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Proposed Transmission Pricing Methodology (TPM)

1. This is Vector's submission on the Electricity Authority's (Authority) proposed TPM.

2. The proposed TPM reflects the Authority's 2020 TPM guidelines, which have significant flaws. We do not consider the proposed TPM is in the long-term benefit of consumers as it will result in a substantial wealth transfer from consumers to generators.

3. Rather than incorporate the proposed TPM into the *Electricity Industry Participation Code 2010* (the Code), the Authority should revisit the 2020 Guidelines to address fundamental issues. This is the last chance to remedy these defects. Such concerns have been raised extensively by stakeholders repeatedly throughout the 10-year consultation process on the Guidelines.

4. We appreciate Transpower and the Authority have provided models to illustrate the potential impact of the TPM on prices in the short term. i.e. the indicative pricing for 2021/22. However, it is a concern that the long term and cumulative impact of price increases under the TPM remains unclear. This lack of transparency and the uncertainty it creates falls well short of regulatory best practice which the Authority should address before implementing the TPM.

The Authority should revisit the TPM guidelines to address fundamental flaws

5. Prior to incorporating any proposed TPM in the Code, the Authority should revisit the guidelines to address the following flaws to ensure the new TPM that is incorporated promotes the long-term benefit of consumers.

Benefit-based charge in the 2020 Guidelines

6. A key issue with the benefits-based charge is the Authority's decision to include historic investments. These are sunk costs so their inclusion is inconsistent with the intent of the benefit-based charge to provide pricing signals and encourage appropriate scrutiny of

transmission investments. Instead, the inclusion of historic investments will result in arbitrary wealth transfers for no efficiency gain and is punitive on nominated beneficiaries.

7. As explained in Vector's Compass Lexecon expert report, achieving efficiency requires sunk cost recovery to be done in a way that minimises distortions. This should be done using a "wide base" approach, applying a low charge on all users of the grid.[1] Accordingly, a wide-base should require all grid users to contribute to the recovery of sunk assets.

8. The TPM should be focussed on providing efficient location signals to generators since this is the largest source of transmission investment and generators are the party with the greatest ability to respond to these signals. Indeed, the new TPM removes the only locational signal in the old TPM – namely the high-voltage direct current (HVDC) charge. The HVDC charge allocated to South Island generators provided a locational signal of the transmission cost for generation to be located at significant distances from the key load centres (i.e. Auckland). Whilst the Authority has suggested this charge is distortionary it will encourage future generation to continue to locate at vast distances from key load centres and cause the need for substantially more transmission grid than a TPM that provides the right pricing signals for generation location.

Residual charge in the 2020 Guidelines

9. We remain strongly opposed to the decision to apply the residual charge only to load. The residual charge is required to recover the substantial portion of Transpower's RAB recovering its legacy sunk assets (excluding the historic beneficiary-pays assets). As discussed above, Compass Lexecon were unequivocal that a principled approach to sunk cost recovery should result in the "wide base" for recovery. This should result in all grid users – including generators - paying the residual charge.

10. The Authority's stated rationale for this decision - that residual charges on generation would be passed on to load through higher energy prices - has not been supported with empirical evidence. Vector has submitted two expert reports that show this should not be the case. The residual charge should be a fixed cost for generators and assuming the wholesale energy market is a competitive market then dispatching decisions would be determined by marginal costs.[2]

11. If that is not the case the conclusion must be drawn that the wholesale energy market is not effectively competitive, and generators retain sufficient market power for their bidding prices. If so, then it is more important for the Authority to understand the cause for market power and how that is undermining the long-term benefit of end-users than dedicating its resources to modify transmission pricing.

[1] Professor Pablo T Spiller and Marcelo A Schoeters, Transmission pricing in New Zealand: an Analysis of the Electricity Authority's Proposed Options (11 August 2015) at 6 -7

[2] Professor Pablo T Spiller and Marcelo A Schoeters, Transmission pricing in New Zealand: an Analysis of the Electricity Authority's Proposed Options (11 August 2015) and Professor Derek Bunn, A Commentary on the Electricity Authority 2019 Issues Paper on the Transmission Pricing Review (25 September 2019)

Removal of Regional Coincident Peak Demand charge in the 2020 Guidelines

12. We consider removing the RCPD charge without a replacement equivalent price signal at peaks will remove a significant lever for incentivising the uptake of peak shifting technologies and flexibility services such as load control which would ultimately reduce the need for expensive grid upgrades.

13. We note Transpower's analysis suggests that removing the RCPD would lead to a potential demand increase of 303 MW. [3] This is a significant increase and underscores the benefit the RCPD charge for the HVAC grid has delivered in terms of avoiding future investment.

14. For Vector, minimising the RCPD charge for our customers has been the dominant reason to control load during peak demand periods. With the removal of the RCPD charge, Vector will pursue other opportunities for its load control which will likely preclude us from load controlling during peak times. The new TPM therefore appears to have muted a key driver for peak demand management and encouraging flexibility services which are important attributes in an electrifying economy.

15. Accordingly, while the grid may not currently face constraints, this may not be the case in future and - if this occurs - incentives for peak shifting load control will be needed. If the RCPD is removed, it will be critical for Transpower to instead contract for peak shifting load control services to ensure load control is available in times of need.

<u>The 9 August grid emergency highlights load control is critical to system security</u>

16. The events of 9th August demonstrate the importance of peak shifting technology for the security of our energy system. On 9th August, a lack of generation, record demand and insufficient reserves led to a grid emergency resulting in more than 34,000 households losing power.

17. A key finding of the Hodgson review into the 9 August grid emergency is that the market requires much greater demand side participation. This is essential to achieve the goals of electrification and decarbonisation.[4]

18. The Hodgson report stated the following:

> "*The key findings of this investigation concern the demand side, its potential, its use, and its neglect.* ***While the demand side's discretionary load was put to good use in the 9 August event, it was underexploited. It could have saved the day entirely****. It ought to have been fully exploited, as the available supply side was.*

[3] Transpower, TPM – Removal of Regional Coincident Peak Demand: Outcomes for the System Operator (July 2021)

[4] Pete Hodgson and Erik Westergaard, Investigation into electricity supply interruptions of 9 August (November 2020) page 29

We propose that in future the demand side's discretionary load be accorded attention equivalent to the supply side."[5] [emphasis added]

19. We are unclear how the Authority reconciles its decision to remove the peak price signal with the findings of the Hodgson review. Rather than encourage demand side participation, the Authority instead risks putting a nail in the coffin for ripple control investment and maintenance.

20. We recognise the Authority and Transpower's view that the risk of widespread congestion is low and that Transpower can manage short term congestion risk with the tools available to it as system operator.[6] However, we are concerned that - in the absence of incentives for peak load control - this will not be sufficient in extraordinary circumstances such as the 9 August grid emergency.

21. Accordingly, if the RCPD signal is removed we recommend Transpower contract to ensure sufficient load control is available in times of need. Otherwise the system will be at risk of further - and worse - events like August 9th.

The new Standalone Prudent discount policy (PDP)

22. We consider the approach to assessing the PDP should be consistent with the way benefits are measured for the benefits-based charge – i.e. it should be based on a full supply chain benefit of grid connection relative to the benefit of a standalone system, along with the financial viability of technically bypassing the transmission grid elements, the proposed bypassing applicant should need to demonstrate that bypass provides the same level of benefits as the grid.

23. The PDP appears to have been designed specifically for New Zealand Aluminium Smelters (NZAS) and allows them to apply for a prudent discount based on the estimated costs of building a proprietary transmission line from Tiwai Point to Manapouri (despite the fact such a project almost certainly would not obtain the required resource consent so could not actually be undertaken). This application should be assessed on whether the line would also produce equivalent benefits to existing grid connection, such as supply security for both network and generation stock.

24. While we do not support the introduction of the PDP in its current form, we consider there will be bypass options in Vector's network that would meet the test of falling below standalone cost and hence would be eligible for a prudent discount under the criteria. We are exploring these options.

Contractual arrangements – interposed model for distributors

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[5] Pete Hodgson and Erik Westergaard, Investigation into electricity supply interruptions of 9 August (November 2020) page 29

[6] Transpower, TPM Proposal Reasons Paper (30 June 2021), Chapter 15: Transitional Congestion Charge at 55 - 58

25. The contractual arrangements for transmission also undermine the efficiency of the TPM.

26. The majority of transmission charges on load are levied through contracts between Transpower and EDBs as intermediaries for most load customers excluding a small number of direct connect loads.

27. The TPM assumes consumers face the price benefits from new transmission investments, however, there is currently no requirement on retailers for cost reflective pricing. Consumers may therefore not receive lower electricity prices to offset the higher transmission prices, thereby becoming worse off overall.

28. Prior to incorporating the TPM into the Code, the Authority should consider whether the transmission contractual arrangements are fit for purpose to deliver the efficiency gains intended by the TPM to the end user. It may be necessary for the Authority to implement retailer tariff pricing principles to ensure any price benefits are passed-through to consumers.

Comments on the proposed TPM

29. Our comments on the proposed TPM are set out below. As discussed above, we are concerned that neither Transpower or the Authority have been able to provide an indication of the potential future impact on transmission charges (for example, in the next 10 years).

Benefits-based charge in the proposed TPM

30. The proposed TPM provides three methods for allocating costs under the benefits-based charge.

31. As described by the Authority's consultation document, the price-quantity method uses modelled price changes to determine regional beneficiaries, and then uses either quantities during periods of benefit (standard method in clause 52), or both quantities and prices (clause 53), to allocate between the identified beneficiaries.

32. It is left to Transpower's judgement whether the standard method in clause 52 or the clause 53 method is used to allocate costs. Transpower will use the clause 53 method if it determines quantity alone would not result in an allocation that is broadly proportional to expected positive net private benefits.

33. This exercise of judgement could have a significant impact on transmission charges so, along with the criteria provided in clause 53 of the TPM, we consider stakeholders should have an opportunity to provide their views as to which method is used.

34. We note the standard price-quantity method involves netting private benefits and private dis-benefits to determine overall benefits. However, to allocate the charges peak or flow is used. We are concerned whether this could result in a supplier with a private dis-benefit still ending up with an allocation of the cost.

35. For the resiliency standard method, we are unclear why this approach spreads costs across load customers only given generators will equally benefit from resiliency investments that prevent island wide cascade failure. Consistent with the intent of the benefits-based charge, the resiliency standard method should include generators along with load.

36. For the simple allocation method, we agree the proposed 50:50 split between load and generation is appropriate.

37. Given the impact on transmission charges - and the intent behind the benefits-based charge - identified beneficiaries should have express rights to scrutinise, and where appropriate veto, investment plans.

38. We support Transpower's decision not to include additional component E which would extend the benefit-based charge to other pre-2019 benefit-based investments. We agree with Transpower and the Authority's reasoning that the complexity and administrative costs involved in implementing additional component E would outweigh any benefits.

39. These investment costs are sunk so we do not consider any potential efficiency benefits could arise from including additional pre-2019 investments. Accordingly, we do not consider the proposed TPM should leave open the possibility of including additional component E at a later date. This will create further uncertainty for no additional benefit.

Adjustments

40. We agree with the Authority's intention stated in the consultation document that "the proposed TPM would require Transpower to reduce the BBC for a transmission investment in certain circumstances if the investment turns out to be a 'white elephant' and customers make significantly less use of it than Transpower had originally anticipated."

41. However, the consultation paper also notes "Transpower considers there is no need for such an additional provision regarding reallocation, in part because reallocation will rarely if ever be an appropriate response to oversizing, and in any event because the adjustment provisions capture events, (eg, a large customer exiting) that could result in over-sizing and because the provision is inconsistent with the allocations being fixed-like. Thus, reallocation of charges between customers (in contrast to the reduction of the covered cost for a BBI) is unlikely to be needed."[7]

42. We consider the proposed TPM should include an additional provision to reduce charges if Transpower's forecast demand fails to materialise. While we agree with Transpower any use of such a provision is likely to be rare, its inclusion would provide a better incentive against overbuilding.

[7] At 8.53 - 8.54

Recovery of opex

43. We note the consultation document states overhead opex is recovered through benefits-based charges while opex attributed to fully depreciated benefits-based investments is recovered through the residual. We are unclear why this opex is removed from the benefits-based charge given it is still incurred for these beneficiaries.

Residual charge

44. As discussed above, we are strongly opposed to the residual charge being applied solely to load.

45. The approach in the TPM has been designed to place batteries on equal footing with generators. However, this is a narrow lens to consider grid connected batteries.

46. Charging batteries based on gross energy rather than gross anytime maximum demand (as applied to other load customers) is discriminatory to load and may have distortionary effects. We consider it vitally important the new TPM is technology neutral across all customers.

47. If the Authority adopts this proposal, Vector recommends all load customers be levied on a gross energy basis. This will ensure there are consistent pricing incentives for all potential options for flexibility and alternative generation offerings. We note a gross energy basis for levying customers does remove the nexus of the charge from the driver of transmission costs, being peak demand.

48. It is critical flexibility is encouraged in all its forms rather than bespoke pricing arrangements to different forms of flexibility (such as that offered by grid connected batteries). The Authority needs to develop a residual charge that is technology agnostic and provides appropriate incentives to all forms of flexibility.

49. In the current form, the technology specific difference for batteries being charged on gross energy and other loads on historical gross anytime maximum demand is a clear distortion and should be remedied before the new TPM comes into effect. Accordingly, we recommend all load be charged on gross energy.

Connection assets: first mover disadvantage

50. The proposed TPM contains provisions to address two potential competition issues around connection assets, being:

- Where the first mover bears the full cost of a connection asset even if other customers connect, termed the First Mover Disadvantage Type 1 (FMD Type 1); and
- Where the first mover must carry the full cost of connection capacity in excess of its own requirements, until subsequent customers connect (FMD Type 2).

51. We recognise the value identified by Transpower and the Authority of progressing solutions to FMD issues now ahead of increased electrification and new generation.

<u>FMD Type 1</u>

52. Transpower should also consider the impact of its New Investment Contract (NIC) practices on connection customers.

53. The current terms of NICs generally prescribe a five-year recovery for assets creating a significant difference between the technical life and cost recovery profile of an asset. As part of the solution to the FMD problem, we encourage Transpower to revisit the terms it offers for NICs as this should help reduce the magnitude of the problem it has identified with connection assets being fully recouped from first movers.

<u>FMD Type 2</u>

54. In our view, if Transpower unilaterally decides additional capacity is warranted for a connection customer then it should bear this risk for deploying the additional assets until that capacity is online.

55. The Authority has proposed a benefits-based approach to connection charges to recover costs associated with any anticipatory capacity of investments. If this approach is progressed - consistent with our comments on the benefits-based charge - anticipatory beneficiaries should have express rights to scrutinise, and where appropriate veto, investment plans.

56. In addition, there would need to be a reallocation mechanism if the anticipated demand fails to materialise.

Transpower costs

57. We note the Authority recently requested the Commerce Commission (Commission) reconsider Transpower's individual price-quality path (IPP) to recover its costs incurred in developing the TPM.

58. We would welcome guidance from the Authority as to when it would request the Commission reconsider a price-path under s54V of the *Commerce Act 1986.*

General comments

59. Beyond the TPM, we have provided comments below on mechanisms we consider would deliver the best value for consumers in our energy market.

Whole of system costs should be considered

60. We encourage the Authority and Transpower to consider the whole of systems metric of cost (WESC) when assessing investment decisions. We consider the WESC is the best way to achieve system value as it considers the impact of investment options in terms of their value or cost across the whole system.

61. The WESC was initially commissioned by the UK Department of Business, Energy and Industrial Strategy to capture the wider costs and benefits associated with different generation technologies. It was extended by the ReCosting Energy project to also assess demand-side technologies within this whole system framework. This compared digitally enabled demand response with generation technologies on a like for like basis.

62. Vector commissioned Frontier to apply this to the New Zealand energy market.[8] The WESC makes the true consumer value of digital and demand response technologies visible – revealing that the potential value of these technologies is accrued across multiple parts of the energy system.

63. In our view the current market does not send signals which incentivise the most efficient investments for consumers as decisions and investments in our electricity system are assessed in strict market silos – i.e., by generators, the transmission network, distributors, and consumers separately. Decisions within these silos do not reflect the impact of investments on the whole electricity system.

64. For example, decisions to build new generation plant for instance are made independently of the impact on transportation or balancing costs which are borne by consumers. These transmission costs increase when there is a lack of localised generation. The TPM ultimately pushes these costs onto consumers removing incentives for generators to localise generation even though this would increase system resilience and reduce prices.

Transpower cashflows

65. While outside the Authority's statutory remit, we note the cost impact of transmission investment on today's transmission customers could be alleviated by changing Transpower's IPP cashflow profile.

66. Unlike distributors, Transpower's regulated asset base (RAB) is not indexed to inflation which results in a front loaded cashflow profile where revenue recovery brought forward earlier in the assets life, relative to an unindexed RAB. This becomes infinitely more important as nominated beneficiaries are required to fund BBI assets over the life of the assets. Therefore, the inter-generational equity between grid users of BBI assets is important for understanding how recovery is reflected over time. The timing of recovery based on whether a BBI asset is indexed or unindexed will ensure whether the Authority's principle of "beneficiary pays" applies to both which users pay and who should pay over time.

[8] Frontier economics, Whole Electricity System Costs: A report for Vector (25 March 2021)

67. We note the Australian Energy Market Commission (AEMC) recently declined a rule change request from the transmission operators in NSW and SA (Transgrid and ElectraNet) on the SA-NSW interconnector, a project requested by the Australian Energy Market Operator (AEMO) for system security. Transgrid and ElectraNet had requested this project be unindexed from the RAB to bring revenue recovery forward assisting project financeability. The AEMC did not accept their argument that the regulatory framework hindered financeability and rejected the request.

68. This is notable as it involves a regulator declining an unindexed RAB for transmission suppliers even in the instance of specific high cost transmission investments the transmission operators were requested to build and considered they were unable to fund through their cashflow.

69. We would welcome views from the Authority and the Commission on the appropriate cashflow timing for Transpower.

Yours sincerely

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