Orion

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SUBMISSION ON TRANSMISSION PRICING REVIEW – 2019 ISSUES PAPER

Introduction

1 Orion New Zealand Limited (**Orion**) welcomes the opportunity to comment on the "2019 issues paper – Transmission pricing review" consultation paper (the **paper**) released by the Authority in July 2019.

2 The primary focus of this submission is the aspects of the proposal in the paper that are materially different or new compared with previous proposal(s) and which might lead us to revise our previously expressed views.

3 As we see it the changes are in four key areas:

3.1 The very different cost benefit analysis (CBA) result and in particular the significant benefits said to flow from the removal of RCPD,

3.2 The link to the recently revised distribution pricing principles,

3.3 The even stronger reliance on nodal prices as a signal that supports efficient grid investment, and

3.4 The proposed method of allocating the residual using anytime maximum demand.

4 We also include more general comments on the paper.

5 In preparing this submission we have had to deal with the fact that the proposed guidelines are in many areas quite permissive of Transpower exercising discretion as it develops the detail of the TPM, but subject to the Authority approving Transpower's exercise of that discretion. We have generally taken the view that the Authority is unlikely to approve proposals that are materially different to the position it has taken in the paper. Obviously our perspective on the TPM that would actually emerge from the proposal could be quite different, but we do not know at this stage what that actually would be.

6 In summary we consider that:

6.1 The benefits of the proposal as set out in the CBA are illusory and are based on a number of misconceptions,

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6.2 There are significant contradictions between the proposed TPM and the distribution pricing principles,

6.3 Nodal prices are not sufficient to ensure good grid investment planning and decision-making, and

6.4 Anytime maximum demand, and especially as conceived in the paper, is not a reasonable basis for residual cost allocation.

7 Overall we believe that much less ambitious changes to the TPM, delivered via more principles-based guidelines from the Authority would achieve most of the Authority's objectives at lower cost and have a much lower risk of unintended consequences.

8 The remainder of our submission is in two parts:

8.1 Comments on key aspects of the paper, particularly with respect to previous comments we have made, and

8.2 Comments on some other aspects of the paper.

9 We have not specifically responded to the questions in the paper.

10 The Electricity Networks Association (ENA) has also submitted on the paper. Orion endorses the ENA submission.

Comments on the changes

The cost-benefit analysis and RCPD

11 The paper claims net benefits of around $2.7 billion in present value terms from the proposals. This is a more than a factor of ten increase from the CBA associated with the 2016 paper, for what is, in essence, the same proposal.

12 Central to the much larger benefits – making up about 90% of them - is a new and in our opinion radical inclusion of an estimate of the allocative efficiency losses associated with RCPD. There is nothing wrong with radical, but obviously it needs to be subjected to even greater scrutiny than more orthodox approaches.

13 We have not analysed the workings of this approach in detail, so our comments here focus more on the conceptual basis of the method as set out in the paper (for example Figure 1 on page vii) and companion material, which we first describe.

14 In essence RCPD is seen as discouraging grid use (consumption) at peak times, but since there is not actually a constraint at those times, this reduced consumption comes at a cost – a considerable cost.

15 To estimate this cost, a TOU pricing structure is first devised that reflects RCPD charges. To allow for the fact that it isn't possible to say exactly when the top 100 RCPD trading periods will occur, the peak price period is defined as being the top 1600 trading periods, which is roughly two four-hour blocks (or 16 trading periods) every working weekday (20 per month) for the (5)

winter months. Recovering the roughly $100 per kW per year of RCPD over this period implies a price of around $125 per MWh during these peak TOU periods. The RCPD price at all other times is zero. The method then sees this $125 being added to the spot price at peak times, so roughly doubling the effective nodal price that consumers face.

16 Because there is (in the model) no actual economic cost to meeting demand at these peak times, the $125 is effectively a hefty tax or premium on consumption at those times. There is a deadweight loss associated with this premium, with the magnitude of that loss depending on the elasticity of demand.

17 The proposal is to replace RCPD with what are seen as much more incentive-free arrangements. This looks to be modelled for CBA purposes as being the equivalent of recovering the relevant part of transmission costs on a flat-rate basis - presumably around $20 per MWh. (It can't be - or stay - zero because Transpower's revenue requirement must still be met.) In other words the peak / off peak TOU structure is turned into a flat rate structure. The segmentation of the market into peak and off-peak must then result in the reduction of deadweight loss for the 'peak market' (resulting from the price going from $125 per MWh for transmission down to $20 per MWh) exceeding the increase in deadweight loss from the 'off-peak' market (resulting from the price going from zero to $20 per MWh).

18 In due course the changes to consumption patterns flow through to nodal prices with higher peak prices and lower off-peak prices. Together these create a further net increase in consumer surplus.

19 We make the following observations on this method:

19.1 The paper acknowledges that, as of now, perhaps not many consumers face prices as posited, but that this will likely increase over time as distributors change to more cost reflective pricing, including TOU, and nodal energy prices change to reflect changes in demand. We challenge this, and we believe it reflects a fundamental flaw in the logic of the deadweight loss modelling. (It also highlights a problem with TOU pricing that we have been highlighting for several years[1], but that is for another discussion.)

19.2 The fact that a distributor *might* decide to structure its pricing in a TOU way so as to recover RCPD based transmission costs does not mean that it can sensibly or sustainably do so over time if that pricing leads to the response presumed. The nature of RCPD is that it is a zero sum game, at least in the short term. If a distributor introduces a TOU pricing structure that creates any sort of response to avoid the high price periods, it will certainly get less revenue, and so can expect to under-recover its transmission costs in any year. But there is no reason to suspect that the reduction in *consumption* during the TOU peak times will reduce either the RCPD kW result or, even if it does reduce the kW, the RCPD charges for the following year. The only sensible response to this outcome is for the distributor to reduce the price differential so that there is no inefficient response. In the limit this reduces to the flat rate counterfactual response that we believe is used to deliver more

[1] For example see https://www.oriongroup.co.nz/assets/Company/Corporate-publications/Retailer-Consultation-Paper-Final.pdf, p17.

than $2 billion of deadweight loss benefits in the CBA. But since the factual is an implausible disequilibrium these benefits are entirely illusory.

19.3 It concerns us that so much of the CBA modelling is based on what looks to be a misconception.

19.4 Leaving aside these more fundamental concerns, we note that consumption at peak times is described as being "highest value" (para 3.21, page 17). We agree. To us this should mean that the elasticity of demand in the peak market is much lower (more inelastic) than in the off peak market. Yet the companion technical paper (Table 13) has a peak period elasticity value of -0.49, while off peak is slightly higher at -0.43. We have not delved deeply enough to be sure how these elasticity estimates were arrived at, but we can say they are counterintuitive given the "highest value" description. To us this further calls into question the reliability of the deadweight loss results. We note a more orthodox arrangement for recovery of 'natural monopoly' revenue in a least distortionary way is Ramsey pricing where the price should, in this example, be higher in the peak market than the off-peak market.

20 The CBA includes a less material but still significant (around $200 million) benefit of the proposal that would result from deferring or avoiding a very large amount of inefficient investment in utility scale batteries - about 3,000MW by 2040.

21 The modelling of battery investment decision-making is set out in the companion CBA technical paper. Unlike the deadweight loss calculations, it does not assume that batteries would respond to a known TOU price structure. Rather the charging and discharging of the batteries follows a strategy of seeking to minimise an RCPD quantity, while acknowledging this is an uncertain business.

22 We have not analysed the modelling in great detail but we note the following:

22.1 As mentioned at the technical workshop, the modelling appears to assume that the battery can costlessly connect to a network. This is not the case. By way of example, on the Orion network a 1 MW connection would pay around $65,000 per year, for capacity related charges and around $5,000 per year for the transformer. These charge components are not avoidable via RCPD response. Together these are approximately the same as the annual costs of owning and operating the battery as of now (based on the $733k per MW, and excluding the cost / value of energy). Unlike the battery costs, there is no reason to expect that these charges would decline over time. We are unsure if the modelling has taken this cost into account.

22.2 Assuming the battery owner could find an agreeable distributor it might be able to have a pricing arrangement that allowed it to face zero peak related charges if it can avoid charging the battery at all during RCPD periods. This is not a financial benefit to the battery owner by way of *reduced* delivery charges, but it would make the incremental cost of charging pretty much just the cost of the energy.

22.3 The distributor might further be prepared to pay the battery owner ACOT for any amounts exported during RCPD periods, but this is unlikely as such payments are not (any longer) recoverable costs under Part 4 price-quality regulation. We are unsure if Transpower would be prepared to make demand response payments to the battery owner, but even if it was such payments can hardly be laid at the door of RCPD.

22.4 More generally, the RCPD battery investment model appears to assume that incremental investment in batteries will continue to provide material gains when it would appear more logical that these would reduce over time. As battery capacity increases it will become increasingly difficult for a battery owner to avoid RCPD peaks (which, as a reminder, are determined retrospectively) given that many other battery owners will be trying to do the same.

23 There is no doubt that RCPD creates some perverse incentives - we have yet to see a network pricing arrangement that does not - but we do not believe that these manifest as material allocative efficiency losses and further that there are significant productive and dynamic efficiency gains. It might be helpful to set out our perspective on it in the context of the arguments in the paper.

23.1 In very simple terms, Orion considers that prudent network owners invest to accommodate peak demands. While this doesn't directly relate peak demands to periods of highest value consumption, the paper's perspective on this is intuitive and reasonable. At least in the Orion area, peak demands occur when businesses are starting up, or households are getting ready for work in the morning or households are returning home in the evening. Underpinning these demands will be the need for lighting, heating, cooking, commercial and industrial processes, and entertainment. The cost to consumers of not being able to do those things at those times would be high indeed, which is why VoLL is such a big number.

23.2 A key attribute of these demands is diversity – the fact that customers do not all do everything, even high value things, at the same time. A typical house has probably 50kW of appliances of various sorts that might be turned on at some point, but the house will happily get by with a 15kW (60 Amp) supply fuse, set a half hourly anytime maximum demand of around 8kW yet only make a 3kW contribution to coincident network peak demand, the latter being the demand that drives HV distribution network investment and transmission investment.

23.3 But within that peak demand there will always be some uses of energy that are not so immediately valuable and which can be deferred at least for a while. The standard example is storage water heating. Where these uses can be managed in a coordinated way at peak times it allows for a lower level of peak capacity to be built - we can do even better than diversity – and so the same amount of energy can be delivered over a smaller capacity network – a straightforward productive efficiency benefit that translates into dynamic efficiency when considered over time and across the supply chain (there being a related reduction in the need for peak generation capacity). This approach has been a feature of distribution network design, build and operation in New Zealand for decades. Generally, end-consumers choosing to contribute to this coordination partnership are rewarded by some form of price discount. RCPD, whatever its other limitations, is consistent with this longstanding arrangement.

23.4 This coordination typically acknowledges that the cost associated with deferral of these less critical components of demand starts off very low, and increases with the duration. Most distributors manage this trade-off by the use of service levels, which set a limit on the amount of time that loads can be off within any given period. For example Orion has a 'no more than 4 hours off in any 8 hours' standard. The basis of this standard is to attempt to deliver the coordinated load management in such a way that there is no impact on customers.

23.5 The arrangement also has a key attribute that it cannot easily be retro-fitted. Having some form of reward as a sustained component of pricing helps ensure that new connections (mainly houses) will be built so that storage hot water heating will be sized to be consistent with participation.

24 Whatever the apparent problems with RCPD, they also need to be considered in light of the flexibility inherent in the structure, notably:

24.1 The number of trading periods used for assessment is effectively completely variable anywhere between 1 and 17,520 (in any year) enabling almost continuous smoothing. It could even, in principle, be extended over multiple years,

24.2 It can accommodate any number of areas, and in principle the cost of service provision in those different areas could be different (that is, not postage stamp),

24.3 It tends to pick up changes in grid use over time reasonably well, and automatically, both across and within regions, and

24.4 Being a coincident demand measure it inherently allocates the cost of a shared service more reasonably than other demand measures.

25 Finally, if the paper is correct that a flat-rate representation of RCPD can deliver more than $2 billion of benefit:

25.1 This should be ample reason to specifically regulate *now* how distributors recover transmission charges so that they are *not* recovered on a TOU basis. At the very least the pricing principles and practice note should clearly signal the expectation.

25.2 Distribution network cost and investment drivers are not materially different to transmission and our conventional wisdom has also been that avoiding use at peak times (using low cost deferral mechanisms) is generally a good thing. We should thus assume that a move to a TOU approach to distribution pricing will deliver allocative efficiency losses at least as great as those said to flow from TOU recovery of transmission costs, again suggesting a clear regulatory response.

26 Such regulatory responses would help guide distributors now on pricing changes currently under consideration, which predominantly include moves *towards* TOU. We discuss other aspects of the relationship between distribution and transmission pricing further below.

Links to the distribution pricing principles

27 The paper states (page iii) that the proposed TPM is "aligned with" the distribution pricing principles recently revised by the Authority. We consider that this view is not well founded.

28 The discussion above on the CBA highlights the inconsistency between TOU pricing and allocative efficiency. But the pricing principles and in particular the associated practice note and scorecards state that TOU, while not ideal, is better than flat rate.

29 But much more fundamentally there is an inconsistency between the subsidy free test in the principles and the approach being proposed in the CBA. The principles reflect the orthodoxy that due to the features of natural monopolies there is a wide range of distribution prices – between incremental cost and standalone cost – that are allocatively efficient. The CBA methodology turns this on its head.

30 However, what this pricing discussion does highlight is that to the extent that the TPM is a pricing methodology at all - as opposed to a cost allocation methodology - it is what distributors do with it in their own pricing that matters, as that is what most consumers actually see, even if this is in turn via the pricing structures that retailers offer.

31 This is more than a concern about the low-fixed charge regulations (and our views on that are not repeated here). The two key components of the proposal are:

31.1 A benefits based charge to transmission customers which is pretty much a fixed share of the cost of an investment for the life of the investment and determined at the time of the investment, and

31.2 A residual charge that is based on historical AMD shares and designed to be as incentive free as possible.

32 These are both discussed elsewhere in this submission from other perspectives, but here we simply focus on what a distributor can, and can't do with them. In short, we do not have the ability to on charge retailers or end-consumers in either of these ways; one way or another consumers pay an amount related to their use of the network and the service they receive from it, be that a fixed charge (regulated or not), a capacity charge, a demand charge or a consumption-based charge or charges. These can be organised in ways that *reduce* the ability to avoid them, but they never match the attributes of the proposed TPM charges. In considering the TPM then, we urge the Authority to think about what can realistically be achieved rather than what might result in the unattainable, and undesirable world where we can contract with retailers and end consumers in the same way Transpower contracts with distributors.

The role of nodal prices

33 The paper takes a more definite position than earlier papers on the primacy and sufficiency of nodal prices in supporting efficient grid investment.

34 The invocation of Hogan is heroic, but we see nothing that undermines the positon set out in the Authority's LRMC working paper:

> "However, nodal pricing is likely to result in price signals systematically below LRMC [because]
>
> > (a) the SRMC of the use of the transmission network is signalled through differences in nodal prices – but if spot prices do not reflect the true value to customers of lost

load, price differences will at best send a muted signal of the true marginal cost of the transmission network. While scarcity pricing has been introduced in New Zealand, its application is limited to separate scarcity prices for the North and South Island, so the value of lost load at a more disaggregated level is still not priced. This means within-island price differences, at least, send a muted price signal below the true marginal cost of the network…"[2]

35 Put another way, any grid owner that waited for a scarcity price[3] to actually occur before considering investment would be grossly negligent. It is perfectly sensible for the grid owner to consider the current wholesale market outcomes and how they might change over time as a result of various scenarios. But it will never be acceptable to *only* do that. The results of a model that by necessity is a quick-to-solve short-run DC approximation of the grid can never substitute for a considered medium to long term view of the grid and the market acknowledging voltage, reactive power and reliability considerations. We are confident that VoLL is an important input to grid planning irrespective of how nodal prices are determined.

36 We can also say, as a stakeholder in the process, that we are largely indifferent to nodal prices. We will, perhaps even more than the grid owner, be focussed on whether the proposed investment is justified for medium term capacity and / or reliability / quality reasons, and if it passes those tests, whether the proposed timing is right and available alternatives have been adequately considered.

The residual and AMD

37 Under the proposal the residual seems likely to be large, at least at first. The paper proposes using historical AMD as the basis of the allocator.

38 AMD, at least from a distributor perspective, is a good allocator of costs associated with assets that are close to / more specific to the customer (for example transformers) but not very good for allocating the cost of shared assets that are higher up the network, such as the sub-transmission network, where some measure of coincident demand is more appropriate. The residual costs being allocated under the proposed TPM relate to shared assets not specific assets.

39 If AMD is to form part of transmission cost allocation, we have the following comments:

39.1 AMD, at least when measured at (calculated at and then summed across) GXPs, tends to overstate the share of distributors with multiple GXPs, other things equal.[4] This random effect will be exacerbated where a distributor switches load on its network in such a way that it is fed from different GXPs. This is at odds with the principle stated in the paper that similar circumstances should lead to similar cost outcomes. It can be readily resolved by taking the AMD after summing interval data across a wider area, say balancing area. This approach would also deal with the possible anomalies associated with changes such as

[2] Electricity Authority, Transmission Pricing Methodology Review: LRMC charges Working paper, July 2014, p30. A number of the other good reasons set out in that paper are not repeated here.

[3] The real-time pricing project will implement a wider scarcity pricing approach than was in place when the Authority wrote the LRMC paper, but we do not believe that changes the substance of our argument.

[4] It will do this except in the highly unlikely event that each GXP AMD occurs at exactly the same trading period.

distributor acquisition of GXPs. We note by way of example that the data analysed for Orion includes demands for Addington and Middleton in 2014/15, effectively double counting those demands in that year as Orion acquired the GXP during that period. This overstates Orion's AMD (compared with the following years) by over 100MW.

39.2 A single AMD in any year is not a good measure. It will tend to be volatile over time (a concern the paper expressed with respect to RCPD in the Ashburton case study) and be a rather random allocation across distributors. We strongly suggest that this be smoothed by taking the average of the top, say, 100 half hours.

39.3 While we understand the rationale of using historical measures to reduce the risk of inefficient avoidance in future, there is a trade-off in that circumstances do really change over time yet it is difficult to avoid locking in circumstances from too long ago if this approach is taken too far. As with RCPD, the ability to avoid charges decreases with an increase in the number of averaging periods. On that basis it would be better, we think, to use more recent data but more of it, rather than less data from potentially, 10 years ago.

39.4 A further aspect of the proposed approach to AMD is the adding back of DG (actually export, which isn't necessarily the same thing). Again we understand the rationale, but it does seem to be creating a significant impact on at least two small South Island distributors (not Orion), which in turn leads to the need to cap the increases for those two. Perhaps durability and simplicity would be served by letting some bygones be bygones with respect to the residual.

40 In the absence of these types of changes we consider that the proposal to use AMD to allocate the residual is unacceptable. Even with our proposed changes we consider it to be inferior to some coincident demand measure for the purposes of allocating shared costs.

Comments on other aspects of the paper

Peak pricing

41 We believe that some form of peak pricing can play an important role in ensuring that grid investments are efficient – the right size at the right time. It is pleasing that the proposed guidelines permit Transpower to develop a peak pricing component.

42 However the permission is proposed to be conditional and time bound, and as such renders the concept empty in our view. An effective peak pricing signal is long term. Moreover, the development of the concept and technical details will involve significant resource. Either the guidelines permit Transpower to develop a peak pricing component at and for any time, or they don't permit it at all. We note though that an approach of not permitting might actually be OK if Transpower's ability to enter into bespoke arrangements (like demand response) is sufficiently flexible. We note that our own thinking, perhaps aligned with some of IPAG's thinking, is that arrangements that reward the availability of network support (with discretion over its use) might be the best approach. Under such an approach any such payments would be funded from the residual.

43 If the final guidelines do permit a peak pricing component on an enduring basis, then the way this interacts with the other charge components needs further work. In our view the guidelines need to be set up in such a way that the introduction of a peak pricing component does not

increase the amount the customer(s) it is applied to pays when compared with not having the peak component.

Benefits-based cost allocation

44 The transmission system benefits everyone, all the time even when it is lightly loaded. There is no electricity market and indeed no modern economy without it. In this sense transmission pricing and cost allocation has always been and will always be benefits-based. But the question is whether applying an SPD-based approach (or possibly some other approach for future investments) to all major future and some existing transmission investments captures and assigns those benefits reasonably and usefully, and materially improves future use and decision-making.

45 With respect to some existing investments, the key argument for this is that it is required for durability. Put another way, it is required to quieten parties not wanting to pay as much as they currently do for some assets, notably the HVDC and significant parts of the grid recently built in the north of the North Island.

46 It has never been clear to us why such an approach, if it can be done reliably at all, should not be applied to **all** of the existing interconnected grid. As proposed (adding up the values in Table 12 on page 61 of the paper), only a little over a quarter of the current cost will be allocated via the SPD benefits method, leaving three quarters for the residual. We discussed the proposed allocation method for the residual above, but such a large residual almost guarantees that some parties are paying an inappropriate – when compared with benefits – share of the grid. We note the provision in the proposed guidelines for Transpower to include some form of this approach (allocating additional pre-2019 investments - “Additional Component E”) but this leaves a very material amount of transmission cost allocation very much up in the air. A key rationale for the proposal is stated in the companion brochure as *Transmission Pricing for the Future*: “The current charges spread the cost of regional transmission investments across New Zealand regardless of the benefit the users … get from the grid.” Indeed, and so to a very large extent would the proposed residual charges. Surely, and at the very least, the overall *proportions* of benefits from the seven historical assets is a better proxy for allocation of the remaining pre-2019 grid costs than what is being proposed? Being benefits-based it is *prima facie* superior under the Authority’s decision-making and economic framework.

47 More technically, the use of an SPD approach for allocating benefits – be it to existing or future investments – has been consistently criticised by a number of parties since first being proposed in 2012. Amongst the criticisms has been that the results are very much dependent on the assumptions, to the point where pretty much any result can be produced. We do not believe the paper has adequately addressed these criticisms. We acknowledge that the guidelines provide some flexibility around what benefits-based method Transpower applies, but the status being given to SPD approaches still seems unjustified.

48 What we can say is that the paper presents a good example of some of the criticisms. The 2016 second issues paper (Figure 32 on page 249) shows significant (around $20 million per year) benefits from the NAaN investments, mostly, unsurprisingly, to parties in the north of the North Island. By contrast the latest paper states that (para B.147 on page 139) “our vSPD modelling was not able to identify material benefits for transmission customers commensurate with the costs of these [including NAaN] investments.” What happened?

49 This NAaN zero result is then locked in via Schedule 1 of the proposed guidelines, which effectively means that NAaN costs can never be applied to its beneficiaries even if they do eventually emerge over its presumably long life. By implication if we could do away with the NAaN assets, we should. We probably can't do that at reasonable cost, but perhaps we can avoid the opex associated with maintaining and operating an asset that can apparently never provide any benefits? At the very least we can disconnect the asset and then remove it from the grid that is modelled for wholesale market pricing purposes. We exaggerate for effect, but for us this shows the limitations of the SPD method.

50 But even if NAaN was a bad investment that doesn't mean the rest of the pre-2019 grid was. Those costs might be able to be better allocated on a benefits basis. After all, it only has to be better than being allocated via the residual.

51 NAaN's new lowly status raises again for us the need to understand why bad investment decisions have been made in the past so that we can learn from this and make better decisions in future. All the paper tells us is that, on one approach to an SPD benefits assessment, NAaN was a bad investment. It tells us nothing about why. What was the information that should have been brought to the process that was not? Or was it an example of a decision that was good at the time – based on the best information then available – but bad in hindsight, as any decision can be.

52 One particular aspect of the proposed approach to benefits based cost allocation puzzles us greatly. This is the claimed need for this to be – in normal circumstances - largely locked in once an investment is made (for example in para 168). We can see and agree that during consideration of a new investment it would be useful for parties to have some reasonably accurate idea of the likely financial consequences. We consider this would be useful under any TPM. But what we cannot understand is the basis of the idea that once the investment is made the charge associated with it should be allocated in the same way for what, in the normal course of events, could be the life of the investment.

53 We do not follow the logic for this position, but in any case the paper provides a compelling argument against it in the context of the rationale given for, now, allocating the cost of the HVDC across a wider range of beneficiaries. This is set out in paras B59 to B61 of the paper. The situation with the changes over time in the role that the HVDC plays in the system can be written for any transmission investments, and what is more the story that might be told in 10, 20 or fifty years' time cannot be written now.

54 The only sensible approach within a TPM that will have to deal with material changes over time in the use of the grid - who benefits from it and by how much - is for this to be routinely updated and adjusted. It is fine to have some sort of materiality threshold (we think low) for changing allocations, and it is also fine to have transitional arrangements if for some reason the regular recalculation results in substantial swings in cost allocations. But it simply defies common sense to set the default to only change benefit allocations if the 'substantial and sustained test' is met. This pretty much guarantees that if and when a change is required it will cause angst and disputes due to the financial implications. For proof, think how much of the last seven years' discussion on the TPM has been about the extent of the step resulting from reallocation of HVDC costs.

Distributor load management

55 In the discussion on the proposed removal of RCPD it is suggested that distributors might nevertheless continue to carry out load management. We cannot speak for others, but Orion certainly will. However, the nature of that could change. Of particular relevance here is that load management is a cooperative activity: distributors might send, and continue to send signals, but consumers determine whether those signals do anything, and the consumer decision is based, at least to some extent, on price. If the price reflects value from the transmission system, and that value goes away, then the response to distributor signals will reduce.

56 Regarding using the capability for other purposes, we agree this is possible in theory, but note the following:

56.1 The capability is already available most of the time for other purposes, but we have been unable to generate interest in its use,

56.2 Orion's technology does not support participation in interruptible load, as the response is not fast enough (the ripple signal takes too long to propagate across the network),

56.3 When, admittedly some years ago now, we proposed to all retailers, at the request of one retailer, the specific use to help manage exposure to high spot prices one retailer opposed this. (As our load management is a broadcast signal we cannot restrict it to only a subset of retailers so, absent an agreed governance arrangement which we have suggested could be devised but which has not been forthcoming, unanimity is required.)

Transpower discretion

57 As well as some discretion in developing the TPM, the proposed guidelines would give Transpower discretion to change the allocation of charges. For example:

57.1 Guideline 26 allows changing the allocation of benefit-based charges,

57.2 Guidelines 33 to 38 set out a process where parties may apply for reassignment of charges,

57.3 Guideline 41 requires that there be a process by which the residual allocation can be changed.

58 It is difficult at this remove to tell how this will all work in practice, but we can see considerable scope for lobbying of Transpower by parties wishing to reduce their allocation of charges. This will be entirely rational for the parties, but could impose a significant burden on Transpower to design and manage the associated processes and potential associated disputes. We see some risk that the durability concerns that the paper sets out for the current TPM simply shift to Transpower as administrator of the TPM.

59 However there is one area where Transpower could usefully have some discretion and it would in our view be useful for this to be set out in the guidelines. We propose that Transpower have the discretion to reallocate charges between consenting designated transmission customers provided this does not impact on the charge to any other parties.

60 It might be thought that parties can agree to such arrangements outside of the TPM, for example by way of what is effectively a swap, and in principle they can. But charges established

under the TPM have a different regulatory status. Specifically, charges under the TPM are recoverable costs for distributors, whereas any payments or revenues made outside of the TPM are not.

61 The specific example we are thinking of here is the potential for smoothing of volatility of the sort described in the paper in the Ashburton case study. We acknowledge this is a particular feature of RCPD, which is not part of the proposal, but a general ability to enter into such swap arrangements under the umbrella of a new TPM strikes us as desirable to manage any volatility that might arise from the interaction of the various elements of the new TPM.

Capping

62 The proposed guidelines include a capping mechanism. Based on the indicative re-distributional impact of the proposal (Table 12) we make the following observations:

62.1 Given the significant lead time likely between when any new TPM guidelines become Code and when any new TPM is actually implemented by Transpower, there is a question of whether capping is required at all. Notice may be sufficient to allow participants to adjust.

62.2 A capping mechanism should in our view involve the parties whose charges reduce under the TPM compensating those that pay more, with this phasing out over time. The example in the paper (as captured in Table 12) envisages parties that pay more also contributing to the cap. This seems counterintuitive.

Concluding remarks

63 Thank you for the opportunity to make this submission. Orion does not consider that any part of this submission is confidential. If you have any questions please contact Bruce Rogers (Pricing Manager), DDI 03 363 9870, email bruce.rogers@oriongroup.co.nz.

Yours sincerely

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