Efficient investment in a decarbonising economy

Report prepared for Vector Ltd | 1 February 2023

Contents

1 Executive summary

1.1 Background and context

1. Frontier Economics has been engaged by Vector Limited to consider the extent to which current regulatory frameworks are robust to the significant capital expenditure that is required over a very short period of time to support New Zealand's decarbonisation commitments.

2. The scale of investment that is required over the next decade is unprecedented. Boston Consulting Group (BCG) estimates that $30 billion of new network investment will be required before 2030, $22 billion of which is for distribution networks.[1] The scale of this investment is made apparent by noting that, as of 2021, the regulated asset base of New Zealand's Electricity Distribution Businesses (EDBs) totalled $13.5 billion, with total capex in that year of $1.1 billion. That is, the new EDB capex that is required before 2030 is materially more than the total current value of the entire set of regulated distribution assets. Moreover, BCG expects that transmission and distribution infrastructure will require a further spend of $35 billion in both the 2030s and 2040s.

3. In this vein, the Origin Energy CEO recently described the required expenditure in Australia (which has made similar decarbonisation commitments) as being "akin to the wartime reconstruction effort."[2]

4. In this report, we document the scale and pace of investment that is required to meet New Zealand's decarbonisation commitments. We also set out the benefits to consumers that are expected to flow from this investment. Those benefits include reaching decarbonisation goals, as well as potential future wholesale price reductions, and the unlocking of benefits from consumers' behind-the-meter expenditure.

5. The main purpose of this report is to identify potential roadblocks to the required expenditure. Our goal here is not to provide solutions or recommended changes – because the issues are not yet fully understood. Rather, the purpose of this report is to raise a series of real issues that have already started arising in order to begin a dialogue among regulators, stakeholders, and government.

6. A crucial aspect of the issues that we identify is that solutions are likely to become more difficult and more costly if we delay in addressing them.

1.2 The three potential road blocks to required investment

7. We identify three potential road blocks that require consideration as soon as possible:

   a. Whether the current regulatory framework can accommodate the quantum and speed of the required expenditure.

[1] Boston Consulting Group, *Climate Change in New Zealand: The Future is Electric*, 25 October 2022.

[2] https://www.afr.com/companies/energy/deep-pockets-of-global-capital-keen-to-fund-transition-origin-ceo-20221121-p5bzvj.

We note that the standard regulatory regime has been designed to accommodate 'business as usual' network operations. It is not clear that this framework is robust to the scale and speed of new investment that will be required to meet decarbonisation commitments.

Under the current regulatory regime, financeability issues can arise in relation to large investment projects and work programs – particularly where such investments do not immediately generate cash flows to service that investment. Even where regulatory allowances are such that an investment or work program is NPV=0 over its expected life, it can be the case that those allowances are 'back-ended' such that investment projects do not support investment grade credit metrics over the construction period and early years of operation.

Commercial businesses are highly unlikely to proceed with a new project that would result in the firm losing its investment grade credit rating. That applies even if the proposed project would generate significant net benefits for consumers and even if the regulatory allowances would be NPV=0 over the expected life of the project.

b. Whether allowed returns reflect commercial benchmarks.

The standard regulatory regime produces an allowed return that reflects business-as-usual (BAU) operations of the regulated firm. One component of these BAU operations is replacement and minor augmentation CAPEX. However, the allowed return may not properly reflect the risk (and required return) associated with the sorts of major construction projects and work programs that will be required to support decarbonisation commitments.

It is now more important than ever that allowed returns properly reflect commercial benchmarks. There is global competition for capital to support network investment, and for workforces able to execute the rebuilding task.

c. Whether consumers will be willing to fund the required investment.

Questions have been raised about the possible willingness of consumers to fund the major expenditure that is required to meet decarbonisation commitments while still ensuring reliability of supply. We note that:

- There may be a decade of higher network charges to support the financeability of the required capital investment before any benefits to customers become evident;
- The investment will be required over a period of rising interest rates which will flow through to higher electricity prices under the current regulatory framework;
- This creates the risk that the capital expenditure program becomes unsustainable in that customers (in the short- to medium-term) are unwilling (or unable) to pay what is required to make the investment commercially viable; and
- There may be a potential role for government here. If government policy is to complete the transition at a pace beyond that which customers are willing (or able) to finance, there is a potential role for government involvement of the financing of that investment.

1.3 Questions for the Commission to consider

8. We have identified a number of questions for the Commission and stakeholders to consider:

a. Is the current regulatory regime robust to the scale and speed of capital expenditure that is required to meet decarbonisation commitments?

b. Does the current regulatory regime enable the required expenditure to be made while maintaining the benchmark investment grade credit rating? If not, what changes would be required to achieve that objective?

c. Should the Commission adopt a nominal approach for EDBs as well as Transpower – at least for the period of decarbonisation investment?

d. Is it appropriate to adopt a nominal allowance, at least in relation to the return on debt – which is issued in nominal terms?

e. Should the regulatory regime support efficient investment, or is it acceptable that such investment is only commercially viable with government support?

f. Does the current approach to allowed returns reflect commercial benchmarks?

g. Is the risk associated with construction activities the same as the BAU risk of an operating network? If not, should a different return be allowed over that construction period?

h. Are there aspects of the regulatory approach that differ from observed market practice? In such cases, should the regulatory allowance be set to reflect the return that real-world network investors actually <u>do</u> require, or what the regulator might think those investors <u>should</u> require?

i. Are consumers likely to be willing (and able) to fund the required investment?

j. Does the current regulatory framework simultaneously support:

- The commercial viability of the required investment (scale and timing); and
- Consumers' likely willingness to pay?

k. If not, are there any changes to the regulatory regime that *would* simultaneously support these dual objectives?

l. If not, what would be the most efficient form of government intervention to simultaneously support these dual objectives?

1.4 Implications for the 2023 IMs review

9. This report identifies a number of potential roadblocks to the unprecedented amount of network investment that is required to meet New Zealand's decarbonisation commitments. Importantly:

a. The solutions to these potential roadblocks are not immediately obvious and will require consultation between regulators, government, networks and their stakeholders; and

b. Any delay to addressing these issues is likely to reduce the possibility of finding acceptable solutions and/or increase the cost of implementing any solutions. In particular, to the extent that there is a delay in investment even during 2023 and 2024, the task of making the required investment over the rest of the decade will be made even more difficult.

10. For these reasons, it is important for the Commission to consider the types of issues set out in this report as soon as possible.

11. The scale and timing of the investment task would not seem to permit the luxury of a 'turn the handle' 2023 IMs review, delaying proper consideration of these issues until the following review. Indeed, even with an IM framework that properly supports the required investment, it will be very difficult to achieve the level of new investment that is required this decade.

2 The scale and pace of investment that is required

2.1 Overview

12. This section of the report documents the decarbonisation commitments made by the New Zealand government and identifies the scale of network investment that will be required to meet those commitments. Electrification is at the core of New Zealand's decarbonisation strategy and this will require extensive investment in transmission and distribution networks over a short period of time.

13. Indeed, it will be impossible for New Zealand to meet its decarbonisation commitments without this extensive network investment. In addition to meeting these commitments, we identify other consumer benefits that flow from this network investment.

14. Boston Consulting Group (BCG) estimates that $8 billion and $22 billion will need to be invested in the 2020s to upgrade transmission and distribution infrastructure respectively. BCG expects that transmission and distribution infrastructure will require a further spend of $35 billion in both the 2030s and 2040s.[3]

15. Investment of this scale is unprecedented. As of 2021, the regulated asset base of New Zealand's Electricity Distribution Businesses (EDBs) totalled $13.5 billion, with capex in that year of $1.1 billion. Thus, the required capital expenditure is orders of magnitude higher than current levels of expenditure. And this high level of expenditure is required year after year for decades – in order for New Zealand to meet its current decarbonisation commitments.

2.2 Government policy on decarbonisation

16. The Climate Change Response (Zero Carbon) Amendment Act of 2019 and the Nationally Determined Contribution (NDC1) set out three main emissions reduction targets for New Zealand:

    a. 50 per cent reduction of net emissions below gross 2005 levels by 2030;

    b. Net zero emissions of all greenhouse gases excluding biogenic methane by 2050;

    c. 24 to 47 per cent reduction below 2017 biogenic methane emissions by 2050, including 10 per cent reduction below 2017 biogenic methane emissions by 2030;

17. In May 2022, New Zealand released its First Emissions Reduction Plan, which establishes emissions budgets (as shown in **Table 1** below) and sets out how New Zealand aims to achieve its emissions targets.

[3] Boston Consulting Group, *Climate Change in New Zealand: The Future is Electric*, 25 October 2022.

Table 1: First three emissions budgets by subsectors (Mt CO_2-e)

Sector	Emissions Budget 1 (2022–2025)	Emissions Budget 2 (2026–2030)	Emissions Budget 3 (2031–2035)
Transport	65.9	76	56.8
Energy and industry	70.1	72.8	63.3
Agriculture	159.4	191	183
Waste	13.7	14.9	12.7
Fluorinated gases	6.8	7.5	5.9
Forestry	-26.4	-57.2	-81.6
Total	**290**	**305**	**240**

Source: New Zealand Government, 2022.[4]

18. Pertinent to the energy sector, the Plan sets a 50% target on total final energy consumption to come from renewable sources by 2035, with an aspirational target of 100 per cent by 2030.

19. The electrification of transport is a key focus of the Plan and is expected to place increased demand on EDBs. The Plan sets a target of increasing the share of electric vehicles to 30 per cent of the total light vehicle fleet by 2035. This will be achieved through the continuation of government incentives such as the Clean Car Discount, which provides rebates to hybrids and electric vehicles.

20. A second emissions reduction plan will be published by 31 December 2024.

21. NZ$100m has been allocated to the New Zealand Battery Project – a potential solution to New Zealand's 'dry year' problem as it moves to 100 per cent renewable energy.[5] Early estimates indicate the project could cost NZ $4 billion, to be clarified in the feasibility study released at the end of 2022.

2.3 The scale of network investment that is required

22. New Zealand produces just over 82 per cent of its electricity through renewable sources, however only 28 per cent of total energy consumption (including transport and heat) comes from renewable sources.

23. New Zealand's Climate Change Commission recognises that electrifying transport and process heat will require significant expansion in electricity generation capacity. It also

[4] New Zealand Government, *Aotearoa New Zealand's First Emissions Reduction Plan,* May 2022.

[5] https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/low-emissions-economy/nz-battery/.

recognises that increased demand and generation must be accompanied by expanding infrastructure and distribution.[6]

24. Transpower New Zealand estimates that an additional 70 per cent of renewable generation is required to electrify process heat and transport, to decarbonise the New Zealand economy. [7]

25. Transpower's submission to the Climate Change Commission stated that New Zealand's electricity sector will need to build and deliver *"as much new electricity generation in the next 15 years as they have in the last 40 years"*. [8]

26. Transpower also estimates that 60 to 70 new grid scale connections will be required before 2035 to meet the increased electricity demand. [9]

27. BCG's 2022 report into New Zealand's decarbonisation roadmap estimates that an investment of $42 billion across generation, transmission and distribution will be required before the end of the decade. This amount includes:

    a. $10.2 billion in new utility-scale renewable generation capacity;

    b. $1.9 billion in new flexible generation and demand resources;

    c. $8.2 billion in transmission infrastructure; and

    d. $22 billion in distribution infrastructure. [10]

28. BCG expects this investment to increase in the 2030s and 2040s as shown in **Table 2** below:

Table 2: BCG analysis of investment required to reach net zero by 2050

Decade	Transmission Investment (NZ $ billion)	Distribution Investment (NZ $ billion)
2020s	8	22
2030s	10	25
2040s	11	24

Source: Boston Consulting Group. [10]

29. BCG modelling also indicates that by 2050, annual generation must increase by 79 per cent and annual capacity must increase by 163 per cent.

[6] Climate Change Commission, *Inaia tonu nei: a Low Emissions Future for Aotearoa*, 31 May 2021.

[7] Transpower, *A Roadmap for Electrification: Decarbonising transport and process heat,* 10 February 2021.

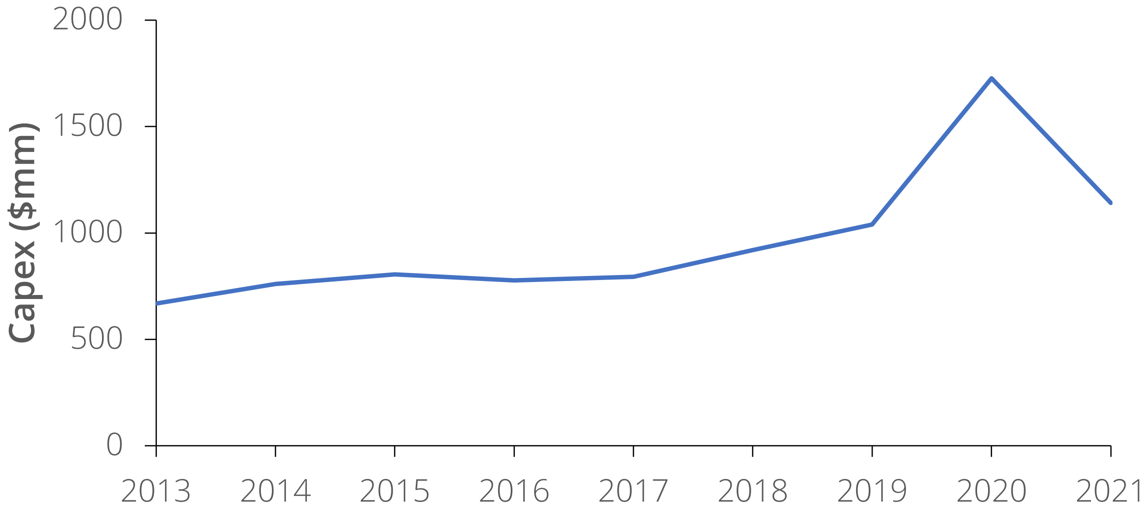
[8] Transpower, *Transpower submission on Climate Change Commission first draft advice to Government*, p.8, March 2021.

[9] Transpower, *Submission to the Infrastructure Commission on the Commission's strategy consultation document - Infrastructure for a Better Future*, p.7, 2 July 2021.

[10] Boston Consulting Group, *Climate Change in New Zealand: The Future is Electric*, 25 October 2022.

30. To put this level of investment into perspective, New Zealand's EDB regulatory asset base as of 2021 was $13.5 billion, with total capex in 2021 of $1.1 billion.[11]

Figure 1: Total EDB capital expenditure



Source: Commerce Commission Data[12]

31. **Figure 1** above shows the historical total capital expenditure for the 29 EDBs across New Zealand. BCG's estimated $30 billion transmission and infrastructure spend in the 2020s would require annual capex to ramp up by more than triple the 2021 expense of $1.1 billion. It is clear that this level of expenditure is not business-as-usual capex, rather an extensive augmentation of the existing network.

32. It is important to note the timing constraints of network expansion. Transpower recognises that a standard timeline for network infrastructure involves 2-3 years for investment approval and 3-7 years for consenting and land access before the project build commences.[13] Therefore, meeting the forecasted increases in electricity demand will require planning and capital investment on an ahead-of-time basis, rather than a just-in-time basis.

2.4 The types of network projects that are required

33. The Electricity Networks Association's Network Transformation Roadmap report – first published in 2019, and subsequently updated in 2022 – provides EDBs with information and recommendations on 'least regrets' actions to achieve the 2050 targets. Importantly,

[11] Commerce Commission New Zealand, *Electricity distributor performance and data*, accessed 25 November 2022 https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-distributor-performance-and-data/performance-accessibility-tool-for-electricity-distributors.

[12] Commerce Commission New Zealand, *Electricity distributor performance and data*, accessed 25 November 2022 https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-distributor-performance-and-data/performance-accessibility-tool-for-electricity-distributors.

[13] Transpower, *Submission to the Climate Change Commission*, 28 March 2021.

the report establishes that the onus is on the EDBs to adapt to the changing conditions that will arise from the electrification of the network.[14, 15]

34. However, many EDBs are uncertain about the impact that electrification will have – specifically, on the extent to which demand will increase due to electrification. This has been reflected in recent Asset Management Plans (AMPs) of many EDBs.

35. For example, Aurora Energy's 2022 AMP notes the uncertainty surrounding decarbonisation and the impact that it may have on its network. To model potential increased demand from electrification, Aurora Energy considers three possible decarbonisation scenarios:

Table 3: Aurora Energy decarbonisation scenarios

Scenario	Network Impact	Impact on Aurora Energy
Sustainable	• Net zero met by electrification. • Organised connection and operation. • Minimised impact on peak demand.	• Consumers with DERs contribute to the operation of the network. • Minimal cost increase for consumers.
Chaotic	• Net zero met by electrification. • Chaotic uptake and use of low carbon technology. • Substantial impact on peak demand.	• Increased capital equipment investment is required to meet demand. • Consumers pay increased prices to recoup capital investment.
Alternative Energy	• Net zero met by electrification and hydrogen energy.	• Consumers adopt alternative fuels and require less services from Aurora Energy.

Source: Aurora Energy. [16]

36. Pursuant to the 'Sustainable' scenario, Aurora Energy is currently trialling the use of third-party distributed energy resources (DERs) as a non-network solution to meet the demand accompanying decarbonisation-driven electrification.

37. Vector's 2022 Annual Report references similar uncertainty surrounding decarbonisation, with its two decarbonisation pathways (see **Figure 2**):[17]

    a. **Orderly Decarbonisation:** Network peaks are reduced by managing distributed energy resources such as electric vehicle charging and hot water load.

[14] Electricity Networks Association, *Network Transformation Roadmap,* April 2019.

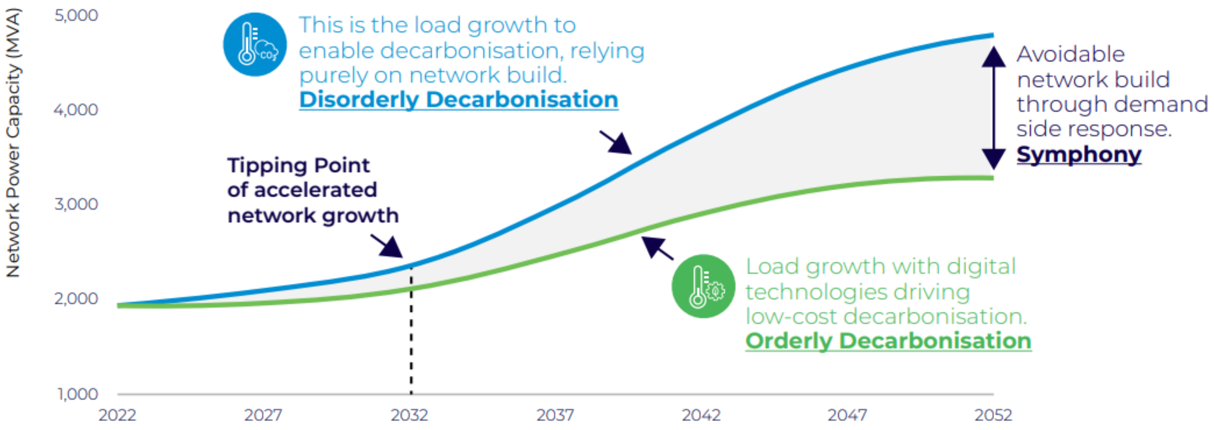
[15] Electricity Networks Association, *Network Transformation Roadmap: A three-year update,* April 2022.

[16] Aurora Energy, *Asset Management Plan April 2022 – March 2032,* March 2022.

[17] Vector, *Annual Report 2022,* August 2022.

b. **Disorderly Decarbonisation**: Absence of demand-side management results in clustered electric vehicle charging, increased peak-load demand and higher wholesale electricity prices passed through to consumers.

Figure 2: Growth of Auckland Network under Vector's Disorderly and Orderly decarbonisation scenarios



Source: Vector 2022 TCFD Report.[18]

38. Other EDBs also recognise the high level of uncertainty surrounding the adoption of decarbonisation commitments in their capex forecasts. Vector notes in its 2021 AMP that:

> *Forecasts beyond the first years of the period remains uncertain due to the unpredictability of the timing of large customer projects and the ongoing uncertainty around the rate of customers' adoption of climate change and carbon emission mitigation technologies.*[19]

39. Similarly, Powerco does not make provisions for certain decarbonisation related capex in its 2021 AMP and note:

> *In particular, there is significant potential for higher uptake of distribution edge devices associated with increasing trends to decarbonisation. This would be further accelerated by legislation in response to CCC recommendations. These factors could have a major impact on required network expenditure. However, in light of the timing uncertainty, we have not made material provision for this in our AMP expenditure forecast.*[20]

40. Despite the uncertainty, many EDBs and network participants are conducting research into the impact that electrification will have on the network. For example:

a. Powerco, Vector and Wellington Electricity have conducted various electric vehicle smart charging studies to understand consumer charging behaviour and manage demand peaks as electric vehicle adoption accelerates.[21,22,23]

[18] Vector, *TCFD Report 2022*, p.17, August 2022.

[19] Vector, *Electricity Asset Management Plan 2021-2013,* p.258, March 2021.

[20] Powerco, *Electricity Asset Management Plan 2021,* p.11.

[21] https://www.powerco.co.nz/what-we-do/our-projects/smart-ev-charging-project.

[22] https://www.vector.co.nz/articles/ev-smart-charging-trial.

[23] https://www.welectricity.co.nz/about-us/major-projects/ev-connect/.

b. Powerco is in the process of a 'Smart Grid Trial' which assesses the impact of DERs on network performance.[24]

c. Transpower is reviewing feedback on the possibility of piloting Renewable Energy Zones (REZs) in Northland. In a REZ, multiple generators or electricity users agree to co-locate to enable cost-effective investments in electricity infrastructure.[25]

41. A reliable supply of electricity is a major concern when moving to 100 per cent renewables. The NZ government has committed funding of $30 million for the initial feasibility study (phase 1) and $63 million for development of a detailed business case (phase 2) for the NZ Battery Project. More detail on this project is set out in **Box 1** below.

Box 1: NZ Battery Project: a potential solution to the 'dry year' problem

New Zealand requires 3 to 5 terawatt hours of renewable energy storage to deal with the dry year electricity supply problem – a period in which renewable energy is less available due to reduced hydro inflows (impacting hydro generation) and calm, cloudy weather conditions (impacting wind and solar generation).

Just over $100m of funding has been provided to the NZ Battery Project to manage or mitigate dry year risk as New Zealand moves towards 100 per cent renewable energy.

Pumped hydro at Lake Onslow is the option which is currently being assessed through a feasibility study. Early estimates indicate the project could cost $4 billion dollars.

Source: New Zealand Ministry of Business, Innovation & Employment. [26, 27]

[24] Powerco, *Powerco 2022 AMP Update,* p.9, March 2022

[25] Transpower, *Renewable Energy Zones*, 31 May 2022

[26] Ministry of Business, Innovation & Employment, *Update on the New Zealand battery project,* 22 June 2022 https://www.mbie.govt.nz/dmsdocument/23346-update-on-the-new-zealand-battery-project-proactiverelease-pdf.

[27] Ministry of Business, Innovation & Employment, *Lake Onslow option*, accessed 25 November 2022 https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/low-emissions-economy/nz-battery/lake-onslow-option/.

3 How consumers will benefit from network investment

3.1 Overview

42. Recent modelling demonstrates that network investment over the next decade will benefit consumers in a number of ways, including:

    a. Significant decarbonisation is impossible without electrification, which in turn requires material investment in networks;

    b. Enhanced network infrastructure facilitates more competition in the generation market, supporting a reduction in wholesale energy costs; and

    c. Augmentation of networks is required to enable customers to extract full value from their investment behind the meter, including rooftop solar, electric vehicles, and electric appliances.

43. For example, modelling by the Australian Energy Market Operator (AEMO) identifies that every dollar of approved transmission network expenditure is expected to generate $2.20 in customer benefits.

44. That is, the previously considered trade-off between customer prices on one hand and service quality and reliability on the other is now redundant. It is no longer the case that consumer benefits come at the expense of higher prices. Even disregarding any benefits to consumers associated with decarbonisation itself, recent modelling shows that targeted network expenditure can simultaneously:

    a. Create tangible benefits for consumers; and

    b. Lower the total price paid by consumers.

3.2 Example: The Australian Energy Market Operator's Integrated System Plan

45. In June 2022, the Australian Energy Market Operator (AEMO) published its 2022 Integrated System Plan (ISP).

46. AEMO identified:

    > *the three intrinsic benefits from investment in renewables: to reduce the cost of energy, to increase energy security, and to reduce emissions.* [28]

47. As part of its ISP, AEMO conducted an extensive cost benefit analysis in relation to a series of major transmission projects that formed the "Optimal Development Plan" (ODP). AEMO concluded that every dollar of expenditure on these actionable ISP projects is expected to generate $2.20 of consumer benefits. AEMO concluded that:

[28] Australian Energy Market Operator, June 2022, Integrated System Plan, p. 27.

> *The transmission projects within the ODP are forecast to deliver scenario-weighted net market benefits of $28 billion, returning around 2.2 times their cost of approximately $12.7 billion4. They represent just 7% of the total investment in NEM generation, storage, and network to 2050; optimise benefits for all who produce, consume and transport electricity in the market; and provide both investment certainty and the flexibility to reduce emissions faster if needed.*
>
> *All of the transmission projects in the ODP are needed. They will cost-effectively serve the needs of consumers, support Australia's transition to net zero emissions, and support regional employment and economic growth.* [29]

48. AEMO further identified that its Optimal Development Plan would produce the following benefits:

> *The primary benefits of the ODP are that it would:*
>
> - *provide a reliable and secure power supply,*
> - *deliver $28 billion in net market benefits52 by saving costs elsewhere,*
> - *retain flexibility to decarbonise the NEM at least as fast as current government, corporate and societal ambitions, and*
> - *be resilient to events that can adversely impact future costs to consumers, and relatively insensitive to changes in input assumptions.* [30]

49. And that:

> *These benefits highlight the value of the transmission network in an efficient power system transformation. The network would allow NEM consumers to secure the full benefit of zero-emission VRE [variable renewable energy] generation, which will become even more cost-efficient over the ISP time horizon. Without that transmission, the NEM would require more expensive generation capacity nearer to load centres – either offshore wind, or gas-fired generation with carbon capture and storage (CCS) to manage its cumulative emissions. These technologies have higher capital costs than land-based VRE with, in the case of gas, higher fuel costs.* [31]

50. AEMO estimated that:

> *Of the total benefits, 50% are from deferring or avoiding the capital cost of generation and storage projects, and 40% from fuel cost savings.* [32]

51. In particular, but for these network projects, the stated decarbonisation objectives could only be achieved by building more expensive generation facilities closer to existing grid connections and by building gas generation for firming purposes.

52. Importantly, the AEMO assessment of customer benefits does not include any value obtained from behind-the-meter investment.

[29] Australian Energy Market Operator, June 2022, Integrated System Plan, p. 15.

[30] Australian Energy Market Operator, June 2022, Integrated System Plan, p. 63.

[31] Australian Energy Market Operator, June 2022, Integrated System Plan, p. 64.

[32] Australian Energy Market Operator, June 2022, Integrated System Plan, p. 65. See also Table 4, p. 64 and Figure 30, p. 66.

3.3 Proposed network expenditure in New Zealand

53. Section 2 above demonstrates the uncertainty surrounding the kinds of network expenditure that may be required for New Zealand to reach its decarbonisation commitments. The speed at which customers switch to electricity-intensive activities such as electric vehicle charging and the subsequent impact that this will have on electricity demand and prices all uncertain. Importantly, the extent to which consumers are willing to pay for this investment remains is also unknown.

54. Consumer studies such as the Better Futures Report[33] surveyed 1,517 New Zealanders on sustainability and social and economic issues that are pertinent to them. With regards to decarbonisation, the survey found that consumers were 15% less likely to remain with their current electricity supplier, rather than switching to green energy as compared to 2021. While this may indicate that some customers are considering the climate impact of their electricity providers, the survey did not assess their willingness to pay for these changes.

55. Willingness to pay is the key question and perhaps the lack of information in this regard points to the gap between expenditure that is required and the expenditure that consumers are willing and able to pay.

[33] Kantar, *Better Futures 2022*, https://www.kantarnewzealand.com/better-futures-2022/.

4 Potential roadblock #1: Can the current regulatory framework accommodate the quantum and speed of the required expenditure?

4.1 Overview

56. In this section, we consider whether allowed revenues under the standard regulatory regime support efficient investment of the quantum and speed that will be required to meet decarbonisation commitments. We note that the standard regulatory regime has been designed to accommodate 'business as usual' network operations. It is not clear that this framework is robust to the scale and speed of new investment that will be required to meet decarbonisation commitments.

57. We have noted above that the quantum and speed of required network expenditure is well beyond anything that has been experienced by the current regulatory regime. The CAPEX that is required over the next decade is orders of magnitude greater than business-as-usual expenditure. The current regime was not designed with this sort of transformational expenditure in mind.

58. Under the current regulatory regime, financeability issues can arise in relation to large investment projects – particularly where such large investments do not immediately generate cash flows to service that investment. Even where regulatory allowances are such that an investment is NPV=0 over its expected life, it can be the case that those allowances are 'back-ended' such that large investment projects do not support investment grade credit metrics over the construction period and early years of operation.

59. Commercial businesses are highly unlikely to proceed with a new project that would result in the firm losing its investment grade credit rating. That applies even if the proposed project would generate significant net benefits for consumers and even if the regulatory allowances would be NPV=0 over the expected life of the project.

60. Where investment also faces some risk of ex post non-recovery (e.g., due to an IRIS penalty arising in circumstances where there is some uncertainty about precisely what investments are required to meet decarbonisation commitments), the above financeability issues will be magnified.

61. In this section, we provide two examples where these sorts of financeability issues have arisen and identify the approaches that are available to address these issues.

4.2 Example 1: Project Energy Connect

62. Project EnergyConnect (PEC) is a major transmission inter-connector between South Australia and New South Wales via Victoria. This project links the three state grids enabling

surplus renewables output in one region to be exported to another when available and for dispatchable generation in one region to be supplied to another when required.

63. The project has a total cost of $2.28 billion (of which $1.8 billion is to be financed by Transgrid, the NSW transmission operator), making it one of Australia's largest energy infrastructure projects. IT was also the largest single investment project undertaken by Transgrid at the time.

64. The business case for PEC identified that it would deliver vital infrastructure required to connect the power grids of NSW, SA and Victoria and expand the wholesale energy market across these three states—increasing reliability and security of electricity supply, while lowering power bills for consumers. Modelling indicated that it would reduce average residential electricity bills by $100 per year for consumers in South Australia and that it would save NSW electricity consumers a total of $180 million per year once it was operating.

65. The project was supported widely by stakeholders, it passed the AER's transmission Regulatory Investment Test (RIT), and it received cost approval by the AER. There was no doubt that PEC would promote the long-term interests of consumers of electricity—if it were to proceed.

66. However, PEC very nearly did not proceed. The returns that would have been generated by this project under the regulatory regime that would have applied to it were insufficient to support a commercially viable business case.

67. Under the Australian regulatory regime, there is no opportunity for a regulated firm to seek any amendment to the allowed return. Consequently, Transgrid had no other recourse but to seek a Rule Change that would have changed the timing of the cash flows in a way that would have enabled the business case to move forward. Under the prevailing regulatory regime, there is no return of capital allowance until the asset is commissioned, and no return of capital allowance on land assets. These features of the regulatory regime resulted in a period of very significant construction expenditure matched with very small allowed revenues.

68. Whereas much of the Rule Change process focused on different interpretations of the meaning of 'financeability,' the core issue was whether or not the project was commercially viable. Under the prevailing regulatory arrangements, it was not, primarily because the lack of cash flows over the construction period and early years of operation meant that credit rating metrics would not support an investment grade rating for Transgrid.

69. That is, proceeding with the project under the regulatory benchmark financing arrangements would have resulted in Transgrid's credit rating being downgraded to sub-investment grade. Consequently, PEC could not proceed as it was not commercially viable.

70. The project only became commercially viable when Transgrid was able to secure nearly $300 million in Federal Government support provided by the Clean Energy Finance Corporation (CEFC) — the largest investment the CEFC has made to date. That funding was made in the form of mezzanine debt that had equity-like characteristics that enabled Transgrid to maintain the credit rating metrics to support an investment grade rating throughout the construction period.

71. In the absence of this government financial support, PEC would not have proceeded.

4.3 Example 2: Transpower

72. The Commission's approach to electricity distribution businesses (EDBs) is to allow the business to charge prices that are sufficient to provide a *real* return on capital. Specifically, the Commission's approach is to:

    a. Compute what it considers to be the appropriate *nominal* rate of return;

    b. Subtract the Commission's estimate of future inflation;

    c. Allow the business sufficient revenues to provide for the resulting *real* return; and

    d. Add back actual inflation via RAB indexation.

73. By contrast, the Commission's approach to Transpower is to make no deduction for forecast inflation and to provide no RAB indexation. Under this approach, the business is permitted revenues that are sufficient to provide for the full *nominal* rate of return.

74. Both approaches satisfy the NPV=0 principle, however the Transpower 'nominal' approach provides for higher cash flows in the early years of an asset's life relative to the EDB 'real' approach.

75. The Commission explained its reasons for adopting a nominal approach for Transpower in its 2010 Transpower IMs. In particular, the Commission highlighted the magnitude of Transpower's proposed investment pipeline and the long length of the construction period for major projects prior to capitalisation in the RAB:

    > *In its draft decision and reasons paper for not declaring control of Transpower the Commission concluded that the higher cash flows that are associated with an un-indexed approach in the first years following an investment were better suited for Transpower's investment profile going forward than CPI-indexation would be. This was particularly important given the magnitude of Transpower's proposed investments, and the fact that the associated capex would often span multiple years prior to commissioning. Based on these factors, and given the scrutiny of Transpower's investments under Part F of the Electricity Governance Rules (EGRs) by the EC and the magnitude and timing of proposed Transpower investments, the Commission accepted Transpower's settlement proposal.* [34]

76. The Commission expanded on its reasons noting that its investment pipeline was very large relative to the existing RAB. The Commission concluded that a nominal (un-indexed) approach would produce higher revenues in the short term better matching the required investment profile:

    > *The Commission considers an un-indexed approach is appropriate for Transpower for the following reasons:*
    >
    > - *Transpower is planning to invest over $3 billion in upgrading and renewing the transmission network over the next five years, which will more than double the value of Transpower's RAB. This level of proposed investments is significantly larger than any of the EDBs in both an absolute and relative sense. In addition, unlike the EDBs, a significant portion of Transpower's planned investment programme involves expenditures being incurred a number of years in advance of commissioning. The level of Transpower's investments will result in it having,*

[34] New Zealand Commerce Commission, December 2010, *Input methodologies (Transpower)*, pp. 29-30.

relative to other lines businesses, high investment programme funding requirements;

- *updating the RAB value using an un-indexed approach will, given the likely age structure of Transpower's asset base, be likely to lead to higher revenues for Transpower over the near term. This level of revenue will be likely to be better matched to Transpower's investment needs.* [35]

77. During the 2010 EDB IMs review, the Commission recognised that RAB indexation has the effect of slowing the recovery of the investment in regulated assets:

> *If no indexation was applied to RAB values, then cash flows generated by each asset would be brought forward because depreciation in the earlier years would be higher. Such an approach would be consistent with suppliers having sufficient cash flows to finance their debt obligations, and would generally result in a more rapid recovery of the value of each supplier's investments.*[36]

78. It is important to recognise that infrastructure firms (such as electricity network businesses) tend to issue nominal debt that requires nominal interest payments to be made. Thus, a real (RAB indexation) approach results in a real revenue allowance that is insufficient to cover the nominal interest payments on debt. This shortfall must be made up by equity holders, who are then reimbursed (in expected NPV terms) from the higher future allowances that come from RAB indexation.

79. The Commission makes an important point when it recognises that a nominal (un-indexed) allowance would just be sufficient to cover the nominal interest payments that are required to service standard nominal debt obligations. This becomes even more important during a major investment program where:

    a. There are nominal interest payments that must be made from the time the debt is raised;

    b. There are no (or minimal) allowed cash flows until the asset is commissioned; and

    c. Even after commissioning the 'standard' framework provides only a real allowance in relation to debt.

80. The Commission has further noted that Transpower's investment profile may change in the future, in which case the Commission would consider whether a change to a real (indexed RAB) approach may be appropriate:

> *Some of the above factors might be more relevant over the short to medium term than over the long-term (e.g. because of Transpower's current tranche of investment). In the case of EDBs, the Commission considers the greater protection against inflation risk that is afforded by CPI-indexation is sufficient reason to prefer such an approach over an un-indexed approach. In Transpower's case this factor is currently outweighed by the factors discussed above. In the longer term, some of the differences between Transpower and EDBs might become less significant, in which case consideration of greater alignment in some of the*

[35] New Zealand Commerce Commission, December 2010, *Input methodologies (Transpower)*, pp. 30-31.

[36] New Zealand Commerce Commission, December 2010, *Input Methodologies (Electricity Distribution and Gas Pipeline Services) Reasons Paper*, p. 117.

approaches for electricity distribution services and electricity transmission services might be warranted. [37]

81. In its 2016 IMs, the Commission decided to maintain its nominal (un-indexed) approach for setting allowed returns for Transpower:

> *Our lack of indexation of Transpower's RAB means that capital recovery is frontloaded relative to an indexed approach (as applied to the EDBs). We considered this was appropriate in 2010 given their relatively large investment programme, since an un-indexed approach would likely lead to higher revenues in the near term that better matched their investment needs…On balance, we propose to maintain the current approach, whereby we do not index Transpower RAB to inflation. We have not identified any problems in relation to our approach and we are not aware of a compelling enough reason that warrants a change to the status quo.*[38]

4.4 Considerations for the Commission

82. The above examples give rise to a number of questions for the Commission to consider:

    a. Is the current regulatory regime robust to the scale and speed of capital expenditure that is required to meet decarbonisation commitments?

    b. Does the current regulatory regime enable the required expenditure to be made while maintaining the benchmark investment grade credit rating? If not, what changes would be required to achieve that objective?

    c. Should the Commission adopt a nominal approach for EDBs as well as Transpower – at least for the period of decarbonisation investment?

    d. Is it appropriate to adopt a nominal allowance, at least in relation to the return on debt – which is issued in nominal terms?

    e. Should the regulatory regime support efficient investment, or is it acceptable that such investment is only commercially viable with government support?

[37] New Zealand Commerce Commission, December 2010, *Input methodologies (Transpower)*, p. 31.

[38] New Zealand Commerce Commission, June 2016, *Input methodologies review draft decisions: Topic paper 1: Form of control and RAB indexation for EDBs, GPBs and Transpower*, p. 54.

5 Potential roadblock #2: Do allowed returns reflect commercial benchmarks?

5.1 Overview

83. In this section, we consider whether allowed returns under the standard regulatory regime reflect commercial benchmarks for major new construction projects.

84. The standard regulatory regime produces an allowed return that reflects business-as-usual (BAU) operations of the regulated firm. One component of these BAU operations is replacement and minor augmentation CAPEX. However, the allowed return may not properly reflect the risk (and required return) associated with the sorts of major construction projects that will be required to support decarbonisation commitments.

85. Indeed, it is now more important than ever that allowed returns properly reflect commercial benchmarks. There is global competition for capital to support network investment, and for workforces able to execute the rebuilding task.

86. What is relevant here is the return that real-world network investors actually do require, not what the regulator might think those investors should require. For example:

    a. The regulatory framework assumes BAU capital expenditure so provides a BAU allowed return. But if investors consider major construction projects to involve more than BAU risk, the BAU return will be unattractive. For precisely this reason, there are regulatory examples of a temporary additional allowance to support periods of major capital investment; and

    b. Some aspects of the current regulatory approach are inconsistent with observed commercial practices. For example, the Commission uses a 5-year risk-free rate (based on theoretical reasoning) whereas the uniform observed market practice is to use a 10-year rate.

87. We conclude that there is some value in the Commission considering whether its current approach to setting BAU allowed returns is consistent with commercial benchmarks.

5.2 Do construction projects involve a different level of risk?

88. The commercial viability of new investment requires careful consideration of the risks involved; in particular, the extent to which new projects involve economic risks and have characteristics that are unlike business-as-usual network operations upon which the current allowances are based.

89. Many new projects have the characteristics of construction projects for a period before becoming part of the regular operations of the network. This can be the case for a single new major project or for a significant program of work consisting of a large number of smaller projects. Given their scale and nature, these projects or programs of work involve considerably more risk than the normal operation and maintenance of an existing network.

Consequently, businesses involved in these activities (which are necessary to deliver the energy transition) require different returns in their early phases to ensure they are commercially viable.

90. Several regulators have recognised that major construction projects differ from the ongoing operation of regulated infrastructure assets and have put in place regulatory arrangements that reflect those differences. For example, Heathrow Airport was allowed a special 'construction margin' on capital invested during the construction phase of its new Terminal 5 (or T5) and the European Commission recommended that national regulators should also allow higher rates of return during the roll-out phase of fibre networks. These precedents reflect the widely accepted view that construction activities support relatively less debt finance and have a higher level of systematic risk than BAU network operations.

91. In relation to Heathrow's T5, for example, the UK economic regulator, Civil Aviation Authority (CAA) observed that:

> *The scale of a project like Terminal 5 clearly involves accessing the capital markets as it is unlikely to be possible to fully finance such a project from internally generated cash flow. Large investment projects tend to be risky in a number of ways. The scale of Terminal 5 will increase BAA's risks, not only with respect to construction risk but also risks of uncertain demand and risks associated with the Terminal 5 triggers as pointed out by the Competition Commission.*[39]

92. This led to the CAA allowing a higher return on equity than would have been the case in the absence of the major T5 construction project. In relation to the higher regulatory allowance, the CAA observed that:

> *This figure reflects the uncertainty surrounding the cost of equity, and especially the cost of new equity, and the importance of enabling BAA to finance Terminal 5 on a commercial basis given the risks involved. The other side of the coin is clearly that all risk, i.e. demand risk as well as cost risk, lies with BAA. This implies that whatever capital structure BAA and its financiers adopt, the risk associated with this structure lies entirely with BAA and its financiers.* [40]

93. Similarly, the European Commission (Commission) recommended that national regulators should provide a higher rate of return allowance in relation to the additional risks involved in the capital-intensive roll-out of fibre networks. The Commission stated that:

> *Investment risk should be rewarded by means of a risk premium incorporated in the cost of capital. The return on capital allowed ex ante for investment into NGA [next generation access] networks should strike a balance between on the one hand providing adequate incentives for undertakings to invest (implying a sufficiently high rate of return) and promoting allocative efficiency, sustainable competition and maximum consumer benefits on the other (implying a rate of return that is not excessive). To do so, NRAs [National Regulatory Authorities] should, where justified, include over the pay-back period of the investment a supplement reflecting the risk of the investment in the WACC calculation currently performed for setting the price of access to the unbundled copper loop.*[41]

[39] CAA, February 2002, Economic Regulation of BAA London Airports (Heathrow, Gatwick and Stansted) 2003-2008 - CAA Decision (CAA 2003-2008 Decision BAA London Airports), pp. 44-45.

[40] CAA, 2003-2008 Decision BAA London Airports, February 2002, p. 45.

[41] European Commission, September 2010, Commission Recommendation on regulated access to Next Generation Access Networks (NGA), annex 1, item 6.

94. The Commission further identified the sorts of risks that would justify an additional premium during the network construction / roll-out phase as follows:

> *NRAs should estimate investment risk, inter alia, by taking into account the following factors of uncertainty: (i) uncertainty relating to retail and wholesale demand; (ii) uncertainty relating to the costs of deployment, civil engineering works and managerial execution; (iii) uncertainty relating to technological progress; (iv) uncertainty relating to market dynamics and the evolving competitive situation, such as the degree of infrastructure-based and/or cable competition; and (v) macroeconomic uncertainty.*[42]

95. We note that large projects or programs of work can involve significant construction-type risks including environmental, bio-diversity, geotechnical, and land access risks, tight delivery timeframes, and shortages in available labour and construction resources. For major projects or programs of work, like the examples above, the scale of these construction-related risks is well beyond that which pertains to replacement or more incremental business-as-usual augmentation CAPEX.

96. We recognise that the regulatory framework includes various mechanisms to deal with risk such as cost pass-throughs, consideration of contingent projects, and staging of contingent projects. However, these mechanisms are not designed to address the fundamentally different characteristics of businesses essentially having a construction division for several years.

97. The designers of the current regulatory framework did not anticipate the kind of transformation in the electricity system (in terms of scale and speed) that is required to support New Zealand's decarbonisation objectives. During the period where some networks will effectively have construction divisions, that activity should be appropriately compensated to ensure that the investment is economically viable. This might not be achieved within the context of a business-as-usual benchmark allowance – it requires a full consideration of the extent to which construction activities might differ from network operation activities.

98. In principle, ongoing network operations and new construction activities should each be compensated in accordance with the risks involved – rather than assuming that new construction activities have the same risk, and therefore return, profile as ongoing network operations. Once construction is complete and the new project becomes a functioning part of network operations, it would receive an allowed return commensurate with the risk of network operations. This is the basis for the regulatory precedent in relation to the Heathrow and European fibre rollout examples above.

99. It would be straightforward to accommodate a 'construction' allowance during the construction phase of new projects or work programs. The Commission would first identify which new construction projects or projects go beyond business-as-usual replacement capex and ordinary/incremental augmentation capex. These new projects and work programs would be placed into a separate regulatory asset base (RAB) during the construction phase and would be allowed a return commensurate with the increased risk associated with construction. This would involve a beta estimate commensurate with construction risk, gearing commensurate with such construction activities, and the prevailing return on debt. When the new assets are commissioned and become a working

[42] European Commission, September 2010, [Commission Recommendation on regulated access to Next Generation Access Networks (NGA)](), annex 1, item 6.

part of the network they would be rolled into the standard RAB and would receive the standard regulatory allowance from that time forward.

5.3 The regulatory allowance should reflect standard commercial benchmarks

100. The commercial viability of major network investment requires that the allowed return meets commercial requirements during the construction phase *and* during ongoing operations.

101. In relation to the operating phase, it is important that the allowed return reflects the return that network investors do require, even if that differs from the return that the regulator considers that investors should require.

102. In this regard, we note that NPV=0 requires that the allowed return must be set to match the return that real-world investors actually do require. This is because the *raison d'etre* for NPV=0 is to incentivise efficient investment, which promotes the long-term interests of consumers. Efficient investment is incentivised by setting the allowed return to just match the market cost of capital that is required *by the investors* who will be making that investment. This remains the case even if the regulator forms a view (based on its own theoretical reasoning or otherwise) that investors should require a different rate of return.

103. An example of this point has recently arisen in Australia, where the Australian Energy Regulator is considering whether the allowed return should be set using a 5-year risk-free rate (based on its own theoretical reasoning) in contrast to the uniformly observed commercial practice of a 10-year risk-free rate. This is also relevant in New Zealand, where the Commission adopts a 5-year risk-free rate, also contrary to the observed commercial practice.

104. A long-term (10-year) risk-free rate is consistent with:

    c. Observed commercial practice documented in surveys and submissions from real-world network investors;

    d. The practice adopted in independent expert valuation reports, including for regulated network firms;

    e. The approach recommended in academic and practitioner textbooks; and

    f. The approach adopted by regulators around the world.

105. By contrast, a 5-year risk-free rate (to match the length of the regulatory period) is said to be based on theoretical reasoning set out in a 1989 paper by Professor Richard Schmalensee.[43] However, a recent report by Professor Schmalensee concludes that his 1989 paper has been misinterpreted and that the NPV=0 principle is achieved by setting the regulatory allowance to reflect the return that real world investors actually require.[44]

[43] See, for example, Lally, M., 2004, 'Regulation and the Choice of the Risk Free Rate', *Accounting Research Journal*, vol. 17 (1), pp. 18-23.

[44] Schmalensee, R., July 2022, *Statement of Richard Schmalensee PhD to the Australian Energy Regulator*, available at https://www.aer.gov.au/system/files/ENA%20-%20Attachment%20B%20-%20Schmalensee%20Expert%20Report%20-%20July%202022.pdf.

106. Professor Schmalensee describes the suggestion that NPV=0 can be achieved by adopting a 5-year because that is what investors should require as "almost exactly backwards" [45] and "an amazing bit of sleight of hand." [46]

107. This is one example of a broader issue as to whether the regulatory allowance should be set to reflect the return that real-world network investors actually do require, or what the regulator might think those investors should require.

108. We note that there is some evidence that the current level of returns allowed by the Commission may be insufficient to incentivise efficient investment. From February 2020 onwards Vector increased its customer capital contribution for new connections to 100% and introduced a system growth charge for upstream impact on the network from December 2021. This has resulted in a marked increase in capital contributions relative to net CAPEX. This is a form of revealed preference evidence whereby Vector has taken steps to reduce the amount of CAPEX that flows into the RAB to earn the allowed return, revealing its preference for investing capital elsewhere.

5.4 Considerations for the Commission

109. The above examples give rise to two key questions for the Commission to consider:

    a. Is the risk associated with construction activities the same as the BAU risk of an operating network? If not, should a different return be allowed over that construction period?

    b. Are there aspects of the regulatory approach that differ from observed market practice? In such cases, should the regulatory allowance be set to reflect the return that real-world network investors actually do require, or what the regulator might think those investors should require?

[45] Schmalensee, R., July 2022, *Statement of Richard Schmalensee PhD to the Australian Energy Regulator*, p. 9.

[46] Schmalensee, R., July 2022, *Statement of Richard Schmalensee PhD to the Australian Energy Regulator*, p. 9.

6 Potential roadblock #3: Will consumers be willing to fund the required expenditure?

6.1 Overview

110. In this section, we consider the possible willingness of consumers to fund the major expenditure that is required to meet decarbonisation commitments while still ensuring reliability of supply. We note that:

    a. There may be a decade of higher network charges to support the financeability of the required capital investment before the benefits to customers become evident;

    b. This creates the risk that the capital expenditure program becomes unsustainable in that customers (in the short- to medium-term) are unwilling to pay what is required to make the investment commercially viable; and

    c. There may be a potential role for government here. If government policy is to complete the transition at a pace beyond that which customers are willing to finance, there is a potential role for government intervention – such as in the PEC example above.

6.2 The timing of costs and benefits

The benefits from decarbonisation investment will not be apparent for many years but the costs must be incurred now

111. Consumers in developed economies such as Australia and New Zealand currently enjoy a very high level of service quality from their electricity providers. Supply is safe, reliable, and largely affordable. However, meeting decarbonisation commitments will require substantial new network investment. Whereas this new investment is likely to bring ultimate benefits to consumers (e.g., by achieving decarbonisation commitments and potentially lowering wholesale energy costs), those benefits are unlikely to be evident in the short to medium term. Indeed, it is entirely possible that consumers see no apparent benefit from this investment over the next decade.

112. This creates a timing mis-match whereby very significant expenditure is required in the short-term, but the benefits are not made apparent to consumers until many years later. Indeed, the benefits from this expenditure are likely to accrue to future generations of consumers. This raises the question of whether current consumers will be willing to continue to fund the required expenditure while there is no obvious benefit to them.

113. This issue has recently been raised by Frank Calabria, CEO of Origin Energy in Australia. The *Australian* has recently reported that:

> *Origin Energy chief executive Frank Calabria has called for honesty about the likely increase in power bills from the "truly staggering" scale of transformation required for the energy*

> *transition this decade, warning that community support for the task ahead could be lost and put the whole effort at risk.*
>
> *Mr Calabria said the messaging to the community about the scale of the investment required, estimated at $76 billion by 2030, needed to be "much more than virtue signalling about achieving emissions reduction".*
>
> *"**I don't believe it's helpful to underestimate the challenges ahead as it's only by facing into them that we can find solutions**," he told a Committee for the Economic Development of Australia lunch in Sydney.*
>
> *"**It is a truly staggering task to achieve those 2030 targets**, and we must act with more urgency, as each month that passes makes the challenge harder with the propensity for adding costs."*[47]

114. The *Australian* has further reported that:

> *The investment required this decade to transform supply includes 44 gigawatts of new renewables needed to reach the Albanese government's 82 per cent renewables target by 2030. Of that, 28 GW would be in utility-scale plants, the equivalent of about 110 projects of about 250 MW each. In addition, 15 GW of "firming" capacity is needed to back up renewables, mostly in storage, and 10,000 kilometres of new transmission.*
>
> *"**All of this will be occurring concurrently, representing a magnitude of investment and construction akin to the wartime reconstruction effort**," Mr Calabria said.*
>
> *"**That $76 billion in investment to deliver the transition … needs to be paid for**."*
>
> *The federal budget estimated an increase of 56 per cent in power bills for households over the next two years, and **Mr Calabria warned that there were limits to the magnitude of price increases the community could absorb on the premise it would result in cheaper and cleaner energy over time**.*
>
> *He would not estimate the impact on bills from the $76 billion of investment required, but said price increases needed to be "kept in check over time".* [48]

115. However, it is not clear how prices can be "kept in check" while still funding the level of investment that is required.

116. For example, one way of potentially addressing this timing mis-match would be to delay allowed revenues in a NPV-neutral way, to better align the timing of costs and benefits from a consumer perspective. However, this would exacerbate the commercial viability issues set out above, so is unlikely to be a viable option.

117. But the alternative of ensuring that investment projects *are* commercially viable would require consumers to make an immediate contribution to the construction of these projects, when any benefits might not be apparent for many years into the future. It seems likely that there would be a limit to consumers' willingness to fund projects in advance of any observable benefits. As Mr Calabria has observed above, "messaging to the

[47] https://www.afr.com/companies/energy/deep-pockets-of-global-capital-keen-to-fund-transition-origin-ceo-20221121-p5bzvj, emphasis added.

[48] https://www.afr.com/companies/energy/deep-pockets-of-global-capital-keen-to-fund-transition-origin-ceo-20221121-p5bzvj, emphasis added.

community about the scale of the investment required…needed to be much more than virtue signalling about achieving emissions reduction."[49]

Limits to regulatory smoothing

118. One of the outcomes of the building block approach to infrastructure regulation is the recovery of capital outlays over the life of the regulated assets. This feature is important as it allows for long-lived infrastructure assets to be 'paid for' by the several generations that benefit from that asset. It avoids a situation whereby one generation of consumers pays for long-lived infrastructure assets which then go on to benefit subsequent generations that are not required to contribute to the cost of those assets.

119. In the case of business-as-usual augmentation CAPEX, this regulatory smoothing works seamlessly. New (marginal) expenditure is rolled into the RAB and consumers over the life of that asset contribute to the return of capital and return on capital building block allowances.

120. Whereas individual augmentation projects might fail financeability metrics on a stand-alone basis (because the speed of cash flow recovery does not support investment grade credit metrics), an existing network can accommodate an incremental amount of such expenditure on a business-as-usual basis.

121. However, the quantum of investment required to meet decarbonisation commitments goes well beyond business-as-usual augmentation CAPEX. As set out above, the amount of investment required to support decarbonisation commitments may exceed the amount that can be accommodated under the current regulatory arrangements, while still supporting an investment grade credit rating.

A potential role for government

122. For the reasons set out above, there is no obvious way of reconciling the immediate cash flow that is required to support the commercial viability of the required investment, while simultaneously satisfying consumers' willingness to pay within the current regulatory framework. This raises the question of whether there is a role for government, rather than regulation, to bridge this gap. That is, it may be that some form of government intervention is required to support the financing of the required investment, to be repaid out of the future benefits that are projected. The potential forms of such interventions are discussed in Section 6.4 below.

6.3 The required investment coincides with an increase in interest rates from historical lows

123. Under the New Zealand regulatory building block approach, the allowed return on capital is linked to market interest rates. Specifically:

    d. The allowed return on equity is determined by adding an effectively constant market risk premium to the prevailing yield on New Zealand government bonds; and

    e. The allowed return on debt is set on the basis of the yield on New Zealand corporate bonds.

[49] https://www.afr.com/companies/energy/deep-pockets-of-global-capital-keen-to-fund-transition-origin-ceo-20221121-p5bzvj, emphasis added.

124. Over the last two years, the yields on New Zealand government and corporate bonds have increased materially, as illustrated in **Figure 3** and **Figure 4** below. This flows through to an increase in the allowed return on capital and consequently to the prices paid by consumers.

Figure 3: New Zealand 10-year government bond yield

Source: https://tradingeconomics.com/new-zealand/government-bond-yield.

Figure 4: S&P New Zealand investment grade corporate bond index: Yield to maturity

Source: https://www.spglobal.com/spdji/en/idsenhancedfactsheet/file.pdf?calcFrequency=M&force_download=true&hostIdentifier=48190c8c-42c4-46af-8d1a-0cd5db894797&indexId=92278261.

125. The increase in consumer prices that automatically flows from these increases in interest rates is occurring at the same time as record investment is required to support decarbonisation commitments. That is, there are two separate sources of price increases operating at the same time.

126. To the extent that there is an upper bound to the willingness or ability of consumers to meet price increases, or the Commission's willingness to allow price increases, the increase

in interest rates will have the effect of 'squeezing out' the extent to which price increases can be used to fund the required investment. This is another factor that points towards the possible role of government in facilitating the required investment at this point in time.

6.4 The potential role of government

127. We have noted above that there is no obvious way of reconciling the immediate cash flow that is required to support the commercial viability of the required investment, while simultaneously satisfying consumers' willingness to pay within the current regulatory framework. This problem arises due to (a) the size of the required investment relative to the existing asset base and (b) the constraints on short-term price increases.

128. One way to address this problem is via some form of government intervention. This would involve government securing the financeability of decarbonisation projects by way of guarantees and/or the provision of capital in a way that supports the maintenance of an investment grade credit rating.

129. The mezzanine financing structure in the PEC case above is an example of a government agency providing capital in a way that enabled the proponent to maintain an investment grade credit rating.

130. There are also several examples of governments taking a central role in the development of new infrastructure assets. This has occurred where it has not been financially viable for commercial entities to finance those assets in light of the regulatory framework and/or consumers' willingness to pay.

131. For example, in 2008 the Australian government invited commercial entities to tender for the construction of a national broadband network. No bidder was able to meet the government's requirements or to raise the capital required. This led to the establishment of the government-owned NBN Co in 2009. In December 2022, NBN Co announced that it plans to recover only $12.5 billion of the $44 billion of construction costs and accumulated operating losses.[50] The effective write-down of $31 billion is essentially the government's contribution to bridge the gap between the cost of the NBN and consumers' willingness to pay for it.

132. As another example, the New Zealand government established a government-owned entity to manage the construction of the Ultra-Fast Broadband network. This entity was provided with government equity and an interest-free loan. Thus, consumers are not required to provide a full commercial return on capital for this network.

133. Similarly, Sydney Airport Limited elected not to exercise its right to build the Western Sydney airport, concluding that it would not be commercially viable for it to do so. This led to the Australian government establishing a government-owned entity to develop the project.[51]

[50] https://www.afr.com/companies/telecommunications/nbn-writes-off-recovering-31b-of-government-investment-20221201-p5c2xv.

[51] https://www.smh.com.au/business/companies/sydney-airport-finally-turns-down-chance-to-build-new-airport-at-badgerys-creek-20170502-gvwunr.html.

6.5 Considerations for the Commission

134. The above discussion gives rise to two key questions for the Commission to consider:

a. Are consumers likely to be willing (and able) to fund the required investment?

b. Does the current regulatory framework simultaneously support:

- The commercial viability of the required investment (scale and timing); and
- Consumers' likely willingness to pay?

c. If not, are there any changes to the regulatory regime that *would* simultaneously support these dual objectives?

d. If not, what would be the most efficient form of government intervention to simultaneously support these dual objectives?

Frontier Economics

Brisbane | Melbourne | Singapore | Sydney

Frontier Economics Pty Ltd
395 Collins Street Melbourne Victoria 3000

Tel: +61 3 9620 4488
https://www.frontier-economics.com.au

ACN: 087 553 124 ABN: 13 087 553 124