encourage generation at times and locations of transmission network stress;
- networks have already been able to begin observing reaction to removal of the 2023/24 interconnection charge;
- phase out would cost distribution-connected consumers on the order of $22.5million over two years;
- Transpower can contract for grid support services, or use tools such as load control or demand response, if needed to manage reliability risks arising from network congestion; and
- in 2020, Transpower "concluded that the tools available to the system operator and grid owner are sufficient controls to mitigate short term elevated congestion risk arising from removal of RCPD" and opted not to propose a transitional congestion charge.

These arguments can be broadly summarised as: (i) there is unlikely to be a change in behaviour of distributed generation that risks grid reliability, as nodal prices can fulfil this role adequately in isolation; (ii) other tools are sufficient to manage any unexpected network congestion risks; and (iii) given the above, a transitional phase out of ACOT payments is not worth its additional cost.

We question the validity of all three of these core conclusions.

# 2. OUR VIEW

Our view is that the value of a transition has been fundamentally undervalued (and thus incorrectly dismissed):

- The removal of ACOT payments represents a fundamental reset in how distributed generation resources are remunerated, from a structure of regulated contractual payments under ACOT to the open market supply and demand dynamics of nodal pricing, the limited effects of which are assumed, not tested.
- Nodal prices are just one part of a much broader ecosystem that influences the entry, exit, usage and generation decisions of end users and DG resources, and there is no guarantee that this wider ecosystem is ready to support the removal of ACOT payments.

- ACOT payments have historically facilitated a default, regulated 'proxy' contractual arrangement between DG resources and the transmission provider, something that left to a free market may be sub-optimal due to the informational and bargaining power asymmetries between parties.
- It is not clear that the alternative mechanisms to ensure grid reliability, in absence of well-defined market contracts or other proven precedents, can yet provide sufficient assurance compared to a continued transitional reliance on ACOT payments.
- The energy transition only adds to the this uncertainty and makes the need for contractual instruments, mechanisms, and hedging strategies more pronounced.
- A transition is about providing time, in the presence of uncertainty (particularly given other concurrent regulatory and market reforms), to provide valuable information about how customers respond and to allow valuable mechanisms and responses to be tested and mature.
- It is wrong to characterise distributed generators as having known this would be coming and to have already had the time to learn and be ready to adapt and respond in an efficient manner, which depends in any event on multi-lateral rather than unilateral actions.

We explore these points in more detail in the sections which follow.

## 2.1. Limited Impact on Behaviour and Grid Reliability Is Assumed Not Tested

The near-term impact of removing ACOT payments would be substantially that of a value transfer from those currently receiving ACOT payments for services that were once considered valuable, to customers who then no longer would face charges that include recovery of those ACOT payments.

> *Certain pre-2017 distributed generators are currently eligible for payments from distributors for avoided costs of transmission (ACOT). ACOT payments, which are addressed in Part 6 of the Code, are a recoverable cost for distributors. In the year ended 31 March 2021, distributors paid approximately $35 million to distributed generators and recovered this amount from other distribution customers (and ultimately from electricity consumers).*[1]

The Authority acknowledges that the impact of removing ACOT payments may lead to decisions that would reduce the availability of potentially valuable supply resources. In extremis, demand might increase due to the associated removal of Regional Coincident Peak Demand (RCPD) charges and supply might decrease in some locations due to the elimination of ACOT payments. The uncertainty of these two effects together is a new factor that the market must digest in the near term.

1 Electricity Authority (2022) "Avoided Cost of Transmission (ACOT) – Proposed TPM-Related Amendments". Consultation Paper. Executive Summary, page i.

The Authority has provided no specific analysis of these effects but now seeks specific examples of possible supply-side exit by distributed generation resources whose ACOT payments would end to be brought forward for consideration. Absent these, the Authority appears inclined to adopt Option1, involving no transition, rather than Option 2, involving a modest 2-year transition in which ACOT payments are reduced first by 50%, then by 25%, and then to zero.

The Authority appears to implicitly judge that, given the value of lost load that has been adopted, it would be difficult for a combination of unexpected increased demand and reduced supply to cause sufficient lost value to offset the annual savings available from the removal of ACOT payments (which in 2021 totalled $35million). But this narrow focus is neither a wholly appropriate nor complete evaluation construct. Distributed generators that have been in the system for many years have been part of the grid planning environment for all those years as well. The impact that logically accords with ACOT payments is not the short-term impact on nodal prices but the longer-term impact on grid costs. This has not been considered.

Unfortunately, we suspect that immediately evident examples of supply-side exit will not be easy to identify or point to, in part due to this being new ground and in part due to the time stakeholders are likely to require to prudently parse the growing complexity of the market and regulatory environment. Given apparent climate and demand uncertainty, we must also consider risk and perception, as the purpose of transitions can be as much about managing these during vulnerable moments for changing markets and regulatory systems. If we are correct, then we may simply not know the effect on both supply and demand until things become more real. Much may ultimately depend on the readiness of other contractual instruments and processes, both of which appear still to be uncertain if not problematic at this point.

The Option 2 transition proposal would help avoid these issues and risks.

## 2.2. Immediate Exit Behaviour is Not the Right Focus Point

In the immediate term, the changes to the TPM are more likely to stifle inbound investment than to lead to a significant exit of in-place resources.

Decisions taken to enter a market are different from those to exit a market, as the financial thresholds associated with the corresponding optimal decision are different. You enter if you have access to sufficient value to meet your hurdle rate. You exit if doing so loses you less money than continuing to operate. The two standards, (one for entry; one for exit), being different, signal different behaviours and warrant different assessments of market circumstances. In the context of nodal prices, entry decisions depend on nodal prices being high enough, but also on whether they will stay high enough long enough after you have entered and, most probably, on whether you can yourself from a post-entry nodal price collapse through a contract or other mechanism (like ACOT).

The Authority allows that there could be some unexpected consequence from removing ACOT payments entirely, though the Authority believes[2] that the existing nodal pricing framework in the wholesale market will be adequate. Yet, as we shall come onto discuss, the purpose of ACOT payments is not the same as the purpose of nodal prices – ACOT payments are a long-term signal more akin to a contract that covers a wide range of services or sources of value. Nodal prices are the essence of a wholesale electricity spot market. They may spike and then the spike may be gone. The prospect of ACOT payments alters the bidding behaviour of distributed generation resources, increasing assurance of their availability to better align with what an equivalent amount of transmission capability would support.

The Option 2 transition proposal allows greater focus on these other more important transitional risks and concerns.

## 2.3. Uncertainty at a Time of Increasing Peak Demand

While there is inherent uncertainty of response, due to the complex mix of factors that will influence entry (investment), exit and generation decisions beyond the observed nodal prices (which we describe in more detail later), this is all taking place in the context of a system which has been experiencing increasing peak demand. Indeed, Transpower data shows that the 10 highest system peak demands in the last decade have all occurred since mid-June 2021. Transpower attributes this to the combination of load growth and RCPD removal (including through the reduced value and use of ripple control).

Adding uncertainty of distributed generation response to a system that is already seeing growing peak demand, the effects of RCPD charge removal and nodal price reform makes for a very unpredictable market environment that ultimately dictates nodal price formation. In turn, the ease with which distributed generators can extract a clear signal from these prices, with so many concurrent regulatory changes and market trends, and respond in a way that is efficient and expected is by no means clear. Evidence also speaks to a weak link between peak demand periods and high nodal prices, given the many other factors that influence the determination of spot prices.

2 As per Section 4.4 of the consultation paper, the Authority's confidence that the removal of ACOT payments will not heighten reliability risks is attributed in part to the argument that nodal prices provide a more efficient signal than ACOT payments for coordinating the operation of distributed generation. In some instances this may be true, but there has been little evident confirming analysis of the correlation between grid use and nodal prices, whether the correlation is sufficient and sufficiently predictable to be 'bankable' and whether there are any other concerns or factors that could either influence dampen nodal price outcomes (including the new trading conduct rules) or otherwise result in a classic 'missing money' situation quite commonly observed in other markets. We shall come onto discuss, but there are good reasons to believe that reliance on nodal pricing and market forces alone may not deliver the kind of efficient investment, generation and grid reliability outcomes as the Authority appears to anticipate.

With uncertainty of both: (i) how well network constraints are conveyed by spot prices; and (ii) how easily distributed generators can interpret and are willing to act upon spot price signals, it is difficult to conclude that "stopping ACOT payments is unlikely to change distributed generator availability or behaviour" without more detailed and nuanced assessment.

ACOT payments have and can continue to provide a more stable and credible decision tool for distributed generation, at least for some transitional period to allow these uncertainties more time to play out. Key to recognising the value of a transition in this context, is an understanding of the fundamental differences between ACOT and nodal pricing, and therefore the *incremental* value that ACOT provides. It is to this issue we now turn.

The Option 2 transition proposal mitigates risk associated with these uncertainties.

## 2.4. Nodal Pricing and ACOT Payments are Purposefully Different

Nodal prices have received a great deal of attention concerning their theoretical economic efficiency as a signal (which we have commented on at some length in previous submissions and do not go into again in detail here), but the challenge is not nodal prices per se but how they interact with everything else (and conversely).[3] Moreover, a market design that is *capable* of transmitting an accurate nodal price signal will not necessarily (be allowed to) transmit an efficient one. Among other things, the theory of an efficient nodal market depends on essentially uncapped nodal prices, free from intervention – two conditions that most wholesale electricity markets around the world fail to either meet or sustain.

New Zealand has recently taken quite significant and material steps to alter bidding behaviour in its energy only market. The new conduct provisions and associated material penalty (up to $2 million) have had an impact. As noted by the Authority:

> *The new trading conduct provisions came into effect on 30 June 2021. The new provisions require participants to ensure that their offers reflect the offers that would be made in a competitive market.*[4]

3 The Authority has placed high importance on the role of nodal prices. Nodal prices are mathematical results. Suppose they are implacably correct in a short-term sense, yet whether, which, and how stakeholders respond to them are what determine their efficacy in a long-term sense. ACOT payments and RCPD type charges have an inherent long-term orientation. They are opposites to nodal pricing in terms of their temporal orientation. Also, in their mathematical construction, ACOT payments are naturally less accurate in the short-term at the specific locational level but are (conceptually) intended to be reasonably accurate over time.

4 Electricity Authority "Post implementation review of the trading conduct provisions". Page 5.

> *[…] However, the overall picture presented by these indicators suggest the new trading conduct rule is having a positive impact on offer behaviour and prices. There continues to be an increase in the frequency of very low prices, price separation continues to be more pronounced, the percentage of high-priced offers has decreased since the WMR period and offers seem to be reflecting underlying conditions more closely.* [5]

The picture painted by the Authority suggests that the new conduct provisions are reducing the flow of value from the spot market to generation, which we suggest in turn will have an uncertain (but certainly not positive) impact on investment timing and resource adequacy. This is one of the quid pro quos observed when seeking to wring more and more market power out of a given system, as some tolerance for market power in an energy-only market is a practical solution to the 'missing money' problem that arises commonly when bidding behavior is suppressed.

The Authority supports the removal of ACOT payments on the grounds that the role they serve, in signalling grid congestion and remunerating those that relieve that congestion, can just as well be served by nodal pricing in isolation. If true, then it might imply a degree of double counting that could be wound back. However, the linkage between nodal pricing and grid support values is not necessarily highly correlated. And the availability of alternative contractual instruments or mechanisms is not yet well established. A transition would allow these other value-enhancing functions of ACOT to continue, while providing time to observe whether the *market* can deliver these same benefits in a more, or at least, equally efficient, and fair manner. Finally, the purpose of nodal pricing for congestion management and ACOT payments for reducing transmission investment costs is different as well.

Without the wildness or potentially extreme volatility of nodal prices (or the perceived risk of such), the incentive to enter longer-term contracts to manage the risk of nodal price exposure withers quickly. Without a contract, the bankability of new investment or the potential continuation and upgrade of existing resources naturally diminishes. The prospective timeliness of investment to meet accepted standards of adequacy and reliability is then undermined.

In this setting, modest compromises such as avoided costs of transmission or distribution (ACOT or ACOD) payments (and RCPD type approaches), capacity market mechanisms, and targeted powers of intervention can all play useful roles even if none are necessarily present in a theoretically pure energy-only market design. Nodal prices are one part of an entire ecosystem that ultimately determine how investors and operators respond to various market signals of potential opportunity or risk.

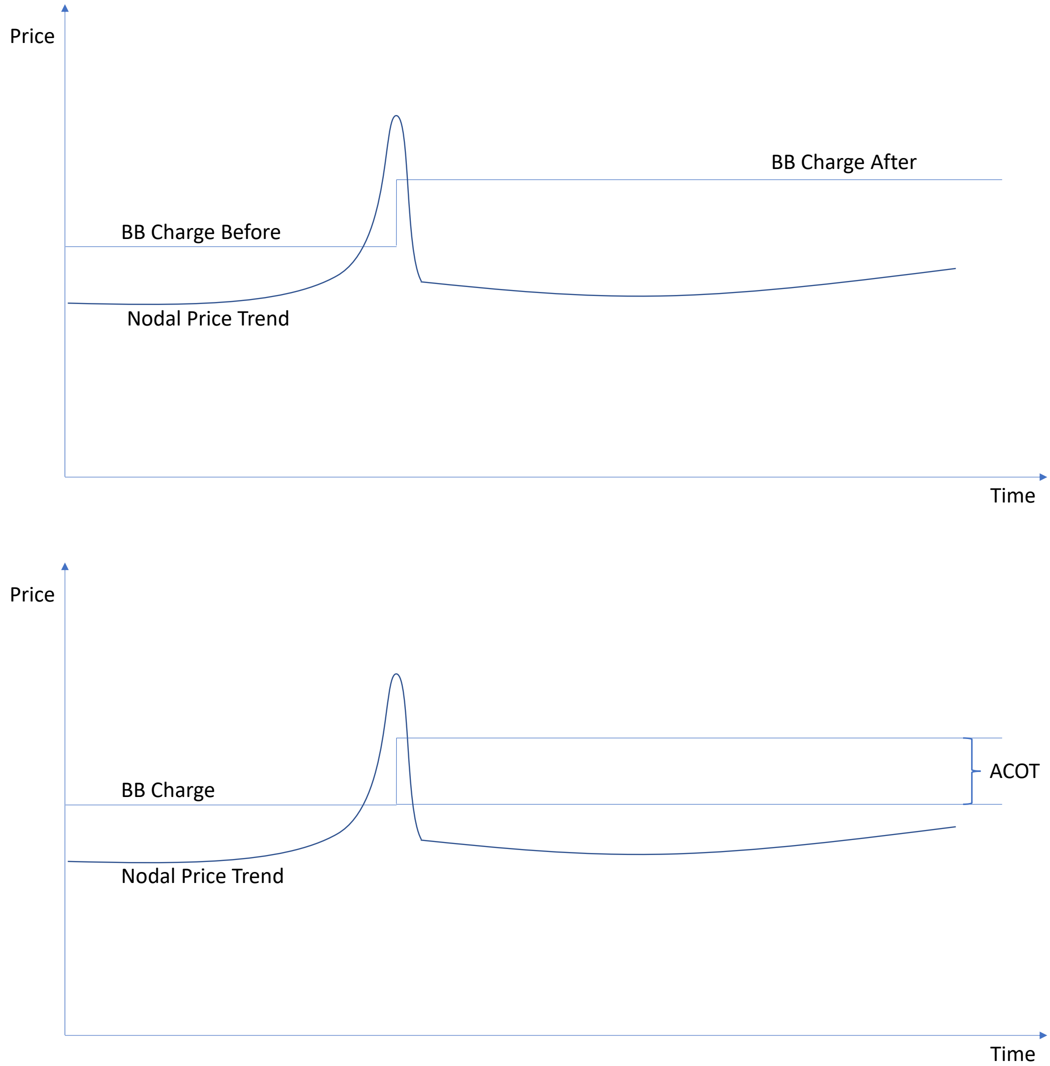
The Option 2 transition proposal provides time for observing and responding to evolving situations and for developing further the necessary instruments.

5 Electricity Authority "Post implementation review of the trading conduct provisions". Page 10.

## 2.5. ILLUSTRATING THE ROLE OF NODAL PRICES, ACOT AND GRID COST RECOVERY

The figures below illustrate the conceptual role that ACOT payments (or other forms of contracts or similar instruments) play as an alternative to higher grid investment and grid cost recovery. Anticipating or reacting to a potentially spiking nodal price or other emerging constraint, Transpower may consider transmission enhancement at a location. Under the new TPM a higher BB charge might then apply unless some other solution is found. Alternatively, an DG alternative might provide an equivalent solution (or is already providing it under the current ACOT regime). Whether on a forward-looking basis or on a backward looking counterfactual, the prospectively higher BB charge and the alternative ACOT are conceptually related. Reliance primarily on nodal prices going forward offers insufficient basis for Transpower (it requires BB charges) as well as a possible transmission alternative resource (it requires ACOT or some other BB charge equivalent style contract). Nodal prices or the future anticipated threat of their volatility and uncertainty can be useful, but they are by no means substitutes for an ACOT-type value stream.

**Figure 1: Illustrating Importance of ACOT or Similar**



The existence of nodal prices does not reduce the value nor contradict the purpose of a transition from ACOT to the fully implemented and realised new TPM.

The Option 2 transition proposal is not about nodal pricing but about everything else.

## 2.6. ACOT, Like RCPD, Is About Being Right On Average in the Long-Term

The Authority's TPM review highlighted that the grid has capacity to accommodate higher demand in many places, and so ACOT payments may not be providing any 'value' as they are not avoiding any costs. But this is an unavoidable aspect of ACOT as a framework, as such a framework works 'on average' over a longer period of time. ACOT is not intended conceptually or otherwise as a short-term signal or grid capacity spot market. The imperfections of ACOT are to be acknowledged as being intrinsic to the simplification of a great deal of complexity for the express purpose of reducing dependence on an otherwise even more complex and intricate (and potentially contentious) set of interactions that are subject to their own sources of inaccuracy and imprecision. ACOT (and RCPD) provides a framework that supports practical, even if not perfect, contractual proxies for generation (and demand-based) transmission alternatives.

Inefficiencies in the use of ACOT payments (and RCPD charges) arise from their specific set values, not their conceptual application or existence. The assumption when setting up an ACOT-based regime is that, over a reasonable period, on average if not in every specific instance, the costs avoided and the payments made will correlate and reasonably converge. There of course can be steps taken to recalibrate or even enhance the granular and locational accuracy of such charges. The overarching aim, however, is *not* a spot market for cost avoidance but something akin to a longer-term contractual signal.

In doing so, the value of ACOT payments is to increase the planning certainty of response by available resources. In an ACOT framework-based system, distributed generation resources (similar to demand-side resources responding to an RCPD type charge) can be (and are) incorporated into Transpower's grid planning and investment outlooks as they exist and can reasonably be assumed to behave in ways that align with the drivers of long-term grid investment requirements.

Whereas the nodal price framework incentivises short-term responses, it has a much less certain impact over the longer-term given the multitude of complex inter-dependencies and assumptions that are required to connect the dots from short-term spot market prices to long-term investment financing. The ACOT payment framework, however, is, by design, a longer-term framework. It is hard to conclude that nodal price signals are equally 'robust' in their bankable impact on investment as ACOT payments – a point that holds more weight given how the recent new trading conduct provisions introduction (discussed earlier) have had an apparent but as yet uncertain impact on spot market pricing and behaviours going forward.

In the limit, efforts to ensure that bidding conduct approach a perfect competition ideal tend to also introduce costly uncertainty around the definition and acceptable evidence of opportunity cost and the basis for evaluation and the cost of inefficient penalty avoidance behaviours. We observe that bidding behaviour constraints can lead to the subsequent realisation of new and material missing money problems as has been seen in other markets. Once the debate turns to encompass the problem of 'missing money,' the questions usually turn to what other forms of intervention are now needed. Everything connects to everything.

It is not clear what the Authority's full-on road map of future issues looks like, but by taking a more purist perspective and abolishing both RCPD and ACOT type payments, the road is unlikely to be very smooth. Eliminating ACOT payments leaves a hole in the market that nodal prices do not fill.

In our view, ACOT payments for distributed generation is a flip-side of RCPD-based benefits for curtailable loads. Whereas we imagine the Authority views both with equal disdain, we think that is a pity because each provides a balanced and pragmatic solution to what are a much more difficult and intricate set of challenges.

## 2.7. The Benefits are Still There

Distributed generation that sits within Transpower's planning outlook shapes that outlook and influences capital expenditure requirements over time. Consequently, there is a savings attributable to such assets which naturally varies with specific market conditions but is nonetheless real over time, on average.

Logically, a region with distributed generation that is then compared with itself without such distributed generation (as a counterfactual) could logically face a need for less additional transmission investment, all else equal. To the extent that any such investment would manifest under the new TPM as a higher benefits-based (BB) charge, the existence today of distributed generation assets reduces that BB charge from what it might otherwise be. And the potential existence in the future of distributed generation would need to be evaluated in the context of an efficient transmission alternative. Either way and in both ways, we are talking about a contractual opportunity and we are talking about the very strong likelihood that the value of such opportunity is not fully captured by contracting strictly or solely around nodal prices (either looking backwards in a counterfactual 'what-was-the-benefit?' sense or looking forward in a 'can-a-project-exposed-only-to-the-spot-market-get-long-term-financing?' context). ACOT plays this role.

If ACOT is not applicable anymore, what is an already existing distributed generator to do that is still providing these benefits in the form of a lower-than-the-counterfactual BB charge to a distributor's connected customers? The answer to this question will clearly take some time to analyse and assess.

Just because ACOT is removed, does not remove the effect of connected distributed generation, it just removes a path by which those assets can be compensated for value provided. Even if nodal prices are now lower and the grid in a region is capacious without the distributed generation, that does not mean that the distributed generation had no impact or a bad impact or that the BB charges would not otherwise be even higher but for existing distributed generation resources.

One can imagine that without ACOT payments there could easily be new disputes about compensation for counter-factually derived BB-linked benefits linked to Transpower's historical investment decisions. A transition provides valuable time for such issues to find practical and less contentious resolution.

## 2.8. Moving from ACOT to Market-Based Contractual Arrangements

The effectiveness and efficiency of the contracting environment matters materially to any assessment of whether the TPM will deliver the benefits expected of it. The arguments quickly become circular. Nodal pricing can provide efficient short-term signals, but only if the underlying investments are also timely and appropriate, which in turn depend on the investor perceiving nodal pricing accurately and without any distortion or bias. We are frankly unsure how to reconcile this conundrum within the new TPM and see this as a problematic complication that will keep surfacing as the TPM moves forward.

We have spoken already of how nodal pricing is just part of a wider ecosystem that shape the incentives and decisions that various markets participants make. Nodal pricing alone is just the first of a complex string of dependences and downstream assumptions about how everything works together. ACOT payments (and RCPD-based charges) may not be as 'efficient' in a technical or hypothesized sense, but they offer a practical way to minimise the risk of failure arising from a misfire across any of these other complex inter-dependencies.[6] Such an approach is consistent with the wider observed reality that most energy-only markets are walking, or have walked, back from accepting that level of volatility exposure and moving towards capacity markets or other forms of intervention for a mix of good, bad, and ugly reasons.

6 Put differently, just because nodal prices provide an efficient signal, that is not sufficient to conclude that what stakeholders can do to manage their exposure (direct or indirect) to those signals is equally efficient. This is where things with the new TPM will become murky and more complex and contentious. ACOT payments, however inefficient they may be in a given implementation or specification (and there has always been considerable scope to enhance the accuracy of ACOT payments), are a stand-in for reliance on contractual interactions for which we must now assume will take place in an efficient manner, voluntarily, under the new TPM. We made the point before that the shift to the new TPM involves leaps of faith. This is one.

If the contracting environment is to include the value of network cost optimisation or constraint management then the reliance on nodal prices alone as compared to nodal prices plus some form of avoided cost payment structure signifies a willingness to rely on negotiations between distributed generation investors and monopoly regulated distribution or transmission entities.  Whilst regulation may well intend to support 'as if' competitive behaviours in such negotiations with monopoly entities, it takes faith to believe the results will be materially better than using some form of avoided cost payment as a standing proxy contract.

Up to now, ACOT and ACOD payments have served as a proxy for the kind of contractual relationship between a generation or demand resource and loads in a network region for services (costs) that might otherwise take the form of network costs that must also be recovered.  This contractual proxy avoids the problems of the inherently asymmetrical positioning and negotiating power that exists between, on one hand, the stakeholders who compete to provide generation and demand resources and the monopoly grid entities to whom they are beholden when offering transmission alternatives. ACOT and ACOD avoided cost payments offer a pragmatic and efficient way to rebalance this negotiation posture.

Removing ACOT payments would otherwise represent a reset of the negotiation framework between resources that are currently receiving ACOT payments and any other insurance value that they may be providing. Whilst nodal prices would provide a backstop or fall-back 'market' within which some value may still be realised, other grid-related values that might be associated with the existence of distributed generation in those locations are automatically reset to zero, which means that any value other than nodal price related value must be re-negotiated.  This new negotiation context should be reviewed through the perspective of the balance of power.  The incentive of the grid owner to negotiate or pay for any value is only as strong as the regulatory regime is perfect.  It is one thing to negotiate something before you commit capital, it is another to negotiate your position after you have done so.

An asymmetry exists in any negotiation between an already existing distributed generation resource and a monopoly grid.  Similar concerns were raised in relation to the asymmetric buying power of distributors and how this could lead to overcharging distributed generation for connection services and under-remunerating them for avoided costs of distribution.  It was such arguments that led to the Authority not changing the Distributed Generation Principles (DGPP) back in 2016.

These issues will become increasingly pertinent and material as New Zealand moves (as other markets around the world are moving) to increase focus on the need for more flexibility and responsive supply and demand supported by contracts and mechanisms and signals that go beyond traditional ancillary service products and wholesale prices. Battery storage will be responding faster than any market will be dispatching or determining prices. Mixtures of technologies and events and circumstances will greatly increase the diversity of situations to which supply and demand must respond if security of supply is to be maintained. In many cases the grid will be a candidate to either secure, inform, or provide such services. The balance of power is a crucial concern in such instances and is, and will continue to be, a significant challenge for regulation.

In summary, we do not express as much concern about the use or reliance on nodal prices as an important signal as these have been a feature of the market since the start, but we do re-express doubt that the shift to near sole-reliance on nodal pricing plus voluntary contract negotiations will achieve materially better outcomes when considering small competing interests needing to negotiate with regulated monopolies acting as monopsony buyers of such services (should they choose to be interested at all). The pivot from ACOT to non-ACOT (and an inherently dynamic RCPD-charge to a fixed BB charge) is not a simple, stepwise path towards greater efficiency.

As we previously noted, BB charges are what they are as much because of all that happened up to this point, which includes the impact of distributed generation resources taken into account by Transpower in its planning and investment activities. Clearly if BB charges are lower than they would otherwise be, then an ACOT style payment is merited by the resources that contribute to those savings. The services cannot just suddenly be assumed to be provided without compensation.

The concerns around market-based contractual negotiations, and the potential exercise of monopsony power, adds to the compelling case for a transitional approach. It will help to provide important near-term information about how well market-based contractual arrangements will work in filling the ACOT void, as well as in the future as markets for flexibility services continue to grow.

The incentive for seeking efficient distributed generation or load-response-based solutions to problems that could also be addressed through grid investment will always be of significant regulatory concern. The new TPM relies on commercial interactions almost exclusively, which either means that nodal pricing must be 'enough' to support all valuable investment or operational outcomes or that the negotiation framework between demand and generation resources that stand as alternatives to transmission or distribution is sufficiently efficient and robust. The combination of asymmetric bargaining power and the possibility of structural 'disinterest' that a regulated entity might have given the absence of a genuine underlying incentive to act fully 'as if' a competitive entity, is a significant regulatory challenge.

We continue to warn that the presumptive efficiency gain of the new TPM is founded on discounting important trade-offs and downplaying clear complexities. The Option 2 transition provide more time to observe, measure and adjust as appropriate.

## 2.9. A Transition Provides Time to Learn About Behaviour

A common thread across several of the points we have raised so far, is that the removal of ACOT payments is a more fundamental reset in how distributed generation is incentivised and its benefits valued. It is a change in underlying mechanics, concurrent with many other regulatory and market reforms, that add to an overall uncertain picture. In this context, an allowance for more time and information has greater value.

When transitioning from one purposeful regime (as use of ACOT very clearly was) to another very different equally purposeful regime (as the new TPM may be), there is a natural desire to transition smoothly. To ensure that everything works as intended. To ensure that all assumptions vested in the new arrangements are as valid as they need to be. To avoid any unsettling disruptions that were not anticipated.

Whereas the Authority's concern appears to be that there is too much embedded generation due to overcompensation embedded in existing ACOT payments which historically have flowed from avoidance activity linked to avoidable RCPD charges (rather than costs), the risk at the other end of the spectrum is that of too little embedded generation and load control[7] due to under-compensation, increased risk exposure, and/or an ineffective or non-aligned contracting framework between competitive and regulated functions. Giving a little more time via a modest transition to watch and ensure that these important but so far largely presumed future interactions evolve prudently is where the value (of a transition) resides.

In comparing the combination of ACOT and nodal prices with nodal prices alone, the investor in embedded generation must determine whether to be exposed to nodal prices only or to seek some form of contract. Logically, an instance where a distributed generation resource would enter a location on the basis of an ACOT payment being available *may* still choose to enter the same location on the basis of nodal prices being sufficient. However, this entry decision depends on multiple other factors as well. In particular: are multi-year contracts available with which to hedge these risks? There is little information available today on which to judge how such decisions and market dynamics will unfold. A managed transition will reveal such information gradually, with the potential to identify problems or the lack thereof, that at this stage can only be hypothesised.

Relatedly, we take heart in the Authority's openness to consider a possible "future role for regulated price signals" for grid support in some instances. Its position on this speaks to the complexity of considerations around network pricing signals and therefore, in our view, the significant value of additional time, information and analysis that a transitional approach can provide – not only in the future, but also today:

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7 There is already evidence of such behaviour with Transpower noting in their 2022 Transmission Planning Report that: "Some of our customers have chosen to reduce their use of demand management during system peaks…"

> *While the Authority's proposed Code amendment, if adopted, would mean that ACOT payments do not continue, there may still be a future role for regulated price signals for grid support technologies. Ensuring that any such price signals would be efficient and competitively neutral is far from straightforward. As such, whether such an approach could have a limited role in future, and with appropriate safeguards, is best considered as part of longer-term work that examines matters such as network and technology neutrality, the effectiveness of network pricing signals for distributed generation, and the balance between Transpower's role and the role of distributors.*[8]

The degree of assurance of 'efficiency' will drive the degree of difficulty involved, yet it is good to be mindful that the overall system we are dealing with – especially in the context of a policy-led energy transition – must achieve directional accuracy whilst remaining pragmatic rather than dogmatic. An approach to setting and adjusting key parameters that is more inherently self-correcting than self-catalysing is a good practical objective.[9]

An Option 2 transition therefore offers a better and valuable window to observe the impact of changing ACOT payment levels on behaviours. Such observations would surely yield important insight to inform some of the queries embedded in the "far from straightforward" work that the Authority signals may be needed in the future. Moreover, its proposal for "longer-term work that examines… the effectiveness of network pricing signals for distributed generation" implicitly suggests that the efficiency of nodal pricing as a signal to manage grid reliability is somewhat less certain than the wider consultation paper appears to convey.

In summary, we consider that the ability to observe the reactions to the withdrawal of ACOT charges is a valuable source of market insight for an energy transition in which responsive behaviours will play an increasingly important role. Any opportunity to see how different contractual and pricing structures influence behaviours has value.

## 2.10. Alternative Mechanisms to Support Grid Reliability May Be Sufficient, But Are Also Second-Best

In the event that nodal pricing fails to deliver sufficient grid reliability, the Authority considers that the variety of other mechanisms available to the grid owner and system operator are sufficient to manage any residual risk. However, while it is one thing to argue that other mechanisms are *sufficient*, it is another to argue that these mechanisms are strictly preferable to any others (including ACOT payments).

The Authority specifically mentions drawing on the following mechanisms to ensure grid reliability:

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8 Electricity Authority (2022) "Avoided Cost of Transmission (ACOT) – Proposed TPM-Related Amendments". Consultation Paper. Executive Summary, page i.

9 The core problem is one of incentives. Getting monopoly entities to act like competitive ones is tantamount to seeking nirvana. The best most can hope for is growing self-enlightenment.

- Service contracts with the grid owner (for distributed generation and demand response).
- The possible introduction of a transitional congestion charge.
- The use of tools by the system operator, including shortfall warnings and administrative load control.

We have already spoken at some length in Section 2.8 to the issues that may arise with respect to establishing service contracts, including the monopsony buying power of the grid owner.  Meanwhile Transpower has already set out its position that transitional congestion charging is unworkable at present under the criteria defined by the Authority, and it seems difficult to justify the public and political fallout that would accompany an uptick in administrative load controls.  Therefore, while these measures may become sufficient, it quickly appears difficult to argue that they are *preferable* to a transitional ACOT payment that provides a stable and transparent signal to distributed generation. We have discussed at length in this paper the additional value that ACOT payments provide in this respect.  It would seem counterproductive to drop this signal (without some transition), when the alternatives are either uncertain (market-based contracts), as yet still unworkable (transitional congestion charges), or non-price-based (administrative load control).

## 2.11. The Energy Transition Adds Further Uncertainty

Given the challenges of decarbonisation, we are moving progressively into less-well-charted territory.  The prospect of setting up an electricity market linked to fundamentals of supply and demand but not also burdened with a complex, costly, urgent, yet uncertain energy transition was one type of challenge that was well met back in the 1990s.  But the new challenges of the energy transition invite much closer market and government interactions.  These may not be as well suited to traditional energy-only markets.  Investor response to nodal pricing given a degree of risk aversion and general uncertainty could easily lead to an increase in price levels and volatility – as these are the only ways in which markets overcome the higher investor hurdle rates that accompany greater uncertainty.

Energy markets are in flux given the challenges of the energy transition. Pure market mechanisms for decarbonisation are lacking. Whereas New Zealand's energy only market design is well-regarded, and rightly so, for its attention to fundamentals of supply and demand, the uncertainty introduced by decarbonisation in terms of investment and operational impacts is something altogether new. It's a heroic act of faith to assume that the existing energy only market design will work in all cases even as the approach to decarbonisation necessarily remains unclear and in flux, as it must be. Even when governments have the best currently available plan, even a plan that contemplates a 100% zero carbon end point, the eventual decarbonisation pathway still depends on many assumptions panning out in particular ways. Plans are made to guide, not to lock-in behaviours irrespective of what happens in the future. Plans will naturally evolve and the more tools and mechanisms that are available with which to respond to changing circumstances or awareness the better. In New Zealand as everywhere else, we still have a long and hard road to go with more changes to come than we have yet thought to consider.

The common evidence globally of this is on-going contemplation of capacity markets and security of supply mechanisms. In other markets we are seeing renewed focus on long-term PPAs and questions of how to gracefully transition out of old technologies as well as into new ones. These are active considerations that run counter to the more passively structured outcomes of market-based solutions.

Changes in the New Zealand market are clearly creating challenges for managing security of supply and these changes and challenges will continue and may increase. Like everywhere else that has a market-based foundation, some key issues are gaining increasing attention and focus

Key issues include:

- Electrification outlook driving up demand in the longer-term;
- RCPD roll-back increasing peak demand in the near-term;
- Climate variability which translates into an uncertain reset of probabilities of hydrological and temperature variability as future trends become more likely to be shaped by factors that are operating differently to what they were in the past;
- A growing proportion of the generation fleet being intermittent with less contribution to winter peak load periods;
- Greater challenges scheduling outages and maintenance due to fewer or shallower windows within which to accommodate lumpy or protracted planned outages (exposing system to greater cost of possible unplanned outages compared to similar periods in the past);
- Reduced availability of peaking generation capacity over some peak load periods (e.g., fast SFD start peakers and Rankine units);
- Less flexible thermal generation unable to respond to capacity shortfall situations closer to real-time (6-12 hours);

- Recent Security of Supply Annual Assessment (SOSA) indicating NI winter capacity margins at or below the security margins (630-780MW) for the next few years; and
- Relatively small addition to peaking capacity, e.g., 35MW WEL network battery expected by Winter 2023.

A recent grid security notice is another indication of the uncertain current environment.

TRANSPOWER GEN

**Grid Emergency Notice**

| | | | |
|---|---|---|---|
| **To:** | GEN NZ Participants | **From:** | The System Operator |
| **Sent:** | 07-oct-2022 07:15 | **Telephone:** | 0800 488 500 |
| **Ref:** | 4497985229 | **Email:** | NMData@transpower.co.nz |

**Revision of:**

| | |
|---|---|
| **Cause:** | Insufficient Generation offers North Island |
| **Region or GXP affected:** | North Island |
| **Starting:** | 07-oct-2022 07:15 |
| **Ending:** | 07-oct-2022 09:30 |

This is a North Island emergency. The System Operator advises there is a risk of insufficient generation and reserve offers to meet demand and provide N-1 security for a contingent event.

**Consequences on the power system:**

Reduced reserves for the CE risk may be dispatched, and/or the system operator may need to manage demand.

| **For the period above you are requested to:** | **At:** |
|---|---|
| Decrease demand by: using controllable load (that is not offered as instantaneous reserve) and increasing distributed generation | North Island |
| Increase energy offers | North Island |
| Increase instantaneous reserve offers | North Island |

| **Demand Allocations:** | **Total** |
|---|---|

**Consequences if insufficient responses by participants:**

If participant response across the North Island is insufficient, the system operator will manage demand to alleviate the Grid Emergency. The system operator may instruct the grid owner to disconnect feeders without further notice to connected parties.

System operator will manage demand to restore power system security.

For more information contact the Security Coordinator on 0800 488 500

This notice is issued in accordance with Technical Code B - Emergencies, Schedule 8.3, Part 8

There are extraordinary stresses and changes on-going in the market at this time. A transition is prudent if only to provide a degree of freedom to enhance the system's capability to manage such uncertain and complex interactions.

## 2.12. Has There Been Enough Advanced Notice?

The Authority suggests that there is no need for a transition as this intended change has been signalled for quite some time. Yet, we must disagree given the contentious history of the TPM debate. It would indeed be well-signalled if one holds the view that the new TPM was the inevitable, widely accepted, fait accompli achieved through unyielding efforts of the Authority without material regard to other stakeholder views. But that would invalidate the openness of the consultations over the past several years and is surely not the message the Authority intends to convey.

Whilst true that the Authority clearly signalled that an important area of historical regulatory canon was to be fundamentally reconsidered, the very novelty and 'at the vanguard' nature of the new TPM, the fact that Transpower and many others argued against vast swaths of it, that the CBA was so hotly contested, and so on, all suggest that no reasonable transition could possibly be argued to have commenced before the decision was finally released. Key fundamental shifts in the Authority's thinking over the course of the TPM review epitomise this. In 2019, for example, the Authority was of the view that locational marginal pricing (LMP) in New Zealand is sufficient for managing congestion and grid use, but four years prior to this had claimed that "reliance on nodal pricing is insufficient to promote efficient transmission investment".[10]

As such, all that existed before the ultimate TPM decision was mounting regulatory uncertainty. Now, going forward, that general regulatory uncertainty has been replaced by a new set of uncertainties – those related to how exactly the new TPM will actually work and what impact it will have on stakeholder interactions.

We suggest a different perspective. Rather than consider that the change has been well signalled, it is more accurate to say that a certain material type of regulatory uncertainty has been resolved and a new type of regulatory and industry uncertainty is now upon us. This is neither intended to be good or bad – it is just a factual assessment of what such a major change like the new TPM means in a complex, multi-stakeholder, market setting. Accordingly, Option 2 is the only option that provides stakeholders with an opportunity to adjust and observe.

## 2.13. Investor Confidence

Alongside the potential impacts on grid reliability, the Authority posed the other potential benefit of a transitional approach would be to avoid the dent to investor confidence that a sudden termination of cashflows may cause. However, it dismisses this line of argument on the grounds that the likely termination of ACOT payments have been signalled for many years, and that since the Authority's 2016 decision, distributed generators have benefited from a further six years of ACOT payments.

10 Electricity Authority, *Transmission Pricing Review, TPM options, Working paper,* 16 June 2015, p.53.

We do not think that such factors are relevant to a judgement of investor confidence. As set out above, it is hard to characterise the changes as a "likely outcome" when the TPM was going through such a fundamental rethink over an extended period, and with divisive mix of views across major stakeholders. Even then, the extent of forewarning and expectedness are only part of the mix of factors shaping investor confidence. The sheer materiality of any change in direction is another. The discontinuation of what would likely have been considered an assured and relatively stable regulated revenue stream at the time of investment is such a change. Even if behaviours are not materially affected ex post, it does not mean that investor confidence has not been negatively affected. As we have already described, entry and exit decisions are made on different sets of information, so a decision not to exit under this future framework is not synonymous with a decision that the same distributed generator would enter under those same future market conditions. Value and investor returns can be damaged, without necessarily resulting in any behavioural change in the short-term. But perceptions of risk and required premia may ultimately readjust.

# 3. SUMMARY

We recommend Option 2, a transitional ACOT arrangement for all the reasons suggested. We are not persuaded by the casual cost benefit assessment provided by the Authority and consider that wider and more important objectives are best met with the time afforded by Option 2.

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# CASE STUDY – KAIMAI GENERATION GRID SUPPORT

# REPORT PREPARED FOR MANAWA ENERGY

Final – 20 October 2022

# 1 Scope

Manawa Energy **(Manawa)** has engaged Calderwood Advisory to provide advice in relation to grid support provided by the Kaimai hydroelectric power scheme **(KMI)** owned Manawa. Traditionally grid support has been compensated by way of avoided cost of transmission **(ACOT)** payments under the existing Transmission Pricing Methodology **(TPM)**.

This report describes the impacts of the removal of the RCPD signal and associated ACOT payments may have on the operation of KMI if the preferred solution proposed by the Electricity Authority **(the Authority)** is adopted.

# 2 Authority's preferred option

The Authority's preferred option is to cease all ACOT payments to eligible generators from 1 April 2023 when the new TPM comes into effect. In the absence of any other commercial arrangement with Transpower there is no incentive other than responding to spot prices for Manawa to operate KMI to support N-1 security into Tauranga Substation **(TGA)**.

Chapter 4 of the consultation paper refers to a 'phase out' option where the ACOT payments are ramped down over two years to allow alternative commercial arrangements for grid support to be developed. The remainder of this report demonstrates the critical support that KMI gives to the grid and the increasing reliance on generation at local peak demand periods to support security.

# 3 Regulatory Framework

Transpower is jointly regulated by the Commerce Commission **(CC)** and the Authority.

Part 12 of the Electricity Industry Participation Code 2010 **(the Code)** requires the EA to set grid reliability standards **(GRS)**. The present GRS defines the 110 kV lines connecting to TGA as core grid and therefore must meet N-1 security.

The CC's grid Investment test **(GIT)** allows Transpower to invest to relieve any constraints with a solution that has the highest **expected net electricity market benefit**. This may be negative when the investment is needed to satisfy the deterministic limb of the GRS.

# 4 Breach of GRS

It does appear from the latest Transmission Planning Report[1] **(TPR)** published by Transpower in September 2022 that for the lines into TGA the GRS is not met.

# 5 Reliance on Kaimai Generation

KMI is relied on not just for relief of constraints into TGA, but also into the wider region.

The following extracts from the TPR indicates the need to constrain on KMI for an outage of the Kaitemako interconnecting transformers, or the 110 kV transmission lines.

The chart in Box 2 shows that even now transmission capacity is reliant on KMI generation.

[1] https://www.transpower.co.nz/sites/default/files/publications/resources/2022%20Transmission%20Planning%20Report.pdf

### 10.4.2 Kaitimako 220/110 kV interconnection and Okere–Te Matai transmission capacity

#### Issue

The main supply for the Western Bay of Plenty 110 kV regional grid is via two interconnecting transformers at Kaitimako, with support from the 110 kV Owhata–Tarukenga–Te Matai circuit.

The two Kaitimako 220/110 kV transformers provide:

- total nominal installed capacity of 300 MVA
- n-1 capacity of 223/225 MVA (summer/winter).

The following issues were identified:

- from winter 2022, a Kaitimako interconnecting transformer outage may overload the Okere–Te Matai section of the Owhata–Tarukenga–Te Matai 110 kV circuit[151]
- from around winter 2024 or 2025, a Kaitimako interconnecting transformer outage may overload the other transformer
- from around winter 2026 or 2027, both Kaitimako interconnecting transformers exceed their nominal rating pre-contingency.

#### What next?

In the short term, the overloads can be managed operationally post-contingency, by increasing Kaimai generation and opening the Kaitimako–Te Matai circuit. These operational measures are suitable for only a few years, until even full Kaimai generation becomes insufficient to remove the overload and opening the Kaitimako–Te Matai circuit begins to cause low voltages at Te Matai and overloading on the Tarukenga–Te Matai circuit (see section 10.4.6).

Selecting the best solution to address these overloading issues is part of our Western Bay of Plenty grid enhancement strategy which is being developed in collaboration with Powerco. Possible options include a third 220/110 kV interconnecting transformer (and a third 220 kV bus section) at Kaitimako or transferring load from the 110 kV system to a new 220 kV grid exit point.

#### Base E&D capex investments

| | |
|---|---|
| **Project name:** | Kaitimako interconnection capacity |
| **Project description:** | Install a third 220/110 kV transformer and a third 220 kV bus section at Kaitimako |
| **Project's state of completion:** | Possible |
| **OAA level completed:** | None |
| **Grid need date:** | 2026 |
| **Indicative cost [$ million]:** | 15 |
| **Reliability or Economic investment?** | Reliability (Grid Reliability Report) |

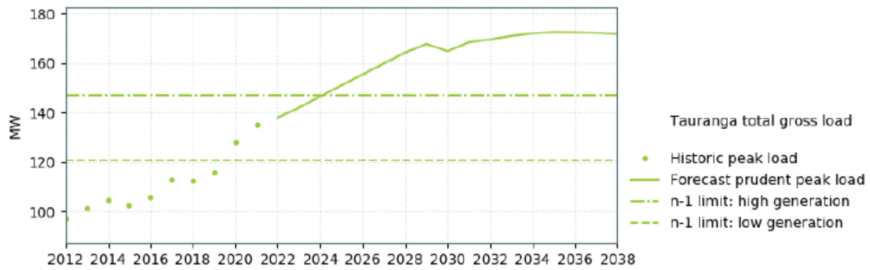
*Box 1 - Kaitemako Constraint*

The Kaimai hydro generation is connected within Powerco's distribution network at Tauranga.

Since 2020, with low generation at Kaimai, the peak load has exceeded the n-1 capacity of the two circuits connected at Tauranga (see Figure 10-5). The frequency and duration of the overload is very sensitive to the output of the Kaimai generation. From winter 2025, dispatching the Kaimai generation at its maximum output will not be enough to keep the Tauranga peak load below the Kaitimako–Tauranga n-1 transmission capacity.

Powerco has informed us that it expects the load growth at Tauranga may occur earlier and be higher than our forecast shown in Figure 10-5. A large part of the forecast load increase at the Kaitimako 33 kV grid exit point may instead be supplied from the Tauranga 33 kV grid exit point (if this is a more practical and lower cost development of the transmission and distribution networks).

Figure 10-5: Kaitimako–Tauranga transmission capacity for low (14 MW) and high (42 MW) Kaimai generation levels




*Note: Any difference in the supply capacity on the graph (in MW) and the asset rating (in MVA) is due to load power factor and impedance.*

*Box 2 - 110 kV line constraint*

The constraint has bound infrequently up to now[2]. This is because KMI schedules its daily generation during peak periods to ensure it is operating at close to maximum output for RCPD peak periods, which tend to correlate with local peak demand periods. KMI offers it generation at $0/MWh due to the need to manage the hydrological constraints of the cascade generation stations with storage at the two lower stations.

[2] Based on reviewing reconciled data with net demand above 100 MW.

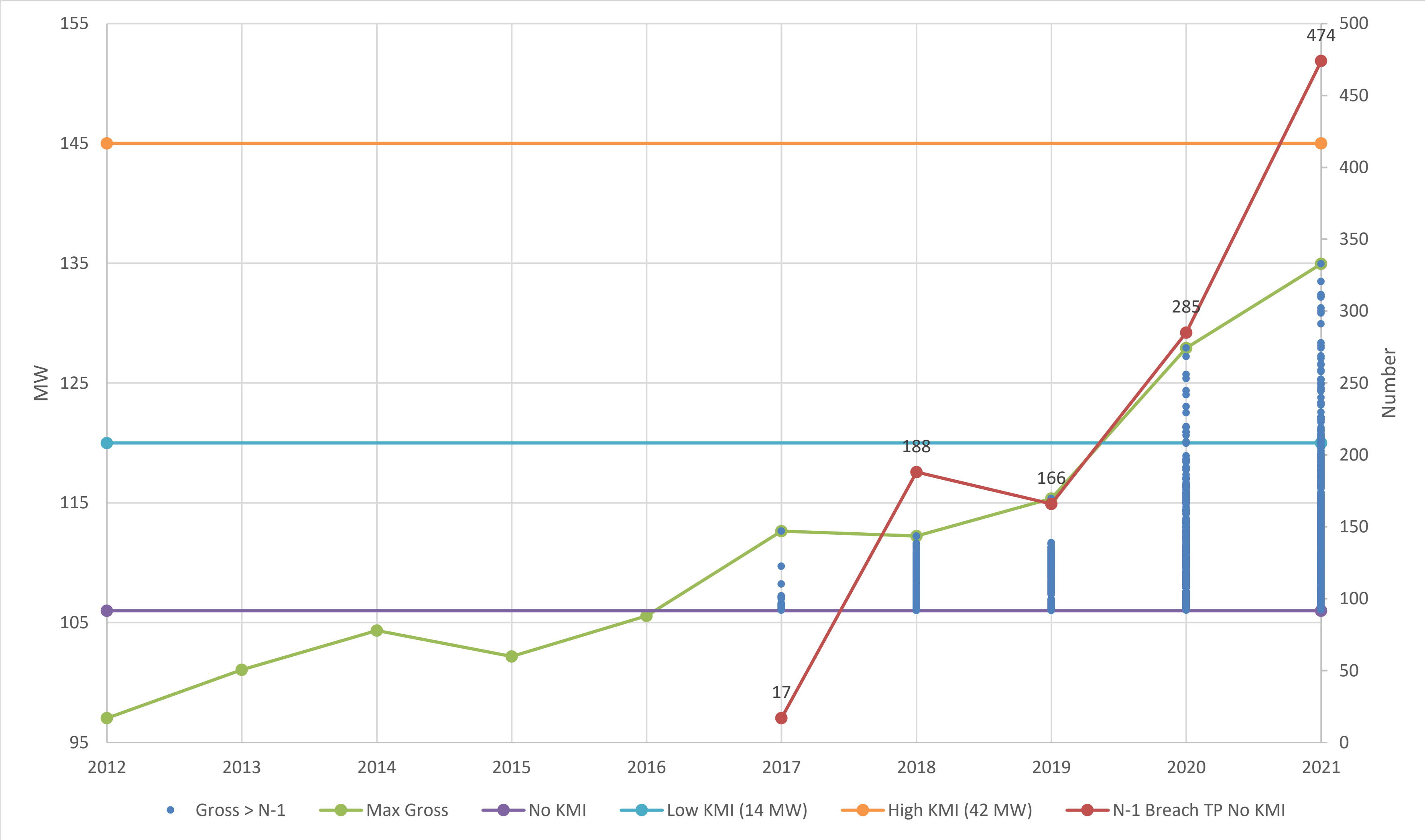



*Figure 1 - KMI N-1 Support*

Figure 1 attempts to explain the contribution that KMI gives to support security at TGA. This chart is similar to the one in Transpower's TPR but adds some extra information.

Based on the chart in Box 2, I have estimated the gross TRG demand levels that trigger a breach of N-1 security at 14MW and 42MW KMI generation as 120MW and 145MW respectively. I have estimated the level at which N-1 is breached at 106MW with no KMI generation.

As well as single highest peak each year between 2012 and 2021 I have also plotted with a blue dot each half hour trading period that exceeded N-1 security with no KMI generation. This indicates the essential backup that KMI provides. Also on the chart is a line with a count of the number of occurrences in each year. For 2021 this was 474. That means that in 2021 there were 474 trading periods where some KMI generation was required to maintain N-1 security.

# 6 The problem going forward

The question is how Transpower ensures that KMI is generating when the supply into TGA is not meeting N-1 security.

Up until now KMI has been compensated for supporting security at TGA via ACOT payments. If these are not available from 1 April 2023, or from some later date then, in the absence of a grid support contract with Transpower, there is no incentive for KMI to operate at peak periods, other than to maximise spot revenue. Given that KMI offers its generation at $0/MWh volumes provided for grid support via ACOT there will be minimal constraint payments when it is needed to relieve a constraint. Altering offer strategies may breach the trading conduct provisions under the code.

I understand Transpower has advised Manawa that it believes the spot market is the solution so that KMI receives constraint payments. As a consequence, Transpower does not see they need to enter into a grid support contract. Transpower may be reluctant to contract for grid support in the case of KMI because of its own regulatory regime.

Box 3 is an extract from a Transpower document describing the design features of grid support contracts.[3] . An arrangement with Kaimai would not be considered as a Major Capex Proposal or included in Transpower's opex proposal.

**4.2 Including GSC costs in Transpower's regulated revenue**

Transpower as a commercial company will not offer GSCs unless it can recover the costs, which requires that they are included in its regulated revenue. There are two approval avenues from the Commerce Commission:

- Include GSCs in a Major Capex Proposal[11,12]
- Include GSCs as part of Transpower's opex proposal at the start of the regulatory period (five year).

For an MCP, the CapexIM defines non-transmission solution as costs incurred by Transpower in relation to one or more of the following things:

- Electricity generation
- Energy efficiency
- Demand-side management
- Local network augmentation
- Improvement to the systems and processes of the System Operator
- The provision of ancillary services[13]

Transpower recovers its regulated revenue from designated transmission customers in accordance with the transmission pricing methodology (TPM)[14].

*Box 3 - Grid Support Contracts*

[3] https://www.transpower.co.nz/sites/default/files/plain-page/attachments/design-features-for-grid-support-contracts_0.pdf

Thus, there does not seem to be a way for Manawa to be compensated for providing support services from KMI. This suggests there is a strong case for a transitionary period while alternative grid support arrangements can be put in place.

Guidance from the Authority on how it expects grid support arrangements to be remunerated would be welcome.