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Mr Matt Webb
Executive General Manager Grid Development
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By email: grid.investments@transpower.co.nz.

Dear Mr Webb

HVDC link upgrade programme – short-list consultation

1. Transpower is proposing to spend up to $1.4 billion replacing the HVDC link with four new cables, which would increase its transfer capacity by 200MW. The existing cables are nearing the end of their design lives, and an unplanned failure would have severe consequences for the electricity market and the wider economy. Vector therefore supports a rigorous review of all viable options to ensure the selected solution delivers the best outcome for New Zealand as a whole. Transpower's preferred approach may ultimately prove sound, but several important questions need to be addressed first. We elaborate in the remainder of this submission.

2. Given the scale of the project, options such as a competitive tender process for the build or other parties owning assets and leasing them to Transpower should also be considered. We note in NSW, the Central-West Orana REZ transmission project was subject to a competitive tender process.[1]

Transpower's preferred option

3. The HVDC upgrade is a classic lumpy investment: most of the expense would be incurred up front in mobilising a specialised cable-laying vessel, fabricating the conductors and shipping them to New Zealand. Once those fixed costs have been sunk, adding a fourth cable would lift total capacity by a further 200MW at a lower incremental cost per megawatt than the first 1,200MW. In other words, when measured in dollars per megawatt, the final 200MW would therefore be significantly cheaper than the first 1,200MW.

4. Consequently, it is easy to see why Transpower prefers the larger build. Commissioning all four cables in a single campaign would capture the economies of scale in vessel mobilisation and avoid the cost and disruption of bringing a specialist cable-laying ship back later. The larger link would also provide an additional spare cable for contingencies and expand the reserve margin, strengthening grid resilience. The question is: would those benefits outweigh the additional cost that consumers would have to pay for the fourth cable?

[1] More information on this project is available: https://www.acerez.com.au/the-project

5. The answer is not straightforward. Although the incremental cost of the final 200MW would be well below that of the first 1,200MW, the marginal benefit would also likely be smaller. If the additional capacity is seldom, if ever, used - or if other solutions can meet the same underlying demand closer to where it arises – the additional cable may not represent value for money despite its lower unit cost. In addition, waiting carries a positive option value, because it preserves flexibility to respond to actual demand trends. That option value is absent from the assessment.

6. Transpower's cost–benefit analysis also relies on a series of detailed modelling choices that materially influence the results. Some of these appear to favour its preferred option yet in several cases the rationales are unclear, and alternative assumptions have not been tested. Set out below are several of the more significant assumptions, along with suggestions for further analysis to improve the robustness and transparency of the evaluation. A particularly important gap is the complete lack of visibility into how each option would affect final transmission prices – a critical issue that remains entirely opaque.

Option value benefits

7. Transpower has rightly accounted for the efficiencies of building the larger link as a single project. However, that up-front commitment would also remove flexibility. There is a distinct possibility that the fourth cable may prove to be unnecessary – at least for some of the investment's lifespan. For example, if North-Island demand or renewable development grows more slowly than Transpower's 'Growth' or 'Environmental' scenarios, the additional 200MW could remain under-used for many years while consumers, including Vector's, foot the bill for it.

8. Deferring the fourth cable would keep valuable options open. Installing three conductors now would restore the present 1,200MW rating, secure most of the immediate resilience benefit and leave scope to add a fourth when evidence of need is more concrete. That timing flexibility would reduce the risk of locking customers into paying for capacity that may never be fully utilised and preserves capital for alternatives, such as large-scale storage, demand response or other emerging technologies, that might be able to deliver the same service at lower cost.

9. Vector does not claim that these option-value benefits would necessarily outweigh the economies Transpower has identified. They may or may not. What matters is that those benefits are real and should be included in the assessment. The current evaluation recognises every advantage of building bigger, sooner, yet assigns no value to the flexibility that would be lost by committing to the fourth cable now. Excluding that cost risks tilting the analysis in favour of the larger build, introducing an undesirable bias.

10. We therefore recommend that Transpower amends its analysis to recognise the positive option value explicitly. Specifically, the assessment should compare: (a) installing three cables now and adding a fourth only if demand later warrants it; with (b) the current proposal to install all four cables in a single project. Incorporating this comparison would provide industry participants with a clearer basis for judging whether immediate installation of the fourth cable represents the best outcome for New Zealand Inc.

South-bound transfer constraint

11. A core modelling assumption is the treatment of south-bound transfers. Transpower's modelling allows power to flow south at the full rating of the proposed four-cable link. Yet, in practice, the HVDC link can send no more than 950MW in that direction until a separate package of AC-grid upgrades is delivered. Transpower acknowledges that those other investments would be needed before the full 1,400MW capacity can be used. That being the case, their timing, cost and

interaction with the HVDC upgrade would inevitably influence not just the total level of net benefits, but also the pattern of those benefits across regions and participants.

12. By removing the 950MW constraint, the model effectively assumes those upgrades are already in place – allowing every extra megawatt of HVDC capacity to generate wholesale market, loss-reduction and reserve savings from day one. Reinstating the real-world limit would presumably defer a material share of those benefits and could also shift the allocation of indicative benefit-based charges, particularly since south-bound transfers tend to favour North Island generators more than northern load.

13. Vector consequently requests that Transpower re-run the dispatch model with the 950MW south-bound constraint reinstated and publish the resulting changes in both net benefits and the indicative benefit-based charges (a matter we discuss further below). This would give stakeholders a clearer view of how Transpower believes they will be affected by the broader suite of investments required to unlock the full 1,400MW transfer capacity. At present, parties are being asked to respond to only part of the investment picture – without visibility of how the HVDC upgrade interacts with the other upgrades it relies on. That lack of context limits transparency and makes it harder for stakeholders to provide informed, meaningful feedback.

Battery availability for reserves

14. Another important modelling choice is the treatment of battery storage. In the cost-benefit analysis, every utility-scale battery – existing and forecast – is assumed to be continuously available to provide instantaneous reserve cover. That means batteries are modelled as being able to respond to under-frequency events at all times, across all trading periods, regardless of their size, state of charge or commercial operation.

15. In reality, that assumption seems unduly optimistic. Utility-scale batteries have finite energy and are often deployed to chase arbitrage revenue, cycling between charging and discharging as market conditions shift. It is unclear whether such assets could – or would – be held continuously in reserve, especially during peak periods when their energy may already be committed. A more realistic cap on availability – such as a four-hour limit on consecutive reserve cover – might significantly reduce the modelled reserve savings that currently underpin a significant portion of the benefits attributed to Transpower's preferred option.

16. If it is feasible for batteries to deliver that level of reliability at scale and at low cost, it also raises a broader question: whether a non-network alternative could substitute for at least part of the capacity the fourth cable is intended to provide. To be clear, Vector is not suggesting that current battery technology is a substitute for the firm, long-duration, inter-island capability offered by the HVDC link. But if the fourth cable is expected to be used only occasionally – e.g., providing additional capacity during rare events or short-lived peaks – then smaller-scale investments in batteries might still offer a more cost-effective solution. That possibility deserves to be explored.

17. Accordingly, Vector considers that further sensitivity testing is warranted. First, we request that Transpower either provides evidence that an assumption of continuous battery availability is realistic, and why, or, if it is not, that it re-runs the modelling with more conservative assumptions and discloses the effect on the net benefit estimates for the various options. Second, it would also be helpful to see a high-level comparison of what it might cost to deliver the same benefits through large-scale battery storage or other non-network alternatives. Without that, stakeholders are left with an incomplete view of the real options available to meet the need.

Deliverability risks

18. Deliverability risk is another important factor that warrants closer attention. Transpower notes that lead times for cable manufacture, testing and vessel mobilisation are currently estimated at seven to ten years, meaning even the most straightforward option will not be delivered until well into the 2030s. However, the modelling assumes each of the shortlisted options proceeds on time and that benefits begin accruing immediately once commissioned.

19. That assumption may understate the risks – particularly for Transpower's preferred option. The four-cable build involves the largest marine scope, the greatest number of cables to fabricate and test and the longest installation process. A one-year delay would defer the onset of benefits while financing costs continue to accrue, reducing the project's net present value. That downside may be more pronounced than for smaller-scale alternatives.

20. The difference in scope could also bring consenting and environmental factors into play. A four-cable installation would disturb approximately 30% more seabed than a three-cable option. If environmental regulations or cultural conditions tighten before work begins in 2029, the additional works could face delays, require new offset measures or trigger more complex engagement processes with affected iwi. None of these risks are accounted for in the current modelling, yet they may be material. The three-cable, 1,200MW build may therefore offer unrecognised advantages. With one fewer cable to manufacture, test, and lay, it would reduce scheduling pressure, shorten the marine installation window and lower exposure to permitting or cultural risk.

21. Therefore, Vector considers it would be helpful for Transpower to test the sensitivity of its results to a one-year delay and to publish a qualitative comparison of deliverability risk across the shortlisted options – including differences in consenting risk, iwi engagement complexity and contingency allowances. That additional visibility would allow stakeholders to better assess which options are genuinely most robust to the uncertainties that lie ahead.

Benefit timing and scenario sensitivity

22. Transpower's cost–benefit analysis applies three demand scenarios from the Electricity Demand and Generation Scenarios (EDGS) suite: 'Reference', 'Growth' and 'Environmental'. The central case gives most of the weight to the two higher-growth scenarios, both of which assume strong load growth, rapid EV uptake and accelerated renewable build. These are plausible futures – but also optimistic ones. Under such scenarios, the full 1,400MW HVDC capacity is likely to be needed sooner, which helps support the case for installing all four cables at once.

23. What is less clear is how quickly the fourth cable delivers material value under more subdued assumptions. A sensitivity based on the 'Reference' scenario – where demand and new generation build are more restrained – would help reveal how long it would take for the additional 200MW to 'earn its keep' if growth is slower than Transpower is forecasting. That question is particularly important given that customers would begin paying for the upgrade in the early 2030s, regardless of when – or whether – the full capacity was actually used.

24. To help stakeholders assess this, Vector considers it would be useful for Transpower to publish an annualised timeline of modelled benefits under each scenario. This would allow parties to see whether the bulk of the present-value benefit is concentrated in the 2040s and 2050s – and whether the claimed justification for the fourth cable continues to hold if demand growth takes longer to materialise.

Prioritising transmission investment

25. We note there is a clear need for investment in transmission infrastructure in the upper North Island to provide capacity to support renewable energy development. We are interested in how

Transpower determines how to prioritise investment in capacity. Transpower appears to be prioritising surplus capacity for the HVDC over investment in the upper North Island that could support additional generation.

26. This raises questions around whether costs and benefits are truly being considered from a whole of system perspective and whether resilience is being valued appropriately. We note if the TPM does not reflect the real transmission cost of locating generation in the South Island or the benefits accruing to South Island generators then overall costs to consumers will increase as a result of these distorted investment signals.

Impact on transmission prices

27. One of the central aims of the new TPM was to encourage greater engagement and scrutiny of Transpower's major investment proposals by those who would ultimately pay for them. The Electricity Authority's view was that if parties faced charges based on the benefits they were expected to receive, they would have stronger incentives to assess those benefits critically – supporting investments that were genuinely efficient and challenging those that were not.

28. The logic was straightforward: if a party knew it would face a benefit-based charge (BBC) of $*X*m over the life of a proposed investment, it would ask whether it was likely to receive at least $*X*m in return – and engage with Transpower accordingly. Whether that dynamic was ever fully realistic is open to debate. But what is clear is that meaningful engagement is not possible unless affected parties are told what they are likely to pay. Without visibility of the *X*, the intended feedback loop simply cannot function. That concern is directly relevant here, because Transpower has:

    a. Provided only indicative customer allocations, expressed as broad percentage ranges;

    b. Supplied those allocations for its preferred option only; and

    c. Basing them on the allocation method from a previous HVDC investment – a project with a very different purpose to the current proposal.

29. This is unsatisfactory. Stakeholders are left with virtually no basis for understanding what BBCs they might face each year under the different options, because:

    a. A percentage allocation tells a customer nothing about the expected dollar amount of its annual bill over the 40-year life of the investment - and calculating it is not straightforward;

    b. It is impossible to compare allocations across options, let alone prices, because Transpower has only released this information for its preferred option; and

    c. There is no reason to assume the benefit pattern from the previous converter-transformer upgrade would carry over to a project focused on cable replacement and capacity expansion.

30. Better visibility of the likely BBCs under each option is essential if the TPM is to function as intended. Vector considers that indicative BBCs should be provided much earlier in the process, ideally during the long-list consultation. By the time options are shortlisted, many of the key trade-offs have already been framed, making it far harder for stakeholders to influence the outcome. The fact that this information is still missing at such an advanced point is highly problematic. Vector therefore requests that Transpower publish indicative BBCs for all shortlisted options as a matter of urgency.

31. Vector appreciates the scale and complexity of the investment decision Transpower is facing and recognises the importance of ensuring the HVDC link remains fit for purpose. However, the

significance of this proposal and its long-term cost implications for consumers makes it essential that all credible options are thoroughly tested and clearly explained. We encourage Transpower to refine its analysis, engage openly on the assumptions underpinning its preferred option, and provide greater transparency around pricing impacts. Doing so will help build confidence in the final decision and ensure the chosen solution delivers enduring value for New Zealand.

32. We would welcome the opportunity to discuss these matters with you in more detail.

Yours sincerely,

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GM Economic Regulation and Pricing