Peak charges under proposed TPM guidelines

Information paper and next steps

March 2020

Executive summary

This information paper sets out the Authority's current thinking about its proposed approach towards peak charging in light of submissions on the 2019 Issues paper.

The Authority has analysed the risks and practicalities of its proposed approach, and this paper considers what else may need to be done to manage any immediate transitional and ongoing risks.

One concern raised by many stakeholders is that demand peaks may no longer be adequately controlled if the Regional Coincident Peak Demand charge is removed, leading to potential reliability and congestion problems. A related point that has been raised is that the removal of a peak transmission charge will bring forward transmission investment that is inefficient.

The Authority is confident that such concerns can be managed by the range of mechanisms that would be available, including:

- time- and location-specific nodal price signals that will stimulate demand response or local generation (enhanced by the implementation of real time pricing in 2022)
- Transpower's own demand response programme and grid support contracts (including with distributed generation) to defer or avoid the cost of transmission
- the option for a temporary congestion charge if important pre-conditions for efficient nodal prices are not yet in place, or participants do not react to the changes as expected (described in the 2019 Issues paper as a 'transitional peak charge').

We appreciate that many stakeholders are not wholly convinced by the reasoning the Authority put forward in the 2019 Issues paper and have asked that the proposed TPM guidelines provide for something more than reliance on nodal prices.

The Authority acknowledges there is uncertainty, and that risks could be more acute if some of the mitigants we have noted are not implemented as expected. This is why the Authority proposed a transitional peak charge as an additional component of the proposed TPM guidelines and provided for the extension or re-introduction of the charge if that proves desirable.

Having considered and heard stakeholders written and oral submissions, we believe that this is the most effective way to respond to the uncertainty. It provides Transpower with a genuine option for a targeted congestion charge in addition to nodal pricing and the other tools available to manage congestion until transmission expansion is justified and in place. Such a congestion charge would be:

- available to be used as long as there are transmission constraints that cannot be managed efficiently and effectively through nodal prices or transmission alternatives
- targeted at locations where there are constraints.

The Authority also currently considers that this charge may be more appropriately named the transitional congestion charge, as this is a more accurate description of its purpose as was detailed in the 2019 Issues paper.

Transpower is in principle the best party to identify and propose if and where a specific targeted congestion charge is needed – it knows its network and the specific congestion risks that might occur and is best placed to assess how to mitigate those risks. For example, mitigation could be through a targeted congestion charge, local demand response, a local distributed generation response, or administrative load control (until a grid investment is in place if that is an efficient solution).

The Authority recognises the uncertainty would be greatest in the initial period after a new TPM is introduced. We sought an independent assessment from Concept Consulting (‘Concept’) as to how participants are likely to react after the RCPD charge is removed. Their report finds the proposed guidelines, if adopted, would in general not have a material impact on the reliability of supply in peak demand periods. Concept’s report is provided alongside this information paper.

However, we also recognise that we cannot be sure how participants would react, or whether all the business processes and contracts will be in place or effective at the outset – the same uncertainty stakeholders have raised. Concept points this out too and identified some locations with higher risk of congestion and unserved demand, such as in the Waikato and Upper North Island. The latter is where Transpower is currently proposing to progress investment and demand response ahead of winter 2023 to manage potential voltage issues associated with rising demand.

The cause of uncertainty includes the fact that practical parameters for a transitional congestion charge (should Transpower propose it) would need to be developed – for example, the specific circumstances in which it might be needed, its role compared to non-transmission alternatives, its optimal coverage and level, and the approach to phasing-out and monitoring risks.

If the Authority’s proposed guidelines were to be adopted, we agree that it would be useful to progress work on designing a potential transitional congestion charge as soon as possible, so stakeholders have more certainty of its design ahead of implementation of a TPM consistent with any new guidelines.

The Authority has spoken with Transpower, and Transpower concurs there is merit in it leading a sector workshop on the design of practical parameters for the transitional peak charge. As this is contingent on the guidelines that the Authority may decide to adopt, the details will need to be confirmed later, but at this stage the intent is for a workshop to occur in the middle of the year. The scope of such work would be to start the design of the practical parameters for such a charge.

The Authority notes its review of the TPM and consideration of the proposed TPM guidelines is ongoing and we will take the time we require to consider all the issues raised in submissions, including in relation to peak charge issues. The Authority anticipates making its decision on the proposed TPM guidelines in the second quarter of 2020.

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1 Purpose

1.1 This paper seeks to respond to stakeholders' concerns about the approach to peak charging as proposed in the Authority's 2019 Issues paper, and to set out next steps.[1]

1.2 In July 2019 the Authority proposed a new approach to transmission pricing. Under the proposed guidelines the regional coincident peak demand (RCPD) charge and the high voltage direct current (HVDC) charge would be replaced by benefit-based and residual transmission charges.

1.3 These transmission charges sit alongside a range of mechanisms that ensure demand and supply operate within local transmission constraints:

- time- and location-specific nodal price signals that will stimulate demand response or local generation (enhanced by the introduction of real time pricing)
- Transpower's own demand response programme or grid support contracts to defer or avoid the cost of transmission investment
- the option for a congestion charge (that is not enduring) if important pre-conditions for efficient nodal prices are not yet in place, or participants do not react to the changes as expected.

1.4 Submissions on the 2019 Issues paper expressed concerns about what could happen if the RCPD charge were removed without it being replaced with some other peak transmission charge.[2] Many consider a permanent peak transmission charge is needed.

1.5 One concern is that without a peak transmission charge there would be a sudden increase in demand at peak times, and that this would create operational issues and inefficiently bring forward transmission and distribution investments. A related concern is that nodal prices do not signal the cost of potential future grid investments.

1.6 Similar points had been expressed in response to the 2016 Second issues paper. Accordingly, Appendix E of the 2019 Issues paper investigated the issues in some detail. The Authority's view, as set out in that paper, was that a system based on nodal prices, and expected responses to those prices, was the most efficient means to constrain grid use. It avoids the issue with the current RCPD charge of artificially constraining consumers' use of electricity when there is plenty of capacity.

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[1] For full details see Electricity Authority, *2019 Issues paper, Transmission Pricing Review consultation paper, 23 July 2019*, available at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/

[2] See submissions on the 2019 Issues Paper at www.ea.govt.nz. For example, see: Buller Electricity p1 p6 p7, Distribution Group p6 15-16, EA Networks p2, Electra p2 p5, Electric Kiwi p1 p3, ENA p4 p10 and cross submission, EPOC, Energy Trusts of NZ p3 p11, Flick, Golden Bay Cement p3, Independent Electricity Generators Association p2 and cross submission, KCE p2, Lower Waitaki Irrigation Company p2, Melhuish p4, Network Waitaki p5-6 p12, New Zealand Steel p2 p15-16 p26 and cross submission, New Zealand Wind Association p6-8, Norske Skog and cross submission, North Otago Irrigation Company, Northpower p6 p27-29, Oji Fibre, Orion, p7 p9, PanPac p6, Pioneer, Refining NZ p5-6, Solarcity, Southern Generation p2, Sustainable Energy Forum, Tilt Renewables, Transpower p5 p8 p17 pp C16-C17, Axiom Economics for Transpower p4-6 p18-19, p26-37 p44-45, The Lantau Group for The TPM Group p7 p9 p28 and cross submission, Trustpower p vi p32-38 and cross submission, Creative Energy Consulting for Trustpower, Unison and CentraLines p3 p5-7, Vector p4 p11 and cross submission, Vocus Group, Waitaki Irrigators Collective, Waitaki Power Trust p15 p21, WEL Networks p1, Wellington Electricity p1, Joint cross-submission by Ecotricity Electric Kiwi energyclubnz Flick Pulse energy and Vocus. A permanent peak charge was opposed by Buller Electricity Ltd p1, 8, Meridian p24, Nova, and Rio Tinto p5, 33.

1.7 However, the Authority also acknowledged there are risks, particularly in the near term. For example, business arrangements and load management practices may not change as expected. This motivated the Authority to propose the guidelines also provide for a transitional peak charge that Transpower could propose to be part of any new TPM. This provision could be used beyond any initial transitional period – it allows for a congestion charge as and when it is needed, but with an expectation that the charge will not be permanent (as the congestion will ultimately be relieved, for example by transmission investment, demand response or distributed generation).

1.8 The Authority has heard stakeholders' concerns in their written and oral submissions. We considered it important to re-test our thinking and provide a response to stakeholders now. We have thought further and in some detail about the proposed approach. This paper summarises the Authority's current thinking on these matters, and what else might be required to further mitigate risks.

1.9 This assessment has been informed by:

- an expert review of the 2019 proposal and critiques (Hogan 2020, provided alongside this information paper)
- a review of the practical settings for nodal pricing to work as intended informed by, among others, Creative Energy Consulting's assessment (for Trustpower) of the gap between theory and practice, discussed in section 4
- an update and extension of an assessment of the risk of unserved demand that may result if the RCPD charge were removed, summarised in section 5 (Concept 2020, provided alongside this information).

1.10 The Authority notes its review of the TPM and consideration of the proposed TPM guidelines is ongoing and we will take the time we require to consider all the issues raised in submissions, including in relation to peak charge issues. The Authority anticipates making its decision on the proposed TPM guidelines in the second quarter of 2020.

2 Background to proposal for peak charging

2.1 Under the current TPM, 70% of Transpower's regulated revenues comes from the RCPD charge. This charge is allocated to customers based on 100 coincident peak half hour trading periods in each of four transmission zones in a year.

2.2 The RCPD charge for each transmission customer in any year is based on their contribution toward those peaks in the prior year. Customers cannot know for sure when those coincident peaks occur, so that to reduce their own charges they have to take avoidance actions for well over 100 trading periods – maybe 150 or 200 or more trading periods, depending on the level of the charge and the cost of avoidance. Even then they cannot be sure at the time what the impact will be on their bill for the subsequent year.

2.3 Transpower sends its bills to direct connect load customers (large industrials) and distributors. The latter will pass through these costs along with local lines charges direct to larger commercial customers in their network or to retailers.

2.4 At around $2,000 per MWh[3] the RCPD charge is overly strong, and will suppress demand whether or not there are grid capacity constraints.[4] It is like charging peak fares when the bus is only half-full so there is no need to encourage passengers to travel off-peak, or having a road congestion charge in areas without grid-lock issues.

2.5 The high RCPD also causes industrial customers to adjust their production processes, and others to make investments in distributed generation and other options, such as grid-scale batteries, to avoid and shift the RCPD charge. It results in large, unnecessary costs for consumers. This is discussed in more detail in the 2019 Issues paper.

2.6 Some stakeholders note the RCPD charge defers costly grid investment. However, deferring investments would not be in the interest of consumers if benefits exceed costs.

2.7 Others worry that removing the RCPD will increase demand at peak times, and that this will be met by more fossil fuel generation, increasing carbon emissions. The Authority does not agree with those concerns because: renewable energy already meets most of peak demand, and this share is growing; the economics favour renewables like solar and wind as their capital costs reduce over time, whereas emissions pricing will increase the fuel cost of fossil fuel-based generation.

2.8 Overall, however, stakeholders acknowledge the RCPD charge is problematic, even where they do not agree with the Authority's proposed solution.

2.9 For example, the Lantau Group (for the TPM Group) notes (p3) that "the current RCPD charge is *clearly far too high* during the peak-period", but that this is best solved by recalibrating the RCPD charge, perhaps to a level that mitigates inefficient investment to avoid charges. Professor Bunn, for Vector, agrees the RCPD distorts, and "believes in principle that RCPD should be phased out, unless there are special circumstances in some regions." (p9), and that "[p]erhaps a more modern solution would be to take out RCPD and encourage the transmission company to contract for flexibility services… to the extent …they offer better value than … strengthening its network" (p8).

3 In 2019/20 the RCPD charge is $2,188 per MWh and will be $1,968 per MWh in 2020/21. https://www.transpower.co.nz/industry/revenue-and-pricing/pricing.

4 The RCPD charge also appears significantly higher than indicative estimates of long run marginal cost (LRMC) of transmission, based on a range of $30-80/kW cited in Transpower 2017, Battery storage in New Zealand, https://www.transpower.co.nz/about-us/transmission-tomorrow/battery-storage-new-zealand, and forecast capital expenditure for regulatory control periods 3-5 and estimates beyond.

3 Role of nodal prices alongside transmission charges

Efficient locational prices for using the grid

3.1 For the purpose of this paper, the salient changes proposed in the 2019 Issues paper are to replace the RCPD and HVDC charges with benefit-based and residual transmission charges. These would be fixed-like charges.

3.2 The proposed guidelines do not provide for a permanent transmission peak charge. Instead, differences between nodal prices established in the wholesale electricity market would signal the marginal cost of using the grid at specific times and locations. These are proportionate price signals to grid users – enabling the effective and targeted management of congestion without all the side-effects of the RCPD charge.

3.3 This approach reflects the Authority’s thinking that there is a key distinction between demand peaks that are accommodated by the available capacity, and peaks that exceed or risk exceeding capacity constraints that may cause reliability, voltage, or security of supply issues. In the first case, there is no need for a price signal to constrain demand; in the second case, an efficient price signal encourages efficient use of the available grid capacity.

3.4 To explain further, wholesale nodal prices would optimise local demand and electricity supply, given local transmission constraints. When demand at a node exceeds transmission capacity (or is expected to):

- local generation behind the node would be able to offer in, and as this is likely at a higher price it will set a higher price at the node
- demand would likely respond to higher prices – for example, industrial consumers may adjust their use and retailers or third-party aggregators may initiate a demand response.[5]

3.5 In a workably competitive wholesale market, nodal prices provide an efficient market signal of the cost of using transmission. They would deliver information about the marginal value to consumers of using the available grid, and of addressing transmission constraints by way of more local generation, demand response, or transmission.[6]

3.6 Where responses can be targeted, the outcome is likely to be more efficient than having to rely on a peak charge that may apply even where there are no operational or reliability issues that can arise from congestion.

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5 For example, Concept Consulting 2020 estimates that about 233MW of demand from typical net load of large industrial consumers (including through co-generation) is sensitive to nodal prices, and that about 44MW has been shown to respond to RCPD signals. It assumes a similar amount from other commercial users within local networks (eg cool stores).

6 Hogan, 2020, Léautier, 2018, International Energy Agency, 2007, Hogan, 1992.

A congestion charge option for the transition

3.7 The Authority does recognise the relevant arrangements to allow reliance on nodal prices may not be sufficiently developed at the outset, and that it is uncertain as to exactly how the market would respond immediately after removal of the RCPD charge.

3.8 This uncertainty was noted in an analysis the Authority commissioned in 2016 on the ability of the system to meet peak electricity demand. Concept found that the Authority's proposal would reduce the winter capacity margin to within or somewhat above the optimum economic range (or, less likely, below that range). The winter capacity margin balances the cost of satisfying peak demand and the cost of potential shortages or outages. An updated analysis is discussed later in this paper.

3.9 In July 2018, the Authority invited Transpower "to provide evidence as to whether or not the removal of the RCPD charge would have an adverse effect on the ability to meet peak demand." Transpower's report is discussed in the 2019 Issues paper (Appendix E).

3.10 Transpower found that removing RCPD charges would bring forward transmission investments and increase spot prices during the peak periods.[7] It concluded peak pricing for transmission saves consumers money and is a vital component of the TPM.

3.11 The Authority agrees that removing an overly strong peak charge would increase peak demand, bring forward transmission investment, and increase spot prices at peak. This is an expected and efficient outcome from removing an inefficient charge. Deferring investment is not in the interest of consumers if the investment's benefits exceed its cost.

3.12 However, the Authority does recognise it is uncertain how participants would react at the outset, as it involves distributors and others changing their business arrangements, and the implementation of real time pricing which is scheduled to occur in 2022.[8]

3.13 Given these transition risks, the 2019 Issues paper proposed an additional component that enables Transpower to propose transitional peak charges which:

(a) are targeted at geographic areas, circuits or other circumstances which otherwise would likely experience congestion

(b) are justified if grid demand will not be adequately controlled by, for example, nodal pricing or administrative load control associated with scarcity pricing

(c) would phase out within five years of the TPM coming into effect, though could be paused, reinstated, extended or newly introduced subject to Authority approval.

3.14 This provides Transpower an additional option to manage the consequences of congestion. While 'peak' has been a convenient shorthand, the additional component is more accurately described as a transitional congestion charge, in line with its purpose. This is how we refer to it in the rest of the paper.

3.15 Revenue from transitional congestion charges would reduce the amount to be allocated via the residual charges. Congestion charges would be paid by customers in locations that face transmission constraints, just like the cost of transmission alternatives would be paid by their beneficiaries. Residual charges would reduce for all transmission customers, so Transpower stays within its allowable revenue.

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7 The increase in spot prices at those peaks partially offsets the removal of the RCPD charge that would otherwise apply.

8 Trustpower, which considers peak prices should be a core component of any replacement of TPM Guidelines, suggests that maintaining peak prices will enable low-cost, hot water load control to be relied on while alternative forms of demand management develops over the medium term (2019, p32).

But no role for a permanent transmission peak demand charge

3.16 The absence of a specific transmission peak demand charge would be a significant departure from the current TPM, as submissions have noted. However, the Authority did not propose a permanent peak charge as it considers this would likely be unnecessary:

- nodal prices provide efficient peak price signals – they rise only where, when and to the extent needed to constrain demand to grid capacity (and offered electricity)
- if market dynamics at para 3.4 look to be insufficient, Transpower can:
  - operate its demand response programme or contract distributed generation where this efficiently defers or avoids the cost of transmission investment[9]
  - trigger administrative load control. Under real time pricing this will trigger scarcity prices, in turn stimulating local responses.

3.17 One argument put forward in support of a permanent peak charge is that nodal prices are short-run prices, but that a forward-looking price is needed to signal the future cost of transmission investments, such as a long run marginal cost (LRMC) price.[10]

3.18 However, as Borenstein recently put it, the presence of lumpy investments does not change the efficiency of short run marginal pricing, given the investments that are in place.[11] An LRMC charge sets the price too high when there is plenty of unused capacity and too low when the system is stressed.

3.19 Under the Authority's proposal, the pattern of nodal prices would likely give efficient, location-specific information on the trade-off between doing nothing (accepting higher prices and a risk of unserved demand at times transmission is stressed), demand response, more local generation, or future transmission expansion.

3.20 Further, the expectation of benefit-based charges associated with transmission expansion would in fact give forward-looking price information. We therefore consider that all the appropriate signals would be in place to inform both short- and long-term use and investment decisions by Transpower and grid users.

3.21 As such, the Authority's view is that there are no compelling reasons for a permanent transmission peak charge in addition to the combination of wholesale nodal prices and the benefit-based charges. As Professor Hogan (2020 p10) notes:

"Adding another variable charge on top of [locational prices] would create perverse incentives for load management to avoid such transmission charges… In the presence of economies of scale and scope, with average cost of expansion greater than attributable marginal cost, preserving short-and-long term efficiency calls for a two-part pricing structure that is a fixed charge coupled with real-time energy [locational marginal prices]. This efficient two-part pricing is a core feature of the Authority's proposal"

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9 Transpower continues to be able to enter into, and recover the cost of, transmission alternatives including via its demand response programme or its grid support contracts including with distributed generators, battery owners and aggregators.

10 For example, Axiom Economics for Transpower, Eastland Generation cross-submission, ENA p10, Electric Kiwi p3, Horizon p1, New Zealand Wind Association, The Lantau Group (for The TPM Group) p12-14 26-29

11 Borenstein, 2019. See also Frischmann & Hogendorn, 2015 for a review of the economic debate on these issues.

4 Ensuring settings are appropriate

Practical settings v the theoretical ideal

4.1 A specific concern that has been raised is that the practical settings that deliver nodal prices do not reflect the theory so that the Authority cannot be certain its proposal will deliver more efficient outcomes. For example, Creative Energy Consulting (CEC), for Trustpower, notes (p5):

"Currently, with no nodal scarcity pricing and very limited demand-side participation, it is unlikely that nodal prices live up to the [Authority's] theoretical ideal…. Possibly that might be achieved, or being closer to being achieved, in the future. But an effective TPM must reflect the practical realities of today's market."

4.2 CEC considers improvements are needed to the conditions that deliver nodal prices, before they may be the best means of restricting the use of the grid to its capacity:

- scarcity pricing – so all demand (including unserved demand) has a price[12]
- more demand-side participation – because that further reduces the (small) risk that high-value load is curtailed with or instead of low-value load, which is inefficient
- enhanced risk management to deal with potentially more volatile nodal prices
- adjustment of some transmission investment policies – the reliability limb of the grid reliability standards may trigger grid investments early, suppressing nodal prices[13]
- a signal of the long run cost of maintaining and expanding transmission capacity to drive efficient generation and load users' investment decisions (but see our response to this in section 3 above).

4.3 The Lantau Group (p13) similarly notes nodal prices "do not have all the properties that [they are] theoretically supposed to have under the conditions where you can rely on [them] as a stand-in for any other form of transmission charge."

4.4 In the absence of such conditions being in place, CEC states (pii): "That means, at the very least, providing for effective and flexible transitional arrangements so that administered transmission prices can continue to fill the gap between the *ideal* and the *actual* nodal price outcomes."

Settings are good, but can be improved

4.5 The Authority agrees nodal prices do not meet the theoretical locational marginal pricing ideal, despite New Zealand's wholesale market pricing design being world-leading in many respects.

4.6 However, in the Authority's view, the relevant standard is not how close the proposal will get to attaining a theoretical ideal, but to how much of an improvement it is on the current charging arrangements or feasible alternatives. That is, settings need to be effective but do not need to be perfect for the proposal to be for the long-term benefit of consumers.

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12 Nova's submission suggests improvements to SPD formulae (q55).

13 Counties Power made a similar point in its submission. Orion stated a grid owner would be grossly negligent to wait for nodal (scarcity) prices to rise before considering investment, and that while it might anticipate such market outcomes, in its long term planning it should also consider for example reliability considerations.

4.7 Further, some of the concerns raised are overstated given the actual New Zealand electricity market arrangements, as discussed below.

4.8 Nevertheless, the Authority does agree that it would be desirable to continue to improve the settings related to nodal prices, and to provide for flexible transitional arrangements. And as Hogan (2020, p7) notes, “the solution would be to address any such problems directly rather than to use the instrument of transmission investment charging to balance other deficiencies in market design.”

Scarcity pricing

4.9 The current electricity market design already includes a scarcity pricing mechanism[14] that introduces a price floor and price cap to the spot market when an electricity supply emergency causes forced power cuts (called emergency load shedding) throughout one or both islands. That mechanism is somewhat rudimentary in that it influences spot prices at a New Zealand wide or island level, not at a nodal level.

4.10 Real time pricing (scheduled to become operational in September 2022) will implement the real time calculation and publication of spot prices.[15] This removes a major cause of uncertainty about what spot prices are, which will improve the quality of price signals, and real time action by generation, consumers, and their retailers and other agents, including aggregators.

4.11 The real time pricing project will also implement default scarcity prices, so all demand has a price, even when there is a supply shortfall and Transpower (as the system operator) instructs load shedding. It also delivers an economically meaningful price, because it is set to account for the cost of investing in new last-resort generation and the cost of load shedding. Most importantly, this scarcity pricing signal will be applied at a nodal level, rather than at a New Zealand wide or island level as currently occurs.

4.12 It means consumers and generators who can alter their operations at short notice will have much more reliable price signals to guide their actions.[16]

More demand-side participation

4.13 We expect new technology and business models, in conjunction with real time pricing, will lead to the substantial growth of market-based demand response, which can be dispatched into the wholesale market. Initiatives such as open networks and the default distribution agreement facilitate such developments.

4.14 Implementation of real time pricing will also include a Dispatch Notification class that seeks to help smaller-scale purchasers and generators to participate in dispatch, encouraging a broader and more diverse participation.

4.15 This mitigates CEC’s concern that load curtailment is fairly indiscriminate between high and low value load. The Authority’s current view is that this concern is overstated as it does not reflect how load shedding is in fact instructed in New Zealand. Nevertheless, under real time pricing, load management will become more visible and more valuable. This is because default scarcity pricing should ensure that load shedding results in high

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14 https://www.ea.govt.nz/operations/wholesale/spot-pricing/scarcity-pricing/

15 https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/development/real-time-pricing-project-update/

16 Scarcity pricing will also be signalled in the forward-looking schedules, potentially providing up to 36 hours’ notice of a possible scarcity situation.

spot prices that participants can act on, whereas today load shedding usually suppresses spot prices.

4.16 Submissions have expressed a concern that, as distributors are not exposed to nodal prices, they will stop hot water ripple control in the absence of a peak transmission charge, adding a substantial amount of low value demand at peak periods.

4.17 The Authority is aware of those concerns, but also notes that recent oral submissions by a number of distributors on this point suggested the RCPD signal played a modest role at most, as distributors tend to be more concerned about conditions on their own networks.

4.18 This accords with Concept Consulting's assessment (see also section 5), which is that, of an estimated 644MW of ripple control capacity available at peak times, the majority will continue to be used primarily for local network purposes, and some will end up being offered as interruptible load. A number of distributors already offer into the reserves market and also participate in Transpower's demand response programme.[17] This practice could be expected to increase to an extent, and new arrangements between distributors with retailers and third-party aggregators are also anticipated to emerge (noting submissions about potential current technological and contractual limitations). Emerging technologies will provide solutions and further facilitate mass market load to be more responsive to prices.

4.19 The removal of a strong RCPD charge could well assist distributors to design distribution pricing that more clearly reflects their own costs and network issues. Distributors are reviewing the efficiency of their pricing structures, by making them more cost-reflective and by using time-of-use pricing to manage their own network issues – the Authority has been encouraging distributors to do this with urgency, and progress is being made.

Price risk management

4.20 Some submitters pointed out that, if nodal prices work as the Authority anticipates, nodal prices could become more volatile. The Lantau Group expressed concern about the absence of hedges or contracts to deal with such volatility. Flick and Pioneer submitted better hedge (and spot) market arrangements should be put in place first.

4.21 Intermittent high nodal prices caused by transmission constraints would provide valuable information. A degree of price movement is vital in any market, and in the electricity market context signals the times and locations where more flexible generation, demand response or a transmission response would be most valuable. The Authority also notes the current TPM causes significant volatility in charges after-the-fact.

4.22 It is already the case that the New Zealand electricity sector provides services to help parties manage price risk:

- over-the-counter contracts – agreements between buyers and sellers on prices
- futures products offered on the ASX, facilitated by market-making arrangements – this also allows all market participants to observe the forward price of electricity
- Financial Transmission Rights (FTRs) that allow spot market participants to cover their price risks between two locations, or nodes, on the national grid.

[17] In its 2018/19 Annual Review, Transpower reported (p33) that 184MW of capacity was registered under the programme.

4.23 Nevertheless, we agree the proposal could increase the volatility of nodal prices, increasing wholesale market price risk for parties such as standalone retailers. That in turn could impede the entry and growth of new retailers and stymie competition.[18]

4.24 This underlines the importance of continuing to improve the hedge market, as well as other risk management tools, including demand response and access to DER. The Authority is progressing work that will improve and expand the options for participants, including market-making in the hedge market, information disclosure in the wholesale market, and Dispatch-Notification in RTP. In future, the number of Financial Transmission Rights (FTR) nodes and products could also be revised, depending on demand.

Grid Reliability Standards

4.25 Some submissions have stated that nodal prices will never rise high enough to effectively manage congestion, because of the reliability limb of the grid reliability standards (GRS), and that transmission investments are made primarily for reliability reasons, rather than economic considerations.[19]

4.26 Investments put forward for approval under the reliability limb do not need to show net electricity market benefits. The outcome is that transmission investment may be triggered before differences in nodal prices or other benefits justify it, or before alternatives to grid investment, such as generation or demand response can operate to defer or avoid grid investments. Decarbonisation objectives may do the same in future.

4.27 It is unclear how significant this issue will be in practice. Reliability investment proposals are still scrutinised by the Commerce Commission under the investment test, by the beneficiaries who will face the related benefit-based charges, and by potential suppliers of transmission alternatives.

4.28 A review of the GRS can be initiated if this turns out to be a significant issue for the efficient operation of the TPM. If that turns out to be difficult or time consuming to resolve, the transitional peak charge provisions of the proposed guidelines are sufficiently flexible to allow an appropriate congestion charge to be implemented.

18 For example, CEC p4-9

19 For example, see The Lantau Group, p26 Axiom pxii and p28, Counties Power p2

5 Re-assessment of the winter capacity margin

5.1 The Authority commissioned Concept Consulting to update its 2016 assessment of the effect of removing the RCPD charge on the ability to serve peak electricity demand. This reassessment considers how participants may change their behaviour at the outset:

- many distributors use hot water ripple control to manage their own network, which would not change in the absence of a peak transmission charge. Any operational changes are likely to be phased-in (rather than be abrupt)
- distributors will have incentives to offer ripple control into the reserves market as instantaneous load (as a number of North Island distributors already do)
- industrial demand response that is focused solely on avoiding the RCPD charge will cease, although the associated volume is small compared to ripple control capacity
- most distributed generation will continue to supply during system stress (eg peak) as spot prices will exceed the short run marginal cost of generation, except for diesel.

5.2 Concept found the Authority's proposal would reduce the total projected winter capacity margin to be at the upper end of the optimum economic range (or, less likely, below or well below that range in two sensitivities) around the first year of implementation – that is, it is not likely to cause general operational difficulties.[20] There are uncertainties, such as with data sources, but the main source of uncertainty is how distributors with significant ripple control capacity will react.

5.3 In terms of risk in the Upper South Island and Upper North Island – the same regions Transpower used as case studies in its 2018 paper – Concept concludes as follows:

- Upper South Island – removal of the RCPD may well bring forward the need for transmission investment, but that would be within the context of significant underlying demand uncertainty and revisions in projections
- Upper North Island – removal of the RCPD would have a smaller impact (95MW) than assessed by Transpower in 2018 (181MW), primarily because hot water ripple control by distributors is assessed as operating for their own network purposes

  Transpower currently indicates the Waikato and Upper North Island (WUNI) transmission investment may be required for winter 2023. If a new TPM based on the proposed guidelines were to be implemented earlier, say in 2022[21], Concept considers the demand may need to be managed earlier.[22]

5.4 These findings indicate that, given uncertainty is greatest at the start of a new TPM, it is prudent in the context of the Waikato and Upper North Island region to consider the roles of targeted demand response, grid support contracts with distributed generation, or a targeted, temporary transmission congestion charge.

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20 The winter capacity margin reflects the ability to serve demand during peak periods or in case of an unexpected generation or transmission outage. The economic optimum range is based on the trade-off between the risk of shortages and cost of additional generation plant. In the two less likely scenarios there would be a "higher chance of not being able to meet demand during a cold winter evening".

21 No decisions have been made on implementation timing, as the Authority's review of TPM guidelines is ongoing.

22 Transpower has sought Commerce Commission approval (draft decision for consultation due May 2020) for the first stage of WUNI voltage stability project. The proposal includes a post-fault demand management scheme and the future investigation of non-transmission solutions.

6 Next steps: managing the risk during the transition

Acknowledging the uncertainty

6.1 The Authority appreciates that many stakeholders are not wholly convinced about that aspect of its proposal which would rely on nodal prices to constrain demand to available grid capacity and that stakeholders have asked that the proposed TPM guidelines provide for a peak or LRMC charge.

6.2 Noting the review of the proposed TPM guidelines is still ongoing, and no decisions have been made, at this point the Authority considers that the concerns raised by stakeholders can be managed by a range of mechanisms that would be available: nodal prices, Transpower's option to deploy demand response or to contract generation to defer or avoid grid investment, and the option of a transitional congestion charge.[23]

6.3 We have confidence that, in aggregate, the proposed guidelines would not have a material impact on the reliability of supply in periods of peak demand or congestion. However, the Authority acknowledges there are uncertainties, particularly at the outset.[24]

6.4 Risks could be more acute if some of the anticipated developments, such as real time pricing, were not implemented as expected. We can also not be 100% sure of how participants would react to change.

6.5 For example, Concept notes contractual arrangements between parties might impact on how ripple control use will react to changed incentives. Vector made a related point in its submission, and Orion submitted that at least their ripple control technology currently does not support nimble and targeted load management. As Buller Electricity noted in its submission, it may well take some time for new business models and load management practices to emerge if transmission peak charges were unwound, and for these changes "to become evident and accepted".

Managing the risk

6.6 As is discussed in section 3 above, this uncertainty is a key reason the Authority is proposing a transitional congestion charge as an additional component of the proposed TPM guidelines. It would provide Transpower with an option in case some form of charge were to be needed in addition to nodal pricing to efficiently manage congestion until transmission expansion could be justified.

6.7 Transpower would be the best party to identify and propose if and where a specific targeted congestion charge is needed – it knows the network and the specific congestion risks and is best placed to assess how to mitigate those risks; for example, whether that should be a targeted congestion charge, local demand response, a local distributed

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23 Orion at paragraph 42 of its submission stated that the conditional and time-bound nature makes the peak pricing component an empty concept, and that – while it prefers some form of peak pricing – it might be OK not to have a transitional peak price if Transpower has sufficient flexibility to enter into demand response or other bespoke arrangements that reward network support, and if this is funded from the residual.

24 As RCPD charges are based on customers' demand patterns in the prior year, it is possible that transmission customers change their behaviour in the year before a new TPM is implemented. This brings forward benefits in the situations where the RCPD charge inefficiently suppresses demand. But in locations with constraints it could bring forward the risks discussed in this paper. Such risks can be managed through the range of mechanisms described, noting also that the operational details of a new TPM would also be known in advance which would affect incentives.

generation response, or administrative load control. This is why the task of identifying specific requirements and developing the detailed design is left to Transpower.

Further engagement with industry

6.8 Having said that, the Authority also recognises the value to participants of understanding how this would work. Further, the Authority considers that risks discussed in this paper are likely greatest in the early stages of implementation.

6.9 Therefore, if the Authority's proposed guidelines were to be adopted, we agree that it would be useful to progress work on designing a potential transitional congestion charge as soon as possible, so that stakeholders have more certainty of its design ahead of implementation of a TPM consistent with any new guidelines. This work could be considered specifically in the context of locations with current or emerging congestion-related operational requirements (eg, the Waikato and Upper North Island or the Upper South Island).

6.10 The Authority has spoken with Transpower, and Transpower concurs there is merit in it leading a sector workshop on the design of practical parameters. As this is contingent on the guidelines that the Authority may decide to adopt, the details will need to be confirmed later, but at this stage the intent is for a workshop to occur in the middle of the year. The scope of such work would be to start the design of the practical parameters for such a charge.

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