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Submissions
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CONSULTATION PAPER - TRANSMISSION PRICING REVIEW

Network Waitaki welcomes the opportunity to comment on the 2019 Transmission Pricing Methodology (TPM) issues paper.

We appreciate that the Authority has highlighted issues with the current TPM and has worked for many years to find a durable and workable alternative without success and is eager to conclude this work, however we have significant concerns that what has been proposed in the current consultation paper does not (in our view) achieve the outcomes the Authority is seeking, nor does it provide a durable and robust methodology for allocation of transmission costs.

More specifically, what has been proposed in the consultation paper makes simplified assumptions on a number of crucial inputs, it under values the importance of peak demand signalling, and has an over-reliance on market forces to determine prices which will in turn manage the demand and utilisation of the grid. From a theoretical perspective this may appear satisfactory, however in practice this is unlikely to be realised.

In the case of Network Waitaki, the proposal will be extremely disadvantageous to our consumers, and the economy of the North Otago region, as transmission costs are modelled to increase by 55% with no increase in service level. The consequence of this is an additional $1.6 million leaving the local economy for no additional benefit.

The significant increase in cost arising from this proposal for the use of the transmission grid does not reflect our unique circumstances, including our load profile and timing of peak demand and the existing transmission constraint which restricts growth in our region. The excessive cost to use the whole transmission grid when we have at least 865MW of large-scale generation located within our network area means we have to seriously consider alternatives to the use of the Transpower grid should the pricing proposal produce undesirable or inefficient outcomes for us.

The biggest impact for Network Waitaki will be the move to Gross Anytime Maximum Demand (AMD) based residual charges that will lead to a significant increase in Network Waitaki's annual transmission costs.

The main reason why this has such an impact on us is that the current interconnection charge is based on Network Waitaki's contribution to the regional coincident peak demand (RCPD) periods which, in our region (the Lower South Island – 'LSI'), occur primarily during winter – whereas the growth in irrigation throughout our network footprint means that our demand peaks in summer. By moving to an AMD based charge, this does not recognise or value the benefit of Network Waitaki not only having demand out of RCPD periods, but completely out

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of season with the wider region. This allows for increased utilisation of the grid at times which require no further investment or increase the operating costs of the grid.

Effectively, this change penalises Network Waitaki for using the grid more efficiently.

In addition, our concerns relate to:

- The proposed benefit-based charge made up of seven major historical investments of which five are in the North Island with the allocation of cost disproportionately allocated to South Island consumers. In addition, three qualifying investments have been excluded to the detriment of South Island consumers despite the benefits largely being attributable to North Island consumers;
- Contribution to the 3.5% cap with cross-subsidies to support energy-intensive industry customers;
- Pockets of consumers will pay significantly more while the proposal claims "significant benefits to consumers compared to the current TPM";
- No consideration of pre-existing contractual arrangements resulting in a probable over-statement of gross AMD;
- Inconsistencies between the proposed Transmission pricing methodology and Distribution pricing principles promoted by the Authority;
- The difference in Transpower service levels between core and non-core grid that together with this TPM proposal makes bypassing the grid a potential option for Network Waitaki;
- Load control under the proposal will depend on the ability to obtain signals from nodal pricing, which an Electricity Distributor does not have easy access to, compared with peak demand information;
- The incorrect assumption that Electricity Distributors have spare capacity on their networks; and
- Specific modelling issues as explained during the modelling workshop on 10th September 2019.

We elaborate on the concerns summarised above in the sections below.

We would welcome the opportunity to further discuss our concerns and invite the Authority to North Otago to explain the benefits of this proposal to our consumers and regional stakeholders who may find it challenging to see how this proposal provides benefits to them.

For any questions or clarifications please contact Cornel van Basten, our Regulatory and Network Services Manager on cornelb@networkwaitaki.co.nz.

Yours Sincerely

Geoff Douch

Chief Executive

NETWORK WAITAKI COMMENTS ON THE TPM CONSULTATION PAPER

The following sections elaborate on the concerns referred to in the cover letter and is structured as follows:

1 RESIDUAL CHARGE

The TPM proposal has as its main approach the idea of benefit-based allocation of costs, where those who benefit from specific grid investments would pay for them. The new charges replace the current RCPD and HVDC charges and "… are purposely designed to be independent of grid use and so hard to avoid…". This is an interesting design criterion for a pricing system: Independent of use, and hard to avoid.

The Residual charge will be based on gross Anytime Maximum Demand as a proxy for a Transpower Customer's size and is intended to recover any remaining transmission costs in a way which does not distort incentives to invest or use the grid or to provide any pricing signals.

The move to gross Anytime Maximum Demand (AMD) as the defining measure of an EDB's size might be considered a good proxy. Most EDBs (all EDBs with typical customers as the majority) would not have a significant difference between RCPD as defined now, and AMD as defined in the TPM 2019 proposal. The ratio between the AMDs of most EDBs would be mostly similar than the ratio between RCPDs.

A small number of EDBs, including Network Waitaki, are not typical, and contain consumers with radically different consumption patterns than the average EDB – in our case large levels of summer irrigation. From this sample, a few might benefit from these differences, leaving an even smaller minority who could be severely compromised by the proposed change from an RCPD derived measure to an AMD derived proxy of the relative size of each EDB.

It is our contention that the move from an RCPD derived measure to a gross AMD derived one has the potential to cause serious economic harm to a small number of EDBs of which Network Waitaki is one, with a seasonally mixed or non-typical consumer base.

The view that an a-typical EDB like Network Waitaki has benefited from “lower costs” due to its usage during off-peak times are not correct as illustrated in the graph below. The graph shows that Network Waitaki’s consumers have paid Transmission charges on par with the rest of EDBs.

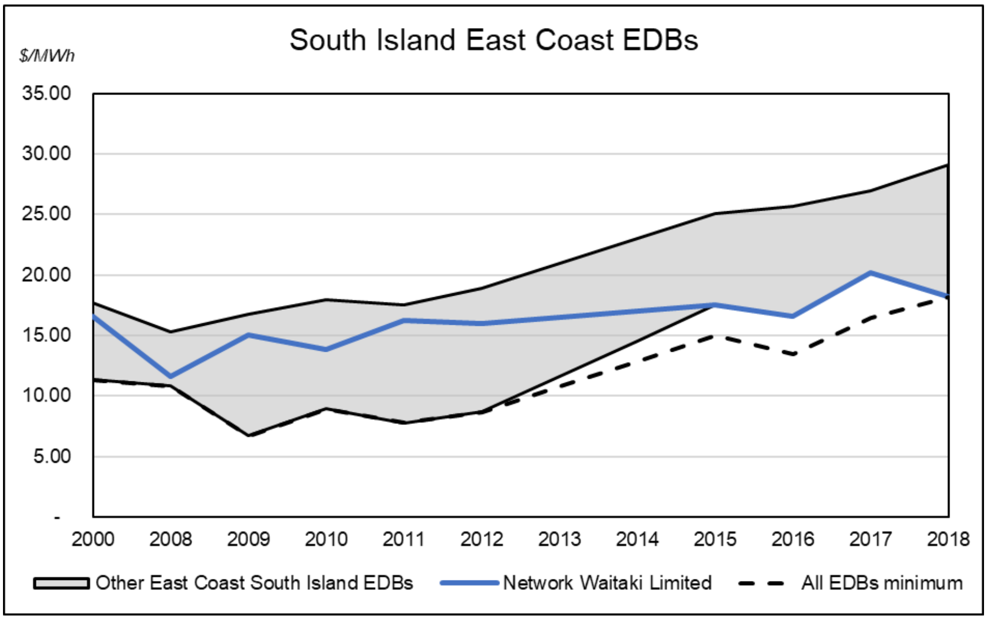

Figure 1: Network Waitaki Transmission charges

1.1 Our concerns with the Residual Charge:

- The residual charge as per the TPM proposal **accounts for more than 60% of Transpower’s revenue**, and due to the size of this charge it has a huge impact on consumer behaviour and thus provides pricing information to consumers related to a static historic gross AMD value as a proxy of size. It is imperative in our view that any such pricing signals are aligned with the long-term based transmission cost structure, which in this case it is not. By excluding feedback regarding changing demand, and by including demand from periods when the grid is under-utilised, inefficient behaviour cannot be discouraged through pricing feedback.

  To optimise the operational efficiency of its transmission network, Transpower relies on its customers managing their coincident peak demand. This requirement applies, irrespective of the level of spare capacity that exists within the transmission network. It appears counterproductive therefore to implement a charge that effectively penalises Transpower customers for managing their peak demands.

- **Core grid investments driven by winter peak demand**: An average gross AMD charge does not acknowledge that core grid investments, to meet either capacity or security constraints, are typically driven by winter peak demand not summer and middle of the night demand. Summer usage of the transmission network provides diversity in usage patterns and improves the overall load factor of the transmission network.

  Future middle of the night charging of Electric Vehicles (EVs) should be encouraged, which this proposal would not because the anytime maximum demand of some EDBs could be driven by EV chargers and this might increase future residual charges for them. The implementation of an AMD charge would therefore not be service based nor cost reflective and could distort incentives to invest and/or use the grid. It provides a pricing signal based on discretionary decision-making that would be unpredictable and could incorrectly include demand from any time of the day or year.

- **Removal of peak period signals:** A gross AMD charge would remove all peak period signals from the TPM and would leave Transpower with a very weak mechanism for signalling to connected parties that a section of the grid was becoming congested and that coincident peak demand should be reduced to avoid premature upgrading of interconnected assets. It is agreed that energy-intensive consumers might respond to nodal pricing, but it is difficult to understand how EDB end use consumers would respond meaningfully due to their isolation from nodal prices through repackaged retailer pricing.

  Recognising the limitations, the proposal does identify the need for Transpower to have discretion over introducing a transitional peak charge (which would again add to unpredictability of pricing outcomes). A prudent transmission network operator would seek to optimise usage of its assets by providing forward-looking pricing signals to its customers to indicate that peak period usage increases both losses and constraints which will eventually require the assets to be upgraded.

  In addition, it would also provide pricing signals that would promote off-peak usage of the network. This ensures that the network assets are used efficiently as customers will manage their load in the peak usage periods to avoid the peak usage charges. Such a pricing approach would also enable Transpower to extend the operational life of its existing assets and avoid premature investment to meet peak demand or security constraints. The proposed TPM will remove these signals and deter customers from managing their load during peak periods as apart from avoiding future benefit-based charges there would be no immediate financial benefit.

- **Using an average gross AMD**: Averaging of the gross AMD over any number of years (at least two years suggested in clause 3.8, clauses H.21 and 4.54 suggests 4 and 5 years respectively) preceding 2019, and then not to adjust this number at all unless a material change in demand was observed, appears to reflect a view of stability in relative demand contribution of EDBs to total demand and the only good attribute of this would be the promotion of price stability. It unfortunately would also introduce an unpredictable influence of judgement on price level development over time. Some areas, particularly Auckland and the Waikato, are experiencing significant growth in demand which means historic demand may not be a good proxy for current and future demand. Other areas may have slower, more gradual changes in demand (either through growth in consumption, or increased levels of DG lowering demand) which may not be considered material, but should be factored in through the pricing mechanisms.

- **Nodal pricing signals:** The suggestion that nodal prices provide "…a timely and efficient signal…" does not consider the substantial buffers isolating the nodal prices from end use consumers and EDBs, and retailers would have difficulty in responding to nodal price signals if the infrastructure required to respond in real time does not exist due to a lack of incentives for EDBs to invest and maintain it.

  The implementation of such a charge could potentially result in distribution companies decommissioning their load control assets which would prevent them from responding to any Transpower signals to reduce coincident peak demand. This may not be an issue in the short term if there are no core grid constraints, but it will become a significant issue when transmission constraints begin to appear. It is our view that at any time, nonconstrained system peak signalling will lead to lower transmission cost over the longer term.

- **Demand response and capacity constraints**: The proposal explains why managing demand during RCPD periods is inefficient, mainly because it curtails demand when no constraints are present. However, demand response without constraints is helpful in many ways, for example it makes it possible to define utilisation of capacity and that allows planners to know how much load growth can be accommodated before the next investment.

  Furthermore, demand side management of consumers is mostly provided by domestic and small commercial storage heating such as water heating cylinders. Switching these appliances during peak demand periods does not forgo consumption, it simply moves it from a peak period into a non-peak period of the day. The movement of load from peak periods to low demand periods is a well-established practice within the distribution industry and helps Transpower to optimise the use of its interconnection assets, and also to a certain extent manages the requirement for peak generation capacity.

- **Customers' location decision**: The TPM proposal appropriately identifies in clause 2.27 the grid users with the ability to respond to, and who should be targeted with, locational price signals as energy-intensive industries and generation, but then in general proceeds as if the intention is to also influence the location of EDBs.

  It states that the "…RCPD distorts customers' location decisions…" in the heading on page 22. In reality what the proposal seems to mean is the "postage stamp" approach of the current "interconnection charge" fails to influence location decisions of energy-intensive industries and generation grid users (it does not explicitly exclude EDBs, but we know EDBs can't move). The residual charge is in essence also a "postage stamp" approach, which then **does not contribute to an improved pricing approach** in relation to this point.

- **Network Waitaki transmission constraint**: The Transpower assets supplying Oamaru (non-core interconnection between Waitaki and Glenavy) cannot support NWL's peak summer demand and therefore NWL is obliged to load control and shift load during the peak irrigation season to remain within the Transpower interconnection constraints.

  In requiring Transpower to charge a gross AMD charge that is unresponsive to changes in demand, the TPM proposal is seeking to implement a charge for services that Transpower has not been able to provide for almost a decade. We believe that such a charge would be unfair.

- **Pre-existing Contractual Arrangements:** The TPM proposal determined the AMD and the residual charge for Network Waitaki without recognition of the contractual arrangements regarding one of the biggest consumers in Waitaki. The North Otago Irrigation Company (NOIC) has a dedicated supply at the Black Point GXP with a contractual arrangement where Transpower treat NOIC as being notionally embedded at the Waitaki GXP. NOIC contributes 17% to the calculated average 4-year AMD for Network Waitaki in the TPM model which needs to be considered as the Black Point demand is already accounted for in the current Transpower/NOIC contractual arrangement. Other EDBs might have similar contractual arrangements.

- **Service levels: Core and non-core Transmission assets**: The TPM proposal creates uncertainty about the future of core and non-core grid assets and how the distinction would be handled in future. Our assumption is that non-core assets and required capacity increases would remain at N security levels and paid for by the requesting EDB unaided.

For NWL it would mean paying the overall benefit-based charge and then paying exclusively to ensure sufficient supply capacity to its own supply area via non-core interconnection assets. This double charging to be in a position to satisfy demand for electricity in the supply area is a discriminatory pricing outcome for all EDBs supplied through non-core transmission assets. In effect a group of consumers are prevented from obtaining an affordable supply in the same manner as most consumers in New Zealand due to historical decisions.

Our Recommendation:

In our view it would be more sustainable to use a three year (or five year) moving average of a broadly defined contributing measure (Coincident Maximum Demand measured in peak and shoulder periods, for example) as a proxy of size, to achieve price stability that also provides a predictable adjustment of contributions to mirror ever changing conditions.

2 BENEFIT-BASED CHARGE

According to the TPM proposal, benefit-based charges will be applied to seven major historical grid investments. In practice this has the implication that some EDBs will be severely affected by benefit-based charges while other EDBs will be paying mostly an average residual price until a benefit investment one day affects them. Furthermore, we question the decision of the Electricity Authority to leave three historical investments (over $50 million each) in the residual charge. We note clause G.63 that there are no net benefits for these three investments, but in our view, they qualify in terms of the threshold of investments to be included in the benefit-based charge.

For example, the North Auckland and Northland investment provided "…significant avoided investment costs in Vector's network…" and our understanding is that these avoided costs were not taken into account when arriving at the lack of net benefits. In our view, excluding such a major investment from the benefit-based charges is significant and might distort prices to a measurable degree.

The discussion regarding the lack of benefits of these three investments and the alleged doubt the finding raises about the timing appropriateness of these investments should not be a determining factor to exclude them as the projects in question were, based on the best information at the time, executed to solve real issues related to the quality of supply of specific grid users.

It is not envisaged that all benefit-based charges will be recalculated on a regular basis to ensure the benefits are benchmarked against reality, so excluding these three investments from conversion to benefit-based charges appear to be unfair.

It is our contention that socialising some investments but not others appear to be a selective approach and that it would be worth considering converting all transmission assets for inclusion in benefit-based charges, to ensure all grid users are fully exposed to benefit payments (properly depreciated for each case) with the average residual price at a minimum.

We recognise the difficulty for Transpower to obtain the required information, but assumptions already had to be made with regard to the seven major investments currently proposed to be included. This full introduction of the whole benefit picture would result in more averaged prices across the country, with better price stability and an opportunity to test the benefit/effort equation of the proposed TPM right from the outset.

Appendix 1 contains a simplistic analysis of the seven major investments included in the benefit-based charge to assist us in understanding the impact on the prices for EDBs.

The analysis in Appendix 1 confirms that the results of the benefit-based charges for the seven investments are against expectations and counter-intuitive. In summary:

- **Bunnythorpe-Haywards Reconductoring:** EDBs south of the investment bear the brunt of the costs at an average of $1.00/kW versus EDBs north of the investment paying only a nominal 20c/kW for their benefit.

- **HVDC Costs:** Against expectations South Island contributes about 30% of the annual cost of the HVDC but power only flows South approximately 15% of the time. For Network Waitaki the annual cost reduces from $350,000 per year to $175,000 for the HVDC benefit if benefit-based charges are adjusted to reflect the reality of power flowing South 15% of the time. Our understanding from the explanation provided was that the result was obtained through questionable judgements when the benefits were calculated.

- **Lower South Island Reliability:** For this transmission investment, the results are as expected.

- **Lower South Island Renewables:** Counter-intuitive results as South Island EDBs are the main contributors to the cost of this investment while the investment improves Distributed Generation connection to all loads. It is not clear why the benefits are so strongly reduced for all EDBs on the North Island, when some North Island investments are so strongly exported to the South Island.

- **North Island Grid Upgrade and Upper North Island Dynamic Reactive Support:** Counter-intuitive results with South Island EDBs contributing more than a few North Island EDBs.

- **Wairakei Ring:** Counterintuitive that the area within which the investment takes place, and two immediate neighbours, do not contribute to the benefit-based charge but the far South does.

At first glance, the idea of benefit-based charges might work, although the possibility for price shocks as a result of the increase in transmission cost directly after capacity is made available could be impediments to the efficiency of the initiative. In this regard, we agree with clause 2.32 that "an efficient cost reflective charge would rise when the grid gets congested and drop when there is spare capacity." However, the benefit-based charge approach will result in an increased cost of transmission as soon as the investment is made, exactly what the current RCPD charge is criticised for.

The detailed analysis as per Appendix 1, furthermore, shows the benefit-based charges to be counter-intuitive for the most part. The contribution results for at least five of the seven benefit investments do not answer to the intuitive idea that consumers north of investments will benefit, while south of the investment, consumers will be exposed to limited benefits. With these results, it would be difficult in our view to convince South Island consumers about the fairness of this pricing principle.

Attendance of the Modelling Workshop on 10 September 2019 in Wellington has strengthened the view that the requirement for judgement in too many areas could be the reason for these discrepancies, and it actually highlights one of the major weaknesses of the proposed TPM.

If a cost reflective charge, quantifying benefits for grid users, are to be used, there are better methodologies available to achieve similar results. Load-flow based analysis would achieve results for all users based on a technical analysis right from introduction, with minimal effort and no controversial judgement required to construct “counter-factual” scenarios, and there will be no need to use temperamental and overly sensitive long term trading models. For example, the intra-utility-wheeling version of the MW-Mile pricing approach successfully allocate portions of assets to each grid user, based on peak flow analysis, allocating the long-term cost of assets on the ground to grid users.

Pricing so derived is based on clear rules applied to the model to decide up front whether price stability is the main objective over strength of pricing signals, and over time prices at a specific location would not increase sharply after investment, first movers are not penalised, lumpiness of transmission investments are well managed, generators and loads are treated similarly without need for further judgement, and any specific pricing objectives can be designed into the rules to prevent further interventions that could be perceived as discriminatory. The method produces an allocation of cost to grid users on a technical basis, and after agreement is reached on the set of fairly simple assumptions, it would produce prices with little controversy that are clearly cost reflective according to the agreed assumptions.

Comparative results can be demonstrated using a simplified spreadsheet model, which we are happy to share with the EA if requested.

Our Recommendation:

Address the benefit-based charges that do not align with expected intuitive outcomes. In order to accept the benefit-based charges presented in this TPM Consultation Paper and defend it to consumers in our area of supply, we need to be convinced the benefit areas are properly defined and charges correctly calculated.

Consider inclusion of all historic investments in benefit-based charges, to ensure all grid users are fully exposed to benefit payments (properly depreciated for each case) with the average residual price at a minimum.

This full introduction of the whole benefit picture would result in more averaged prices across the country, with better price stability and an opportunity to test the benefit/effort equation of the proposed TPM right from the outset.

Consider the use of a simple load flow-based approach such as the Intra-Utility MW-Mile methodology.

3 PRICE CAP OF 3.5%

The proposal includes a cap of 3.5% on the increase in the total electricity bill of an average EDB consumer although directly connected large industrial customers, and generators have been included in the calculation of the 3.5% cap. According to the proposal Network Waitaki falls under this 3.5% threshold and thus consumers will be required to contribute $100,000 to fund the payment to four large industrial customers who otherwise would experience total electricity cost increases above 3.5%. This is in effect a socialisation of charges to ensure some consumers don't end up with price shocks, which in our view defeats the intent of the pricing structure change (which was to make it cost reflective and not to socialise costs).

Large industrial consumers will be the consumer category with the best opportunity to exploit the opportunity in the current TPM rules to quantify RCPD as a short term single year measure. It does not appear fair that captive EDB end use consumers now have to cross-subsidise large industries that managed to avoid RCPD charges in the past.

Counter to various statements in the proposal that it is consistent and aligned with the new distribution pricing principles, the price cap is an example of inconsistency with clause (a)(i) of the new distribution pricing principles, namely that "…prices are to signal the economic costs of service provision, including by being subsidy free…"

The largest beneficiaries of this cap are New Zealand Rail, Norske Skog, NZ Steel and Pan Pacific. In our view the intention to have EDB end use consumers cross-subsidise the large industrial customers of Transpower is grossly unfair.

Our Recommendation:

No electricity consumer should be expected to cross-subsidise to limit the price impact on large industrial customers who were benefiting from the current system and now need to be funded to limit price shocks.

Each grid user category should be treated separately: Generators, Large Industrial Customers, and EDBs as a separate grid user group to prevent perverse cross subsidies between groupings.

4 INCONSISTENCY WITH DISTRIBUTION PRICING

The proposal in several instances claims to be consistent and aligned with the new distribution pricing principles and that consumers will benefit from more efficient grid use as they become increasingly exposed to cost-reflective distribution pricing.

Concern is expressed in clause B.229 that the residual charge might be passed through to mass-market consumers through variable consumption charges, which would "artificially discourage electricity use" and would result in inefficient use of the grid. The concern is then concluded with the statement that this issue will be "addressed through the Electricity Authority's review of distribution pricing".

The fact of the matter is that residual charges will definitely be passed through as volume-based charges at this point as Electricity Distributors have to comply with the Low Fixed Charge Regulations. Both this TPM proposal, and the distribution pricing reform have high dependence on the removal of the Low Fixed Charge Regulations.

Inconsistency with pricing principles are discussed in more detail in Appendix 2.

It is our view that there is limited consistency between the 2019 TPM proposal and distribution pricing principles, and that the Low Fixed Charge Regulations present a barrier to implement more efficient pricing structures.

5 TRANSPOWER SERVICE LEVELS

Core grid assets are subject to the Grid Reliability Standards (GRS) which specifies a minimum-security level of N-1. Major core grid transmission investments proposed by Transpower are subjected to the Grid Investment Test (GIT) as applied by the Commerce Commission. According to the regulatory process the GIT determines whether the investment will provide net market benefits when compared with alternatives. Non-core grid assets are excluded from the GRS and are only required to have an N security level.

These regulations effectively halt all Transpower investment in non-core interconnection assets under the GIT unless the N security rating of the asset is being compromised. This has meant that Transpower has been unable to resolve the issues with the supply to the Oamaru GXP under the current investment criteria. The 110kV Transmission line between Waitaki and Glenavy has been capacity constrained during the summer period for several years and significant new load cannot currently be connected to this line unless it is subject to a Transpower special protection scheme. To operate within the Transpower transmission constraints at the Oamaru GXP NWL has been obliged to load control during the summer months and has also implemented an emergency load shedding process that will be activated if Transpower declares a grid emergency on this line as it did in 2015.

Despite being faced with rapidly increasing demand NWL cannot simply request Transpower to upgrade these non-core interconnection assets as this would not meet with the requirements of the GIT. NWL is therefore faced with the issue of growing demand with no options under the current regulatory environment to increase the capacity of the existing interconnection assets classified as non-core. The difference in service levels experienced by different customers seem to be ignored in the 2019 proposal.

At the present time there is a disconnect between the service levels that Transpower provides to its customers as per its current TPM and the proposed TPM.

Under the proposal as per clause B.246 one of the examples provides that Transpower could choose to "disproportionately scale back the benefit-based charges for those pre-2019 assets that are part of the core grid. This would have the advantage of limiting the scaling back of the charges for non-core grid assets (such as the 110kV network) for which individual ownership contestability is most practicable." On the face of it this means that a network such as Network Waitaki will have to contribute to all scaled back benefit-based charges through the residual charge (contributing to investments across the country) and will then have to face the full cost of the non-core 110kV investment required to alleviate the Transmission constraint into Oamaru as it will be the main beneficiary.

In our view the benefit-based charge will continue to penalise Network Waitaki for its location and its consumers will need to pay for solving Transmission capacity constraints in the 110kV lines and the limited functionality of some of the associated non-core interconnection assets.

Our Recommendation:

A review of the classification of the core and non-core grid is required to ensure that all Transpower customers receive an equal service.

6 NODAL PRICES AND ELECTRICITY DISTRIBUTION PRICES

It is clear how energy-intensive industry and generation can react to nodal prices to improve efficiency in transmission, being exposed to such price movements and able to react due to the nature of their businesses. For EDB end use consumers it is not so clear, since nodal prices are isolated from these consumers through retailer and distributor pricing arrangements where nodal prices might not be reflected at all, and the EDB not controlling the loads of its end use consumers with the same authority an energy intensive business would have over its own load. In general, the energy-intensive industry and bigger generation grid users are also generally directly connected to the transmission grid and thus have limited or no interface with distribution networks.

As a result, a substantial amount of grid demand would not be exposed to nodal price influence on the use of transmission, with proportionally less support to enhance efficiency for transmission pricing.

Nodal prices are by nature a reflection of the short-term conditions on the network. Transmission cost is overwhelmingly long-term costs, related to the cost of long life assets. The short-term conditions are influenced by long-term decisions, and could be a symptom of insufficient investments, but the grid reliability criteria are more of an investment trigger than nodal prices.

Even if the nodal prices are important for the short term operational efficiency of the grid, it does not contribute towards cost recovery as part of transmission pricing, signalling short term market conditions instead. In addition, since nodal prices already exist, this TPM proposal does not meaningfully change anything where nodal prices are concerned.

Our Recommendation:

It is our view that the assumption on the impact of nodal pricing is overstated and does not consider the fact that many EDBs (and the EDB end use consumers) are not exposed to and will not be able to react to nodal prices.

7 DISTRIBUTION CAPACITY

Paragraph 4.161 considers the possible interaction between transmission investments and distribution cost. It assumes the average condition where all distribution networks have spare capacity, and as a result the benefit of the transmission investment would be higher than the incremental cost of distribution. As was mentioned before, these simplifications based on averages are required to maintain a reasonable level of simplicity in the design of pricing systems, but in certain cases it is necessary to check for general validity, especially where the possibility to do economic harm exists.

In specific cases, it is easy to imagine scenarios where transmission investments could impact on distribution projects (relative to the size of the affected EDB) where such projects could require cancelation, delays, or perhaps a need to be brought forward. For a specific area of supply, it could be a sizable impact on the cost of distribution. We know from the records available that in the North Auckland and Northland proposal (excluded from the benefit-based charges due to a lack of benefits better than cost) that the transmission investment "…relied on significant avoided investment costs in Vector's network…" which might have been the factor that originally made this investment attractive for New Zealand, even if in the proposal it was deemed to have been inefficient from a pure transmission point of view.

The interface between transmission and distribution appears to have been simplified out of necessity, but the result is perhaps not satisfactory. In the case quoted above, the transmission investment reduced the cost of distribution, apparently substantially. It can be envisaged that other transmission investments might increase the cost of distribution, perhaps through a need to bring distribution spending forward in time.

The whole concept of introducing price differentiation based on location for the EDB groups of consumers (especially since only energy-intensive industry and generation were identified in clause 2.27 who need location information) adds major complications to the pricing methodology with doubtful gains in efficiency, since EDBs are not going to change their specific locations, ever. The impact of transmission investments on distribution cost is only of concern where location specific price differentiation (as suggested in the benefit-based charge) is present, and the economic benefit of this complication is hard to quantify, considered against the complications to get it right and not to cause economic harm when the results are inaccurate, while EDB consumers are basically stuck where they are as consumers.

Our Concern:

The interface between transmission and distribution appears to be overly simplified in the TPM proposal by incorrectly assuming that all EDBs have spare capacity and not considering the potential for economic harm.

8 IMPACT ON CONSUMERS

The proposal contends that consumers will experience significant benefits while seemingly ignoring the fact that pockets of consumers will be extremely disadvantaged. The proposal on page 58 indicates that the impact of the change on transmission customers is smaller than in 2016 due to several factors, such as fewer pre-2019 investments included and different modelling assumptions. However, **in the case of Network Waitaki, the impact has doubled**.

Waitaki is in the process of trying to turn around from a shrinking district to a vibrant and growing area of growth. At present the economic benefit derived from the use of electricity lags behind surrounding areas and the country, as shown below:

	Waitaki	Otago	South Island	New Zealand
Energy (GWh)	250	1,990	9,470	38,620
GDP ($ million)	1,370	12,700	63,700	284,700
$ of GDP per kWh	5.48	6.38	6.73	7.37

Table 1: Waitaki GDP per kWh

For Waitaki to grow into an attractive economic environment for people to work and live, the availability of electricity for growth at a competitive price is crucial. Electricity enables economic activity, and with climate change challenges in a country with clean electricity, this is the energy source of choice for economic growth.

An increase of 55% in transmission charges will be a severe blow to economic development in the Waitaki District, especially considering that this 55% increase does not factor in the potential additional costs to address the current transmission constraint on interconnection assets that cannot be socialised outside the Waitaki area.

It will be very difficult to defend a $1.6 million increase to consumers for no additional benefit. In the Network Waitaki supply area, small commercial and residential consumers make up about 85% of consumers (34% on the Low Fixed charge tariff), with large commercial, industrial and farming making up the balance. The median income in the area is only $25,200 per annum and half of the population in the area is above 65 years (22% of the Waitaki District population) and survive on less than $20,000 per year.

By applying the principles that the Electricity Authority promotes of cost reflective pricing, we could target specific consumer groups and allocate the additional cost of the TPM proposal according to the contribution of each group to our summer peak demand. As the summer peak is largely influenced by the agricultural sector, for example, this could result in no increase for residential consumers and an approximate 12% increase in final bills for farming and irrigation consumers which would have a significant increase on farm operating costs.

This increase will have a flow-on effect in the local economy. Simplistically put, for every dollar increase in cost with no added value there will be a direct impact on each business or farmer of less available income to spend within their business, make investments in productive assets, employ people or expand production. The indirect impact will be less expenditure on goods and services from suppliers in the community, stores will earn less revenue, staff downsizing might occur in certain instances leading to less employment and people leaving the community for better prospects elsewhere. The impact will eventually snowball as the cost will eventually have to be carried by a smaller number of consumers in the community.

The unfairness of the proposal in our view is illustrated in Appendix 3 where the impact of the TPM proposal is measured against the economic output of each supply area in New Zealand. From the information in Appendix 3 neither the current TPM nor the proposed TPM is aligned with economic requirements to use electricity as an enabling mechanism for economic growth in the lesser developed areas of New Zealand.

The average price of electricity in the Network Waitaki area had been contained in the past, and this feature of the district has supported local economic growth. Network Waitaki has been consistently delivering a service to the district with a distribution price (including pass-through and recoverable cost) in the lower quartile of country-wide prices, according to the Ministry of Business, Innovation and Employment (MBIE) quarterly surveys. This enabling and competitive performance of Network Waitaki will be compromised should the TPM proposal be implemented.

In general, even though the major benefit of the proposal from the EA perspective is efficient grid use, we question the economic efficiency gains to be had from pricing signals to consumers who are not going to respond strongly to such signals. It is well known that electricity shows very little price elasticity, and the reasons for that is easy to understand: it can’t be stored easily and cheaply (as yet) and it is required for essential applications at specific times of the day. Furthermore, the total value of electricity in the economy is small (less than 2% of GDP), with transmission at about a tenth of the 2% GDP contribution. The North Otago region’s GDP is small, at about 0.7%. of the New Zealand GDP. The possibility to do unintended harm in specific small regions of the country that have strong growth potential and features a-typical environments (in terms of electricity demand) should not be underestimated. When regional development is on a knife’s edge, even a small push could discourage investment needed to grow selected areas where de-population trends could have been reversed.

Furthermore, decarbonisation is a priority for government as evident in the Zero Carbon Bill. Sectors across the economy are encouraged to increasingly focus on carbon reduction initiatives. These initiatives come at a cost and by increasing the price of electricity transmission so substantially in our district, with no added service or benefit, large industrial customers will be disincentivised to invest in decarbonisation to use more renewable electricity but then at the same time face substantially higher electricity prices.

Our Concerns:

Economic growth and development in the North Otago region will be severely impacted and disadvantaged as a result of the TPM proposal.

Local industrial users in the process of converting from coal to electricity will reconsider the economic case for these investments in the face of potential future electricity price shocks.

9 CONSUMER PERCEPTION

In our view consumers will not be convinced by the “benefits” of the TPM proposal:

- The proposed change to Transmission pricing will not resolve the long-standing transmission constraints on interconnection assets that continue to impact on development in this area and the operational constraints that NWL must work under;
- In an environment where benefit-based pricing is discussed, NWL will not derive any benefit from its location adjacent to a major generation hub with almost 50% of hydro generation within a 200 km radius which put the whole benefit calculation into doubt;
- A pricing methodology that have similar charges for both peak and off-peak periods. End use customers generally understand that service providers will charge more during peak periods than during off-peak periods. However, they will perceive this type of pricing as a prime example of a monopoly imposing unfair and unreasonable pricing on its captive customers;
- Any action taken to reduce demand will not reduce transmission charges. In the NWL supply area, controllable load is predominantly provided by domestic customers. These customers benefit from lower fixed charges and lower night time energy charges in exchange for allowing NWL to move their energy consumption from peak day to off-peak night periods. Under the TPM proposal, NWL will not be able to reduce its residual charge and will have to increase its transmission pass-through charges to recover the increase in Transpower charges. NWL will still be required to load control to operate within the transmission interconnection constraints, however we do not believe that our customers would continue to provide us with controllable load if we charged them on the same basis that EA is proposing in the TPM guidelines.

Our Concern:

The TPM proposal will be perceived as an increase in the already high level of cross subsidisation that exists in the current TPM as our customers will not only be required to subsidise core grid connected networks but also neighbouring winter peaking networks.

10 SPECIFIC MODELLING ISSUES

During the Modelling Workshop on 10 September 2019 in Wellington, a few areas of significant concern were identified. In general, the sensitivity of the model to small changes in data and assumptions was confirmed and is a serious concern. It is not clear whether the implications of such sensitivity to the trustworthiness of results are recognised.

The point was made that significant judgement is required to define the starting point for benefit-based charges related to each investment. As a result, small differences in judgement would lead to changes to starting point data and other assumptions, which could result in significantly different results for slightly different judgement calls. This does not provide comfort in the proposed TPM as a robust methodology for long term asset-based pricing.

Appendix 4 highlights the issues related to the HVDC benefit-based charge and utility size battery bank modelling.

Our Concern:

We have significant discomfort in the level of judgement and assumptions applied in the modelling of benefit-based charges resulting in significant costs to EDBs such as Network Waitaki.

11 VIABLE BYPASS ALTERNATIVES AND PRUDENT DISCOUNT

We are pleased to see the TPM proposal contains a mechanism for the application of a Prudent Discount where a lower cost viable alternative exists.

In the specific case of Network Waitaki, we have a significant amount of large-scale hydro generation within our network area operated by others. Across the Waitaki hydro schemes we have access to generation capacity of approximately 865 MW which is far larger than our current peak demand of approximately 65 MW (2019).

Given the existing transmission constraint on non-core interconnection assets supplying into Oamaru, and the proposed significant increase in transmission charges for the core grid, it makes the option of bypassing the Transpower grid entirely a real possibility. An option we will explore involves building our own transmission network connecting directly to the generation stations and making commercial arrangements with the operators of those stations, and avoid using the Transpower grid, thus avoiding any charges for use of the core grid.

This would lead to a perverse outcome, and the inefficient duplication of high voltage assets, to avoid paying for use of the Transpower grid when a viable and potentially lower cost option exists. We would expect the Prudent Discount would be applied to achieve a sensible outcome which again would lead to elements of cost socialisation and thus not achieve the outcomes the Authority desires.

12 CONCLUDING COMMENTS

The case for the proposed TPM has not been proven in our view.

a) In our view the EA has overstated the issues with the existing interconnection charges and the proposed replacement of this charge with the benefit-based charge and residual charge will not achieve the efficiency gains claimed by the TPM proposal.

b) We are concerned about the stated objectives of the TPM proposal, being “purposely designed to be independent of grid use”. This feature seems to disconnect the service provided from the payment expected, making it difficult to comprehend how any meaningful pricing signal can be delivered to paying users of the grid. The reference that these charges should be “hard to avoid” is contrary to a general principle that a consumer should pay for the service required and should not be captive with no possible response to charges levied.

c) Our analysis of the benefit-based charges did not convince us about the appropriateness of the charges in the way it is presented in the TPM proposal with alarmingly counter-intuitive results and obvious non-beneficiaries of Transpower investments shouldering surprisingly high portions of the cost.

   In the majority of cases the benefit-based charges do not correspond with the understanding that consumers downstream would benefit from transmission investments when such investments, being part of the supply path, reduce the chances for constraints to such consumers. If the benefit payments are indeed as intended, a much better explanation regarding the concept of a benefit in the TPM environment would be needed to convince Waitaki consumers of the fairness of the TPM proposal. The analysis we have done exposed counter-intuitive results within the TPM proposal.

d) The mechanisms in the TPM proposal do not acknowledge the long-standing transmission constraints that continue to impact on development in the Network Waitaki area and the operational constraints that Network Waitaki must work under. In addition, while a benefit-based charge is proposed, Network Waitaki will not derive any benefit from either its location adjacent to a major generation hub (865MW of large scale hydro sited within our network area), nor from its out of season and off-peak use of the transmission grid (summer daytime, vs. winter night time for the regional peak). With a constrained non-core interconnected transmission circuit connecting Network Waitaki to the core network, it is highly questionable whether any of the so-called benefits from the seven investments are currently available to Network Waitaki consumers.

e) The Modelling Workshop in Wellington confirmed that the benefit-based charges are overly sensitive to small variations in modelling variables (such as timing and virtual prices) and is reliant on substantial judgement calls that have a significant impact on results. The calculation process does not appear to be robust in any way – small variances in judgement could result in enormously different outcomes.

f) We also do not believe that sufficient weight has been given to the potential negative impacts that the proposed residual charge could have in terms of the efficient operation of the transmission system. The residual charge penalises Transpower customers whose gross AMD falls outside the regional peak demand period and those who utilise distributed generation to reduce their peak demand. These customers provide the means by which Transpower achieves operational efficiency of the transmission network. The residual charge does not therefore promote the operational efficiency of the transmission network and we fail to see how this aligns with the EA requirement to promote the efficient operation of the electricity market.

g) There are many references to service based and cost reflective pricing in the proposal but there is little evidence of this in the proposed charges. There are no service or cost reflective charges within the residual charge which accounts for more than 60% of the charges – the use of gross AMD might even render it counter-cost reflective.

h) While we appreciate that the EA are seeking an economically efficient outcome from the proposed TPM guidelines, economic efficiency (which is not particularly certain in the proposal) does not equate to operational efficiency, and many of the proposed charges in the TPM guidelines do not promote operational efficiency.

i) The CBA supporting the TPM proposal is not robust and does not provide any certainty that the benefits of the proposed TPM will be achieved. We also do not believe that any of the potentially negative outcomes have been incorporated in the CBA.

j) At the present time it would appear that the EA does not have a cohesive vision for the future of the industry, as there are a number of conflicting statements in the TPM proposal and the Distribution Pricing principles. The linkage with Distribution service-based and cost-reflective pricing is not clear.

   In recent years the EA have promoted the installation of smart meters to enable retail customers to choose whether to use electrical energy during high cost peak periods or lower cost off peak periods. The EA also supported the adoption of new technologies such as PV and micro wind generators, and retail customers were encouraged to adopt DG as Retailers were paying the full retail price for energy exported into the network. However, the whole impetus has changed, and the EA is seeking to discourage customers from investing in DG. The EA is seeking to remove any dynamic pricing signals from the TPM proposal. A consumer would not provide distributors with controllable load if they do not receive any price relief for the sacrifice. It appears that the EA have discounted the potential for adverse market impacts from the changes they are seeking to implement.

k) The TPM proposal will have a significant financial impact on the North Otago region and depending on whether the pass-through of the cost is socialised or allocated to the causers, consumers will have to pay this increase in an area where they have invested based on several considerations amongst others electricity supply costs.

l) Local industrial users in the process of converting from coal to electricity will reconsider the economic case for these investments in the face of potential future electricity price shocks.

m) Due to the inherent inefficiencies in the TPM proposal, grid bypass becomes an attractive option that Network Waitaki will seriously consider, particularly given the extent of large-scale generation within our network area.

13 RECOMMENDATIONS

The TPM proposal contains significant changes to the current TPM and Network Waitaki request that the EA objectively consider all our concerns.

Summary of recommendations:

a) Instead of a gross AMD charge use a three year (or five year) moving average of a broadly defined contributing measure (Coincident Maximum Demand measured in peak and shoulder periods, for example) as a proxy of size, to achieve price stability that also provide a predictable adjustment of contributions to mirror ever changing conditions.

b) Address the benefit-based charges that do not align with expected intuitive outcomes. In order to accept the benefit-based charges presented in this TPM consultation paper and defend it to consumers in our area of supply, we need to be convinced the benefit areas are properly defined and charges correctly calculated.

   Consider inclusion of all historic investments in benefit-based charges, to ensure all grid users are fully exposed to benefit payments (properly depreciated for each case) with the average residual price at a minimum.

   This full introduction of the whole benefit picture would result in more averaged prices across the country, with better price stability and an opportunity to test the benefit/effort equation of the TPM proposal right from the outset.

c) No electricity consumer should be expected to cross-subsidise to limit the price impact on large industrial customers who were benefiting from the current system and now need be funded to limit price shocks. Each grid user category should be treated separately: Generators, Large Industrial Customers, and EDBs as a separate grid user group to prevent perverse cross subsidies between groupings.

d) Split grid user groups into at least three groups to appropriately price the transmission service to energy-intensive industry and to generators with strong signals to efficiently locate future plant, while recognising that EDB consumers should have no requirement for a locational signal.

e) Consideration be given to address different transmission service levels of customers associated with core and non-core interconnection assets for the sake of fairness.

f) Review and account for the terms and obligations as per pre-existing Transpower contractual agreements, e.g. notionally embedded arrangements, to ensure proposed residual charges are accurate and not double-accounted for.

g) The proposal should be tested to determine whether it could cause significant distortions and even economic harm in specific supply areas. What works well on average might not be harmless in all cases, so it is of utmost importance that any atypical characteristics that could be hidden in some EDBs are not prohibitively compromised through measures that were deemed safe when looking at the bigger picture.

14 APPENDIX 1: ANALYSIS OF SEVEN MAJOR INVESTMENTS

The following section contains a simplistic analysis based on our reading of the seven major investments included in the benefit-based charge to assist us in understanding the impact of these investments on South and North Island EDBs and to test whether it makes intuitive sense.

Overall, our conclusion is that the benefit-based charges are mostly counter-intuitive and the impact on North vs South is against what we would have expected.

The results of this analysis follow.

Explanation of Figures 2 to 7:

- EDBs on the X axis are arranged from North to South in New Zealand starting with Top Energy at the left and ending with Electricity Invercargill on the right.
- The big red dot is at the approximate EDB location of the benefit area investment.
- Network Waitaki is shown with a light blue bar.
- The left-hand axis shows the transmission cost in dollar per kW of AMD, as this was decided to be the measure for EDB contribution to transmission cost for TPM 2019. (Reflecting the cost as dollars per MWh does not change the outcome substantially.)

On average one would expect to see the blue bars more to the left side (north side) of the red dot to reflect higher benefits, because power is flowing North more than 80% of the time and the graphs are considering end consumers only, not generators. Any transmission investment, one would think, would tend to benefit consumers downstream of the investment, thus with power mostly flowing north it would benefit EDBs to the left of the red dot, except perhaps for the Lower South Island where power would be flowing South.

14.1 **Bunnythorpe-Haywards Reconductoring**

Bunnythorpe-Haywards re-conductoring was done due to age and accelerated coastal wear, and as one of the parallel pathways between the HVDC terminal and Auckland, it assists with moving power between the two islands.

With generation on the South Island and Auckland as the major load area, one would expect the benefit of this investment to be focused on consumer loads on the North Island, or generators on the South Island. Figure 2 shows a counter-intuitive result with EDBs to the South of the investment paying significantly more per kW than those to the North.

As part of additional reasons for the reconductoring the Draft Decision and Reasons paper by the Commerce Commission in Clause B19 states: "*During dry periods in the South Island these lines may be required to transfer power from the North Island to the South Island and outages may not be available*."

These lines are a major part of the grid connecting the HVDC terminal on the North Island to the rest of the network. It provides for the ability to take lines out on maintenance while still supplying all load on the network. During very dry years (one in eight years on average since 1965) the additional capacity of the new conductors would provide added benefits by reducing possible constraints, but still only if no outages are allowed. However, during the balance of the time it carries power north and provide benefit to upstream consumers at all those times, reducing losses and giving better reliability during planned and unplanned outage conditions. If the proposed TPM 2019 can practically ignore 85% of the benefit and price significantly on only a possibility of benefits during the odd dry year, it is cause for concern regarding the perceived fairness of the proposed methodology.

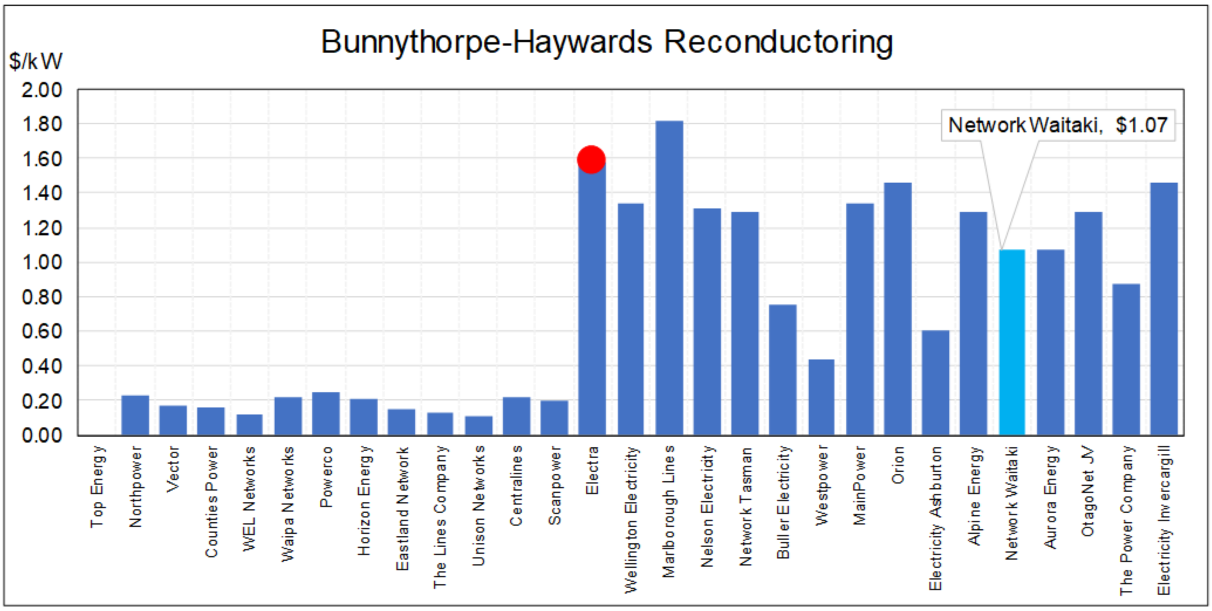

Figure 2: Bunnythorpe-Haywards Reconductoring

14.2 **HVDC Costs**

Our understanding is that the HVDC system on average moves power from the South Island to the North Island 85% of the time, while supporting the South Island with generation from the North during less frequent dry years when hydro generation could be limited.

Figure 3 illustrates the contribution of EDBs to the HVDC cost. The results are counter-intuitive as our calculations show that South Island EDBs contribute around 30% towards the HVDC system while only receiving power 15% of the time. Furthermore, it is not clear why some South Island EDBs pay so much more than North Island counterparts given the fact that power flow North around 85% of the time.

The modelling workshop in Wellington provided some explanation for this anomaly, but not convincingly so. The judgement calls made to model the “counter-factual” scenario without the HVDC link in place was highly prejudicial towards the South Island consumers, mainly by not adjusting the water levels in reservoirs as a result of the absence of the HVDC link, or alternatively by not limiting the cost of “counter-factual” back-up generation supplies, as was done for other “counter-factual” scenarios.

Figure 3 includes a second set of narrower light blue bars to reflect benefit-based charges based on an 85% contribution of North Island and 15% contribution of South Island EDBs to the HVDC annual cost, respectively. For Network Waitaki the annual cost then reduces from $350,000 per year to $175,000 for the HVDC benefit which is more realistic in our view.

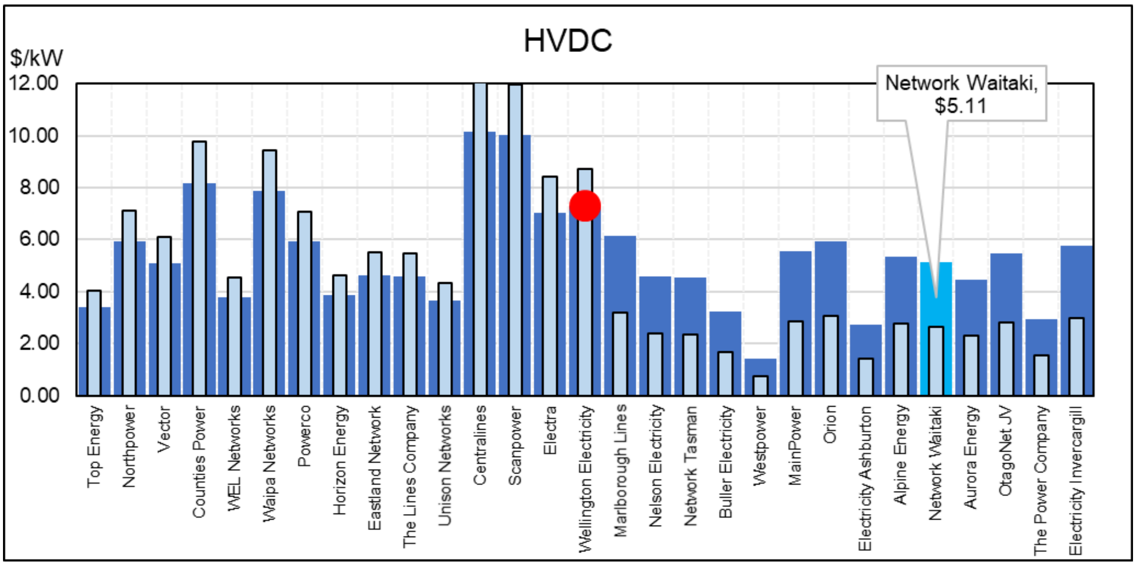

Figure 3: HVDC Costs

14.3 Lower South Island Reliability

For this transmission investment, the results are as expected. The lower South Island pays for the investment in the lower South Island, albeit with small anomalies.

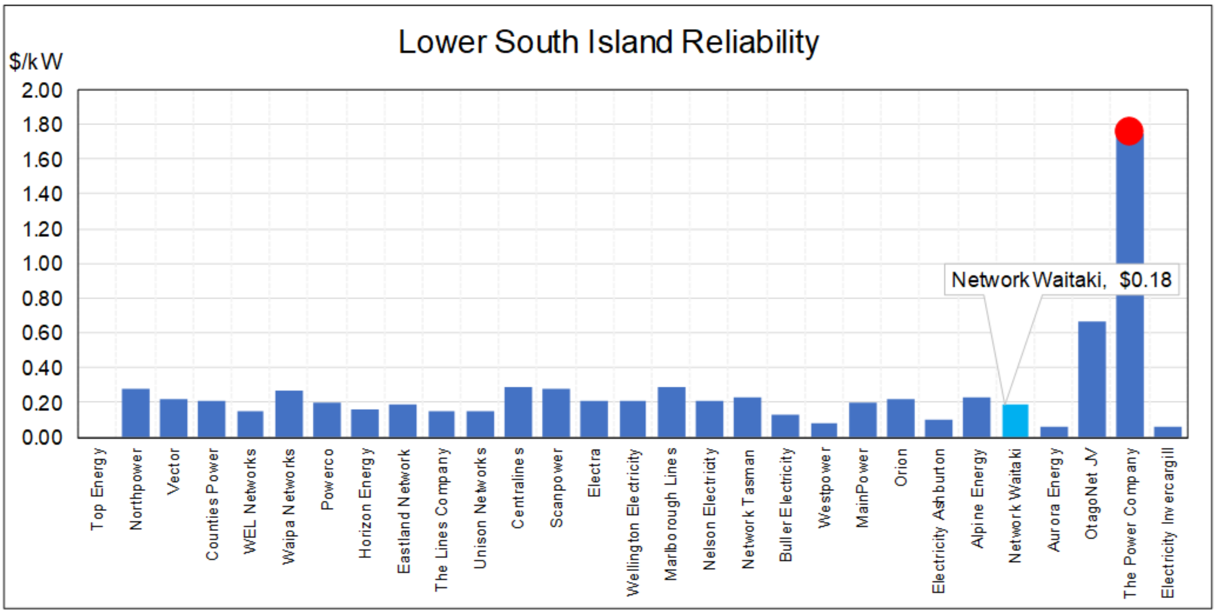

Figure 4: Lower South Island Reliability

14.4 Lower South Island Renewables

This transmission investment would improve the connection of Distributed Generation to all load consumers. The result is somewhat counterintuitive with only the South Island consumers giving a meaningful contribution towards paying the cost of this investment.

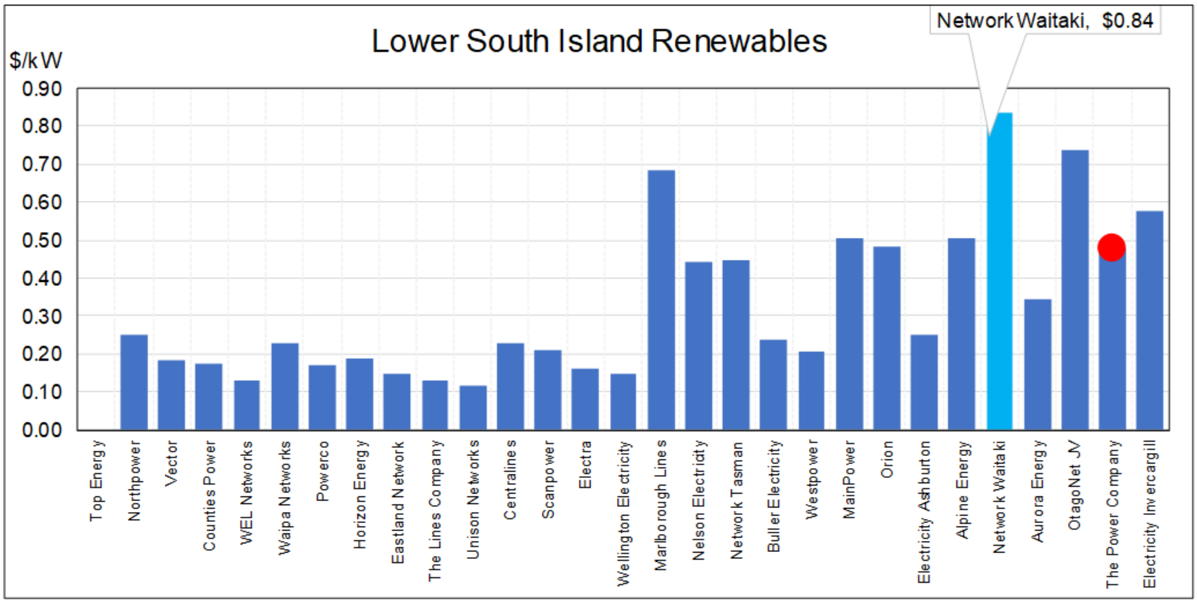

Figure 5: Lower South Island Renewables

14.5 North Island Grid Upgrade and Upper North Island Dynamic Reactive Support

It is interesting and against expectations that the benefit-based charges send more cost south for North Island investments than it sends cost north for South Island investments. North Island EDBs contribute around 20 cent/kW for the South Island investments, but for this North Island upgrade the South Island consumers contribute around $1.20/kW.

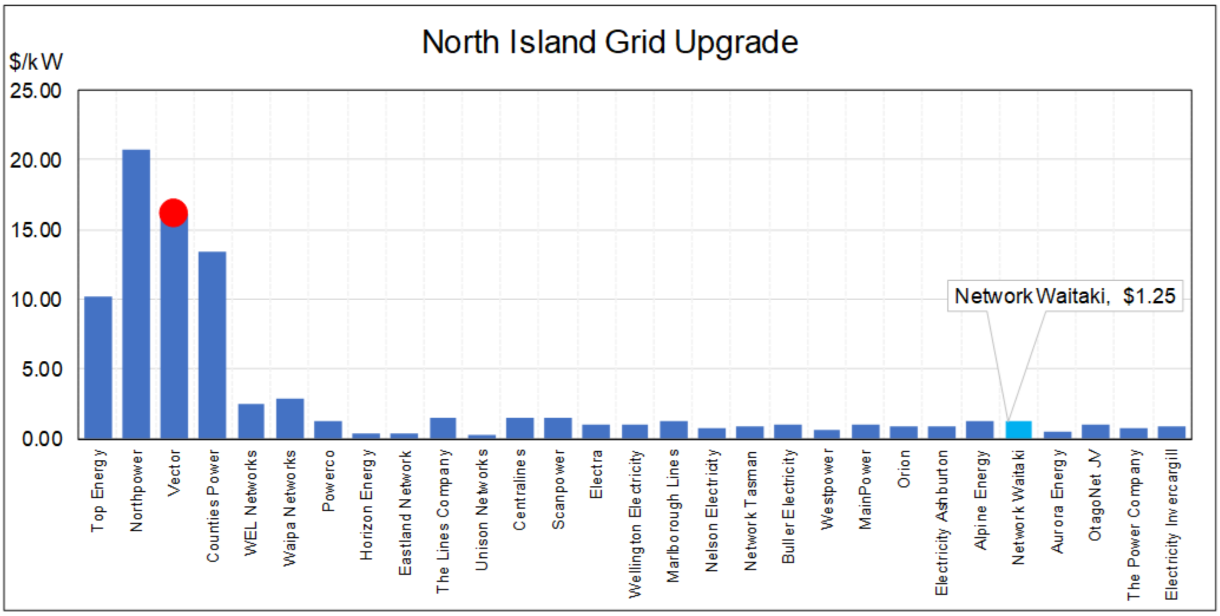

Figure 6: North Island Grid Upgrade

It would also be interesting to understand why some North Island EDBs contribute almost nothing while some South Island EDBs contribute quite significantly to this North Island Grid Upgrade.

14.6 **Wairakei Ring**

This investment, just north of Taupo, also delivers counter-intuitive results. It appears that the area in which the investment has been made is not benefiting while the far South is.

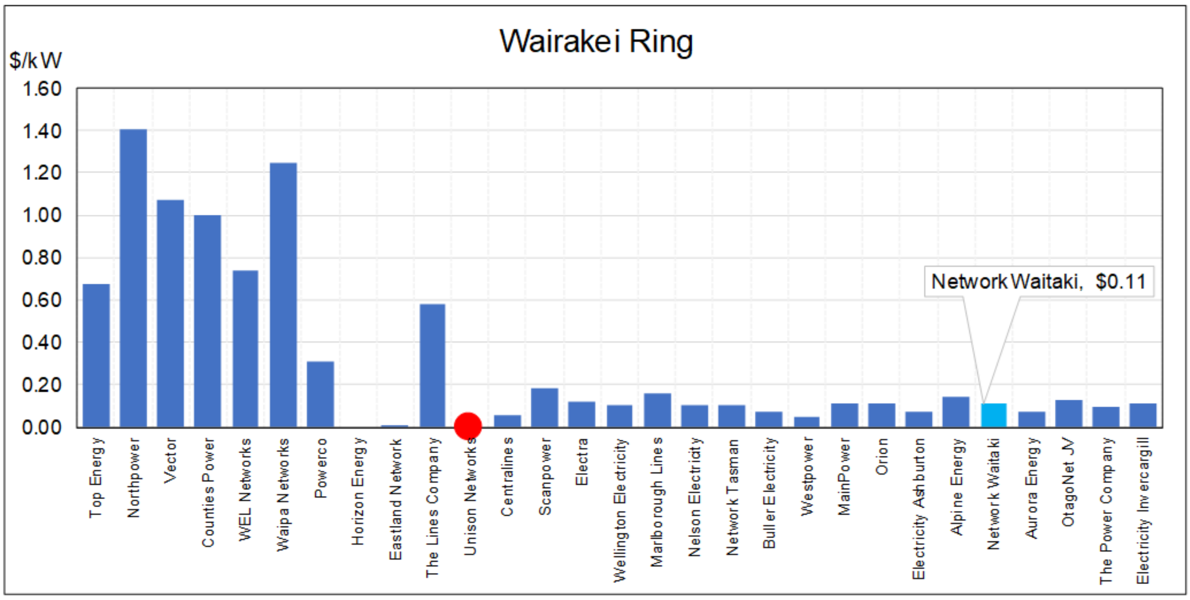

Figure 7: Wairakei Ring

Figure 8 below, summarises the findings of the analysis of the 7 investments.

Explanation of figure 8:

- The investment costs are shown per MWh, indicating that capacity or energy produce the same results.
- The red dotted line (indexed) shows the cumulative spending on the investments moving North.
- The solid red line is a logarithmic trendline of the cumulative investment cost.
- With power flowing North 85% of the time the solid red line also represents the expected benefit for each EDB derived from the investments.
- The solid blue line represents the average $/MWh of benefit-based charge allocated to each EDB.
- The horizontal blue line is the average $/MWh of benefit-based charges for all EDBs.

As expected the benefit-based costs (depicted by the solid blue line) peak in the north. However, we would have expected the blue line to show a reducing cost to the right-hand side of the graph, similar to the trend shown by the red line. Five of the seven investments clearly benefit the North Island Consumers (and South Island generators) during the highly dominant northern power flow periods but the benefit-based charges do not reflect this expectation.

While it is appreciated that the benefit is not usage based but rather derived from energy price differences in the market with and without the investment, the results are not convincing and are based on simulations that are sensitive to many assumptions, realising a result dependent on significant "balancing" of input data until a usable result is achieved. This does not appear to be a robust methodology to base long-term transmission asset prices on, and the distortions might look innocent enough on average but is perceived to be quite damaging in specific areas such as Network Waitaki.

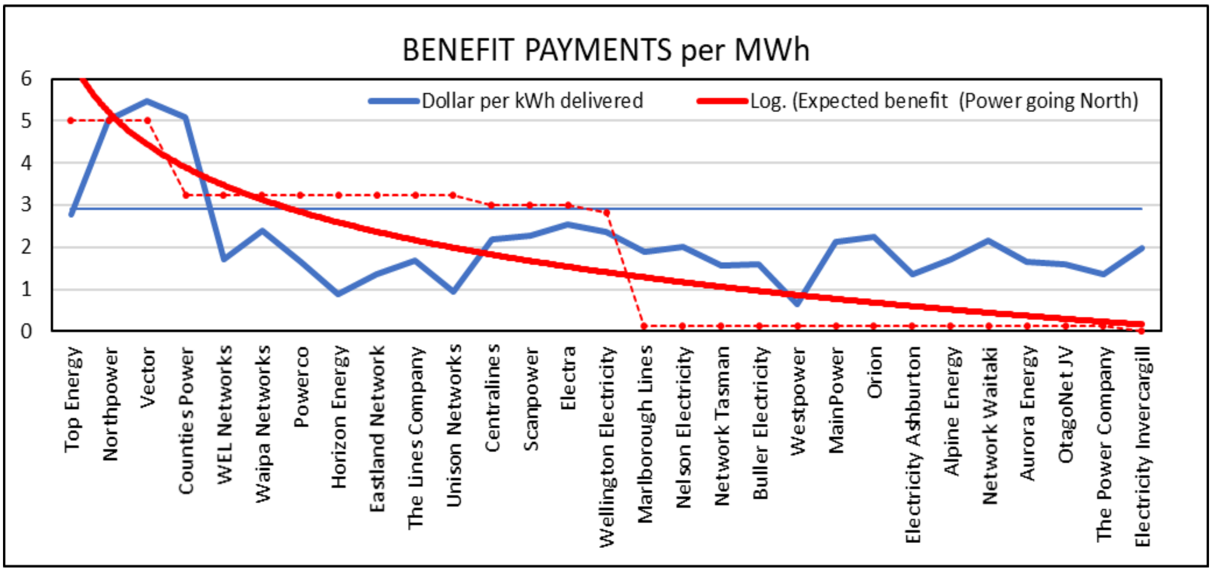

Figure 8: Total Benefit Cost and Expectation

15 APPENDIX 2: INCONSISTENCIES WITH DISTRIBUTION PRICING PRINCIPLES

The table below outlines the broad inconsistencies between the TPM and the new Distribution Pricing Principles.

2019 Distribution pricing principles	Inconsistency with proposal
(a) Prices are to signal the economic costs of service provision, including by:	There is no way to signal the economic cost of the proposal as the LFC regulations inhibits the ability of EDBs to pass through unavoidable fixed costs to consumers, except in the form of a volume-based charge.
(i) being subsidy free (equal to or greater than avoidable costs, and less than or equal to standalone costs);	The price cap will require electricity consumers cross-subsidising large industrial customers who managed to effectively reduce their charges under the current system. In Network Waitaki's case the proposed step change in Transmission charges will make disconnecting from the grid a viable option which will not be an efficient outcome and not what was intended by the distribution pricing principles.
(ii) reflecting the impacts of network use on economic costs;	As nodal prices will not be directly visible to EDBs or consumers it is hard to understand how these prices will be able to signal the economic costs of service provision. Furthermore, it is a stated objective of the TPM proposal to be "…purposely designed to be independent of grid use and so hard to avoid…" The impact of network use thus is purposely neglected.
(iii) reflecting differences in network service provided to (or by) consumers; and	There is no indication of price differentiation for grid users with different levels of service. This is especially obvious in Network Waitaki's case, receiving a lower service, but facing a high step change with no benefit. This matter is expanded on in the section related to "Transpower Service Levels".
(iv) encouraging efficient network alternatives	It is hard to understand how efficient network alternatives are being encouraged through the proposal as an EDB will not be able to do anything to reduce its cost. In fact, the Issues Paper comments on customers who "…unnecessarily invest in technologies such as batteries and distributed generators…" and clearly prefer to limit such investments. There do not seem to be any reason to continue investing in load control alternatives as there is no incentives to limit usage on the network.
(b) Where prices that signal economic costs would under-recover target revenues, the shortfall should be made up by prices that least distort network use.	It is claimed the proposed residual charge will not distort network use, but it is feared it will distort the cost environment by being unrelated to actual contribution of an EDB to transmission cost as well as mostly unresponsive to changing conditions, except through highly unpredictable discretionary decisions.

2019 Distribution pricing principles	Inconsistency with proposal
(c) Prices should be responsive to the requirements and circumstances of end users by allowing negotiation to:	The proposal does not appear to have any intent to be responsive to requirements and circumstances as it wants this benefit-based approach to result in charges that are "unavoidable".
(i) reflect the economic value of services; and	The Issues Paper has clearly indicated it is not concerned with the economic value of services, but only with the overall efficiency of the electricity industry. (Paragraph 4.223)
(ii) enable price/quality trade-offs	As the residual charge will recover more than 60% of Transpower's revenue requirement, it is not clear from the proposal whether any trade-offs will be possible. This is not mentioned in the Issues Paper. Network Waitaki is supplied on a N-security level because of the non-core status of Transmission interconnection assets. Being supplied by non-core assets compromised quality of service but the pricing does not provide discounts for such quality trade-offs.
(d) Development of prices should be transparent and have regard to transaction costs, consumer impacts, and uptake incentives	Transparency is questioned with the possibility of the use of judgement in a number of areas that could affect cost. The fixed nature of the gross AMD residual charge is a case in point. Similarly, the definition and inclusion of investments into benefit-based charges appears to contain judgement.

Table 2: Inconsistencies between the TPM and the new Distribution Pricing Principles.

16 APPENDIX 3: IMPACT OF THE TPM PROPOSAL ON NETWORK WAITAKI

Figures 9 and 10 illustrate the impact of the TPM proposal on NWL.

- Description of figures: Gross Domestic Product (GDP) is an indication of economic wealth in a region. The yellow bars illustrate the current state of economic development relative to electricity delivered in each Electricity Network Supply area.

- The red horizontal line shows the average new proposed cost of Transmission for New Zealand.

- The blue bars reflect the current Transmission cost paid by consumers of each Electricity Network.

  The red bars provide an indication of the proposed Transmission cost to be paid by consumers of each Electricity Network from 2024 onwards.

Figure 9 (below) illustrates the impact of the TPM proposal on all EDBs in terms of average delivered price of energy ($/MWh). Network Waitaki faces one of the highest Transmission cost increases measured in $/MWh. This indicates the potential final delivered cost of energy in our network area will be above average and will have one of the highest ratios compared to GDP output.

Furthermore, the TPM Issues Paper shows that Network Waitaki residential consumers are the worst affected of all residential consumers in New Zealand with a $42.60 per year increase.

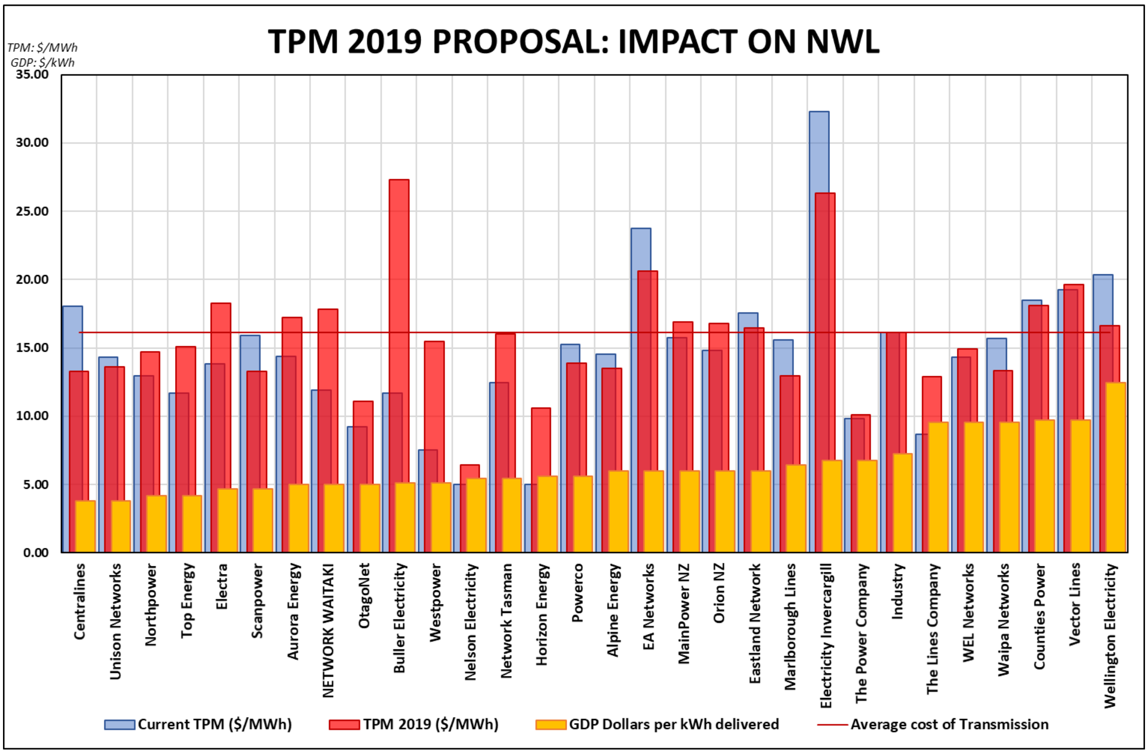

Figure 9: TPM (Current and 2019 proposal) and GDP per kWh delivered

Figure 10 illustrates the impact, including the additional cost for Network Waitaki to alleviate the Transmission constraint. Challenges experienced to increase the supply capacity from the transmission network, given the non-core status of the main supply points, and the possibility of major price increases as a result of that, and as a result of the TPM proposal, could cause serious economic harm to the district in an environment where consensus views are in support of growth of all New Zealand regions.

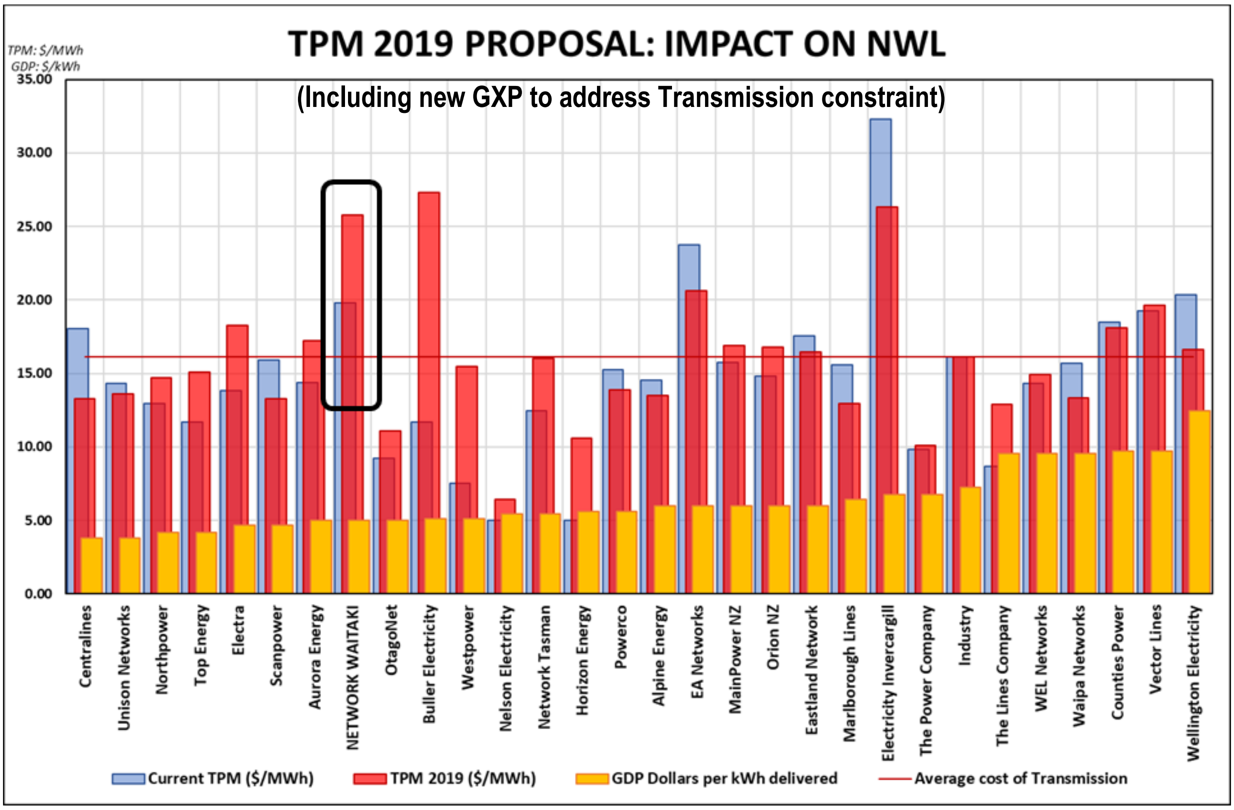

*Figure 10: TPM (Current and 2019 proposal) and GDP per kWh delivered **(NWL GXP included to address transmission constraint)***

Interpretation of Figures 9 and 10:

- By comparing an area like Wellington with a GDP of $13/kWh with Network Waitaki with a GDP of $5/kWh there is clearly a difference in the economic growth potential of the two areas.

- Wellington's new proposed transmission cost will be in the order of $16/MWh, receiving a significant reduction from current transmission cost ($20/MWh). In contrast, Network Waitaki's new transmission cost will be $26/MWh, a significant increase from its current cost of $20/MWh.

- There is a clear unfair difference in the proposed cost faced by each area and a big differential between the current and proposed costs faced individually by each.

17 APPENDIX 4: COMMENTS ON TPM 2019 MODELLING

We have not considered all the modelling in detail, but there are two specific modelling results that we found to be highly questionable, namely the HVDC benefit-based charge and battery modelling.

17.1 HVDC Benefit Based Charges

A specific case in point is the way the South Island was treated in the calculation of benefit-based charges related to the HVDC investment. To calculate the benefit-based charge, the model uses a "counter-factual" scenario where the investment to be studied does not exist, to provide comparisons with the factual situation. The discussion below highlights our concerns with the judgement calls made in defining the counter-factual scenario.

1. The first judgement call relates to historical data. The proposal calls for the use of the latest four years of historical data. This is a curious judgement call. The direction of power flow on the HVDC system is highly sensitive to rain and snow figures over the previous 12 months. Weather in general has very long periodic cycles, and even a specific ten-year period could include anything between zero and five dry years.

Our Concerns:

Was there any statistical analysis done to support the choice of four years?

What is the standard deviation for the number of dry years per successive four-year periods on record?

Just by chance one of the last four years had water constraints at the hydro generators of the South Island, which resulted in a reverse of power flow direction on the HVDC system for the factual case. If the four-year period did not include such a constraint (or if it included two dry years by chance), the results would have looked totally different. Why should the specific result, based on judgement calls with very little scientific backing, be considered a good result. Apparently, for the last ten years, the four-year average was the same as the ten-year average, and that was considered to be a good enough reason to go for four-year data only.

If a longer period was used to define counter-factual costs, at least a 20-year period to reflect the long-term nature of transmission investments and of weather systems, the results would again be quite different. Two or three dry years out of twenty will have a much less severe impact on South Island costs in the model, even with some of the other doubtful judgement calls still in place. Chance could still have a significant impact on eventual results, which is not ideal.

The weighting of dry to wet years was one in four, which is not what the current rainfall statistics shows as the long-term average from construction date of the HVDC system.

It can thus be argued that the counter-factual period should be much longer than four years, to take into account the long-term nature of transmission investments and of weather cycles, and to at least reduce the sensitivity of results to chance occurrences.

2. A second judgement call significantly increases the cost for South Island consumers. It would appear the modeller did not consider the relationship between reservoir water levels

and generator output. Calculations were done without the HVDC system in place, but with water levels very low as if preceding generation were at levels only possible with the HVDC link in place.

The huge over-capacity of generation capacity (a result of the HVDC system to start with) was used to penalise the South Island community, while not recognising that low water levels would have been avoided if the HVDC link was not present.

This seems to be an unreasonable starting condition: without the HVDC link, the reservoirs on the South Island would have contained enough water at the start of the dry year to last for multiple dry years in succession, given the new situation where no HVDC link is in place.

3. A further judgement call was made to reason that the hydro generators are so big in comparison to South Island loads that no back-up generators can be considered, nor can a limitation on the cost of any back-up be tolerated on the South Island, while for other counter-factual scenarios the generation cost was limited to 20% above normal. South Island generation cost during constraints as a result of no HVDC system was instead allowed to go to levels about 10 to 15 times the normal level.

   In reality hydro generation facilities would have been much smaller, and the knowledge that no link with the North Island existed would most likely have resulted in a back-up plan for the occasional dry period. Even diesel generators would have been significantly cheaper than the costs the model lumped onto the South Island consumers.

The over-capacity of generation capacity (a result of the HVDC system to start with) in the counter-factual scenario is used to penalise the South Island community.

This judgement call resulted in the South Island eventually contributing at least twice the expected amount to the HVDC benefit-based charge, due to the high energy cost during generation constraints that would not have been experienced in any event for a no-HVDC link scenario.

These examples of the impact of inconsistent judgement calls one after the other signifies the danger of judgement calls where specialist knowledge of a variety of matters (statistics, weather, transmission planning, generation planning, risk analysis - to name a few) might be required but would most likely not be available. For example, depending on judgement, rainfall statistics shows one in 8 years as moderately dry or worse, for rainfall statistics from 1967 until 2016 in the south west of the South Island. Using this would half the impact of a dry year on results.

The South Island hydro generation is so intrinsically linked to the existence of the HVDC link to the North Island that the counter-factual scenario would require expert system planning knowledge to reduce the system to any level that would be viable in any way.

17.2 **Utility Sized Battery Bank Modelling**

The presented strategy for use of utility sized battery banks was not convincing.

The first concern appears to indicate a lack of understanding of certain issues. The TPM proposal specifies the size of batteries in kW or MW when referring to the energy storage capabilities of the battery. Wattage refers to instantaneous power that can be delivered or absorbed by a battery. Energy is measured in Joules, and is expressed as kWh for electrical systems, since energy is power multiplied by time.

The battery strategy presented showed a very short cycle period where the battery was discharged and then immediately again charged to be discharged again when full, and so forth, and all this happened during a single peak load period. The modeller seemed unaware that the power required to charge the battery would be added to system demand, negating the assistance provided by the battery during the discharge part of the cycle.

A battery can only provide a cost benefit if it is exclusively charged during off-peak periods, and the power so stored is released back into the system during peak periods to reduce demand when it is measured as part of the peak trading periods. Any charging of the battery during the peak trading periods will make matters worse for the agency using the battery, because battery cycle losses will now be included in the demand.

A response from presenters (on a written question posed) argues as follows: “We have considered long(er) discharge periods (*than 1.29 hours charging for 1 hour of discharge*) but our assessment was that these are likely to be less profitable as (a) arbitrage strategies will be most profitable by maximising the amount of discharge when prices are high(est) and (b) the profitability of avoiding regional coincident peaks hinges on being able to charge and discharge in short cycles to maximise the number of coincident peak periods in which the battery is discharging.”

This response is confusing, since maximum discharge during peak periods would be achieved when the battery discharges for the full peak period, with no charging at all unless it is not a peak period. That might mean discharging at a lower rate than maximum kW rating of the battery to ensure it can discharge for the full peak period over multiple hours.

It also argues that short cycles are necessary to be profitable during “coincident peak periods”, but it is difficult to understand how such a strategy would be better than charging during off-peak periods and using the charged battery to discharge continuously at an appropriate rate to reduce demand uniformly during the full contiguous peak period. By charging during the peak period, the average demand is not decreased, since for each one hour of discharging (reduced demand on generators), there would be 1.29 hours of charging (increased demand on generators).