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Trends in local lines company performance

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Executive summary

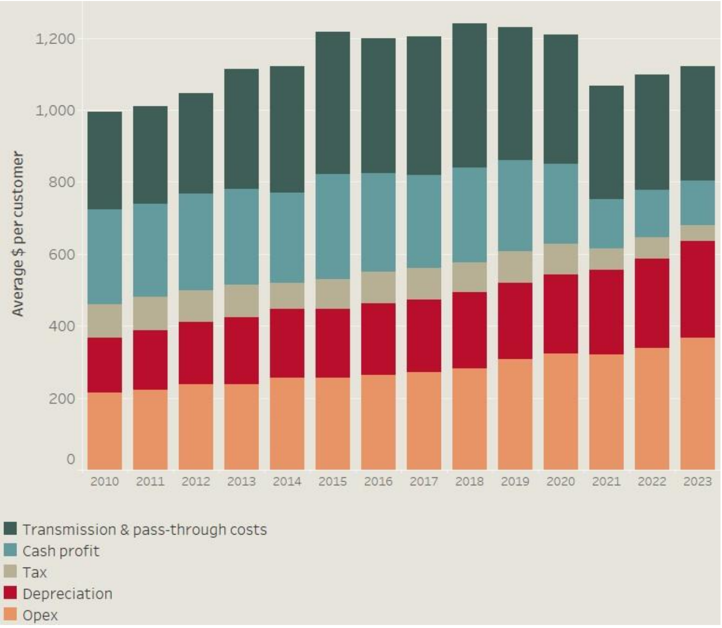
We regulate all 29 local lines companies and Transpower under Part 4 of the Commerce Act. They are regulated because they operate in markets where there is little or no competition (and little prospect of future competition).

Transmission and distribution lines charges combined make up approximately 38% of the average consumer electricity bill. We require all local lines companies to disclose information on their performance, and for 16 of them, we also set maximum revenue limits and minimum quality standards.

This report is a snapshot of revenue, profitability, and service reliability trends for local electricity lines companies in New Zealand. Local lines companies provide electricity 'distribution' services. They own the poles and wires around cities, towns, and rural areas, which deliver electricity from the high-voltage transmission system, as well as local generators, to households and businesses.

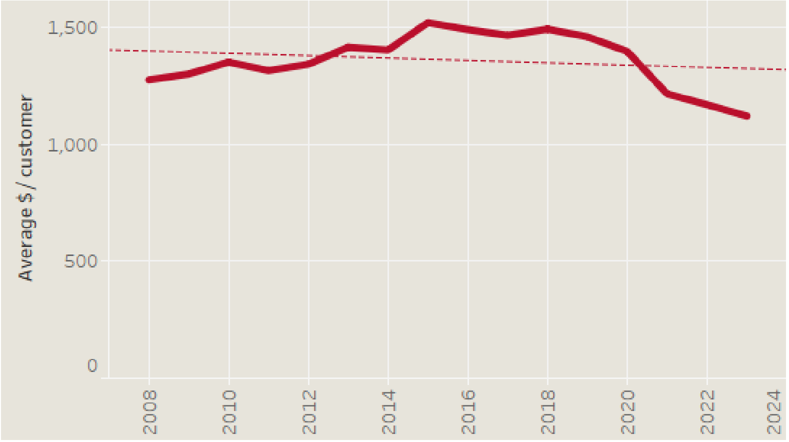
Lines charges have fluctuated over time and have fallen in real terms per customer

Local lines companies collect their regulated revenue through lines charges. Lines charges have fluctuated over time. The chart to the right shows the changes in lines charges between 2010-2023 (in nominal terms).



The three main causes of the fluctuations were:

- significant increased transmission investment (2008-2018)
- changes in the finance rate
- changes in inflation.



In real terms (adjusted for inflation), individual customers have paid less for lines companies' services over the period. This is shown in the chart to the left.

Local lines companies' profitability has generally been reasonable

We estimate a reasonable return on investment for local lines companies and use it when we set maximum revenue limits. The return on investment across the industry has generally been around 5%-6% between 2013 and 2020 and decreased in 2021. Return on investment in 2022 and 2023 was more than 8% (in nominal terms) in each of these years due to the effect of increased inflation.

Overall, local lines companies are not collectively making excessive profit because profitability has been generally lower than our estimate of a reasonable return on investment.

Growth in local lines companies

Local lines companies have grown since 2010, with growth in network connections, peak system demand, revenue, and investment. These metrics are detailed in the table below.

Growth since 2010

Industry	Size in 2023	Avg. yearly growth
Network connections	2.2M	↑ 0.9%
Peak system demand	6,808 MW	↑ 0.7%
Revenue	$2.5B	↑ 2.4%
Investment	$1.1B	↑ 7.0%

Size in 2023 gives network connections, peak system demand (megawatts), revenue ($ billions) and investment expenditure ($ billions).

Average yearly growth gives the percentage that these measures grew each year on average using a trend line.

There's room for improvement in connection practices

We have observed a range of performance levels across local lines companies from their reported information about their practices on new or altered customer connections. We have found room for improvement, for example, in relation to how companies are minimising costs to customers, providing flexible service offerings and actively monitoring the costs of new or altered connections.

The reliability of local lines companies

Average number of outages per customer per year

1.9

The long-term trend is an annual increase of **2.4%** per year

Average total length of outages per customer per year

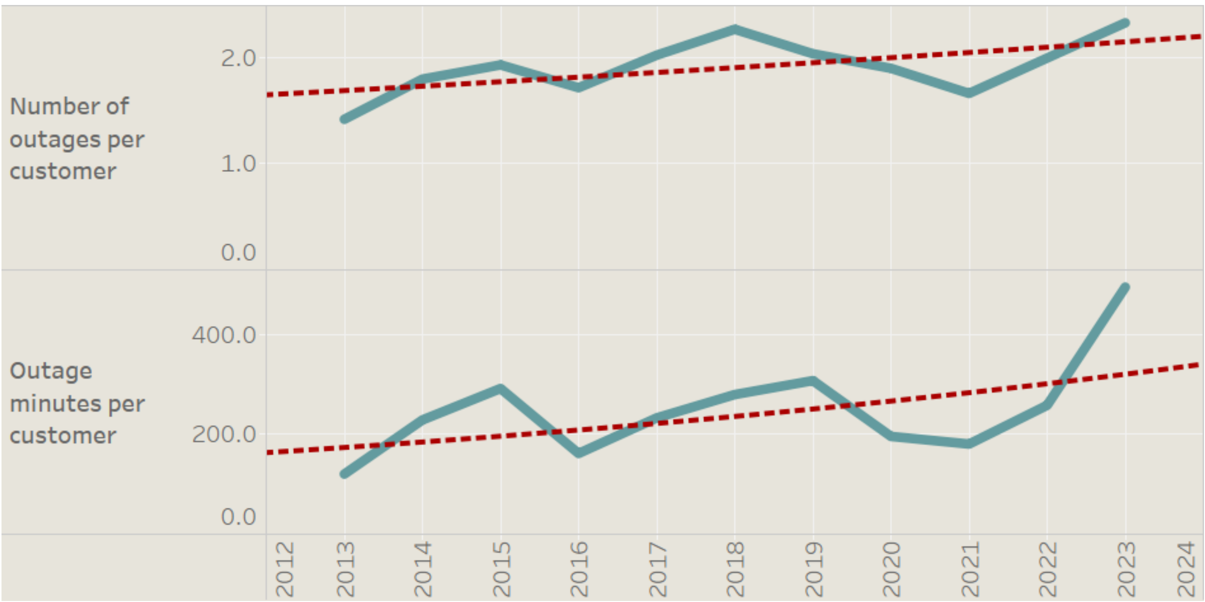
250 minutes

The long-term trend is an annual increase of **6.2%** per year

Network reliability has changed over time as shown in the chart below. Outages are categorised as planned (notified in advance) or unplanned. Planned outages allow work to be done on the network, while unplanned outages are caused by external factors like weather events.

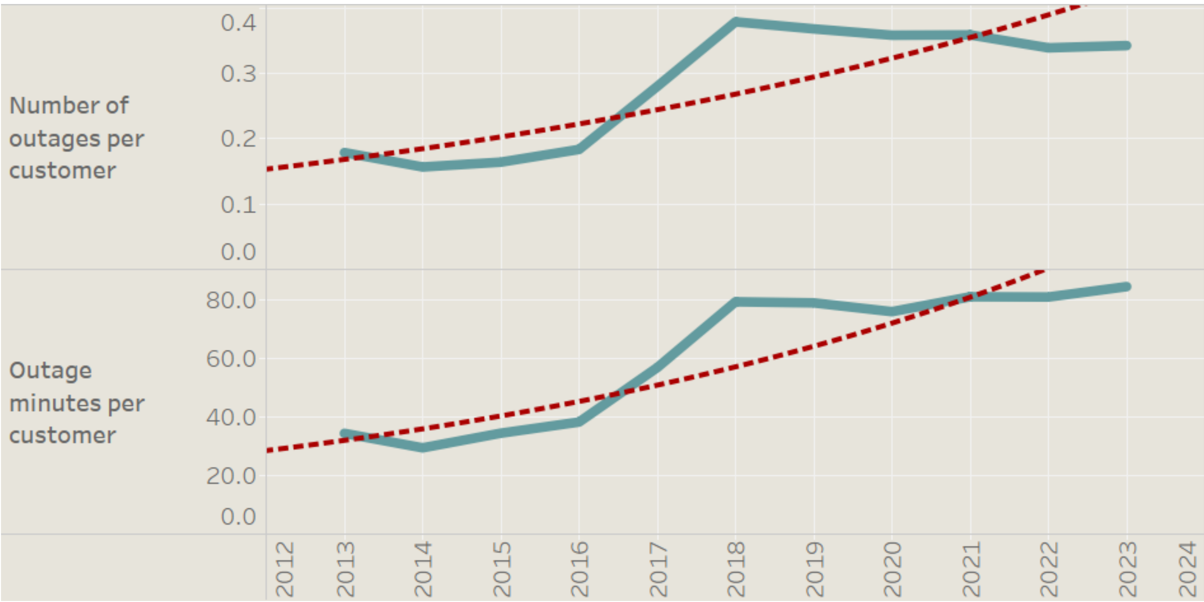
Overall, the long-term trend between 2013-2023 shows that there have been more outages in total and each outage lasts longer. The long-term trend of the annual increase in the average number of outages per customer per year is 2.4%, and for the average total length of outages per customer per year, it is 6.2%.

Total outages per customer

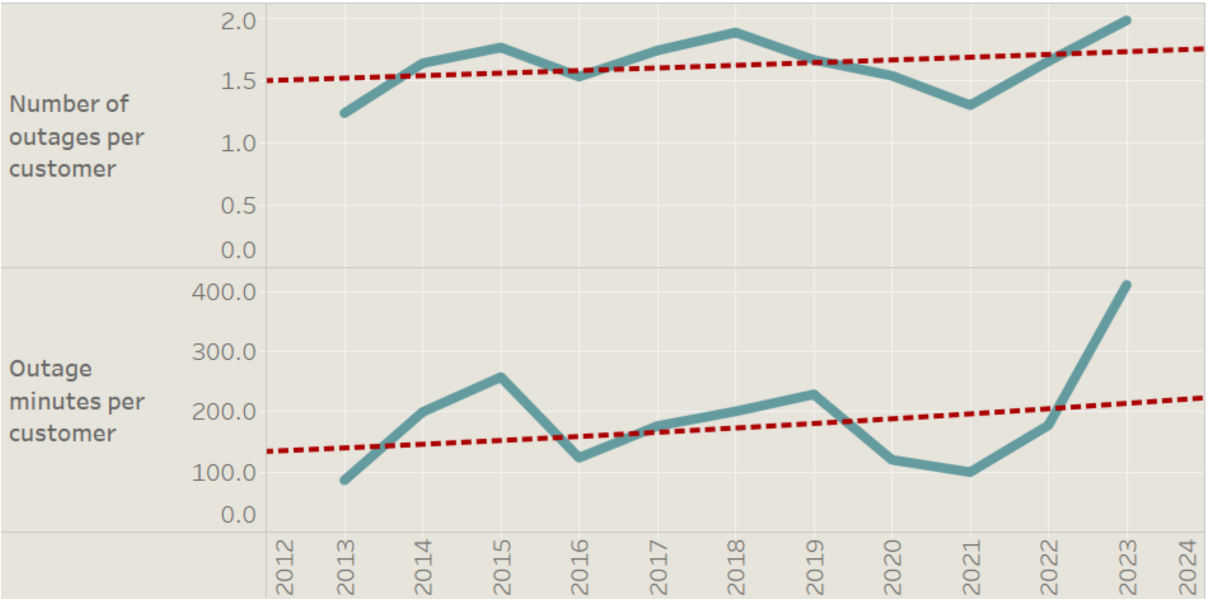


Planned outages have increased more than unplanned outages over time as shown in the two charts below. Unplanned outages have been broadly similar over time, except for 2023 when there has been a significant increase due to severe weather events - Cyclone Gabrielle and Auckland Anniversary flooding.

Planned outages per customer



Unplanned outages per customer



Chapter 1: Introduction

Purpose of this report

The purpose of this report is to help people to better understand how and why the price and quality of services provided by local electricity lines companies have changed over time. The aim is to provide insights into the issues affecting local lines companies, which can then help to inform a clearer impression of their performance.

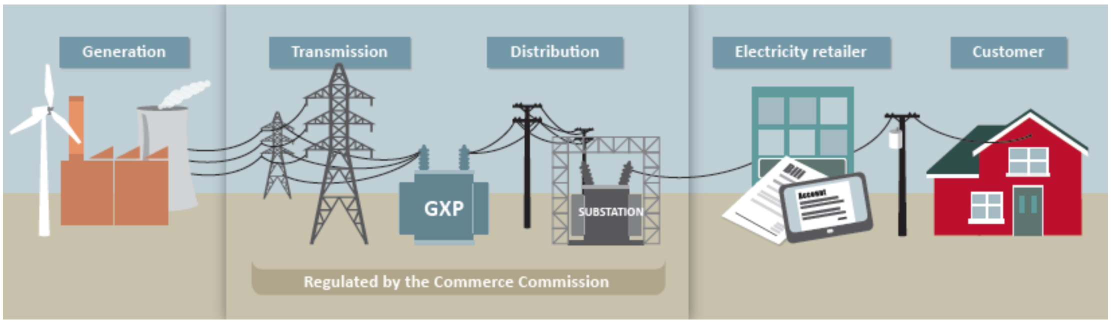
This report presents and discusses analysis that we have undertaken to identify past trends in local lines companies' performance such as revenue and reliability and examines the underlying drivers of those trends. It gives a high-level picture of these trends at an industry and individual company level and helps identify areas that warrant deeper examination in future pieces of performance analysis.

Local lines companies provide electricity 'distribution' services. They own the poles and wires around cities, towns and rural areas, which deliver electricity from the high-voltage transmission system, as well as local generators, to households and businesses.

Local lines companies pay Transpower, the owner of the high-voltage transmission system, for its delivery of electricity. The trends in this report on the revenue of local lines companies therefore include a component of the revenue that is passed on to Transpower.

We are responsible for regulating electricity transmission and distribution services (or 'electricity lines services') under Part 4 of the Commerce Act 1986. We regulate all local lines companies by requiring them to disclose information on their performance. We also regulate 16 out of 29 local lines companies by setting maximum revenue limits and minimum quality standards (called price-quality paths).[1] Our responsibilities under the Commerce Act in relation to local lines companies are described in our Approach paper, titled 'Approach to trend analysis of local lines companies' which can be found on our website here. Many local lines companies also supply services that are unregulated, such as electricity contracting services.

Figure 1: We regulate local lines companies and Transpower under the Commerce Act



[1] Our website has more information on our role in electricity lines. See also Commerce Commission "2020-2025 electricity default price-quality path".

We use the term 'customers' to mean the entities that are connected to the local lines company, which can be households or businesses. Most customers do not have a direct relationship with their local lines company. Rather, they will engage with an electricity retailer to which they pay their bill. A portion of each customer's electricity bill is made up of 'lines charges'—around 38%[2] for a typical household—which the retailer passes on to local lines companies to cover the costs of both transmission and distribution services. Lines charges make up almost all local lines companies' regulated revenue, which is the revenue received from the supply of electricity distribution services. By analysing changes in local lines companies' (regulated) revenue, we can improve understanding about those businesses, the impact that their activity has had on customers through paying lines charges, and the effectiveness of our regulations.

Our analysis draws on information that New Zealand's 29 local lines companies disclosed under information disclosure (ID) requirements from 2008 to 2023 (years ending on 31 March).[3] Some of our analysis does not go back as far as 2008 because of data limitations in those early years. It considers the local lines companies' revenue and costs, and the quality of electricity distribution services they provided over that period.

We expect this analysis will be of interest to all stakeholders. Electricity sector stakeholders need to have confidence that the prices paid by electricity customers to local lines companies reflect an industry that is working effectively, and for the long-term benefit of customers. This analysis will be an important input into assessments of the performance of local lines companies and the effectiveness of our regulation.

We have published other summary materials

We intend this to be a regular report that is updated on a two-yearly basis. We will add fresh analysis and insights as appropriate. This report was first published in December 2020, and again in July 2022. For this 2024 report, it has been updated with data from the 2023 information disclosures.

This report is supported by further materials that highlight our key findings and allow stakeholders to better understand the data behind them. These materials provide stakeholders with easy access to the data, at a level appropriate for their interest, and allow them to view the analysis as new data becomes available. These materials include:

- A paper titled 'Approach to trend analysis of local lines companies', which can be found on our website here. This paper describes the technical detail of the analytical approaches we used and the legislative context in which we undertake this approach.
- A fact sheet highlighting some of the key findings of our analysis from this report.
- An online interactive dashboard that walks users through the key findings and allows them to look further into the results if they choose.

2 Electricity Authority, "Your Power Bill".
3 All years discussed in this report are years ending 31 March unless otherwise specified.

This report and the supporting materials add to our existing suite of summary and analysis

The analysis presented in this report and supporting materials add to an existing suite of summary and analysis of local lines companies' ID data that we have undertaken over time, which can be found on our website.[4]

We publish and update the following range of summary and analysis on a regular basis:

- *ID datasets*—this groups together the raw data disclosed by local lines companies and is published in accessible output formats.
- *The Performance Accessibility Tool*—this is an online portal that visualises the ID data, including profit and revenue, capital and operating expenditure, asset condition and age, and reliability/outage data. The tool is interactive, allowing the data to be interrogated and summarised at various levels.[5]
- *Annual 'one-page' performance summaries*—these summaries provide high-level statistics on each local lines company's performance, including measures such as profitability, capital and operating expenditure, asset condition, line charge revenue and reliability. They are updated each year as new data becomes available.[6]

We also produce in-depth pieces of analysis across the range of performance areas. Examples of our publications over the last five years include:

- An external report on the level of risk preparedness demonstrated in local lines companies' asset management plans.[7] This was published in 2019 and was intended to further the conversation on risk and resilience with regard to information that is readily available for interested stakeholders.
- A review of local lines companies' asset management reporting, completed in 2021.[8] This review aimed to encourage improved asset management by ensuring that asset management plans include a high standard of communication to stakeholders about issues relating to reliability, and local lines companies' planned response to addressing such issues. The resulting report highlighted examples of best practice reporting and instances where we considered the discussion could be improved.
- A report in 2021 reviewing local lines companies' asset management plans in relation to decarbonisation's impact on network services.[9]
- In April 2024, we completed the review of the 2023 asset management plans (AMPs) of EDBs. EDBs are required to publicly disclose AMPs which provide a forward-looking

[4] Commerce Commission "Electricity distributor performance data".
[5] Commerce Commission "Performance Accessibility Tool for electricity distributors".
[6] Commerce Commission "Performance summaries for electricity distributors".
[7] Commerce Commission "Review of asset management plans".
[8] Commerce Commission "Reporting of asset management practices by electricity distributors".
[9] Commerce Commission "Review of Electricity Distribution Businesses' 2021 Asset Management Plans in relation to decarbonisation - Summary paper" (18 November 2021).

view of how EDBs plan to invest in, maintain and operate their networks. The AMPs include forecast expenditure for the next 10 years and set out EDBs' approach to issues such as climate change and resilience planning.[10] We engaged Innovative Assets Engineering (IAEngg) to undertake the review of the 2023 AMPs. We have published the reports by IAEngg about EDBs' forecasting and planning methodologies, the current AMP disclosure requirements, and EDBs' resilience planning.[11]

- We recently engaged Cambridge Economic Policy Associates (CEPA) to produce a reported titled "EDBs Productivity study". The report assesses the productivity of Aotearoa's local lines companies over the 2008-2023 period. This supports our priority to help customers and other stakeholders to understand how local lines companies are performing. This includes understanding their productivity performance, which can encourage the industry to improve performance at a further level.[12]

- As well the analyses above, we have also reviewed the ID requirements and made changes:

  - In November 2022, we completed Tranche 1 of the Targeted Information Disclosure Review (TIDR). Tranche 1 imposed new requirements on local lines companies to improve the availability of performance information to customers and stakeholders. These new requirements are intended to provide greater transparency on how companies manage their assets, their preparation for the impact of decarbonisation and the quality of service to customers.[13]

  - In February 2024, we completed our TIDR (2024) which requires EDBs to disclose new and improved information about their performance and to ensure that ID requirements remain fit for purpose in a changing environment. Our focus for this review was information on quality, decarbonisation, and asset management, as well as aligning our ID requirements with other regulatory rules.[14]

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10 Commerce Commission "Review of asset management plans".

11 Innovative Assets Engineering (prepared for the New Zealand Commerce Commission) "NZ EDB 2023 AMP Review – Forecasting and Planning Assessment Report" (29 January 2024).
Innovative Assets Engineering "EDB 2023 AMP Review – Consultant Report – AMP Information Disclosure Requirements Review" (22 February 2024).
Innovative Assets Engineering (Prepared for the New Zealand Commerce Commission) "NZ EDB 2023 AMP Review – Resilience Assessment Report" (17 April 2024).

12 Commerce Commission "Productivity and efficiency study of electricity distributors".

13 Commerce Commission "Targeted information disclosure review for electricity distribution businesses".

14 Commerce Commission "Targeted information disclosure review for electricity distribution businesses".

Chapter 2: Our key findings

Purpose of this chapter

This chapter discusses the key findings across our range of trends analysis. These key findings are based on the nation-wide averages, although we have also provided some detail on individual local lines companies. The experience will also be different for different customers, as the averages cover all customers from small residential customers to large industrial customers.

Since the last Trends Report, the key changes over the last two years were higher inflation which affected the value of EDBs' assets the impact of severe weather events on the number of outages. These events include Cyclone Gabrielle and the Auckland Anniversary flooding in 2023.

On average, we found that the amount of profit that local lines companies receive from each customer had remained roughly the same for the period 2008 to 2020, with a reduced level of profit in 2021. However, over the last two years, the value of local lines companies' assets increased significantly, in line with higher than usual inflation, which is recorded as profits.

Overall, when compared to the inflation-adjusted cost of capital, local lines companies made profits in line with expectations set by the regulatory regime.

Rising costs meant that customers were paying $229 more per year in 2023 than in 2008. However, if costs are adjusted for inflation, customers paid $155 less in 2023 than in 2008. This is equivalent to an increase of 26% in nominal terms, and a reduction of 12% after adjusting for inflation. The increase was greatest from 2008 to 2015, and then slowed for a variety of reasons including lower inflation and lower finance costs until 2020, before dropping back to near-2012 levels in 2021. However, the figure rose again in nominal terms during the years 2022 and 2023 when inflation was higher than usual.

Of this increase of $229, around 40% of it ($93) relates to cost increases that local lines companies have passed on to customers from other parties—most notably Transpower, which is recovering the costs of large investments it made in the transmission network.

The rest of the increase in what customers pay allowed local lines companies to recover their own higher costs. On average, local lines companies recovered $127 more from each customer so they could recover the costs of increased investment that they made to support growth and maintain their assets. Local lines companies are spending more on running their businesses and operating their electricity networks too, resulting in a $164 average increase per customer since 2008.

The average number of unplanned power outages per customer across the industry has remained similar over this time, with the exception of the most recent regulatory year, 2023, which includes data from severe weather events including Cyclone Gabrille and the January 2023 Auckland floods. Most local lines companies have had more planned outages, and these tended to last longer than they used to. Planned outages are generally less inconvenient to customers than unplanned outages and are required for the local lines companies to undertake important maintenance and investment. One of the reasons for longer and more frequent planned outages have been the changes that local lines companies made to their health and safety practices, such as undertaking more work under power outages, rather than working on live power lines. We discuss changes in outage trends in more detail later in this report.

Except where we refer to single-year figures, or state that a figure is absolute, our analysis refers to the growth implied by the trend, rather than the absolute increase in dollars or dollars-per-customer, for the reasons explained in our Approach Paper which can be found on our website here.

Further, unless otherwise stated, the charts and figures for monetary data are given in nominal terms—i.e., they have not been adjusted to exclude the impact of inflation. In this trends report, in light of the higher inflationary environment in the 2022 and 2023 regulatory years, we have also included a number of charts. There is a small selection of charts that are clearly described as being adjusted for inflation.

Customers on average pay local lines companies $229 per year more than 15 years ago

Local lines companies' revenue has increased faster than networks have grown

In aggregate, local lines companies' revenue grew by 46% in nominal terms from 2008-2023, and 26% on a per-customer basis due to the growth in the number of customers being served.[15] The revenue growth is shown in Figures 2 and 3.

The number of customers connected to a local lines company, and the energy and peak power supplied to those customers have all grown during the same period - by 16%, 15% and 11% in total, respectively.[16] However, revenue has increased faster than these drivers of network growth, meaning customers on average have experienced an increase in price. In 2023, customers paid, on average, approximately $229 more than in 2008 (in nominal terms).[17] This is shown in Figure 3.

We have used the number of customers to represent growth in demand in this report. We estimate the number of customers by the number of installation control points (ICPs), which are the metered connections to the network.

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15 Our analysis refers to the growth implied by the trend, rather than the absolute increase in dollars or dollars per customer from 2008-2023.

16 Energy and power are closely related but are not the same physical quantity. Energy can be measured in watt-hours (or kWh, MWh, GWh etc); power is the rate of producing or demanding energy, and is measured in watts (or kW, MW, GW etc).

17 New customers may also have paid an upfront amount to help fund their connection to the network, as we discuss later.

The trends would largely be the same if we had instead used energy (kWh) or peak (power) demand (kW) as measures of growth.[18]

Local lines companies' nominal revenue has fluctuated over time

Figure 2 shows that local lines companies' annual revenue has decreased in nominal terms in 2021 before rising again in 2022 and 2023. Both Figures 2 and Figure 3 show that total revenue and average revenue per-customer fell by more than 10% from 2020-2021 before rising again in a higher inflationary environment in 2022 and 2023. Between 2020 and 2023, total revenue fell by 3% and revenue per-customer fell by 7%.[19]

The decrease in 2021 was mainly because of the maximum revenue limits set out in our price-quality paths, which generally decreased in 2021 after we reset default price-quality paths for price-quality regulated lines companies.[20] The Commission is in the process of setting default price-quality paths (DPPs) for the five-year period starting on 1 April 2025, with the decision due in November 2024.

Figure 2: Total revenue and trend for all local lines companies, 2008-2023

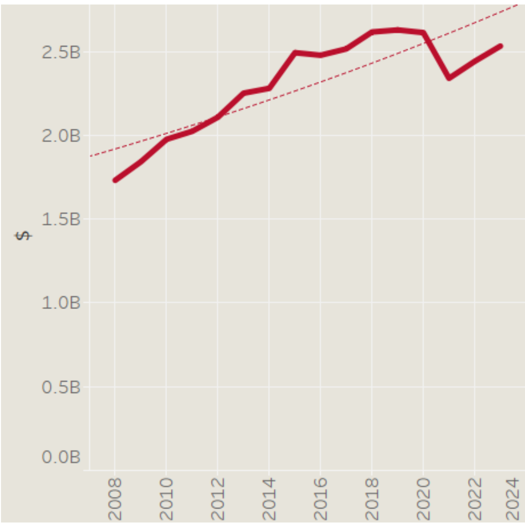
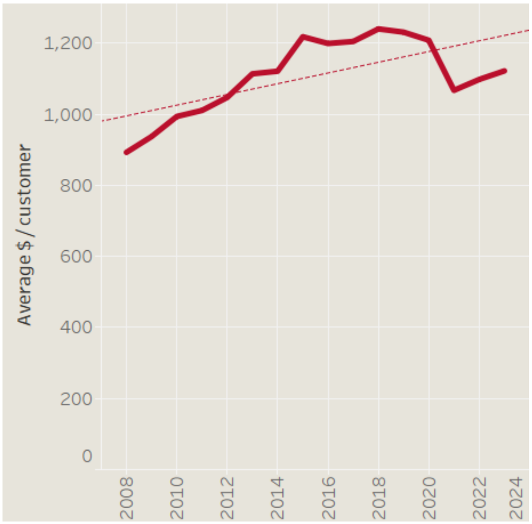


Figure 3: Average revenue per-customer and trend, 2008-2023



Local lines companies' revenue per-customer has decreased in real terms

Some of the nominal increase in revenue reflects general price pressures that impact across the whole economy. Local lines companies' annual revenue grew by 46% in total, or by $229 per-customer, in nominal terms. After adjusting for inflation using the consumer price index,

18 We have chosen to use ICPs in preference to kWh or kW, though variation in the energy used by each customer will mean this does not allow a full appreciation of the rate of change in the 'use' of a network in all cases.

19 It may seem counterintuitive that profit is going up while revenue is going down. This is due to the nature of our regime that allows price-quality regulated suppliers to index the value of their assets to inflation. In a high inflation environment, it means the value of assets of regulated suppliers increase which is reported here as profit.

20 More information on price-quality regulation—including which local lines companies are covered by it—is provided on our website. See Commerce Commission "Our role in electricity lines".

revenue decreased by 12% in total, with an overall annual reduction of $155 per-customer in real terms.

Figure 4 shows the. Inflation has varied over time and had a rapid increase in annual over two years from 2021 to 2023. This is shown in Figure 4, which gives the annual rate of inflation, as described by Statistics New Zealand's consumer price index.

Figure 5 shows the rate of change in local lines companies' revenue after removing the effects of inflation. This shows that local lines companies' revenue has fluctuated significantly from year-to-year. The percentage change in revenue steadily declined to 2021, with an increase from 2021-2023.

Figure 4: Annual rate of inflation

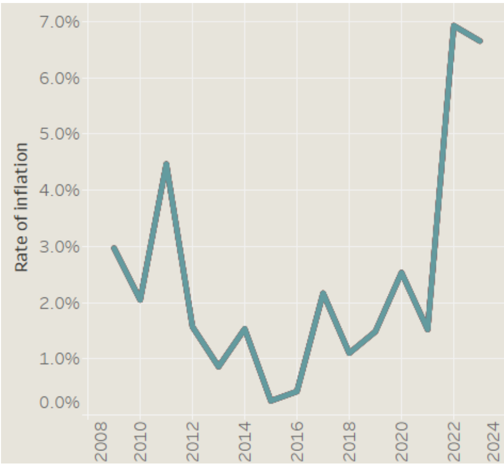
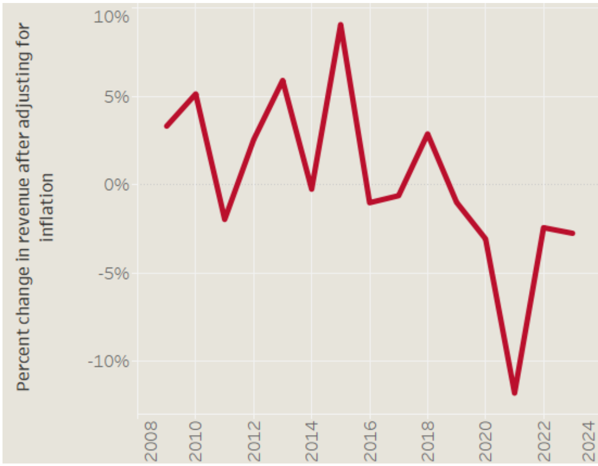


Figure 5: Change of local lines companies' revenue after adjustment for inflation



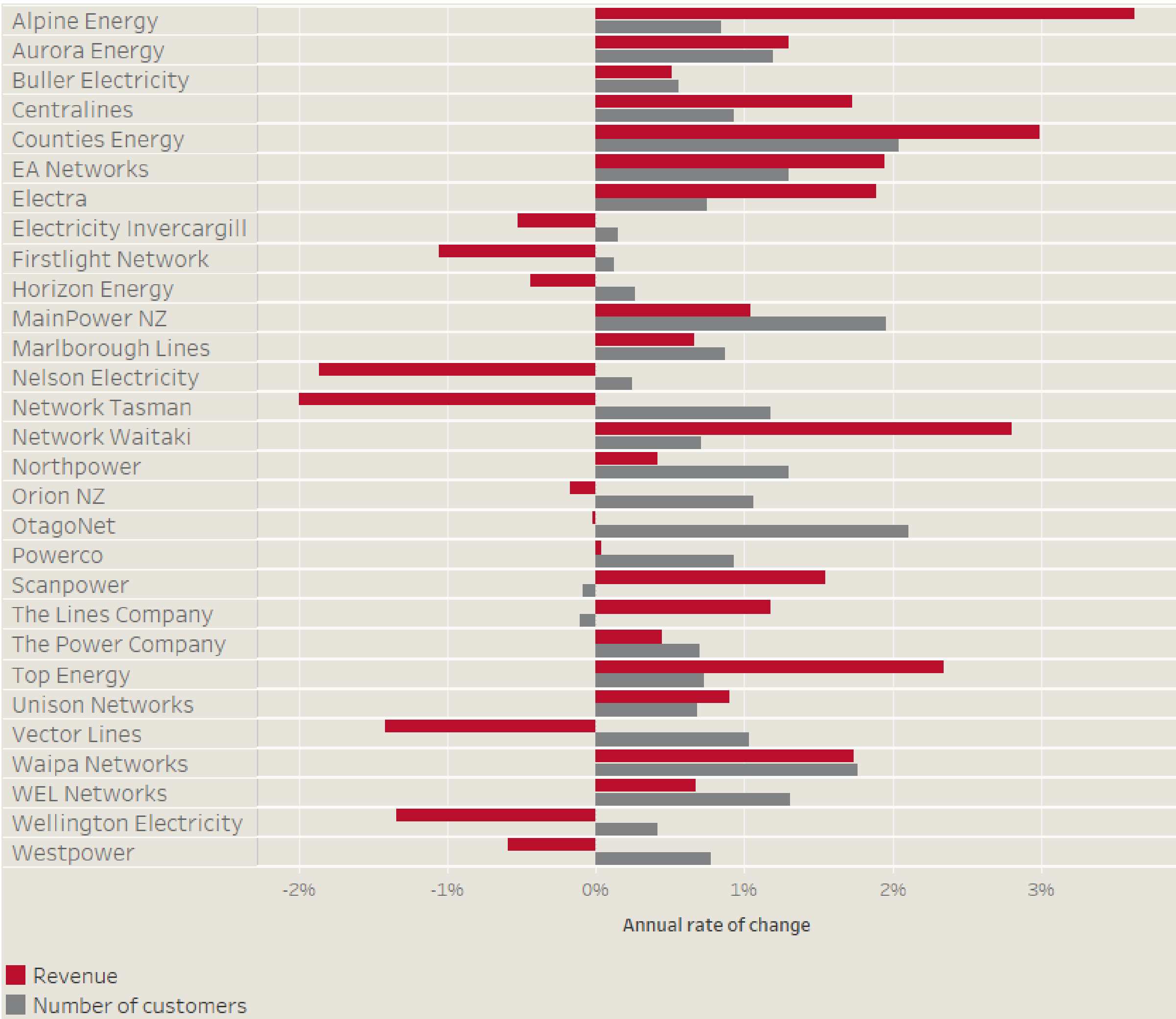
We first set price-quality paths for price-quality regulated local lines companies in 2010 and reset them again in 2013 and 2015. [21] Step-change increases in revenue are evident in each of these years, as we had sought to allow each supplier's forecast revenue to align with their reasonable forecast costs. We typically allow for any significant realignment in the first year of the regulatory period, with only changes in line with inflation allowed in subsequent years of the price-quality path. While the values in Figure 5 include local lines companies that are exempt from price-quality regulation, the price-quality regulated local lines companies dominate the results because they include the largest companies. The price-quality regulated local lines companies earned 80% of the total revenue out of all local lines companies from 2008-2023.

[21] More information on price-quality regulation—including which local lines companies are covered by it—is provided on our website. See Commerce Commission "Electricity lines price-quality paths".

Revenue growth varies across local lines companies

Each local lines company's rate of revenue growth has differed quite significantly. Some local lines companies have had their revenue increase faster than their increase in customers, and some companies have not. This is shown by Figure 6, which shows the annual rate of revenue growth in constant 2023 dollar terms (red bars), along with the rate of annual customer growth (grey bars).[22] It covers a shorter period (2010-2023) due to data limitations.[23]

Figure 6: Annual rates of change of revenue (adjusted to account for inflation) and customers by local lines company, 2010-2023



[22] The annual rate of revenue growth refers to the average annual change in the trend rather than the average of each annual change.

[23] This analysis uses the period from 2010 rather than 2008 because Vector's sale of assets to Wellington Electricity affects the results for those businesses.

Figure 6 above shows that the annual average revenue growth (adjusted to remove the impact of inflation) has ranged from 3.7%for Alpine Energy (61% over the 13 years since 2010) through to an annual decrease of 1.9% for Network Tasman (down 22% over the 13 years since 2010).

For price-quality regulated local lines companies, the rates of growth of revenue reflect the maximum revenue limits that we imposed. For example, we allowed the increase for Top Energy to allow for a normal return and because of their need for revenue to fund the necessary investment programme. Similarly, the decrease in revenue by Vector is reflective of significant restraints on revenue that we introduced in 2013 to limit excessive profits.

Local lines company revenue funds five primary components

Line charges provide local lines companies with revenue that allows them to recover five high-level components:

- costs for services provided by other parties—most notably Transpower. The local lines companies 'pass-through' or recover these costs by bundling them into line charges and passing on the funds they receive from customers (via retailers) to the parties providing the services, without any mark-up[24]
- a component they retain as a cash profit[25]
- tax - which is primarily driven by taxable profit[26]
- depreciation— which represents the recovery of capital expenditure invested in the local lines company over the assets' lifetimes, and
- operational expenditure—which are costs that are borne by the local lines company and relate to the services that the company provides using its assets.

Figures 7 and 8 show for all local lines companies in aggregate, the breakdown of revenue into these high-level components, and how those components have varied over time in nominal terms. Figures 7A and 8A, show the real changes for these components.

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24 As well as the costs of transmission services, these also recover costs for services provided by the system operator, rates, and various levies, amongst other ancillary items.

25 In this report, the term 'cash profit' does not strictly refer to cash, but is used to refer to profit excluding non-cash gains that are made from the increase in value of assets due to inflation. These non-cash gains are termed 'revaluations' in our regulations, and are a significant component of total profit.

26 Our analysis only identifies the corporate income tax owed by the local lines companies. It does not include taxes paid by Transpower or other parties on any funds passed through to them, nor does it include the GST component of customer bills.

Figure 7: Breakdown of revenue (in nominal terms), 2008-2023

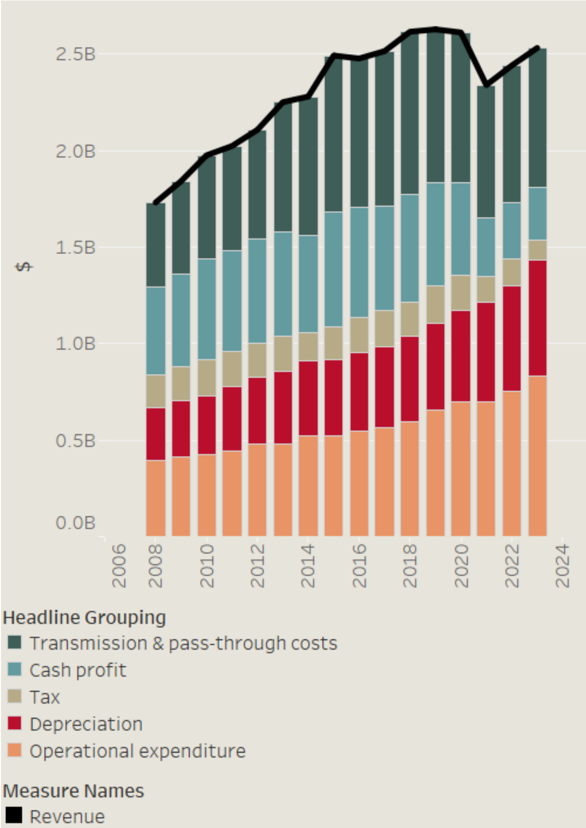


Figure 7A: Breakdown of revenue (in real terms), 2008-2023

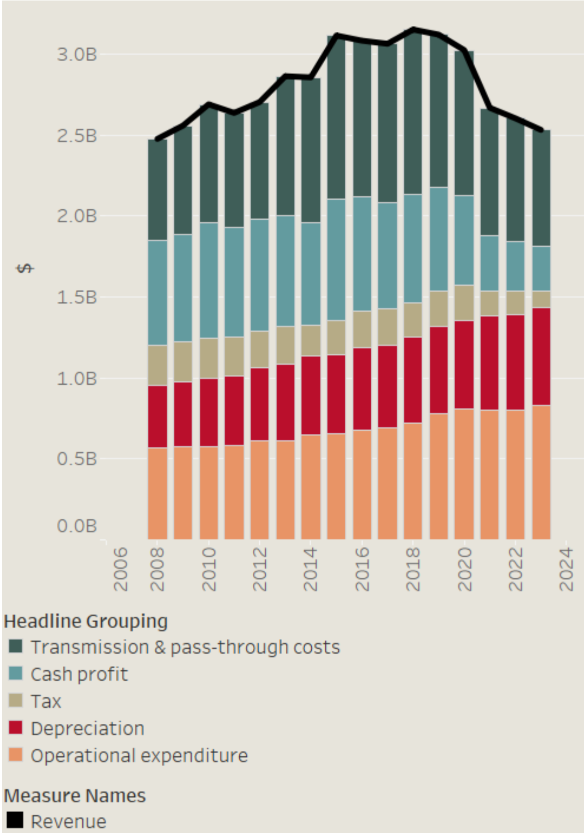


Figure 8: Change in components and trends (in nominal terms), 2008-2023

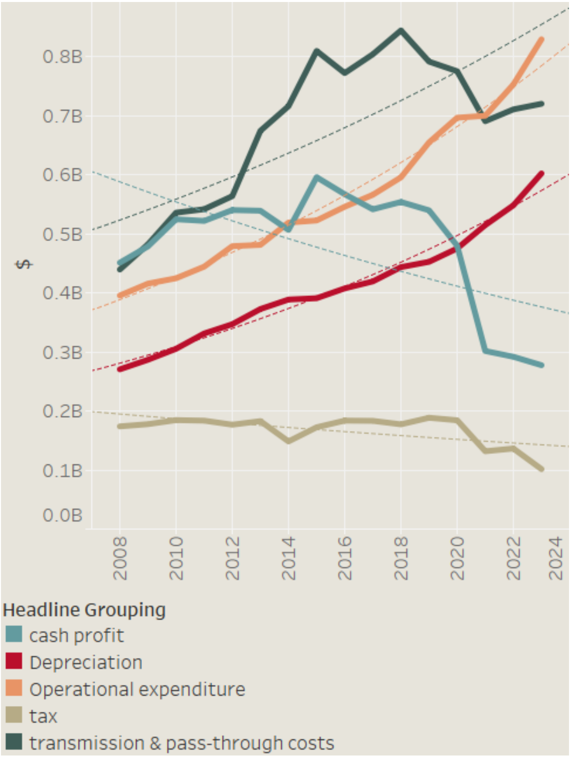
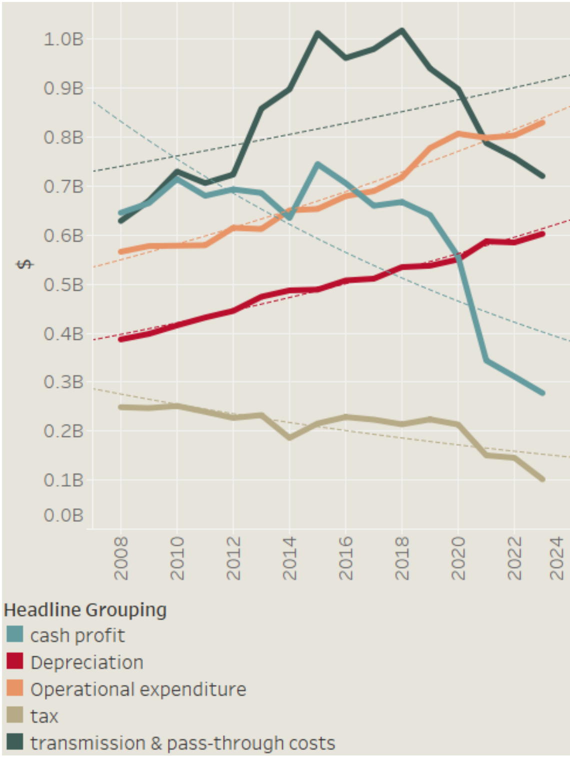


Figure 8A: Change in components and trends (in real terms), 2008-2023



These figures highlight that depreciation is the fastest growing component of revenue in percentage terms, for these local lines companies. Depreciation increased at an annual rate of 5.5% in nominal terms from 2008-2023, or 3.0% in real terms, reflecting capital expenditure on new assets during this period.[27] Around 18% of all revenue over the period went towards depreciation. Over the 15 years since 2008, depreciation has risen by around 123% or $332 million in nominal terms. In real terms, depreciation has risen by 56% or $215 million.

Transmission and other pass-through costs were the largest component of local lines companies' revenue from 2008-2023 at 30%. In nominal terms, this is increasing at an annual rate of 3.3%, or by $281 million over the 15 years since 2008 and in real terms, at an annual rate of 0.9% or $91 million over the same period.

Operational expenditure comprised a smaller proportion of revenue over the period, at around 24% of all revenue. Operational expenditure has increased consistently over the period at an annual rate of 5.1% in nominal terms, or around $434 million in total over the 15 years since 2008. In real terms, operational expenditure has increased annually by 2.6% or $264 million in total.

Cash profit has declined at an annual rate of 3.2%, in nominal terms falling by $174 million over the 15 years since 2008. In real terms, cash profit has declined at an annual rate of 5.5% or $368 million over the same period.

Tax, in nominal terms, has declined at an annual rate of 3.5%, falling by $72 million over the 15 years since 2008, reflecting the changes in profit combined with reductions in the corporate tax rate.[28] In real terms, tax has declined at an annual rate of 5.8% or $147 million over the same period.

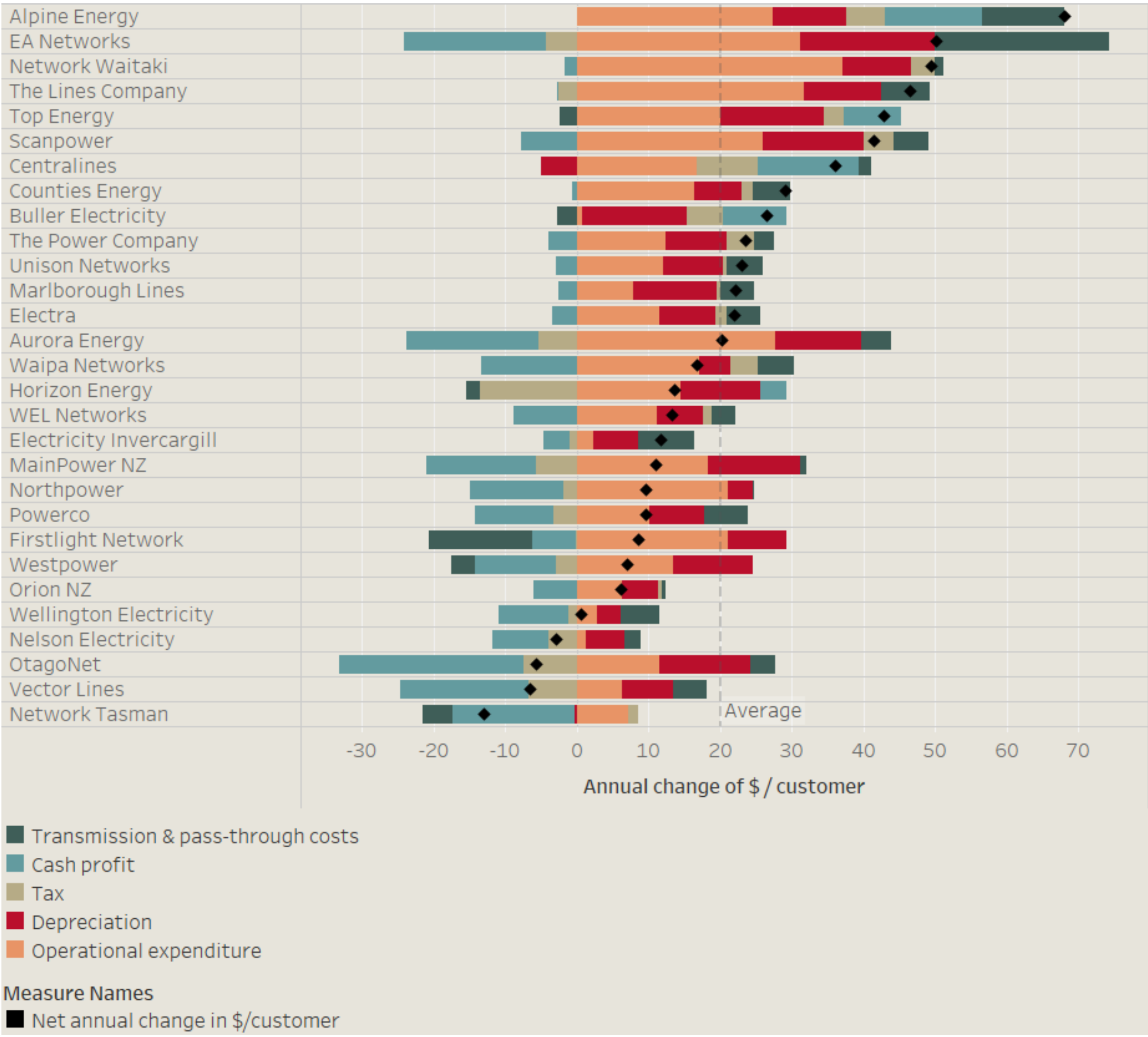
The particular components exerting cost pressure differ for individual local lines companies. This is shown in Figure 9 for 2010-2023. This figure gives the average annual per-customer change in revenue for each local lines company in nominal terms.[29] This is broken down into the same components as Figures 7 and 8. Figure 9 shows that those local lines companies that have experienced the greatest rate of revenue growth have tended to have had increases in each cost component, shown by a stacked bar extending to the right. Other local lines companies have had average annual increases in some components (bars extending right) offset by decreases in others (bars extending left). The net annual average change in revenue per-customer is given by the black diamond, with companies arranged in decending order of the magintude of that change.

27 Changes in capital expenditure are discussed in more detail from page 26.

28 The corporate tax rate was reduced from 30% to 28% from the 2011 tax year (i.e., also ending 31 March).

29 The annual rate of revenue growth refers to the annual change inherent in the trend rather than the average of each annual change.

Figure 9: Trend in cost categories (dollars per-customer, by local lines company, 2010-2023)



Around 40% of the increase in network prices is due to cost increases for transmission services

Around 30% of local lines companies' revenue has paid for the costs of services provided by other parties. These costs, which the local lines companies pass-through to customers without any mark-up, are responsible for close to 40% of the total increase in average revenue per-customer. In 2023, customers on average paid around $93 more per year, in nominal terms, towards these costs than they did in 2008.

Around 90% of these pass-through costs are from Transpower. Transpower owns and operates the transmission network. Like local lines companies, we regulate how much revenue Transpower can earn, sufficient to recover its reasonable costs and receive a fair return on the capital it employs. Transpower collects this revenue by charging its transmission customers, which are local lines companies and a handful of very large industrial electricity users like New Zealand Steel. The local lines companies then pass these costs on to their customers.

A further 6% of pass-through costs are from distributed generation.[30] These costs are payments that local lines companies make under contract to some generators that are connected to their networks, relating to transmission charges the generator helps the local lines company to avoid. From a customer's perspective, these costs are a de facto transmission cost.

The remaining 4% of pass-through costs are split amongst several other parties.[31]

From 2008-2018, the costs that local lines companies have passed on from Transpower for transmission services increased from $415 million per year to over $753 million per year. More recently, transmission pass-through costs have decreased, in both nominal and real terms, as shown in Figures 10 and 10A.

Figure 10 also shows that payments to distributed generators increased materially in nominal terms from $22 million in 2008 to over $60 million in 2014 but have since steadily decreased to $36 million in 2023.[32] In real terms, as shown by Figure 10A, this increase was from $32 million in 2008 to over $77 million in 2014, decreasing to $38 million in 2023.

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30 Distributed generation is generation that is connected to a local lines company's network, as distinct from generation that is connected directly to the transmission network. Distributed generation tends to be relatively small-scale.

31 These include costs for services provided by the system operator, rates, various levies including those applied under the Commerce Act, amongst other ancillary items.

32 Some of this decrease reflects intervention by the Electricity Authority, who assessed that the payments did not always relate to avoided economic costs, and rather shifted transmission charges to customers on other networks. In December 2016, the Electricity Authority decided to amend the Electricity Industry Participation Code 2010 so that distributed generation that does not efficiently defer or reduce grid costs (i.e., economic costs) would no longer receive these payments under regulated terms. Subsequently, the Electricity Authority has decided to remove these payments entirely from 1 April 2023.

Figure 10: Total transmission, distributed generation and other pass-through costs (in nominal terms), 2008 -2023

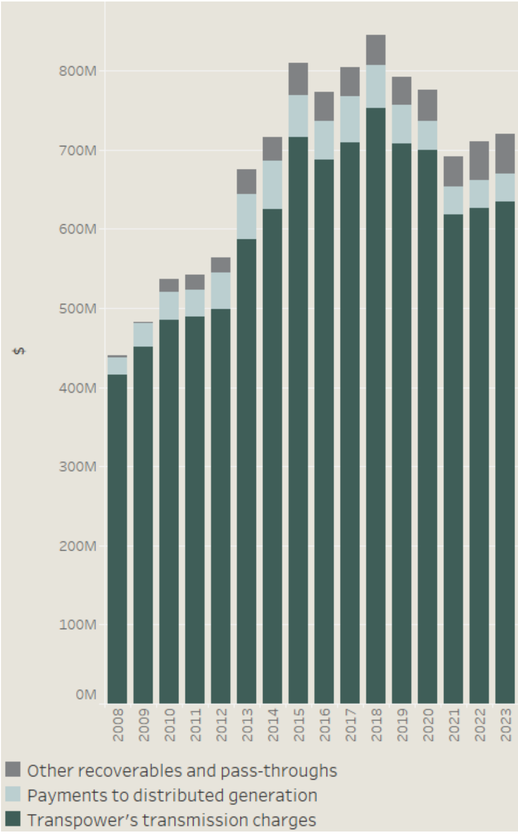
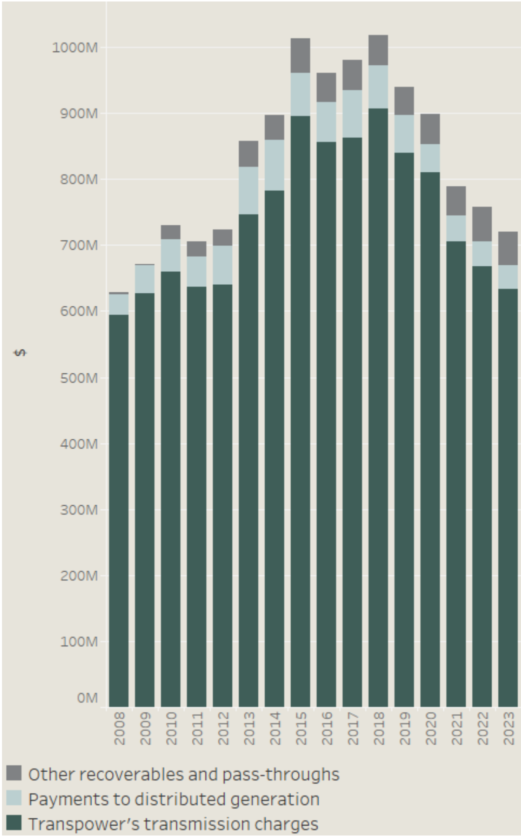


Figure 10A: Total transmission, distributed generation and other pass-through costs (in real terms), 2008 -2023



The increase in costs passed through from Transpower allowed Transpower to pay for several major capital projects that it carried out during the period (up to 2018). These projects were approved by the former Electricity Commission.[33] Notable projects include:

- the 'North Island Grid Upgrade' project which cost around $900 million and was approved in 2007 and commissioned in 2012
- the 'HVDC pole 3' project which cost $670 million and was approved in 2008 and commissioned in 2013
- the 'North Auckland and Northland' project which cost $470 million and was approved in 2009 and commissioned in 2014, and
- the 'Bombay Otahuhu Regional major capex project' which cost $35.9 million and was approved in 2021 and commissioned in 2023.

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[33] The Electricity Commission was disestablished in 2010, with the Commerce Commission taking over responsibility for setting an individual price-quality path for Transpower, and assessing and approving major capex proposals.

In total, from 2008-2023, the value of Transpower's regulated asset base more than doubled—increasing by just under $3 billion in nominal terms.[34] [35]

Some parts of the transmission network have a discernible customer, and Transpower charges those customers directly for the relevant assets. However, the majority of Transpower's costs—including the costs of the major capital projects listed above—relate to the shared transmission network. During the analysis period the costs of most shared assets were allocated across transmission customers based on their contribution to periods of peak demand on the transmission network.[36] The cost of the high voltage inter-island link was borne by generators. Because Transpower's increased costs were shared broadly across local lines companies, the average customer represented by each local lines company will have been similarly impacted.

However, it will not have been an even impact because there have been changes in the extent to which local networks rely on the transmission system when it is experiencing peak demand. Peak demand on the transmission system has remained broadly the same throughout the data period, but increased contributions to peak demand from some local lines companies have been offset by decreased contributions from others. Changing contributions will depend on:

- changes in demand from customers, for example, due to the number and type of customer connections and disconnections, changes in energy efficiency, and changes in incentives or disincentives to use electricity at times of peak demand, and
- changes in the amount of distributed generation on local networks, which reduces the need for electricity to be delivered by the transmission system. This may have reduced the transmission costs that a local lines company attracts but may also have increased their payments to distributed generation.

Figure 11 shows the average cost of transmission services per-customer—including Transpower charges and payments to distributed generation—for each local lines company between 2010-2023 (left-hand side). It also shows the annual rate of change in these costs (right-hand side) implied by the trends over 2010-2023.[37] The chart on the right-hand side presents the annual change in dollars per-customer rather than percentage change and the other annual-change charts in this report do the same unless we explicitly state otherwise.

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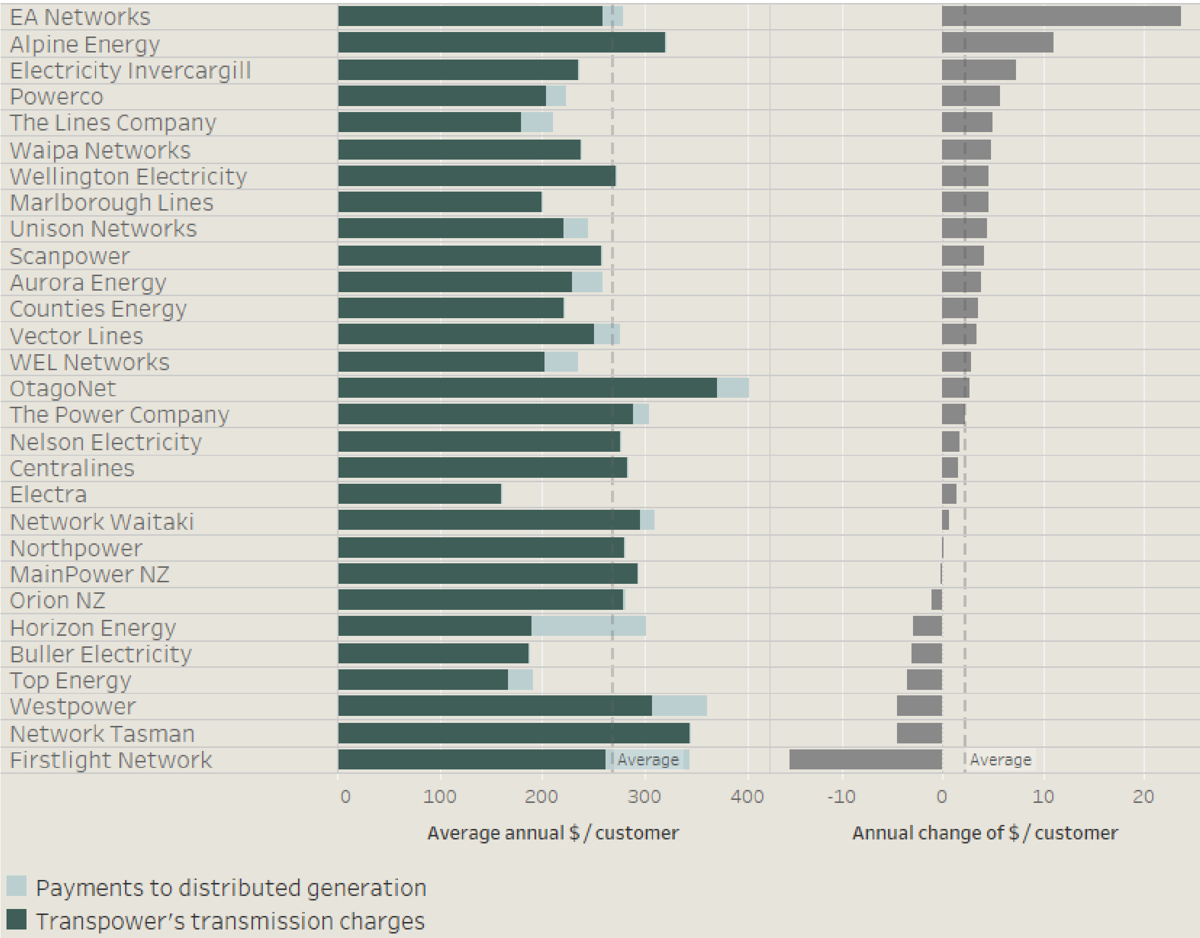
[34] The regulated asset base, also known as RAB, is an accumulation of the value of assets that are employed by a regulated company in the provision of the regulated service.

[35] This calculation is based on Transpower's own reporting, which operates on a June year-end, whereas the other analysis in this report is based on a March year-end.

[36] The specific approach to charging changed during the period. Until 2016, Transpower's costs were allocated based on the 12 highest peak demand periods in each of four sub-national regions. In 2016, Transpower started allocating costs based on the highest 100 peak demand periods in each of two sub-national regions. Further changes will occur in the future, because the Electricity Authority adopted a new transmission pricing methodology which Transpower implemented in April 2023.

[37] We have excluded other types of costs that are passed on from third parties ('recoverable and pass-through costs') from this further analysis because they are not subject to the same cost drivers and are a minor component of total recoverable and pass-through costs.

Figure 11: Average transmission cost per-customer, and change in that cost over time by local lines company, 2010-2023



The left-hand side of Figure 11 highlights that there is generally a relatively low level of variation in the average cost per-customer for transmission services across the local lines companies.

Figure 11 shows that Firstlight Network (formerly Eastland Network) has had a notable decrease in transmission costs per-customer over the period. Firstlight purchased connection assets from Transpower and no longer pay Transpower's charges specific to those assets. However, this decrease will be offset by increases in local network costs, as the local lines companies will now incur the costs of owning and maintaining those assets.

Customers are paying more to cover the cost of increased investment

Around 18% of local lines companies' revenue was required to recover the companies' costs of investing in their networks to support growth and maintain their assets. Local lines companies recover the cost of their investments over the life of their assets through depreciation, and this is what is reflected in the lines charges paid by customers.[38]

The change in depreciation, shown by the grey portion of the bars, over time is shown in Figure 12. Figure 12A shows the change in depreciation in real terms.

Figure 12: Aggregate network costs (in nominal terms) by sub-component, 2008-2023

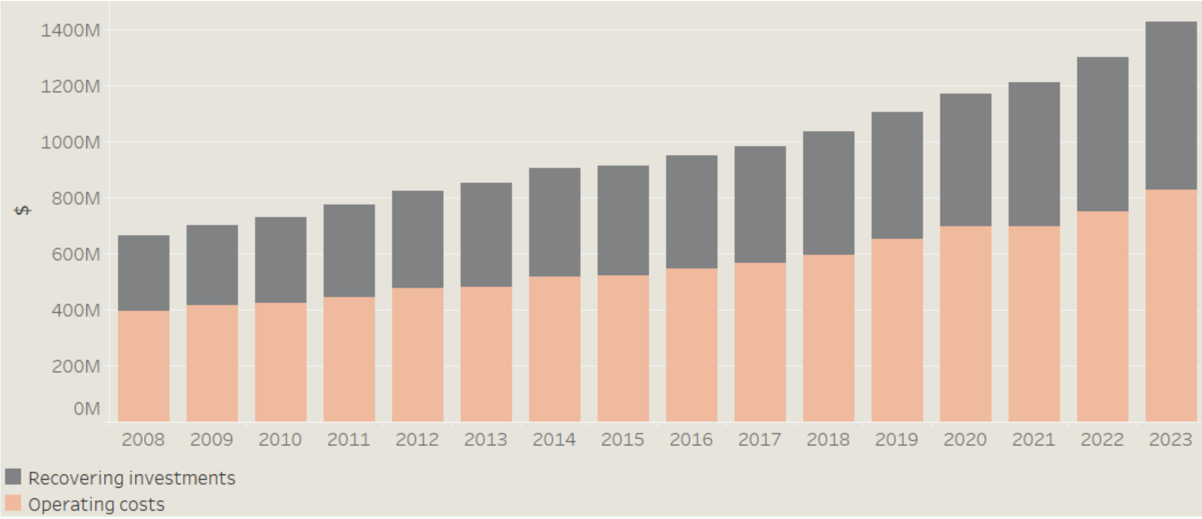
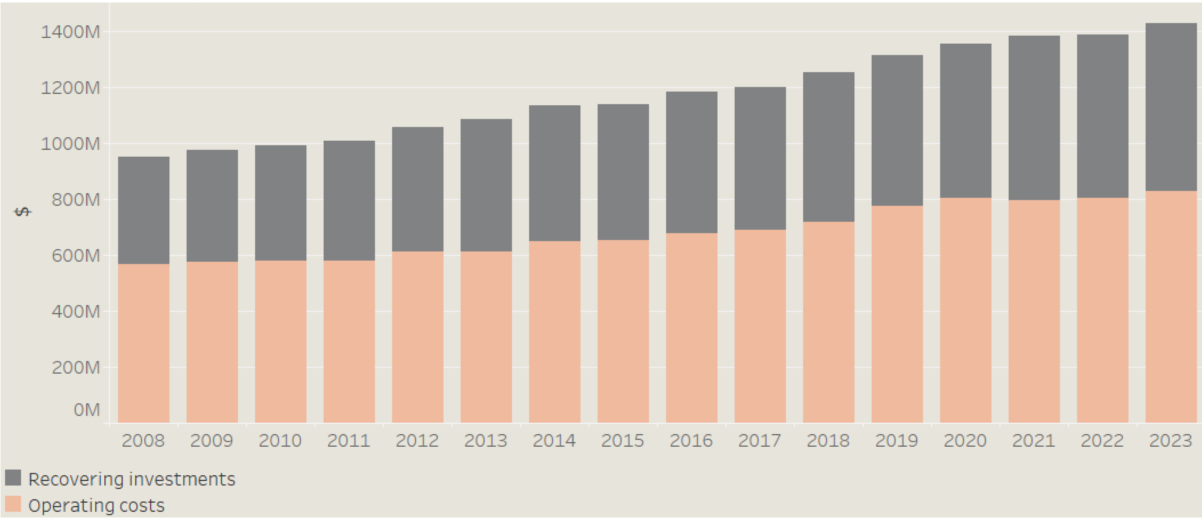


Figure 12A: Aggregate network costs (in real terms) by sub-component, 2008-2023



[38] Depreciation does not allow for a return on the capital cost of investments, which is captured in profit, discussed later.

Depreciation is higher because of increased investment in local networks

The total value of local lines companies' regulated asset base reached $15.9 billion in 2023, having increased by $8.0 billion since 2010.

This increase reflects $10.7 billion of new assets that were commissioned (including purchased assets) and gains in the value of assets of $3.8 billion, partially offset by $6.0 billion of depreciation of the asset base over time.[39]

Local lines companies need to invest in new assets to support network growth and maintain their networks. There are sub-categories of capital expenditure that fit within these broad descriptions, which we have mapped in Table 1. Figure 13 shows the expenditure that local lines companies have made under these categories since 2010.[40]

Table 1: Mapping of categories and purpose of expenditure

Category used	Capital expenditure category in ID	Purpose of expenditure
Maintaining assets	Asset replacement and renewal	Ensure asset integrity and quality of supply
	Reliability, safety and environment	Improve network reliability or safety or to mitigate the environmental impacts of the network
Support growth	Customer connection	Connect new customers or alter connections of existing customers
	System growth	Increase capacity because of changes in demand or generation on part of the network
Office and support	Non-network	Support distribution services but not part of the network itself
Other investment	Asset relocations	Moving existing assets in response to a request
	Costs of financing and value of vested assets	Technical adjustments

39 Plus, minor changes for asset disposals, lost and found assets and reallocated assets.
40 This is a shorter period due to data limitations, as not all capital expenditure was allocated to a category in 2008 and 2009.

Depreciation has remained at a consistent proportion of the total regulated asset base since 2010, as shown by the line in Figure 14. This suggests there is no significant industry-level change in the accounting life of the assets within the asset base. Therefore, higher depreciation reflects that there are more assets to recover the costs of, rather than substantially different ones.[41]

The increase in depreciation has been faster than customer connection growth. Based on the trend, each customer on average pays around $113 more per year in nominal terms than they did in 2010 for local lines companies to recover investment costs. In real terms, each customer on average pays around $61 more per year. Figure 14 gives the average amount of depreciation recovered per customer.

Figure 13: Investment in assets, 2010-2023[42]

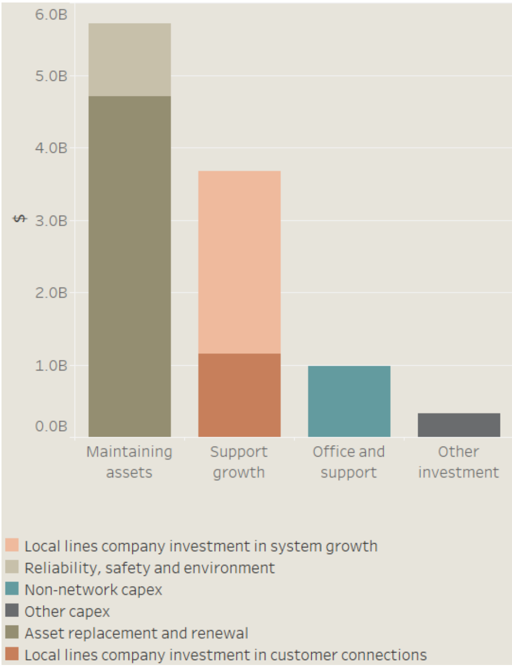
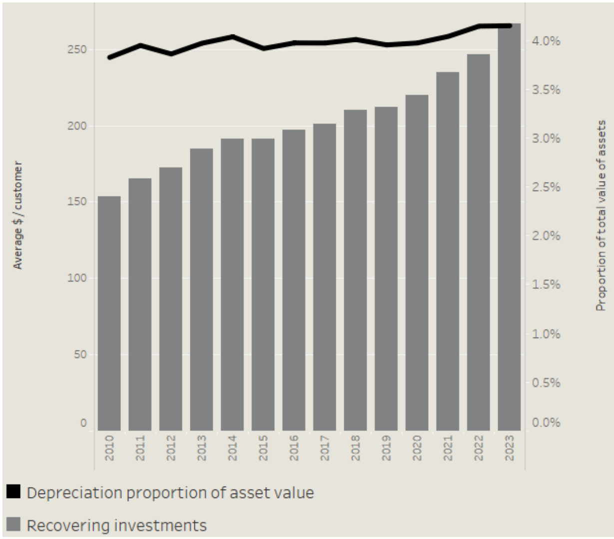


Figure 14: Total depreciation per-customer and as a proportion of total value of assets, 2010-2023



Almost all networks have been recovering more in depreciation. However, the increase has been significantly greater for some local lines companies than others. This largely reflects that some have been investing more in new assets than others. It also reflects the different characteristics and age of each network. Figure 15 shows, for each local lines company, the average depreciation cost per customer from 2010-2023, (left-hand side), and annual change in this metric implied by the trend (right-hand side).

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41 This includes assets that might have been fully depreciated within the regulatory accounts for some time, and have been subsequently replaced with new assets.

42 Local lines company investment totalled $10.7 billion from 2010-2023.

Figure 15: Trend in depreciation in $/customer by local lines company, 2010-2023

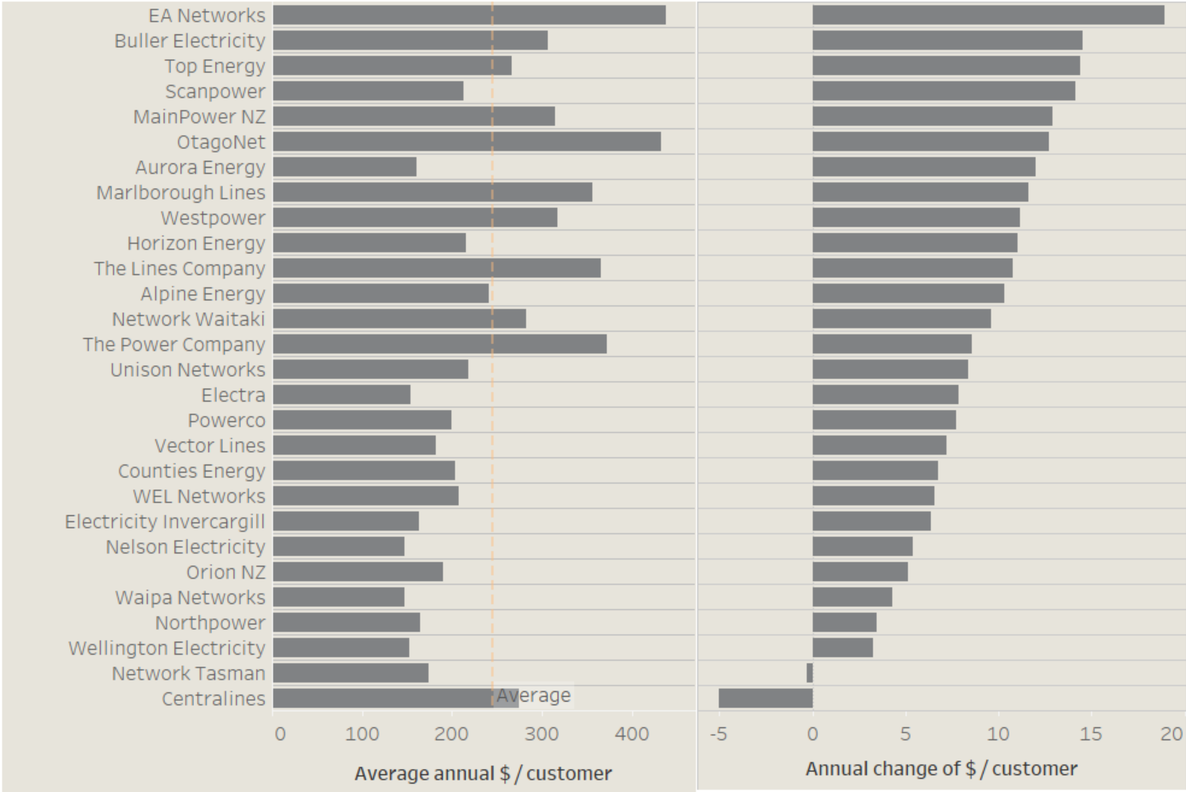


Figure 13 showed that just over a third ($3.7 billion) of the investment that local lines companies made in their assets from 2010-2023 was for supporting network growth.

Customers themselves invested a further $1.7 billion to partially cover the costs of the assets needed for them to connect to the local network or increase their demand.[43] Local lines companies are allowed to require customers to contribute financially up-front to the capital costs of connecting them to the network. However, local lines companies cannot earn any profit on the assets that customers fund, and they are required under ID to disclose their methodology on their websites for determining the level of the customer contribution.

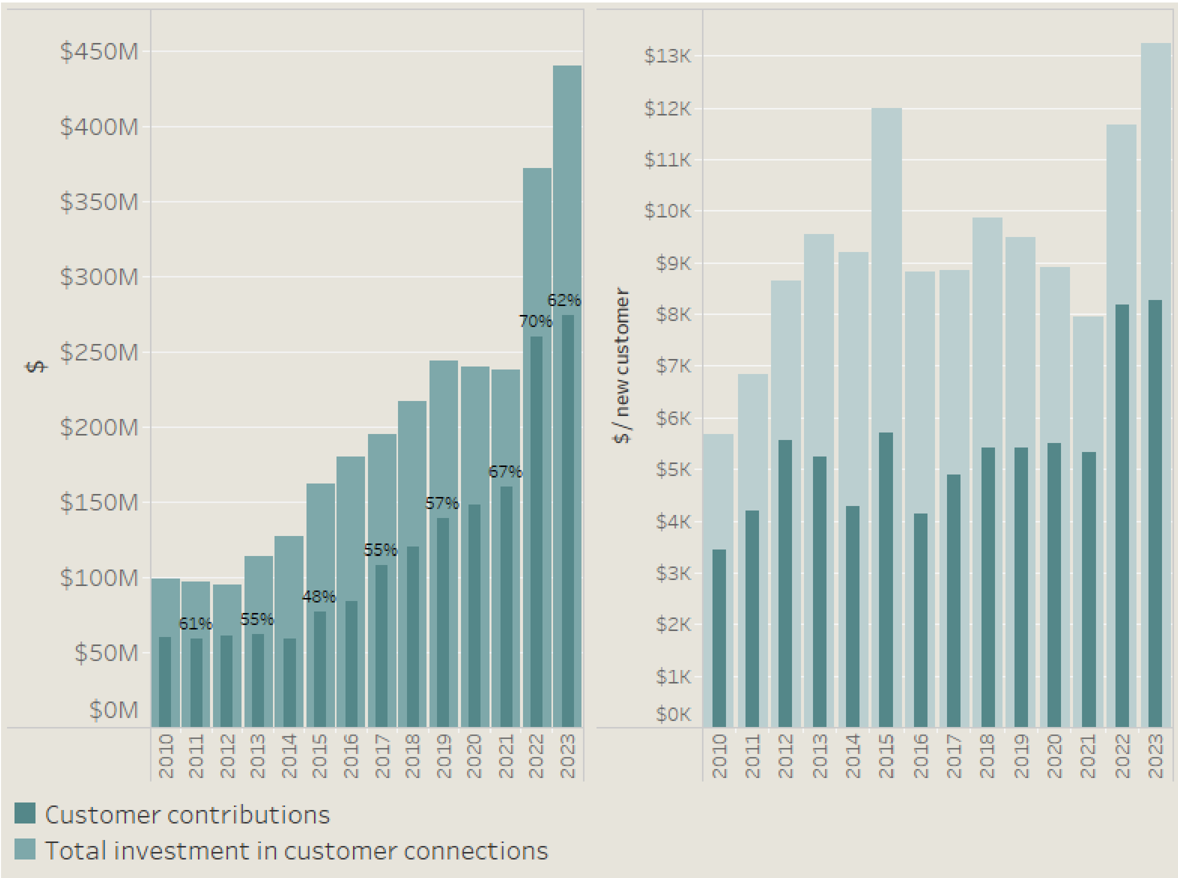
Expenditure to support network growth includes two categories of capital expenditure – 'customer connection' expenditure (the direct costs of connecting new customers) and 'system growth' expenditure (costs associated with growing use of the network).

[43] They may face further costs for assets on their own property that are not owned by their local lines company.

Figure 16 shows aggregate expenditure on customer connections since 2010, and the proportion made up by capital contributions made by customers.[44] Figure 17 also shows these same costs spread across the new connections that were added.[45]

Figure 16: Customer connection expenditure and customer contributions, from 2010-2023

Figure 17: Customer connection expenditure and customer contributions per new connection, from 2010-2023



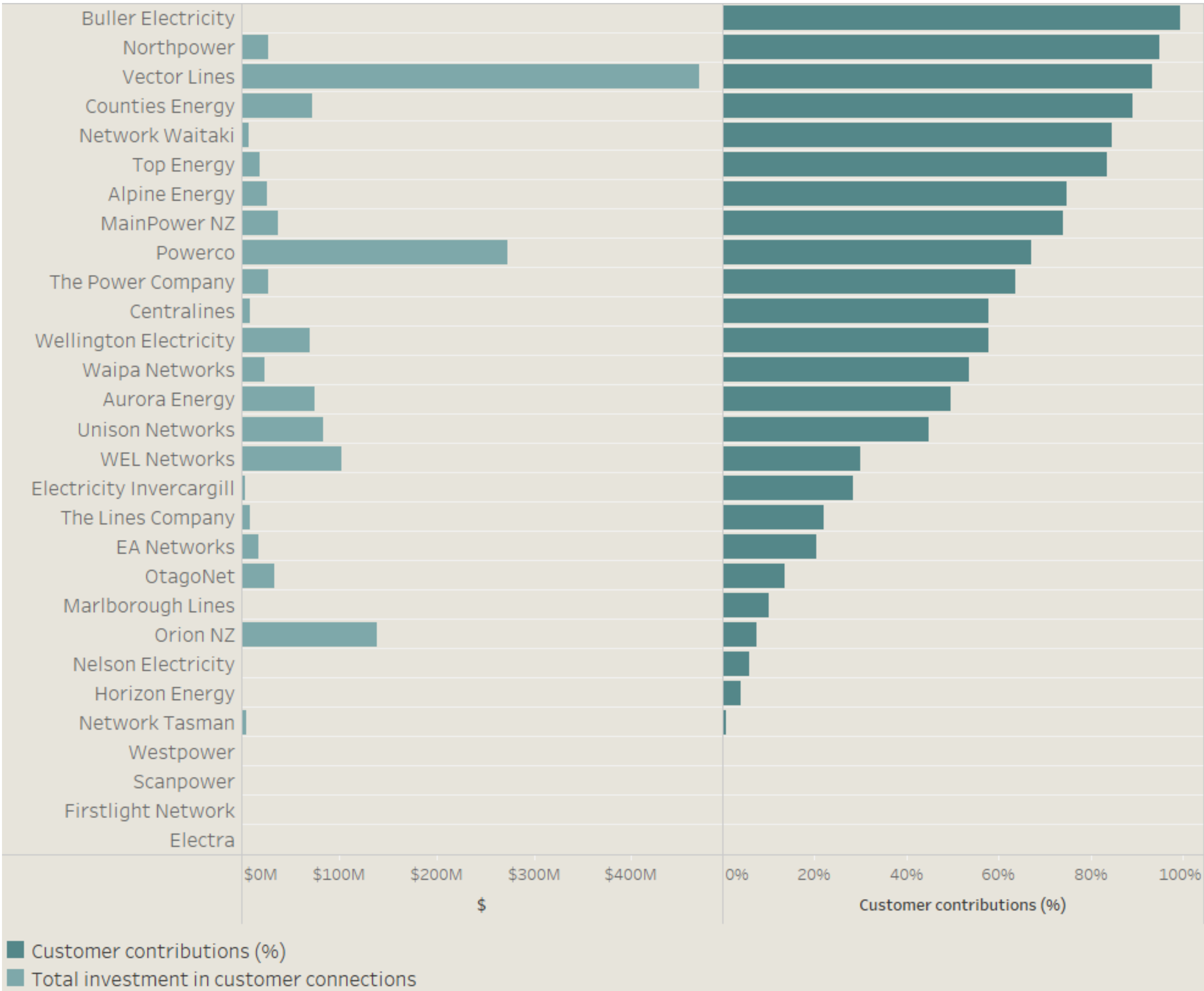
44 We have estimated the share of the investment met by capital contributions for all local lines companies from 2010-2012, assuming that the proportion of total capital contributions that are for customer connection has remained consistent through-out the data period. The same approach has been applied to the investment met by capital contributions in 2013 for Alpine Energy, Buller Electricity, Horizon Energy, Vector Lines, and Westpower only.

45 Figure 16 shows the customer connection expenditure and customer contributions from 2010-2023. Figure 17 shows the customer connection expenditure and customer contributions per new connection from 2010-2023. The percentages are calculated by dividing the second by the first after aggregating to an industry level. On the other hand, Figure 18 presents the total investment in customer connections and average percentage of customer contribution from 2019-2023. Figure 18 was completed by calculating the percentage for each year and then calculating the average over multiple years. We used two different approaches to give a high-level picture of the industry in Figure 16 and Figure 17, and present the variation between local lines companies in Figure 18.

The graphs show that customer connection expenditure has increased progressively since 2012. This appears to be driven by an increase in activity, over most of the thirteen-year period from 2010-2023, with inflation also contributing from 2021-2023.

Upfront customer contributions generally cover around half of the direct costs of connection on average – a proportion that has increased slightly over time. However, this will vary by local lines company depending on their own policies.[46] Figure 18 shows that there is a wide variation between local lines companies in the proportion of customer connection investment that is covered by direct contributions from customers.

Figure 18: Total investment in customer connections and average percentage of customer contribution, 2019-2023 [47]



[46] Capital contributions are treated in the regulatory accounts as a reduction in the associated asset values. This means that the return on assets and depreciation components of revenue are lower than they would be without capital contributions.

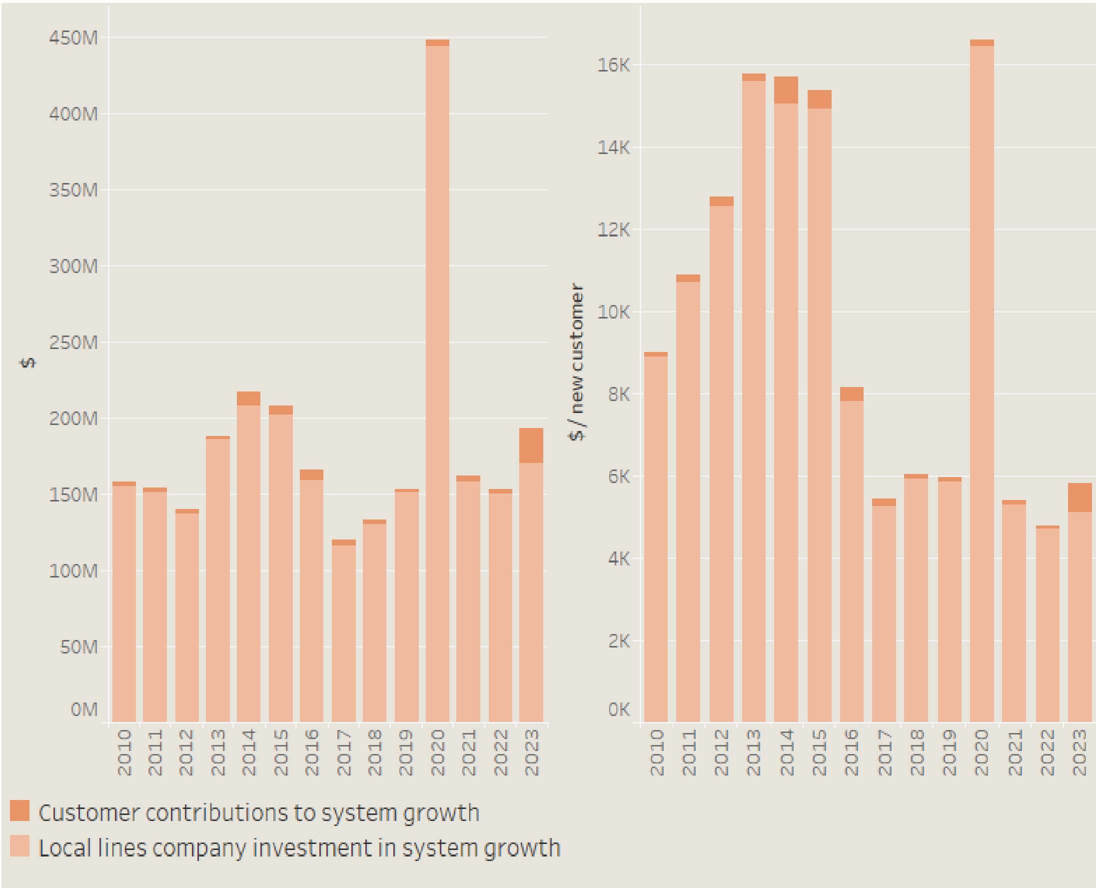
[47] Some EDBs have customer connection expenditure that is too low to be visible in Figure 18. Total investment in customer connection expenditure was: Buller Electricity ($1050k), Nelson Electricity ($287k), Horizon Energy ($1042k), Firstlight Network ($383k), Electra ($114k), Scanpower ($351k), Marlborough Lines ($854k), Westpower ($1313k).

Demand growth and new connections can cause a need to reinforce parts of the network, which may require investment in assets that are used by large numbers of customers. Figure 19 and Figure 20 show the local lines companies' 'system growth' expenditure in total and per new connection.

These graphs highlight a smaller 'bubble' of expenditure for system growth from 2013-2016, with a larger rise peaking more recently in 2020. A transaction from Vector of approximately $300 million in 2020 is included in the current representation and shows that Vector sold and leased back to itself some significant assets. This representation is consistent with the latest revised data. Around 60% of system growth expenditure was invested in zone substations and sub-transmission assets.

Figure 19. System growth expenditure and customer contributions, 2010-2023

Figure 20. System growth expenditure and customer contributions per new connection, 2010-2023



Most local lines companies will experience occasional periods of higher investment in system growth. This reflects the big step-changes in capacity that sub-transmission assets typically provide and the high costs of those investments.

Figure 21 shows, for each local lines company, their combined investment in network growth if attributed only to new connections.

Figure 21: Capital expenditure for customer connection and system growth per additional connection, from 2010-2023

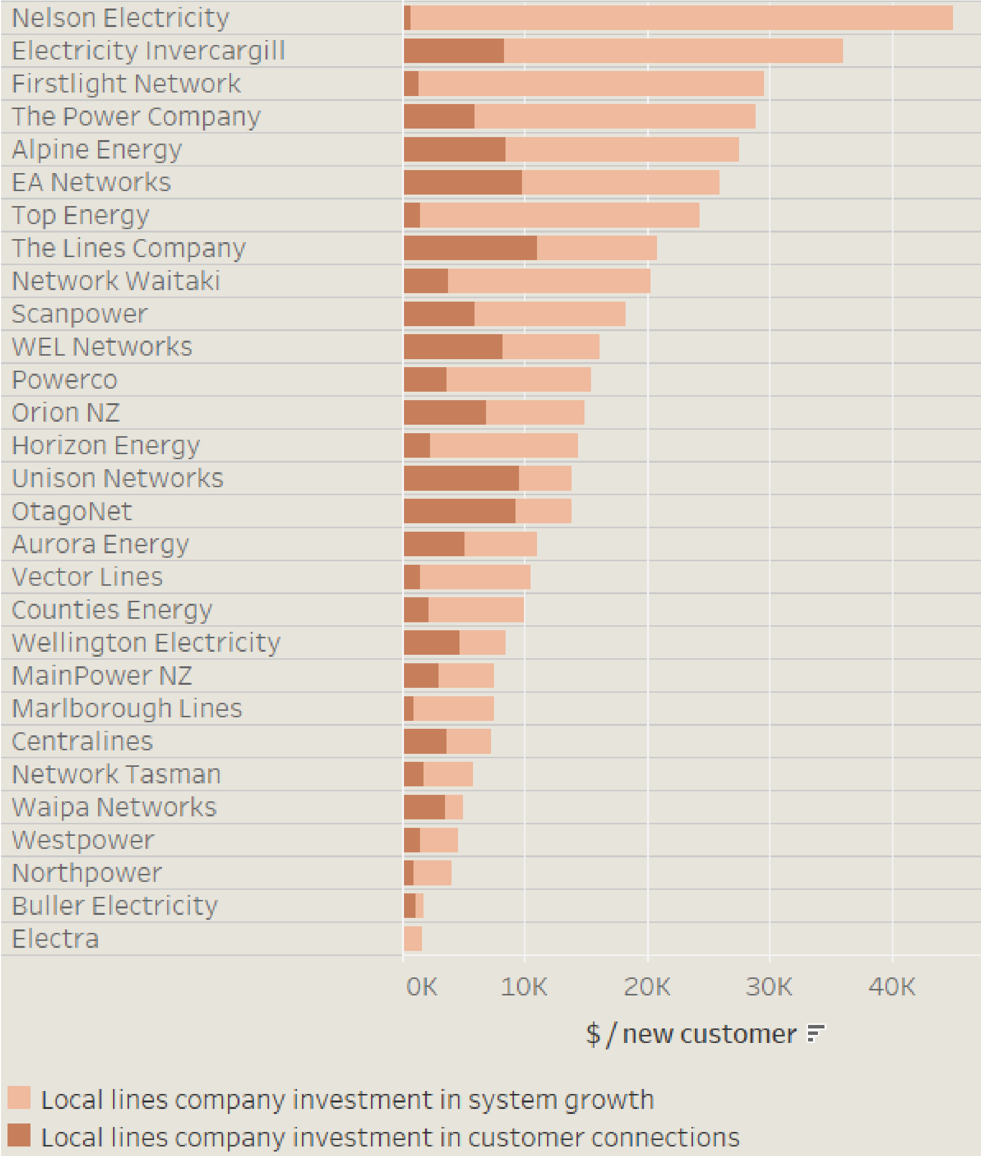


Figure 21 highlights that several local lines companies had significant expenditure on system growth relative to expenditure for additional connections. This suggests they had been in a period of reinforcing shared assets that had been nearing capacity.

System growth investment may have been necessary due to general growth in demand by all customers, increased demand from a subset of customers, or because of new customer connections.[48] Individual customers may not always cover the full incremental costs of their additional demand, which may instead be shared quite broadly. Investment increments tend

48 Based on information disclosure data, consumers in New Zealand have used an average of 15,900 kWh of energy per year and 3.1 kW of power per year since 2010 – figures that have remained virtually static over time.

to be much larger than the increment in demand that necessitated them. Also, local lines companies may not always be able to identify specifically which customers benefit from or cause a need for network reinforcement.

As an example, Nelson Electricity invested in a new connection to the transmission network—a very large investment that is unlikely to be repeated for the foreseeable future. Further, several rural local lines companies feature near the top of the graph. Network Waitaki, Alpine Energy and EA Networks are understood to have experienced growth in high-capacity connections associated with the dairy industry, necessitating broader reinforcement of those networks at a cost that may exceed the cost that is recovered from the new connections themselves.

New or altered customer connections

In November 2022, we introduced new requirements for local lines companies to report on their practices for providing new or altered connections for customers. With the increase in customer connection expenditure in recent years and the capital contributions being made by customers (as shown in Figure 16), it is more important than ever to appraise the practices of local lines companies in providing new or altered connections.

We have observed a range of performance levels across the local lines companies from the information reported in their disclosures. Overall, the reporting leaves room for improvement, particularly in reporting what the local lines companies are doing to minimise the cost for customers.

Many of the local lines companies have given a reasonable account of their process for new connections and noted that the process is also explained on their website. Some EDBs have noted that their processes, such as the application of standardised designs support the minimisation of costs for customers. We understand that some customers have found the process differences between local lines companies create inefficiencies for their own businesses, so working towards more nationally standardised designs and processes may help customers.

One practice that many local lines companies have reported on, is whether the connecting party has a choice of contractor and whether the lines company actively supports the development of a competitive contracting market. It is good to see this area covered because we agree that a more competitive contracting market is likely to improve the process for customers and reduce the costs. The reporting on competitive contracting markets shows that the detail is also important in the reporting because the detail of the local lines companies practices effect the degree to which a competitive contracting market is supported.

Another area that could help reduce the cost for customers is that only a small number of local lines companies reported on flexible service offerings. This could involve the local lines company offering a lower capacity connection, a lower security level connection, or a connection with demand management requirements.

We also consider that the local lines companies could actively monitor the costs of their new or altered connections as a key metric of customer outcomes, which may help the local lines companies identify concerns and potential improvements.

Some of the local lines companies report very little on cost minimisation strategies, and some focus on their capital contribution policy which allocates the cost (ie, is an aspect of pricing) rather than minimises the total cost to customers.

Local lines companies will be required to report their practices for providing new or altered connections again in their next full asset management plan, which is optional on 31 March 2025 and mandatory on 31 March 2026.

Local lines companies have been investing to maintain assets

Network growth also appears to have driven investment in non-network assets. These are assets that do not directly relate to delivering electricity and generally covers assets such as offices, vehicles, and IT infrastructure. Non-network assets are a small proportion of the overall regulated asset base but have increased materially over time. This is shown across all local lines companies in Figure 22. The jump in non-network asset values in 2013 appears to reflect a combination of significant investments by some companies, and changes in the way others categorised assets when we updated our ID requirements.

Figure 22: Value of non-network assets within regulated asset base for all local lines companies, 2008-2023

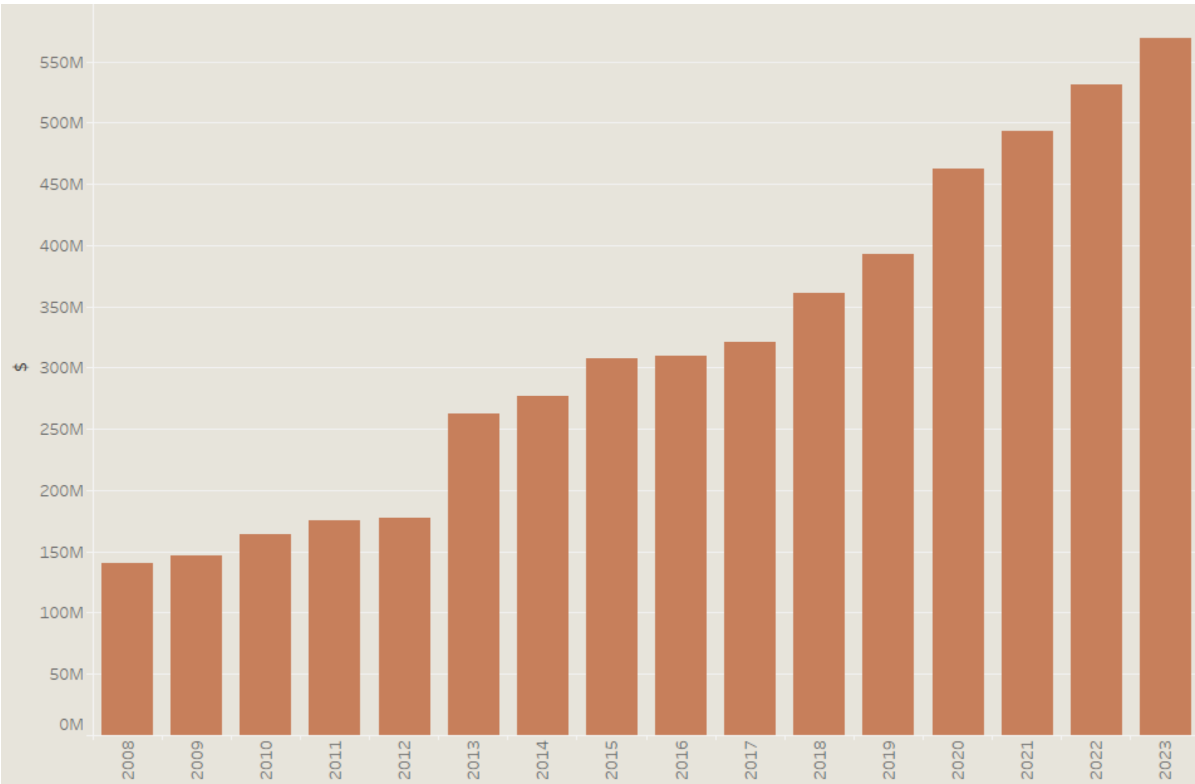
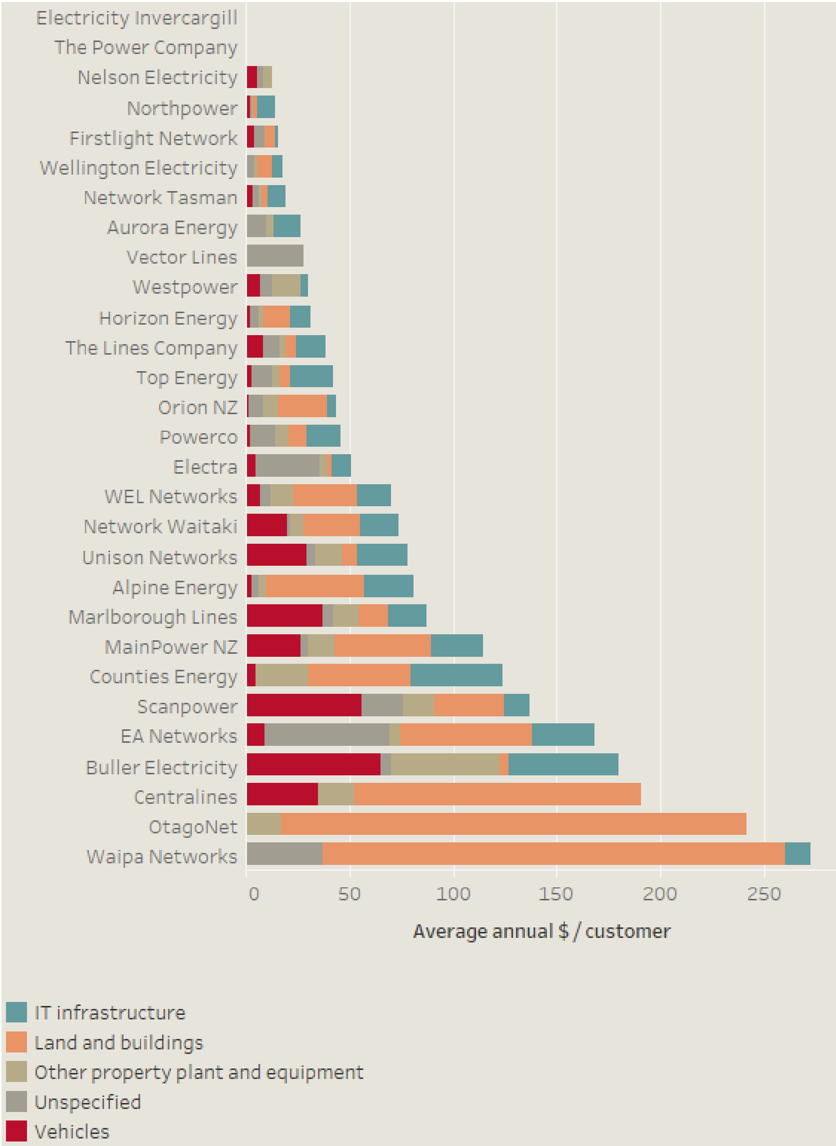


Figure 22 shows that the overall value of non-network assets has increased by around $428 million since 2008, or close to 305%. Some of the increases from 2018 onwards may be due to the capitalisation of some operating leases by some local lines companies in response to a change to the accounting standards.

Figure 23 shows the investment made in non-network assets by local lines companies from 2013-2023. It uses dollars per customer for easier comparison between local lines companies and breaks the expenditure down further into categories of assets.[49]

Figure 23: Average capital expenditure on non-network assets by local lines company and asset category, 2013-2023

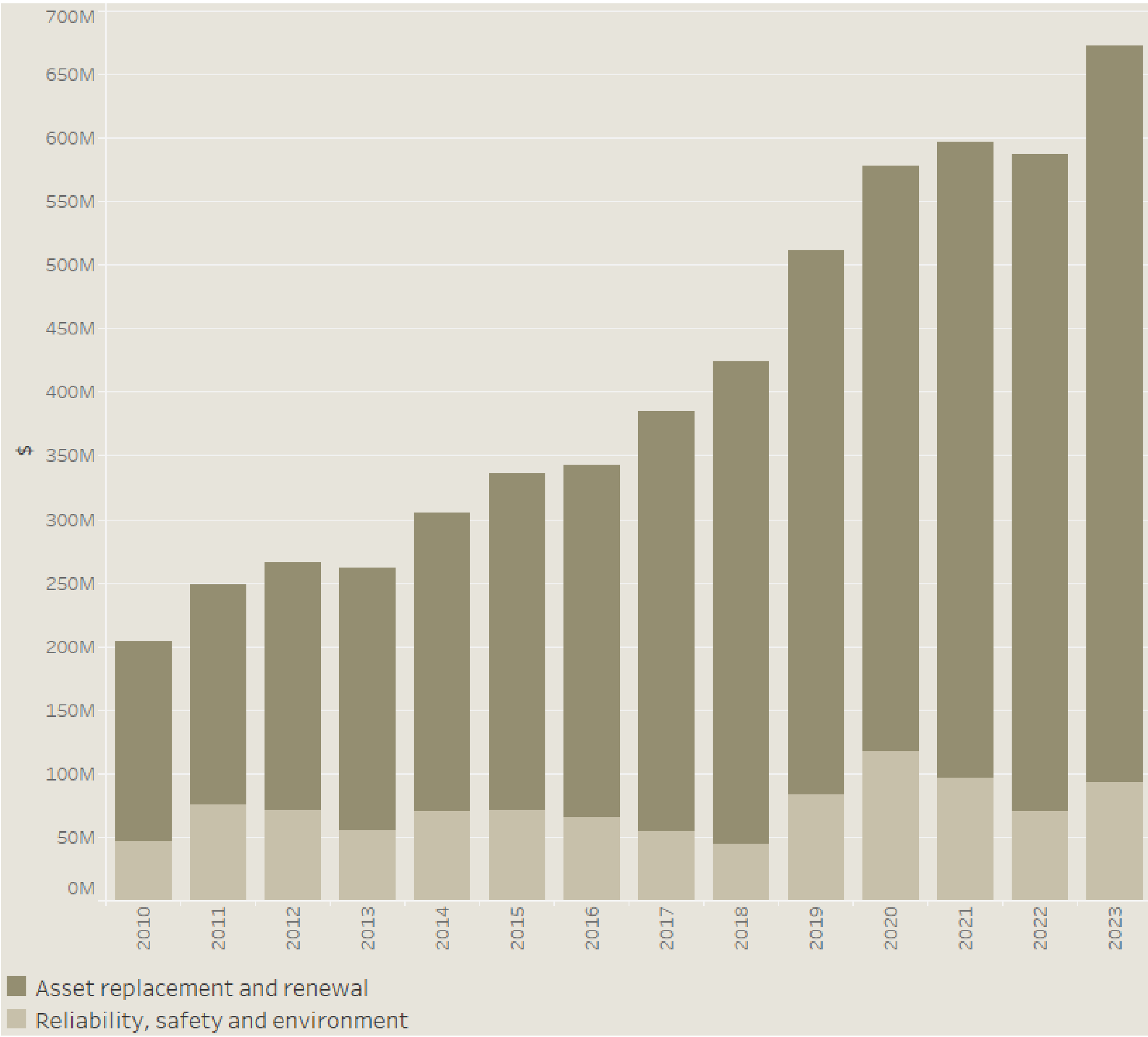


49 Local lines companies are required to specify the project or programme to which the expenditure relates as a free text entry. We have split the expenditure into key categories by searching for relevant words within the programme/project title. These categorisations are hence imperfect.

Figure 23 highlights that some local lines companies have made large investments relative to their size in non-network land and buildings, which is identifiable because the chart is given in expenditure per customer. This may mean they have been reacting to growth in their overall business size and capabilities. In some of these cases, these may be one-off investments that are unlikely to be repeated in the foreseeable future.

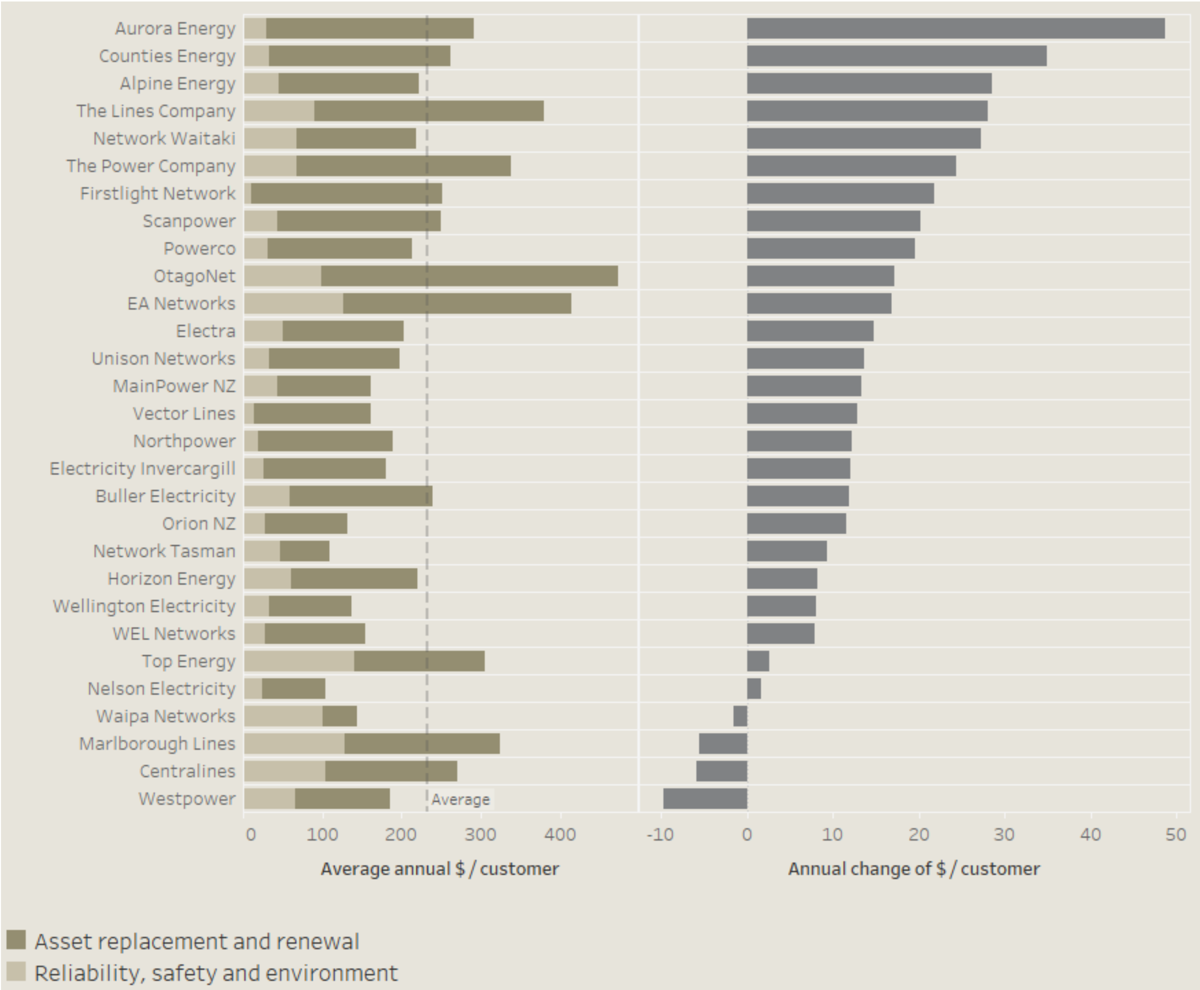
About half ($5.7 billion) of the investments that local lines companies have made in new assets from 2010-2023 were to replace or improve their existing assets to ensure they remain safe and fit-for-purpose. This investment occurred at an accelerated rate over the period. This is shown in Figure 24.

Figure 24: Capital expenditure to replace and improve existing assets for all local lines companies, 2010-2023



Almost all local lines companies have increased their spending to replace and improve their assets since 2010. The rate of increase has been very high for some local lines companies. This is shown in Figure 25, which gives the average replacement and improvement expenditure per customer for each local lines company from 2010-2023 on the left-hand side. The right-hand side shows the rate of change in this expenditure implied by the trend.

Figure 25: Average annual capital expenditure on replacement and improvement per customer, and rate of change, 2010-2023



The left-hand side of the graph shows significant variation between local lines companies in terms of their average expenditure on replacing and improving their assets. Variation between local lines companies over this kind of timeframe is expected because different networks will have different numbers and types of assets coming up for replacement – particularly noting the relatively short time series compared to the long life of assets such as poles, cables and transformers.

The right-hand side of the graph shows expenditure to replace and improve assets increased at an annual rate of $48 per customer for Aurora Energy. The expenditure for asset replacement and improvement increased at an annual rate of greater than $20 per customer for eight further local lines companies. Many local lines companies increased this expenditure over the period since 2010 as they prioritised work to replace and improve assets. For example, Counties Energy completed a network reliability study in 2019 and accelerated its replacement and renewal of ageing assets and as a result, Counties Energy increased this expenditure significantly.

A decline in investment expenditure in asset replacement and renewal was highlighted following a decline in asset investment by Aurora Energy before undertaking a customised price-path programme. As part of this programme, Aurora Energy significantly increased capital expenditure from 2018-2023 to replace failing infrastructure and bring its network up to a safe and reliable standard.[50]

Across the sector as a whole, we are generally seeing good levels of investment. Our reviews of asset management plans identified good practices such as implementing asset criticality and asset health assessments continue to mature, leading to investment in the right place at the right time.

Figure 25 also shows four local lines companies whose replacement and improvement spending per customer has declined over the period. Based on further inspection of the data, both Centralines and Westpower appear to be coming off the back of replacement and improvement spending programmes early in the period.[51] This is suggested by their annual average expenditure being broadly in line with the industry average, despite the declining trend.

Information on replacement and improvement spending is useful to understand productivity and efficiency but it has limited value if it is too high-level to compare to asset information. We gather a lot of information from local lines companies about the age and condition of their assets through ID. However, the detailed nature of the asset category data, compared to the less-detailed expenditure data, makes it challenging to understand the relationships between expenditure and cost drivers, and therefore productivity and efficiency. We recently engaged Cambridge Economic Policy Associates (CEPA) to produce a reported titled “EDBs Productivity study”.[52] The report assesses the productivity of Aotearoa’s local lines companies over the 2008-2023 period. This supports our priority to help customers and other stakeholders understand how local lines companies are performing. This includes understanding their productivity performance, which can encourage the industry to improve performance further.

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50 Aurora applied for a customised price-quality path which we granted in April 2021 to enable it to continue a higher level of asset replacements. Its capital expenditure began ramping up before the beginning of the customised price-quality path. See Commerce Commission “Aurora Energy’s CPP and enhanced information disclosure requirements.”

51 In 2021, the ownership structure of Centralines was changed. Centralines became ‘consumer owned’ and was exempt from price-quality regulation but still subject to information disclosure regulation. See Centralines Limited “Centralines history”.

52 Commerce Commission “Productivity and efficiency study of electricity distributors”.

Customers are paying more because local lines companies have spent more on running their businesses

Around 53% of local lines companies' own costs (ie depreciation and operational expenditure) allowed them to run their businesses and operate their networks on a day-to-day basis.

As shown in Figure 26, annual operating expenditure by all local lines companies reached $830 million in 2023, having increased from $396 million in nominal terms since 2008. The trend shows local lines companies are recovering around $164 more per customer to fund this expenditure. In real terms, figure 26A shows local lines companies recovering $79 more per customer in 2023 compared to 2008.

There are several defined categories of operating expenditure. Changes in disclosure requirements and inconsistencies in how local lines companies have categorised costs over time makes it difficult to meaningfully assess changes prior to 2013. We therefore focus most of our discussion on changes from 2013-2023, which accounts for approximately 76% of the total increase in operating costs.[53] The changes are shown in Figure 27, in nominal terms, for the following categories:

Table 2: Operational expenditure categories and purpose of expenditure[54]

Category	Purpose of expenditure
System operations and network support	Control centre and office-based operations such as network planning
Business support	Corporate activities such as human resources, legal and information technology
Service interruptions and emergencies	Reactive work to respond to unplanned outages
Asset replacement and renewal	Maintain asset integrity to ensure quality of supply
Routine and corrective maintenance and inspection	Testing and general maintenance
Vegetation management	Trimming of trees around overhead power lines

53 As 2013 was the first year of new information disclosure requirements, it may include some incorrect allocation of operating expenditure to the different categories. For example, vegetation management appears to be artificially low in 2013.

54 For more specific definitions, see Commerce Commission "Electricity Distribution Information Disclosure Determination 2012".

Figure 26: Breakdown of operating expenditure (in nominal terms), 2008-2023

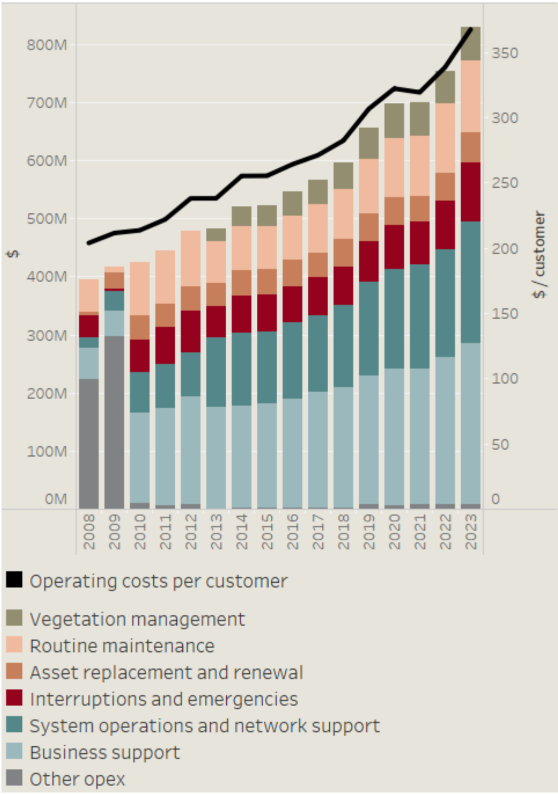
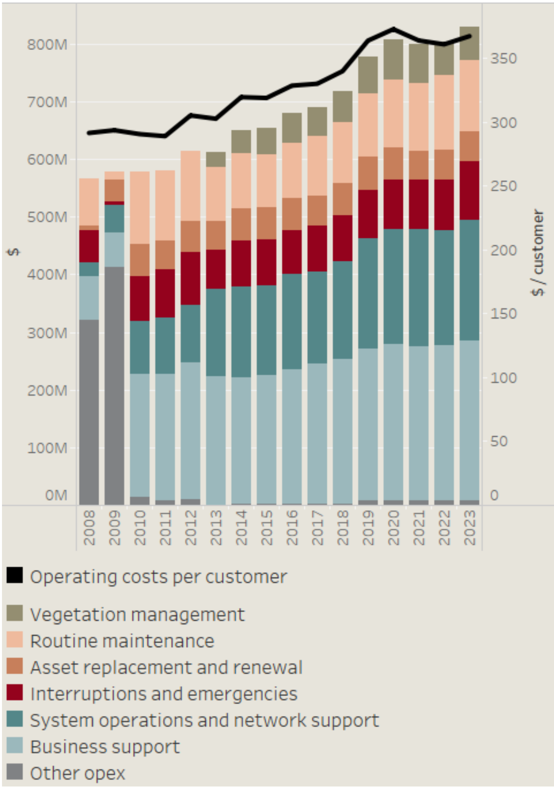


Figure 26A: Breakdown of operating expenditure (in real terms), 2008-2023



Figures 26 and 26A highlight that the increase in operating costs has been consistent over the full data period. This increase is notably faster than network growth resulting in higher per-customer costs on average.

When we set price-quality paths for the local lines companies that are subject to price-quality regulation, we consider their likely operating costs. We do not analyse each of the individual components of operating costs, but in aggregate, we expect operating costs to:

- scale with the forecast number of customers and the total length of power lines, as operating costs tend to increase with the size of the network
- increase with forecast inflation, to reflect general economy-wide pressures that affect local lines companies' input costs, including labour
- change with expectations of industry-wide changes in productivity
- increase for specific significant and uncontrollable step-changes in costs.

In the DPP2 price period and 2021, the first regulatory year of the DPP3 price period, the aggregated operating costs of the local lines companies that are price-quality regulated were broadly in line with what we had anticipated when we set revenue limits for that period. However, inflation turned out to be much higher in 2022 and 2023 meaning that economy-wide cost pressures have driven operating costs higher.

Figure 27: Components of (nominal) operating expenditure and trends, 2013-2023

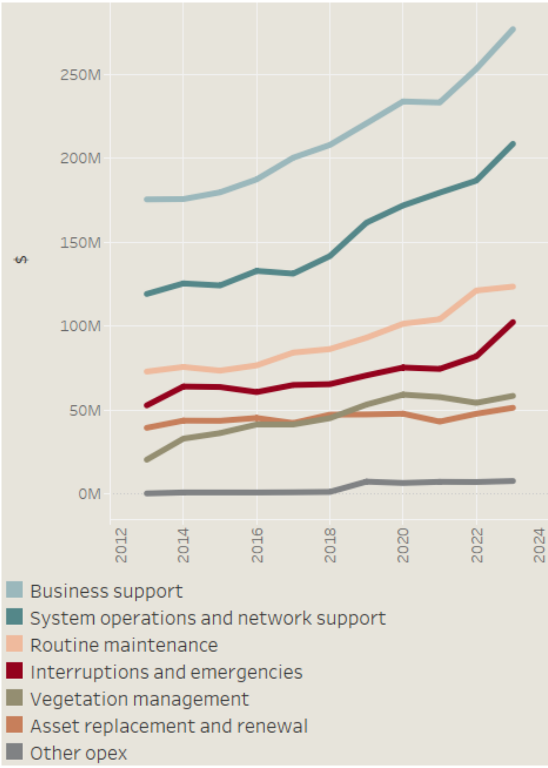


Figure 27 highlights that there were increases in the three largest components of operating cost – being business support, system operations and network support, and routine maintenance. There has been a noticeable increase in operating costs associated with interruptions and emergencies in 2023, resulting from Cyclone Gabrielle during this year.

Figure 28 shows that the change in operating costs per customer has differed significantly for different local lines companies, suggesting that cost pressures were not experienced consistently. The figure shows the average annual per-customer change in operating costs for each local lines company implied by the trend over the 2013-2023 period. This change is broken down into the same components as Figure 27. Increases in operating costs for a category extend to the right, while decreases in costs extend to the left. The net change per customer on average is indicated by the black diamond.

Figure 28: Trend in operating expenditure categories in cost-per-customer by local lines company, 2013-2023

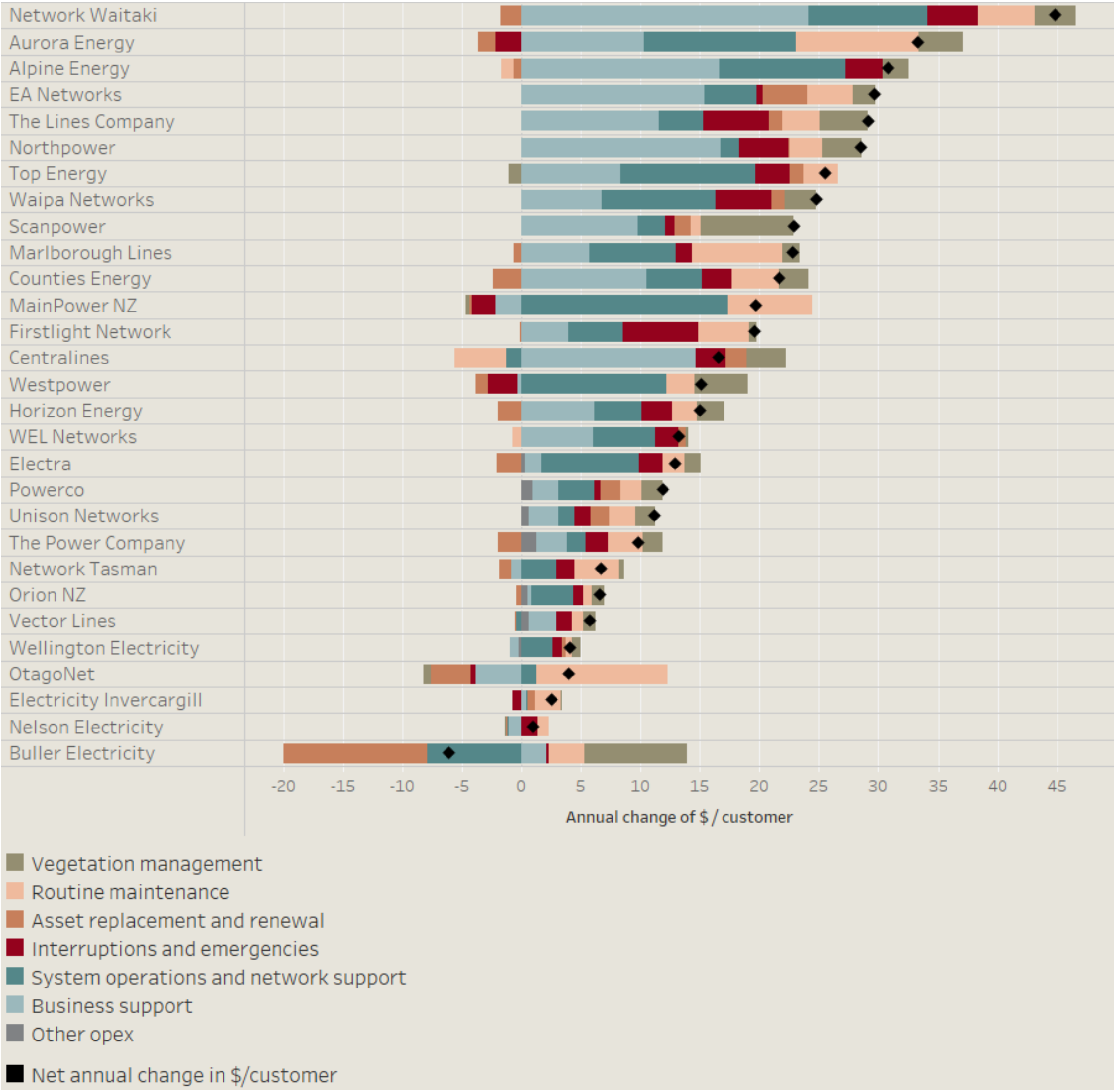


Figure 28 shows that all but one local lines company have been spending more per customer on operating their businesses day-to-day in nominal terms. Network Waitaki's operating costs increased the fastest, at a rate of over $44 per customer each year. Conversely, Buller Electricity's operating costs declined by around $6 per customer each year, which as we understand, reflects a restructuring following the loss of revenue from a large customer.

The graph also shows that while the categories driving the changes in costs differ for each local lines company, 'business support' and 'system operations and network support' feature particularly strongly. Both categories are considered 'non-network', in that they do not immediately relate to providing electricity distribution services.

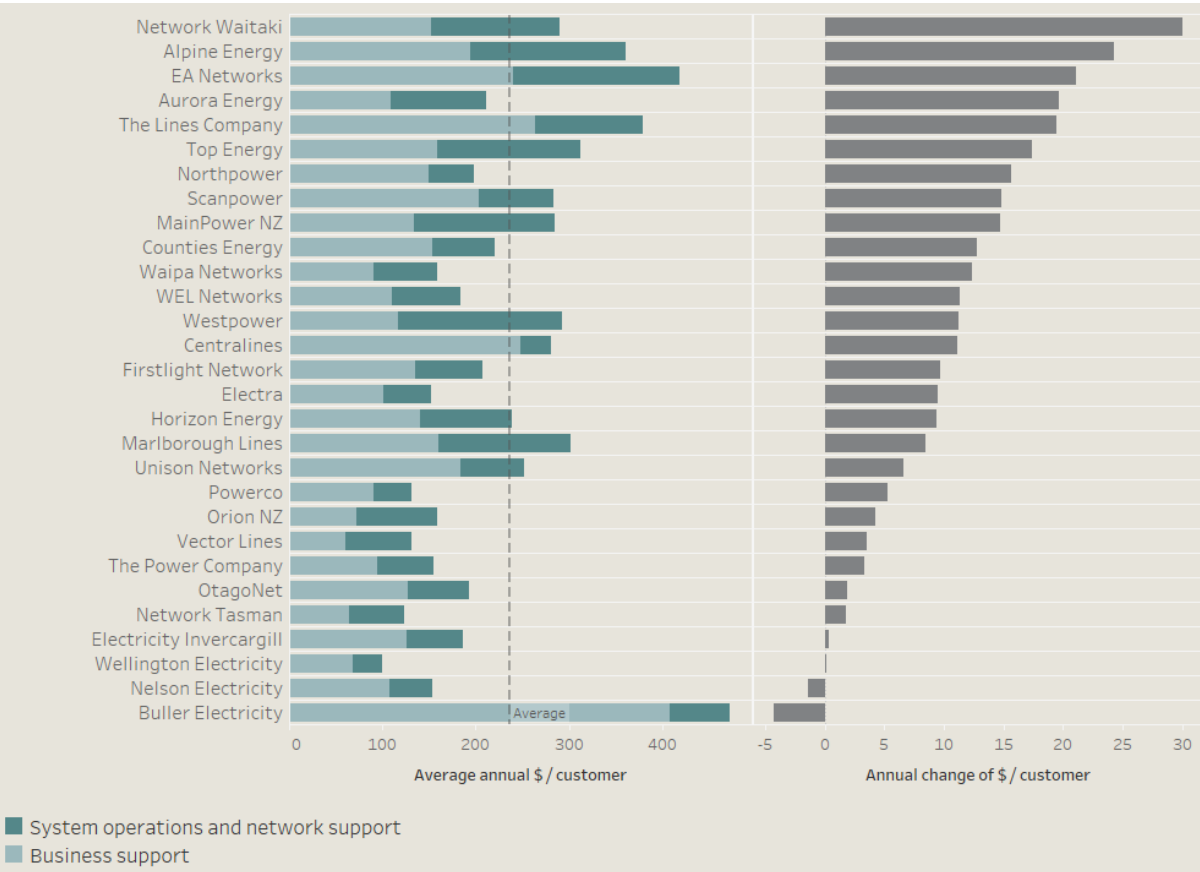
Local lines companies have spent more on non-network operating expenditure

The two largest components of local lines companies' operating expenditure are for 'business support' and 'system operations and network support' – both considered to be non-network expenditure. These components respectively comprised around 34%and 25% of total operating expenditure from 2013 - 2023.

Business support operating expenditure relates to general corporate activities. Systems operations and network support expenditure relates to the design, management, and planning of the network, as well as customer interactions. These categories of operating costs have been increasing at annual rates of 4.7% and 5.8% respectively since 2013. Overall, in 2023, customers on average paid around $96 more, in nominal terms, than they did in 2013 to support this expenditure.

All but two local lines companies have had increases in non-network operating expenditure on a per customer basis, though there is a wide variation in changes. This is shown in Figure 29, which shows the average non-network operating cost per customer for each local lines company (left-hand side), and the annual rate of change in that cost (right-hand side) based on the trend since 2013.

Figure 29: Average annual non-network operating expenditure per customer and rate of change in that expenditure per customer by local lines company (2013-2023)



ID does not provide a further breakdown of these expenditure categories. Therefore, we are unable to readily analyse what specific factors caused them to increase.[55]

Higher insurance costs are one factor that has affected local lines companies' non-network operating expenditure, and we explicitly allowed for a step increase in insurance costs within price-quality paths when we reset them in 2010 and are considering so for the upcoming DPP4 reset.[56] [57]

During the DPP3 and DPP4 consultation processes, local lines companies suggested other factors that may have been placing pressure on non-network operating expenditure, including:

- increasing regulatory requirements, including the need to meet stricter health and safety requirements
- changing customer demands and engagement
- changes in technology, including industry-specific technology such as smart meters and network monitoring equipment, as well as information technology services.[58]

Given the significance of these costs, we consider that gaining a greater understanding of their drivers and scope for efficiency should be an area of future work. We have made changes to our ID requirements to support this work as part of our ongoing review of ID requirements for local lines companies, for example, vegetation management and flexibility services are new opex categories added in our Targeted ID Review.[59]

Local lines companies have been spending more to maintain their assets

Network assets require regular maintenance, including replacement parts.[60] Local lines companies must also keep electricity lines free of vegetation to avoid unplanned outages. Figures 30 and 31 show that local lines companies have been spending more on these activities since 2013.

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55 Some of this (e.g. staffing) would likely be found in corporate reports, but we have not looked into these as part of this analysis.

56 A step increase refers to an increase over and above the base level of insurance that EDBs are currently spending.

57 Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2025 – Draft decision – Reasons paper" (29 May 2024), para 2.86.

58 When we reset the price-quality paths for 2020, local lines companies submitted that several such issues were sufficient to justify 'step-changes' in the operating expenditure allowance that we gave to local lines companies. However, we note that these issues did not meet the threshold required to be specifically included within allowances. See Commerce Commission "Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision – Reasons paper", page 164.

59 We made changes as part of the Targeted Information Disclosure Review (TIDR) for 2022 and 2024, to add some new ID requirements including decarbonisation. For further information, see Commerce Commission "Targeted information disclosure review for electricity distribution businesses".

60 For the purposes of this discussion, we have grouped 'asset replacement and renewal opex' and 'routine and corrective maintenance and inspection opex', as these both relate to maintaining existing assets.

Figure 30 shows 'routine maintenance' and 'asset replacement and renewal' operating expenditure in total for all local lines companies (bars), and as a proportion of the value of the total asset base (line). Figure 31 shows the total vegetation management expenditure (bars) and this expenditure per kilometre of power line (line).

Figure 30: Total operating expenditure on routine maintenance, and proportion of asset base, 2013-2023[61]

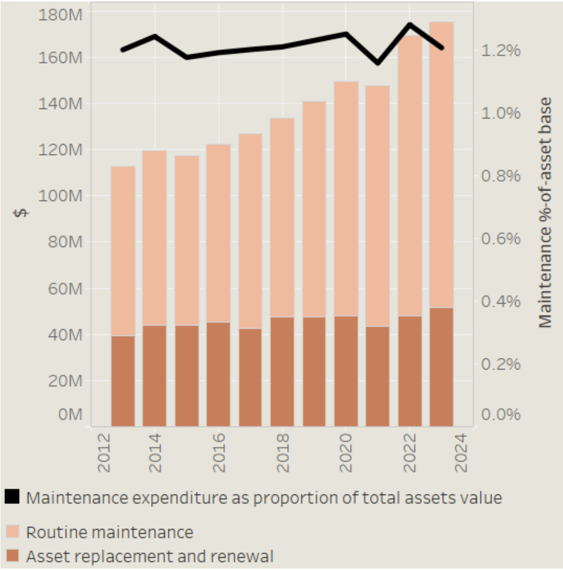


Figure 31: Total operating expenditure on vegetation management, and per km of power line 2013-2023

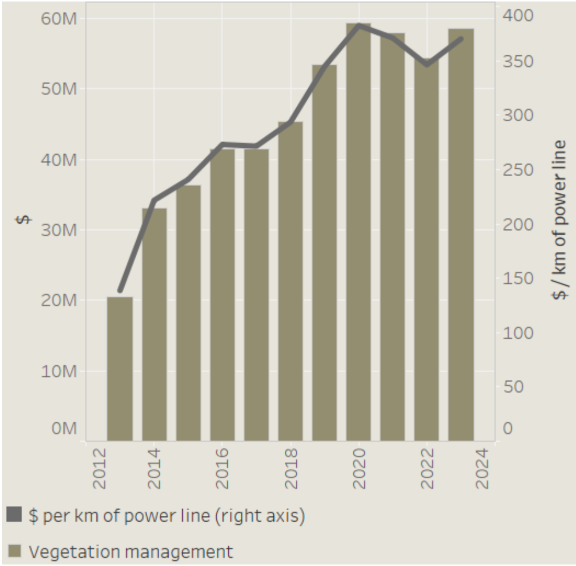


Figure 30 shows that replacement and renewal operating expenditure has increased by about $12 million in nominal terms since 2013, with routine maintenance spending increasing by around $51 million in nominal terms during this period. This combined expenditure has remained relatively consistent with the general growth in the asset base. While not shown, there is variation between individual local lines companies.[62] Most spend between 0.5-2.0% of the value of their asset base on these expenditure categories, with some increasing their proportional spend and others decreasing it.

The bars of the chart in Figure 31 show that expenditure on vegetation management has increased by around $38 million or 185% since 2013. However, we note that reported expenditure on vegetation management may be artificially low in 2013 due to incorrect categorisation of expenditure in that year, which likely occurred because it was the first year of new categorisation requirements under ID. The line shows that this growth reflects an increase in cost per kilometre of power line, rather than being caused by an increase in the total length of power lines.[63] In conducting our ongoing analysis of asset management practices and asset management plans, we assessed that the major driver of this higher

61 Value of the asset base at the start of the year.

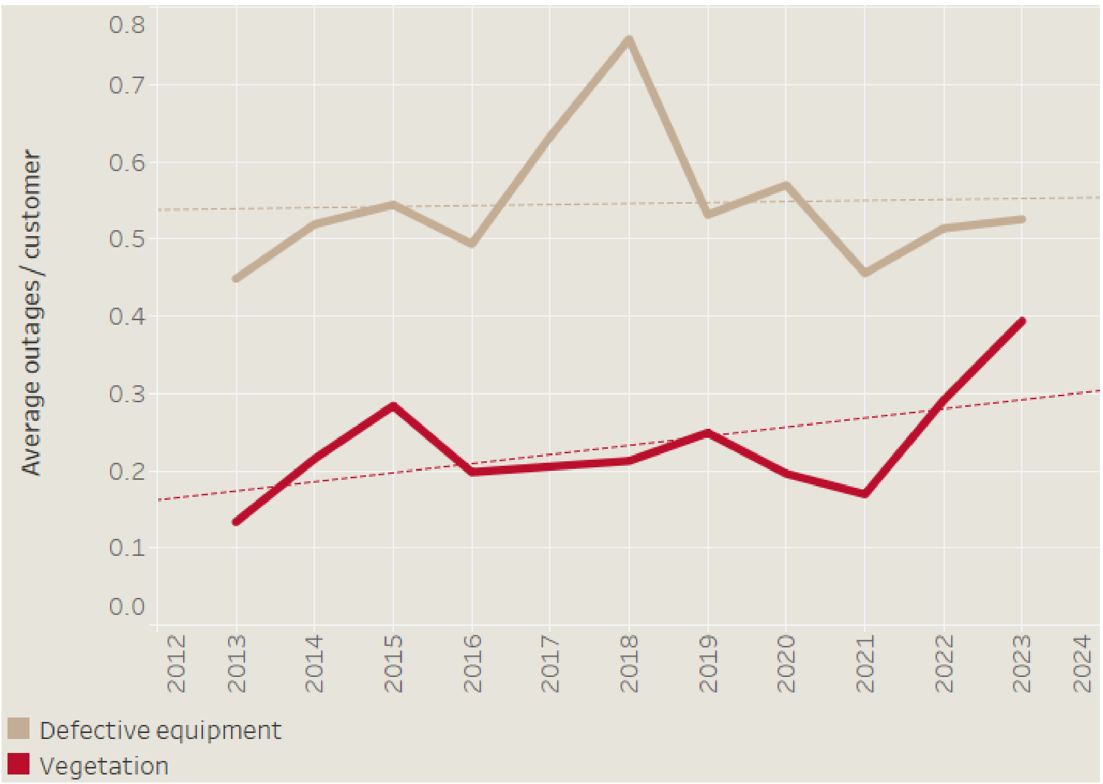
62 This is available on the Performance Accessibility Tool.

63 Our current ID requirements means that local lines companies need to disclose the length of power lines on their network that specifically requires vegetation management. However, this data is subject to network location and changes in vegetation. Therefore, undertaking any comparative analysis does not provide meaningful information, so we have chosen not to provide any comparative analysis.

spending is likely to be that local lines companies have been engaging in more comprehensive management of vegetation in the vicinity of existing lines, increased requirements for traffic management.

Despite the increased spending on both vegetation management and routine maintenance since 2013, there has been a major deterioration over the period in the average number of outages per customer that were caused by vegetation interfering with power lines. Further, the average number of outages per customer caused by defective equipment has slightly worsened. This is shown in Figure 32. However, this is influenced by a particularly high average number of outages per customer in 2018, and in recent years, has been trending back down towards 2013 levels, before rising again in 2022 and 2023. Further, external events such as Cyclone Gabrielle and the quality of reporting have influenced these trends. We have seen an increase in severe event days being reported by local lines companies in 2022 and 2023.

Figure 32: Average outages experienced by customers that were caused by defective equipment and vegetation, 2013-2023



These deteriorating aggregate trends also disguise a more positive trend in the performance of many of the individual local lines companies. This is shown by Figure 33, which shows the average number of interruptions per customer due to vegetation and defective equipment for each local lines company (left-hand side). The rate of change implied by the trend in this metric is shown on the right-hand side, where an increase in the number of outages is represented by a bar extending to the right, and vice versa.

Figure 33: Average annual number of outages per customer and annual change in outages per customer caused by defective equipment and vegetation, by local lines company, 2013-2023

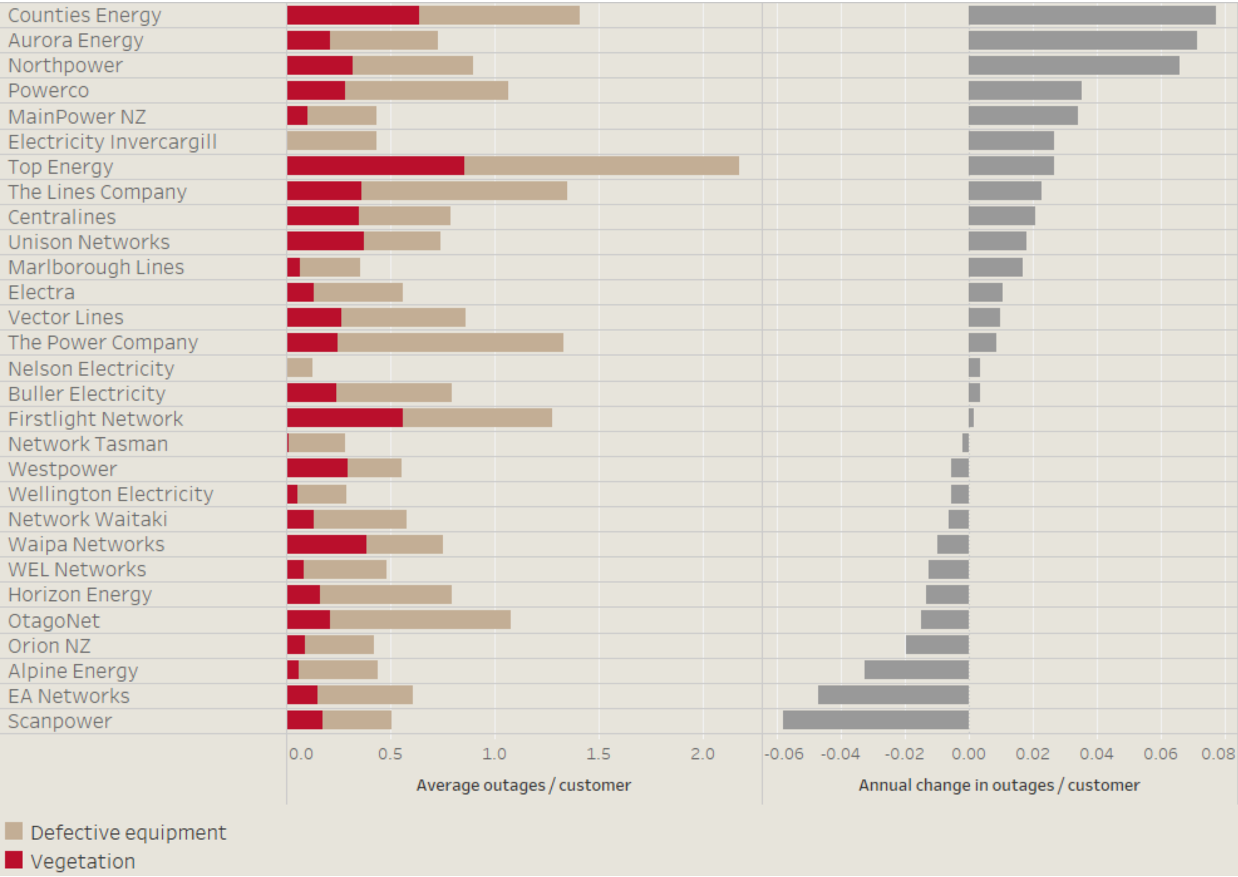


Figure 33 shows that around half of local lines companies have had a steady or declining number of outages per customer attributed to vegetation and defective equipment. However, increases by some large local lines companies influence the overall effect on customers seen in Figure 32 - most notably, Vector and Aurora Energy who have both faced Court-imposed penalties for breaches of the reliability standards that we have set. Conversely, the local lines companies that have shown improvements in the number of outages per customer are comparatively small in size. Cyclone Gabrielle and the Auckland Anniversary Day flooding in 2023 also had a noticeable effect on the trend in the 2023 regulatory year in the areas where these weather events occurred. These impacted areas were the - upper North Island and the East Coast of the North Island. With the introduction of new ID requirements in February 2024, stakeholders will have a clearer view of the impact to customers caused by out-of-zone trees making contact with conductors, the risk to overhead lines and the cost of managing such out-of-zone trees.

The Ministry of Business, Innovation and Employment (MBIE) has reviewed the Electricity (Hazards from Trees) Regulations 2003, which is to be expected to be in effect from September 2024.

In February 2024, we introduced a number of new ID requirements. These new disclosure requirements include information on vegetation management costs, performances, and risks. We are of the view that ID for vegetation management should be updated as soon as possible (disclosure requirements are by 31 August 2026), and consider it appropriate to rely on the systems (e.g., the tree regulations) in place currently. The impacts of climate change are causing a greater frequency and magnitude of extreme weather events in some parts of New Zealand, with increased wind speeds and rainfall, which will likely cause greater tree damage. Despite this, some EDBs may not be aware of the risk that their networks are exposed to from vegetation (particularly considering these evolving factors). As a result, these EDBs take a largely reactive approach towards asset management, particularly in relation to out-of-zone trees.

Unplanned outages have increased but the average restoration cost per unplanned outage has decreased

The number of unplanned power outages has trended upwards at an industry level since 2010. However, the costs of restoration have changed much less quickly. This is shown in Figure 34, which shows the expenditure for interruptions and emergencies and the number of unplanned outages. Figure 35 shows that the restoration costs-per-outage have trended down until 2018 and since then has been trending up.

Figure 34: Expenditure for interruptions and emergencies versus unplanned outages, 2010-2023

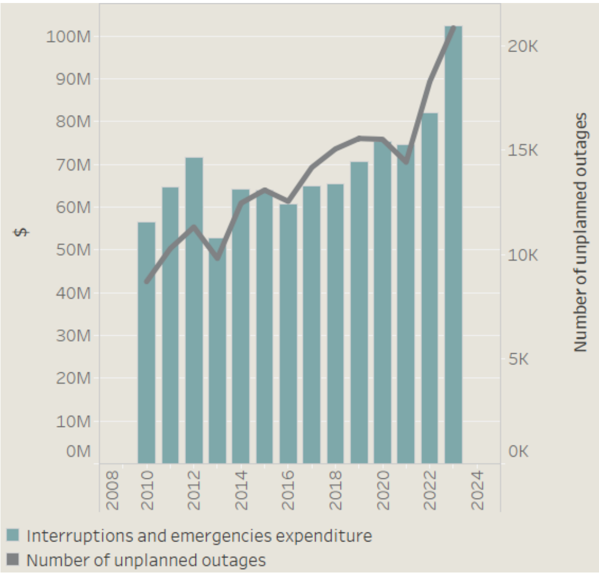


Figure 35: Average restoration opex per unplanned outage, 2010-2023

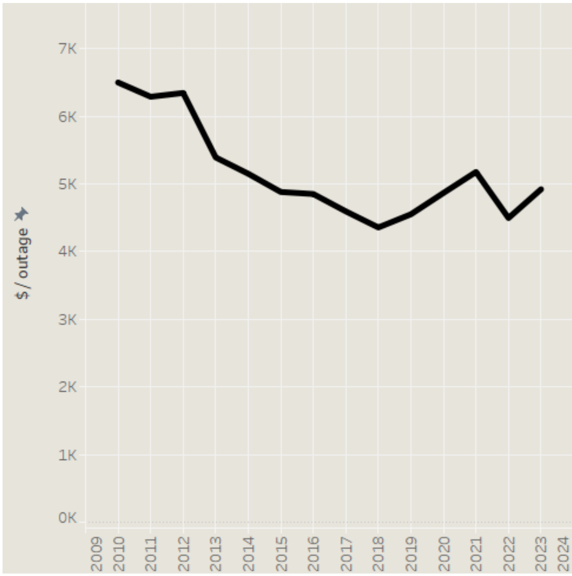


Figure 36 shows how the average restoration costs have changed for each individual local lines company. The colour of the bars indicates the total number of unplanned outages across the full period, with a darker bar indicating relatively more outages.

Figure 36: Rate of change of per-outage expenditure on restoration by local lines company, shaded by number of outages, 2010-2023

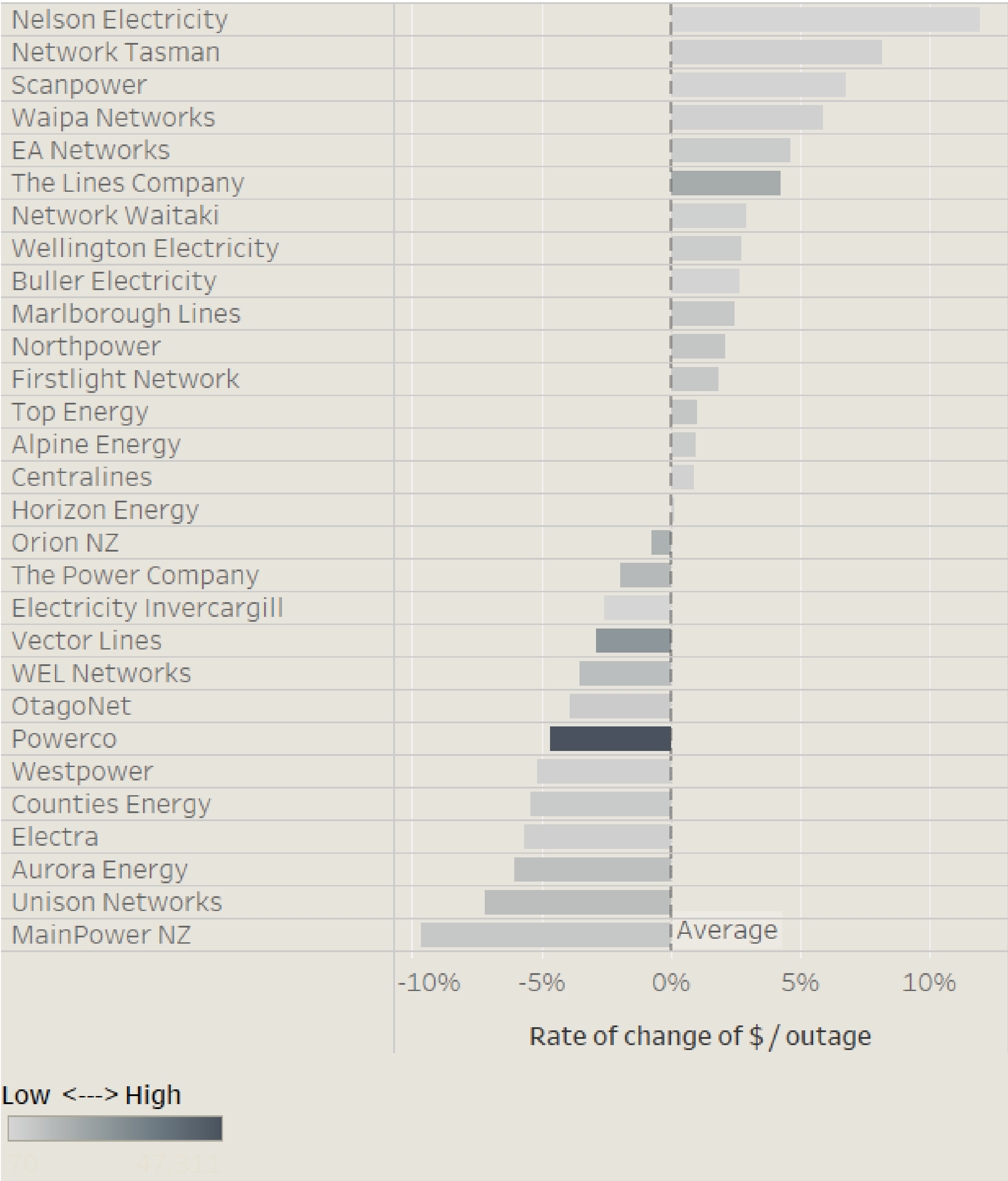


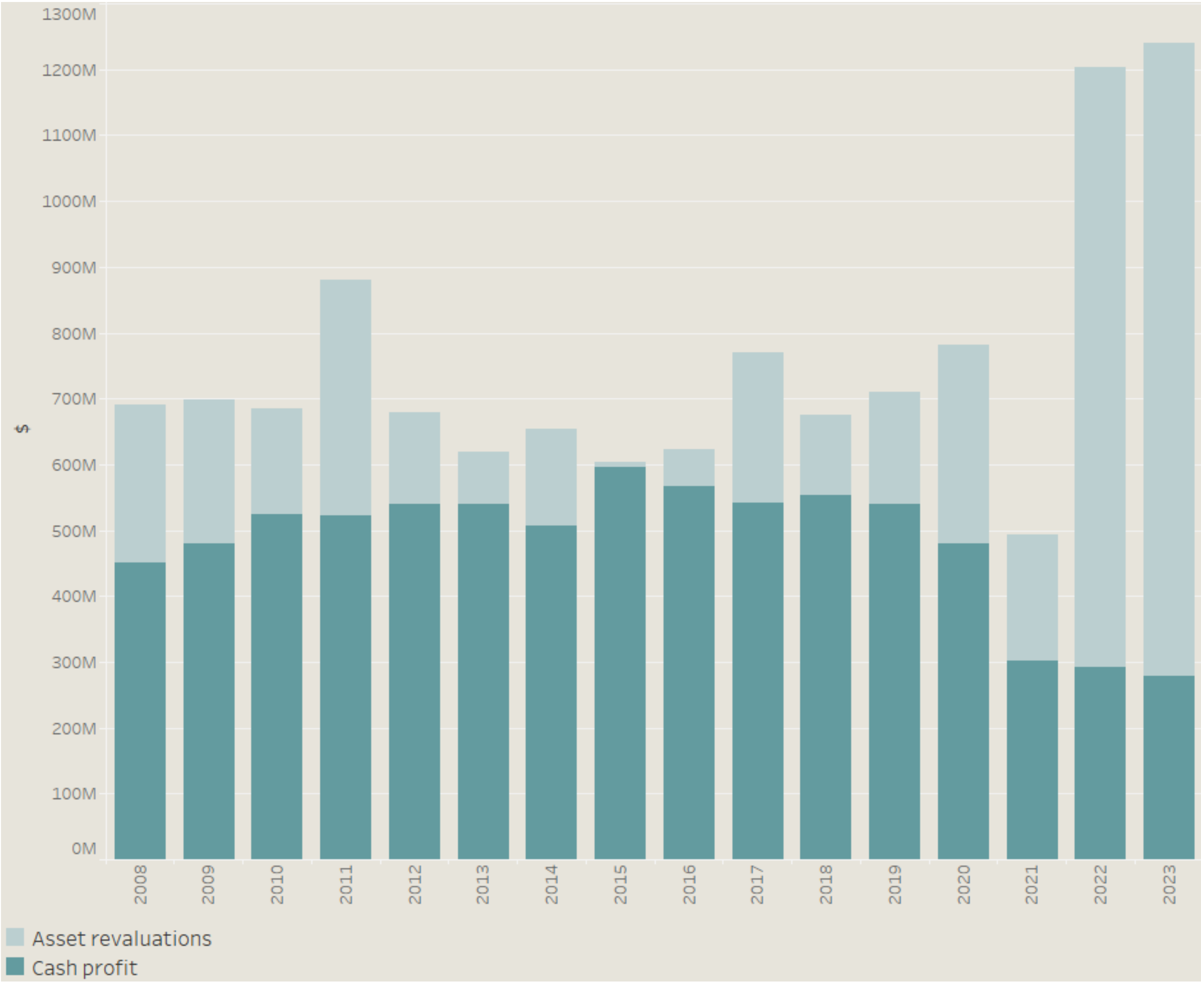
Figure 36 shows that the trend for outage restoration costs is not universal across local lines companies. While some local lines companies have experienced significant cost declines, some other companies show significant cost increases. However, the larger local lines companies have tended to have costs decline, and these companies also contribute the most to total outages (largely because of their size). This explains the overall industry trend. The decline in costs for these local lines companies may reflect an increase in investments in 'self-healing networks', which allow for more automated restoration, but may have longer-term impacts on the number of outages.

Local lines companies' profit from asset revaluation has increased over the last two years, driven by higher inflation

Collectively, local lines companies earned $1.2 billion in total regulatory profit after tax in 2023. This is the total profit that we recognise under our regulatory rules as reported under the ID requirements. Regulatory profit excludes any profit the local lines company might earn from unregulated business interests. The profit in 2023 consisted of:

- $278 million in cash profit, and
- $962 million of non-cash asset revaluation gain (in line with inflation).[64]

Figure 37: Total regulatory profit after tax for all local lines companies, 2008-2023



[64] This is a capital gain that ensures local lines companies asset values do not degrade in real terms. The local lines companies do not receive an immediate monetary benefit from asset revaluations. Rather, these are added to the value of the regulatory asset base and are recovered slowly over time in future years through depreciation.

Figure 37 shows the change in profit and the breakdown over time from 2008-2023. The overall trend in total profit was relatively flat between 2008-2020, with a significant dip in 2021. There was then a very large increase in profit in 2022 and 2023 due to much higher rates of inflation.

In general, much of the variation in total profit is driven by the annual revaluation of assets at the rate of inflation, which does not have an immediate impact on customers' bills.

Figure 37 shows that cash profit (the teal bars) trended gradually upwards at an industry level from 2008-2015, before declining towards an all-time low in 2023.

There are three key factors that have driven the level of cash profit:

- As explained earlier, local lines companies have increased their investment in new assets. Local lines companies are incentivised to invest because they can earn a return on their investments, which is their cash profit. Inflation has also further increased the value of assets.
- Offsetting this, historical reductions in interest rates until 2021 meant the cost of capital needed to invest has reduced, which we reflected in the return we allowed price-quality regulated local lines companies to earn on their investments when we reset the price-quality path for DPP3 (which started in 2021)This meant that cash profit from 2021 to 2023 did not need to be as high to ensure appropriate compensation to local lines companies for their investments. However, the increases in interest rates and inflation in 2022 and 2023 mean that the profits due to asset revaluations have climbed significantly.
- Multiple local lines companies that are owned by their customers have recently changed the discounts they provide to customers from being discretionary discounts to being discounts in their scheduled prices. Doing this means that the discounts are now considered to be a reduction in regulatory revenue, whereas previously they were akin to a dividend. Of these companies, most made the change in 2020, though some did so earlier.

The net result of the above factors is that the level of cash profit decreased by around 3.2% per year, or 38% over the 15 years since 2008.

The non-cash gains from asset revaluations (light bars in Figure 37) represent the increase in the value of assets due to inflation, which is significant for local lines companies because the local lines companies' assets have a high value. This profit will be realised in cash by the local lines companies in future years through lines charges to customers.[65] Over the period since 2008, the revaluations have been variable but consistent with measured inflation.[66]

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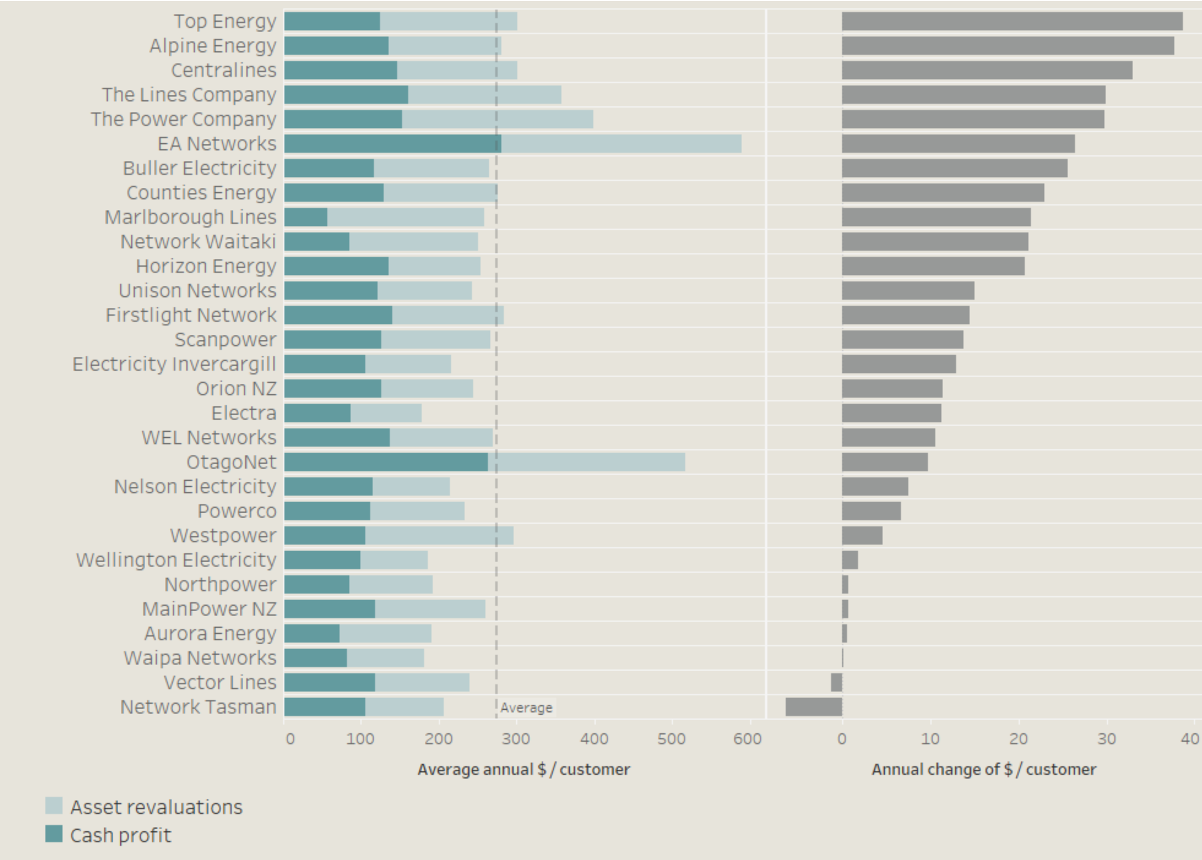
65 This is because line charges are set with regard to the value of the asset base, to provide for a recovery of investment through depreciation and also a return on that investment.

66 We note the inflation index used to revalue assets is calculated differently from that shown in Figure 4 under our input methodologies.

There are differences in the total profit across different local lines companies. Figure 38 shows the average annual profit per customer, using the same breakdown as in Figure 37 (left-hand side). It also shows the annual change in total regulatory profit after tax over time implied by the trend for each local lines company (right-hand side).

Figure 38: Average annual total profit after tax and rate of change by local lines company, 2010-2023



The left-hand graph highlights that there is variation in the average profit per customer earned by local lines companies around the country. To some extent, this variation reflects that some local lines companies have an asset base that has a comparatively high value relative to the number of customers on their network due to low-density or high-demand customers.

The right-hand graph shows that two local lines companies have had their total profit after tax trending up by more than $35 per year on a per-customer basis. We set price-quality paths for each of these companies. The price-quality paths we set for them in 2015 allowed for revenue to increase above inflation to reflect significant investments in their networks and to allow for normal returns.

On the other hand, three local lines companies, Waipa Networks, Vector Lines, and Network Tasman have seen their total profit after tax trend down from 2010-2023.

Local lines companies have been effectively limited in their ability to earn excessive profits

Figure 39 shows the total regulatory profit after tax expressed as a percentage of the total value of assets from 2013-2023 (teal bars).[67] This is given for price-quality regulated local lines companies, exempt companies, and all companies, weighted by the value of their asset base. The orange dots show the required rate of return (inflation-adjusted) also known as weighted average cost of capital or WACC that we estimated at the time of setting each DPP, after tax, and adjusted for the difference between forecast inflation and ex-post or 'actual' inflation.

Total profit as a proportion of the value of assets is a measure of profitability known as the return on investment. By comparing this with a company's required rate of return - the level of return demanded by its investors - it is possible to assess whether companies are making excess profit. Comparing the rate of return on investment to an adjusted WACC is intended to represent a comparison in real terms.

Figure 39: Return on investment for local lines companies, 2013-2023[68]

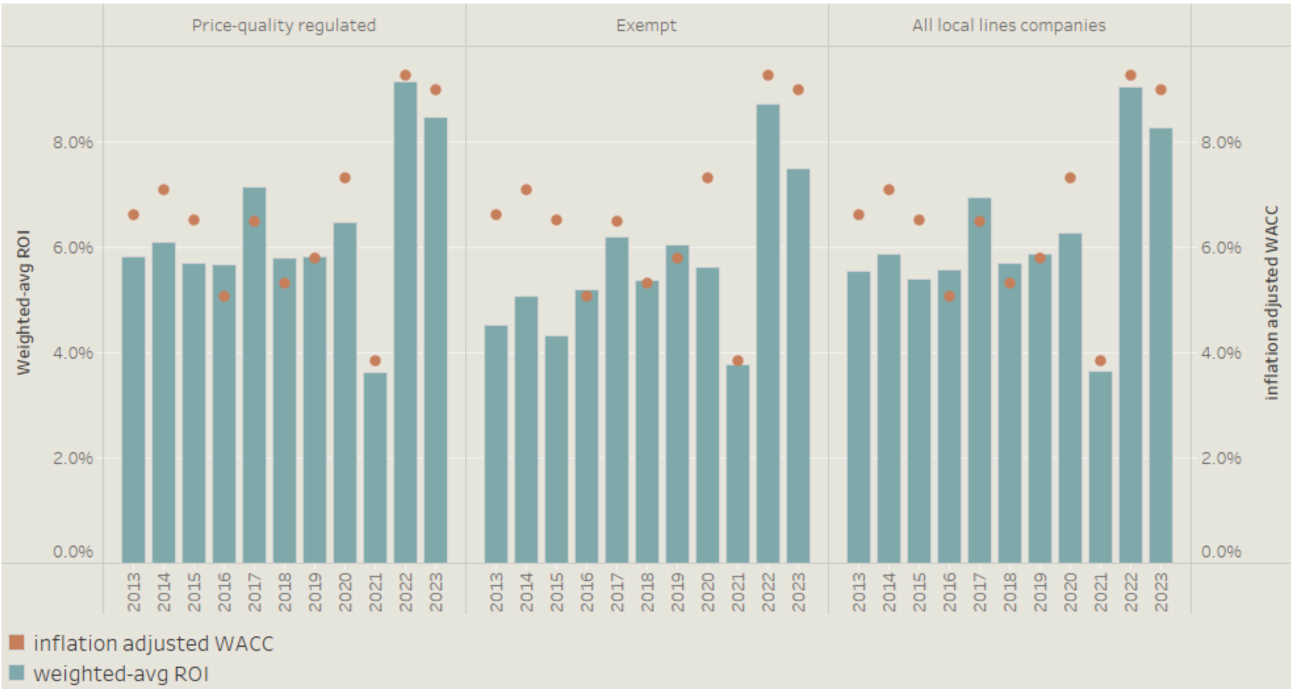


Figure 39 shows that return on investment had been increasing slightly for the total industry before dropping significantly in 2021, and then climbing again in 2022 and 2023. The increases in 2022 and 2023 are mainly driven by inflation which increases the revaluation of assets as previously shown in Figure 37.

67 The period of this analysis begins in 2013 given changes in the ID requirements which make earlier comparisons challenging.

68 This calculation uses the opening value of the regulatory asset base, and the post-tax return on investment disclosed by local lines companies, covering all revenue received.

The local lines companies that are exempt from price-quality regulation have had gradually increasing returns over the period with a dip in 2021, and markedly higher returns in 2022 and 2023 due to higher inflation. The total industry result is generally reflective of the results of price-quality regulated local lines companies because the majority of the industry (in terms of asset value) consists of these price-quality regulated businesses.

Our estimate of the weighted average cost of capital that we used to set price-quality paths for price-quality regulated local lines companies was 7.8% for 2011 to 2015, 6.4% for 2016 to 2020, and 4.2% for 2021 to 2025.[69] Note that these WACC figures have been inflation-adjusted in Figure 39. Actual inflation has been lower in the majority of the period prior to 2022 than afterward. The industry returns were generally lower than these levels, suggesting that local lines companies were not collectively making excessive returns.[70]

Customers of many local lines companies have experienced increases in outages

As well as looking at the trends in the revenue and expenses of local lines companies, we have analysed how the quality of the service they provide to customers has changed over time.

Figure 40 shows for the whole country from 2008-2023, three key statistics that help to describe the quality of the electricity distribution service provided by local lines companies:

- the total number of outages that occurred
- the typical number of outages that each customer experienced on average
- the total amount of time that each customer tended to have their power out.

The graphs separately identify outages that are planned by the local lines company, which customers may be given advance notice about and those that are unplanned. Unplanned outages can occur for a variety of reasons, including adverse weather and lightning; defective equipment; human error; and third-party, wildlife, or vegetation interference. Prior to 2023, we excluded outage data for the relevant local lines company in the year when a severe event occurred, such as the Canterbury earthquakes and particularly severe storms.[71] However, for 2023, we have included outages arising from events such as Cyclone Gabrielle to show the effect of the increase during this period.

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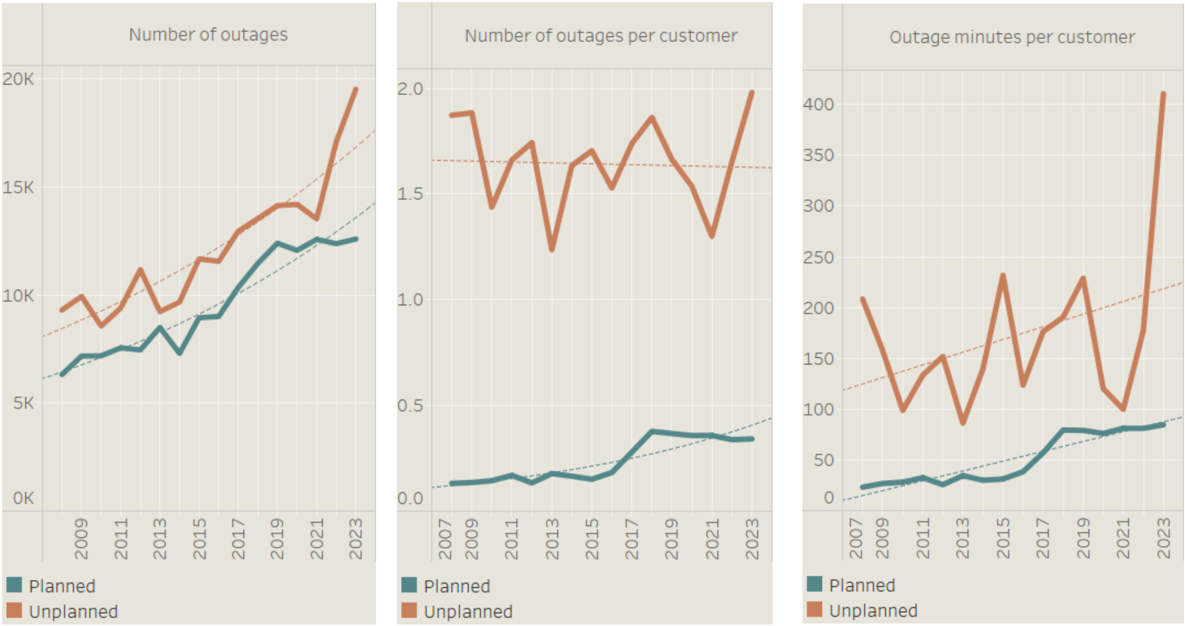
69 Based on our estimate of the equivalent post tax weighted average cost of capital. For 2010 to 2015 we used the 75th percentile of our estimate, while for 2016 to 2020 and 2021 to 2025 we used the 67th percentile. Our decision to use a lower percentile point of our estimate was explained in the relevant reasons paper on our website. See Commerce Commission "Amendment to the WACC percentile for price-quality regulation for electricity lines services and gas pipeline services – Reasons paper" (30 October 2014).

70 This is a high-level analysis of returns, which is a complex subject. We undertake more detailed analysis in other publications such as our 2016 report on local lines company profitability.

71 The observations we make generally hold whether we adjust for these events or not. However, we exclude them because such events can make it more difficult to distinguish other observable trends that relate to issues more reasonably within the control of local lines companies.

The reason for not excluding 2023 data is that we would have to exclude all data in 2023 for those local lines companies that are impacted by the weather events. For example, Cyclone Gabrielle impacted most of the local lines companies in the North Island in 2023. Removing most of the 2023 data for the North Island would provide us with little ability to provide relevant commentary for this Trends Report.

Figure 40: Statistics of planned and unplanned outages including trends, 2008-2023



From Figure 40, we can make three observations about the period prior to 2023:

- Recently, there have been materially more outages from local lines companies than there used to be — both planned and unplanned.
- The average customer experienced more planned outages but slightly fewer unplanned ones, combined, the average customer experienced slightly more outages overall.
- Outages have been more likely to last longer than they used to.

Combined, these observations suggest that outages tend to be longer but smaller in scope, affecting fewer customers at a time. They are also increasingly likely to be planned rather than unplanned outages.

We have identified three significant reasons why outages are lasting longer on average:

- Vector and Aurora Energy have both faced Court-imposed penalties for breaches of the reliability standards that we have set, and their customers make up a substantial proportion of the total customer base. PowerCo and Aurora Energy were moved to a customised price-path for 2018-2023 and 2021-2026 (respectively) which permitted a higher level of planned and unplanned SAIDI to allow for major network upgrades.

- There has been a clear increase in outages caused by adverse weather and vegetation from our data on unplanned outages. Electricity lines were the main assets being affected. We can make the correlation that storms and trees caused damage to electricity lines. This type of damage caused to the electricity network takes time to repair because a tree falling on an electricity line can take hours to clear. Then, it could take hours to fix the damaged power line or pole.

- Around 2018, some local lines companies implemented a range of operational changes to reduce health and safety risks, such as reducing the extent to which they work on power lines when they are still live. These changes may mean it can take longer to restore power after an outage.

These factors imply that service quality can vary significantly depending on the local lines company that a customer is connected to.

Figure 41 (on the next page) shows the changes for each individual local lines company in planned and unplanned outages from 2008-2023, on a per customer basis. It shows that most local lines companies have seen increases in the average minutes of outages per customers. Cyclone Gabrielle and the Auckland weather event which both occurred in 2023 have increased the average minutes of unplanned outages per customer in the affected regions. This has contributed to the overall increase in unplanned outages. Planned outages have increased much more than unplanned outages. The increase in planned outages was to maintain the network and this has a less severe impact on customers because they are provided warnings in advance.

Figure 41: Average outage minutes per customer and annual percentage change by local lines company, 2010-2023