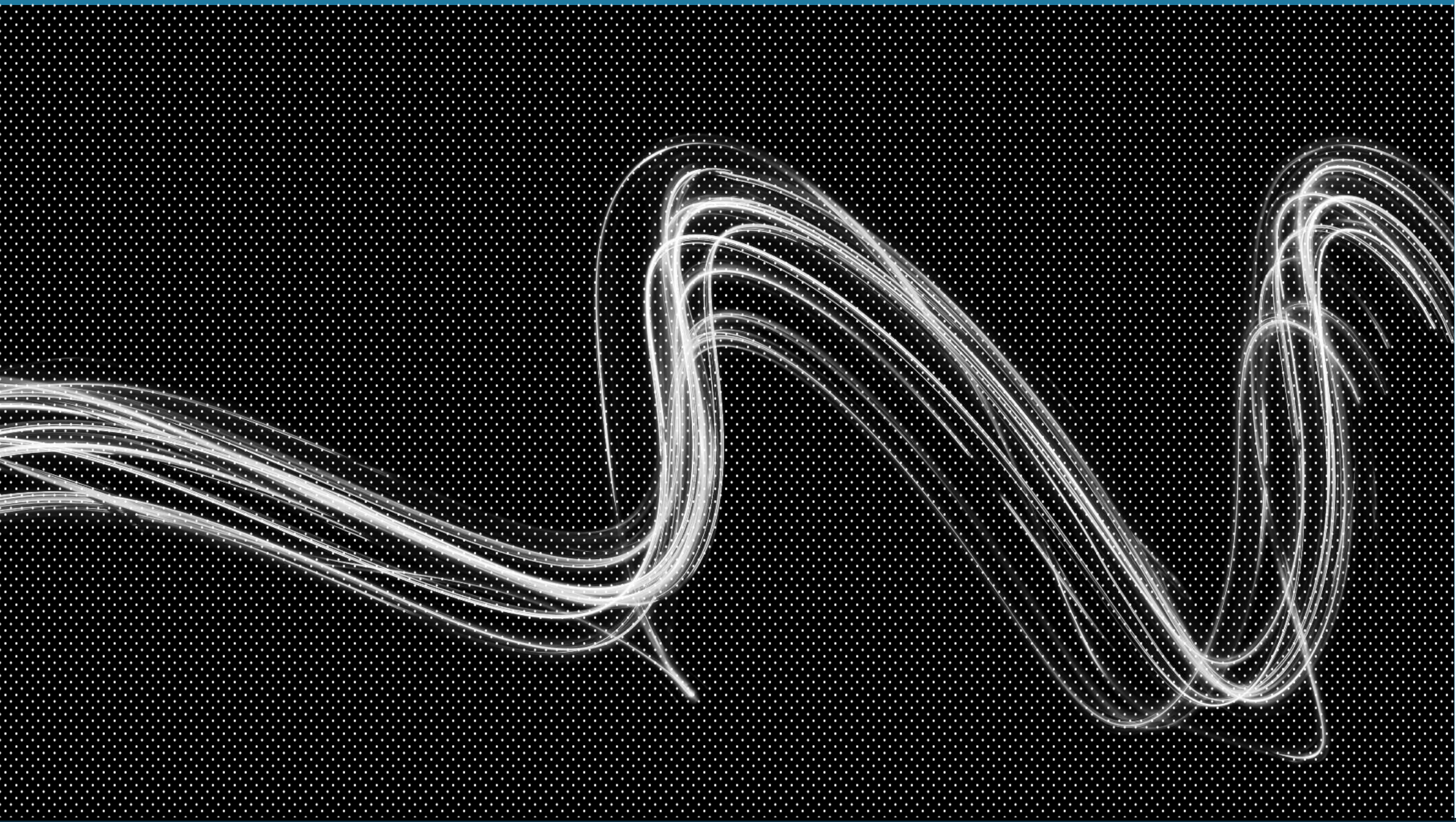


The IM review: Investing to enable decarbonisation and realise the benefits of electrification

A report for the B6 |Final | 18 November 2022

Contents

Tables

Figures

Boxes

1 Executive summary

The Big Six (B6) Electricity Distribution Business (EDBs) – Aurora, Orion, Powerco, Unison, Vector, Wellington Electricity – are engaged in the New Zealand Commerce Commission's (the Commission's) review of the Input Methodologies (IMs) for EDBs. The B6 have asked Frontier Economics to provide advice on:

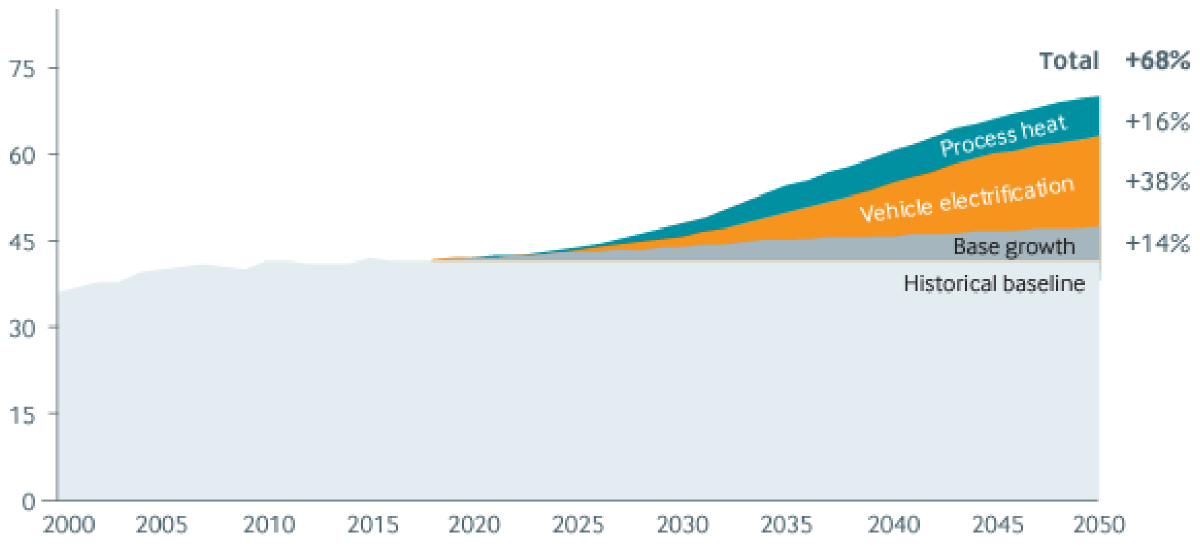
- Can acting or investing now (that is, ahead-of-demand) achieve lowest cost decarbonisation for consumers in the long term?
- Will electrification of transport and heating save on the overall financial costs to households in New Zealand? and
- Does the IM/DPP regulatory regime enable a lowest cost decarbonisation and related financial savings for households?

New Zealand faces a set of ambitious and uncertain decarbonisation pathways

The New Zealand Government is committed to decarbonising the economy consistent with global efforts to limit global warming to 1.5˚C above pre-industrial levels. New Zealand has a distinctive emissions profile where many gains in renewable electricity generation or using forestry as carbon sinks have been realised. The energy sector will play an outsized and crucial role in meeting New Zealand's emissions budgets and targets.

Customer energy demand will increasingly shift to electricity supply supported in part by small scale renewable generation connected to the distribution network. The largest electrification drivers relate to the shift away from natural gas and the change to electric vehicles. Transpower expects demand growth of 68% between 2019 and 2050.

Figure 1: Gross electricity demand and 'the ramp'



Source: Transpower.

EDBs are critical enablers to New Zealand's electrification and decarbonisation goals

EDBs will play a central enabling role in achieving New Zealand's decarbonisation goals and this process will occur over multiple EDB DPP regulatory periods. The Emissions Reduction Plan recognises that investment by networks will be needed to support electrification and to ensure an orderly energy transition that is efficient, affordable and equitable. EDBs are already undertaking and planning actions to support the electricity sector transition and decarbonisation. The Electricity Networks Association (ENA) has released an updated Network Transformation Roadmap (NTR) to support the role of the EDBs as enablers of the transition to a low carbon future.

Decarbonisation results in greater uncertainty for EDBs about the policy environment, technology, customer demand and investment requirements. To promote the long-term interests of consumers, the IM/DPP regulatory framework should allow EDBs to recover their efficient costs and ensure that risks are appropriately allocated between EDBs and customers.

The regulatory framework should be improved to enable decarbonisation

The IM/DPP regulatory framework may prevent EDBs from undertaking prudent and efficient investment required to enable decarbonisation. This is primarily because the IM/DPP is a 'steady state' regime which sets expenditure allowances based on historic expenditure profiles. Notwithstanding this, the DPP is complimented with some narrow within-period mechanisms to manage uncertainty and a time and resource intensive Customised Price-quality Path (CPP) option.

There are several issues with the IM/DPP framework which may prevent EDBs investing prudently and efficiently to enable decarbonisation:

- First, the approach adopted by the Commission to develop expenditure forecasts under the DPP process does not adequately account for future changes in EDB expenditure as a result of decarbonisation;
- Second, the risk management mechanisms in the current IMs are unlikely to adequately address uncertainty that arises from a range of uncertain decarbonisation pathways; and
- Third, targeted incentives for innovation under the IM/DPP framework are low powered and appear to be ineffective.

Given these considerations, it seems that the Commission's objective should be to amend the IMs to allow EDBs to rely on the DPP to promote efficient investment in, and operation of, their network consistent with the New Zealand Government's decarbonisation and net zero emissions targets. The Commission have indicated that this is within the bounds of its existing statutory objective. Whilst there are benefits to allowing EDBs to opt for a CPP over a DPP to better meet their individual circumstances, given the costs and complexities of undertaking a CPP, it is desirable that the CPP process be the exception rather than the norm.

Real options and investing under uncertainty

The real options literature recognises that investing early can create new opportunities or value that would otherwise be delayed or unavailable without that investment. For example, a technology company may invest in developing a digital platform that allows it to enter and compete in one market. Establishing its initial platform may then provide the company with the option to develop further functionality that would allow it to serve new or different types of customers, and to expand into new markets. The options that are created following the initial decision to invest are referred to in the literature as *expansion options.*

Applying this to EDBs, expansion options offer value via the two channels of removing barriers to consumer investment and enabling EDBs to flexibly respond to changes in consumer behaviour:

- Firstly, consumers will require certain network infrastructure that only EDBs can provide in order to adopt decarbonisation technologies (e.g., EVs, solar panels). By making that infrastructure available through early investment, EDBs can remove some of the barriers that might otherwise deter adoption of decarbonisation technologies; and
- Secondly, investing ahead of demand by installing additional capacity would allow EDBs to respond more quickly to requests from consumers for new connections and connection upgrades. This would allow more rapid electrification, thus accelerating the benefits of decarbonisation. That is, investing early can create options for EDBs to respond more flexibly to changes in consumer behaviour that would support decarbonisation.

Scale efficiencies that result in savings to consumers may also be available if EDBs can make large, lumpy investments in capacity ahead of demand.

The financial impacts of electrification for New Zealand households

One of the key drivers of electrification for households in New Zealand is the financial benefits derived from electrification. Where there are savings available to households through electrification, it would be expected that households will electrify their transport or heating, resulting in increases in electricity demand. The analysis undertaken demonstrates, for a typical customer, based on current prices and costs:

- It is unlikely to be financially beneficial to switch from natural gas to electricity based on current prices of natural gas and electricity and current appliance costs. However, customers may still choose to electrify their natural gas for a number of other reasons, including to reduce the emissions from their energy use, due to personal preference for electrical appliances rather than natural gas appliances, or in order to make greater use of the electricity generated by rooftop solar panels. The financial impacts of electrification will change as energy prices and appliance costs and efficiency change. For instance, increases in gas prices, without corresponding increases in electricity prices, and/or rebates for higher efficiency electrical appliances, could make switching to electrical appliances financially beneficial in the future.
- It is likely to be financially beneficial now for many new car customers to switch from an ICE vehicle to an EV, at current prices and costs. The total household cost of electrifying transport use is expected to become lower compared to ICE vehicles by either 2025 or 2026, depending on the household's baseline usage of liquid fuels. Furthermore, it is expected to be financially beneficial for more customers each year as the price premium of EVs relative to ICE vehicles falls and the efficiency of EVs improves.

With switching to EVs becomes financially attractive to a large number of customers over coming years, it is likely that the adoption of EVs will also increase rapidly. This will have material effects on customers' use of electricity networks. With the electricity required for a typical household's transport needs amounting to around 3,000 kWh per annum, areas with high EV adoption could see very significant changes to total electricity demand. Depending on how and when customers choose to charge their EVs, meeting this additional electricity demand could require material network augmentation.

International emerging best practice supports increasing flexibility

The risks and uncertainties inherent to New Zealand's decarbonisation pathway, such as the scale of change, the role of new technologies and uncertainty about the most efficient transition path, are held in common with other regulatory jurisdictions in Great Britain, Australia, Singapore, and Ireland.

While it is widely established that there is no one-size-fits-all solution to addressing this problem, across the economic regulators surveyed, both ex ante and within period regulatory responses are critical elements of the standard regulatory response. In summary, this takes the form of higher expenditure allowances for decarbonisation-related expenditure and targeted uncertainty mechanisms intended to support EDBs to innovate, digitalise and react flexibly.

Options to amend the IM/DPP framework to enable decarbonization and realise the benefits of electrification

The IM review is an opportunity to shape the regulatory regime to ensure it is fit-for-purpose. The biggest issue facing EDBs over the coming years will be in facilitating decarbonisation under conditions of uncertainty about the policy environment, technology, customer demand and investment requirements. Under these circumstances, efficient outcomes are likely to be supported by enabling:

- EDBs to invest ahead of demand under the DPP to support decarbonisation and electrification;
- an adaptive and flexible IM/DPP regulatory framework that proactively manages risks related to decarbonisation; and
- improved incentives to accelerate innovation and increase energy affordability.

The following broad areas of amendment to the IM/DPP regulatory framework are recommended (some requiring IM amendments, some not):

- Allow expenditure forecasts to reflect the expected profile of expenditure, rather than the historic profiles;
- Introduce uncertainty mechanisms to manage specific decarbonisation-related uncertainties and broaden the suite of DPP reopeners to manage risks related to the transition; and
- Provide up front guidance on compliance processes to decrease regulatory burden and improve regulatory certainty.

The benefits to consumers associated with proactive management of decarbonisation risks are significant, while the costs associated with the added complexity can be managed through clear processes and guidelines, including consultation with stakeholders to figure out what will work best.

2 Introduction

2.1 Background

The Big Six (B6) Electricity Distribution Business (EDBs) – Aurora, Orion, Powerco, Unison, Vector, Wellington Electricity – are engaged in the New Zealand Commerce Commission's (the Commission's) review of the Input Methodologies (IMs) for EDBs. The Commission formally began its IM review in February 2022 and it must be completed by December 2023.

The IM review is an opportunity to assess whether the existing regulatory regime is fit-for-purpose, especially given the rapidly evolving environment in which EDBs operate, and make necessary amendments that are in the long-term interests of consumers.

The IM Review is occurring against a backdrop of significant change in the New Zealand economy and policy environment. New Zealand's path to a net zero economy is in its early stages of development, and the electricity sector is at the beginning of its transition. The exact path New Zealand will take to net zero is still uncertain and the regulatory regime will need to recognise and manage its exposure to these new uncertainties.

Consumers' adoption of new technology and energy sector decarbonisation are coinciding to create a level of unprecedented change and unpredictability for EDBs. The industry is seeking regulatory certainty on these issues, as is demonstrated by Commission workshop summaries and stakeholder submissions, and related IM review stakeholder submissions.[1]

2.2 Our objective

The B6 have asked Frontier Economics to provide advice on:

- Can acting or investing now (that is, ahead-of-demand) achieve lowest cost decarbonisation for consumers in the long term?
- Will electrification of transport and heating save on the overall financial costs to households in New Zealand? and
- Does the IM/DPP regulatory regime enable a lowest cost decarbonisation and related financial savings for households?

We understand this work will inform the B6's submissions in relation to the Commission's IM review.

2.3 Key findings

EDBs investing proactively to enable decarbonisation is consistent with achieving lowest cost decarbonisation. In the long-term, New Zealand consumers will also benefit financially from the electrification of transport and heating.

[1] Commerce Commission 2022, *Workshop on the impact of decarbonisation on electricity lines services summary of stakeholder views from workshop held 7 December 2021,* 1 February; New Zealand Commerce Commission, *Part 4 Input Methodologies Review 2023 Process and Issues Paper*, ISBN 978-1-99-101210-4, 20 May 2022.

The IM review should look to amend the regulatory framework to proactively manage uncertainty, and as a result enable decarbonisation-related investment in consumers' long term interests.

Our key findings:

- There are numerous potential transition pathways for New Zealand to achieve its 2030 and 2050 decarbonisation goals. There is consensus that electricity will play a disproportionate role in helping New Zealand meet its decarbonisation objectives. As a result of the investment and change required, the impacts of decarbonisation will occur over multiple EDB DPP regulatory periods;
- The EDBs, and the regulatory settings under which they operate, will be critical enablers of the energy transition. However, in our view, the approach adopted by the Commission to develop expenditure forecasts under the DPP process is unlikely to adequately account for EDBs' future expenditure needs to enable decarbonisation. In addition, the risk management mechanisms in the current IMs will not adequately address the uncertainty that arises from the potential decarbonisation pathways;
- The 2050 target, emissions budgets, and related emissions reduction plan require significant investment by EDBs.;
- The theory of real options can inform prudent investment making under uncertainty. Theory suggests that early investment by EDBs can create valuable options and opportunities for consumers to alter the way they use, generate and supply power by:
  - making infrastructure available through early investment. EDBs can remove some of the barriers that might otherwise deter adoption of decarbonisation technologies realising economics of scale in delivery;
  - investing ahead of demand by installing additional capacity. This would allow EDBs to respond more quickly to requests from consumers for new connections and connection upgrades; and
  - investing in foreseeable large, lumpy investments in capacity ahead of demand. This could realise scale efficiencies and de-risk deliverability. These efficiencies would ultimately be passed through as savings to consumers.
- Many households are likely to financially benefit from electrifying their transport already, with more households benefitting with each year. This suggests that it is likely that adoption of EVs will increase rapidly. However, at current energy prices and appliance costs, households are not likely to financially benefit from electrifying their natural gas use. Electrification of gas use may still be driven by other factors – including a desire to reduce emissions, a preference for electrical appliances or to make greater use of generation from rooftop solar panels. Electrification may become financially beneficial with increases in gas prices and/or rebates for higher efficiency electrical appliances.
- Other economic regulators are experimenting in their regulatory approaches to managing uncertainty related to decarbonisation. Section 6 of this report steps through the approach of comparable jurisdictions. The economic regulators surveyed recognise that decarbonisation will require a step-change in investment given the expected increase in electricity demand driven by electrification, as well as increased penetration of flexibility services and distributed energy resources in the network. We find that both ex ante and within period regulatory responses are critical elements of the standard regulatory response; and

- To promote the long-term interests of consumers, the IM/DPP regulatory framework should provide for:
  - EDBs to invest prudently ahead of demand under the DPP to support decarbonisation and electrification. This will require expenditure allowances which reflect expected changes in decarbonisation related investment, rather than historic expenditure profiles;
  - Regulation that can adapt to manage risks related to decarbonisation. The current IM settings can be complemented with additional within-period flexibility and uncertainty mechanisms which will act to address deficiencies in ex-ante expenditure allowances and efficiently share risk with consumers; and
  - Higher powered incentives to accelerate innovation and improve energy affordability as the economy transitions to net zero.

2.4 Report Structure

The remainder of the report is structured as follows:

- Section 3 describes the role of EDBs and the IM/DPP regulatory framework settings in New Zealand's decarbonisation;
- Section 4 describes the Commission's decision-making framework for the IM review and introduces an economic framework for making prudent investments under uncertainty;
- Section 5 articulates and where possible quantifies the benefits to consumers that could be derived from electrification as EDBs invest and prepare their networks to support the energy transition;
- Section 6 surveys international regulatory practices adopted to tackle decarbonisation objectives;
- Section 7 evaluates the merits of amending the IM/DPP framework to allow EDBs to invest ahead of demand to prepare networks to support New Zealand's decarbonisation efforts, consistent with the Part 4 purpose and the Commission's IM review Decision Making Framework;
- Attachment A provides a summary of potential IM/DPP framework amendments identified during this project.

3 NZ’s decarbonisation goals and the IM/DPP framework

This section describes the role of EDBs and the IM/DPP regulatory framework settings in supporting New Zealand’s decarbonisation objectives (summarised in **Figure 2**). The decarbonisation enabling role of EDBs highlights the importance of the IM/DPP regulatory framework allowing for prudent investment under uncertainty.

Figure 2: Investment to enable decarbonisation

Source: Frontier Economics

3.1 Trends and uncertainties in achieving net zero

The New Zealand Government is committed to decarbonising the economy consistent with global efforts to limit global warming to 1.5˚C above pre-industrial levels. Examples of this commitment include:

- the Climate Change Response Act 2002, which was amended in 2019 to set three targets: net-zero carbon emissions by 2050, and biogenic methane emissions reduced below 2017 levels by 10% by 2030 and by 27 to 47% by 2050. [2]
- the Emissions Budgets and Emissions Reduction Plan released in May 2022 were designed to act as stepping stones to New Zealand’s long-term targets and provide a set of policies and strategies for meeting the targets, respectively;[3] and

[2] The Climate Change Response (Zero Carbon) Amendment Act 2019.

[3] Ministry for the Environment 2022, *Emissions budget and the emissions reduction plan,* 16 May, https://environment.govt.nz/what-government-is-doing/areas-of-work/climate-change/emissions-budgets-and-the-emissions-reduction-plan/

- the National Adaptation Plan released in August 2022, sets out the work needed to prepare New Zealand for the challenges of a changing climate, including the actions needed to ensure that infrastructure is resilient.[4]

While New Zealand's decarbonisation objectives are clear, the exact path forward and pace of change remains subject to an inherent and significant degree of uncertainty.

New Zealand faces a set of uncertain decarbonisation pathways

Decarbonisation in New Zealand will face unique challenges compared to other developed economies. New Zealand has a distinctive emissions profile where many gains in renewable electricity generation or using forestry as carbon sinks have been realised. Indeed, the New Zealand Government emphasised the high potential costs of decarbonisation in its most recent Nationally Determined Contribution (NDC): [5]

> *The likely cost to the New Zealand economy of meeting this NDC target in terms of GDP is high relative to many other Parties. This is due to a number of factors, such as the existing high level of renewable electricity generation (80-85 per cent), and the make-up of our emissions profile, where almost half of our total emissions originate from agriculture.*

New Zealand's latest Nationally Determined Contribution (NDC) towards the Paris Agreement sets a headline target to reduce net greenhouse gas (GHG) emissions to 50 per cent below gross 2005 levels by 2030.[6] This equates to a cumulative net emissions budget of 571,000 kt CO_2-e between 2021 and 2030. In order to achieve the 2030 target, New Zealand must reduce its gross GHG emissions to about 41.2 million tonnes of CO_2-e by 2030.

New Zealand's gross and net emissions have flattened over the last decade, after steadily rising before the mid-2000s (see **Figure 3**). In 2019, New Zealand's gross GHG emissions were 82.3 million tonnes of CO_2-e, which was 0.2 percent lower than 2005 levels.

The Climate Change Commission states that to meet the 2050 net zero target, New Zealand needs to transition away from fossil fuels and rely more heavily on renewable electricity and low-emissions fuels like bioenergy and hydrogen, while also improving energy efficiency.[7]

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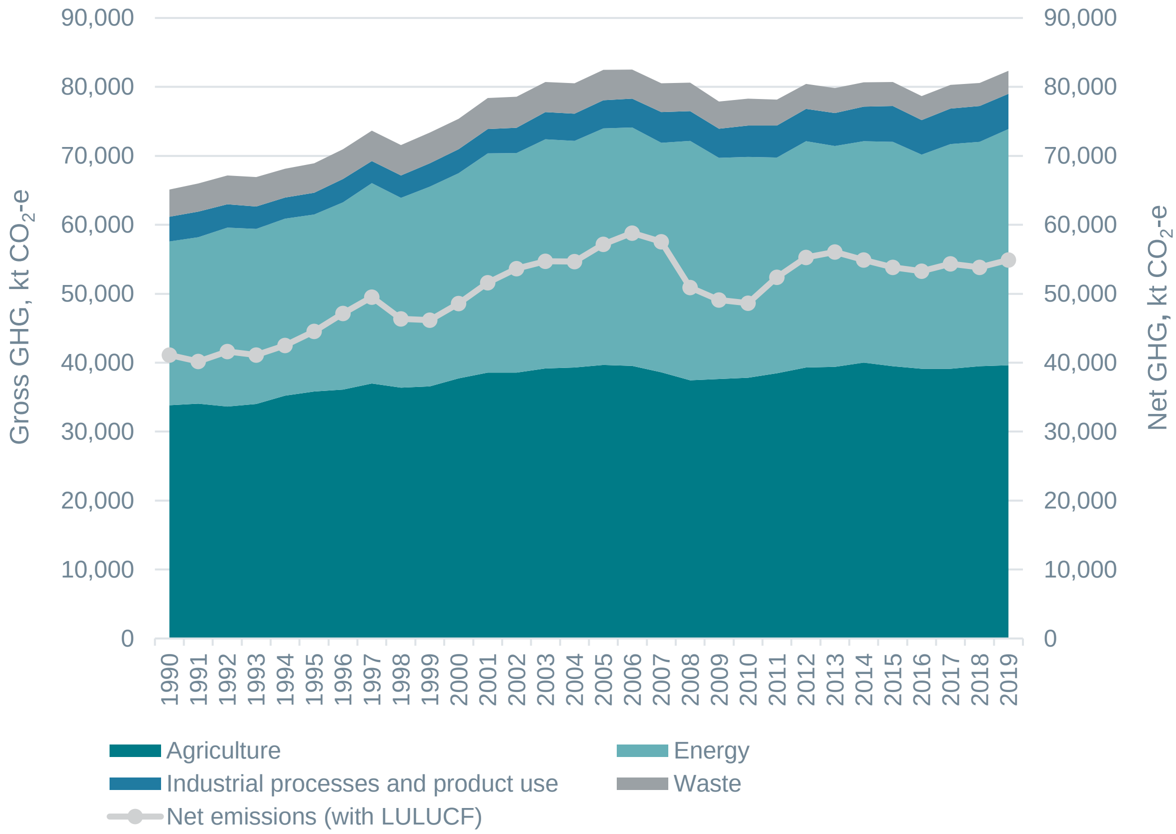
4 Ministry for the Environment 2022, *Adapt and thrive: Building a climate-resilient New Zealand*, 3 August, https://environment.govt.nz/publications/aotearoa-new-zealands-first-national-adaptation-plan/

5 New Zealand Government 2021, *Submission under the Paris Agreement New Zealand's first Nationally Determined Contribution (updated 4 November 2021)*, p. 15, viewed 12 September 2022, https://www4.unfccc.int/sites/ndcstaging/PublishedDocuments/New%20Zealand%20First/New%20Zealand%20NDC%20November%202021.pdf

6 New Zealand Government 2021, *Submission under the Paris Agreement New Zealand's first Nationally Determined Contribution (updated 4 November 2021)*, viewed 12 September 2022, https://www4.unfccc.int/sites/ndcstaging/PublishedDocuments/New%20Zealand%20First/New%20Zealand%20NDC%20November%202021.pdf

7 Climate Change Commission 2022, *a low emissions future for Aotearoa*, p.277, https://www.climatecommission.govt.nz/our-work/advice-to-government-topic/inaia-tonu-nei-a-low-emissions-future-for-aotearoa/

Figure 3: Trends in New Zealand's gross GHG by sector and net GHG emissions



Source: Ministry for the Environment, New Zealand's Greenhouse Gas Inventory 1990–2019 Snapshot, viewed 12 September 2022, https://environment.govt.nz/publications/new-zealands-greenhouse-gas-inventory-1990-2019-snapshot/emissions-trends-by-sector/

In May 2022, the Government published its first of three Emissions Budgets (2022–2025, 2026–2030, 2031–2035) and an Emissions Reduction Plan (ERP) to put New Zealand on course to meet its emissions budgets.[8]

The energy sector will be central to achieving least cost decarbonisation

The Government identified the energy sector as being crucial to meeting the first emissions budget's targets. [9] In 2019, emissions from the energy sector were 44.3 per cent higher than in 1990 – mostly driven by road transport (96.2 per cent increase since 1990), and the use of fossil fuels in manufacturing and construction.

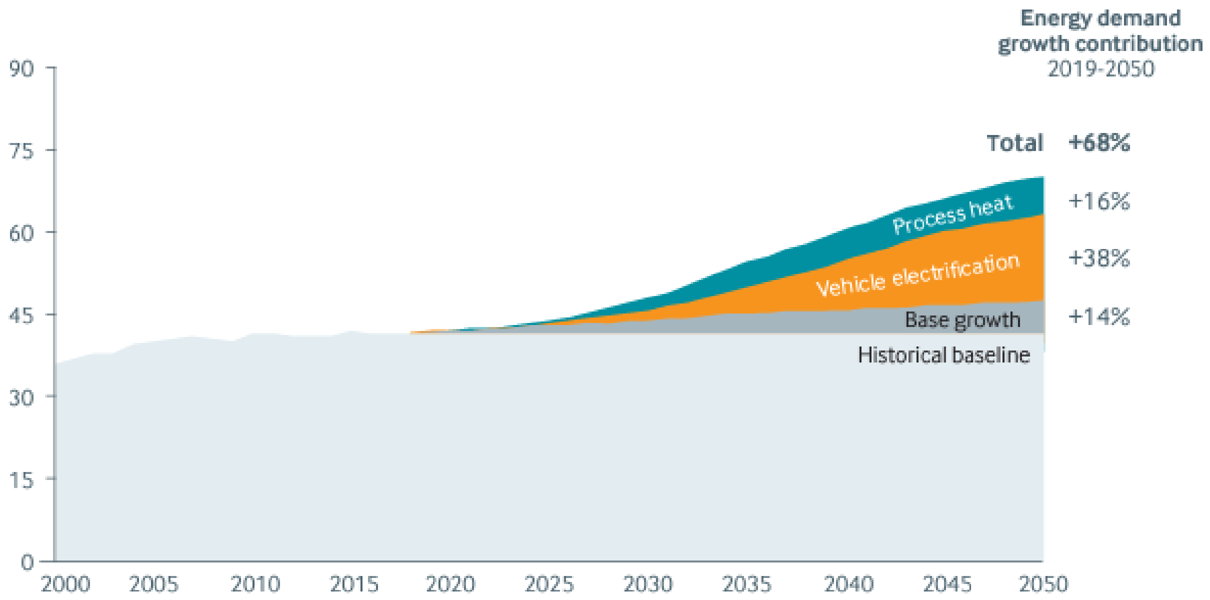
8 Ministry for the Environment 2022, *Te hau mārohi ki anamata Towards a productive, sustainable and inclusive economy Aotearoa New Zealand's first emissions reduction plan*, New Zealand Government, ISBN: 978-1-99-102526-5, https://environment.govt.nz/publications/aotearoa-new-zealands-first-emissions-reduction-plan/

9 Ministry for the Environment 2022, Te hau mārohi ki anamata Towards a productive, sustainable and inclusive economy Aotearoa New Zealand's first emissions reduction plan, New Zealand Government, p. 36, ISBN: 978-1-99-102526-5, https://environment.govt.nz/publications/aotearoa-new-zealands-first-emissions-reduction-plan/

There is a consensus that electricity will have an outsized role in helping New Zealand meet its decarbonisation goals.[10] Average electricity demand is projected to grow above recent historical trends with peak demand also expected to rise substantially. Transpower presents an 'accelerate electrification' base case which it describes as a realistic yet aspirational scenario for the New Zealand economy and electricity industry. Transpower considers this scenario the most likely, being supported by underlying economic, technological and social forces promoting widespread adoption of electric vehicles and electrifying process heat.[11]

Figure 7 highlights Transpower's base case of 68 per cent growth in electricity demand between 2020 and 2050. The 'ramp' in electricity demand is slow in the five years between 2020 and 2025, from 42 to 44 TWh, but materially grows in the 2025–2030 period, in which total electricity demand increases by approximately 10 per cent from 44 to 48 TWh.

Figure 4: Gross electricity demand and 'the ramp'



Source: Transpower.

The further electrification of transport and heating, even with improvements in energy efficiency, is likely to significantly increase electricity demand. Meeting this electricity demand will require

10 Ministry of Business, Innovation & Employment, *Electricity demand and generation scenarios: Scenario and results summary*, July 2019, available at: https://www.mbie.govt.nz/dmsdocument/5977-electricity-demand-and-generation-scenarios , Transpower, *NZGP1 Scenarios Update: NZGP1 Scenarios and modelling result for an unconstrained transmission grid*, December 2021, available at: https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/Transpower_NZGP_Scenarios%20Update_Dec2021.pdf . New Zealand Government: *New Zealand's First Emissions Reduction Plan*, June 2022, available at: https://environment.govt.nz/assets/publications/Aotearoa-New-Zealands-first-emissions-reduction-plan.pdf .

11 Transpower 2020, *Whakamana i Te Mauri Hiko Empowering our Energy Future*, March, https://tpow-corp-production.s3.ap-southeast-2.amazonaws.com/public/publications/resources/TP%20Whakamana%20i%20Te%20Mauri%20Hiko.pdf?VersionId=FljQmfxCk6MZ9mIvpNws63xFEBXwhX7f

significant grid investment over time but will also enable significant benefits. Transpower states:[12]

> *The outcomes of achieving an Accelerated Electrification future are very positive: the development of a genuinely low carbon economy, reduced household expenditure on energy, significantly improved terms of trade and using the New Zealand brand to showcase to the world how to lead the response to climate change.*

The ERP highlights the need to ensure the electricity system is ready to meet future needs through 'reducing barriers to developing and efficiently using electricity infrastructure, including transmission and distribution networks.'[13] The ERP states that in the short term, this means 'ensuring our markets and regulations are fit for a low-emissions future.'[14] These views were also echoed in the Climate Change Commission's advice to the New Zealand Government on its emissions budgets, which noted that 'traditional ways of operating may not deliver the most efficient solutions at the pace required for the transition'.[15]

Vehicle electrification is expected to be significant

Transpower expects vehicle electrification to drive electricity demand growth between 2025 and 2050. Under the Climate Change Commission's demonstration path,[16] EVs would make up at least half of total light vehicle imports by 2029. By 2035, 46% of all light vehicle travel would be in EVs and 36% of light vehicles on New Zealand's roads would be electric (**Figure 5**).[17]

12 Transpower 2020, *Whakamana i Te Mauri Hiko Empowering our Energy Future*, March, p. 19, https://tpow-corp-production.s3.ap-southeast-2.amazonaws.com/public/publications/resources/TP%20Whakamana%20i%20Te%20Mauri%20Hiko.pdf?VersionId=FljQmfxCk6MZ9mlvpNws63xFEBXwhX7f

13 Ministry for the Environment 2022, *Te hau mārohi ki anamata Towards a productive, sustainable and inclusive economy Aotearoa New Zealand's first emissions reduction plan*, New Zealand Government, p. 201, https://environment.govt.nz/publications/aotearoa-new-zealands-first-emissions-reduction-plan/

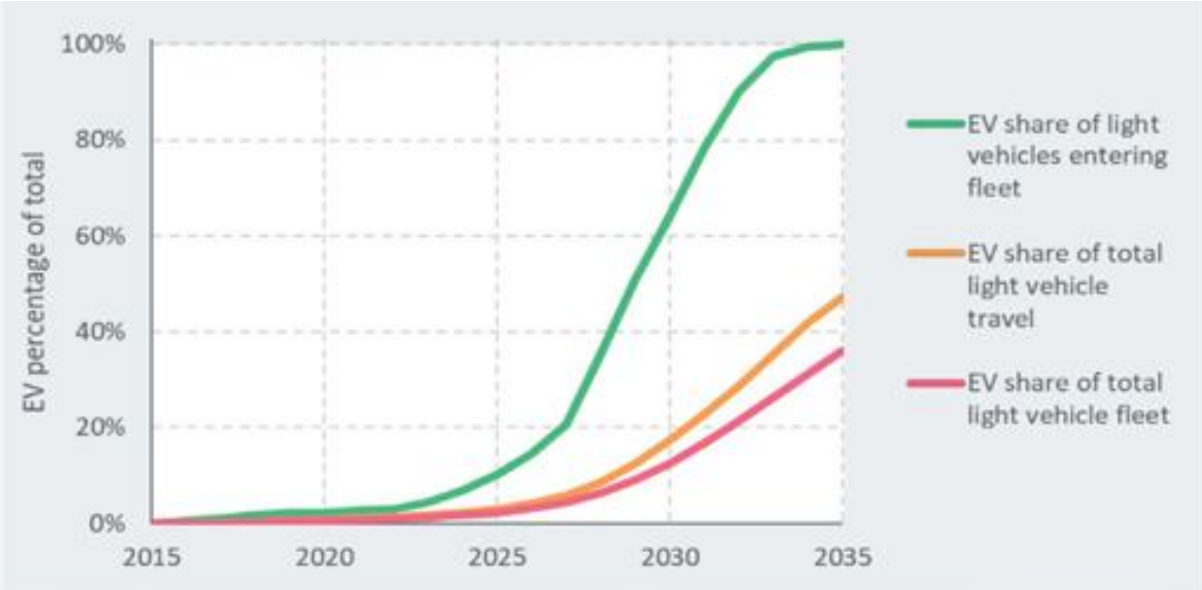
14 We note that the Government is intending to deliver its Energy Strategy by the end of 2024 and its Gas Transition Plan by 2023.

15 Climate Change Commission 2022, *a low emissions future for Aotearoa,* p.282, https://www.climatecommission.govt.nz/our-work/advice-to-government-topic/inaia-tonu-nei-a-low-emissions-future-for-aotearoa/

16 The demonstration path is one set of measures and actions within each sector that would deliver on the Climate Change Commission's recommended emissions budgets.

17 Climate Change Commission 2021, *Ināia tonu nei: a low emissions future for Aotearoa*, p.107, https://environment.govt.nz/news/the-release-of-the-climate-commission-final-report/

Figure 5: Uptake of light EVs in the demonstration path



Source: Climate Change Commission.

Under its demonstration path the Climate Change Commission assumes an accelerated uptake of electric and zero emissions cars, buses and trucks across Emissions Reduction Budget One and Emissions Reduction Budget Two.[18] The New Zealand Government is providing incentives to further increase the uptake of electric vehicles (EVs), aiming to have EVs accounting for 35% of new vehicle registrations by 2035.

Under the demonstration path the Climate Change Commission assumes supporting transmission and distribution grid upgrades to support electrification and expanding renewable generation will occur.[19] However, this is not necessarily a valid assumption given current settings in the IM/DPP regulatory framework.

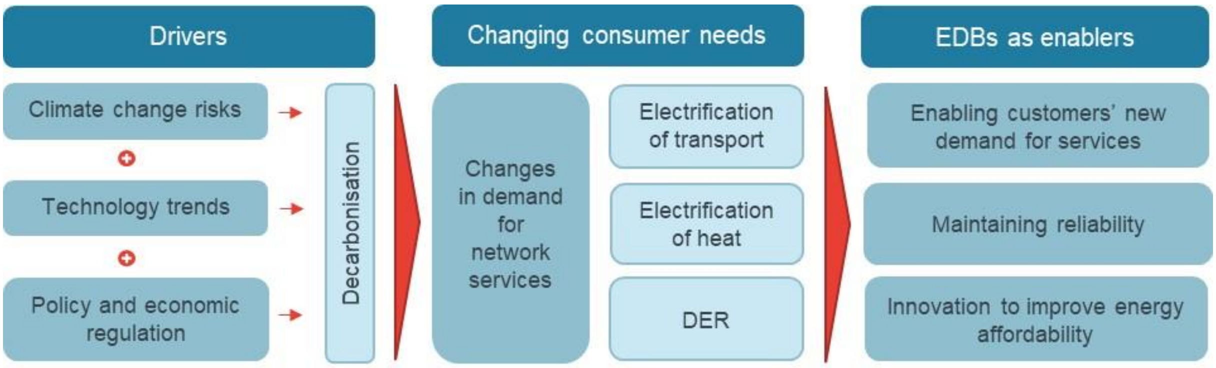
3.2 The role of EDBs in achieving New Zealand's carbon neutrality goals

New Zealand's EDBs will play a central enabling role in achieving New Zealand's decarbonisation goals and in facilitating the benefits of electrification for consumers including through enabling new low-emission technologies to emerge, while minimising the risk of energy hardship during the transition. A summary of EDBs role is provided in **Figure 6**.

18 Climate Change Commission 2021, *Ināia tonu nei: a low emissions future for Aotearoa*, 31, May, p. 103, https://www.climatecommission.govt.nz/our-work/advice-to-government-topic/inaia-tonu-nei-a-low-emissions-future-for-aotearoa/

19 Climate Change Commission 2021, *Ināia tonu nei: a low emissions future for Aotearoa*, 31, May, p. 103, https://www.climatecommission.govt.nz/our-work/advice-to-government-topic/inaia-tonu-nei-a-low-emissions-future-for-aotearoa/

Figure 6: EDBs enabling role to support decarbonisation and electrification



Source: Frontier Economics

The network transformation roadmap and interacting drivers of change

Households and businesses are changing their behaviour and demanding energy from more affordable, renewable sources, as well as generating their own electricity. Government and corporate policies to reduce carbon emissions are also encouraging the development of new renewable energy sources.

The ENA's New Zealand Electricity Distributor Network Transformation Roadmap highlights three fundamental and interacting changes that are expected to impact on the electricity industry over the coming years: [20]

- The requirement to meet climate change objectives, which can be achieved largely by switching energy use to renewable electricity;
- New consumer technology, which is increasing the options for consumers to produce, store and use electricity in new ways; and
- The rise of prosumers – consumers who generate and supply surplus electricity back into the grid for other consumers to utilise.

At the centre of these changes are EDBs delivering more electricity, increasingly providing network services to consumers to sell their electricity back to the market and taking on the role of adopting new technologies to facilitate innovation and enable the transition to a net zero economy.

There are significant network investment needs associated with decarbonisation

The EDBs will need to invest to respond to the decarbonisation trends occurring in their networks, as well as to meet their own decarbonisation goals. The Emissions Reduction Plan recognises that investment by networks will be needed to support electrification and to ensure that the electricity system can support more renewables.[21]

Electricity distribution networks are at the interface of many of the new, low emissions energy technologies. An increasing amount of distributed energy resources (DER) is being connected to the distribution network and will meet energy needs. DER is being installed by businesses and

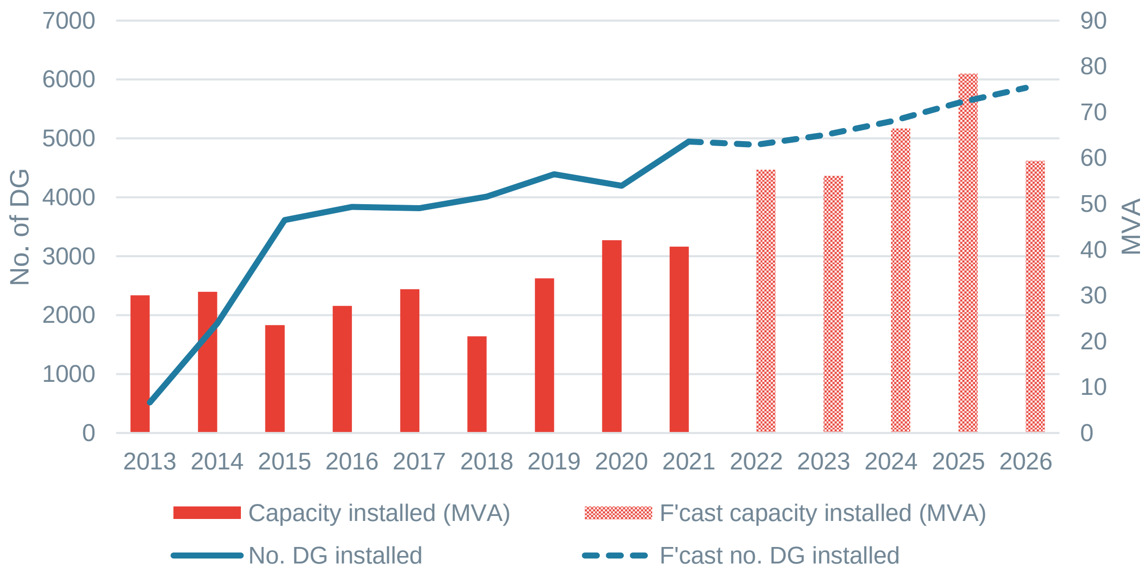
[20] Electricity Networks Association 2019, *New Zealand Electricity Distributor Network Transformation Roadmap*, April, p. 6, https://www.ena.org.nz/resources/publications/document/483

[21] Aotearoa New Zealand's first emissions reduction plan, Action 11.2.3, p. 214.

households - especially rooftop solar and batteries (large and small scale) and can also encompass other 'behind the meter' technologies such as smart appliances, energy management systems and EVs. DER investment will only increase as it continues to become more affordable and efficient, and will provide an important contribution to decarbonisation of the New Zealand energy system.

On behalf of the Electricity Authority, Sapere estimated that if Distributed Energy Resources (DER) were to realise its potential, the net benefit from 2021 to 2050 is expected to be $6.9 billion in net present value terms.[22] **Figure 7** presents actual and forecast growth in DER for all EDBs.

Figure 7: EDB distributed generation – actual and forecast, all EDBs



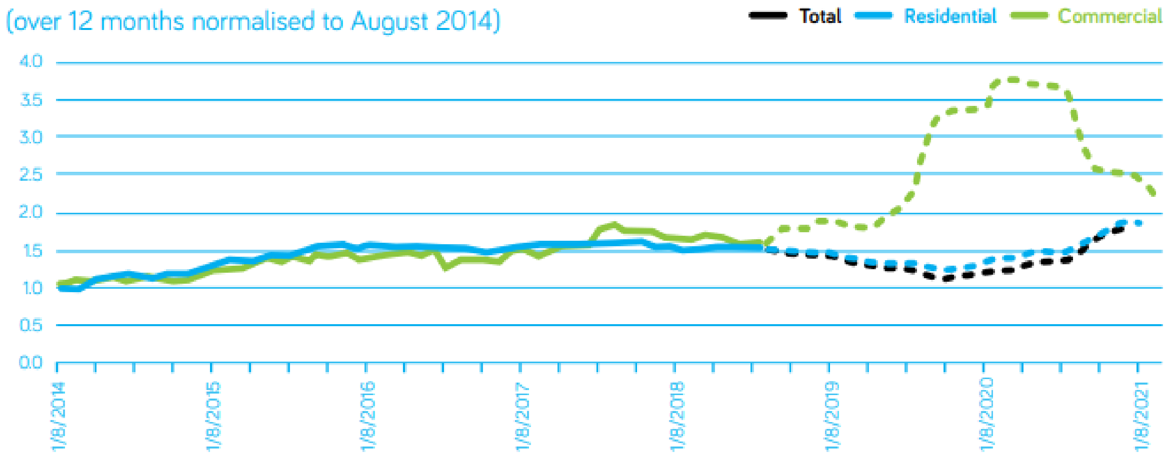
Source: New Zealand Commerce Commission EDB performance summary data; Frontier Economics.

The Electricity Networks Association (ENA) report that DER growth has been relatively slow to date, growing from a low base but with a noticeable increase in solar PV installation by commercial customers (see **Figure 9**). Overall rooftop solar PV penetration is at around 1.6% of connections, growing at 2% per annum.[23]

22 Sapere 2021, *Cost-benefit analysis of distributed energy resources in New Zealand*, 7 July,

23 Electricity Networks Association 2022, *Network Transformation Roadmap*, April, p. 5.

Figure 8: Number of new solar PV connections, normalised to August 2014



Source: Electricity Networks Association 2022, Network Transformation Roadmap, April, p.6.

As well as the investment in small scale renewable generation connected to the distribution network, it is expected that significant sources of customers' energy demand will shift to electricity supply. The largest electrification drivers relate to the shift away from natural gas for heating and cooking and the change to electric vehicles. These trends have the potential to substantially increase electrical loads on the distribution networks, adding both to peak demand and overall consumption. Controls are likely to be required to manage the growth in peak demand such as cost-reflective tariffs and smart devices when higher levels of penetration are reached, particularly of electric vehicles.

The NZ Government's recent forecast of electricity demand in NZ shows that whilst total electricity demand is expected to grow, the extent of this growth is highly uncertain. Demand was forecasted across a range of five scenarios, and the results suggest that electricity demand was projected to increase between 18-78% over the NZ Government's projection period.[24]

Table 1: Electricity demand forecast (TWh)

Scenario	2017	2035	2050
Reference	39.7	48.4	56.7
Growth	39.7	52.0	65.1
Global	39.7	44.1	46.7
Environmental	39.7	54.3	66.5
Disruptive	39.7	55.2	70.5

Source: NZ Government 2019, Electricity demand and generation scenarios: Scenario and results summary, July, p. 23

24 NZ Government 2019, *Electricity demand and generation scenarios: Scenario and results summary*, July, p. 23

These are major changes to the electricity system that will have profound impacts on distribution networks, their operation and future investment needs.

A major change is the need to modify the distribution networks that were built to bring electricity one-way (from large scale, central generation to consumers) so that they are capable of providing two-way power flows. Allowing excess distributed energy to be exported to the electricity grid will be necessary to achieve New Zealand's emission reduction plan and to unlock the investment in the distributed, renewable generation sources. Electricity distribution businesses internationally are investing and innovating to deliver two-way transport services. This typically involves investment in a combination of network assets and information and communications technologies (ICT) capability providing greater visibility and dynamic operation of the network, including the Low Voltage (LV) network.

As noted above, the other key change is the growth in electricity demand and consumption that must be supported by the distribution networks. This will inevitably require investment to augment network capacity. The challenge for the distribution networks is to find ways to efficiently manage these rising costs. Part of the solution is likely to be provided by the more dynamic operation of the network referred to above.

It will also be important to provide customers with incentives to reduce demand at peak periods and to use their solar electricity in the middle of the day when there is excess supply and network congestion due to exports. This may involve a range of mechanisms including better targeted network tariffs, control systems (including network and customer control systems), etc. This will be supported by the development of customer energy management systems and new retail business models that offer integrated energy solutions to customers (e.g., solar, battery, EV and smart appliance integration and optimisation with grid electricity supply) that are in their infancy but developing rapidly. This could assist in smoothing the demands on the networks, including shifting some consumption and exports away from peak periods.

The combination of increasing DER and electrification is also creating new challenges for the safe and stable operation of distribution networks. This is because the network is experiencing larger peaks and troughs in network loading and more rapid shifts between these states. This creates challenges for all levels of the electricity supply chain, including for distribution networks in maintaining power quality and preventing outages. This is also driving a need for new types of investment in network management systems and to encourage customers to reduce the extent of variation in their loading of the network at different periods each day.

We note that in general there will be greater interaction between network and customer systems as part of the management of the distribution network. This should also extend to greater investment in customer engagement. This would ensure that cost/service level trade-offs reflect customer needs and willingness to pay and that customer have input to the design of solutions to manage customer demands on the network in a decarbonising system.

Finally, EDBs will also be undertaking their own investments in solutions to reduce emissions associated with providing their services. This may take a number of forms including:

- Investment in efficient non-network solutions such as distributed batteries and Stand Alone Power Systems (SAPS)[25] which draw on renewable electricity systems;

25 Providing network services via a stand-alone power system, typically including solar, battery and back up diesel instead of via the network. This may be a more efficient solution in remote areas.

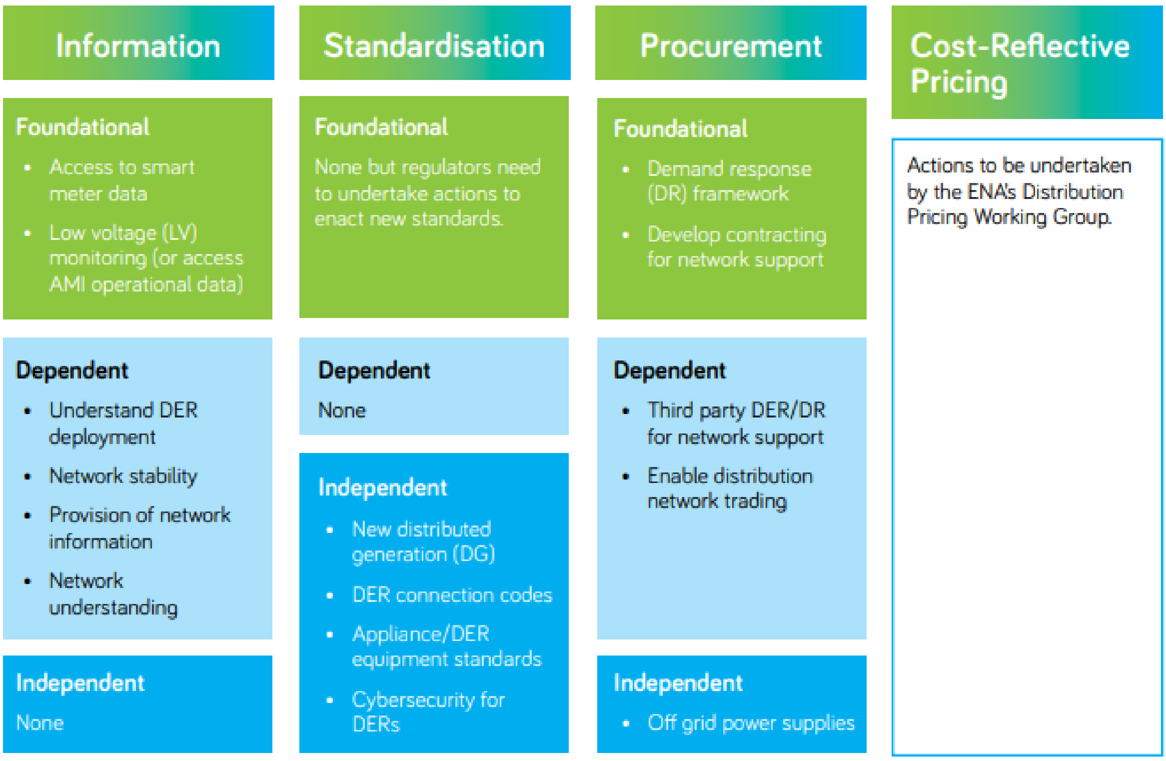
- A range of innovations in network operation and maintenance including greater use of sensing and drone technologies and fleet electrification;
- Greater innovation in demand management and tariff design; and
- Voluntary reporting of Task force on Climate-related Financial Disclosures (TCFD) designed to demonstrate how climate-related risks and opportunities are incorporated into their risk management and strategic planning processes.

Actions the EDBs are already taking to support decarbonisation

The EDBs are already undertaking and planning actions to support the transition and decarbonisation. The Electricity Networks Association (ENA) has released an updated Network Transformation Roadmap (NTR) to support the role of the EDBs as enablers of the transition to a low carbon future.

The NTR consists of 7 workstreams and 19 'least regrets' actions to assist EDBs to prepare for the new energy future over the course of the next decade, up to 2030. This includes accessing smart meter data, developing a demand response framework, improving LV network monitoring and visibility and contracting for network support. The key changes made to the initial NTR include providing greater clarity to highlight key actions in the NTR, identifying dependencies and redefining 2, 5 and 10-year targets (as shown in **Figure 9**).

Figure 9: NTR update core focus areas



Source: Electricity Networks Association 2022, Network Transformation Roadmap, April, p. 14.

In addition, the Commission's 2021 review into EDB's Asset Management Plans (AMPs) in relation to decarbonisation found that EDBs:

- Recognised the likely increase in demand for electricity and the way electricity will be produced and transported around the network, as well as the increased role of EVs and DER;
- Some EDBs had embedded decarbonisation into their AMP strategic objectives, resulting in a more comprehensive and consistent suite of policies regarding decarbonisation; and
- Were already undertaking actions in preparation of decarbonisation. Most common was the monitoring of low voltage sections of the network, given that the uptake of EVs and DER in these sections could lead to capacity constraints and may require intervention.[26]

3.3 The Commission's price-quality regulatory framework

The EDBs, and the IM/DPP regulatory settings under which they operate, will be critical enablers of an orderly energy transition that is efficient, affordable and equitable. While EDBs are already incorporating decarbonisation strategies into their own plans, it is imperative that the regulatory settings have an appropriate level of incentive and flexibility to ensure that the benefits of electrification can be realised.

3.3.1 The application of DPP regulation to EDBs should be the norm

EDBs are regulated under either a Default Price-Quality Path (DPP) or a Customised Price-Quality Path (CPP). A DPP in many ways assumes a regulatory 'steady state' whereby key expenditure and demand variables change incrementally through time, with an expectation that the past is a reasonable predictor of the future. A CPP involves a more forensic analysis of expenditure and demand variables, and thereby allows individualised pricing paths for EDBs facing significant changes to the network.

The Commission uses a 'building blocks' model to establish a DPP for regulated EDBs in New Zealand. Under this approach, the Commission establishes allowances to cover expected operating expenditure, capital expenditure, the return on capital, the return of capital (through a depreciation allowance) and taxation. The sum of these allowances represents the total revenue that each EDB may earn over the regulatory period. This, in turn, helps determine the DPP for each business.

In order to set the cost allowances that feed into the building blocks model, the Commission must develop forecasts of opex and capex for each EDB subject to the DPP. When developing forecasts, the Commission must bear in mind that the purpose of DPP regulation, as set out in the section 53K of the Act, is to:

26 Commerce Commission of New Zealand 2021, *Review of Electricity Distribution Businesses' 2021 Asset Management Plans in relation to decarbonisation*, 18 November 2021, p. 4-5.

> *... provide a relatively low-cost way of setting price-quality paths for suppliers of regulated goods or services ...*

Whilst there are benefits to allowing EDBs to opt for a CPP over a DPP to better meet their individual circumstances, given the costs of undertaking a CPP process (to the businesses and the Commission), it seems desirable that the CPP process be the exception rather than the norm. This means that the DPP framework should be made as robust as possible (in terms of satisfying the purpose of the Act) in light of the New Zealand Government's decarbonisation and net zero emissions targets.

Given these considerations, it seems that the Commission's objective should be to amend the IMs to allow EDBs to rely on the DPP framework to promote efficient investment in, and operation of, their network in light of the New Zealand Government's decarbonisation and net zero emissions targets, without EDBs needing to apply often for a CPP to cover their reasonable expenditure requirements. In order to meet this objective, it is first necessary to understand the limitations of the current DPP framework that may constrain the ability or incentive of EDBs to efficiently respond to decarbonisation strategies that have been or will be implemented.

3.3.2 Risk management mechanisms available to EDBs

Ensuring a supplier has a reasonable opportunity to recover its efficient costs in providing regulated services to customers is a fundamental tenet of sound economic regulation. It also protects the long-term interest of customers by ensuring that the EDBs have sufficient funds to efficiently operate and invest in its network to provide safe, secure/resilient and reliable services to customers.

In line with this, the IMs include mechanisms to help EDBs manage costs and revenue risks that are uncertain and/or unforeseen. In particular, the IMs allow the Commission to reconsider a DPP if it is satisfied that:[27]

- A **catastrophic event** has occurred – This is an event that is beyond the reasonable control of an EDB, that could not have been reasonably foreseen at the time the DPP was determined, and for which action required to rectify its adverse consequences cannot be delayed until a future regulatory period without quality standards being breached. The additional costs of responding to the event must be at least 1% of aggregate allowable revenue in the relevant years in which costs will be incurred;[28]
- A **change event** has occurred – This refers to a change to an existing legislative or regulatory requirement (or the addition of a new requirement) applying to an EDB under a DPP which necessitates the EDB to incur additional reasonable costs to respond to the requirement. The additional costs of responding to the event must be at least 1% of aggregate allowable revenue in the relevant years in which costs will be incurred;[29]

[27] EDB IMs, clause 4.5.6.

[28] EDB IMs, clause 4.5.1.

[29] EDB IMs, clause 4.5.2.

- There has been an **error event** – this covers circumstances where the Commission has identified an error in the basis upon which the DPP was determined, including that incorrect data was used, or that data was applied incorrectly, in setting the price path, quality standards or quality incentive measures. The error must either affect the price path by an amount equivalent to at least 1% of aggregate allowable revenue in the relevant years in which costs will be incurred, or the value of quality metrics;[30]
- a **major transaction** has occurred – this refers to a transaction under which the EDB acquires assets, disposes of assets, acquires rights or interests, or incurs obligations or liabilities, and the value of the transaction is more than 10% of the opening RAB in the relevant year;[31]
- **false or misleading information** has been provided – this refers to a circumstances where an EDB has provided false or misleading information to the Commission, and the Commission has relied on that information to make its DPP determination;[32]
- a project or programme of that EDB is an **unforeseeable major capex project** – this covers connection, system growth or asset relocation capex that was not included nor reasonably foreseeable at the time of the DPP determination, but which is committed (for connection and asset relocation capex) or prudent (for system growth capex), and the capex exceeds either 1% of allowed revenue for the relevant period, or $2 million;[33] or
- a project or programme of that EDB is a **foreseeable major capex project** – this covers connection, system growth or asset relocation capex for projects that were included in the current DPP determination, but for which the costs are expected to exceed the allowance provided for in the DPP determination by 1% of allowed revenue for the relevant period, or $2 million.[34]

Alternatively, EDBs under the DPP have the option to prepare and submit a CPP application to the Commission. The CPP is unlikely to be the appropriate or cost-effective means for EDBs to access additional funding for decarbonisation projects, given the uncertainty and pace of change. The CPP is flexible, but not timely or cost effective. This may deter EDBs from applying for CPP and prevent investment in decarbonisation projects – with implications for NZ's transition.

3.3.3 Limitations with the current DPP framework

The drive towards decarbonisation and net zero emissions creates a number of cost and revenue risks for EDBs. The DPP framework should allow EDBs to recover its efficient costs and ensure that risks that are outside of its control are appropriately allocated between EDBs and customers. However, the approach adopted by the Commission to develop expenditure forecasts under the DPP process will not adequately account for future changes in EDB expenditure as a result of decarbonisation. In addition, the risk management mechanisms in the current IMs will not adequately address the uncertainty that arises from the decarbonisation pathway. We address each of these points below.

30 EDB IMs, clause 4.5.3.

31 EDB IMs, clause 4.5.4.

32 EDB IMs, clause 4.5.6(3).

33 EDB IMs, clause 4.5.5A.

34 EDB IMs, clause 4.5.5B.

Accounting for step changes in expenditure under the DPP process

EDBs have a role in providing the infrastructure needed to support decarbonisation. Achieving the benefits associated with decarbonisation will likely require EDBs to incur additional capital and operating expenditure (over and above historical levels) to respond to changes in demand patterns and address increasingly complex power flows.

However, the Commission's current approach, based on historical expenditure profiles, to forecasting expenditure under a DPP process does not adequately allow for step changes in efficient expenditure (as against historical levels). This means that the expenditure forecasts developed under the DPP process are unlikely to provide EDBs sufficient revenue to cover their efficient costs of decarbonisation.

For example, in setting DPP3, operating expenditure allowances were set using a high-level 'base-step-trend' approach.[35] The base year is taken as year four of the five year period (in order to implement the opex IRIS) and the trend is defined by network scale effects, forecast input prices, and partial productivity of opex. Step changes to the base year are possible subject to a set of criteria.[36]

In outlining its high-level approach, the Commission stated:[37]

> *It is appropriate to forecast opex in this way because most opex relates to activities that recur. As such, the expenditure is likely to be repeated regularly, and can be expected to be influenced by certain known and predictable factors.*

The use of a base-step-trend model is not uncommon. A number of regulators in other sectors and jurisdictions apply a similar model to estimate operating expenditure, including for example the Australian Energy Regulator. Typically, the use of step changes is designed to add or subtract costs that are not otherwise captured in base operating expenditure or the rate of change. However, we understand that the Commission has been reluctant to recognise positive step changes in the DPP process. This means that operating expenditure allowances provided under a DPP are unlikely to capture prudent and efficient operating costs that EDBs incur in responding to changing market conditions, regulatory obligations or other factors.

35 Commerce Commission 2019, *Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision Reasons paper*, 27 November, https://comcom.govt.nz/__data/assets/pdf_file/0020/191810/Default-price-quality-paths-for-electricity-distribution-businesses-from-1-April-2020-Final-decision-Reasons-paper-27-November-2019.PDF

36 The Commission stated in its final DPP3 decision that it requires step changes to be: Significant; robustly verifiable; not captured in other components of its projection (base year, trends factors, capex or recoverable costs); largely outside the control of distributors; and be applicable to most, if not all distributors.

37 Commerce Commission 2019, *Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision Reasons paper*, 27 November, p. 151.

Box 1: Enabling Low Voltage network monitoring and visualisation

Decarbonisation of the energy system will be digitally driven to balance the intermittent nature of renewable energy and manage electric vehicle charging impacts on the network peak. The DPP approach to setting opex allowances, which worked well while the sector was in steady state, is preventing such investment to support an efficient energy transition.

A benefit of EDBs acquiring smart meter data is that it allows better visibility of the LV network. If EDBs do not invest in smart tools and data to manage this new demand and complexity, it risks locking-in a higher-cost and unreliable energy system.

In its DPP3 decision, the Commission rejected EDB requests for a 'step' to their expenditure allowances relating to LV monitoring, stating:

> *A72 We do not consider LV monitoring satisfies the step change criteria. This is because we lack evidence to determine the significance, to robustly verify the expense, or to know how applicable this cost is to most distributors. We note that one distributor quantifies the costs in a confidential submission. However, given the uncertainties involved, we do not consider it appropriate to allow this (or any other amount) ex-ante*

The DPP framework provides limited alternatives to funding activity. LV monitoring will become increasingly important as it is likely to be the first part of the network impacted by emerging technologies, such as electric vehicles or battery storage.

Source: Vector; Commerce Commission 2019, Default price-quality paths for electricity distribution business from 1 April 2020 – Final decision, 27 November, para A72.

Capital expenditure allowances are based on the Commission scrutinising categories of capex within EDBs' AMP forecasts.[38] The Commission's approach includes calculating 'fall-back' expenditure if forecasts do not reflect cost drivers and the applications of caps to minor categories of expenditure. Overall, the Commission capped its aggregate capital expenditure forecasts for each EDB at 120% of its historical average expenditure. In our view, the application of a cap on capital expenditure is arbitrary and may unnecessarily limit efficient investment to support decarbonisation.

38 Commerce Commission 2019, *Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision Reasons paper*, 27 November, p. 200.

Box 2: Enabling large scale connections

In order to support the Emissions Reduction Plan, the government recently announced expanded funding of around $650 million for the Government Investment in Decarbonising Industry fund (GIDI) to support a number of decarbonisation projects, including accelerating business decarbonisation.

EDBs are relying progressively more on capital contributions to finance large electrification projects. Players in the transport industry from heavy vehicle electric charging stations, buses, ferries and fuelling stations are co-ordinating with EDBs for opportunities to decarbonise their infrastructure. At present many EDBs must charge 100% of those investments back to customers to recover their investments.

Current DPP settings create a financing risk for EDBs in supporting decarbonisation. EDB cashflows are currently to be 'back-ended', meaning that investments are recovered closer to the end of an asset's life. Given the significant amount of investment forecast to enable the electrification of transport, gas use, and industrial process heat, back ended cashflows will likely present significant funding challenges, similar to those already observed in Australia.

Source: Vector.

We note that the CPP process exists to provide EDBs and the Commission to undertake a more forensic review of expenditure forecasts. In our view, while the interactions between the DPP and CPP work well for idiosyncratic changes in the network, there are likely efficiency gains in developing a framework whereby the DPP is able to account for the role of decarbonisation and enable EDBs to alter expenditure in the face of this uncertainty. As noted above, the DPP is the preferrable price path. Requiring EDB's to use the CPP process would also impose considerable costs on both the businesses and the Commission if all EDB's in New Zealand were required to use the customised pathway. We note that the Commission is not required to consider more than 4 proposals for a customised price-quality path relating to the same type of regulated service in any one year and may defer additional proposals subject to prioritisation.[39]

In our view, reliance on the CPP process to address these issues is unlikely to result in efficient outcomes. Greater focus should be placed on amending the DPP process to allow for greater flexibility in how expenditure allowances are set and so ensure that EDBs under the DPP process are adequately compensated for efficient decarbonisation costs.

[39] S53Z, Commerce Act 1986.

Mechanisms to manage material movement in efficient costs from uncertain events

The reopeners identified in the IMs address a number of cost uncertainties that EDBs face. However, there are several risks that may arise as a result of decarbonisation which will not be captured. In particular, a reopener will not apply in circumstances where an uncertain event occurs that results in EDBs incurring additional operating expenditure than that adopted by the Commission in determining allowable revenue for the relevant period. In addition, stakeholders have also noted that the costs associated with responding to new regulatory requirements are unlikely to trigger the 1% threshold for a DPP reopener, even though cumulatively they may impose a material cost increase on the business.[40] This may result in EDBs under a DPP not being compensated for efficient costs that they have incurred.

Stakeholders have also raised concerns that the Commission's reopener process is administratively burdensome, and if several EDBs applied at once the Commission may not have the capacity to deal with multiple applications in a timely manner. For example, the current process requires EDBs to individually apply to the Commission for a reopener and does not allow mass reopener events to address issues common across EDBs. In addition, it does not allow for any automatic adjustment of revenues if certain events occur. Automatic revenue adjustments may be appropriate if expenditure requirements are uncertain in scale or timing at the time of the DPP reset, and the need for such expenditure can be tied to the occurrence of a specific 'trigger event'. Finally, the process itself is time-consuming and does not provide EDBs with sufficient flexibility to respond rapidly to market developments.

Box 3: Unforeseen major capex reopener

In 2021 Unison applied to the Commission to reopen the DPP3 price path to increase allowance revenue to cover a project Unison considered is a 'unforeseeable major capex project.' The project is to provide an electricity network connection between Contact's Tauhara generation station and Unison's distribution network. The Commission accepted Unison's application and reopened its price path to allow for the unforeseeable capex project.

The Commissions' decision did not provide for operating expenditure sought by Unison as the EDB IMs for unforeseeable and foreseeable major capex projects are limited to capex, and exclude opex. In discussing its decision, the Commission:

> *'acknowledge[d] [that] non-network alternatives to capex are likely to play an increasingly important role in the supply of electricity lines as decarbonisation and electrification become greater priorities.'*

The Commission highlighted that the IM review process would provide an opportunity to consider the scope and wording of the two reopeners in greater depth.

Source: Commerce Commission 2022, Reconsideration of default price-quality path for Unison Networks Limited – unforeseeable major capex project to supply Tauhara geothermal power station, 4 March.

40 See, for example: Unison Networks, *Submission on input methodologies process and issues paper and draft framework paper*, 11 July 2022, p.18.

Innovation incentives to support the transition

The innovation project allowance was introduced by the Commission in DPP3 in the form of a recoverable cost term in the EDB IMs. In describing the innovation project allowance the Commission stated:[41]

> *While the regime already provided incentives for innovations that improve the efficiency and the quality of distribution services, and distributors are already delivering a range of innovations, we have bolstered these incentives for DPP3. We anticipate that the innovation project allowance will encourage distributors to try new ways of doing business where they might not otherwise have done so*

Despite this intent, the innovation allowance mechanism hasn't encouraged EDBs to apply for innovation funding because of its time and resource intensive application process, relatively small allowance (0.1% of allowable revenue or $150,000 over the DPP3 period), and its ex-post approval structure combined with a requirement that EDBs must have already incurred an amount of costs on the innovation project that is at least equivalent to 200% of the proposed application amount.

Further to investing ahead of demand to support the energy transition, EDBs may also need to innovate ahead of demand to enable lower-cost decarbonisation pathways. The Commission has identified the CPP as the most appropriate mechanism to apply greater scrutiny, and to vary the way the price-quality path functions to account for innovative approaches. For the same reasons identified in Section 3.3.2 we consider that the CPP is unlikely to be fit for this purpose.

41 *Commerce Commission 2019, Default price-quality paths for electricity distribution business from 1 April 2020 – Final decision, 27 November, p. 4.*

Box 4: Innovation allowance

In June 2021, Orion submitted an innovation project allowance for the sum of $583,000. Some of this quantum had been spent already however the majority of costs were to be incurred over the next 4-5 years. The project related to voluntary carbon offsetting.

The Commission provided a non-binding view in November 2021 that it would be unlikely to approve an incentive payment for the project, because:

- DPP3 only allows for approval of costs as recoverable under the innovation project allowance after an EDB has incurred them, not before;
- Voluntary carbon offsetting falls outside of electricity lines service; and
- Even if voluntary carbon offsetting was, hypothetically, an electricity lines service it would be unlikely to consider it sufficiently innovative to meet the definition of 'innovation project.'

Subsequent correspondence between Orion and the Commission focused on the Commission's assessment that carbon neutrality falls outside the scope of electricity lines services. This example suggests that the incentive scheme may contribute little to EDBs' incentives to innovate.

Source: Commerce Commission 2021, Orion Innovation Project Allowance Application – June 2021, November.

4 Framework for investing to enable decarbonisation

This section outlines and develops the concept of prudently investing to enable decarbonisation..

4.1 IM review Decision Making Framework

4.1.1 The Commission's overarching objectives of the IM review

In its framework paper,[42] the Commission states that it will only propose changes to the IMs that meet the overarching objectives of the IM review. The Commission lists the overarching objectives of the IM review as to:

- promote the Part 4 purpose in section 52A more effectively;
- promote the IM purpose in section 52R more effectively (without detrimentally affecting the promotion of the section 52A purpose); and
- significantly reduce compliance costs, other regulatory costs, or complexity (without detrimentally affecting the promotion of the section 52A purpose).

Where it considers it relevant, and consistent with promoting the section 52A purpose of Part 4, the Commission has stated it may have regard to other Part 4 provisions (including section 54Q) and the permissive consideration under section 5ZN of the CCR Act where they are consistent with promoting the purpose of Part 4 (**Box 5**).

Box 5: Section 5ZN CCR Act & 54Q Commerce Act.

Section 5ZN of the CCRA provides for the Commission to consider New Zealand's 2050 emissions target when making decisions:

> ***5ZN 2050 target and emissions budget are permissive considerations***
>
> *If they think fit, a person or body may, in exercising or performing a public function, or duty conferred on that person or body under law, take into account—*
>
> *(a) The 2050 target; or*
>
> *(b) An emissions budget; or*
>
> *(c) An emissions reduction plan*

Section 54Q of the Commerce Act highlights the Commission's responsibilities as they relate to promoting energy efficiency:

[42] Commerce Commission 2022, *Part 4 Input Methodologies Review 2023 Framework paper* 13 October, p. 7

54Q Energy efficiency

The Commission must promote incentives, and must avoid imposing disincentives, for suppliers of electricity lines services to invest in energy efficiency and demand side management, and to reduce energy losses, when applying this Part in relation to electricity lines services.

Source: Climate Response Act 2002; Commerce Act 1986.

In reference to its recent GPB DPP decision, the Commission considers that taking account of the permissive considerations under section 5ZN of the CCR Act is a matter of expert judgement based on available evidence, with the 2050 target, emissions budgets, and related emissions reduction plan making up, 'the factual matrix and may be relevant to consideration when applying the section 52A purpose.'[43]

4.1.2 The Commission's key economic principles

The Commission has outlined three economic principles that it proposes to use to support its application and analysis of the overarching objectives of the IM review, summarised here as: [44]

- Ex-ante financial capital maintenance (FCM): EDBs should have the *ex-ante* expectation of earning a normal return, and of maintaining their financial capital in real terms over timeframes longer than a single regulatory period;
- Allocation of risk: Ideally, risks should be allocated to suppliers or consumers depending on which are best placed to manage them; and
- Asymmetric consequences of over-/under-investment: There could be asymmetric consequences, over the long term, of underinvestment versus overinvestment. If a material asymmetry exists, this principle allows the Commission to mitigate the risk to end-users

In describing the principle of asymmetric consequences, the Commission notes that it, 'in many cases it involves trading off the costs to consumers of promoting investment (i.e., higher prices) against any expected benefits associated with reducing the risk of under-investment (such as improved quality, including reduced risk of large-scale supply outages).'[45] This example can be extended further to include the expected benefits of decarbonisation and the efficient utilisation of new and emerging technologies.

[43] Commerce Commission 2022, *Part 4 Input Methodologies Review 2023 Framework paper* 13 October, p. 20.

[44] Commerce Commission 2022, *Part 4 Input Methodologies Review 2023 Framework paper* 13 October, p. 9.

[45] Commerce Commission 2022, *Part 4 Input Methodologies Review 2023 Framework paper* 20 May, p. 51.

4.2 The trade-off between static and dynamic efficiency

The primary lens through which the Commission views regulation is through its promotion of the efficient use of, and investment in, infrastructure for the long-term benefit of customers. The term 'efficiency' is widely accepted as having three dimensions:

- **Productive efficiency**, which is concerned with the means by which goods and services are produced, and is attached when production takes place with the least cost combination of inputs
- **Allocative efficiency**, which is concerned with what is produced and for whom, and is attached when the optimal set of goods and services is produced and allocated so as to provide the maximum benefit to society
- **Dynamic efficiency**, which is concerned with achieving efficient production and allocation of goods and services over time, in the face of changing productivity, technology, and consumer preferences.

When considering the impact of changes to the IMs, there is an inherent trade-off between short term or 'static' effects (i.e., the impact on productive and allocative efficiency) versus longer term or 'dynamic' effects (i.e., the impact on dynamic efficiency). Changes that may be in consumers' short-term interests may not be in their long-term interests if those changes undermine incentives to make efficient investments and operational decisions over time. Consider, for example, changes that provide customers with short-term price decreases at the expense of efficient network investment. These changes may not be in the long-term interests of customers if they increase future network costs by more than the short-term price savings, reduce consumer choice, or reduce other societal benefits, such as the benefits from decarbonisation.

The Commission does not propose to elevate the promotion of dynamic efficiency benefits above static efficiency benefits.'[46] Dynamic effects are of greater materiality to the long run interests of consumers now than they were at the time of the last IM Review; reflecting decarbonisation, electrification and government mandated national emissions targets, as discussed in Chapter 3. That is, the nature of the trade-off between static and dynamic efficiency has changed and the IM/DPP framework should reflect this to best promote the outcomes under section 52A(1) in a balanced way. Such recognition does not require the artificial elevation of dynamic efficiency benefits above static efficiency benefits.

To meet New Zealand's decarbonisation goals, decisions will need to be made by EDBs and the Commission before fundamental uncertainties are fully resolved. However, making confident decisions about decarbonisation requires the IMs to strike the right balance between achieving static and dynamic efficiencies. In considering where this balance should be struck, we consider that the regulatory decision making framework should:

- proactively manage uncertainty to provide consumers with confidence in the cost efficiency of network investment in the long term;
- incentivise, or (at least) not create a barrier to, networks undertaking activities that might reasonably be necessary for consumers to have confidence to make complementary investments (e.g., consumers understanding they will be able to charge their EVs at home);

46 Commerce Commission 2022, *Part 4 Input Methodologies Review 2023 Framework paper* 13 October, p. 55.

- not lock the sector and New Zealand into high-carbon pathways resulting in higher-cost decarbonisation across future regulatory periods.

4.3 Investment under uncertainty

The preceding sections have explained that the New Zealand Government has set an ambitious decarbonisation target for the country by 2050 and has committed to that target by enshrining it in legislation. The sections above also explain that EDBs have been identified as being critical to achieving the legislated decarbonisation targets. EDBs will need to make potentially large investments in their existing networks in order to play this enabling role.

The value of waiting to invest

However, these investments will need to be made in an environment of considerable uncertainty over:

- the profile of future growth in electricity demand (e.g., as consumers switch away from gas or adopt new technologies such as EVs); and
- the future demand for new or emerging services—such as DER.

Moreover, those investments will be sunk (i.e., cannot be reversed at all or easily) once they have been made.

The conventional theory of *real options analysis* suggests that when making irreversible investments under significant uncertainty, there can be a large option value associated with waiting until at least some uncertainty is resolved before investing.[47]

For example, a firm that is considering a large investment in research and development of a new product may be better off delaying that expenditure until it is confident (e.g., through early market testing) that there will be sufficient demand for that product once it is launched. This is because if demand for the new product fails to materialise as anticipated, the firm would be unable to recoup through sales its upfront investment, and would consequently make an economic loss. The value of expected economic losses that could be avoided by delaying investment until uncertainty is resolved is referred to in the real options literature as the *value of waiting* or the *value of flexibility*. Investing immediately in the face of material uncertainty is said to extinguish the value of waiting.

In the context of regulated EDBs making network investments to support decarbonisation, the simplest real options theory would suggest that EDBs should delay investments until there is sufficient certainty over the need for those investments.[48] Under the DPP framework, once the capital expenditure associated with those investments is included within EDBs' regulatory asset base (RAB), those costs would be expected to be recovered fully from consumers—provided the Commission continues to adhere to its long-established principle of Financial Capital Maintenance. If, with hindsight, it turns out that some or all of those investments were not required to support decarbonisation, then consumers would have paid more (ex post) than was actually required (or at least paid for some capacity ahead of time). In these circumstances, the value of waiting would be the costs that consumers could avoid if it turns out that the investments made ahead of demand are not required.

47 Dixit, A. K., Pindyck, R. S. (1994), Investment under uncertainty, Princeton: New Jersey.

48 Frontier Economics, Building electricity networks under demand uncertainty, 2020.

However, real options theory also suggests that there may be some reasons why it might be efficient to make irreversible investments now, even in the face of significant uncertainty:

- Investing pre-emptively, in advance of the demand for the services delivered by those investments may accelerate or 'unlock' future opportunities or wider societal benefits that would otherwise be delayed or not realised at all; and/or
- There may be scale efficiencies associated with making one large early investment, rather than staggering investments or investing sequentially. If the efficiencies that can be realised by investing at scale now exceed the value of waiting, then it would be optimal to invest early—even if that means an extinguishment of the option to delay investment.

Further, in the case of investing to facilitate electrification and decarbonisation, a practical benefit lies in deliverability. As described in section 3.1, New Zealand will likely see a period of increasing growth in electricity demand that could overwhelm deliverability. In turn, a proactive investment strategy of 'staying ahead of the curve' could be a key aspect of EDBs investment strategy.

Investing now to unlock future opportunities

The real options literature recognises that investing early can create new opportunities or value that would otherwise be delayed or unavailable without that investment. For example, a technology company may invest in developing a digital platform that allows it to enter and compete in one market. Establishing its initial platform may then provide the company with the option to develop further functionality that would allow it to serve new or different types of customers, and to expand into new markets. The options that are created following the initial decision to invest are referred to in the literature as *expansion options*.[49]

There are two ways in which EDBs investing ahead of demand, in an anticipatory fashion, may create or enable new opportunities that would support decarbonisation:

- Firstly, consumers will require certain network infrastructure that only EDBs can provide in order to adopt decarbonisation technologies (e.g., EVs, solar panels). By making that infrastructure available through early investment, EDBs can remove some of the barriers that might otherwise deter adoption of decarbonisation technologies. For instance:
  - a lack or sparsity of charging infrastructure is likely to deter widespread adoption of EVs. However, if EDBs were to invest in infrastructure that supports a comprehensive rollout of charging stations, that would increase the feasibility of widespread EV adoption by consumers; and
  - a lack of investment in distribution networks that would allow reliable two-way power flows may deter some consumers from installing rooftop PV. However, if EDBs were to invest in network assets that could facilitate electricity export services while maintaining the stability and reliability of the power system, some consumers that might otherwise have been reluctant to install solar panels without battery storage may do so.

  In both of these examples, early investment by EDBs (i.e., ahead of imminent demand) creates new investment options and opportunities for consumers that would support decarbonisation. The absence of those early investments might result in some consumers never adopting decarbonisation technologies, or doing so much later.

49 Brealey, R. A, Myers, S. C., Allen, F. (2014), Principles of corporate finance, 11th edition, McGraw-Hill: New York, pp. 258-259. Damodaran, A. (2001), Corporate finance: Theory and practice, 2nd edition, Wiley: New Jersey, pp. 897-901.

- Secondly, investing ahead of demand by installing additional capacity would allow EDBs to respond more quickly to requests from consumers for new connections and connection upgrades.[50] This would allow more rapid electrification, thus accelerating the benefits of decarbonisation. That is, investing early can create options for EDBs to respond more flexibly to changes in consumer behaviour that would support decarbonisation.

In summary, early investment by EDBs can create valuable options and opportunities for consumers to alter the way they use, generate and supply power that would support decarbonisation efforts in New Zealand.

Economies of scale

The real options literature also recognises that there is a trade-off between the flexibility that gained by investing cautiously and incrementally in response to uncertainty, and the cost savings that can be realised by investing at scale. The seminal text on real options analysis by Dixit and Pindyck (1994) explains this trade-off as follows:

> *As students of economics or business learn early on, economies of scale can be an important source of cost savings. By building a large plant instead of two or three smaller ones, a firm might be able to reduce its average cost and increase its profitability. This suggests that firms should respond to growth in demand for their products by bunching their investments, that is, investing in new capacity only infrequently, but adding large and efficient plants each time.*
>
> *What should firms do, however, when there is uncertainty over demand growth (as there usually is)? If the firm irreversibly invests in a large addition to capacity, and demand grows only slowly or even shrinks, it will find itself holding capital it does not need. Hence when growth of demand is uncertain, there is a trade-off between scale economies and the flexibility that is gained by investing more frequently in small increments to capacity as they are needed.*[51]

In the context of EDBs contemplating network investments that would support decarbonisation in New Zealand, the EDBs could either:

- make small, incremental investments over time in response to demand. This approach would limit the risk of EDBs inadvertently investing more capacity than is actually required—because the capacity invested can track closely the actual needs of consumers. The cost of any underutilised capital expenditure would ultimately be borne by consumers; or
- make large, lumpy investments in capacity ahead of demand in order to realise scale efficiencies. These efficiencies would ultimately be passed through as savings to consumers.

Which of these approaches would be most optimal (from the perspective of consumers) will depend on how large the economies of scale associated with making large, upfront investments

[50] Frerk, M., Investing for net zero in the face of uncertainty: Real options and robust decision-making, Oxford Martin School, March 2021.

[51] Dixit, A. K., Pindyck, R. S. (1994), Investment under uncertainty, Princeton: New Jersey, p. 51.

are compared to the potential overinvestment costs that could be avoided by consumers if EDBs were to invest incrementally.

The outcome of that trade-off depends on the extent of uncertainty over the consumer demand for the services that would be delivered by the additional network investments. If the uncertainty over future demand is very high, then it is likely that a more cautious and incremental approach to investment in network capacity would be preferable—since the risk of inadvertent overinvestment will be high. If, however, future demand is relatively easy to predict, then the value of waiting (investing incrementally) will be relatively low—potentially lower than the scale efficiencies that could be realised by building more upfront (Box 6).

Box 6: Expected decarbonisation de-risks proactive investment in capacity

The Government's decarbonisation targets should provide a positive indication of future electricity demand. As outlined in sections 3.1 and 3.2, electrification will more than likely play a disproportionate role in helping New Zealand meet its decarbonisation commitments, notwithstanding the fact that there are numerous potential transition pathways for New Zealand to achieve its 2030 and 2050 decarbonisation goals.

This observation has implications for the potential costs of overinvestment. In many markets it is the case that if, following an investment, demand is lower than anticipated the investment may become stranded. However, in the case of electricity networks it is more likely to be the case that an investment in capacity will ultimately be utilised – the uncertainty lies in precisely when this will occur as electrification and decarbonisation plays out.

This dynamic has been recognised in other jurisdictions. The British Energy Security Strategy identifies the requirement to anticipate need and invest ahead in order to minimise costs and public disruption.[52] The strategy states:

> *On costs, building ahead of need, where good value for money, may mean paying more in the short term for an asset that isn't efficiently utilised immediately but is the cheapest option over the long term and reduces the need for repeated disruptive works to continually upgrade the system.*
>
> *On uncertainty, whilst there are many future decisions yet to be taken, and a need for an agile approach to network infrastructure, we do know that electricity demand is highly likely to double by 2050.*

It is in consumers' interests to recognise that the Government's climate change targets will more than likely result in significant growth in electricity demand, and for the regulatory framework to reasonably allow for the potential benefits of scale efficiencies in meeting that demand to be realised.

52 UK Government 2022, *Policy paper British energy security strategy*, 7 April, https://www.gov.uk/government/publications/british-energy-security-strategy/british-energy-security-strategy#networks-storage-and-flexibility

5 Financial impacts of electrification for households in New Zealand

This section articulates, and where possible quantifies, the financial impacts of electrification for households in New Zealand.

5.1 Decarbonisation and household costs

New Zealand's decarbonisation aspirations will likely lead to significant changes in the way that households consume (and produce energy) and the costs that they face for the energy that they use.

In particular, electrification of household energy use is likely to play an important role in decarbonisation in New Zealand. New Zealand's First Emissions Reduction Plan recognises the roles that electrification can play in decarbonising energy use; for households, electrification of transport can reduce emissions from the use of liquid fuels and electrification of heating can reduce emissions from natural gas. Similarly, Transpower's Transmission Planning Report 2022 identifies electrification as a major electricity industry trend as the sector works towards decarbonisation.

However, forecasting electrification is challenging, particularly due to unpredictable advancements in technology and changes in government policy. Transpower's Transmission Planning Report 2022 concludes that accurately forecasting where, when and how electrification will occur at a grid exit point is inherently fraught. Transpower notes that this is, in part, because electrification is driven by individual decisions that have their own drivers on the timing and extent of electrification.

In this section we investigate one of the key drivers of electrification for households in New Zealand, the financial impacts of electrification. Where there are savings available to households through electrification it would be expected that households will be more inclined to electrify their transport or heating, resulting in increases in electricity demand.

5.2 Methodology

We consider the financial impacts for households in New Zealand of electrifying their use of natural gas for heating and cooking, and the financial impacts for households in New Zealand of electrifying their use of liquid fuel for transport.

In each case the financial impacts depend on:

- **Changes in household energy costs**. Electrification will bring about changes in the costs to households of purchasing energy. Electrification of household use of natural gas will mean that households will no longer face natural gas bills, but will face higher electricity bills, reflecting higher electricity consumption. Similarly, electrification of household use of liquid fuel for transport will mean that households will no longer face the costs of purchasing liquid fuel, but will face higher electricity bills, reflecting higher electricity consumption. The total energy bill that households face are one part of the financial impact to households of electrification.

- **Changes in household appliance costs**. Electrification will also bring about changes in the costs of appliances that households use. Electrification of household use of natural gas will mean that households will need to purchase and install electrical appliances for cooking and heating, rather than natural gas appliances. Similarly, electrification of household use of liquid fuel for transport will mean that households will need to purchase EVs, and install charging infrastructure in their premises, rather than internal combustion engine (ICE) vehicles.

We estimate the financial impacts for households from both of these changes – changes in energy costs and changes in appliance costs.

The financial impacts for households will depend, to an extent, on the characteristics of those households. For example, the type and size of a dwelling, the age of appliances, and patterns of energy use have significant implications for both household energy bills and household appliance costs. For this reason, in order to estimate the financial impacts of electrification for households we first need to define the characteristics of the households that we are assessing.[53]

Household types

For this project, we consider the financial impacts of electrification for 3 representative household types. We note that these are representative households with natural gas, since natural gas is not used by most households in New Zealand. Based on the number of households that have natural gas water heating (the most common gas appliance type) only 18% of households in New Zealand use natural gas.

The representative households with natural gas that we consider are:

- A typical residential gas customer in New Zealand, being a household with average annual consumption of natural gas for cooking and heating, and which owns the average number of vehicles (1.8 per household) and travels the average number of kilometres by car each year.
- A high-consumption residential gas customer in New Zealand, being a household that consumes 50% more natural gas than the average household and drives 67% more kilometres than the average household.[54]
- A low consumption residential gas customer in New Zealand, being a household that consumes 50% less natural gas than the average household and drives 44% fewer kilometres than the average household.[55]

We also consider how the decisions of this typical residential customer would change depending on the age of their appliances and their purchasing intentions.

Calculating energy bills

We calculate energy bills for two circumstances:

[53] We are assuming that there will be no changes in the positive incentives to electrify through government intervention (e.g., no new subsidies for EVs).

[54] The increase of 67% is based on the difference between a household owning 1.8 vehicles (which is the average in New Zealand) and a household owning 3 vehicles (which is the case for 13% of households), assuming that each vehicle drives the same distance in a year.

[55] The decrease of 44% is based on the difference between a household owning 1.8 vehicles (which is the average in New Zealand) and a household owning 1 vehicle (which is the case for 37% of households), assuming that each vehicle drives the same distance in a year.

- Baseline energy bills, which are based on baseline consumption for electricity, natural gas and liquid fuels. The baseline energy bills are the energy bills that a household will face if the household *does not* electrify.
- Electrification energy bill, which are based on baseline consumption for electricity plus the additional consumption of electricity if all household natural gas and liquid fuel use is electrified. The electrification energy bill is the energy bill that a household will face if the household *does* electrify.

Comparing energy bills in these two circumstances provides an estimate of the impact of energy bills if a household electrifies.

Baseline energy bills are calculated for each source of energy by multiplying baseline consumption by retail prices. The estimates of baseline consumption and retail prices that we use, and the sources of those estimates, are summarised in **Table 2**.

The electrification energy bill is calculated by multiplying total electricity consumption in the electrification case (that is, the sum of baseline electricity consumption and the additional consumption of electricity if all household natural gas and liquid fuel use is electrified) by retail electricity prices. Additional consumption of electricity is calculated by assuming that households require the same output (heat provided, in the case of natural gas, and distance travelled, in the case of liquid fuel for transport). This means that:

- the amount of additional consumption of electricity due to electrification of natural gas use is determined by the relative efficiency of electrical appliances and natural gas appliances; and
- the amount of additional consumption of electricity due to electrification of liquid fuel use is determined by the relative efficiency of ICE vehicles and EVs.

For example, taking an average household heating scenario, electrical energy would result in a 66% reduction in household energy use for heating (when compared against natural gas energy) as detailed below.

On the assumption that a gas heater has an efficiency of 85%, while an electrical heat pump used for heating has a coefficient of performance of 2.5, a household would require the equivalent of 34% of its natural gas energy if substituted for electrical energy. Given the importance of the relative cost and efficiency of electrical appliances, and the number of options available to customers, we examine the financial impact of electrification for customers that choose higher efficiency / higher cost electrical appliances and for customers that choose lower efficiency / lower cost electrical appliances.

The estimates of appliance and vehicle efficiency that we use, and the sources of those estimates, are summarised in **Table 2**.

The electrification energy bill is calculated using the same retail electricity price estimates as are used to estimate the baseline electricity bill.[56]

[56] The retail price used is modelled on a typical NZ customer who is on a plan with low fixed charges (<30c/day). The energy bill calculations do not adjust for the fixed charge portion of the bill which means retail prices could be slightly inflated. However, as an example, for a household who uses 22kWh per day (8,000 kWh per year), their fixed cost charge would be at most only around 4% of the total annual electricity bill, therefore, the adjustment would not be significant.

Table 2: Input assumptions for estimating energy bills

Data input	Value	Source
Energy prices		
Retail electricity prices	NZ average: 32.4 c/kWh	MBIE (Using PowerSwitch data)
Retail natural gas prices	40.02 $/GJ	MBIE
Retail petrol prices	225 c/L	MBIE
Energy consumption		
Baseline natural gas consumption by appliance per household per year	Gas cooktop: 339 MJ Space conditioning: 16,876 MJ Water heating: 9,121 MJ	Residential Baseline Study (RBS)
Average distance travelled by passenger vehicles per year per household (km)	14,962 km	Transport NZ (Number of kilometers travelled by vehicle type)
Average number of motor vehicles per household	1.8	Stats NZ
Appliance efficiency		
Natural gas appliance efficiency	Gas cooktop: 40% Space conditioning: 85% Water heating: 85%	GHD analysis for the Victorian Governments gas substitution report
Electrical appliance efficiency / Coefficient of performance	Higher efficiency appliances: Induction cooktop: 75% Space conditioning: 2.5 Water heating: 2.0 Lower efficiency appliances: Induction cooktop: 75% Space conditioning: 100% Water heating: 95%	GHD analysis for the Victorian Governments gas substitution report
ICE vehicle efficiency	9.2 km/L, improving 1%/annum	Frontier Economics analysis
EV efficiency	21.6 kWh/100km, improving 3%/annum	www.fueleconomy.gov

Notes: Dollar values are inclusive of GST

Calculating appliance costs

As with energy bills, the appliance costs for two circumstances are calculated on the basis of:

- Baseline appliance costs, which are based on continued use of a mix of electrical and natural gas appliances, and ICE vehicles.
- Electrification appliance costs, which are based on a switch to all electrical appliances and EVs.

The differences in costs that households would face depend on whether they purchase higher efficiency electrical appliances or lower efficiency electrical appliances.

The costs of appliances that households face extend beyond just the cost of purchasing new appliances. Households will also face a number of other costs associated with appliance replacement and installation. The potential appliance costs that we consider in this study are:

- The cost of removing existing appliances, including any rectification work that might be required. This includes activities such as covering up existing ducts, plastering, and painting[57].
- The cost of purchasing new appliances.
- The cost of installing new appliances, including labour and materials.
- The cost of purchasing a new vehicle.
- The cost of installing EV charging.

Whether a household faces each of these costs, and the extent of these costs, will depend on the characteristics of a household. For instance, a new build household will not face costs of removing any existing gas appliances and will likely face lower installation costs. However, an existing household simply looking to replace existing gas appliances will face the costs of removing existing gas appliances and will also likely face higher costs of installing new electrical appliances (since this installation will be a retrofit). The scenarios below consider appliance costs for an existing build, where appliance and fuel decisions have already been made, and a new build scenario, where appliance and fuel decisions have not been made.

The difference in baseline appliance costs and electrification appliances costs will also depend on the age of existing appliances. Where a household has existing gas appliances, and an existing ICE vehicle, that have not reached the end of their life, electrification will involve bringing forward appliance costs. This will result in relatively higher costs.

The estimates of appliance costs that we use, and the sources of those estimates, are summarised in **Table 3**.

57 Our analysis assumes that households have the option to replace their existing gas appliances with electrical appliances. For instance. we do not consider a case where there may be no suitable location for a heat pump water heater to replace an instantaneous gas water heater.

Table 3: Input assumptions for estimating appliance costs

Data input	Value	Source
Appliances Costs		
Appliance purchase costs – **Higher efficiency appliances**	Gas – appliance costs Gas hob: $751 Central ducted gas heater: $2,834 Instantaneous water heater: $1,417 Electricity – appliance costs Induction cooktop: $1,541 Multi split RCAC: $3,639 Heat pump water heater: $3,671	Frontier report for GAMAA
Removal of existing gas appliances and installation of new appliances – **Higher efficiency appliance**s	Gas – removal and installation Gas hob: $794 Central ducted gas heater: $2,018 Instantaneous water heater: $1030 Electricity – removal and installation Induction cooktop: $1,481 Multi split RCAC: $4,089 Heat pump water heater: $2,254	Frontier report for GAMAA

Appliance purchase costs – **Lower efficiency appliances**	Gas – appliance costs Gas hob: $751 Indoor flued gas heater: $3,605 Instantaneous water heater: $1,417 Electricity – appliance costs Resistance cooktop: $751 Panel heaters: $1,542 Storage water heater: $2,370	Frontier report for GAMAA
Removal of existing gas appliances and installation of new appliances – **Lower efficiency appliances**	Gas – removal and installation Gas hob: $794 Gas space conditioning: NA Gas water heating: $1,030 Electricity – removal and installation Electric cooktop: $1,481 Electric space conditioning: NA Electric water heating: $2,254	Frontier report for GAMAA
Electric vehicle Costs		
EV purchase costs	Assumed $24,000 for an average ICE and applied the multiplier	NZ specific websites such as driveelectric.org.nz

Notes: Dollar values are inclusive of GST

5.3 Results

The financial results for households in New Zealand are totalled by calculating the impacts on energy costs and the impacts on appliance or vehicle costs. These costs are calculated separately for electrification of natural gas use and electrification of liquid fuel use. The calculations are based on the specified assumptions in **Table 2** and **Table 3**. Potential drivers of the financial impact of electrification that are not included in our analysis, but may vary in future, include:

- significant technological advancement (other than the assumed improvements in vehicle efficiency outlined above);
- changes in retail prices for electricity, gas and petrol;
- customer adoption of rooftop PV of batteries;
- new government policy which incentivises or disincentivises relevant consumer behaviour (e.g., rebates for new appliances, for rooftop solar or for batteries).

5.3.1 Financial impacts of electrifying natural gas use

The **impact on energy bills** of electrifying natural gas use depends on the relative prices of natural gas and electricity and the relative consumption of natural gas and electricity to meet a household's energy needs.

Currently, retail prices for natural gas in New Zealand are materially lower than retail prices for electricity in New Zealand. Based on data from MBIE, the retail price for natural gas is 14.41 c/kWh and the retail price for electricity is 32.35 c/kWh. Both natural gas and electricity retail prices change over time, and the implications for changes in these prices are discussed below in section 5.3.1.

While retail electricity prices are higher than retail gas prices, because of the greater efficiency of electric appliances relative to natural gas appliances, consumers use less electricity to meet their household energy needs than they use natural gas. The extent of the reduction in energy use depends on whether households buy higher efficiency / higher cost electrical appliances or lower efficiency / lower cost electrical appliances. For customers that choose higher efficiency appliances, our estimates are that a typical household using 7.32 MWh/annum of natural gas would only need to use 2.72 MWh/annum of electricity to meet the same energy needs. For customers that choose lower efficiency appliances, our estimates are that a typical household using 7.32 MWh/annum of natural gas would only need to use 6.30 MWh/annum of electricity to meet the same energy needs.

The type of electrical appliances that customers would choose to replace their gas appliances has a very large effect on the bill impacts of electrification. For households that choose higher efficiency electrical appliances, electrification results in lower total energy bills. The reason is that the reduction in energy use for these customers as a result of electrification more than makes up for the higher per unit cost of electricity. However, for households that choose lower efficiency electrical appliances, electrification results in higher total energy bills. The reason is that the reduction in energy use for these customers as a result of electrification is only modest, and does not make up for the higher per unit cost of electricity. This is shown in **Table 4**.

The annual consumption of households has a very large effect on the bill impacts of electrification. Unsurprisingly, the bill impacts are magnified for households with higher consumption. So, for households that choose higher efficiency appliances, the reduction in energy bills as a result of electrification increases with annual consumption. For households that choose lower efficiency appliances, the growth in energy bills as a result of electrification increases with annual consumption. This is shown in **Table 4**.

The **impact on appliance costs** of electrifying natural gas use depends on the relative cost of purchasing and installing gas and electrical appliances. These costs depend on the efficiency of the appliances that a household chooses.

For a household that would choose *higher efficiency electrical appliances* we estimate costs as follows:

- For a household that already has natural gas appliances installed, but is looking to replace those natural gas appliances because they have reached the end of their life, the cost of removing existing gas cooking, gas space heating and gas water heating appliances, purchasing new gas appliances and installing those new gas appliances is $8,845. At a discount rate of 7%, this amounts to an annual cost of $1,259 per annum over 10 years.
- The cost of removing existing gas cooking, gas space heating and gas water heating appliances, purchasing new electrical appliances and installing those new electrical appliances is $16,675. At a discount rate of 7%, this amounts to an annual cost of $2,374 per annum over 10 years.

For this household, the additional cost of having electrical appliances is $1,115 per annum (excluding the impact on bills).

For a household that would choose *lower efficiency electrical appliances* we estimate costs as follows:

- For a household that already has natural gas appliances installed, but is looking to replace those natural gas appliances because they have reached the end of their life, the cost of removing existing gas cooking, gas space heating and gas water heating appliances, purchasing new gas appliances and installing those new gas appliances is $7,598. At a discount rate of 7%, this amounts to an annual cost of $1,082 per annum over 10 years.
- The cost of removing existing gas cooking, gas space heating and gas water heating appliances, purchasing new electrical appliances and installing those new electrical appliances is $8,398. At a discount rate of 7%, this amounts to an annual cost of $1,196 per annum over 10 years.

For this household, the additional cost of having electrical appliances is $114 per annum (excluding the impact on bills).

These differences in appliance costs are shown in **Table 4**.

Table 4 also shows the total financial impacts of electrification for these customer types, which is the sum of the impact on energy bills and the impact on appliance costs.

For customers that would choose *lower efficiency appliances*, the additional cost of appliances is relatively small, at $114/annum, with this being primarily a result of the additional cost of installing electrical appliances in houses that currently have gas appliances. However, because of the higher per unit cost of electricity, these customers would also face materially higher energy bills from electrifying, from $492/annum for households with low consumption to $1,477 for households with high consumption. In total, this means that these customers face higher costs from electrification.

For customers that would choose *higher efficiency appliances*, the additional cost of appliances is much higher, at $1,115/annum. Because of the efficiency of these appliances, these customers will face lower energy bills, from $87/annum lower for households with low consumption to $261/annum for households with high consumption. However, the savings in energy bills is smaller than the increase in appliance costs, so that these customers also face higher costs from electrification.

Table 4: Summary of results for financial impacts of electrifying natural gas use

Appliance efficiency	Household consumption	Change in appliance costs due to electrification (annualised)	Change in annual energy bills due to electrification	Change in total annual costs
Lower efficiency electrical appliances	Low	$114	$492	**$606**
Lower efficiency electrical appliances	Average	$114	$985	**$1,099**
Lower efficiency electrical appliances	High	$114	$1,477	**$1,591**
Higher efficiency electrical appliances	Low	$1,115	-$87	**$1,028**
Higher efficiency electrical appliances	Average	$1,115	-$174	**$941**
Higher efficiency electrical appliances	High	$1,115	-$261	**$854**

Source: Frontier Economics

The results we present in **Table 4** are, of course, a reflection of the assumptions that we make, as summarised in **Table 2** and **Table 3**. It is worth considering a number of factors that would change these results.

Gas and electricity prices

Our analysis is based on the latest estimates of retail electricity and retail gas prices from MBIE. These prices will certainly change over time. Indeed, since the estimated retail gas price from MBIE was released, the Commerce Commission has announced the default price-quality path for gas pipeline businesses, with the new requirement taking effect from 1 October 2022. The Commerce Commission estimate that the impact of this would be to increase the retail price of gas by 3.8% per annum for each of the next four years. By the end of the four year period this would mean that average household bills are $190/annum higher. Assuming no equivalent change in electricity retail tariffs, this would mean that the total increase in cost of electrification would be lower for all customers.

There are reasons that retail gas prices could continue to increase beyond the next four years. For instance, further increases in pipeline costs may be necessary to further accelerate depreciation of these assets.

Appliance costs or efficiency

Changes in appliance cost or appliance efficiency can also change the financial impacts of electrification for customers.

For instance, higher efficiency electrical appliances (such as induction cooktops and heat pumps) are relatively newer appliances that may be expected to undergo further reductions in costs or improvements in efficiency. If this occurs, this will reduce the financial impact of electrification.

Similarly, rebates for higher efficiency electrical appliances could materially change the financial impact of electrification. As discussed above, it is the higher cost of purchasing and installing these higher efficiency electrical appliances that mean customers are likely to face higher total costs as a result of electrification. If customers are eligible for rebates for these higher efficiency appliances, this would change the financial impact for those customers. Based on the assumptions discussed above, and summarised in **Table 2** and **Table 3** to make the average sized household indifferent, the household would need a rebate of around $6,500 for higher efficiency appliances. If retail gas prices were $190/annum higher as a result of the recent price-quality path, and retail electricity prices remained unchanged, the average sized household would need a rebate of around $5,000.

Households that are building new homes

For a household that is building a new home, or undertaking a substantial renovation, a decision to switch to electrical appliances would not result in any appliance removal costs, and appliance installation costs are likely to be more similar for gas and electrical appliances. This would mean that the difference in cost of having gas appliances and electrical appliances is likely to be driven mostly by the difference in appliance purchase costs.

If we exclude removal costs and installation costs from the estimates of the annualised change in appliance costs due to electrification shown in **Table 4**, the change in appliance costs becomes:

- a *saving* of $158/annum from electrifying for households that choose lower efficiency electrical appliances
- a *cost* of $548/annum from electrifying for households that choose higher efficiency electrical appliances

This suggests that the total increase in cost of electrification would be lower for all households that are building new homes.

5.3.2 Financial impacts of electrifying liquid fuel use

The **impact on energy costs** of electrifying the use of liquid fuel for transport depends on the relative prices of petrol and electricity, and the relative consumption of petrol and electricity to meet a household's transport needs.

Currently, retail prices for petrol are lower than retail prices for electricity in New Zealand. The retail price for petrol is 23.67 c/kWh ($2.25/litre) and the retail price for electricity is 32.35 c/kWh. However, because of the greater energy efficiency of electricity vehicles relative to ICE vehicles, as indicated by the efficiency estimates seen in **Table 2**, a household that electrifies its transport use would use less electrical energy to meet their transport needs than they use energy from petrol.

Because our estimate of the reduction in energy use through electrification is greater than our estimate of the increase in prices through electrification, we find that the total energy costs for transport will fall as a result of electrification. We estimate that, for a typical household in New Zealand:

- Petrol costs would be $3,600 per annum in 2022, falling over time in line with assumptions about the improved energy efficiency of ICE vehicles.
- The increase in the household electricity bill from electrifying their transport use would be $1,254 per annum in 2022, falling over time in line with assumptions about the improved energy efficiency of EVs.

As a result, a typical household in New Zealand would achieve an average reduction in energy costs of $2,346 per annum by electrifying their transport. These reductions in energy costs would be lower for lower consumption households and higher for higher consumption households, as seen in **Table 5**.

However, in order to achieve these reductions in energy bills, the household will need to purchase EVs and install charging infrastructure, and this can come at an additional cost compared to purchasing ICE vehicles.

For a household that is buying a new vehicle in any case, the relevant cost is the purchase coast of the vehicle and, for EVs, the cost of installing charging infrastructure. An estimate of these costs based on the stated assumptions follows:

- A typical ICE vehicle will cost $24,000 in 2022. At a discount rate of 7%, this amounts to an annual cost of $3,417 per annum over 10 years, for each vehicle that a household has.
- The current premium for an EV of a similar ICE vehicle is 152%, which means that the EV will cost $36,480 in 2022. Charging infrastructure costs an additional $1,184 At a discount rate of 7%, this amounts to an annual cost of $5,363 per annum over 10 years, for each vehicle that a household has.

This suggests that, currently, the additional cost of having an EV is $1,945 per annum (excluding the impact on fuel costs). This additional cost will fall over time, as the assumed premium for EVs is expected to fall over time (with prices assumed to be equivalent in 2032).

The total cost of vehicles to a household will depend on the number of vehicles. The assumptions used are:

- a low consumption household has one vehicle;
- an average consumption household has 1.8 vehicles (which is the average across New Zealand); and
- a high consumption household has three vehicles.

Based on the assumptions above, **Table 5** shows the year in which the additional annual cost of ownership of EVs is lower than the annual saving in energy costs from ownership of EVs. For each household type, electrifying transport use is expected to become lower cost in either 2025 or 2026.

Table 5: Summary of energy cost results for electrifying transport

Household consumption	Change in annual energy costs	Year that energy cost savings become larger than additional vehicle cost
Low	-$1,303	2026
Average	-$2,346	2026
High	-$3,910	2025

Source: Frontier Economics

The results presented in **Table 4** are, of course, a reflection of the assumptions made, as summarised in **Table 2** and **Table 3**. There are a number of factors that would change these results.

Petrol and electricity prices

The analysis is based on the latest estimates of retail petrol prices and retail gas prices from MBIE. These prices will certainly change over time. If petrol prices were to increase in future, without corresponding increases in electricity prices, electrifying transport use could become lower cost sooner than 2025 or 2026.

Vehicle costs

Rebates for EVs can materially change the financial impact of electrification.

For instance, a rebate of $7,500 per vehicle under the Clean Car Programme is sufficient to make electrifying transport use lower cost from today.

Households with existing vehicles

For customers that already have an ICE vehicle that they do not intend to replace, the additional cost of purchasing a EV will be higher (but, presumably, these customers will also derive some additional value from a newer vehicle). For these customers it may not make financial sense to purchase an EV until closer to the time that they would purchase a new vehicle in any case.

For customers comparing more expensive vehicles, for which the dollar difference in price between an ICE vehicle and an EV is higher, and for whom the rebate may not be available, it may not make financial sense to purchase an EV until the difference in price falls (which it is expected to do over coming years).

5.3.3 Comparison with Sapere report for the ENA

Sapere has recently undertaken a study for the Electricity Networks Association of total household energy costs in New Zealand for customers using different combinations of appliances.[58] The Sapere report considers similar comparisons to this report, including

[58] Sapere, *Total Household Energy Costs NZ*, Prepared for the Electricity Networks Association, 23 November 2022.

comparing the costs an ICE vehicle with the cost of an EV and comparing the costs of natural gas and electricity for household use.

Sapere's assessment of the relative costs of an ICE vehicle and an EV leads to a similar conclusion to the assessment made in this report. Sapere concludes that households would face lower total costs with an EV by around 2025 or 2026. At this point, Sapere finds that the increased capital cost of an EV is more than offset by annual savings in running costs. As discussed above, this reports finds that electrifying transport use is expected to be lower cost in 2025 or 2026, with expected reductions in capital costs by 2025 or 2026 meaning that higher capital costs are offset by lower costs of charging compared to purchasing petrol.

Sapere's assessment of the relative costs of electrifying household natural gas use, however, leads to a different conclusion to the assessment made in this report. Sapere concludes that households would face *the same* total costs today (including appliances and bills), regardless of whether they continue to use natural gas or electrify their natural gas use; by 2025, however, Sapere find that households would face *lower* total costs if they electrify their natural gas use. In contrast, this report finds households would face *higher* total costs if they electrify their natural gas use. Without a detailed comparison of all the input assumptions in Sapere's work, we cannot be certain of what drives these differences in results. However, two factors that do seem important are:

- **Different assumptions about appliance purchase, installation and rectification costs** - Based on the information presented in Sapere's report it appears that they are using estimates of these costs that are lower than the estimates that we use. One possible reason for this is that Sapere does not consider rectification costs in its assessment. In this report, the assessment that these upfront costs are significant, is a key driver of the conclusion that households would face higher costs if they electrify their natural gas use.
- **Difference assumptions about electricity and gas prices** - A possible key driver of the change in relative costs over time in Sapere's results is the assumed future changes in electricity and gas prices. Sapere assumes that the increase in gas retail prices over time is greater than the increase in electricity retail prices over time. In contrast, it is assumed in this report that electricity and gas retail prices remain constant over time. Sapere also assumed a retail electricity price of around 25 c/kWh which is materially lower than the assumed retail electricity price in this report, which used data from MBIE (32.4 c/kWh. Including GST[59]). The lower electricity price would make electrification more financially attractive for households. For example, using the retail electricity price of around 25c/kWh and keeping all else constant would mean the current total annual cost of electrifying all household appliances (for an average gas consumption household who purchases high efficiency electric appliances) is more expensive than gas use by around $741 as compared to the $941 as seen in **Table 4**.

5.4 Implications for the IM review

The analysis in this report suggests that, for a typical customer:

- It is unlikely to be financially beneficial to switch from natural gas to electricity based on current prices of natural gas and electricity and current appliance costs. Customers may still choose to electrify their natural gas for a number of other reasons, including to reduce the emissions from their energy use, due to personal preference for electrical appliances rather

[59] The electricity prices from MBIE are based on current advertised prices for the plans surveyed by the ministry. The forward price of electricity is not considered when deriving the household electricity price.

than natural gas appliances or in order to make greater use of the electricity generated by rooftop solar panels. The financial impacts of electrification will change as energy prices and appliances costs and efficiency change. For instance, further increases in gas prices (without corresponding increases in electricity prices) and/or rebates for higher efficiency electrical appliances, could make switching to electrical appliances financially beneficial in future.

- It is likely to be financially beneficial now for many new car customers to switch from an ICE vehicle to an EV, at current prices and costs. Furthermore, it is expected to be financially beneficial for more customers each year as the price premium of EVs relative to ICE vehicles falls and the efficiency of EVs improves.

With switching to EVs becoming financially attractive to a large number of customers over coming years, it is likely that the adoption of EVs will also increase rapidly. This will have material effects on customers' use of electricity networks. With the electricity required for a typical household's transport needs amounting to around 3,000 kWh per annum, areas with high EV adoption could see very significant changes to total electricity demand. Depending on how and when customers choose to charge their EVs, meeting this additional electricity demand could require material network augmentation.

6 Insight from international regulatory practice

This section surveys international regulatory practices adopted to meet decarbonisation objectives and assess their applicability to New Zealand's regulatory framework.

6.1 A common decarbonisation task

The risks and uncertainties inherent to New Zealand's decarbonisation task, such as the scale of change, the role of new technologies and uncertainty about the most efficient transition path, are held in common with other regulatory jurisdictions.

We have surveyed recent decisions and commentary made by the following regulatory regimes to draw out themes in regulatory practice which may be applicable to New Zealand's regulatory framework:

- The Economic Regulatory Authority (ERA) responsible for electricity networks on Western Australia;
- The Australian Energy Regulator (AER) and Australian Energy Market Commission (AEMC) responsible for electricity networks on Australia's east coast;
- Great Britain's Ofgem and its recent RIIO-ED2 draft determination;
- Singapore's Energy Market Authority; and
- Ireland's Commission for Regulation of Utilities.

These regulators are referred to as the 'economic regulators' in the remainder of this report. The following sections summarise the broad regulatory responses which may apply to the IM/DPP regulatory framework.

6.2 Regulatory approaches and rationale to support decarbonisation

Economic regulators are experimenting in their regulatory approaches to managing uncertainty related to facilitating decarbonisation. There is a growing momentum toward change as economic regulators recognise that decarbonisation will require a step-change in investment given the expected increase in electricity demand driven by electrification, as well as increased penetration of flexibility services and distributed energy resources in the network.

Whilst most jurisdictions have expressed an urgency to meet their respective decarbonisation goals, against a similar backdrop of energy affordability and security challenges, it is widely established that there is no one-size-fits-all solution to addressing this problem.

However, generally speaking, economic regulators recognise that EDBs will play a vital role in facilitating the net zero transition in the sector and wider economy. The expected rapid growth in Low Carbon Technologies (LCTs), e.g., Electric Vehicles (EVs), Community Energy Storage (CES), solar photovoltaic systems (PVs) will require EDBs to ensure that there is sufficient local distribution network capacity to meet this growing demand. However, as in New Zealand, there is a lot of uncertainty surrounding when and where in the networks will this growth occur.

Regulators have tended to focus on managing new sources of uncertainty through putting in place funding and uncertainty mechanisms intended to support EDBs to innovate, digitalise and react flexibly. These responses are related to, but distinct from, adopting a stance of investing ahead of demand.

The economic regulators in our survey have implemented a range of approaches to setting expenditure allowances and flexibility and uncertainty mechanisms to facilitate electrification. The subsequent subsections provide a summary of each of these different categories.

6.2.1 Ex-ante allowances

Economic regulators have begun setting ex-ante capex and opex allowances to ensure that networks have sufficient funding to support electrification and the grid upgrades that are likely to be required. Ex-ante allowances are often provided to support distribution network upgrades and to cater to the expected rapid growth in EVs and other LCTs.

Recent examples of allowances which aim to facilitate the net zero transition provided by economic regulators include:

- ERA (West Australia) – The ERA proposed a capex allowance to support electrification and new technologies (e.g., advanced metering, cyber security, undergrounding) in its recent draft decision for Western Power Network. It also allowed for steps to decarbonisation-related opex expenditure. [60]
- AER (Australia – NEM) – In Jemena's Final Determination for 2021-26, the AER proposed to set aside a capex allowance called DER integration capex, dedicated to facilitating and integrating DERs on Jemena's distribution network. This decision supports Jemena in accommodating solar PV growth on its network. DER integration capex addresses increasing DER penetration on the distribution network.[61]
- Ofgem (Great Britain) - In Ofgem's recent RIIO-ED2 draft determination, Ofgem proposed to fund £2.68bn of load related expenditure within distribution networks' baseline allowances. These load-related allowances would largely be spent on connections, primary, secondary and fault level reinforcements. These ex-ante baseline allowances reflect the expected increase in demand for grid capacity to support the growth in EVs and HPs. [62]

Similar to other jurisdictions, the Commission is able to amend its expenditure forecasting approaches in order to provide upfront allowances for specific decarbonisation-related projects.

[60] Economic Regulation Authority 2022, *Draft decision on proposed revisions to the access arrangement for the Western Power Network 2022/23 – 2026/27*, September p. 8 Draft decision on proposed revisions to the access arrangement for the Western Power Network 2022/23 – 2026/27 (erawa.com.au)

[61] AER 2021, *FINAL DECISION Jemena Distribution Determination 2021 to 2026 Overview*, April p. 5 https://www.aer.gov.au/system/files/AER%20-%20Final%20decision%20-%20Jemena%20distribution%20determination%202021%E2%80%9326%20-%20Overview%20-%20April%202021.pdf

[62] Ofgem 2022, *RIIO-ED2 Draft Determinations – Core Methodology Document*, 29 June p. 28 https://www.ofgem.gov.uk/sites/default/files/2022-06/RIIO-ED2%20Draft%20Determinations%20Core%20Methodology.pdf

The introduction of flexibility and uncertainty mechanisms tends to play a complementary role to ex ante allowances in supporting decarbonisation related expenditure.

6.2.2 Flexibility and uncertainty mechanisms

In response to distribution networks needing to make investments under highly uncertain conditions (e.g., uncertainty surrounding the rate of growth of LCTs, when and at which locations demand for grid connection will be required etc), regulators around the world have complemented ex ante allowances with a range of mechanisms aimed at allocating risks between networks and customers in an efficient manner.

Table 6 presents a summary of flexibility and uncertainty mechanisms adopted in comparable jurisdictions. The IM review is the process under which to introduce or amend EDB flexibility and uncertainty mechanisms. However, in doing so the likely approach to setting expenditure allowances at the time of DPP reset should be simultaneously considered to ensure complementary settings and incentives.

Table 6: Flexibility and uncertainty mechanisms in comparable jurisdictions

Regulator	Type of mechanism
ERA (West Australia)	• Access arrangement reopener – In the event further investment is required to support decarbonisation and electrification during the regulatory period, the network can reopen its access arrangement during the regulatory period to request for additional revenue to fund the investment • Investment Adjustment Mechanism – applies to capex relating to the State Underground Power Program and provides for an adjustment to target revenue in the next access arrangement period
AER (Australia – NEM)	• Capex reopener mechanism – allows the EDB to apply to the AER to alter the revenue determination due to an event (or series of events) beyond the reasonable control of the EDB that could not have reasonably been foreseen. The total required to rectify the impacts of the event must exceed 5% of the value of the RAB. • Cost pass through mechanism – allows the EDB to apply to the AER to pass through the costs of an event. This can be related to a regulatory change, service standard, tax change, insurance event or any other event specified as a pass through event in the determination. • Reforming tariff structures to help distributors provide better price signals to retailer and help the transition to more cost-reflective pricing • Contingent projects – A contingent project is a project assessed by the AER as reasonably required to be undertaken but excluded from the ex-ante capex allowance in a revenue

	determination because of uncertainty about its requirement, timing or costs • Demand Management Incentive Scheme (DMIS) - incentivises EDBs to undertake efficient expenditure on alternatives such as small-scale generation and demand response contracts with large network customers (or third-party electricity aggregators) to time their electricity use to reduce network constraints
Ofgem (Great Britain)	• Re-openers uncertainty mechanism e.g., net zero re-opener, load related expenditure re-opener – Ofgem's net zero re-opener will enable investment to adapt quickly to support the high uptake of low carbon technologies (LCTs) in distribution networks. • Volume driver uncertainty mechanism e.g., secondary reinforcement volume driver - Ofgem expects the main driver of secondary reinforcement to be uptake of LCTs, specifically EVs
CRU (Ireland)	• LCT uptake uncertainty mechanism - This mechanism would address the uncertainty surrounding LCT cost, timing and output and could be triggered during the PR5 price control period if the Distribution System Operator (DSO) is able to provide evidence to several agreed upon conditions have been met • DSO flexibility mechanism – This mechanism would allow the DSO to access opex from its capex allowance (or vice versa) where it is in the best interest of consumers to do so

Source: Frontier Economics

6.2.3 Innovation incentives

All economic regulators in our survey have applied some form of innovation incentive in their respective jurisdiction. Generally, the purpose of these innovation incentives is to encourage innovation by identifying and funding projects which can accelerate the transition to net zero at the lowest cost to consumers.

Recent examples of innovation allowances and funding proposed by regulators include:

- ERA (West Australia) and AER (Australia – NEMS) – Both regulators have a Demand Management Incentive Allowance Mechanism (DMIAM) fixed innovation allowance for each regulatory control period which aims to provide DNSPs with funding in demand management projects that have the potential to reduce long term network costs. This will fund innovative projects that have the potential to deliver ongoing reductions in demand or peak demand. [63] [64] Over the 2 years to June 2021, approximately $20 million of innovation allowance funding was approved by the AER. [65]

- Ofgem (Great Britain) – Ofgem has in place a Strategic Innovation Fund (SIF) and Network Innovation Allowance (NIA) to support the transition to a smarter, more efficient, more flexible and sustainable low carbon energy system, at a low cost for consumers. The SIF is devoted to large-scale transformational R&D projects, whilst the NIA would focus on smaller-scale innovation projects.[66] In RIIO-ED2, Ofgem is proposing to retain the same NIA funding levels as in the previous price control. In the previous price control, each distribution network was awarded a NIA as a percentage of their base revenue (ranging from 0.5% to 0.7%).[67] Meanwhile, Ofgem's SIF is expected to invest £450m by 2026, and as of September 2022, £12.6m of SIF funding has been allocated to 58 projects.[68]
- CRU (Ireland) – CRU proposed in its PR5 determination an Innovation and R&D Mechanism which provides revenues needed for innovation projects not captured by other mechanisms and that cannot be funded through ex-ante allowances. [69]
- AER (Australia – NEMS) – The AER released a position paper on finalising their approach to delivering a regulatory sandbox toolkit. The toolkit aims to help innovators understand how their new technologies or business models fit within current regulations and make it easier for innovators to trial their proposed services in a real-world environment. The regulatory sandboxing toolkit is expected to benefit innovators by enabling their projects to proceed. This includes supporting energy businesses get new and innovative services up and running.[70]
- Similarly, the Energy Market Authority (EMA) in Singapore also has in place regulatory sandboxing for energy sector innovations as well as grant calls and partnerships to encourage R&D of innovative technologies and solutions. An example of a recent Grant Call is the call for

63 Economic Regulation Authority 2022, *Draft decision on proposed revisions to the access arrangement for the Western Power Network 2022/23 – 2026/27 Attachment 10*, September pp. 16 https://www.erawa.com.au/cproot/22857/2/Attachment-10---Expenditure-incentives-and-other-adjustment-mechanisms.PDF

64 AER 2017, *Final decision: Demand management incentive scheme and innovation allowance*, December pp. 1 https://www.aer.gov.au/system/files/D17-173575%20AER%20-%20Fact%20Sheet%20-%20Final%20demand%20management%20incentive%20scheme%20and%20innovation%20allowance%20mechanism%20-%2013%20December%202017.pdf

65 AER 2022, *State of the energy market 2022 report*, 29 September, p. 96 https://www.aer.gov.au/publications/state-of-the-energy-market-reports/state-of-the-energy-market-2022

66 Ofgem 2022, *RIIO-ED2 Draft Determinations – Core Methodology Document*, 29 June p. 47 https://www.ofgem.gov.uk/sites/default/files/2022-06/RIIO-ED2%20Draft%20Determinations%20Core%20Methodology.pdf

67 Ofgem 2022, *RIIO-ED2 Draft Determinations – Core Methodology Document*, 29 June p. 50 https://www.ofgem.gov.uk/sites/default/files/2022-06/RIIO-ED2%20Draft%20Determinations%20Core%20Methodology.pdf

68 Innovate UK 2022, *Ofgem Strategic Innovation Fund (SIF) Annual Report 2022*, 28 September, p.3 https://www.ukri.org/wp-content/uploads/2022/09/IUK-300922-InnovateUKOfgemSIFAnnualReport2022.pdf

69 CRU 2020, *PR5 Regulatory Framework, Incentives and Reporting, 18 December*, p. 39 https://www.cru.ie/wp-content/uploads/2020/12/CRU20154-PR5-Regulatory-Framework-Incentives-and-Reporting-1.pdf

70 AER 2022, *Regulatory sandboxing Positions Paper*. April, p. 4 https://www.aer.gov.au/system/files/AER%20-%20Regulatory%20sandboxing%20-%20Positions%20Paper%20-%20April%202022.pdf

proposals for R&D projects that will develop new capabilities in the areas of distributed generation to prepare Singapore for a decentralised energy system.[71]

The Commission's Innovation Allowance, with its ex-post nature and relatively low value, suggests that the incentive scheme may contribute little to EDBs' incentives to innovate. There are opportunities for the Commission to introduce higher powered innovation incentives in order to accelerate innovation and improve energy affordability as the economy transitions to net zero.

71 Energy Market Authority 2022, Research Innovation, Enterprise and Deployment, viewed 12 October 2022, https://www.ema.gov.sg/Industry_Energy_Research_and_Development.aspx

7 Enabling decarbonisation through proactive investment

This section evaluates options for changing the IM which would allow EDBs to invest ahead of demand to prepare networks to support decarbonisation efforts.

7.1 Economic efficiency and the Part 4 purpose

As outlined in this report, there are numerous potential transition pathways for New Zealand to achieve its 2030 and 2050 decarbonisation goals. There is consensus that electricity will play a disproportionate role in helping New Zealand meet its decarbonisation objectives and that this process will occur over multiple EDB DPP regulatory periods.[72]

Decarbonisation results in greater uncertainty for EDBs about the policy environment, technology, customer demand and investment requirements. This changing set of circumstances means that it may be efficient under certain circumstances for:

- EDBs to invest ahead of demand under the DPP to support decarbonisation and electrification;[73] and/or
- The IM/DPP to be more adaptive and flexible to manage risks related to decarbonisation; and
- Higher powered incentives to accelerate innovation and improve energy affordability as the economy transitions to net zero.

The existing IM/DPP regime may prevent these efficient investments from being made. This is primarily because the IM/DPP is a 'steady state' regime which sets expenditure allowances based on historic expenditure profiles, albeit with some within-period mechanisms to manage uncertainty and the CPP option.

We identified options to incorporate into the IM/DPP framework that could enable EDBs to facilitate New Zealand's decarbonisation and electrification.[74] A summary of these options is provided in Attachment A.

72 Ministry of Business, Innovation & Employment, *Electricity demand and generation scenarios: Scenario and results summary*, July 2019, available at: https://www.mbie.govt.nz/dmsdocument/5977-electricity-demand-and-generation-scenarios , Transpower, *NZGP1 Scenarios Update: NZGP1 Scenarios and modelling result for an unconstrained transmission grid*, December 2021, available at: https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/Transpower_NZGP_Scenarios%20Update_Dec2021.pdf . New Zealand Government: *New Zealand's First Emissions Reduction Plan*, June 2022, available at: https://environment.govt.nz/assets/publications/Aotearoa-New-Zealands-first-emissions-reduction-plan.pdf .

73 The is most clearly the case where the scale and location of the demand are relatively sure; only the timing differs (e.g., the electrification of the mass markets). Large 'lumpy' investments in capacity (e.g., industrial connections or large DG) require an approach which balances investing to meet demand and investing to enable.

74 These options were developed in reference to stakeholder comments on the IM review, our review of international regulatory practice, and a workshop with the B6.

7.2 Packages of potential amendments

This section outlines two packages of options to amend the IM/DPP framework, intended to facilitate:

- Efficient investment to support decarbonisation and electrification, some of which may be ahead of demand; and
- Increased regulatory adaptability and flexibility to more efficiently allocate and manage risks related to decarbonisation.

Package 1 relates to changes that do not require IM amendments and Package 2 contains changes that would require IM amendments, as described in **Table 7** below. Package 1 would look to ensure that ex-ante allowances are set to account for expected future changes, while package 2 looks to set suitable risk management mechanisms to account for unexpected and unanticipated changes related to the transition.

These packages are designed to assist the B6 to assess fit-for-purpose IM/DPP regulatory framework amendments, that is, amendments that enable decarbonisation at a rate New Zealand has committed to. As presented in section 6, both ex ante and within period regulatory responses are critical elements of a standard regulatory framework, this is included in Package 3.

Table 7: Packages of potential amendments to the IM/DPP framework

Package	Features of change	Description
1	Doesn't require IM amendments	• Allow expenditure forecasts to reflect the expected profile of expenditure, rather than the historic profiles: o Amend DPP opex base-step-trend forecasting approach to provide guidance and allow for reasonable step changes related to decarbonisation; o Amend DPP capex forecasting approach to reflect future decarbonisation investment needs, including through increasing or removing arbitrary expenditure caps; and o Explore new information disclosures under Part 4 to support incorporation of uncertainty analysis into DPP expenditure allowance setting.
2	Requires IM amendments	• Introduce uncertainty mechanisms to manage a range of decarbonisation-related uncertainties: o Index revenue adjustments to consumer investment in low-carbon technology, e.g., connection infrastructure to supply EV charging stations or DER; and/or o To incorporate contingent projects into the DPP, in order to manage demand timing uncertainty; and

		◦ Introduce mechanisms to allow for efficient interaction between network and non-network solutions, i.e., capex and opex substitutability. • Broaden the suite of DPP reopeners to manage risks related to the transition: ◦ Widen the scope of the existing capex reopeners to include opex and reduce the 1% cap; ◦ Decarbonisation specific re-opener to reflect unique characteristics of decarbonisation projects; and ◦ Broaden the change event reopener to mitigate 'inevitable policy risk' of future significant climate policy changes. • Provide up front guidance on compliance processes to decrease regulatory burden
3	Both packages	• Allow expenditure forecasts to reflect the expected profile of expenditure, rather than the historic profiles; • Introduce uncertainty mechanisms to manage a range of decarbonisation-related uncertainties; • Broaden the suite of DPP reopeners to manage risks related to the transition; and • Provide up front guidance on compliance processes to decrease regulatory burden.

Source: Frontier Economics

Further to the potential changes presented in **Table 7**, we consider there is a case for higher powered incentives to accelerate innovation and potentially improve energy affordability. The options contained in Packages 1 and 2 are more likely to enable the investment required to facilitate decarbonisation and we have focused on those. Improvements in the DPP's innovation settings remain important but are not assessed here (Box 7).

Box 7: Higher powered innovation incentives

Given the scale of the decarbonisation objectives facing the industry and its consumers, the potential long-run benefits to consumers from EDB innovation are likely significant. Innovation in the energy sector can lead to better services and lower costs for consumers. Here, we highlight two complementary amendments to the IM/DPP regulatory framework that could deliver higher powered innovation incentives:

- **Reform the innovation allowance**: The innovation project allowance introduced by the Commission in DPP3 has not encouraged EDBs to innovate. In our view, this is because of its time and resource intensive application process, relatively small allowance (0.1% of allowable revenue or $150,000 over the DPP3 period), and its ex-post approval structure combined with a requirement that EDBs must have already incurred an amount of costs on the innovation project that is at least equivalent to 200% of the proposed application amount.
- **Regulatory sandboxing**: A regulatory sandbox is a framework within which participants can test innovative concepts in the market under relaxed regulatory requirements at a smaller scale, on a time-limited basis and with appropriate safeguards in place. This may be particularly relevant over the coming years as transportation and process heat in New Zealand electrify:
  - it is also a tool for regulators to learn about particular innovations and develop the right regulatory environment to accommodate them; and
  - there is the potential for collaboration between EDBs, including collaboration on innovation and pilot implementations and sharing of intellectual property arising from successful innovations.

  Regulatory sandboxing is undertaken in Singapore and is being considered by the AER as outlined in section 6.

Source: Frontier Economics

7.3 Evaluation of potential amendments

We have evaluated the merits of Packages 1 and 2 against the Commission's overarching objectives of the IM review (see section 4.1), which are:

- to promote the Part 4 purpose in section 52A more effectively, i.e., promote the long-term interest of consumers;
- to promote the IM purpose in section 52R more effectively (without detrimentally affecting the promotion of the section 52A purpose), i.e., the purpose of the IMs is to promote certainty for suppliers in relation to the rules, requirements, and processes applying to regulation;[75] and

[75] Section 52R states: The purpose of input methodologies is to promote certainty for suppliers and consumers in relation to the rules, requirements, and processes applying to the regulation, or proposed regulation, of goods or services under this Part

- to significantly reduce compliance costs, other regulatory costs, or complexity (without detrimentally affecting the promotion of the section 52A purpose).

In considering the objectives of the IM review, we have had regard to the Commission's key economic principles. As noted by the Commission, 'the principles are a means to an end, the end being the effective application of the overarching objectives and the sections 52A and 52R purposes they focus on.'[76] We find that a combining Packages 1 and 2 best promote the long-term interests of consumers.

Table 8: Economic principles

Criteria	Description
Asymmetric consequences	Asymmetric consequences of over/under-investment: There could be asymmetric consequences, over the long term, of underinvestment versus overinvestment. If a material asymmetry exists, it is necessary to mitigate it for end users.
Risk allocation	Ideally, risks should be allocated to suppliers or consumers depending on which are best placed to manage them.
Financial capital maintenance	In the context of decarbonisation, EDBs should have the ex-ante expectation of earning a normal return, and of maintaining their financial capital in real terms over timeframes longer than a single regulatory period.

Package 1: Changes that do not require IM amendments

Package 1 relates to changes that do not require IM amendments – specifically the approaches used to set DPP expenditure allowances to provide for decarbonisation-enabling investment. While the approach to setting expenditure allowances for the DPP is not an IM review decision, it informs the profile of decarbonisation-related risks under the regulatory framework.

Overall, adopting forward looking expenditure forecasting approaches will allow for EDBs to better facilitate decarbonisation. These changes will account for expected investment requirements, but unexpected investment requirements may be hindered without increased within-period flexibility and uncertainty mechanisms. **Table 9** below summarises the high-level assessment of package 1.

[76] Commerce Commission 2022, *Part 4 Input Methodologies Review 2023 Framework Paper*, 13 October, p. 47.

Table 9: High-level evaluation of package 1

Criteria	Assessment summary
Promote the Part 4 purpose in section 52A more effectively	• Material to promoting the long-term interests of consumers as: ○ Allows EDBs to undertake prudent and efficient investment to account for expected future changes that might not be reflected in historical outcomes and hence might not be captured under the current DPP approach; and ○ The asymmetric consequences of under-investment are more likely to be mitigated than the status quo, including through the allowance for proactive investment to enable decarbonisation;
Promote the IM purpose in section 52R more effectively	• N/A as methodologies to set DPP expenditure allowances are outside of the DPP IM.
Significantly reduce compliance costs, other regulatory costs, or complexity	• Greater guidance and therefore regulatory certainty could be provided on how decarbonisation risks will be addressed in ex ante allowances (e.g., opex step criteria), but arguably this adds to the complexity of the DPP process.

Source: Frontier Economics

Package 2: Changes that do require IM amendments

Package 2 relates to changes that would require IM amendments – specifically the introduction or broadening of within-period flexibility and uncertainty mechanisms which act to address revealed deficiencies in ex-ante expenditure allowances and share risk with consumers. If the Commission considers that it will continue with its current approach to expenditure forecasting, more pressure is placed on the IM provisions to manage uncertainty related to decarbonisation.

Overall, greater reliance on within-period flexibility result in greater costs and complexity. This will be especially the case if expected changes in expenditure requirements are not accommodated in the DPP ex ante allowances. **Table 10** below summarises the high-level assessment of package 2.

Table 10: High-level evaluation of package 2

Criteria	Assessment summary
Promote the Part 4 purpose in section 52A more effectively	• Material to promoting the long term interests of consumers: ○ The asymmetric consequences of under-investment are more likely to be mitigated by allowing the DPP to address unexpected opex, or unexpected capex that currently falls beneath the 1% cap; but ○ Timeliness of decarbonisation-enabling investment may suffer, preventing expansion options and delaying consumer benefits.
Promote the IM purpose in section 52R more effectively	• Material if rules, requirements and processes for managing uncertainty are included in the IMs, rather than the DPP decision.
Significantly reduce compliance costs, other regulatory costs, or complexity	• Potentially adverse as greater reliance on within period mechanisms necessarily involves compliance costs, other regulatory costs, and potential unintended consequences related to complexity. • Mitigation in the form of up-front guidance on how the flexibility and uncertainty mechanisms will be applied if fit-for-purpose (e.g., eligibility, evidence requirements, process, and timelines.)

Source: Frontier Economics

7.4 Findings

The IM review is an opportunity to shape the regulatory regime to ensure it is fit-for-purpose, especially given the rapidly evolving environment in which EDBs operate. The IM/DPP framework should be amended to allow for both:

- Expenditure allowances which reflect expected changes in decarbonisation related investment, including investing ahead of demand to enable decarbonisation; and
- Additional within-period flexibility and uncertainty mechanisms which will act to address deficiencies in ex-ante expenditure allowances and efficiently share risk with consumers.

As noted in section 7.2, improvements in the IM/DPP's innovation settings remain important but are likely secondary to the incentives contained on Packages 1 and 2 in terms of investing to enable decarbonisation.

Package 1 provides for expenditure allowances to reflect expected changes in decarbonisation investment requirements, but unexpected changes within period may be hindered by the current set of uncertainty and flexibility mechanisms. Package 2 alone would require expected changes to be addressed through within-period adjustments, potentially adding complexity vis-à-vis being able to capture these impacts in ex ante forecasts.

Package 3, a combination packages 1 and 2, reflects both ex ante and within period regulatory responses is most likely to promote the long-term interests of consumers.[77] These features are collectively critical elements of a standard regulatory framework. **Table 11** below summarises the high-level assessment of package 3.

The benefits to consumers associated with proactive management of decarbonisation risks are significant, while the costs associated with the added complexity can be managed through clear processes and guidelines, including consultation with stakeholders to figure out what will work best.

Table 11: High-level evaluation of package 3

Criteria	Assessment summary

Promote the Part 4 purpose in section 52A more effectively	• Material to promoting the long-term interests of consumers:
	  ○ The IM/DPP framework can balance the allocation of risk between consumers and suppliers.
	  ○ Ex-ante allowances: Allows EDBs to undertake prudent and efficient investment to account for expected future changes that might not be reflected in historical outcomes and hence might not be captured under the current DPP approach; allowing for
	  ○ The asymmetric consequences of under-investment are more likely to be mitigated than the status quo, including through the allowance for proactive investment to enable decarbonisation;
	  ○ Uncertainty and flexibility mechanisms: The asymmetric consequences of under-investment are more likely to be mitigated by allowing the DPP to address unexpected opex, or unexpected capex that currently falls beneath the 1% cap;

Promote the IM purpose in section 52R more effectively (without detrimentally affecting the promotion of the section 52A purpose)	• Material if rules, requirements and processes for managing uncertainty are included in the IMs, rather than in DPP decisions.

77 We note that in the absence of any amendments to the DPP/IM framework, EDBs may either choose to not invest or will elect to apply to the Commission for a CPP.

Significantly reduce compliance costs, other regulatory costs, or complexity (without detrimentally affecting the promotion of the section 52A purpose).	• Greater complexity in setting ex ante allowances and administering flexibility and uncertainty mechanisms. Mitigation in the form of up-front guidance on how the IM/DPP framework will be applied (e.g., eligibility, evidence requirements, process, and timelines.)

Source: Frontier Economics

A Summary of potential IM/DPP regulatory framework amendments

This section provides a summary of the potential IM/DPP framework amendments that were identified during the course of this project. These options were developed in reference to stakeholder comments on the IM review, a review of international regulatory practice, and a workshop with the B6 obtaining market information.

These options broadly align to those making up package 1 and 2 of potential amendments in section 7.2, that is:

- Changes to the regulatory framework that would not require IM amendments (i.e., ex ante expenditure setting approaches); and
- Changes to the regulatory framework that would require IM amendments (i.e., within period flexibility and uncertainty mechanisms).

Both packages are critical elements of a standard regulatory framework designed to manage risks related to decarbonisation, consistent with the themes of emerging regulatory practice in other jurisdictions (see section 6 for details).

The remaining sections in this attachment summaries the list of potential IM/DPP framework amendments.

Changes that do not require IM amendments

The final decisions on this IM review are due in December 2023 and will guide the next EDB DPP determination after the current DPP3 ends on 31 March 2025. While the approach to setting expenditure allowances for the DPP is not an IM review decision, it informs the profile of decarbonisation-related risks under the regulatory framework.

Table 12: List of potential changes that do not require IM amendments

Option	Focus areas
Allow expenditure forecasts to reflect the expected profile of expenditure, rather than the historic profiles: Opex	• The Commission review its evaluation criteria regarding 'steps' in the base-step-trend approach to allow decarbonisation-related opex to recognise the asymmetric consequences of underinvestment, the inherent uncertainty in transition and the principle of investing ahead of demand. • The Commission to provide guidance on how EDBs may justify step changes, which may take the form of a template or reference to best practice. An independent expert or consumer willingness to pay study may provide further assurance.

	• The Commission utilise EDB AMP opex forecasts (of specific categories of) subject to criteria aligned with capital expenditure forecasting approaches.
Allow expenditure forecasts to reflect the expected profile of expenditure, rather than the historic profiles: Capex	• Different approaches to be applied for different categories for capex spend based on differing levels of uncertainty and hence risk. For example, uncertainty on growth capex is much higher than would be for replacement capex. • Treat expenditure differently by categories in AMPs, e.g., remove caps for investment to support DER or EVs, and recognise the potential benefits of investing ahead of demand. • Allow for external assurance from an independent auditor or willingness to pay study to support capital expenditure above current thresholds.
New information disclosures under Part 4 to support incorporation of uncertainty analysis into DPP expenditure allowance setting	• Voluntary disclosure of expenditure forecasts against climate change scenarios / TCFD categories risks / demand scenarios. Information support Commission's acceptance of EDB expenditure forecasts at time of DPP reset.

Changes that do require IM amendments

If the Commission considers that it will continue with its current approach to expenditure forecasting, more pressure is placed on the IM reopener provisions to address future deficiencies in expenditure allowances. We note that DPP reopeners should generally be designed to accommodate issues affecting multiple suppliers (4+) that arise after the DPP is set. [78]

Table 13: List of potential changes that do require IM amendments

Option	Focus area

Connection capex volumetric uncertainty mechanism	• Mechanism similar to the connection capex mechanism that applies to Chorus under the fibre regime.
	  ○ Baseline allowance, including connection capex than is relatively certain. Connection capex unit costs and connection types.
	  ○ Variable adjustment, representing the difference between the baseline allowance (based on forecast volumes) and actual connection volumes. Variable adjustment based on same connection capex unity costs used to determine the baseline allowance.

78 Per High Court in Wellington International Airport Ltd & Ors v CC.

	• Note that this mechanism is similar to those applied by Ofgem and CRU (below).
Incorporation of triggers to expenditure allowances	• An Uncertainty Mechanism which releases revenues in response to identified needs of the system, for example increased uptake of low-carbon technology and new connections. These triggers would be tied to certain milestones, such as the number of EV registrations.
Contingent projects to manage timing uncertainty and improve responsiveness	• Addressing an uncertain timing of a decarbonisation project. Contingent project allowances that automatically trigger on the occurrence of specific events. Potentially as per CPP IM.
Widen the scope of existing capex reopeners for non-network / opex alternatives	• The scope and wording of the two capex reopeners is reconsidered to include opex. This could mitigate a potential capex bias and allow for opex-based non-network solutions. • Unforeseen capex reopener could be triggered by 'incremental demand growth' (e.g., EV growth or customers switching from gas to electricity) rather than just large new connections. • Amend 1% revenue threshold applying to several existing reopeners or reduce it for decarbonisation-related events. • 'Foreseeable' capex reopener to be replaced with a contingent project approach as the uncertainty is driven by project timing rather than project need. This will reduce compliance costs and improve timeliness.
Decarbonisation-specific reopener reflecting unique economics of decarbonisation projects	• Taking account of the unusual nature of the investments including the size of the investment, the timing of rolling the investment into the RAB (i.e., expensed versus commissioned), avoiding first-mover disadvantage, and variability of the investment (i.e., alternatives to traditional poles and wires solutions). • The reopener could involve an investment test taking a long-term view.
Broaden the change event reopener to mitigate 'inevitable policy risk'	• Climate Change event DPP/CPP reopener arising from government climate policy or other relevant matters (link to ERP, etc), including criteria and materiality thresholds.
CPP IM	• Alternatives to specific re-opener mechanisms include a single-issue CPP. A single issue CPP (i.e., a CPP that focuses on only a single incremental change to the existing price-quality path) may be similar to a DPP reopener.

	• Amend the CPP IM to allow for an IPP style multi-period option to support sustained investment profiles for New Zealand's largest EDBs (i.e., allow movement of investment across regulatory years and periods, minimise costs associated with applications)
Allow efficient interaction between network and non-network solutions	• Allow more flexibility of spend between opex and capex allowing an EDB to access opex from its capex allowance (or vice versa) for non-network solutions (as per CRU). • Adopt totex regime. Current regulatory regime may favour capex over opex (even with neutral incentive rates) because opex is based on historical data and capex is forward-looking.
Consequential amendments to IRIS	• A potential barrier to amendments to ex ante allowance, the introduction of volume-linked expenditure re-openers, or totex approaches are the implications for the IRIS schemes.
Compliance costs and complexity of approvals	• Streamlining the approvals process as it relates to reopeners. The Commission could take uncertainty out of the approvals process through clear published guidelines. • Decarbonisation is a common challenge to EDBs. Current re-openers, pass throughs and CPP processes require individual EDB applications. Allowance for joint applications may streamline processes, reduce compliance costs, and ensure consistency.
Financeability and cashflows	• Business decarbonisation will require large scale connections from which recovery of costs are currently 'back-ended' presenting risks to cashflow. The Commission may adopt a 'front-ended' approach similar to Transpower IPP. • Introduce financeability test to the DPP. Ensure that EDBs can finance their networks efficiently, potential cost of debt benefits.

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